A Work Project, presented as part of the requirements for the Award of a Master's degree in

Economics from the Nova School of Business and Economics.

Assessing the location-specific Levelised Cost of Energy for Offshore Wind: The case of the western coast of Portugal

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17/05/2024

Abstract

This study assesses the Levelised Cost of Energy (LCOE) for floating offshore wind (FOW) installations along the western coast of Portugal, focusing on the proposed areas within the ”Plano de Alocação de Energias Renováveis (PAER)”. Key findings indicate that the northern regions present lower LCOE values, due to better wind resources and favourable site conditions. The study also highlights how variables like the costs of capital and adequate project development timeline of the total capacity goal can significantly affect the overall LCOE. Moreover, the potential external effects are also discussed to assess the social dimension. The potential for investment retention and industrialisation development is also addressed.

Keywords: Floating Offshore Wind Energy, Levelised Cost of Energy, Marine Spatial Planning, Ecosystem Services, Renewable Energy, Portugal.

This work used infrastructure and resources funded by Fundação para a Ciência e a Tecnologia (UID/ECO/00124/2013, UID/ECO/00124/2019 and Social Sciences DataLab, Project 22209), POR Lisboa (LISBOA-01-0145-FEDER-007722 and Social Sciences DataLab, Project 22209) and POR Norte (Social Sciences DataLab, Project 22209).

1 Introduction

As part of Portugal's ongoing revision of its energy and climate strategy, the PNEC (*"Plano Nacional de Energia e Clima"*) 2030 [1] outlines specific targets for the offshore wind sector. By 2030, it aims at installing 2GW of offshore wind capacity and allocate seabed rights for an additional 10GW (PNEC 2023).

In support of this initiative, the XXIII Portuguese government established a working group tasked with the planning and operationalisation of renewable energy power plants that utilise oceanic sources. This group is responsible for analysing and making recommendations on various topics: which sea areas should be allocated for development; the auction model; the sequence of area development; and the integration with land-based grid infrastructure; among other duties. Their preliminary findings have contributed to the drafting of the Proposal for the Allocation Plan for Offshore Renewable Energy (PAER), which is currently under public consultation, with conclusions yet to be drawn (Group 2023) (DGRM 2023b).

The ambitious goal of developing 10GW is then segmented into seven main areas in the working group report, as detailed in Table 2 and seen in the Appendix. Notably, in the PAER, Sines has been consolidated into a single area with a potential capacity of 1.5GW, aligning with the overall 10GW target. Additionally, Viana do Castelo has undergone minor modifications, resulting in a slight increase in area and power capacity in the northern sector and a corresponding reduction in the southern one. These adjustments are illustrated in Figure 1 seen in the Appendix. Although these areas are not exclusively designated for Floating Offshore Wind (FOW), the characteristics of the sites and the stage of development of FOW technology in comparison to other ocean based renewable sources make it a leading candidate for development.

For the purpose of this study, the focus will be on those areas identified by the (Group 2023), which theoretically, based on available wind resources should be more competitive and easier to develop. They present as well less social and environmental risks and therefore should be the most suitable for the development of FOW[2]. These areas are *Viana do Castelo*, *Leixões*, and

[1] PNEC mentioned and discussed along this study refers to the draft document of June 2023. A new version is expected to be published during 2024.

[2] As can be seen in the Appendix in the Ericeira analysis section this area is actually the one with the lowest LCOE, nevertheless is not the most attractive overall (more on this is the Appendix).

Figueira da Foz, which together account for 80% of the total planned capacity.

First and foremost, it is crucial to acknowledge the complexity and the vast array of decisions involved in FOW projects, as well as how those decisions impact both private and social outcomes. A diagram illustrating some of these interactions and how they might affect the final results is shown in Figure 3 in the Appendix. Not all interactions detailed in the diagram are modelled in this study; thus, further research will be required.

The primary objective of this work is to develop a private economic model that calculates the LCOE for the designated areas. This model will examine how various variables and options influence that cost. Additionally, the study will also draw some considerations regarding net social costs and the ambitious 10GW target established in the PNEC.

1.1 Floating Offshore Wind Global Perspective

Taking a step back is important to understand where the FOW industry currently stands. Unlike its counterpart, fixed bottom offshore wind, the floating wind sector is still in the nascent stages of implementing fully commercial projects. Portugal has been at the forefront of the market. It pioneered the industry in 2011 with the construction of the WindFloat 1 prototype. This steel semi-submersible, designed by Principle Power, supported a Vestas 2MW wind turbine and operated from 2011 to 2016. Building on this, the WindFloat Atlantic project emerged, featuring three 8.4MW turbines totalling a 25MW capacity and using the same floating platform technology (WindPlus 2024). Other noteworthy projects include the *Kincardine* 50MW project and the 30MW *Les Éoliennes Flottantes du Golfe du Lion*, with the former operational since 2021 and the latter still under construction, both employing technology similar to WindFloat Atlantic (Power 2024b) (Power 2024a). Additionally, the industry experienced other technological developments through the TetraSpar Demonstrator and DemoSATH prototypes deployment in Norway and Spain, respectively, which utilise tension leg platforms and concrete semi-submersibles technologies (RWE 2024); the 88MW Hywind Tampen project in Norway that uses concrete spar floating technology (Equinor 2024) and the Provence Grand Large project further diversifies the technological base with a 24MW capacity utilising an SBM tension leg platform (Memija 2024). Prototype projects continue to develop across the US and Asia as well,

highlighting a global interest in advancing floating platform technologies (Edwards 2023).

The Global Wind Energy Council (GWEC) reported that the total commissioned capacity for Floating Offshore Wind (FOW) was approximately 235MW in 2024, with Europe accounting for 88% of it (GWEC 2024). GWEC's market intelligence also anticipates that FOW will not achieve full commercialisation until 2030, despite forecasting an installed capacity of 10.9GW by that year. In spite of this, FOW is still deemed crucial in achieving a Paris-compliant net-zero scenario by 2050.

The GWEC's new installation outlook for 2022 to 2032 estimates that FOW will achieve a 26.2GW capacity, representing about 6% of the total offshore wind capacity by 2032. Installations per year are depicted in Figure 2 seen in the Appendix. Notably, GWEC's projection for Portugal suggests an addition of 750MW to the existing 25MW by 2030, which falls significantly short of the 2GW target.

2 Methodology

To develop an LCOE model, this study incorporates several assumptions and functions based on the literature. This section provides a succinct description of these elements. It is divided in three main sections: Annual energy production (AEP); Costs; Net cash flow (NCF) and LCOE.

2.1 AEP Model

The complete scheme mapping the whole AEP calculation is shown in Figure 5 in the Appendix. The AEP model has three main steps: the first is the creation of a turbine layout with a wind and bathymetry value assigned for each turbine, the second is the simulation of annual wind speed distribution that each turbine will experience and the final is the calculation of the AEP using a estimated power curve.

2.1.1 Wind Speed and Bathymetry Data

To accurately compute the LCOE for any offshore wind project, it is crucial to obtain precise location specific variables, specifically wind and bathymetry data for the targeted area. Typi-

cally, for initial assessments projects utilise average values for these variables while on later stages it is expected that these estimates are improved using more precise measures obtained by the use of LiDARs, geological sureveys data, among others to properly assess the project areas. The accuracy of using average values can vary depending on the site-specific fluctuations which can be a risk to be considered.

In this study, due to the interest in analyzing how sensitive the results are to the specific area, to each potential turbine position is assigned its own wind speed and bathymetry. To achieve this, a fine grid with a resolution of 0.0001 degrees was created using *QGIS*. For each grid point, a wind value at the height of 10 meters and the corresponding bathymetry are estimated, based on data from the Global Wind Atlas wind and bathymetry maps.(World Bank Group 2023)

2.1.2 Turbine Layout and Data Matching

The layout of turbines within the wind farm is determined based on a geographic area defined by a polygon that is created by using the coordinates available in (DGRM 2023a) for each planned area, the wind farm's capacity, and the physical dimensions of the turbines, particularly the rotor diameter which influences the spacing between turbines. The standard spacing between turbines is then of eight and a half rotor diameters in both north-south and east-west directions, aligning with discussions found in the literature, such as in (Barthelmie 2010). While there is potential for optimising this spacing based on site-specific conditions like prevailing wind directions, this optimisation is not included in the current analysis. Turbine spacing is also accounted for in the calculation of wake losses, as detailed in (Nielsen 2022).

Each turbine's position is matched with the nearest wind speed and bathymetry data from the grid created as mentioned in section 2.1.1. It is important to note that the model works with GPS coordinates to facilitate this matching process.

2.1.3 Power Law and Wind Speed Distribution Simulation

To accurately simulate annual wind speed distributions and avoid overestimating the expected Annual Energy Production (AEP) using merely average wind speeds, industry standard practices usually employ an Weibull distribution to simulate annual wind speed distributions,

as described in equation 1. (Tizgui 2019)

More precisely, this distribution often assumes the form of a Rayleigh function, where the shape factor (k) is set to 2, as detailed in equation 2. This formulation can be adapted to incorporate the mean wind speed (v_m), as shown in equation 3.

$$f_W(w) = \left(\frac{k}{c}\right)\left(\frac{w}{c}\right)^{k-1} \exp\left(-\left(\frac{w}{c}\right)^{k}\right), \tag{1}$$

$$f(v) = \frac{2v}{c^2} \exp\left(-\left(\frac{v}{c}\right)^{2}\right), \tag{2}$$

$$f_r(v) = \frac{\pi v}{2v_m^2} \exp\left(-\frac{\pi}{4}\left(\frac{v}{v_m}\right)^{2}\right) \tag{3}$$

In this study, the actual distribution of wind speeds is determined by using a Monte Carlo simulation, as outlined in equation 5. This simulation computes a series of wind speeds (n), assuming a shape factor (k) of 1.9 based on values from the Global Wind Atlas for Portugal (World Bank Group 2023). The scale factor (c) for each wind speed is derived from the mean wind speed at hub height, which is calculated using the power law (equation 4) applied to values for a height a 10m, determined as discussed in sections 2.1.1 and 2.1.2. The power law coefficient, α, is set at a standard value of 0.11, according to industry standards (Hsu 1994). This is just another way of computing an Weibull distribution.

$$V = V_0 \left(\frac{HubHeight}{Height_0}\right)^{\alpha} \tag{4}$$

$$V = c\,(-\ln(1-r))^{\frac{1}{k}}, \quad \text{where} \quad c = \frac{2v_{\text{hubheight}}}{\sqrt{\pi}} \tag{5}$$

The wind speeds generated by a Monte Carlo simulation are categorised into bins with 0.5 m/s intervals, and the percentage distribution for each bin is calculated. To assess the simulation's accuracy, the deviation from the assumed average wind speed is measured. The expected accuracy range for the calculated mean wind speed is within $\pm 0.25\%$ of the assumed mean. An illustration of the simulated wind speed distributions, which will be applied to each turbine, is provided in Figure 12 in the Appendix.

2.1.4 Power Curve and AEP Calculation

To calculate the Annual Energy Production (AEP) of the wind farm, it is essential to define the power curve of the wind turbine. In this study, the power curve is derived using the DTU

pywake generic wind turbine library. Given three key variables: rotor diameter, nominal power, and turbulence intensity the library model defines the WTG power curve. The library model also uses other factors such as air density and generator losses which are set to default values, as detailed in (DTU 2018). The turbulence intensity is specifically calibrated for a 15MW turbine with a 240m rotor to align with the IEA 15MW reference turbine to a value of 0.025 (NREL 2020) (See Figure 13 in the Appendix).

Once the turbine power curve is set, the AEP calculation process involves the following steps: Transform wind data to the selected hub height using the power law; For each turbine, conduct wind simulations as described in section 2.1.3; Match the wind speed distribution bins for each turbine and calculate the product of the number of hours in each bin with the power curve values at the respective velocities; Add the energy produced from each bin to derive the AEP for each turbine.

To this gross AEP fixed losses, including assumed values for turbine downtime[3], electrical losses, and other potential losses, set at 8%, 3%, and 1% respectively, are added, following conservative estimates based on (Horn 2019) and (Kucuksari 2019). Wake losses are also added and calculated based on the number of turbines and turbine spacing according to (Nielsen 2022). The model also calculates the required wind farm area and both the gross and net capacity factors.

2.2 Private Cost Model

This section describes the cost model, which encompasses development (DevEx), capital (CapEx), operation (OpEx), and decommissioning (DecEx) costs. Potential gains from recycling materials at the project's conclusion and the possibility of extending its lifespan are excluded. The model primarily draws from the Floating Offshore Wind Guide by BVGA (BVGA 2023), which simulates a 450MW floating wind farm equipped with 15MW turbines. It also integrates findings from various studies and articles focusing on 15MW turbines, in order to ensure this way a more accurate model for turbines around this rating. Variables which are not obtained from specific references are based on author's knowledge and experience. Tables

[3]Time which the turbine is not able to produce because either is waiting for maintenance or it is in maintenance.

containing the formulas, values and references can be found in the Appendix for each of the chapters in this section as well as the complete mapping diagrams of the model - Figures 6 and 7.

2.2.1 DevEx Costs

On the development costs are included all the expenses related to development and consenting services, all environmental, geological and hydrographical surveys, wind resource and metocean assessments as well as engineering, project management and consulting needed to develop such a project. (BVGA 2023)

These costs are estimated based on BVGA's figures, adjusted by the square root of the ratio of the wind farm's reference capacity and the one being calculated. Therefore, it tries to accounts for fixed costs irrespective of project size and variable costs, such as potentially geological surveys and engineering where project size can impact the DevEx costs.

2.2.2 CapEx for Turbine and BoP Component Procurement

Turbine and Floating Platform Costs - The baseline reference for turbine components and platform costs is derived from the BVGA study (BVGA 2023). An image with the the main components handled by the model can be seen in the Appendix (Figure 14). Cost are scaled linearly to the mass of each component, except for blades, while the mass scaling adheres to scaling laws from the literature:

1. **Blades**: The model follows (Mehta 2024) study, where the rotor mass is scaled based on a defined rotor diameter and rated wind speed. For the cost calculation the Metha study follows NREL's work which underpins the rotor cost, attributing part of the cost to mass increase (60%) and the rest to non-mass-related factors.

$$mass_{\text{rotor}} = mass_{\text{rotor_ref}} \left(\frac{diameter_{\text{rotor}}}{diameter_{\text{ref_rotor}}} \right)^3 \left(\frac{V_{\text{rated}}}{V_{\text{ref_rated}}} \right)^2 \tag{6}$$

$$cost_{\text{rotor}} = 0.6 \times cost_{\text{rotor_ref}} \times \left(\frac{mass_{\text{rotor}}}{mass_{\text{rotor_ref}}} \right) + (1 - 0.6) \times cost_{\text{rotor_ref}} \times \left(\frac{diameter_{\text{rotor}}}{diameter_{\text{ref_rotor}}} \right)^2 \tag{7}$$

2. For the **nacelle** [4] a mass scaling laws is used as defined in (Sergiienko 2022). Nacelle

[4] See Figure 14.

mass is then dependent on the rotor diameter. The mass of the hub is also considered as part of the Nacelle. It is worth noting that the nacelle mass can highly vary for the same turbine capacity and rotor diameter depending on the architecture and technology design of the specific OEM technology.

$$mass_{\text{nacelle}} = \left(\frac{12.3 \times diameter_{\text{rotor}}^{2} + 0.23 \times diameter_{\text{rotor}}^{2.46}}{1000} \right) \tag{8}$$

3. For the **tower** a similar scaling law is used according to (Sergiienko 2022). Based on engineering knowledge and the cited paper and given that we are discussing turbines for floating wind, an increase of 50% in mass is added if the turbine capacity is equal or above $15MW$, due to the possible change in turbine technology when compared to fixed bottom turbines[5].

$$mass_{\text{tower}} = \begin{cases} \frac{12.65 \times diameter_{\text{rotor}}^{2.07}}{1000} \times 1.5, & \text{if turbine rating} \geq 14 \\ \frac{12.65 \times diameter_{\text{rotor}}^{2.07}}{1000}, & \text{otherwise} \end{cases} \tag{9}$$

4. For the **floating platform**, the findings of (Sergiienko 2022) are followed, suggesting that a mass scaling procedure, as described in the equation below, closely approximates reality. However, due to the innovative nature and limited number of existing floating platforms, the number of points from which the scaling laws are derived is relatively small. This limitation impacts the precision of such evaluations, requiring extra caution when interpreting the calculated values.

$$mass_{\text{floater}} = mass_{\text{floater_ref}} \times \left(\frac{mass_{\text{turbine}}}{mass_{\text{turbine_ref}}} \right)^{\frac{1}{3}} \tag{10}$$

These calculations are based on the use of horizontal axis wind turbines and steel semi-submersible platforms, which represent the most advanced technologies currently available for offshore wind applications.

Mooring - Mooring lines anchor the turbine and platform to the seabed. There are two main types of mooring lines: catenary and taut with a third, semi-taut, being a mix of the two. Given that the studied site areas do not exceed depths of 200m, only the catenary option is considered

[5]This happens because the natural frequency of a usual tower that would be built for fixed bottom starts to overlap with wave excitation frequencies, the vibrations caused by this phenomena on the tower might lead to structural issues hence the need to stiffen the tower by increasing the mass.

relevant [6]. The latter type typically incorporates a combination of rope and chain. The end of each line features an anchor, which might be of different types depending on soil type and depth — drag embedment anchors (DEAs), driven piles, suction piles among others (BVGA 2023). To streamline the model, similar to the approach in (Strag 2022), we calculate costs using a general cost per ton for mooring line material and a fixed cost for anchoring, as per (BVGA 2023). This simplification may overlook the impact of anchor type on costs as well as different combinations of rope and chain; however, as soil type is not a variable in the model, this assumption is assumed to be reasonable.

The mooring calculation is structured as follows: The chain's weight per meter is scaled linearly with the mass of the floating platform and turbine set; The length of each mooring line is determined based on a catenary curve, adjusted for the specific bathymetry surrounding each turbine; Costs are computed using a reference cost per ton, then multiplied by the number of mooring lines.

A critical assumption is made regarding the number of mooring lines; while earlier projects utilised a three-line system, it is anticipated that larger turbines will require an increase in the number of mooring lines. For turbines rated above 15 MW, six lines are presumed necessary. A capacity adjustment factor is also applied to the chain weight - assuming more lines but weaker and therefore cheaper. (Campanile 2018)

IACs and Export System - The model calculates the IACs (Intra-Array Cables) and the export system by initially establishing a simple cable layout. It considers the locations of the offshore substations, the cable landing point, and the onshore substation. Turbines aligned along the same latitude are interconnected in a string format, which is then connected to the nearest substation. Substations are uniformly distributed along the easternmost boundary of the study area - placing the substation in shallower water to allow for the possibility of fixed bottom substations. The export cable extends directly from the substations to the land point, and subsequently, to the onshore substation. An illustrative example of this layout is shown in Figure 15 in the Appendix. The total length of the IACs and export cables is then computed. To the total length of the IACs, water depth times a factor of 1.8 is added to account for cable

[6]This is not entirely true since part of *Figueira da Foz* area actually presents depths between 200 and 500m.

lazy-wave configuration.

For the IACs, a cost per kilometre of cable is applied based on the pricing data from (Strag 2022). This cost varies depending on the specific layout of the farm that influence both the size and the length needed. The model does not perform layout optimisation and therefore this considerations are an exclusion of it.

Regarding the export system: the number of substations is determined by evaluating the most cost-effective scenario between using a larger (350MW) or smaller (250MW) export cable. It is assumed that each substation can accommodate two cables. The model selects the optimal cost scenario for number of substations and cable size based on the wind farm's rating. Costs per kilometre for the export cables are calculated based on the characteristics and expenses outlined in (BVGA 2023), with additional costs for both onshore and offshore substations adjusted according to substation capacity and project scale from the same source.

For some analyses, the model excludes the costs associated with export cables and substations when evaluating sensitivities. This allows for the calculation LCOE from the project developer's perspective, since the export system is typically outside the purview of the developer and on the purview of the Transmission System Operator (TSO) (Mora 2019).

2.2.3 CapEx for Installation

To perform the installation calculations, some general assumptions are adopted, particularly regarding weather contingencies. Specifically, a 5% weather contingency for port operations and a 20% contingency for site operations are assumed. Additionally, a 20% cost increase is factored into each operation to cover expenses related to fuel, surveys, and other equipment such as ROVs.

The installation calculation is structured into four primary steps:

Wind Turbine Integration and Port Storage Costs - This step of the model addresses the costs associated with port usage and turbine assembly. The calculation is split into two main components. The first component calculates the required port space based on the (Maness 2017) model. It considers the rotor diameter and the rated capacity of the selected turbines to calculate the area needed for storage. In the calculation is also established a fixed number of turbines and

platforms — twelve — that must be stored at the port at all times. A predetermined price per square meter, as cited from (Strag 2022), is applied for port area usage costs. For turbine integration, the number of available quayside slots is inputted along with the mobilisation and daily rates for the ring crane and harbour tugs. It is estimated that nine days are needed for each turbine integration.

Additionally, this step includes calculations for the inbound transportation of components to the port and the offshore logistics required for all installation processes. These are calculated on a megawatt-hour (MWh) basis, as mentioned in (BVGA 2023).

Mooring Pre-Lay - The mooring laying process generally precedes the towing of the floating platform, with the already integrated turbine, to the installation site. For this task, an Anchor Handling Vessel (AHV) is required. The capacity of the AHV is determined based on the turbine's rating, which then serves to estimate the number of trips needed for the AHVs to complete the mooring pre-lay and account for transit days. For the actual mooring laying, a task time of 50 hours per line is assumed.

IAC and Export System Installation - For the installation of IACs (Inter-Array Cables) and export cables, it is assumed that a CLV (cable laying vessel) will be used. The daily rate for the vessel is aligned with the numbers provided in (BVGA 2023). The vessel's capacities, derived from (Jandenul 2024), which along with typical cable weights from (Scotland 2024) together with the cable lengths, are utilised to calculate the necessary transit days for this activity. Cable laying speeds determine the number of laying days required; for IACs, speeds are sourced from (Devin 2021). For export cables, the speed is assumed to be 80% of the IAC speed to accommodate the larger size and increased handling effort of the export cables.

Additionally, a fixed installation cost is assumed for each offshore substation. For onshore cables, the costs are calculated per kilometre, following the cost references set forth in (BVGA 2023).

Towing and Hook-up - For the towing process, a tug vessel is used. It is assumed to have the same daily rate as the Anchor Handling Vessel (AHV). An assistant tug is also employed, with daily rates specified as in (Urbano 2021). A towing speed guideline is taken from (Crowle 2022). Additionally, a Crew Transfer Vessel (CTV) provides support, with its daily rate based

on (Ramachandran 2021). The task time for the mooring hook-up procedure is derived from (Altuzarra 2022), and additional costs per megawatt for the electric cable pull-in are accounted for as per (BVGA 2023). The calculation also considers the distance between each turbine's position in the layout and the port used for turbine integration.

2.2.4 Other CapEx Costs

In addition to the specific procurement and installation costs, other CAPEX costs are also considered. These relate to insurance, legal, and financing expenses. An overall contingency is additionally factored in. These costs are calculated as a premium on the total CAPEX based on the values in the Appendix.

2.2.5 OpEx

Although the choice of an O&M port can significantly affect the total operational and maintenance costs, the current model handles these aspects simplistically. Future versions should develop a more detailed model to better capture the costs dependent on O&M port choice. As it stands, operation costs, including turbine maintenance, and the maintenance of floating platforms, moorings, and export systems, are calculated at a fixed price per turbine, derived from (BVGA 2023). This price encompasses the scheduled maintenance along with minor and major repairs.

For major component replacements, failure rates are taken into account as in (Urbano 2021). In cases of failure, while full replacements are assumed for IACs and mooring lines, the cost of turbine replacements is estimated at an average of 2.5% of the total turbine cost. Additionally, towing costs and the costs of laying mooring lines and IACs are included based on the specific failure incidents. In this way it also assumes that the WTG major component replacement (MCR) is the same as the towing port.

Moreover, a contingency cost of 5% is factored in to address unforeseen expenses.

2.2.6 DecEx

The decommissioning cost model is also simplistic as it is calculated as a percentage of the installation costs following (Strag 2022) values. It should be mentioned that given the impact created by decommissioned a choice might be made to leave some components in the seabed, for example the mooring anchor as this can be of greater benefit for the environment

2.3 LCOE Model

To calculate the LCOE, all expenses are distributed over the lifespan of the project with the final goal of calculating the real electricity price for which the total net cash flow of the project is equal to 0. This involves several key assumptions. For instance, projects under one GW typically require at least four years for development, while larger projects might need five years. The timeline from the Final Investment Decision (FID) to the Commercial Operation Date (COD) is used to allocate capital expenditures (CapEx) for procurement and installation, which vary based on the project's duration. The interval from the FID to the COD is primarily dictated by the lengthiest installation phase, determined by the number of integration days, plus an additional year. Operational and maintenance (O&M) costs are evenly spread across the operational years. Decommissioning costs are equally divided over the two years following the project's conclusion. These are standard assumptions and may not fully represent the actual timelines of a real project.

$$\text{LCOE} = \frac{\sum_{t=1}^{T} \frac{\text{CAPEX}_t + \text{DEVEX}_t + \text{OPEX}_t + \text{DECEX}_t}{(1+r)^t}}{\sum_{t=1}^{T} \frac{\text{AEP}_t}{(1+r)^t}} \tag{11}$$

The costs are then adjusted for inflation and then discounted using predefined interest and discount rates, with the discounting periods calculated on a semi-annual basis. To simplify the analysis, the costs of offshore installation, along with the export system and its installation, are consolidated.

Annual Energy Production (AEP) values are discounted without inflation adjustments, enabling the calculation of a real LCOE rather than an annually inflated figure. Additionally, to account for blade erosion and general loss of efficiency, a loss factor of 0.25% is applied

annually to the AEP (Han 2018).

An initial LCOE calculation can be derived from Equation 11. However, this value may not be comprehensive as it initially omits several critical costs. To rectify this, two additional expenses are incorporated: seabed leasing costs and annual tax obligations.

Seabed leasing costs - These are calculated using the Scottish model, where the tariff is divided into two phases. Prior to the Commercial Operation Date (COD), a fixed payment is made based on the allocated area obtained through auction. For the purpose of this study, a fixed rate of 0.1165 million EUR per square kilometre is assumed. After the wind farm becomes operational, a fixed tariff of 1.25 EUR per MWh is applied, subject to annual inflation adjustments. These values are aligned with (Laido 2022).

Tax Obligations - To calculate the annual tax rate, it is essential to first determine the project's revenue. This is initially assumed to match the electricity price set at the LCOE derived from Equation 11 without taxes and tariffs. In order to refine the LCOE calculation, a loop is implemented that adjusts the electricity tariff until the net cash flow equals zero, thereby affecting the actual tax charge. Notable tax rules in Portugal include a limitation of 65% of taxable profit that can be offset by tax losses in any given year, though losses carryovers are not capped. Deductible expenses for tax purposes encompass development, O&M, insurance, legal and financing costs, as well as seabed leasing costs. Asset depreciation is also deductible, which is done utilising a straight-line method at a rate of 8%. (KPMG 2023)

The corporate income tax rate is considered to be 21% with additional supercharges of (i) 3 percent on profits between mEUR 1.5 and mEUR 7.5, (ii) 5 percent on profits between mEUR 7,5 and mEUR 35 (on the part exceeding mEUR 7.5), and (iii) 9 percent on profits exceeding mEUR 35 according to (KPMG 2023). In the model the project is treated as a company for taxable purposes even tough this might not be the case given that profits might end up being treated in a larger company with tax reports comprising several projects and assets instead of an isolated project.

Additionally, it is important to consider certain cost exclusions that could impact the LCOE. Specifically, costs related to the clawback mechanism, the extraordinary contribution of the energy sector (ESEC), the electricity social tariff, VAT, taxes, and tariffs applicable in EPC

contracts are noteworthy (KPMG 2023). However, it is relevant to mention that some of these costs have been exempted in similar auctions for other renewable projects.

The actual final reported LCOE is then the electricity price calculated for which the net cash flow of the project is equal to 0, that is, the estimated long-run average cost.

3 Results and Discussion

The result section is divided in two main parts. In the first the focus is on the areas that were proposed to be the first put to auction by the government working group set for that purpose. The second part focuses on a series of sensitivity analysis to better explore the choices as well as alternative ones both made and to be made for FOW development.

3.1 Baseline

The government working group on offshore wind has identified several areas for the initial auction: *Viana do Castelo Norte* Area (VCNA) with a capacity of 1GW, *Leixões* Area (LA) with 500MW, and *Figueira da Foz* Area (FFA) with 2GW. Notably, *Viana do Castelo* represents a complete seabed allocation, while *Leixões* and *Figueira da Foz* are segments of larger zones that total 2GW and 4GW, respectively (Group 2023).

Baseline calculations were performed using the IEA 15MW turbine with a 240m rotor reference model (NREL 2020). In addition, Ferrol, Spain was chosen as the towing and assembly port. The use of this port is supported by the INEGI study conclusions according to which the Portuguese ports need significant intervention and are not prepared to fully support the first GWs[7] (Cabrita-Mendes 2023). The discount rate is set at 8.5% based on (Thornton 2019) UK unlevered values. Although that survey is from 2018 the recent pressure on the sector is expected to either have moved the discount rates to these values, after a more favourable market for a couple of years, or even lead it to higher values. It is also worth nothing that no economies of scale are at this moment considered in the model.

The main findings are summarised in Table 1. The analysis presents four distinct LCOEs estimates. Unless specified otherwise, the discussion will focus on the LCOE that excludes

[7]The complete study is still unpublished.

inflation but includes seabed leasing costs and taxes. Across these calculations, the LCOE ranges from 202.5 to 332.7 EUR/MWh. Specifically, this range reflects the lowest LCOE for VCNA, which excludes seabed leasing costs and taxes, and the highest for the inflated LCOE of FFA.

Table 1: Baseline LCOE results for the proposed areas for the first auction allocation rounds.

	Viana Norte	**Leixões**	**Figueira da Foz**
Wind Farm Capacity Assumed/Actual (MW)	1,000 / 1005	500 / 495	2,000 / 1,955
Number of Turbines	67	33	133
Discount Rate		8.5%	
Towing Port		Ferrol	
Annual Average Wind Speed (m/s)	8.76	8.80	8.52
Average Water Depth (m)	116	155	198
Average Turbine AEP (MWh)	49,390	51,384	46,166
Net Capacity Factor (%)	37.6	39.1	35.1
DevEx & CapEx (mEUR)	5510 (64.5%)	2884 (65.3%)	11845 (65.5%)
$OpEx_{30Year}$ (mEUR)	2749 (32.2%)	1371 (31.1%)	5586 (30.9%)
DecEx (mEUR)	286 (3.3%)	319 (3.6%)	660 (3.6%)
$LCOE_{excluding\ taxes\ and\ tariffs}$ (EUR/MWh)	**202.5**	**205.1**	**248.6**
LCOE (EUR/MWh)	**225.1**	**228.5**	**281.5**
$LCOE_{inflated\ at\ 2\%\ excluding\ taxes\ and\ tariffs}$ (EUR/MWh)	**232.1**	**235.0**	**297.1**
$LCOE_{inflated\ at\ 2\%}$ (EUR/MWh)	**255.3**	**259.1**	**332.7**
Without Export System (Onshore and Offshore Substations and Export Cables)			
DevEx & CapEx (mEUR)	4915 (61.8%)	2496 (62.0%)	10261 (62.1%)
$LCOE_{excluding\ taxes\ and\ tariffs}$ (EUR/MWh)	**183.8**	**181.5**	**220.1**
LCOE (EUR/MWh)	**203.2**	**200.9**	**247.5**
$LCOE_{inflated\ at\ 2\%\ excluding\ taxes\ and\ tariffs}$ (EUR/MWh)	**211.5**	**208.7**	**264.1**
$LCOE_{inflated\ at\ 2\%}$ (EUR/MWh)	**231.0**	**228.4**	**293.4**

Examining the values, it becomes apparent that VCNA and LA have a comparable Levelized Cost of Energy (LCOE), while FFA is significantly more expensive. This disparity can be attributed to several factors. Firstly, a decrease in the annual average wind speed from approximately 8.8 to 8.5 m/s reduces the net capacity factor of the wind farm, with values varying from 35% to 39% . It's also important to note that some of the variance in net capacity can be attributed to wake losses, which are calculated based on the number of turbines at each site. Although LA and FFA are not fully developed, and these losses are expected to increase, this factor has not been considered at the current stage. Additionally, FFA has the deepest average

water depth, 198m, which increases mooring line costs when compared with the other two sites (+136 mEUR compared to VCNA). Costs also increase overall for all components related to the export system (around 200 mEUR compared to VCNA), given the larger distance to shore and to the landing points as expected. Finally, it is also worth mentioning the increase in the offshore installation costs (+87 mEUR compared to VCNA) which will be further explored in section 3.2.2.

Moreover, the weight % of each component in the LCOE is shown in Figure 16 seen in the Appendix. CapEx is responsible for almost three quarters of the LCOE most of it coming from the turbine - 25 to 30% of the LCOE - and floating platform - 20 to 35% of the LCOE procurement costs.

A full breakdown of costs is presented in Figure 17, in the appendix for LCOE, component and expenditure costs. One important fact that should be highlighted in this analysis is that even though LA is closer in cost per kW to FFA than to VCNA the increase in AEP is able to absorb the extra cost per kw resulting in a lower LCOE.

As it is expected that the export system falls under the TSO[8] scope, the LCOE excluding the export system components is also computed to assess the LCOE as seen by the project developer. Results are presented in Table 1. As observed, there is a decrease between 20 to 30 EUR/MWh when excluding the export system of the LCOE.

3.2 Sensitivity Analysis

In this chapter a series of sensitivity analysis are performed based and expanding on the baseline results, regarding discount rates, ports, allocated areas and allocation schedule. Furthermore, in the Appendix two further analysis are made regarding an increased capacity factor resulting from a softer approach to losses and a second one related to WTG size.

3.2.1 Discount Rate

In capital-intensive projects like FOW, the discount rates predominantly affect the LCOE, presenting significant opportunities for cost reductions (IREC 2019). Since 2022, the industry

[8]REN - *Rede Eléctica Nacional*.

has experienced significant shocks due to increased interest rates, rising material costs, and supply chain disruptions, which have escalated the costs of projects (Wood 2023). It is then essential to explore how the cost of capital influences the LCOE of the project.

The model evaluates discount rates ranging from 5.5% to 9.5% (8.5% being the baseline) across the various baseline areas as described in section 3.1. The findings, depicted in Figure 18 seen in the Appendix, show that the resulting LCOE varies between 164 to 249 EUR/MWh for VCNA and 197 to 314 EUR/MWh for FFA, illustrating the significant impact of discount rate fluctuations on LCOE. Cost of capital is then an important driver of the economic feasibility of these projects.

3.2.2 Ports

Port investment and industrialisation play crucial roles in the success of a floating offshore wind (FOW) project. The required investment is substantial, as ports may need to be adapted for manufacturing parts or entire floating platforms (FPs), along with their assembly and turbine integration. Additionally, ports must have sufficient storage space and equipment to manage all components involved in an FOW project. They must also meet specific requirements for handling wind turbine generators (WTGs) and FPs, such as maximum draft, channel width, quayside capacity, and docking quay length. (Crowle 2014) (Elkinton 2022)

The operations, such as WTG integration and FP fabrication and assembly, can be allocated to several ports. According to the current model, it is assumed that the assembly of the FP and WTG integration occur at the same port, from which the platform is towed to its final location. This model also includes a fixed rate of inbound transport of components per MW to this port. However, the model does not account for the possibility that the entire FP fabrication could be conducted on the same port or that there could be a split of fabrication tasks, with at least a part occurring at different ports, or even an FP assembly port different from the WTG integration port. The discussion on economic direct gains in the Appendix will further touch on this point.

Considering these factors, a sensitivity analysis for selecting different ports is conducted to assess the impact of this choice on the LCOE of the project. For a complete analysis an assessment of the investments needed would have to be conducted, which is behind the scope

of this work. So here, it is assumed that the ports would have the necessary conditions to perform the required activities. The results can be seen in Figure 19 as seen in the Appendix.

Three ports are selected for this analysis: the Port of Ferrol in Spain, the Port of Aveiro, and the Port of Setubal. The Portuguese ports are chosen according to (Group 2023) and for their available maximum draft of 10 meters or more, as drafts lower drafts may pose challenges for WTG integration (Crowle 2014). The Port of Ferrol is included as it was mentioned in the INEGI study used for the baseline assessment. As depicted in Figure 19, the impact on the LCOE is relatively small, ranging between 2 and 5 EUR/MWh. It is important to note that this impact is constrained by the proportion of offshore installation costs in the LCOE, which accounts for 7 - 9%. However, when total costs are considered, they vary significantly, ranging from 90 million EUR for VCNA, 40 million EUR for LA, and 200 million EUR for FFA, with the Port of Aveiro being the least costly for all three projects.

Towing distances are the primary contributors to the current cost differences. A larger impact might be observed by using a more detailed model that incorporates modular fabrication, assembly, and WTG integration at various sites, along with different port costs for various processes, components, and stages. Therefore, a more detailed location-specif analysis is required.

3.2.3 Area Allocation

In order to understand how the LCOE could potential vary along different areas other than the ones defined in the PAER, an area of study was defined within the Portuguese continental platform with the following limits: above *Nazaré* Canyon, below the north limit of the Portuguese ZEE and within a maximum and minimum bathymetry of 500 and 50m respectively.

Within this area the LCOE as well as total costs, net capacity factors and turbine average AEP (Appendix Figures 20, 21 and 22) were calculated by dividing the area in equal groups of 17, 33 and 67 turbines, corresponding to 250, 500 and 1000MW. The group division followed an heuristic approach where the number of rows was fixed but the number of columns could vary to accommodate the shape of the area. Two group random groupings were computed for each set of resulting variables. Each resulting variable was assigned to the gps coordinates of the midpoint of each group and with the help of QGIS the results were extrapolated for the

complete area of study.

From Figure 20 some conclusions can be drawn:

1. The most northern areas are clearly the ones with most potential to develop offshore wind at a lower price. Still price wise there seems to be no advantage on bringing the areas closer to shore.

2. The northern part of the LA seems more interesting than the southern part, resulting at least partially from a lower net capacity factor as seen in Figure 22. The area closer to shore and above the *ZEC* reserve seems to have more potential that the southern part of the LA area given that a similar net capacity factor (around 38% for the 500MW interpolation) is compensate by the lower costs - around 4450 vs 4300 mEUR.

3. FFA, the area around it and the area between it and LA are clearly more expensive than the others. When FFA is developed there might be an interest in starting trough the south eastern part as it is cheaper without a significant difference in the capacity factors.

At a first glance it seems that the areas under study by the (Group 2023) were placed on purpose as further apart as possible from the shore but within the continental platform. Nevertheless, these proposed areas show in general lower LCOEs mostly because they are within more favourable winds, given the increase in the net capacity factor as seen in Figure 22 that compensates the increased costs mainly of the export system and mooring, even though there might be increased construction risks. The only potential clear chance of improvement, without moving into protected areas, could be the shift of the LA southern are to a more north eastern location above the special zone of conservation, possibly as an extension of the northern part. This area does not seem to be in conflict with any other activity as defined in (DGRM 2023a).

Overall the results for the LCOE are within the intervals already seen specifically for the each of the area in the baseline discussion.

3.2.4 Allocation Schedule

To analyse the overall LCOE for building an eight out of the 10GW capacity ambitioned by 2040, six scenarios are developed under both optimistic(O) and pessimistic(P) financial con-

ditions regarding the cost of capital. These scenarios are detailed in Tables 3 and 4 in the Appendix. The analysis is based on two critical assumptions:

1. The maximum turbine capacity is capped at 18MW. Although larger turbines may become available within the next decade (de Vries 2024), a gradual transition is anticipated. The shift should be slow, as the value chain is currently transitioning towards turbines in the 15MW range, and there is an increasing pressure to reach profitability with the current generation of WTGs throughout the value chain, from ports, to vessels to OEM manufacturers.

2. Learning rates, which denote cost reductions in both Capital Expenditure (CapEx) and Operational Expenditure (OpEx), are incorporated. These rates are derived from projected CapEx and OpEx values published by the International Renewable Energy Agency (IRENA) and mentioned in the PNEC (PNEC 2023). These learning curve are simplified, as the follows. For projects allocated in 2027, which should have a FID by 2031/32 and a COD from 2034-36 a cost reduction of 20% is applied for both CapEx and OpEx values. For projects allocated in 2030, with FID by 2034-35 and a COD from 2038-40 a further 5% is taken form the costs.

The export system costs are excluded from this analysis as it is harder to make assumptions on how this costs will evolve - for example, on floating substations and its costs.

The results of this setup are shown in Figures 23, 24 and 24 in the Appendix. The scenarios are divided in two groups, one with two allocation moments and the second one with three. In each group we have an allocation based on the 3.5GW at the first auction, same as our baseline, an allocation based on the 2GW PNEC goal for 2030 and finally a first smaller auction of 1GW[9].

The lowest overall LCOE is probably associated with the most likely scenario of postponing most of the projects to the future, due to the potential increased learning rates and reduced capital costs. The lowest LCOE then is equal to 122 EUR/MWh and it is associated with the optimistic AS6. This happens because a larger % of the total capacity takes on the benefits of bigger turbines, better financing and improved learning rates. This does not mean though

[9]Even though not modelled is important to note that bigger projects can be delivered in phases, for example a 3GW project can come online 1GW at a time, therefore having different COD dates.

that this should be the allocation schedule to follow. Allocating more volume earlier can bring benefits if this strategy is capable of inducing and generating a larger economic value for the country through industrial development. This industrial development can be a direct impact, by retaining more of project investment of the country projects, or indirectly by creating a supply chain capable of exporting value. Down the road it is even possible that the higher LCOE at the beginning is offset by a lower LCOE driven by a larger and more valuable local supply chain.

A trade-off needs to be stroked between the direct project output gains - clean electricity at a cheaper or more expensive price - and the indirect project gains - a project inducing larger or smaller economic output for the country. This discussion will be further expanded on section 3.3.

There are some key takeaways from the results obtained:

1. In none of the scenarios we have an overall LCOE below 100 EUR/MWh, not even when looking at the LCOE per year - Figure 24.

2. Delaying the development of the FFA seems reasonable. It is clearly the area presenting the large variance in the LCOE allocation schedule scenarios. When comparing the overall result for earlier to later allocation scenarios that difference is of 96EUR/MWh between AS1 and AS6 allocation scenarios.

3. The 1st auction 3.5GW allocation scenario (AS1 and AS5) is clearly the one with the highest overall LCOE variation which is between 20 and 35 EUR/MWh when compared to the the lowest comparable scenarios [10]. However, between the 1GW and 2GW 1st auction allocation scenarios the difference are not that large - between 6 and 7 EUR/MWh for the two moment auction scenario and between 10 and 12 EUR/MWH for the three moment extended auction scenario.

A remark on cost reductions follows: Although the learning rate is applied to all the CapEx and OpEx it is not expected that the learning and therefore the cost reduction happens uniformly across all components of a FOW. According to an inquiry conducted recently by DNV the LCOE reductions for next years are expected to be driven mainly by the standardisation and

[10]Compared within the two or three auction moments and the pessimistic and optimistic groups.

industrialisation of the floating platforms, by the use of larger turbines, the increasing experience in the installation offshore and by economies of scale of larger wind farms (DNV 2023).

3.3 Discussion

In this section the FOW implementation as well as the results from the previous section are discussed from different perspectives. An additional discussion about value and investment retention is added in the Appendix.

3.3.1 Overview of the Results in the Context of the Literature

How do the results described compare with the literature? Notably, Lazard's last year report (Lazard 2023) places offshore wind LCOE between 67 and 130 EUR/MWh. The study assumes capacity factors between 45 and 55%. In contrast, the model created for this study projects capacity factors between 35 and 40%, partially due to lower wind speeds as well as possibly a more conservative approach to losses. The US market figures, as reported by (Berlin 2023), show LCOE values between 105 and 170 EUR/MWh for offshore wind. However, these studies do not differentiate between bottom-fixed and floating offshore wind, a distinction that could significantly impact LCOE calculations as FOW is expected to be in the higher end.

A more focused analysis on FOW by Frazer for the UK government (Frazer-Nash 2023) includes a sensitivity analysis showing LCOE for first-of-kind[11] projects at around 130 EUR/MWh, possibly ranging between 105 to 180 EUR/MWh based on factors such as material cost fluctuations, varying discount rates, and capacity factors. (Santhakumar 2022) presents an LCOE range that significantly decreases with scale, from 122.8 EUR/MWh at 1GW installations to 32 EUR/MWh at 100GW, due to factors such as CapEx reductions, increased capacity factors, project lifetime extensions, and decreased costs of capital contributing to the decrease.

For the Portuguese market, LCOE values are estimated between 135 and 160 EUR/MWh (Martinez 2022). Older studies, such as (Castro-Santos 2020), are deemed less realistic, presenting significantly higher LCOE estimates.

It is evident that most of the literature reports lower LCOE values comparable to those

[11] The first small scale projects using technology not previous employed at scale.

obtained in this study. The discrepancy found can be attributed to several key differences in our modelling approach:

1. Our model incorporates detailed cost modelling tailored to specific site characteristics, unlike most studies that use fixed values for CapEx and other expenditures.

2. The model aggressively accounts for Annual Energy Production (AEP) losses. These losses are calculated based on the number of turbines, incorporating factors such as wake effects, performance degradation over time, and an initial loss of 8% due to turbine / floating platform unavailability.

3. Additionally, the model includes costs for seabed leasing and taxes—expenses not typically covered in other models—which can increase the LCOE - by 20 to 30 EUR/MWh for this specific study case.

This modelling approach is more realistic, providing a comprehensive and site-specific analysis, potentially explaining the higher LCOE values observed. Though these values are not deem unrealistic in any manner. For instance, in the last years offshore wind allocation round auction (AR6) the UK crown state had to increase the maximum strike price, that is, the regulator´s target price, for FOW from 136 to 206 EUR/MWh due to the lack of interest of the developers for such an initial LCOE value (GOV 2023). It should be highlighted that the UK in general has stronger potential for OW and for FOW in particular given the advantage of better wind resources across several regions [12] and a stronger and more experienced value chain across the board which should result in lower costs overall.

Before moving on to further considerations it is important to note that the LCOE is not a perfect cost measure. The LCOE ”measures the total lifetime cost of a generation project with all its cost components divided by the total production of electricity, measured in dollars per MWh, or the average price per MWh at which a plant must sell generated electricity to break even”(Berlin 2023). In fact, it can be considered as an estimate of the long-run average cost.

[12]Some areas in Scotland can reach a annual average wind speed of 11.5 m/s whereas in the Celtic Sea that average is not below 9.5m/s. In Portugal, the average annual wind speed for the areas under study varies between 8 and 8.8 m/s for a hub height of 150m.

One of its important drawbacks is its failure to account for the intermittence of renewable energy. The fact that the electricity produced is not dispatchable and no large-scale that minimises its effects exists means that it might not be available when demand needs it, which can increase the opportunity cost of the producer by missing out possible gains. Another issue is the potential over-capacity that can exist in a renewable energy base system, requiring curtailments where production is there but demand is not. There are already solutions that can potentially mitigate these risks, namely, storage solutions like batteries or pumped hydro, or using the produced electricity to produce green hydrogen to be used as energy source across different sectors. In the presence of storage solutions, when implemented directly into the layout of a wind farm, the new LCOE for the project can have a smaller or larger variation depending on whether intermittency and curtailment are taken into account. A detailed study that accounts for the market dynamics would be needed in this case. In the case of green hydrogen production the overall cost impact will depend on the development of an hydrogen economy and the resulting demand across different sectors, transportation, industry etc. (Brouwer 2016) (McDonagh 2019)

3.3.2 Environmental Impacts and Social Costs

(Hooper 2017) provides and overview of what are the expected impacts on ecosystem services resulting from the construction and operation of offshore wind farms. A summary of the different impacts can be seen in Table 6 in the Appendix. It is important to keep in mind that the article does not make a distinction between fixed bottom OW and floating OW. Although, some disparities are expected, namely the impact during installation which is expected to be significantly lower for FOW given that no large foundation needs to be installed onto the seabed and most of the construction takes place in the port (Farr 2021). It should also be mentioned that the aesthetics impact should not be a major concern in this study case. Although some of the parks should be visible from the coast under good weather conditions they should be far enough to not create a major impact (Sullivan 2012)

The full characterisation and quantification of these impacts is still in its infancy, so it is important to keep including in wind farm projects research that allows for scientific community to expand the knowledge on this area. Economic quantification of impacts on the ecosystem

service dynamics is then a difficult task to undergo at this stage. In contrast, it is possible to estimate the net contribution of carbon emissions. This includes both the direct emissions generated by the project and the potential reductions in carbon emissions achieved by displacing fossil fuel-based electricity production with FOW.

For the carbon emissions attributable to OW projects, a value of 0.032 tCO2eq/MWh is adopted (Mendecka 2019). That figure represents the upper limit of the range provided in the study, chosen conservatively due to the relatively untested nature of FOW [13]. It is important to note that this figure represents CO2 equivalents, not just CO2 directly. While offshore wind farms do not emit greenhouse gases, they are notably resource-intensive. The manufacturing, installation, and recurring O&M activities also contribute significantly to those emissions, varying according to fuel consumption of the vessel fleet employed and the different technologies chosen. (Mendecka 2019).

For the benefits resulting from the displacement of fossil fuel electricity generation values from the (PNEC 2023) and (EMBER 2024) are considered. PNEC shows that by 2030 if the strategy and goals led out are achieved the expected electricity production by gas and other fossil fuel sources should be of 7.56 TWh [14]. This corresponds to a decrease of 4.55 TWh relatively to the 12.2 TWh produced in 2023 as reported by (EMBER 2024). This decrease corresponded to less 2.23 mT of CO2 produced. For this analysis it is also considered that from the 10.22 TWh of electricity imported from Spain in 2023 part could also come from fossil fuels and therefore can also be displaced. That amount is calculated according to the total distribution of the electricity produced in Spain due to lack of better data. So, in this case from the imports an extra 2.95 TWh producing 1.529 mtCO2 can also potentially be displaced. These two values result in a combined 3.72 mtCO2 that can be displaced with a carbon intensity of 0.5 tCO2/MWh.

Based on some of the work by (Greenstone 2012). The total avoided social carbon cost per MWh is calculated by multiplying the carbon intensity 0.032 tCO2eq/MWh for the FOW

[13] As an example of a novelty not accounted/discussed: the ballast water used in most of the existing floating platforms concepts needs to be treated and disposed of after the lifetime of the project due to a possible high metal concentration.

[14] Value obtained by reading the graph with the help of a Web Plot Digitizer.

life-cycle, and 0.5 tC02/MWh for the carbon potentially displaced by FOW[15], by three different costs of carbon: 47 EUR/tCO2 a low value for the social cost of carbon currently use by the US government[16] (Asdourian 2023), 85.3 EUR/tCO2 which is the average 2023 price for the European ETS market [17] (Qin 2024) and 147 EUR/tCO2, a higher value for the optimal carbon tax considering the impact on the natural capital stock (Bastien-Olvera 2021). The first resulting value is then added to the private cost while the second is subtracted from it, whereas the private costs in this case is considered to be 191 EUR/MWh [18]. The results are shown in Figure 28 in the Appendix.

When considering the net social costs of carbon the overall price for FOW can decrease significantly, in this study case up to 70EUR/MWh. It is also clear that a substantial increase in the price of carbon affecting fossil fuel based energy production can even further down the relative costs of FOW. Nevertheless, it is important to acknowledge that not all the social costs are accounted for in these calculations. More notably, the impacts on natural ecosystems, such as fisheries and possible conflicts when fishing areas may be restricted by those projects, impacts on birds' migration corridors, the use of rare materials that may degrade their natural condition either in land or in the ocean (deep sea), and the fact that some of them are not yet recyclable, raising numerous concerns. Since those impacts can lead to displacement of those activities to less constrained areas, such as to developing countries, where control and effective monitoring is lacking, the consequent degradation may induce migration of those populations not only to congested centres in those countries but also to developed countries as it is currently the case. Possible curtailment of production can also be considered an added social cost as we need to pay for energy that we are not using. It is also worth reminding that the PNEC goal for 2030 is that wind energy produces 34.1 TWh [19] of which 34% should be for the production of green hydrogen. So to calculate the comprehensive social costs we would also need to consider the H2 cost of production and its potential for the decarbonisation of other sectors. More on the

[15]The 0.032 and 0.5 are not completely comparable given that the first is a life cycle value and the second is direct emissions but for the sake of this simplistic analysis this is overlooked.

[16]$51 is the value currently being used in the US although EPA proposed a nearly fourfold increase to $190 deeming $51 as low (EPA 2023).

[17]It should be noted that the ETS market is a limited market since it does not cover all of the relevant sectors so it does not reflect the full social cost of carbon.

[18]Average between scenarios $AS4_P$ and $AS4_O$ for 2024 costs corresponding to possible 2GW scenario in 2030.

[19]Once again using the web plot digitizer on the graphs in (PNEC 2023)

PNEC current goals is presented in section 3.3.3

3.3.3 Portuguese Energy Market and the PNEC in the Context of the Results

According to REN data hub, 2023 saw the Portuguese electricity consumption rise to 50.71 TWh, of which 60.6% were from renewable sources. This value is quite significant when compared to the European average of 44% of renewable in the energy production mix. Portugal has been then at the forefront of the energy transition to renewable sources.

This is also reflected in the prices of the wholesale market where the average price in 2023 was 88.27 EUR/MWh only beaten slightly by Spain and in larger degree by the Scandinavian countries, according to OMIEs annual report[20] (OMIE 2024). This average value contrasts with the LCOE values calculated by the model in study of a minimum of 176 EUR/MWh for the 2GW optimistic extended scenario ($AS4_0$), that is around twice the spot price. Although it is worth mentioning that this average price still has some influence from the Iberian mechanism used in recent years to control for the rising cost of gas therefore it does not fully reflecting the end cost of electricity in spot market. (Hidalgo-Pérez 2024)

The beginning of 2024 was also characterised by low prices due to the high penetration of renewable. These low prices have pressured producers, due to the risk of curtailments in hours of excessive production and the loss of revenues for those without fixed remunerations. (Novais 2024) (Oliveira 2024)

It is not the plan of this study to evaluate the market as whole. Nevertheless, it is important to have a first look that can help evaluating the results of this study and contribute to further research. Two important takeaways can be derived:

1. The LCOE values presented in this study are considerable higher when compared to the current average wholesale price of electricity.

2. The pressure created by the amount of renewables already in the system increases the risk of the FOW projects due to the possibility of curtailment and resulting revenue losses in the absence of large-scale storing.

[20]The average price for the electricity produced in Portugal with guaranteed remuneration schemes is expected to be around 102 EUR/MWh in 2024, see Figure 32. There is some degree of decoupling between the spot and the actual price also seen through here.

Furthermore, the current design of the wholesale electricity market may not be yielding the most efficient outcomes or providing the appropriate signals. For instance, the Portuguese Energy Services Regulatory Authority (ERSE) recently had to increase the grid access tariffs for the second half of the year. This adjustment is necessary to compensate electricity producers, predominantly those generating renewable energy with fixed tariffs, which are secured through mechanisms like feed-in tariffs, due to the ongoing low wholesale prices below the year's projected average by ERSE (ERSE 2024). Such compensation is obtained by increasing the burden of the *"Custos de interesse económico geral"* (CIEGs), which are included in the grid access tariffs. As a result, we are witnessing a potentially distorted wholesale market that does not accurately reflect the true cost of electricity. There has been an effort at the European level to address these issues, where various market reforms are being suggested and discussed. These reforms emphasise the need for introducing more Contracts for Difference (CfDs) and long-term contracts like PPAs (Fabra 2022). But the question that remains is about the future of the spot market. This is particularly important for Portugal given the connection between the spot and the the remuneration of the producers with fixed tariff. How do we reform in a way that sends the right signals and do not penalise consumers?

Regarding the PNEC figures, the projected wind energy production is expected to be of 34 TWh by 2030. Of this, 34% is earmarked for green hydrogen production. At the same time, by 2030, the target capacity for onshore wind is set at 10.9 GW (PNEC 2023). This last figure is important because if assumed an average capacity factor of 25% for onshore wind, according to (Jung 2023), the estimated production should be about 24 TWh, or roughly 70% of the 34 TWh goal. With such a large percentage of the overall 2030 goal focused on hydrogen and around 70% possibly being fulfilled by onshore wind this can result in large competition for offshore wind, increasing its development risk, even if the latter presents higher capacity factors with more constant and predictable winds. It is worth noting that the onshore wind infrastructure in Portugal is comparatively aged, as the country was among the pioneers in wind sector development. Consequently, substantial investment is anticipated for re-powering of the existing onshore wind to achieve the 10.9 GW target but it is also expected that the required electricity price for these will be significantly lower compared to the existing FiTs (Vieira 2024).

Going back to the figures, of the onshore projected 24 TWh, an additional 6.6 TWh could be expected from the 2 GW capacity as outlined in our AS4 scenario, bringing the total to approximately 30.6 TWh. This figure falls slightly short of the 34 TWh target. However, more crucial is understanding that the price of FOW alone may not be sufficient to assess the degree of its viability in Portugal. Market dynamics, coupled with advances in energy storage and hydrogen production for decarbonisation of other sectors like transportation and more polluting industries, should play significant roles in determining the economic feasibility and desirability of the scale to which is desirable to develop FOW in Portugal.

4 Conclusions and Further Research

The main goal of this work is to design a model to estimate the LCOE for the development of floating offshore wind in Portugal and evaluate the choices made and to be made concerned with it. The following main conclusions are drawn as a result of our framework of analysis:

1. Economic Viability and LCOE: The LCOE for floating offshore wind remains relatively high compared to conventional energy sources and even other renewable options. Although, it is important to note that the developed model is considered conservative.

   The study conducted only shows values just below 100 EUR/MW for individual site areas under very specific scenarios - see Figure 25. While for the complete 8GW in study, the overall LCOE in the worst case scenario is around 190 EUR/MWh in the best case is around 120 EUR/MWh, without considering the export system. Given these results it would be important to better define the fundamentals of the 2GW and 10GW goals set out by the PNEC. For example, it would be interesting to understand what is the optimal capacity for FOW when not accounting for green hydrogen production given the extra layer of risk created by it.

2. Private Cost Reduction Potential: Within the sensitivity analysis the discount rate (cost of capital) can be the main cost reduction driver, while port choice has the lowest potential. Although the latter still is one of the largest risks for development of FOW and should not be disregarded (DNV 2023). The proper allocation schedule can also lower the overall

LCOE of the full capacity deployment. Given the balance that needs to be stroked between the price of electricity and the ambition of creating an industrial hub there might be a need to reconcile the industrial development goal with the overall transition goals related to FOW.

3. Geographical Context: The northern areas of the proposed development zones, particularly *Viana do Castelo*, show more favourable conditions for cost-effective FOW development due to higher wind resources and better capacity factors. These areas offer the potential for lower LCOE compared to southern regions in the study, *Figueira da Foz* and the southern area of *Leixões*.

4. External Effects: While FOW projects contribute positively to carbon emission reductions by displacing fossil fuel-based electricity, they also raise challenges on marine ecosystems and local communities. Nevertheless, considering the social costs of carbon can significantly impact positively the cost of developing FOW.

Finally, three main points are highlighted to guide further research:

1. It is important to perform a general equilibrium analysis together with an overall LCOE total system analysis to understand how FOW fits within an already highly renewable penetrated system. This analysis should account for how much capacity is really needed to reach the country net zero goals and how much would that cost depending on the choices made not only for offshore wind, but for onshore wind, solar, hydro, storage and possibly others not only for Portugal but within the MIBEL, and in other possible contexts such as in the case the where interconnections with central Europe increase in the future.

2. Given the increased pressure on the spot market with low values and the threat of needed curtailments, an environment is created where market economic incentives might not exist without a fixed remuneration scheme. It is therefore important to understand what a market reform should look like to allow for a more efficient approach to the deployment of renewable energy and others towards the net zero goals in line with the European Union planned reform of the electricity market (European Comission 2023).

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Appendix

Areas as defined by the offshore wind working group and the PAER

Table 2: Area, minimum and maximum distance from the coast, possible power capacity, and number of lots for each proposed area. (Group 2023)

Proposed Areas	Area (km2)	Min and Max Distance from Coast (nm)	Possible Power (GW)	No. of 500MW Lots
Viana do Castelo North	301	6.9 and 19.5	1.01	2
Viana do Castelo South	294	10.5 and 17.9	0.99	2
Leixões	644	22.5 and 32.3	2	4
Figueira da Foz	1325	21.7 and 34.1	4	8
Ericeira	171	7.5 and 12.4	0.5	1
Sines North	102	11.5 and 17.3	0.3	1
Sines South	287	8.2 and 10.6	1	2
Total	3125	—	9.8	20

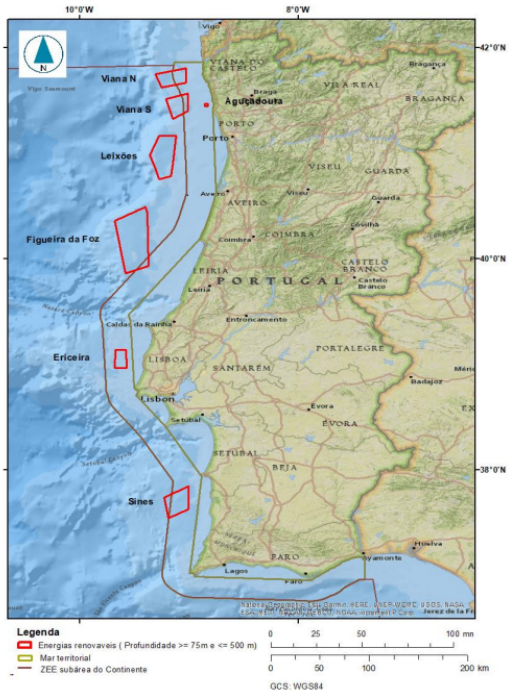


Figure 1: PAER sea areas for allocation to offshore renewables (DGRM 2023b).

GWEC FOW installation outlook 2022-2032

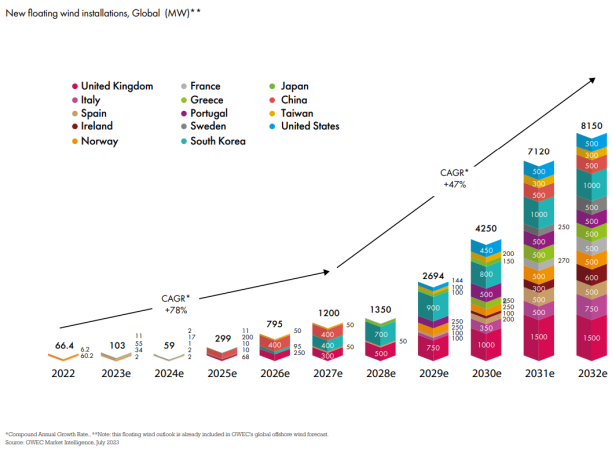


Figure 2: GWEC 2023 New Installation Outlook 2022 - 2032. (GWEC 2023)

Interactions Between Turbine and Wind Farm Choices, Ecosystem Services, Other Activities and LCOE

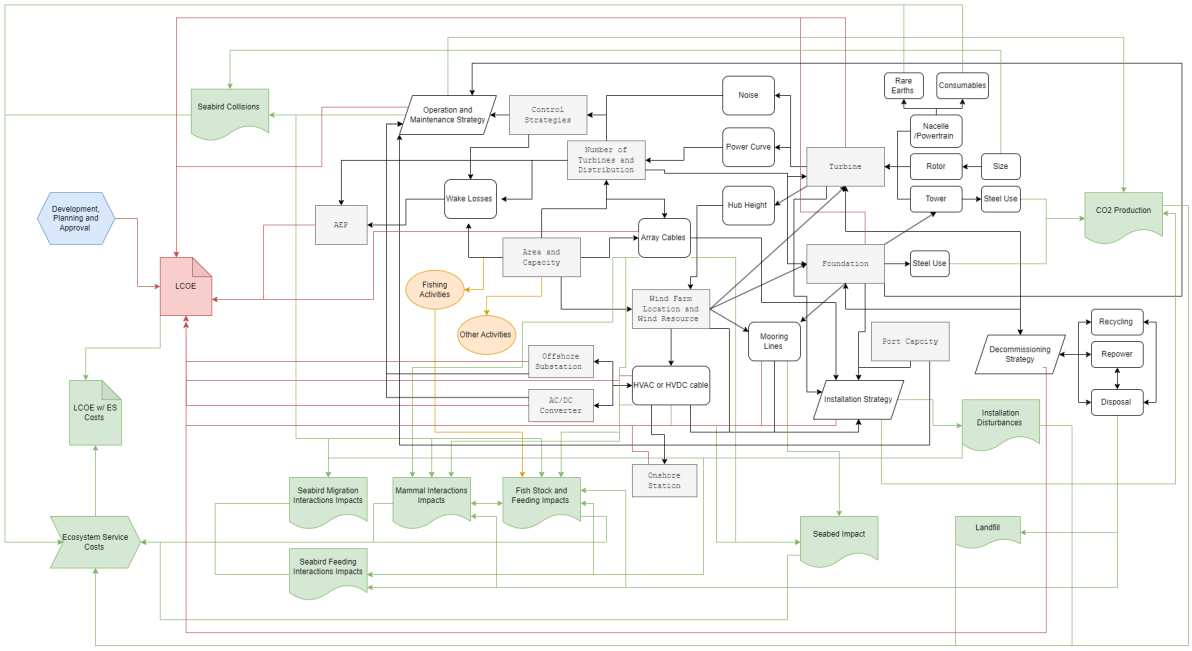
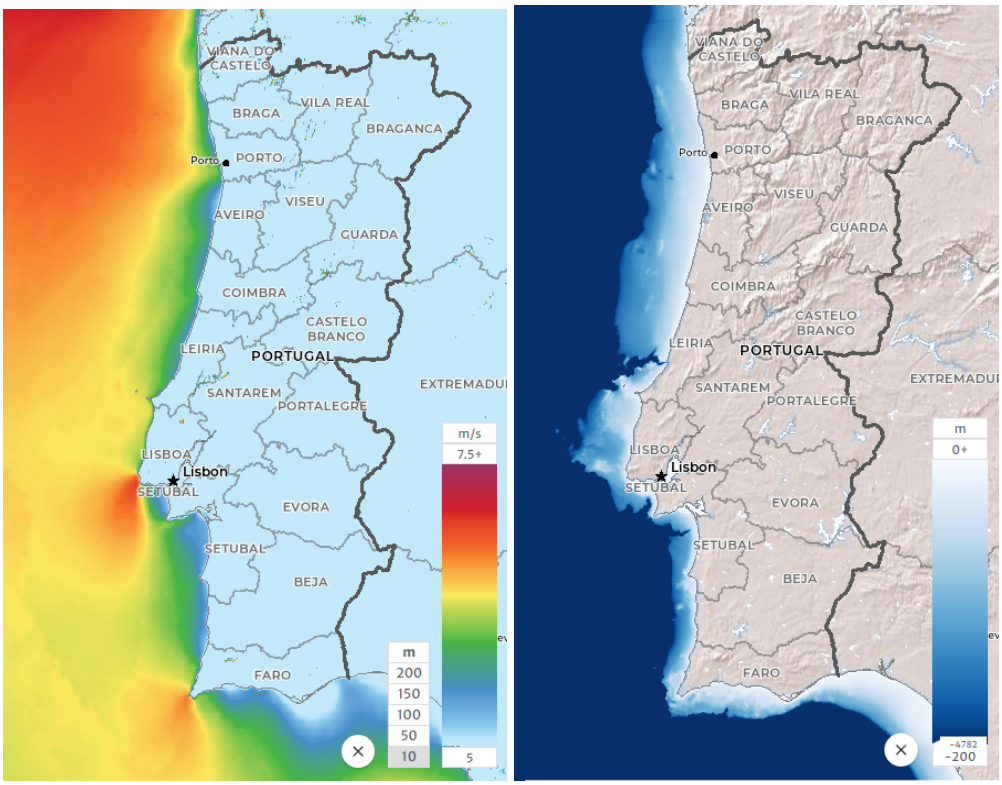
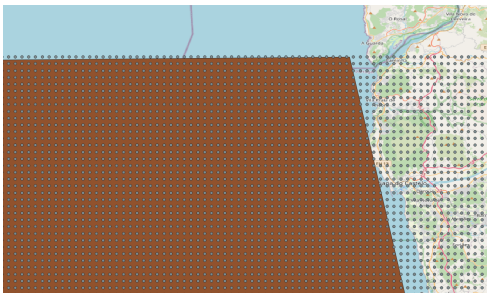


Figure 3: Interactions Between Turbine and Wind Farm Choices, Ecosystem Services, Other Activities and LCOE.

Wind and Bathymetry Data Used



(a) (b)



(c)

Figure 4: Global Wind Atlas Wind (a) and Bathymetry (b) data for the Portuguese Coast and QGIS grid for data association (c).

Model diagram maps

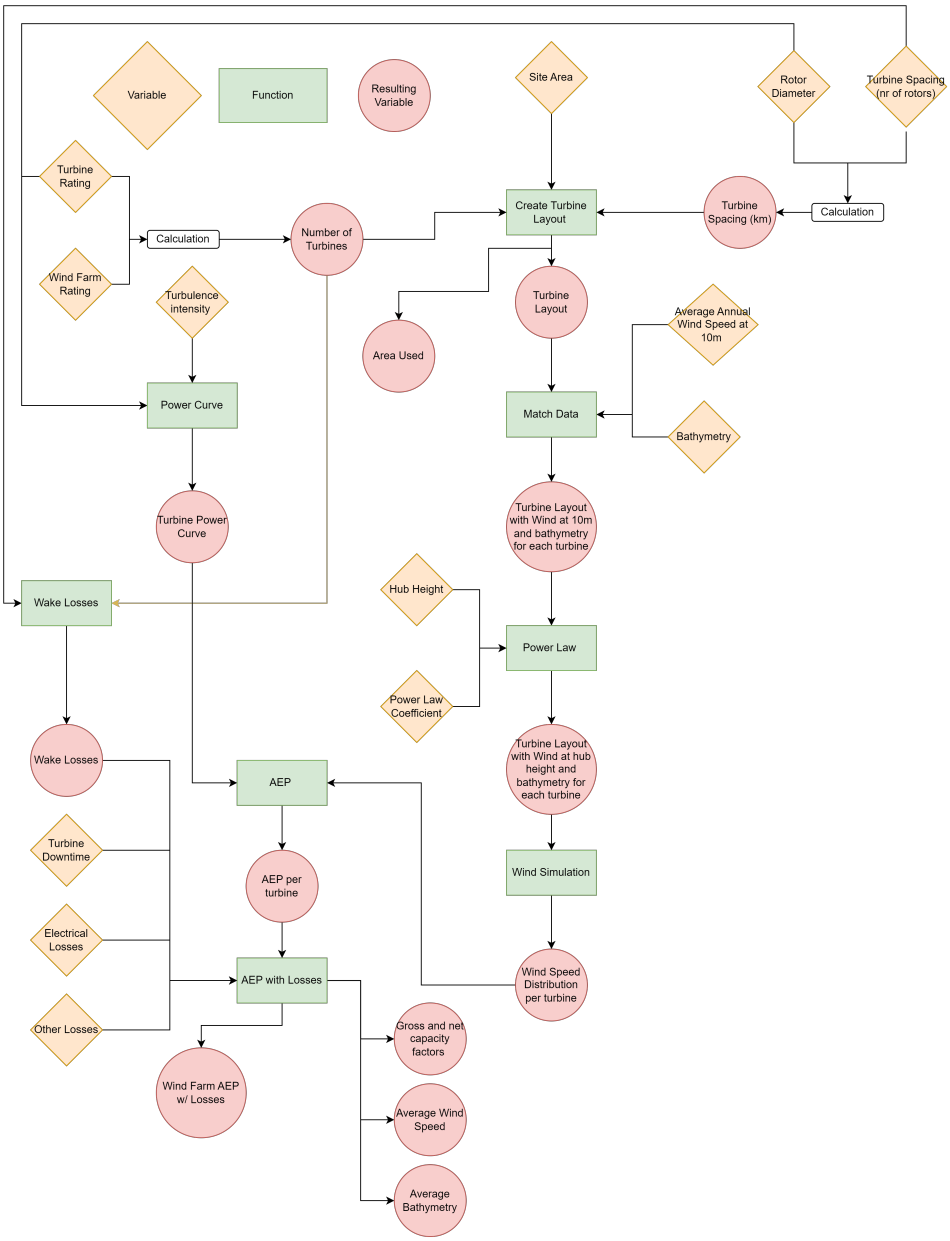


Figure 5: AEP model setup.

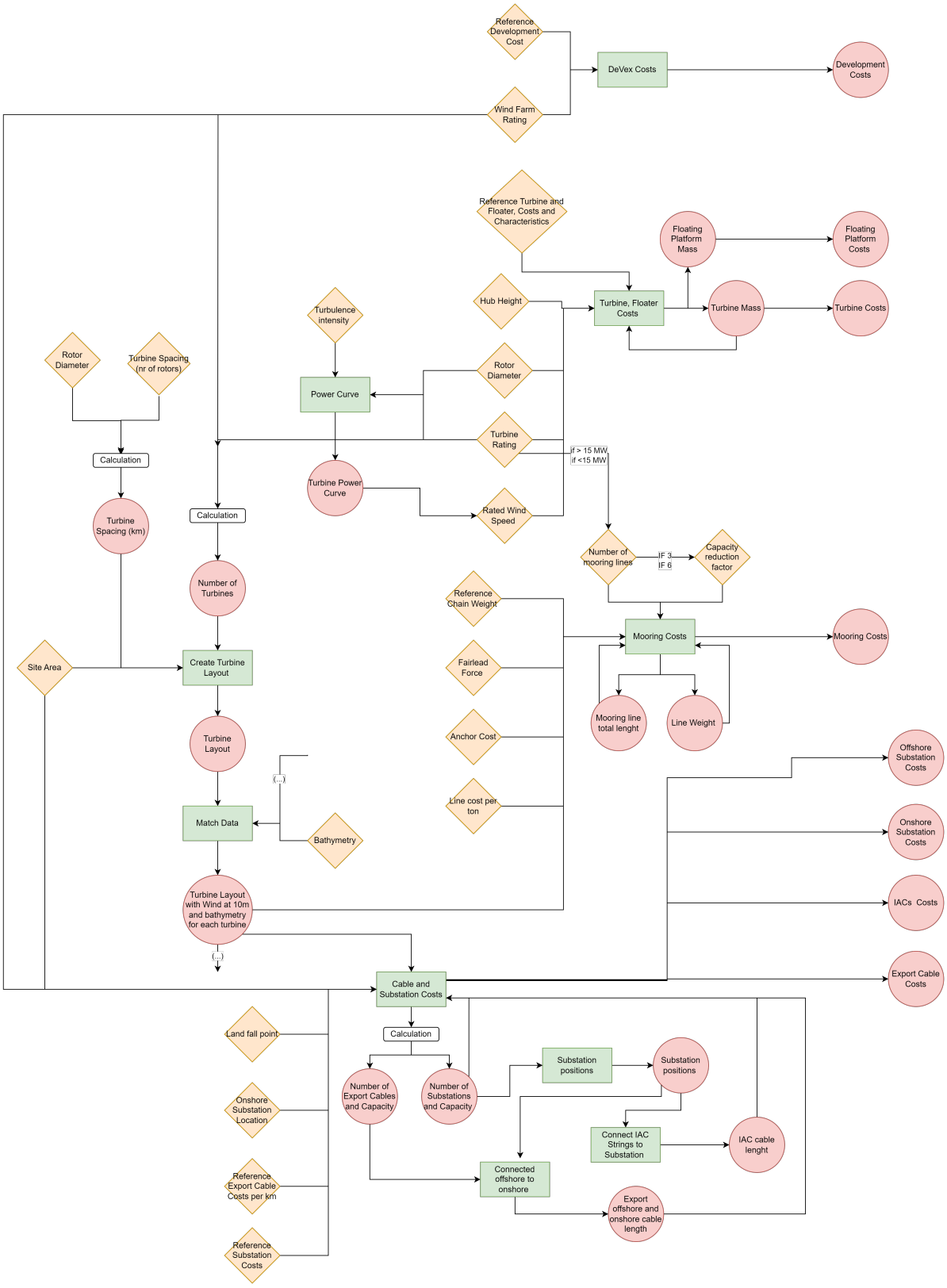


Figure 6: DeVex and CapEx Turbine and BoP Procurement Costs model setup.

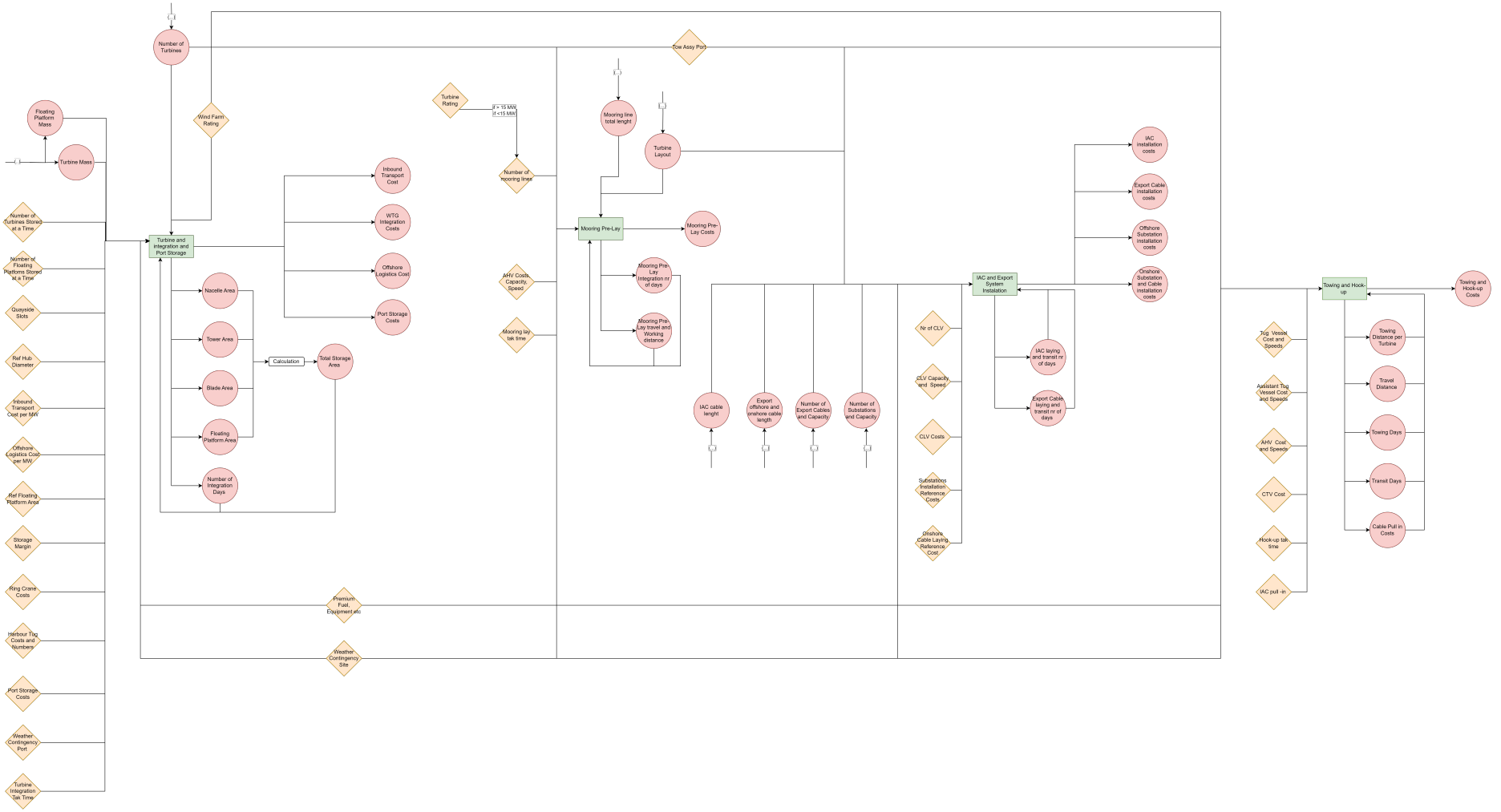


Figure 7: CapEx installation model setup.

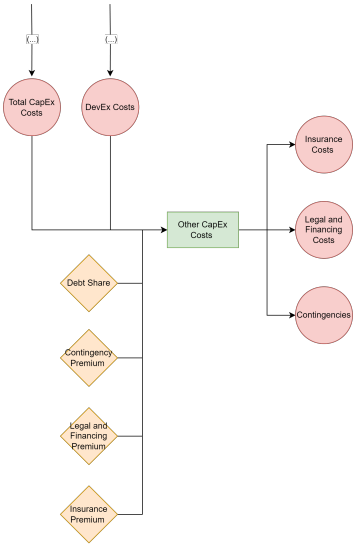


Figure 8: Other CapEx costs model setup.

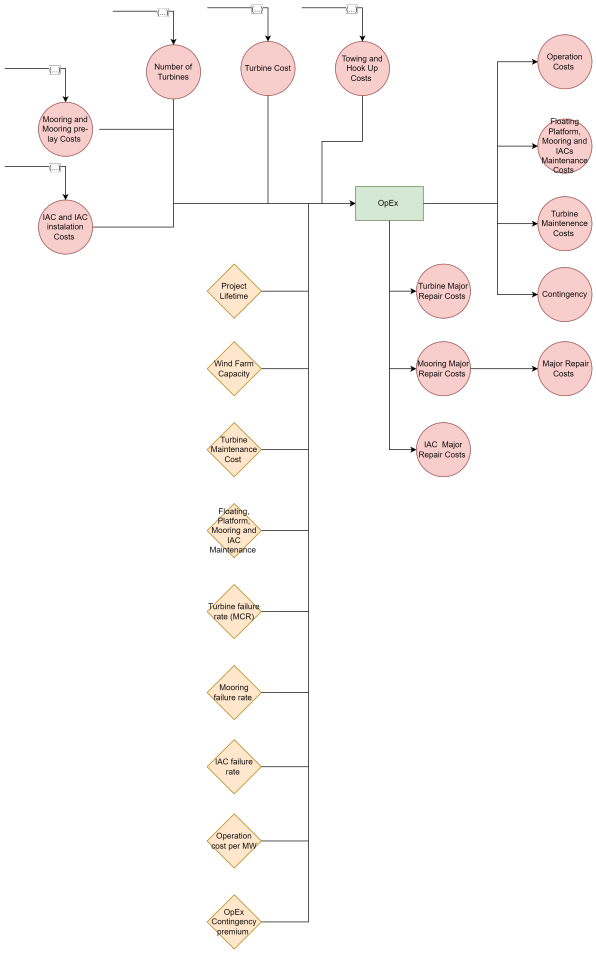


Figure 9: OpeX costs model setup.

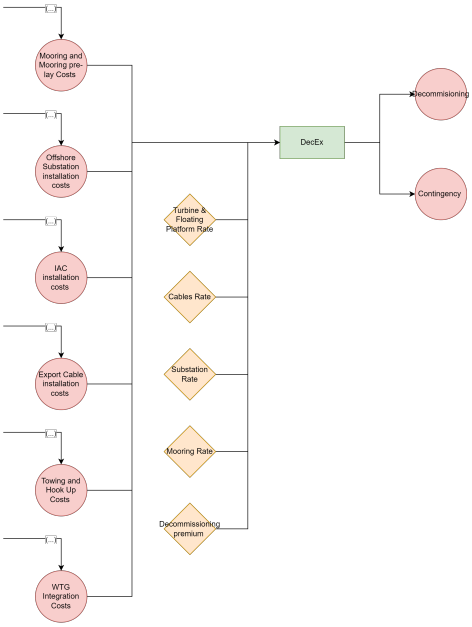


Figure 10: DecEx costs model setup

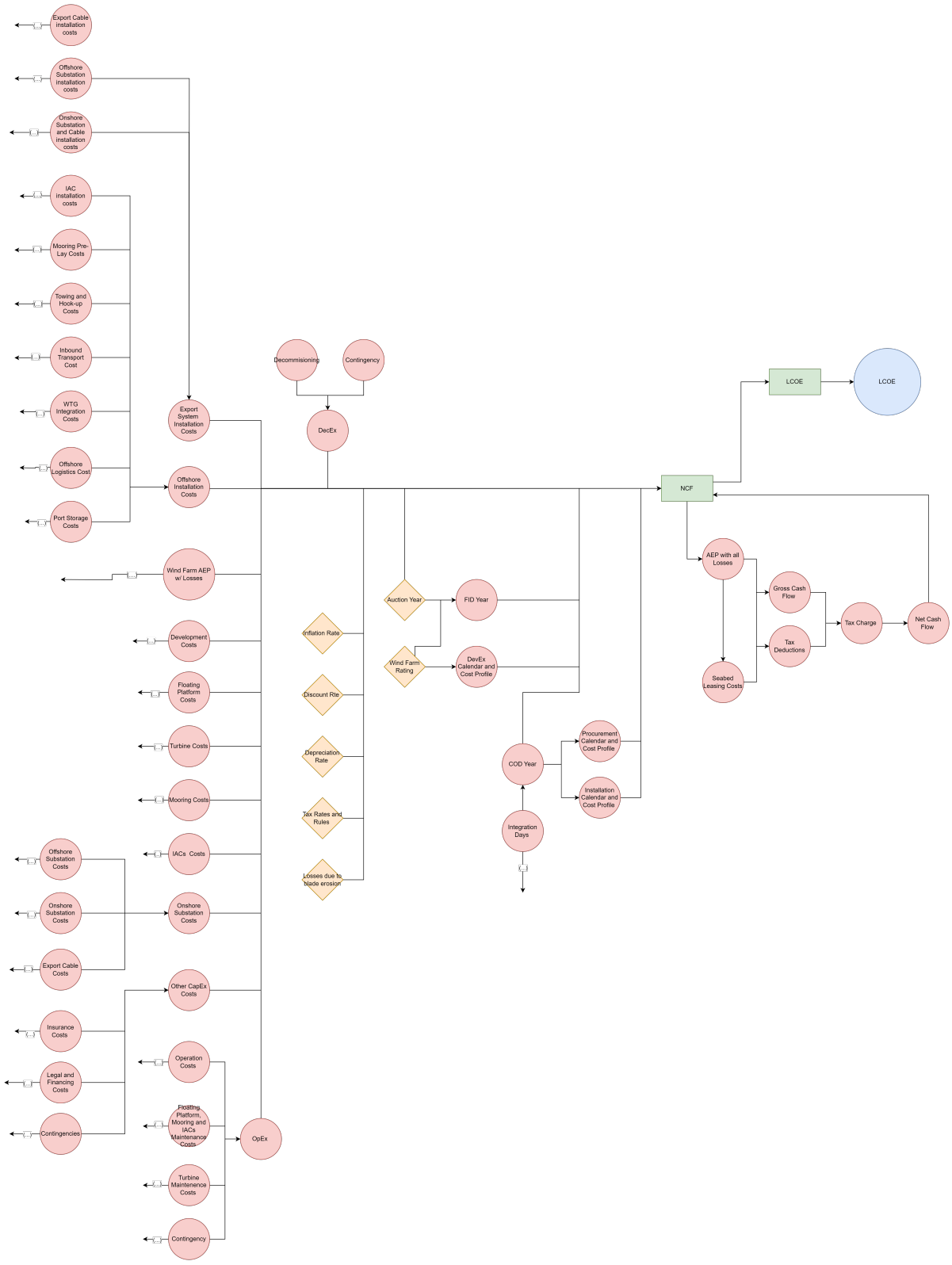
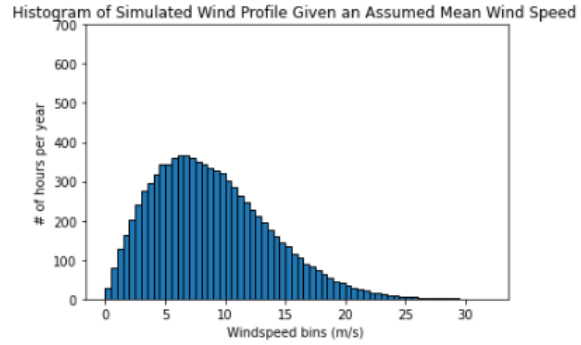


Figure 11: LCOE model setup

Example of simulated wind speed distribution




```
Calculated annual average wind speed (m/s) 8.923
Deviation from assumed average wind speed 100.191%
Last simulated wind speed (m/s)  10.617
Confirmation that we cover 100% of the time 100.00%
```

Figure 12: Example of the wind distribution simulation done for each turbine location.

Calibration of turbine power curve using DTU pywake and IEA 15MW reference turbine

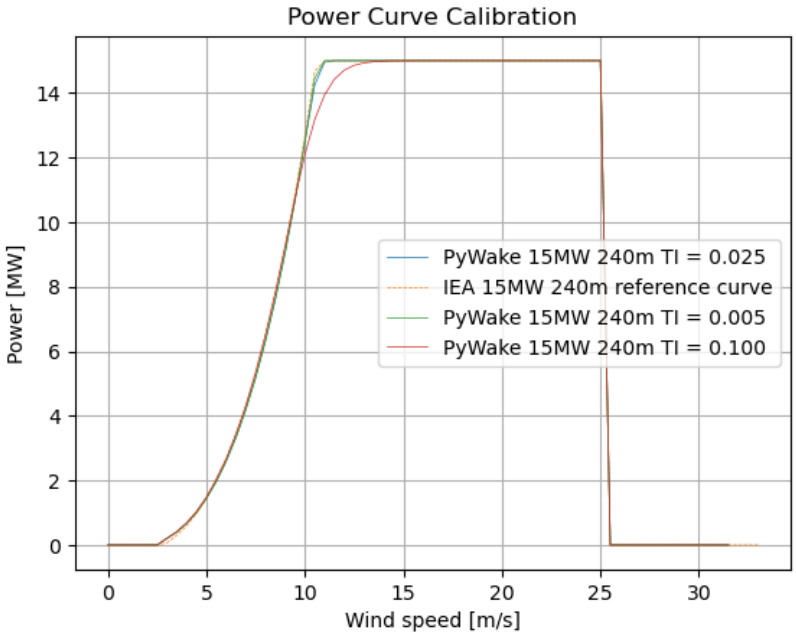


Figure 13: Calibrating turbulence intensity for power curve based on IEA 15MW reference curve.

Floating Offshore Wind Components

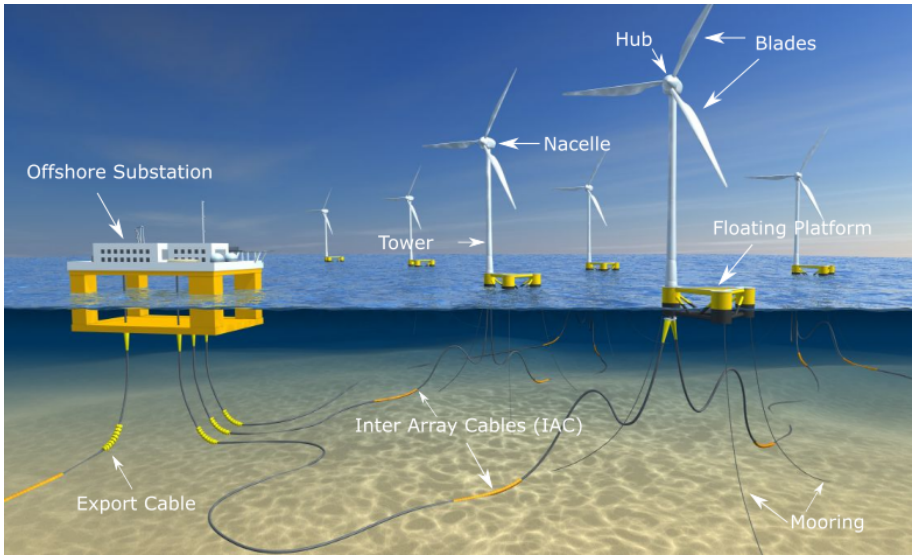


Figure 14: Floating Offshore Wind Components (EXSTO 2024).

Model Cable Layout Example

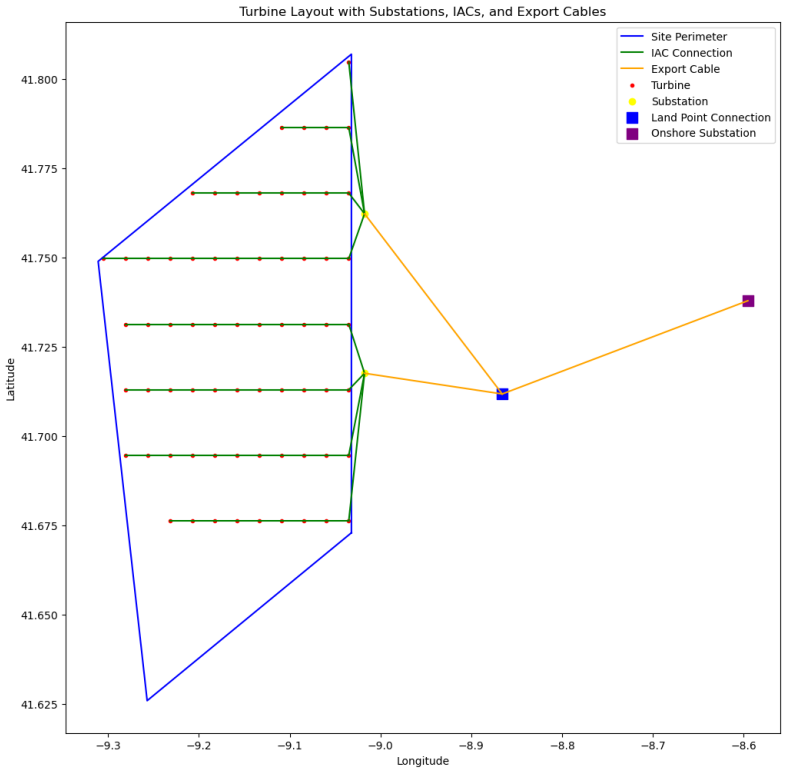


Figure 15: Model Cable Layout Example.

Baseline results - Cost weight distribution and LCOE and cost breakdown

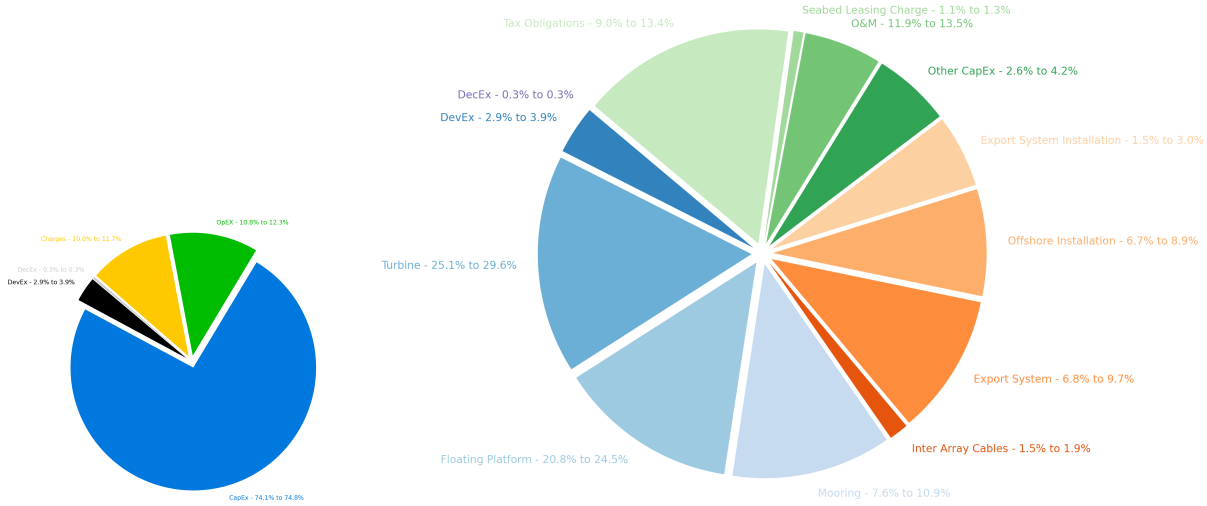
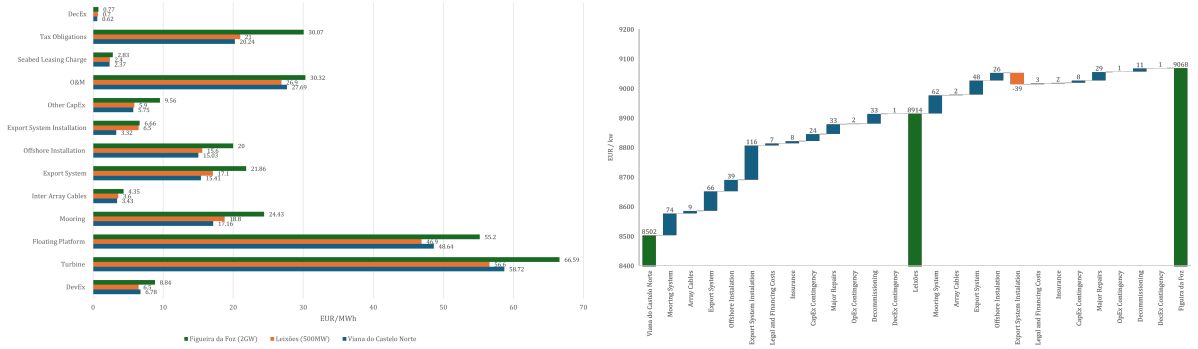
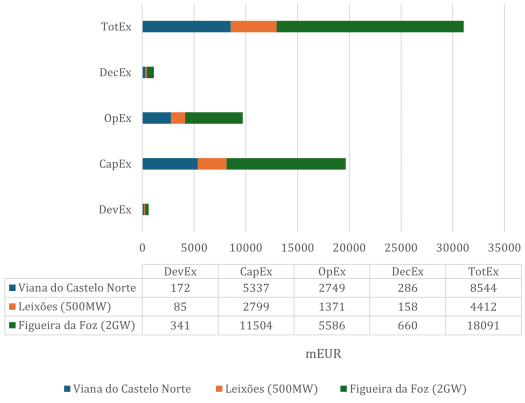


Figure 16: Component weight % contribution for the LCOE.



(a) (b)



	DevEx	CapEx	OpEx	DecEx	TotEx
Viana do Castelo Norte	172	5337	2749	286	8544
Leixões (500MW)	85	2799	1371	158	4412
Figueira da Foz (2GW)	341	11504	5586	660	18091

(c)

Figure 17: Baseline Results Breakdown. (a) LCOE component. (b) Cost per kW. (b) Expenditure type.

Discount rate sensitivity analysis results

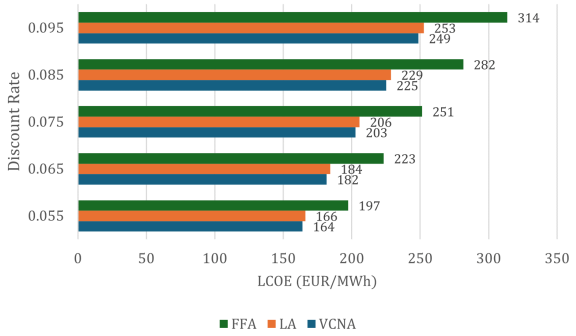


Figure 18: LCOE sensitivity to the discount rate across the baseline areas.

Ports sensitivity analysis results

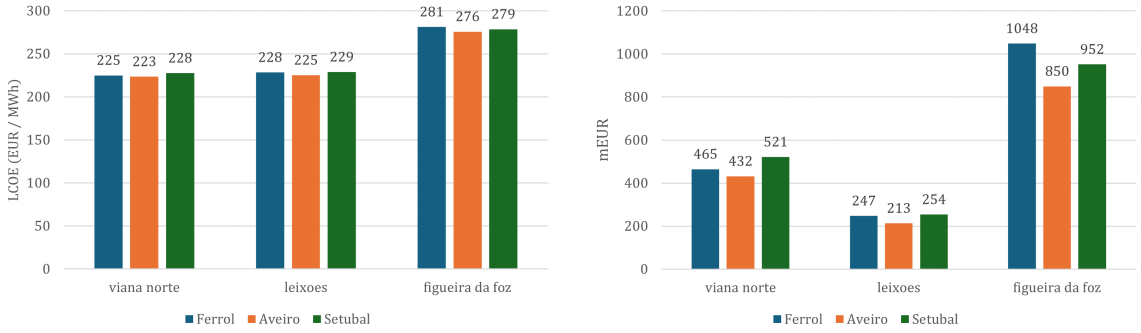


Figure 19: (a) LCOE sensitivity to port choice (EUR/MWh). (b) Offshore installation total costs based on port choice (mEUR).

Area allocation sensitivity analysis results

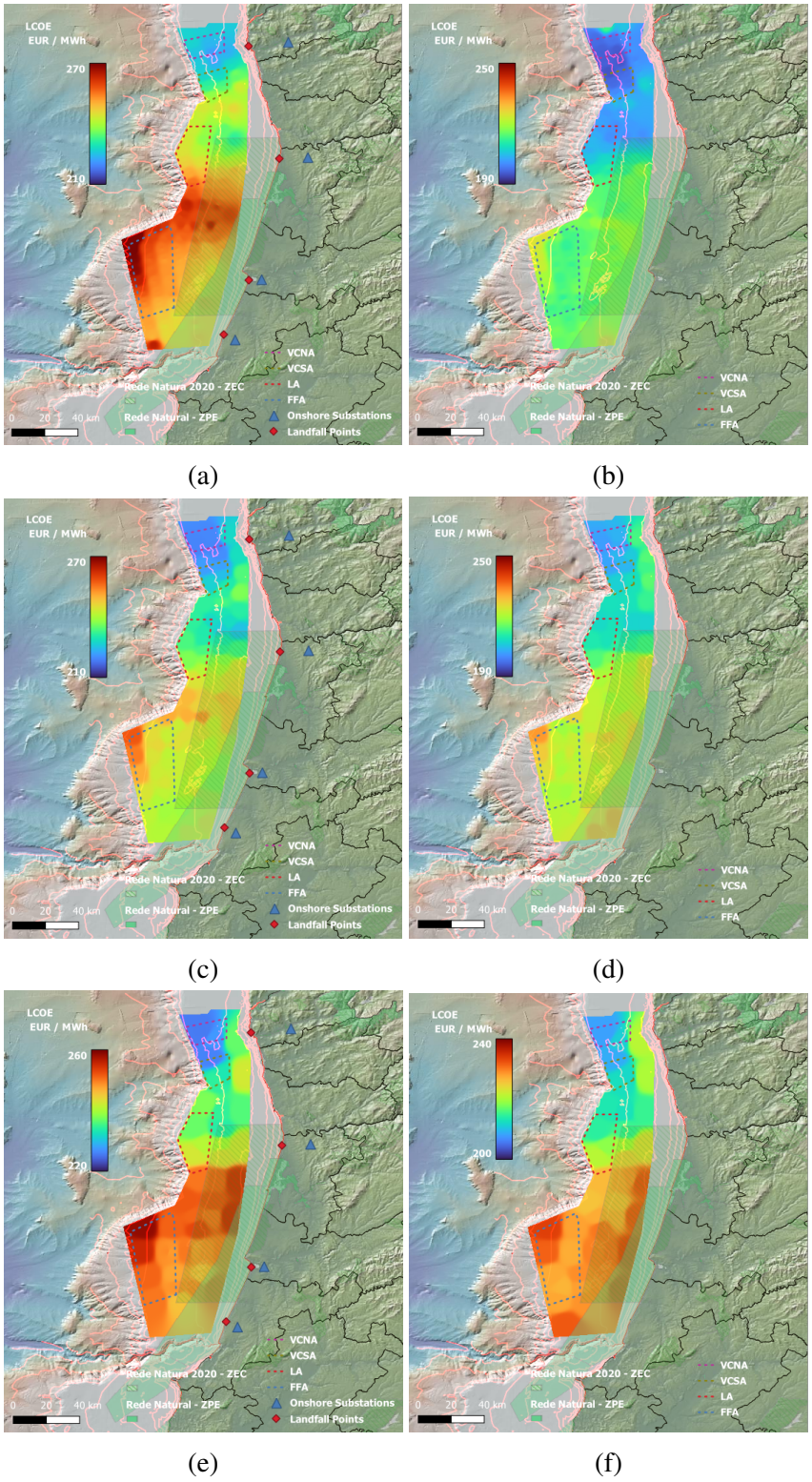


Figure 20: LCOE calculated along the continental platform between water depths of 50 and 500m with different wind farm sizes (a) 250 MW (b) 250 MW without export system (c) 500 MW (d) 500 MW without export system (e) 1000 MW (f) 1000 MW without export system.

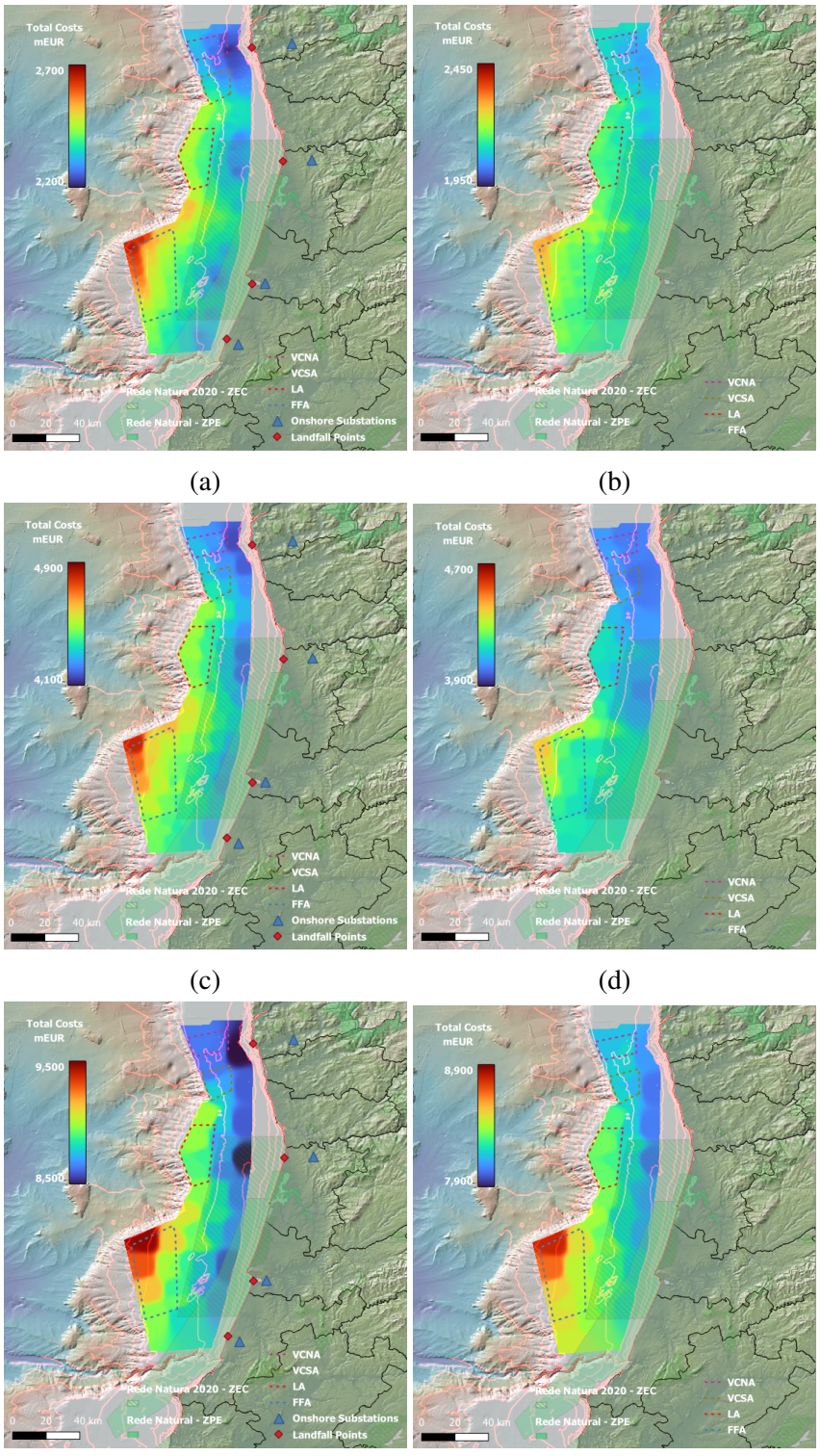


Figure 21: Total costs calculated along the continental platform between water depths of 50 and 500m with different wind farm sizes (a) 250 MW (b) 250 MW without export system (c) 500 MW (d) 500 MW without export system (e) 1000 MW (f) 1000 MW without export system.

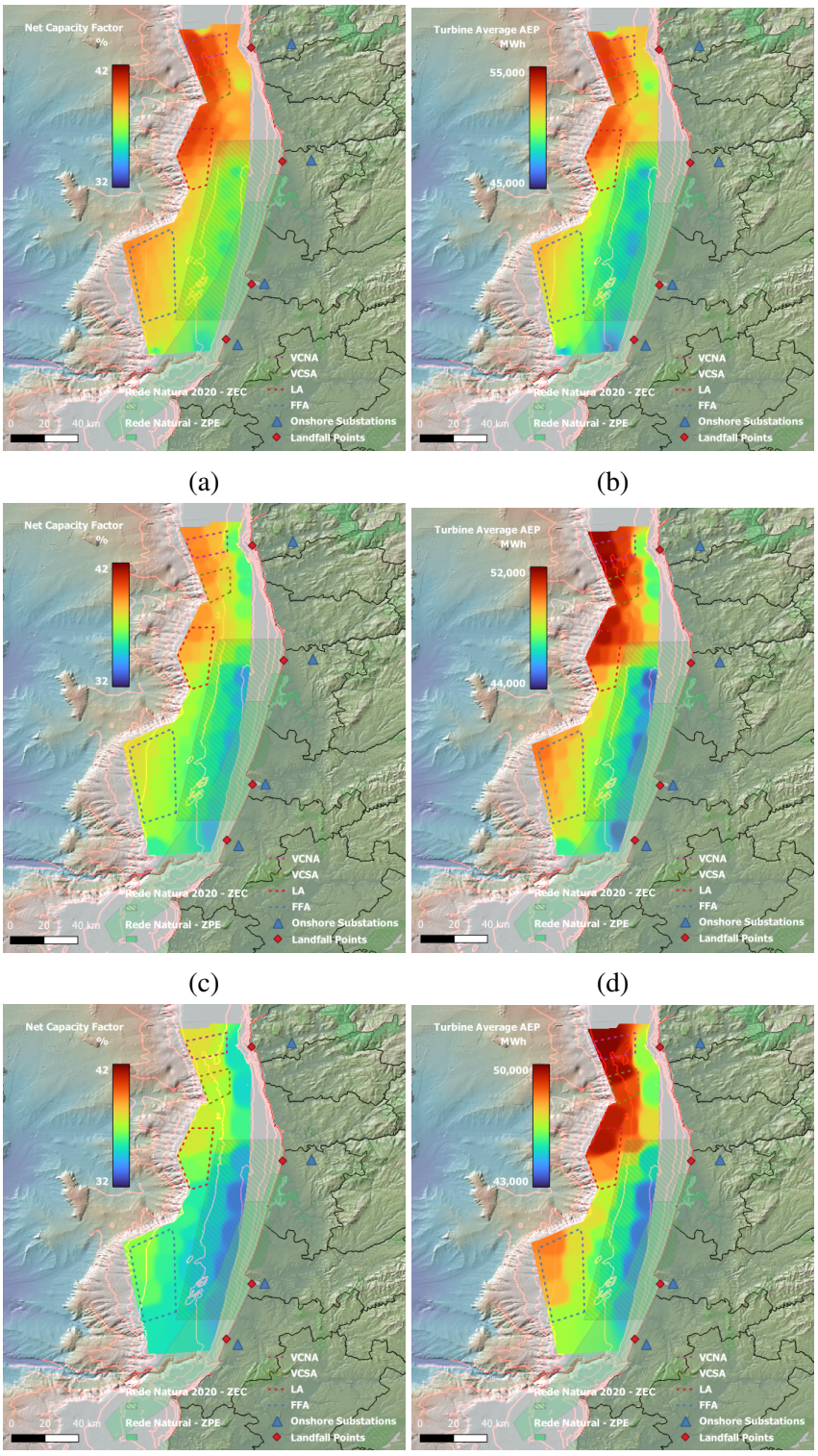


Figure 22: Net capacity factors and average turbine AEP calculated along the continental platform between water depths of 50 and 500m with different wind farm sizes (a) and (b) 250 MW (c) and (d) 500 MW (e) and (f) 1000 MW.

Allocation schedule sensitivity analysis definition and results

Table 3: Capacity Allocation Schedule.

Allocation Year FID		**2024** (2028-29)	**2027** (2031-32)	**2030** (2034-35)
AS1 - Based on Working Group Proposal	Viana Norte	1000	-	-
	Viana Sul	0	1000	-
	Leixões	500	1500	-
	Figueira da Foz	2000	2000	-
AS2 - Small 1st Auction	Viana Norte	500	500	-
	Viana Sul	0	1000	-
	Leixões	500	1500	-
	Figueira da Foz	0	4000	-
AS3 - Based on 2GW 2030 Ambition	Viana Norte	1000	0	-
	Viana Sul	0	1000	-
	Leixões	1000	1000	-
	Figueira da Foz	0	4000	-
AS4 - Based on 2GW 2030 Ambition - Extended	Viana Norte	1000	-	-
	Viana Sul	-	-	1000
	Leixões	1000	1000	-
	Figueira da Foz	-	1000	3000
AS5 - Based on Working Group Proposal - Extended	Viana Norte	1000	-	-
	Viana Sul	-	-	1000
	Leixões	500	1500	-
	Figueira da Foz	2000	-	2000
AS6 - Small 1st Auction - Extended	Viana Norte	500	500	-
	Viana Sul	0	-	1000
	Leixões	500	500	1000
	Figueira da Foz	0	1000	3000

Table 4: Allocation schedule parameters for different years.

Allocation Year	Turbine (Rating / Rotor)	Learning Rate	Discount Rate (Pessimistic)	Discount Rate (Optimistic)
2024	15 MW - 240m	0 %	8.5	7.0
2027	16 MW - 260m	−20 %	7.5	6.0
2030	18 MW - 280m	−25 %	6.5	5.0

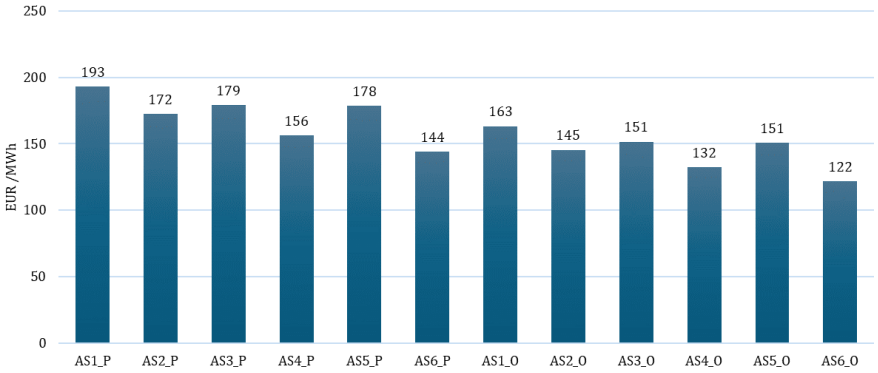
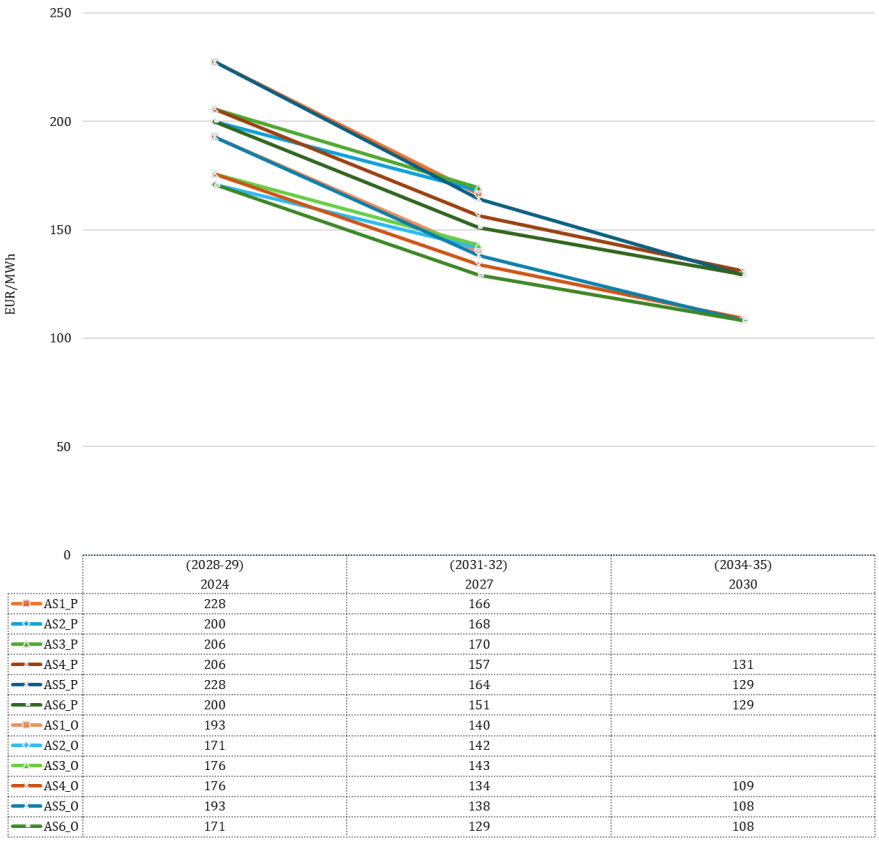


Figure 23: Overall LCOE for the installation of 8GW across different allocation scenarios.



	(2028-29) 2024	(2031-32) 2027	(2034-35) 2030
AS1_P	228	166	
AS2_P	200	168	
AS3_P	206	170	
AS4_P	206	157	131
AS5_P	228	164	129
AS6_P	200	151	129
AS1_O	193	140	
AS2_O	171	142	
AS3_O	176	143	
AS4_O	176	134	109
AS5_O	193	138	108
AS6_O	171	129	108

Figure 24: Overall LCOE for the installation of 8GW per allocation (FID) year across different allocation scenarios.

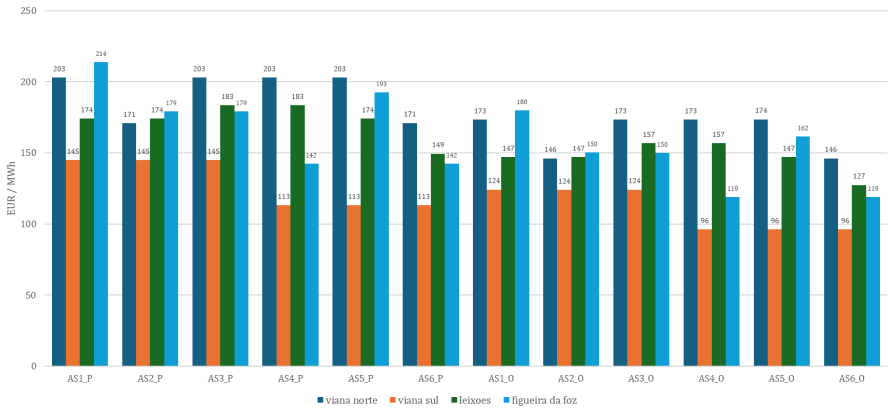
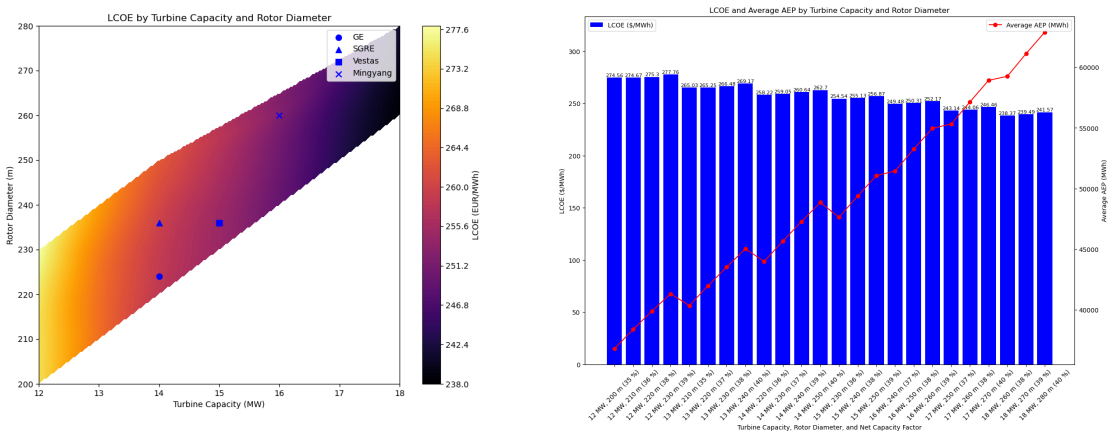


Figure 25: Overall LCOE for the installation of 8GW per site across different allocation scenarios.

Sensitivity analysis to wind turbine choice

As previously mentioned, this study does not delve into specific technology selections; instead, it assumes the use of a standard horizontal axis wind turbine paired with a steel semi-submersible floating platform, which are among the most developed technologies for floating offshore wind projects. Despite this standardisation, the size of the wind turbine—including turbine ratings and rotor diameters—significantly influences the LCOE and the overall economics of the project. Bearing this in mind, a sensitivity analysis was conducted for various turbine sizes, with the results displayed in Figure 26. The computations were carried out specifically for the VCNA site as it is theoretically the most promising as well as the one where development already exists as a result of the WindFloat Atlantic project.



(a) (b)

Figure 26: WTG rotor diameter and turbine capacity sensitivity.

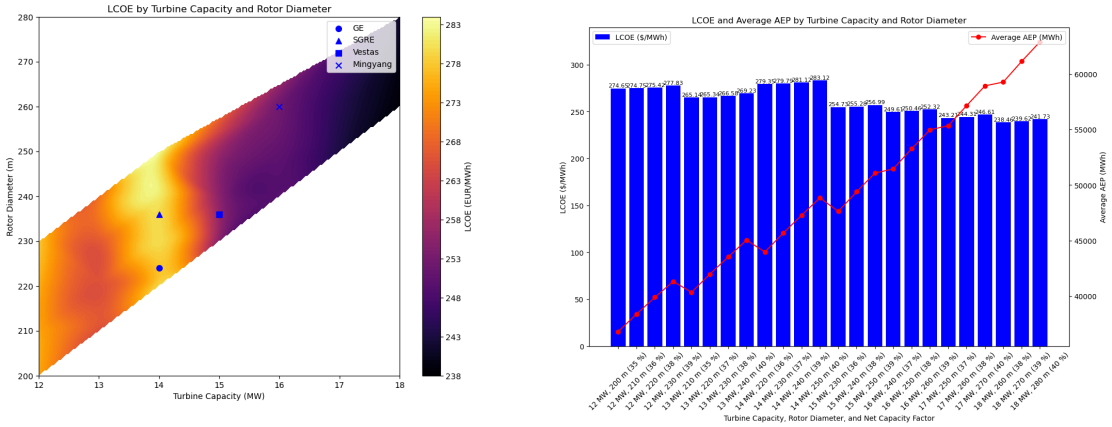
These results warrant careful examination. Fristly, the scaling of the Wind Turbine Generators (WTG) and Floating Platforms (FP) largely follows the scaling laws described in (Sergienko 2022). However, these scaling laws primarily account for changes in rotor diameter and might not fully capture the cost dynamics associated with different WTG ratings with same sized rotor diameters. For example, Vestas offers a 15MW turbine with a 236m rotor diameter, while Siemens Gamesa provides a 14MW turbine with the same rotor size; according to this model, both would incur the same costs, which may not reflect reality.

Bearing this in mind, and upon reviewing the results, it becomes evident that an increase in

turbine size correlates with lower LCOEs[21]. The LCOEs range between 238 and 278 EUR/MWh for 18MW 260m and 12MW 230m WTGs, respectively, within a 1GW wind farm (WF) at VCNA — showing an increase of 40 EUR/MWh. This relationship is not strictly linear, and various unknown variables could potentially sway the results in either direction. Figure 26 also includes the largest available WTGs with at least one prototype in operation.

It is crucial to acknowledge that although this model incorporates cost increases due to changes in tower technology and number of mooring lines, as outlined in (Sergiienko 2022) specifically for 15MW+ WTGs, this is not a straightforward assumption and can change depending on site and technology choices. Additionally a sensitivity analysis is also done, detailing the impacts of altering the thresholds for tower technology changes and mooring line numbers from 15MW to 14MW. See Figure 27.

Moreover, other considerations such as potential decreases in reliability and increases in maintenance costs associated with larger turbines (Aflaki 2024), as well as short-term disruptions and cost increases due to industrial scaling up for larger turbines should be taken into account, even though they are not modelled in this study (Caduff 2012) (Reed 2024).



(a) (b)

Figure 27: WTG rotor diameter and turbine capacity sensitivity threshold for tower and mooring line change at 14MW.

[21] Inflated, including seabed leasing and taxes.

Sensitivity analysis to an increased net capacity factor (less losses) sensitivity analysis

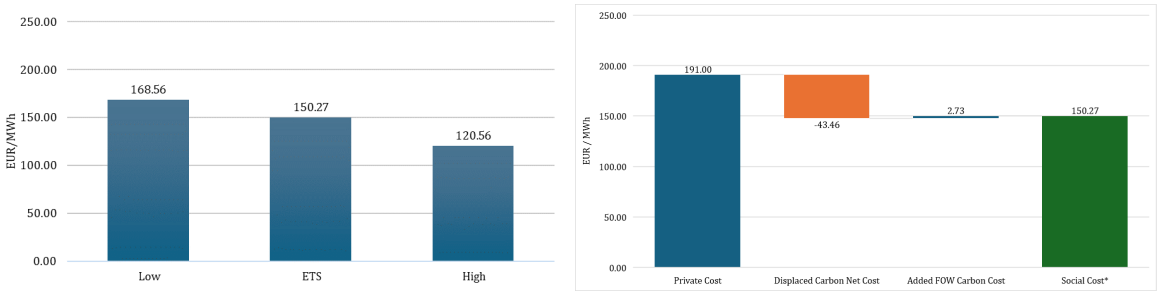
One of the points mentioned for the overall higher values that this model calculates when compared to the recent literature is the fact that it is a bit more aggressive when accounting for losses. It is aggressive because it considers degradation and as result lost of efficiency, something that is not usually consider in traditional LCOEs. It considers as well high values, within the intervals found in the literature, in what other losses are concern. This section presents the results of the LCOE with the increase net capacity factor by reducing 2.5% out of the total losses consider throughout the rest of the study.

As can be see in Table 5, this increase in capacity factors depending on each site has an impact between 11 and 16 EUR/MWh. It is therefore not a neglectable impact which means that proper O&M strategies to reduce turbine downtime and degradation, as well as an optimised layout that is capable of reducing wake losses can be determinant to improve the economic feasibility of these projects.

Table 5: Baseline LCOE results vs Sensitivity with increase NCF for the proposed areas for the first auction allocation rounds.

	Viana Norte	**Leixões**	**Figueira da Foz**
Wind Farm Capacity Assumed/Actual (MW)	1,000 / 1005	500 / 495	2,000 / 1,955
Number of Turbines	67	33	133
Discount Rate		8.5%	
Towing Port		Ferrol	
Annual Average Wind Speed (m/s)	8.76	8.80	8.52
Average Water Depth (m)	116	155	198
Baseline Results Without Export System (Onshore and Offshore Substations and Export Cables)			
Average Turbine AEP (MWh)	49,390	51,384	46,166
Net Capacity Factor (%)	37.6	39.1	35.1
$LCOE_{excluding\ taxes\ and\ tariffs}$ (EUR/MWh)	**183.8**	**181.5**	**220.1**
LCOE (EUR/MWh)	**203.2**	**200.9**	**247.5**
Increase Net CF Sensitivity Study Results Without Export System (Onshore and Offshore Substations and Export Cables)			
Average Turbine AEP (MWh)	52,615	54,646	49,299
Net Capacity Factor (%)	40.0	41.6	37.5
$LCOE_{excluding\ taxes\ and\ tariffs}$ (EUR/MWh)	**172.5**	**170.6**	**206.1**
LCOE (EUR/MWh)	**190.8**	**189.0**	**231.9**

Social costs results considering displaced emissions and added FOW emissions



(a) (b)

Figure 28: Social costs of offshore wind considering carbon emitted and displaced (a) Low, ETS and high costs of carbon (b) Cost variation assuming the 2023 average ETS carbon price. *This is not the complete social cost as the ETS market is not currently design to reflect that cost.

Table 6: Impacts of Offshore Wind Farms on Ecosystem Services

Ecosystem Services	**Impact Type**	**Effect**	**Description**
Provisioning Services	Biomass of fish/shellfish	Positive	Increase in biomass through habitat creation for marine life, providing new resources for commercial fishing and natural diversity.
		Negative	Some studies suggest potential negative impacts or no significant change on certain fish populations due to disruption from construction and operation phases.
Regulating Services	Pest control	Negative	Offshore wind farms facilitate the spread of non-native species, which can disrupt local ecosystems and lead to ecological imbalances.
	Waste mediation & carbon sequestration	Positive	Mussels that colonize turbine foundations enhance waste mediation and carbon storage, contributing positively to environmental health.*
	Hydrological changes	Mixed	Changes in water movements and sediment transport can both benefit and harm local ecosystems depending on the specific environmental conditions.
Cultural Services	Aesthetics	Negative	The presence of turbines can negatively impact the visual landscape, potentially reducing enjoyment of the seascape for residents and tourists.
	Research and education	Positive	The development of offshore wind farms increases knowledge about marine systems through extensive research, contributing to educational advancements.
	Marine mammals	Mixed	Marine mammals may experience disturbances during construction but often adapt over time; the long-term impacts vary by species and location.
	Birds	Mixed	Birds may alter flight paths to avoid turbines, potentially increasing energy expenditure and affecting migration patterns; some species may benefit from new perching and feeding opportunities.
Supporting Services	Habitat creation	Positive	Offshore wind farm foundations serve as artificial reefs, providing new habitats for various marine species and enhancing marine biodiversity.
	Biodiversity	Mixed	Positive effects on biodiversity are observed at turbine bases due to habitat creation, but surrounding areas might experience negative or neutral effects, impacting overall ecosystem health.

* It should be mention that this marine growth might have to be partially clean from time to time (possibly every 5 years) so inspections can be performed on the platform and underwater components as per (DNV 2021).

Value Chain Creation and Investment Retention

The Portuguese offshore wind strategy goes beyond decarbonising the energy system; it aims to establish an industrial hub for components' home production and export, as it is outlined in the *"Estratégia Industrial para as Energias Renováveis Oceânicas (EI-ERO)"* from, 2017. This plan not only targets the offshore wind energy sector but also includes wave energy. The approach involves supporting pioneering projects and offering incentives to the sector. By 2020, the strategy aimed to generate €280 million in added value, attracting €254 million in investment, and create 1500 new jobs. However, it remains unclear whether these goals were achieved or evaluated.

In the offshore wind (OW) segment, the strategy identifies various industry sectors, emphasising different components and companies crucial to fostering export growth. Notably, in the turbine segment, the production of blades and nacelles mentions Enercon[22] and Ria Blades[23]. For tower production, it mentions companies like ASM Energy (now CS Wind), Tegopi, and Martifer Energy Systems, with room for new players to enter the market. Nowadays, CS Wind stands out among all of the others mentioned for producing significant strides in offshore wind business by producing tower pieces and transition pieces for bottom-fixed offshore wind, with the capacity to produce them in Portugal.

In the floating platform (FP) segment, opportunities are highlighted to lie in the production and assembly of the platform itself, ASM Energy (CS Wind), Tegopi, and AMAL Group are mentioned. Additionally, for the production of mooring lines' rope section there could also be capacity in the country, with Lankhorst Euronete and Oliveira & Sá as potential suppliers. Moreover, for the production of IACs, Solidal and Cabelte are mentioned. Notably, WindFloat Atlantic saw the participation of several of these companies, including CS Wind (formerly ASM) in FP production and assembly, and Lankhorst in producing the rope section for the project's mooring lines. WindFloat 1 also featured Solidal in the production of the HV cables and ASM in FP production. (Minstério do Mar 2017) (Durakovic 2019a) (Lankhorst 2021) (Solidal 2012)

[22]Enercon does not have an offshore division

[23]Now owned by Siemens Gamesa but only focus on onshore for the moment

The positive externalities of this strategy and investments have yet to be capitalised upon by other projects, as other pre-commercial projects, similar to WindFloat Atlantic, have used potential values chains created by this initial investment. For instance, Kincardine chose to have the floating platforms constructed and assembled in the port of Ferrol, by Navantia, while for the *Les Eoliennes Flottantes du Golfe du Lion* project, the columns are being produced in Turkey, and the assembly will take place in a port close to the project site in France. (Durakovic 2019b) (Bajic 2024)

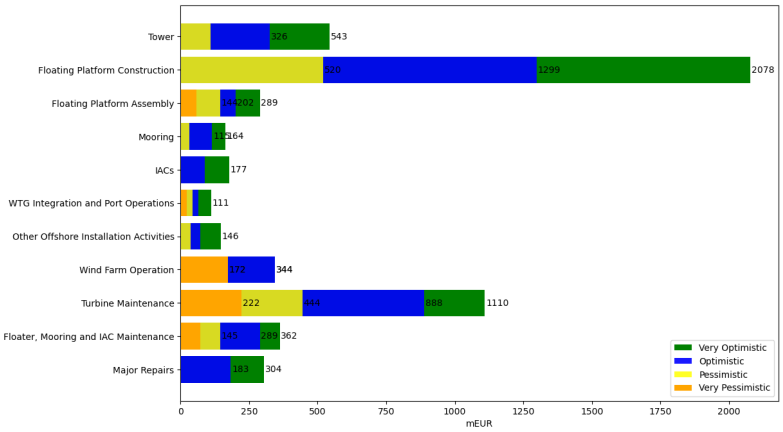
Considering this information and getting back to the model and its results, four scenarios are created to illustrate the potential project investment that could be captured in the country with the right industrial structure, as in Table 7. This approach simplifies the complexities associated with building all of the planned GWs of energy; for example, it does not account for potential bottlenecks causing project delays or the need to source suppliers elsewhere because existing players don't have the capacity to supply all these projects or even the presence of new players. So it not does pretend to be a value chain evaluation but only highlighting, simplistically, the different parts of the investment that could be potentially captured.

Table 7: Different Scenarios for Investment Capture by the Country.

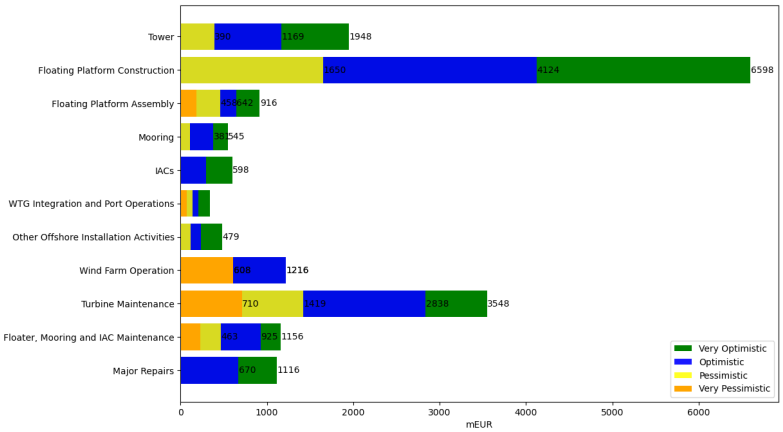
Category	**Item**	**V. Opt.**	**Optimistic**	**Pessimistic**	**V. Pess.**
CapEx	Tower	100%	60%	20%	0%
	Float. Plat. Construction**	80%	50%	20%	0%
	Float. Plat. Assembly**	100%	70%	50%	20%
	Mooring*	100%	70%	20%	0%
	IACs	100%	50%	0%	0%
	WTG Integrat. Port Operat.	50%	30%	20%	10%
	Other Offshore Installation Activities	20%	10%	5%	0%
OpEx	Wind Farm Operation	20%	20%	10%	10%
	Turbine Maintenance***	50%	40%	20%	10%
	Floater, Mooring and IAC Maint.***	50%	40%	20%	10%
	Major Repairs	50%	30%	0%	0%

* Assuming that the rope is 15% of the total mooring cost.
** Assuming that assembly is 10% of the total floating platform costs.
*** May vary depending on the spare parts and consumables availability and labour experience adequacy.

For 2GW, the total investment that could be potentially captured under the optimistic scenario would be around 3,870 mEUR while under the pessimistic that it could be around 545 mEUR (18460 and 1800 mEUR for the 8GW scenario respectively). These values are cal-



(a)



(b)

Figure 29: Potential investment industrial capture under different optimistic and pessimistic scenarios (a) 2GW (b) 8GW as per AS4 described in Table 3

culated using the results of the model for allocation scenarios AS3 and AS4 as mentioned in section 3.2.4. The main bottleneck it is possibly in the port infrastructure. As for the exporting of components and the creation of a industrial hub the question is harder to answer. Market growth and dynamics will play a huge in how the possible materialisation of these scenarios happens. It is important thought, to note the fact that a lot of the countries betting on FOW also aim to bank from it industrially. In Europe the UK is the front runner, but France, Spain, Norway and Italy also have plans for FOW in the short medium term.

Sines and Ericeira Areas Analysis

It is the choice of this study to focus on the areas identified by the (Group 2023) as the most promising among all the areas define. This cover 80% of the total planned capacity and in theory are the most interesting ones. Nevertheless, a quick analysis is made regarding the other two areas left out of the main study. These are *Ericeira* planned for a capacity of 500MWs and *Sines* planned for a capacity of 1.5GWs. Results can be seen in Table 8.

Table 8: Baseline LCOE results for VCNA vs Ericeira and Sines Areas

	Viana Norte	**Ericeira**	**Sines**
Wind Farm Capacity Assumed/Actual (MW)	1,000 / 1005	500 / 495	1500 / 1500
Number of Turbines	67	33	100
Discount Rate		8.5%	
Towing Port	Ferrol	Setúbal	
Annual Average Wind Speed (m/s)	8.76	8.51	7.91
Average Water Depth (m)	116	85	316
Average Turbine AEP (MWh)	49,390	49,352	42,362
Net Capacity Factor (%)	37.6	37.5	32.2
Baseline Results Without Export System (Onshore and Offshore Substations and Export Cables)			
$LCOE_{excluding\ taxes\ and\ tariffs}$ (EUR/MWh)	**183.8**	**181.5**	**236.4**
LCOE (EUR/MWh)	**203.2**	**200.5**	**265.8**

It is clear from the values presented in table that one of the areas seems more interesting than the other in terms of the LCOE. *Ericeira* is actually the cheapest area in this analysis, although the values are pretty close to VCNA and to developing 500MW in the LA. This low cost is achieved through a combination of a good wind resource, with low bathymetry, also lower wake losses when compared to VCNA due to smaller size of the projected capacity. Although not study, if the export system would have also been part of the calculation it could be expected that the difference would enlarge to make Ericeira cheaper, given that its closure to shore than the other areas. The reason why this area is not so attractive is because it raises some concerns in different topics: it is in between two special zones of protection (*ZPE - Rede Natura 2020*) within a general sea sensitive area - Figure 30; It is close to shore where aesthetics might start to cause some push back, especially because that shoreline area has a lot of tourism and nautical sports; There is underwater communication cables within the area which are also a source of increase risk. Nevertheless, although not a priority, the area is still to be approved in the context

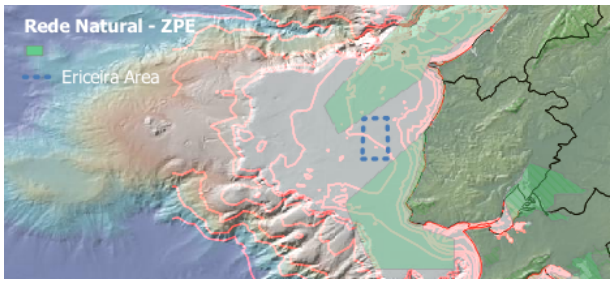


Figure 30: Ericeira Area and Special Zones of Protection.

of the PAER for future energy development so it should be mention that if obstacles are to be overcome it is a area with a lot of potential (Group 2023). As for Sines, even though a lot of industrial development is planned within the area that could benefit from a source of energy like offshore wind (Government 2023). The area itself seems to be very much unattractive in comparison. It has the worst LCOE within all of the areas, this is the main result of being the area with the weakest wind resource while at the same time being the one with the largest average bathymetry, The calculated LCOE is of 265.8 EUR/MWh, and if the export system was to be considered it could potentially be very close to 300 EUR/MWh.

CfDs

A Contract for Difference (CfD) in the context of offshore wind is a financial mechanism used to support and incentivise the development of renewable energy projects, including offshore wind farms. A CfD is a long-term agreement (typically 15 years or more) between a renewable energy generator, such as an offshore wind farm operator, and a government entity or a designated body. The mechanism usually defines a strike price. This is is the fixed price per unit of electricity agreed upon in the CfD contract and its meant to provide a predictable revenue stream for the generator.

A standard fixed priced CfD usually works like this: When the market price is below the strike price the government pays the generator the difference between the strike price and the market price ensuring that the generator receives a steady and predictable income. When the market price is above the strike price the generator pays the difference back to the government ensuring that the consumers benefit from lower market prices.

The financial stability provided by CfDs shoud also makes it easier to secure financing for large and capital-intensive projects like offshore wind projects.

CfDs are often allocated through competitive bidding processes, where developers submit bids specifying the strike price they require to undertake their projects. The lowest bids that meet the criteria are typically awarded the contracts. This auction process encourages efficiency and cost reduction, as developers compete to offer the lowest possible strike price.

Besides the standard fixed priced CfD there is other types of CfDs: indexed CfD - adjusts to inflation; Cap and floor CfD - determining a minimum payment (floor) for a generator and maximum price that can be captured in the market (cap); virtual CfDs - simulates the economic effects of a CfD through financial instruments; among others.

In summary, CfDs are a crucial policy tool that helps stabilise revenue for offshore wind projects, encourages investment, and supports the broader goals of increasing renewable energy generation and reducing greenhouse gas emissions.

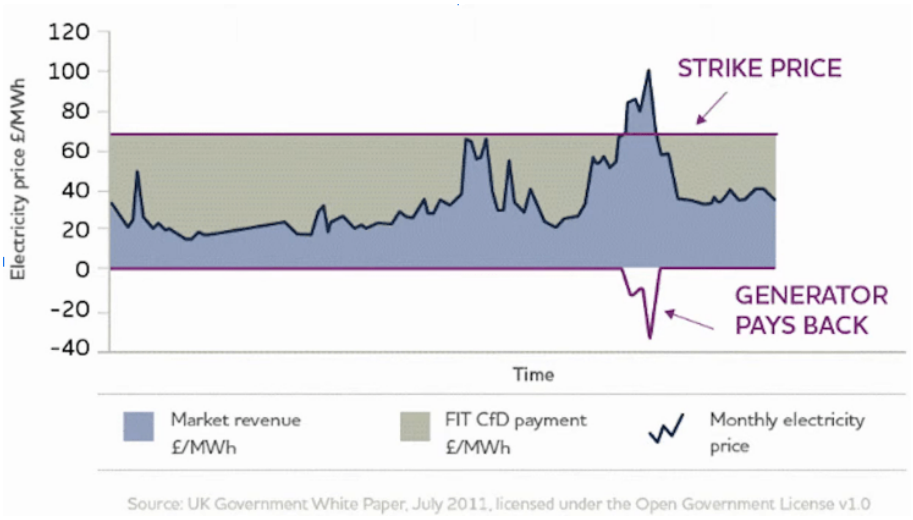


Figure 31: CfD illustration.

Model Variables Referenced and Used

Table 9: Wind Speed Distibution Simulation and Turbine Layout Rules

Variable	Value	Reference
Reference Wind Data Height (m)	10	(World Bank Group 2023)
Weibull Rayleigh Shape Factor	1.9	(World Bank Group 2023)
Power Law Coefficient	0.11	(Hsu 1994)
Turbulence Intensity	0.025	
Number of wind speed simulations (n)	1 000 000	
Turbine Spacing X and Y	8.5 * $Rotor_D$	

Table 10: Development Costs Calculation

Variable	Value	Reference
Reference Development Costs (mEUR)	77	(BVGA 2023)
Reference Wind Farm Capacity (MW)	450	(BVGA 2023)

Table 11: Turbine and Floating Platform Costs Calculation

Variable	Value	Reference
Reference Rotor Diameter (m)	224	(BVGA 2023)
Reference Rated Wind Speed (m/s)	11	(NREL 2020)
Reference Turbine Capacity (MW)	15	(BVGA 2023)
Reference Wind Farm Capacity (MW)	450	(BVGA 2023)
Reference Rotor Cost (mEUR)	7.01	(BVGA 2023)
Reference Nacelle Cost (mEUR)	12.86	(BVGA 2023)
Reference Tower Cost (mEUR)	3.51	(BVGA 2023)
Reference Floating Platform Cost (mEUR)	16.66	(BVGA 2023)
Reference Rotor Mass (mT)	230	(BVGA 2023)
Reference Nacelle Mass (mT)	700	(BVGA 2023)
Reference Tower Mass (mT)	860	(BVGA 2023)
Reference Floating Platform Mass (mT)	4000	(Orsted 2024)

Table 12: Mooring System Parameters and Costs Calculation

Parameter	Value or Formula	Reference
Number of Mooring Lines	$\begin{cases} 3, & \text{if Turbine Capacity} < 15 \text{ MW} \\ 6, & \text{if Turbine Capacity} \geq 15 \text{ MW} \end{cases}$	
Reduction Factor	$\begin{cases} 1, & \text{if Turbine Capacity} < 15 \text{ MW} \\ 1.4, & \text{if Turbine Capacity} \geq 15 \text{ MW} \end{cases}$	
Reference Chain Weight (t/m)	0.75	(Strag 2022)
Reference Fairlead Force (t)	250	(BVGA 2023)
Anchor Cost (mEUR)	0.1	(BVGA 2023)
Reference Mooring Cost (mEUR/mT)	0.006	(Strag 2022)

Table 13: Export System and IAC Costs Calculation

Variable	Value	Reference
Reference Wind Farm Capacity (MW)	450	(BVGA 2023)
Reference Offshore Substation Cost (mEUR)	78.71	(BVGA 2023)
Reference Onshore Substation Cost (mEUR)	43.47	(BVGA 2023)
Reference IAC Cost (mEUR/km)	0.5	(BVGA 2023)
Reference Export Cable 350MW Cost (mEUR/km)	1.2	(BVGA 2023)
Reference Export Cable 250MW Cost (mEUR/km)	0.857	(BVGA 2023)
Reference Onshore Export Cable Cost (mEUR/km)	0.36	(BVGA 2023)

Table 14: General Parameters for Instalation Costs Calculation

Variable	Value	Reference
Weather Contingency for Port Operations	5%	
Weather Contingency for Site Operations	20%	
Premium for Personnel Surveys and/or Small Equipment	20%	(Frazer-Nash 2023)
Premium for Project Management and Engineering	5%	(Frazer-Nash 2023)

Table 15: Wind Turbine Integration and Storage Costs Calculation

Variable	Value	Reference
Reference Hub Diameter (m)	7.94	(NREL 2020)
Reference Rotor Diameter (m)	224	(NREL 2020)
Number of Tower Sections	4	
Reference Floating Platform Mass (mT)	4000	(Orsted 2024)
Reference Floating Platform footprint (m^2)	2000	
Storage Margin in Port	2	
Number of Turbines in Storage at a Time	12	
Reference Port Storage Cost Rate (EUR/m^2day)	0.35	(Strag 2022)
Number of Days for Turbine Integration per Turbine	9	
Ring Crane Daily Rate (EUR/day)	250 000	(Strag 2022)
Harbour Tug Daily Rate (EUR/day)	15 000	(Urbano 2021)
Number of Harbour Tugs	3	
Quayside Slots	1 / 2	

Table 16: Mooring Pre-Lay Costs Calculation

Variable	Value	Reference
Number of AHVs	1/2	
AHV Daily Rate (EUR/day)	108 472	
AHV Transit Speed (km/h)	37	
AHV Deck Mooring Line Capacity	2/3	
Mooring pre-lay Tak Time	50	

Table 17: Export System and IAC instalation Costs Calculation

Variable	Value	Reference
Number of CLVs	1/2	
IAC and Export Cable CLV Daily Rate (EUR/day)	175 000	(Ramachandran 2021)
IAC and Export Cable CLV Carrousel Capacity (mT)	1 250	(Jandenul 2024)
IAC and Export Cable CLV Transit Speed (km/h)	23.15	(Jandenul 2024)
IAC CLV Laying Speed (m/day)	400	(Devin 2021)
IAC Cable Weight (kg/m)	70	(Scotland 2024)
Export Cable Weight (kg/m)	150	(Scotland 2024)
Offshore Substation Installation Cost (mEUR)	11.9	(BVGA 2023)
Onshore Cable Installation Cost (mEUR/km)	0.35	(BVGA 2023)

Table 18: Towing and Hook-up Costs Calculation

Variable	Value	Reference
Number of Tugs	1/2	
Offshore Tug Daily Rate (EUR/day)	108 472	(Strag 2022)
Offshore Tug Transit Speed (km/hr)	37	(Strag 2022)
Offshore Tug Towing Speed (km/hr)	5.56	(Crowle 2022)
Assistant Tug Daily Rate (EUR/day)	30 000	(Urbano 2021)
Hook-up Vessel Daily Rate (EUR/day)	108 472	
CTV Daily Rate (EUR/day)	4 500	(Ramachandran 2021)
Hook-up Tak Time (ht)	52	(Altuzarra 2022)
IAC Cable Pull In Cost (mEUR/MW)	0.0125	(BVGA 2023)

Table 19: Other CapEx Costs Calculation

Variable	Value	Reference
Debt Share of Project Financing	70%	
Contingency Premium	8%	
Legal and Financing Premium	3.5%	
Insurance Premium	2.5%	

Table 20: OpEx Costs Calculation

Variable	Value	Reference
Turbine Maintenance Cost (mEUR/(Turbine Year))	0.572	(BVGA 2023)
FP, Mooring and Electric BoP Cost (mEUR/(Turbine Year))	0.18	(BVGA 2023)
Failure Rate Turbine	0.0315	(Urbano 2021)
Failure Rate Mooring	0.0025	(Urbano 2021)
Failure Rate IACs	0.016	(Urbano 2021)
Operation Cost (mEUR/MW)	0.0285	(BVGA 2023)
Contingency Premium	5%	

Table 21: DecEx Costs Calculation

Variable	Value	Reference
Decommission rate applied on installation costs - Turbine and FP	70%	(Strag 2022)
Decommission rate applied on installation costs - Cables	10%	(Strag 2022)
Decommission rate applied on installation costs - Export System	90%	(Strag 2022)
Decommission rate applied on installation costs - Mooring	90%	(Strag 2022)

Table 22: Taxes and Seabed Leasing Charges Costs Calculation

Variable	Value	Reference
Depreciation Rate	8%	(KPMG 2023)
Seabed Leasing Charge in Operation (EUR/MWh)	1.25	(Laido 2022)
Tax Rate (without surcharge)	21%	(KPMG 2023)

Description	**Values**
Auction Year	2024 / 2027 / 2030
Development expenditure profile	[0.1, 0.2, 0.4, 0.3] (if wind_farm_capacity $<$ 1000) [0.1, 0.1, 0.25, 0.3, 0.25] (if wind_farm_capacity $\geq$ 1000)
Financial Investment Decision (FID) year	auction year + 4 (if wind_farm_capacity $<$ 1000) auction year + 5 (if wind_farm_capacity $\geq$ 1000)
Integration Days : Number of days required for WTG integration	Calculated by the model
Years to COD: Number of years to the Commercial Operation Date	integration_days/365
Commercial Operation Date (COD) year	FID_year + $\lceil$years_to_COD$\rceil$ + 2 (if $\lceil$years_to_COD$\rceil$ = 1) FID_year + $\lceil$years_to_COD$\rceil$ + 1 (if $\lceil$years_to_COD$\rceil > 1$)
Installation expenditure profile from FID to COD	[0, 0.4, 0.6] (if $\lceil$years_to_COD$\rceil \leq 3$) [0, 0.25, 0.5, 0.25] (if $\lceil$years_to_COD$\rceil$ = 3) [0, 0.2, 0.3, 0.3, 0.2] (if $\lceil$years_to_COD$\rceil >$ 3)
Procurement expenditure profile from FID to COD	[0.6, 0.4, 0] (if $\lceil$years_to_COD$\rceil \leq 3$) [0.3, 0.5, 0.2, 0] (if $\lceil$years_to_COD$\rceil$ = 3) [0.1, 0.3, 0.4, 0.15, 0.05] (if $\lceil$years_to_COD$\rceil$ > 3)
Other capital expenditure costs profile from FID to COD	[0.2, 0.3, 0.3] (if $\lceil$years_to_COD$\rceil \leq 3$) [0.4, 0.2, 0.2, 0.2] (if $\lceil$years_to_COD$\rceil$ = 3) [0.4, 0.15, 0.15, 0.15, 0.15] (if $\lceil$years_to_COD$\rceil > 3$)
Project Lifetime	30
Decommissioning expenditure profile	[0.5, 0.5]

Table 23: NCF Spending Profiles

Other

Production Type	Production (GWh)	Average Acquisition Price (EUR/MWh)	Total Cost (10^3 EUR)	Reference Price for PRG Differential Calculation (EUR/MWh)	PRG Differential of the Year (10^3 EUR)
Wind	13,016	92.8	1,207,785	83.4	121,587
Hydro	693	111.2	77,079	83.4	19,234
Biogas	814	131.7	107,202	83.4	39,018
Biomass	1,278	138.9	177,540	83.4	70,736
Photovoltaic	352	247.2	87,001	83.4	57,678
Offshore Wind	0	0.0	0	83.4	0
Waves	0	0.0	0	83.4	0
MSW (Municipal Solid Waste)	950	45.0	42,748	83.4	-36,496
CHP (Non-Renewable)	2,826	99.4	280,943	83.4	45,080
CHP (Renewable)	1,898	105.3	199,781	83.4	41,899
Micro/Mini/UPAC/UPP	80	116.0	9,280	83.4	2,613
Photovoltaic Auctions	29	20.0	580	83.4	-1,837
Total Production with Guaranteed Remuneration	**21,113**	**102.1**	**2,154,884**	**83.4**	**393,019**

Figure 32: Data on electricity produced with guaranteed remuneration as forecast for 2024 (ERSE 2024).

Acronyms

- AEP - Annual Energy Production
- LCOE - Levelized Cost of Energy
- DTU - Danish Technical University
- IEA - International Energy Agency
- NREL - National Renewable Energy Laboratory, U.S. Department of Energy
- BoP - Balance of Plant
- IAC - Inter Array Cable
- TSO - Transmission System Operator
- AHV - Anchor Handling Vessel
- CTV - Crew Transfer Vessel
- FID - Financial Investment Decision
- COD - Commercial Operation Date
- CapEx - Capital Expenditures
- OpEx - Operation Expenditures
- DevEx - Development Expenditures
- DecEx - Decommissioning Expenditures
- TotEx - Total Expenditures
- WTG - Wind Turbine Generator
- FP - Floating Platform
- VCNA - Viana do Castelo Norte Area

- LA - Leixões Area
- FFA - Figueira da Foz Area
- WF - Wind Fram
- FOW - Floating Offshore Wind
- MCR - Major Component Replacement
- PAER - Plano de Afetação de Energias Renovaveis
- CfD - Contract for differences
- GWEC - Global Wind Energy Council
- FEED - Front End Engineering Design
- OEM - Original Equipement Manufacturer
- FiT - Feed in Tariff
- ZEC - Special Zone of Conservation
- ZPE - Special Zone of Protection