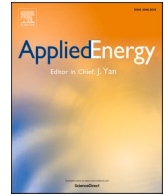


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Modelling the installation of next generation floating offshore wind farms

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HIGHLIGHTS

- Novel installation tool for fixed/floating offshore wind farms.
- Tool validated for floating wind against installation data for Hywind Scotland.
- Provides reference case-study with full input details to promote re-use.
- Installation costs are sensitive to weather operational limits and durations.
- Results: LCoE of €52.3–64.59/MWh for floating wind farms in the Celtic Sea, 2035.

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ABSTRACT

The offshore wind industry is advancing with larger turbines (10 MW+) into sites in deeper waters (>60 m), necessitating innovative floating substructures. However, Floating Offshore Wind (FOW) must still be proven to be cost-efficient, with special attention paid to developing installation, Operations and Maintenance (O&M) and decommissioning strategies that will ensure FOW is competitive. Simulation is an efficient way to assess the viability of new technologies and the innovative operations required to install and maintain them. This paper presents a novel tool that simulates the installation of fixed/floating offshore wind farms across an hourly time-series of Metocean data, producing a total estimation of costs as part of the total capital expenditure (CAPEX). The paper validates the model by simulating installation of Hywind Scotland, the FOW farm, and comparing results with published data. Given the lack of real-world cost data and experience, this paper then seeks to provide a well-defined case-study for future researchers to develop further in other regions and with different technologies. The tool is applied to a theoretical large commercial 1GW FOW farm commissioned in 2035 at a representative site in the Celtic Sea. This considers a promising location for FOW development outside the existing demonstration/early commercial FOW projects, which are primarily focused on the North Sea. Results indicate a CAPEX (including installation) of €3492/kW, which is in line with industry expectations. Sensitivity analysis applies a learning rate to reduce platform costs, and varies farm capacity, demonstrating the potential economies of scale when increasing farm size. Simulation identifies weather operational limits and cable installation duration as key contributors to installation time and costs. This quantifies where cost-savings can be found and optimisation should focus. Further modelling considers the scale of their impact on results. A final Levelised Cost of Energy assessment estimating an LCoE range of €52.3–64.59/MWh, placing the FOW farm in the context of global economic targets.

1. Introduction

There have been dramatic reductions in the cost of installing

Offshore Wind (OW) farms over the last 15 years, with a record low bid of £37.35/MWh (€42.76/kWh)¹ in the United Kingdom auction scheme 2022. Cost reductions can be attributed to the combined effects of

Abbreviations: CAPEX, Capital Costs; FOW, Floating Offshore Wind; GW, Gigawatt; HLV, Heavy Lift Vessel; Hs, Significant wave height; kW, Kilowatt; LCoE, Levelised Cost of Energy; NCF, Net Capacity Factor; m, Metre; m/s, Metre per second; MW, Megawatt; O&M, Operations and Maintenance; OW, Offshore Wind; TLP, Tension Leg Platform; UCC, University College Cork.

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¹ Based on current exchange rates of £1 = €1.14

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experience and new technology in the form of rapidly increasing turbine size, vessels with improved operational capability, improved turbine reliability etc. The OW industry is now advancing with turbines >10 MW and into sites in deeper waters, posing new technological and logistical challenges. The development of deep-water sites necessitates innovations in substructure design, specifically floating substructures for where water depths exceed 60 m. Hywind Scotland (30 MW) was the first commercial floating wind farm, located 30 km off the Scottish coast at Peterhead. Several demonstration projects are currently in operation including WindFloat Atlantic, which deployed three 8 MW turbines installed on semi-submersible substructures. The Kincardine OW farm Aberdeen Bay, Scotland is a 50 MW farm consisting of five 9.5 MW turbines on semi-submersible platforms. Equinor's 88 MW Hywind Tampen project in the North Sea, is the largest FOW farm and came on stream on 2023. It is estimated that by 2030, global installed FOW capacity could be in the range of 5–30GW [1]. The US alone have targets of 15GW of FOW by 2035, much of which would be on the west coast with water depths ranging from 750 to 1000 m. The Japanese government aims to deploy 10GW of OW by 2030, including floating wind as it has similar topography as the US west coast. These ambitions will require significant growth in deployments. However, FOW must still be proven to be cost-efficient, with special attention paid to developing bespoke installation, Operations and Maintenance (O&M) and decommissioning strategies. [2] suggest significant cost reductions can be achieved in the installation phase, which can comprise 5–10% of the total investment costs for Floating Offshore Wind (FOW). For fixed OW, the industry will require new vessels that can install increasingly large structures in higher sea states. Pre-installing FOW turbines on their substructures at the quay side and towing to site with relatively cheaper vessels than used for fixed OW may give FOW farms an advantage when it comes to installation costs. However, with only approximately 192 MW pre/early commercial FOW installed capacity globally, there is very little real-world experience of how installation will be undertaken for the variety of platform technologies, as well as the ever-increasing turbine capacity >10 MW.

[3] [4,5] review some of the key marine operations challenges towards the commercialisation of FOW. However, the current literature is not extensive on FOW logistics, with most work focused on the technical efficiency and challenges of the floating platforms [6]. Modelling tools are useful to determine the implications of different technologies (e.g. substructure choice), installation strategy and logistics on the OW farm capital cost (CAPEX), as well as the overall Levelised Cost of Energy (LCoE). Kaiser and Snyder [7] present a model that predicts installation costs and durations. Irawan et al. [8] compare a metaheuristic approach to an exact method (using CPLEX) to optimise OW farm installation costs and durations. Sarker and Faiz [9] present a model that estimates the cost of turbine transportation and installation as a function of the chosen installation method and turbine rated power. However, these models do not consider the variation and impact of weather. Peterson et al. [10] calculate the average installation rate (days per turbine) and the average weather downtime for each phase of an OW farm installation using a probabilistic model. It uses Markov Chain modelling to generate a weather time-series and Monte Carlo simulation to assess the uncertainty of the results. Barlow et al. [11] carry out discrete-event simulation of OW installation using a synthetic time-series, which applies a correlated autoregression model to historical weather data. A subsequent optimisation process identifies installation schedules that are least susceptible to weather delays. Ursavas [12] presents a mathematical model for optimising planning of OW installations by characterising the uncertainty in the weather at a given site. Commercial software for modelling OW installation includes ForeCoast Marine [13], but it models general marine activities and is not specific to installation or OW. ECN Install [14] software matches OW installation activities and vessel operations against historical weather data to determine time and costs. ORBIT is an open access tool that assess the balance of system (BoS) costs (e.g. CAPEX of all components other than the turbine) and

uses a discrete event simulation framework to determine installation costs [15]. ORBIT currently only considers the installation of monopile substructures. In fact, there are very few FOW-specific installation models with most focused on fixed OW farms. Castro-Santos et al. [16] developed a parametric model for calculating FOW farm installation costs, providing a detailed inventory, but does not consider the impact of weather delays. [2] developed a formulaic model to determine logistic values, asserting that the tool can help plan the main logistics and installation aspects of a FOW farm and is applicable to the main types of floating platforms.

Ultimately, while there are a number of relevant tools, this research area is missing a FOW-specific discrete-event installation simulation tool that can model the variety of technologies and potential operations that may be utilised now and in the future. Existing tools are also only validated using figures from the current literature, where there are very few assessments of detailed FOW installation costs and that are not derived from fixed OW installation figures. Key early cost studies specific to FOW installation include [17] [18], which present a cost estimate of the different components. [19] presents a lifecycle cost model for FOW farms bringing together the most up-to-date data and parametric equations from databases and literature. [16] applies a tailored methodology to calculate the installation costs of FOW farms. [20,21] assess the costs related to floating wind turbines, considering spar-buoys (SBs), semi-submersibles (SSPs) and Tension Leg Platform (TLP) technologies. These studies provide a good basis that must be built upon with more detailed cost estimates for FOW deployments and realistic modelling of the time and associated costs for installing them. Given the ambitious industry FOW deployment targets, studies also need to consider the costs and installation of large-scale FOW farms in order to provide an accurate reference case for future work.

The aim of this paper is to present a tool, developed to assess the CAPEX and model the installation of fixed or FOW farms. An overview of the installation model is given by Judge et al. [22], and is described in detail in Section 2.1 of this paper. To provide confidence in the methodology and assumptions, and take validation a step further than previous work, the tool is corroborated for FOW wind applications by modelling the Hywind Scotland wind farm (Section 2.2 and 2.3) considering the results against real costs and timeline of activities. It is then applied to a future 1GW FOW farm at a theoretical representative site in the Celtic Sea with 12 MW turbines on floating semi-submersible substructures (Section 3). A development at this scale using turbines in the 12–20 MW range is considered to represent the next generation of floating offshore wind farms. There is limited data available for researchers and industry regarding costs and logistics of installing large-scale FOW arrays, particularly beyond 5 MW turbines and demonstration/early commercial size farms. Therefore, this paper will provide a reference study for future research in this sector. Having determined installation costs and total CAPEX (Section 4.1), sensitivity analysis (Section 4.2) will then test key scenario assumptions and their impact on results. Section 5 uses LCoE analysis to place results in the overall context of project finances and compares with industry expectations for FOW up to 2050.

2. Methodology

2.1. Installation model overview

The installation model was developed in University College Cork (UCC) and is a discrete-event simulation tool that models capital and installation costs of fixed or floating offshore wind farms. Considering the latter, it simulates on- and offshore activities in the installation phase of an OW farm against an hourly time-series of Metocean data. This must be input by the user for their study. The tool produces a cost and time breakdown of the installation process and an estimation of total capital costs (CAPEX), enabling the user to identify areas for optimisation in future scenarios. The model can be used as part of the lifecycle financial

model presented in [22]. The following constitutes a comprehensive description of the functionality and assumptions.

Model inputs include details (e.g. rating, cost) of the project assets: the turbines; substructures; substation; inter-array cabling; export cabling; and balance of plant costs (e.g. project development and onshore works). The user specifies the mode of transporting components to a port e.g. by land or sea, inputting the distance and cost/km. A database contains pre-determined installation options for different asset types as summarised in Table 1. Installation methods are selected for each project asset from the database by the user. While the model focuses on cost, the user should also consider the different levels of risk associated with the different methods when making the selection.

For each installation activity, the user can select from a range of installation vessels (e.g. Heavy Lift Vessels (HLVs)) whose features are stored in the database. Vessel inputs include mobilisation costs and day rates, fuel consumption, travel speed, wind and wave operational limits and positioning time. Up to 3 vessels can be selected for seabed preparation and installation of substructures and turbines, and 1 vessel each for installation of cabling and substation. The user specifies the carrying capacity for each vessel e.g., number of turbines. The database is also editable; the user can input their own bespoke installation activities or vessel. The model calculates the cost of the transportation of the project assets from the manufacturer to the supply port (by road and/or by sea). The time associated with this aspect is not calculated; however, a load time from quayside to vessel can be added before a consignment of assets is deployed. The user can specify an annual installation season to model seasonal vessel chartering. The season start and end dates can be varied to minimise the impact of weather delays, depending on the environmental conditions at the site location. During weather delays, vessels can be instructed to remain offshore for up to a specified number of hours to wait for the next weather window. However, they must return to port after the time specified for regular maintenance and refueling. Optimal installation activities are highly dependent on the vessel capabilities and the installation schedule. The user determines the number of substructures; turbines; or length of cable a vessel can transport in one consignment. The model can accommodate the installation of turbines and substructures by the same vessel. Parallel installation of turbines and substructures is also possible, where the user can specify the number or “batch” of substructures that must be deployed before the next batch of turbines are installed. Fig. 1 provides a flowchart of the installation model inputs, processor and outputs.

Based on the inputs, the model generates a proposed schedule of installation activities that the model then attempts to complete considering the time series of Metocean data. The model determines the time

spent carrying out each activity; any delays; and the vessels used. It should be noted that the array layout is not currently considered in the model, with an average array distance specified by the user to simulate movement within the farm. The installation model uses Monte Carlo simulation, which involves running numerous simulations of a single scenario and each simulation varies elements that have inherent uncertainty. For example, in this model, the stochastic element is the weather time series since weather is inherently variable. The model uses a “bootstrap” method, randomly selecting years from the dataset provided by the user (ideally at least 10 years or more) to create a different time-series for the full project duration for each simulation.

The installation model presented in this paper is still being improved in line with industry interests and needs, alongside a decommissioning model [23]. As described in [22], validation of the installation model was carried out as part of the FP7 LEANWIND project. This involved simulating the installation of three existing wind farms, C-Power Phase 1 (30 MW), C-Power Phase 2&3 (288 MW) and Teesside (62 MW) and comparing the results to published data. It was found that the installation predicted model total costs within 1% of the figure reported by C-Power Phase 1. This validation exercise dealt with fixed OW farms. Therefore, to confirm the ability of the model to predict the cost and durations of installation activities associated with FOW; this section models the Hywind farm at Peterhead, Scotland and compares results with published data.

2.2. Scenario definition

Hywind is the world's first commercial floating wind farm, commissioned in October 2017. It is operated by Equinor, and located in the North Sea, approximately 30 km offshore of Peterhead, Scotland. Farm capacity is 30 MW, powered by five Siemens 6 MW turbines with an onshore substation at Peterhead. Details regarding the Hywind farm, the installation operations undertaken and the specific vessels used by Hywind were obtained from the following sources that are publicly available: [24] [25] [26] [27] [28] [29] [30] [31] [32]. The main inputs to the installation model are presented in Table 2. Table 3 provides a detailed list of the vessels used. Vessel mobilisation and charter costs; the cost of inter-array and export cabling; and development, onshore substation and ancillary works were estimated based on [33] and engineering experience. The turbine costs were estimated by scaling up the costs of a 5.64 MW turbine calculated by [34]. The substructure costs were estimated using the sources and assumptions outlined in Table 4.

The following describes the installation activities undertaken at Hywind based on [24–32] unless otherwise stated. The turbines were assembled onshore at Stord, Norway; mated to the spars in the deep water adjacent to the port; and towed individually to the site 490 km away. The model assumes that the full assembly including mating to the substructure is done at the quayside. The mating was carried out in the deeper water at Stord using the Saipem 7000 vessel; the use of this vessel is included as an additional logistics related cost rather than simulated directly by the model. The time allocated to this process is included in the turbine pre-assembly activity. This and other additional logistics-related activities not simulated by the model are discussed Table 5. Once at site, the turbines and spars were connected to the pre-installed anchors. The specific durations for activities are not available. Based on discussions with industry, the model assumes it takes 48 h to pre-install all three anchors for each turbine; 36 h to attach the moorings to the anchors and connect the platform at site based on [39], which suggest this process took approximately 3 days per turbine. Export cables were buried 1.5 m under seabed. There is very little information available indicating the activities and duration required to install cabling at Hywind or elsewhere. This may be extremely site specific determined by the cable installation strategy chosen; the seabed type; the equipment and vessels utilised. For this study, it is assumed that cables were installed using pre-trenching and simultaneous lay and burial using a cable plough. Installation for export cable is estimated to take 12 h/km.

Table 1
Asset installation options.

Asset	Installation options
Turbine	• Components individually (7 lifts)
	• Pre-assembled nacelle and hub with 2-part tower (6 lifts)
	• Pre-assembled nacelle and hub with 1-part tower (5 lifts)
	• Bunny ears with 2-part tower (4 lifts)
	• Bunny ears with 1-part tower (3 lifts)
	• Pre-assembled rotor with 2-part tower (4 lifts)
	• Pre-assembled rotor with 1-part tower (3 lifts)
Substructure	• Fully preassembled (1 lift)
	• Pre-installed on substructure (0 lifts)
Cable	• Craned
	• Float-out
Seabed prep	• Plough burial
	• Separate trench and lay
Substation	• Site specific
	• Craned
Substation substructure	• Float-out
	• Craned

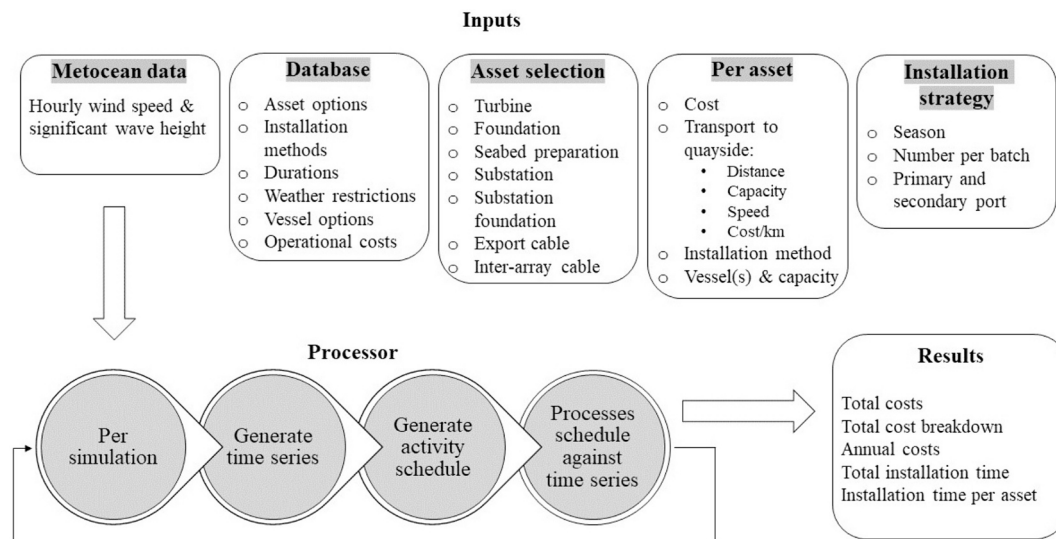


Fig. 1. Installation Model Flowchart.

Table 2
Validation case study model inputs.

Item	Input
Site	Hywind
Location	30 km offshore of Peterhead, Scotland
Operational	October 2017
Capacity	30 MW
No. of turbines	5
Water depth	95–120 m
Staging port	Stord, Norway
Distance from port	490 km
Wind data	Wind_meteo_2_Europe_station 67,443 (Copernicus Climate Change C3S programme [35])
Wave data	Data point 258,903; ECMWF ERA5 Reanalysis Dataset [36]
Turbine	Siemens SWT-6.0-154
Turbine cost	€6.6 m
Substructure details	Spar and catenary chain mooring system with 3 lines
Substructure cost	€12.7 m
Installation method	Turbine pre-installed on substructure & floated to site
Vessels	Normand Ranger/Drott and 2 tugs
Seabed preparation	3 suction anchors per turbine
Seabed prep vessel	Deep Explorer
Inter-array cabling (IAC) rating	33 kV
IAC length	15 km
IAC cost per km	€148 k/km
Installation method	Plough burial
IAC vessel	Skandi Acergy
Export cable (EC) rating	33 kV
EC length	35 km
EC cost per km	€148 k/km
Installation method	Plough burial
EC vessel	Skandi Acergy
Port costs	Unknown
Development, onshore substation & ancillary works	€5 m [33]
Project management (PM)	10% of total installation costs
Insurance & contingency	9% of total CAPEX

This is based on [40], which indicates that cable can be laid at a rate of 8 h/km depending on the seabed type. Additional time is added for as-found and as-left surveys; platform preparation; cable pull-in; derigging equipment; and cable and protection system testing. The same assumptions are applied to install inter-array cables. The model uses 10 years of Metocean data obtained (see Table 3 for details) using a data

Table 3
Validation case study - vessels.

Activity	Vessel name /type	Mobilisation cost*	Daily charter rate
Anchor transport & installation	Deep Explorer: Anchor handling/diving support vessel	€180 k	€90 k
Towing of preassembled structure (Stord to site)	Normand Ranger/ Normand Drott: Anchor handling tug supply (AHTS) vessel plus 2 tugs	€240 k	€120 k
Cable installation	Skandi Acergy: Cable-laying vessel	€300 k	€150 k

* Mobilisation is a lump-sum cost incurred when a vessel is first mobilized for an operation.

Table 4
Substructure, mooring and anchor cost for a single platform.

	Item	Cost	Source
Substructure materials and manufacturing	Steel consumption (tonnes)	2300 t	[28]
	Steel cost (€/tonnes)	€1 k	
	Manufacturing complexity factor (%)	120%	[18]
	Manufacturing cost (€/tonnes)	€1.2 k	
	Ballast consumption (tonnes) – 5500 t iron ore and 4200 t water	9700 t	[27]
	Ballast cost (€/tonne)	€70	[38]
	Outfitting cost (% of material and manufacturing cost)	10%	
	Contingency (% of material and manufacturing cost)	25%	
	Total production cost per substructure	€7.7 m	
	Cost per suction anchor	€974 k	[18]
Mooring lines	Cost of 3 x chain mooring lines	€2 m	
Total cost		€12.7 m	

point closest to the Hywind site. Weather restrictions applied in the model for offshore turbine installation activities (including towing) are 2 m Hs and 14 m/s wind speed (the latter is based on feedback from industry where wind speed is not considered a limiting factor unless you are conducting operations at height. However, this may be quite a liberal

Table 5

Validation case study – additional activities & costs.

Vessel	Mobilisation	Day-rate	Charter duration	Vessel cost
Substructure transportation from Bilbao to Stord (2 spars per trip of 2300 km)				
Albatross: Semi-submersible vessel	€900 k	€450 k	36 days	€17 m
Substructure float-off, upending and ballasting				
Two tugs, floating crane and barge	€540 k	€270 k	35 days	€10 m
Turbine tower transportation from Bilbao to Stord (1 tower per trip of 2300 km)				
BigLift Traveller	€300 k	€150 k	60 days	€9 m
Turbine to spar mating - lifting				
Saipem 7000: Semi-submersible crane vessel	€1 m	€500 k	21 days	€12 m
Turbine to spar mating – assisting				
Three tugs	€324 k	€162 k	21 days	€4 m
		Total		€52 m

assumption). The wind speed data used is measured at 10 m and scaled to hub height – 101 m – using the following wind shear correction formula $U_x = U_r(Z_x/Z_r)^a$ where U_x is the hub height wind speed; U_r is the upper measured wind speed; Z_x is the hub height; Z_r is the height of the upper measured wind speed and a is the wind shear exponent. A value of 0.14 is recommended for the exponent for offshore wind speeds based on [41]. Restrictions are set to 2 m Hs and 16 m/s wind speed for cable installation (again a liberal wind speed assumption based on discussions with industry where wind speed is not considered a particularly limiting factor for this operation). This is based on discussions with industry and experience from previous research projects. Table 5 presents the major logistical operations that are not simulated directly by the model and their associated costs.

2.3. Validation results

The installation model was run for 1000 simulations and the results are presented in Table 6 and Table 7. The total predicted CAPEX of €204.6 million is very close to the reported Hywind cost of NOK 2 billion [42] (€200 million or €6667/kW). Therefore, model cost predictions are considered reasonable. The durations for the activities simulated are compared with the schedule published by [26] in Table 7. In general, good agreement was obtained between the modelled and published figures, with a slight over prediction of the time taken for turbine and cable installation.

The standard deviation of installation costs is €989,390 with a standard error of the mean of €31,287.

Table 6

Validation case study - CAPEX.

	Installation model results	Published Hywind data
Dry CAPEX¹	€109 m	
Anchor installation	€4 m	
Turbine assembly, towing & hook-up	€8.6 m	
Cabling	€12 m	Breakdown unavailable
Additional installation costs	€52 m	
Project management, construction insurance & contingency	€19 m	
Total installation costs	€95.6 m	
Total CAPEX	€204.6 m	€200 m

¹ Includes development and asset costs on and offshore.

Table 7

Validation case study – installation duration.

Installation Activity	Simulated	Published data
Anchors (3 per turbine = 15)	42 days	~42 days
Turbines (5)	72 days	~70 days
Inter-array cabling	26 days	~70 days
Export cabling	47 days	
Total duration	187 days	182 days

3. FOW case study

This section presents a case study of a 1GW floating wind farm in the Celtic Sea. This is a theoretical OW farm at a representative potential site. Fig. 2 provides a visual representation. It is not based on any current projects for development but was selected due to the large number of potential future FOW arrays that are proposed/under investigation in the Celtic Sea (e.g. the Emerald, Blackwater, Myrddin, Llywelyn projects etc.). A key aim of this paper was to model next generation FOW arrays (larger turbines and large-scale farms) and at sites beyond the existing FOW demonstration/early commercial projects, primarily focused on the North Sea.

The theoretical OW farm is commissioned in 2035 and consists of 83×12 MW turbines. These are installed on a semi-submersible steel floating substructure with a catenary chain mooring system of three lines secured with three pre-installed drag embedment anchors. It should be noted that a detailed geotechnical assessment and verification of the mooring design is outside the scope of this paper. This mooring system was chosen as it is the most common and appropriate for most seabed soil conditions. The assembly takes place at the quayside and the full structure is then towed to site where it is connected to the anchors. It is assumed that it takes 36 h to pre-install the anchors for each turbine; 23 h to assemble the turbine and platform; 6 h to transfer the floating platform to the water at the quayside; 12 h to attach the moorings to the anchors and connect the platform at site; and an additional 12 h for the dry-mate connection to the inter-array cabling. A key assumption is the maximum Hs restriction for towing, which has been set to 3 m Hs and 16 m/s wind speed. This is higher than the Hywind case-study and the limits suggested by [44]. However, [45] found that that 5 m Hs was the maximum wave height for the allowable towing condition of two submerged floating offshore wind turbine concepts. Therefore, 3 m Hs is considered feasible, particularly assuming that greater stability has been achieved in FOW substructure design in the future. It is assumed that the farm has two 500 MW substations which are pre-installed on its substructure and floated to site in the same manner as the turbines. Cable laying is done by pre-trenching and simultaneous lay and burial using a cable plough. Cable lengths are estimated based on an assumed basic site layout.

The turbine cost of €13.3 million is based on the figure given in [33]. A cost of €15.2 million is assumed for the substructure based on the assumptions outlined in Table 8. These were devised from discussions with industry but are not representative of a specific design.

The substation costs are based on [18], while cabling costs are estimated from [33]. Details of the costs and other model inputs are given in Table 9.

Cork is set as the staging port for installation operations. The vessels and associated rates applied are outlined in Table 10.

4. Results

4.1. Case study results

The average total CAPEX for this study is €3492/kW. A breakdown of results is presented in Table 11.

Over 1000 Monte Carlo simulations, results ranged from €3.468–€3.489 billion with 94% of occurrences falling in the region of

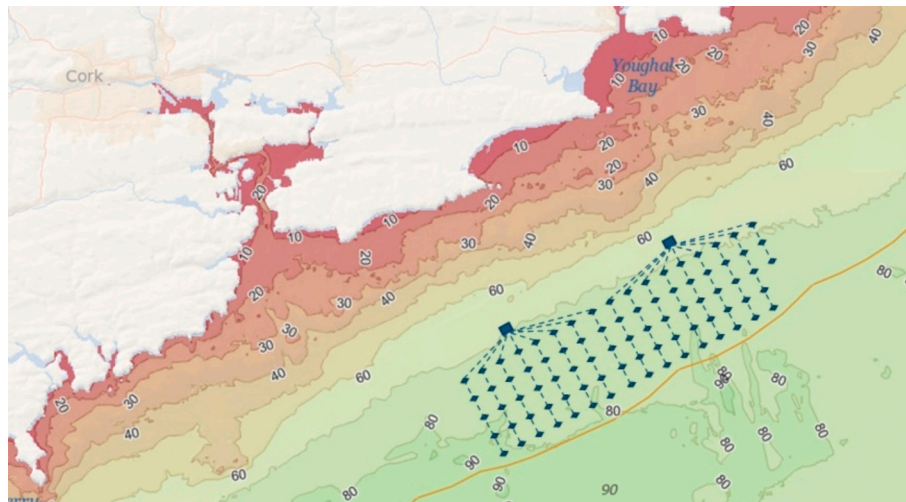


Fig. 2. Visual representation of theoretical case study [43].

Table 8

Substructure, moorings and anchor cost estimates – generic steel semi-submersible.

	Item	Cost	Source
Substructure materials and manufacturing	Steel consumption (tonnes)	3180 t	
	Steel cost (€/tonnes)	€1 k	[18]
	Manufacturing complexity factor (%)	200%	[18]
	Manufacturing cost (€/tonnes)	€2 k	
	Outfitting cost (% of material and manufacturing cost)	10%	
	Contingency (% of material and manufacturing cost)	25%	
	Total production cost per substructure	€12.9 m	
Anchors	Cost of drag-embedment anchor (€)	€342 k	[18]
Mooring lines	Cost of chain mooring lines (€)	€2 m	
Total (€)		€15.2 m	

€3.472–3.485 billion (Fig. 3).

The breakdown of the activity durations of the scenarios modelled are presented in Table 12.

Considering the installation cost alone (€485,011/MW), results are in line with €431,800/MW quote for a semi-submersible platform in [19]. [47] estimates a CAPEX of \$5264/kW (€4973/kW²) for a 600 MW FOW farm (8 MW turbine) in 2019 but a reduction to \$3456/kW (€3265/kW³) for a 600 MW farm in 2032 considering a larger turbine (15 MW) and learning rates resulting in approximately 34% savings. Therefore, the Celtic Sea FOW CAPEX estimate of €3492/kW for a 2035 project is considered reasonable. However, it is interesting to note that it is quite low compared with the Hywind Scotland figure of €6667/kW. The studies are compared in Table 13 to identify the key variations between results:

There is not a significant variation between the Dry CAPEX since similar assumptions were made. However, there is a reduction per kW in the substructure where the Hywind concept was assumed to cost €12.6 m per platform for a 6 MW turbine while the Celtic Sea case study cost €15.6 m per platform for a 12 MW turbine. For cabling, Hywind used 33 kV at €148 k/km throughout while The Celtic Sea study used 66 kV at €221 k/km and 220 kV at €754 k/km for inter-array and export cabling

Table 9

FOW case study.

Item	Input
Site	Celtic Sea
Location	South coast of Ireland
Capacity	996 MW
No. of turbines	83
Water depth	80 m
Staging port	Cork, Ireland
Distance from port	22 km
Wind data	Wind_meteo_2_Europe_station 47,215 (Copernicus Climate Change C3S programme [35])
Wave data	Data point 254,222; ECMWF ERA5 Reanalysis Dataset [36]
Turbine	12 MW [46]
Turbine cost	€13.3 m
Turbine installation	Pre-installed on substructure
Substructure details	Semi-submersible (steel) and catenary chain mooring system with 3 lines
Substructure cost	€15.2 m
Installation method	Turbine preinstalled on substructure and floated to site.
Vessel	2 × 2 tugs
Seabed preparation	3 drag embedment anchors per turbine
Seabed prep vessel	AHTS vessel
Substation	2 × 500 MW on semi-submersible platform
Substation cost	€161.7 m
Installation method	Floated to site
Vessel	AHTS and 2 tugs
Inter-array cabling (IAC) rating	66 kV
IAC length	204 km
IAC cost per km	€221 k/km
Installation method	Plough burial
IAC vessel	Cable-laying vessel
Export cable (EC) rating	4 × 220 kV
EC length	125 km
EC cost per km	€754 k/km
Installation method	Plough burial
EC vessel	Cable-laying vessel
Development, onshore substation & ancillary works	€199 m [33]
Offshore logistics & operations base	€7 m [33]
PM	10% of total installation costs
Insurance & contingency	9% of total CAPEX

respectively.

For installation, there is a significant reduction in costs with Hywind costing €3187/kW and the Celtic Sea study at €487/kW. PM,

² Based on current exchange rates of \$1 = €0.94

³ Based on current exchange rates of \$1 = €0.94

Table 10
Celtic sea case study: vessels.

Activity	Vessel name /type	Mobilisation cost	Daily charter rate
Anchor transport and installation	AHTS	€180 k	€90 k
Towing of preassembled structure (Stord to site)	2 tugs	€60 k	€30 k
Export and inter array cable installation	Cable-laying vessel	€300 k	€150 k
Substations	AHTS & 2 tugs	€252 k	€110 k

Table 11
Celtic sea case study – CAPEX.

Dry CAPEX	€2,993,224,937
Anchor installation	€21,016,630
Turbine assembly, towing & hook-up	€13,141,714
Offshore cable installation	€106,620,420
Offshore substation installation	€57,561
Offshore logistics management & base	€7,187,085
Onshore substation construction & cable installation	€33,171,163
PM, construction insurance & contingency	€303,817,213
Total installation costs	€485,011,788
Total CAPEX	€3,478,236,724
Cost per kW	€3492/kW
Standard deviation	€3,666,331
Standard error of the mean	€115,940

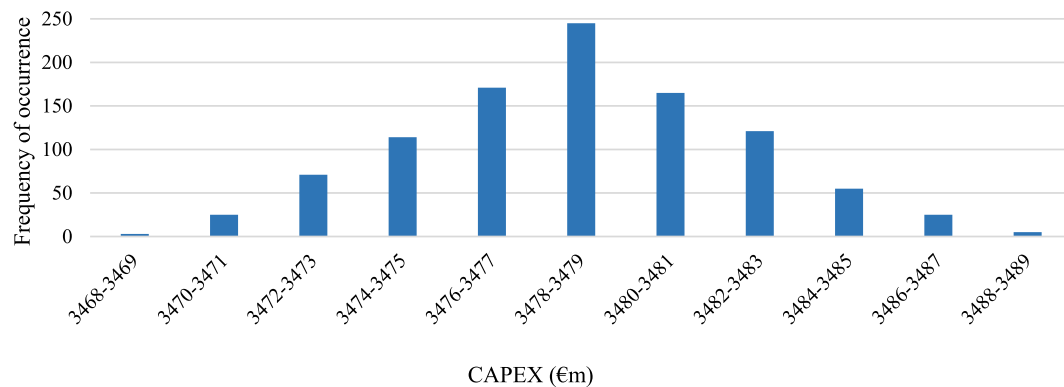


Fig. 3. Histogram of CAPEX results.

Table 12
Celtic sea case study – installation durations.

Installation	Durations – total (months)
Anchors (3 per turbine)	3.65
Turbines	6.06
Substation and substructures	0.27
Inter-array cabling	12.76
Export cabling	9.25
Total duration	28.11

construction insurance and contingency are calculated proportionately while the substation installation is not a significant addition to the Celtic Sea cost. Key differences between the studies are the significant additional installation costs assumed for the Hywind study (outlined in Table 5). It is also important to note the distance from installation port is a lot further for the Hywind study (490 km) compared to the Celtic Sea study (22 km), which would add to the time and cost of installation. Durations (e.g. for anchor installation and turbine hook-up) were reduced while weather limitations were increased (e.g. to 3 m Hs and 16 m/s wind speed for turbine tow-out) for the Celtic Sea case-study. This

reflects assumed improvements in the platform design and stability as well as experience in undertaking activities repeatedly for a large-scale FOW farm in 2035 for the Celtic Sea study. This also led to reduced durations and costs to install anchors and turbines as outlined in Table 13. Cabling is cheaper per kW for the Celtic Sea case-study due to economies of scale when comparing the amount of cabling required between farm sizes i.e. 50 km for 30 MW versus 329 km for 996 MW leading to a ratio of 1.67:0.33. However, cable installation it is more expensive per km at €324 k/km versus €243 k/km in the Hywind scenario. This makes more sense when viewed alongside durations as the Celtic Sea export cabling took 68% longer to install despite an increase in weather limitations from 2 m Hs to 3 m Hs from the Hywind case study. The additional duration is due to the timing of the export cable installation. Installation for the Hywind farm generally took place between April and October of a single year, with export cabling occurring c. June–August. For the Celtic Sea study (which also commenced installation in April of a given year), export cabling generally occurred primarily during winter months between October to June. This led to more delays and the additional time and costs per km.

In general, the additional costs for the Hywind project make sense as it is a demonstration farm and costs should be significantly higher. This is illustrated in the figures for Hywind Tampen, where the 88 MW project investment forecast was NOK 7.4 billion, or €7116/kW.⁴ This is a decrease of 35% per installed MW from Hywind Scotland when adjusted for price developments since 2016/2017 [48]. The Celtic Sea study attempted to represent some of the main differences and key savings between a demonstration and full-scale commercial deployment. It

incorporated assumptions to represent learning and experience that would occur by the time a 1GW FOW array is installed, specifically operation duration reduction and weather limit increases. There were also some economies of scale in terms of the CAPEX costs and the cable installation cost for a 1GW farm as described above. This phenomenon is further explored in section 4.3. However, further reductions could also be applied e.g. additional learning rates to further reduce platform costs. The operation duration reductions and weather restrictions are also very uncertain assumptions. These aspects are further examined in section 4.2.

4.2. Sensitivity analysis

This section presents additional modelling, conducted to test key scenario assumptions and their impact on costs. Analysis will also demonstrate the benefits of using simulation to identify which assumptions have the highest impact on results, and quantifying where the

⁴ Based on current exchange rates of NOK1 = €0.085

Table 13
Hywind and Celtic sea study comparison.

		Unit	Hywind	Celtic Sea
Cost	Dry CAPEX	€/kW	€3633	€3005
	Turbine	€/kW	1105.71	1105.71
	Substructure	€/kW	2111.61	1268.42
	Inter-array cabling	€/kW	74.03	45.26
	Export cabling	€/kW	172.73	94.64
	Substation	€/kW	0.00	324.70
	Development and Balance of plant - onshore substation and works	€/kW	169.73	166.52
	Total Installation	€/kW	€3187	€487
	Anchor installation	€/kW	€133	€21
	Turbine assembly, towing & hook-up	€/kW	€287	€13
	Additional installation costs	€/kW	€1733	~
	Cable installation	€/kW	€400	€107
	On and offshore substation and logistics management	€/kW	~	€41
	PM, construction insurance and contingency	€/kW	€633	€305
	Anchor installation	days/anchor	2.80	0.45
Duration	Turbine assembly, towing & hook-up	days/turbine	14.4	2.22
	Inter-array cabling	days/km	1.73	1.90
	Export cabling	days/km	1.34	2.25
	Substation and substructure	days	~	8.34
		total	~	8.34

most savings can be found.

4.2.1. Learning rates

Platform costs are estimated and are uncertain given the lack of validated information for a platform design and the associated production costs. In addition, it is likely that costs would decrease for mass production, fabrication optimisation and experience. This phenomenon is often illustrated by applying a learning rate and [49] asserts that learning rates of 10–32% could be achieved for renewable energy technologies, assuming a doubling of the quantity would result in a 20% learning rate. Using these assumptions, sensitivity analysis was undertaken to illustrate the impact of varying platform costs. Table 14 presents the potential reductions due to learning rates of up to 32% for a 1GW farm. This suggests that savings of up to 12% could be reasonably assumed due to a learning curve.

4.2.2. Weather restrictions

A key bottleneck for installation is finding sufficient weather windows to complete activities in the shortest possible time, thereby reducing costs. This is dependent on the characteristics of the selected site but also the weather limits assumed for each operation (the maximum significant wave height or wind speed at which an operation can be undertaken). While general assumptions can be made based on discussions with industry this can be dictated by a number of factors such as the stability of the device during tow-out and the experience of the personnel undertaking the operation. Operational weather limits

Table 14
Impact of learning rates.

Learning rate %	No. of turbines	Platform cost (million)	Total CAPEX (€/kW)	% Saving
0%	5	€15	€3492	0%
10%	10	€14	€3365	−4%
20%	20	€12	€3239	−7%
30%	40	€11	€3112	−11%
32%	80	€10	€3086	−12%

may only really be determined based on real-life experience. Sensitivity analysis was performed to assess the impact of increasing/decreasing the wind speed and Hs limits by 30% in 10% increments for all installation activities. For example, an operation with a Hs limit of 3 m was increased to 3.2 m; 3.4 m and 3.6 m respectively. Fig. 4 illustrates the impact in terms of the installation and overall CAPEX cost per kW.

This suggests that a 30% increase in wind and wave weather restrictions could reduce installation costs by almost 3% but a reduction in the maximum Hs or wind speed could increase costs by 15%. This illustrates the significant potential impact of these assumptions.

4.2.3. Operation durations

Results demonstrate that cable installation takes the most time and costs. Therefore, analysis was done to examine the impact of increasing and decreasing cable installation durations, again by 30% in 10% increments. Fig. 5 illustrates the results showing only a 1.6% reduction in installation costs when durations are reduced by 30%, but an almost 5% increase in costs when durations go up by 30%.

Table 15 illustrates the impact of varying installation durations for cable; substructure & turbine; and substation activities. This suggests that within the 30% range of uncertainty applied, variation in the substation installation durations will not have a significant impact on results. Reducing durations will have more of an impact than increasing them for the substructure and turbine installation activities.

4.3. Farm capacity and size

The current scenario assumes installation would occur in 2035. However, it is likely that smaller FOW farms will be installed prior to this date. Therefore, sensitivity analysis was conducted to examine the impact of farm size on the project CAPEX. Results are illustrated in Fig. 6 and demonstrate the expected economies of scale when moving from a 150 MW to 1GW farm. While costs and installation of substructures/turbines will grow proportionally; costs and installation of the substation and cabling will not increase in the same way, reducing the total installation time per megawatt.

It would also be interesting to examine the impact on installation and CAPEX of increasing turbine size while fixing farm capacity i.e. fewer turbines. This would require assessing the requirements of larger-scale turbines >12 MW so is outside the scope of this paper. However, it would help address whether larger turbines have a purely positive impact on costs or will require different installation strategies, equipment and lead to additional unexpected expenses. For example, with growing turbine capacity and platform size, mooring lines and anchors will also grow and could require larger AHTV vessels to install that are not currently available on the market.

5. Discussion

To place the results in context, a simplified LCoE analysis was undertaken using the LCoE formula presented in the [33] study. However, it is important to note that a range of LCoE methods could be applied, as detailed in [50]. A Net Capacity Factor (NCF) of 57.1% was applied based on the average found for Hywind Scotland up to May 2022 [51]. NCF considers any losses due to downtime and was applied to consider the farm energy production. The CAPEX is based on the figure in section 4.1. Annual operational and decommissioning costs were taken from the NREL study for a 2032 farm [47]. Energy and annual operational costs were discounted using a real rate⁵ of 3.9%. This results in an LCoE estimate of €58.72/MWh, which is in line with industry expectations for FOW costs 2025–2050 (Fig. 7). These industry estimates are based on DNV figures in [52].

While the above suggests that the Celtic Sea FOW case study results

⁵ Considering inflation at 2.5%

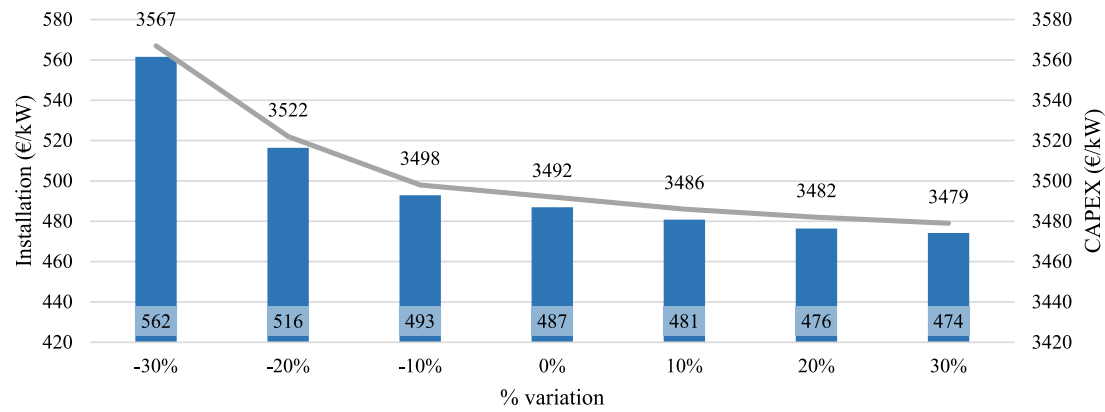


Fig. 4. Impact of varying weather restrictions on CAPEX and installation costs (€/kW).

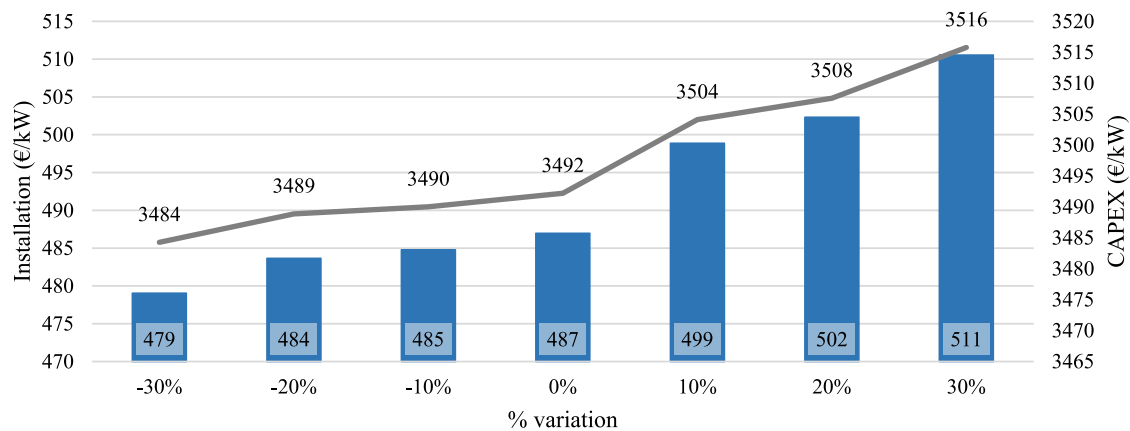


Fig. 5. Impact of cable installation durations on CAPEX and installation costs (€/kW).

Table 15

Impact of varying installation durations on installation costs.

% variation in operation durations	% increase/decrease in installation costs		
	Cabling	Substructure & turbine	Substation
-30%	-1.6%	-2.6%	-0.2%
-20%	-0.7%	-1.9%	0.0%
-10%	-0.4%	-0.3%	0.0%
+10%	2.4%	0.4%	0.1%
+20%	3.2%	0.6%	0.0%
+30%	4.8%	0.8%	0.1%

are reasonable, it is very difficult to assign a single LCoE estimate, considering the the lack of reliable data for FOW resulting in considerable uncertainty in the assumptions. As outlined in [53], LCoE targets for FOW by 2030 range from €53–76/MWh. Even this range will be dependent on the expected 7GW of FOW being installed in Europe, creating a mature supply-chain and developing the experience required to de-risk projects and bring down costs. Therefore, an LCoE range that incorporates uncertain assumptions would be more accurate. The paper demonstrated the sensitivity of results to key assumptions: learning rates; weather restrictions; and operation durations. In addition, the offshore wind industry is facing challenges due to the highest inflation rates seen in 30 years, increasing uncertainty in current cost estimates. To account for these the paper applies the maximum learning rate (12% reduction in turbine CAPEX); + - 30% variations in the weather

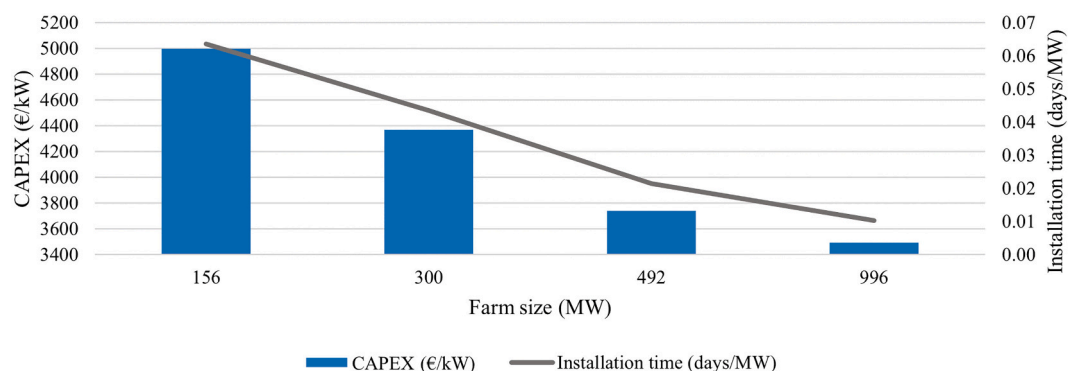


Fig. 6. Impact of farm capacity.

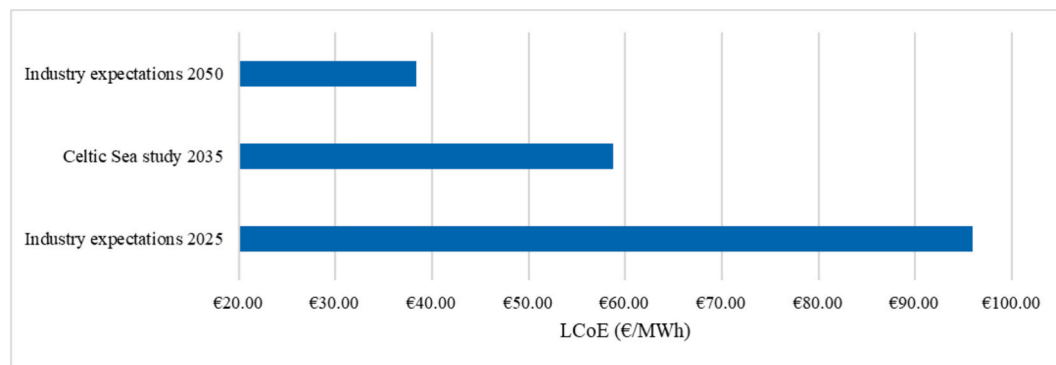


Fig. 7. LCoE estimate summary.

restrictions and installation operation durations outlined in 4.2.3 and 4.2.4; and adding 10% to dry-CAPEX to signify an uncertainty in cost estimates. A final LCoE range of €52.3–64.59/MWh is estimated for this case-study.

Further real-world experience of installing FOW is needed to better validate the inputs used to model the installation processes and increase confidence in the results. However, this paper can serve as a basis for further research for the installation of large-scale FOW farms and globally. It should be noted that this case-study has been based on a shallow water site (80 m); therefore, future work could focus on medium (2–300 m) and deep-water (700–1000 m) sites to provide more representative studies for other regions e.g. the deep waters of the US west coast and Japan. The water depth would ultimately impact the CAPEX assumptions in terms of the platform and mooring designs e.g. a TLP or spar buoy may be more applicable for these regions and this would have implications for the installation strategy.

It should be noted for future research that some key challenges for large-scale FOW installation will include:

- the lack of adequate ports with deep waters to facilitate float out of FOW turbines >10 MW;
- the development of grid infrastructure to facilitate integration of offshore wind energy production;
- potential supply-chain issues such as the supply of steel chain most prevalently used for mooring lines;
- the lack of suitable vessels due to shortages in the exiting market and requirements for larger vessels to accommodate large FOW turbines, particularly their heavier moorings and anchors.

6. Conclusion

This paper presents an installation model, which simulates the activities associated with the construction of an OW farm. The model was successfully validated for FOW scenarios by modelling the Hywind Scotland wind farm and comparing the results to published data. It was then applied to a hypothetical 1GW case study in the Celtic Sea to provide a reference study for future research into the next generation of large-scale FOW. The resulting CAPEX estimate of €3492/kW is in line with industry expectations for a commercial farm commissioned in 2035. Several sensitivity studies were conducted to test the key assumptions and their impact on costs including applying a learning rate to reduce platform costs; varying farm size to demonstrate economies of scale; weather operational limits and installation activity durations to show their potential impact on results. This sensitivity analysis demonstrates how the installation model can be used to identify key bottlenecks and optimise a strategy. Finally, the paper places results in context by modelling the LCoE for this next generation FOW farm. Estimates incorporate the key uncertain assumptions identified in the sensitivity studies as well as the current high rates of inflation, resulting

in an LCoE range of €52.3–64.59/MWh, which is in line with industry expectations.

This paper aims to provide a well-defined case study for researchers to build upon, developing their own studies in other regions and with different technologies. Future studies should consider turbines >15 MW as industry continues to move towards larger capacities, and address whether a reduced number of higher capacity turbines would also reduce costs or have unexpected implications for the installation strategy. It would also be interesting to look in more detail at CAPEX of different platforms and mooring configurations if more detailed reference designs become available. For example, the IEA Task 49 are developing a set of reference FOW farm designs. Future farms might also consider innovations such as shared moorings and anchors. The tool is currently undergoing further development to better simulate port and quayside activities e.g. wet storage, which will be required for the large-scale roll out of FOW farms. In addition, accurate modelling of export cable installation would require consideration of metocean conditions along the route or at representative points, while the model currently only considers the site conditions. External challenges for the installation of FOW farms should be considered in future studies such as the available supply-chain for component supply and the impact this could have on the flow of installation activities. Vessel availability will also be a major consideration with rates increasing due to demand as FOW competes with other industries, and could considerably impact the CAPEX.

CRediT authorship contribution statement

Fiona Devoy McAuliffe: Writing – review & editing, Writing – original draft, Validation, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Frances M. Judge:** Writing – review & editing, Validation, Investigation, Formal analysis. **Jimmy Murphy:** Writing – review & editing, Supervision, Formal analysis.

Declaration of competing interest

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

Data availability

I have provided all the available data within the paper

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