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A Buoyant Future

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In recent years, floating wind has gradually matured as a technology, progressing from being the subject of academic research to a handful of full-scale, stand-alone prototype projects (Hywind in Scotland, Principle Power in Portugal and the FORWARD project in Japan), to the development of multiple pre-commercial arrays. Technological advances in floating wind will open up opportunities to exploit the abundant wind resource in deeper water sites where it is currently not possible to deploy fixed-bottom foundations, making this an important area of research for the offshore wind industry. This article analyses the costs and risks of the three most common types of floating wind structure and compares them to those of a fixed-bottom monopile wind farm. It also provides an outlook on the technology's future and notes areas where further research is needed.

Floating wind still lags far behind fixed-bottom wind in terms of commercial readiness and will rely on governmental support in the medium term if it is to achieve – or even outstrip – costs associated with conventional fixed foundations in the long term. However, as floating wind moves closer to full commercialisation, new supply chain opportunities are emerging. The natural synergies with the oil and gas sector mean this technology offers potential for those affected by the recent downturn in the oil and gas industry.

The three most common types of floating wind substructure are spar, tension leg platform (TLP) and semi-submersible (see Figure 1). In this article we have analysed the costs and risks of these typologies and compared them to those of a fixed-bottom monopile wind farm. To reflect on the recent increase in designs that use concrete as the primary material, both a steel and a concrete semi-submersible are included in the analysis.

The four substructures analysed are generic floating wind substructures and do not represent specific concepts. The following assumptions are used:

- The monopile has a grouted transition piece and is installed in water 40 metres deep.
- The monopile benchmark is part of a 500MW wind farm with 8MW turbines.
- The steel TLP has no self-stability in tow.
- Steel and concrete semi-submersibles do not use active ballasting.
- The steel spar employs a slurry ballast.

Analysis

We have considered the costs and risks associated with all three technologies against a fixed turbine reference for the key stages of an offshore wind project.

Development and Consent

Cost: Slightly less expensive (than fixed-bottom monopile wind farm)
Risk: Slightly more risky

The cost of developing and consenting a floating wind farm is expected to be slightly more favourable than a fixed-bottom, with a possible exception in the case of TLPs. Shallower bore samples for geotechnical surveys could potentially contribute to these savings; however, more samples would be required to account for multiple anchors.

The risk profile for floating wind may be perceived to be higher than for monopiles, due to the emerging nature of environmental monitoring and consenting. The front-end engineering is also less developed for floating wind, and lacks bespoke standards, including for each typology. Visual impact could be reduced by installing turbines further offshore in deeper waters. However, this advantage could be cancelled out if assembly and major repairs were to be performed near densely populated areas. Some opposition might also be voiced from the fishing community (particularly for catenary mooring designs), airspace users (MoD, airports and air traffic control) and other stakeholders, such as the shipping industry.

Wind Turbines

Cost: Neutral
Risk: Neutral

The wind turbines used in fixed-bottom and floating situations are nearly identical. Both use adapted onshore turbines, and modifications are made to the blade pitch control algorithms for floating turbines. In some cases this can lead to hardware implications, such as the necessity for new blade pitch actuators.

Substructure and Mooring System

Cost: More expensive
Risk: Less risky

Compared to monopiles, substructures for floating wind turbines are, for now, considerably more expensive to manufacture and assemble. Steel substructures are many times heavier and more labour-intensive to assemble, whereas concrete substructures are cheaper per tonne of material but an order

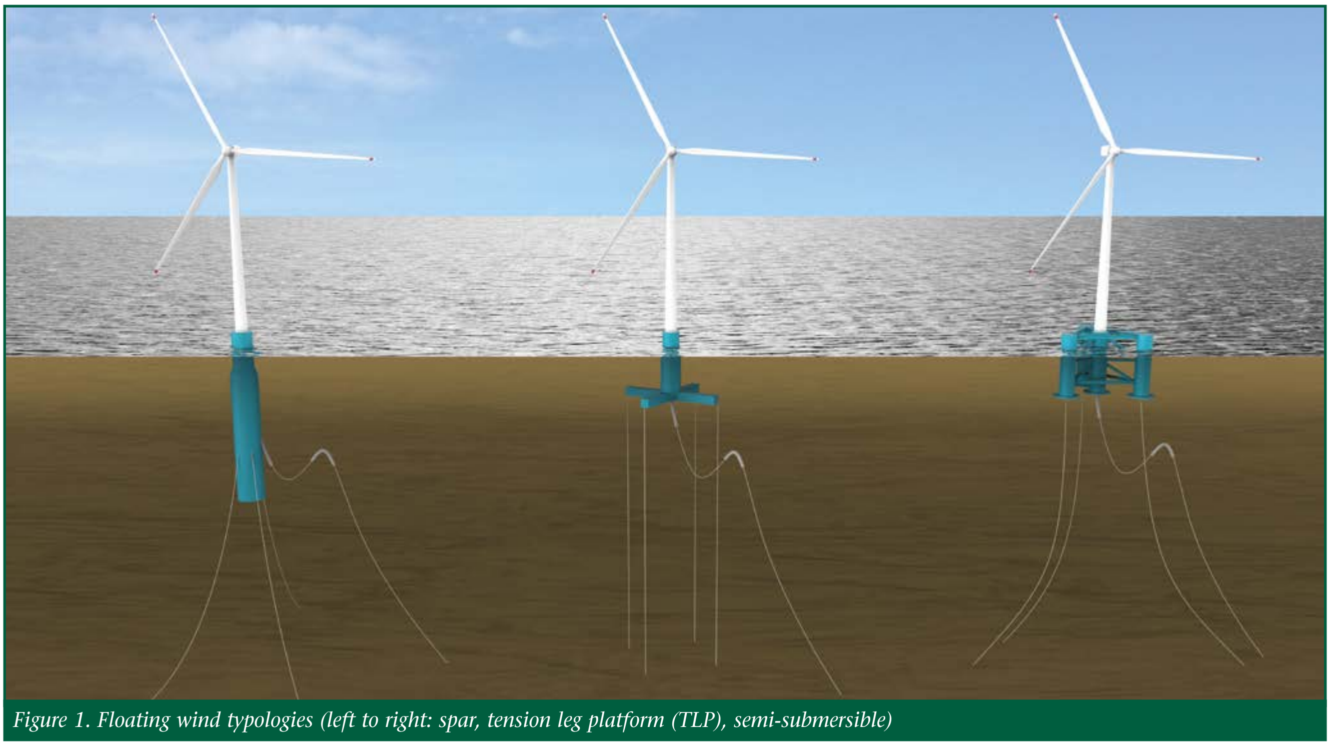

Figure 1. Floating wind typologies (left to right: spar, tension leg platform (TLP), semi-submersible)

of magnitude heavier. In addition to this, all floating wind turbines require mooring lines and anchors.
In terms of risk, this is of a comparable scale between monopiles and steel substructures. The latter can make use of the existing supply chain for fixed-bottom wind, and are exposed to the volatility of steel prices. Floating substructures consist of more parts, and as a result are more complex to assemble. However, they benefit from much higher standardisation as they are not directly coupled to the seabed.

Concrete substructures are an exception, in terms of risk profile. These are manufactured and assembled in one process that can be performed in a port, cutting out the need for transporting the large, heavy substructure sections from their manufacturing facility to the assembly site. They are also much less exposed to the high volatility of steel prices, although some steel is still required for concrete reinforcement. The main risks for concrete substructures lie in the concrete curing process, which requires long periods in a controlled environment, and soil-bearing capacity at ports, which need to bear the weight of the heavy structures.

Mating

Cost: Less expensive
Risk: Mixed/varies by typology

Mating is one of the areas where floating wind has a clear advantage over fixed-bottom: turbines can be installed on their substructures in a much more controlled environment, and without the use of expensive jack-up vessels.
While semi-submersibles (steel and concrete) and TLPs can perform turbine and substructure mating at port, this is not the case for spars. These require deep, sheltered waters for the spars to be up-righted by means of installing the ballast, followed by mating using expensive offshore cranes. Currently, this process is highly costly and brings additional risks compared to other floating wind typologies (e.g. the mating being performed in a floating–floating arrangement and a lack of deep, sheltered waters).

Array Cables

Cost: Slightly more expensive
Risk: More risky

Floating wind array cables can be installed before turbine installation, allowing multiple processes to be performed in parallel. This gives floating wind an advantage over fixed-bottom, in which array cables are installed only once foundations are in place.
Array cables for floating wind are currently more expensive, as they require dynamic cables (umbilicals) and bespoke electrical connectors, of which there is a limited availability.

Installation

Cost: Neutral (TLPs: More expensive)
Risk: Neutral (TLPs: More risky)

Installation of floating wind turbines and connecting all the dynamic cables and mooring lines requires deploying multiple vessels for an extended period of time – specifically tug boats for towing the foundations and anchor handling vessels (AHVs) for electrical and mechanical coupling.

While more vessels are required for floating wind installation compared to monopiles, these are considerably cheaper to charter than a jack-up vessel. An exception would be in the case of TLPs that, if not self-stable in towing, require bespoke installation barges, which would incur a significant expenditure. Installation of TLPs would also have to be performed in a highly

Element	Semi-sub (steel)		Semi-sub (concrete)		TLP (steel)		Spar (steel)	
	Cost	Risk	Cost	Risk	Cost	Risk	Cost	Risk
Turbine	○	○	○	○	○	○	○	○
Substructure and Mooring System	🔴	○	🔴	🟢	🔴	○	🔴	○
Installation	○	🟩	○	🟩	🔴	🔴	○	🟩
Mating	🟢	🟢	🟢	🟢	🟢	🟠	🟠	🔴
Array Cables	🟠	🔴	🟠	🔴	🟠	🔴	🟠	🔴
PM and Other Costs	○	○	○	○	○	○	○	○
Contingency	○	○	○	○	○	○	○	○
Development & Consent	🟩	🟠	🟩	🟠	○	🟠	🟩	🟠
Transmission	🔴	🔴	🔴	🔴	🔴	🔴	🔴	🔴
Scheduled O&M/Minor repairs	○	○	○	○	○	○	○	○
Major Repairs	🟩	🟢	🟩	🟢	🟠	🟠	🟠	🔴
Decommissioning	🟢	🟩	🟢	🟩	🟩	🟠	🟩	🔴

Table 1. Summary of current costs and risks for floating wind compared to monopiles

controlled environment to guarantee tendon and substructure integrity.

Project Management, Contingency and Other Costs

Cost: Neutral
Risk: Neutral

The costs around project management, contingency and insurance are expected to be broadly similar for monopiles and floating wind. While there are more operations to undertake offshore for floating wind, these include fewer offshore heavy lifts, balancing the cost and risk profile of both technologies.

Transmission

Cost: More expensive
Risk: More risky

The higher costs and risks for floating wind transmission come from the necessity of putting an electrical substation in deep waters. While this could take the form of a fixed or floating platform, a floating solution would require the development and qualification of very high-power dynamic cables, which are currently not available on the market.

Scheduled O&M and Minor Repairs

Cost: Neutral
Risk: Neutral

The costs and risks for scheduled O&M and minor repairs are expected to be very similar for monopiles and floating wind. Tests have demonstrated the applicability of crew transfer vessels (CTVs) used in fixed-bottom offshore wind to floating turbines. In the case of concrete substructures, inspection frequency could be further reduced. While the majority of risks are very similar in fixed and floating wind, the floating-to-floating configuration of technician transfer between a floating turbine and a CTV must be accounted for.

1: More expensive/risky	🔴
2: Slightly more expensive/risky	🟠
3: Neutral	○
4: Slightly less expensive/risky	🟩
5: Less expensive/risky	🟢

Major Repairs

Cost: Varies by typology
Risk: Varies by typology

The cost of performing major repairs is highly dependent on the typology, and the process is, in essence, a reversal of the installation procedure. Semi-submersible structures can be decoupled from the mooring and electrical systems, and towed back to port for repairs. This makes them cheaper than monopiles, as expensive jack-up vessels are not required.
Bespoke equipment is required for TLPs and spars – in the case of TLPs this means transportation barges and for spars a heavy lift vessel (HLV) or crane barge in deep, sheltered water. These would all simultaneously incur costs and increase risks. Additionally, spar repairs would have to be performed in a floating-to-floating configuration, increasing risk.

Decommissioning

Cost: Less expensive
Risk: Varies by typology

Decommissioning costs for floating wind turbines are expected to be lower than for fixed-bottom. This is particularly true for semi-submersibles that do not require bespoke equipment or heavy lift operations offshore. While the cost is lower for all typologies compared to a monopile, the risk profile is only favourable for semi-submersibles. TLPs require bespoke vessels, while spars require HLVs for turbine decommissioning in deep, sheltered waters, and removal of hard ballast before substructures can be decommissioned in port. Despite all this, steel substructures benefit from greater recyclability and resale value.

Summary

Table 1 summarises the findings of our analysis, with cost and risk placed alongside each factor for easier comparison. In general, cost and risk are both reduced compared to fixed-bottom where operations can be performed onshore rather than offshore, or are still performed offshore but with less complex, more readily available vessels. This is seen predominantly in turbine and substructure mating, O&M and decommissioning. Areas where we see cost and risk downsides in the near term are those requiring further technology development, such as dynamic export and array cables.

Outlook

For floating wind to continue reducing costs and risks, the key areas of focus should be in the following:

- Decreasing substructure manufacturing costs through floating wind-specific fabrication, assembly, load-out and staging facilities, as well as learning.
- Reducing installation time through experience and optimisation of designs for at-sea operations.
- De-risking of bespoke barges for TLPs for installation, major repairs and decommissioning.
- Proving of TLP designs that are self-stable in tow.
- The potential development of techniques and/or technology to reduce costs – and eventually reduce risks – for mating procedures for spars (also applicable to major repairs and decommissioning). An example of this can be seen in Statoil's Hywind floating wind installation innovation challenge.
- Developing and verifying dynamic cables and connectors.
- Developing substations for deep water, including offshore transmission modules (OTMs).
- Better understanding of mean-time-to-failure of components due to motions and accelerations associated with floating wind turbines.
- Developing techniques for hard ballast recovery in spars.

Table 2 illustrates the potential for cost and risk for floating wind compared to monopiles, this time assuming that the suggested learning and innovation in floating wind is developed and implemented, and no significant developments occur to reduce the costs and risks around monopiles.

Element	Semi-sub (steel)		Semi-sub (concrete)		TLP (steel)		Spar (steel)	
	Cost	Risk	Cost	Risk	Cost	Risk	Cost	Risk
Turbine	○	○	○	○	○	○	○	○
Substructure and Mooring System	🟠	○	🟠	●	🟠	○	🟠	○
Installation	🟢	🟢	🟢	🟢	🟢	🟢	🟢	🟢
Mating	●	●	●	●	●	🟢	🟢	○
Array Cables	○	○	○	○	○	○	○	○
PM and Other Costs	○	○	○	○	○	○	○	○
Contingency	🟢	○	🟢	○	🟢	○	🟢	○
Development & Consent	🟢	○	🟢	○	○	○	🟢	○
Transmission	○	○	○	○	○	○	○	○
Scheduled O&M/Minor repairs	○	○	○	○	○	○	○	○
Major Repairs	🟢	●	🟢	●	🟢	🟢	○	○
Decommissioning	●	🟢	●	🟢	●	○	●	○

Table 2. Summary of costs and risks for floating wind compared to monopiles if suggested innovations are implemented

It should be noted that monopiles have been, and will continue to be, put through continuous and rigorous cost-cutting exercises. Some of the innovations that could reduce the costs and risks of monopiles include the development of integrated monopile and transition piece designs, which would result in fewer lifting operations offshore, fewer parts and a reduction in weight.

Once floating wind technology matures, there are no areas (apart from the cost of substructures) where cost or risk will lag materially behind monopiles. Reductions in the cost and risk of floating wind will be driven by the development of specific components and enabling systems, techniques and infrastructure, such as electrical connections, and bespoke vessels and port facilities. ■

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(Disclaimer: The results presented in Tables 1 and 2 are an amalgam of outputs from a number of different ORE Catapult projects, and are not representative of any one particular project or specific concept.)