Wild Atlantic Wind Farms, Are They Cost-Effective?

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***Abstract* — Ireland has ambitious targets to deliver 7GW of offshore wind capacity by 2030. Although to date, only the 25MW Arklow Bank wind project is installed; there are significant offshore wind resources that could potentially power the entirety of Ireland's electricity needs and export to mainland Europe. Initially development will focus on delivering fixed OW farms on the East Coast in the Irish Sea. However, the substantial resources in the Celtic Sea (South Coast) and Atlantic Ocean (West Coast) could be exploited by FLOW.**

Wind farms moving into deeper waters are often further from shore, in harsher conditions. Sites in the Atlantic Ocean will have particularly dynamic metocean conditions. A year-round accessibility of only 26% has been calculated at a representative location off the West Coast c.71km from shore, assuming a 6-hour window where the Significant Wave Height (Hs) is <= 2m. [1] Standard accessibility challenges will be exacerbated with the new problems of deploying a nascent FLOW technology with no convergence on logistical best practices/standards. Therefore, developers must consider whether the substantial potential resource of Atlantic Ocean sites can outweight the difficulties they will encounter when deploying and operating FLOW farms. The purpose of this paper is to determine with Atlantic FLOW can be cost-effective.

The paper models the installation and Operation and Maintenance (O&M) of a theoretical 1GW FLOW farm off the West Coast of Ireland. It applies a suite of logistics and financial models designed to simulate activities across an hourly time-series of metocean data. Outputs include estimates of costs, broken down for each life-cycle stage, and energy production. These will be used to calculate a final Levelised Cost of Energy (LCoE) estimate for the case-study, which will be validated against FLOW farm cost estimates in the literature. A series of sensitivity studies test the case-study assumptions and the impact of potential improvements to operational weather restrictions, reliability and reductions in CAPEX. Analysis identifies the key bottlenecks to achieving high production and low costs. Finally, the paper presents a worst, medium and best-case LCoE estimate to determine whether and/or under what conditions (e.g. reliability, accessibility, O&M strategy) the potential of the wild Atlantic winds can be harnessed.

The paper concludes that the best-case LCoE at the Atlantic Ocean is an average of €81.58/MWh for a deployment of 2030-2035. Taking industry targets of €53-76/MWh as a baseline for achieving cost-effectiveness, the paper finds that this site is not competitive with the current assumptions and the nascent state of the Irish Offshore Wind industry. However, there are a number of potential areas for improvement that could provide further LCoE reductions and enable exploitation of the Atlantic Ocean wind resources. These include, increasing site accessibility and improving availability from 91%-95% and applying further CAPEX and OPEX cost reductions in line with cost-reduction pathway methodologies in the current literature. Further work is needed to determine how these could be achieved at this site.

Keywords—floating offshore wind, levelised cost of energy, logistics

I. Introduction

Fixed Offshore Wind (OW) has become cost-competitive with traditional sources of power generation. The industry is now seeking to further optimise production and reduce costs, but also expand into sites in deeper waters, requiring innovating floating substructure technology. Floating Offshore Wind (FLOW) farms are currently still at demonstration/early commercial scale with the largest array at 50MW (Kincardine, Scotland). However, the technology is maturing rapidly and it is expected that up to 30GW of FLOW could be installed globally by 2030.

Ireland has ambitious targets to deliver 7GW of offshore wind capacity by 2030. Although to date, only the 25MW Arklow Bank wind project is installed; there are significant offshore wind resources that could potentially power the entirety of Ireland's electricity needs and export to mainland Europe. Initially development will focus on delivering fixed OW farms on the East Coast in the Irish Sea. However, the substantial resources in the Celtic Sea (South Coast) and Atlantic Ocean (West Coast) could be exploited by FLOW. There is approximately 3.3GW of FLOW farm projects proposed e.g. the Moneypoint FLOW project. The Shannon Foynes port has a strategic vision to become a leading international FLOW hub by 2041 and anticipates up to 30GW of FLOW could be installed by 2050.

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Wind farms moving into deeper waters are often further from shore, in harsher conditions. While higher wind speeds bring the promise of higher production and revenue, higher wave heights particularly pose significant challenges to accessing the site for installation and mainteneance. This can increase the time required to complete activities, thereby increasing costs. Conditions can also lead to more downtime, waiting for a weather window to get offshore and repair failures, resulting in lower power production and revenue. Sites in the Atlantic Ocean will have particularly dynamic metocean conditions. A year-round accessibility of only 26% has been calculated at a representative location off the West Coast c.71km from shore, assuming a 6-hour window where the Significant Wave Height (Hs) is <= 2m. [1] Adding to accessibility challenges, there will also be new problems associated with deploying a nascent FLOW technology with no convergence on logistical best practices/standards. Therefore, developers must consider whether the substantial potential resource of Atlantic Ocean sites can outweight the difficulties they will encounter when deploying and operating FLOW farms.

The purpose of this paper is to determine whether Atlantic FLOW can be cost-effective. To achieve this, the paper will model a theoretical 1GW FLOW farm off the West Coast of Ireland (Section II.A). The paper will model the installation; Operation and Maintenance (O&M); and decommissioning strategies defined for the case-study (Section III.A). It will apply a suite of logistics and financial models (Section II.B), designed to simulate offshore wind farm activities across an hourly time-series of metocean data. Outputs include estimates of costs, broken down for each life-cycle stage, and energy production. These will be used to calculate the Levelised Cost of Energy (LCoE) (Section II.C) for the case-study. Results will be validated against existing FLOW farm cost estimates (Section IV.A). A series of sensitivity studies (Section IV.B) will test the case-study assumptions and the impact of potential improvements. The paper will determine an optimal logistics scenario and present a worst, medium and best case LCoE estimate to determine whether and/or under what conditions (e.g. reliability, accessibility, O&M strategy) the potential of the wild Atlantic winds can be harnessed. Analysis will identify the key bottlenecks to achieving high production and low costs, identifying where the scenario can be further optimised (Section IV.C).

II. Methodology

A. Reference Farm

The 1GW FLOW farm will comprise 66 x 15MW turbines using the NREL turbine power curve on a steel semi-submersible substructure with 6 mooring lines and drag-embedment anchors. The farm is estimated to comprise an area of approximately 151km^2 and will be located off the Coast of Clare (Fig. 1) at the coordinates of 52.7N, 10.2W (from site centre). The site water depth is 90-105m and the seabed character is coarse substrate, sand and muddy sand. The farm is 45km from the onshore Grid Connection at Moneypoint (400 kV S/S) and 77km from the Shannon Foynes port. The paper assumes that development has occurred at Shannon Foynes to facilitate either installation and/or O&M activities and that the onshore grid infrastructure is sufficient to support this level of OW development.

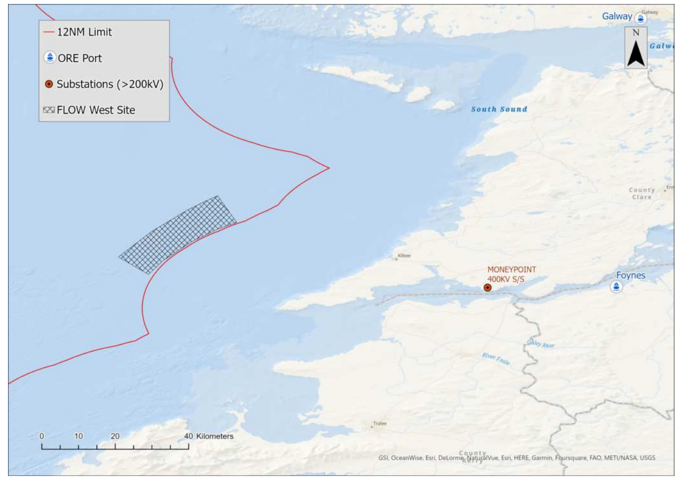

Figure 1 Case-study Farm location (Image courtesy of Ross O'Connell)

B. Metocean Data

27 years (1992-2018) of hourly wind speed (m/s) and significant wave height (Hs) data were gathered at representative coordinates 52.75N, 10.25W for wind and 52.7N, 10.2W for wave. The wind data was provided by the Copernicus Climate Change C3S programme, 2020 and includes hindcasted data and forecast data based on future trends. The wave data is from the ECMWF ERA5 Reanalysis dataset (ERA5-ECMWF, Accessed 2020) and is a mixture of modelled data and satellite observations. The average wind speed at hub height (150m) at this site is 10.6m/s and the average Hs is 2.66m.

C. Models

The paper uses a suite of logistics and financial modelling tools to simulate the project-specific installation and O&M of the case-study farm, determining energy production and costs. These outputs feed into a cashflow model to calculate the LCoE. The installation model (Matlab) and financial cashflow model (excel) were developed by UCC as modules of the LEANWIND Financial Model [2]. The O&M model, hereafter referred to as the ORE logistics tool (Matlab), was developed by UCC to consider the O&M schedule, costs and energy production for any Offshore Renewable Energy (ORE) farm, wind, wave or tidal.

The installation model considers the offshore deployment activities of the farm including installation of the electrical infrastructure (export cable, inter-array cable, offshore substation – foundation and topside); anchors and mooring lines; and substructures and turbines. Based on the user inputs, the model simulates these activities across an hourly time-series of Metocean Data for a number of iterations. It uses Monte Carlo simulation, varying the time-series for each iteration using a "bootstrap" method; randomly selecting years from the original data provided to compile a different time-series for each iteration. This methodology is applied to consider the uncertainty of weather and its potential impact on

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installation activities and costs. Installation inputs for this case-study are described in Section III.

Like the installation tool, the ORE logistics model also uses Monte Carlo simulation, varying the weather data as well as the failures that occur to account for their stochastic nature and the impact on production and costs. The tool varies the time-series in the same way as the installation model, using the "bootstrap" method described above. For failures, the user can input an annual failure rate for farm components e.g. gearbox, mooring lines, blade, anchor etc. Using a normal distribution curve with a standard deviation of 10%, the model randomly determines the first Mean Time To Fail (MTTF) for each component for each iteration. As each failure is addressed with Corrective Maintenance (CM), the tool will apply the same procedure to determine the next MTTF for that component. The ORE logistics tool can also apply Preventive Maintenance (PM) scenarios e.g. regular schedule maintenance or half-life overhauls. However, users should be aware that the current version of the model does not consider any improvement in component health when PM is undertaken, and CM is always prioritised over PM. O&M inputs for this case-study are described in Section III.

The cashflow model takes inputs from the installation and ORE logistics tools as well as the project Discount Rate (DR) to determine the LCoE using the methodology in Section II.D.

D. *Levelised Cost of Energy*

The LCoE is the most commonly used Key Performance Indicator (KPI) in energy project financial assessment. It refers to the average net present cost of electricity generation over a project lifetime and is essentially the breakeven price at which capital costs are recovered. LCoE can be a useful metric when comparing different projects. The paper will use this metric to determine whether large-scale commercial FLOW farms off the west coast of Ireland are cost-effective. The paper will consider a result cost-effective if it reaches/exceeds LCoE targets for similar projects.

When using the LCoE, it is important to specify exactly what is being included/excluded to ensure you are comparing like-with-like or explain the differences between results. This paper applies the following equation (1) based on [3].

$$LCoE = \frac{\sum_{k=1}^{n} \frac{I^k + A^k}{(1+r)^k}}{\sum_{k=1}^{n} \frac{E^k}{(1+r)^k}} \tag{1}$$

It should be noted that this LCoE calculation does not consider debt loan repayments or tax. However, the simple LCoE calculation is the most commonly used to provide an initial and indicative financial assessment of a project. It essentially considers the total lifetime costs (using a pre-tax project cash flow) divided by the total energy produced. These are discounted to determine the Net Present Value (NPV) by a DR. The DR selected will have a significant impact on the LCoE; however, as described in [3], the DR is very project-specific, dependent on a number of assumptions as well as the audience and can be very subjective. Therefore, this paper will apply a range of DRs (5%; 6.5%, 8% and 10%) to the case-study to demonstrate the impact this has on results. The selected range is based on the estimated range of 8.25-9.5% determined for OW in Ireland according to a 2017 Renewable Energy survey launched to gauge investors' perception of cost of capitals [4]. It is likely that this only considers fixed OW; therefore, the maximum DR was increased to 10% to consider the less advanced FLOW technology. It is also likely that the DR will drop significantly as FLOW becomes more established, and investor confidence increases, reducing the cost of financing etc. Therefore, lower DRs of 6.5 and 5% are also considered and are in line with [5] expectations of a real DR of 5.5% c. 2030. A real DR means that values are modelled and quoted in real terms and have already adjusted for inflation.

III. Scenario Inputs

This section outlines the inputs and assumptions applied to the base case-study.

A. *Project summary*

TABLE I. PROJECT SUMMARY

Project Summary		
Item	***Unit***	***Value***
Project lifetime	years	25
Base	text	Shannon-Foynes
Distance to base	km	77
Grid connection	text	Moneypoint (400kV S/S)
Distance to grid connection	km	45
Turbine capacity	MW	15 [6]
Turbine hub height	m	150
Rotor diameter	m	240
Substructure	text	Semi-submersible (steel) with 6-line catenary mooring system and drag embedded anchors
Farm Capacity	MW	990
Start Date	year	2035
Inter-array cabling	kV	66
Inter-array cable length (total)	km	141
Export cabling	kV	220
Number of export cables	number	3
Export cable length (total)	km	162
Offshore substation capacity	GW	1

The farm layout includes 16 strings of 4 turbines and 1 string of 2 turbines, each connected to the offshore substation. The inter-array cabling length was calculated assuming a distance of 1.68km between each row of turbines (7 x rotor diameter) plus cabling to the substations and 20% for contingency. The export cable length was calculated assuming the distance to grid connection plus 20% contingency for connections, to go around exclusion zones etc. Due to the water depth, it is assumed that the offshore substation will also use a floating substructure similar to the turbines i.e. steel semi-submersible.

B. Fixed Capital Expenditure (CAPEX)

Table II outlines the fixed CAPEX which include the turbine, substructure (including mooring lines and anchors), electrical system (onshore and offshore), project development costs and "soft" costs, as well as offshore logistics management during the installation phase. This paper will model the variable CAPEX (i.e. installation of offshore elements) and combine with fixed costs to estimate the total CAPEX.

TABLE II. CAPEX - FIXED

Item	*Unit*	*Value*	*Reference*
Turbine	€	17,953,800	[7] [a]
Substructure	€	21,939,727	See Table III
Inter-array cable	€/km	220,000	Based on discussions with industry
Export cable	€/km	754,000	
Offshore substation	€	323,400,000	[8]
Onshore substation and grid connection	€	33,171,163	[9]
Development costs	€	82,882,800	[7] [a]
Soft costs	€	939,945,600	[7] [b]
Offshore logistics management	€	3,869,969	[9]

a. Converted from dollar $1 = €0.92

b. Lease price, plant commissioning, decommissioning bond, contingency, construction financing, insurance during construction.

Given the early commercial status of FLOW, the industry are still converging on optimal substructure designs. Therefore, substructure costs are relatively unknown and highly dependent on the design (e.g. barge, semi-submersible, TLP) and project specific elements (e.g. water depth, seabed type). In addition, the largest FLOW turbine deployed to date is the 9.5MW turbines in the Kincardine project. The expected increase in turbine capacity will also impact the substructure design and costs, but it is not known how and to what extent. This paper estimates the cost of this theoretical FLOW turbine substructure considering:

- the cost of raw materials (steel assuming €1250/t);
- manufacturing costs based on the level of complexity (in this case 200% of the total material costs in line with [8] assumptions for the WindFloat concept);
- and outfitting and contingency costs as a percentage (35%) of a) and b) (based on discussions with industry).

This methodology is applied in Table III to determine the cost of a single substructure and mooring system.

TABLE III. SUBSTRUCTURE COST

Item	*Unit*	*Value*
Substructure material	text	steel
Material weight	t/MW	250
Steel cost	€/t	1250
Material cost	€	4,687,500
Manufacturing complexity	%	200
Manufacturing cost	€	9,375,000
Outfitting and contingency	%	35
Total substructure cost	€	**18,984,375**
Mooring system	text	Catenary
Anchor type	text	Drag embedment
Mooring line and anchor number	number	6
Anchor cost (total) [10]	€	**1,143,052**
Line type	text	Steel chain
Line cost	€/m	350
Line length per line	m	863 [11]
Mooring line cost (total)	€	**1,812,300**
Total substructure, mooring and anchor system cost	**€**	**21,939,727**

C. Installation

The installation method for this case-study assumes activities will begin with the export cables and pre-installation of the anchors and moorings for the substation substructure and the turbines. The substation topside and turbines will then be pre-installed on the substructure at port and floated to site where they are connected to the mooring lines. The laying and connecting of inter-array cables begins once 10 turbines have been installed. Installation activities begin in May of the first year of the time-series, making best use of the summer season. However, once initiated, work will continue 24/7 until all elements have been installed. The following outlines the installation method for each offshore element.

a) Export cable installation

Installation methods and assumptions for the export and inter-array cabling are based on [12]. For export cabling, three cables are installed. For each section, installation starts at landfall with loading the cable on to the Cable Laying Vessel (CLV) (6hrs) and vessel preparation or positioning/depositioning will take 0.5hrs at the start and end of work for each section. Firstly, the cable is pulled to the onshore connection using a winch wire at a rate of 5km/hr

(0.8hrs). The cable is then pulled-in, terminated and tested at the onshore base before offshore installation begins (11hrs). At the vessel, the cable is lowered to the sea floor (1hr) and a simultaneous lay and burial method (using a plough to create the trench) begins at a rate of 5hrs per km (250hrs for each export cable). The cable is pulled in at the substation, terminated and tested (11hrs). It is assumed that the CLV can carry the full length of each cable and the model does not currently consider the vessel returning to port except to begin installation of the next section/export cable. This assumes the CLV has a cable carousel of 5,000t e.g. the Nexus CLV [13], and that the export cable weighs approximately 90tonnes/km [9] i.e. approximately 4860t each.

b) Inter-array cable installation

The inter-array cabling will be loaded at port (6hrs). The CLV vessel will transit to site, position, prepare cable and lower it to the seafloor (2.5hrs). For each section (cable between turbines, approximately 2km), the cable will be pulled-in to the turbine, terminated and tested (11hrs), followed by simultaneous lay and burial at a rate of 5hrs per km i.e. 10hrs per 2km section. This continues until all inter-array cabling is installed. The vessel depositions from the site (0.5hrs) and returns to shore. As above, it is assumed that the CLV can carry the full length of cable and the model does not currently consider the vessel returning to port during installation. This again assumes the CLV has a cable carousel of 5,000t e.g. the Nexus CLV [13], and that the inter-array cable weighs 18.5tonnes/km for 800mm cross section [14] i.e. the total cable weight is 2,614t. It should be noted that the CLV for inter-array cabling is likely to be smaller and less expensive than the one used for export cabling (see Table IV).

c) Anchors and mooring lines

It is assumed that the anchor and mooring lines will be pre-installed for the turbines. Based on discussions with industry and engineering judgment, the case-study assumes that it will take 12 hours to install each anchor and mooring line i.e. 72 hours in total for each turbine using an Anchor Handling Support Vessel (AHSV) (see Table IV).

d) Turbines and substructure

The substructure is loaded into the water at quayside (6hrs) and the turbine is preinstalled on the substructure (23hrs). These are floated to site using 2 tug-boats where it takes 24 hours to connect to the preinstalled mooring lines.

e) Offshore substation

This is constructed in a similar way to c) and d) with preinstallation of anchors and mooring lines (72hrs); preinstallation of the substation on the substructure at port (8hrs); load into the water (6hrs); and float out to site where it is connected to the mooring lines (24hrs). However, it is assumed that an ASHV and 2 tugs are required for float-out given the significant size of this structure.

f) Weather restrictions

The success of all offshore activities relies on good weather conditions. For each installation activity a maximum wind speed (m/s) and significant wave height (Hs) (m) have been defined. In order to complete an activity, the installation model must find a weather window where conditions are below these restrictions. For the majority of installation operations, the case-study applies a maximum wind speed and Hs of 16m/s and 2m respectively. This is based on experience and discussions with industry. The key exception is a lower Hs of 1.5m required for the pre-installation of anchor and moorings of the turbines. It is assumed that very calm conditions are required to facilitate the precision work involved. For vessels, most activities (e.g. transit to site; positioning; depositioning) are restricted to 2m Hs and 16m/s wind speed. However, it is assumed that the AHTV can transit to site in Hs up to 2.5m and the CLV can transit to site in Hs up to 3m. This is because they are not considered to be transporting delicate cargo and the CLV is likely to be substantially larger than the other vessels, thereby able to navigate in harsher conditions. Restrictions for positioning of the export cable CLV have been set to 4m Hs and 20m/s wind speed as this will occur at port and should not be restricted considering site conditions.

Table IV provides an overview of the installation vessels and costs applied in the case-study.

TABLE IV. INSTALLATION VESSELS

	CLV1	***CLV2***	***AHSV***	***2 tugs***	***AHTS and 2 tugs***
Farm Element	Export cabling	Inter-array cabling	Anchors and moorings	Substructures and turbines	Substation
Number	1	1	3	3	1
Vessel speed (knots)	3	3	10	5	3
Day rate (€)	175,000	120,000	96,000	70,000	166,000
Mobilisation cost (€)[c]	437,500	300,000	240,000	175,000	415,000
Positioning/ depositioning (hrs)	1.3/0.5	2.5/0.5	0.33/0.16	0.33/0.16	0.33/0.16
Fuel consumption (tonnes/hr)[d]	0.41	0.41	0.34	0.34	0.68

c. Mobilisation costs are applied once a season/year
d. Fuel costs are calculated assuming €1000 per tonne

D. O&M

The O&M scenario is derived from [15]. That paper uses a different O&M tool, developed to look at failure rates and O&M strategies in more detail. However, both tools use the same case-study assumptions for their baseline scenarios and produced similar results, validating the outcomes through inter-model comparison.

The baseline case-study only applies CM when a failure occurs, with no scheduled PM. A mixture of Crew Transfer Vessels (CTV), Service Operations Vessels (SOV), AHSV and tug vessels are deployed to address different minor and major failures. While most maintenance occurs offshore, major blade and major gearbox failures require turbines to be towed to shore.

The average annual failure rate per turbine is 7.65. Components considered include the floating substructure, mooring lines and anchors, turbine tower, the pitch system, gearbox, generator, turbine electrical system, blades, yaw system and some cabling. However, the wider farm electrical system including the substation have not been considered in analysis.

[15] should be consulted for more detail of the O&M baseline case-study inputs and assumptions. One notable difference between this paper and [15] is the inclusion of operations costs (fixed Operational Expenditure (OPEX)) in this paper. This is necessary to consider all cost components of an LCoE. A figure of €45,084,600 per annum is applied based on [7] and scaled up to a 1GW farm.

IV. RESULTS

This section presents the results of the baseline case-study (scenario 1.0); sensitivity analysis, applied to consider improvements in technology and logistics due to learning and offshore experience; and an optimised low, medium and high LCoE estimate for a FLOW farm off the West Coast of Ireland. Results will determine whether they are in line with expectations for similar FLOW farms, thereby indicating whether Atlantic wind farms can be cost-effective.

A. Scenario 1.0

Table V presents results for scenario 1.0. For comparison, results of the NREL 2021 study of a 600MW (75 x 8MW) FLOW farm off the coast of California [7] and ORE Catapult's study of the WaveHub 32MW (4 x 8MW) FLOW farm in the Celtic Sea [16] are also included. The [7] study uses 2018 figures and [16] assumes a commissioning date of 2023/2024. Therefore, they are considered suitable for comparison with the baseline case-study assuming it has a start date of 2023-2025.

TABLE V. BASE CASE-STUDY 1.0 RESULTS

Scenario	1.0	WaveHub[16] [e]	NREL [7] [f]
CAPEX (€/kW)	4,518	4,717	5,131
OPEX (€/kW/yr)	102	135	109
Energy Production (MWh/MW/yr)	3,558	unknown	3,336
Net Capacity factor (%)	41	unknown	38
Availability (%)	80%	unknown	n/a
Discount Rate (%)	10%	unknown [g]	3.4% [h]
LCoE (€/MWh)	163.40	138.99	122.36

e. Figures have been converted from pounds to euro using an exchange rate of £1 = €1.13

f. Figures have been converted from dollar to euro using an exchange rate of $1=€0.92

g. Quoted as 2012 pre-tax real terms

h. The study applies a nominal and real after-tax Weighted Average Capital Cost (WAAC) DR of 5.29% and 2.72%. This equates to a pre-tax real WAAC DR of 3.4%

When reviewing figures some key differences in the scenarios will impact results. Firstly, scenario 1.0 examines a much larger farm (1GW) and turbine capacity (15MW) compared to [7] and [16] (600MW and 32MW respectively; and 8MW turbines). Therefore, some economies of scale are expected. Indeed, CAPEX is substantially lower than the NREL study (19%) and slightly lower than [16] (4.4%). TABLE VI provides a detailed CAPEX breakdown, identifying where the primary differences occur.

TABLE VI. TOTAL CAPEX BREAKDOWN (€/KW)

Scenario	1.0	WaveHub [16]	NREL [7]
Turbine	1197	1130	1197
Development and project management	84	107	84
Substructure and moorings	1463	1679	1922
Electrical infrastructure	515	23.72	687
Assembly and installation	311	377	291
Soft costs	949	970	949

Since the turbine; development; and soft costs are based on [7], these are the same for scenario 1.0. These estimates are also relatively in line with [16] costs. The main differences ore that the WaveHub farm turbine cost per kW is c. 6% lower. This suggests that either the case-study and [7] cost figures are too pessimistic or the WaveHub farm figures are optimistic. While soft costs are only 2% higher for [16] compared with scenario 1.0 and [7]; development costs are 27% higher. This may be due to the smaller pre-commercial farm scale of [16], resulting in higher development costs per kW.

The key differentiating figures between scenario 1.0 and [7] are substructure and moorings; electrical infrastructure; and assembly and installation costs. These deviations suggest the following:

- The lower substructure and moorings estimate may indicate an overly optimistic assessment in scenario 1.0, although the [16] estimate suggests that [7] is quite high. However, given the lack of data available, it is very difficult to validate these.
- The larger farm capacity with fewer, larger turbines in scenario 1.0 is likely to result in economies of scale and lower electrical infrastructure costs. Therefore, this is in line with expectations since it is lower than the 600MW farm in [7]. However, it should be noted that the electrical infrastructure costs for [16] are extremely low as these only consider array cabling. Due to the smaller scale, it is likely that no substation was considered in this scenario or onshore grid infrastructure, resulting in a much lower cost.
- It may be assumed that installation costs would reduce per kW with fewer, larger turbines for a larger farm capacity; however, higher figures for 1.0 versus [7] are not unexpected given the more dynamic site conditions on at the Atlantic site. This will be further discussed below. The higher installation costs in [16] are likely due to the pre-early commercial farm scale.

It should be noted that the NREL site represents first leases in California where the average wind speed is 8.24m/s at hub height (102m). [16] is based on the WaveHub test site 16km off the north coast of Cornwall in approximately 50m water depths and assume an average wind speed of 8m/s. This is substantially lower than the West Coast Atlantic site (average of 10.6m/s at a hub height of 150m). If availability could be improved, the Atlantic site would have considerably more potential energy production and a lower overall LCoE. However, based on the current assessment, the Atlantic case-study LCoE is substantially higher than the [7] estimate, despite having a lower CAPEX and higher energy production. This may be significnatly due to the DR applied. Table VI demonstrates the impact the DR will have on results. This range was selected based on the methodology outlined in Section II.D.

TABLE VII. IMPACT OF DISCOUNT RATE

DR	5%	6.5%	8%	10%
LCoE (€MWh)	116.58	129.78	143.76	163.40

When applying a lower DR (5%), closer to the [7] (3.4%) input, the LCoE (€116.58/MWh) for the Atlantic case-study looks quite cost-competitive. This is based on the current estimates for FLOW, which range from €150-250/MWh for farms installed between 2020-2025 [17]. However, there is a lack of infrastructure (e.g. port, grid), supply-chain, clear marine spatial planning and consenting processes with adequate support schemes available for FLOW in Ireland.

To date, Ireland only has one fixed offshore wind farm (Arklow Bank). As part of the new Maritime Area Consenting regime, 7 projects were granted MACs and can apply for the first Offshore Renewable Energy Support Scheme (ORESS), which opened in 2022. ORESS is expected to deliver 2.5GW of energy with farms beginning construction c. 2026. However, these will only include fixed offshore wind farms on the east coast where the pressure is already on Eirgrid to upgrade the grid so that it can facilitate up to 4GW of offshore wind by 2024. Timelines and plans for the inclusion of a FLOW preference in the subsequent ORESS auctions are unclear. There are currently no ports on the island of Ireland that could facilitate the deployment of FLOW. Therefore, there is an urgent need for investment and development. However, there are no concrete plans beyond policy/strategy documents e.g. Shannon Foynes. These bottlenecks will not increase investor confidence or reduce the cost of capital. Therefore, it is not feasible that a 1GW farm could be deployed off the West Coast in the immediate future. Therefore, a DR of 10% seems to provide a more realistic, even optimistic LCoE (€163.40) as such a project would be high-risk and would incur high costs of capital to implement. While this LCoE is within the expected range [17], such a project is not considered possible in this time frame. The next section re-evaluates scenario 1.0 assuming a deployment date of 2030-2035. This is considered the earliest possible timeframe for construction of a large-scale commerical FLOW farm off the West Coast of Ireland.

LCoE targets for FLOW by 2030 range from €53-76/MWh, provided the expected 7GW of FLOW are installed in Europe [18]. In line with these targets, [16] estimate an LCoE of €72/MWh considering a 500MW FLOW farm (using 15MW turbines) 60km west of Cornwall in the Celtic Sea (water depth 100m) in 2030. In order to achieve cost-competitive figures, substantial improvements are needed to the Atlantic case-study. Section IV. B examines the potential areas of improvements due to learning and experience from other FLOW deployments, which could ultiamtely reduce future costs and increase production.

B. *Potential Improvements*

It is likely that by the time a commerical large-scale FLOW farm is deployed, there will have been streamlining and the development of best practises for installation logistics and O&M operations, as well as improved technology reliability, reducing the likelihood of failures and maximising revenue. A number of sensitivity studies were run to consider the impact of potential improvements in the installation and O&M phases including:

Installation

- Scenario 1.1: Installation operational weather restrictions were increased to a minimum of 2m Hs and 25m/s wind speed. This assumes that increased vessel capabilities and/or experience from previous smaller projects and the repetition of operations would allow installation activities to be completed at higher limits.
- Scenario 1.2: Building on scenario 1.1, this study reduces installation operation durations by 20% assuming increased experience and the development of standardised best practices will optimise procedures.

O&M

- Scenario 1.3: O&M vessel weather restrictions were also increased for the same reasons outlined above. The baseline case-study sets a maximum Hs of 1.75m for CTV operations; 2.5m for SOVs; and 1.5m for AHSV. This scenarios increases these limits to 2m; 3m and 2m respectively.
- Scenario 1.4: Building on study 1.3, this study reduces annual failure rates by 20%, assuming that technology will improve and increase reliability.
- Scenario 1.5: Building on study 1.4, this study reduces O&M operation durations by 20% assuming increased experience and the development of standardised best practices will optimise procedures.

Results are presented in Table VIII. These all apply a DR of 10%.

TABLE VIII. SENSITIVITY ANALYSIS – POTENTIAL IMPROVEMENTS

Scenario no.	CAPEX (€/kW)	OPEX (€/kW/yr)	Energy production (MWh/MW/yr)	Availability (%)	LCoE (€/MWh)
1.0	4,518	101.88	3,558	80%	163.40
1.1	4,397	101.88	3,558	80%	159.68
1.2	4,339	101.88	3,558	80%	157.91
1.3	4,518	102.33	3,868	87%	151.50

1.4	4,518	87.17	3,999	90%	142
1.5	4,518	86.10	4,071	91%	139.51

These studies indicate that increased availability and the resulting power production will have the strongest impact on LCoE as scenarios 1.3-1.5 collectively reduced the base case-study LCoE by 14.62%. It may be noted that OPEX actually initially increases from scenario 1.0 to 1.3. This is because site accessibility has improved due to higher operational weather restrictions, increasing the amount of O&M that can occur. However, OPEX reduces in 1.4-1.5 due to the reduction in failure rates i.e. less O&M required (-15.49%). In all cases, the availability (+13.75%) and energy production increases (+14.42%). Improvements in installation (1.1-1.2) reduced the LCoE by 3.36%.

In addition to improved site logistics and technology reliability, it may be assumed that there will be reductions in the fixed CAPEX e.g. cost of turbines, substructures and electrical infrastructure due to large-scale manufacturing and streamlined procedures/designs. Learning rates of 5 and 10% (based on figures quoted in [5]) have been applied to the fixed CAPEX of scenario 1.0. These result in LCoEs (using a 10% DR) of €156.84 and €150.47 respectively. This is a significant saving in the LCoE (-8%).

C. *Optimised Scenarios*

Based on the sensitivity analysis (IV.B), this section presents a worst-case, medium and best-case scenario of the Atlantic case-study assuming deployment in C. 2030-2035. These are defined as follows:

- Scenario 1.6: Applying a 5% learning rate to reduce fixed CAPEX.
- Scenario 1.7: A learning rate of 5% reduces fixed CAPEX and a combination of scenario 1.1 and 1.3 increases the installation and O&M operational weather restrictions.
- Scenario 1.8: A learning rate of 10% reduces fixed CAPEX and a combination of scenario 1.2 and 1.5 increases weather restrictions; reduces installation and O&M operation durations; and reduces failure rates.

It is assumed for all three scenarios that increased investor confidence and reduced cost of capital will bring the DR down to 8% by 2030. However, given the uncertainty of this assumption and the deployment year range of 2030-2035; results considering rates of 6.5, 5% and 3% are also presented (Table IX).

TABLE IX. LCoE (€/MWh) – Optimised Scenarios

Scenario no.	DR 8%	DR 6.5%	DR 5%	DR 3%
1.6	**138.25**	124.95	112.39	96.95
1.7	124.98	112.88	101.5	87.58
1.8	108.42	97.77	87.73	**75.43**

The best-case scenario (1.8, 3% DR) is just within targets of €53-76/MWh [18]. However, to achieve a real DR of 3%, this would require similar assumptions made in [7] i.e. a real post-tax Weighted Average Cost of Capital (WACC) of 2.72% (3.4%, pre-tax). This is quite low for a project in Ireland starting c. 2030-2035, given the bottlenecks identified in section IV.A. While industry remains confident that it is possible to have FLOW farms in Irish waters by 2030, the issues suggest an LCoE range of €75.43-87.73/MWh with an average of €81.58 is more realistic for a time frame of 2030-2035. This would be outside the industry targets, implying the West Coast is not cost-competitive. However, it should be noted that the scenario assumptions are still quite conservative. [7] present a cost-reduction pathway for FLOW farms from 2018-2030 figures. This suggests that an increase in energy production (+28%); reduction in OPEX (-53%) and reduction in CAPEX (36%) are possible and would result in an estimated LCoE of €54.59/MWh in 2030. However, the levels of savings that can be achieved will be very project and site specific.

The higher LCoE estimates for the Atlantic case-study are not surprising considering the dynamic and challenging weather conditions in the Atlantic Ocean. A maximum availability of 91% achieved in scenario 1.8. Typically, an availability of 95% is expected for fixed OW farms [19] and an annual availability of 93-94% was achieved by the 25MW Windfloat Atlantic project, the first ever semi-submersible FLOW farm [20]. Based on section IV.B sensitivity analysis, improved availability and energy production are likely to have a significant impact on LCoE; therefore, this is a key area for further optimisation. Reducing OPEX and CAPEX will also help improve the cost-competitiveness at this site. However, it should be noted that the impact of reducing CAPEX will be significantly more valuable than OPEX. While the previous "rule of thumb" was that OPEX was 30% of the cost of energy; ORE Catapult and NREL have increasingly found this figure to be closer to 15% for fixed offshore wind [21]. The relative influence of CAPEX has thereby increased accordingly.

V. Conclusion

This paper has examined the potential LCoE of a 1GW FLOW farm in the Atlantic Ocean off the West Coast of Ireland. A farm considering present-day figures (c. 2023-2025) proves to be very expensive €163.40/MWh. This assumes a high DR of 10% to account for the current state of OW development in Ireland, which would lead to low investor confidence and high costs of capital. Given the unlikely deployment of FLOW farms in Ireland prior to 2030, the paper re-considers the scenario assuming construction c. 2030-2035. The paper applies a series of improvements to the baseline scenario (1.0) to account for potential learning and advancements by the deployment of a 1GW FLOW farm in 2030. These include:

- optimising installation and O&M logistics assuming experience will provide standardised best practise and streamlined procedures.
- increasing reliability assuming technological improvements.

- applying CAPEX reductions, assuming these would occur due to economies of scale and learning rates.

Results are presented including a range of DR from 3-8% to consider the uncertainty of this parameter and the Irish OW industry landscape. The paper concludes that an LCoE of €81.58/MWh is a reasonable assumption for this site and within this timeline. However, the average exceeds industry targets (€53-76/MWh). With the current assumptions, the Atlantic site has not yet definitively proven cost-effective (lower than or equal to targets for similar projects). However, the paper identifies key areas for potential optimisation that could provide further savings and/or increase production. These include improving site accessibility and farm availability and further reducing CAPEX and OPEX (although the priority should be the latter). Further future work is needed to determine how these improvements could be achieved at the Atlantic Ocean site.

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