HIghly advanced Probabilistic design and Enhanced Reliability methods for high-value, cost-efficient offshore WIND

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Definitions:	

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List of Abbreviations

AEP	Annual Energy Production
BoP	Balance of Plant
CAPEX	Capital Expenditure
DEVEX	Development Expenditure
DOE	Design of Experiment
EYA	Energy Yield Assessment
LCOE	Levelized Cost of Energy
MCS	Monte Carlo Simulation
MTTF	Mean time to failure
MTTR	Mean time to repair
O&M	Operation and Maintenance
OPEX	Operational Expenditure
WACC	Weighted Average Cost of Capital
WP	Work Package

1. Executive summary

The present report summarizes the work done in Task 6.2 of HIPERWIND. The objective of this task is to quantify the impact, on the levelized cost of energy (LCOE), of the technology improvements delivered by the other works packages (WPs) of the project. For that purpose, a tool for estimating LCOE has been developed. This tool, built in a flexible and granular Python framework, consists of various modules for calculating key components of LCOE: namely the capital expenditure (CAPEX), the operational expenditure (OPEX), and the annual energy production (AEP). The architecture, of this Python tool, was designed to allow specific component or activity optimization impact assessments. The overall impact on the LCOE is estimated by computing the effects of the HIPERWIND technologies on each of its components.

This first section of the document details the methodology for estimating the main terms of the LCOE.

The CAPEX is computed as the sum of the costs of the turbine's components, the overall infrastructure (referred to as the balance of plant or BoP), and additional costs associated with the project's development and insurance (referred to as Owner's cost). The cost of each component of the CAPEX is estimated using values available in the literature.

OPEX is subdivided into two categories the operational cost and the maintenance costs. The operational costs, covering land fees and other fees are assumed to be constant each year. Maintenance is broken down into several activities. Each activity is associated with a probability of occurrence, a material cost, a type of vessel, a repair time, and the mean time to repair (MTTR). The cost associated with an activity is the sum of material and vessel costs. Monte Carlo simulation (MCS) is used to estimate the number of maintenance activities, from the probability of occurrence, and the associated costs. In addition to the varying maintenance costs, fixed costs are considered to account for the salary of the technicians.

AEP is estimated by first computing the theoretical, or raw, energy production using the distribution of ambient conditions provided by WP2. Wake, electrical, and availability losses are then discounted from the raw value to obtain the "effective" AEP value. Wake and electrical losses are assumed to be constant each year. The wake losses are computed using the farm flow simulation results from WP3. Electrical losses are assessed using standard values from the literature. The availability losses are computed from the OPEX model and therefore depend on the number of yearly failures.

The obtained CAPEX, OPEX, and AEP values, are then levelized using the weighted average cost of capital (WACC) as a proxy for the discount factor to compute the LCOE.

The optimized design of the structural components delivered by WP4 allows for reductions of mass of the tower and foundation by 18.17% and 24.87% respectively. The impact on the cost of each component is estimated to be 80% of the mass reduction. Overall, this leads to a reduction of the CAPEX of approximately 4.32%. Which meets the target set at the beginning of the project (between 4% and 6%).

The optimized maintenance schedule delivered by task 6.1, allows to reduce the repair time of the gearbox replacement by approximately 14%, which drives a 12% in the vessel costs by 12%. Even though the optimization was performed only for the gearbox replacement, these results are assumed to be transposable to all major component replacements. For the reference wind farm considered in HIPERWIND, Teesside the optimization of the maintenance schedule leads to a reduction of the OPEX of approximately 7.1% This also meets the target for OPEX reduction for HIPERWIND.

One of the major findings of this study is that the value for the OPEX heavily depends on the choice of the wind farm design. The maintenance costs scale linearly with the number of replacements which depends on the probability of failure and the number of turbines installed. For a fixed farm capacity, a lower turbine rating requires the installation of more turbines. This has the impact of increasing the number of failures and associated costs. To illustrate such effect two scenarios are considered in this study. The first is Teesside, analyzed as it was at the time of its construction in the early 2010s (referred to as “as built”). The second scenario considers a virtual wind farm comprising 75×8MW turbines (total capacity 600MW) and is referred to as “state-of-the-art”. LCOE is estimated for both scenarios, each considering a baseline case, without any HIPERWIND improvement and an optimized case, including the CAPEX and OPEX reductions. For the as-built scenario, the reduction in LCOE is found to be approximately 5.12%. Which is lower than the HIPWERWIND target of 9%. On the contrary, for the state-of-the-art scenario, LCOE reduction due to the optimized design is found to be 10.36%, exceeding the HIPERWIND target.

The individual cost reduction targets are met for both the CAPEX and OPEX. For other components, of the LCOE, such as the development cost, the cost of capital, and the AEP, no improvement could be derived from the project’s findings. This is mainly because these parameters depend on factors that were outside of the scope of the project. Nevertheless, HIPERWIND delivered substantial LCOE reduction, even exceeding the original target, depending on the scenario considered. This result acknowledges the fact that the project has delivered substantial advancements and paved the way towards better competitiveness of offshore wind technology.

2. Introduction

2.1. Context

The European Commission has set an ambitious target of up to 450GW of offshore wind by 2050. With offshore wind power set to form the backbone of green electricity production in Europe, there is an urgent need for a cost-effective improvement of the reliability of all major wind turbine systems/components. This can only be achieved if the industry has highly efficient and accurate design tools that reduce the uncertainty in safety margins by ensuring a robust turbine design delivering the intended performance and safety.

Managing uncertainties is consequently a key driver in reducing costs and improving the production, reliability, and thereby the value of offshore wind. Uncertainties translate into higher safety margins adding materials to components, shorter maintenance cycles, and increases in the cost of financing wind farms.

HIPERWIND team researched new methods in wind energy basic science to reduce the Levelized Cost of Energy (LCOE) by 9% by reducing capital expenses (CAPEX) by 4-6%, lowering operational expenses (OPEX) by 5-7%, increasing Annual Energy Production (AEP) by 2-3%, and reducing the Weighted Average Cost of Capital (WACC) by 2-5% (Figure 1 and Figure 2). In addition, HIPERWIND tools can assist in increasing the market value factor of offshore wind power plants by 1%, a change driven by the increase of capacity factors by 1-3% due to reduced unscheduled maintenance and improved operations. Achieving these targets may result in at least 460 million EUR of annual cost savings for the wind energy sector by 2030.

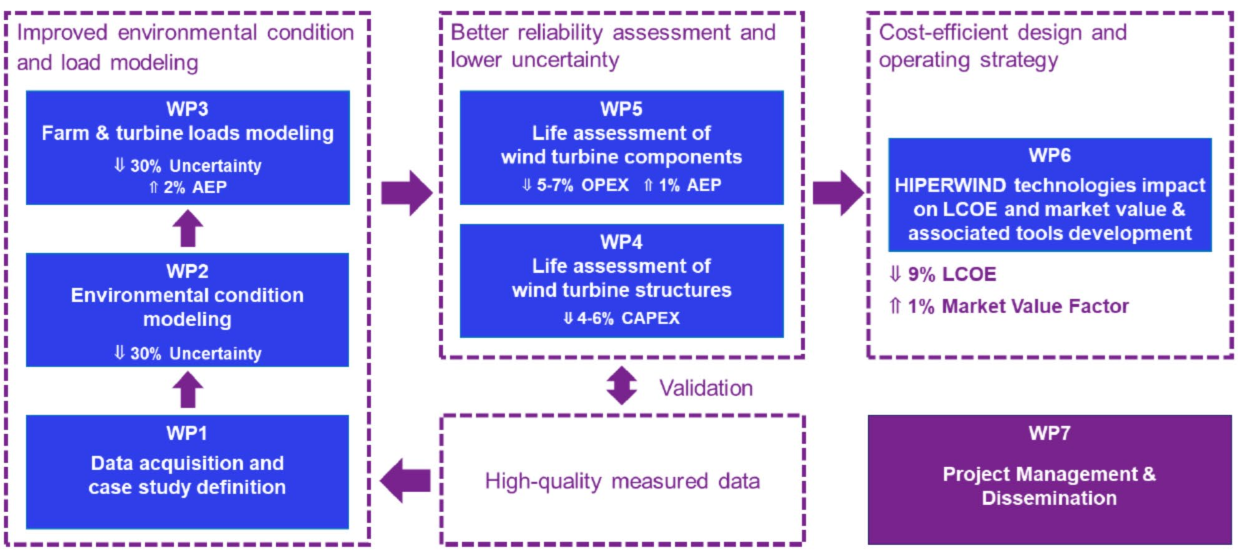

Figure 1. Overview of the organization of the HIPERWIND project and work packages.

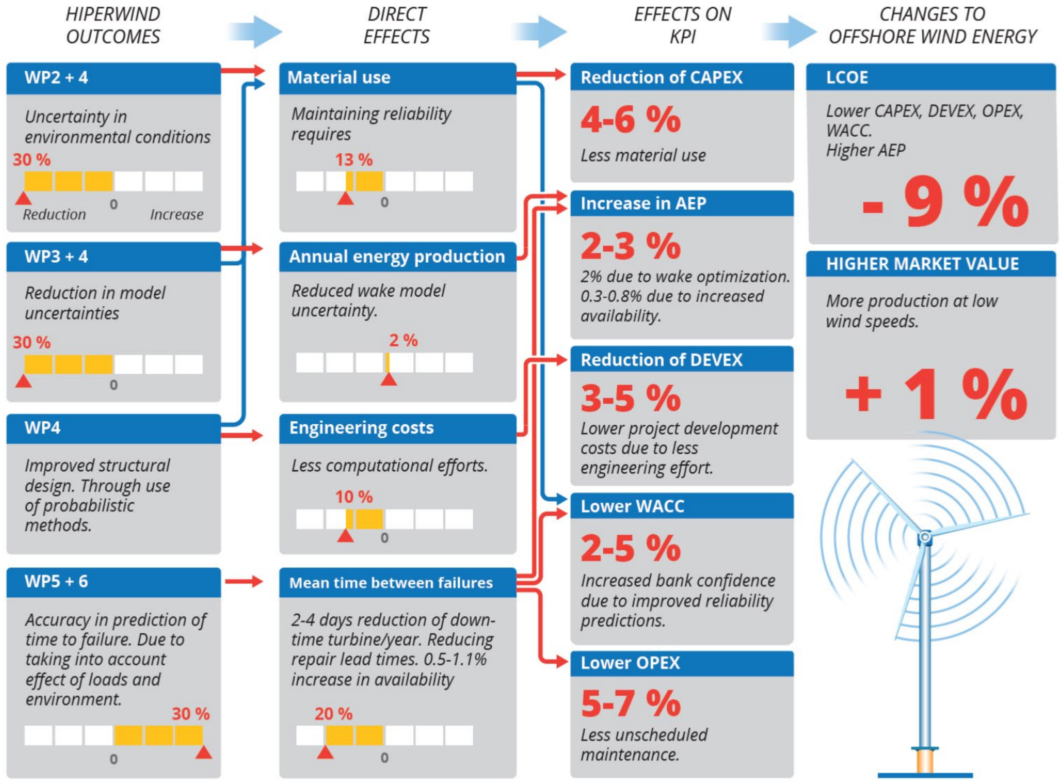

Figure 2. Overview of the expected LCOE reduction from the HIPERWIND project.

2.2. Scope of work and objective

The main objective of Work Package 6 (WP6) is to assess the impact of the HIPERWIND technologies delivered by the project's other work packages on key metrics. Specifically, Task 6.2 (T6.2) aims to quantify the reductions in LCOE achieved through these technological advancements.

To compute such cost reduction, T6.2 leveraged the following inputs from the other work packages:

- WP2: Accurate description of ambient wind conditions for estimating the AEP of the case study wind farm.
- WP3: State-of-the-art farm flow simulation results to estimate effective wind conditions at turbine location, required to assess the wakes' impact on AEP.
- WP4: Optimized turbine design that reduces the mass and cost of structural components of the turbines (tower and foundation).
- WP5: Reliability map for the turbine major systems/components coupled with site-specific information to improve failure anticipation and maintenance budget forecasting.
- WP6 (Task 6.1): Optimized maintenance schedule to reduce costs associated with major component replacements.

In T6.2, a tool for estimating LCOE was developed, leveraging results from the previous HORIZON project (INNWIND [1]), literature review, and EPRI projects [2], [3]. This tool, built in a flexible and granular Python framework, consists of various modules for calculating key components of LCOE. The architecture was designed to allow specific component or activity optimization impact assessments. LCOE estimation is conducted for multiple cases. The baseline case, which excludes HIPERWIND improvements, serves as a reference. The optimized case, integrating all HIPERWIND project deliverables, is then compared to the baseline to quantify LCOE impact.

The objective of this deliverable report is to detail the tools and methods developed in T6.2 and to summarize the main findings of the project concerning cost reductions. The remainder of the document is organized as follows:

- Section 3 details the methodology for LCOE calculation. It introduces the main formula, outlines its key components, and provides an in-depth explanation of the steps involved in the LCOE calculation.
- Section 4 discusses the impact of key parameters on LCOE that are not directly linked with HIPERWIND. This section is crucial for understanding how the analysis results can be influenced by the choice of the reference case and how to interpret the results presented in the third section.
- Section 5 presents the LCOE results obtained for different reference scenarios. For each scenario, the results are presented for both the baseline and optimized cases, allowing quantification of the impact of the HIPERWIND technologies.
- Section 6 discusses the quantification of the impact of HIPERWIND on offshore wind LCOE considering several scenarios.
- Section 7 summarizes the work done in T6.2, highlights the key findings, and HIPERWIND value and discusses perspectives for future research.

In addition to the main sections defining the body of this report, several appendices are provided. They summarize the main model parameters as well as the different scenarios used in the LCOE calculation.

3. Methodology

This section details the methodology applied for the calculation of the Levelized Cost of Energy (LCOE) in HIPERWIND. It first introduces the general formula for LCOE and defines the main factors. A second subsection details the calculation of each of the components within the LCOE equation.

3.1. LCOE calculation

As defined in [4] the LCOE quantifies the average cost, discounted by the analysis period, required to produce one unit of energy. It can be calculated using the equation (3-1):

$$LCOE = \frac{\sum_{n=1}^{N_{year}} \frac{CAPEX_n + OPEX_n}{(1+w)^n}}{\sum_{i=1}^{N_{years}} \frac{AEP_n}{(1+w)^n}} \quad (3\text{-}1)$$

Where:

- LCOE is the levelized cost of energy, expressed in $\$/MWh$.
- N_{years} is the number of years in the analysis period, usually the lifetime of the project.
- w is the discount factor.
- $CAPEX_n$ represents the portion of the capital expenditure due to be paid for a given year n.
- $OPEX_n$ represents the operational expenditures for a given year n.
- AEP_n is the annual energy production for a given year n.

3.2. Definition of the main term

This section presents the step-by-step process, used in HIPERWIND, to estimate the main factors in the LCOE formula.

3.2.1. Discount rate

The discount rate is a metric to determine the present value of future cash flows. It reflects the time value of money and the risk associated with the project. Estimating its value can be challenging since it depends on the investors' perception of the risk. Different projects are, therefore, very likely to have different nominal discount rates. As detailed in [5], a common practice is to use the weighted average cost of capital (WACC) as a proxy for the discount rate. The WACC can be estimated as follows:

$$WACC = \eta_{debt} \cdot (1 - t_{eff}) \cdot c_{debt} + \eta_{eq} \cdot c_{eq} \quad (3\text{-}2)$$

Where:

- η_{debt} is the fraction of the capital that is financed by debt.
- t_{eff} is the effective tax rate.
- c_{debt} is the cost of the debt or interest rate.
- η_{eq} is the fraction of the capital that is financed as capital ($\eta_{eq} = 1 - \eta_{debt}$).
- c_{eq} is the cost of equity.

Results in this study are presented in constant dollar value. This requires correcting the "nominal" value of the WACC from the effect of inflation, also referred to as the "real" value of the WACC. The relationship between the real and nominal values is given by the Fisher equation [6], as follows:

$$WACC_r = \frac{WACC_n - e}{1 + e} \tag{3-3}$$

Where:

- $WACC_r$ is the "real" value for the weighted average cost of capital, accounting for the effect of inflation required for constant dollar value analysis.
- $WACC_n$ is the nominal for the weighted average cost of capital given per equation (3-2).
- e is the inflation rate.

3.2.2. Capital Expenditure (CAPEX)

The capital expenditures, or CAPEX, encapsulate all costs that are capitalized for the project. It includes the cost of the procurement of the wind turbines and the entire infrastructure, as well as the cost of the erection and commissioning of the wind farm. The development costs are also included in the CAPEX, as well as the insurance for the project.

CAPEX breakdown and main components.

Following the approach from previous EPRI studies [2], [3], the overall capex is broken down into three main categories, the turbine's costs, the balance of plan (BoP) cost, and the so-called owner's costs. The latter encapsulates the expenses associated with project development and project financing and is divided into two main categories the development cost (often referred to as DEVEX) and the insurance costs. The turbine category regroups all the components that play an active role in the conversion from the wind energy to mechanical to electrical power (rotor, and drivetrain), as well as the structural part of the nacelle and the tower. The remaining part of the infrastructure, such as the foundation, and the electrical infrastructure is a part of the BoP which also includes the erection and contingency costs. Table 1 below summarizes the different components of the CAPEX.

Table 1. Component breakdown for CAPEX calculation following EPRI approach detailed in [3].

Tower	
Rotor	Includes the purchase price for the wind turbine generators (WTGs) from the OEM. This price includes the cost of the complete WTG (rotor, hub, nacelle, drivetrain, generator, down tower assembly, tower, control system, options, and warranty), transportation and delivery to the staging port, and commissioning support. The breakdown of the turbine components follows the one proposed by NREL [7], [8] and IRENA [9]
Blades	
Hub	
Pitch system	
Nacelle	
Nacelle structure	
Drivetrain	
Electrical component	
Yaw System	
Tower	
BoP	
Engineering & Management	Includes the cost of hiring and oversight of personnel (e.g., managers, engineers, and laborers) who develop the project design and perform equipment selection.
Substructure & Foundation	Includes the procurement costs for the structures that support the wind turbines.
Port and Staging	Includes the costs incurred as a result of installation activities staged and carried out at a selected port. Costs include fees for the entrance and exit of vessels, docking fees, loading, and unloading fees, storage, and staging of equipment and materials, as well as costs for the use of port cranes.
Electrical Infrastructure	Includes the infrastructure required for exporting power generated by the project, including cables and power equipment (e.g., transformers). Costs associated with the construction of both an offshore (voltage step-up) and onshore (interconnection) substation are assumed.
Assembly and Installation	Includes the costs incurred during assembly and installation of the substructure foundation, turbine erection, and electrical system installation, and also includes vessels and equipment necessary to perform these activities. Vessel and equipment mobilization costs are considered as well as an allowance for downtime associated with unsafe weather conditions.
Commissioning	Includes expenses related to testing and verification of proper operation of the project upon construction completion
Contingency	
Owner's Cost	Include those expenses associated with project development and project financing. Project development costs cover project feasibility analyses, wind resource assessments, geotechnical studies, other consultant's fees, contracting for land access, transmission access, entering into offtake agreements, permitting, and financing costs.

Estimating component costs and CAPEX

The CAPEX is the sum of all the components cost as listed above. In literature, costs are often provided per unit of installed power ($\$/kW$). The resulting value for the CAPEX is obtained by scaling each cost by the rated power of the turbines installed for the project.

$$CAPEX = \sum_{i=1}^{N_{turb}} \sum_{j=1}^{N_{comp}} cost(comp_j) \times P_{rated,i} \tag{3-4}$$

Where:

- N_{turb} is the number of turbines.
- $comp_j$ refers to the components listed in Table 1.
- $P_{rated,i}$ is the rated power of the i[th] turbine.

The unitary costs for each of the CAPEX components are summarized in Appendix A and shown in Figure 3 below.

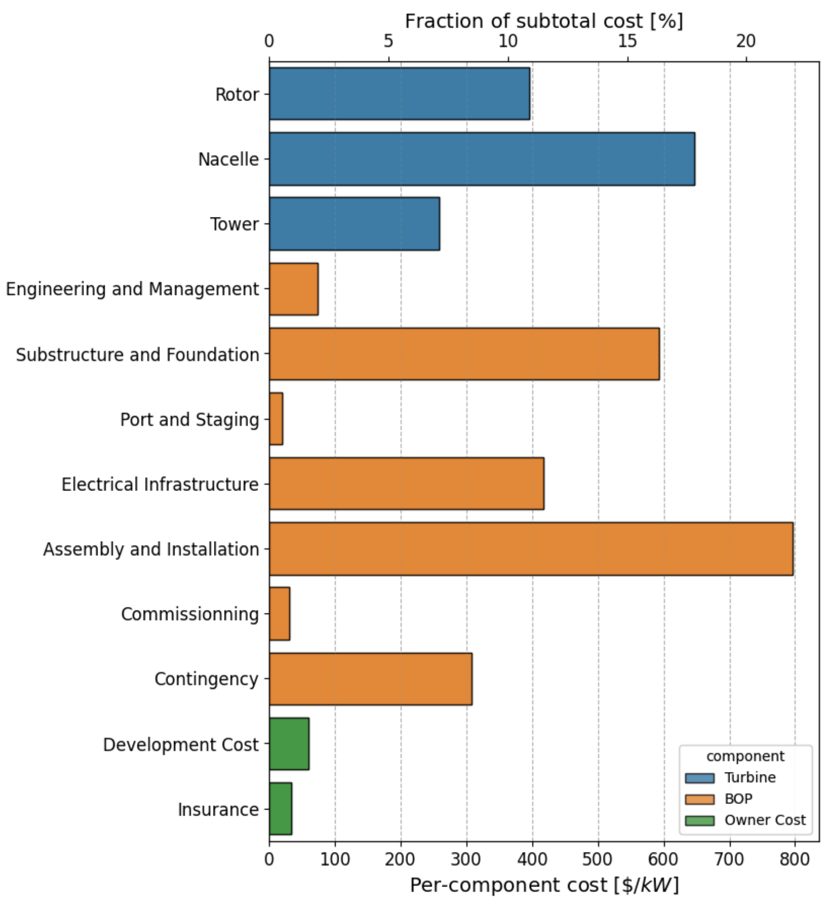

Figure 3. Unit cost (in $\$/kW$) of the CAPEX component retained for the HIPERWIND project. Costs are derived from previous EPRI [3] work and results available in the literature [8], [9].

Converting "overnight" CAPEX to "real" CAPEX value

The value of the CAPEX obtained from the equation (3-4) is referred to as the "overnight" CAPEX. It represents a simplified, idealized snapshot of the total capital costs required to build the wind farm instantly ("overnight"), excluding financing costs and construction period interest. In contrast, the "real" CAPEX includes these financing costs and interest accrued during the actual construction period and is typically higher than the overnight CAPEX. Such effect is accounted for by scaling the value of the CAPEX value using a so-called financial factor, as follows:

$$CAPEX_{real} = \eta_{financing} \times CAPEX_{overnight} \tag{3-5}$$

Where:

- $CAPEX_{real}$ is the real value of the CAPEX accounting for the financing costs and interest during construction.
- $CAPEX_{overnight}$ is the value of the overnight CAPEX computed using the equation (3-4).
- $\eta_{financing}$ is the financing factor.

The value of the financing factor is taken from [3], and is listed in Table 20 in Appendix C.

Computing capital and debt payments

The CAPEX value obtained from the equation (3-5) is divided into two parts. The "equity" part corresponds to the fraction of the CAPEX financed directly by the wind farm owner, while the "debt" part represents the portion financed by a loan. The "debt fraction" (η_{debt}) parameter introduced in section 3.2.1 is used to compute the values of the debt and equity parts, as follows:

$$loan = \eta_{debt} \times CAPEX_{real} \tag{3-6}$$

$$equity = (1 - \eta_{debt}) \times CAPEX_{real} \tag{3-7}$$

Where:

- $CAPEX_{real}$ is the real CAPEX value from the equation (3-5).
- η_{debt} is the debt fraction as introduced in 3.2.1.
- $loan$ is the "debt" part of the CAPEX.
- $equity$ is the equity part of the CAPEX.

The equity part is assumed to be paid at the moment the wind farm is built (referred to as year "0"). Conversely, the loan portion is paid in annual installments, spread over the life of the loan from the first year of the project's life (referred to as year "1"). A portion of each annual payment is used to pay back the loan. The remainder of the payment covers the interest associated with the loan. The total amount of interest to be paid depends on the value of the loan (see equation (3-6)), the number of payments (referred to as the loan period), and the value of the WACC (see equation (3-2) from section 3.2.1), and can be computed easily using public libraries such as "NumPy financial" [10].

3.2.3. Operational Expenditure (OPEX)

The operational expenditures, or OPEX, regroup all the costs associated with the operation of the wind farm. It includes the costs that are indissociable from the operation of the wind farm, referred to as operational costs, and the maintenance costs. The latter arises from the activities that are necessary to keep the wind farm in a running state. They include the planned (service) and unscheduled maintenance activities. The operational cost essentially includes the annual land lease and fees.

3.2.3.1. Operation cost

The operational costs are generally modeled as a linear function of the windfarm annual energy production as illustrated by the formula below:

$$OPEX_{op}(n) = \alpha_{op} \times AEP(n) \tag{3-8}$$

Where:

- $OPEX_{op}(n)$ represent the operation part of the OPEX for the year n (in \$).
- $AEP(n)$ is the annual energy production for the same year n, in MWh.
- α_{op} is the model constant in $\$/MWh$

The optimization of the operational costs is not within the scope of HIPERWIND. Indeed, these are unlikely to be affected by optimization of the turbine design since they essentially cover land leases and other annual fees. Moreover, these costs only represent a small fraction of the OPEX, which is dominated by maintenance costs. This is particularly true for offshore wind farms. In the context of this study, the operational costs are, then, modeled using a fixed value for α_{op} whose value is taken from the literature (see [8]) and listed in Table 17 of Appendix B.

3.2.3.2. Maintenance Cost

While several studies and reports offer detailed breakdown costs for maintenance of onshore wind farms [11], [12], [13], less information is available regarding the maintenance of offshore wind farms. For this reason, maintenance costs are often reported in an aggregated form and scaling as a function of installed capacity or annual energy production. However, for HIPERWIND, it is required to get more granularity in the cost calculation to study the impact of optimization of specific tasks on the overall maintenance costs. To that end, a model for OPEX based on the cost of component failure is developed, following the approach detailed in [14]. The maintenance costs are defined as the sum of three components, as follows:

$$OPEX_{maintenance}(n) = Material(n) + Vessel(n) + Labor(n) \tag{3-9}$$

In equation (3-9), the labor costs account for the salary of the technicians that are assigned to the maintenance of the wind farm. They are calculated from the number of staff and a base salary (assumed to be fixed for the entire period), and, therefore, constant for each year of the project.

$$Labor = N_{staff} \times Cost_{staff} \tag{3-10}$$

Material costs are associated with the prices of the components that are required to perform the maintenance activities. They cover tooling and small components or pieces used during the maintenance, as well as the price of the major components (blade, gearbox, and so on) when those need to be replaced. The material costs for a given year are the sum of all the materials used during that period.

$$Material(n) = \sum_{i=1}^{N_{failure}} mat(failure_i) \tag{3-11}$$

The costs of the vessels required to bring the technicians from the nearest harbor to the wind farm are modeled on a per-mission basis. The cost breaks down into a mobilization cost, paid every time a vessel needs to be mobilized, and a variable cost depending on the mission duration (days) and the vessel's daily rate.

$$Vessel(n) = \sum_{i=1}^{N_{mission}} M_{vessel} + Day_i \times C_{vessel} \quad (3\text{-}12)$$

Grouping maintenance activities

To account for the fact that the material and vessel costs vary significantly depending on the type of maintenance activity performed, these are grouped into five categories below based on the approach proposed by Dinwoodie. [14] and Caroll [15].

- **Manual reset**: Requires sending a technician to the turbine for a restart. Does not require any material.
- **Minor repair**: Requires sending a technician to the turbine for a simple repair that does not require heavy tooling or material.
- **Medium repair**: Requires sending a technician to the turbine for a slightly complex repair that still does not require heavy tooling or material.
- **Major repair**: Requires sending a technician to the turbine for a complex repair requiring heavier tooling and material.
- **Major replacement**: Requires sending a technician to the turbine for replacement of a major turbine component. This activity can only be carried out using a heavy-lifting vessel.

The material cost associated with each maintenance activity varies for each category. Manual resets do not require any material and, therefore, have no associated cost. Minor, medium, and major repairs are all assigned with a constant cost. These are representative of the bulk of the maintenance activities grouped into each category and are taken from [14]. For the major replacement, each of the turbine components is treated independently. Associated material cost varies with the component and is considered to have the same price as the component considered in the CAPEX (see 3.2.2).
Similarly, each category is also defined considering the mean time to repair. For the major replacements, these are defined for each component. The repair time spans from the beginning to the end of the maintenance operation and represents the time spent offshore by the technicians. It is used to compute the associated vessel cost as per the equation (3-12). The mean time to repair quantifies the duration between the occurrence of the failure and the moment the turbine gets back online. It includes the repair time, but also delays associated with the mobilization of the vessels and inaccessibility due to weather conditions. It defines the downtime associated with each maintenance activity and is used for the calculation of the availability losses. This point is discussed in further detail in the subsection 3.2.4.

The values for the material costs, repair times, mean time to repair, and type of vessel associated with each failure category are detailed in Appendix B.

Estimating the number of failures and deriving maintenance costs.

The model described in the previous paragraph can be used to estimate the cost involved each time one of the maintenance activities is performed. Estimating the OPEX requires assessing how many of these operations needs are to be executed for each year of the project. This is done using Mont Carlo simulation (MCS), treating the time-to-failure, and defining the duration of two occurrences of maintenance activity as a random variable. Each maintenance group is defined with a probabilistic distribution that is used to generate random values for the time to failures. The number of maintenance interventions to be performed for a given year is found by listing all maintenance activities whose time to failure falls within that year. Components are allowed to fail multiple times throughout the project lifespan. To model this, every time a maintenance activity is performed a new value of the time-to-failure is drawn from the underlying distribution and offset by the year at which the previous failure occurred. Failures can, thus, occur multiple times during the same year if the associated failure rate is high. This process is repeated many times to generate multiple realizations of the number of yearly failures. For each simulation, the corresponding material and vessel costs are computed using the methodology described in the above paragraph. Such an approach results in a distribution for all the quantities of interest. The expected value of the maintenance costs can thus be approximated by the arithmetic average across all the samples. Similarly, the confidence interval can be derived from the variance of the observed costs.

Different distributions are used to model the probability of occurrence of the failure associated with each maintenance group. Time-to-failures for the manual reset and minor, medium, and major repairs are all modeled, assuming an exponential distribution. This is equivalent to considering a constant annual failure rate. The distribution parameters are taken from [14]. Major components, on the other hand, are modeled using two-parameter Weibull distributions. Indeed, such distributions capture the fact that the reliability of the component tends to decrease with time. The shape and scale parameters of the Weibull distribution are derived from EPRI's wind turbine reliability database (See Wind Network for Enhanced Reliability, WinNER[TM] [16], [17]). Appendix B summarizes the distribution choice and associated parameters for all the maintenance activities. Figure 4, below, gives an example of the annual failure rate for the major components of interest.

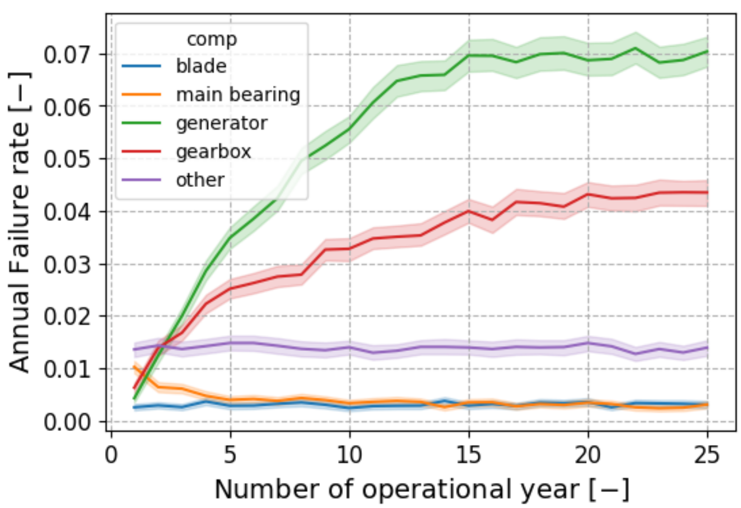

Figure 4. Example of the major components annual failure rate resulting from the Monte Carlo simulation.

The outcome of the Monte Carlo simulation can also be used to provide insights into the variability of the OPEX results. Figure 5, shows the distribution of OPEX, averaged over the years, resulting from the MCS, considering each sample as an independent draw. The results are shown for the Teesside wind farm (see Appendix C, for more details). The blue histogram represents the raw outcome of the simulation and the red dashed line, the normal distribution fitted to these results. In this case, the OPEX can be reasonably well approximated by a normal distribution of mean $\mu = 193.42\ \$/kW$ and standard deviation $\sigma = 20.01\ \$/kW$. The variability of the OPEX result is quite large, with the standard deviation being approximately equal to 10% of the mean. This implies that when considering a single realization, there is a 16% probability that the resulting OPEX value exceeds 10% or more of the expected value. This can have a significant impact on the project finance. This result highlights the necessity to account for such variability in the LCOE estimation and to propagate uncertainty throughout the entire process.

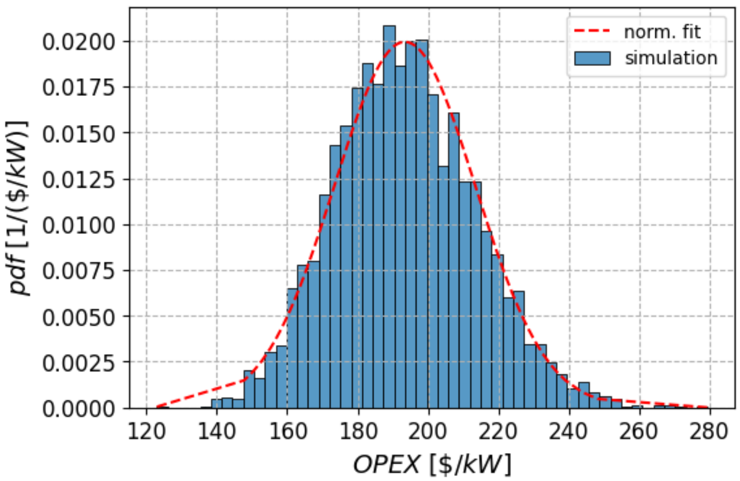

Figure 5. Distribution of the OPEX results obtained from Monte Carlo simulation. The blue histogram represents the outcome of the simulation and the red curve the normal distribution fitted to the results.

3.2.4. Annual Energy Production (AEP)

The effective annual energy production is computed by first estimating the “raw” value for the AEP, and then discounting the fixed and variable losses. The “raw” AEP is defined as the maximal theoretical energy a wind farm could produce if there were no losses. It depends on the distribution of wind speed at the site location and the power curve of the turbine(s) as per the following equation:

$$AEP_{raw} = 8760 \times \sum_{i=1}^{N_{turb}} \int_{ws} P_i(ws) \cdot pdf(ws) dws \quad (3\text{-}13)$$

Where:

- AEP_{raw} is the “raw” AEP value in MWh.
- N_{turb} is the number of turbines for the wind farm.
- $P_i(ws)$ is the value of the power curves of the ith turbine for the wind speed (w_s).
- $pdf(ws)$ Is the value of the probability density function for the wind speed (w_s).
- 8760 is the number of hours in one year.

The “net” AEP value is obtained by discounting the production losses from the raw AEP value as per the following formula.

$$AEP_{net} = \prod_{k} (1 - \zeta_k) \times AEP_{raw} \quad (3\text{-}14)$$

Where ζ_k is the value of the kth losses. Three types of losses are considered in (3-14), namely the wake losses, the electrical losses, and the availability losses.

Calculation of the AEP losses

For the Teesside wind farm, wake losses are estimated using the results of D3.2. [18]. These are the results from a "design of experiment" (DOE) linking ambient wind conditions, defined at the scale of the wind farm, to the "effective" wind conditions (including the wake of neighboring turbines) experienced by each turbine. The DOE for D3.2 was performed on a truncated distribution, ignoring wind speed values below the cut-in and above the cut-out wind speeds. Consequently, these results cannot be used directly to assess the net AEP of wind turbines, as it would be overestimated. Nevertheless, they can still be used to assess relative wake losses by comparing the turbine's predicted power output, calculated by injecting the turbine's effective wind speed distribution into the equation (3-13), with the predicted raw power output - obtained by injecting the DOE's ambient wind speed distribution into the equation (3-13). In doing so, the raw and net AEP values are overestimated in the same proportion. The ratio of both quantities is therefore unaffected by the truncated distribution. Wake losses are evaluated independently for each wind turbine. The results are then averaged over the whole wind farm to obtain a single figure to insert into the equation (3-14). Appendix C presents the wake losses calculation in more detail and summarizes the values obtained for each turbine and the resulting farm average value.

No information on electrical losses is provided in the HIPERWIND project. They are therefore estimated based on standard values reported in the literature, as in [19]. This study also provides some measures of the uncertainty of electrical losses by comparing actual values with estimates from several consultants and for several projects. The value adopted for the analysis presented in this project is the average of all the projects considered and is summarized in Appendix C.

The OPEX model as detailed in section 3.2.3 provides an estimation of the mean time to repair (MTTR) associated with each maintenance activity. The MTTR defines the amount of time the turbine spends offline (downtime) when a failure occurs. The total downtime is the sum of all the MTTR of all individual failures. The assumption is made that the failures/maintenance are uniformly distributed over the year. The availability can thus be computed using the following formula.

$$\zeta_{avail} = 1 - \frac{\sum_l mttr_l}{N_{turb} \cdot 8760} \qquad (3\text{-}15)$$

Where:

- N_{turb} is the number of turbines for the wind farm.
- 8760 is the number of hours in a year.
- $mttr_l$ is the mean-time-to-repair associated with the "l^{th}" failure.

Because the OPEX is estimated, using Monte Carlo simulation (see section 3.2.3), the results of availability losses also consist of a set of samples that can be used for estimating the underlying distribution. Figure 6 shows the distribution of availability losses obtained from the MCS. The blue bars form the histogram made from the raw results, and the red dashed line presents the resulting normal distribution fitted on these results. Availability losses seem to be reasonably approximated by a normal distribution of $\mu = 15.29\ \%AEP$ and standard deviation $\sigma = 0.26\ \%AEP$. It is interesting to mention that the variability of the availability losses appears to be less important the variability of the maintenance costs, reported in section 3.2.3.2. This result may be explained by the fact that the availability losses, for the wind farm considered in this example, are dominated by manual reboots and minor repairs. These events are associated with a high probability of failure. The availability losses are then the sum of the individual contribution of a large number of instances of the same event and therefore are less subject to variability than the maintenance which, in contrast, results from fewer occurrences of the major replacement events.

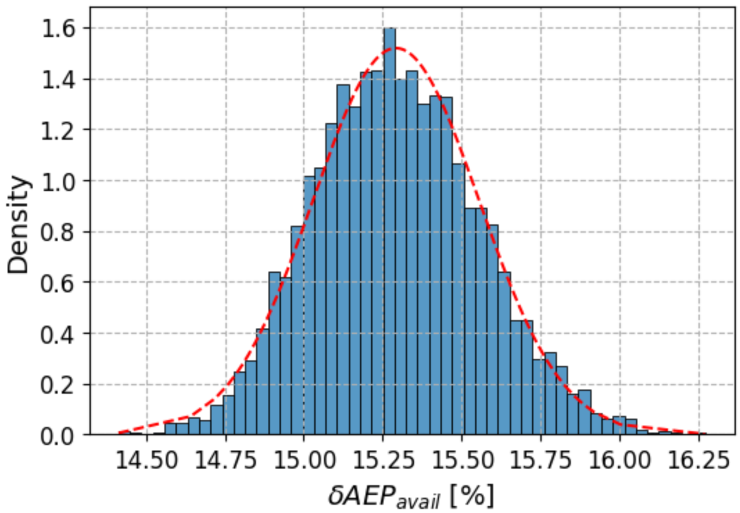

Figure 6. Distribution of the availability losses obtained from Monte Carlo simulation. The blue histogram represents the outcome of the simulation and the red curve the normal distribution fitted to the results.

4. Integrating cost reduction from other work packages

This section details the cost reduction obtained by the HIPERWIND technologies (work packages) and how those are integrated into the calculation of the LCOE.

4.1. Mass reduction from WP4

Results from work package 4 of HIPERWIND provided a substantial reduction of the mass of the turbine's tower and foundations [20]. These are listed in Table 1 above.

Table 2. Mass reduction of the tower and foundation from the WP4 results.

Component	Mass (original)	Mass (optimized)	Reduction
	tons	*tons*	%
Tower	139.31	114	18.17%
Foundation	437.76	328.9	24.87%

Both the tower and foundations are structural steel components. According to the Global Construction yearbook [21], the cost of material accounts for 80% of the overall cost of structural steel components such as the tower and foundations of offshore wind turbines. The remaining 20% represents the labor and infrastructure costs. Under such an assumption, the cost of each component of the optimal design can be expected to be reduced, compared to the original design, by an amount equivalent to 80% of the mass reduction. The overall impact on CAPEX is computed as the sum of the individual cost reduction weighted by the component's contribution to the CAPEX. As shown in Figure 3, the foundation and tower respectively account for approximately 16% and 7% of the capital expenditure of the original design. The optimized HIPERWIND design therefore allows to reduce the CAPEX by about 4.32%. Such values fall within the range of expected reduction estimated at the beginning of the project ($4\% - 6\%$). Table 3 summarizes the cost reduction and their impact on CAPEX.

Table 3. Impact of the mass reduction on the CAPEX

Component	$\Delta M/M$	$\Delta cost/cost$	Contribution to CAPEX
	%	%	%
Tower	-18.17%	-14.53%	7.40%
Foundation	-24.87	-19.89%	16.34%
CAPEX reduction	$\mathbf{4.32\%}$		

4.2. Optimized maintenance schedule from D6.1

4.2.1. Impact on maintenance cost and overall OPEX

The work from task 6.1 provided an optimized maintenance schedule for the gearbox replacement at Teesside wind farm while considering multiple scenarios for the electricity price [22]. Only the results considering a fixed strike price are used in this study since these are more consistent with the LCOE formulation. Indeed, under the fixed price assumption, optimizing maintenance automatically leads to a reduction in turbine downtime since this minimizes both the cost (vessel) and the loss of revenue (due to lost energy). Under the varying price scenario, on the other hand, the optimized maintenance schedule may favor larger downtime periods, if they are planned when electricity price is low. Even though this translates into larger vessel costs and increased gross energy losses, it can still be more interesting, from an economic standpoint, since it minimizes the revenue loss. The formulation of LCOE implicitly assumes that the electricity price does not vary with time by considering only the AEP as a scaling factor for the lifetime costs. The optimized maintenance schedule, with varying price assumptions, may therefore result in higher LCOE values since the metric disregards the revenue losses. Considering fixed electricity price, thus, ensures consistencies between the approaches, allowing for quantifying the impact of the maintenance optimization on the cost through the lens of the LCOE.

Figure 7 shows the impact of the maintenance optimization from D6.1 on the repair time for the gearbox replacement. The blue bars represent the repair times without optimization, assuming component replacement can only be performed during a fixed period in the summer. The orange bars represent the repair times resulting from the optimization of the schedule to minimize the cost while considering a fixed electricity price. Regardless of the number of gearboxes to be replaced during the year, the optimized maintenance schedule always results in reduced turbine downtime. The ratio of optimized to baseline downtime is always approximately 0.86. Optimization of the maintenance schedule, therefore, allows reducing the downtime for gearbox replacements by close to 14%.

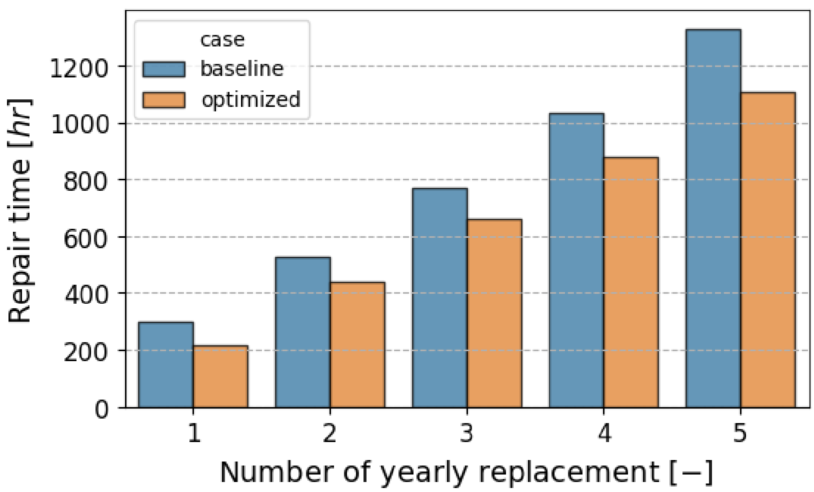

Figure 7. Comparison of repair time for the gearbox replacement for the baseline (blue) and optimized (orange) cases and for different numbers of early replacements. Result obtained from [22].

The vessel costs are directly impacted by the reduction of the repair time, as per the equation (3-12). Such a result is illustrated in Figure 8, which shows the comparison, between the baseline (blue) and optimized (orange) cases, of the repair costs (including vessel and material costs) for the gearbox replacement at the Teesside wind farm. For the optimized case, the gearbox repair costs are approximately 11.7% lower than the ones of the baseline case. Such cost reduction is slightly less than the reduction in downtime reported in the previous paragraph. This result is explained by the fact the reduction in downtime only affects the vessel costs. Indeed, the material costs only depend on the number of components to replace, which remains the same since the component failure probability was not changed between the two cases. Additionally, the vessel costs also include a fixed mobilization cost (see Appendix B) that must be paid each time a component is replaced. Only the variable part of the vessel costs is affected by the reduction of the repair time. These results are summarized in Table 4.

Table 4. Summary of the cost reduction for the gearbox replacement.

Case	Material Cost	Vessel Cost	Repair Cost (total)
	$\$/kW$	$\$/kW$	$\$/kW$
Baseline	2.07	44.93	47.00
Optimized	2.07	39.47	41.53
Rel. Delta	0%	12.10%	11.70%

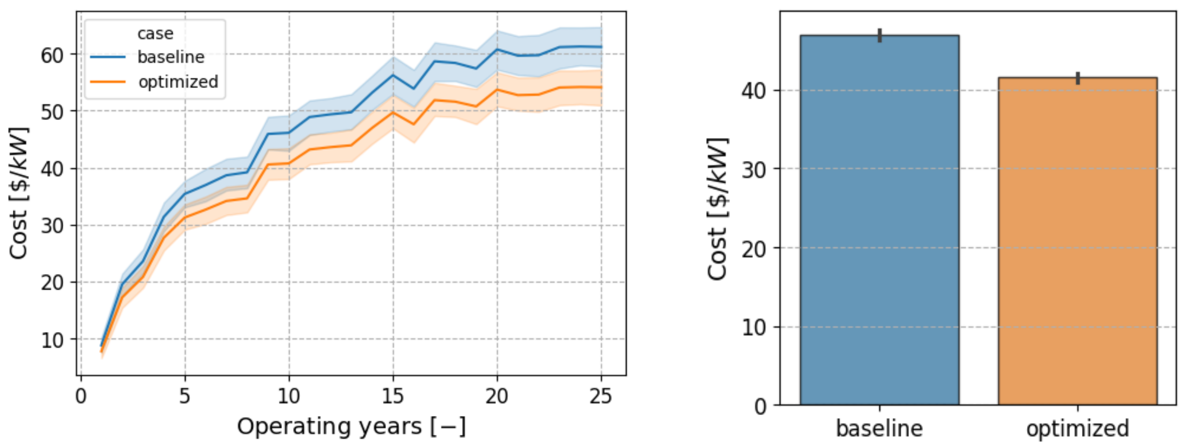

Figure 8. Comparison of the gearbox replacement cost (material + vessel), for the Teesside wind farm, for the baseline (blue) and optimized (orange) cases. The left part shows the evolution of the yearly cost as a function of the number of operating years, while the right figure shows the lifetime average cost. All costs are normalized by the wind farm capacity ($\$/kW$).

The breakdown of the repair costs associated with the replacement of the major component is shown in Figure 9. Results are shown for the baseline case, only, and are expressed in $\$/kW$ (left axis) and as a fraction of the total OPEX (right). The costs are dominated by the replacement of the generators and gearboxes that account for 31.5% and 24% of the OPEX, respectively. Such a result is consistent with the fact that these two components have a higher failure rate compared to the others. Indeed, the replacement of a single gearbox, or generator, is lesser than the cost of a single blade replacement both in terms of material cost (the part is cheaper) and vessel costs (lower repair time requires less time at sea). However, because of the higher failure rates, replacements of these components are expected to occur more often. This results in a higher contribution to the overall OPEX, when integrated over the life of the project.

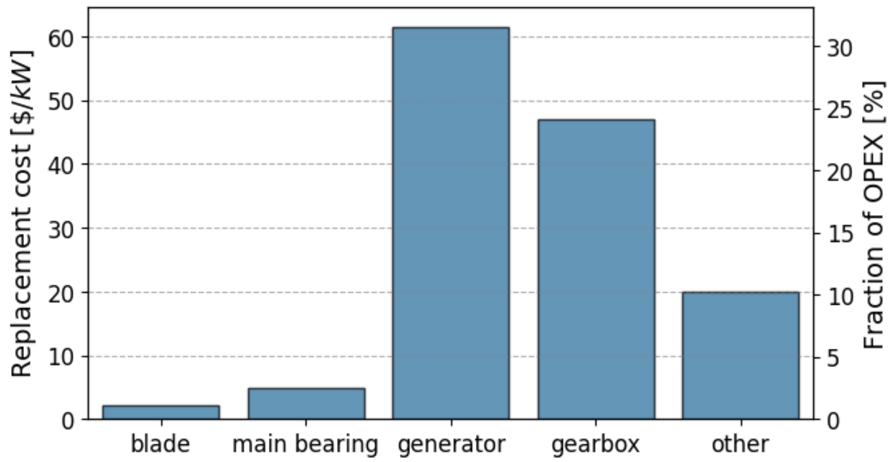

Figure 9. Breakdown of the repair costs associated with replacement of the major components, for the baseline case of the Teesside wind farm. Results are expressed in $\$/kW$ *(left axis) and as a fraction of the total OPEX (right axis).*

The overall impact of maintenance schedule optimization for gearbox replacement is estimated to be approximately 2.81% of the total OPEX. This is done by combining the cost reduction listed in Table 4 with the contribution of this specific task to the total OPEX reported in Figure 9. Such results consider that only the gearbox replacement was optimized. However, the methodology developed in task 6.1, could be applied to the other major components replacement to optimize the maintenance schedule and reduce the associated costs. Indeed, under the fixed electricity price scenario, which is retained for this study, the optimization of the maintenance schedule from D6.1 aims to reduce the downtime for each replacement in order to minimize production losses and associated financial losses. This is achieved by distributing the maintenance activities all over the year, whenever wind and wave conditions allow. This results in better utilization of all available time slots, compared reference approach which only allows maintenance to be carried out during summer. In theory, this approach should be applicable to the replacement of all the major components, even though only the gearbox was considered in practice due to insufficient time and computing resource limitations. It results that the cost reduction obtained for the gearbox replacement should be transposable to the other components, at least partially. Table 5, summarizes the reduction in OPEX calculated for each major component replacement by applying the same 14% reduction of repair time obtained from the optimization of the gearbox maintenance schedule. For all the components, this translates into a reduction of the repair cost, for the optimized case, which ranges between 9.74%, for the generator, up to 12.55%, for the main bearing. The bulk cost reduction of 7.48% is calculated as the sum of these individual cost reductions weighted by the fraction is each component represented in the overall OPEX. Such scenarios are likely to be optimistic since they rely on the assumption that the same 14% reduction of repair time can be applied for all the major components. Nonetheless, it provides a reasonable estimation of the potential OPEX reduction that could be obtained by optimizing the maintenance schedule for all the major components. It seems reasonable to claim that the “real” OPEX reduction lies somewhere between 2.81% (only the gearbox being optimized) and 7.48% (all components being optimized). In the following of this document, both scenarios are used to define a range of potential OPEX reductions.

Table 5. Summary of the OPEX reduction obtained by applying the 14% downtime reduction to all major component replacements.

Component	Baseline cost	Fraction of total OPEX	Optimized cost	Relative Delta	OPEX Reduction
	$\$/kW$	%	$\$/kW$	%	%
Blade	2.08	1.07	1.84	11.63	0.12
main bearing	4.96	2.54	4.33	12.55	0.32
Generator	61.44	31.53	55.46	9.74	3.07
Gearbox	47.00	24.12	41.53	11.63	2.81
Other	19.91	10.22	17.64	11.41	1.17
Blade	2.08	1.07	1.84	11.63	0.12
Total	**135.39**	**100%**	**120.80**	**7.48**	

4.2.2. Impact of maintenance optimization on downtime and windfarm availability

As detailed in section 3, the model of OPEX is also used to compute downtime and associated AEP losses. The mean time to repair used to derive availability losses in the equation (3-15) is meant to encapsulate the repair time. The optimized maintenance schedule obtained from deliverable T6.1 should, therefore, provide a reduction in downtime. The assumption is made that only the portion corresponding to the actual repair time is impacted by the maintenance optimization. Indeed, the remainder of the mean time to repair, accounting for delays due to vessel mobilization and site accessibility constraints, is considered as externalities that can hardly be influenced. The value of the mean time to repair, of each major component, is calculated for the optimized case by subtracting, the value in the baseline case, and the time reduction of repair time derived from deliverable 6.1.

The reduction in repair time, and thus mean time to repair, obtained from deliverable 6.1 is not considered to apply to maintenance activities other than major component replacement. This is to account for the fact that, as reported by [14] for maintenance that does not require a heavy lift vessel, most of the downtime is caused by difficulties in accessing the site to perform the repair rather than the repair itself. The breakdown of the availability losses associated with each maintenance activity for the Teesside wind farm is shown in Figure 10. Contrary to the maintenance costs, availability losses are dominated by manual reboots, minor repairs, and service activities. Indeed, these are associated with a much larger probability of occurrence (up to seven times per year and per turbine on average, for the manual reboot see Appendix B). This leads to a higher cumulative downtime each year, even though the mean time to repair associated with a single failure is small compared to the downtime caused by one occurrence of major component replacement.

Because the affected maintenance activities have little impact on the overall downtime, the optimized maintenance schedule from deliverable 6.1 will have little impact on improving the Annual Energy production of the Teesside wind farm. These are considered, nonetheless, as the availability losses due to major component replacements could be higher at other wind farms. The updated values of the mean time to repair for the major component replacement are summarized in Appendix B of this document.

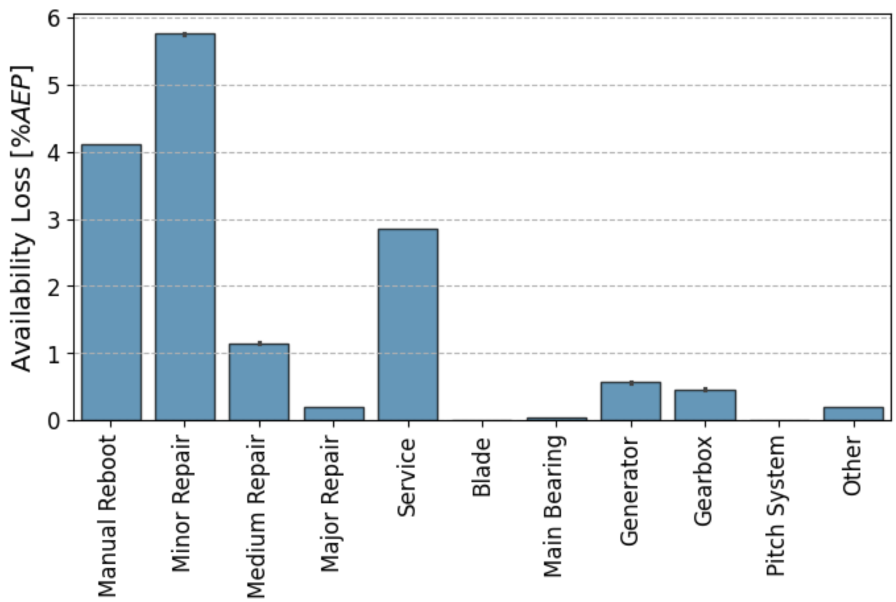

Figure 10. Availability losses associated with each maintenance operation for the Teesside windfarm (baseline case, no optimization).

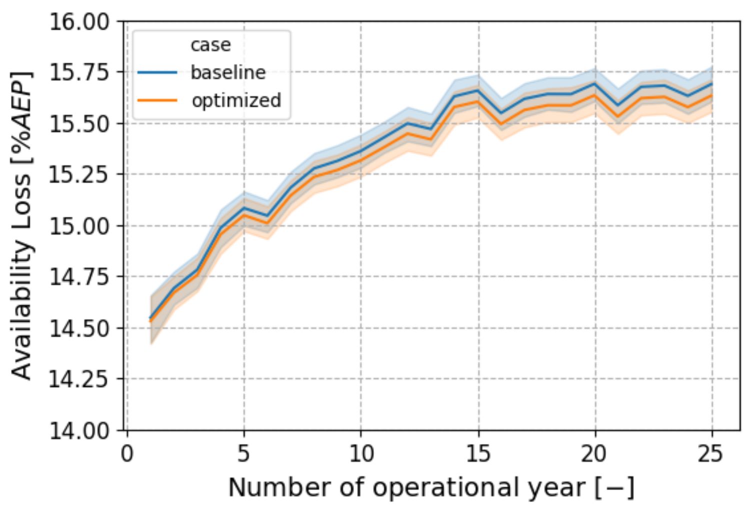

Figure 11. Yearly availability losses specific to Teesside wind farm due to turbine downtime, for both the baseline (blue) and optimized case (orange).

The results for availability losses are shown in Figure 11, for both the baseline (blue) and optimized (orange) cases, as a function of the number of years in operation. Overall losses are around $15\% - 16\%$. Limited year-to-year variation can be observed with a slight trend of increasing losses as the wind farm's age is increasing. Such a result is consistent with the fact that, for the Teesside wind farm, the losses are dominated by the manual reboot and minor repairs. These events are modeled using a constant annual failure rate. The number of maintenance, and associated downtime, are therefore expected to be the same every year. The increased number of major component replacements for the last years of operation explains why the availability losses have this slight tendency to increase with time. As expected, very little variations can be seen between the baseline and optimized case, since only the repair time for the major component replacement is impacted by the optimized maintenance schedule. However, it is important to mention that these results are specific to the Teesside wind farm. Other wind farm designs could exhibit a more significant AEP increase in case of a higher percentage of major component failures.

4.3. Improved flow modeling from WP3

The work done in T3.2 focused in delivering accurate estimates of the effective wind conditions (accounting for the effects of the wakes of the neighboring turbines) for all the turbines of the reference wind farms of the HIPERWIND project [18]. To that end, engineering flow models were validated against higher fidelity models such as LES of DWM results. The primary focus of that task was to provide accurate inputs for the assessment of mechanical loads, but the outcome of the farm flow simulations can also be used for AEP estimation. However, no clear reduction of the modelling errors regarding was found in this work package. Therefore, no AEP improvement is considered in this study.

Nonetheless, it is important to mention that the results from the DOE used for estimation of the wake losses in section 3.2.4 sets the stage for propagation of the uncertainty through the farm flow simulation process. This could be leveraged to estimate the dependency of the net AEP to the different sources of uncertainty attached to the energy yield assessment (EYA) process. This would provide a measure for the uncertainty of the AEP results which, when compared to standard values available in the literature (see [19], [23], [24]), would allow estimating the impact of HIPERWIND on the EYA. However, such a study could not be performed due to lack of time.

In the following of this document, no uncertainty concerning the AEP is propagated to the LCOE estimation, except the variability due to the availability losses which originates from the OPEX model introduced in section 3.2.3. A more accurate quantification of the EYA uncertainty using the HIPERWIND technology would be a valuable follow-up of the work done in T6.2.

5. Discussion on LCOE influencing parameters.

This section discusses the influence of parameters on LCOE that are not directly linked with the HIPERWIND technologies.

5.1. Interest rate and WACC

The choice of the discount rate is crucial when estimating LCOE, even though this is not the primary focus of HIPERWIND. Different values of the WACC typically result in significantly different outcomes of the metric. Since this parameter attempts to quantify the "time value of money". This has the effect of dampening the importance of payments that occur toward the end of the analysis period. The value of OPEX is directly impacted by such an effect since the trend is for the number of component failures to increase over time as the wind farm ages. A higher cost of capital leads to a lower levelized OPEX. Conversely, CAPEX, increases with the WACC, since this implies a larger amount of interest payments. These counterbalancing effects of the cost of capital on the LCOE are illustrated on Figure 12 which shows the evolution of the levelized values of CAPEX (blue) and OPEX (orange) with varying values for the WACC. The results are normalized to the values specific to the Teesside wind farm, corresponding to a WACC value of 11.2%. The latter is representative of the financing schemes at the time the wind farm was built (early 2010s) [25]. For more recent projects, the cost of capital is typically lower, around 6% [26], [27]. According to the figure, reducing the WACC from 11.2% down to 6% should reduce the CAPEX by approximately 40%, while increasing the OPEX by approximately 6%.

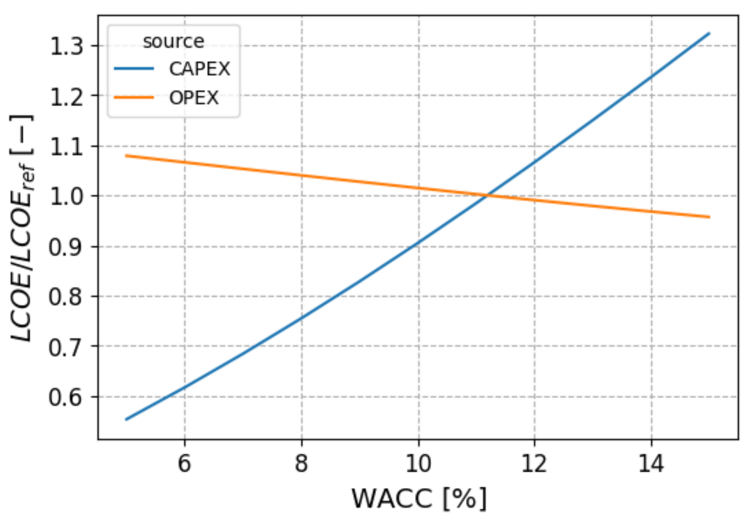

Figure 12. Influence of the WACC value on the CAPEX and OPEX contributions to LCOE. Results are normalized by the values corresponding to a WACC of 11.2% (value for Teesside).

These effects are further detailed on Figure 13 and Figure 14 which shows the breakdown of LCOE results for WACC values of 11.2% and 6%, respectively. The OPEX (maintenance + operation) increases from 61.48 $\$/MWh$ to 65.55 $\$/MWh$ ($+6\%$), while the CAPEX (turbine + bop + owner costs) drops from 128.93 \$/MWh to 79.59 $\$/MWh$ (-38%). Overall, this reduces the LCOE by approximately 24%.

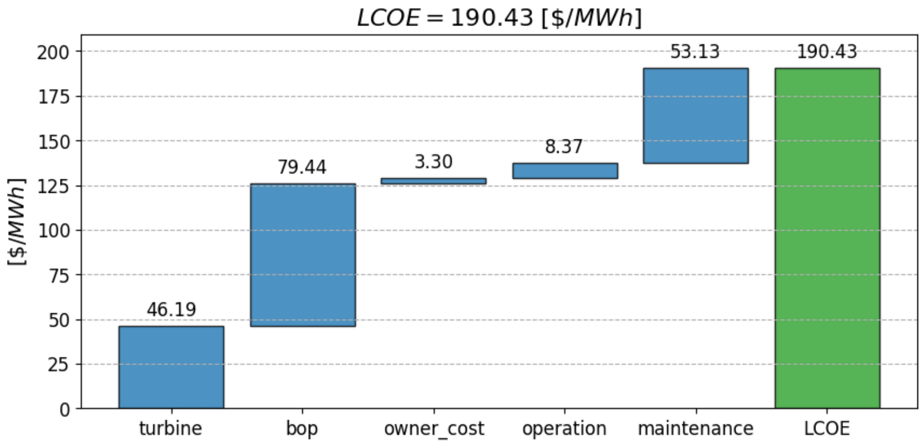

Figure 13. Breakdown of LCOE results for the Teesside windfarm using a WACC value of 11.2%.

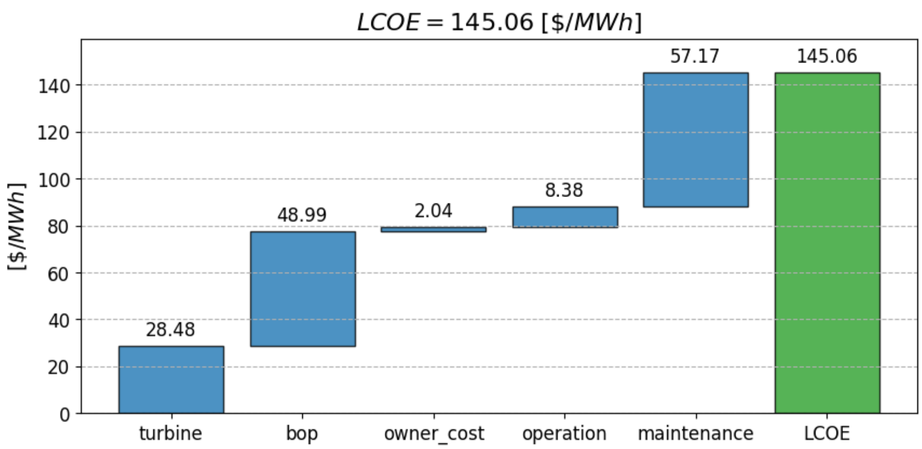

Figure 14. Breakdown of LCOE results for the Teesside windfarm using a WACC value of 6%.

The results presented in this sub-section highlight that the assumptions made regarding the financial parameters of the LCOE formulation dramatically impact the outcome of the calculation. Therefore, it is critical to consider a value for the cost of capital that is representative of the market at the time the wind farm is built to ensure that the LCOE results accurately reflect the current state of the technology.

It should be noted that regardless of the selected value for the WACC, the LCOE figures reported in this section are higher than the values that are usually reported in studies [3], [8]. However, these are recent studies. In both cases, the reference wind farm of the study is equipped with a turbine model with a unit capacity of over 8MW. In comparison, the HIPERWIND reference wind farm, Teesside, was built in the early 2010s and is equipped with much smaller turbines (2.3MW). It is interesting to note that studies contemporary with the construction of Teesside report LCOE values similar to those presented in this report [9], [28]. The choice of the turbine technology therefore has a significant impact on the LCOE. This result could be explained by the fact that a smaller turbine rating requires the installation of more turbines to achieve a given capacity. More turbines mean more component failures/replacements, and therefore higher OPEX. This point is discussed in more detail in section 5.2.

5.2. Wind turbine rating

The choice of turbine rating significantly impacts the resulting OPEX in a wind farm. For a fixed wind farm capacity, the turbine rating determines the total number of turbines to be installed. Smaller turbines require a larger quantity to meet the capacity, and vice versa. Additionally, increasing the number of turbines leads to higher OPEX due to more frequent component failures. As explained in section 4.2, maintenance costs are primarily driven by the expenses associated with vessels needed for major turbine component replacements which depend on the number of replacements to be done. The occurrence of component failures can be viewed as independent samples drawn from the same random distribution. This implies that the expected number of replacements per year scales linearly with the number of turbines in the wind farm, akin to increasing the number of draws. Even without considering the impact of denser arrays on wake losses, leading to lower AEP, and, thus, higher LCOE, two wind farms with the same capacity but different numbers of turbines will yield different OPEX values.

To illustrate this behavior is a small sensitivity study is carried out, on a virtual wind farm with a capacity of $600MW$, similar to the wind farm described in Appendix D. Several scenarios are considered, varying the rating of the turbine, while keeping the farm capacity constant. The number of turbines is therefore adjusted in order to reach $600MW$ of installed power. A hundred turbines are required for a $6MW$ rating, seventy-five for $8MW$, and so on. The corresponding OPEX value is assessed in each case using the methodology detailed in section 3.2.3. Certain simplifications have been made. The material costs are assumed to scale linearly with the turbine rating, according to the values reported in Table 13 of Appendix A. The real dependencies of component costs with turbine size/rating follow more complex relationships, such as the ones detailed in [29]. Nevertheless, this should have a limited impact on the results since maintenance costs are dominated by vessel costs. Moreover, the aim of this study is essentially to provide an overview of how technology choices can affect the results, and not to provide precise LCOE estimates for all the considered scenarios. Consequently, these simplifications of the material costs modelling are deemed acceptable.

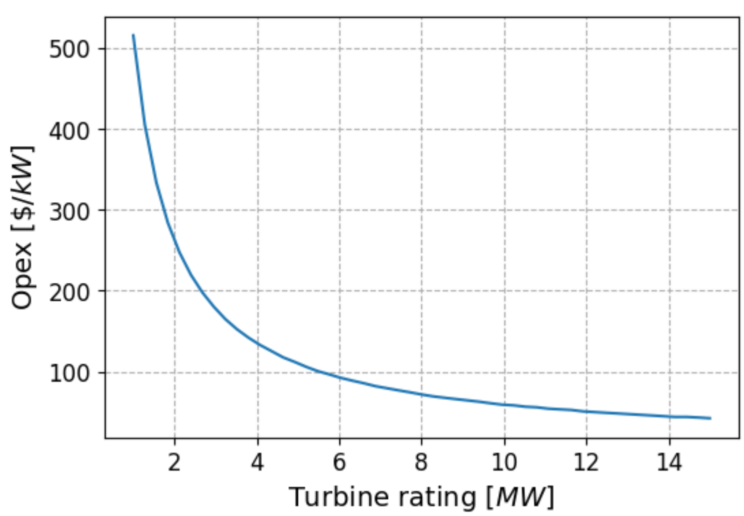

Figure 15. Influence of the turbine rating on the OPEX values for a virtual wind farm of 600MW capacity.

The results of the sensitivity study described in the above paragraph are shown in Figure 15 which shows the evolution of the maintenance portion of the OPEX as a function of the turbine rating. It can be seen that for this experiment, the costs scale are inversely proportional to the turbine rating. This confirms the dependency of OPEX to the wind farm's design. Carefully selecting a reference wind farm is therefore a critical step to get LCOE estimations that are representative of the current state of the offshore wind technology. The Teesside wind farm used as a reference for the HIPERWIND may not be the best candidate in that regard. Indeed, Teesside was built in the early 2010s and is made of 27 instances of the Siemens 2.3-93 model (more details in Appendix C). This is a relatively low turbine rating (2.3MW) compared to the models that are being installed in new wind farms as they typically exceed $10MW$ per turbine. The future generation of offshore turbine is even expected to reach up to $20MW$ of unit power. Such a gap in turbine size makes the results for OPEX obtained for Teesside harder to transpose to a more recent wind farm.

6. LCOE calculation results

This section details the outcomes of the LCOE calculation. Results are presented for two cases. First, the "baseline" case does not consider any improvements from HIPERWIND. The LCOE value is computed from data readily available in the literature. The "optimized" case on the other hand includes the reduction of CAPEX and OPEX detailed in sections 4.1 and 4.2, respectively. Results from the "optimized" case are then compared against the "baseline" to quantify the impact of the HIPERWIND deliverables on the LCOE for offshore turbines.

6.1. Scenarios for LCOE calculation

The results presented in this section 5 demonstrate that the LCOE is influenced by parameters that are not directly related to the wind turbine design. When considering projects built in the early 2010s, which had higher interest rates and smaller turbines, the resulting LCOE is necessarily much higher than if evaluated for more recent projects with lower WACC and larger turbines. Such a result is expected and reflects that the technology has matured over time to become more competitive. Nevertheless, in the context of HIPERWIND, this makes the choice of the reference scenario a critical step influencing the interpretability of the results. The impacts of mass reductions and optimized maintenance schedule from the other HIPERWIND work packages are directly applicable to the Teesside wind farm since this was the case study for the project. On the other hand, the resulting LCOE is harder to interpret and to transpose to other, more recent, wind farms.

To overcome this limitation, two wind farms, referred to as "scenarios," are considered for LCOE calculation. The first is Teesside, analyzed as it was at the time of its construction. Thus, the Weighted Average Cost of Capital (WACC) is set to be representative of the early 2010s. This scenario is referred to as the "as-built" scenario and is described in more detail in Appendix C. The second scenario considers a virtual wind farm comprising $75 \times 8MW$ turbines (total capacity $600MW$). The latter is inspired by the NREL work [8] and is designed to be more representative of the wind farm being currently installed in Europe. In this case, the financial parameters are chosen to be the representative of the state of the market today, leading to a lower WACC. The CAPEX and OPEX models are the same for both the Teesside and virtual wind farm. In the following sections, this scenario is referred as the "state of the art" scenario, and it is presented in detail in Appendix D.

The applicability of the cost reduction derived from Teesside to the virtual case may be debatable. However, The LCOE variations obtained for the virtual wind farm may better reflect the impact the HIPERWIND cost reductions can have on the current state of the technology.

6.2. Results for the Teesside windfarm ("as-built" scenario)

This subsection describes the results and comparison between the optimized and baseline cases, obtained using the Teesside wind farm as the reference configuration for the LCOE calculation. The details of this scenario are presented in more detail in Appendix C.

Table 6 summarizes the resulting values of the CAPEX and OPEX obtained for both the baseline and optimized cases. The values in the table are the "raw" values for the cost, meaning that they are not levelized. The CAPEX values represent only the principal payments. Interest payments are not considered. The OPEX values are shown as the average yearly cost. The reduction of the mass of the structural component leads to a reduction of about 4.3% of the overall CAPEX. This result is discussed in more detail in section 4.10. Similarly, the optimized maintenance schedule led to a reduction of the OPEX for the wind farm configuration of this scenario of approximately 7.1%. Under this cost reduction scenario, the HIPERWIND technologies met the target defined at the beginning of the project, both for the CAPEX (target: $4\% - 6\%$) and OPEX ($5\% - 7\%$).

Table 6. Summary of the CAPEX and OPEX reduction for the "as built" scenario.

Variable \ Case	Baseline	Optimized	Δ_{rel}
CAPEX [$\$/kW$]	3629.00	3473.37	-4.3%
Turbine [$\$/kW$]	1300.00	1262.35	-2.9%
BoP [$\$/kW$]	2236.00	2118.02	-5.3%
Owner's costs [$\$/kW$]	93.00	93.00	0.0%
OPEX [$\$/kW/y$]	193.60	179.94	-7.1%
Operation [$\$/kW/y$]	22.66	22.66	0.0%
Maintenance [$\$/kW/y$]	170.94	157.28	-8.0%

Results for the AEP calculations are summarized in Table 7. Since no change is made to the wind farm model, the values for the raw AEP, internal losses (wake + electrical) and, net AEP are the same for both cases. Only availability losses are slightly varied, due to the reduction in downtime. Although, this effect is minor, as it only affects the replacement of the major component while the availability losses are dominated by the minor repairs and manual reboots (see section 4.2.2.) For both cases, the effective averaged AEP value, obtained after discounting after both the internal and the availability, is almost identical and close to 161.3 MWh.

Table 7. Summary of AEP calculation results for the "as built" scenario.

Variable \ Case	Baseline	Optimized	Δ_{rel}
AEP raw [GWh/y]	224.35		0.0%
Internal Losses [%]	11.65%		0.0%
AEP net [GWh/y]	198.20		0.0%
Avail. Losses [%]	18.63%	18.58%	-0.2%
AEP effective [GWh/y]	161.28	161.37	0.1%

Cost and AEP results are combined to estimate LCOE. Results are summarized in Table 8, for the baseline and optimized cases. The third column represents the relative variations between the two cases.

Results are broken down as the contribution of each expense to the overall LCOE. The contribution of the CAPEX to LCOE is reduced by approximately 4.3%. Which is identical to the cost reduction reported Table 6. This is expected since the financial parameters remain the same, and the proportion of interests to principal payments is consistent in both cases. Conversely, the reduction of the OPEX's contribution to LCOE is about 6.8%. This is slightly lower than the gross reduction reported in Table 6. This difference can be explained by the optimized maintenance schedule's influence on major component replacements, which are concentrated towards the later years of the analysis period. The contribution of these payments to LCOE is slightly dampened due to a stronger discount factor in these years. Overall, the estimated LCOE reduction is about 5.12% Such a result needs to be compared to the 9% reduction target set at the beginning of the project. For the "as-built" scenario, the LCOE reduction is therefore lower than the initial event though the individual reductions of CAPEX and OPEX achieved their target values. However, it is important to mention that the results presented in this section consider that the cost of capital is the same between the two cases, and do not include any improvement in the AEP.

Additionally, as mentioned in section 6.1, the choice of the Teesside wind farm as a reference case may be subject to debate since the results may not be transposable to more recent wind farms. For both cases, the value of LCOE is of the order of magnitude of $200\ \$/MWh$, consistent with values found in the literature for projects built in the early 2010s [25], [28], [30], but significantly higher than more recent studies reporting LCOE values around $100\ \$/MWh$ or lower [8], [27]. Parameters such as the cost of capital and the wind turbine rating, likely explain part of this difference, as discussed in section 5. Considering various scenarios for LCOE estimation is, therefore, necessary to quantify the influence the wind farm design can have on the result. This is the object of the following section on modern wind farms.

Table 8. Summary of the LCOE results for the "as built" scenario.

. Variable \ Case	Baseline	Optimized	Δ_{rel}
	[$/MWh]		[%]
CAPEX	136.10	130.20	−4.3%
Turbine	48.75	47.32	−2.9%
BoP	83.86	79.39	−5.3%
Owner's costs	3.49	3.49	0.0%
OPEX	64.45	60.09	−6.8%
Operation	8.37	8.37	0.0%
Maintenance	56.08	51.72	−7.8%
Total	**200.55**	**190.29**	**−5.12%**

The OPEX and availability loss samples from the Monte Carlo simulation are propagated throughout the entire simulation process to estimate the distribution of LCOE due to the variability of the maintenance activities. The results are shown in Figure 16, where the blue and orange histograms represent the distributions for the baseline and optimized cases respectively. Table 9 summarizes the estimated values for the 50th, 75th, 90th and 95th percentiles of the two distributions. The fourth column of the table gives the ratios of the optimized to baseline quantiles. It can be seen that the reduction of the OPEX, originating from the maintenance schedule optimization, has the effect of shifting the entire LCOE distribution towards lower values. All quantiles are reduced by the same proportion (about 5%), indicating that the overall shape of the discussion remains unchanged. Such a result is consistent with the fact that only the cost associated with each failure is updated between the two cases. Variability of the occurrences of failure is not affected by the maintenance optimization, leading to overall similar distributions.

From this result, it cannot be concluded that the HIPERWIND technologies allow for reducing variability in the LCOE, and therefore reduce the risk associated with the project. However, only the variability due to the OPEX is considered in this analysis, since other uncertainty sources (e.g., from the EYA estimation) were not included due to lack of time or available information. The framework developed for T6.2 would be capable of carrying over the uncertainty arising from the main LCOE components and quantifying sensibility of the results to key design parameters. This point is discussed further in section 7.

Table 9. LCOE quantiles estimated from the Monte Carlo simulation, for the baseline and optimized cases. The fourth column, summarize the ratios of optimized to baseline quantiles.

Percentile	Baseline $\$/MWh$	Optimized $\$/MWh$	Optim/Baseline %
p_{50}	199.71	189.50	94.89%
p_{75}	206.79	195.86	94.72%
p_{90}	213.87	202.22	94.55%
p_{95}	218.11	206.04	94.46%

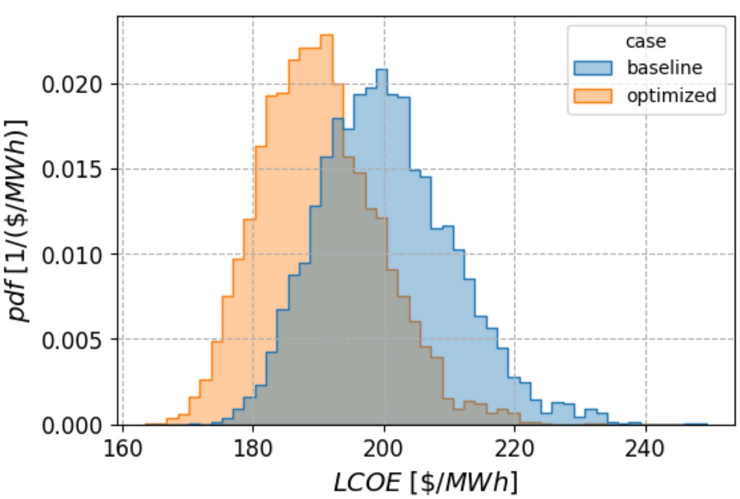

Figure 16. Comparison of the LCOE distributions, resulting from Monte Carlo simulation, for the baseline (blue) and optimized (orange) cases of the "as-built" scenario.

6.3. Result for a modern wind farm ("state-of-the-art" scenario)

This subsection describes the results, and comparison between the HIPERWIND optimized and baseline cases obtained using the virtual windfarm of $75 \times 8MW$ turbines for the LCOE calculation. The details of this scenario are presented in more detail in Appendix D. As mentioned in the previous paragraph results for this scenario provide a comparison point for the results of the "as built" scenario and highlight the influence of the wind farm design on the LCOE.

Table 10 summarizes the resulting values of the CAPEX and OPEX obtained for both the baseline and optimized cases. The values in the table are the "raw" values for the cost, meaning that they are not levelized. The CAPEX values represent only the principal payments. Interest payments are not considered. The OPEX values are shown as average yearly cost.

The reduction of the CAPEX is identical to the one obtained in the "as-built" scenario. Indeed, the turbine cost, per unit of power, is the same for both scenarios. This is a simplifying assumption since the assembly and installation costs should be affected by the number of turbines. No information was found in the literature to provide such granularity. Nevertheless, reducing the number of turbines should go in the direction of reducing the CAPEX, since it steers the installation cost down. Therefore, the results presented in Table 10 can be seen as an upper bound for the CAPEX.

The behavior for the OPEX, on the other hand, is significantly different. First, for the "state of the art" configuration, the resulting values are significantly lower (about 50%) of what was reported for the as-built scenario. This result is consistent with the findings discussed in paragraph 5.2, that the value of the OPEX for a given farm capacity tends to decrease for higher turbine ratings. Additionally, the reduction obtained for the optimized is about 23.63%, which is more than three times the reduction obtained in the previous scenario. This result highlights the dependency of the OPEX, and thus the resulting LCOE, to the choice of the of the reference wind farm. It is important to mention that the results presented in Table 10 are the raw output of the OPEX model, and not the levelized cost. They are not influenced by the choice of the cost of capital, in any way. The observed differences between the baseline and optimized cases are therefore uniquely due to the choice of the wind farm design.

Table 10. Summary of the CAPEX and OPEX reduction for the "state of the art" scenario.

Variable \ Case	Baseline	Optimized	Δ_{rel}
CAPEX $[\$/kW]$	3629.00	3473.37	-4.29%
Turbine $[\$/kW]$	1300.00	1262.35	-2.90%
BoP $[\$/kW]$	2236.00	2118.02	-5.28%
Owner's costs $[\$/kW]$	93.00	93.00	0.00%
OPEX $[\$/kW/y]$	100.44	76.71	-23.63%
Operation $[\$/kW/y]$	28.76	28.76	0.00%
Maintenance $[\$/kW/y]$	71.68	47.94	-33.12%

Table 11 summarizes the results of the AEP calculation. Similar to the "as-built" scenario, no adjustment is made to the wind farm model between the two cases. The resulting raw AEP and internal losses remain identical. Nevertheless, the availability losses are slightly lower for the optimized case, leading to an AEP improvement of approximately 0.3%. This reflects the fact that for this wind farm configuration, the major component replacements have a slightly higher contribution to the overall downtime. Therefore, the optimization of the maintenance schedule has a minor impact on the AEP.

Table 11. Summary of AEP calculation results for the "state of the art" scenario.

Variable \ Case	Baseline	Optimized	Δ_{rel}
AEP raw $[GWh/y]$	2876.74		0.0%
Internal Losses [%]	15.50%		0.0%
AEP net $[GWh/y]$	2430.84		0.0%
Avail. Losses [%]	18.86%	18.60%	-1.4%
AEP effective $[GWh/y]$	1972.33	1978.80	0.3%

Results for the LCOE calculation of the "state of the art" scenario are presented in Table 12. For the baseline case, the estimated LCOE is about 92.62 $\$/MWh$, while it is approximately 83.03 $\$/MWh$ for the optimized case. These values are close to the one reported by NREL for a similar reference wind farm [8]. The remaining differences can be explained, at least partially, by the differences in the financial model parameter values between the two analyses. Nevertheless, these results demonstrate the consistency of the approaches and confirm that the higher LCOE values reported in paragraph 6.2 for the "as built" scenarios are likely explained by the higher cost of capital and lower turbine rating.

Table 12. Summary of the LCOE results for the "state of the art" scenario.

. Variable \ Case	Baseline $[\$/MWh]$	Optimized $[\$/MWh]$	Δ_{rel} [%]
CAPEX	64.19	61.25	−4.6%
Turbine	23.00	22.26	−3.2%
BoP	39.55	37.35	−5.6%
Owner's costs	1.65	1.64	−0.3%
OPEX	28.43	21.78	−23.4%
Operation	8.41	8.38	−0.3%
Maintenance	20.03	13.40	−33.1%
Total	**92.62**	**83.03**	**−10.36%**

For the state-of-the-art scenario, the LCOE reduction between the baseline and optimized cases is about 10.36% which exceeds the 9% target for the HIPERWIND project. However, these results must be interpreted with caution. It is questionable whether the cost reductions achieved for Teesside can be directly transposed to a wind farm. Firstly, the mass reduction of the main structural components (tower and foundations) was achieved by optimizing the original design, dating from 2010. It seems likely that the state of the art has evolved since then, and that some of this gain has already been incorporated into the design of more recent turbines. Similarly, the results of the maintenance optimization are highly dependent on weather conditions, the location of the wind farm, and other parameters specific to Teesside, making these results harder to generalize.

Nevertheless, the aim of this analysis is mainly to highlight the dependence of the results on parameters that are independent of the turbine design, such as those listed in section 5. By comparing the results obtained for each of the two scenarios, it is evident that the LCOE reduction depends, to a large extent, on the CAPEX and OPEX reductions deriving from the HIPERWIND technologies, but also on the choice of reference wind farm used for this evaluation.

7. Summary and discussion

7.1. Summary of the HIPERWIND impact

In HIPERWIND, the reduction of the LCOE is essentially achieved on two levels. First, the optimization of the turbine design, from work package 4, allows for reducing the mass of the structural components such as the tower and the foundation. A lighter structure reduces the cost of the turbine and hence the capital expenditure. Secondly, the optimization of the maintenance schedule, from work package 6 (task 6.1), coupled with a more accurate estimation of the component lifetime, delivered by work package 5, allows for mitigating the costs associated with the replacement of the turbine's major components (gearbox, main bearing, and so on), reducing the operational expenditure.

The aim of the work in Task 6.2, presented in this document, is to quantify the actual cost impact of the optimization provided by the HIPERWIND work packages and to estimate the corresponding LCOE impact and value. To this end, a Python tool for LCOE estimation was developed. Special care was paid to the architecture of the tool such that it can provide the level of granularity required to study the impact of a specific action, such as reduction of the component mass, or optimization of the maintenance schedule on the LCOE.

The LCOE tool considers the CAPEX as the sum of the turbine, BoP, and owner's costs. Each of these three categories is broken down into several components whose cost is estimated as a function of the turbine's rated power. Such an approach follows the methodology from previous EPRI studies [2], [3].

The LCOE model for OPEX divides the expense into two main categories: the operational and the maintenance costs. The operational costs, which are not the primary focus of HIPERWIND, are modelled as a linear function of the wind farm AEP. The maintenance costs, on the other hand, are directly impacted by the optimization of the maintenance schedule and need to be evaluated in more detail. These are modeled using a failure-based approach, similar to the one from [14]. Different categories of failures and corresponding maintenance operations are defined. Each one is defined with a corresponding failure probability, material cost, repair time, and mean time to repair. The number of maintenance operations to be performed during a year is estimated using a Monte Carlo simulation. The cost associated with each operation is the sum of the material cost and the vessel cost. The latter is derived from the repair time and the type of vessel used during the operation. In this analysis, each of the turbine's major components is considered separately with its own failure probability and cost (derived from the CAPEX model). In addition to these variable costs, the model also considers a fixed labor cost to account for the salary of the technicians assigned to the wind farm maintenance.

The impact of the mass reduction from WP4 is estimated by scaling down the cost of the tower and foundations. Following the recommendation from [21], the assumption is made that 80% of the mass reduction can be converted in to cost reduction. Ultimately, this translates into a CAPEX reduction of approximately 4.3%. This result meets the target of the CAPEX reduction set for the HIPERWIND project.

The impact of the maintenance schedule on the OPEX is not as direct as it is for the CAPEX. Results from task 6.1, showed that the repair time for the major component replacement could be reduced by 14%. This has a direct impact on the costs of the vessel and hence of the maintenance operation. However, the total maintenance costs depend on the number of maintenance operations to be performed and therefore on the design of the wind farm. For the Teesside wind farm the optimization of the maintenance operation is found to reduce the OPEX by approximately 7.1%. This also meets the target for OPEX reduction for HIPERWIND.

The resulting LCOE reduction resulting from the CAPEX and OPEX optimizations specific to the Teesside wind farm is found to be approximately 5.12%. This is lower than the HIPERWIND target of 9% LCOE reduction, even though the target is met individually for each component. Part of it can be because the 9% target also includes reductions of the cost of the capital and enhanced AEP that are not included in this analysis due to limited available data. More importantly, the LCOE is also found to be sensitive to other parameters, such as the wind farm design. The turbine rating, for instance, influences the number of turbines to be installed to reach a given capacity. More turbines imply an increased number of maintenance of operations and thus higher OPEX. Similarly, the cost of capital also has a strong influence on the results, by scaling up the CAPEX due to increased interest payments, by also by reducing the OPEX due to a stronger effect of the discount factor for the final year of the project. All these make the resulting LCOE value sensitive to the choice of the wind farm used as a reference for the calculation. To illustrate such effects, LCOE is also computed for a virtual wind farm considering a larger turbine rating (8 MW) than the Teesside (2.3MW). In this scenario, the application of HIPERWIND technologies and improvements is found to reduce the LCOE by 10.36%. Exceeding the HIPERWIND target of 9%.

7.2. Limit to the current work and perspectives.

In addition to estimating the impact of HIPERWIND on CAPEX and OPEX, this study has shown that LCOE depends to a large extent on the design of the wind farm and other external parameters, such as the method of financing. In addition, certain assumptions and parameter choices can have a strong influence on the results. For example, maintenance costs depend directly on the probability of turbine component failure and the repair time. These parameters are fixed in the model, whereas, in practice, they will depend on local wind conditions. A higher wind speed may reduce the service life of certain components (such as the gearbox) and make access to the turbine for repair more difficult. Similarly, increasing the size of turbines can have an impact on mean time to failure, which could cancel out some of the reduction in maintenance costs observed by reducing the number of turbines. All this calls for a better quantification of the uncertainties inherent in the model, to be able to better estimate the variability of the LCOE. Such a study was not carried over due to lack of time.

A potential follow-up to the study presented in this paper could therefore be to better quantify uncertainties. To this end, the model developed for HIPERWIND task 6.2 would be a suitable tool. Indeed, the latter provides LCOE estimates with good granularity, enabling the influence of specific parameters to be assessed at a low computational cost. It therefore seems possible to use it to explore a wide range of parameters and quantify their respective influences on LCOE. Once the main parameters have been identified, a second step would be to quantify the uncertainty associated with each of them. For this, the advanced models developed in other HIPERWIND work packages could be used. For example, the maintenance optimization tool developed in Task 6.1 could be used to quantify the variability of repair time and costs associated with component replacement. Similarly, the Uncertainty Propagation Method in Work Package 3 could be used to quantify the variability of AEP as a function of the variability of ambient wind conditions. And so on. Once identified, all these uncertainties could be propagated to the LCOE calculation. The result would be a more accurate prediction of this metric and of the associated uncertainty.

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Appendix A Details of the CAPEX model

The Table 13 summarizes the components, and sub-components used to compute CAPEX. The proposed categories follow the nomenclature from previous EPRI research [2], [3]. The Breakdown of the turbines cost is based on NREL's cost of wind energy report [7], [8].

Table 13. Component breakdown used for CAPEX calculation.

Assembly/Component	Cost ($\$/kW$)	Fraction of total
Turbine assembly	**1300**	**35.82%**
Rotor sub-assembly	395	10.88%
Blades	256	7.05%
Pitch system	79	2.18%
Hub	60	1.65%
Nacelle sub-assembly	646	17.80%
Nacelle structure	130	3.58%
Drive train	259	7.14%
Electrical components	209	5.76%
Yaw system	48	1.32%
Tower sub-assembly	259	7.14%
BoP assembly	**2236**	**61.61%**
Engineering & management	73	2.01%
Substructure and foundation	593	16.34%
Port & staging	19	0.52%
Electrical infrastructure	417	11.49%
Assembly and installation	796	21.93%
Commissioning	30	0.83%
Contingency	308	8.49%
Owner cost assembly	**93**	**2.56%**
Development costs	60	1.65%
Insurance	33	0.91%
Total	**3629**	**100.00%**

The figures, below, show the contribution to CAPEX of each assembly (Figure 17) and for each component of the assemblies (Figure 18). Results are presented both in $\$/kW$ (bottom x-axis) and as fraction of the total CAPEX (top x-axis).

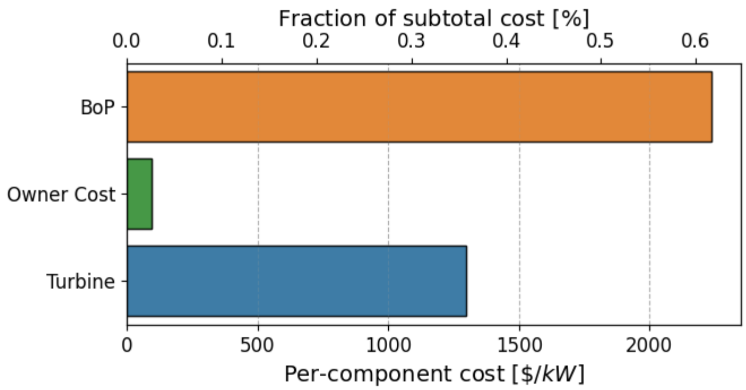

Figure 17. Contribution to overall CAPEX of the three main components: Turbine (blue), BoP (orange) and Owner Costs (green). The bottom x-axis shows the price per component in $/kW while the top x-axis displays the component the as a fraction of the total CAPEX.

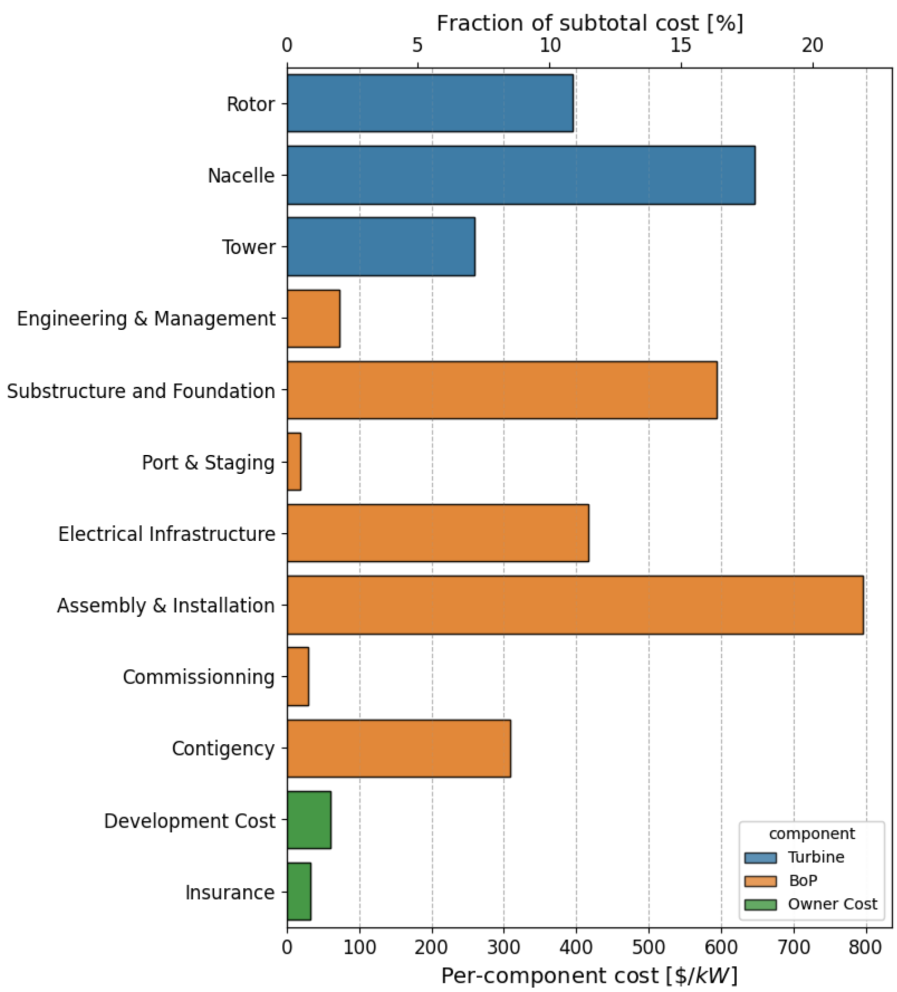

Figure 18. Contribution to overall CAPEX of the component of each assembly. Components are colored by their corresponding assembly: Turbine (blue), BoP (orange) and Owner Costs (green). The bottom x-axis shows the price per component in $/kW while the top x-axis displays the component the as a fraction of the total CAPEX.

Appendix B Details for the OPEX model

The tables below summarize the settings for the OPEX for the baseline (Table 14) and optimized (Table 15) cases. For the optimized case (Table 15), only the cells highlighted in **green** contained updated values compared to the one in Table 14. The "Distrib." column details the type of distribution used to estimate the component failure probability. Two types of distribution are considered: either exponential distribution ("exp.") or two-parameters Weibull ("weib."). The scale column contains the value of the scale parameter of the corresponding distribution (for the exponential distribution, the scale parameter is the inverse of the annual failure rate). Only the Weibull distribution requires a shape parameter. The details of the vessels associated with each repair are given in Table 16. Finally, Table 17 summarizes the values of the model parameters for the fixed O&M costs.

*Table 14. Repair type considered in the OPEX model for the **baseline** case.*

Repair/Component	Vessel	Cost $	Repair Time hr	MTTR hr	Distrib. –	Scale $year$	Shape –
manual reboot	CTV	0	6	48	$exp.$	0.13	
minor repair	CTV	1250	24	168	$exp.$	0.33	
medium repair	CTV	23500	62	367	$exp.$	3.64	
major repair	FSV	93000	74	433	$exp.$	25.00	
service	CTV	23500	60	250	$exp.$	1.00	
blade	HLV	From CAPEX (see Annex A)	76	306	$exp.$	333.33	
main bearing	HLV		268	1071	$weib.$	840.03	0.673
generator	HLV		229	918	$weib.$	16.50	1.915
gearbox	HLV		306	1224	$weib.$	24.95	1.538
pitch system	HLV		102	300	$exp.$	333.33	
other	HLV	45000	319	1275	$exp.$	71.43	

*Table 15. Repair type considered in the OPEX model for the **optimized** case. Only the cells highlighted in **green** have updated value compared to the baseline case.*

Repair/Component	Vessel	Cost $	Repair Time hr	MTTR hr	Distrib. –	Scale $year$	Shape –
manual reboot	CTV	0	6	48	$exp.$	0.13	
minor repair	CTV	1250	24	168	$exp.$	0.33	
medium repair	CTV	23500	62	367	$exp.$	3.64	
major repair	FSV	93000	74	433	$exp.$	25.00	
service	CTV	23500	60	250	$exp.$	1.00	
blade	HLV	From CAPEX (see Annex A)	76	306	$exp.$	333.33	
main bearing	HLV		66	295	$weib.$	840.03	0.673
generator	HLV		230	1033	$weib.$	16.50	1.915
gearbox	HLV		197	886	$weib.$	24.95	1.538
pitch system	HLV		263	1181	$exp.$	333.33	
other	HLV	45000	88	286	$exp.$	71.43	

Table 16. Details of the vessel used for the OPEX model.

Vessel type	Short name	Mobilization cost $\$$	Daily rate $\$/day$
Crew Transfer	CTV	0	2025
Fleet Support	FSV	0	12000
Heavy lift	HLV	630000	190000

Table 17. Parameter for the fixed O&M costs.

Variable	$Value$	$Unit$	Comment
Labor Cost	$\$ 100k$	$\$/pers/y$	From [14]
Operational Cost	30	$\$/MWh/y$	From [8]

Appendix C Overview of the Teesside wind farm

The Teesside wind farm which serves as a reference for HIPERWIND is described in detail in deliverable D1.1 [31]. Only the main characteristics which are relevant for the LCOE calculation are summarized in this Annex. The wind farm is made of 27 Siemens 2.3MW turbines and was commissioned in 2013. The layout of the farm is shown in Figure 19. The turbine power curve is shown in Figure 20, which also displays the wind speed distribution. The latter is derived from the three-parameter Weibull distribution fitted to the measurement data in WP2. The distribution parameters are summarized in Table 18.

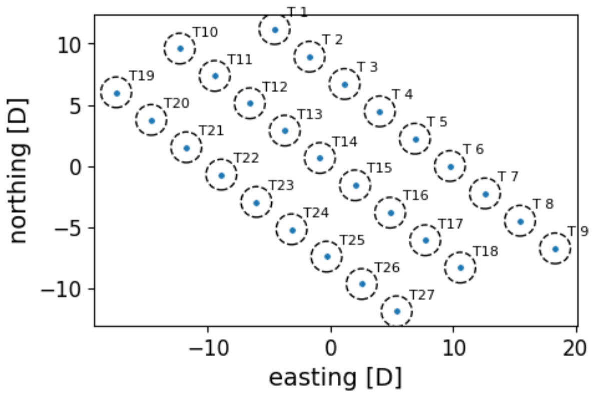

Figure 19. Layout of the Teesside wind farm. Coordinates are normalized by the rotor diameter of the turbine.

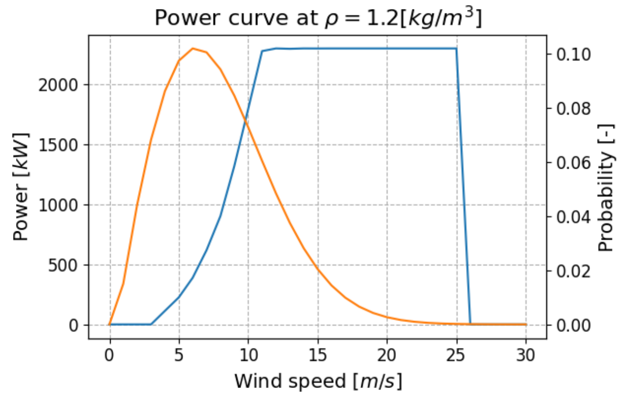

Figure 20. Power curve of the Siemens 2.3MW superposed with the Weibull distribution from WP2 [32].

Table 18. Parameter of the Weibull distribution for the Teesside Windfarm from WP2 [32]

Parameter	Value	Unit
Scale (α_w)	8.240031	m/s
Shape (β_w)	1.948360	$-$
Loc (γ_w)	0.273299	m/s

Results of the AEP calculation for the Teesside windfarm are summarized in Table 19 and Figure 21. The value of the Raw AEP is computed as the expected value of the power production, as detailed in section 3.2.4. The value of the wake losses is derived from the farm flow simulation performed for deliverable D3.2 [18] as detailed in the following of this Appendix. Value for the electrical losses is taken from industry standards.

Table 19. Results of the AEP calculation for the Teesside Windfarm.

Variable	Value	Unit	Comment
Raw AEP	236.87	GWh	See below for details
Wake Losses	9.85%	%	See AEP section below
Electrical Losses	2%	%	Fixed as default
Net AEP	209.27	GWh	Does not include availability Losses.
Capacity factor C_f	38.87%	%	

The table below summarizes the key financial parameters used for LCOE estimation of the Teesside wind farm.

Table 20. Summary of the financial parameters for LCOE estimation of the Teesside wind farm.

Variable	Value	Unit	Comment
WACC	11.2%	%	See [28]
Loan period	20	yr	See [30]
Inflation rate	2.5%	%	See [30]
Financing factor	1.04	−	See [3]
Debt fraction	60%	%	See[26]

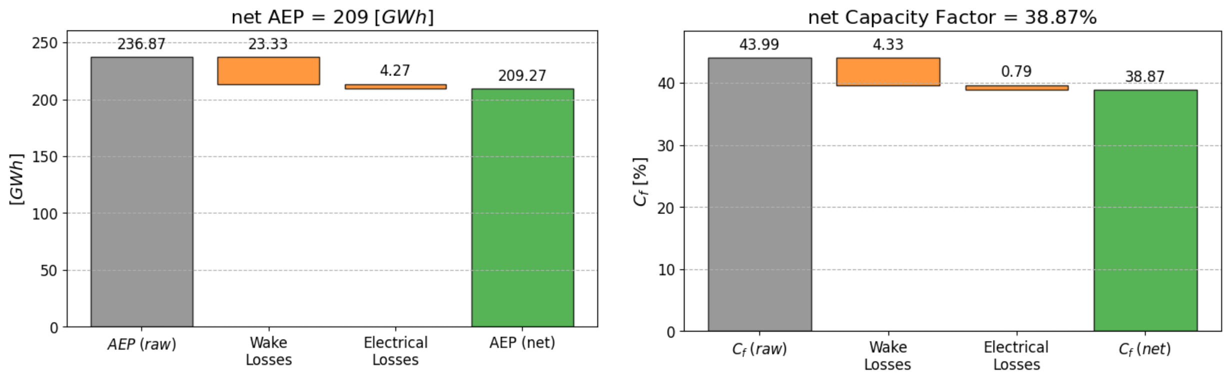

Figure 21. Breakdown of the AEP (left) and Capacity Factor (right) results. The gray bars represent the "raw" values, not considering any losses, while the green bar represent the "net" values obtained after discounting for the losses. The losses are represented by the orange bars, where the height of the bar represent the amount loss.

Estimating the wake losses for the Teesside windfarm.

Wake losses for the Teesside wind farm are estimated from the results of the farm flow simulations performed in WP3.2. The dataset consists of a design of experiment (DoE) of 8000 wind farm simulations. Each simulation is defined by a triplet of ambient conditions (wind speed, turbulence, and wind direction). The simulation results contain the rotor-averaged wind speed for each of the twenty-seven turbines of the wind farm. Figure 22, shows the distribution of the wind speed derived from the ambient conditions of the DoE. The resulting distributions of rotor average wind speed are shown in Figure 23, where each turbine is shown on a separate plot. The orange lines represent the turbine data, and the dark grey lines are the ambient conditions provided as a reference.

To compute the wake losses, it is first required to estimate the raw power production using the methodology described in section 3.2.4 considering the wind distribution wind speed shown in Figure 22. Then, the same process is applied, using the distributions of rotor-averaged wind speed from Figure 23, for estimating the net power production of each turbine. Finally, wake losses are computed for each turbine (wt) as the relative difference between the net and raw power production.

$$\Delta E_{wake}(wt) = 100 \times \left(1 - \frac{AEP_{net}(wt)}{AEP_{raw}}\right)$$

It is important to mention that using the wind speed distributions from the DoE leads to overestimating the AEP. Indeed, the DoE data do not contain any ambient wind speed value outside of the operating range of the wind turbine ($[3;\ 25]m/s$). Considering such truncated distribution in the calculation of the expected power production is therefore equivalent to considering that the turbines are producing power all the time. Nevertheless, that method remains valid for estimating the wake losses since the net and raw values of the AEP are overestimated in the same proportion.

Figure 24 shows the results of the wake loss estimations. The magnitude of the estimated losses varies from one turbine to another, ranging from approximately 4% up to almost 14%. From Figure 26, it can be seen that turbines with lower losses are all distributed on the southernmost row of the wind farm, while turbines located on the middle and northernmost rows all exhibit losses above 10%. Such a distribution of the losses in the windfarm is consistent with the wind rose. Indeed, as shown in Figure 25, the dominant wind direction at Teesside is from the South-Southwest, meaning that the turbines of the southernmost row spend more time in freestream conditions, resulting in lower losses than the turbines from the other rows that are more severely by the wakes. Average wakes for the wind farm are about 9.85%. This value can be used for calculating the AEP of the wind farm and is reported in Table 19, above.

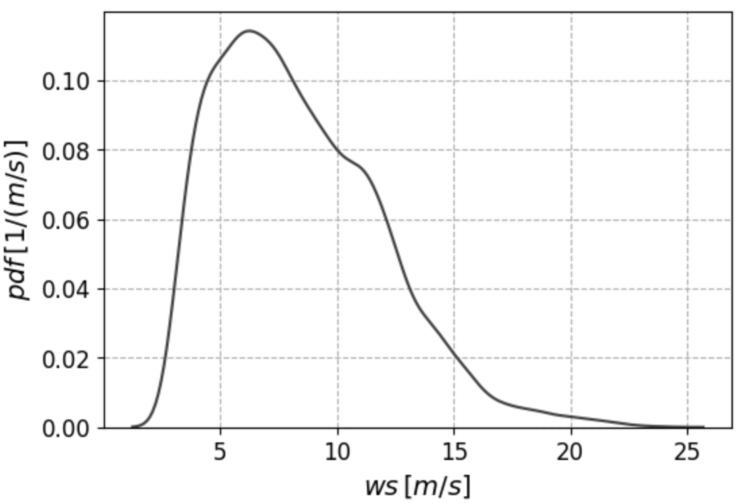

Figure 22. Probability density function of the ambient wind speed derived from the design of design of experiment (DoE) of farm flow simulation performed in WP3.2

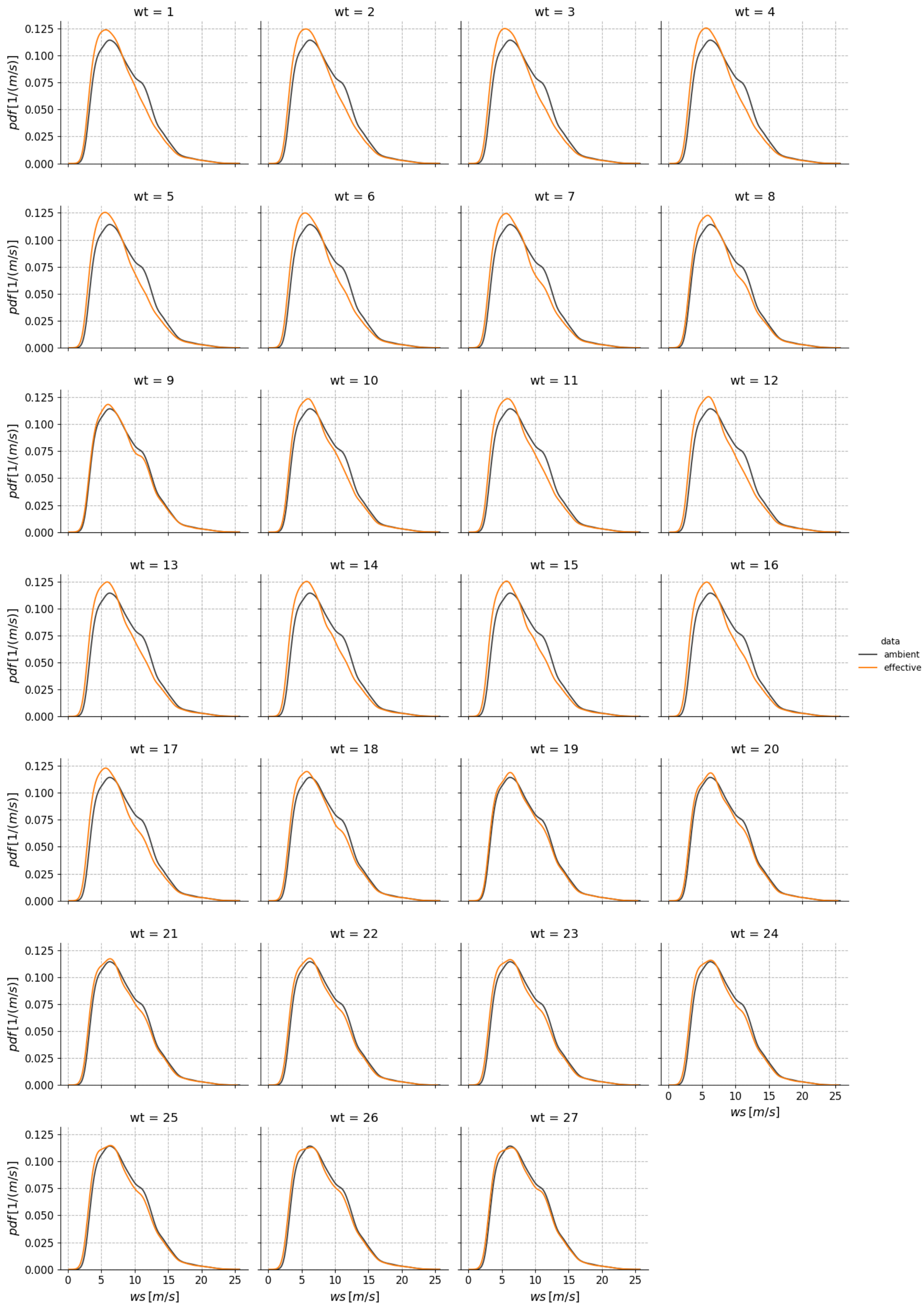

Figure 23. Probability density function of the rotor average wind speed for each turbine of wind farm obtained from the farm flow simulation in WP3.2. The orange curves represent the turbine data, while the dark lines represent the ambient conditions.

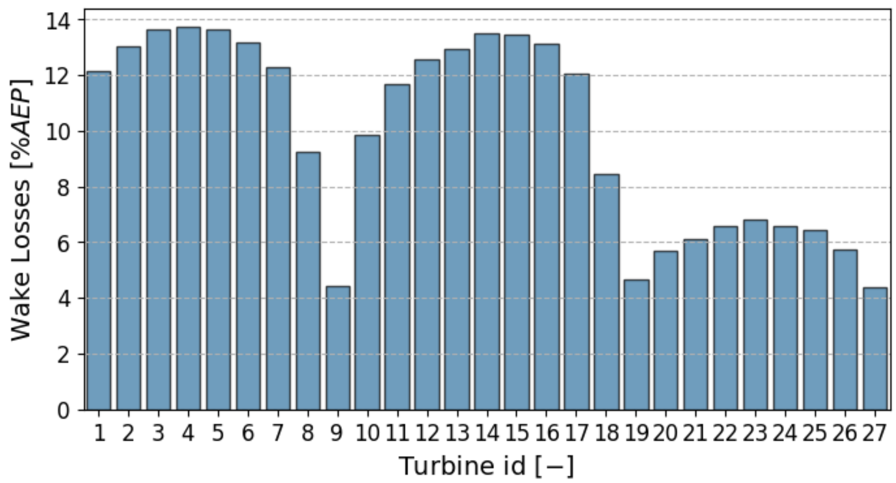

Figure 24. Results of the wake losses calculation from the DoE data of WP3.2.

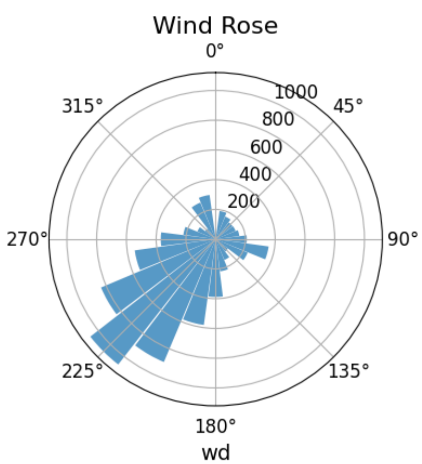

Figure 25. Wind rose for the Teesside windfarm derived from the ambient conditions of the DoE.

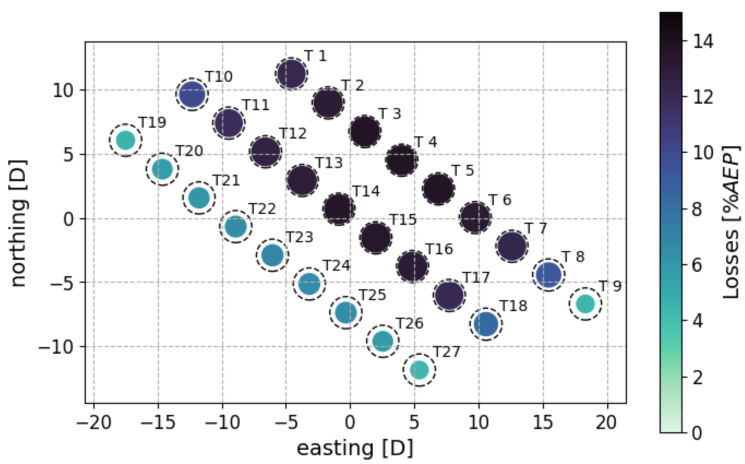

Figure 26. Plot of the Teesside layout where each the size and color of each marker depends on the value of the wake losses for the corresponding turbine. Darker and larger maker implies larger wake losses.

Appendix D Overview of the virtual wind farm

Table 1 summarizes the settings for the virtual wind farm used for LCOE calculation. The design of this wind farm is inspired from the fixed bottom reference wind farm used by NREL in [8]. The wind farm is made of 75 turbines of $8MW$ each, for a total wind farm capacity of $600MW$. The turbine power curve is taken from NREL's 2016 8MW reference wind turbine [33], and is shown on Figure 27, alongside with the wind distribution for the site (also taken from [8]). The settings for CAPEX and OPEX are identical as the one used for the Teesside windfarm and are summarized in Appendix A and Appendix B, respectively.

Table 21. Settings for the virtual wind farm used for LCOE calculation.

Windfarm Settings	Value	Unit	Comment
Total Capacity	600	MW	See [8]
Number of turbines	75	–	
Turbine rating	8	MW	
Wake losses	13.78%	%	
Electrical losses	2%	%	
Wind conditions			
Mean wind speed	9	m/s	See [8]
Shape factor	2.1	–	
Financial settings			
loan period	15	yr	See [26]
financing factor	1.04	–	
inflation rate	2.11%	%	
interest rate	3%	%	
cost of equity	8%	%	
debt fraction	60%	%	
tax rate	27.98%	%	

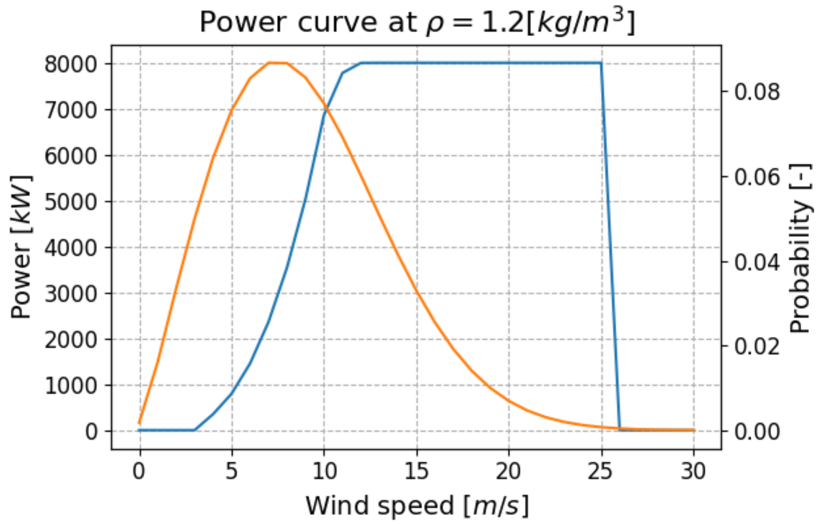

Figure 27. Power curve of 8MW reference turbine [8] used for the virtual wind farm, superposed with the site wind speed distribution taken from [8].