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Dedicated large-scale floating offshore wind to hydrogen: Assessing design variables in proposed typologies

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ABSTRACT

To achieve the Net-Zero Emissions goal by 2050, a major upscale in green hydrogen needs to be achieved; this will also facilitate use of renewable electricity as a source of decarbonised fuel in hard-to-abate sectors such as industry and transport. Nearly 80% of the world's offshore wind resource is in waters deeper than 60 m, where bottom-fixed wind turbines are not feasible. This creates a significant opportunity to couple the high capacity factor floating offshore wind and green hydrogen.

In this paper we consider dedicated large-scale floating offshore wind farms for hydrogen production with three coupling typologies; (i) centralised onshore electrolysis, (ii) decentralised offshore electrolysis, and (iii) centralised offshore electrolysis. The typology design is based on variables including for: electrolyser technology; floating wind platform; and energy transmission vector (electrical power or offshore hydrogen pipelines).

Offshore hydrogen pipelines are assessed as economical for large and distant farms. The decentralised offshore typology, employing a semi-submersible platform could accommodate a proton exchange membrane electrolyser on deck; this would negate the need for an additional separate structure or hydrogen export compression and enhance dynamic operational ability. It is flexible; if one electrolyser (or turbine) fails, hydrogen production can easily continue on the other turbines. It also facilities flexibility in further expansion as it is very much a modular system.

Alternatively, less complexity is associated with the centralised offshore typology, which may employ the electrolysis facility on a separate offshore platform and be associated with a farm of spar-buoy platforms in significant water depth locations.

1. Introduction

1.1. Context and background

Each of the last four decades has been successively warmer than any decade that preceded it since 1850; this is due to increased greenhouse gas (GHG) emissions [1]. In a decarbonised world, the share of Renewable Energy Supply (RES) must increase to displace fossil fuel systems. In recent years, energy production, transportation, storage and usage have undergone a profound change [2]. By 2050, in the most ambitious scenario, electricity is expected to be the main energy carrier with over 50% (direct) share of total final energy use, up from 21% today [3]. A bridge is needed to transform green electricity to other final energy use vectors which are available for transport and heat.

According to the International Energy Agency (IEA), to achieve Net-Zero Emissions (NZE) by 2050 hydrogen as a clean energy carrier and as a precursor to hydrogen-based fuels (also known as electrofuels) will have a leading role [4]. In this scenario, global hydrogen use would expand from less than 90 Mt in 2020 to more than 200 Mt in 2030 and the proportion of low-carbon hydrogen would rise from 10% in 2020 to 70% in 2030 [4]. Blue hydrogen, is considered by some as low-carbon; it is generated from fossil natural gas with CO_2 emissions reduced through carbon capture use and storage (CCUS) [5]. Although blue hydrogen

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Nomenclature table

Abbreviations

AC	Alternating Current
AEL	Alkaline Electrolysis
AEM	Anion Exchange Membrane
CAPEX	Capital Expenditure
CCUS	Carbon Capture Use and Storage
CER	Chlorine Evolution Reaction
CF	Capacity Factor
COREWIND	COst REduction and increase performance of floating WIND technology
CRI	Commercial Readiness Index
EIA	Environmental Impact Assessment
EU	European Union
FLNG	Floating Liquefied Natural Gas
FOW	Floating Offshore Wind
FOWT	Floating Offshore Wind Turbine
FPSO	Floating Production, Storage and Offloading
GHG	Greenhouse Gas
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
LCC	Line Commutated Converters
LCoE	Levelized Cost of Energy
LOHC	Liquid Organic Hydrogen Carrier
NZE	Net-Zero Emissions
O&M	Operation and Maintenance
OPEX	Operating Expenditure
ORE	Offshore Renewable Energy
PE	Polyethylene
PEMEL	Proton Exchange Membrane/Polymer Electrolyte Membrane Electrolysis
PLEM	Pipeline End Manifold
RO	Reverse Osmosis
SOE	Solid Oxide Electrolysis
TDS	Total Dissolved Units
TLP	Tensioned Leg Platform
TRL	Technology Readiness Level
TSO	Transmission System Operator
VLCC	Very Large Crude Carrier
VSC	Voltage Source Converters
WACC	Weighted Average Cost of Capital

Symbols and Indices

S	Cable rated power
c_{1-3}	Cost coefficients
C_{cable}	Offshore static cable cost per unit distance
Q	Energy flow through the pipeline
V_o	Volumetric flow rate
ρ	Density of the gas
HHV	Higher heating value
A	Cross section of pipe
v	Flow velocity of the gas
Re	Reynolds number
D	Pipeline diameter
η	Dynamic viscosity
N	Pumping power
Δp	Pressure drop
L	Pipeline length
ζ	Resistance coefficient
$E_{comp(t)}$	Required energy by the compressor
η_{comp}	Compression efficiency
c_p	Specific heat at constant pressure
c_v	Specific heat at constant volume
γ	Ratio between the specific heat capacities for hydrogen
N_{st}	Number of compression stages
$P_{comp,i}$	Pressure of the hydrogen out of the electrolyser
$P_{comp,o}$	Pressure of hydrogen required by the pipelines connecting the string of all turbines
Δt	Time of compression
$CAPEX_{Compression}$	Compression CAPEX
$\dot{W}$	Compression power

offers some advantages, it is not inherently carbon-free due to the limits on efficiency of CCUS technology [5]. A recent study by Howarth and Jacobson [6] suggests that despite the capture of carbon dioxide from exhaust gases in steam methane reforming, the GHG footprint of blue hydrogen can be similar to or greater than that of natural gas. The output of the analysis depends on the input variables (such as level of methane slippage and efficiency of CCUS process) but suffice it to say that blue hydrogen offers lower levels of decarbonization than those required to achieve the 2050 NZE target. Green or renewable hydrogen is produced from a renewable energy source by water electrolysis. To be called green hydrogen, the hydrogen needs to have a carbon footprint that is at a minimum below 36.4 g CO_2eq per MJ of lower heating value (LHV) [7]. By 2050, it is anticipated that 30% of electricity use will be dedicated to green hydrogen production and its derivatives (electrofuels) such as e-ammonia and e-methanol [4]. These electrofuels are expected to play a pivotal role in sectors where direct electrification is challenging especially in hard to abate sectors, such as steel, chemicals, fertilisers, and long-haul transport, shipping and aviation [2,8].

On average, green hydrogen costs two to three times more than blue hydrogen at present, pushing the viability into further research to realize its potential [2]. Electricity input for water electrolysers accounts for much of the production cost for green hydrogen and falling renewable power costs are expected to narrow the gap [2]. The challenge for hydrogen is the balancing act in ensuring that renewable electricity receives sufficient remuneration to allow commercial feasibility whilst not too paying too much for the renewable electricity which would lead to too expensive hydrogen. Producing green hydrogen through electrolysis is a commercially mature technology; however, the focus has primarily been as a seasonal storage and a curtailment solution rather than a means of producing affordable hydrogen [9]. Green hydrogen cost is highly dependent on the type and cost of renewable energy supply used, electrolysis technology, the plant scale, as well as the energy vector used in transportation. According to the European Commission's July 2020 hydrogen strategy, blue hydrogen costs on average 2 €/kg, while green hydrogen may cost in future scenarios between 2.5 €/kg and 5.5 €/kg[1] [10]. Using low-cost renewable electricity (of the order of 17 €/MWh), it is suggested that green hydrogen could be produced at a price competitive with blue hydrogen by 2030 [3]. If rapid up-scaling of the industry occurs in the next decade, the cost of green hydrogen may according to IRENA continue to fall below 1.31 €/kg (€1 = $1.14 [11]) [3]; however, achieving those figures relies on a large rollout coupled with climate and energy policies that are yet to materialise. As for all future projections of costs, there are different perspectives; McDonagh et al. (2020) [12] argued that curtailment could be cheaper than hydrogen production in a hybrid model (producing electricity and hydrogen from offshore wind) if the value obtained for hydrogen was

[1] IEA 2019 Hydrogen report [43], and based on electricity prices between 35 and 87 €//MWh.

less than c. 3.70 €/kg. However, whatever the discussion on actual costs of hydrogen in the future, there is little disagreement, but that hydrogen has a huge role to play in decarbonization especially beyond applications traditionally associated with electrification. According to IRENA (2021) [3] around 12% of the total global final energy use will be accounted for by hydrogen and its derivatives by 2050. To achieve this, close to 5000 GW of hydrogen electrolysis capacity will be required, up from just 0.3 GW today.

1.2. State of the art

The viability of offshore wind to provide this significant resource of energy is investigated in this paper. The technical potential of offshore wind can be divided into shallow water (<60 m), and deep water (60–2000 m) [13] with high energy resource in deeper waters offering opportunities and potentially fewer objections from coastal communities. It can also be divided by distance from shore with near shore sites being those less than 60 km and far shore sites being those up to 300 km from shore [13]. Some countries such as Japan, for instance, have offshore wind potential encompassing more than 9000 TWh per year located in deep water that would require floating platform technology to harness [13]. Given the anticipated growth in demand for green energy and the fact that according to Eurek et al. (2017) 80% of the global offshore wind resource is located in waters deeper than 60 m (sites where only floating technologies are viable) [14] it is likely that large scale floating wind will be coupled with hydrogen production over the coming decades.

Offshore wind projects dedicated to green hydrogen production could offer significant cost advantages over projects using electricity directly from the grid. It is partly because of the potential for cost reductions if transmission is reduced or eliminated [13]. For example, the levelized cost of energy (LCoE) of offshore wind in the European Union (EU) in 2030 is projected to be in the range of 35.02–61.28 €/MWh including transmission (with a 4% weighted average cost of capital (WACC)), but just 26.27–43.78 €/MWh (€1 = $1.14) without transmission [13]. Other advantages include for avoiding curtailment, this; however, requires the additional costs of hydrogen production, transportation, and storage systems.

To achieve this major increase in green hydrogen production, the renewable electricity used should offer both, a promising deployment capacity, as well as a competitive cost as represented by the LCoE. According to Offshore Renewable Energy (ORE) Catapult, floating offshore wind (FOW) should achieve considerable cost reduction to the extent that it can be subsidy-free in the UK in the early 2030s [15]. It is estimated that this technology will grow significantly in the coming decades, reaching up to 30 GW by 2030 and including for around 5–15% of the global offshore wind installations by 2050 (almost 1000 GW) [16]. The HyWind Scotland floating wind farm recorded a very high average capacity factor (CF) of 57% in 2020 [17]; such high CFs associated with FOW is a key synergy for coupling with hydrogen production. The key roadmap drivers for efficient cost reduction were assessed as ramping-up the scale of the FOW farms deployment as well as using the largest available turbine capacity [15]. The floating offshore wind turbine (FOWT) has already demonstrated high levels of technical readiness (TRL) of system demonstration on several prototypes, and several small pilot farms are currently under construction on European coasts over the full range of expected conditions (TRL 8–9). Nevertheless, the Commercial Readiness Index (CRI) still lacks the ability to move from the 'Commercial Trial' phase to the 'Commercial Scale Up' phase. Commercialization of FOW farms, as well as the bottom-fixed wind farms, will broaden the market and increase the investment and volume needed to cut costs [18]. The LCoE values of several FOW platforms are estimated to range between 106.3 €/MWh and 287.8 €/MWh depending on the platform [19]. Hywind Scotland, a 30 MW floating farm installed off the coast of Peterhead in 2017, achieved an LCoE of 211.43 €/MWh [20]. This appears unfavourable in comparison to the cost of current bottom-fixed offshore wind farms at 64.60 €/MWh in the UK [21]. However, their advantage of giving access to wide unused wind resources makes them a competitive candidate for this required scale of electrolysers; this is especially so for future projections and accelerates the path to reach decarbonization goals. It must be stated that Hywind Scotland is still considered a demo project with developers expecting a further 40% drop in costs between Hywind Scotland and the Hywind Tampen project in 2022 [22]. Nevertheless, research is presently under way to further reduce costs and to investigate the impact of different site conditions on costs [19].

A crucial step of any energy system is transporting the energy. Energy transmission does not only include for electric power lines as there are other energy vectors for transporting energy [23]. The focus of this work is bulk energy transmission of the hydrogen dedicated FOW farm output, with the option of having hydrogen as an energy transmission vector as well as the conventional power line transmission. This must be seen as a very different concept to the ongoing discussions of blending hydrogen with natural gas in existing pipelines for decarbonization of a range of sectors that utilize natural gas [24].

1.3. Beyond state of the art

This paper examines possible coupling typologies, addressing the suitable FOW platform used in each typology, as well as proposing some optimum system key design factors. Several scientific works in the literature include for investigation of fixed-bottom offshore wind to hydrogen systems [12,23,25–27]. In a viability assessment study of hydrogen production from dedicated fixed-bottom offshore wind farms off the East Coast of Ireland conducted by Dinh VN et al. (2020) [26] with underground storage capacity ranging between 2 days and 45 days of hydrogen production, the system was claimed to be profitable in 2030 at a hydrogen price of 5 €/kg. Another study by K. Meier (2014) [27] that investigated offshore hydrogen production with seawater electrolysis using Norwegian offshore wind energy suggests that although it is possible to build large offshore hydrogen production platforms with current technology, the cost of the components and the comparison between the hydrogen price and current fuel prices would make the product unprofitable. Other literature investigated hydrogen (gas or liquified) and electricity as energy transmission vectors [23,28,29]. In an economic comparison between the use of hydrogen and electricity for the transmission of bulk power at sea, R. d'Amore-Domenech et al. (2021) [23] found that for large offshore wind farms, the hydrogen energy transmission vectors (gas in pipelines or liquified transported by ships) are better in comparison to the electric alternatives. Another study by Miao B et al. (2021) [28] investigated the economic feasibility of renewable energy transmission via power cables and hydrogen gas pipeline. The study concluded that despite the higher cost of installing pipelines per unit length, they possess greater energy transmission capacity. The authors also stressed that scaling-up the transmission capacity is the out of the box solution to gain economic advantage. In a further investigation of the different offloading pathways for offshore wind hydrogen production, B.A. Franco et al. (2021) [29] concluded that in most cases, hydrogen vessels or hydrogen carriers do not outperform pipeline transport unless the distance is greater than 150–250 km. Therefore, this solution would only be useful when hydrogen has to be transported long distances, internationally, or even between continents.

To the best of the authors' knowledge, this is the first paper to investigate direct coupling of dedicated off-grid floating offshore wind with green hydrogen through hydrogen pipelines and/or electric transmission cables. Investigating hydrogen pipelines as a cost-effective solution for bulk energy transmission over long distances is a major research question in this work. Over recent years, there has been increasing interest in coupling offshore wind with hydrogen production. Table 1 summarises the most relevant ongoing projects to the scope of this work.

Table 1
State of the art in industry.

Project Title	Ref.	Project Scope	Scale	Expected Completion Year
AquaVentus initiative	[30]	Hydrogen produced at electrolysis plants installed at sea by using the electricity generated by wind farms. Hydrogen later transported via a pipeline.	10 GW	2035
DOLPHYN	[31]	Production of hydrogen at scale from offshore floating wind in deep water locations.	4 GW	Mid 2030s
Bantry Bay green energy facility	[32]	A joint venture between Zenith Energy and EI-H2 to develop a 3.2 GW energy offshore wind facility at Bantry Bay in Ireland to produce green hydrogen and green ammonia.	3.2 GW	2028
Lhyfe and Centrale Nantes - SEM-REV	[33]	The world's first offshore green hydrogen production facility. The plant is powered by electricity from a nearby floating wind turbine, called Floatgen to be installed at the SEM-REV demonstration site, off the coast of Le Croisic in France.	10 to several hundreds of MW	2024
OYSTER	[34]	Development of a desalination, electrolysis, and hydrogen production system that is completely “marinized,” or modified for marine use.	MW-scale	2024
The Salamander Project	[35]	A collaboration that uses the ERM DOLPHYN design in a location off Aberdeenshire.	5 GW	2030
Esbjerg Offshore Wind-to-Hydrogen Project	[36]	Project will be commissioned in Denmark by Swiss energy company H2 Energy Europe, the second large-scale Power-to-X plant in Esbjerg region.	1 GW	2024
Siemens H2Mare Projects	[37]	Fully integrate an electrolyser into an offshore wind turbine as a single synchronized system to directly produce green hydrogen.	–	–
PosHYdon	[38]	Three different energy systems will be integrated on one platform: offshore wind, offshore gas, and hydrogen. On a platform located 13 km from Scheveningen, the electrolysis system will be installed within a sea container.	–	–
Deep Purple	[39]	A dynamic process simulator for green hydrogen production system powered by offshore wind will be included in the project, which will also develop an advanced control and advisory system. Hydrogen will be stored under the seabed.	–	–
OceanH2	[40]	Project objectives include the design and evaluation of the first offshore green hydrogen plant utilizing floating wind and photovoltaic technology.	–	–

1.4. *Objectives*

The objective of this paper is to investigate three typologies for a FOW farm dedicated to hydrogen production. The typologies discussed in Section 3 include for:

- centralised electrolysis conducted onshore;
- decentralised electrolysis conducted offshore;
- centralised electrolysis conducted offshore.

The three major variables that impact on these typologies (discussed in Section 2) include:

- selection of electrolyser technology (including for requirement of seawater desalination)
- selection of FOW platform
- selection of energy transmission vector (electric transmission lines or offshore hydrogen pipelines).

2. Materials and technologies

This section includes introductions to and discussions of the key enabling technologies required for FOW to be paired with green hydrogen. They are discussed with respect to their suitability to the FOW platform and the relative advantages and disadvantages of each. This is subsequently used to inform Section 3 where the suitable typologies are proposed.

2.1. *Selection of electrolyser technology*

Electrolysis can be considered the main process in the system. It is the method through which the water molecule is separated into hydrogen and oxygen by applying an electric current [41]. Solid Oxide Electrolysis (SOE), Alkaline Electrolysis (AEL), and Proton Exchange Membrane Electrolysis (PEMEL) are the current key industrial green hydrogen production technologies [42]. Hydrogen typically has an energy value of 33.33 kWh/kg or 120.1 MJ/kg on a lower heating value (LHV) basis [43]. The electrolyser energy consumption depends on the energy efficiency of the system. For example, Reuβ et al. [44] mathematically modelled the hydrogen supply chain with a PEMEL, adopting an energy efficiency of 70% which amounts to 47.6 kWh/kg of electricity consumption per kg of hydrogen produced.

The SOE is a high-temperature electrolysis technology. Presently, SOE systems have gained increasing attention with work ongoing in academia to develop their commercial readiness [45]. Efficiencies can be over 79% if a high temperature (around 700 °C) source of heat is available [46,47]. Their high operational temperature is a significant challenge for material stability [48]. This creates a particular increased challenge in offshore environments associated with the risk anticipated in event of material failure. This could result in hydrogen leakage with the probability of a fire event. Such an event would endanger the marine environment, result in loss of equipment and lead to injury or mortality. Consequently, this leads to a more frequent maintenance. Whilst the technology has a higher electrical efficiency compared to the other technologies, more fundamental and commercialization work is needed before this technology is ready for deployment offshore on floating platforms [49].

AEL uses a liquid electrolyte. These tend to offer a cost-effective solution; however, this liquid electrolyte increases the likelihood of leakage and maintenance requirements [31]. The required frequency of electrolyte change is also a challenge for the offshore environment. The produced hydrogen may also include traces of electrolyte which requires removal prior to export [41]. The liquid electrolyte in principle has a relatively limited response to fluctuations in electrical inputs, especially the response of electrolysers to sudden changes in the power supply such as a complete interruption or an impulse. This is a considerable challenge given that wind turbines have a highly variable electrical input [41]. Various research papers have investigated the increase in the compatibility of AEL to fluctuating input current; this technology is expected to be more commercially mature in the near-future [41].

The PEMEL uses expensive catalysts such as platinum (at the cathode side) and iridium (at the anode side) which increases the cost of the electrolyser. They have the highest TRL (7–8) when it comes to coupling with a dynamic electric input [50,51]. The PEMEL efficiency depends on several factors, and manufacturers are actively competing to create new efficiency benchmarks. High efficiencies were recently achieved by "Silyzer 300" from Siemens Energy, which has a stated plant efficiency of greater than 75.5% [52]. PEMEL features shorter start-up times, especially from cold, and the production rate can be varied over the full load range; hence they facilitate rapid response to fluctuations in electrical input which is critical for a decentralised coupling with FOW farms [48]. The relatively compact design of PEMEL is also another advantage [48].

Other novel electrolysis technologies are under development such as Anion Exchange Membrane (AEM) which aims to replace the conventional noble metal electrocatalysts with low-cost transition metal catalysts [53].

In case the electrolysis system is connected to one wind turbine, it will be subjected to a discontinuous electricity supply. Therefore, a high range of operability conditions and fast responses are necessary to follow this variation in electrical supply. The time of response for AEL and PEMEL technologies ranges between 1 s and 1 min. The response time depends also on the technology, temperature, pressure, and other factors. From this discussion, the potential of the low-temperature PEMEL and AEL seem to be the most promising technologies for near to mid-term applications. The operational parameters of both are listed in Table 2.

In the EU, offshore wind projects are predicted to have increasing CFs in the range 51–59% between 2020 and 2050, as larger wind turbines and other technology improvements make the most of available wind resources [4]. Since this work aims to assess an off-grid wind to hydrogen configuration, the electrolyser should in theory capture the maximum possible electricity output of the turbines. Determining the exact load factor of the electrolyser and matching the corresponding electrolyser size with the turbine size would require further detailed analysis which is not considered in this paper. The output of the turbines is technically operating all the other system components and not just the electrolyser. The electrolyser should be sized on the maximum share of electric output it can cater for.

2.2. Requirement for seawater desalination

Water electrolysis requires high purity water, either directly in membrane electrolysers or in a mixture with salts for alkaline water electrolysers. Water purity should have a maximum of 0.5 ppm total dissolved units (TDS) [27]. Around 9 L of water are needed to produce 1 kg of hydrogen [43]. In onshore environments, this is relatively easy to secure from mains water supply. It can be provided by incorporating water purification systems into the electrolyser system or via external pre-treatment [55].

Freshwater access is an issue for offshore facilities. The direct use of seawater in electrolysis can lead to corrosive damage and chlorine production. In this case, chloride ions from the most abundant seawater salt sodium chloride (NaCl) are present in the electrolyte solution [56]. This may push a competing chlorine evolution reaction (CER) as described in Equation (1) at the anode, leading to chlorine production [57].

$$2Cl^{-} \rightarrow Cl_{2(g)} + 2e^{-} \tag{1}$$

However on-going research is examining the use of seawater in electrolysis. In the absence of such saline water electrolyser technologies, seawater desalination must be conducted in advance of electrolysis. There are several proven desalination technologies. These can be divided into electrical and thermal solutions [27]. Although there is a potential for heat recovery from the electrolysis unit to run a thermal desalination unit, the preferred solution employs reverse osmosis (RO). RO is an electrical solution, which is seen as a strong candidate for offshore deployment and has already been used in marine applications, especially with the PEMEL technology [58]. Seawater RO is already used for PEMEL without a significant effect on performance [58]. It can operate autonomously and can be easily adapted to different flow and conductivity requirements.

A desalination unit typically requires seawater pumping. It has a relatively lower energy demand with respect to the electrolyser. The range of energy demand for the RO process depends on the feed water salinity, the efficiency of the pumps, and brine discharge. The overall specific energy consumption can be estimated within the range of 2–4 kWh/m^3 [59]. For off-grid FOW and hydrogen coupling, the

Table 2
PEMEL and AEL operational parameters for the year 2019, 2030 and a long-term prediction, data from [43,54].

Operational Parameter	PEMEL			AEL			Ref.
	2019	2030	Long term	2019	2030	Long term	
Hydrogen output pressure [bar]	30–80	–	–	1–30	–	–	[43]
System electric efficiency [%, LHV]	56–60	63–68	67–74	63–70	65–71	70–80	[43]
Load range (%, relative to nominal load)	0–160	–	–	10–100	–	–	[43]
Footprint [m^2/GW]	48,000	–	–	95,000	–	–	[43]
Operational current density [A/cm^2]	2	–	–	0.5–0.7	–	–	[43,54]
CAPEX [€/kWe] (€1 = $1.14)	963 - 1576	569–1313	175–788	438–1226	350–744	175–613	[43]

desalination unit gains its operational power directly from the turbine electricity output. Hydrogen production costs are only slightly increased by this with an increase in total costs of water electrolysis of 0.0088–0.018 €/kg (€1 = \$1.14) of hydrogen [43]. The volumetric seawater inflow is synchronized with the turbine electric output. As a result, the desalination unit does not have a constant volumetric water inflow; however, for design purposes, it should have a nominal volumetric seawater inflow with the maximum possible water inflow to the electrolyser, that is originally based on the maximum electric output of the turbine.

Along with the technological and economic issues, seawater purification presents environmental issues related to the disposal of the residual products of the pre-treatment, such as brine. When released in the sea, marine ecosystems are directly affected by brine, and actions have to be taken. In a comprehensive review, Panagopoulos et al. [60] stated that to resolve the environmental impacts associated with desalination plants, an environmental impact assessment (EIA) should be conducted. Through models, several issues can be addressed, such as the diffusion and mixing behaviour of the discharged brine. From these analyses, the appropriate location for desalination facilities can be found [61]. In the context of the EIA, environmental monitoring plans should be developed to ensure the effectiveness of measures for securing the marine environment from the detrimental effects of brine discharge and to take protective measures when environmental damage has been detected [62–64].

2.3. Selection of floating offshore wind platform

There is a number of FOW foundation platforms [65]. The key types of floating turbine platforms shown in Fig. 1 are: the tensioned leg platform (TLP), the barge, the spar-buoy or spar, and the semi-submersible platforms [66]. In principle, any FOW platform can be integrated with hydrogen production. The semi-submersible platform and the spar platform are more viable options in economic terms [67]. HyWind Scotland uses the spar platform, which is a good candidate in deep water with widely used applications in the oil and gas industries [68].

Selection of the FOW platform depends on the full configuration of the farm. The key to cost-effective energy production is having the biggest possible turbine size [15]. The IEA 15 MW reference turbine is currently the biggest reference design [69]. The EU Horizon 2020 project COREWIND (COst REduction and increase performance of floating WIND technology) designed a conceptual spar floater for the IEA Wind 15 MW reference turbine model “WindCrete” [70], which seems a good candidate for the spar floating concept in this context. It is a large and reasonable design with all the required data available to conduct the required analysis.

In a configuration that does not require integration of the electrolysis facility on the floating deck, technically all FOW platform types can be considered based on the merits of the specific FOW technology. If the electrolysis facility is to be installed on the deck of the FOW turbine itself, preference would be based on the deck’s area, which should be sufficiently large. In principle, the barge and the semi-submersible platforms could be suitable for such integration. The semi-submersible platform has several robust and well-validated open-source designs, is favourable from an economic perspective and as such is the technology considered in this study. The semi-submersible floating platform provides ample deck space for the inclusion of an electrolysis facility. The semi-submersible category itself comes in different foundation designs. The popular semi-submersible foundations are: three-legged semi-submersible floating foundation; ring-shaped floating foundation; and compact and v-shaped floating foundation [71]. The INNWIND

Fig. 2. - *The INNWIND semi-submersible three-legged foundation platform* [72]. Permission to reuse this figure was given from the EU INNWIND WP4 leader Daniel Kaufer.

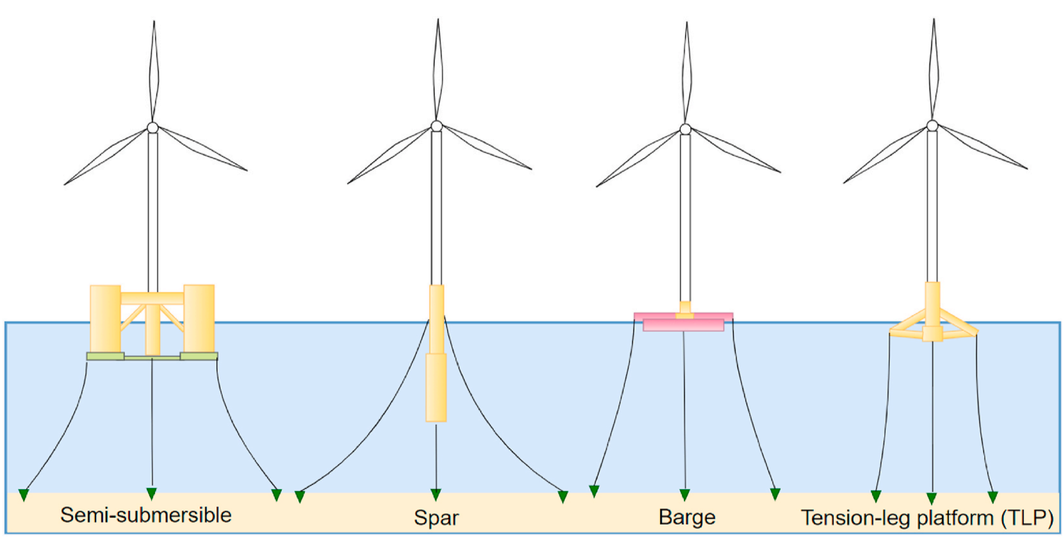

Fig. 1. Floating offshore wind platforms.

semi-submersible platform [72] is an open access design (Fig. 2) and is chosen for investigation in this work. It was developed by CENER for the INNWIND 10 MW wind turbine. The INNWIND design falls under the three-legged foundation. It comprises an equilateral triangular clear area base of floating cans with the turbine located directly onto one of the corners [73]. Global dimensions for the platform include the column diameters set at 14.5 m, the spacing between columns at 66 m, theoretically offering a plain area of around 1840 m^2. These dimensions may vary with the design of a specific wind farm subject to different wind and wave environments. To accommodate the electrolysis facility, it needs to be provided with a base connecting the three cylinders.

The “Silyzer 300” PEMEL from Siemens Energy (discussed in Section 2.1) could be suitable for integration with the INNWIND platform. It can be sized according to plant specifications. A half array system (12 modules) has a power rating of 8.7 MW. The footprint of the array is around 60 m^2 with a height of 3.7 m. It is a modular-based system that can produce hydrogen at high pressure, up to 100 bars [74]. It can also offer a dynamic response of 0–100% in 10%/s [52].

In principle, the IEA Wind 15 MW reference wind turbine is a good candidate as discussed earlier; however, a dedicated semi-submersible design with it installed on one of the corners should be developed first. Consequently, the 10 MW DTU reference turbine already used with the INNWIND platform will be the size considered here. Integrating the electrolysis facility on deck will impact the hydrodynamic performance. This would require design modifications resulting in additional costs; however, this aspect is considered beyond the scope of this paper. It is also worth mentioning that presently there is a significant industrial revolution in large-scale electrolysers production. Specifications such as dimensions, footprint and weights are predicted to be different in the medium term up to the 2030s. The bulk production of electrolysers is only beginning so there may well be design changes to make these electrolysers more suitable to integrate with platforms in the offshore environment.

2.4. Energy transmission vectors

2.4.1. Electric power transmission

Transporting the wind farm yield in an electric energy vector can be considered as the conventional configuration, especially for farms that normally export their yield to national electricity grids. Large electricity export occurs in high voltages to allow efficient transmission (lower dissipative losses) of this scale of electric power over long distances [75]. In principle, the high voltage cables can be overhead, underground, or submarine. Submarine (or subsea) cables are used for bulk electric power transmission across large distances across wide and deep-water sites [76]. This technology has been operating reliably for decades with various examples of cable systems [75]. Bulk electric transmission types may be divided into two categories: High Voltage Alternating Current (HVAC) and High Voltage Direct Current (HVDC). It has been proven that HVAC transformer substations generate fewer losses than their HVDC counterparts and tend to be cheaper as well [75]. However, an HVAC cable of equal amperage requires a larger section due to skin effect and self-induced reactance; therefore, it is more costly per unit of length than an HVDC cable [75]. In cases of transmission distance greater than 60 km subsea or 200 km overhead, HVDC generally performs better economically [76]. Since the required scale of wind resource of this work is more likely to be secured at distances greater than 60 km, HVDC is the technology investigated here.

Whether it is HVAC or HVDC, the power losses in transmission depend on several factors such as: the high voltage levels, number of cables, farm size and the distance of transmission. By increasing voltage, the losses are reduced and the capacity of the line is increased [77]. With respect to the generated power, power loss must be calculated. The resistance of the cable must be larger when the transmission distance is longer. In turn, the higher resistance leads to larger losses in the cable. HVDC (the better option for transmission distances over 60 km submarine) has power losses slightly above 4% for distances up to 150 km [77].

Typically, there are two types of HVDC links; line commutated converters (LCC) and voltage source converters (VSC) [75]. Despite being more advanced and flexible than LCC, VSC technology generates higher losses at both end substations than LCC. One of the main advantages that VSC offers over LCC is the “black start capabilities”, which is the ability to have a completely grid-independent end unit. This is especially valuable when using such technologies in renewable energy parks such as offshore wind farms. In this way, they reduce the cost of transferring power by avoiding the need to receive power back. Additionally, VSC technology requires about half the projected horizontal area or footprint of LCC, which in turn reduces the offshore facilities costs [23]. VSC HVDC is foreseen as the most suitable technology for future super grids in Europe [78] and as such seems to be a promising choice for offshore wind connection [79].

Submarine electric cable technology is proven and commercially available, typically connecting the offshore and onshore substations for mature fixed-bottom offshore wind farms [80]. The submarine cables used with FOW can be classified into two main categories: static cables and dynamic cables. Static cables are buried in the seabed, or commissioned on the surface with external protection, while dynamic cables operate in the water column [19]. The main point of differentiation is that dynamic cables employ double-layer armouring to provide hydrodynamic stability during installation and operation [80]. Dynamic cables collect the electricity yield from the turbines and transfer it to an offshore substation, gathering the whole farm yield and stepping the voltage up for export. Static power cables are used to transmit the stepped-up voltage from the offshore substation to another onshore one.

A dynamic inter-array cable of 33 kV AC used to be a standard electrical specification for an offshore wind farm. However, to target further cost reductions, a 66 kV AC developed by JDR cables is now available in markets and was already demonstrated on the WindFloat Atlantic wind farm [81]. Depending on the water depth, the offshore substation can be either bottom-fixed, or in more recent applications, floating. Floating offshore substation foundations utilize the same concepts as wind turbine foundations and include for semi-submersibles, tension leg platforms, barges, or even spars [82]. It is also worth noting that bottom-fixed substations can still be considered, even in deep water. They may still be financially feasible in the near to mid-future, whilst floating substations are developed and de-risked.

The stepped-up voltage from the offshore substation for export can reach 500 kV for the submarine HVDC system [83]. The capacity of the submarine cables is another major criterion in the assessment regarding such large-scale wind power parks. The transmission system operator (TSO) TenneT, is currently working with a consortium to develop a 2 GW capacity submarine HVDC cable [84]. This means that a 10 GW scale hydrogen dedicated farm would need 5 submarine HVDC systems, which is a significant weight in the Capital Expenditure (CAPEX). This also gives an insight on the flexibility of scaling up a given wind power park in the future.

The cost of static submarine HVDC cables depends on different parameters such as the power transmitted and the voltage it is transmitted at. It is defined as a unit cost per unit distance. This highlights how long distances directly add to the cost. The European Commission considered [85] various scenarios in order to assess the potential benefits of a meshed offshore grid in the North Sea, Irish Sea, and the English Channel. Techno-economic information of the greatest size of submarine HVDC cable (2146 MW) was assessed at 1.47 M€/km at 500 kV. The cost of dynamic cables is given as a unit cost per unit distance. An exponential cost function was defined for offshore static cables as in Equation (2) [86]:

$$C_{cable} = c_1 + c_2 \exp(c_3 S) \tag{2}$$

where S is the cable rated power in MVA, c_{1-3} are cost coefficients and

C_{cable} is the offshore static cable cost per unit distance. Cost coefficients are given in Table 3.

Up to 33 kV, dynamic cables will cost approximately 30–50% more than static cables of the same capacity. A major cable manufacturer reported that a dynamic cable is 60–90% more expensive than an equivalent static cable up to 66 kV [80].

2.4.2. Offshore hydrogen pipelines

Hydrogen exhibits the lowest volumetric energy density (c. 10.79 MJ/m^3) at standard temperature and pressure, relative to other more common fuels with density 3000 times higher such as petrol or diesel (c. 30–38 GJ/m^3) [88]. Pumping high-pressure hydrogen in gaseous state in an offshore pipeline is investigated here as an energy transmission infrastructure in contrast to submarine high voltage cables.

Hydrogen pipelines in principle are not a novel innovation, they already exist around the world onshore [89]. For example, approximately 2575 km of hydrogen pipelines are currently operating in the United States. Belgium has 600 km and Germany almost 400 km [43]. Hydrogen pipelines are usually found near large hydrogen consumers, such as petroleum refineries and chemical plants [90]. However, one of the most important barriers that interrupt the broad use of hydrogen is the present lack of hydrogen infrastructure [91].

A number of studies have been conducted to see 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 because of embrittlement challenges [24]. Manufactures claim there is no other difference in transporting natural gas or hydrogen apart from the embrittlement that might need some modifications to assure the robustness of the pipes [92]. Hydrogen embrittlement represents the most challenging issue in the offshore pipeline configuration, and regular inspections should be carried out to assess the durability of the pipelines. In order to reduce diffusion leaks and enhance hydrogen embrittlement resistance, materials used in pipeline transport of large quantities of hydrogen need to be carefully selected [23]. A specific pipe configuration using several different materials is necessary for a 100% hydrogen piping system. Polyethylene (PE) is deemed a good candidate, since it can be extruded and also withstand 100% hydrogen, thus preventing embrittlement problems. However, these PE pipelines would still encounter hydrogen losses due to diffusion. Due to the light weight of hydrogen, hydrogen pipeline leaks are approximately 1.3–2.8 times larger than leaks of methane, and four times greater than leaks of air under the same conditions [89]. Besides the installed capital costs of the pipeline, hydrogen delivery costs are influenced by the compression and storage costs [93]. Furthermore, welding procedures and leak testing are likely to be more onerous for hydrogen pipelines than for natural gas pipelines.

Transportation efficiency of hydrogen in pipelines is usually compared to that of natural gas. Transportation efficiency may be correlated with pressure drop as a result of distance travelled and further depends on the thermal energy of the substance transported [93]. The energy flow through the pipeline Q [MW] can be calculated through Equation (3):

$$Q = V_o \rho HHV = Av\rho HHV \tag{3}$$

where; V_o is the volumetric flow rate [m^3/s]; ρ is the density of the gas [kg/m^3]; HHV is the higher heating value [MJ/kg]; A is the cross section of pipe [m^2]; v is the flow velocity of the gas [m/s]. According to work by Bossel and colleagues [94,95], the densities of methane and hydrogen are 7.2 and 0.9 kg/m^3, respectively, at a pressure of 1 MPa (10 bar). According to Equation (3), for the same amount of energy to flow through the same diameter pipe, the velocity of hydrogen must be 3.13 times that of methane.

The Reynolds number (Re) is given by Equation (4):

$$Re = \frac{\rho v D}{\eta} \tag{4}$$

where; D is the pipeline diameter [m]; η is the dynamic viscosity [kg/(m.s)]. The dynamic viscosities for methane and hydrogen at a pressure of 1 MPa (10 bar) are 11.0 * 10^6 and 8.92 * 10^6 kg/(m.s), respectively. Therefore according to Equation (4), for a pipe diameter of 1 m, the Reynolds numbers for methane and hydrogen are 6.55 * 10^6 and 3.16 * 10^6, respectively [96]. With both values exceeding 2000, both flow regimes are turbulent. To determine the pumping power N [W] required for turbulent flow, Equation (5) is used:

$$N = V_o \Delta p = Av\Delta p = \frac{p}{4}D^2 v\Delta p = \frac{\frac{p}{4}D^2 v \frac{L}{D}}{2}\rho v^2 \zeta \tag{5}$$

where; Δp is pressure drop [Pa]; L is pipeline length [m]; ζ is resistance coefficient.

From Equation (5), the ratio of the theoretical pumping powers N_{H2} for hydrogen and N_{CH4} for methane can be shown in Equation (6):

$$\frac{N_{H2}}{N_{CH4}} = \left(\frac{\rho H2}{\rho CH4}\right)(vH2/vCH4)^3 \tag{6}$$

From this it may be assessed that hydrogen requires about 3.85 times as much energy as natural gas for the same energy flow.

Pressure drop occurs over the length of the pipeline. For example in a typical North Sea line, it is estimated that the pipeline experiences a pressure drop of 3–10 bar/100 km, though higher values up to 25 bar/100 km are not considered unusual [97]. Accordingly, hydrogen must be pressurised sufficiently to compensate for this pressure drop over the distance travelled in the pipes. However, increases in pressure increase the threat of embrittlement.

Hydrogen pipelines are expected to offer advantages in comparison to high voltage submarine cables from an economic point of view for large-scale farms and long distances. A hydrogen pipeline can accommodate a farm bigger than the maximum capacity of the 2 GW offered by a submarine HVDC cable. The flexibility of scaling up an existing wind farm making use of the same infrastructure is also promising with hydrogen pipelines.

2.4.2.1. Static pipelines. Submarine hydrogen pipelines are not yet commercially mature. Submarine natural gas pipelines are used in this assessment as a proxy as to how submarine hydrogen pipelines would respond to these conditions, with emphasis on the difference between both gases. Submarine pipelines experience similar conditions to submarine cables. However, for natural gas pipelines, they are of longer and deeper reach. For instance, the Langeled pipeline carries natural gas from Norway to the UK a distance of 1166 km reaching depths of 360 m at pressures between 157 and 250 bar and transporting a daily capacity of 80 Mm^3 [98]. Submarine pipelines, however, can be more costly and challenging than submarine cables to repair if broken [23]. One of the

Table 3
Dynamic cable cost coefficients for the year 2013, data from [80,87].

Voltage (kV)		Cost Coefficient			Range	Units	Year	Ref.
Rated	Max	c1	c2	c3	(MVA)			
33	36	−49.42	112.20	0.041	[17.0, 44.0]	k€/km	–	[80]
MV	–	300–800	0	0	–	€/m	2013	[87]

major challenges of the submarine pipelines over cables, is the required frequency of maintenance. Pipelines are required to be cleaned periodically to remove accumulated condensates in their interiors. This is a labour-intensive process carried out with specialized equipment as well as with dry air [98]. This increases the operating expenditure (OPEX).

Applying an epsilon factor, or surface roughness, of 0.5 mm for 100% dedicated hydrogen pipelines, results in a velocity limitation of 20 m/s [99]. Designing such a pipeline would be based on the installed farm capacity, the distance hydrogen would travel, and the required output pressure. In theory, this would result in a list of minimum diameters needed for different combinations of distance to be travelled and installed capacity of offshore wind. The maximum volume of hydrogen in kg/s that can be transported via the pipeline could then be determined considering the efficiency of the electrolyser. The electrolyser capacity is set equal to a certain percentage of the wind farm capacity.

For instance, a 12-inch (0.3048 m) diameter pipeline is needed to transport 1 GW of wind energy converted to hydrogen over 100 km [97]. In order to guarantee that hydrogen reaches shore at a reasonable pressure of 68 bar without exceeding the velocity-limits, 86 bar input pressure would be needed to overcome the pressure drop. If a large pipeline (with lower input pressure) was chosen to manage constraints associated with velocity limitations, this may lead to variations in input pressures [97,99]. Fig. 3 is based on a study conducted to assess new offshore hydrogen pipelines in the North Sea [99]; it shows the hydrogen pipeline size required for hydrogen transport as a function of distance travelled and the installed capacity. This study considers the electrolyser capacity set equal to the wind farm capacity with a load factor of 0.6. An input pressure of 86 bar is also considered in all the presented capacities to reach the shore with 68 bars.

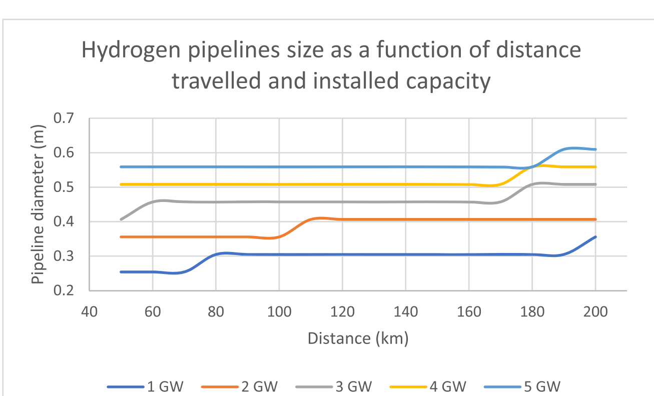

Fig. 3. Hydrogen pipelines size as a function of distance travelled and installed capacity with hydrogen output pressure of 68 bars and input pressure of 86 bars adapted from information in Ref. [95].

2.4.2.2. Flexible pipelines and risers. The dynamic nature of the floating platform requires a flexible pipeline solution at the hydrogen collection point at the exit of the electrolysis facility; this is can also be called the riser section [92]. These flexible pipelines can be used to connect with the main export rigid gas pipelines in the seabed all the way to the shore. Flexible pipelines, or risers, are not a novel innovation and are widely used in the offshore environment of the oil and gas industry.

Flexible risers are commercially available in a variety of diameters and material specifications. They can be either bonded or unbonded. In comparison with the homogeneous steel pipes, these kinds of pipes are advantageous in providing high bending flexibility, allowing an easier transport and installation, and consequently reducing costs [100]. The bonded structure is primarily used in highly dynamic applications. Unbonded flexible risers comprise a number of layers as shown in Fig. 4 which have the ability to move independently of each other, facilitating flexibility without excessively straining the materials. Each layer serves a specific purpose, including protecting against the inner fluid, providing pressure containment, protecting against external impacts, supporting the weight of the riser, and providing insulation and external corrosion protection [92]. A variety of structural configurations and their adaptability to different environmental requirements make unbonded flexible pipelines attractive for offshore applications [92]. In principle, not all layers are required for every riser design and specifications. For instance, it is only the innermost layer that is directly in contact with hydrogen, thus it must be specified to contain hydrogen and avoid hydrogen embrittlement. Due to the relatively high mobility of the floating structure, unbonded risers will be required. Flexible pipelines generally range in internal diameter from 0.05 m to 0.5 m [92].

Fig. 4. - *Unbonded flexible pipe* [100]. *License provided by Elsevier and Copyright Clearance Center to reuse the figure. License Number: 5143880975921.*

2.4.2.3. Export compression. If AEL is the selected electrolysis technology, then a compression system is required for an efficient hydrogen transmission due to its current 30 bar maximum pressure of produced hydrogen. The compressor can operate on the electric output of the turbine. The selection of compressors is highly dependent on the difference between the pressure of hydrogen out of the electrolyser and the required inlet pressure of hydrogen in the pipeline, as well as the mass flow rate of hydrogen arriving at the compressor. The adiabatic compression formula in Equation (7) [101] is used to calculate the required energy by the compressor, $E_{comp(t)}$.

$$E_{comp(t)} = \frac{286.76 * \dot{m}_{H(t)} * T_{mean}}{\eta_{comp} * G_H * 3.6 * 10^9} * \left(\frac{\gamma * N_{st}}{\gamma - 1}\right) * \left(\frac{P_{comp,o}}{P_{comp,i}}\right)^{\frac{\gamma-1}{\gamma * N_{st}}} - 1 * \Delta t \qquad (7)$$

where η_{comp} is the compression efficiency, assumed to be 50% [102] due to frequent load variations; γ is the ratio between the specific heat capacities for hydrogen ($\gamma = c_p/c_v$), where c_p is the specific heat at constant pressure and c_v is the specific heat at constant volume; N_{st} is the number of compression stages. $P_{comp,i}$ is the pressure of the hydrogen out of the electrolyser, $P_{comp,o}$ is the pressure of hydrogen required by the pipelines connecting the string of all turbines, and Δt is the time of compression.

Mechanical compression is the methodology followed for gas compression. There are two main gas compression technologies: centrifugal compressors and reciprocating compressors. Centrifugal compressors are not optimized for hydrogen due to its low molecular weight, which requires higher circumferences. These larger circumferences need different materials, which could pose challenges for reliability, cost-effectiveness, and energy efficiency [93]. For hydrogen applications, reciprocating compressors, especially oil-free models, are commonly used when pressures over 30 bars are required [88]. Typically, they are used at volume flow rates lower than 1700 m^3/h (0.472 m^3/s). Those used with natural gas can also be used with hydrogen without major design modifications. Nevertheless, hydrogen diffusivity is higher, making seals a special consideration [93]. According to their diffusion coefficients, hydrogen can diffuse up to four times faster than natural gas [103]. A gas' diffusivity is strongly influenced by the material in which it is flowing. Cast iron and fibrous cement, for example, present a high leakage risk. However, on the distribution level, mostly PE pipelines are used. While hydrogen diffuses five times more than natural gas through PE pipelines, it is still negligible. The annual loss of hydrogen leakage is calculated at around 0.005 to 0.001% of the total volume of hydrogen transported [104].

Most of the literature use a single parameter for cost estimation, which is based on the compressor power. For a more accurate estimation of compression costs, other references such as [105] consider both the suction pressure and the compressor power. Following the methodology of André et al. [106], an estimate of the compression CAPEX can be conducted through Equation (8). This method relates in a linear way to the compression power ($\dot{W}$):

$$CAPEX_{Compression}[€] = 2,655.04 \times \dot{W} \tag{8}$$

Utilizing this method does not require more detailed engineering specifications [97]. CAPEX calculated by this formula considers the entire compressor package, accounting for driver and ancillary equipment.

3. Typologies

Based on initial research and the technology review in Section 2, three main typologies are proposed in this paper. The offshore distance and the capacity of the farm are key-drivers for the suitable transport methodology [28]. The two main solutions have either electrolysis performed onshore with submarine electric cables as the energy transmission vector, or have electrolysis performed offshore with hydrogen pipelines as the energy transmission vector. These are explored in more depth in this section.

3.1. Centralised onshore electrolysis

In non-remote locations, a green hydrogen production plant running on an offshore wind facility, by means of a conventional grid connection can be normally built onshore where: (i) land is cheap; and (ii) there are no major health and safety implications or critical nearby infrastructure; and (iii) the capacity of the electricity grid is sufficient for the level of hydrogen proposed. However, the work assessed here proposes a centralised onshore typology for remote areas with no or limited grid connection, taking electricity from a FOW farm in water with significant depth.

The FOW output is sent to shore using submarine electric cables where it is then converted to hydrogen, which goes through the rest of the supply chain for storage and distribution. A proposed layout of the centralised onshore electrolysis is shown in Fig. 5. This typology assesses electric cables as the only energy vector used in the energy export.

Since electrolysis takes place onshore, the footprint and weight of the electrolyser in this typology is less of an issue than if it was at sea. This makes AEL a viable candidate for the onshore electrolysis facility, due to the cost effectiveness as compared to PEMEL. In addition, AEL also offers a competitive system efficiency (as discussed in Section 2.1) although the final choice is still subject to detailed analysis. A cooling unit is typically associated with the electrolyser system. The water needed to operate the electrolysis facility might be obtained from water supply; provided a sufficient local supply is available, or another route would be to have a desalination plant developed close to the shore (as discussed in Section 2.2) [107].

A spar FOW platform (Fig. 1) would be a viable candidate if the farm site has very deep water, mainly because of its commercial readiness, especially as no specific requirements are needed for the floating deck (as discussed in Section 2.1). The electric output of individual turbines is collected using the dynamic cables (discussed in Section 2.4.1) and is received centrally by an offshore substation. This typology would require an offshore as well as an onshore substation as part of the wind farm design. The floating or bottom-fixed offshore substation (depending on the depth of water) integrates the AC output power from the individual turbines within the farm and steps up the voltage for export to the onshore substation [108]. The stepped-up voltage electric output is exported in static VSC HVDC submarine cables. The onshore substation then steps down the voltage of the electricity received to operate the onshore electrolyser. This onshore substation together with the electrolysis system make up the onshore electrolysis facility. Ideally, the facility should be located close to the shore to minimise any further required electricity transmission on land.

3.2. Decentralised offshore electrolysis

Producing large-scale offshore hydrogen would require a robust methodology for transportation. Alternative methods can be proposed including for systems which: (i) pipe hydrogen in a gaseous state, (ii) liquify hydrogen and transport it in ships, (iii) convert hydrogen to ammonia and transport it in ships, and (iv) combine hydrogen with a liquid organic hydrogen carrier (LOHC) and transport it in ships [43]. Pipelines have low operational costs and lifetimes of between 40 and 80 years [43]. This is a major advantage for this energy transmission vector. The offshore electrolysis typologies are primarily proposed to assess the cost-effectiveness of offshore hydrogen pipelines. In this typology, hydrogen is produced offshore by the farm then exported in hydrogen pipelines to the shore for storage and distribution.

In a current day wind turbine, the electrical power is first generated in AC. In a first stage, it is converted into DC initially to flatten the frequency. In a second stage, it is converted back to AC so that it can be fed into the array cables with a 50 Hz frequency in Europe (or 60 Hz in the United States). Finally, it is converted to DC again if fed into an

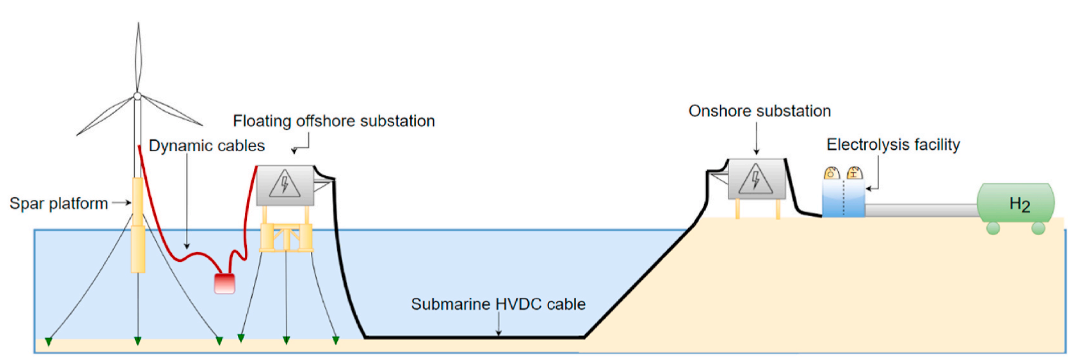

Fig. 5. Onshore electrolysis system typology layout using spar platform, dynamic electric cabling, and both an offshore and onshore substation.

electrolyser. If the electrolyser is located on the turbine platform, avoiding any type of electrical power transmission, the second and third steps are not necessary. This would avoid the use of converters, leading to energy and cost savings.

The decentralised term comes from conducting electrolysis in a decentralised configuration on the floating deck of individual turbines. A proposed layout of the decentralised offshore electrolysis is shown in Fig. 6. The offshore electrolysis facility in this typology is comprised of the electrolyser, a cooling unit, a seawater desalination unit, a hydrogen buffer (storage tank) and a battery system for back-up power to the facility.

A main advantage of this typology is that if one electrolyser fails, hydrogen production can easily continue from the other wind turbines. From discussions in Section 2.1 PEMEL is believed to be a viable candidate for the decentralised typology, with compactness as a key-drive parameter, and the dynamic performance needed in the decentralised configuration. Electrolysis water is sourced by water desalination in this typology.

In general, the whole electrolysis facility would require a backup source to maintain the minimum operational thresholds at times the wind output is very low. A reasonably scaled battery system serves an optimum solution for the system. The hydrogen buffer is another important component of the electrolysis facility, it is simply a hydrogen tank that dampens the fluctuating nature of hydrogen produced before transmission in the offshore pipelines. As discussed in Section 2.1, PEMEL can achieve a pressure of 80 bars or more with no need for a separate compression system. This would eliminate the need for a compression system in the electrolysis facility. This is an important reason why PEMEL is a viable candidate for this typology, apart from its compactness.

The H2Mare initiative [37] looks at developing a novel electrolyser prior to integration with a fixed-bottom offshore turbine. The FOW deck (semi-submersible or barge) can eliminate this need. Having a commercially ready electrolyser offshore with no pre-requisite modifications can be considered a key advantage of the decentralised system. This could allow for substantial cost savings and reduced development times.

The required key features of a FOW platform in this typology include for a sufficiently large area to house the electrolyser system, as well as mechanical stability even after integrating the electrolysis facility on the foundation. The semi-submersible FOW is a viable candidate in this typology, mainly because of the ample floating deck area it can provide, and its commercial readiness as discussed in Section 2.3.

The unbonded flexible pipes discussed in Section 2.4.2.2 are used to collect the produced high-pressure hydrogen from individual turbines. As it can be seen in Fig. 6, flexible pipes from all turbines can be gathered using a subsea manifold. The hydrogen is then exported to a larger diameter main export riser (flexible pipe) that will transport the hydrogen to a pipeline end manifold (PLEM) at the seabed [109]. This manifold then connects to the main export static pipeline.

From an environmental perspective, as discussed in Section 2.2, an advantage of the decentralised typology is that brine discharge of the seawater desalination is also decentralised, this allows for greater dispersion of the brine posing less of a risk to marine life (based on the acceptance of this practice as assessed in an EIA).

3.3. Centralised offshore electrolysis

This typology is close to the centralised onshore one but with the electrolysis facility installed offshore. Produced hydrogen is sent to the shore in hydrogen pipelines, and these are the only energy transmission vector considered. This configuration offers easier and quicker maintenance access for individual turbines, and generally a less complex system than the decentralised one. A proposed layout of the typology is shown in Fig. 7. The offshore electrolysis facility is installed in a centralised configuration on a floating vessel. Similar to the decentralised typology, it is comprised of the electrolysers, cooling units, seawater desalination units, hydrogen buffer, and a battery system for back-up power to the facility. It might also have compressors as it is discussed later in this section.

The footprint and weight of the electrolyser in this typology is also less of an issue as it is in the centralised onshore one. From discussions in Section 2.1, this makes both AEL and PEMEL viable candidates, the final choice would be however subject to detailed analysis.

Choosing AEL would make use of the current cost-effectiveness it offers. However, due to its current 30 bars maximum pressure of produced hydrogen, a compression system would be required as discussed in Section 2.4.2.3. In this case, compression would take place in a centralised setting. Large reciprocating compressors that are commercially available would be capable of compressing the total produced hydrogen of the farm from 30 bars to around 80 bars.

Selection of the floating platform would still be dependent on the site assessed with the most cost-effective selection with the given depth and met-ocean conditions. The spar FOW would be a viable candidate in this typology if the water depth is significant. This configuration is technically comprised of both electric and hydrogen transmission. Dynamic cables are required at individual turbine collection points, relatively smaller-sized ones. An offshore substation would also be required to integrate the electric output of the farm. A larger dynamic cable would transmit the electricity output from the substation to the floating vessel to directly operate a centralised offshore electrolysis facility. The compressed hydrogen would then be exported out of the floating vessel in a large flexible pipeline that connects to the main static hydrogen pipeline and from there to the shore.

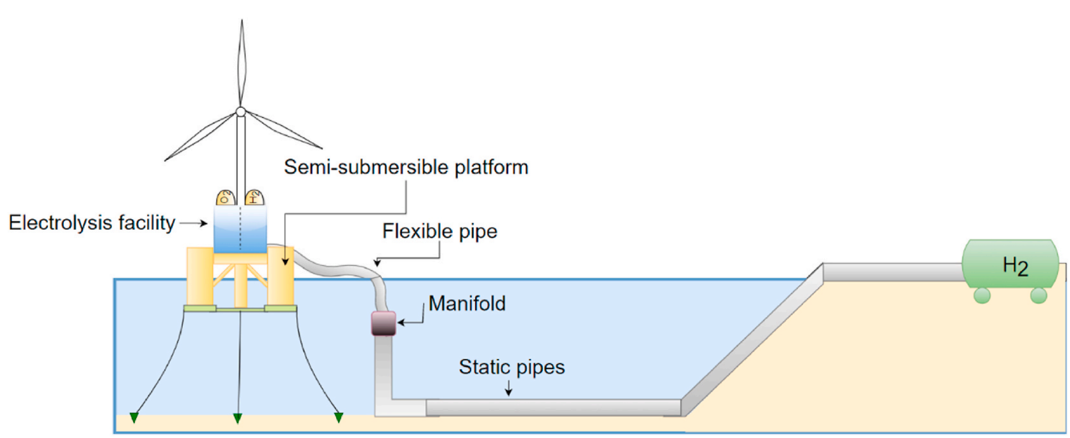

Fig. 6. Decentralised offshore electrolysis typology layout using a semi-submersible platform with a flexible pipe connected to static submarine pipelines.

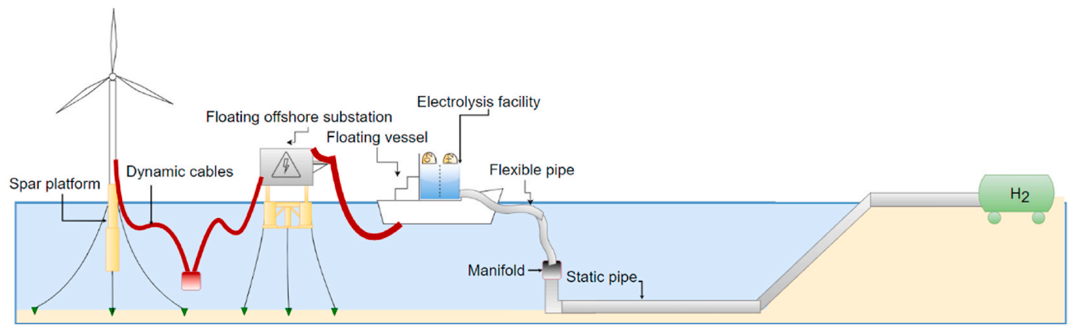

Fig. 7. Centralised offshore electrolysis typology layout using a spar platform with a floating vessel accommodating the electrolysis facility.

The general approach is to size the components at the maximum possible size while being cost-effective. In comparison with the FOW semi-submersible deck, the vessel has a larger area with less mechanical stability challenges from a footprint or weight point of view.

One challenge for this typology, is in the event of failure there is a disturbance in the whole plant production, as the centralised configuration has no redundancies (as compared to the decentralised system). This typology would also need on-site personnel. The operation and maintenance (O&M) procedures could be split into two main teams: the wind turbine team and the electrolysis teams and all their associated sub-systems. Splitting these two functions would make the O&M in principle more manageable. However, from an environmental perspective having a brine discharge in a centralised setting could have a greater chance of negatively impacting the ecosystem and as such greater care must be taken.

Depending on the location of the project, the electrolysis facility could also be accommodated on an island. This would however also require on-site personnel, but would eliminate the investment of another floating offshore solution [110]. Otherwise, ideally one or more platform vessels (depending on the farm scale) could be used together. Suitable vessels can be those used in the offshore oil and gas industry as the floating production, storage and offloading (FPSO) system, or the floating liquefied natural gas (FLNG) system [111], or very large crude carrier (VLCC). The final required space and vessel selection depend on various variables in the system configuration selection. It is worth noting that vessels are a significant addition to the CAPEX of the system. This makes this typology potentially less economically attractive in comparison with the decentralised typology in shallow or moderate water location.

4. Discussion

In this study three main coupling typologies were presented. Hybrid solutions between these three can be envisioned: for example, having part of the farm on a spar platform with a centralised configuration and another part on a semi-submersible platform in a decentralised configuration.

The study revolves primarily around the suitable energy transmission vector. Similar analysis by Jepma et al. [112] stated that on average pipeline transport requires much less CAPEX than transporting electricity, but also that energy losses in hydrogen transport are significantly less than those associated with electric cables.

Offshore applications of electrolysers can be further de-risked if the challenges regarding their operation in an isolated and harsh environment are addressed. It is possible to summarize the main barriers for an efficient and cost-competitive offshore operation comparable to the onshore as follows:

i) Low-grade water supply: At significant distances from shore an electrolyser would source its supply from seawater, whose characteristics are not compatible with the materials currently used in the electrolysers thus, requiring on-site desalination plants, which add to cost and complexity and the associated environmental challenges with disposing of brine as discussed in Section 2.2. Tong et al. [55] reviewed developments in electrode materials/catalysts for water electrolysis using low-grade and saline water. The review article discussed problematic aspects of electrolyser design and potential future approaches, which may allow for highly active and selective electrolyser materials in the presence of common impurities such as metal ions, chlorides, and bio-organisms. However, for low-grade or saline water electrolysers to be cost-competitive they need to be cheaper than the combined cost of current electrolyser, purification, and desalination technology.

ii) Discontinuous electricity supply: As it is disconnected from the onshore grid, the offshore electrolyser relies only on the electricity produced by the wind turbines to which it is connected to, limiting its operational time. Therefore, a high range of operability and fast responses are necessary to follow this variation of the electrical supply [50]. Building on the specifications of the electrolysers as discussed in Section 2.1, a fast response electrolysis technology is crucial to overcome this challenge. PEMEL would generally serve a reasonable dynamic operational performance in an off-grid context. A backup power source such as a battery system would however be required to maintain the minimum operating conditions of the electrolyser and rectify the wind output intermittency [113].

iii) High hydrogen pipeline pressures: High pressure is needed to overcome the pressure drop on the pipeline from the electrolyser to the shore. The longer the pipeline, the larger the pressure drop and the higher the pressure required. Accordingly, depending on the electrolyser technology implemented an on-site compression system might be needed. In their review, David et al. (2019) [114] divided scientific works in these topics in two categories: (a) those which propose to design electrolysers that directly produce gases with greater pressure and (b) those who model this as a loss of efficiency. The motivation behind this last group (b) is that, in comparison to electrolysers operating at higher pressures, atmospheric electrolysers are more efficient due to the energy consumption in the auxiliary equipment and the loss of gas during operation. In support of this pressurised electrolysers are more affected by corrosion, hydrogen embrittlement, operation complexity, dynamic response and costs [115]. The motivation behind the first group (a) [116,117] is that it takes more energy to compress gases than the theoretical energy of dissociating water. Therefore, despite the fact that it is theoretically possible to increase the efficiency of the system by increasing the pressure and temperature, there remain technical issues to be resolved, among which cross-contamination of gases and materials stability stand out.

The focus of this study is green hydrogen, but similar arguments can be made for green ammonia. Converting hydrogen into ammonia by combination with nitrogen is relevant to a future iteration of this study. Liquid ammonia has a 50% higher volumetric energy density than liquid hydrogen, and can offer a convenient energy transmission vector [43]. Ammonia in this case would probably be used as fuel in the maritime sector [69] or for use as fertiliser. A hybrid transport solution of hydrogen pipelines and ships carrying liquid ammonia would still be an option. This would highly depend on the rest of the supply chain and the sectors the plant would benefit from.

5. Conclusions

This paper proposed three typologies for a FOW farm dedicated to hydrogen production, namely: centralised electrolysis conducted onshore; decentralised electrolysis conducted offshore; centralised electrolysis conducted offshore. The typologies were assessed through assessing the three major variables: selection of electrolyser technology; selection of FOW platform; energy transmission vector (electrical power or offshore hydrogen pipelines).

Table 4 shows an overview of the main advantages and disadvantages for the three typologies which are discussed here. The energy transmission vector was the key feature of the three typologies discussed with emphasis on the major components of the systems, to limit the complexity of the paper while highlighting more detailed topics for future analysis.

For the centralised onshore electrolysis typology, AEL is the recommended electrolyser; Spar is the preferred FOW platform in significant water depths, with submarine HVDC cables for energy transmission to shore. This is suggested as a sensible solution for relatively near offshore distances, yet both energy losses and lack of flexibility in the potential for further expansion plans could be its main challenges.

The two offshore typologies (decentralised and centralised) would use submarine hydrogen pipelines as their energy transmission vector. In comparison with high voltage cables, the offshore typologies facilitate expansion as the system is not limited to 2 GW transmission per cable; offshore hydrogen pipelines are also believed to be more economical for large scale farms, especially those with longer offshore distances. For the decentralised offshore typology, PEMEL is suggested as a viable electrolysis candidate given its compactness and dynamic operational ability. A semi-submersible FOWT could accommodate the electrolysis facility on the deck without the need for an additional separate structure, or modifications to the electrolysis unit itself. This typology is flexible; if one electrolyser (or turbine) fails, hydrogen production can easily continue. This typology also facilities flexibility in further expansion as it is very much a modular system. From an environmental perspective, the brine discharge level has the potential to fall within the acceptable range, especially as compared to the centralised offshore typology. The typology is yet challenging in the complexity of the O&M and needs further validation in the offshore operational conditions. The centralised offshore typology may employ either PEMEL or AEL; the final choice would be based on a detailed analysis. The spar or the semi-submersible FOW platform can also be used in this typology; however, spar would be preferred if the site is of a significant water depth.

In contrasting offshore typologies, the centralised offshore typology may compete well when compared with the decentralised typology especially in the ease of maintenance of individual turbines. The centralised system in general is less complex and might open doors for more cost-effective options for some of the components. For example, the ongoing development work in scale up of large size cost-effective electrolysers may lead to cheaper hydrogen. On the other hand, the challenge to the centralised system is in the event of a failure, hydrogen production would cease for the whole farm. Another disadvantage of the centralised offshore typology is the concentration of brine discharge from the desalination facility associated with a large electrolyser in one spot with the associated environmental impact on marine life; or else the holding capacity of the brine if it needs to be discharged onshore. The centralised offshore system also has additional CAPEX of a floating vessel accommodating the electrolysis facility.

Credit author statement

Omar S. Ibrahim: Conceptualization, Methodology, Formal analysis, Investigation, Data curation, Writing – original draft, Visualization. **Alessandro Singlitico:** Investigation, Writing – original draft Sections 2.2 and 4 (part of), Writing – review & editing. **Roberts Proskovics:** Validation, Funding acquisition. **Shane McDonagh:** Validation, Resources, Writing – review & editing. **Cian Desmond:** Conceptualization, Validation, Writing – review & editing, Project administration, Funding acquisition, Supervision. **Jerry D. Murphy:** Validation, Writing – review & editing, Supervision.

Table 4
Overview of the main advantages and disadvantages of the three typologies.

Centralised Onshore Electrolysis		Decentralised Offshore Electrolysis		Centralised Offshore Electrolysis	
Advantages	Disadvantages	Advantages	Disadvantages	Advantages	Disadvantages
• Easier installation and lower costs of electrolysis onshore	• Challenge of scaling up	• Can use existing electrolyser technology	• Electrolyser response to offshore conditions needs validation	• Reduced maintenance for individual turbines	• More challenging in failure events
• Electrolysis technology does not need further validation for offshore conditions	• Submarine HVDC costs higher than pipelines in large farms at longer distances from shore	• Relatively more manageable in failure events as modular system	• Complex system	• Relatively quicker repair times	• May require multiple large offshore vessels with multiple decks to accommodate the electrolysers
• Competitive at deep-water sites with the spar platform	• High cost of HVDC converters	• No separate additional support structure is required	• Challenging O&M procedures (two different systems on the same platform)	• Hydrogen pipelines are cost-efficient for large farms and long offshore distances	• Vessels or islands require permanently manned crew
	• Energy losses through electrical transmission	• Hydrogen pipelines are cost-efficient for large farms and long offshore distances		• Competitive at deep-water sites with the spar platform	• High CAPEX of the vessels
		• Brine discharge (if permitted) is more diffuse as compared to centralised offshore typology and as such should minimise impact to marine life			• High asset risk due to all electrolysers in single location
					• Electrolysis response to offshore conditions needs validation
					• Brine discharge (if permitted) impact to the marine environment

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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