Qualification of innovative floating substructures for 10MW wind turbines and water depths greater than 50m

Project acronym	LIFES50+
Grant agreement	640741
	Collaborative project
Start date	2015-06-01
Duration	40 months

Deliverable 2.2. LCOE tool description, technical and environmental impact evaluation procedure

Lead Beneficiary	Fundació Institut de Recerca en Energia de Catalunya-IREC
Due date	2016-09-30
Delivery date	2016-10-06
Dissemination level	Public
Status	Completed
Classification	Unrestricted

Keywords	Floating offshore wind turbines, evaluation procedure, general frame
Company document number	

The research leading to these results has received funding from the European Union Horizon2020 programme under the agreement H2020-LCE-2014-1-640741.

Disclaimer

Document information

Version	Date	Description	
0.1	2016-09-01	Updated version for review	
		Prepared by	Gabriela Benveniste
		Reviewed by	Markus Lerch, Mikel de Prada
		Approved by	Gabriela Benveniste
0.2	2016-09-29	Version for peer-review	
		Prepared by	Gabriela Benveniste, Markus Lerch, Mikel de Prada
		Reviewed by	Bård Wathne Tveiten, Luca Vita
		Approved by	Gabriela Benveniste
1.0	2016-09-30	Final version for QA before submission to EC	
		Prepared by	Gabriela Benveniste
		Reviewed by	Matthias Peter Nowak
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Definitions & Abbreviations

AEP	Annual Energy Production
AdP	Non-fossil Abiotic Depletion Potential
ANOVA	Analyis of Variance
AST	Administrative Support Team
CAPEX	Capital Expenditure
CLP	Pipe Anchor Installation
CO2	Carbon Dioxide
DECEX	Decommissioning Expenditure
DG	Distibuted generation
DLC	Design Load Cases
DNV-GL	Det Norske Veritas – Germanischer Lloyd
DTU	Danmarks Tekniske Universitet
EC	Evaluation Committee
EUR	Euro
EWM	Extreme Wind Speed Model
FLS	Reinforced Steel
FES	Reinforced Steel
FOWAT	Floating Offshore Wind Assessement Tool
FOWT	Floating Offshore Wind Turbine
FOWPP	Floating Offshore Wind Power Plant
FWS	Reinforced Steel
GA	General Assembly
GBP	Great Britain Pound
GWP	Global Warming Potential
HV/MV	High Voltage/Medium Voltage
HVAC	High Voltage Alternate Current
HVDC	High Voltage Direct Current
ILCD	International Reference of Life Cycle Data
KPI	Key Performance Indicator
LCA	Life Cycle Assessment
LCCA	Life Cycle Cost Assessment
LCOE	Levelized Cost of energy
NOK	Norwegian Crown
NREL	National Renewable Energy Laboratory
O&M	Operation and Maintenance
OPEX	Operational Expenditure
OSS	Offshore Substation
OWF	Offshore Wind Farm
OWTG	Offshore Wind Turbine Generator
PC	Project Coordinator
PE	Primary Energy
PM	Project Manager
RNARNA	Rotor-Nacelle-Assembly (also know as WTG)
ROV	Remotely operated underwater vehicle
TLP	Tension Leg Platform
USD	United States Dollar
USTUTT	University of Stuttgart
WPL	Work Package Leader
WP	Work Package
WTG	Wind Turbine Generator
XLPE	Cross-linked polyethylene

Executive Summary

This document describes FOWAT by including a detailed description of the economic evaluation module, the environmental evaluation module and the description of the technical Key Performance Indicators (KPI) that are used in the evaluation. Following the projects objectives, the Overall Evaluation Tool here reported includes the procedures to enable the calculation of the following aspects to be considered in both Phase I and Phase II evaluation of the concept designs:

- Economic assessment: LCOE calculation expressed in €/MWh and included in LCOE module of the Single Calculation Mode of the tool.
- Environmental assessment: LCA analysis using 3 environmental indicators included in LCA module
- Risk evaluation: Technology risk assessment included in Risk Module
- Uncertainty assessment: Provides LCOE calculation considering an uncertainty range as per the inclusion of uncertainty ranges in some of the inputs used for the LCOE computation. This assessment is available in the LCOE Module in the Evaluation Mode of the tool
- Concepts designs ranking generator: calculation of the final evaluation ranking of the designs using the results of LCOE, LCA and Risk assessment (multi-criteria analysis). This operation is executed in the Multi-Criteria module.
- KPI information: Concept design technical description using key performance indicators and generation of a KPI .pdf report.

Section 2 of the report includes a brief review of existing available LCOE tools that have been taken into account to inspire the development of the LIFES 50+ evaluation tool. The aim of this section is to provide a general overview of existing and similar tools to calculate LCOE for offshore wind technology, but a thorough review and comparison of tools has been omitted.

Section 3 provides a general description of the tool and how it has been structured. Including the general description of the modules (LCOE, Risk, LCA, KPI report maker, Uncertainty and Multi-Criteria).

The LCOE calculation approach in section 4 will give and detailed description, which include methodology, general assumptions, life cycle cost of floating wind farms, energy production calculation approach, LCOE uncertainty approach and finally an overall description of the evaluation tool.

Further the LCA analysis will be dealt with in section 5 focuses on describing the methodology behind this assessment and the selection of 3 environmental impact indicators that are going to be calculated for the 4 concepts at each site (Global Warming Potential, Non-fossil abiotic depletion potential, Primary Energy consumption).

Section 6 provides a description and list of the technical Key Performance Indicators that have been selected to characterize the concept designs. These KPI will be used during the data collection process in order to verify the consistency of the data provided by the concept designers for the LCOE calculation. Besides, KPI will not be included in the multi-criteria decision methodology for selecting the 2 concept designs for Phase 2 evaluation.

Section 7 of this deliverable has provided a description of the Multi-criteria methodology that has been implemented in the tool to provide a single final ranking of the 4 concept designs using the following weighting factors:

- Economic Assessment-LCOE= 70%
- Risk Assessment= 20%
- Environmental Assessment- LCA= 10%

The Multi-Criteria module will store in the different matrix results of the LCOE and LCA calculation for each site and concept design. Each matrix will be treated in order to convert the absolute values (e.g. €/MWh for LCOE, or kg CO_2eq for LCA) into scores from 1 to 4 as explained in D2.5. There will be no need of further treatment of the outputs from the Risk module, as they will be expressed in the same dimensionless scoring system.

Section 8 gives a detailed case description of the LCOE module tool being tested by defining a FOWPP at a specific location and calculating its LCOE. The specifications of the components are based on available data from literature. However, some restrictions are related to the Lifes50+ project such as a minimum water depth of the location of 50 m and an offshore wind turbine with a rated power of 10 MW.

Finally, section 9 concludes as follows: The aim of this deliverable is to describe modules that comprehend the LIFES 50+ Overall Evaluation tool named “Floating Offshore Wind Assessment Tool- FOWAT” that has been developed within this project to qualify the four concepts designs under an economic, environmental, risk and technical perspective. The objective of this deliverable is to provide the methodological framework used for the development for both LCOE and LCA modules, to describe the tools architecture and the data introduction Excel document and to provide a visual description of the Overall tool appearance and how the specific modules have been integrated.

As a final remark, it should be stated that the methodology that this document presents for the LCOE ranking considering the uncertainty has been proposed by IREC to the Evaluation Committee and its use within the project is subject to its approval by the end of M17 (October 2016).

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1 Introduction and objectives

The aim of this deliverable is to describe modules that comprehend the LIFES 50+ Overall Evaluation tool named "Floating Offshore Wind Assessment Tool- FOWAT" that has been developed within this Project to qualify the four concepts designs under an economic, environmental, risk and technical perspective.

For this reason, this document depicts the Overall Evaluation tool by including a detailed description of the economic evaluation module capable to calculate the Levelised Cost of Energy (LCOE), the environmental evaluation module that performs the Life Cycle Assessment (LCA) of the concepts and the description of the technical Key Performance Indicators (KPI) that are used in the evaluation. The description of the Risk assessment methodology and its tool is provided in Deliverable 2.5.

The objective of this deliverable is to provide the methodological framework used for the development for both LCOE and LCA modules, to describe the tools architecture and the data introduction Excel document and to provide a visual description of the Overall tool appearance and how the specific modules have been integrated.

In any case this document provides specific information regarding the concepts and information regarding the use of the tool.

2 Baseline: tools literature review

This section includes a brief review of existing available LCOE tools that have been taken into account to inspire the development of the LIFES 50+ evaluation tool. The aim of this section is to provide a general overview of existing and similar tools to calculate LCOE for offshore wind technology, but a thorough review and comparison of tools has been omitted.

2.1 KIC Innoenergy DELPHOS tool

KIC InnoEnergy's new cost evaluation platform, DELPHOS, is designed to make publicly available a series of cost models and basic datasets to improve the analysis of the impact of innovations on costs and to allow the research community, industry, policy makers and investors to make robust decisions about the role of innovation in the energy sector as well as to feed their strategy definition processes. KIC InnoEnergy's goal is that DELPHOS become a reference tool for the evaluation of the impact of single and concrete innovation on the typical economical parameters of energy facilities, being the levelised cost of energy (LCOE) the key indicator. DELPHOS provides a simple but exhaustive methodology to assess the impact of innovation on typical renewable energies power plants such as wind energy (onshore and offshore), photovoltaics (coming soon) and solar-thermal electricity.

KIC InnoEnergy, together with BVG Associates, is developing credible future technology cost models in four renewable energy generation technologies using a consistent methodology. DELPHOS is an online and simplified version of these cost models [1].

The purpose of these cost models is to enable the impact of innovations on the levelised cost of energy (LCOE) to be explored and tracked in a consistent way across the four technologies and over the next 12 to 15 years. A specificity of those models is that the impact of innovations is not only modelled according to their technicality but also taking into account their marketability. While the priority is to help focus on key innovations, DELPHOS also consider real world effects to ensure a realistic overall LCOE trajectory.

Together with the robustness of the model, credibility is also ensured by the use of datasets recognised by major players of the industry. Of course those datasets correspond to a picture of a sector at a certain point in time and might become outdated. For this reason DELPHOS was designed to allow users edit the existing datasets and adapt the cost tool to their own experience.

DELPHOS tool is then a valuable tool to consider when estimating the LCOE reduction due to the introduction of a change in the technology or component in an existing scenario, but it does not provide a detailed cost breakdown of the total costs (CAPEX, OPEX and DECEX). Furthermore, the tool does not allow the simulation of scenarios for turbines larger than 8MW.

More information regarding KIC-Innoergy activities and DELPHOS tool can be found at:

http://www.kic-innoenergy.com/delphos/

2.2 USTUTT LCOE Calculation Tool

At the University of Stuttgart (USTUTT), Ebenhoch et al. developed a tool for the estimation of the LCOE of offshore wind turbine foundations including both floating and fixed-bottom structures. The tool helps to analyse the key aspects of new designs already during the planning and pre-design phase. The main cost drivers of concepts can be identified by breaking down the costs into different categories and by applying a sensitivity analysis. The data basis is compiled from publicly available sources increasing the transparency. Besides the evaluation of the economic feasibility, the purpose of the tool is to achieve a design optimisation in terms of cost. A description of the tool is given in [2] and more detailed in [3].

2.2.1 Methodology/Capabilities

The tool performs a Life Cycle Cost Analysis (LCCA) in which all costs of the different design cycle phases listed in the following are considered: wind farm development, manufacturing, acquisition and installation of components, operation, maintenance, and decommissioning. Basically, the tool takes all CAPEX, OPEX, and DECEX of a offshore wind turbine over lifetime into account.

The basic methodology of the tool is shown in Figure 1. The main input parameters are the water depth, turbine size and the distance to shore. The latter two result in a scaling factor which is applied to the basic costs of a component. The main input parameters can be set individually for each wind turbine component aiming for a differentiated consideration. Further entries can be defined manually and include for instance gross load factor, losses, availability, WACC etc. The basic cost information of different substructure concepts were derived from a literature study and can also be extended for new concepts. Additionally, the literature values were used to generate cost functions to predict the development under changing main parameters. All cost information are compiled in look-up data sheets and are used in order to evaluate CAPEX, OPEX and DECEX in a next step. Finally the LCOE calculation is performed based on the following approach [4]:

$$\mathbf{LCOE} = \frac{\mathbf{I_0} + \sum_{\mathbf{t=1}}^{\mathbf{n}} \frac{\mathbf{A_t}}{(\mathbf{1+i})^{\mathbf{t}}}}{\sum_{\mathbf{t=1}}^{\mathbf{n}} \frac{\mathbf{M_{el}}}{(\mathbf{1+i})^{\mathbf{t}}}} \qquad (\mathbf{1})$$

$LCOE$: Levelized cost of electricity in €ct/kWh

I_0: Capital expenditure (CAPEX) in €ct

A_t: Annual operating costs (OPEX) in year t

M_{el}: Produced electricity in the corresponding year in kWh

i: Weighted average cost of capital (WACC) in %

n: Operational lifetime in years

t: Individual year of lifetime (1,2,…n)

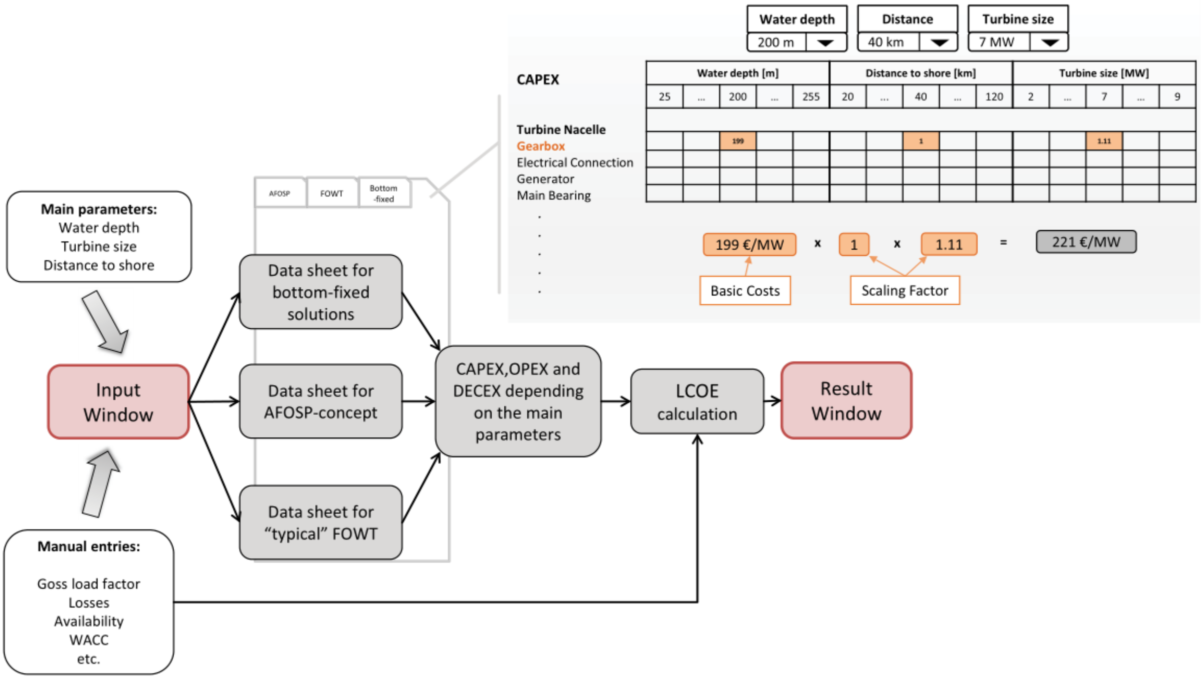

Figure 1. Methodology of LCOE calculation tool [2]

2.2.2 Tool Output

The results of the LCOE calculation are visualised in different figures. A summary of the composition of the LCOE cost is given in a bar chart (see Figure 2). In this chart the share of the total LCOE can be seen clearly for each parameter. Furthermore different concepts can be compared to each other.

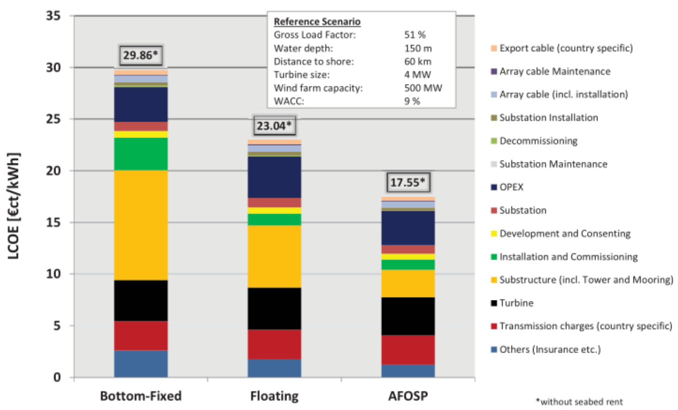

Figure 2. Composition of the LCOE [2]

A more detailed insight into the costs is given in the output of a sensitivity analysis (see Figure 3). With the help of this plot the impact of specific parameters can be identified. This is done by varying the parameters originating from a reference point. A high gradient of a curve indicates a high sensitivity of the associated parameter. Knowing this, one can decide which parameter or component respectively is worth to improve.

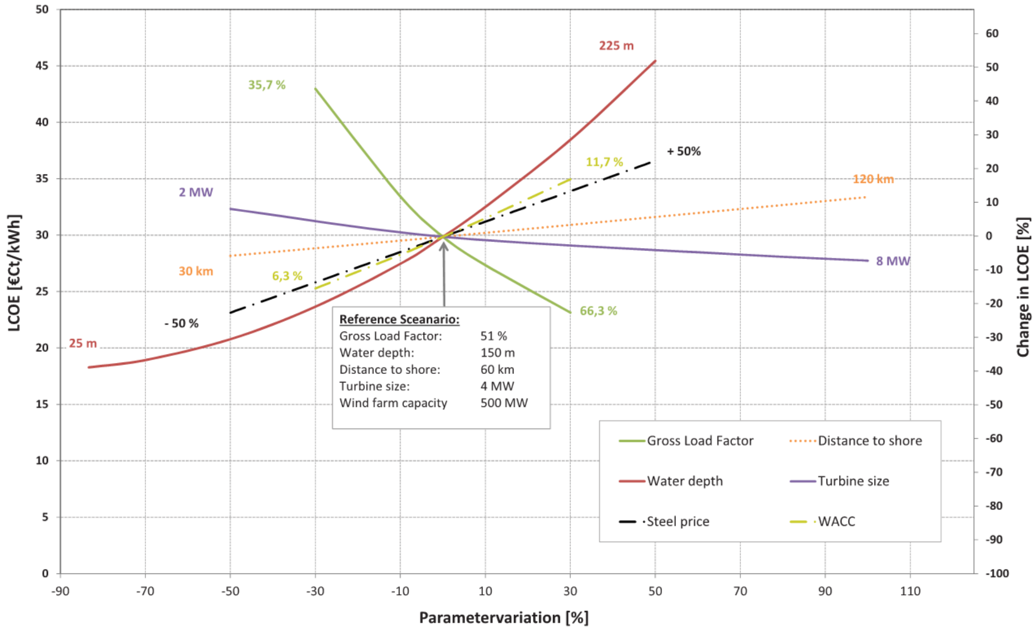

Figure 3. Output of Sensitivity Analysis [2]

2.3 NREL LCOE tool

The National Renewable Energy Laboratory (NREL) levelized cost of energy (LCOE) calculator provides a simple calculator for both utility-scale and distributed generation (DG) renewable energy technologies that compares the combination of capital costs, operations and maintenance (O&M), performance, and fuel costs.

This tool, that can be applied to different renewable energy technologies does not include financing issues, discount issues, future replacement, or degradation costs. Each of these would need to be included for a thorough analysis.

The tool provides a simplified estimation of the cost of energy, using the slider controls or enter values directly to adjust the values. The calculator will return the LCOE expressed in cents per kilowatt-hour (kWh).

Although no offshore wind projects have been installed in the United States to date, the first project began offshore construction in April 2015 and is scheduled to begin operation in the fall of 2016.The lack of domestic experience with offshore wind technology introduces considerable uncertainty into cost estimates for potential domestic offshore wind projects in the United States. The market data used for the tool development has been provided in the 2014–2015 U.S. Offshore Wind Technologies Market Report [5]. This report provides an analysis of offshore wind cost trends in Europe as well as projections for the United States. It updates the previous offshore market research by drawing on global fixed-bottom offshore wind market data, utilizing past offshore wind economic analyses and running NREL's suite of cost and performance models.

The tool then includes fixed-bottom offshore wind reference projects which were derived from representative characteristics of 2014 wind projects consisting of 147 3.39-MW turbines (500 MW of total installed capacity) with a 115.4-m rotor diameter on an 85.8-m tower. [6]

More information can be found at: http://www.nrel.gov/analysis/tech_lcoe.html

3 LIFES 50+ Overall Evaluation tool description

This section provides a general description of the tool and how it has been structured. Including the general description of the modules (LCOE, Risk, LCA, KPI report maker, Uncertainty and Multi-Criteria). The description here reported can be completed with the information included in deliverable D2.5 regarding the statistical methods used for the uncertainty analysis and the methodology behind the multi-criteria selection approach.

3.1 Objectives of the tool

Following the projects objectives, the Overall Evaluation Tool reported here includes the procedures to enable the calculation of the following aspects to be considered in both Phase I and Phase II evaluation of the concept designs:

- Economic assessment: LCOE calculation expressed in €/MWh and included in LCOE module of the Single Calculation Mode of the tool.
- Environmental assessment: LCA analysis using 3 enviromental indicators included in LCA module
- Risk evaluation: Technology risk assessment included in Risk Module. A detailed explanation of the Risk module and the methodology is reported in D2.5.
- Uncertainty assessment: Provides LCOE calculation considering an uncertainty range as per the inclusion of uncertainty ranges in some of the inputs used for the LCOE computation. This assessment is available in the LCOE Module in the Evaluation Mode of the tool
- Concepts designs ranking generator: calculation of the final evaluation ranking of the designs using the results of LCOE, LCA and Risk assessment (multicriteria analysis). This operation is executed in the Multi-Criteria module.
- KPI information: Concept design technical description using key performance indicators and generation of a KPI .pdf report

The Overall Evaluation Tool has been named FOWAT, acronym for “Floating Offshore Wind Assessment Tool”.

3.2 Tool structure

A general scheme of the tools structure and interaction of the different modules that are included is presented below in Figure 4.

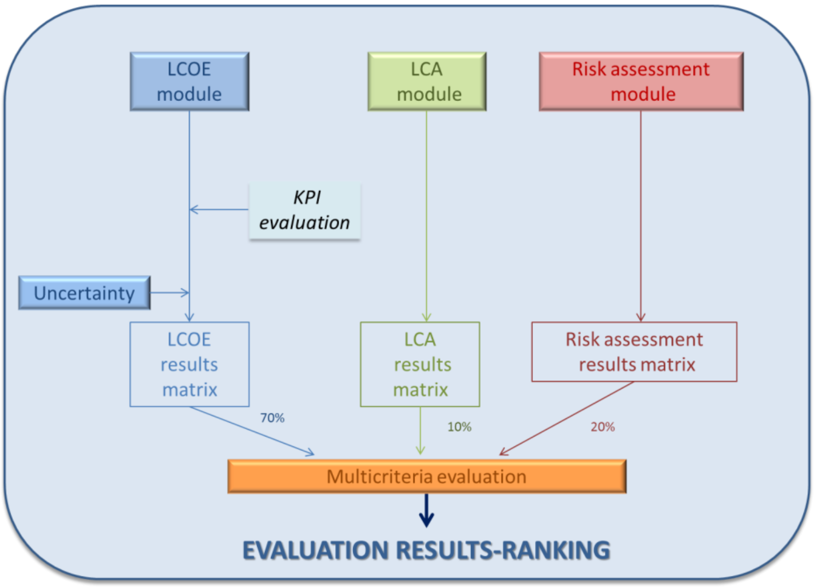

Figure 4. Overall evaluation tool structure

Coloured boxes (LCOE module, LCA module, Risk assessment module, Uncertainty, Multi-Criteria evaluation) indicate those modules that generate results to be used in the concepts designs final ranking. The KPI evaluation module generates a .pdf report with the information collected by filling the KPI table and supports the data quality assurance for LCOE and LCA calculation. However, it does not generate values to be used for the concept design ranking.

The percentages depicted in the figure represent the weighting factors that have been agreed among WP2 members and Evaluation Committee to ponderate the results coming from the different modules and to obtain the final ranking. More information regarding the weighting factors that are applied can be found in D2.5.

3.3 Data collection questionnaire

FOWAT performs its calculations using specific data regarding each design and site. In order to simplify the data collection, a specific data collection questionnaire has been prepared and distributed among all concept designers.

The data collection questionnaire includes all the input data that is required to perfom LCOE and LCA calculations. The data varies from concept to concept since it is design dependent. For this purpose, the questionnaire includes different sheets to collect information regarding the costs and LCA associated to each life stage. The last sheet of the questionnaire includes information that will be used for the KPI assessment. Questionnaires have been distributed among the concept developers who were asked to complete them for each site and for 1,5 and 50 turbines wind farm size.

The multi-criteria evaluation will be carried out considering the 50 turbines wind farm size for the 3 pre-defined sites. The 1 and 5turbines wind farm sizes will be used supportively for assessing the path to commercialization of the designs. However, they are not included in the multi-criteria ranking of the designs.

The information collected in the questionnaires will be treated as confidential and only visible to the Evaluation Committee members.

4 LCOE calculation approach

4.1 Methodology

The levelized cost of energy (LCOE) calculation is a method used to obtain the cost of one unit energy produced and is typically applied to compare the cost competitiveness of different power generation technologies. The LCOE value is generally in the local currency and a chosen unit of energy. In this project, the unit chosen is €/MWh. The LCOE model sets in relation the life cycle cost (LCC) to the total energy provided as shown below [6].

$$\mathrm{LCOE} = \frac{\text{Life cycle cost}}{\text{Electrical energy provided}} = \frac{C_0 + \sum_{\mathrm{t}=1}^{\mathrm{n}} \frac{\mathrm{O\&M_t}}{(1+r)^t} + \frac{\mathrm{D_n}}{(1+r)^n}}{\sum_{\mathrm{t}=1}^{\mathrm{n}} \frac{\mathrm{E_t} - \mathrm{L_t}}{(1+r)^t}} \tag{2}$$

The life cycle cost (LCC) includes all costs occurring in the lifetime of the FOWPP such as the capital cost (C_0) for the initial investment in the power plant, the cost during the operation and the maintenance phase ($O\&M_t$) as well as the decommissioning cost (D_n) at the end of lifetime. The energy provided refers to total energy generated (E_t) during the lifetime minus the energy losses (L_t) that occur in generation, collection and transmission of the energy [7]. Since the costs occur in different years (t) they have to be discounted to their present value. The discounting of cash flows is based on the concept that money has different values in time. For instance, money received at beginning of a project has a higher value than money that will be received in the future. Therefore, it has to be discounted to its present value by a discount rate (r) as shown below [8]

$$\text{Present value} = \frac{Cash\ flow}{(1+r)^t} \tag{3}$$

The discount rate has a large influence on the LCOE and should represent the market value of equity and debt. Furthermore, project risk and return yield should be considered. The rate is, therefore, also known as weighted average cost of capital (WACC) [8]. For this project, the value chosen for WACC is 10% and it will be subjected to uncertainty analysis as described in section 4.6. [9].

The LCOE equation contains in the denominator an energy term that is discounted. This is the result of the algebraic solution of the equation and is not an indication of the physical performance of the system [6].The LCOE model is used in project as method for an economic evaluation of a FOWPP, because it is a common measure to compare the cost of energy across technologies. It represents the minimum price of energy required for a project to become profitable since the LCOE represents the total cost of the power plant per energy generation [10].

In the following sections the methodology considered to calculate energy production, losses and life cycle costs is presented.

4.2 General assumptions

For the economic assessment, the following parameters have been considered and applied as common parametres for all the concept designs and sites (Table 1 and Table 2).

Table 1. Economic general parametres

Parametre	Value
Wind Farm operation time	25 years
Discount rate	10%
Baseline year for currency conversion	2015

All costs will be expressed in Euros. In case that different currencies are used, it has been decided that the 2015 average currency conversion rates will be applied for the most probable currencies that might be used in the project, extracted from the European Central Bank website [11].

Table 2. Currency rates

Currency conversion rates[12]	EUR	USD	GBP	Chinese Yuan	NOK	Indian Rupee
Average 2015	1	1,1095	0,72584	6,9733	8,9496	71,1956

4.3 Life cycle costing of floating wind farms

Life cycle costs (LCC) is the second factor in the LCOE calculation apart from the energy production. LCC contain all costs occurring in the lifetime of the FOWPP such as the capital expenses (CAPEX), the operation and the maintenance expenses (OPEX) as well as the decommissioning expenses (DECEX) see Figure 5.

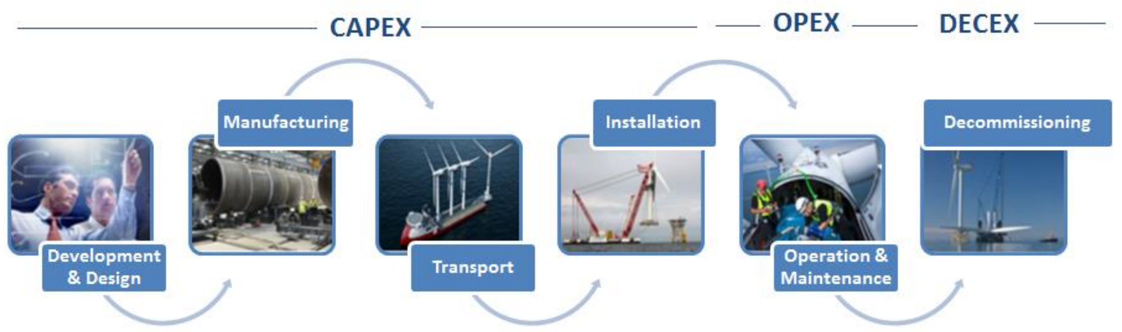

Figure 5: Life cycle cost of a FOWPP, adapted from [8]

CAPEX includes the costs related to development, manufacturing, transportation and installation of the FOWPP. These costs are also defined as investment costs since they occur at the beginning of the project before the wind farm starts to generate energy. OPEX contains the costs related to operation and maintenance activities during the lifetime of the project.

Finally, at the end of the lifetime, the FOWPP needs to be decommissioned and disassembled. The costs related to those activities are called decommissioning expenses [13] The total life cycle costs are obtained as the sum of all components.

Life cycle cost:

$$LCC = TC_{D+D} + TC_{M+A} + TC_{Transp} + TC_{Ins} + TC_{O+M} + TC_{Dec} \qquad (4)$$

Where, TC_{D+D} is the total costs for development and design, TC_{M+A} the total cost for manufacturing and acquisition, TC_{Transp} the total costs associated to transportation, TC_{Ins} the total cost occurring during the installation phase, TC_{O+M} represents the total cost for operation and maintenance and TC_{Dec} is the total cost decommissioning. In the following sections the methodology for calculating the cost of each life cycle phase is presented.

4.3.1 Development and Design

The development and design phase includes all activities related to the initial development and design of the FOWPP up to the point at which the official orders for production and purchasing are made[14]. This first phase is highly important for the projects outcome since a well-planned design and schedule will enable a construction on time and with low added costs. However, an unfavourable feasibility study could also bring a project to an early stop. A list of typical activities and studies that are performed during the first life cycle stage are presented next. The list is not exhaustive since the studies that are performed depend on the project and each project is different (Table 3).

Table 3. Development and design aspects included

Development	Environmental impact study	Assesses any environmental impacts of the wind farm on animals and environment in the sea and air
	Coastal process study	Evaluates the impact of the wind farm on sedimentation and erosion of the coastline
	Metereological and metocean campaign	Measure and analyse metereological and metocean conditions
	Geophysical and geotechnical campaign	Analyse sea bed conditions at site
	Human impact study	Impact on community living near the site including visual, noise and socio-economic assessment
	Project development and management	Feasibility study, market study, quality control, quality assurance, risk assessment, licensing, management, legal issues

Design	Front end engineering design	Concept development in advance and evaluation of technical uncertainties
	Detailed engineering	Definition of the design
	Certification cost	Cost of certifying the concept

The total costs of design and development are affected by the number of turbines included in the FOWPP. Generally, the more turbines are considered, the higher is the total cost. Since no large FOWPP has been constructed so far, no information is available regarding the development and design costs. It is expected that the cost for engineering and met-ocean studies will be higher for FOWPP due to the immaturity of the technology and the application in deep waters. In order to include the development and design costs in the LCC calculation the cost for a bottom fixed wind farm is considered. The following table contains reference costs in percentage of total capital cost for the development and design (D&D) of a 500 MW bottom fixed offshore wind farm that were found in literature.

Table 4: Development and design cost in percentage, based on 1: [14] **2:** [15] **3:** [9] **4:** [6] **5:** [16] **6:**[15]

Reference	Crown Estate[1]	Scottish Enterprise[2]	Howard[3]	NREL[4]	EWEA[5]	Garrad Hassan[6]
500 MW D&D cost (%)	4	6.5	5.8	4.6	9.5	4

The average of the considered reference costs percentages is 5.7%. This value is used in the life cycle cost calculation as a common base case for each design.

4.3.2 Manufacturing and acquisition

In this section the methodology for calculating the costs related to the manufacturing or acquisition of the individual components of the FOWPP is presented. The focus is in this project on the manufacturing of the floating substructure (including station keeping system). Therefore, the wind turbines and the electrical infrastructure are considered to be purchased. The total manufacturing and acquisition costs can be obtained as shown below.

Manufacturing and acquisition:

$$TC_{M+A} = TC_T + TC_{FS} + TC_{ML} + TC_A + TC_{Sub} + TC_{Cable} \quad (5)$$

Where, TC_T is the total manufacturing costs for the turbines, TC_{FS} is the total cost for the floating substructures, TC_{ML} is the acquisition cost for the mooring lines, TC_A the acquisition costs occurred by the anchors, TC_{Sub} the total substation costs and TC_{Cable} the total acquisition cost for the power cables. The calculation for each component is presented next.

4.3.2.1 Wind turbine and tower

In contrast to onshore wind power plants, where turbines generally represent the major cost component with up to 70% of the CAPEX, for offshore wind power plants the costs are relatively evenly distributed between turbines, balance of plant and transportation and installation. Figure 6 shows a typical cost breakdown of the capital expenses for a bottom fixed offshore wind power plant (BFOWPP). The reason for this is that the construction of a wind power plant offshore is more complex and requires costly vessels for the transportation and installation. Furthermore, the balance of plant is significantly higher offshore, since different technologies are used such as offshore substations, submarine cables and offshore foundations. However, a more equally distributed CAPEX does not mean a lower price for the turbines, quite the contrary: offshore wind turbines have higher capital cost. A typical cost breakdown of an offshore wind turbine is shown in Figure 7 taken from [13].

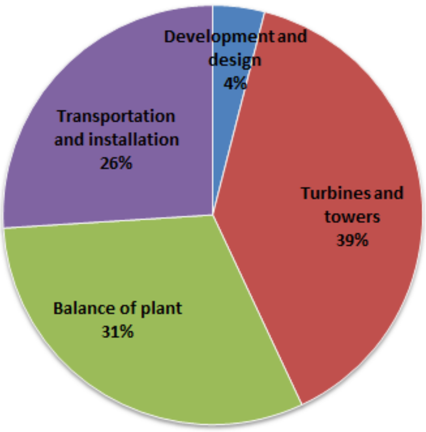

Figure 6: CAPEX breakdown BFOWPP

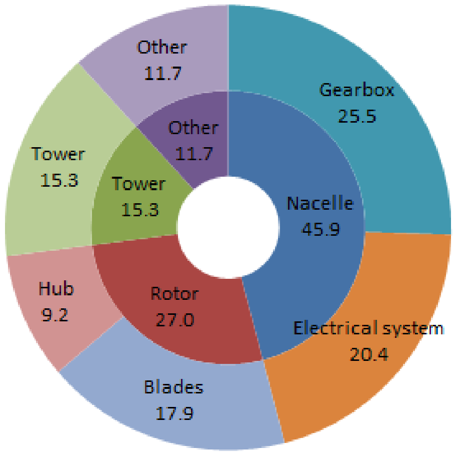

Figure 7: Wind turbine cost breakdown

Floating offshore wind has the potential to lower the high costs involved in offshore wind power projects by a reduced need for heavy-lift vessels offshore and lower CAPEX costs.

For this specific project, a 10 MW turbine has been considered and a common cost for all concept designs of 1.3M€/MW for this component has been taken into account. This cost will be subjected to uncertainty analysis as explained in section 4.6.

4.3.2.2 Floating substructure

Floating substructures are considered in this project for carrying the wind turbines but not for the substation since the LCOE calculation should only reflect the cost variation with floating turbines. The total manufacturing cost of the floating substructures is obtained as shown next.

Total substructure cost: $$TC_{FS} = N_T * (C_{FS} + C_{LO}) + C_{Area} \quad (6)$$

Where, N_T represents the number of turbines installed, C_{FS} is the manufacturing cost of a single floating substructure, C_{LO} the load-out cost and C_{Area} the lease for the manufacturing area. The manufacturing costs consist of labor cost, material cost and overhead cost. Labor and material costs are also known as direct costs since they are directly related to the manufacturing process, whereas overhead costs occur apart from the production but are indirectly related to the product [7].

Single substructure cost: $$C_{FS} = TC_{LC} + TC_{MC} + TC_{OC} \quad (7)$$

Where, TC_{LC} stands for the total labor cost, TC_{MC} is the total material cost and TC_{OC} the total overhead cost. A single substructure consists of several (n) components that have to be manufactured such as different columns, pontoons, transition pieces, etc. The composition and amount of components depend on the individual floating substructure concept. Thus, the total labor cost for a single substructure is obtained by the sum of labor costs for each of the components of a substructure.

Total labor cost: $$TC_{LC} = \sum_{i=1}^{n} t_{FSi} * c_{LCi} \quad (8)$$

Where, t_{FS} represents the manufacturing time in hours (h) and c_{LC} the hourly labor cost in (€/h). The total material costs are the sum of material costs for each of the components of a substructure and is obtained as shown in Equation 46.

Total material cost: $$TC_{MC} = \sum_{i=1}^{n} \sum_{j=1}^{m} m_{ij} * c_{ij} \quad (9)$$

The material cost of a single component is obtained by the sum of the different materials (m) used in processing the component. Where, m is the mass of the material in (t) and c is the cost of the material in (€/t). In this equation the cost of the material is calculated for each of the processing phases such as preparation, creation, painting and finishing. The total material cost will be then calculated considering the sum of all the components (n).

In this project for the sake of simplicity the designers are asked to provide final costs for each component of the floating substructure that include the material cost and the labour cost. The reason is that the manufacturing processes and the materiales applied could vary largely between concepts.

Overhead costs are not directly related to the manufacturing process but are necessary to run the business activity. A non-exhaustive list of overhead costs is presented in Table 5.

Table 5: Overhead cost contributors

Overhead cost contributors					
Labor cost administration	Labor cost technicians	Labor cost maintenance	Labor cost warehouse	Office materials	Other materials
Utilities	Rent	Amortization	Depreciation	Rent	Legal expanses

The cost of manufacturing overhead must be assigned to the manufacturing cost in order to accurately calculate the unit cost of a substructure. Two methods exist to calculate the overhead cost. In the first method each of the cost contributors are calculated separately and divided by the amount of substructures produced in the considered time. The second method applies a percentage for the overhead cost and a typical value is about 27 % of the total manufacturing cost [7]. In this project the second method is applied and concept developers are required to provide the value for the overhead cost. The manufacturing process of a floating substructure is most similar to the one of a ship. The construction is carried out typically near or in the harbor area in order to use existing facilities and equipment. An exemplary manufacturing process with an illustration of the manufacturing area is shown in Figure 8.

Figure 8: Manufacturing area and process, adapted from [17]

Each number in the figure represents a manufacturing process and the location where it is carried out. The manufacturing process of a floating substructure is explained next.

At first the construction is planned, which includes design, procurement and arrangement of facilities and materials. This is carried out in the office building represented by number 1 in the figure. The second step involves the pre-treatment of the materials and manufacturing of small parts of the floating substructure, which is carried out in a manufacturing hall. Afterwards, the pre-treated components are cut according to the drawings (3). The area (4) is used for assembling the cut and processed components of the floating substructure. In building number (5) the components are outfitted with the required equipment and forwarded to the next hall for the coating process. The erection and final assembly is carried out in area numbered (7) with the help of gantry cranes. The load-out of the substructure to the water is performed afterwards in step (8). The load-out can be simplified by assembling the substructure in a dry dock and flooding it afterwards. Alternatively, a building slip can be used, which is an inclined structure on which the floater is first built and then used to move into the water. In the production step (9) the floating substructure is tested in the water regarding its sea performance and the compliance with requirements. The last step (10) is the delivery. In case the assembly of the wind turbine to the substructure is performed at the same location where the floating substructure is being built no delivery has to be considered. Otherwise transportation has to be included to the site where the final assembly is performed.

The load-out of the floating substructure on the sea bed by the quay or in a dry dock can be performed with lifting means such as port cranes or crane barges. The associated cost C_{LO} can be calculated as shown next.

Shipyard cost:

$$C_{LO} = C_{means} * t_{means} * N_{means} \tag{10}$$

Where, C_{means} represents the day rate of the crane, barge or vessel used in (€/d), t_{means} is the time period in (d) and N_{means} the amount of machines used.

The lease for the manufacturing area can be calculated as shown next.

Lease area:

$$C_{Area} = C_{lease} * t_{lease} * A_{substr} \tag{11}$$

Where, C_{lease} represents the lease rate of the area in (€/d/m^2), t_{lease} is the leasing time in (d) and A_{substr} the area required for the manufacturing of the floating substructures. It is worth to mention that the manufacturing area should include all area required such as support buildings, workshops, offices, etc,..

In any case, concept designers will be asked to elaborate the data provided to account for these costs differentiating whether the manufacturing is carried out in a factory or at the harbour.

4.3.2.3 Station keeping system (mooring line, excluding anchor)

The price of the mooring lines depends on the type and material as well as the number of mooring lines used.

Total cost mooring lines:

$$TC_{ML} = C_{ML} * N_T * N_{LS} \tag{12}$$

C_{ML} is the cost of a single mooring line, N_{LS} is the number of mooring lines per floating substructure and N_T is the number of turbines to be installed. The cost of a single mooring line depends on the weight of the line and can be calculated as shown next.

Single mooring line: $$C_{ML} = C_m * l_{ML} * m_{ML} \qquad (13)$$

Where, C_m is the cost of the mooring line in (€/kg), l_{ML} is the length in (m) and m_{ML} is the mass of the mooring line in (kg/m). Depending on the material and desired length the cost of the total mooring lines will change. Commonly used are steel chains, steel fiber wires or synthetic fiber rope. The last named is the most expensive type of material, but it is lighter [7].

4.3.2.4 Anchor

It is assumed that each mooring line is fixed with an individual anchor in the sea bed. Thus, the total cost for anchors is obtained by the considering the cost of a single anchor C_A, the number of mooring lines per floating substructure and the number of turbines to be installed N_T.

Total anchor cost: $$TC_A = C_A * N_T * N_{LS} \qquad (14)$$

Depending on the type of anchor the unit price will vary. To simplify, only unit price will be considered for simplification.

4.3.2.5 Substation

The total substation cost includes the offshore and onshore substations. In case, an onshore substation already exists and is, therefore, not required to be constructed, the cost is set to zero.

Total substation cost: $$TC_{Sub} = C_{TS} * N_{TS} + +C_{OS} \qquad (15)$$

C_{TS} is the total cost of a single transformer substation, N_{TS} is the number of transformer substations (here N_{TS}= 1) considered and C_{OS} represents the cost of the onshore substation. The cost of a single transformer substation includes the platform, the transformer itself, switchgears as well as other equipment such as protection devices and shut capacitors. [8].

4.3.2.6 Power cable

Different power cables are used in the FOWPP such as dynamic and static inter-array cables as well as export cables. Different cable sections are used according to the power to be transmitted. Thus, the total cable cost includes the sum of each cable cost.

Total cable cost:

$$TC_{Cable} = \sum_{i=1}^{n} C_{PC} * l_{PC} * N_{PC} \qquad (16)$$

C_{PC} is the cost of a single cable in (€/m), l_{PC} the length in (m) and N_{PC} the number of this cable used.

4.3.3 Transportation

In this section only the transportation concerning to the construction of the FOWPP is considered since it belongs to the CAPEX. The transportation activities involved in the operation and maintenance as well as the decommissioning of the FOWPP are included in the respective calculations. Transportation costs regarding raw materials and components to the manufacturing site are included when providing the costs of theses elements in the manufacturing stage. Figure 9 shows the transportation possibilities included in this section.

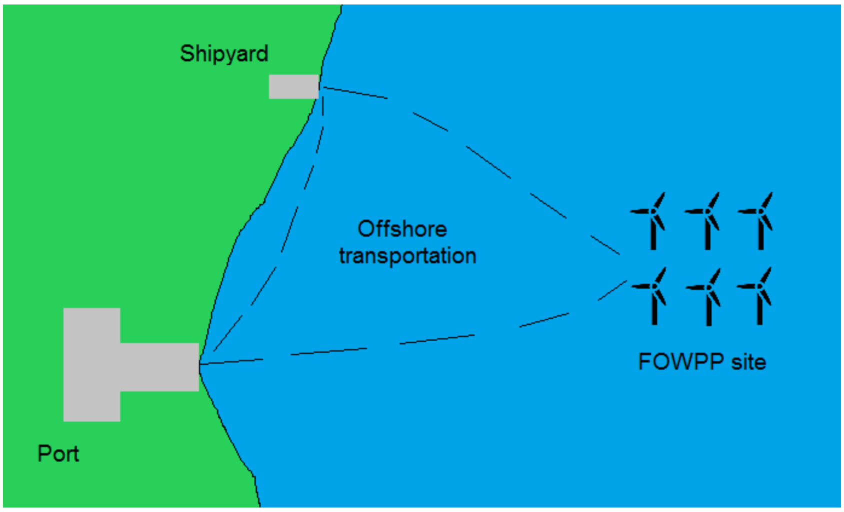

Figure 9: Transportation possibilities

Transportation is considered between three locations, the shipyard, the port and the FOWPP site. The shipyard is the location where the floating substructure is being manufactured, the port is the location where the pre-assembly takes place and the FOWPP site is the actual offshore installation site. It is assumed that all components that have been purchased such as turbines and electrical machines are located in the port. No transportation is considered for delivering the components from the manufacturers' site to the port since this cost is already included in the purchasing price.

The substructure can be transported either from the shipyard to the port, where it will be assembled to the turbine or directly transported to the wind farm site. In case the floating substructure is manufactured in the port no transportation from the shipyard will be considered.

The total transportation cost consists of the offshore transportation cost C_{Off} as well as associated activities in the port C_{Port}.

Total transportation cost: $$TC_{Transp} = C_{Off} + C_{Port} \tag{17}$$

The offshore transportation cost consists of the cost for the transportation from the shipyard to the port and to the FOWPP site as well as the transportation from the port to the offshore site.

Offshore cost: $$C_{off} = N_{TV} * C_{TV} * t_{SY-Port} + N_{TV} * C_{TV} * t_{SY-FOWPP} + N_{TV} * C_{TV} * t_{Port-FOWPP} \tag{18}$$

Where, C_{TV} is the day rate of a transport vessel in (€/d), N_{TV} the number of vessels used, $t_{SY-Port}$ is the time period in (d) that the vessel is used for the transportation between shipyard and port, $t_{SY-FOWPP}$ the time period for the transportation between shipyard and FOWPP site and $t_{Port-FOWPP}$ the time period for the transportation between port and FOWPP site.

The costs related to port activities are based on crane and auxiliary means utilization as well as the rental of storage area that is required during the loading of the vessels. A rental time and usage time is considered. No weather windows are considered.

Port cost: $$C_{Port} = N_{crane} * C_{crane} * t_{crane} + N_{Aux} * C_{Aux} * t_{Aux} \\ A_{storage} * C_{Storage} * t_{storage} \tag{19}$$

C_{aux} represents the cost of a auxiliary mean in (€/d), N_{aux} the number of auxiliary means used and t_{aux} is the time period in (d) that it is used. $A_{storage}$ is the storage area in (m^2), $C_{Storage}$ stands for the rental cost in (€/m^2/d) and $t_{storage}$ for the storage time in (d).

This cost differs from port costs added under manufacting when floating substructure is not manufactured in the same port where assembly with turbine is realized or additional equipment vessels are used for load out.

The cost of the transportation vessels depends on several factors, such as the kind of vessel used, availability and contract length. Vessel day rates are high volatile and can change from day to day, by season and also with the region [18]. The cost of a vessel includes also mobilization and demobilization as well as fuel consumption and it is defined by each concept designer. In the transportation phase vessels are used typically for the transportation of cargo and personnel or tugging operations. These vessels are generally smaller and cheaper than installation vessels. Figure 10 shows examples of vessels that are used in the transportation phase.

Figure 10: Vessels used in the transportation phase (Principle Power, 2015) (Ugland Companies, s.f.) (Shipping and Marine, 2016)

The first picture shows a floating turbine towed by a tugboat on the sea. The second picture shows a heavy lift crane vessel operating in the port and the third picture displays a supply vessel transferring wind turbine blades to the offshore site.

The methodology presented in this section for the calculation of the transportation cost is applied for each component of the FOWPP such as floating substructures, wind turbines, power cables and offshore substation.

4.3.4 Installation

The total installation cost consists of the individual cost for the installation of the offshore turbine with floating substructure C_{T+FS}, the anchor and mooring system C_{A+M}, the electrical system C_{ES}as well as the final commissioning C_{Com} and required insurance C_{Ins}.

Total installation cost:

$$TC_{Ins} = C_{T+FS} + C_{A+M} + C_{ES} + C_{Com} + C_{Ins} \qquad (20)$$

Mobilisation and demobilization costs are included in the vessels rates, while, for simplication, costs derived by the application of wheather windows are not included

The calculation of the cost components is presented next.

4.3.4.1 Floating substructure with turbine

The installation process is closely related to the transportation since the activities to be included depend on the strategy pursued. Figure 11 displays four different transportation and installation strategies that are considered for the floating turbine.

Figure 11: Transportation and Installation Strategies, adapted form[7]

The first strategy considers that the floating substructure and turbine are completely assembled and joined together onshore in the port or shipyard, where the construction was carried out. The floating turbine is then towed out to sea by a tugboat and taken to the offshore site where the installation takes place. Since the floating turbine is already assembled only an anchor handling tug vessel is required to perform the final installation, which includes mooring lying and anchor setting [3]. This strategy is commonly applied for semi-submersible platforms, which has a good stability without moorings and are capable to be transported afloat. Costs and risk associated to offshore installations are therefore reduced. However, ballast and mooring line stabilized substructures are not inherently stable, thus different means of transportation have to be used. Iberdrola has developed for its TLP design a unique u-shaped semisubmersible barge, which can be used to transport a wind turbine installed on top of the Iberdrola TLPWIND floating substructure. According to Iberdrola this would simplify offshore operations, reduce overall risks and costs [19].

The second strategy considers that the turbine and the substructure are transported separately and assembled offshore. The turbine is transported on a jack-up vessel and the floating substructure is towed by a tugboat. If the turbine itself is assembled before transportation onshore or if the complete assembly is realized offshore depends on the availability of suitable vessels. In the port the pre-assembly of the components is performed, as well as the loading of the transportation vessel. Furthermore, the floating substructure is launched to sea. Offshore the assembly and final installation of the turbine and floating substructure are performed with the help of an installation vessel that is equipped with a crane for lifting heavy weights The third strategy is similar to the second with the only difference that the floating substructure is not towed in the water to the offshore site but transported on the deck of a jack-up vessel or barge. If turbine and substructure can be transported on the same vessel depends on the size and availability of the vessels. Strategy four considers that turbine and floating substructure are transported and installed by the same crane vessel with a large storage capacity. This would decrease the amount of tugboats and transportation vessels needed. However, crane vessels with large storage capacity are scarce and more expensive

The four strategies do not cover all possible options of transporting and installing a floating substructure with wind turbine, but they show clearly the relation between both life cycle phases and that in some cases one vessel can be used to do both the transportation and installation and thus merging both phases. However, the calculations of both phases are kept separated in order to include all possible transport and installation options and present a clearer distribution of costs in the life cycle of a FOWPP. Most likely all concept developers in the Lifes50+ project are pursuing strategy 1 for the transportation and installation of the floating substructure.

Turbine and substructure installation cost:

$$C_{T+FS} = \sum_{i=1}^{m} C_{Inst} * N_{inst} * t_{ins} \qquad (21)$$

C_{Inst} is the day rate of an installation vessel in (€/d), N_{inst} the number of vessels used and t_{inst} is the time period in (d) the vessel is in operation. Different installation vessels might be used, thus all installation vessel costs are summed up.

The most common types of vessels used in the installation phase are jack-up vessels or barges. Jack-up vessels in contrast to barges are self-propelled and might possess a dynamic positioning system. Both are equipped with heavy cranes and newer models possess large storage capacities to reduce the need of additional transport vessels [18]. Figure 12 shows a jack-up vessel installing a wind turbine offshore. When installing a wind power plant, it is very time consuming and costly to transfer the crew daily to the offshore site. Accommodation vessels can, therefore, be used for constructions sites far offshore. These vessels function as floating hotels and provide accommodation for the personnel near to the construction site. Figure 13 shows an accommodation vessel and a smaller boat transferring the crew to the vessel. An accommodation vessel can provide the same services as an onshore hotel such as restaurant, fitness rooms and up to a cinema.

Figure 12: Jack-up vessel installing offshore [20]

Figure 13: Accommodation vessel[5]

4.3.4.2 Anchor and mooring system

An anchor handling vessel is usually used to install the anchor and mooring system. It is a powerful vessel that has a large deck area to carry the mooring line and anchors as well as an open stern to launch the anchor to the water. Figure 14 displays the vessel. It can additionally be used to tow the floating substructure from the port to the offshore location and thus combining the transportation of the floating substructure with the anchor handling operation, which reduces the cost of additional vessels. However, another method based on the experience from oil and gas business suggests pre-installing the mooring system and highlighting it with buoyancies for the later assembly to the floating substructure. This would reduce the installation time of the floating substructure offshore and avoid possible weather window limitations. The anchor handling vessel carries the anchor already connected to the mooring. At the offshore location the anchor with the connected mooring line are then launched into the water with the help of a powerful winch. The positioning of the anchor by the vessel is realized regarding the requirements of the individual anchor. The anchor positioning procedure is explained exemplary for the drag-embedded and suction anchor. The simplest method for the drag-embedded anchor is to lower the anchor to the seabed by using the mooring line. When the anchor reaches the ground, the vessel should move slowly forward to ensure a correct immersion of the anchor into the seabed. Attention has to be paid that the anchor does not turn around while sinking. Additionally, a chaser can be connected to the anchor for an optimal positioning of the anchor. Figure 15 displays the anchor laying procedure [21].

Figure 14: Anchor handling vessel

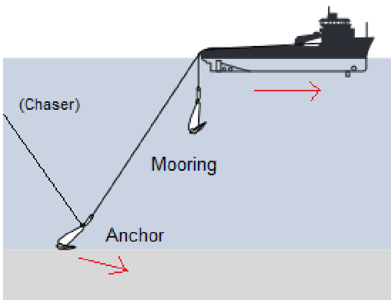

Figure 15: Drag-embedded anchor laying [21]

The setting of the suction pipe anchor is more complex. A pump connected to the top of the pipe creates a pressure difference, which forces the suction anchor into the seabed. Afterwards, the pump is removed and the anchor is hold in its final position (CLP, s.f.). Figure 16 shows the installation of a suction pipe anchor.

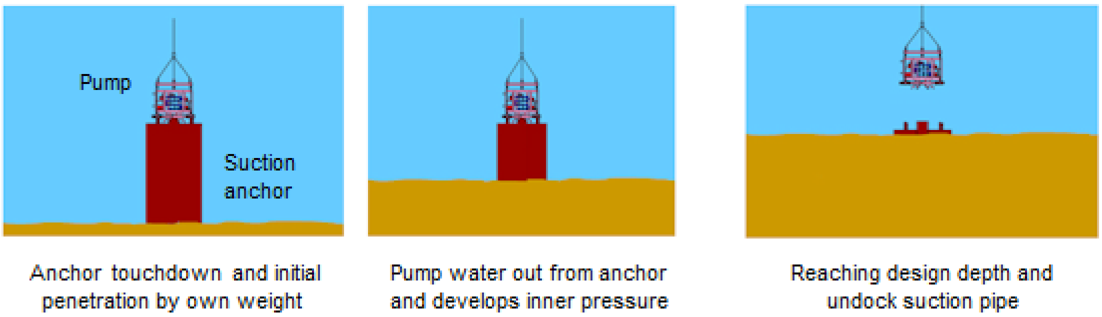

Figure 16: Section pipe anchor installation (CLP, s.f.)

For this type of installation a remotely operated underwater vehicle (ROV) is often additionally be used for monitoring the installation process [8]. In some cases also divers are required and the associated costs have to be considered in the total installation costs.

Anchor and mooring installation cost:

$$C_{A+M} = C_{Inst} * N_{inst} * t_{ins} + C_{ROV} * t_{ROV} + C_{Diver} * t_{Diver} \quad (22)$$

C_{Inst} is the day rate of an installation vessel in (€/d), which is usually the anchor handling vessel, N_{inst} the number of vessel used and t_{inst} is the time period in (d) the vessel is in operation. C_{ROV} is the day rate of a ROV in (€/d) and t_{ROV} the time of usage. C_{Diver} represents the labor cost of a diver in (€/d) and t_{Diver} the working time in (d).

4.3.4.3 Electrical system

The electrical system is referred to the inter-array cables installed in the collection grid, the export cables and the substations. The total cost for the installation of the electrical system is calculated as shown next.

Electrical system installation cost:

$$C_{ES} = C_{IPC} + C_{IOffs} + C_{IOnS} \quad (23)$$

Where, C_{IPC} is the installation cost of the power cables, C_{IOffs} the installation cost of the offshore substation and C_{IOnS} the respective cost for the onshore substation. In case the construction of the onshore substation is realized by a third party or already exists then the cost is set to zero.

The installation of the power cables is realized by the use of a cable laying vessel. Those vessels contain on-deck carousels for storing the cable, cable guiding sheaves as well as remotely operated vehicles for trenching activities. Modern vessels also possess dynamic positioning devices to keep steady position under harsh weather conditions.

Figure 17: Cable laying vessel [22]

The equation to calculate the installation costs of the power cables is shown next.

Power cable installation:

$$C_{IPC} = \sum_{i=1}^{n} C_{IV} * t_{PC} * N_{PC} \quad (24)$$

C_{IV} represents the day rate of the installation vessel in (€/d), t_{PC} the time period of vessel rental (d) and N_{PC} the number of vessels used for power cable installation. Since different power cables exist, for instance dynamic and static inter-array cables as well as export cables, the sum of all associated installation costs is considered.

The substation consists typically of the foundation structure and the topside structure. The foundation structure might be a jacket or monopile substructure or a floating substructure depending on its application. In this project only the bottom fixed substructure is considered for the offshore substation. The topside includes all electrical equipment and components.

Both structures are fully assembled onshore and transported separately to the site, where the topside is mounted on the foundation structure. The submarine cables are then connected to the substation and final commissioning completed. The installation process requires large and expensive crane vessels. Figure 18 displays the installation of an offshore substation with a heavy crane vessel.

Figure 18: Offshore substation installation with crane vessel

The following equation is used to calculate the offshore substation installation cost.

Offshore substation: $$C_{IOffS} = C_{InstOS} * N_{instOS} * t_{insOS} \qquad (25)$$

C_{InstOS} is the day rate of the vessel that performs the installation of the substation in (€/d), t_{insOS} represents the time in (d) required for installing one offshore substation and N_{instOS} is the number of substations that will be installed.

The installation cost of the onshore substation can be calculated as shown next:

Onshore substation: $$C_{IOnS} = C_{Prep} + C_{Cement} + C_{Instal} \qquad (26)$$

Where, C_{Prep} is the preparation cost of the area, C_{Cement} represents cementation cost for the building and C_{Instal} includes the total cost for installation with cranes

4.3.4.4 Commissioning

Commissioning contains the activities performed after all components of the FOWPP are installed. This can include electrical tests of the turbine and substation as well as inspections of the civil works. A comprehensive testing is essential in order to deliver a full functioning plant and satisfy the customer. The commissioning may take up to several days. After the commissioning the FOWPP is handed over to the operator, who will be responsible for the operation and maintenance of the FOWPP

For the installation cost calculation a constant value C_{Com} in (€) is considered. This includes also the fee for the grid connection, which varies between countries.

4.3.4.5 Insurance and Contingency

The construction and operation of an offshore wind farm is a complex and capital-intensive endeavour that involves risks and uncertainties. A careful planning of each life cycle stage is highly important to avoid delays in the construction of the wind farm. However, not everything can be planned and some events are unavoidable. Thus, insurances are important to provide financial protection from cost overruns. They are most commonly applied in the construction and operation phase, where delays or failures can result in high costs. The construction insurance provides financial protection against delays and damage in the assembly, transport and installation phase of the FOWPP. A common construction insurance policy has a cost of 50,000 € per MW. Insurances are highly important to potential investors since they take the risk of cost overruns, which would otherwise negatively affect the cash flow.

A contingency could be applied to cover uncertainties that are not covered by insurance or other guarantees. The contingency is defined as percentage addition to the CAPEX and is generally about 10 % of the total CAPEX costs [8]. However, since contingencies are used for unforeseen events the value may decrease with more development experience and learning curve effects. The contingency is usually added in order to stay within the planned budget. It is, therefore, rather a parameter for financial planning than a component of the LCOE, since it does not represent a real cost [8]. For this reason it will not be considered in the LCOE calculation.

4.3.5 Operation and Maintenance

The operation and maintenance begins after the commissioning of the FOWPP. The costs associated to this phase include fixed costs that occur annually for operating the FOWPP as well as costs related to maintenance activities. In this section at first the operational costs are outlined and afterwards the maintenance of the plant explained.

The total operation and maintenance costs can be obtained as shown below.

Operation and maintenance cost:

$$TC_{O+M} = C_O * t_{lifetime} + C_M \quad (27)$$

Where, C_O is the annual operation cost in (€/year), $t_{lifetime}$ the lifetime in (years) and C_M represents the total maintenance cost in (€).

4.3.5.1 Operation

The operation costs refer to expenses occurring by monitoring, sales and administration activities during the defined 25 years lifetime of the FOWPP. These costs represent normally a smaller part of the total O&M costs [15]. A table of possible cost components is presented below (Table 6).

Table 6: Operation cost components [6]

Operation cost components					
Insurance	Transmission charge	Offshore land lease	Onshore land lease	General management	Monitoring
Generation planning	Operating facilities	Sales expenses	Turbine consumption	Marine Management	Weather forecasting

Table 6 represents an exemplary list of operation cost components. In practice it depends on the individual project, which services and activities are required to operate the FOWPP. The operation phase insurance is an important part since it covers costs occurring from failures of the components that cause a loss of power production such as turbines and substations. It does not cover the actual repair of the components since this belongs to maintenance cost, rather it covers the financial claims due to the contract that arise from a power loss. The policy has a typical cost of 15,000 to 20,000 € per MW per year.

Further costs that might occur in the operation phase include leases for land and buildings onshore, for instance workshops and storage areas in the port and offshore land lease. Furthermore, expenses typically occur for sales activities, general management and monitoring of the FOWPP. Charges can also occur for power consumption of the turbines and substation during the operation and services for monitoring of met-ocean conditions..

For the operation cost a constant annual value C_O in (€) is considered in this project, that covers the activities and services required for operating a FOWPP.

4.3.5.2 Maintenance

The objective of maintenance is to ensure a high availability of the FOWPP and reduce downtimes. It includes preventive and corrective maintenance.

Preventive maintenance includes all activities that aim to avoid the failure of a machine or component. This includes minor and major maintenance activities. Minor activities such as inspections and replacements of wear parts or lubricants are routinely performed at the offshore site. Major maintenance, on the other hand, involves the replacement of larger components, which are performed either offshore or in port. An accurate planning of the maintenance activities is crucial to limit maintenance cost and prevent breakdowns of the machines. Thus, a maintenance plan is prepared that schedules the maintenance activities. Minor maintenance is performed routinely, whereas major activities are scheduled on a yearly, three or five year basis [23]. The maintenance plan has to consider all components of the FOWPP including mooring system, substructure, turbine, power cables and substations. It is expected that for the floating turbine system the turbine will require a more frequent maintenance for its mechanical-electrical components compared to the fixed substructure, which consists mainly of structural components and a balance system..

Corrective maintenance responds to the failure of a component of the FOWPP. In contrast to preventive maintenance, corrective maintenance is carried out after a failure has happened and includes the repair or replacement of the components. The corrective maintenance can be scheduled even when the failure was unplanned. For example, in case a single component fails that has only a low impact on the overall performance of the FOWPP, its repair can be coordinated with a scheduled maintenance activity or postponed until a larger component fails.

The maintenance of an offshore wind power plant is much more complex than onshore, because of the harsh offshore conditions. A FOWPP adds another level of difficulty to it due to the motion of the floating substructure. Thus, the maintenance activity requires a careful planning.

The vessels that are used for maintenance activities have a large influence on the maintenance costs based on the volatile charter rates, which are related to the market dynamics. For minor maintenance activities smaller vessel can be used such as crew transfer and supply vessels. Accommodation vessels might also be used when maintenance takes several days or the site is far offshore.

Helicopters might also be used in the operation and maintenance phase for transporting technicians to the offshore site. Technicians can be transported and winched down directly to the nacelle of the turbine or substation. Helicopters have the advantage of transporting crew rapidly to the site over long distances and being less effected by wave heights. However, helicopters possess a small transport capacity, involve high charter rates and their operation is restricted by visibility due to clouds. Besides that, the application to a floating turbine has not been tested yet.

Maintenance strategy refers to how major maintenances activities are performed such as the replacement of large components. This might be done offshore with the use of heavy Jack-up vessels or in the port by towing back the whole floating substructure with cheaper tugboats. However, this depends on the capability of the floating substructure to be towed with the turbine mounted on top.

Besides that, it depends also on the mooring system and power cables to be designed for a quick disconnection and reinstallation without impacting the performance of nearby floating turbines [24].

The availability of ports is also important to consider in a maintenance plan, in particular, the distance from the port to the offshore site since it impacts the transportation time and cost. Suitable ports for offshore wind require generally a water depth of at least 10m, long quayside length and sufficient area for storage and assembly. The consideration of a suitable port is not only important in the operation and maintenance phase but has significance in all life cycle phases of the FOWPP.

The cost associated to maintenance activities can be calculated as shown next.

Maintenance cost: $$C_M = C_{MPr} + C_{MCor} \quad (28)$$

C_{MPr} represents the preventive maintenance and C_{MCor} the corrective maintenance cost. The preventive maintenance includes the scheduled maintenance activities, which cost can be calculated relatively precisely as shown next.

Preventive maintenance: $$C_{MPr} = (t_{MPr} * C_{\text{vehicle}} + C_{\text{Mat}} + C_{\text{diver}}) * N_{Main} \quad (29)$$

$C_{vehicle}$ is the day rate in (€/d) for the vehicle used for the maintenance, which can be a vessel or helicopter. t_{Mpr} represents the time in (d) required for the maintenance activity. C_{Mat} is the material cost, which depends on the type of maintenance. In case of minor maintenance the cost consists of the replacement of tear parts or lubricants. In case of major maintenance activities, where larger components are replaced the cost is associated to the new component in (€). When divers are required a cost C_{diver} is added consisting of personnel cost and duration. N_{Main} represents the number of maintenance activities carried out in the lifetime of the FOWPP. When the maintenance is performed in the port, then the cost associated to crane activities is added to the cost of vehicles.

Corrective maintenance responds to the breakdown of a component. The cost associated to the corrective maintenance activity can be estimated by considering the failure rate $P_{failure}$ of each component.

Corrective maintenance: $$C_{MCor} = P_{failure} * t_{lifetime} * \left(t_{Mpr} * C_{vehicle}\right) + C_{Mat} + C_{Diver} \quad (30)$$

For the corrective maintenance cost the same methodology is considered as for the preventive maintenance. The only difference is that for corrective maintenance the failure rate in (failures/year) of each component is included. It should be stated that the cost is considered the same every year throughout the life cycle.

The methodology for the preventive and corrective maintenance cost calculation is applied to each component (c) of the FOWPP such as the wind turbine, the floating turbines, the mooring and anchors as well as the power cables and substations. When maintenance of several components is realized with one transport vehicle and in a single shift then the cost related to the transportation is considered only once.

4.3.6 Decomissioning

The projected lifetime of a wind power plant can be extended by repowering of the turbines or a continuing operation. However, at a certain lifetime it will not be technical or economical feasible anymore to operate the wind power plant and a decommissioning is required. The owner of an offshore wind power plant is generally obligated to remove all structures that were built and clear the complete offshore site after the lifetime end. Typically, the developer is required to present a preliminary decommissioning plan already in the development phase to prove its ability for decommissioning and in some case financial securities. However, it also depends on national regulations and in some cases a decommissioning of all components might not be required when associated risks are too high or the impacts of remaining structures are not significant. No benchmarks are available for decommissioning cost since no large offshore wind power plants have been decommissioned so far.

Decommissioning can be considered as a reversed installation process and includes the disassembly of the FOWPP as well as the transportation back to the port. Besides that, the final treatment of the various components of the FOWPP is considered as well as the cleaning of the site.

4.3.6.1 Turbine and floating substructure

Floating substructures have the potential benefit of a simpler disassembly procedure in comparison to bottom fixed wind turbines and thus saving time and costs. While bottom-fixed substructures require special equipment and vessels in order to be removed, floating substructures have the advantage to be able to be towed back to shore by a simple tug vessel after disconnecting the mooring system. However, the procedure depends on the individual floating design and different strategies exist for disassembling the turbine and floating substructure.

The first strategy considers that the floating substructure is being towed back with keeping the turbine mounted on top. At first the substructure is disconnected from the mooring lines and then a tug vessels is used for the towing process. The disassembly of the turbine is performed in the port. This strategy saves costs for large vessels, decreases the risk associated to offshore operations and lowers the dependency on weather windows. However, not all floating substructure designs allow transportation with the assembled turbine.

The second strategy considers the disassembly offshore. It begins with the removal of all turbines. At first the power cables are disconnected from the turbine and then all lubricants and hazardous materials are removed. The turbine and the floating substructure are then transported separately to the port.

The costs resulting from the decommissioning of the wind turbine and floating substructure can be modeled as shown next.

Decommissioning turbine and floating substructure:

$$C_{Dec\,T+FS} = C_{dis} + C_{Off,Transp} + C_{port} \quad (31)$$

C_{dis} is the cost resulting from the disassembly of the turbine and floating substructure, $C_{Off,Transp}$ represents the offshore transportation cost and C_{port} includes the costs associated activities in the port such as unloading, handling, transporting and storing of components. In case the first decommissioning option is used where turbine and floating substructure are transported fully assembled and the disassembly takes place in the port, then the disassembly cost C_{dis} accounts for the dismantling performed in the port. The cost associated to the disassembly can be calculated as presented next.

Disassembly turbine and floating substructure:

$$C_{dis} = \sum_{i=1}^{m} C_{Dis,vess} * N_{Dis,vess} * t_{Dis,vess} \quad (32)$$

$C_{Dis,vess}$ is the day rate of the vessel used for the disassembly process in (€/d), $N_{Dis,vess}$ is the number of vessels used and $t_{Dis,vess}$ represents the time period in (d) the vessel is in operation. Different vessels might be used, thus all installation vessel costs are summed up.

The transportation cost of the disassembled components can be calculated as:

Offshore transport:

$$C_{Off,Transp} = \sum_{i=1}^{m} C_{Dec,transp} * N_{Dec,transp} * t_{Dec,transp} \quad (2)$$

Where, $C_{Dec,transp}$ represents the day rate of a transport vessel in (€/d),$N_{Dec,transp}$ the number of vessels used and $t_{Dec,transp}$ is the charter time of the vessel in (d).

The costs regarding port activities can be calculated as:

Port activities:

$$C_{port} = C_{veh,port} * N_{veh,port} * t_{veh,port} + C_{store} * A_{store} * t_{store} \quad (34)$$

$C_{veh,port}$ is the day rate of a vehicle used in the port such as a crane or transportation vehicle in (€/d), $N_{veh,port}$ is the number of machines used and $t_{veh,port}$ is time in (d) it is used. Since some components need to be stored for a while a storage area has to occupied and the associated day rate is C_{store} in (€/m^2/d). A_{store} is the required storage area in (m$^{2)}$ and t_{store} is the storage period in (d).

4.3.6.2 Anchor and mooring system

Since there is no information available regarding mooring and anchor system for floating wind projects, the decommissioning principles of the oil and gas industry are considered.

Anchor and mooring disassembly cost:

$$C_{Dec\ A+M} = C_{AHV} * N_{AHV} * t_{dec,A+M} + C_{ROV} * t_{ROV} + C_{Diver} * t_{Diver} \quad (35)$$

C_{AHV} represents the day rate of an anchor handling vessel in (€/d), N_{AHV} the number of vessel used and $t_{dec,A+M}$ the time period in (d) the vessel is in operation. C_{ROV} is the day rate of a ROV in (€/d) and t_{ROV} the time of usage. C_{Diver} represents the labor cost of a diver in (€/d) and t_{Diver} the working time in (d).

4.3.6.3 Power cables

The environmental impact of submarine power cables is not well known. Some studies state that the electromagnetic field generated by electric power transmission can disturb the behavior of marine species and the heat loss could increase locally the sea bottom temperature. However, these studies also state that the environmental impacts are generally limited close to the cable routes and are temporarily. The uncertainty about the environmental impact of submarine power cables caused the absence of clear regulation on the decommissioning part. It often depends on the specific case and circumstances wether a removal of the power cables is required or not. For instance, when power cables are located in trawling fishing areas or not deeply buried, it is more likely that the removal is desired. The cable removal process involves typically a cable laying vessel, a ROV and if needed a diver. First, the ROV recovers the submarine cable and attaches it to the winch of the vessel. Then, the cable is winded up by the engine of the winch until the entire cable is loaded on the vessel. The cable might be cut in pieces for easier transportation. The explained cable removal procedure is applied for both, the inter-array cables as well as the export cables. The associated costs can be calculated as shown next.

Power cable removal:
$$C_{Dec\ PC} = \sum_{i=1}^{n} C_{CV} * t_{PC} * N_{PC} \qquad (36)$$

C_{CV} is the day rate of the vessel in (€/d), t_{PC} the time the vessels is rented in (d), and N_{PC} the number of vessels used to remov the cables. Since different power cables exist, for instance dynamic and static inter-array cables as well as export cables, the sum of all associated removal costs is considered.

4.3.6.4 Substation

The offshore substation is likewise disassembled as it was installed. The topside is removed and transported separately to the port. In case the foundation is made of a fixed bottom substructure then it will be cut about 4 to 5 meters below the mudline, lifted up with a crane vessel and transported to the port. When the foundation consists of a floating substructure, then the same procedure is applied as for the floating turbine. The mooring system and topside have to be separated at first and then a tug boat can tow the floater to the port.

Onshore substation:
$$C_{Dec\ Off,Subs} = C_{Dis\ OS} * t_{Dis\ OS} * N_{Dis\ OS} \qquad (3)$$

$C_{Dis\ OS}$is the day rate of the vessel that performs the disassembly of the substation in (€/d), $t_{Dis\ OS}$ represents the time in (d) required for disassemble one offshore substation and $N_{Dis\ OS}$ is the number of offshore substations that will be removed. The decommissioning cost of the onshore substation can be calculated as shown next:

Onshore substation: $$C_{Dec,OnSub} = C_{Dem\ OnS} * t_{Dem\ OnS} * N_{Dem\ OnS} \quad (4)$$

$C_{Dem\ OnS}$ is the day rate of the crane and auxiliary means that perform the demolition of the onshore substation area in (€/d), $t_{Dem\ OnS}$ represents the time in (d) required and $N_{Dem\ OnS}$ is the number of cranes used. The total cost for the decommissioning of the substations is finally obtained by the sum of offshore and onshore substation decommissioning costs.

Onshore substation: $$C_{Dec,Sub} = C_{Dec,OnSub} + C_{Dec\ Off,Subs} \quad (39)$$

4.3.6.5 Site clearance

Site clearance is the last activity in the offshore decommissioning process. After all components of the FOWPP are disassembled and transported back to the port the offshore site has to be cleaned, which involves the removal of debris on the sea floor. Offshore regulations and lease terms require generally that the offshore site is left in a state similar to how it was found before. The total clearance cost includes the cleaning cost C_{clean} in (€/m^2) and the total area of the offshore construction site A_{site} in (m^2).

Site clearance: $$C_{Clear} = C_{clean} * A_{site} \quad (40)$$

4.3.6.6 Final treatment

The final treatment of the disassembled components of the FOWPP consists of reusing, selling or disposal. It is expected that the potential to reuse some of the components such as power cables, tower or machineries will be low due to the age of the components and likely high corrosion. Components that have a value such as steel structures can be sold at steel scrap prices to the market. However, the selling price has to consider that costs occur for cutting the steel component into saleable units as well as for potential transportation. The last option would be to simple dispose the components in a landfill. However, this method also involves costs for the transportation and the disposal. Some components could also be disposed in an incineration plant.

The cost of the final treatment can be calculated as shown next.

Final treatment: $$C_{FT} = C_{disposal} + C_{sell} \quad (5)$$

Where, $C_{disposal}$ represents the disposal costs and C_{sell} the selling costs.

Disposal cost: $$C_{disposal} = C_{disp} * m_{disp} + C_{veh,dis} * t_{veh,dis} * N_{veh,dis} \qquad (6)$$

The disposal cost consists of the cost demanded by the landfill and the transportation cost. C_{disp} is the cost for disposal in the landfill in (€/t) and m_{disp} is the total weight of the components to be disposed in (t). $C_{veh,dis}$ represents the day rate of the transport vehicle used for transporting the components to the landfill in (€/d), $t_{veh,dis}$ the required time for transportation in (d) and $N_{veh,dis}$ the amount of vehicles used.

Selling: $$C_{sell} = -C_{sell,mat} * m_{sell} + C_{veh,sell} * t_{veh,sell} * N_{veh,sell} + C_{process} * m_{sell} \qquad (43)$$

The selling of a component generates an income to the company and is treated as a negative cost. $C_{sell,mat}$ is the selling price of a material in (€/t) and m_{sell} is the total weight to be sold in (t). $C_{veh,sell}$ represents the day rate of a transport vehicle used for transporting the components to the scrap yard in (€/d), $t_{veh,sell}$ is the required transportation time in (d) and $N_{veh,sell}$ the amount of vehicles used. $C_{process}$ represents the cost for processing the components into sellable units in (€/t). It is assumed that a reuse of a component and incineration would not result in costs to be included in the life cycle of the FOWPP.

4.4 Energy production calculation methodology

The generation of electric energy from the available wind energy at a specific location is realized by the wind turbine in different phases. At first the kinetic energy of the wind is transformed into mechanical energy by the interaction of the wind on the blades, which causes a torque on the shaft by the rotation of the rotor blades. The mechanical energy is then converted into electrical energy by the generator, which is spun by the rotating shaft. The electrical energy generated by the turbine is then transferred to the next substation and finally to the customer. However, each energy transformation and the transportation imply losses, which cause that only a part of the available energy can be provided [25]. Figure 19: Energy losses at different phases of generation and transmission [25] illustrates these losses.

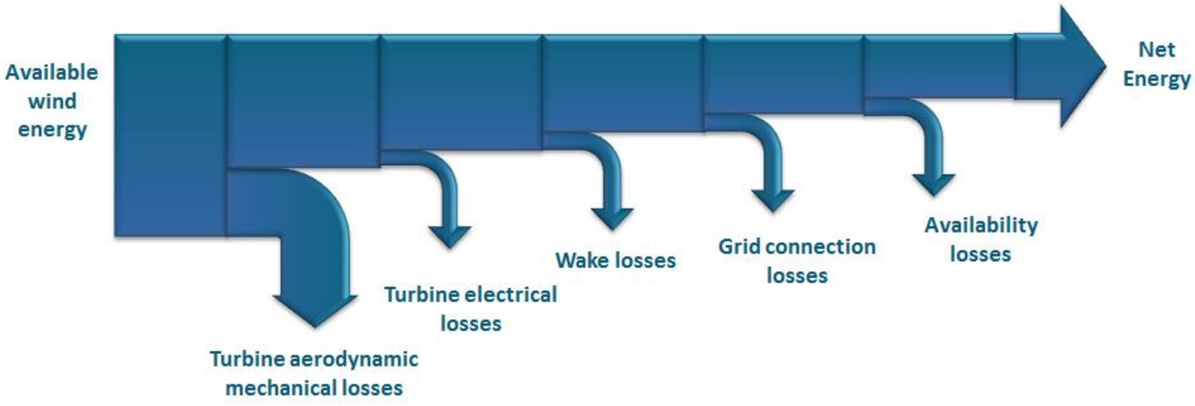

Figure 19: Energy losses at different phases of generation and transmission [25]

In the next sections the energy production and losses are explained in detail.

4.4.1 Available wind energy

Wind is a source of energy subjected to large fluctuations in time, location and intensity. Higher wind speeds can, generally, be expected in higher altitudes as well as in locations with fewer obstacles such as offshore. Wind is not unpredictable and can be measured in terms of wind speed and wind direction. The wind energy that is available at each of the selected offshore sites Golfe the Fos, Gulf of Maine, and West of Barra is calculated based on the wind data provided for the corresponding site. A detailed description of the wind data for each site is presented in Deliverable D1.1. The following figure illustrates the wind conditions at each site based on the Weibull Distributions computed for each wind direction.

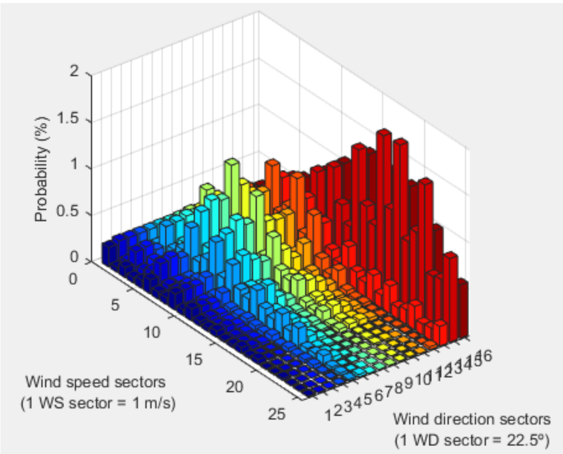

Figure 20 Gulf de Fos wind data

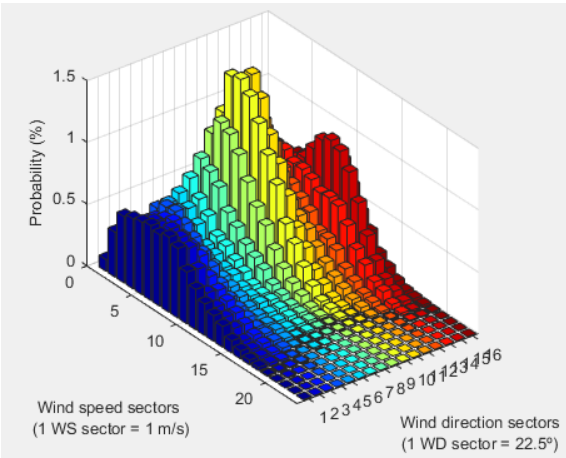

Figure 21 Gulf of Main wind data

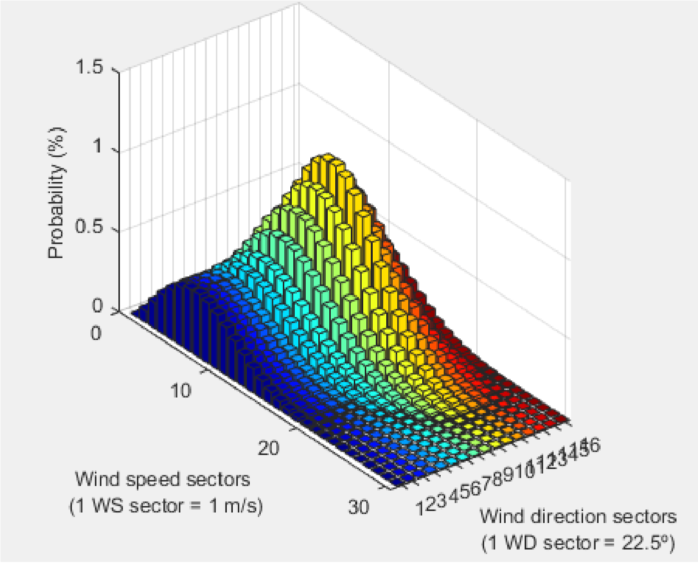

Figure 22. West of Barra wind data

The wind energy available at a specific site is in the form of kinetic energy (E), which is commonly defined as:

Kinetic Energy: $$E = \frac{1}{2} * m * v^2 \qquad (44)$$

Where, m represents the mass and v the velocity.

The wind mass flow that passes through the rotor area A of the turbine with the diameter d can be defined as:

Wind mass flow: $$m = p * \pi * (\frac{d}{2})^2 * v \quad \text{in (kg/s)} \qquad (45)$$

Where, p stands for the density of wind. Substituting the mass flow rate in the energy equation yields the wind power equation (Zubiaga, 2012).

Wind power: $$P_w = \frac{1}{2} * p * \pi * (\frac{d}{2})^2 * v^3 \quad \text{in (W)} \qquad (46)$$

The characteristics of the chosen DTU 10MW reference wind turbine such as the rotor diameter (d) can be found in Deliverable D1.2.

In order to obtain the wind energy (E_w in Wh) the power is multiplied by the time sequence of the specific wind speed, which is the period of time in the year the wind speed occurs. This sequence is obtained by multiplying the Weibull probability (f (V)) of the specific wind speed by the total hours considered, for instance 8760 hours per year. In order to obtain the entire amount of energy generated during the time period the calculation has to be repeated for all wind speeds and directions (Sathyajith, 2006). Furthermore, it was agreed by the consortium to increase the annual energy production by 2% (as suggested by a concept designer) for each location in order to reflect the use of better airfoil profiles and the technological improvements by a 10 MW wind turbine.

4.4.2 Turbine aerodynamic mechanical losses

By harvesting the wind energy and converting it into mechanical energy the wind is slowed down. The power coefficient is used as a measure to describe the efficiency of the wind turbine. It is used in this project as the ratio of the mechanical power produced by the turbine to the total wind power flowing into the rotor swept area. The following figure shows the power coefficient as function of wind speed for the DTU 10 MW reference wind turbine and the mechanical power.

Wind speed [m/s]	Mech. Power [kW]	Thrust [kN]	C_P [-]	C_T [-]
4.0	280.2	225.9	0.286	0.923
5.0	799.1	351.5	0.418	0.919
6.0	1532.7	498.1	0.464	0.904
7.0	2506.1	643.4	0.478	0.858
8.0	3730.7	797.3	0.476	0.814
9.0	5311.8	1009.1	0.476	0.814
10.0	7286.5	1245.8	0.476	0.814
11.0	9698.3	1507.4	0.476	0.814
12.0	10639.1	1270.8	0.402	0.577
13.0	10648.5	1082.0	0.317	0.419
14.0	10639.3	967.9	0.253	0.323
15.0	10683.7	890.8	0.207	0.259
16.0	10642.0	824.8	0.170	0.211
17.0	10640.0	774.0	0.142	0.175
18.0	10639.9	732.5	0.119	0.148
19.0	10652.8	698.4	0.102	0.126
20.0	10646.2	668.1	0.087	0.109
21.0	10644.0	642.1	0.075	0.095
22.0	10641.2	619.5	0.065	0.084
23.0	10639.5	599.8	0.057	0.074
24.0	10643.6	582.7	0.050	0.066
25.0	10635.7	567.2	0.044	0.059

Figure 23. Power coefficient as function of wind speed for the DTU 10 MW reference wind turbine

C_P and C_T as function of wind speed for the DTU 10MW reference wind turbine[1].

Besides the reduction in power generation by the power coefficient the wind turbine limits the power generation also in the wind speed. Each wind turbine has a specific cut-in wind speed at which the turbine first starts to rotate and a specific cut-out wind speed at which the rotor is brought to stop since with extreme wind speeds the forces on the structure increase and damage the rotor (Ackermann,

[1] Source: Deliverable: "Generic layout for the 3 sites with calculated production loss. ".

2005). The cut-in wind speed of DTU 10 MW reference wind turbine is defined for 4 m/s and the cut-out wind speed for 25 m/s.

Furthermore, there occure also electrical losses in the turbine. For these losses a rate of 6 % is defined[1]. The energy generated by the wind turbine can finally be obtained by multiplying the wind energy by the power coefficient and the electrical loss rate (c_{el}) considering the different wind speeds and directions.

$$E_{gen} = E_w * c_p * c_{el}$$

The following figures show the gross energy production at each site considering the wind turbine power coefficient and wind speeds at hub height.

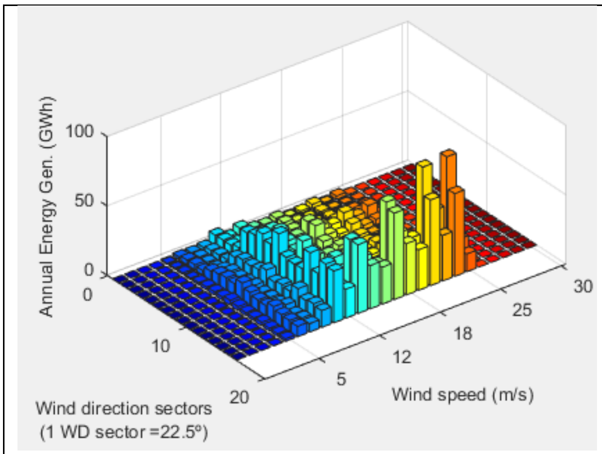

Figure 24 Gross Energy Golfe de Fos

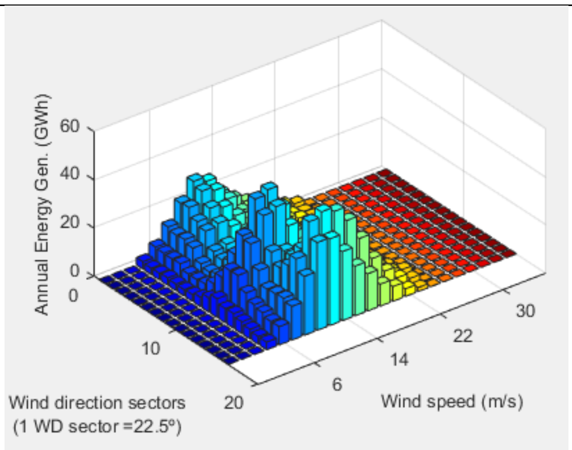

Figure 25 Gross Energy Gulf of Main

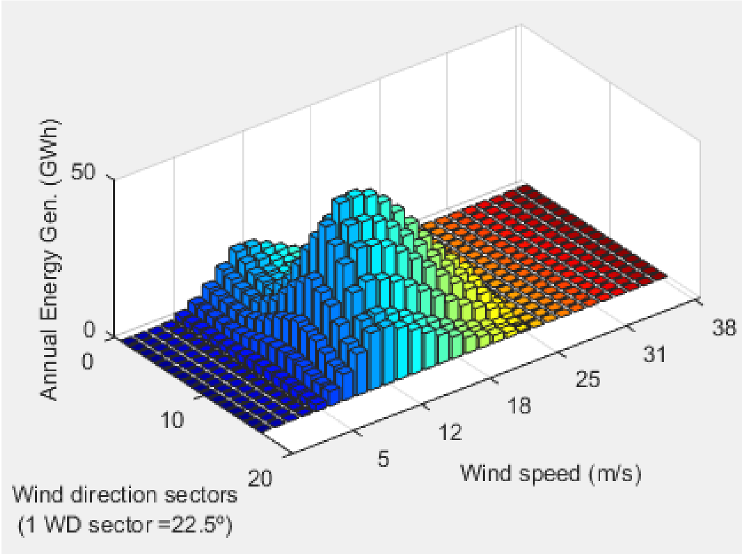

Figure 26: Gross Energy West of Barra

4.4.3 Wake losses

Wake losses are wind power losses caused by the wake effects from the neighbouring wind turbines. The wake losses were computed according to the WAsP Park-model, which is a row-based calculation of power loss and based on the single-turbine wake model of NO Jensen (1983), supplemented by an empirical model wake-interaction and combined with the local statistical distribution of the mean wind speed. The wake losses for each location and wind farm sizes were provided by the Technical University of Danemark. A more detailed explanation of the model and the wake losses are presented in the DTU document [2].

4.4.4 Grid connection losses

Grid connection losses are defined in this project as power losses that occur in the collection and transmission grid as well as in the electrical components of the substations. In the collection and export cables power losses occur due to the resistive heating of the cable. The loss depends on the specific conductor, current flowing, length of the cable and the chosen transmission technology [26]. In this section the power loss calculation is presented at first for the case of a HVAC cable, followed by the total loss calculation for the collection and transmission grid. It is based on the theory explained in [27], [28] and [29]. The tools is also capable to calculate lossess in case of a HVDC scenario, though this deliverable does not include the description of this case since it is not included in the project scenarios.

4.4.4.1 HVAC power loss calculation

Figure 27 shows a simple equivalent circuit of a HVAC cable that is used for transmitting the power generated by a wind farm to the local grid.

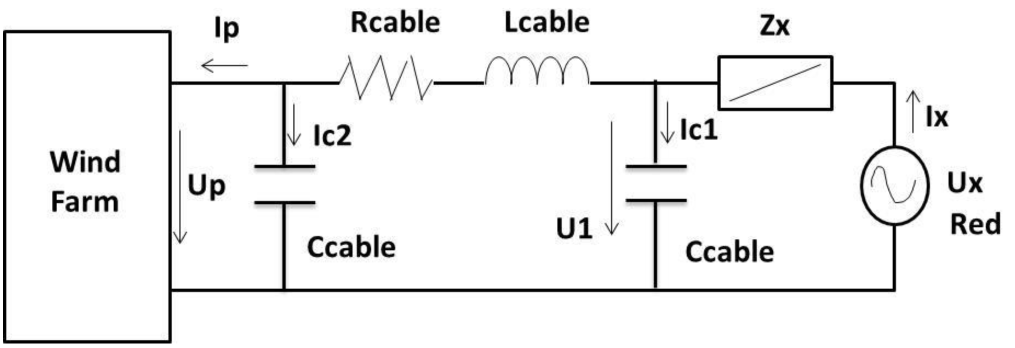

Figure 27: Equivalent circuit of HVAC transmission, adapted from [28]

Assuming that the voltage and the generated power of the wind farm are known, the following methodology is used to calculate all the currents, voltages and powers in the different branches of the cable.

[2] Deliverable: "Generic layout for the 3 sites with calculated production loss. ".

Wind farm current:

$$I_p = \frac{S_p}{Up} \quad (47)$$

Where, S is the apparent power in (VA) consisting of active and reactive power and Up the wind turbine voltage in (V). All values are considered for a single phase. Thus, the voltage Up needs to be divided by the root of 3.

Reactive power:

$$Q = \frac{-P}{PF} * \sqrt{1 - PF^2} \quad (48)$$

Where, P is the rated power of the turbine considering one phase in watt and PF is the power factor.

The power factor is the ratio of the real power P that is used to work and the apparent power S that is supplied. The difference between both is the reactive power in (var). The power factor can vary between 0 and 1 and usually a value closer to 1 is preferred since any power factor lower than 1 means that additional power has to be supplied for a required amount of real power, which also implies larger power losses. However, nowadays wind turbines can control reactive power and shunt reactors in the transmission system are used to compensate it. Reactive power can also be useful to control the voltage.

Current that flows through capacitor C2:

$$I_{C2} = \frac{U_p}{Z_{C2}} \quad (49)$$

Where, Z_{C2} is the impedance of capacitor 2 in (Ohm) and calculated as:

Impedance of capacitor:

$$Z_C = -\frac{1}{2 * \pi * f * C * l} * i \quad (50)$$

Where, f is the frequency in (Hz), l is the length in (km) and C is the capacitance of the cable in (F/km). The capacitance can be obtained from the manufacturer table of the cable.

Current through RL branch:

$$I_{RL} = I_p + I_{C2} \quad (51)$$

Voltage U1

$$U_1 = U_p + I_{RL} * Z_{RL} \quad (52)$$

Where, Z_{RL} is the impedance of the conductor in (Ohm) and is obtained as:

Impedance of conductor

$$Z_{RL} = R * l + 2 * \pi * f * L * l * i \quad (53)$$

Where, R is the resistance of the cable in (Ohm/km) and L the inductance in (H/km), which can be obtained from the manufacturer table. In case the resistance of the cable is not available it can be calculated by taking into account the chosen cross section and cable length.

$$R = \rho * \frac{l}{S} * 1000$$

Where, ρ is the resistivity that has a value for copper at 90ºC of about 0.0219 (Ohm*mm²/m), S the section of the cable in (mm²) and l the length of the cable in (km).

Current through capacitor C1 $$I_{C1} = \frac{U_1}{Z_{C1}} \quad (54)$$

Where, the impedance Z_{C1} has the same value as Z_{C2}.

Current injected to the grid $$I_x = I_{RL} + I_{C1} \quad (55)$$

Apparent power generated $$S_{gen} = U_P * I_p \quad (56)$$

Apparent power injected $$S_{grid} = U_1 * I_x \quad (57)$$

Efficiency of cable $$\eta = \frac{S_{grid}}{S_{gen}} \quad (58)$$

The power loss in the cable can finally be obtained by the difference between the real power generated and injected or by the consideration of the resistance and current.

Power cable loss $$P_{loss} = P_{gen} - P_{grid}$$ $$P_{loss} = R * {I_{RL}}^2 \quad (59)$$

4.4.4.2 Collection grid losses

In the collection grid the current is usually calculated for each cable of the feeder.

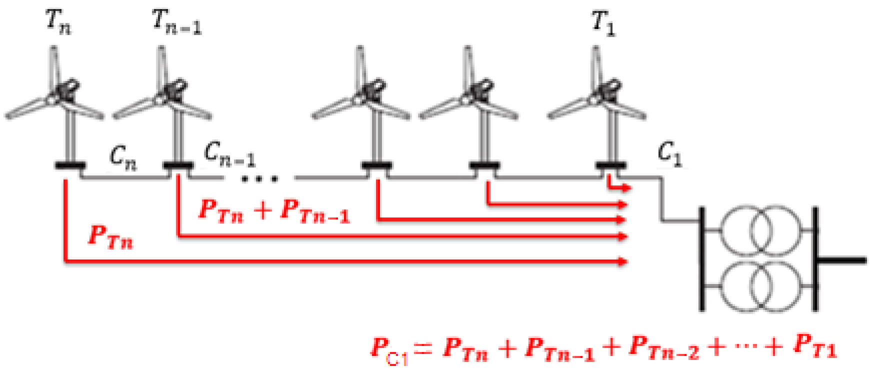

Figure 28: Power flow in a feeder

Figure 28 shows a feeder of a wind farm and the associated power intensities in the cable sections. The feeder consists of several cables connecting the wind turbines in series. Each cable has a different section according to the power to be carried. For instance, the last connected turbine T_n has a rated power of P_n and therefore the associated cable C_n has to be designed accordingly to carry this power. However, the next cable in series C_{n-1} is required to transmit the power of both, the last and the penultimate wind turbine. Following this concept, the first cable in series connecting the turbine T_1 has to be designed to carry the sum of all power generated (P_{C1}) in the feeder. The first step in calculating the cable losses of the whole collection grid is to define the required cables. The definition depends on the ampacity of the cable, where the maximum current I_{max} that flows through the cable is calculated as:

$$I_{n,max} = \frac{P_n}{\sqrt{3} * V * PF} \quad (60)$$

Where, n is the number of cable in series, P_n is the total power to be transmitted by this cable; V is the collection grid line voltage and PF the power factor.

For HVDC technology the power factor is zero since no reactive power exist and the phase voltage is considered in this equation. Usually, a safety factor is added to the maximum current in order to consider possible voltage drops.

Then, a suitable conductor cross section is selected from the manufacturer sheet for the maximum current calculated. For HVAC cable the capacitance and inductance of the cable are taken from the manufactures table and are used for calculating later on the impedances of the inductor and the capacitors. Once all the cable parameters are known, the same procedure as presented before can be applied in order to calculate the current injected to the grid and finally the power losses in the specific cable of the feeder. However, each cable of the feeder has a different cable section according to the power to be transmitted and therefore also a different power loss. Thus, the total loss of the collection grid is the sum of all power cables losses.

Collection grid power loss

$$P_{loss,CG} = \sum_{n=1}^{N_{cs}} {I_n}^2 \cdot R_n \cdot l_{ccs} \quad (61)$$

Where, N_{cs} is the number of cables in the collection grid, R_n is the cable resistance in (Ohm/km) and l_n is the length of the specific cable in (km).

The methodology presented is the theoretical approach for calculating the losses in the cables of the collection grid. However, in practice the choice of power cables is an optimization problem regarding costs and power losses. For instance, developers tend to reduce the amount of different cables in order to save cost for installation and maintenance. Furthermore, economies of scale are important to consider since the purchasing of different cables would be much more expensive than the purchasing of a large amount of identical cables. Thus, the practice is to use a cable with a larger cross section capable to conduct the power produced by several wind turbines for several cable sections in the feeder. The oversizing of the cable would result in power losses in some parts of the collection grid, but it would be compensated by cost savings.

4.4.4.3 Transmission cable losses

The calculation of the power losses in the export cables differs slightly in the evaluation of the current, which is calculated by regarding the number of cables required to export the power.

Current in export cable n

$$I_n = \frac{P/N_{TC}}{\sqrt{3} * V * PF} \tag{62}$$

Where, P is the total power produced by the offshore wind farm, N_{TC} is the number of export cables required for transmitting the energy; V is the transmission grid line voltage and PF the power factor. For HVDC technology the power factor is zero since no reactive power exist and the phase voltage is considered in this equation. The same methodology as for the collection grid is applied for calculating the power losses in HVAC and HVDC cables. The total power losses in the transmission lines are obtained as shown next.

Total power losses in transmission

$$P_{loss,TC} = \sum_{n=1}^{N_{TC}} {I_n}^2 \cdot R_n \cdot L_n \tag{63}$$

Where, N_{TC} is the number of export cables, n the specific cable, R_n is the cable resistance in (Ohm/km) and l_n is the length of the specific cable in (km).

4.4.4.4 Further AC power cable losses

The power losses for AC cables presented previously are conductor losses and caused by the conductor current passing through the resistance of the conductor. Those losses represent the largest portion of power losses in the cable, however, there are also some losses caused by the insulation, sheath, and screens. The cable insulation is a dielectric material and when subjected to a varying electric field energy losses are caused. The losses are related to the voltage level and with higher voltages the power losses increase. For low voltage levels, however, the loss is usually insignificant and can be neglected. For instance, according to IEC 60287 the dielectric loss can be neglected for PE cables under 127kV and for XLPE filled cables under 63.5kV. The next equation shows the formula to calculate the dielectric loss of a power cable.

Dielectric loss $$W_d = \omega * C * {U_0}^2 \cdot \tan\delta \qquad (64)$$

ω represents the angular frequency, C the cable capacitance, U_o the cable related voltage and $tan\delta$ the loss tangent. The loss tangent value can be found in literature for different insulation materials. The dielectric losses only apply for AC cables since DC cables contain a static electric field.

4.4.4.5 Losses in electrical components

Electrical power is also lost in the substation by stepping up the voltage in the transformer or in case of the HVDC technology by converting the current from AC to DC and vice-versa. The power losses are considered by their efficiencies and the number of devices operated.

4.4.5 Availability

Availability is an important measure of the performance of a wind power plant. It is defined as the proportion of time a wind power plant is capable to produce energy.

Availability: $$K = \frac{T_A}{T_N} \qquad (65)$$

Where, K is the availability of the FOWPP, T_N is the nominal, and T_A is the available time. T_N is defined as the total time that is considered without any interruption and is generally taken as 8760 hours per year. The available time T_A is the actual period of time the FOWPP is generating energy and is obtained by the difference of nominal time and downtime T_D .

Available time: $$T_A = T_N - T_D \tag{66}$$

The availability of the wind itself is not included, since it is already considered in the wind energy production by the Weibull distribution formula. Downtime is the time period in hours the FOWPP is not producing energy and thus results in a loss of energy production. The downtime is caused by failures and breakdowns of components in the FOWPP such as the wind turbines, the substation and cables. However, if one component such as a single turbine fails the wind power plant is still capable to produce energy to a reduced degree. Thus, the availability is measured for each component and the impact is calculated on the total power production and resulting losses.

Extraordinary circumstances such as ice accumulation, grid requirements, and interventions by third parties might also cause a downtime of the FOWPP. The time the wind turbine is not running, because of wind speeds above the cut-out or below the cut-in limit, is not included here, because it is included in the power production methodology.

In this project a loss in energy production based on the availability of the floating wind farm is considered for each of the 3 sites. The availability is therefore defined as an efficiency rate. Since so far no floating offshore wind power plant exists that as been operated for a longer time the availability rate has to be defined considering bottom fixed offshore wind power plants. For the site Golfe of Maine an availability rate of 96% is defined, for the offshore site West of Barra a rate of 94% and for Gulf of Fos a rate of 97%. These availability factors will be subjected to an uncertainty variation as it is defined in section 4.5.

4.5 LCOE Uncertainty approach

LCOE calculation will be subjected to a certain degree of uncertainty due to the fact that some of the inputs that will be used for the CAPEX, OPEX and energy production assessment are given with a specific uncertainty range.

Table 7 reports the uncertainty drivers that have been considered within this project after a careful revision from concept developers, IREC and ORE Catapult.

Table 7. LCOE selected uncertainty ranges

Item Number	Description	Scope	Base	How?
1	Discount rate	Common	10%	±2%
2	Turbine supply cost	Common	EURO 1.3m/MW	High EURO 1.5m/MW Low EURO 1.2m/MW
3	Anchor and Mooring Installation vessel rate (inc. labour)	Developer	Design-specific	Design-specific. Developers should provide detail on how range of costs has been derived. See "Vessels" tab for reference
4	Anchor and Mooring Installation time	Developer	Design-specific	Design-specific. Developers should provide detail on how range of costs has been derived
5	Substructure Installation vessel rate (inc. labour)	Developer	Design-specific	Design-specific. Developers should provide detail on how range of costs has been derived. See "Vessels" tab for

				reference
6	Substructure Installation time	Developer	Design-specific	Design-specific. Developers should provide detail on how range of costs has been derived
7	Turbine Installation vessel rate (inc. labour) (if applicable for substructure type)	Developer	Design-specific	Design-specific. Developers should provide detail on how range of costs has been derived
8	Turbine Installation time	Developer	Design-specific	Design-specific. Developers should provide detail on how range of costs has been derived
9	Array Cable Installation vessel rate (inc. labour)	Developer	Design-specific	Design-specific. Developers should provide detail on how range of costs has been derived
10	Array Cable Installation time	Developer	Design-specific	Design-specific. Developers should provide detail on how range of costs has been derived
11	Export Cable Installation vessel rate (inc. labour)	Common	Site-specific	IREC defines this cost and the uncertainty range
12	Export Cable Installation time	Common	Site-specific	IREC defines this cost and the uncertainty range
13	Array cable supply costs	Developer	Design-specific	Design-specific. Developers should provide detail on how range of costs has been derived. See "Vessels" tab for reference
14	Export cable supply costs	Common	Site-specific	IREC defines a cable section and the associated uncertainty
15	Uncertainty in turbine availability	Common	Site-specific	TBC, likely ±2% on base case for each site (considering baseline values described in D2.2)
16	Gross capacity factor variation	Common	Site-specific	± 5% on gross capacity factor
17	Substructure fabrication cost	Developer	Design-specific	Design-specific. Developers should provide detail on how range of costs has been derived
18	Substructure onshore assembly cost	Developer	Design-specific	Design-specific. Developers should provide detail on how range of costs has been derived
19	Substructure onshore assembly cost	Developer	Design-specific	Design-specific. Developers should provide detail on how range of costs has been derived
20	Cost of moorings	Developer	Design-specific	Design-specific. Developers should provide detail on how range of costs has been derived
21	Cost of turbine major repairs	Common	Site and design specific	Apply same uncertainty range (+- 7%) on all concepts unless O&M strategy suggests more potential downside or upside
22	Cost of turbine minor repairs	Common	Site and design specific	Apply same uncertainty range (+- 7%) on all concepts unless O&M strategy suggests more potential downside or upside

23	Cost of substructure major repairs	Developer	Site and design specific	Apply same uncertainty range on all concepts unless O&M strategy suggests more potential downside or upside
24	Cost of substructure minor repairs	Developer	Site and design specific	Apply same uncertainty range on all concepts unless O&M strategy suggests more potential downside or upside
25	Potential variation in Transmission capex and opex and/or transmission fees	Common	TBC	TBC, likely +/-6%
26	Total development costs	Developer	Site and design specific. Reference 5.7%	Design-specific. Developers should provide detail on how range of costs has been derived. Uncertainty reference range +-10%

Specifically, for the Vessel used in the marine operations, the following uncertainty ranges have been considered for each type of transport mean when data was available (Table 8).

Table 8. Vessels average day rates with uncertainty ranges

Type	Name	Average day rate (€)	Variation +	Variation -
Anchor Handling Tug Supply (AHTS)	No name	13.748	47%	74%
		19.052	43%	76%
		60.000		
	Bourbon Liberty 200	NA	NA	NA
	Damen 200	NA	NA	NA
	Normand Progress	NA	NA	NA
	KL Saltfjord	NA	NA	NA
	AHT/Offshore tug	18.250	27%	70%
	AHT/Offshore tug	14.133	27%	70%
Support tug	No name	5.806	8%	13%
	No name	5.806	8%	13%
ROV	No name	7.980	17%	33%
	No name	7.193	17%	33%
OCV/AHT/PSV	No name	35.000	22%	44%
	No name	30.000	25%	50%
ROV / Survey vessel	No name	15.000	NA	NA
Crew transfer vessel	No name	2.000	NA	NA
	Master P	NA	NA	NA
	Wandelaar	NA	NA	NA
Towing tug boat	No name	28.000	NA	NA
		20.000	NA	NA
Multicat / hook-up DP vessel	No Name	25.000	NA	NA

The LCOE calculations using these uncertainty drivers, derives in adding more complexity to the original calculations and also implies that the ranking of the four different concept designs becomes not a trivial issue.
For this reason, from IREC side, using ORE CATAPULT support, different statistical approaches have been studied. To choose the approach, first of all it is needed to identify which distribution family do the drivers belong to. The triangular distribution is often used when there is only limited simple data and specially in cases where the relationship between variables is known but data is scarce. Therefore, this type of distribution is an excellent candidate to fit these data. Thus, every driver which will follow a triangular distribution must be combined to obtain afterwards the LCOE final value[30].

The assumptions considered to adopt the triangular distribution are:

1. It has been agreed that information regarding the most likely value (denoted as c), a minimum (denoted as a) and a maximum (denoted as b) possible value for the drivers, for all the inputs subjected to uncertainty used in thee LCOE computation, would be provided.
2. The uncertainty region must be considered and analysed to allow performance comparison among the concepts designes. It is therefore not acceptable to simply compare mean values for the LCOE results for each concept design and site.
3. Partners have agreed not to take the factor structure site into consideration.

The LCOE distribution for each site and concept will be calculated considering that each uncertainty driver range to be used in the LCOE accounting represented as a central value (mode) and minimum and maximum values, fit to a triangular distribution [31]. The following algorithm for the LCOE calculation will be considered.

1. Fitting a triangular probability distribution using the minimum, central and a maximum value for each of the uncertainty drivers;
2. Generate a random number from every fit triangular distribution;
3. Compute the LCOE using the random values from point 2 for each uncertainty driver;
4. Go to step 2 and repeat 250 times;
5. Combine the results obtained in step 2 for each of the 3 sites, obtaining 750 LCOE simulation results for each concept
6. Plot the 750 LCOE simulation result for each concept design

The choice of 250 simulation routines per concept per site has been chosen based on the balance between resource requirements (mainly processing time) and accuracy of results (1000 simulations take around 6 six times longer with minimal added value to the final results).

The Uncertainty module will then calculate LCOE distributions generated by the 750 simulations carried out for each concept (total 3000 simulations), with the aim of obtaining 4 distribution curves descrbing the LCOE behaviour for each concept. The statistical analysis of these distribution curves, as explained in D2.5 section 4, will determine the obtention of the concept design ranking based on economic (LCOE) aspects.

It is worth mentioning that the methodology chosen for LCOE ranking considering the uncertainty has been proposed by IREC to the Evaluation Committee and its use within the LIFES50+ project is subject to its approval by the end of M17 of the project (October 2016).

4.6 Overall Evaluation tool description

4.6.1 FOWAT

FOWAT is the acronym for Floating Offshore Wind power plant Assessment Tool. It will be used in the project to assess different floating substructures by a multi-criteria evaluation including LCOE, LCA, and Risk as well as an uncertainty determination and KPI assessment. The algorithm and equations that are implemented in the tool are based on the methodology explained previously in this document for computing LCOE, LCA, Risk and KPI evaluation.

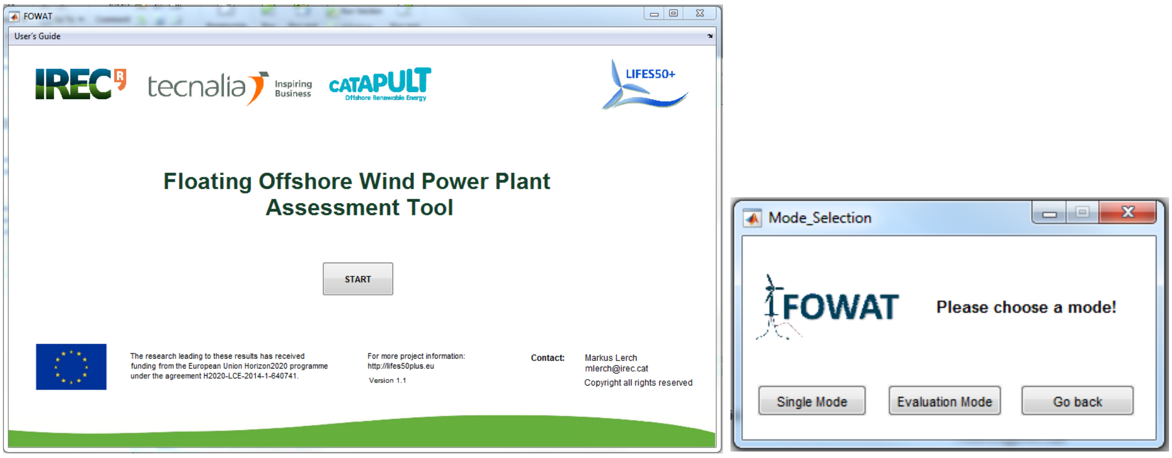

Figure 29: FOWAT tool main screen

The tool consists of two separate modes of operation. The first mode Single Mode is used to assess one floating offshore wind power plant at a specific location. The user has to select a concept, a site and a specific wind farm capacity such as 1, 5 or 50 wind turbines. For this individual case the LCOE, LCA and Risk assessment is performed as well as a KPI report produced. A single LCOE value for the floating offshore wind power plant is calculated and a breakdown of costs is presented according to life cycle cost components, CAPEX, OPEX and DECEX. Furthermore, the energy production and losses in generation and transmission phase can be seen. The second mode Evaluation Mode, on the other hand, is used to assess all different designs concepts considering all three locations and to perform the ranking for the final selection. Here, no breakdown of costs or energy is shown since the LCOE calculation considers uncertainty ranges and a distribution of LCOE values is computed.

In the following sections at first the ´Single Mode´ is presented and afterwards the ´Evaluation Mode´ described more in detail.

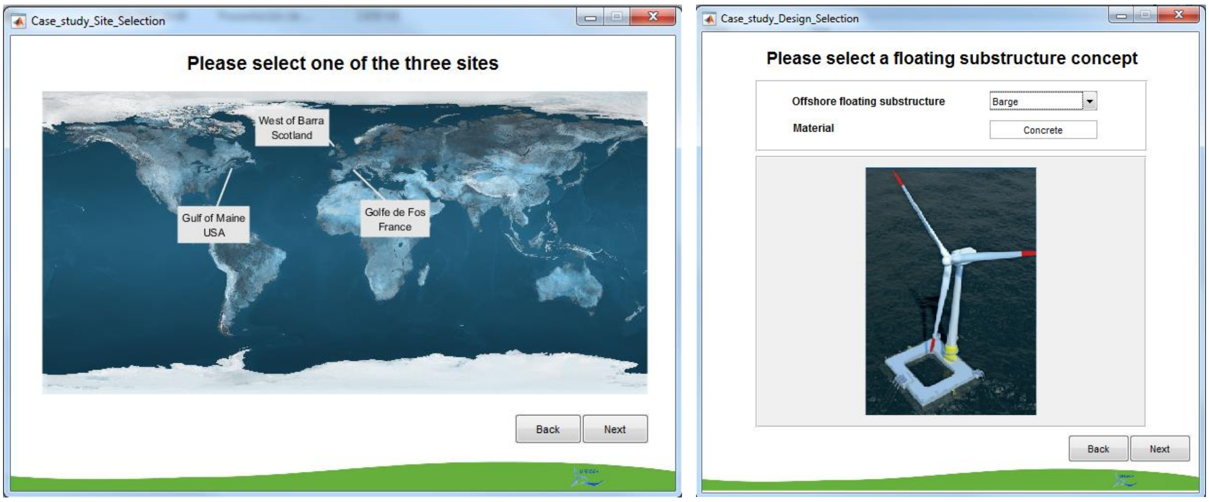

Figure 30: Site and Concept Selection

After starting the Single Mode the user has to select one of the three sites Gulf of Maine, West of Barra or Golfe de Fos. The next step is to choose one of the four floating substructure concepts and finally to select the desired wind farm capacity 10, 50 or 500MW. After all criterias for the calculation are defined the user is required to load the input data. The input data includes the information provided by the concept developers for their specific design as well data for the components of the floating offshore wind power plant that are common such as turbine, substation and export cables.

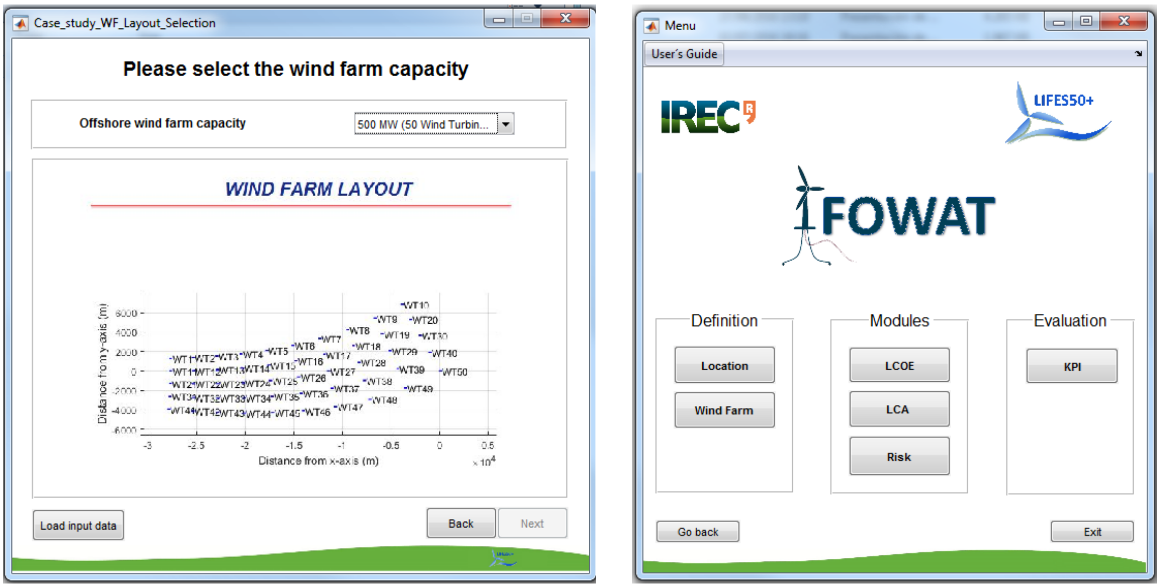

Figure 31: Wind Farm Capacity Selection and Menu

The Menu of the Single Mode shows all operations that can be performed in this part of the tool. It consists of the sections Definition, Modules and Evaluation.

The Location Definition is used to define the location of the FOWPP including General Data and Wind Conditions. General Data contains for example the name of the related country and ocean, the latitude and longitude as well as location specifications such as type of soil, distance to shore and water depths. In Wind Conditions the wind speeds are defined according to their probability of occurrence at the site and a Weibull distribution is shown for each wind direction. Figure 32: General Data and Wind Conditions shows both sections.

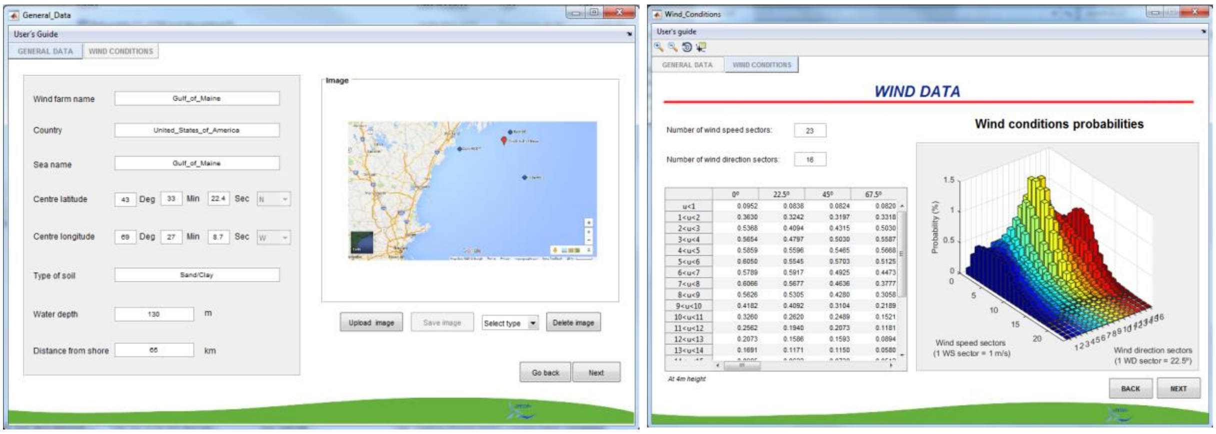

Figure 32: General Data and Wind Conditions

The second part of the Definition section concerns the wind farm and contains the sections Wind Turbine, Wind Farm Layout and Grid Connection. Wind Turbine contains information regarding the wind turbine and the floating substructure. The section Wind Farm Layout presents the pre-defined wind farm layout according to the chosen location and capacity. The section Grid Connection contains all necessary data concerning the collection grid, offshore substation and transmission grid such as nominal voltage, frequency, number of power cables, etc. A scheme of the collection grid and the location of the substation are also shown.

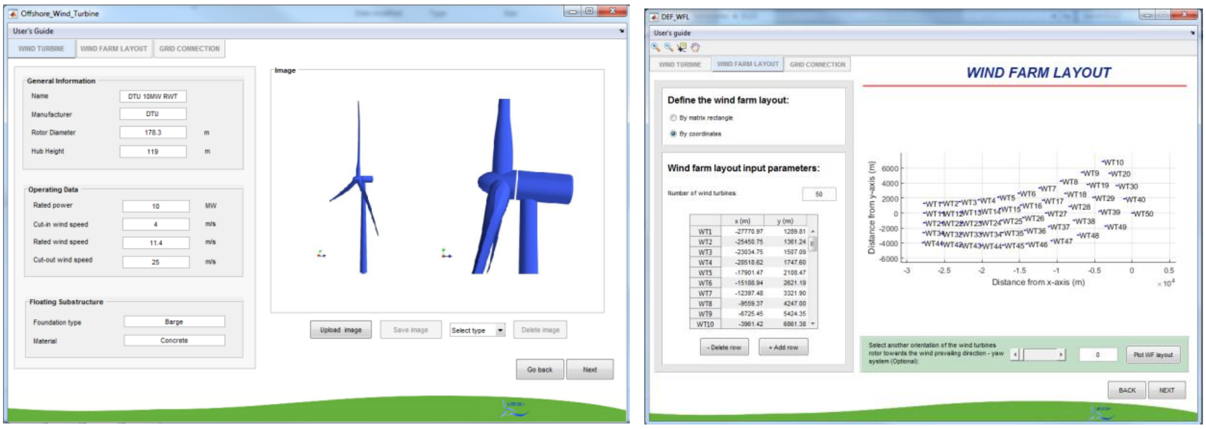

Figure 33: Wind Turbine Data and Wind Farm Layout

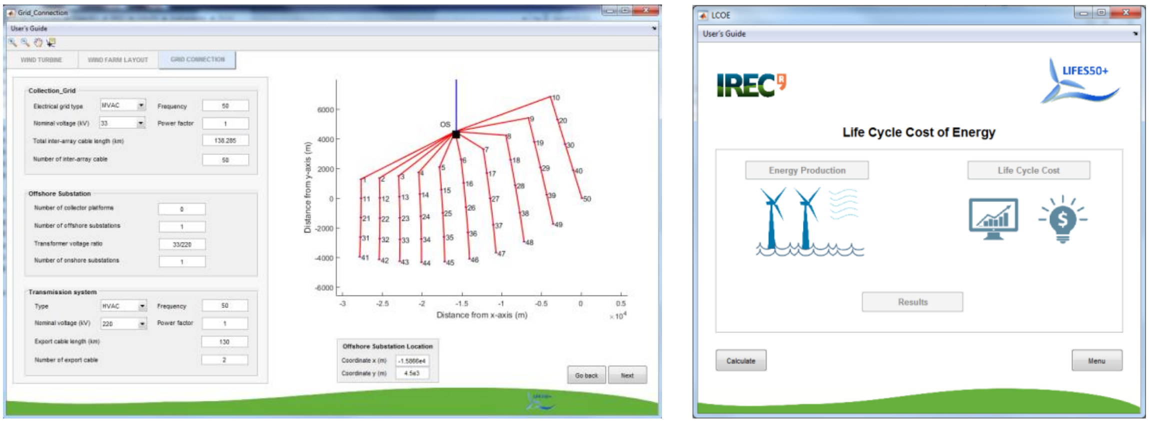

Figure 34: Grid Connection and LCOE Module

The LCOE module shown in Figure 34 consists of the Energy Production section and Life Cycle Cost section as well as the Results section. The LCOE module is used to calculate one LCOE value for the defined floating offshore wind power plant. The section energy production includes all parameters that are used to calculate the energy generation and losses in all components of the wind farm as well as the consideration of wake.

The section Life Cycle Costs contains all cost parameters that are used for the calculation and occurring during the different life cycle phases. Some exemplary images of these sections are presented next.

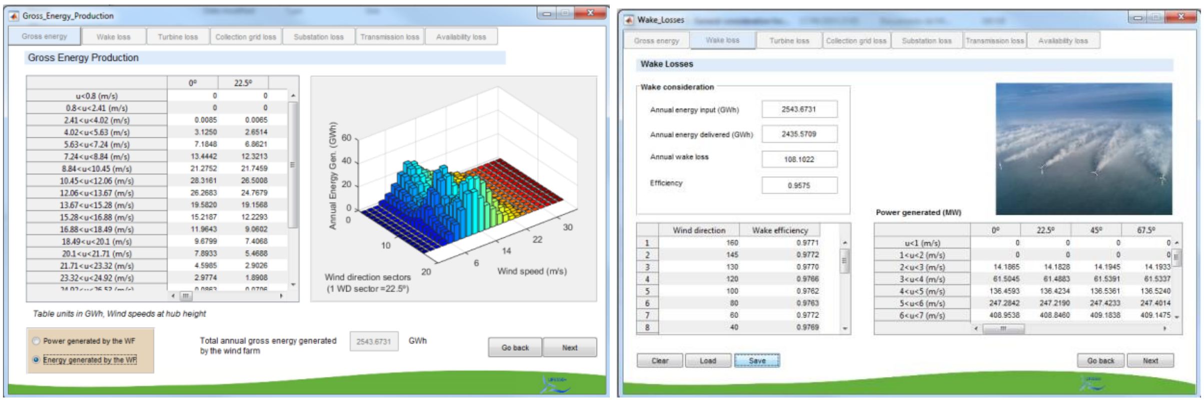

Figure 35: Gross Energy Production and Wake Losses

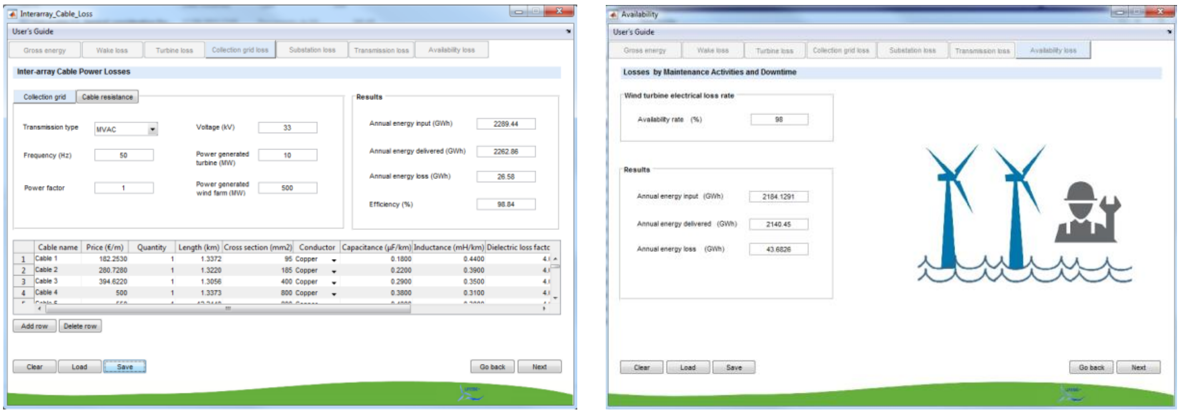

Figure 36: Collection Grid Losses and Availability Loss

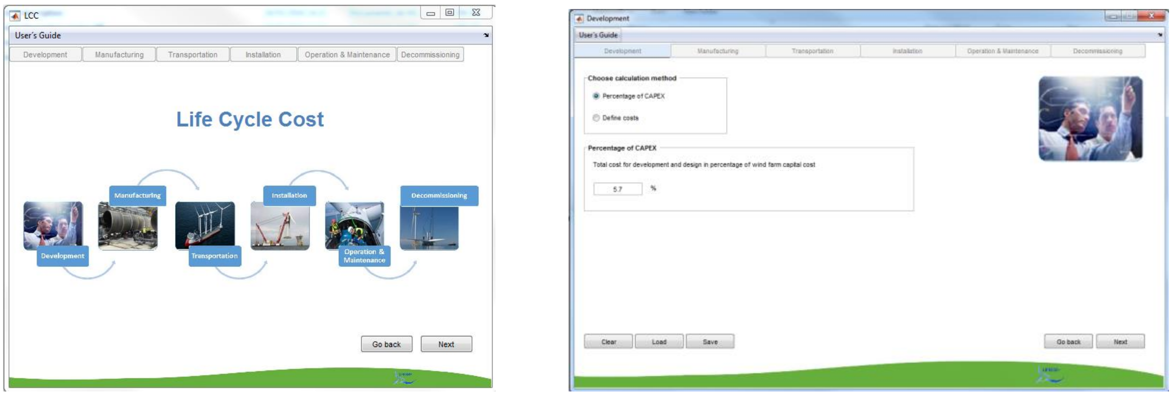

Figure 37: Life Cycle Cost and Development Cost

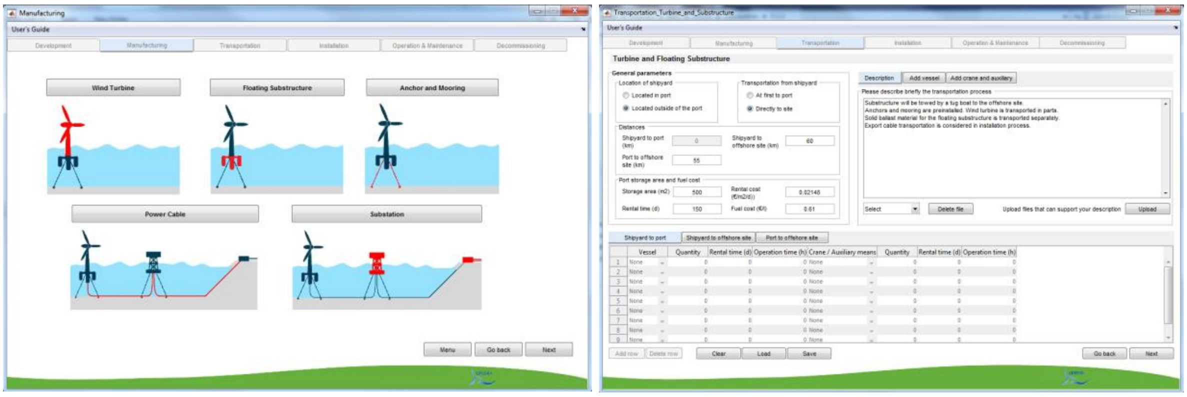

Figure 38: Manufacturing Overview and Substructure Transportation

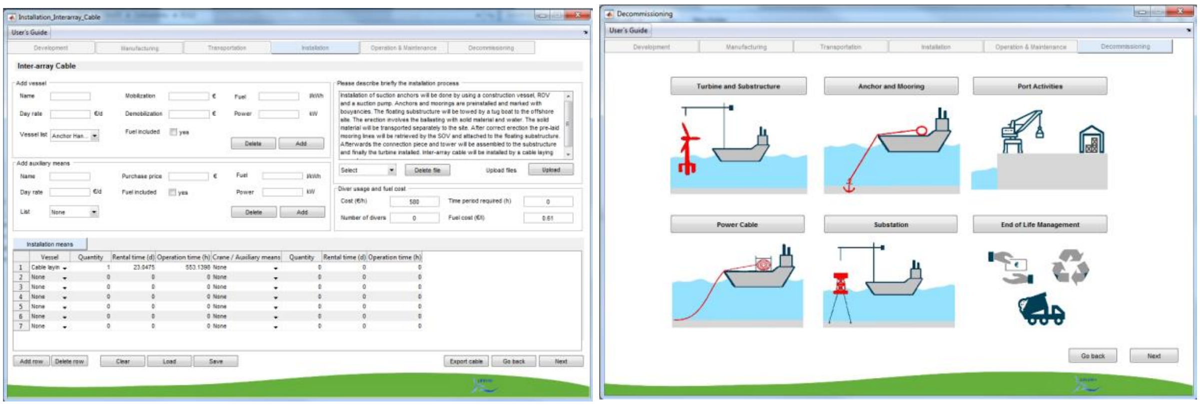

Figure 39: Power Cable Installation and Decommissioning Overview

The results section contains the calculated LCOE value as well as the total energy production and life cycle costs considering the entire lifetime of the wind farm. Besides that, graphics are used to illustrate the energy losses in the system, as well as life cycle costs.

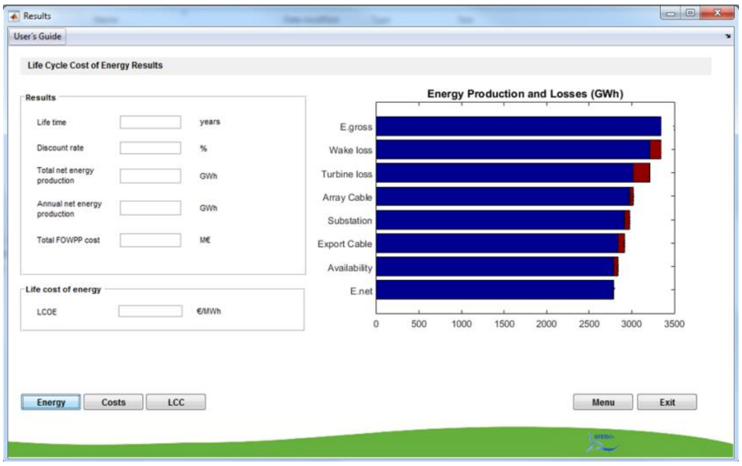

Figure 40: Results Section

The LCA Module calculates the parameters Global Warming Potential, Primary Energy, Abiotic Depletion Potential and Energy Payback Time for the defined floating offshore wind power plant. The Risk module calculates the 4 commercial risk values for this case. The following figure shows both modules.

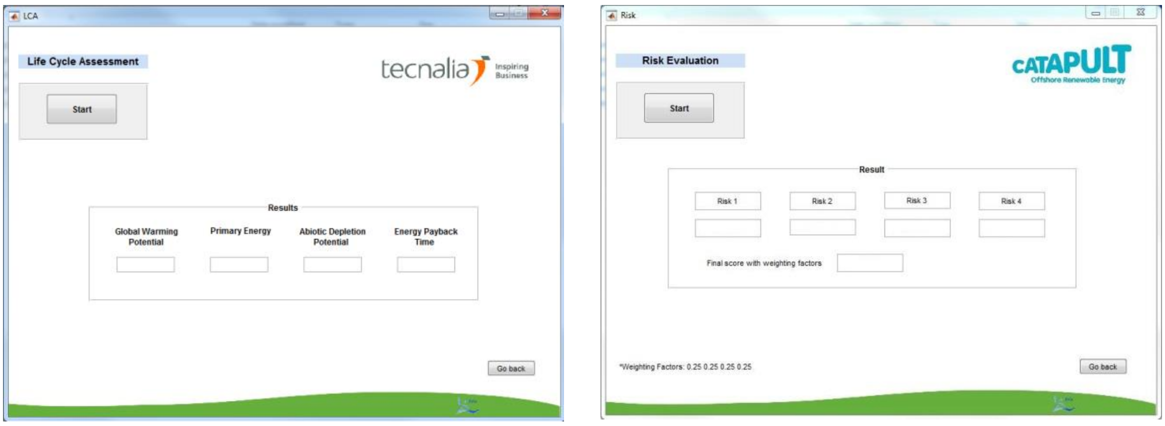

Figure 41: LCA and Risk Module

The KPI evaluation section is used to create a PDF containing all KPI parameters used for this evaluation process. The next figure shows this section in the tool.

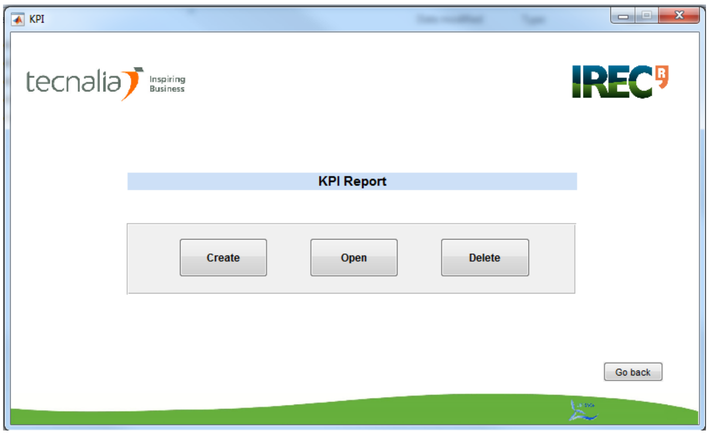

Figure 42: KPI Report Section

The Evaluation Mode in contrast to the Single Mode is used for the ranking of the different concepts and will be explained next.

After selection of this mode and the upload of all required data the menu of this part of the tool is shown. The menu differs from the one of the Single Mode since in this part of the tool the Multi-Criteria Evaluation can be selected. Furthermore, the LCOE Module includes the uncertainty assessment. As shown in the following figure the menu contains also the Definition Section. The user can therefore also select a specific wind farm and check the wind farm layout and wind conditions at the offshore site. However, a breakdown of the costs and energy losses is not available in this part of the tool since a distribution of LCOE values is computed.

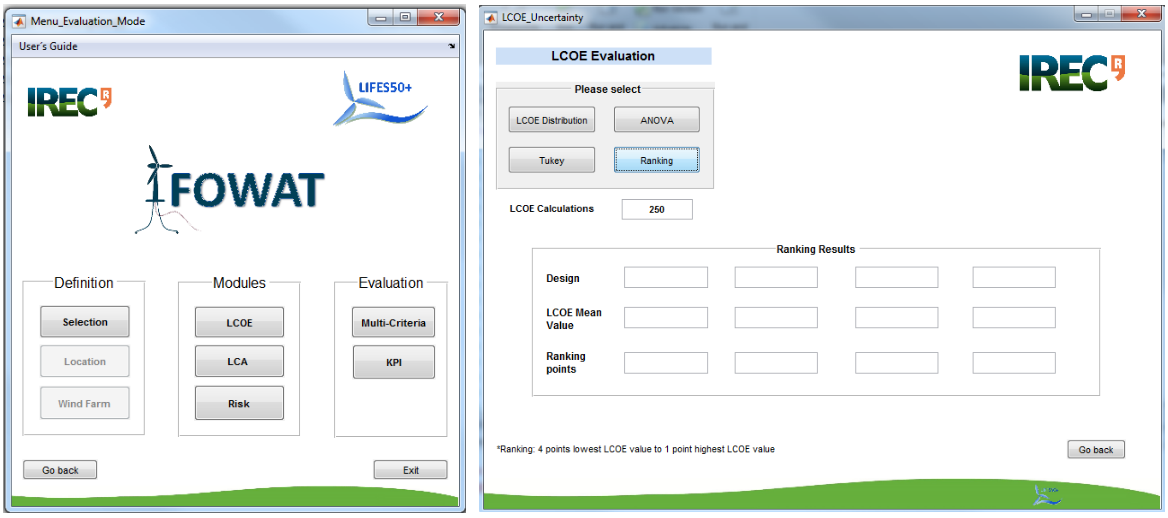

Figure 43: Menu Evaluation Mode and LCOE module

The LCOE Module is shown in Figure 43 , it consists of the LCOE calculation considering the uncertainty parameters and the amount of calculations used for computing the LCOE distributions for each concept. This module is used to present graphically the LCOE distribution values and to rank the concepts according to the mean values of the distributions based on ANOVA and Tukey tests. The following figure presents exemplary the LCOE Tukey test distributions.

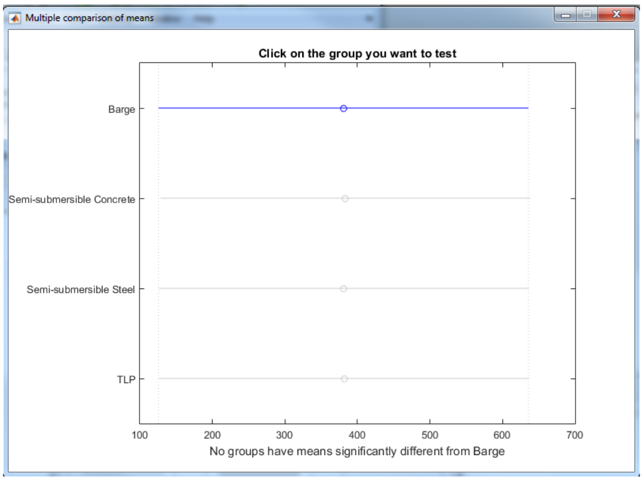

Figure 44: LCOE Distribution Figure

The LCA module is similar to the one of the Single Mode, but in this case shows the LCA parameters for all concepts and provides the ranking according to the LCA results. The same applies for the Risk module, which now computes the risks values for all concepts and provides the ranking.

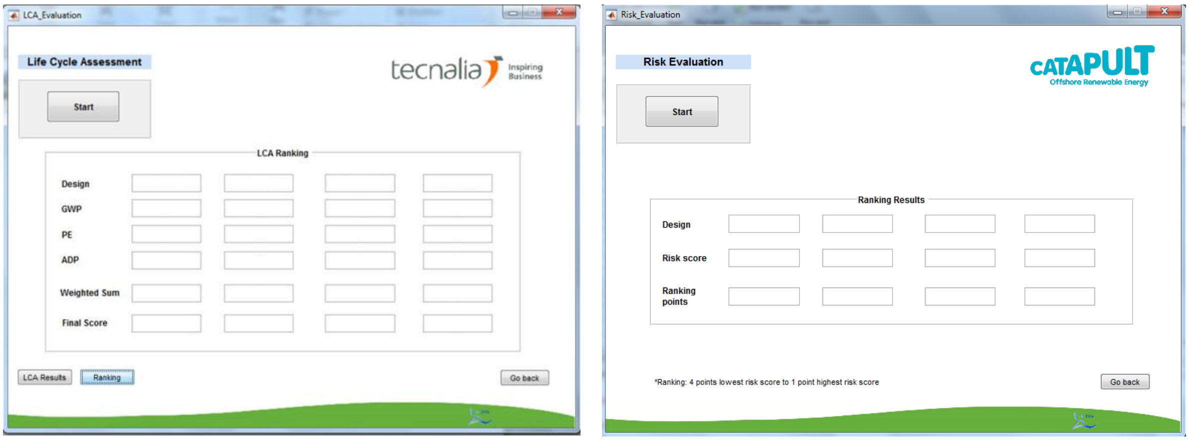

Figure 45: LCA Module and Risk Module

The KPI Section is also similar to the Single Mode and provides in this part of the tool different reports according to each site and concept developer. The Multi-Criteria Evaluation Section finally shows all rankings of the differnet concepts according to LCOE, LCA and Risk. In this section the final ranking is performed considering the weighting factors of each evaluation module. The next figure shows this section.

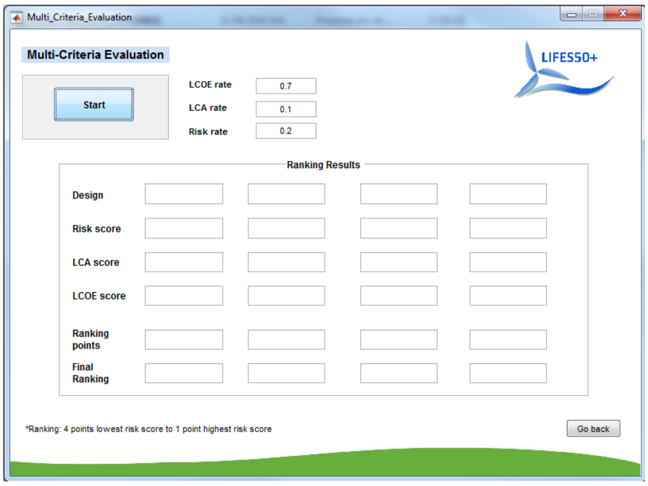

Figure 46: Multi-Criteria Evaluation

5 Life Cycle Assessment analysis

Life Cycle Analysis (LCA) is a useful method to comprehensively evaluate and compare the environmental impacts of products, processes or organizations. LCA relies on a standardised method (ISO 14040-44) to model the environmental indicators or impact assessments of a product.

LCA methodology has been taken into account in LIFES 50+ project in order to introduce environmental impact results in concept selection process. This means that LCA results of the concepts will be part of the multicriteria assessment that will allow the selection of the best concept design. The following sections describe the LCA methodology and how the LCA is performed using the tool developed for supporting the assessment.

5.1 Methodology

Life Cycle Assessment (LCA) is a scientific, structured and comprehensive method that is internationally standardised in ISO 14040 and 14044 [32], [33]. It quantifies resources consumed and emissions that are associated with any specific goods or services [34]. It could cover many different environmental impact categories such as climate change, summer smog, ecotoxicity, human cancer effects, material and energy resource depletion, and so on. Crucially, it allows for direct comparison of products, technologies and so on based on the quantitative functional performance of the analysed alternatives.

Moreover, LCA captures the full life cycle of the system being analysed: from the extraction of resources, through production, use and recycling, up to the disposal of remaining waste. Critically, LCA helps to avoid an unwanted `shifting of burdens´ whereby a reduction of environmental pressures at one point in the life cycle leads to an unwanted increase elsewhere in different environmental pressures. LCA helps to identify and avoid situations in which, for example, waste issues are created while improving production technologies, land is degraded while reducing greenhouse gas emissions, or toxic pressures are increased in one country while reduced in another.

LCA is therefore a vital and powerful decision support tool that complements other methods to help make society more sustainable and resource-efficient.

LCA assessment applied in LIFES 50+ follows the next life cycle stages specified in the standars:

- **Goal and scope definition**: The goal in LCA is the intended application of the study, including the reasons for carrying out the study and the intended audience. The scope in life cycle assessments is related to the function, the functional unit and the reference flow. Initial choices such as the system boundaries and data quality are defined in this step too.

In case of LIFES 50+ project, the goal of the LCA assessment is to quantify and compare the environmental impacts of the concepts developed in the project. For this prupose, a unit of structure is considered as functional unit. **The function of this substructure is to support 10MW turbine during 25 years.**

- **Inventory analysis**: Compilation and quantification of inputs and outputs: Preparing for data collection, data collection, calculation procedures, allocation and recycling.

The inventory process followed in the project is explained in the following paragraphs.

- **Impact assessment:** Assessment of the importance of the potential environmental effects with the aid of the results of the inventory analysis.

The impact assessment results will be presented in next deliverables of the project. In LIFES 50+ project, 3 environmental impact assessment categories are quantified:

- GWP Climate Change measured in CO_2 equivalents
- Abiotic Depletion Potential, measured in Antimony (Sb) equivalents
- Net Primary Energy, measured en MJ equivalents

- **Interpretation**: Conclusions, recommendations, analysis, all related to goal and scope of the research

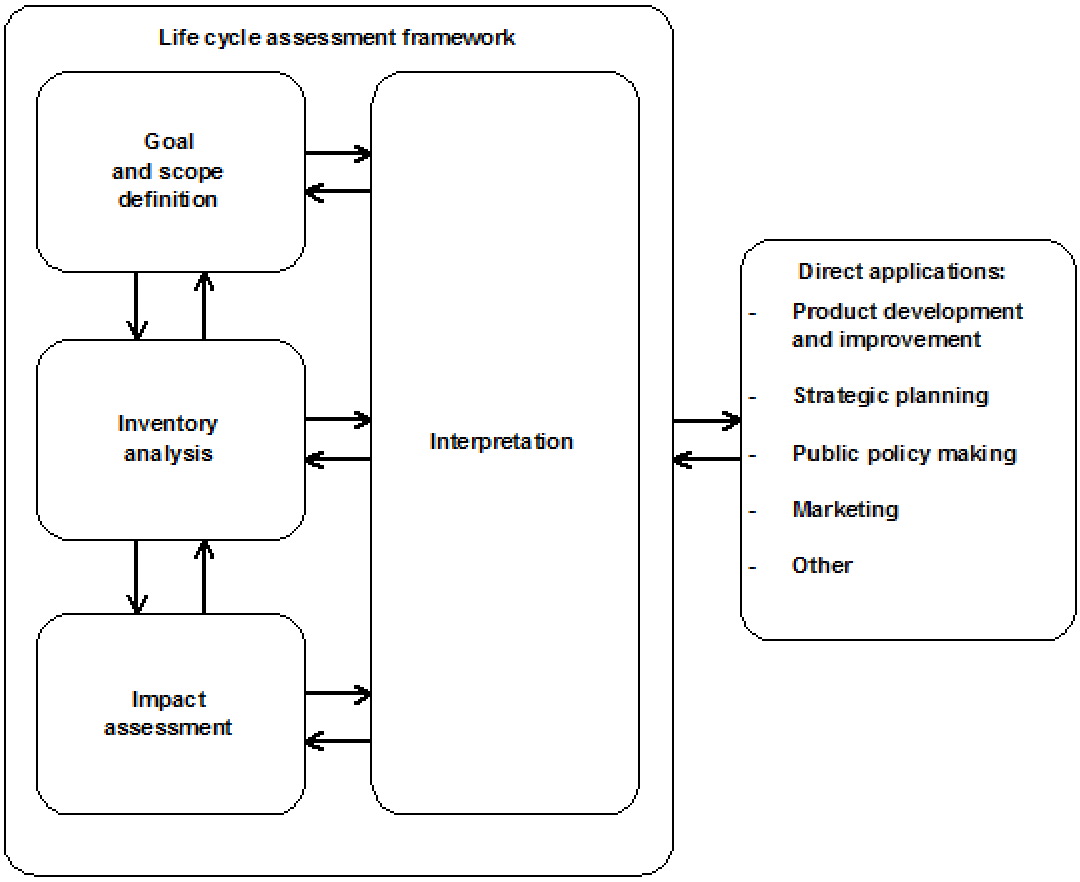

Figure 47. Life Cycle Assessment phases as ISO 14040 defines

This section details the approach that is taken into account by the tool to quantify the impact categories in each life cycle phase. Parameters in which the assessment is based, data that is part of the tool database (default data) and modifiable data are also described.

5.2 Life cycle stages

The life cycle stages of the structure that have influence in the LCA assessment are: manufacturing, transport, installation, operation and maintenance and decommissioning. The following paragraphs describe the approach taken into account by the tool to quantify the environamental impacto of each them in next steps of the project.

5.2.1 Manufacturing

The impact of the manufacturing phase of the structure is calculated while considering the raw materials consumption and handling. Parameters considered in the assessment are: types and quantities of materials (also needed for the environmental impact calculation of transports).

Default data: a database considering the environamental impact of 1kg of materials is part of the tool. The following list of materials it is included:

- Rolled Steel NV A
- Rolled Steel NV D
- Steel Reinforcement
- Concrete: Sole plate and foundation
- Concrete: unspecified
- Concrete: high exacting requirements
- Aluminium: wrought alloy
- Aluminium: ingot
- Ballasting: Concrete
- Ballasting: Magnetite
- Ballasting: Iron ore
- Ballasting: Sea water

Modifiable data: types and quantities of materials to be part of the structure.

5.2.2 Transport

Six different kinds of transports were identified considering the whole life cycle of the structure:

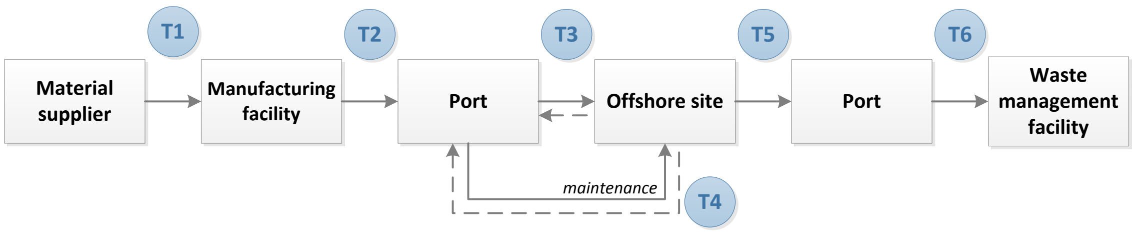

Figure 48: Transports in the structure life cycle

The approach to measure the impact of each of these transport is:

1) Transport of raw materials from the material supplier to the manufacturing facility (T1).

Parameters considered: distance (km), weight of material to be transported (kg) and type of transport.

Default data: raw material transport scenario has been considered and it is part of the LCA tool database. This scenario considers the type of transport (lorry and freight ship) and the number of kilometres from supplier to manufacturing facility following this information:

- Transport from local supplier: identified by FLS acronym, it considers 50 kilometer of distance by lorry.
- Transport from European supplier: identified by FES acronym, it considers 2000 kilometers of disctance by freight ship.
- Transport from rest of the world supplier: identified by FWS acronym, it considers 8000 kilometers of disctance by transoceanic freight ship.

This information is loaded in the tool when the concept developer introduces information about quantities of materials from the materials list described in previous section. This means that for each material, 3 different options exist depending on the supplier, for instance, for the steel reinforcing material:

- Steel Reinforcement (FLS)
- Steel Reinforcement (FES)
- Steel Reinforcement (FWS)

In this example the material is always the same, but the provider changes following the criteria described before.

Modifiable data in the tool: weight of the materials to be transported. When the user introduces this information for the manufacturing phase, the impacts related to transports are automatically calculated.

Example about how it works in the tool: if the user indicates 500 kilograms of "Steel Reinforcement (FLS)", the tool calculates the environmental impacts of the material on the one hand and the transport by lorry of 500kg of this material along 50km on the other hand.

2) Transports T2, T3, T4, T5 and T6: to calculate the impact of these transports the same approach was consider, because of that it is explained together in the same paragraph. In this case, the assessment is based on the fuel consumption and combustion of the vessels. For this purpose, the tool calculates the fuel consumption of each transport and translates it to impacts based on the information of its database.

Parameters considered: fuel consumption of the vessels (MJ or kg) calculated considering the power, distance, the load factor and opertating time.

Default data: impacts related to the consumption and combustion of 1MJ or kg of different kinds of fuels.

Modifiable data in the tool: there are 2 different options:

- The user defines the vessels by introducing information about the power, the fuel consumption in g/kWh, the distance, the load factor and the operating time.
- If the user does not introduce the information about the fuel consumption, the tool considers a default consumption of 200g/kW. The definition of the rest of parameters is needed.

5.2.3 Installation

The environmental assessment of the structure installation is based on the energy consumption of the vessels and equipment used to install the structure. Related to **vessels**, parameters to be considered in the assessment are, as mentioned before, number and type of vessels, diesel consumption of the vessels (g/kWh) and power (kWh), load factor and time of duration of the each phase of installation. As the vessels are the same as the ones used for transport the structure to the offshore site, the information needed in this case is the hours of duration of the installation phase and the use factor.

In case of **equipment**, data needs are: number and type of equipment, diesel consumption of each of them (kg/kWh) and power (kWh), use factor and time of duration of the each phase of installation (as same as for vessels.

Default data: environmental impacts related to the consumption and combustion of 1MJ or kg of different kinds of fuels.

Modifiable data: number, types and use factor of vessels and equipment, hours of duration of installation phase.

5.2.4 Operation and Maintenance (O&M)

It is expected that O&M phase won't have a high influence in the comparative LCA. This is because there is no environmental impact (for the three environmental impact categories considered) related to structure operation and the maintenance in terms of materials of the different alternatives will be similar. Thus, the approach for calculating the impacts of this phase is the same used for the installation phase. This means that the fuel consumption of the vessels and auxiliary means used in maintenance operations are considered:

Default database: environmental impacts related to the consumption and combustion of 1MJ or kg of different kinds of fuels.

Modifiable data: number, types and use factor of vessels and equipment, hours of duration of maintenance operations. Frequency of maintenance operations.

5.2.5 Decomissioning

In order to quantify the impacts of decommissioning phase, the tool considers 2 different issues.

On the one hand, the impacts related to the decommissioning process are measured. These impacts are calculated considering the fuel consumption of the vessels and auxiliary means used in this phase. For this purpose parameters such as the number, types and use factor of vessels and equipment and hours of duration of decomissioning operations are needed.

On the other hand, the same quantities and types of materials specified in manufacturing phase are considered materials to be manage during the end of life of the structure. In order to quantify the impact, the destination of these materials has to be indicated. In a summarized way, the parameters in which the assessment is based are: quantities, types of materials and waste management plan for each of them. Note that in case that the structure is not decommissioned at its end of life, the tool considers that the materials are landfilled.

Default database: environmental impacts related to the consumption and combustion of 1MJ or kg of different kinds of fuels; quantities and types of materials (as they were specified before for the manufacturing phase, it is not needed to introduce this data again),

Modifiable data: number, types and use factor of vessels and equipment, hours of duration of decommissioning operations. Destination of each material (incineration, landfill).

6 Technical KPI analysis

Key Performance Indicators (KPIs) are commonly used in marketing, human resources or online traffic, ads and sales. KPIs are used to condense data into more simple, actionable numbers for management, to detect trouble-spots or potential opportunities, and as metrics to track performance over time, set targets and track progress towards their achievement.

In the wind industry they have been used most notably to track progress and define targets for costs [35]. Within the FP7 Innwind Project (2012-2017), on upscaling offshore wind turbines to the 10-20 MW range, a number of KPIs have been defined with application to identify key cost drivers and trends and the optimum range of various parameters to achieve the lowest cost of energy [36].

6.1 Design applications of technical KPIs

Within LIFES50+, indicators relating directly to costs are the focus of the LCOE tool. One purpose of technical KPIs is thus to complement that analysis and provide quantitative information on aspects of platform performance that are not considered or not fully accounted for in the cost calculations.

Uncertainties related to cost estimates are high in early project phases. They usually involve many assumptions, approximations or simplifications. For this reason early design may be best guided by a focus on improving certain technical aspects that are known to drive real-world cost, rather than on one final LCOE figure that may be highly dependent on uncertain assumptions.

One of LIFES50+ objective is to provide a KPI-based methodology for floating offshore platform design. The methodology is thus developed with a view to be broadly applicable in subsequent design work. This should be facilitated by the fact that the project includes very different concepts: semi-submersible, barge, TLP, as well as steel and concrete platforms.

Ideally, in combination with the LCOE tool, they would help trace back any differences in costs to differences in technical characteristics. They could even quantify the sensitivity of final LCOE to each detail of the platform structure. This is in fact quite difficult as technical characteristics all interact non-linearly to create the final cost estimate. It is unlikely that this will be possible with the current KPIs and tool.

The technical KPIs proposed will be useful if they help identify potential trouble spots resulting from changes in design. As metrics they should help quantify the impact of different design options on key technical characteristics. It is hoped that applied in early design work, they will help better identify issues that will require attention in the more advanced design stages. For example, they should help optimise design by bringing to fore any differences in reserve factors to normative requirement, and ensure that all systems are designed to a similar level of safety.

6.2 KPIs for evaluation within LIFES50+

In general KPIs should be used more carefully when used to compare fundamentally different things. KPIs are generally more useful either to compare similar systems, or track the evolution in time of one system.

In this respect, an important update to initial plans is that the technical KPIs will not be used for the selection of the two of four platforms that will advance to second stage and tank testing in this project. There was broad consensus among developers, WP2 partners and members of the Evaluation Committee (EC) that they should not be used for that purpose.

One reason is that many KPIs proposed are not suited to rank very different floater concepts. There is no unique, objective way to prioritise and weigh the many different aspects of technical performance. The only weighting that would make sense would be one proportional to the impact of each KPI on costs. But as discussed earlier this is quite difficult even for one concept, let alone four very different ones.

Technical KPIs will regardless of this be an important tool for the evaluation process within LIFES50+. They should help the Evaluation Committee easily detect any significant differences between designs that require attention. For example the KPIs could help:

- *Ensure that similar assumptions are used* regarding loads, material properties and other design parameters. Although the design basis (D7.2) specifies the normative reference to be applied, certain parts of the standards leave room for interpretation. If there are differences in the way standards are applied, the KPIs should provide a way to identify and measure these differences.

- *Characterise the turbine operating conditions*. The reserve to operational limits should be quantified, as this may be an important competitive advantage that may not be easily discerned among the many factors affecting the cost analysis results.

- *Assess the different designs' trade-offs of LCOE with other platform characteristics.* Minimising LCOE estimates entails optimising safety margins, fatigue life, steel or concrete weight, etc. The objective is to provide KPIs that signal if one design stands out in any of these aspects.

- *Ensure that DLC outputs are reported consistently.* For example, static stability parameters offer a rough but easily verifiable benchmark to check reported dynamic stability parameters. Also, the KPIs could be used to check for any differences in the way the DLC outputs are used to calculate the ULS characteristics loads.

The evaluation tool will collect the KPIs and generate a 'report' to be used by the Evaluation Committee (EC). Concept developers may be required to provide more information or clarify figures during the evaluation process.

6.3 Overview of the proposed technical KPIs

There are three main types of KPIs in this method.

- One type includes KPIs that are simply recollecting the values chosen for key design parameters. The evaluation tool should display them in a format that will allow easy spotting of any difference that require attention.
- Another type of KPI asks basic configuration and sizing, most notably those on static stability in the first section. They quantify fundamental properties of the platform and should facilitate bringing out any salient differences. Also, they should help perform quick checks on the stability performance reported from the numerical simulation of the design load cases.
- A third type is based on outputs from the numerical simulations of the Design Load Cases (DLCs) specified in the design basis. Output is requested from specific variables in specific load cases in order to make most manifest any difference in performance on key technical aspect. The structure of the technical KPI questionnaire is summarised in the following table.

The five sections in the KPI questionnaire are listed in the following table.

Table 9 Summary of the KPI questionnaire

Technical KPIs sections
1. Static stability performance
2. Loads, reserve factor survivability 2.1. Scantling loads for this site 2.2. Partial material properties 2.3. Corrosion 2.4. Thickness of walls and plates 2.5. Resonance issues 2.6. Mooring 2.7. Platform fatigue life
3. Turbine operating conditions 3.1. Heel angle at nacelle 3.2. Horizontal acceleration at nacelle 3.3. Max total bending moment at tower base 3.4. Tower mode excitation 3.5. Rotor-nacelle assembly load variations
4. Power production
5. Use of marine space

6.4 Static stability KPIs

For any floating structure a fundamental and critical property is adequate stability. This is even more so for large floating offshore wind applications where a turbine thrust often weights over 100 tons, with a lever arm over 100 m, exerts a tremendous overturning moment rarely seen in other marine structure. In addition even a small tilt in the turbine tower may significantly reduce power production relative to the vertical. It can be said that the central challenge of floating offshore wind is to develop platform concepts that manage the destabilising thrust - cost-effectively and without major drawback in terms of wave action.

For these reasons the first section in this list of KPIs focuses on this fundamental aspect of platform performance. These KPIs summarise the designs' basic stability characteristics that result from general configuration and sizing. The requested figures on dimensions, masses and mooring tension allow a rough evaluation of the forces acting on the platform and should permit a rudimentary check of the dynamic stability properties reported thereafter in the questionnaire.

This section illustrates quite well why KPIs cannot be used to rank different concepts. The stabilisation mechanisms and forces at play are quite different. For a spar type the key is a centre of gravity sufficiently lower than the centre of buoyancy, where these two forces provide the righting moment. For semi-submersible platforms and barges it is the rapid change in horizontal position of the centre of buoyancy with floater inclination, i.e. the height of the metacentre. For tension-leg plaforms the extra buoyancy and tendon traction provide the righting moment. It simply does not make sense to compare the metacentric height of a semi-submersible with the tether tension of a TLP.

DNV-OS-J103:2013-06/Sec.10, Sections 2.3, 2.4 and 2.5 specify the requirements for these three stabilisation mechanisms for offshore wind floaters. The following table presents the KPIs proposed for static stability.

Table 10: Technical KPIs for static stability

Static stability performance	Data	Units	Comments
Platform mass exclusive of mooring		Ton (10^3 kg)	Platform fully equipped for normal operation, inclusive of normal ballasting. NOTE: If ballast mass is considered confidential or is varying significantly during operation; please provide hull structural mass and possibly a range for ballast mass and add a comment to clarify what value is provided
Height of center of gravity		m	relative to mean water line in operation at mean water level, mass exclusive of mooring
Displacement at rest, moored		Ton (10^3 kg)	Displacement in operation at mean water level. Seawater density as in D7.2/D1.1, or default to 1025 kg/m3.
Design draft		m	
Height of center of buoyancy		m	relative to mean water line in operation at mean water level
Water plane area at rest		m^2	
Metacentric height (GM)		m	As distance from centre of mass to metacentre. Relevant mostly to self-stabilised structures. Ignore marine growth for this value.
Does design account for change in GM from marine growth?		(Y|N)	
If so, what is the value of GM at thickest growth?		m	
Mooring: number of lines		-	
tension at rest		Ton (9.81 kN)	in one line
moment arm		m	distance to line of action of buoyancy
Inclination		deg	mooring line angle from vertical at point of action on structure
Heel angle at max. turbine thrust, no active ballast		deg	
w/ active ballast		deg	
Heel angle w/ ELWL and max turbine thrust		deg	ELWL=Extreme Low Water Level
Setdown with ECM, ELWL, and max turbine thrust		m	For TLP only. Current and wind codirectional.
Designed for damaged stability?		(Y|N)	
Heel angle (static) when one compartment is flooded		deg	If designed for damaged stability. With compartment that results in largest destabilisation. No turbine or environmental loads

NOTE: Values 7-12 may in addition also be reported by means of intact static stability curve		*Diagram*	*Static Stability Curve*

6.5 Loads, reserve factor and survivability

Many KPIs in this section relate to the application of standards. They should provide a quick check on their compliance, quantify the safety margins (again, overdesign should not mean extra points), and bring to light any unusually large difference between the different designs in the interpretation and application of the standards. The KPIs in this section should be coherent with the requirements of the design basis.

At the beginning of this section general information on the design is requested.

Table 11: General information KPIs

KPI	Data	Units	Comments
Safety class of hull		Med, High	As per e.g. DNV-OS-J103:2013-06/Sec.2/2/2.1.
Contingency criteria beyond standards requirements		(Y|N)	In case of yes, additional information may be requested

Scantling loads for this site

KPIs in this subsection check that similar formulations were used to evaluate design loads. For example, different drag coefficients may be used. Certain wave forces may be neglected or treated differently. The design hydrodynamic load at the mean water line is requested as bulk indicator aggregating the differences in treatment of wave loads.

As developers use different methods for assessing scantling loads, some of these KPIs will not be relevant. For example, the dynamic amplification factor only makes sense for quasi-static or weakly dynamic analysis. This subsection's KPIs are shown in the table below.

Table 12: Scantling Loads KPIs

Scantling loads for this site			
Design wave height or maximum individual wave		m	If design wave is used. If not, indicate the maximum wave height observed in all realisations of all the DLCs.
Design wave period (of max. individual wave)		s	If design wave not used, indicate the zero-upcrossing period of the wave reported in the previous line.
Contingency factor for Morison loads		-	for ULS. ignore if not using Morison equation. Refers to a factor applied to Morison loads in addition to relevant load factors, see e.g. Table A1 in DNV-OS-C103:2012-10/App.B or RP-C103:2012-04/2.3.3.
Morison eq. added mass		-	As used for main structure. Please

coefficient (C_A)			provide value at the middle of the column.
Morison eq. drag coefficient (C_d)		-	As used for main structure. Please provide value at the middle of the column.
List of wave forces included for design loads		*Description*	Please indicate if e.g. Froude-Krylov or diffraction forces are used in evaluating characteristic environmental loads
If a wave force is neglected please indicate why		*Description*	e.g., is it based on sensitivity studies or know-how
Design hydrodynamic load at mean water line		kN/m2	Sum of all forces in worst case scenario. For stochastic load, please report the highest observed hydrodynamic load in all the DLCs.
Height up to which slamming/slapping considered		m	Height above mean water line where scantling accounts for wave loads including impact loads
Design turbine thrust		kN	As used for tower base design.
Dynamic amplification factor		-	Ignore if not using quasi-static or weakly dynamic analysis for any scantling loads. For all loads inclusive of inertial loads. If different factors are used for different loads, please add rows and provide detail

Material properties

Following the logic of loads and resistance factor design, after the KPIs relating to safety factors for loads, this second subsection looks at safety factors for material properties. These KPIs aim to help detect and quantify any difference in the assumed material properties that may need more attention. Concrete and steel platforms have different indicators.

Table 13: Partial Material Properties KPIs

Partial material properties			Please add to this list if you have additional factors
Type of steel or concrete for main structure		Code or name	If different material used in different parts please add rows and detail
Steel: specified minimum yield stress		MPa (N/mm2)	Please add rows as necessary if: different yield stresses used for different thicknesses, or different types of steel used for different parts
Concrete: compressive strength		MPa	
Concrete: tensile strength		MPa	
Concrete: min. yield stress of reinforcements		MPa	
Material factor for shell (single curvature)		-	Factor by which standard yield stress of the material is multiplied to account for e.g. variability in material characteristics
Normative reference for material factor		*Description*	e.g. DNV-OS-J101/Sec.7/7.2.1.3

Corrosion

There are certain clauses in commonly used standards that leave room for interpretation. Some parameters should vary across platforms. For example, the height of the splash zone is expected to vary with different dynamical properties. But these KPIs will help see if the differences are outside a range that appears reasonable.

Table 14: Corrosion Protection KPIs

Corrosion (all values for lifetime)			
Height of splash zone above mean water line		m	
Corrosion rate in splash zone		mm/yr	
Corrosion rate in submerged zone		mm/yr	
Corrosion allowance in splash zone		mm	
Corrosion allowance in submerged zone		mm	
Corrosion allowance in ballast tanks		mm	
Corrosion allowance for mooring lines (Table 13-1 in J103)		mm	
Coating design useful life		years	
Cathodic protection		*Description*	Please describe briefly if CP present, e.g. Anode material and mass/ton if galvanic, survey and replacement schedule
Other relevant information on corrosion?		*Description*	Please inform or describe any relevant information on how corrosion is dealt with.

<u>Thickness of walls and plates</u>

As a final bulk indicator that aggregates the impact of the values assumed for loads, material properties and corrosion, the thickness of steel plates on the hull at the mean water line is requested. The equivalent indicator for concrete structures is the wall thickness at mean water line. The thickness is requested at the mean water line, where the effect of differences in the representation of wave loads are expected to be strongest and relative changes will not be decreased by a mean hydrostatic load.

Table 15: Thickness of walls and plates

Thickness of walls and plates			
Steel: plate thickness at mean water line		mm	
Steel: commercial thickness or tailor-made?		*Description*	Indicate which. If different for different parts, please detail.
Concrete: wall thickness at mean water line		mm	
Concrete: SLS checks performed for crack propagation?		*Description*	

Resonance issues

Managing the risk of resonant response to wave action is one of the basic requirements for floating platforms. The relevant KPIs and values are different for different platforms. For semi-submersible platforms, it is typically more costly to ensure sufficiently long heave and pitch eigen periods to avoid resonance with long swell. For TLPs, what is more demanding is to have sufficiently short periods to avoid springing response to short wind waves. Requirements typical in the offshore oil and gas industry are reproduced below from[37].

Table 16: Typical requirements to avoid resonance (recommendations, adapted from [37]).

Floater Type	Criteria
TLP	Heave and pitch periods < 4 seconds
Semi-submersible	Heave period greater than 20 seconds
Spar	Heave period > 2 times peak storm wave period

Other than with waves, resonance can occur between the floater motion and the main wind turbine loading frequencies (1P and 3P). This should be checked with a Campbell diagram. Note: KPIs evaluating the potential for interaction between tower modes and platform motion are proposed further down in the secion on turbine operating conditions.

Mooring system eigen periods are also requested. Taut mooring may resonate with waves. Catenary moorings typically have natural periods several times that of long swell, but could be excited by wave groups.

Table 17: Resonance KPIs

Resonance issues			NOTE: if developers agree to provide this, a simplified Campbell diagram could be analysed for this KPI
Long swell resonance: shortest heave eigenperiod		s	Mostly for semis. Ignore marine growth.
shortest pitch eigenperiod		s	Ignore marine growth
Short wave excitation: longest heave eigenperiod		s	Mostly for TLP springing response. Include thickest marine growth (as per design basis.), use 1-year low water level.
longest pitch eigenperiod		s	Include thickest marine growth
Mooring system eigen period in surge		s	Include thickest marine growth
Mooring system eigen period in sway		s	Include thickest marine growth

Mooring

The KPIs in this section first collect basic information on mooring safety class and configuration. The following indicators collect information on loads and margin to minimum breaking load. To keep the number of KPIs manageable, only the load at the fairlead or mooring connector are requested. For chains, that is where the maximum loads are expected. However, for positive buoyancy mooring such as fibre strands, maximum tension may be near the anchor so these KPIs should request instead loads at that point.

The requested load values are based on the numerical simulations of the Design Load Cases (DLCs) of the reduced load case table of the LIFES50+ design basis [38]. KPIs distinguish between the loads in operations (DLC1.x), in parked/survival mode (DLC6.x), and those that include fault and/or mooring line failure. Likewise, maximum excursion values are requested from the DLCs, distinguishing between operation, non-operation and fault cases. Mooring system eigen periods were requested in the previous subsection on resonance.

Table 18: Mooring KPIs

Mooring			
Safety class		Med, High	As per DNV-OS-J103:2013-06/Sec.8. If different for different farm size, please insert row to indicate.
Redundancy of mooring system		*Description*	In addition to (Y/N), also provide info how redundancy is implemented (reference to standard)
Number of mooring lines		-	
Distance of anchor to platform centre at rest		m	
Number of mooring lines necessary for station keeping		-	Ignore if no redundancy. The minimum number of lines with which station keeping achieved in DLCs 9.1-2 and 10.1.
Mooring line minimum breaking load		kN	If there are lines with different MBL, please repeat this and following 5 lines for line(s) with different MBL(s)
Max loads at fairlead or connector			Indicate value for mooring line that is most sollicited (highest ratio to MBL). This is the maximum value in any of the required realisation (seeds) for the load case(s) indicated
in DLC1.x		kN	
in which of DLC1.x		*DLC*	
in DLC6.x		kN	
in which of DLC6.x		*DLC*	Indicate whether 6.1 or 6.2, and inform on peak period, misalignment and multidirectionality of wave
in all DLCs		kN	including DLCs with faults and mooring line failure
which DLC		*DLC*	
Max excursion			
in DLC1.x		m	
in which of DLC1.x		*DLC*	
in DLC6.x		m	
in which of DLC6.x		*DLC*	
in all DLCs		m	
which DLC		*DLC*	

For TLP: Check of slack conditions		*Description*	

Platform fatigue life

This section requests basic information on floater fatigue life. In this version, fatigue life is only requested for two critical points: at tower bottom and at the most critical point in the mooring or tendon. Should other components be checked for fatigue those fatigue lives should be added.

In LIFES50+ fatigue checks will be carried out with a simplified method proposed Ideol [38]. The method is expected to provide reasonably accurate results with 63 additional load cases for each site.

Table 19: Platform Fatigue Life KPIs

Fatigue life			
floater fatigue life (reserve factor) at tower bottom		years	As per analysis in Design Basis Appendix, i.e. for fatigue calculation for one generic site according to IDEOL's proposal. If dedicated site-specific DLC1.2 calculations have been performed as well, you may add the site-specific results here in addition with a brief comment.
mooring/tendon fatigue life (reserve factor) at most critical point		years	

6.6 Turbine operating conditions

Turbines installed on floating platforms will be submitted to loads not experienced in onshore or fixed onshore applications. In particular, heel angle and nacelle accelerations, and corresponding higher inertial loads and moments, are expected to be significantly larger. While in onshore or fixed offshore applications those loads may be highest during transport and installation, on floating platform past-installation loads must be checked.

For the moment no manufacturer has designed turbines specifically for floating applications. Thus, the platforms must not move in ways that exert loads that fixed offshore turbines cannot cope with. Also related to the still small market for floating wind, there are no clear guidelines as to what are the acceptable values for heel angle and horizontal accelerations. The values adopted after some discussion in LIFES50+ are provided in the design basis [38]. Those values may change if manufacturers start incorporating specific requirements for floating applications in their design.

In order to minimise the number of KPIs, only the mean and maximimum values across DLCs are requested. The one exception is the heel angle in operational load cases, as its impact on power production at various wind speeds should be assessed.

Table 20: Heel Angle at Nacelle KPIs

Heel angle at nacelle			

Operational DLCs			NOTE: Since DLC1.2 is not required in Design Basis, we request results from DLC1.1 to provide an indication of behaviour in normal operation
Plot of mean and max in DLC1.1		*Plot (x-Axis: wind speed [m/s] (1-2m/s bins), y-Axis: heel angle mean and max [deg])*	If max. 10 degree and/or mean 5deg in Design Basis is exceeded in DLC, please add contingency measures description and report impact on availability (e.g. shut down of WT in wind speed range X-Y) Mean: for each wind speed time-average on all the realisations, wave periods and misalignments as required in design basis.
Plot of mean and max in DLC 1.x (only input needed for another DLC1.x, if mean or max exceeds DLC1.1)		*Plot (x-Axis: wind speed [m/s] (1-2m/s bins), y-Axis: heel angle mean and max [deg])*	If max. 10 degree and/or mean 5deg in Design Basis is exceeded in DLC, please add contingency measures description and report impact on availability (e.g. shut down of WT in wind speed range X-Y) Mean: for each wind speed time-average on all the realisations, wave periods and misalignments as required in design basis.
Non-operational DLCs			
max in non-operation load cases		deg	Max. 15 degree as per Design Basis 6.4.
in which non-operation DLCs		*DLC*	indicate in which DLC max heel angle was observed, as well as the met-ocean combination for the load case for which it was observed
All DLCs			
max in all DLCs		deg	includes all DLCs required in Design Basis (included for convenience, should be equivalent with one of previous values)
in which DLC		*DLC*	indicate in which DLC max heel angle was observed, as well as the met-ocean combination for the load case for which it was observed (included for convenience, should be equivalent with one of previous values)

Table 21: Horizontal Acceleration at Nacelle KPIs

Horizontal acceleration at nacelle			
Operational DLCs			NOTE: Since DLC1.2 is not required in Design Basis, we request results from DLC1.1 to provide an indication of behaviour in normal operation
max in DLC1.1		g (9.81 m/s^2)	If max. 0.3g in Design Basis is exceeded in DLC, please add contingency measures and report impact on availability (e.g. shut down of WT in wind speed range X-Y)
max in other operational DLCs 1.x		g (9.81 m/s^2)	If max. 0.3g in Design Basis is exceeded in DLC, please add contingency measures and report impact on availability (e.g. shut down of WT in wind speed range X-Y)

in which of DLC1.x (operating condition)		*DLC*	indicate in which of power production DLC the max horizontal nacelle acceleration was observed and the wind, wave and current combination for which it was observed
Non-operational DLCs			
max in non-operation load cases		g (9.81 m/s^2)	Max. 0.6g as per Design Basis 6.4.
in which non-operation DLCs		*DLC*	indicate in which DLC max horizontal nacelle acceleration was observed, as well as the met-ocean combination for the load case for which it was observed
All DLCs			
max in all DLCs		g (9.81 m/s^2)	includes all DLCs required in Design Basis (included for convenience, should be equivalent with one of previous values)
in which DLC		*DLC*	indicate in which DLC max horizontal nacelle acceleration was observed, as well as the met-ocean combination for the load case for which it was observed (included for convenience, should be equivalent with one of previous values)

The maximum total bending moment at tower base is one of the costly design constraints. Differences between designs that may appear in heel angle and hozirontal acceleration should be also reflected in these KPIs.

Table 22: Maximum Total Bending Moment at Tower Base

Max total bending moment at tower base			sqrt(Mx^2+My^2)
Operational DLCs			NOTE: Since DLC1.2 is not required in Design Basis, we request results from DLC1.1 to provide an indication of behaviour in normal operation
max in DLC1.1		kNm	
max in other operational DLCs 1.x		kNm	
in which of DLC1.x (operating condition)		*DLC*	
Non-operational DLCs			
max in non-operation load cases		kNm	
in which non-operation DLCs		*DLC*	
All DLCs			
max in all DLCs		kNm	

in which DLC		*DLC*	

Tower modes excitations, and the risk of interaction with eigen modes of the platform, are checked with a Campbell diagram. As a minimum requirement, the first (fore-aft) mode should be safely away from the 1P and 3P tower shadow effect periods.

Table 23: Interaction with Tower Modes

Tower modes excitation			
Campbell diagram		*Diagram (pdf,excel)*	

A number of KPIs are then proposed that are to help quantify the platform motion's impact on Rotor Nacelle Assembly (RNA) fatigue. In offshore applications blades fail significantly earlier than onshore and replacement costs are also significantly higher due to the need to mobilise large vessels and operate in excellent weather. It is worth noting that some floating platform concepts may allow the replacement of such heavy component at port, where a self-stabilised platform could be towed, which may lead to significant cost reduction.

In LIFES50+ in order to keep computational costs manageable RNA fatigue studies have not been prioritised. Indicators are proposed thus that can be obtained from the normal load cases runs as standard output from the routines simulating aerodynamics and turbine behaviour (e.g. FAST). The standard deviation of the blade root total bending moment load is proposed as a basic indicator, which can be expected to capture reasonably well the differences that different platform dynamics may result in.

A KPI quantifying pitch actuator activity in a simple way is proposed as the standard deviation of the angular velocity of the blade pitch angle, plotted for different wind speeds. This should be useful both to detect any significant differences in the fatigue life of pitch actuator, which can be an issue for operation and maintenance costs, and to check if any control algorithm requires unusually intense work from the pitch actuator. This is a KPI that should be considered when evaluating the differences in reported power production.

Finally, as gear box failure is an important cost driver for offshore wind, two KPIs are proposed to check for potential differences in mean time between failure that may result from different platform dynamics. As with other KPIs in this section, it is unfortunately difficult to discern the effect of turbine control algorithm and platform dynamic characteristics. In addition, non-pure torque loads on the bearings and gear box, which are important contributors to drive train damage, are not represented in FAST so that no KPI can be proposed to quantify them at the moment. The standard deviations of the torque and rotation speed are requested for different wind speeds. While providing an incomplete picture of the platforms performance with respect to drive train fatigue, these two KPIs should help check for any significant differences in the impact of platform dynamics and turbine control on drive train time between failure.

Table 24: Rotor/Nacelle Assembly Fatigue

RNA load variations from DLC1.1			
Blade root total bending moment load standard deviation per wind speed		*Plot*	*x-Axis: wind speed [m/s] (1-2m/s bins), y-Axis: STD Blade root bending moment [kNm]*
Pitch actuator (Blade1) velocity standard deviation per wind speed		*Plot*	*x-Axis: wind speed [m/s] (1-2m/s bins), y-Axis: STD Pitch velocity [rad/s]*
Drive train (LSS) - torque standard deviation per wind speed		*Plot*	*x-Axis: wind speed [m/s] (1-2m/s bins), y-Axis: STD LSS torque [kNm]*
Drive train (LSS) - rotor rotation standard deviation per wind speed		*Plot*	*x-Axis: wind speed [m/s] (1-2m/s bins), y-Axis: STD LSS speed [rad/s]*
			Note: FAST does not output information on non-pure torque loads on the drive train, so their contribution to fatigue, although often crucial, cannot be evaluated easily.

6.7 Power production

How the dynamic characteristics of the platform impact power production is a critical indicator because of its high impact on costs. A change in average power production of 1% impacts LCOE about this much, and the impact on project earnings is multiplied manifold as margins become increasingly tighter with competitive bids in forthcoming auctions. In general, an increase in heel angle is expected to impact production negatively. If is worth mentioning, however, that there is work on bespoke control algorithms which may be able to extract some of the energy of wave induced motion.

As for other quantities relating to turbine operation, for power production it is difficult to discern the impacts of platform motion and turbine control. The latter's contribution may actually dominate in which case KPIs that capture platform performance adequately are difficult to devise. The approach proposed here is to consider the differences in power production, that may be brought to fore in this section, in light of the difference measured by the pitch actuator KPI (subsection on RNA load variations). This KPI should capture some of the controller activity. Should indicate unusually large differences, their impact on power production should be considered. The KPI to measure power production differences between designs is the mean power curve and standard deviation of power production from DLC1.1. DLC1.1 is chosen because the unidirectional wave, co-directional with wind, is the situation in which differences in mean heel angle between the platforms are expected to be highest. The effect of wave induced platform pitch, and the resulting differences in power production between designs, are also expected to be well captured in this configuration. Therefore, any differences in platform performance relative to power production should be most manifest in these DLCs.

Table 25: Power Production KPI

KPI for power production (not used in LCOE tool)	Data	Units	Comments
Power Curve from Power production for single floating turbine in DLC1.1 (no wake)		*Plot*	x-Axis: wind Speed (1-2m/s bins) [m/s]; y-Axis: mean and STD of electrical power

6.8 KPIs for use of marine space

KPIs in this section intent to quantify differences between concepts in terms of use of marine space and impact on the seafloor. While these aspects are not reflected in the LCOE tool, these KPIs could have relevance in markets where coastal fisheries are important and in areas where benthic biodiversity is protected. Also, large platform excursion may increase wake losses as turbines are offset from the optimal layout.

Table 26: KPIs for Use of Marine Space

KPI for use of marine space	Data	Units	Comments
Total mooring line length on seabed at rest		m	may be an environmental issue. Value at 0 excursion, mean water level, sum for all mooring lines.
50 turbine farm capacity per area		W/m2	for the chosen layout
50 turbine farm mean power per area		W/m2	mean farm power / farm area, for the chosen layout

7 Multi-criteria tool description

The Multi-criteria module has been developed in order to collect (read) the results obtained from the LCOE, LCA and Risk tools, combine them appropriately, and provide the final concept's design ranking. The role perfomed by the Multicriteria tool serves at achieving the ultimate goal of obtaining a Global Evaluation of the proposed designs.

The Global Evaluation procedure for LCOE, LCA and risk ranking is explained in D2.5; in this document, a summary of the structure of the Multicriteria module and the weighting factors to be applied to each criteria is provided.

As indicated in D2.5, a schematic of the proposed Global Evaluation procedure is shown in Figure 49

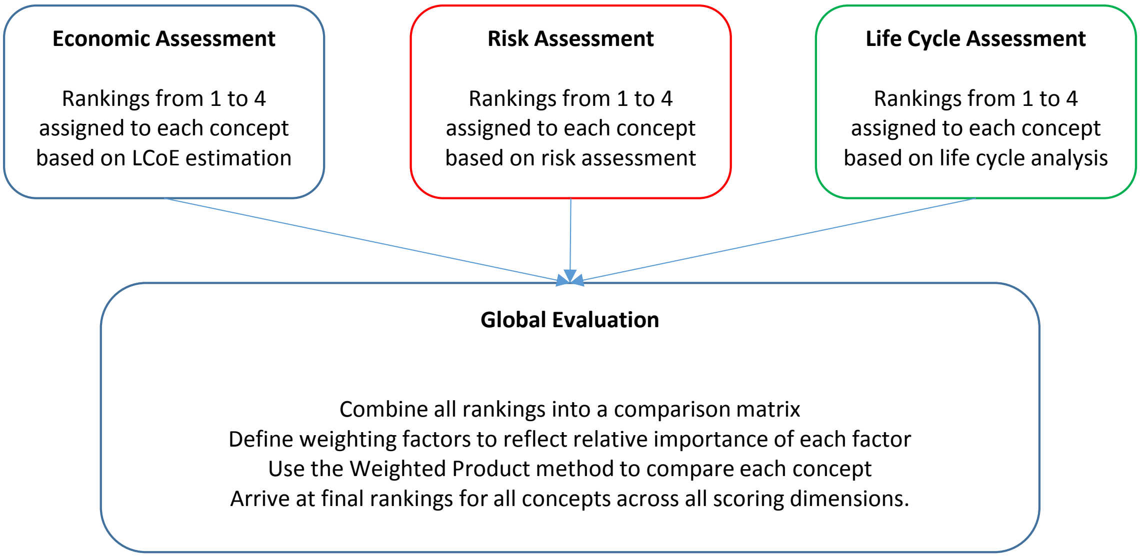

Figure 49: Illustration of Global Evaluation Procedure

A final score for each technology concept will be based on the three sets of rankings related to each of the three sets of evaluation criteria.

The Multi-Criteria module will store in the different matrix results of the LCOE and LCA calculation for each site and concept design. Each matrix will be treated in order to convert the absolute values (e.g. €/MWh for LCOE, or kg CO_2eq for LCA) into scores from 1 to 4 as explained in D 2.5. There will be no need of further treatment of the the outputs from the Risk module, as they will be expressed in the same dimensionless scoring sytem.

Each of these three sets of scores will be given a weighting factor, agreed by the concept designers and the Evaluation Committee as shown in Table 27.

Table 27 . list of the weighting factors for each evaluation criteria set

Evaluation criteria	Weighting factor
Economic Assessment	0.7
Risk Assessment	0.2
Life Cycle Assessment	0.1

An example of this in practice is given in Table 28.

Table 28. Example of Evalutation matrix

Concept	Economic	Risk	LCA	Weighted sum	Final score
Concept 1	3	1	4	2.7	3
Concept 2	1	3	3	1.6	1
Concept 3	2	4	1	2.3	2
Concept 4	4	2	2	3.4	4

Weighting factor	0.7	0.2	0.1

Table 28 above (again note that this is example data, for purposes of illustration only, however, the weighting factors used are the ones agreed by the project consortium). In this example all concepts are ranked 1 – 4 in one dimension, with 4 being the highest ranking and 1 the lowest. e.g. Concept 3 is most highly ranked in terms of risk, Concept 4 is most highly ranked in terms of economics, etc.

The result of running this through the multi-criteria model would be overall score as per the final column: in this case Concepts 1 and 4 would be the selected concepts (highest scores), which mimics the results of economic evaluation due to the high weighting factor associated with it.

8 LCOE module validation

8.1 Case study

The LCOE module tool has been tested by defining a FOWPP at a specific location and calculating its LCOE. The specifications of the components are based on available data from literature. However, some restrictions are related to the Lifes50+ project such as a minimum water depth of the location of 50 m and an offshore wind turbine with a rated power of 10 MW. A detailed description of the case considered follows next.

It should be stated that in parallel of this case study writing some adjustments in the tool were carried out thatmay not be reflected in the results of this example. Furthermore, the input data that is used for calculating the costs in this case study is based on literature references and assumptions are made in cases were not data is available. Therefore, the results of this case study involve a degree of uncertainty and may not reflect the actual cost of energy that floating wind can achieve with data provided from concept designers.

8.2 Offshore Wind Turbine

Since up to now no commercial wind turbine exists with a rated power of 10 MW a turbine has to be chosen that is available in scientific papers. For this reason the DTU 10 MW reference wind turbine was chosen, which was developed by the Technical University of Denmark in cooperation with Vestas. Figure 50 shows DTU 10 MW RWT turbine. This wind turbine has a rated power of 10 MW, a cut-in wind speed of 4 m/s, cut-out wind speed of 25 m/s, a rotor diameter of 187.3 m, and a hub height of 119 m [39]

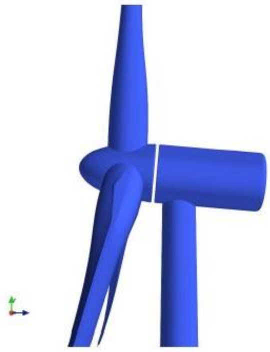

Figure 50 DTU 10 MW RWT

8.3 Floating substructure

There is not much technically information publically available for floating substructures since most of the designs are still in development and only a few prototypes are constructed.

For this study the Hywind spar buoy concept developed by Statoil was chosen. The reason for this is that this concept is the most experienced with more information publically available. Furthermore, it was the first operational deep-water floating wind turbine with a large capacity and a pilot floating wind power plant of 30 MW is planned to be built in the near future. Most of the information concerning the floating substructure and the FOWPP considered for this study was gained from the Environmental Statement published by Statoil in March 2015 for its first FOWPP [40]. Figure 51 shows the Hywind design.

Figure 51: Hywind design

The Hywind floating substructure is a spar buoy design consisting of a steel structure partly filled with water and solid rocks ballast. The floating substructure is hold in position by three mooring lines in catenary form and fixed to the seafloor by one suction pipe anchor per mooring line. Steel chains are considered as the type of mooring line with a line length of 800 m. The spar buoy type requires due to its design a deeper water depth than other floating substructures. For this project a design with a maximum draft of 80 m is considered. Thus, the water at the defined location must possess a sufficient depth.

8.4 Location

The offshore site that was chosen for this project is the Gulf of Maine located on the east coast of the United States of America. The specific offshore site is located 65 km east of the city Portland in the state of Maine. Figure 52 displays the location.

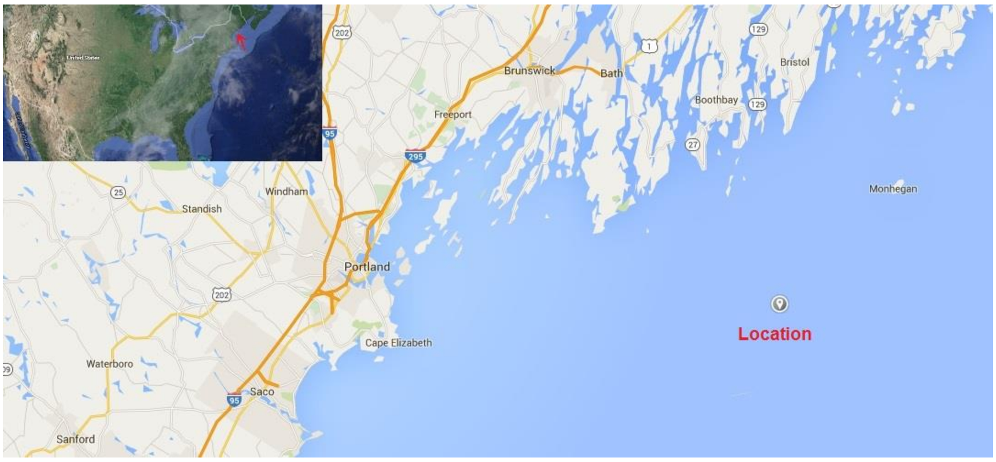

Figure 52: Offshore site Gulf of Maine (Google, 2016)

The offshore site is characterized by deep waters with an average depth of 130 m. The type of soil present at the location is sand as well as clay and the selected suction pile anchor suits to these soils. Close to the offshore site there are three different measurement buoys that are taken for the wind characterization. A complete wind profile is available for the location taken from the buoys including wind speeds registered in 10-minute periods, wind occurrence probabilities as well as a specific wind rose for the wind directions. The Weibull parameters are 6.214 as scale coefficient and 1.701 as shape coefficient. The mean wind speed at 10 m height is 7.34 m/s and at the wind turbine hub height of 119 a mean wind speed of 10.02 m/s is estimated. Based on the available wind information the following wind profile was computed containing the Weibull distribution for each wind direction.

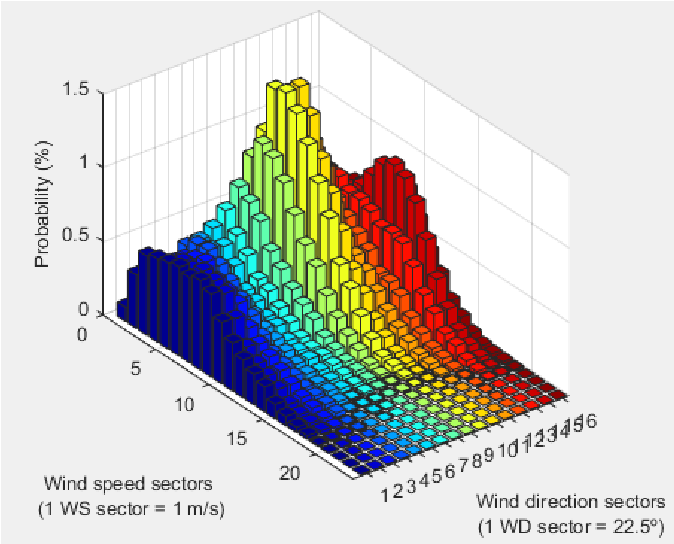

Figure 53: Wind profile at offshore site

8.5 Wind power plant layout

For this project 50 offshore wind turbines are considered totaling a rated power of the FOWPP of 500 MW. A distance of 7.5 times the rotor diameter was considered for the spacing between wind turbines. Furthermore, according to the wind profile and the prevailing wind direction an optimization resulted in a slightly curved wind farm layout as presented in the following figure.

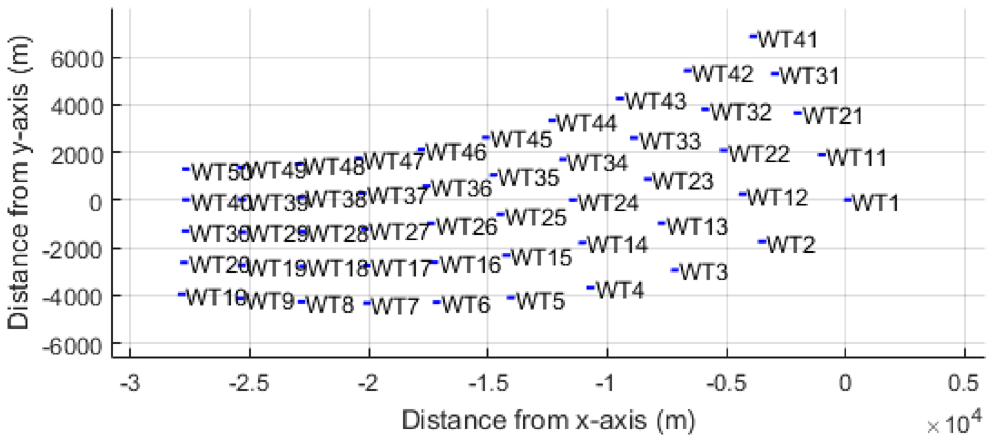

Figure 54: Wind farm layout

It is assumed that the considered layout provides sufficient space between the turbines for placing the mooring lines.

8.6 Collection grid

The 50 floating wind offshore turbines are connected in type of a string. The collection grid consists of 10 feeders connected to the offshore substation. Each feeder contains 5 wind turbines connected in series. In total 50 power cables are considered each with a different cross section according to the power transmitted and ampacity. The collection grid voltage is 33 kV, the frequency is 50 Hz and an AC grid type is considered. The total length of all inter-array cables sums up to 138.28 km.

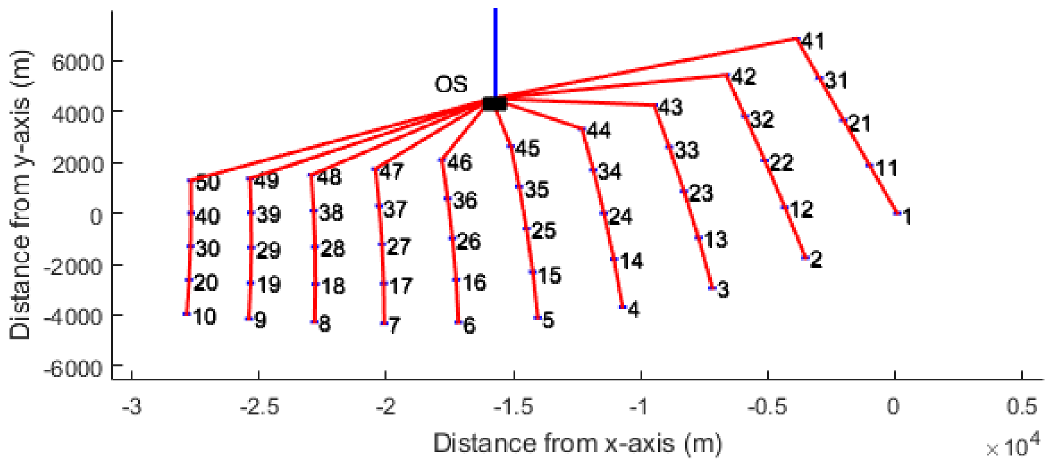

Figure 55: Collection grid

8.7 Transmission

One offshore substation is considered that contains 2 transformers, which step up the voltage to 220 kV. Furthermore, 3 switchgears are located at the offshore substation, 1 at the 33 kV site and 2 at 220 kV site. The energy is transmitted to the onshore substation by two export cables in parallel crossing a distance of 65 km. The transmission type is HVAC and the frequency is 50 Hz. The onshore substation is not considered in the cost calculation since it is assumed that it already exists and is operated by a third party.

8.8 Energy production and losses

The net energy production is calculated by considering the wind characteristics and probabilities of the offshore site. At first an annual energy production is calculated and then considering a lifetime of 20 years the total energy production computed. A lifetime of 20 years was chosen for this study case in order to facilitate the comparison to literature reference values. The energy production is reduced by the wake loss, where for each wind direction a loss factor is considered. For the electrical losses of the turbine a rate of 6 % is considered. The power cable losses are computed based on the methodology explained in this project for a HVAC configuration. For the offshore substation an efficiency of 0.98 is assumed, which is a typical value. Current transformer substations can reach efficiencies of higher than 0.99 %, but for this project a more conservative value is chosen. The availability of the wind turbines depending on maintenance activities is also included as a percentage value.

8.9 Development cost

For the development and design of the FOWPP a rate of 5.7 % of the capital expenses is assumed. This rate is based on the average value of reference percentages calculated in chapter 4.3.1.

8.10 Manufacturing cost

The DTU wind turbine is not commercially available, therefore, no price exists. However, KIC InnoEnergy has estimated a price of 1.498 M€/MW for a generic 8 MW wind turbine (KIC InnoEnergy, 2014). The DTU wind turbine follows a light weight rotor concept, thus, there would be a potential cost reduction. It is also assumed that the actual price of a future 10 MW offshore wind turbine would be a bit lower than the value estimated by KIC InnoEnergy due to technical developments. Therefore, for this study a manufacturing price of 1.3 M€/MW is considered totaling a price of 13 M€ for the DTU 10 MW wind turbine. The tower of the turbine has a weight of about 628 t and together with a market steel price of 1600 €/t the cost for the tower result in 1 M€ (Alibaba, 2016). For the Hywind floating substructure no manufacturing price is publically available. However, a cost estimation was found in[8] for the Hywind substructure designed for carrying a 5 MW offshore wind turbine.

The price estimated in this study is about 3.7 M€. However, since the substructure needs to be designed to carry a 10 MW wind turbine an upscaling is required. The upscaling is not linearly since technically developements are considered. However, it is expected that cost will be significantly since the design consists of a large steel structure. The estimated manufacturing price for the floating substructure is 6 M€. Furthermore, a barge crane is considered with an associated day rate for of 40,000 €/d load-out process of the floating substructure in the fabrication yard. Each floating substructure requires 3 mooring lines and 3 anchors totaling 150 units for the entire FOWPP. The unit cost for a suction pile anchor is assumed to be 1.3 M€ and the mooring line has a cost of 250 €/m totaling 200,000 € for an 800 m steel chain.

The costs for the inter-array and export power cables are estimated based on the unit cost in €/m for the different power cables and according to its cross sections. For example the first cable in the feeder that transmits the power generated by one wind turbine has a cross section of 95 mm^2, with a length of 1.34 km and a unit cost of 182,25 €/m. A complete list of cable costs considered can be found in Annex 6. The cost associated to a typical offshore substation for a 500 MW offshore wind power plant can be assumed according to the Crown Estate as 60 M€.

8.11 Transportation and installation cost

The floating substructure will be built in a fabrication yard outside of the port, whereas the rest of the components will be purchased and supplied to the port. The floating substructure will be transported directly from the fabrication yard to the offshore site. The rest of the components will be transported from the port to the offshore site. The floating substructure, which is previously loaded into the water at the port will then be towed out by a tug boat and transported to the offshore site. The erection and assembly with the turbine is considered to be performed at the offshore site since the spar buoy concept is not suitable for a port side assembly. The floating substructures are ballasted at the offshore site with solid rocks and water [40]. Therefore, a barge is considered for the transportation of the materials. Before the floating substructure is delivered to offshore site the mooring lines and anchors are pre-installed. An anchor handling vessel is considered for this purpose equipped with a remote underwater vehicle that monitors the installation of the anchors and mooring lines. Once the anchors are let down to the seabed a suction pump will force them into their final position. The mooring lines are then marked with buoyancies for their later usage. A complete installation of an anchor and mooring is estimated to take 12 hours per unit. The floating substructure once arrived at the offshore site will be ballasted with the solid rocks and water and with the help of tug boats erected. After the correct positioning and installation of the floating substructures the mooring lines will be retrieved and fixed to the substructure. Finally, a crane vessel is employed to assemble the wind turbines to the floating substructures.

The power cables are transported and installed by a cable laying vessel. In addition, a diver is considered with a cost of 580 €/d. For the inter-array cables an installation rate of 6 km/d is assumed and for the export cables a rate of 4 km/d. The offshore substation will be transported and installed by a crane vessel with large storage area. The fuel cost considered for the vessels is about 0.61 €/l and the lease for the storage area in the port accounts to 0.0215 €/d/m^2. A total storage area for all components to be stored for a longer period in the port is assumed to be 1200 m^2. After complete installation if the entire FOWPP a final commissioning will be performed. A total cost of 600,000 € is taken into account for this activity. Furthermore, a construction insurance with a cost of 50,000 € is considered [7].

8.12 Operation and Maintenance cost

A lifetime of 20 years is defined for the operational period of the FOWPP. Furthermore, a warranty period of 5 years is considered, where cost associated to failures are born by the component suppliers. A cost of 7.5 M€ per year is considered covering all expenses occurring for the operation of the FOWPP such as insurances, land and facility leases, management, monitoring, and sales expenses. The maintenance of the FOWPP is performed as preventive and corrective maintenance. Preventive maintenance will be scheduled annually for the whole FOWPP and carried out with crew transfer vessels and vessels with ROV for the power cable. Helicopters are not considered in this study. In addition to the annual inspection every 5 years a major maintenance inspection will be carried out. For the replacement of spare parts, lubricants and component replacements a total cost of 9,000,000 € for all offshore wind turbines is considered. For the offshore substation 50,000 € is assumed, for the floating substructures 20,000 €, for the power cables 10,000 and mooring lines 500,000 € [8]. Corrective maintenance will be carried out in case of a failure of a component. For the offshore turbine a rate of 10 failures per year is assumed, whereas the other components possess lower failure rates. The floating substructure has a failure rate of 0.1, the power cables and mooring system 0.10. The offshore substation is considered with a failure rate of 0.50.

8.13 Decommissioning

Decommissioning is assumed to be a reverse installation process. The wind turbines will be disassembled from the floating substructures and transported to shore. The mooring lines will be disconnected and removed as well as the power cables. Afterwards the ballast will be removed from the floating substructure and it will be towed back by a tug boat to the port. It is assumed that the entire decommissioning process will be carried out faster than the installation process since lower accuracy is required. Therefore, for the day rates of the vessels a factor of 0.9 of the installation time is considered. Components with a value such as the steel and copper components can be sold. The rest will be disposed. No reuse is considered. Steel scrap metal price is assumed to be around 356 €/t and copper 2640 €/t.

Disposal costs are around 24 €/t and processing cost 10€/t is assumed [7]. The nearest point of sale is located 20 km from the port and the distance to the nearest disposal place assumed to be 50 km. For the transportation for the locations a truck with a day rate of 200 €/d is assumed. Since not all components can be transported at the same upon arrival a storage area has to be rented in the port. For this reason a total area of 15000 m^2 is considered. Besides that, a crane is considered in the port with a day rate of 200 € for transporting purposes. Finally, the site offshore site needs to be cleaned up. A clearance cost of 0.07 €/m^2 is considered with a total offshore site of 137 km^2 [7].

8.14 Results

At the specific offshore location in the Gulf of Maine the FOWPP generates annually a gross energy production of about 2543.67 GWh. Figure 56 shows the annual energy production profile according to the wind directions and wind speeds.

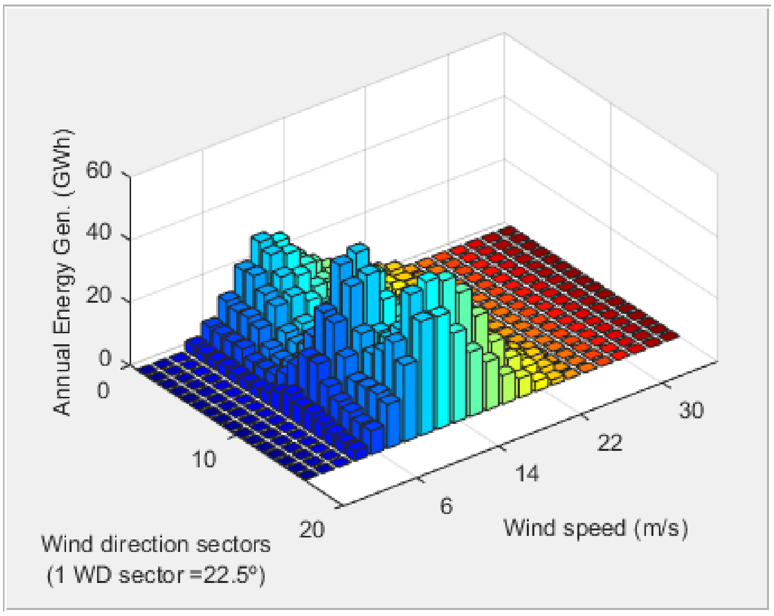

Figure 56: Annual Gross energy production

The net annual energy production considering all energy losses in the wind farm is totalling 2047.82 GWh. The efficiency of energy production is therefore around 80 % and the capacity factor is 46.75 %. Figure 57 shows the breakdown of energy production in the system.

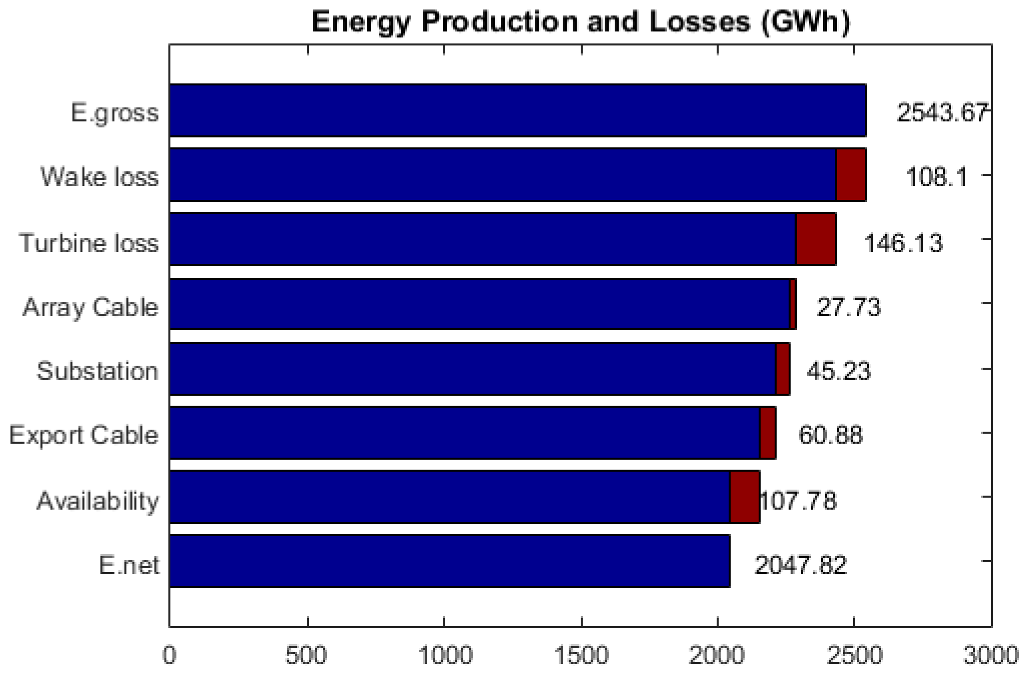

Figure 57: Energy breakdown

Considering a lifetime of 20 years the net energy productions totals to 40956.3 GWh.

For the calculation of the discounted costs a discount rate of 8 % is applied, which represents a conservative assumption for offshore wind power plants. The following figure represents all life cycle cost components.

It can be seen that the manufacturing cost represent the highest portion of the total life cycle cost. Operation and maintenance has the second highest portion since it includes costly repairs and maintenance tasks. Transportation has the lowest share since only a few days are considered for the actual transportation process. Most of the days the vessels are used for the installation process.

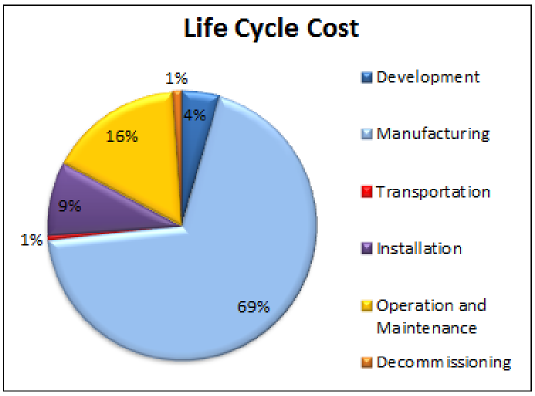

Figure 58: Life cycle cost

Furthermore, it can be seen that the life cycle cost are dominated by the CAPEX, which is the sum of the development, manufacturing, transportation and installation cost. The decommission cost represents a low share since the discounting of costs causes that the value today of the future decommissioning cost is significantly reduced. The next figure shows the manufacturing cost of the different components of the FOWPP. This is of interest since the total manufacturing cost represents the highest share in the life cycle costs.

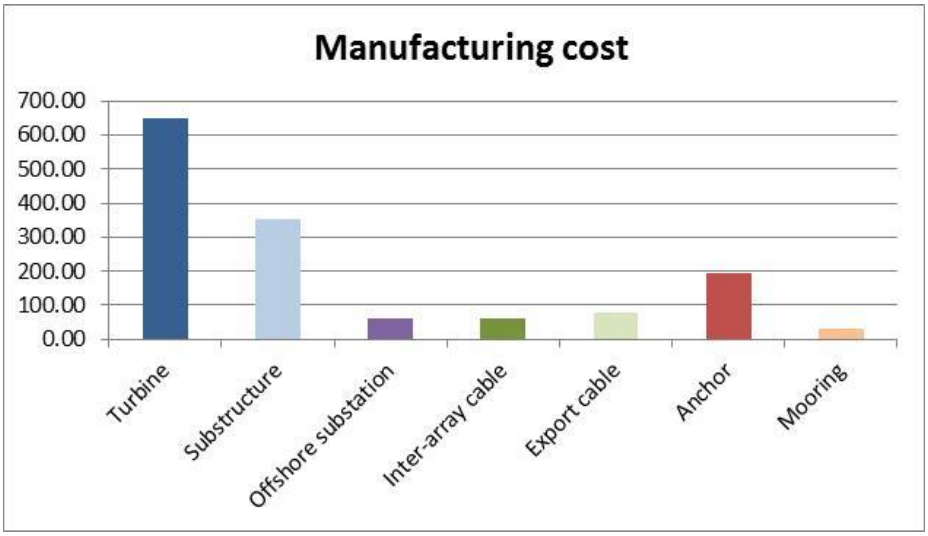

Figure 59: Manufacturing cost components breakdown

The offshore wind turbines represent the highest share as expected followed by the floating substructures. However, the third highest costs are caused by the anchors, which is due to their significantly high price based on the special characteristics of suction pile anchors.

The LCOE value is finally obtained by dividing the total cost of the FOWPP by the net energy delivered considering the 20 years of lifetime. For the considered FOWPP and the specific offshore site a LCOE value of **117.394 €/MWh** is obtained.

8.15 Discussion and comparison

Since floating offshore wind power is a young industry and most of the concepts are under development or at a pre-commercial stage there is a lack of information on realistic cost, which makes a proper LCOE calculation difficult. To obtain reliable information on capital and operation cost a full scale prototype needs to be installed and operated for a certain time. The cost data used in the LCOE calculation in this validation in largely based on literature values, which causes the results to be considered with a high uncertainty. However, in order to validate the calculation tool the obtained result is compared to reference LCOE values.

In 2013 Bjerkseter, C. and Agotnes, A.[8] have estimated in a study the LCOE for different floating wind turbine concepts. They calculated for the Hywind concept considering different configurations of the FOWPP a LCOE range of 103.5 €/MWh to 203.0 €/MWh (Carbon Trust, 2015). Carbon Trust has performed in 2015 a market and technology review of floating offshore wind power and has estimated LCOE values for different floating technologies and in different commercial stages. The company concluded that the LCOE for FOWPP could be in average around 118 M€/MWh ranging from prototypes at 224 M€/MWh to commercial projects of 107 M€/MWh. They also pointed out the cost reduction potential of floating wind power in comparison to bottom fixed offshore wind power plants, which LCOE ranges from 150 to over 220 M€/MWh (Carbon Trust, 2015). The cost reduction potential for floating wind power is based on the savings for the substructures since less material is required and the potential utilization of higher wind speeds at locations farer offshore (Carbon Trust, 2015).

The calculated LCOE in FOWAT validation has a value of 117.394 €/MWh and falls into the range stated by reference values from literature. Therefore, it can be concluded that the LCOE tool has been validated and serves as a proper LCOE calculation tool for FOWPPs.

8.16 Sensitivity analysis

A sensitive analysis is carried out in order to identify how the LCOE varies with changes in key parameters. The parameters that were analyzed in this study are presented next.

Table 29: Key parameters analysed

		Base Case		
Turbine price (M€)	1.1	1.3	1.5	1.7
Distance to shore (km)	30	65	90	200
Project lifespan (years)	15	20	25	30
Discount rate (%)	6	8	10	12

The LCOE was calculated for each variation in the parameters. It has to be mentioned that only a single variation is considered in the LCOE calculation, not the effect on the LCOE based on several variations. The base case is the FOWPP with a distance to shore of 65 km, a turbine price of 1.3 M€, a project lifetime of 20 years and a discount rate of 8%. The results of the sensitivity analysis are presented in the next figure.

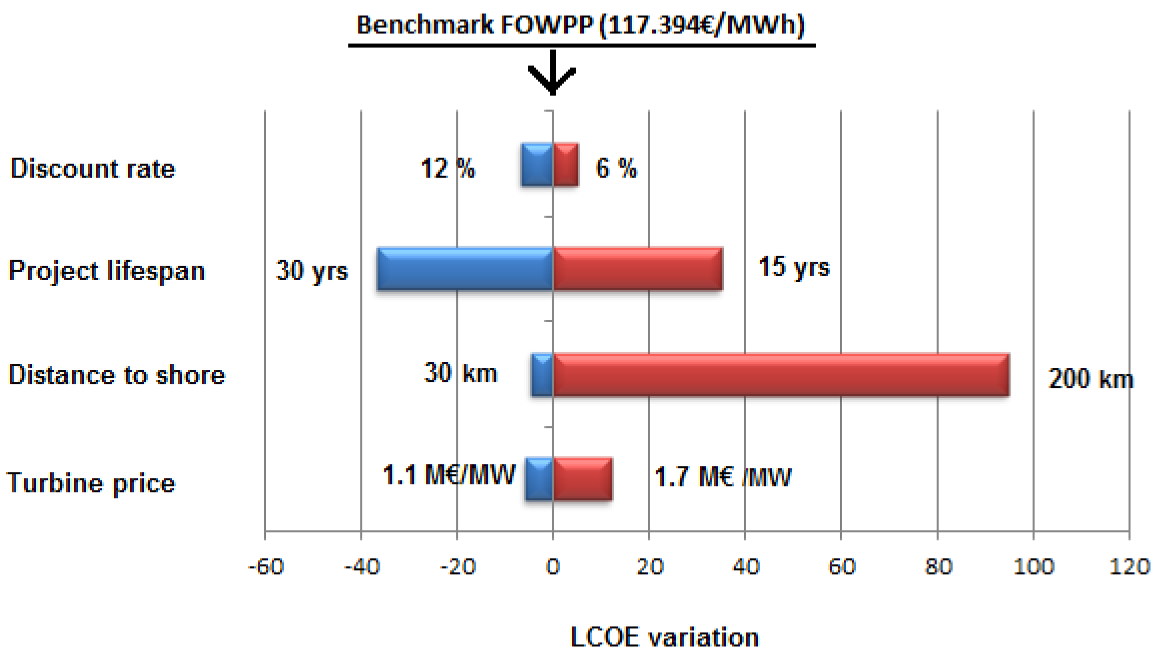

Figure 60: Results of sensitivity analysis

The figure shows the variation in the LCOE according to changes of the key parameters. It can be seen that the change in the discount rate has a relatively low influence on the final LCOE value, but it has to be noted that a lower discount rate will increase the LCOE of the FOWPP. The lifespan of the project has a larger influence on the LCOE. With a higher lifetime of the FOWPP more energy is generated and consequently the LCOE decreases. Furthermore, most of the total costs are based on the capital expenses which occur at the beginning of the project and are not related to the lifetime.

The operation and maintenance costs are comparably low. Thus an increased project lifetime favours the LCOE. The distance to shore has the largest impact on the LCOE. It can be seen that with an increased distance the LCOE increases significantly. This is due to the fact that with a higher distance to shore the export cable length has to be increased, which causes higher energy losses in the cable. Since not only the energy losses increase with a larger distance, the costs are also increasing because of the larger export cables. Thus, consequently the LCOE increases significantly. Finally, the turbine price has also an influence on the LCOE, but not as much as the distance and lifetime. With a higher price of turbine the total costs are increasing and thus the LCOE value increases as well.

9 Conclusions

The aim of this deliverable was to describe modules that comprehend the LIFES 50+ Overall Evaluation tool named “Floating Offshore Wind Assessment Tool- FOWAT” that has been developed within this Project to qualify the four concepts designs under an economic, environmental, risk and technical perspective as depicted in Figure 61. FOWAT Structure

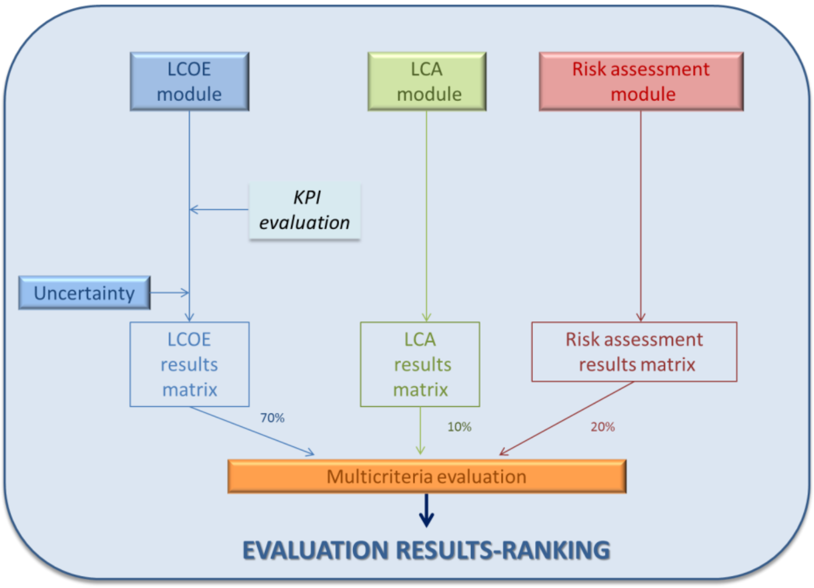

Figure 61. FOWAT Structure

For this reason, this document has depicted of the Overall Evaluation tool by including a detailed description of the economic evaluation module capable to calculate the Levelised Cost of Energy (LCOE) for each life cycle stage, the environmental evaluation module that performs the Life Cycle Assessment (LCA) of the concepts and the descrption of the technical Key Performance Indicators (KPI) that are used in the evaluation.

Regarding the LCOE assessment, the document explains how the costs for each life cycle stage are going to be calculated in the tool, considering both concept designers data and literature data for common components. Furthermore, the document explains the methodology that has been used for energy production calculation using the layouts provided by DTU that include energy lossess due to wake effect.

The LCOE calculations for the evaluation will be carried out together with an uncertainty analysis using a list of 26 uncertainty drivers.

As a final remark, it should be stated that the methodology that this document presents for the LCOE ranking considering the uncertainty has been proposed by IREC to the Evaluation Committee and its use within the project is subject to its approval by the end of M17 (October 2016).

Regarding the LCA analysis, section 5 focuses on describing the methodology behind this assessment and the selection of 3 environmental impact indicators that are going to be calculated for the 4 concepts at each site (Global Warming Potential, Non-fossil abiotic depletion potential, Primary Energy consumption).

This document does not include a description of the Risk methodology nor its calculation tool since this is done in deliverable D2.5.

Section 6 of this document has provided a description and list of the Key Performance Indicators that have been selected to characterise the concept designs. These KPI will be used during the data collection process in order to verify the consistency of the data provided by the concept designers for the LCOE calculation. Besides, KPI will not be included in the multi-criteria decision methodology for selecting the 2 concept designs for Phase 2 evaluation.

Section 7 of this deliverable has provided a description of the Multi-criteria methodology that has been implemented in the tool to provide a single final ranking of the 4 concept designs using the following weighting factors:

- Economic Assessment-LCOE= 70%
- Risk Assessment= 20%
- Environmental Assessment- LCA= 10%

The Multi-Criteria module will store in the different matrix results of the LCOE and LCA calculation for each site and concept design. Each matrix will be treated in order to convert the absolute values (e.g. €/MWh for LCOE, or kg CO_2eq for LCA) into scores from 1 to 4 as explained in D2.5. There will be no need of further treatment of the the outputs from the Risk module, as they will be expressed in the same dimensionless scoring sytem.

In any case this document provides specific information regarding the concepts and information regarding the use of the tool.

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