

Article

Assessment of Onshore and Offshore Wind Energy Potential in the Eastern Baltic Sea Region: LCOE and Wind Turbine Layout Optimisation

Svetlana Orlova *, Nikita Dmitrijevs, Marija Mironova, Vitalijs Komasilovs and Edmunds Kamolins 

Laboratory "Energy Research Centre", Institute of Electronics and Computer Sciences, LV-1006 Rīga, Latvia

* Correspondence: sorlova@edi.lv

Abstract

This study compares the performance of two wind farm sites located in Northern Europe: an onshore site and an offshore area in the eastern Baltic Sea region. This study investigates the optimisation of wind farm performance within a fixed project area by maximising annual energy production (AEP) and increasing energy density. Three wake-loss scenarios ($\leq 10\%$, $\leq 15\%$, and $\leq 20\%$) were examined to assess the sensitivity of layout optimisation to aerodynamic interaction constraints. Several layout configurations were analysed to reduce wake losses and enhance overall energy output. Wind conditions were assessed using NORA3 reanalysis data, and wake interactions were modelled using the Jensen wake model to estimate AEP. Both wind farms were further compared across key criteria, including cost, power generation efficiency, installation and maintenance requirements, and site availability. Offshore wind farms achieve 1.5–1.7 times higher energy density under similar spatial conditions. However, offshore levelised cost of energy (LCOE) remains roughly 25% higher due to higher capital and infrastructure costs, while onshore LCOE demonstrates better economic performance, driven by lower CAPEX and O&M expenses. The findings highlight the trade-offs between cost efficiency and wake-driven energy performance for onshore and offshore wind development in the eastern Baltic Sea region.

Keywords: wind energy; onshore and offshore wind farms; Latvia; wake losses; annual energy production (AEP); levelised cost of energy (LCOE)

1. Introduction

Wind energy development has become a key component of national and regional decarbonisation strategies, particularly in countries seeking to increase renewable electricity generation while reducing reliance on imported fuels. In Latvia, both onshore and offshore wind resources remain largely underutilised [1], despite favourable weather conditions and growing policy support to accelerate large-scale deployment. Recent updates to national energy and climate targets have heightened interest in assessing how various wind farm designs, technological options, and site features affect overall project feasibility. In this context, a comparative analysis of onshore and offshore wind development is crucial for understanding the trade-offs among energy output, cost-effectiveness, spatial constraints, and wake-effect mitigation.

Although wind energy research has advanced rapidly across Europe, the eastern part of the Baltic Sea remains relatively underexplored in the scientific literature. Specifically, Latvia has received limited targeted attention, with few comprehensive studies exploring



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its onshore and offshore wind energy potential within an integrated policy, economic, and technological framework [1–3].

The placement of turbines in both offshore and onshore wind farms is determined by factors such as turbine dimensions, prevailing wind directions, wake effects, existing infrastructure, and available land. In conventional wind farm designs, turbines are typically arranged on a grid in either an aligned or a staggered configuration, characterised by downwind and crosswind spacings. These spacings act as key design parameters, as they determine the degree of wake overlap and thus directly affect the farm's total power output.

Turbine spacing is a widely studied topic influenced by numerous interdependent factors. As a result, wind farm layout optimisation remains an active and essential area of research. Although theoretical spacing recommendations exist to maximise efficiency, they must often be adjusted to accommodate real-world constraints, such as limited land availability and economic considerations. Consequently, a range of optimal spacing configurations has been proposed in the literature. For example, [4] recommends a spacing of 8–12 rotor diameters in the downwind direction to minimise wake losses and 4–6 rotor diameters in the crosswind direction.

In addition, in [5], an experimental investigation of both onshore and offshore wind farm configurations was conducted, using three and six rotor diameters for aligned and staggered layouts. The results show that staggered wind farms with six rotor diameters downwind and three rotor diameters crosswind achieve the highest efficiency. In contrast, aligned layouts and reduced spacing distances lead to notable efficiency losses. Furthermore, their comparison of onshore and offshore wind farm layouts highlights differences in wake dynamics. Onshore farms tend to have broader crosswind wake expansion but faster wake recovery due to higher ambient turbulence intensity. In contrast, offshore wind farms display the opposite behaviour, with narrower wake expansion and slower recovery associated with the lower turbulence levels.

In practice, published studies [6–8] report wake-induced energy losses of roughly 5–20% of the AEP, depending on site conditions, turbine layout, and atmospheric stability. A meta-analysis in [9] shows that many projects report average wake losses of 5–15%, with an average of around 10% often used as a representative value. More recent operational analyses of modern projects find long-term wake losses in the ≈ 2 –6% range for well-designed wind farms [10]. Based on these results, wake losses below about 5–10% can be considered very good or optimised, 10–15% is standard for large or offshore wind farms with higher density, and values above 15–20% generally indicate strong wake interactions and typically motivate further optimisation of turbine spacing, layout, or wake-mitigation control strategies. It should be noted that [11] shows that, even with significant wake losses, removing individual low-productivity turbines is not economically justified: the wind farm's total energy production over 25 years decreases by more than the potential benefit from reducing wake losses. Higher-rated turbines achieve payback more quickly, and high wake losses can still be acceptable from both economic and environmental perspectives.

Numerous comparative studies have evaluated the performance of different wake models, including the Jensen, Larsen, and Gaussian wake models [12–14]. While higher-fidelity wake models, such as Larsen or Gaussian variants, may provide improved physical representation of velocity-deficit distributions, the Jensen model offers a favourable balance between computational efficiency and predictive capability. Despite its simplified assumptions, the Jensen model [15,16] remains widely used in wind farm studies due to its computational efficiency and suitability for layout optimisation applications.

Table 1 displays recent LCOE figures for onshore and offshore wind energy in various countries. Costs generally range from 35 to 90 €/MWh for onshore wind, depending on wind resource quality, terrain complexity, and financing conditions, while offshore

wind costs typically range from 60 to 150 €/MWh and vary widely depending on national conditions and project characteristics.

Table 1. LCOE for onshore and offshore wind by country.

Country	LCOE for Onshore [€/MWh]	Reference	LCOE for Offshore [€/MWh]	Reference
Germany (DE)	43–92	[17]	62–65	[18]
France (FR)	≈51	[18]	≈104	[18]
Spain (ES)	≈39	[18]	≈78	[19]
United States (US)	≈39	[10]	100–154	[10]
Denmark (DK)	≈34	[18]	≈45	[18]
Poland (PL)	≈37	[18]	100–142	[20]
Baltic States (EE, LV, LT)	≈47 ± 10	[18,21]	75–125	[22]

To assess the relevance of this study, it is necessary to evaluate the growth potential of both onshore and offshore wind power installations. Figure 1 presents the cumulative installed wind energy capacity for selected European countries as of 2024. In contrast, Figure 2 illustrates the projected expansion of installed capacities in the Baltic states—Latvia, Lithuania, and Estonia [23,24].

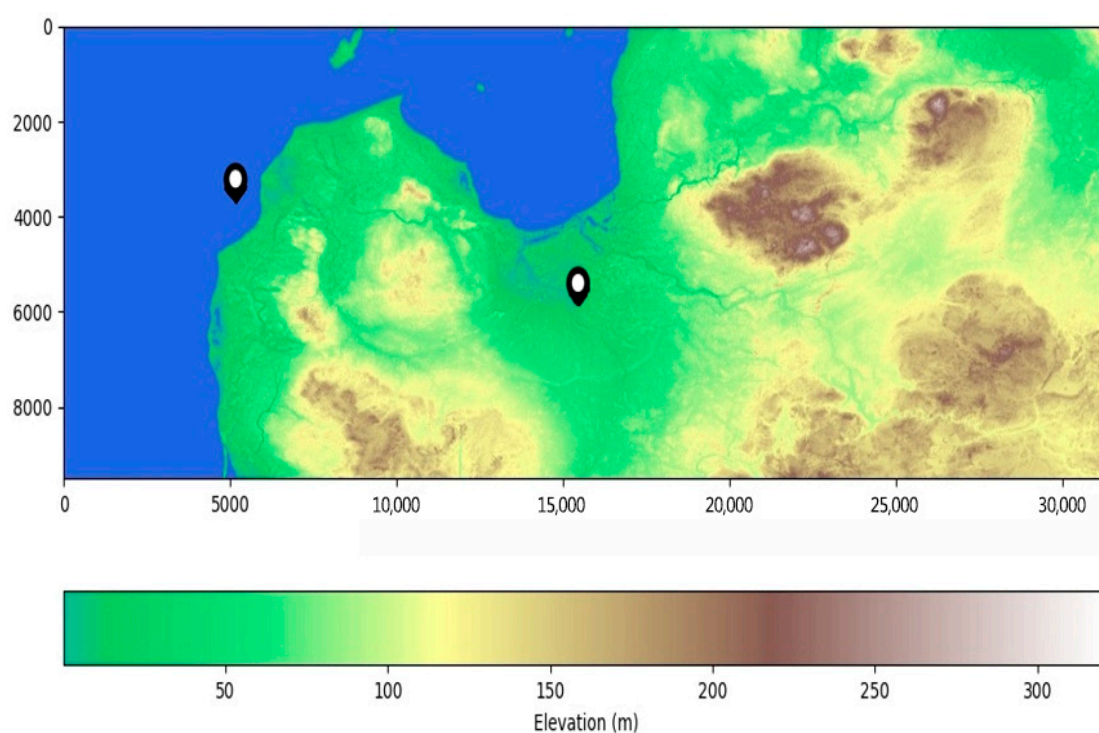


Figure 1. Geographic overview of the onshore and offshore wind farm study areas based on the Copernicus Global 30 m Digital Elevation Model.

Onshore wind turbines typically generate less energy than offshore installations due to lower hub heights and more variable wind conditions, resulting in capacity factors generally ranging from 20% to 40% [25]. In contrast, offshore wind benefits from stronger and more consistent wind speeds, resulting in significantly higher capacity factors—approximately 55% in Baltic Sea conditions compared with approximately 30% onshore [26].

To further highlight the fundamental differences between land-based and marine wind-energy development, Table 2 summarises the key contrasts between onshore and offshore wind farms.

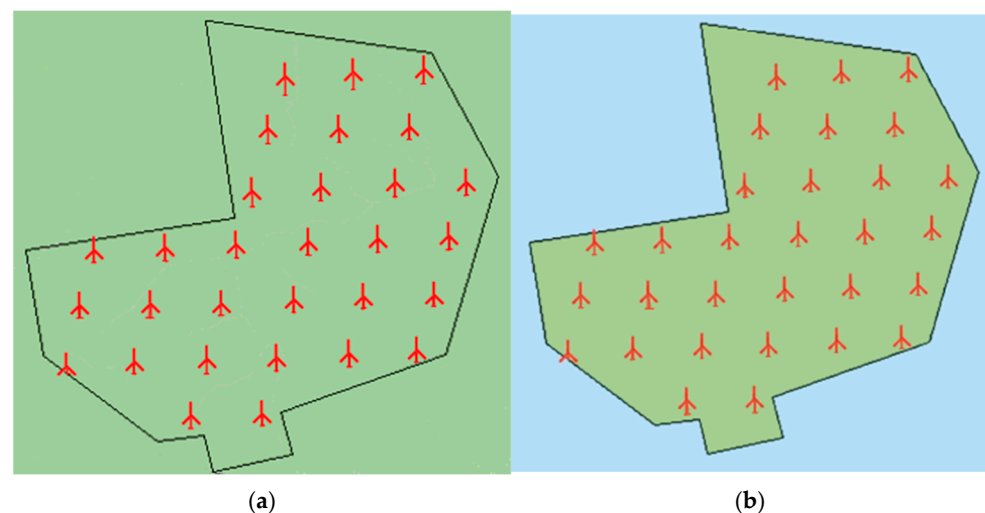


Figure 2. Initial wind farm layouts: (a) Onshore configuration with 30 turbines; (b) offshore configuration with 30 turbines.

Table 2. Comparison of key characteristics of onshore and offshore wind farms.

	Onshore Wind Farms	Offshore Wind Farms
Cost and Economics	Lower capital and operational costs due to simplified logistics, road access, and established construction practices [27].	Higher costs stem from specialised vessels, foundations, cabling, and weather restrictions, as well as increased transmission. Floating technology offers cost savings and easier installation [27,28].
Power Generation and Efficiency	Power fluctuations due to uncertainty of wind, lower wind speeds, and increased terrain-induced turbulence [27,29].	Higher, more stable wind speeds result in significantly higher capacity factors. Enhanced wind speeds are due to smooth terrain and minimal roughness [30].
Environmental Impact	Potential impacts on terrestrial wildlife, especially birds and bats, and on communities from noise and visual disturbance. End-of-life disposal of components remains a significant concern [28,29].	Reduced visual and noise impacts on humans, addressing concerns like effects on marine mammals, fish, seabirds, construction noise (pile driving), spills, electromagnetic fields from cables, and habitat disturbance. Benefits include new habitats and the exclusion of fisheries [31,32].
Installation and Maintenance	Installation, access, and maintenance are generally more straightforward and less affected by weather. Downtime caused by inaccessibility is minimal [27,28].	Accessibility is constrained by weather and sea conditions, raising the risk of downtime and operation and maintenance (O&M) costs. At the same time, offshore turbines also endure greater wear and tear from saltwater corrosion, strong winds, and tidal currents [33].
Site Availability and Location	Restricted by terrain complexity, land availability, rough climate, proximity to transmission, environmental regulations, and public acceptance [34,35].	Large marine areas enable the deployment of large-scale wind farms and larger turbines, suitable especially where land is scarce. Floating technologies extend the potential to deep waters [28,36].
Energy Reliability and Consistency	More susceptible to wind variability due to terrain and diurnal patterns, resulting in less consistent generation profiles. Wind energy uncertainty due to forecast errors [37].	Stronger, more stable offshore wind regimes produce more consistent generation, thereby improving grid integration. Still shows seasonal dependency for energy output [37].

Table 2. *Cont.*

	Onshore Wind Farms	Offshore Wind Farms
Community Impact and Social Acceptance	Local opposition is common due to visual intrusion, noise, land-use conflicts, and perceived environmental impacts [28,35].	Faces lower resident resistance due to remoteness. Opposition from fishery groups and coastal stakeholders is possible [29].
Technological Advancements	Mature, cost-optimised technologies with established supply chains. Limited potential for larger turbines. New strategies improve efficiency in complex terrain [29,38].	Rapidly advancing technologies like floating platforms and giant turbines aim for 17 MW capacity by 2035 with 250 m rotors. Development remains capital-intensive and complex [39].
Capacity Factor	Show lower capacity factors due to more variable wind conditions. Capacity Factor (CF) is commonly 20–40%, depending on terrain and wind resources [27,40].	Typically, 40–55% or higher. Floating offshore may exceed fixed-bottom values in optimal wind regimes [30].
Future Potential and Growth	Land availability, social acceptance, competition with solar, grid integration, and saturation of high-quality sites constrain growth. Possible repowering of existing wind farms [28].	Strong long-term growth potential due to large offshore resource availability and ongoing advancements in floating wind technology [28].

While wind turbines are effectively emission-free during operation, they do not achieve zero emissions over their whole lifespan. Significant carbon footprints and environmental impacts arise primarily during manufacturing and decommissioning. Comparative and case studies have yielded several key findings. For example, [41] demonstrated that onshore wind turbines exhibited a greater environmental impact than offshore counterparts, largely attributable to the intensive production of land-based foundations. This outcome reflects differences in life-cycle system boundaries and material requirements, with the more material-intensive construction of onshore foundations leading to higher aggregated environmental impacts in the assessed case.

Life Cycle Assessment (LCA) research provides consistent evidence that onshore wind farms generally have lower life-cycle environmental impacts than offshore installations. It is shown that onshore wind typically emits wind power greenhouse gas (GHG) emissions varying between 7.8 and 16 g CO₂ eq./kWh for onshore, and 12–23 g CO₂ eq./kWh for offshore [42,43] turbines due to larger foundations, longer transmission cables, and the use of heavy-lift vessels during installation and maintenance. In contrast, offshore systems achieve higher energy yields but at the cost of higher material and installation impacts. Although offshore wind farms tend to exhibit lower greenhouse gas emissions per kWh than onshore installations, offshore turbine sizes are not constrained to the same extent, and the higher costs of marine foundations incentivise the deployment of larger-capacity turbines [44]. The greater impact of offshore is mainly due to higher capital equipment requirements. Offshore also requires more resources (fuel and transport) for installation, and overall material and energy requirements do not counterbalance the benefits of higher energy output compared to the onshore market [45,46]. Increasing wind farm capacity significantly reduces the environmental impact per kWh. Following data harmonisation in the National Renewable Energy Laboratory (NREL) report [47], the estimated life-cycle GHG emissions for both land-based and offshore wind technologies were statistically similar, with a median of 11 g CO₂ eq./kWh.

Despite the rapid growth of wind energy in Northern Europe, a comprehensive, region-specific comparison of onshore and offshore wind development in the eastern Baltic

Sea area remains limited. Existing studies often examine economic performance, energy output, or environmental impacts separately, without combining LCOE analysis and wind turbine layout optimisation within a single framework. Additionally, spatial restrictions, wake-effect interactions, and site-specific wind conditions add further complexity that is not consistently addressed in current planning methods. Therefore, this study assesses the onshore and offshore wind energy potential in the eastern Baltic Sea region by integrating LCOE modelling with wind turbine layout optimisation to evaluate technical performance and economic viability under regional conditions.

The remainder of this paper is organised as follows. Section 2 describes the materials and methods, including the study area, wind turbine specifications, meteorological data, the layout optimisation framework, the wake modelling approach, and the economic analysis. Section 3 presents the results, including the spatial distribution of wind energy and the evaluation of layouts under varying wake-loss scenarios. Finally, Section 4 presents the study's conclusions.

2. Materials and Methods

2.1. Study Area

The two study sites represent contrasting wind-energy environments in Latvia and are illustrated in Figure 1. To ensure consistent comparison of onshore and offshore wind farm performance, both study areas were defined within the same domain, with a site area of 42 km².

The onshore study site is located in central Latvia, within the Zemgale region near Jelgava, and is characterised by the expansive and fertile Zemgale Plain. The landscape is predominantly flat to gently undulating, forming a mosaic of high-value agricultural land interspersed with forest patches. As an inland rural area, it exhibits heterogeneous land cover and relatively higher surface roughness compared to marine environments, which is typical for wind-energy assessment sites across the southern Baltic lowlands.

In contrast, the offshore study site is situated in the eastern Baltic Sea, several kilometres west of the Kurzeme coast, within the Jūrkalne–Pāvilosta sector. This open-sea environment is characterised by minimal surface roughness and the absence of topographic obstacles, resulting in stronger, more persistent wind conditions and lower ambient turbulence compared to onshore locations.

The digital elevation model (DEM) of the Zemgale region (Figure 1) shows predominantly yellow–green tones, indicating low absolute elevations and a weakly dissected terrain. The topography is largely uniform, without sharp elevation gradients. Zemgale is among the flattest regions in Latvia, with elevations generally ranging between 20 and 100 m above sea level. The landscape is shaped primarily by alluvial and glacial-accumulative processes and is marked by broad river valleys embedded within extensive plains.

The marked offshore location represents a marine area in the eastern Baltic Sea, situated west of the Latvian coastline. The site lies within a relatively shallow marine environment characterised by uniform bathymetric conditions and unobstructed exposure to prevailing winds.

A significant number of wind farms in Latvia are located in the Ventspils and Liepāja districts and their surrounding areas in Kurzeme. This location is due to the country's favourable natural conditions on the western coast.

Figure 2 shows the layouts of the onshore and offshore wind farms before optimisation. The turbine placement results in uneven spacing and higher wake interactions, leading to increased wake losses and less efficient energy production. The initial layout used a downwind spacing of 6D (1032 m) and a crosswind spacing of 5D (860 m), where D = 172 m

is the rotor diameter of the selected wind turbine (hub height: 199 m), and a minimum setback distance of more than 800 m from buildings was maintained.

2.2. Wind Turbine Specifications

In this study, the Vestas V172-7.2 MW wind turbine is used as theoretical reference model for power calculations. This modern, large-scale turbine is designed for moderate and low wind speeds (IEC 61400-1:2019 Class IIA/B and IIIA/B) [48]. The following are the main technical specifications of the Vestas V172 7.2 MW turbine: cut-in wind speed, 3 m/s; cut-out wind speed, 25 m/s; rotor diameter, 172 m; rotor swept area, 23,235 m²; and available hub heights, 114 m, 150 m, 164 m, 166 m, 175 m, and 199 m [49].

2.3. Meteorological Data

For assessing the wind resource, historical data from the regional atmospheric reanalysis NORA3 [50] covering the period from January 1999 to July 2025 were utilised.

The prevailing wind direction at the offshore site is clearly dominated by the west–southwest (WSW) sector, whereas the onshore site exhibits a broader distribution of prevailing winds; the corresponding wind roses for both locations are shown in Figure 3.

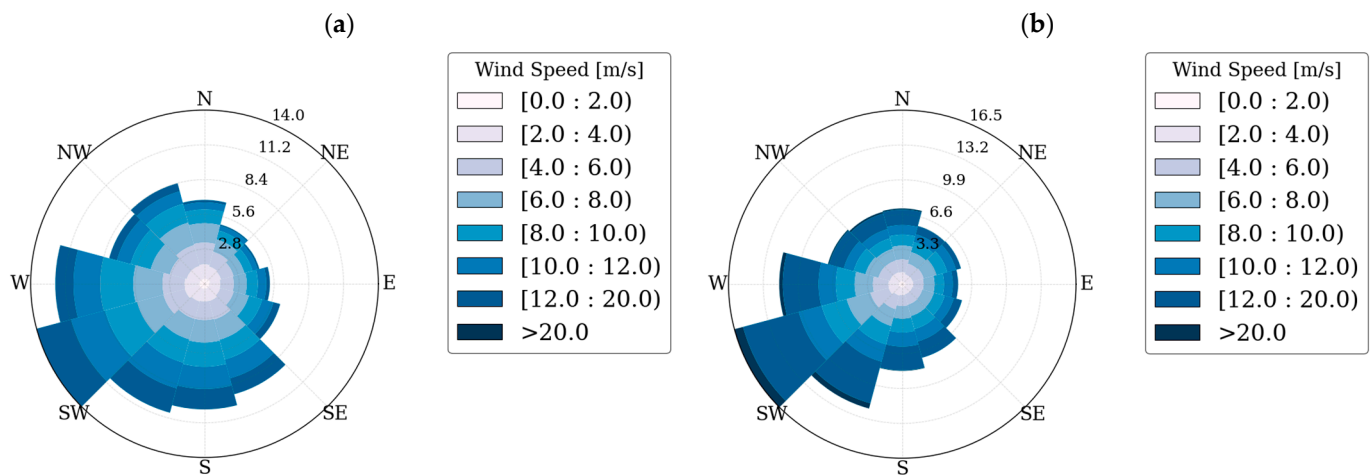


Figure 3. Wind rose diagrams for the onshore (a) and offshore (b) sites at a hub height of 199 m.

Analysis of wind roses, one for the onshore and one for the offshore zones, reveals differences in the structure of wind directions and the distribution of wind speeds. The onshore wind rose (Figure 2a) shows a broad arc of prevailing directions, including WSW, W, and SSW, with the dominant sector accounting for approximately 8–10% of total frequency. Wind speeds are more evenly distributed, and the proportion of flows ≥ 15 m/s remains moderate. Conversely, the offshore wind rose (Figure 2b) is characterised by a clearly defined, much narrower dominance of the WSW sector, contributing approximately 12–15% of the total frequency, and an increased share of high-speed winds. This concentration results in a more stable directional flow and reduced turbulence compared to the onshore zone.

2.4. Wind Flow and Wake Modelling

The Jensen N.O. wake model, implemented in windPRO, (version 4.1) is an analytical model based on simplified aerodynamic assumptions. It assumes that the wake downstream of a wind turbine expands linearly with distance, neglecting the near-wake region behind the rotor. The wake is instead treated as a fully developed turbulent wake or negative jet [51]. Two fundamental equations (see Equations (1) and (2)) describe the wake expansion and the associated velocity deficit [52]. The resulting distribution of

velocity deficits and wake spreading along the downstream direction is illustrated in Figures 4 and 5.

$$R_{\text{wake}}(x) = R_{\text{rotor}} + kx \quad (1)$$

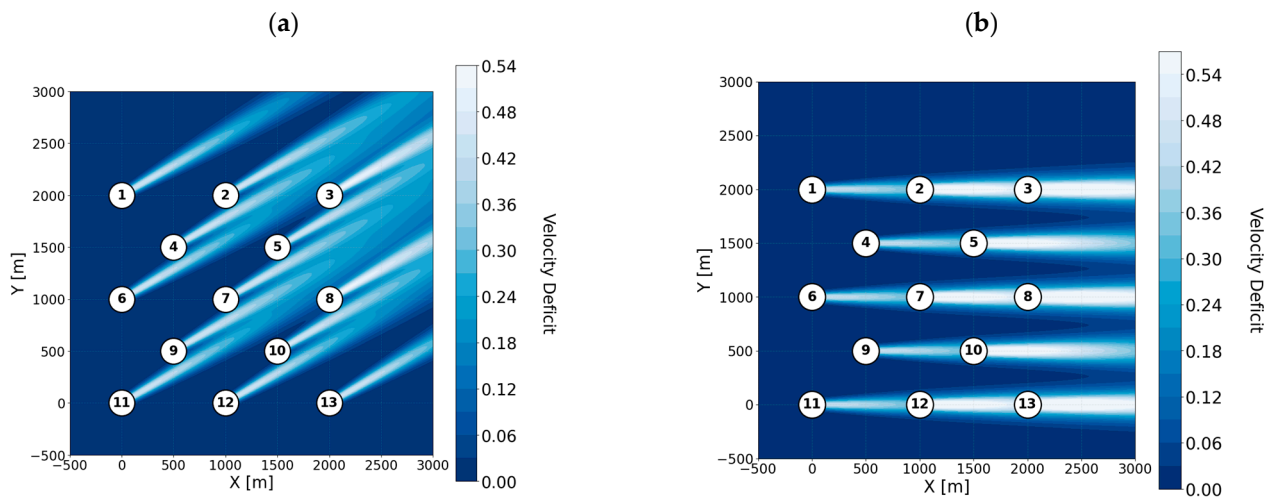


Figure 4. Wake expansion patterns for a chessboard-like turbine arrangement under different incoming wind directions: (a) 240° (south-westerly wind); (b) 180° (southerly wind).

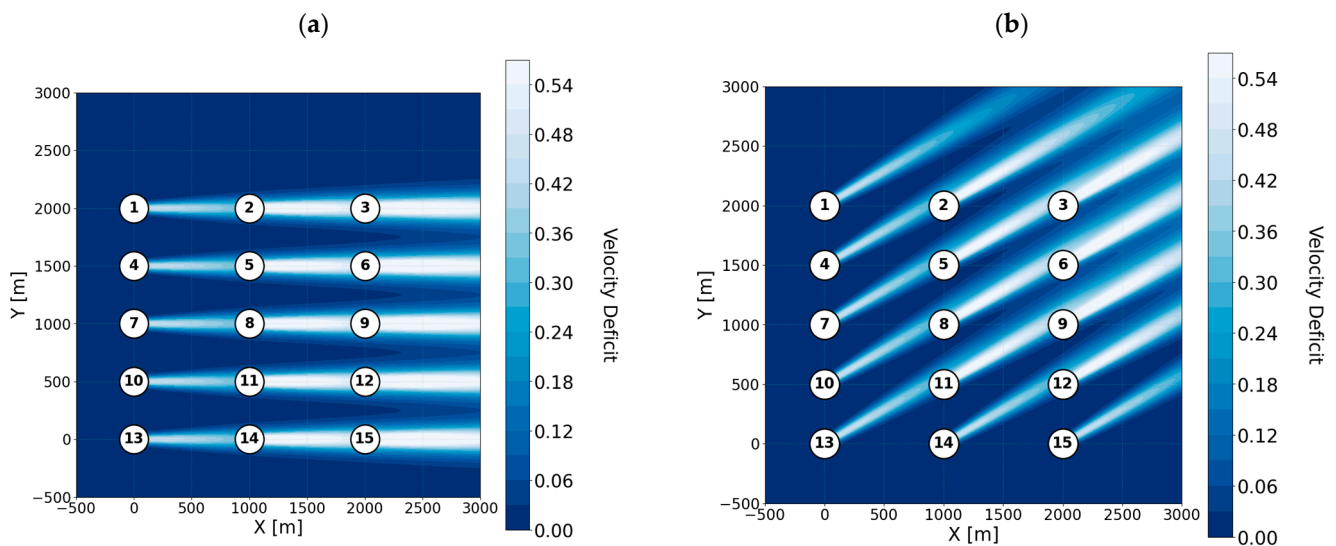


Figure 5. Wake expansion patterns for a linear turbine arrangement under different incoming wind directions: (a) 180° (southerly wind); (b) 240° (south-westerly wind).

To calculate wake radius at downstream distance $R_{\text{wake}}(x)$, the following parameters are used: R_{rotor} —turbine rotor radius [m]; x —downstream distance [m]; and k —empirical wake decay constant.

Standard Jensen Model velocity deficit equation:

$$\frac{\Delta U}{U} = \left(1 - \sqrt{1 - C_T}\right) \times \left(\frac{D}{1 + 2kx}\right)^2 \quad (2)$$

where C_T —thrust coefficient of the turbine; $\Delta U(x)$ —mean wind speed in the wake at the distance x [m/s]; U —free stream wind speed [m/s]; D —rotor diameter [m].

Equation (3) demonstrates a simplified version of the velocity decrease for coding purposes, if the thrust coefficient of the turbine $C_T \approx 1$:

$$\frac{\Delta U}{U} = \left(\frac{D}{D + 2kx} \right)^2 \quad (3)$$

Figures 4 and 5 illustrate the velocity deficit across the simulated wind farm, calculated based on the Jensen wake model equations (Equations (1)–(3)). The velocity deficit distribution results from incoming wind from either a straight direction or a direction dislocated by 30° from the original axis. Each turbine generates a wake, a region of reduced wind speed, immediately downwind. These wakes appear as darker-coloured trails, signifying a high velocity deficit. Consistent with the Jensen wake model, the wake is represented as a simple cone that expands linearly with downstream distance, producing the characteristic straight-edged, cone-like shapes. The staggered turbine layout and wind direction lead to upstream wake interference, resulting in velocity deficits and reduced power production for downstream turbines [53].

2.5. Wind Layout Optimisation and Objective Function

The wind farm layout optimisation was performed by maximising the net AEP. The AEP is calculated as:

$$AEP = 8760 \sum_{i=1}^n P(v_i) \cdot f(v_i) \quad (4)$$

The AEP is calculated as the integral of the turbine power curve, weighted by the wind-speed probability distribution [54].

To account for wake and other technical losses, the net AEP is expressed as [55]:

$$AEP_{\text{net}} = AEP \times \eta_{\text{total}} \quad (5)$$

where η_{total} —overall loss factor. The layout optimisation was formulated as a constrained maximisation problem, with the objective of maximising the net AEP.

Three wake loss scenarios were analysed: 10%, 15%, and 20%. These scenarios were applied to both onshore and offshore configurations.

The three wake-loss thresholds ($\leq 10\%$, $\leq 15\%$, and $\leq 20\%$) were selected to represent a comprehensive range of development strategies encountered in the wind energy industry.

- The 10% threshold reflects a conservative approach, prioritising high aerodynamic efficiency and reduced mechanical loads, typical for onshore sites with ample space.
- The 15% threshold aligns with the current industry benchmark for balanced energy yield optimisation in average site conditions.
- The 20% threshold acts as an upper boundary to test the optimiser's sensitivity under high-density constraints, characteristic of offshore clusters or projects with limited land availability.

The core of this approach centres on sensitivity analysis. Instead of predicting a specific 'correct' value, it investigates how layout optimisation responds to different loss constraints. This allows the identification of non-linearities, such as cases where results change very little between 10% and 15% but then shift markedly between 15% and 20%, effectively revealing a critical threshold. By examining these three distinct levels, the study captures the non-linear response of the layout geometry to varying degrees of aerodynamic interaction, ensuring the robustness of optimisation results across different economic and spatial contexts. The new Optimiser module of the windPRO software (version 4.1) was employed to optimise both onshore and offshore wind farms. When optimisation is

based on AEP, the approach is consistent for both, although site-specific wind resource characteristics and spatial constraints primarily drive differences in the resulting layouts.

2.6. Economic Analysis

The modelling workflow applied in this study is presented in Figure 6. The diagram illustrates the sequential process, beginning with wind resource assessment and site selection, followed by wind farm modelling and energy production estimation, and concluding with the economic evaluation.

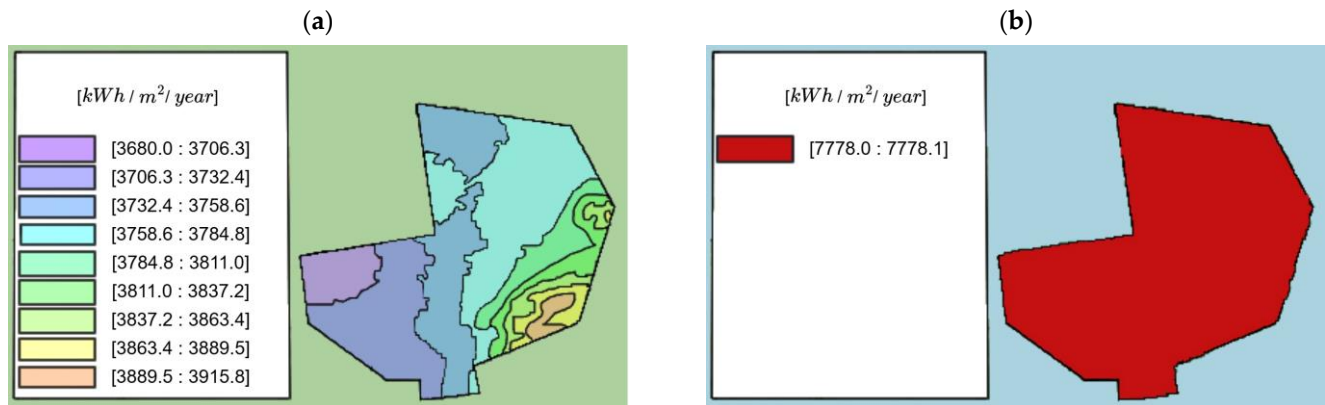


Figure 6. Spatial distribution of specific wind energy (kWh/m²/year) for (a) onshore zones and (b) offshore zones.

The G is calculated using Equation (5):

$$\text{LCOE} = \frac{\text{CapEx} \times \text{FRC} + \text{OpEx}}{\text{AEP}_{\text{net}}} \left[\frac{\text{€}}{\text{MWh}} \right] \quad (6)$$

The variables in the above equation are defined as follows: LCOE is the levelised cost of energy (EUR/MWh); FRC is the fixed charge rate (%); CapEx is the capital expenditures (EUR/kW); EIANet is the net average annual energy production (MWh/MW/year); and o is operational expenditures (EUR/kW/year).

2.7. Model Assumptions

The analysis is based on a set of simplifying assumptions made to ensure consistency and comparability of onshore and offshore wind farm scenarios. The same wind turbine model (Vestas V172–7.2 MW) with a hub height of 199 m was used at both sites, as were identical project lifespans (25 years) and discount rates (5%). Additional simplifying assumptions include the use of an identical site area for both onshore and offshore scenarios, a fixed initial number of wind turbines (30), and a predefined initial layout.

The economic assessment of projects was conducted using standard assumptions regarding capital and operating costs. For offshore wind farms, Development Expenditures (DEVEX), including design, obtaining permits, and conducting Environmental Impact Assessments (EIA), were assumed to be 10% of Capital Expenditures (CAPEX) (8% for development and 2% for permitting documentation). For onshore wind farms, these costs were lower, amounting to 3.5% of CAPEX, including 2.5% for permitting procedures and 1% for EIA. Additionally, for offshore wind farms, site parameters such as a distance to the coast of 2.5 km and water depth of 20 m were considered, as these influence the costs of foundations, cable infrastructure, and installation works.

Environmental and social constraints were not explicitly included in the modelling framework. The study did not perform an EIA, nor were biodiversity protection zones, visual impact restrictions, or social acceptance factors incorporated into the optimisation

process. The analysis focused solely on techno-economic performance within predefined spatial boundaries, assuming general regulatory compliance.

3. Results

3.1. Spatial Distribution of Specific Wind Energy

This section presents the results of the wind resource assessment and layout analysis for both the onshore and offshore study areas. First, the spatial distribution of wind energy potential is analysed, followed by an evaluation of the initial wind farm layouts prior to optimisation.

Furthermore, the spatial distribution of wind resources within the investigated areas is illustrated in Figure 6. The Figure 6a shows the spatial variability of specific wind energy ($\text{kWh}/\text{m}^2/\text{year}$) across the onshore study area, calculated at a hub height of 199 m. In contrast, the Figure 6b presents the spatial distribution of specific wind energy for the offshore study area.

Figure 6 highlights the higher wind-energy potential offshore than in onshore areas. Together, these contrasting characteristics influence AEP, wake behaviour, and layout optimisation, while also reflecting the substantial differences in technical and logistical requirements between onshore and offshore wind farm development.

Starting from a conventional grid-based configuration, the turbine layout was further optimised using the approach outlined in the previous section, aiming to minimise wake losses and maximise the wind farm's annual energy production.

3.2. Scenario 1: Optimised Layout with Wake Loss $\leq 10\%$

In this scenario, the wind farm layout was optimised subject to the constraint that wake losses did not exceed 10%. The optimisation aimed to maximise the net AEP while maintaining low aerodynamic interaction between turbines. Figure 7 illustrates the wind turbine layout configuration of the onshore and offshore wind farms after optimisation, while Table 3 summarises the key technical performance indicators before and after optimisation.

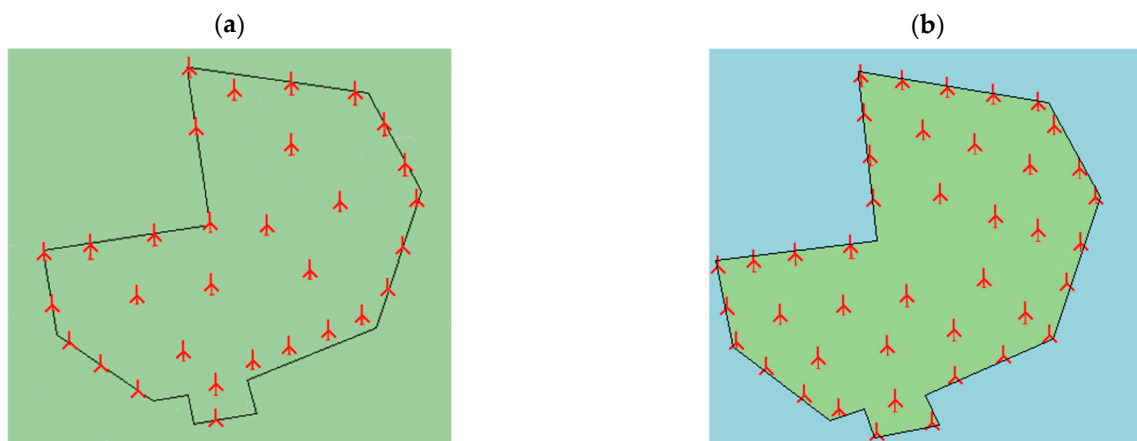


Figure 7. Optimised wind farm layouts with average wake loss $\leq 10\%$: (a) offshore configurations; (b) onshore configurations.

It can be seen that onshore and offshore wind farms have a different number of wind turbine generators. This variation mainly results from the layout optimisation process. By reducing average and maximum wake losses, the optimised layouts enable the installation of more turbines while maintaining energy losses at an acceptable level. This effect is particularly noticeable for the offshore wind farm, where a substantial increase in turbine numbers is realised after optimisation.

Table 3. Comparison of onshore and offshore wind farm performance under wake loss $\leq 10\%$ scenario.

	Onshore		Offshore		Compare Optimised
	Initial	Optimised	Initial	Optimised	
NUMBER OF WTG	30	31	30	42	+11
CAPACITY FACTOR [%]	41.3	42.6	51.9	51.6	21.13%
WAKE LOSE AVERAGE [%]	10.3	7.5	7	7.6	1.33%
LCOE TOTAL [EUR/MWh]	47.65	46.41	58.39	58.68	26.44%
AEP [GWh/y]	782.2	833.2	982.4	1367.1	64.08%

Furthermore, the AEP and total energy yield are higher for the optimised wind farms compared to the initial layouts. When comparing the two non-optimised cases, the offshore wind farm produces considerably more energy than the onshore wind farm. This result is mainly explained by the higher and more stable wind speeds available in offshore conditions, which lead to increased power generation and improved turbine performance.

When analysing the optimised wind farms, the offshore case has a capacity factor approximately 21% higher than that of the onshore wind farm. This indicates more efficient use of the installed offshore capacity, despite the larger number of turbines and total installed power. The slight reduction in capacity factor observed after optimisation in the offshore case may be attributable to increased turbine interactions due to the higher turbine density.

Finally, despite lower energy efficiency and total energy production, the onshore wind farm has a lower total LCOE than the offshore wind farm. This outcome is primarily attributable to the significantly lower capital expenditures and operating costs associated with onshore wind projects, whereas offshore wind farms require higher investments due to installation, maintenance, and grid connection challenges.

3.3. Scenario 2: Optimised Layout with Wake Loss $\leq 15\%$

In this scenario, the wind farm layout was optimised subject to the constraint that wake losses did not exceed 15%. Table 4 summarises the technical performance indicators before and after optimisation.

Table 4. Comparison of onshore and offshore wind farm performance under wake loss $\leq 15\%$ scenario.

	Onshore		Offshore		Compare Optimised
	Initial	Optimised	Initial	Optimised	
NUMBER OF WTG	30	45	30	60	+15
CAPACITY FACTOR [%]	41.3	40.3	51.9	49.2	22.0%
WAKE LOSE AVERAGE [%]	10.3	12.5	7	11.9	−4.79%
LCOE TOTAL [EUR/MWh]	47.65	48.66	58.39	61.13	25.62%
AEP [GWh/y]	782.2	1143.7	982.4	1862.1	62.8%

The results show clear differences between the initial and optimised layouts for both onshore and offshore wind farms. For the onshore case, the number of wind turbine generators increases from 30 in the initial layout to 45 in the optimised configuration. A similar trend is observed for the offshore wind farm, where the number of turbines increased from 30 to 60.

Although the number of turbines has increased significantly, the hub height and rotor diameter remain unchanged across both wind farms. The lifetime and discount rates are also held constant, enabling a direct comparison across the cases. As a result of adding more turbines, the AEP increases strongly for both onshore and offshore wind farms. In the onshore case, the AEP increases by approximately 46%, whereas for the offshore wind farm, it increases by nearly 90%, indicating the strong impact of turbine count on total energy yield.

However, the increase in turbine density also results in greater wake losses. For the onshore wind farm, the average wake loss rises from 10.3% to 12.5. The same behaviour is even more pronounced in the offshore case, where average wake losses increase from 7% to 11.9%. This indicates that the optimisation in this case prioritises energy quantity rather than wake efficiency.

The capacity factor decreases for both wind farms after optimisation. In the onshore case, the capacity factor is reduced by approximately 2.4%, whereas in the offshore case, the reduction is greater, at approximately 5.2%. This reduction can be explained by stronger wake interactions and less efficient use of the installed capacity due to the higher turbine concentration. Nevertheless, the offshore wind farm still maintains a capacity factor about 22% higher than the onshore wind farm in the optimised comparison.

In terms of economic performance, the total LCOE increases for both wind farms after optimisation. The onshore LCOE increases by about 2.1%, while the offshore LCOE shows a higher increase of around 4.7%. Despite this increase, the onshore wind farm still has a lower LCOE than the offshore wind farm, primarily due to lower investment and operational costs associated with onshore installations.

Overall, the results indicate a clear trade-off between maximising total energy production and maintaining efficient turbine operation. While the optimised layouts significantly increase the AEP, they also introduce higher wake losses, reduced capacity factors, and increased LCOE, especially in the offshore case.

3.4. Scenario 3: Optimised Layout with Wake Loss $\leq 20\%$

In this scenario, the wind farm layout was optimised subject to the constraint that wake losses did not exceed 20%. Table 5 summarises the technical performance indicators before and after optimisation.

Table 5. Comparison of onshore and offshore wind farm performance under wake loss $\leq 20\%$ scenario.

	Onshore		Offshore		Compare Optimised
	Initial	Optimised	Initial	Optimised	
NUMBER OF WTG	30	54	30	75	+15
CAPACITY FACTOR [%]	41.3	38.8	51.9	47.1	21.39%
WAKE LOSE AVERAGE [%]	10.3	15.7	7	15.6	−0.64%
LCOE TOTAL [EUR/MWh]	47.65	50.21	58.39	63.57	26.61%
AEP [GWh/y]	782.2	1323.4	982.4	2229.0	68.43%

The table compares the performance and efficiency of wind turbine generator (WTG) setups for both onshore and offshore projects, considering initial and optimised configurations. For onshore installations, the number of turbines increases from 30 to 54 in the optimised setup, resulting in a total power capacity rising from 216.0 MW to 388.8 MW. However, this optimisation also causes a slight decrease in the capacity factor, from 41.3% to 38.8%, indicating that although total output increases, individual turbine efficiency declines slightly. Wake losses due to wind interference between turbines also increase noticeably, from 10.3% to 15.7% on average. Consequently, the LCOE increases by 5.37%, from 47.65 to 50.21 EUR/MWh. Despite this, total AEP increases by 69.19%, indicating that the optimisation still yields substantially higher overall generation.

For offshore setups, the differences are even more striking. The optimised version increases the number of turbines from 30 to 75, boosting total power from 216.0 MW to 540.0 MW. While the capacity factor decreases slightly from 51.9% to 47.1%, total energy production more than doubles, increasing by 126.89%. Offshore wake losses rise steeply, with average losses climbing from 7% to 15.6%, and LCOE increasing by almost 9%, from 58.39 to 63.57 EUR/MWh. Despite these higher losses and costs, the optimisation improves total energy output and provides a clearer view of how scaling up turbine numbers impacts performance and efficiency differently onshore versus offshore.

3.5. Performance Comparison of Onshore and Offshore Wind Farms Across Wake Loss Scenarios

To evaluate the influence of wake loss constraints on overall wind farm performance, a comparative analysis was conducted across all optimisation scenarios and site locations. Table 6 summarises the key performance indicators for both onshore and offshore configurations under initial conditions and for wake loss limits of $\leq 10\%$, $\leq 15\%$, and $\leq 20\%$. This comparison enables an assessment of how varying aerodynamic interaction levels affect energy production and overall park efficiency, highlighting the superior energy yield of the offshore configuration.

Table 6. Comparison of parks with different levels of wake loss.

	Initial	Onshore			Initial	Offshore		
		Optimised $\leq 10\%$	Optimised $\leq 15\%$	Optimised $\leq 20\%$		Optimised $\leq 10\%$	Optimised $\leq 15\%$	Optimised $\leq 20\%$
Number of WTGs	30	31	45	54	30	42	60	75
Area (km ²)	42	42	42	42	42	42	42	42
AEP (GWh/y)	782.2	833.2	1143.7	1323.4	982.4	1367.1	1862.1	2229.0
Energy Density (GWh/km ² /y)	18.62	19.84	27.23	31.50	23.39	32.55	44.33	53.07

The table compares onshore and offshore wind farm performance across different optimisation levels, focusing on turbine count, area, and energy output. For onshore setups, the number of turbines increases from 30 initially to 54 at the highest optimisation level ($\leq 20\%$), with the AEP rising from 782.2 GWh to 1323.4 GWh—an improvement in energy density from 18.62 to 31.50 GWh per square kilometre. Offshore projects show even greater gains, with turbines increasing from 30 to 75 and AEP growing from 982.4 GWh to 2229.0 GWh, resulting in an energy density jump from 23.39 to 53.07 GWh/km². Overall, as optimisation levels increase, both onshore and offshore setups achieve higher energy production efficiency without expanding the area used.

4. Conclusions

This study presented a techno-economic comparison of onshore and offshore wind farms in the eastern Baltic Sea region using identical turbine technology and spatial boundaries. Layout optimisation was applied under three wake-loss scenarios ($\leq 10\%$, $\leq 15\%$, and $\leq 20\%$) to evaluate the influence of wake losses on energy performance within a fixed project area.

The results indicate that offshore wind farms achieve considerably higher AEP and energy density. Under similar spatial conditions, offshore energy density was roughly 1.5–1.7 times that of onshore setups. Across all wake-loss scenarios, the offshore arrangement achieved about a 70% higher AEP than the onshore wind farm. This increase is mainly due to the greater number of turbines that can be installed within the same spatial boundary in offshore conditions. This enhancement is chiefly driven by stronger, more stable wind conditions, lower surface roughness, and more uniform wind flow, leading to reduced wake losses and greater wake stability. Offshore has an LCOE approximately 25% higher than onshore due to significantly higher capital and infrastructure costs.

In contrast, the onshore configuration demonstrated superior economic performance. Despite lower AEP and higher wake sensitivity, the onshore site achieved a lower LCOE, mainly due to reduced capital and O&M costs. Layout optimisation contributed to moderate improvements in capacity factor and reduced wake loss, thereby enhancing cost competitiveness.

The main issues concern the trade-off between high energy density and economic efficiency: offshore projects in the eastern Baltic Sea require significant investment and face technological challenges, while onshore installations are constrained by land availability, wind variability, and social resistance. Additionally, both technologies depend on natural conditions and infrastructure, which affect power generation stability and overall profitability.

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Abbreviations

The following abbreviations are used in this manuscript:

AEP	Annual energy production
AEP _{net}	Net annual energy production
CAPEX	Capital expenditures
CF	Capacity factor
DEVEX	Development expenditures
EIA	Environmental impact assessment
ESS	Energy storage system

WTG	Wind Turbine Generator
IEC	International Electrotechnical Commission
LCA	Life Cycle Assessment
LCOE	Levelised cost of energy
NORA3	The 3 km Norwegian reanalysis data
NREL	National Renewable Energy Laboratory
O&M	Operation and maintenance
OPEX	Operational expenditures

Nomenclature

Symbol	Description	Unit
Latin Symbols		
C_T	Thrust coefficient of the turbine	
D	Turbine rotor diameter	m
$f(v_i)$	Relative frequency of each wind speed interval	
k	Empirical wake decay constant	
$P(v_i)$	Power output for each wind speed interval i	kW or MW
R_{rotor}	Turbine rotor radius	m
R_{wake}	Wake effect radius	m
U	Free stream wind speed	m/s
x	Downstream distance	m
Greek Symbols		
$\Delta U(x)$	Mean wind speed in the wake at the distance x	m/s
η_{total}	Overall loss factor	

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