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Hybrid Fixed and Floating Wind Turbine Siting in the Mediterranean Region: An Energy and Economic Analysis

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Abstract

This study introduces a hybrid siting approach for Offshore Wind Farms by combining bottom-fixed and floating wind turbines to address seabed variability in the Mediterranean region. Using Heraklion Bay, Crete, as a case study, a multi-step methodology was adopted, integrating GIS tools, micro-siting analysis, and WAsP simulations to estimate the energy output of three layout scenarios. A comprehensive energy and economic assessment was performed, including key metrics such as Net Present Value, Internal Rate of Return, Payback Period and Levelised Cost of Energy. Scenario 2, which featured a mixed deployment of Vestas and Siemens Gamesa turbines, proved to be the most financially attractive option, yielding the highest Net Present Value (€167 million) and shortest Payback Period. Sensitivity analysis under a 20% reduction in wind resources confirmed the robustness of this scenario. Results demonstrate that hybrid configurations offer a flexible and scalable solution, particularly in island regions with varied bathymetry and seasonal energy demands. The findings highlight the potential of hybrid offshore systems to accelerate energy transitions, optimise spatial utilisation, and improve cost-effectiveness in medium-depth seas.

Keywords: offshore wind farm; energy analysis; economic analysis; levelised cost of energy; floating wind

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Academic Editor: Lars Johanning

Received: 27 May 2025
Revised: 23 October 2025
Accepted: 28 October 2025
Published: 31 October 2025

Citation: Gkeka-Serpetsidaki, P.; Fotiou, D.; Tsoutsos, T. Hybrid Fixed and Floating Wind Turbine Siting in the Mediterranean Region: An Energy and Economic Analysis. *Energies* **2025**, *18*, 5739. https://doi.org/10.3390/en18215739

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1. Introduction

For islands, transitioning from onshore to offshore power is increasingly critical due to land scarcity, seasonal demand surges, and challenging terrain [1]. Offshore Wind Farms (OWFs) benefit from stronger, more stable wind profiles and fewer physical constraints compared to onshore projects [2]. Additionally, larger turbine sizes and reduced land-use conflicts improve their performance and public acceptance. OWFs near high-demand centres, such as coastal or insular areas, offer efficient energy delivery and contribute to regional decarbonisation [3–5].

This study aims to evaluate hybrid OWF micro-siting in the Mediterranean using bottom-fixed (BFWTs) and floating wind turbines (FWTs), addressing site-specific depth challenges. Crete is selected as the case study due to its strong wind potential and developing grid interconnections with mainland Greece. The research expands on previous geographic siting analyses by incorporating a detailed techno-economic assessment.

The primary aim of this study is to test and combine existing methodologies for the energy and economic assessment of optimal sites for the development of offshore wind energy projects in the Mediterranean region. The second objective is to evaluate

the economic feasibility of combining bottom-fixed with FWTs due to the area's broad variations in sea depth.

The hybrid strategy maximises energy capture by placing BFWTs in shallow water and FWTs in deeper areas, effectively leveraging diverse seabed depths to improve overall energy production and efficiency. This dual approach makes good use of different seabed types and depths, boosting the wind farm's energy capture and overall performance. By utilising the strengths of fixed and floating platforms, the project can adapt to varying seabed conditions, including deeper waters that are usually difficult for fixed installations. The aim is to determine whether such hybrid layouts can improve efficiency, scalability, and cost-effectiveness within realistic economic and technical limits.

Applying this framework to a Mediterranean island like Crete, the research aims to assess the economic viability, energy potential, and sustainability of such projects, while also identifying key technological and financial challenges. Ultimately, the study seeks to support the expansion of offshore wind energy by providing practical, scalable solutions to enhance efficiency and cost-effectiveness. This framework is designed to be replicable and adaptable, enabling the integration of offshore wind energy into various geographical and economic contexts.

Most existing research on OWFs and hybrid fixed–floating configurations has focused on regions such as the North Sea, where shallow waters, mature grid infrastructure, and stable wind regimes enable cost-effective fixed-bottom installations [3,6]. However, Mediterranean conditions differ significantly. Coastal areas are characterised by deeper waters close to shore, more complex bathymetry, and higher seasonal variability of wind resources influenced by local thermal effects [7,8]. Additionally, grid infrastructure in island regions such as Crete remains less developed and more constrained, directly impacting interconnection strategies and overall project feasibility [4,5]. These regional characteristics require tailored siting approaches, turbine selection strategies, and techno-economic assessments. This study builds on previous work in the Mediterranean context [4,5,8] by applying a hybrid fixed–floating layout analysis specifically adapted to these site-specific conditions, thus extending the existing literature beyond the typical North Sea focus.

2. State-of-the-Art

2.1. Feasibility Studies on OWFs

Several studies have examined the techno-economic assessment of OWFs. However, they tend to concentrate on site selection or incorporate it alongside other factors when evaluating their effectiveness.

Using Capital Expenditure (CAPEX) and Levelised Cost of Energy (LCOE) indicators, Ref. [9] conducted an economic analysis of offshore wind projects in the Brazilian Sea, highlighting the most economically and energy-efficient regions. As a result, some emerging areas had a lower LCOE, around US$ 69.9/MWh, and a lower CAPEX, around US$ 2.34/MW.

Moreover, a study [10] carried out to determine whether an OWF could be developed in Turkish waters. To conduct a technical analysis, windPRO 2.9 software calculates the proposed project's potential Annual Energy Production (AEP). For the selected sites, they provided details on investment cost, operations and maintenance cost, annual revenue, Net Present Value (NPV), and LCOE.

Furthermore [11], used Integrated Valuation of Environmental Services and Trade-offs to assess the economic feasibility of OWFs. An analysis of the NPV of a 60-MW OWF with a 20-year lifespan was conducted using CAPEX for grid connection and electricity transmission, Operation and Maintenance Cost (O&M) costs, and other expenses. As a

result, the researchers concluded that the NPV of OWFs is significantly impacted by the distance from the nearest inland substation, highlighting the importance of grid connection.

A multi-objective optimisation model was utilised by [1] to assess the feasibility of the sites. The five objectives of the Life Cycle Cost (LCC) analysis included the costs associated with (1) predevelopment and consenting, (2) production and acquisition, (3) installation and commissioning, (4) operation and maintenance, and finally, (5) decommissioning and disposal.

Upon selecting the site, Ref. [12] applied an economic evaluation that includes CAPEX, Operating Expenses (OPEX), and Decommissioning Cost (DECEX) during the project's life cycle, which results in the total investment costs of the portfolio.

Using a Multi-Criteria Decision Making (MCDM) approach [13], the regions are considered, and a detailed economic feasibility analysis is conducted utilising a discounted cash flow economic model. This model considers the major indicators NPV, LCOE, DPBP, and Internal Rate of Return (IRR) at various discount rates. As a result, the radial electrical design proved to be more cost-effective than the conventional one under certain technological and economic conditions.

An economic analysis was conducted for four sites [14] utilising the Geske compound option model and the CAPEX and OPEX of the wind farm. Based on their findings, the flexibility value and uncertainty factor significantly influence the entire process.

In a study [15], seven WT models were examined using the LCOE, which considered both CAPEX and OPEX. The results showed that V236-15.0 MW and Siemens SWT113 had the highest and lowest capacity factors and power outputs across the seasons and sites, respectively.

2.2. Feasibility Studies on Floating OWFs

High CAPEX and OPEX are the main barriers to installing FWTs. Other uncertainties include the supply chain, commodities, monetary inflation, environmental conditions affecting technical aspects, downtime, and distances between the WF location and coastal facilities [16].

Initially, Ref. [7] analysed floating feasibility in the European and Eastern Mediterranean regions with a detailed cost breakdown, focusing on semi-submersible platforms. The analysis considers CAPEX, the development and consent phase, the turbine and substructure, the mooring systems, electrical infrastructure, the installation phase, decommissioning operations and maintenance, and the AEP.

Subsequently, in Ref. [8], to estimate productivity and to develop a detailed cost model, each layout was evaluated based on the LCOE, considering aerodynamic wakes and transmission losses. As a function of the number of WTs, the normalised optimal LCOE and capacity factors are not significantly influenced by location and reach a maximum difference of 2–3%, suggesting that they are primarily determined by type.

Unlike North Sea projects, Mediterranean sites encounter steeper bathymetric gradients, limited port infrastructure, and grid interconnection constraints, influencing foundation selection, logistics, and cost structure. These regional factors make hybrid layouts especially relevant, enabling deployment across mixed-depth zones while addressing spatial and technical limitations unique to island systems.

Finally, LCOE was calculated for three floating platform formats: Spar-Buoy, Tension Leg Platform and Semi-Submersible [16]. The model evaluated floating foundations in steel and concrete. After that, a holistic LCC was conducted, starting with project development and continuing through decommissioning. It evaluated qualitative factors such as potential employment, environmental, and residential impacts as well as quantitative factors such as IRR, NPV and LCOE. According to the study results, semisubmersible solutions are the

most cost-effective, while tension-leg foundations are the costliest due to higher installation and decommissioning expenses.

2.3. Innovation

Studies that examine site selection processes incorporate technological and economic factors to promote a sustainable scenario. In contrast, this study uses energy and economic factors to evaluate the existing optimal sites identified in the previous research stage.

While offshore wind studies usually focus on either bottom-fixed or floating turbines separately, research on their combined deployment in hybrid arrangements remains limited. This integration offers clear benefits, including better spatial efficiency, adaptability to variable seabed conditions, and enhanced cost-performance trade-offs. Although the methodological tools used here (GIS, WAsP, standard financial metrics) are well-established, their combined application to a hybrid fixed–floating layout in a Mediterranean island context tackles region-specific challenges such as steep bathymetry, grid constraints, and seasonal demand peaks. While not proposing a new methodology, this study shows how existing approaches can effectively adapt to new geographical and technical settings. While the use of Global Wind Atlas data was suitable for this preliminary assessment, future research should include detailed on-site wind measurements to reduce uncertainty and improve the reliability of the predicted energy yield and economic performance.

This study addresses these gaps by providing a detailed, site-specific analysis that integrates technological, environmental, and economic factors, illustrating the potential benefits and challenges of siting hybrid Offshore Wind Turbines (OWTs). By closing this research gap, the study helps optimise OWF design, making renewable energy solutions more adaptable and efficient for island and coastal energy systems in the Mediterranean region. Together, these innovations mark significant progress in offshore wind energy.

3. Materials and Methods

3.1. Theoretical Background

All costs associated with post-commercial operation, prior to decommissioning, that are necessary to ensure the project's efficient operation and guarantee the WT's performance are included in OPEX. Estimating the lifetime cost of OWFs relies on the key drivers of wind energy economics, including CAPEX, OPEX, and DECEX [6].

Approximately 70–80% of the lifetime cost of a WF can be attributed to CAPEX, which includes the cost of the offshore WT, project development, project management, offshore substation, onshore substation, cables, moorings, installation, and commissioning [17].

The overall cost structure was classified into three main categories: CAPEX, OPEX, and DECEX. CAPEX includes project development, turbine procurement, substation infrastructure (onshore/offshore), cabling, foundation, and installation costs, as well as mooring and anchoring for floating turbines. OPEX is subdivided into direct and indirect maintenance costs, while DECEX covers decommissioning and site clearance activities.

Approximately 20–30% of a WF's total cost is devoted to OPEX. Generally, Operation and Maintenance Cost (O&M) can be divided into direct and indirect costs. Direct costs include administrative expenses, security fees, network access fees, and service contracts for scheduled maintenance, whereas indirect costs include scheduled and unscheduled maintenance not covered by fixed contracts, spare parts, and other items [18].

Lastly, the decommissioning cost (DECEX) represents the final phase of the wind farm's lifecycle and is estimated to be roughly 1–3% of CAPEX [19]. This cost category covers activities related to the decontamination of the OWF area. After dismantling the facilities, materials such as steel and aluminium from floating platforms and electrical cables are often recovered and sold as scrap, offering an additional income source that can

help offset the total cost [20]. Furthermore, the recycling and reuse of metal towers and mechanical components of wind turbines is feasible, while ongoing research and technological advances are making notable progress in recycling turbine blades to improve the overall sustainability of offshore wind farms [21]. However, it is important to recognise that although a decommissioning cost of 1–3% of CAPEX is commonly assumed in preliminary feasibility studies, actual costs—especially for floating offshore wind platforms in deep water—may surpass this range due to the complexities involved in mooring system removal, subsea cable retrieval, heavy-lift vessel operations, and port logistics. Consequently, the 1–3% figure used in this study should be regarded as a preliminary planning estimate rather than a definitive cost, and future work should incorporate site-specific engineering assessments to refine decommissioning cost projections.

Regardless of the installation method, the costs of WTs, substations, and cables stay the same. The expense of supporting infrastructure for OWFs can vary significantly depending on whether they are situated in shallow or deep water. In shallow waters, monopile foundations are typically used, which are more cost-effective and simpler to build. Conversely, a more complex mooring system is required in deep water. This difference in cost is important and highlights the need for detailed analysis and understanding of the investment requirements in different locations, emphasising the strategic importance of selecting the right facility based on each project's location and specific needs [1].

The financial parameters applied in this study were carefully selected based on industry standards and peer-reviewed literature. A discount rate of 6% was adopted, consistent with typical values used in offshore wind feasibility assessments in the European context [22], reflecting the expected cost of capital and investment risk associated with such projects. The LCOE calculation assumes constant real prices and includes all cost categories (CAPEX, OPEX, DECEX) over the project's operational lifetime, discounted to present value, divided by the total discounted energy output. CAPEX breakdown values were derived primarily from Ref. [23] and supported by [24], covering development, turbine procurement, infrastructure, installation, and mooring systems. Although these data originate from UK-based studies, they provide widely accepted benchmarks and were adjusted where appropriate to reflect Mediterranean conditions. These clarifications aim to improve transparency and ensure the reproducibility of the economic analysis.

Procurement Cost

Several factors must be considered to determine the economic value of OWTs, including construction costs, installation, grid connection, and maintenance. Several factors influence the project's total cost, including the technology, location, depth of the sea, and the distance from the coast. Given the need for detailed analysis, OWT costs are divided into two main categories: floating and fixed. Offshore wind energy has its own economic profile, as each category has its specific characteristics and challenges.

Bottom-Fixed Wind Turbines (BFWT)

BFWTs are the most common type of OWT in shallow waters. Although they are less expensive than FWTs, their use is limited by sea depth. As technology matures and experience grows, fixed-site WTs are expected to have a lower LCC than mobile WTs after 100 GW of installations, with costs dropping close to 28 €.

It is estimated that the average cost to produce each MWh of energy will be approximately €123 during this initial phase. Due to economies of scale, energy production costs per MWh decrease. Through the building and operation of more WTs, cost reductions are achieved through improvements in technology, with the reduction in material costs, and an overall improvement in efficiency. As a result, energy production becomes more efficient and cost-effective as more WTs are constructed and installed [25].

Floating Wind Turbines (FWT)

The floating OWTs are initially more expensive due to the higher CAPEX, which is attributed to the floating platform, using a lot of material to achieve stability. Despite the complexity of their moorings and static structures, floating OWFs offer several advantages in deep water conditions [26]. LCOE for FWTs begins at 123 €/MWh at a capacity of 1 GW and can be reduced to 33 €/MWh at a capacity of 100 GW, according to a recent study [27]. As the technology matures and the scale of installation increases, this technology is expected to reach cost parity with BFWTs [25].

3.2. Study Area

The island of Crete was chosen as a study area due to its unique characteristics and high wind potential, both on land and in the surrounding sea [28]. Currently, the local population exceeds 600,000, a number that usually doubles during the tourist season [29]. The Ministry of Environment and Energy's Strategic Environmental Impact Study for OWFs in Greece planned a total capacity of 800 MW, with 600 MW allocated for the north-eastern part of the island [30,31].

The total installed capacity of the operating Renewable Energy Source (RES) Stations in Crete is distributed as follows [32]:

210 MW of wind power;

102.3 MW of PV;

0.3 MW Small Hydroelectric Stations.

The sustainable siting of OWFs near the island is crucial, especially considering that the electrical interconnection between Crete and continental Greece is under development (Phase I: 150 kV, 2 × 200 MVA Crete—Peloponnese, completed; Phase II: 2 × 500 MW Crete—Attica, expected to be completed in 2025) [33] (Figure 1).

Therefore, as the region's summertime energy needs are demanding due to tourism [34], the electrical interconnection of the island with the mainland system will offer many possibilities for increased penetration of RES [34]. This combination creates an opportunity to develop OWFs in the island's surroundings.

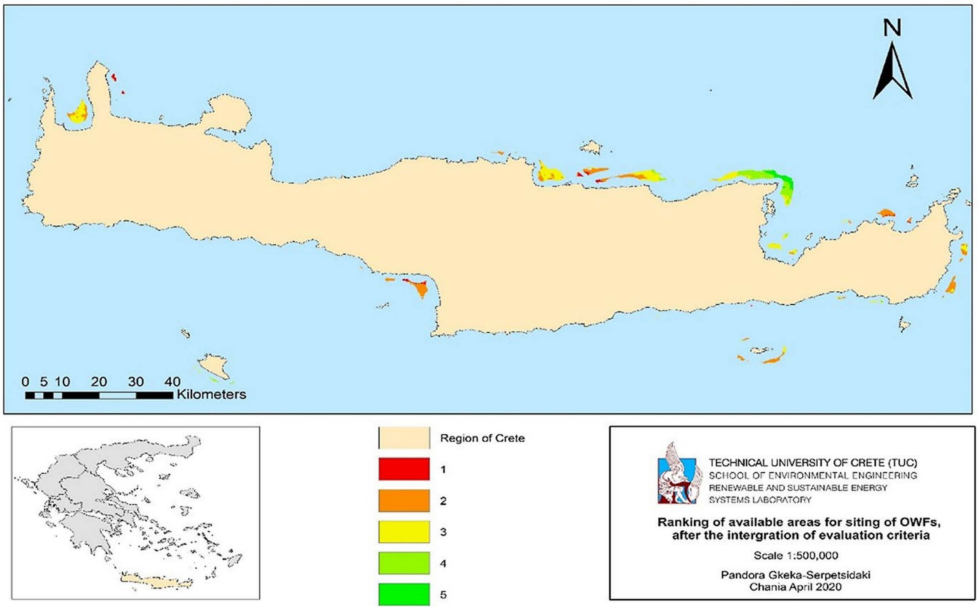


Figure 1. Case study, Crete [5,35].

3.3. Methodological Framework

The study utilises the Wind Atlas Analysis and Application Program (WAsP v.12.6) software to perform dynamic energy performance simulations of wind turbines (WTs)

under varying wind conditions. This advanced tool enables precise modelling and optimisation of WT performance, resulting in more accurate energy output predictions and better decision-making during the planning stage. Additionally, this study offers a comprehensive economic assessment covering all project lifecycle aspects. This includes the initial installation costs (CAPEX), ongoing operational expenses (OPEX), and eventual decommissioning costs (DECEX). Key economic indicators such as the Levelised Cost of Energy (LCOE), payback period, Internal Rate of Return (IRR), and Net Present Value (NPV) are carefully calculated to provide a complete overview of the financial viability and long-term benefits of the wind farm.

The methodological framework of this study follows four sequential steps to ensure transparency, repeatability, and verifiability. First, spatial analysis using GIS was conducted to identify suitable areas for offshore wind farm installation, considering bathymetry, distance from shore, exclusion zones, and marine constraints [5]. Second, wind resource data were obtained from the Global Wind Atlas [36] and processed using the WAsP v.12.6 software to estimate annual energy production. Third, a techno-economic assessment was performed to calculate key financial metrics, including CAPEX, OPEX, DECEX, NPV, IRR, and LCOE, based on the specific configurations of each scenario [23]. Finally, a sensitivity analysis examined how variations in wind conditions affect the project's economic performance and long-term feasibility. This structured workflow provides a clear overview of the data collection, processing, analysis, and reporting stages, ensuring the repeatability and verifiability of the study. The methodology follows a structured sequence of steps (Supplementary Materials, Figure S2):

Site Selection: A Multi-Criteria Decision Making/Analytical Hierarchy Process (MCDM/AHP) method was used during the initial phase of the methodology to select the study area, which indicates that Heraklion Bay would be a suitable location for installing WTs to generate electricity. It should also be noted that this area was selected based on research that had already been conducted [5].

Design in AutoCAD (v. 24.2): After selecting the area, a drawing of it was prepared using AutoCAD software. The next step in the analysis was to create an accurate geographic database using AutoCAD.

Data configuration in QGIS-Geographic Information System (GIS): To import and format the geospatial data designed in AutoCAD, QGIS, a popular software programme for geographical analysis, was used. This process mapped geographical coordinates to their corresponding regions, and the data were prepared for further analysis.

Area configuration in Google Earth: In Google Earth, a popular tool for visualising geographical information, an OWF has been added to the study area. This step provided valuable insight into the geography of the area [37,38].

Micro-siting of WTs: A calculation was performed for each scenario to determine the optimal number of WTs within the given area. To mitigate existing losses between them, the WTs are positioned so that there is a minimum of seven rotor diameters distance in the downwind direction and seven diameters in the crosswind direction [39]. Notably, BFWTs were placed up to the −60 m depth contour, and FWTs were sited beyond this depth (Figure 2).

The 60-metre threshold aligns with industry practice, as fixed foundations are technically and economically viable up to this depth, while floating platforms become more cost-effective beyond it due to mooring feasibility and reduced installation complexity, consistent with the literature's findings.

Wake effects were mitigated by applying a minimum spacing of seven rotor diameters in both directions and aligning layouts with prevailing wind directions (270–300°). WAsP

v.12.6 simulations quantified farm-level wake and shading losses: Scenario 1 = 4.33 percent; Scenario 2 = 4.56 percent; Scenario 3 = 4.47 percent.



(**a**) (**b**) (**c**)

Figure 2. Micro-siting of WTs for Scenario 1 (**a**), Scenario 2 (**b**), Scenario 3 (**c**), respectively.

Use of WAsP v.12.6 software: Climate data were retrieved directly from the Global Wind Atlas platform [36]. This platform provides Generalised Wind Climate data for various regions. Specifically, the Generalised Wind Climate data were collected by entering climate information into the WAsP software, which included wind information and wind roses for various heights and roughness levels.

Wind resource inputs were derived from the Global Wind Atlas. It is important to acknowledge that the wind data used in this study were obtained from the Global Wind Atlas, which, while suitable for preliminary feasibility assessments, cannot fully capture local wind variability, turbulence, or site-specific microclimatic effects. This reliance introduces a degree of uncertainty into the energy yield estimation and, consequently, the economic analysis. Future work should therefore include long-term on-site wind measurements and high-resolution mesoscale modelling to validate and refine the results, particularly for a project of this scale and investment magnitude. Future work will include on-site wind measurements for validation and advanced wake modelling to improve accuracy.

WAsP v.12.6 Map Editor: Models were developed for Vestas V164-9.5 MW, Vestas V236-15 MW [40], Siemens Gamesa SG167-8 MW, and Siemens Gamesa SG154-6 MW WTs [41]. Table 1 shows the adopted scenarios. The characteristics of the WTs and the steps followed in the analysis are presented in the Supplementary Materials.

Table 1. Description of the adopted scenarios.

Type	1st Scenario	2nd Scenario	3rd Scenario
Model of BFWTs	Vestas V164-9.5 MW	Vestas V236-15 MW	Siemens Gamesa SG167-8 MW
Number of BFWTs	19	11	18
Model of FWT	Siemens Gamesa SG154-6 MW	Siemens Gamesa SG154-6 MW	Siemens Gamesa SG154-6 MW
Number FWTs	10	8	11
Sum	29	19	29

The Vestas V164-9.5 MW, V236-15 MW, and Siemens Gamesa SG154-6 MW turbines were selected for their proven reliability and high capacity factors in offshore environments [3]. These models are designed to perform efficiently under seasonal wind variability and elevated thermal effects, which are characteristic of the Mediterranean region [7,16]. Their ability to maintain stable output under fluctuating wind conditions, along with their widespread commercial availability in Europe, makes them suitable for deployment in the study area.

Modelling and calculation of Energy Analysis: The WF model included geographic parameters and meteorological data from the Global Wind Atlas [36]. A calculation was then performed to determine the energy efficiency of each type of WT.

Feasibility analysis: Based on data from similar projects and scientific journals, installation costs, operating costs, retirement costs, additional energy costs, and NPV were calculated.

- Payback period (PP)

  PP is determined via Equation (1):

$$Payback\ period = \frac{Total_{investment}}{Cash\ flow_{perperiod}} \quad (1)$$

- NPV (Net present value)

If NPV > 0 the investment should be carried out because it is economically feasible; If NPV $\leq$ 0, the investment is not feasible and the IRR Equation (3) should not be calculated

$$NPV = -I_0 + \sum_{i=0}^{t} \frac{CF_i}{(1+r)^i} \quad (2)$$

where

I_0: initial investment;
r: discount rate;
Cf_i: cash flow at i-period;
and t: the lifetime of the project.

- Internal rate of return (IRR)

Combining IRR and NPV provides an excellent way to evaluate an investment's attractiveness [16].

The formula for IRR is Equation (3):

$$-I_0 + \sum_{i=0}^{t} \frac{CF_i}{(1+IRR)^i} = 0 \quad (3)$$

where

I_0: initial investment;
Cf_i: C=cash flow at i-period;
and t: lifetime of the project.

- Levelised cost of energy (LCOE)

  The formula for LCOE is Equation (4) [16]:

$$LCoE = \sum_{0}^{t} \frac{\frac{CAPEX+OPEX+DECEX}{(1+r)^i}}{\frac{AEP}{(1+r)^i}} \quad (4)$$

where

CAPEX, OPEX, DECEX
are the capital, operating and decommissioning costs, respectively;
r: discount rate;
t: lifetime of the project.

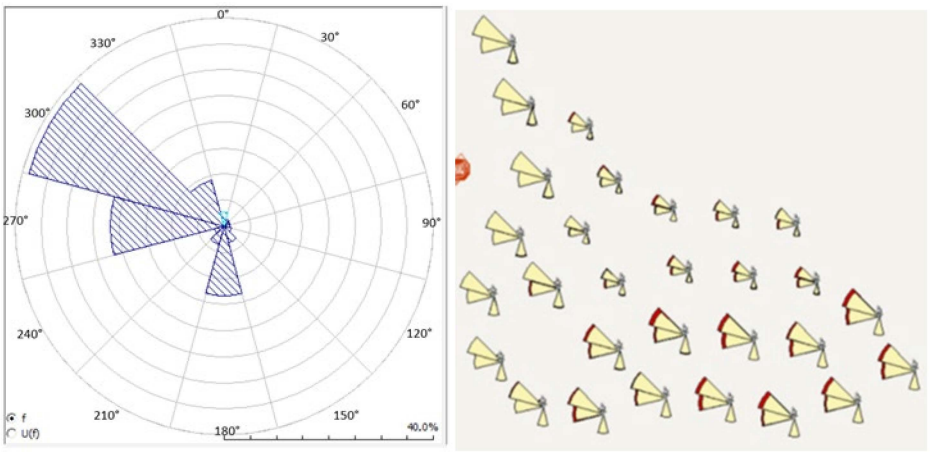
4. Results

4.1. Results from the Energy Analysis

The Vestas V164-9.5 MW model profile was created by the WT Editor, and the power curve for this scenario was configured in the WAsP v.12.6 WT Generator. The final micro-siting and obstacles of WTs for the three scenarios are shown in Supplementary Materials Figure S6.

Supplementary Materials Table S3 details wind conditions for the Vestas V164-9.5 MW and Siemens Gamesa SG154 6 MW models (scenario 1), including wind direction angles, frequencies, and Weibull-k factors, which measure wind speed stability. Higher Weibull-k values (3.15 at 270° and 2.96 at 300°) indicate more stable conditions.

Figure 3a displays the wind frequency and direction distribution at Heraklion Bay, Crete. Angles indicate wind directions, while radial distance shows frequency. Blue patterns emphasise the most common wind directions, around 270° and 300°, indicating prevailing west-to northwest winds. This analysis is vital for optimising WT placement and efficiency by understanding the local wind profile. Shading loss in energy production wind roses for Scenario 1 is shown in Figure 3b). Supplementary Materials Table S5 summarises the WF's performance metrics (scenario 1). Results for the other two scenarios are detailed in the Supplementary Materials.



(**a**) (**b**)

Figure 3. (**a**) Wind rose representing the distribution and frequency of prevailing wind directions for Scenario 1 and (**b**) shading loss distribution in energy production for Scenario 1.

Additionally, shading losses for the three scenarios are shown below:

Scenario 1: Shading losses range from 0.33% to 7.65%, amounting to 4.33%. This suggests a well-designed WT layout that limits shading losses to under 8%.

Scenario 2: Losses range from 0.37% to 8.65%, averaging 4.56%. The WT layout or topography probably causes the rise.

Scenario 3: Losses range from 0.25% to 8.08%, totalling 4.47%, similar to Scenario 1.

Scenarios 1 and 3 exhibit similar efficiency in reducing shading losses, whereas Scenario 2 incurs marginally higher losses.

Furthermore, it illustrates the wind rose of a scenario using Google Earth's interactive platform. The geometric figures display the generated energy yields and shadow losses per WT, thus offering a comprehensive analysis of the design's efficiency.

A comprehensive WT data set is described in the Supplementary Materials, illustrating the complexity of WF performance analysis. In addition to serving as a key benchmark, the Ruggedness Index (RIX) rate also provides insight into the operational efficiency and

reliability of each WT. The percentage Wake Loss value quantifies how aerodynamic interference between WTs reduces the WF efficiency. The capacity factor percentage offers insight into the actual performance of WTs concerning their maximum output. Collectively, these metrics enable a nuanced understanding of WF dynamics, which is vital for optimising RES. Data for the other two scenarios are also provided in the relevant Supplementary Materials.

4.2. Results from the Economic Analysis

The analysis used PP, NPV, IRR, and LCOE metrics to examine CAPEX, OPEX, DECEX, and return on investment. The discount rate (r) was set equal to 6% [42]. The project's lifespan was 35 years from predevelopment to decommissioning. The average and maximum energy values were considered in the following calculation of the economic indicators. While the offshore wind industry typically considers design lifespans of 20–25 years, recent technological advancements in turbine components, anti-corrosion coatings, and platform durability have enabled more extended operational periods, especially for floating systems that can undergo mid-life refurbishments and component replacements. The total project lifetime considered here includes an estimated 7 years for development, manufacturing, transportation, and installation (CAPEX phase), approximately 25 years of operation and maintenance (OPEX phase), and about 3 years allocated for decommissioning and site restoration (DECEX phase). The 35-year assumption is therefore justified as a potential upper-bound scenario, reflecting ongoing trends in extending offshore wind asset lifetimes. However, it is important to acknowledge that this assumption introduces a degree of uncertainty and may lead to slightly more optimistic financial metrics (e.g., NPV, IRR, and LCOE) compared to more conservative 20–25-year estimates. Future sensitivity analyses should investigate shorter design lifetimes to capture the full range of potential outcomes [2].

Analyses were based on WAsP v.12.6 data as well as cost estimates derived from [23] and other reliable sources. According to the Energy Regulatory Authority, the average energy price for September 2023 was 101.96 €/MWh, and the maximum energy price was 128.88 €/MWh. For the assessment, it was recommended to use these prices from the Next Day market, which reflected "wholesale" electricity transactions through RES for Greece [43].

The CAPEX was calculated based on the data provided in [23], and supplemented with detailed cost categories derived from peer-reviewed literature, industry reports, and feasibility studies of comparable offshore wind projects, including [44]. Table 2 presents a comprehensive breakdown of the CAPEX for the OWF development, featuring two types of turbines, V164-9.5 MW and SG154-6 MW. It includes costs associated with project development and management, turbine procurement, foundation and mooring systems, electrical infrastructure, installation, and grid connection. The total CAPEX of Scenario 1 (568.5 M€) is dominated by turbine procurement (≈53%), followed by installation and commissioning (≈32%), balance-of-plant infrastructure (≈11%), and project development and management (≈4%). These proportions are consistent with recent OWF cost benchmarks (Supplementary Materials, Figure S8).

The choice of the Vestas V236-15 MW turbine was based on its high capacity factor, proven reliability in offshore settings, and availability in the European market, making it representative of cutting-edge technology expected to be deployed by 2030. Since turbine procurement accounts for about 50–55% of total CAPEX, even small price changes (±10%) can significantly affect overall project costs and key financial metrics such as NPV and LCOE. Therefore, it is advisable to conduct a sensitivity analysis on turbine cost variations in future studies to understand economic uncertainty better.

Table 2. CAPEX Calculation Data Scenario 1 [16,23,44].

	£	€
Development and licencing services	12,025,000	13,982,558
(i) Environmental studies, (ii) Assessment of resources, (iii) Geological and hydrological studies, (iv) Engineering and consultancy	3,848,000	4,474,419
Other (includes developer staff hours and other subcontracted work)	12,987,000	15,101,163
Project development and management (Sum)	**28,860,000**	**33,558,140**
19 BFWTs (1 M£/MW)	180,500,000	209,883,721
10 FWTs (1.3 M£/MW)	78,000,000	90,697,674
OWTs (Nacelle, rotor, tower, etc.) (Sum)	**258,500,000**	**300,581,395**
Offshore substation (electrical system, facilities, structure)	**28,860,000**	**33,558,140**
Onshore substation (Buildings, access, security, other)	**7,215,000**	**8,389,535**
Cables (Extract & Type & Anchor & Protect)	**40,885,000**	**47,540,698**
Foundation installation	18,050,000	20,988,372
Offshore substation installation	6,317,500	7,345,930
Construction of onshore substation	4,512,500	5,247,093
Onshore installation of export cables	902,500	1,049,419
Offshore cable installation	39,710,000	46,174,419
WT installation	9,025,000	10,494,186
Offshore logistics	541,500	629,651
Other	38,266,000	44,495,349
Installation and commissioning BFWTs (Sum)	**117,325,000**	**136,424,419**
Installation Floating type TLP (steel)	**6,519,767**	**7,581,125**
Synthetic rope	334,884	389,400
Chain	125,581	146,025
Wire rope	20,930	24,337
Mooring (Sum)	**481,395**	**559,762**
Anchor	**265,116**	**308,275**
TOTAL CAPEX	**488,911,279**	**568,501,487**

Moreover, although this study did not conduct a detailed quantitative evaluation of environmental externalities, factors such as marine ecosystem disturbance, seabed alteration, and visual intrusion remain important and are to some extent reflected in the permitting and development costs within the CAPEX estimate.

The project development and management category included services like permitting and environmental impact assessments. Offshore turbine procurement costs varied, with BFWT being cheaper per MW than floating turbines. Infrastructure costs for substations and cables were significant, as were installation and commissioning costs, especially for foundations and cables.

The total CAPEX for the floating base, which involved analysing component costs, including the Tension Leg Platform TLP-type steel structure and mooring systems was calculated. Supported by [23], the analysis provided a solid basis for CAPEX estimation. The average distance from the coast (2000 m) and installation depth (90 m) were key factors, ensuring optimal project performance. CAPEX provided a holistic view of the costs of

building and operating the WF. Based on the study of Spyridonidou et al., [12], OPEX was calculated to be 3% of the total investment cost. Approximately 2% of the total investment cost was estimated to be the withdrawal cost (DECEX) [45].

According to Table 3, Scenario 1 shows a negative NPV of −119,076 k€ at the average price but a positive NPV of 20,112 k€ at the maximum price.

Table 3. Results of Economic Analysis of Scenario 1.

Index	Years	Cost (k€)
CAPEX	8	568,501
OPEX	25	546,278
DECEX	3	22,295
Sum (CAPEX + OPEX + DECEX)	36	1,137,075
Average Energy Price Net Cash Flows	36	412,424
Maximum Energy Price Net Cash Flows	36	821,723
AEP (MWh)	25	15,199
NPV Average Energy Price	36	−119,076
NPV Maximum Energy Price	36	20,112

Analytical data for scenarios 2 and 3 can be found in the Supplementary Materials:

- Scenario 3 incurs a negative NPV of −94,167 k€ at the average price and −28,848 k€ at the maximum price.
- Scenario 2 offers a positive NPV of 12,298 k€ at the average price and a significantly higher positive NPV of 167,140 k€ at the maximum price. It stands out as the most attractive option due to its highest NPVs, lowest total cost, and highest annual revenues, making it preferable over Scenario 1 and Scenario 3 for better economic performance and revenue potential.

Table 4 presents the analysis results for all three scenarios, displaying the average and maximum energy prices for each scenario.

Table 4. Economic analysis results per scenario.

	Scenario	AEP (GWh)	PP (Years)	IRR (%)	NPV (k€)	LCOE (€/MWh)	CAPEX (k€)	OPEX (k€)	DECEX (k€)
1	Average Energy Price	635.45	13th–14th	3.74	−119,076	33.9	568,501	546,278	22,295
	Maximum Energy Price		9th–10th	6.33	20,112				
2	Average Energy Price	708.64	9th–10th	6.23	12,298	27.8	505,037	485,295	19,807
	Maximum Energy Price		7th–8th	8.78	167,140				
3	Average Energy Price	562.47	12th–13th	3.97	−94,167	32.3	492,696	473,436	19,323
	Maximum Energy Price		9th–10th	6.55	28,848				

- Scenario 1: The PP turns positive for the average energy price between years 13 and 14. It becomes positive for the maximum energy price between years 9 and 10, with a 9-year PP observed between −29,699 k€ and 28,270 k€.
- Scenario 2: The PP for the average energy price turns positive between years 9 and 10, with the last negative value at −32,279 k€ and the first positive value at 18,564 k€. The PP turns positive for the maximum energy price between years 7 and 8, ranging from −7532 k€ to 62,227 k€.
- Scenario 3: The PP becomes favourable for the average energy price between years 12 and 13. The maximum energy price turns positive between years 9 and 10, ranging from −13,652 k€ to 37,930 k€.

Scenario 2 offers the fastest PP and highest IRR for both energy prices, making it the most attractive investment. Scenario 1 has a slower PP and lower attractiveness, while Scenario 3 provides a balanced performance.

As concerns NPV:

- Scenario 1: The NPV for the average energy price is −119,076 k€, indicating a negative NPV, while the maximum price is 20,112 k€. Even though the peak value is high, the negative average value may indicate that some periods or conditions are high risk.
- Scenario 2: The average value is positive and reaches 12,298 k€, with a maximum positive and high value (167,140 k€), indicating stable profits and high returns.
- Scenario 3: The average NPV is −94,167 k€, while the maximum is 28,848 k€. Although the maximum value is positive, the average value is negative, indicating a risk of loss.

Comparing the average and maximum energy values per scenario, the second scenario seems to be the most appealing since it has the highest average NPV, which is positive, and the highest maximum value. As a result, this scenario provides the best balance between risk and reward, making it a more attractive investment opportunity.

The three distinct scenarios relate to the LCOE during the assumed operational period from 2031 to 2055. These scenarios aim to attract potential investors and assist in evaluating a project's financial viability. The Levelized Cost of Energy (LCOE) was calculated based on the standard definition, as the ratio of the total discounted lifetime costs (CAPEX, OPEX, and DECEX) to the total discounted lifetime energy output, using a real discount rate of 6%. This method provides a single lifetime-average metric, replacing the previous year-by-year values representing annual discounted costs per MWh rather than the true LCOE. The resulting lifetime LCOE values are 33.9 €/MWh for Scenario 1, 27.8 €/MWh for Scenario 2, and 32.3 €/MWh for Scenario 3.

4.3. Sensitivity Analysis

The sensitivity analysis could offer valuable scientific evidence on how fluctuations in variables such as wind speed impact the sustainability of these projects. A more thorough approach is necessary to address unpredictable scenarios, such as a sudden decrease in energy production caused by a 20% reduction in wind speed. Therefore, in this context, a sensitivity analysis scenario was explored, and the results are shown in Table S16 in the Supplementary Materials.

The sensitivity analysis evaluated the impact of a 20% reduction in AEP. The results show that NPVs for Scenarios 1, 2, and 3 decline to −224 M€, −105 M€, and −187 M€, respectively, while the PPs shift by approximately 4 to 6 years. Despite the overall deterioration in economic indicators, Scenario 2 remains the least sensitive and most resilient option.

Financing and subsidies could offer the necessary financial security to ensure their sustainability. This support can enable adaptation to adverse conditions and secure their ongoing operation. Through direct financing or fiscal incentives, this assistance can diminish investors' risk and enhance projects' economic appeal. Such measures promote environmental and energy objectives while preserving the project's economic viability.

The chosen discount rate of 6% aligns with values typically used in European offshore wind evaluations. The 20% reduction scenario in the sensitivity analysis provides a conservative estimate of wind variability; however, broader reductions (e.g., 30–50%) could be examined in future research to enhance the robustness of the findings.

4.4. Discussion Section

Scenario 1 presents total CAPEX of €568,501, OPEX of €546,278, and DECEX of €22,295, leading to an overall cost of €1,137,075. The NPV for the average energy price is negative

(€−119,076), making the investment unattractive. Conversely, under ideal conditions, the NPV rises to €20,112, indicating the project's economic viability. The project's viability is highly sensitive to fluctuations in energy prices, with reduced energy costs starting at €28.05/MWh and gradually increasing to €45.12/MWh, eventually dropping to zero, which signals the completion of the PP.

Scenario 2 has lower costs with CAPEX of €505,037k, OPEX of €485,295k, and DECEX of €19,807k. The NPV is positive (€12,298k), increasing to €167,140k at maximum energy prices, making it highly attractive to investors. This scenario offers higher initial economic efficiency and a quicker payback, with reduced energy costs starting at €22.40/MWh and rising to €36.03/MWh before decreasing to zero. It demonstrates the best economic performance among all scenarios.

Scenario 3 exhibits the lowest CAPEX (€492,696K), OPEX (€473,436K), and DECEX (€19,323K). Although the NPV at the average energy price is negative (−€94,167K), it turns positive at the maximum price (€28,848K), indicating moderate economic attractiveness. The reduced energy cost starts at €27.51/MWh and rises to €44.25/MWh, demonstrating a balance between cost and efficiency.

In conclusion, Scenario 2 provides the best overall performance—combining the highest economic efficiency with the fastest payback period—making it the preferred investment. Its advantage comes from the use of higher-rated bottom-fixed turbines and an optimised bottom-fixed/floating mix, which increases annual energy production to 708.64 GWh compared to 635.45 GWh in Scenario 1, while also delivering a lower LCOE of 22.4 €/MWh and a reduced CAPEX of approximately €505.0 million (505,037 k€) compared with around €568.5 million (568,501 k€) in Scenario 1. Although wake losses are slightly higher (4.56% vs. 4.33%), the gain in energy yield and improved financial metrics—including a maximum NPV of €167 million—more than outweigh this effect. By contrast, Scenarios 1 and 3 are riskier, showing negative NPVs at average market prices (with Scenario 3 offering only a moderate, lower-cost compromise). In contrast, Scenario 2 achieves the most effective balance of cost, performance, and risk. These findings can inform offshore wind farm planning on other Mediterranean islands with similar wind variability, seasonal demand peaks, and grid constraints. Implementing an optimal fixed-to-floating turbine mix in such contexts may enhance energy security and support decarbonisation efforts in island power systems.

Beyond technical and economic metrics, the successful deployment of hybrid offshore wind farms in the Mediterranean depends on addressing grid integration and social-environmental challenges. Many island grids rely heavily on imported fossil fuels and have limited interconnection capacity [33,34], requiring upgrades and smart management systems to accommodate variable wind generation. Regulatory and permitting barriers, as well as potential ecological impacts, must also be carefully considered. Moreover, stakeholder acceptance is crucial in regions with intense tourism and fishing activity [37,38], ensuring that projects are feasible, sustainable, and socially supported.

Extending the project analysis over a 37-year period enables consideration of additional technological developments and changing energy market conditions. Incorporating new technologies could lower CAPEX and OPEX, boosting each scenario's financial appeal. Aligning with energy policies and regulations may increase the NPV and enhance financial feasibility. Risk management, alongside energy market prospects, can improve investment returns.

A 20% reduction in wind energy production would lead to a 20% decrease in energy output, lowering Scenario 1's production from 15,198,625 MWh to 12,158,900 MWh. This decline would directly affect net cash flows and NPV. For the average energy price, net cash flows reduce from 412,424 k€ to 329,940 k€. At the maximum energy price, net cash flows

fall from 821,723 k€ to 657,379 k€. A substantial decrease in production would negatively impact investment. To mitigate such risks, funding, subsidies, or tax incentives can help ensure the project's viability, enabling adaptation to adverse conditions while maintaining financial feasibility.

Although a detailed environmental impact assessment was beyond the scope of this study, offshore wind farms may affect marine ecosystems, seabed habitats, and the visual landscape. Although not quantified here, these effects are partially reflected in permitting costs and should be investigated further in future research. Additionally, the intermittent nature of wind generation may cause grid stability challenges, such as voltage and frequency fluctuations, which could impact turbine performance, maintenance requirements, and operational costs. Future studies should address grid stability considerations to improve these findings.

It is also important to note that the economic indicators presented in this study, such as NPV and IRR, were calculated without explicitly considering country-specific subsidy schemes. Support mechanisms for offshore wind, including feed-in tariffs, contracts for difference, and investment incentives, vary significantly across Mediterranean countries and could substantially alter project economics. Future work should incorporate sensitivity analyses under different policy scenarios to provide more relevant insights for investors and policymakers.

5. Conclusions

The following points are summarised from the energy and economic assessment conclusions. Using a structured methodological approach, this study conducted a comprehensive energy and economic analysis of an OWF in the Gulf of Heraklion, Crete. The installation and operation of BFWT and FWTs were analysed using tools such as WAsP, AutoCAD, QGIS, and Google Earth. Selecting the bottom-fixed base models Vestas V164-9.5 MW, Vestas V236-15 MW, Siemens Gamesa SG167-8 MW for depths of up to 60 m, and Siemens Gamesa SG154-6 MW for depths exceeding 60 m emphasises the importance of adaptability in technology choice based on marine conditions. Technological flexibility and precise equipment selection are vital to optimise energy efficiency and sustainability.

The economic analysis assessed the project's feasibility by calculating CAPEX, OPEX, DECEX, NPV, LCOE, PP and IRR, providing a comprehensive view of the financial profile of the selected WT configurations. The comparison of costs between floating and bottom-fixed turbines indicates that floating wind technology could become more competitive as project scale increases and the technology matures. The integrated energy–economic analysis provides a holistic framework for evaluating offshore wind farm sites, capturing the complexity of such assessments.

Considering the limitations of this energy and economic assessment and the need for further research, the following conclusions can be drawn. Additional research is necessary to enhance the sustainability and economic efficiency of OWFs. This research could focus on LCC analysis of materials and the social challenges and impacts associated with their development.

Additionally, wind data must be cross-checked with other reliable databases, or wind measurements can be carried out on-site to accurately depict the site. Moreover, additional scenarios concerning the WT models and the micro-siting of WTs need to be assessed. Depending on the case, the costs associated with designing the electrical arrays and the electrical infrastructure may vary significantly.

Furthermore, the possibility of all WTs being either bottom-fixed or floating might be considered, but the depth of the sea greatly affects this. Therefore, it is essential to determine the percentage of floating and bottom-fixed turbines at each site individually.

Costs are likely to vary significantly across different scenarios. Additionally, since the costs of the floating wind industry are expected to decrease substantially in the coming decades, this factor should also be taken into account.

Finally, the success of an OWF project depends on the acceptance and support of local communities. Future research should focus on understanding and addressing the challenges linked to social acceptance.

Supplementary Materials: The following supporting information can be downloaded at: https://www.mdpi.com/article/10.3390/en18215739/s1, Table S1: Comparative Table of Technical Characteristics of selected WT Models; Table S2: Description of the steps followed; Table S3: Scenario 1 wind data (V164–9.5MW &SG154-6MW) (WAsP 12.6); Table S4: Scenario 2 wind data (V236-15MW & SG154-6MW) (WAsP 12.6); Table S5: Total WF performance in Scenario 1; Table S6: Total WF performance in Scenario 2; Table S7: Scenario 3 wind data (SG167-8MW & SG 154-6MW) (WAsP 12.6); Table S8: Total WF performance in Scenario 3; Table S9: Complete data per WT Scenario 1; Table S10: Complete data per WT Scenario 2; Table S11: Complete data per WT Scenario 3; Table S12: CAPEX Calculation Data Scenario 2; Table S13: Results of Economic Analysis of Scenario 2; Table S14: CAPEX Calculation Data Scenario 3; Table S15: Results of Economic Analysis of Scenario 3; Table S16: Results from sensitivity analysis scenarios; Figure S1: CAPEX, OPEX and DECEX breakdown of the study; Figure S2: Analysis process diagram of the adopted methodology; Figure S3: Creation of Siemens GamesaSG167–8 MW profile in the WT Editor and power curve; Figure S4: Creation of Vestas V236–15 MW profile in the WT Editor and power curve; Figure S5: Creation of Siemens Gamesa SG154-6MW Floating profile in the WT Editor and power curve; Figure S6: (a) Micro siting and (b) Obstacles of WTs-1st Scenario, 2nd and 3rd Scenario; Figure S7: Shading loss in energy production windrose—Scenario 2, 3 and illustration of shading loss windrose in Google Earth; Figure S8: Cost breakdown of Scenario 1; Figure S9: Comparison of NPV of average and peak energy price scenarios with time of investment.

Author Contributions: Conceptualization, P.G.-S. and T.T.; methodology, P.G.-S.; software, D.F.; validation, P.G.-S.; investigation, P.G.-S.; data curation, D.F.; writing—original draft preparation, P.G.-S. and D.F.; writing—review and editing, P.G.-S. and T.T.; visualisation, P.G.-S.; supervision, P.G.-S. and T.T. All authors have read and agreed to the published version of the manuscript.

Funding: This research received no external funding.

Institutional Review Board Statement: Not applicable.

Informed Consent Statement: Not applicable.

Data Availability Statement: Data is contained within the article and Supplementary Materials.

Acknowledgments: The authors would like to thank the Department of Wind Energy at the Technical University of Denmark (DTU), developer of the WAsP, for their free licence to use the software version WasP v.12.6.

Conflicts of Interest: The authors declare no conflicts of interest.

Abbreviations

The following abbreviations are used in this manuscript:

AEP	Annual Energy Production
BFWT(s)	Bottom-Fixed Wind Turbine(s)
CAPEX	Capital Expenditure
DECEX	Decommissioning Cost
FWT(s)	Floating Wind Turbine(s)
GIS	Geographic Information System
IRR	Internal rate of return
LCOE	Levelised Cost of Energy

NPV	Net Present Value
OPEX	Operating Expenses
OWF(s)	Offshore Wind Farm(s)
OWT(s)	Offshore Wind Turbines(s)
PP	Payback Period
RES	Renewable Energy Sources
WF(s)	Wind Farm(s)
WT(s)	Wind Turbine(s)

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