Deliverable 1.2.3

PI-based Assessment of Innovative Concepts

(Methodological Issues)

April 2014

Agreement n.:	**308974**
Duration	Nov 2012-Oct 2017
Co-ordinator:	Peter Hjuler Jensen, DTU

Support by:

SEVENTH FRAMEWORK PROGRAMME

Document information

Document Name:	PI-based assessment of innovative concepts (methodology)
Document Number:	Deliverable D1.2.3 Dissemination Level PU
Author:	P.K. Chaviaropoulos, I. Karga, C. Harkness and B. Hendriks
Review:	A. Natarajan
Date:	April 2014
WP:	WP1: Conceptual Design
Task:	Task 1.2: Assessment of Innovation at the Subsystem Level

TABLE OF CONTENTS

INTRODUCTION

1.1. Scope and Objectives

In this document we present the methodology that will be used for the structural assessment and performance evaluation of various innovative concepts that will be developed in the INNWIND.EU project. Given a new design this methodology will be able:

- To indicate that the design is structurally sound and, then,
- To calculate the resulting values of the performance indicators of Deliverable 1.22 using appropriate cost models.

Regarding the first bullet point, the main objective is to develop an easy to use, still reliable, methodology for verifying that the proposed innovative designs can withstand the loads they are to be designed for. The methodology must be applicable for both single components and full wind turbines. The expectation is not a detailed check of the structural integrity of new designs but a preliminary verification of its design.

As regards the second bullet point, the objective is to develop suitable cost models for those components researched in the project, along with realistic assumptions for all others. These cost models will reflect the impact of the new designs on the turbine CAPEX and, therefrom, to the performance indicators adopted and presented in Deliverable 1.22 [0].

To address the above objectives the report is split into two relevant Parts, Part I: Structural Integrity Check and Part II: Cost Models

PART I: STRUCTURAL INTEGRITY CHECK - RECOMMENDATIONS FOR LOAD CASES TO BE CONSIDERED DURING INNOVATION ASSESSMENT

by Christine Harkness and Ben Hendriks

2.1 Introduction

This technical note gives recommendations for which load cases should be considered when assessing new turbine innovations on multi MW scale wind turbines. The recommendations aim at identifying the main impact of the innovation on the design driving mechanical loading on the overall system. These recommendations have been broken down into a ***three stage approach***. *Stage 1* should be used as a first pass concept comparison and *Stage 2* should be used as a first step towards finding any loading issues within a chosen concept. *Stage 3* should be used for detailed turbine design and certification. It should be noted that the load cases in stage 1 and stage 2 should act as a starting point for an initial assessment and comparison of new innovations however they are not a substitute for running a full set of load calculations (i.e. Stage 3).

2.2 Stage 1 – Concept comparison

When assessing new concepts it is first recommended to use a reduced set of load cases as a means to exclude weaker concepts at a very early stage in the analysis. This type of assessment is particularly useful if a large range of concepts are being considered. At least the following load cases should be included for each of the work packages areas are listed below. All load case numbers refer to the IEC 61400-3 Ed. 1. [2]

Blade innovation – work package 2

(It is assumed that the sea states do not affect the blade loads for fixed base wind turbines)

- DLC1.3 – Power production with extreme turbulence model
- DLC2.1 – Power production plus occurrence of fault. The collective pitch runaway to fine fault is considered to be a particularly severe fault within this load case

Drivetrain innovation – work package 3

- DLC2.3 – Power production with extreme operating gust and with grid loss
- DLC2.2 – Generator short circuit

Offshore support structures – work package 4

- DLC 1.1, 1.2 – Power production with normal turbulence model in conjunction with the expected value of significant wave height and peak spectral period considering irregular waves with a JONSWAP spectrum (analysed for both fatigue and extreme).
- DLC 6.1 – Idling with extreme wind model and 50 year significant wave height for extreme load analysis.

It is worth noting that there are several reasons why a viable concept may not pass this initial stage for example if the turbine controller requires further tuning or if the numerical model is a poor approximation of the proposed concept. Several iteration loops of stage 1 may be required before a concept can be progressed to stage 2 or alternatively discarded.

2.3 Stage 2 – Preliminary concept assessment

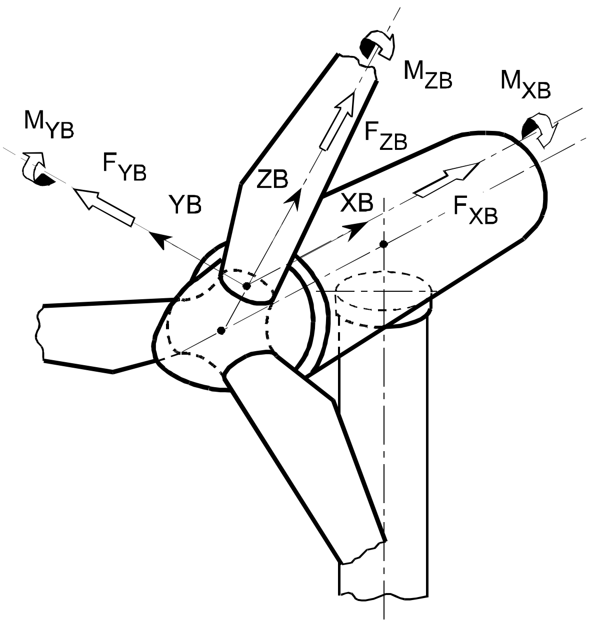
This stage of assessment is useful for any concepts which have passed stage 1 and require further analysis before carrying out a full set of load calculations.

Firstly the load cases which should be considered for any multi MW turbine are listed and finally some additional comments are given for areas which should be considered for specific types of turbine innovations.

As an aid to deciding which load cases to consider, a subset of load components were selected due to their importance for the design and specification of turbine components. These are listed below along with the turbine component which they are likely to drive. The coordinate systems used are defined in the GL standard [1] and are shown in

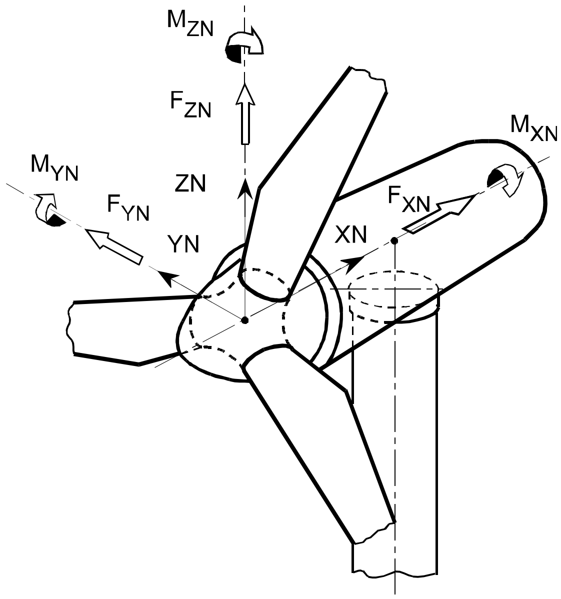
Figure 1 to Figure 3.

- Stationary Hub Mx - gearbox specification (fatigue and extreme)/rotor lock (extreme only)
- Stationary Hub My (fatigue & extreme) - mainframe (negative My combined with hub Fz can be driving for rotor bearings)
- Stationary Hub Myz (fatigue & extreme) - mainframe
- Blade root Mxy (extreme) - pitch bearing specification / blade root design / bolted connections
- Blade root Mz (fatigue & extreme) – pitch locking device / pitch bearing ring gear/ pitch actuator specification
- Blade root Mx (fatigue) – hub design and bolted connection of pitch bearing
- Yaw bearing Mxy (extreme) – yaw bearing
- Yaw bearing Mz (fatigue & extreme) – yaw bearing ring gear / yaw actuator
- Tower base My (fatigue & extreme) – tower design / foundation design
- Blade tip to tower clearance
- Hub Center forces, Fx, Fy (extreme)



ZB	Radially along blade pitch axis.
XB	Perpendicular to ZB, and pointing towards the tower for an upwind turbine, or away from the tower for a downwind turbine (the picture shows an upwind turbine).
YB	Perpendicular to blade axis and shaft axis, to give a right-handed co-ordinate system independent of direction of rotation and rotor location upwind or downwind of the tower.
Origin	At each blade station.

Figure 1 *Co-ordinate system for blade root loads and deflections*



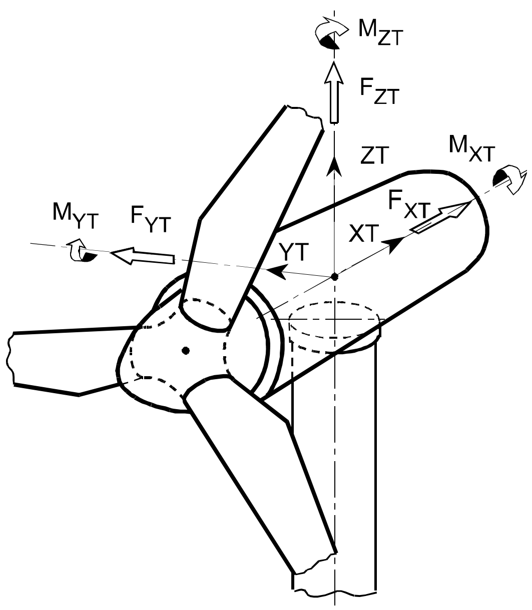
<u>Hub loads in fixed frame of reference:</u>

XN	Along shaft axis, and pointing towards the tower for an upwind turbine
ZN	Perpendicular to XN, such that ZN would be vertically upwards if the tilt angle were zero.
YN	Horizontal, to give a right-handed co-ordinate system independent of direction of rotation and rotor location upwind or downwind of the tower.

<u>Hub loads in rotating frame of reference:</u>

XN	Along shaft axis, and pointing towards the tower for an upwind turbine
ZN	Perpendicular to XN, such that ZN would be aligned with blade 1 axis if the cone angle were zero.
YN	Perpendicular to XN and ZN, to give a right-handed co-ordinate system independent of direction of rotation and rotor location upwind or downwind of the tower.
Origin	At hub centre (intersection of blade and shaft axes).

Figure 2 *Co-ordinate system for hub loads*



XT	Pointing South.
ZT	Vertically upwards.
YT	Pointing East.
Origin	At each tower station.

Figure 3 *Co-ordinate system for tower loads and deflections*

Extreme load cases were selected which are likely to drive the load components listed above for turbines within the multi MW scale. The load cases were selected from the IEC 61400-3 Ed. 1 standard [2] and are listed below. These can relate to onshore conditions as the Rotor Nacelle Assembly is often designed according to generic wind classes and no wave environment for fixed base offshore turbines, as these tend to produce only a very minor effect on these components.

- DLC2.2 – Power production plus occurrence of fault. The pitch seizure fault case (one blade seizes during operation) is particularly severe within this load case.
- DLC1.4 – Extreme coherent gust with direction change
- DLC2.1 – Power production plus occurrence of fault. The collective pitch runaway to fine fault is considered to be a particularly severe fault within this load case
- DLC6.2 – Idling with loss of electrical network connection with extreme wind model. The case where loss of the electrical connection results in inactivity of the yaw drive and therefore large yaw errors is considered to be most severe
- DLC1.3 – Power production with extreme turbulence model
- DLC2.3 – Power production with extreme operating gust and with grid loss
- DLC4.2 – Normal shutdown with extreme operating gust
- DLC8.2 – Uncompleted maintenance load case using the extreme wind model with a one year recurrence period. This case should be modelled according to offshore conditions if the turbine is to be an offshore turbine.

For a reduced set of fatigue loads it would be possible to run a reduced number of wind seeds per wind speed bin when calculating a subset of fatigue loads. In effect when creating simulations for DLC 1.2 (power production with the normal turbulence model) and DLC 6.4 (idling with normal turbulence model) one or two seeds in each wind speed bin would be sufficient for an initial assessment or comparison, instead of six wind seeds as would be required for a full assessment.

In general when moving from small wind turbines towards larger multi MW machines some trends have been observed and should be considered when selecting a sub set of load cases.

- Rotor lock cases are more severe than for smaller turbines. This can be observed in offshore maintenance load cases due to more strict offshore requirements i.e. rotor lock may have to hold for a long period during storms as personal may not be able to reach the turbine.
- Tower clearance issues more frequent due to larger and more flexible blades in larger turbines
- Larger rotor mass compared to smaller machines. This can result in larger moments at yaw bearing which aren't observed in smaller machines.

It has also been noted that in some load components that extreme loads become more dominant than fatigue loads as the size of machine increases. An example of this is the ratio of extreme load to damage equivalent load for Blade root My plotted against rotor diameter as shown by the trend line in Figure 4. This trend line is based on a large set of design loads calculated for a wide range of turbine designs. The gradient of the trend will vary depending on the load components and also some load components show a stronger tendency towards this trend than others. Further the data shows a significant scatter.

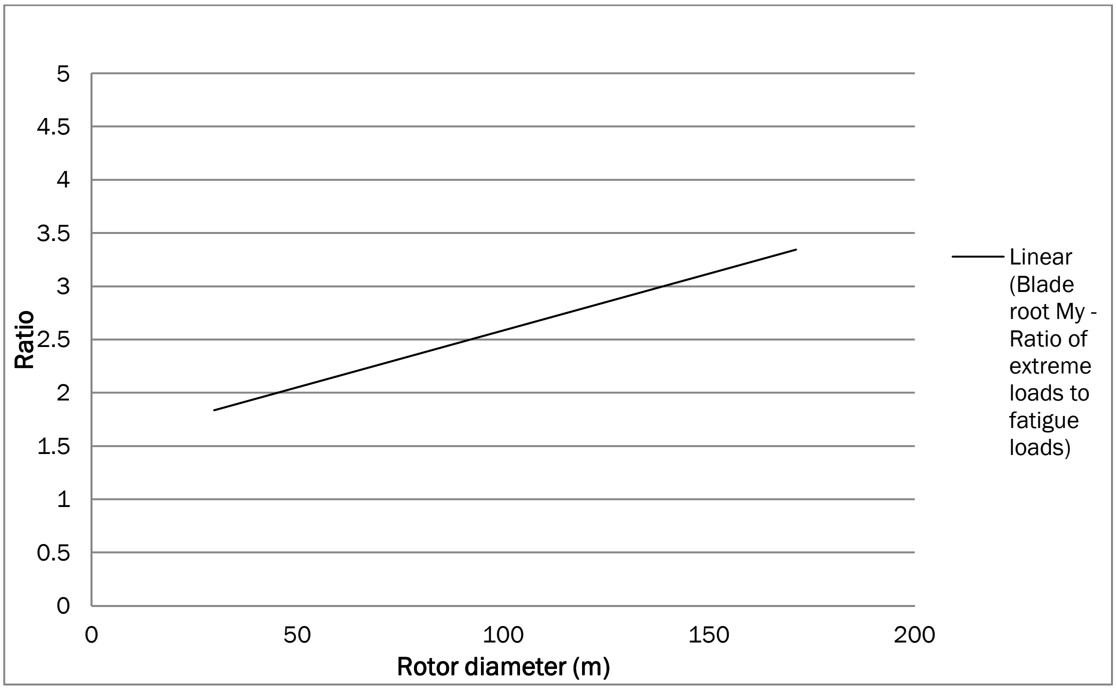


Figure 4 *Blade root My - trend line for ratio of extreme loads to fatigue loads*

Below comments and suggestions are made to assist with the selection of load cases for three areas of turbine innovation.

Blade innovation – work package 2

When thinking of considering additional load cases for areas of blade innovation it would be worth considering the additional fault cases which may occur. An example of this would be a blade which uses active distributed control (or blade flaps) will have additional fault cases which are different than for a traditional blade design. One possible fault case may be a flap on one blade becomes unresponsive. This is unlikely to drive extreme loads along the blade compared to a typical pitch runaway fault, however the fault should still probably be modelled in order to calculate the flap strength requirements. As a general guidance, failure cases of these devices should be included if it's considered to be more severe than the other fault cases included in the extreme subset.

Generator innovation – work package 3

When assessing new generator innovations some thought should be given to any extra fault cases which should be included. An example of this is to include the short circuit fault case if considering a super conducting generator as this may have a large effect on the hub Mx loads. Other areas which may be problematic include increased rotor over speeds in the event of grid loss. In this case DLC2.3 (extreme operating gust with loss of electrical network) should be included in the extreme load analysis.

Fixed Support Structures - work package 4 *(reviewer's addition)*

Many fixed support structure designs are governed by fatigue design loads. Therefore on top of an extreme load analysis, appropriate number of fatigue loads simulations of the wind turbine mounted on the full sub structure must be made, i.e.

- DLC 1.2 with mean wind speeds from cut-in to cut-out in steps of 2m/s bins and with appropriate irregular sea waves
- The effect of soil-pile interaction must be considered
- Wind speeds at which rotor induced support structure excitations can take place must be simulated to a larger extent.
- DNV-OS-J101 offshore design standard and DNV-RP-C203 Recommended practice for fatigue design of offshore structures can be referenced for further guidance.

Floating support structures – work package 4

There are a number of considerations when choosing a sub set of load cases for floating support structures.

- Fully coupled aero-hydro-elastic simulations must be performed which includes mooring line dynamics to the extent of its influence on turbine pitching and yawing motion.
- The platform frequency domain response should be checked when deciding which Tp (peak spectral period) values may give the highest loads for both fatigue and extreme cases (in particular for the DLC 6.x case). Nonlinear waves (either Stokes regular waves or second order irregular waves) with low sub harmonic frequencies should be considered where possible.
- The DNV standard for floating [3] requires that the extreme operating gust case be considered with different time periods as longer time periods may excite the platform modes.
- Additional cases for damaged stability of the turbine and loss of mooring line should be considered (depending on configuration of the concept)
- Single blade pitch failure (DLC2.2 and 7.1) should be considered for platforms which are very flexible in yaw.
- Storm cases with high sea states (DLC1.6) are considered to be worst for floating turbines and should be included in calculations from an early stage
- Generally speaking, an important range of additional cases should be modelled compared to non-floating conditions due to the differences in modelling approaches between both. As an example, fatigue load cases should be run considering the whole 360º directions of wave approach and run using longer simulations (typically 3600s each) to cover the slower frequency responses of the floating platform.

2.4 Stage 3 – Full assessment

A full set of load calculation should be completed to one of the standards e.g. IEC 61400-3 Edition 1 before detailed design commences or if certification is required. It should be noted that the calculations which are given in the standards are a minimum requirement for certification and any novel features of the design should be assessed for potential modes of failure and included in the load calculations if required.

PART II: COST MODELS

by Panagiotis Chaviaropoulos and Ifigenia Karga

3.1 Needs and Specifications

The assessment of innovation necessitates the establishment of a framework where different designs can be compared against a reference one (here the Reference Wind Turbine (RWT) of [3]) on the basis of suitable key performance indicators (KPIs). Following EWII, we have selected in [0] the Levelised Cost of Electricity (LCOE) as the overarching KPI of INNWIND.EU. To estimate LCOE we need the CAPEX (and OPEX) of the reference and the innovative designs. We therefore need detailed enough, sub-component based, cost models that will estimate CAPEX with adequate sensitivity to the key design parameters of the turbine. Parallel to cost, we also need to develop mass models for assessing the downstream influence of the innovative sub-components. Cost modelling of OPEX is not part of the INNWIND.EU project and, therefore, out of scope of the present work.

On the basis of the above needs we imposed the following specifications for the development of the cost and mass models of INNWIND.EU:

- The cost and mass models should be developed at the sub-component level
- The models should be based on key turbine design parameters (Rated Power, Diameter, Hub-height, Rated Torque etc.) and operating conditions, when appropriate (wind class, water depth, soil conditions, distance from land etc.)
- The models should be suitable and flexible enough for up-scaling studies too, taking account of technology learning curves when appropriate
- It is useful for the cost models to take account of variations in raw materials pricing, inflation and currency fluctuations so that cost data from different periods and markets can be synchronised
- Previous experience from earlier cost modelling works in WINDPACT (USA)[1] and UPWIND (EU)[2] should be explored

To satisfy the above specs we developed the INNWIND.EU cost and mass models along the following lines:

1. We adopted the general approach of the NREL Wind Turbine Design Cost and Scaling Model [1]. The model uses the so called ”Producer Price Indexes” (PPIs) sorted by North American Industry Classification System (NAICS) codes that provide a rational grouping of U.S. industries and products. It is, thus, able to provide projections of the impact on cost from changes in economic indicators, such as raw material price changes, GDP changes etc.
2. For “standard” components, not of particular INNWIND.EU focus, we shall be still using the mass and cost models of [1] but properly calibrated with existing mass data for larger turbines, such as the 5 MW NREL and UPWIND [2] turbine or the 10 MW INNWIND.EU RWT [3]. For the innovative components that are developed in INNWIND.EU, such as the smart blades, the superconducting and pseudo magnetic direct drive generators and the offshore support structures dedicated cost models shall be developed and used in the course of the project.
3. Up-scaling mass and cost exponents, taking account learning curve effects, shall be used for including size dependence. Following the formulation presented in [0], we assume these exponents to apply on a “length” scale. In our case, this “length” scale shall be the square root of rated power (closely but not uniquely related to the turbine diameter).

[1] http://www.nrel.gov/wind/windpact.html
[2] http://www.upwind.eu/

4. There is a lack of published CAPEX data regarding the offshore-driven (non-turbine) costs such as transportation and installation, port and staging equipment, scour protection, decommissioning etc. Even when such data exist they address swallower water installations and smaller distances from the cost than those of INNWIND.EU interest. Despite the lack of reliable data, we have maintained these sub-categories in the cost model for completeness. In most of the cases we assume that these costs are proportional to the turbine capacity so that their impact on LCOE is neutral. Similar assumptions are made in [1] and [5].

3.2 Implementation Details

The generalized INNWIND.EU mass model, applied to all sub-components, is given in Eq (1). The mass can be either expressed as a function of design parameters (rated power, rotor diameter, hub-height, ultimate load etc) or, in a much simpler way, through an up-scaling law (the right alternative) which starts with a given mass at a reference size (scale=1) and projects it with a scale exponent (λ_mass) to the scale of interest (s). As earlier discussed, the "lenght" scale used in this context is the square root of the ratio of rated powers. In this case λ_mass incorporates learning curve effects and its lowering from the corresponding classical (similarity based) up-scaling exponent is a measure of technology advancement for this particular subcomponent (for a deeper discussion on up-scaling exponents see [0]).

$$Mass_{sub} = M(Power,\ D,\ \dots) \quad \text{or} \quad Mass_{sub}(\mathrm{s}) = Mass_{sub}(1).\,\mathrm{s}^{\,\lambda\_mass} \tag{1}$$

In a similar way one may devise the generalized cost model of Eq (2). Costs are changing in time, thus the cost model has to address currency and year of reference ($20xx in this case). A simpler version of a cost model is the right-hand-side variant of Eq (2) where the cost is proportionally linked to the sub-component mass through $Cpum$, the "cost per unit mass" (taking account of all cost components, e.g. materials, labour, tooling, etc).

$$Cost_{sub}{}^{\$20\mathrm{xx}} = F(Power,\ D,\ \dots)^{\$20xx} \text{or } Cost_{sub}(s)^{\$20\mathrm{xx}} Mass_{sub}(\mathrm{s}) * Cpum^{\$20xx} \tag{2}$$

Our final goal is to express the INNWIND.EU cost models in € (2012). However, to take full advantage of the NREL cost model, along with the extensive technology evaluation work performed in the WINDPACT project and the rich database on PPIs sorted by North American Industry Classification System (NAICS) Codes, we shall work with USD ($) to translate costs of 20xx to 2012 and then make them € using the 2012 exchange rate (€/$). This procedure is formulated in Eq (3).

$$Cost_{sub}{}^{€2012} = Cost_{sub}{}^{\$20\mathrm{xx}} * (1 + PPI_{sub}{}^{\$2012}_{\$20xx}) * (€/\$)_{\ 2012} \tag{3}$$

The PPIs of NAICS provide a rational grouping of U.S. industries and products. The PPIs database was scoured for categories comparable to wind turbine components. In some instances, a wind turbine component is represented by a composite of several PPI categories, each of them contributing to the component cost at a fraction X. Labour-intensive components such as rotor blades and electrical interface components include a labour cost escalator, which was specified as the general inflation index, based on the Gross Domestic Product (GDP). The overall component PPI derives from the summation of Eq (4) for all contributing categories.

$$PPI_{sub}{}^{\$2012}_{\$20xx} = \sum_{j=1}^{categories} X_j .\, PPI_j{}^{\$2012}_{\$20xx} \tag{4}$$

Figure 5 presents an example of a PPI from the category "Iron foundries / Other ductile iron castings" with a Series Id: PCU33... (useful for a quick search of the database). It is seen that this particular index has been increased by 63% (173-110) the time period 2002-2012. Then, following our notation, the relevant PPI value is, $PPI_{PCU33151..}{}^{\$2012}_{\$2002} = 0.63$.

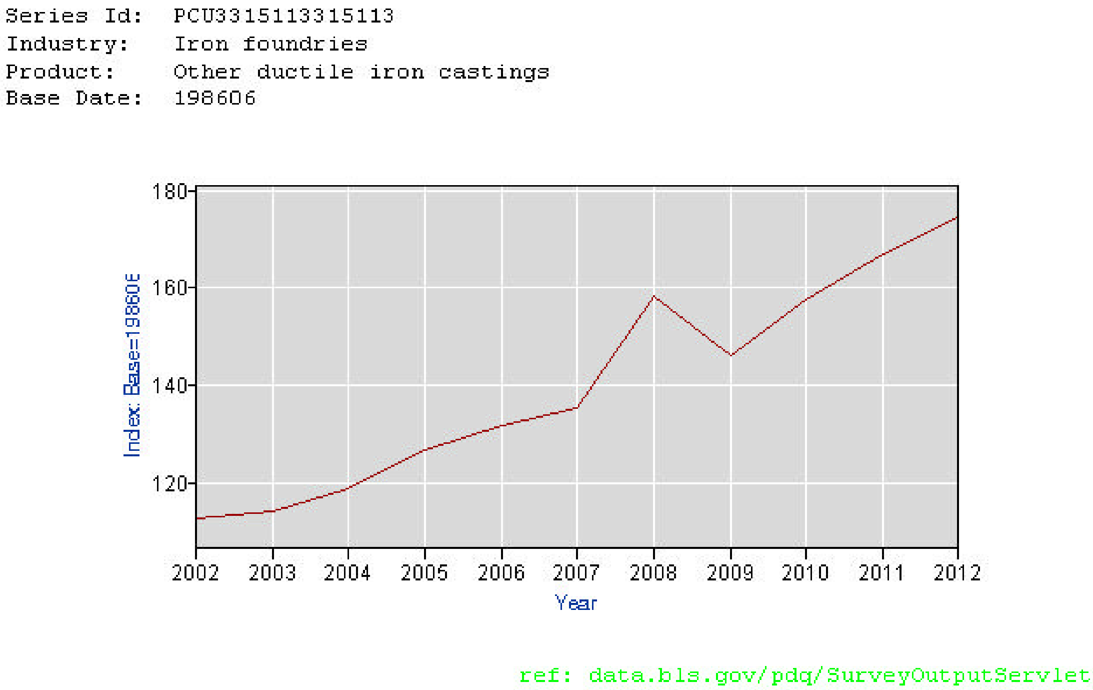


Figure 5 *An example of PPI*

3.3 The Mass and Cost Models Spreadsheet

INPUT PARAMETERS AND RESULTS AREA

The mass and cost models have been implemented in an XLS spreadsheet. We shall present in this section the contents of the spreadsheet and the way to use it.

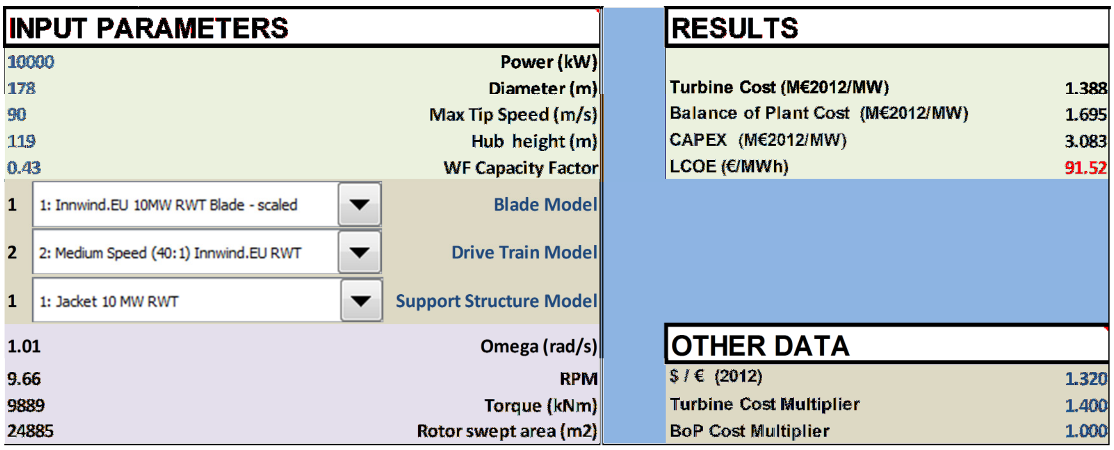


Figure 6 *The I/O section of the cost model*

The input / output area of the cost model spreadsheet is shown in Figure 6. The input parameters at the left are self-explanatory, comprising the turbine rated power and diameter, the tip speed and hub height and the wind farm capacity factor. Here we use the INNWIND.EU RWT data for the turbine, assuming a capacity factor corresponding to the "Classical 10 MW up-scaling" of [0] (figure 5 of the report). Then, the user has the possibility to select a cost model for the three main turbine components researched in INNWIND.EU, the blades, the drive train and the offshore support structure. The models currently implemented for the above three component will be presented below.

At the right-down part of the figure there are some “other data” comprising the USD - Euro exchange rate at the reference year (2012) and two multipliers, one for the turbine cost and one for the balance of plan cost. The cost model refers to the wind farm developer. This means that the turbine cost appearing in the “Results” part of the spreadsheet is the turbine purchasing price and not the turbine cost itself, which is addressed by the turbine cost models. This difference is handled through the turbine cost multiplier. Similar considerations are valid for the BoP multiplier.

The results area, at the upper right side of the figure, include the total CAPEX (the sum of the turbine and BoP cost) per MW installed, as well as the Levelized Cost of Electricity in $€/\mathrm{MWh}$ computed by the LCOE calculator of [0] (embedded in the cost-model spreadsheet).

To facilitate the cost model user regarding the I/O usage we have adopted the following notation for the colours used:

- Numbers in blue fond address INPUT data (the user can change then)
- Numbers in black fond are intermediate OUTPUT data (the user should not change them)
- Numbers in red fond are the most significant OUTPUT data (the user should not change them)
- Areas in green fond are areas that might need revision by the INNWIND.EU experts

TURBINE AND BoP COMPONENTS AREA

This is the spreadsheet area where the turbine and BoP components mass and CAPEX is calculated. The split in subcomponents (or subcategories) is quite detailed for both the turbine and the BoP parts, following [1]. This is even more detailed than the categorization used in [0] (see Tables 4 and 5 of that report).

Figure 7 presents the information provided in the Turbine and BoP Components Area. The content of the columns, moving from left to write, is:

1. The percentage contribution to the turbine or BoP cost of each subcomponent.
2. The name of the component. With capital letters we present major groups (such as ROTOR, DRIVE TRAIN & NACELLE) comprising the sub-components listed below with small letters.
3. The mass Scaling Factor λ_mass when the RHS variant of Eq (1) or (2) is used.
4. The component mass in kg, resulting from Eq (1)
5. The component cost in \$2002 resulting from Eq (2). We use 2002 (as 20xx) since the available cost models from [1] correspond to that reference year.
6. The component cost in \$2012 resulting from Eq (3).
7. The PPI used in the previous column. Evidently, the PPI can be used both ways, from 20xx to 2012 and backwards, if needed. This PPI is calculated following Eq (4).
8. Comment on the mass model used. For most of the subcomponents that are not of particular INNWIND.EU interest (like hub, pitch mechanisms, low speed shaft etc) we use the NREL model of [1]. This is written as a comment “From [1]” to avoid repeating the exact formula. In other cases, for instance “Combination of [2] and [3]” we use available mass data from the UPWIND and INNWIND.EU Reference Wind Turbines. The references numbering in this report and the spreadsheet are the same.
9. Comment on the cost model. For most of the turbine components a mass-based model is used. For the BoP part, rating-based (LCOE neutral) models are used.

	COMPONENT	SF	Mass (kg)	Cost ($2002)	Cost (€2012)	PPI	Comment on Mass	Comment on Cost
21.59%	ROTOR		249,973	2,316,360	2,140,821			
13.55%	Blades		125,148	1,624,080	1,343,803	9%	See blade model below	See blade model below
4.47%	Hub	2.30	88,766	377,254	442,987	55%	Combination of [2] and [3]	Weight * 4.25 $2002/kg [1]
3.39%	Pitch mechanism	2.30	33,287	299,584	335,897	48%	Combination of [2] and [3]	Weight * 9.00 $2002/kg (Assumed)
0.18%	Nose cone		2,773	15,443	18,134	55%	From [1]	Weight * 5.57 $2002/kg [1]
44.44%	DRIVE TRAIN & NACELLE		329,312	3,896,531	4,407,068			
2.95%	Low speed shaft	3.00	76,962	230,885	292,104	67%	From [2]	Weight * 3.00 $2002/kg (Assumed)
3.52%	Main bearing		18,203	320,375	349,500	44%	From [1]	Weight *17.60 $2002/kg [1]
10.31%	Gearbox		85,168	899,375	1,022,017	50%	See drive train model below	See drive train model below
0.16%	Mechanical brake & couplings	3.00	2,828	19,894	15,975	6%	From [2]	From [1]
6.71%	Generator		45,860	618,137	664,966	42%	See drive train model below	See drive train model below
8.27%	Power electronics			790,000	819,924	37%	NA	Rating * 79.00 $2002/kW [1]
0.91%	Bed plate		32,162	76,562	89,903	55%	See drive train model below	See drive train model below
1.19%	Hydraulic & cooling system		800	120,000	118,182	30%	From [1]	Rating * 12.00 $2002/kW [1]
0.89%	Nacelle cover	2.00	26,000	104,000	88,715	13%	From [2]	Weight * 4.00 $2002/kg
5.79%	ELECTRICAL CONNECTIONS			400,000	574,394	90%	NA	Rating * 40.00 $2002/kW [5]
3.75%	YAW SYSTEM		41,329	317,303	371,389	55%	From [1]	From [1]
0.55%	CONTROL, SAFETY SYSTEM, CM			55,000	54,167	30%	NA	From [5]
23.09%	TOWER	2.00	694,920	1,737,300	2,290,077	74%	Combination of [2] and [3]	Weight * (1.50 to 4.25) $2002/kg ([1] Adj)
10.33%	MARINIZATION			1,073,276	1,024,490	26%		From [1]
100%	Turbine		1,274,205	9,078,466	9,916,624			
56.03%	Foundation system		1,920,000	8,766,277	9,496,800	43%	See Foundation Model Below	See Foundation Model Below
9.52%	Offshore transportation			1,500,000	1,613,636	42%	NA	Rating * 100.00 $2002/kW ([1] Adj)
1.28%	Port and staging equipment			200,000	216,667	43%	NA	Rating * 20.00 $2002/kW [1]
9.59%	Offshore turbine installation			1,500,000	1,625,000	43%	NA	Rating * 100.00 $2002/kW [1]
20.07%	Offshore electrical I&C			2,600,000	3,401,667	73%	NA	Rating * 260.00 $2002/kW [1]
0.00%	Offshore permits & engineering				0	26%	NA	
0.00%	Personnel access equipment				0	26%	NA	
3.52%	Scour protection			550,000	595,833	43%	NA	Rating * 55.00 $2002/kW [1]
0.00%	Decommisioning				0	26%	NA	
100%	Balance of Plant (BoP)		1,920,000	15,116,277	16,949,603			
	CAPEX			24,194,743	26,866,227			

Figure 7 *Turbine and BoP components area*

COMPONENT / MADE OF	Fiberglass fabric		Carbon fabric		Vinyl adhesive		Metal fasteners		Urethane & foams		Ductile iron cast		Cast carbon steel		Rolled steel		Heavy construct		Bearings	
NAICS code	3272123				32552044		332722489		326150P		3315113		3315131		331221		BHVY		332991P	
PCU	PCU3272123 272128				PCU3255203 255204		PCU33272233 27223				PCU33151133 15113		PCU33151333 15131		PCU331221331221		PCUBHVY-BHVY		PCU33299133 2991P	
	MUF	PPI	MUF	PPI	MUF	PPI	MUF	PPI	MUF	PPI	MUF	PPI	MUF	PPI	MUF	PPI	MUF	PPI	MUF	PPI
ROTOR																				
Blades	60%	-18%			23%	62%	8%	36%	9%	32%										
Hub											100%	55%								
Pitch mechanism																			50%	44%
Nose cone											100%	55%								
DRIVE TRAIN & NACELLE																				
Low speed shaft													100%	67%						
Main bearing																			100%	44%
Gearbox																				
Mechanical brake & couplings																				
Generator																				
Power electronics																				
Bed plate											100%	55%								
Hydraulic & cooling system																				
Nacelle cover	55%	-18%			30%	62%														
ELECTRICAL CONNECTIONS																				
YAW SYSTEM																			50%	44%
CONTROL, SAFETY SYSTEM, CM																				
TOWER															100%	74%				
MARINIZATION																				
Turbine																				
Foundation system																	100%	43%		
Offshore transportation																				
Port and staging equipment																	100%	43%		
Offshore turbine installation																	100%	43%		
Offshore electrical I&C																				
Offshore permits & engineering																				
Personnel access equipment																				
Scour protection																	100%	43%		
Decommisioning																				
Balance of Plant (BoP)																				
CAPEX																				

Figure 8 *NAICS Codes and PPIs*

COMPONENTS PPI AREA

In this area we implement Eq (4) to calculate the PPI value corresponding to each component. The first column lists the component name (as discussed above). Then there is a number of spreadsheet columns, non-exhausted in Figure 8, where all NAICS categories contributing to the cost of the wind turbine and its BoP are listed. For each component and each NAICS category we assign a X_j and a PPI_j value. The weighting of PPIs over the fractions X over all involved categories provides the component's PPI. For X_j we used the values suggested in [1]. For the PPIs we revisited the NAICS database to get updated values till 2012 (previous works [1] and [5] had an earlier reference year).

COMPONENT MODELS		SF	Mass (kg)	Cost ($2002)	Cost (€2012)	Comment on Mass	Comment on Cost
ROTOR MODEL							
1: Innwind.EU 10MW RWT Blade - scaled		***3.00***	41,716	541,360		Combination of [2] and [3]	From [1] and [5]
2: Baseline WindPact			70,145	913,328		From [1]	From [1] and [5]
3: Advanced WindPact			42,304	549,060		From [1]	From [1] and [5]
4: Repower 5 MW RWT Blade - scaled		***2.45***	41,468	538,118		Combination of [2] and [3]	From [1] and [5]
DRIVE TRAIN MODEL							
1: Three-stage planetary/helical							
2: Medium Speed (40:1) Innwind.EU RWT							
3: Repower 5MW RWT 3SG+HSG							
4: Direct drive							
5: SCDD NbTi							
6: SCDD MgB2							
7: SCDD AmSC - SeaTitan							
8: SCDD Jensen 2G							
9: PDD Magnomatics							
Gearbox							
	1		76,420	1,629,919		From [1]	From [1]
	2		85,168	899,375	1,022,017	From [10]	From [10], €2012/kg=12
	3	***3.00***	178,191	1,629,919		From [2]	From [1]
	4		0	0			
	5		0	0			
	6		0	0			
	7		0	0			
	8		0	0			
	9		0	0			
Generator							
	1		31,630	650,000		From [1]	From [1]
	2		45,860	618,137	664,966	From [10]	From [10], €2012/kg=14.5
	3	***2.00***	34,000	650,000		From [2]	From [1]
	4		174,351	2,193,300		From [1]	From [1]
	5	***2.35***	145,000	1,528,225	1,644,000	From [9]	From [9] in €2012
	6	***2.35***	165,000	2,103,634	2,263,000	From [9]	From [9] in €2012
	7	***3.15***	165,000	2,212,394	2,380,000	From [9]	From [9] in €2012
	8	***3.15***	70,000	8,124,507	8,740,000	From [9]	From [9] in €2012
	9	***3.15***	156,000	1,078,310	1,160,000	From [9]	From [9] in €2012
Bed plate							
	1		55,457	235,663		From [1]	From [1]
	2		32,162	76,562		From [1]	From [1]
	3		55,457	235,663		From [1]	From [1]
	4		30,498	51,324		From [1]	From [1]
	5		30,498	51,324		Assuming DD equiv	Assuming DD equiv
	6		30,498	51,324		Assuming DD equiv	Assuming DD equiv
	7		30,498	51,324		Assuming DD equiv	Assuming DD equiv
	8		30,498	51,324		Assuming DD equiv	Assuming DD equiv
	9		30,498	51,324		Assuming DD equiv	Assuming DD equiv
SUPPORT STRUCTURE MODEL							
1: Jacket 10 MW RWT			1,920,000	8,766,277	9,496,800		Price = 1.2 X Fabrication cost
Transition piece		***2.5***	330,000	1,523,077	1,650,000	From [3]	From [11], 5.0 €2012/kg
The jacket itself		***1.5***	1,210,000	5,361,231	5,808,000	From [3]	From [11], 4.8 €2012/kg
The piles		***1.5***	380,000	420,923	456,000	From [3]	From [11], 1.2 €2012/kg

Figure 9 ***Component models***

COMPONENTS MODEL AREA

This is the spreadsheet area where the mass and cost models of the innovative components developed in INNWIND.EU will be actually implemented. Three such model areas are anticipated, one for the blade, a second for the drive train and a third for the offshore support structure. The COMPONENTS MODEL AREA has a similar structure with the TURBINE & BoP COMPONENTS AREA (the 9 columns presented above), but the first and seventh column are now empty. We shall further discuss what is already available in the spreadsheet.

Blades

We have included the NREL blade models and, in addition, the blades of the UPWIND and INNWIND.EU reference turbine models. All of them are all-glass blades. For the UPWIND RWT (Named Repower 5 MW) and the INNWIND.EU RWT we use the available mass data. The SF of the 5 MW blade (2.45) is such that when the blade up-scales to 10 MW it gets the same weight with the 10 MW INNWIND.EU RWT blade. For the cost we use the mass-based model introduced in [1]. The same model is used in [5]. Clearly, a carbon and a hybrid glass/carbon mass and cost model are presently missing and should be developed at a later stage in collaboration with WP2. Models for smart blades are also missing at this initial stage of the project.

Drive train model

Nine different drive train models have been presently implemented. Each model is split into three sub-models, one for the gearbox, one for the generator and one for the supporting bed-plate. Clearly, the direct drive models (DD) do not have a gearbox component (zero values).

The first model (Index_1) is the standard model of the WINDPACT study, referring to a classical high speed drive employing a three stage (planetary/helical) gearbox.

a) Its gearbox mass value is calculated using [1] and it is obviously too low for a 10 MW turbine, indicating that the applied mass model is out of its application range. The cost model for the gearbox yields a more reasonable value. Still, both have to be rechecked (or abandoned since such a high speed drive train is not expected to be a cost effective option at the power range of our interest).

b) The generator models yield reasonable values. The reason is that the mass and cost of high speed generators up-scale proportionally to the rated power.

c) For the bed-plate we use the mass and cost model of [1]. The results seem reasonable while their influence to the overall drive train cost is limited.

The Index_3 model (Repower 5MW RWT 3SG+HSG) is pretty similar to the Index_1 regarding the technology used and the calculation of costs. The only difference is on the gearbox mass model which uses the actual mass of the Repower 5 MW gearbox, up-scaled with the classical up-scaling exponent SF=3. The gearbox mass is much more reasonable now compared to Index_1.

The Index_2 model corresponds to a medium speed drive train employing a single stage gearbox. It matches very well the specifications of the INNWIND.EU RWT and it can form the basis for our RWT evaluations. The model has been proposed in [10]. The mass models for the gearbox and the generator are torque-based while the cost models are mass-based. For the bed-plate we apply the medium speed drive train model of [1].

The Index_4 model is the direct drive model of [1] (no further details are given whether this corresponds to a permanent magnet or electrically excited synchronous generator or other). Before adopting this direct drive model we invested time in researching more elaborate DD models, like those developed in the two WINDPACT drive train studies reported in [6] and [7]. The end result was rather disappointing when up-scaled at the power range of 10 MW. We have had a similar experience with the medium speed models of [6] and [7] as well. Although the models yield reasonable results at the power ranges they have been developed for, their up-scaling potential is questionable (we re-discussed the issue in Index_1).

Index_5 to Index_9 are the new models developed in INNWIND.EU for superconducting direct drive generators of different operating temperature (Index 5 to 8) and for the PDD drive of Magnomatics (Index_9). The models have been introduced to the spreadsheet following [9]. In most of the cases they have been developed for a 10 MW design only and their scaling factor is not calibrated yet against a larger design. In the absence of suggested SFs we have used a value over 3. This part has to be revisited when the 20 MW deigns are available by WP3.

Support structure model

Presently we have included a single model, addressing a jacket structure. The model includes three sub-models, one for the transition piece, the jacket itself and the piles. The mass model is based on the 10 MW design included in [3], while the cost model derived after communication with WP4 [11]. The scaling factors have been set following the ideas presented in [0] but they have not been calibrated yet against a design for different turbine size. Mass and cost models for floating devices have, also, to be prepared at a later stage of the project.

CONCLUSIONS

Two complementary procedures for assessing the innovative designs of INNWIND.EU are presented in this report. The first is a credible, easy to use, procedure for verifying that the proposed innovative designs can withstand the loads they are designed for. It is applicable for both single components and full wind turbines. It introduces a three-stage evaluation scheme, where the different stages address different purposes and needs. A successful Stage 1 evaluation is the prerequisite for starting the KPIs-based assessment of an innovative sub-component. From those designs that passed Stage 1, the most promising will be re-examined later in the project, at the wind turbine system level, following Stage 2 procedures. Stage 3 addresses the complete design review of a WTGS and, therefore, is out of the scope of the INNWIND.EU project.

Then, we present a procedure for developing suitable cost models for the components and the turbine concepts researched in the project. These cost models are reflecting the impact of the new designs to the turbine CAPEX and, therefrom, to the performance indicators adopted and presented in Deliverable 1.22. The cost models presented have been developed on the basis of the following specifications: i) cost and mass models should be available at the sub-component level, ii) they should be based on key turbine design parameters and operating conditions, iii) the models should be suitable and flexible enough for up-scaling studies too, taking account of technology learning curves when appropriate, iv) they should take account of variations in raw materials pricing, inflation and currency fluctuations so that cost data from different periods and markets can be synchronised and v) they should explore previous knowledge from similar works done for WINDPACT and UPWIND. The cost models have been implemented in an open, publicly available, spreadsheet which is also part of D1.23 of INNWIND.EU.

REFERENCES

Part I Recommendations for load cases to be considered during innovation assessment

1. Germanischer Lloyd, Rules and regulations, IV – Non-marine Technology, Part 1 – Wind Energy, Regulation for the certification of the Wind Energy Conversion Systems. Chapter 1-10
2. IEC 61400-3 International Standard, Wind Turbines – Part 3: Design requirements for Offshore Wind Turbines. First Edition 2009-02.
3. DNV-OS-J103 Offshore standard, Design of Floating Wind Turbine Structures, June 2013

Part II Cost Models

0. Innwind.EU - Deliverable 1.22, Definition of Performance Indicators (PIs) and Target values, February 2014
1. L. Fingersh, M. Hand, and A. Laxson, Wind Turbine Design Cost and Scaling Model, Technical Report NREL/TP-500-40566, December 2006
2. Upwind 5 MW RWT, 2006
3. Innwind.EU - Deliverable 1.21, Reference Wind Turbine Design, May 2013
4. D. A. Griffin, WindPACT Turbine Design, NREL/SR-500-29492, April 2001, Scaling Studies Technical Area 1–Composite Blades for 80- to 120-Meter Rotor
5. T. Ashuri, Beyond Classical Upscaling: Integrated Aeroservoelastic Design and Optimization of Large Offshore Wind Turbines, PhD Thesis, Delft 2012
6. R. Poore and T. Lettenmaier, Alternative Design Study Report: WindPACT Advanced Wind Turbine Drive Train Designs Study, NREL/SR-500-33196, Aug 2003
7. G. Bywaters et al., Northern Power Systems WindPACT Drive Train Alternative Design Study Report, NREL/SR-500-35524, Rev Oct 2004
8. B. Maples, M. Hand, and W. Musial, Comparative Assessment of Direct Drive High Temperature Superconducting Generators in Multi-Megawatt Class Wind Turbines, NREL/TP-5000-49086, Oct 2010
9. Innwind.EU - Deliverable 3.42, First Assessment of Performance Indicators of Superconducting Direct Drive and Pseudo Magnetic Direct Drive Generators
10. S. Schmidt and A. Vath, Comparison of Existing Medium-speed Drive Train Concepts with a Differential Gearbox Approach, Proc. EWEA 2012, Sept 2013
11. Communication with WP4 (Tim Fisher), Jan 2014