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Dutch Offshore Wind Energy Converter

Task 12: Cost Comparison of the Selected Concepts

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Abstract

In this report the work performed for task 12 of the Dowec concept study project is reported. Task 12 consisted of multidisciplinary optimisation of the complete wind energy conversion system, an off-shore wind farm, taking into account the wind turbines, the foundations, the electric infrastructure and the operations and maintenance. The aim of this optimisation was to find quantitative difference between 5 different wind turbine concepts.

Due to limited data for the foundation, electric infrastructure and O&M cost, optimisation was not very useful in the end. The work performed is a cost comparison between 5 different concepts of wind turbines applying the known differences to the cost of the foundations, electric infrastructure and O&M cost/availability.

All concepts had a cost of energy price level between 4.5 €ct/kWh (robust) and 5.5 €ct/kWh (Advanced stall). Recommendation for the further research are given, aiming at a more solid basis for the choice of the wind turbine concept.

Acknowledgement

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CONTENTS

NOTATIONS

AUE	Annual Utilized Energy	kWh
A	Weibull scale factor	-
a	Annuity factor	-
CS	Constant speed	
Dfl	Guilders, currency in the Netherlands till 2002	-
DS	Dual speed	
$E_{pot.}$	Potential energy production for a stand alone wind turbine not influenced by wakes of other wind turbines and/or objects assuming 100 % availability for the given wind speed distribution	kWh/year
I	Investment including possible interest during construction	€
k	Weibull shape factor	-
$K_{avail.}$	Technical availability factor	-
LPC	Levelized production Cost	€/kWh
n	Economic life time	year
r	Discount rate/Real interest	-
TOM	Total (levelized) annual "downline cost"	€
VS	Variable speed	

1 INTRODUCTION

This report describes the work performed in task 12 of the *DOWEC Concept Study project*. Within this study the possible wind turbine concepts for an off-shore wind energy conversion system are qualitatively and quantitatively analysed and compared.

Task 12 is assigned to optimise the concepts derived in task 11: *Selection of Concepts* where the concepts are ranked on a qualitative basis. For a more thorough description and the results of task 11 see the report of that task, [9].

The objective of the optimisation is to generate quantitative data for 5 concepts for a 5 to 6 MW off-shore wind turbine. This data can be divided in technical data like mass and stiffness distribution of the rotor blades but also cost data for the major components.

For a rough description of the concepts see table 1.

Table 1: The general description of the 5 concepts

	1 Base line	2 Advanced	3 Robust	4 Stall-Teeter	5 Smart Stall
Power Control	Active Stall	Active Pitch	Passive Stall	Passive Stall	Smart Stall
number of blades	3	3	2	2	3
Rotor speed	CS/DS	part. variable	CS/DS	VS	VS
Protection 1	Pitch	Pitch	Brake	tip	tip
Protection 2	Brake	Brake	Brake	Brake	Brake
Gearbox Stages	3	3	2	2	3
Generator type	Asynch.	Doubly fed	Asynch.	Doubly fed	Doubly fed
RPM	1500	1500	1000	1000	1500
Inverter	none	30 %	none	full	full
Tower	tubular tower	tubular tower	tubular toweră	truss tower	tubular tower
Jacket	tripod	tripod	mono-pile	truss	tripod
Foundation	piles	piles	mono-pile	gravity based	piles
Up/Down Wind	up	up	up	down	up
Hub	fixed	fixed	fixed	teeter	fixed

The optimisation should not be just a simple optimisation of the energy yield of the wind turbine nor an optimisation of the wind turbine design itself but is aimed at the optimisation of a wind energy conversion power station. That means that the complete energy production system should be modelled, at least with respect to cost and if possible also for technical aspects. Coupling of all these models with the right interaction makes it possible to optimise, i.e. vary design parameters in such a way that the **Cost of Energy** for the complete system is minimised.

The optimisation is carried out with the program BladOpt, [4, 3], a computer program aimed at optimisation of the rotor taking into account the cost of the complete wind turbine. This programme has been extended to incorporate the cost of the wind farm and installation. The models of the (off-shore) foundation, installation and O&M cost are parametric functions for which the data has been determined with OPTIOWECS [6] cost modelling.

The quantitative comparison is based on the Levelised Production Cost (LPC) of Energy at the point where the electricity is fed into the grid. The LPC is determined using the method described in the IEA Recommended Practices for Wind Turbine Testing and Evaluation # 2, [10].

$$LPC = I/\left(a \cdot AUE\right) + TOM/AUE$$

or

$$LPC = 1/AUE \cdot \left(I/a + TOM\right)$$

In which the annuity factor is determined according to $a = \left(1 - 1\left(1+r\right)^{-n}\right)/r$

The results of the optimisation study depend heavily on the cost modelling of all components and sub components. When a cost model does not depend on the design parameters or response parameters it is better not to incorporate the component in the optimisation.
To be able to perform this optimisation cost models for all involved sub systems and components have been developed or tuned for each concept. A description of the wind turbine cost models is given in appendix A and the actual used values for the coefficients are in table 19. The cost models are compared with the cost data from Neg-Micon Denmark and the former NedWind now Neg-Micon Holland, see [8]

A large shortcoming for the project is the lack of knowledge of the foundation and installation cost. While the cost of the foundation is approximately as high as the cost of the wind turbine the sensitivity of the foundation cost model with the design and/or response parameters is poor or not incorporated, see [12].

Optimisation makes not much sense when only for a third of the system cost cost models are available that are sensitive to the design or response parameters.

For example suppose one is interested in the optimum rotor diameter D and assume that the cost of the wind turbine increases with the $D^{2.7}$ and the remaining costs are fixed or increase with some exponent with the rotor diameter.

For simplicity we optimize Price Performance (PP)

$$\mathrm{P}P = \frac{SystemCost}{Yield}$$

$$yield \propto D^2$$

and

$$SystemCost \propto \frac{1}{3}D^{2.7} + \frac{2}{3}D^{exponent}$$

In figure 1 it is shown that when the sensitivities of parts of the system are not correct the optimimum value of design parameter varies.

The external conditions, like wind speed distribution and sea state, are taken from the Terms of Reference, [7].

Due to the lack of time between finishing the cost modelling and preparing this report no full optimisations are completed. Originally the following design parameters were to be varied for all concepts:

- rotor diameter;
- rated power;
- hub height

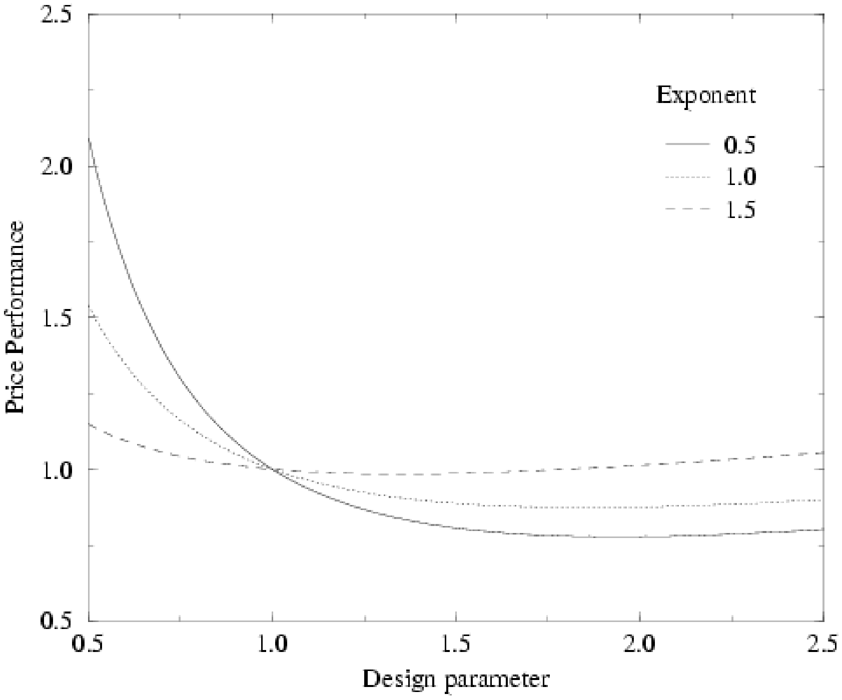

Figure 1: Optimium value of the rotor diameter unknown when sensitivities are unknown.

Due to the fact that not much cost data was obtained about the foundation, installation and wind farm infrastructure it is decided to compare the concepts on the basis of fixed values for the mentioned design parameters. These values are:

rotor diameter = 120 m
rated power = 5.6 MW
hub height = 100 above mean sea level

The remaing design parameter values, like chord and twist distribution, were obtained during the preliminary optimisation of the base line concept. For the two 2 bladed, passive stall rotor concepts a new chord/twist distribution has been determined using the same profiles.

2 WIND TURBINE DESCRIPTION

2.1 The wind turbine model

Within BladOpt the turbine is described with few parameters. The main reason for this is that the program is made for fast optimisation studies and the speed is reduced strongly with the number of parameters to be varied. A reduction in number of free parameters is accomplished by coupling of many rotor parameters.

The rotor blades are described with diameter, chord and twist distribution at a few spanwise stations. The chosen profile distribution is an abitrary choice and is not based on analysis. The intermediate spanwise locations will be interpolated using linear or spline interpolation. The power control concept is determined with 3 parameters:

- variable speed versus constant speed;
- (full/partial) pitch versus fixed;
- pitch to stall versus pitch to vane;

2.2 General wind turbine parameters

Table 2: General turbine parameters

Hub Height	:	100	m
Number of Blades	:	2/3	
Diameter of Rotor	:	120	m
P_{rated}	:	5600	kW
Design life	:	20	y
ρ_{air}	:	1.225	$\mathrm{k}g/m^3$
Drive train model			
Constant loss	:	0.03	P_{rated}
Variable loss	:	0.07	P_{rotor}

The rotor geometry is the result of some preliminary optimisations taking only the wind turbine Price Performance into account and limiting the maximum rotor diameter and tower height to the given values. Without these constraints the optimisation would result in a larger diameter and a higher tower.

2.3 Rotor blade description

2.3.1 General

Table 3: The profile distribution.

	span %	
t profile	from	to
39 % data	6.0	20.0
35 % data	20.0	24.4
32 % data	24.4	33.9
30 % data	33.9	38.6
28 % data	38.6	43.3
25 % data	43.3	52.8
23 % data	52.8	62.2
21 % data	62.2	81.1
18 % data	81.1	100.0

Table 4: The input thickness distribution.

% span	:	% chord
6.0	:	40.0
25.0	:	40.0
40.0	:	28.0
70.0	:	21.0
95.0	:	18.0

2.3.2 Geometry for 3 bladed rotors

Table 5: The input chord distributions.

% span	[m]
6.0	7.20
25.0	6.00
40.0	4.60
70.0	2.35
95.0	1.10

Table 6: The input twist distribution.

% span	θ
6.0	12.0
25.0	12.0
40.0	6.5
70.0	1.0
95.0	0.17

Table 7: The blade element, chord, twist and thickness, distribution.

Radius(i)	chord(i)	twist(i)	thickness(i)
0.0	2.880	12.0	100.0
3.0	2.880	12.0	100.0
6.0	6.947	12.0	40.0
9.0	6.632	12.0	40.0
12.0	6.316	12.0	40.0
15.0	6.000	12.0	40.0
18.0	5.533	10.167	36.0
21.0	5.067	8.333	32.0
24.0	4.600	6.5	28.0
27.0	4.225	5.583	26.83
30.0	3.850	4.667	25.67
33.0	3.475	3.75	24.5
36.0	3.100	2.833	23.33
39.0	2.725	1.917	22.17
42.0	2.350	1.0	21.0
45.0	2.100	0.834	20.4
48.0	1.850	0.668	19.8
51.0	1.600	0.502	19.2
54.0	1.350	0.336	18.6
57.0	1.100	0.17	18.0
60.0	0.850	0.0	17.4

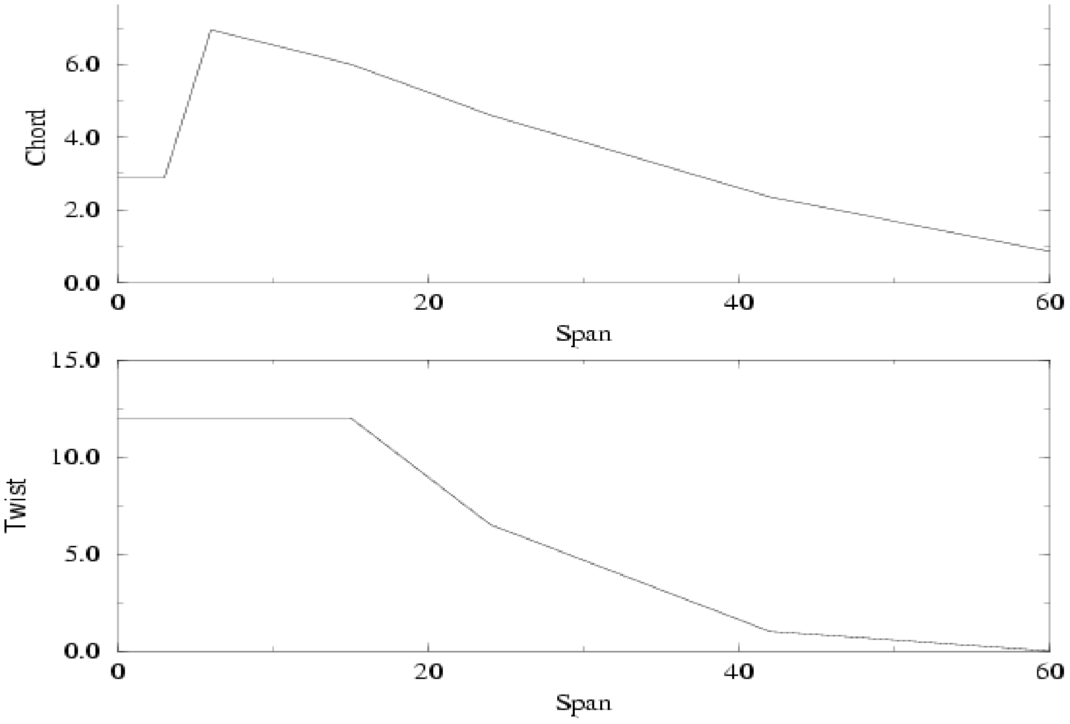

Figure 2: The chord and twist distribution

2.3.3 Geometry for 2 bladed rotors

Table 8: The input chord distribution.

% span :	[m]
6.0 :	7.50
20.0 :	7.50
50.0 :	4.33
95.0 :	1.66

Table 9: The input twist distribution.

% span	θ
6.0 :	7.50
20.0 :	7.80
40.0 :	6.25
99.0 :	0.01

Table 10: The blade element, chord, twist and thickness, distribution.

Radius(i)	chord(i)	twist(i)	thickness(i)
0.0	4.125	7.500	100.00
3.0	4.125	7.500	100.00
6.0	7.500	7.586	40.00
9.0	7.500	7.693	40.00
12.0	7.500	7.800	40.00
15.0	6.972	7.413	40.00
18.0	6.443	7.025	36.00
21.0	5.915	6.637	32.00
24.0	5.387	6.250	28.00
27.0	4.858	5.721	26.83
30.0	4.330	5.192	25.67
33.0	4.033	4.664	24.50
36.0	3.737	4.135	23.33
39.0	3.440	3.606	22.17
42.0	3.143	3.077	21.00
45.0	2.847	2.548	20.40
48.0	2.550	2.019	19.80
51.0	2.253	1.491	19.20
54.0	1.957	0.962	18.60
57.0	1.660	0.433	18.00
60.0	1.363	0.000	17.40

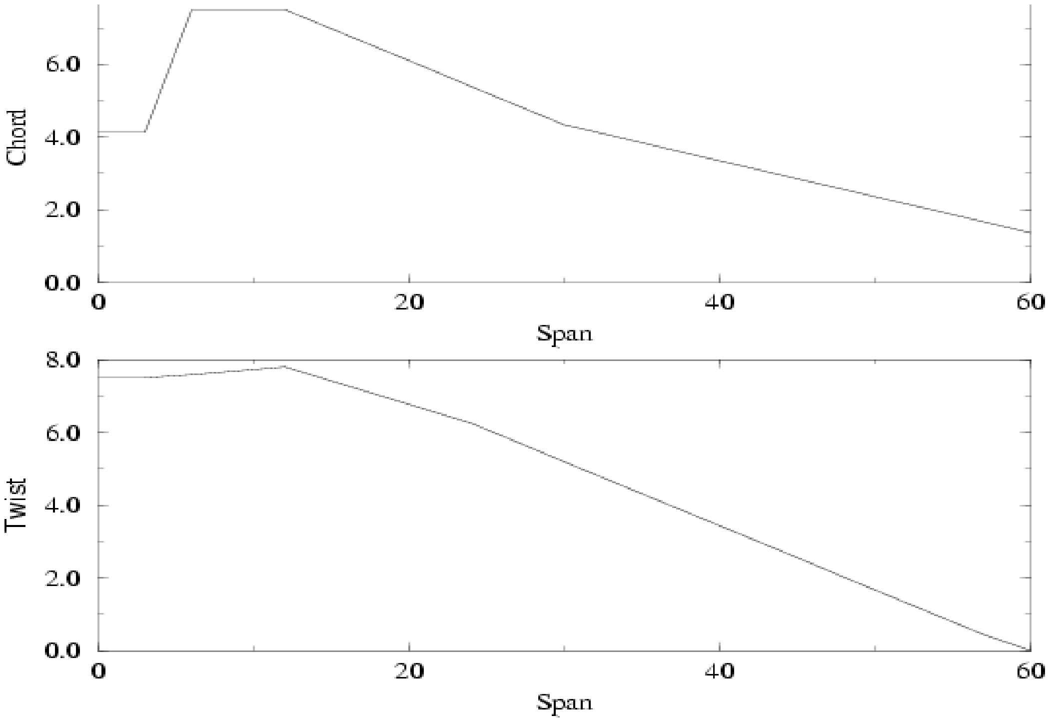

Figure 3: The chord and twist distribution

2.4 Wind conditions

Wind conditions for load model
IEC wind class : 1
IEC turbulence class : B (16%)

Wind conditions for energy production
Average wind speed 100 m : 9.70 m/s
Weibull shape factor 100 m : 2.10 -

2.5 Losses

The follwoing losses in the wind farm and in the connection between the wind farm and the connection to the grid are modelled as:

Array losses due to wake (varies per concept) : ≈ 4 %
Electrical losses in the wind farm and transport to grid : 5 %

3 COST OF ENERGY

3.1 Introduction

The cost of energy is determined for each of the 5 concepts. For ease of comparison it is chosen to determine the levelized production cost while not taking into account any yearly variations which will occur due to wind condition variations, aging, start up – e.g. not all machines can be build in the same year while parts of infrastructure will be available throughout the construction phase –, and close down effects.

To determine the LPC it is necessary to determine

- the investment, including the (possible) interest during construction;
- the annuity factor;
- AUE, annual utilized energy;
- total (levelized) down line cost, being the yearly operating & maintenance cost and the insurance cost (estimated yearly at 0.5% of the total investment).

The investment cost are divided into component investment, transportation, installation and decommissioning and salvage and management cost. Although it was not always possible to split the cost up into these items, e.g. cable cost are not split up in cost of the cables and installation.

The annuity factor is based on the interest on capital and the economic life time.

- real interest $\mathrm{i} = 5\%$;
- economic life time $\mathrm{n} = 20$ years ;

The AUE is determined using the stationary aerodynamic code within BladOpt to determine the power curve and integrating the energy capture for a Weibull distribution with $\mathrm{U}_{100} = 9.70 m/s$ and a shape factor of 2.10 also at 100. m.

The energy capture is reduced with three kinds of energy losses

1. array losses due to wake operation depending on the concept;
2. electrical losses within the wind farm, not depending on the concept;
3. electrical losses between the wind farm and the point where the electricity is fed into the grid, not depending on the concept.

The array losses are given in table 11 which are estimates taken from the near shore study [5]

Table 11: Array losses due to wind farm effects

	Base line	Advanced	Robust	Stall-Teeter	Smart stall
array losses %	4.0	3.0	4.0	4.0	3.0

The electrical losses in the wind farm and transport to shore together are estimated at 5 %.

The energy yield is finally reduced for availability, in task 9 the availability is determined per concept on the basis of the probability failure rates for each concept. The used values are:

Table 12: Availability determined per concept

	Base line	Advanced	Robust	Stall-Teeter	Smart stall
availability. %	95.00	93.60	96.10	93.25	93.45

Due to the fact that no relation is known for availability and loss of energy capture the availability is assumed to be direct measure of the energy capture.

For the partial variable speed concepts, which can not be modelled correctly in BladOpt we assume a reduction in energy yield of 1.6 %.

The energy yield is now determined as follows: $AUE = E_{pot} \cdot K_{avail.} \cdot \eta_{arraylosses} \cdot \eta_{elect.WF}$

The total energy losses assumed in the calculations up to the point where the electricity is put into the grid is:

Table 13: Energy losses due to wind farm effects, availability, transformers and transport

	Base line	Advanced	Robust	Stall-Teeter	Smart stall
total effic. %	86.64	84.83	87.83	85.04	86.11

The influence on the Operating and Maintenance (O&M) cost is not yet determined per concept, although not all concepts require the same effort to maintain the availability as reported in table 12

The *TOM* is assumed to be a fixed proportion of the total investment cost. The annual O&M is assumed to 2 % of the total investment and the annual insurance cost is assumed to be 0.5 % of the total investment. (On shore the insurance is approximately 0.25 % of the total investments. Offshore the insurance is assumed to be higher also in relative sense although only a part of the total investment is assumed to be effected by failures.)

3.2 Cost coefficients

3.2.1 Introduction

In [8] component cost models are derived based on existing NEG Micon wind turbines. To implement the cost relation in that document into BladOpt these models will be adapted by tuning the so-called cost coefficients to give a correct result for the different concepts.

3.2.2 Derivation of the cost coefficients

The derivation of the cost coefficients needed for the Bladopt computer program is fulfilled for each concept in the DOWEC concept study. The method and underlying data is reported in [8] an example is shown below.

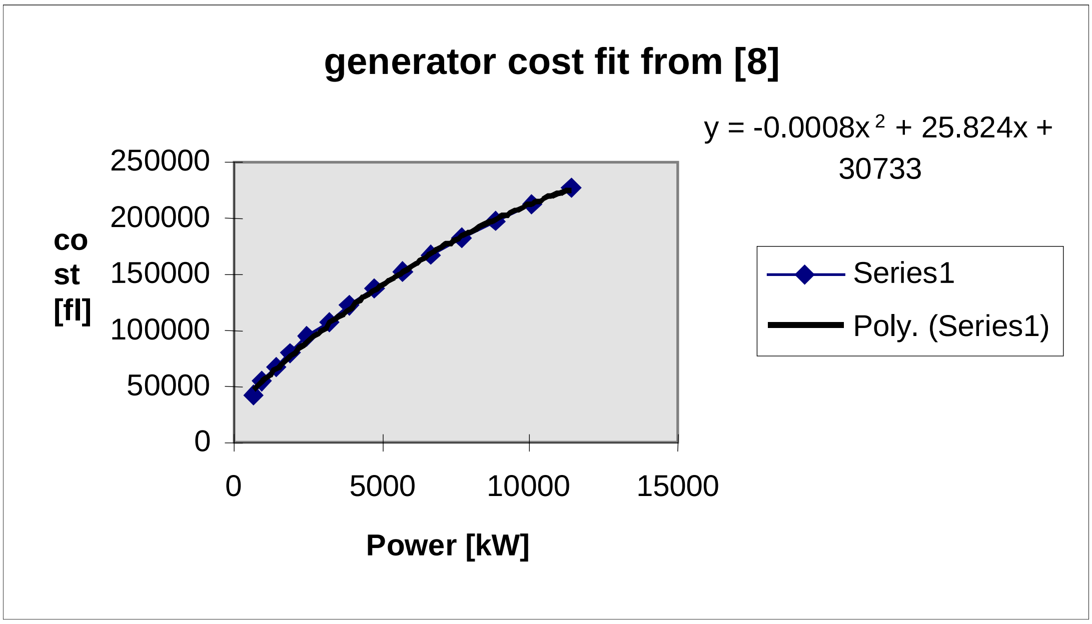

Figure 4: Fit of Generator cost data in BladOpt coefficients (example)

Base line concept

The Base line concept is an existing NEG Micon concept so minimal adaptions are expected. The derivation will be performed in the table 14 below:

Table 14: Derivation of Bladopt coefficients for the base line concept in Dfl

Component	Model based on existing turbines [8]	Adaption	Bladopt model
Blades	$K_{blade} = k_{blade} \cdot m_{blade}$ $M_{blade} = a_{blade} \cdot p^{0.33} \cdot D^{2.7} (3/n)^{0.67}$	No	Engineering model Cost coefficient $k'_{blade} = 20$ fl/kg
Pitch	Included in hub	No	Included in hub
Hub	$K_{hub} = k_{hub} \cdot m_{hub}$ $M_{hub} = a_{hub} \cdot D^{2.7}$	1)	$K_{hub} = 30622(D/25)^{2.7}$
Mainshaft	$K_{shaft} = k_{shaft} \cdot m_{shaft}$ $M_{shaft} = a_{shaft} \cdot D^{2.7}$		Included in hub
Gearbox	$K_{gear} = k_{gear} \cdot m_{gear}$ $M_{gear} = a_{gear} \cdot q$	$a'_{gear} = k_{gear} \cdot a_{gear}$ $= 15 \cdot 8.65 \cdot 2.2 = 288$	$K_{ggear} = a'_{gear} \cdot Q = 288 \cdot Q$
Generator	$M_{gen} = a_{gen} \cdot p^{0.59}$ $K_{gen} = k_{gen} \cdot m_{gen}$	See fit in fig. 4 for $a_{gen} = 79.5$ $k_{gen} = 11.7 \cdot 2.2$	$K_g = -0.0008P^2 + 25.824P + 30733$
E system	$K_{ES} = a_{es}p^{0.9} + b_{es}p^{0.3}$	See fit in fig. 5	$K_{ES} = 30800 \cdot \left[\left(\frac{P}{250}\right)^{0.8} + \left(\frac{P}{250}\right)^{0.2}\right]$
Safety and control	Included in E system	Offshore adaptions will be included	$K_{saf} = a'_{saf} + b'_{saf} f_{saf} + c'_{saf} \cdot f_{pitch}$ $= 40000 + 50000 \cdot 1.2 + 15000 \cdot f_{pitch}$ $f_{pitch} = 2 if pitch$
Nacelle	$K_{nac} = k_{nac} \cdot m_{nac}$ $M_{nac} = a_{nac} \cdot D^{2.7}$ $M_{top} = c_{top} \cdot D^{2.7}$	2)	$M_{top} = 4804 \left(\frac{D}{25}\right)^{2.7}$ $K_{nac} = 2.2 m_{top}$
Yaw mechanism	Included in nacelle	No	Included in nacelle
Tower	$M_{tow} = a_{tow} \cdot D^{2.8} \left(\frac{H}{D}\right)^{1.7} \cdot p^{0.6}$ $K_{tow} = k_{tow} \cdot m_{tow}$	No	Engineering model Cost coefficient $K_{tower} = 4$fl/kg
Offshore cost	From [12] $K_{off} = 14.44$ Mfl	3)	$K_{off} = 9531096 + 149 \cdot P + 33943 \cdot D$
Farm efficiency	96% [5]		
Availability	95% [12]		
Foundation stiffness	Not available yet, take infinite for tripod with flange height $H_f = 40$ m		Infinite: $H_t = H - H_f = 80, H_w = 20$

1) At the moment Bladopt has no main shaft model. For the time being (first concept selection) the main shaft will be extrapolated at D=120 m and p=500 W/m2 (P=5600 kw) and added in the Bladopt hub model:
$A'_{hub} = [a_{hub}k_{hub} + (a_{pitch} - a_{hub})k_{pitch} + a_{shaft}k_{shaft}]$
$25^{2.7} fl/Eu = [0.0866 \cdot 2.68 + (0.18684 - 0.0866) \cdot 17.5 + 0.08224.3] \cdot 25^{2.7} \cdot 2.2 = 30622 fl/m^{2.7}$

2) In BladOpt the nacelle cost is derived from the tower top mass, which is also determined in [8], the cost coefficient is derived from the tower top mass coefficient and the nacelle coefficients: $C'_{top} = c_{top} \cdot 25^{2.7} = 0.807 \cdot 5949 = 4804 kg/m^{2.7}$ In [8] also a power sens-

itivity is used, which is not available in BladOpt yet, for the time being $p = 500W/m^2$ is assumed:
$A'_{nac} = a_{nac} \cdot (p/1000)^{0.33}\, k_{nac} Eu/fl/c_{top} =$
$0.3275 \cdot 0.50^{0.33} \cdot 3.1 \cdot 2.2/0.807 = 2.2$ fl/kg

3) At the moment in [12] no parameter sensitivity is included, for the time being the coefficients from [1] used in BladOpt will be applied, while the cost at D=120 m and $p = 500W/m^2$ (P = 5600 kW) are kept the same, from which the constant can be derived:
$C'_{off} = 14,440,000. - 149 \cdot P - 33943 \cdot D = 9,531,096$ fl

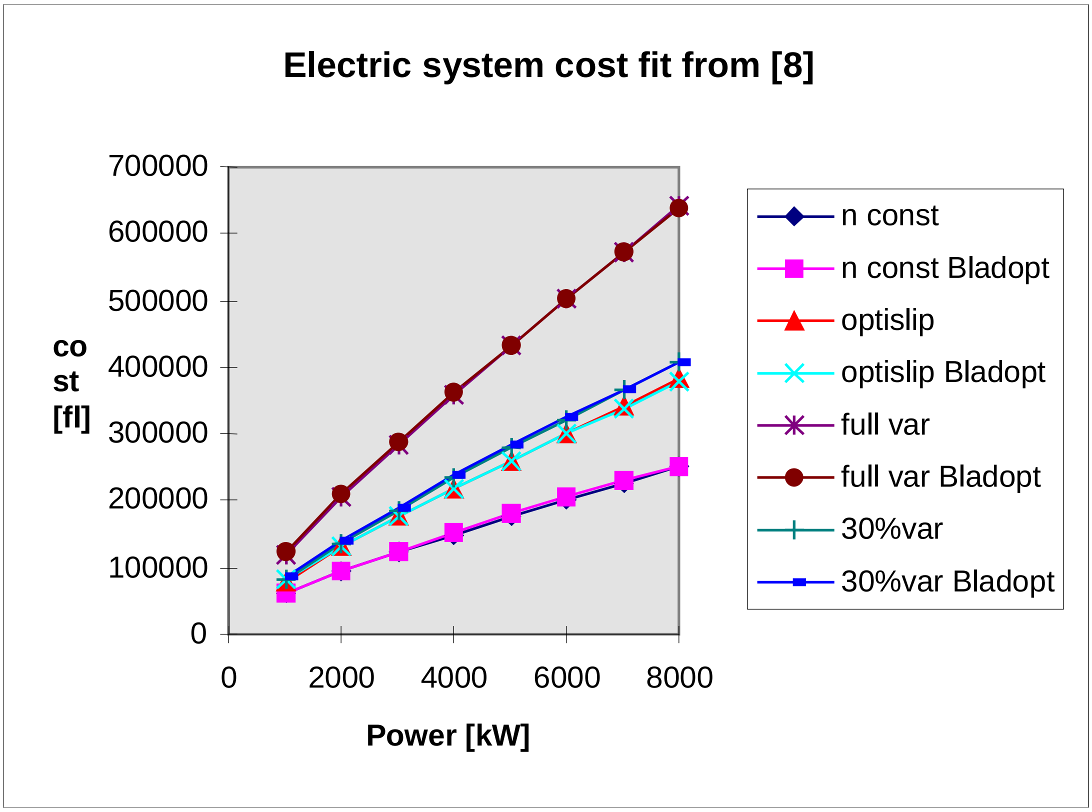

Figure 5: Fit of E-system cost data in BladOpt coefficients

Advanced concept

In the advanced concept active pitch will be applied with 30 % variable speed and doubly fed generator.

For the pitch itselves no extra cost will be charged, the actual cost sensitivity is due to the changement in the load spectra of the turbine. The advanced concept is provided with a limited variable speed system. For the cost of this system it is assumed that the inverter is 2.5 times cheaper as for a full variable speed system. For this system the generator is provided with a slip ring. For the cost of this application it is assumed that the generator is 10% more expensive.

The application of variable speed will lower the gearbox loads and increase the E-system costs, due to the cost of the inverter and generator.

The Bladopt coefficients will be derived from [8] in the table 15, if different from table 14:

Table 15: Derivation of Bladopt coefficients for the advanced concept as far as different from table 14 in Dfl

Component	Model based on existing turbines	Adaption	Bladopt model
Pitch	Included in hub	No	Included in hub
Generator	$M_{gen} = a_{gen} \cdot p^{0.59}$ $K_{gen} = k_{gen} \cdot m_{gen}$	See fit in fig. 4 for $A_{gen} = 79.5$ $K_{gen} = 11.7 \cdot 2.2 \cdot 1.1$	$K_g = -.00088 \cdot P^2 + 28.5 \cdot P + 33806$
E system	$K_{ES} = a_{es} \cdot p^{0.9} + b_{es} \cdot p^{0.3}$	See fit in fig. 5	$K_{ES} = 38000 \left[\left(\frac{P}{250} \right)^{0.8} + \left(\frac{P}{250} \right)^{0.2} \right] + 27 \cdot P$
Farm efficiency	97 % [5]	100% to 30% speed control is 1.6 % extra loss	95.4 %
Availability	93.6 [12]		

Robust Concept

The robust concept operates with passive stall, which leads to another load spectrum and lower turbine costs, at the cost of a lower production. The foundation consists of a mono pile with a low stiffness. This stiffness is calculated in [12] and will be used for the eigenfrequency calculation of the tower.

Because no pitch is available an extra brake system should be applied for safety. For this concept the brake is a low speed brake. A trend of this brake is not available in [8] and will be derived from [11] with the following parameters:

Rotor diameter	Power	Torque	low speed brake cost	specific cost
[m]	[kW]	[kNm]	[fl]	fl/kNm
90	3000	1519	140056	85
120	5600	3961	336701	87.9

The trend is nearly linear and the value at rotor diameter of 120 m is selected. The Bladopt coefficients will be derived from [8] and are presented in table 16.

Stall teeter Concept

The application of a teeter will decrease the asymmetric blade and turbine loads. If applied on a two bladed rotor the asymmetric loads are similar if compared with a three bladed rotor. The cost of the tip brake is extrapolated from a 25 m rotor with a cost of 5000 fl and a diameter sensitivity with the power of 2.7:

$$K_{tip} = 5000 \cdot (D/25)^{2.7}$$

The cost of the teeter hub is extrapolated from the results of the Flexhat Veriflex project [2]

$$K_{teeter} = 13050\,(D/25)^{2.7}$$

This will be added to the cost of the main shaft, see the base-line concept:

$$K_{shaft} = 0.866 \cdot 2.68 \cdot 25^{2.7} \cdot 2.2\,(D/25)^{2.7} = 3073\,(D/25)^{2.7}$$

Table 16: Derivation of Bladopt coefficients for the robust concept as far as different from table 14 in Dfl

Component	Model based on existing turbines	Adaption	Bladopt model
Pitch	No pitch	No	No pitch
Hub	$K_{hub} = k_{hub} m_{hub}$ $M_{hub} = a_{hub} D^{2.7}$	1)	$K_{hub} = a'_{hub}(D/25)^{2.7}$ $=7633(D/25)^{2.7}$
Safety and control	Included in E system	Offshore adaptions will be included	$K_{saf} = a'_{saf} + b'_{saf} f s_{af} + c'_{saf} f_{pitch}$ $=40000 + 500001.2 + 15000 f_{pitch}$ $f_{pitch} = 0$ if no pitch
Low speed Brake	$M_{brake} = a_{brake} q$ $K_{brake} = k_{brake} m_{brake}$ derived from [11]	No $a_{brake} = 6.148 kg/Nm$ $k_{brake} = 14.3 fl/kg$	$K_{brake} = 87.9Q$, included in gear box
Low speed Brake	$M_{brake} = a_{brake} q$ $K_{brake} = k_{brake} m_{brake}$	No $a_{brake} = 6.148 kg/Nm$ $k_{brake} = 14.3 fl/kg$	$K_{brake} = 87.9Q$, included in gear box
Gear box		Low speed brake included	$K_{gear} = (288 + 87.9)Q = 355.9Q$
Offshore cost	from [12] $K_{off} = 10.0710^{6}$	3)	$K_{off} = 5,161,096 + 149P + 33943D$
Farm efficiency	96 % [5]		
Availability	96.1 % [12]		
Foundation stiffness	krot= 1.74 1010 with flange height Hf = 0 m [12]	$k_t = k_{rot} H$ $=1.7410^{10}120$ $=2.0910^{12}$	Infinite:$H_t = H - H_f = 120$ $H_w = 4D_{voet} = ca36m$

1) At the moment BladOpt has no main shaft model. For the time being (first concept selection) the main shaft will be extrapolated at D=120 m and p=500 W/m2 (P=5600 kw) and added in the BladOpt hub model:
$A'_{hub} = (a_{hub} k_{hub} + a_{shaft} k_{shaft}) 25^{2.7} fl/Eu = [0.0866 \cdot 2.68 + 0.0822 \cdot 4.3] \cdot 25^{2.7} \cdot 2.2 = 7663 fl/m^{2.7}$

3) At the moment in [12] no parameter sensitivity is included, for the time being the coefficients from [1] used in BladOpt will be applied, while the cost at D=120 m and p=500 W/m2 (P = 5600 kW) are kept the same, from which the constant can be derived:
$C'_{off} = 10,070,000 - 149P - 33943D = 10,070,000 - 149 \cdot 5600 - 33943 \cdot 120 = 5,161,096$

For this concept a lattice tower is selected, however in BladOpt no lattice tower is available yet. As a quick reference a guyed tubular tower will be used with the tripod foundation beams as guyes and the tower bottom fixed with beams between the tripod foundation. In BladOpt the tubular tower dimension at lower tip level will be calculated from the diameter and wall thickness determined at lower tip level. A tapered distribution of diameter and wall thickness is assumed:

$$bottomdiameter = topdiameter$$

and

$$topthickness = bottomthickness = minimumthickness = 10mm.$$

Due to the small tube diameters this option will also lead to low wave loads. For the cost it is assumed that the tripod beams are included in the foundation. For the frequency calculation the stiffness of the tripod beams will be included.

The concept is applied with full variable speed.

The coefficients for the stall teeter down wind concept are in table 17.

Table 17: Derivation of Bladopt coefficients for the stall teeter down wind concept as far as different from table 14 in Dfl

Component	Model based on existing turbines	Adaption	Bladopt model
Pitch	No pitch	No	pitch brake included in hub: $5000\,(D/25)^{2.7}$
Teeter	No teeter model		Flexhat model $K_{teeter} = 13050\,(D/25)^{2.7}$
Hub	$K_{hub} = k_{hub} m_{hub}$ $M_{hub} = a_{hub} D^{2.7}$	1), tip brake, teeter and main shaft included	$K_{hub} = (13050 + 5000 + 3073)\,(D/25)^{2.7}$ $=21123\,(D/25)^{2.7}$
Mainshaft	$K_{shaft} = k_{shaft} m_{shaft}$ $M_{shaft} = a_{shaft} D^{2.7}$		Included in hub
E system	$K_{ES} = a_{es} p^{0.9} + b_{es} p^{0.3}$	See fit in fig. 5	$K_{ES} = 47000 \left[\left(\frac{P}{250} \right)^{0.8} + \left(\frac{P}{250} \right)^{0.2} \right] + 70P$
Safety and control	Included in E system	Offshore adaptions will be included	$K_{saf} = a'_{saf} + b'_{saf} f_{saf} + c'_{saf} f_{pitch}$ $=40000 + 500001.2 + 15000 f_{pitch}$ $f_{pitch} = 0$ if no full pitch
Offshore cost	From [12] $K_{off} = 11.1710^6$	3)	$K_{off} = 6,261,096 + 149P + 33943D$
Farm efficiency	96 % [5]		
Availability	93.25 % [12]		
Foundation stiffness	Not available yet, take infinite for gravity base flange height $H_f = 40m$		Infinite: $H_t = H - H_f = 80, Hw = 20$

1) see also table 14

3) At the moment in [12] no parameter sensitivity is included, for the time being the coefficients from [1] used in BladOpt will be adopted, while the cost at $D = 120m$and $p = 500W/m^2$ (P=5600 kW) are kept the same, from which the constant can be derived:
$C'_{off} = 11,170,000 - 149P - 33943D = 6,261,096$

Table 18: Derivation of Bladopt coefficients for the smart stall concept as far as different from table 14 in Dfl

Component	Model based on existing turbines	Adaption	Bladopt model
Pitch	Included in hub	No	K$_{tip} = 8981 \left(\frac{D}{25}\right)^{2.7}$ included in hub
Hub	K$_{hub} = k_{hub} m_{hub}$ M$_{hub} = a_{hub} D^{2.7}$	1)	K$_{hub} = (7663 + 8981) \cdot \left(\frac{D}{25}\right)^{2.7}$ $=16644 \cdot \left(\frac{D}{25}\right)^{2.7}$
E system	K$_{ES} = a_{es} p^{0.9} + b_{es} p^{0.3}$	See fit in fig. 5	K$_{ES} = 47000 \left[\left(\frac{P}{250}\right)^{0.8} + \left(\frac{P}{250}\right)^{0.2}\right] 70P$
Safety and control	Included in E system	Off-shore adaptions will be included	K$_{saf} = a'_{saf} + b'_{saf} f_{saf} + c'_{saf} f_{pitch}$ $=40000 + 500001.2 + 15000 f_{pitch}$ f$_{pitch} = 0$ if no full pitch
Farm efficiency	97 % [5]		
Availability	93.45 % [12]		

1) see table 16

Smart stall concept

The smart stall concept consists of a passive control tip activated by the aerodynamic moment. For the cost model the results of the NOVEM control tip projects (Flexhat) and the Nedflex project will be used:

$$\mathrm{K}_{tip} = 2500 \left(\frac{D}{20}\right)^{2.7} + 14500 \left(\frac{D}{20}\right)^{2.7}$$

In BladOpt input format and extrapolated around D=120 m this model can be adapted in

$$\mathrm{K}_{tip} = 8981 \left(\frac{D}{25}\right)^{2.7}$$

The coefficients for the smart stall concept are in table 18.

3.3 Summary of the cost coefficients

For each concept the cost models of the BladOpt program, described in appendix A, have to be tuned with the data given in the tables 14 - 18 to get correct results. The resulting values for the coefficients are given in table 19.

Table 19: The Cost coefficients

	Comment	1 Base line	2 Advanced	3 Robust	4 Stall-Teeter	5 Smart stall
assembly not derived						
C_C_1	[€/m]	13636	13636	13636	13636	13636
sf_1	[–]	1.005	1.005	1.005	1.005	1.005
wind farm						
C_C_1	[€/kW]	67.75	67.75	67.75	67.75	67.75
C_C_2	[€/m]	15429	15429	15429	15429	15429
C_C_3	[€]	4332316	4332316	2345953	2845953	4332316
safety control						
C_C_1	[€]	18182	18182	18182	18182	18182
C_C_2	[€]	22727	22727	22727	22727	22727
C_C_3	[€]	6818	6818	6818	6818	6818
sf_1	[-]	1	1	1	1	1
sf_2	[-]	2	2	0	0	0
hub						
C_C_1	a'hub [€/$m^{2.7}$]	13919	13919	3470	9601	7565
C_C_2	pitch.main shaft and	0.	0.	0.	0.	0.
C_C_3	teeter included	0.	0.	0.	0.	0.
drive train						
C_C_1	a'gear [€/Nm]	131.	131.	162.	131.	131.
E-system						
a	[€/kW^2]	-0.00036	-0.00040	-0.00036	-0.00036	-0.00036
b	[€/kW]	12	13	12	12	12
c	[€]	13970	15366	13970	13970	13970
C_C_1	[€]	14000	17273	14000	21364	21364
C_C_2	[€/kW]	0	12	0	32	32
ngen[1]	[-]	1	1	1	1	1
nacelle						
mc1	a'nac [€/m2.7]	4804	4804	4804	4804	4804
C_C_1	k'nac [€/kg]	1.0	1.0	1.0	1.0	1.0
yaw included in nacelle						
C_C_1		0	0	0	0	0
blade						
k	k‘blade [€/kg]	9	9	9	9	9
tower						
k	k‘tower [€/kg]	2	2	2	2	2

---

[1] 2 speed take ngen-1.5

3.4 Results

3.5 Concept 1: Baseline, active stall CS/DS

Table 20: The cost distribution of the Base-Line concept.

Initial investment cost

Component	Sub-component	Cost	
		€	%*
Wind Turbine	Blades	699730	6.9
	Hub	960219	9.5
	Drive train	462828	4.6
	Electrical system	262408	2.6
	nacelle	331408	3.3
	yaw mechanism	0	0.0
	control/safety systems	59010	0.6
	assembly	302213	3.0
	subtotal Wind Turbine	3077816	30.5
Support structure	Foundations	2173662	21.02
	tower	450576	4.50
	subtotal Support Str.	2624238	26.0
Farm electric	Cable	1343012	13.32
infrastructure	transformers	216516	2.15
Inc. install.	other	73083	0.73
	subtotal E-infra.	1632612	16.2

* % of the total investment cost.

Transportation & Installation cost

Component	Sub-component	Cost	
		€	%*
Transport		30303	0.30
Wind turbine		713909	7.08
Support structures	foundation	480909	4.65
	tower	713909	7.08
Decommis. & salvage		607133	6.02
Management		213904	2.12
	subtotal	2760067	27.4
	Total Investment	10083091	100

Operations & maintenance cost

Component	Sub-component	Cost	
		€	%*
O&M		201662	2.0
Other recurring cost		50415	0.5

Availability and AU E

potential Energy yield	23.0	[GWh]
Losses	13.4	%
AUE	19.9	[GWh]

Cost of Energy

	€cent/kWh
LPC	5.311

3.6 Concept 2: Advanced, active pitch variable speed

Table 21: The cost distribution of the Advanced concept.

Initial investment cost

Component	Sub-component	Cost	
		€	%*
Wind Turbine	Blades	989042	9.56
	Hub	960219	9.28
	Drive train	358862	3.47
	Electrical system	383498	3.71
	nacelle	331408	3.20
	yaw mechanism	0	0.00
	control/safety systems	59010	0.57
	assembly	302213	2.92
	subtotal	3384252	32.7
Support structure	Foundations	2173662	21.02
	tower	403664	3.90
	subtotal	2577326	24.9
Farm electric	Cable	1343012	12.99
infrastructure	transformers	216516	2.09
incl. install.	other	73083	0.71
	subtotal	1632612	15.8

* % of the total investment cost.

Transportation & Installation cost

Component	Sub-component	Cost	
		€	%*
transport		30303	0.29
Wind turbine		713909	6.90
Support structures	foundation	480909	4.65
	tower	713909	6.90
Decommis. & salvage		607133	5.87
Management		213904	2.07
	subtotal	2760067	26.7
	Total	10342615	100

Operations & maintenance cost

Component	Sub-component	Cost	
		€	%*
O&M		206852	2.0
Other recurring cost		71713	0.5

Availability and AU E

potential Energy yield	23.6	[GWh]
Losses v	15.17	%
AUE	20.0	[GWh]

Cost of Energy

	€cent
LPC	5.447

3.7 Concept 3: Robust, passive stall 2 blades CS/DS monopile

Table 22: The cost distribution of the robust 2 bladed concept.

Initial investment cost

Component	Sub-component	Cost	
		€	%*
Wind Turbine	Blades	474411	5.90
	Hub	239349	3.00
	Drive train	828108	10.30
	Electrical system	269466	3.40
	nacelle	331408	4.10
	yaw mechanism	0	0.00
	control/safety systems	45393	0.60
	assembly	370133	4.60
	subtotal	2558268	31.9
Support structure	Foundations	461074	5.76
	tower	878207	11.00
	subtotal	1339281	16.7
Farm electric infrastructure	Cable	1343012	16.77
	transformers	216517	2.70
	other	73083	0.91
	subtotal	1632612	20.4

* % of the total investment cost.

Transportation & Installation cost

Component	Sub-component	Cost	
		€	%*
transport		15152	0.19
Wind turbine		713909	8.92
Support structures	foundation	364318	4.55
	tower	713909	8.92
Decommis.& Salvage		485774	6.07
Management		189632	2.37
	subtotal	2482694	31.0
	Total investment	8007516	100

Operations & maintenance cost

Component	Sub-component	Cost	
		€	%*
O&M		160150	2.0
Other recurring cost		40038	0.5

Availability and AU E

potential Energy yield	21.5	[GWh]
Losses	12.35	%
AUE	18.8	[GWh]

Cost of Energy

	€cent
LPC	4.448

3.8 Concept 4: Stall-teeter, 2 blades passive stall variable speed truss tower

Table 23: The cost distribution of the 2 blade down wind teeter concept.

* % of the total investment cost.

Initial investment cost

Component	Sub-component	Cost	
		€	%*
Wind Turbine	Blades	346602	4.20
	Hub	662357	8.00
	Drive train	536094	6.50
	Electrical system	542492	6.60
	nacelle	331408	4.00
	yaw mechanism	0	0.00
	control/safety systems	45393	0.60
	assembly	302213	3.70
	subtotal	2766559	33.6
Support structure	Foundations	2383128	28.92
	tower	403664	4.90
	subtotal	2786792	33.8
Farm electric infrastructure incl. install.	Cable	1343012	16.30
	transformers	216517	2.63
	other	73083	0.89
	subtotal	1632612	19.8

Transportation & Installation cost

Component	Sub-component	Cost	
		€	%*
Transport		342308	4.154
Wind turbine			
Support structures	foundation	241026	2.925
	tower		
Decomm. & Salvage		321167	3.897
Management		156710	1.902
	subtotal	1061211	12.9
	Total	8240583	100

Operations & maintenance cost

Component	Sub-component	Cost	
		€	%*
O&M		164812	2.0
Other recurring cost		41203	0.5

Availability and AU E

potential Energy yield	21.9	[GWh]
Losses	14.96	%
AUE	18.6	[GWh]

Cost of Energy

	€cent
LPC	4.675

3.9 Concept 5: Smart stall

Table 24: The cost distribution of the smart stall concept.

Initial investment cost

Component	Sub-component	Cost	
		€	%*
Wind Turbine	Blades	656437	6.80
	Hub	521909	5.40
	Drive train	333236	3.40
	Electrical system	542492	5.60
	nacelle	331408	3.40
	yaw mechanism	0	0.00
	control/safety systems	45393	0.50
	assembly	302213	3.10
	subtotal	2733088	28.2
Support structure	Foundations	2173662	22.429
	tower	403664	4.200
	subtotal	2577326	26.6
Farm electric infrastructure	Cable	1343012	13.86
	transformers	216516	2.09
	other	73083	0.75
	subtotal	1632612	16.7

* % of the total investment cost.

Transportation & Installation cost

Component	Sub-component	Cost	
		€	%*
transport		30303	0.31
Wind turbine		713909	7.37
Support structures	foundation	480909	4.96
	tower	713909	7.37
Decomm. & Salvage		607133	6.27
Management		213904	2.21
	subtotal	2760067	28.5
	Total investment	9691450	100

Operations & maintenance cost

Component	Sub-component	Cost	
		€	%*
O&M		193829	2.0
Other recurring cost		48457	0.5

Availability and AU E

potential Energy yield	23.0	[GWh]
Losses	13.89	%
AUE	19.9	[GWh]

Cost of Energy

	€cent
LPC	5.175

3.10 Summary

Table 25: Cost of Energy summarized per concept

Concept	Wind Turbine	Support Structure	Wind farm electric	Transport & Installation	Total Investment	Yield	Efficiency	LPC
	k€	k€	k€	k€	k€	GWh/y	%	€cent/kWh
Base-line	3077.816	2624.238	1632.612	2760.067	10083.091	23.0	86.6	5.311
Advanced	3384.252	2577.326	1632.612	2760.067	10342.615	23.6	84.8	5.447
Robust	2558.268	1339.281	1632.612	2482.694	8007.516	21.5	87.6	4.448
Stall Teeter	2766.559	2786.792	1632.612	2766.559	8240.583	21.9	85.0	4.675
Smart Stall	2733.326	2577.326	1632.612	2760.067	9691.450	23.0	86.1	5.175

4 REMARKS, DISCUSSION AND RECOMMENDATIONS

4.1 Remarks

1. The monopile of the **robust** concept can most probably not be made due to a too large diameter required for the monopile. The present available equipment for driving piles into the seabed is probably not capable for the required diameter of the pile.

2. The 2 bladed rotors, the **robust** and **stall teeter** concept are only provisionally designed. The profiles are not suitable for passive stall.

3. The blade (cost) model is not suited for down wind. The blade load reducing effect due to centrifugal stiffening works in the wrong direction. The load model does not incorporate the change in loading due to the tower wake.
   Besides, due to the teeter the blade might hit the tower during stand still and when the rotor position is vertical. The upper blade will bend backwards due to higher wind pressure which will tilt the lower blade towards the tower.

4. Variable speed looks bad at the moment but has in fact a too low availability in this study. This is mainly due to the lower availability of the inverter. In reality it is possible to make a variable speed system with a constant speed backup in case the inverter brakes down.

5. optimisation with respect to rated power and rotor diameter are still only bound due to user given boundaries. This is probably due to insufficient sensitivity of the support structure and wind farm infra structure cost towards these parameters and response parameters as thrust force and/or tower bending moment. It is not yet certain whether in reality the influence of the design and/or response parameter is there.

6. Latice tower could not be modelled at the moment. Instead a tubular tower is used for dynamics and cost modelling.

7. For the annual O&M cost 2% of the total investment cost are assumed. This value can only be met assuming that purpose built equipment will be developed to reach this value. Use of presently available lifting equipment would lead to a much higher value.

4.2 Discussion

The ranking with respect to LPC is:

	LPC €ct	availability %
1.Robust	4.448	96.1
2.Stall teeter	4.675	93.3
3.Smart Stall	5.175	93.5
4.Base line	5.311	95.0
5.Advanced	5.447	93.6

The outcome of the analysis is very much decided by the type of foundation e.g. the robust concept has a monopile which is much cheaper than the tripod however this type of foundation can not be made for towers with a foot diameter of more than 4 – 5 [m] while for the turbine size discussed here the tower foot diameter is at least 7 [m]. The available information, at the time, is that monopiles can not have larger diameters than 3.5 – 4. m.

The get the given availability some concepts need more maintenance crews than other concepts. This is not reflected in the O&M cost due to lack of knowledge at the time of writing.

4.3 Recommendations

1. Cost model have to be developed towards:
    - foundation cost;
    - installation cost;
    - Operating and maintenance cost relative w.r.t. availability;
    - grid infrastructure.
2. Checks have to be made with a more realistic wind turbine model and load model.
3. Wave loads have to be taken into account for the support structure and the influence on the dynamics of the rotor.
4. grid requirements possibly in relation to the value of the produced energy, e.g. a higher quality or higher controlability of the produced electricity, will be worth something on the energy spot market.

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A DESCRIPTION OF THE COST MODELLING AND THE DEFAULT VALUE OF THE CONSTANTS

For the following components cost models are available:

A.1 Assembly of the wind turbine

$$\mathrm{C}_{assembly} = C\_C\_1 \cdot \left(\frac{dia}{30}\right)^{2} \cdot \left(\frac{H}{42}\right)^{0.5} \cdot sf$$

in which

$$\begin{aligned} C\_C\_1 &= 30000 \\ sf &= 1.005 \end{aligned}$$

A.2 Wind farm

In principle these are the electric infra structure of the wind farm:

$$\mathrm{C}_{windfarm} = C\_C\_1 \cdot P_{rated} + C\_C\_2 \cdot dia + C\_C\_3$$

in which

$$\begin{aligned} C\_C\_1 &= 74 \\ C\_C\_2 &= 3000 \\ C\_C\_3 &= 1900 \end{aligned}$$

A.3 safety & control system

$$\mathrm{C}_{safcont} = C\_C\_1 + C\_C\_2 \cdot sf_1 + Lvarsp \cdot C\_C\_3 \cdot sf_2$$

in which

$$\begin{aligned} C\_C\_1 &= 8000 \\ C\_C\_2 &= 10000 \\ C\_C\_3 &= 3000 \\ Lvarsp &= 0 \mathrm{for constant speed control} \\ &= 1 \mathrm{for variable speed control} \end{aligned}$$

and

$$\begin{aligned} sf_1 &= 1.2 \\ sf_2 &= 2 \end{aligned}$$

A.4 hub including pitch mechanism

$$\mathrm{C}_{hub} = C\_C\_1 \cdot \left(\frac{dia}{25}\right)^{2.7} + C\_C\_2 \cdot \#blades + C\_C\_3$$

in which

$$\begin{aligned} C\_C\_1 &= 8000 \\ C\_C\_2 &= 2500 \\ C\_C\_3 &= 1250 \end{aligned}$$

A.5 drive train

$$\mathrm{C}_{drive} = C\_C\_1 \cdot Q_{max} \cdot \frac{sf}{1.8}$$

in which

$$C\_C\_1 = 900.$$

A.6 Electrical system

Consisting of the generator and electrical system. The cost are divided into three items, the cost of the generator(s), the cost of the electrical system and cost of the variable speed components, like inverter etc.

$$\mathrm{C}_{elsys} = C_{gen} + C_{el} + C_{var}$$

In which

$$\mathrm{C}_{gen} = \#generators \cdot \left(a \cdot \left\{\frac{P_{rated}}{\#generators}\right\}^{2} + b \cdot \left\{\frac{P_{rated}}{\#generators}\right\} + c\right)$$

and

$$\mathrm{C}_{el} = C\_C\_2 \cdot P_{rated}$$

and

$$\mathrm{C}_{var} = C\_C\_1 \cdot \left[\left\{\frac{P_{rated}}{250}\right\}^{.2} + \left\{\frac{P_{rated}}{250.}\right\}^{.8}\right]$$

in which the following default constants are defined:

$$\begin{aligned} a &= 0.25 \\ b &= 25 \\ c &= 50 \\ C\_C\_1 &= 48000 \\ C\_C\_2 &= 65 \\ \#gen &= 1 \end{aligned}$$

A.7 Nacelle

$$\mathrm{M}_{nacelle} = m\_c\_1 \cdot \left(\frac{dia}{25.}\right)^{2.7}$$

$$\mathrm{C}_{nacelle} = C\_C\_1 \cdot M_{nacelle}$$

in which the following default constants are defined:

$$\begin{aligned} m\_c\_1 &= 6000 \\ C\_C\_1 &= 1.375 \end{aligned}$$

A.8 Yaw mechanism

$$\mathrm{C}_{yaw} = C\_C\_1 \cdot \left(\frac{dia}{25.}\right)^{2.7}$$

in which the following default constants are defined:

$$\mathrm{C}\_C\_1 = 6500$$

A.9 Tower

The tower model is not a parametric model but an engineering model. In the tower model a tower is designed using the loads determined in the load module of *BladOpt*. This module is described in [4].

The tower model *designs* a tubular tower with a linear taper of the diameter and a linear taper of the tower wall thickness. So a tower design can be described with four parameters:

- top diameter;
- top wall thickness;
- foot diameter;
- foot wall thickness;

The top wall thickness is prescribed in the model, 0.01 m. The top diameter is determined from the rotor diameter, $1. + c\_d\_1 * dia$

The tower taper is varied and for each tower foot diameter the tower foot wall thickness is determined so that the tower is resistant to

- extreme loads, compared with the yield stress (input parameter);
- fatigue loads, compared with the fatigue stress (input parameter);
- buckling, compared with buckling constant;

The eigenfrequency of the tower, determined using a simple beam theory, may not coincide with the rotor frequency. For constant speed rotors the following checks are performed and an optimum tower is design not violating these constraints.

$$\begin{aligned} \nu_{tower} &\leq a \cdot \omega_{rotor} \\ \nu_{tower} &\geq b \cdot \omega_{rotor} \\ &\leq c \cdot \#_{bl} \cdot \omega_{rotor} \\ \nu_{tower} &\geq d \cdot \#_{bl} \cdot \omega_{rotor} \end{aligned}$$

For a variable speed machine the rotor speed control is adapted in such a way that the rotor speed will pass through this frequency quickly.

The eigenfrequency can depend on foundation stiffness by adding a section below the foundation which will increase the flexibility and modal mass. Clamping length should be tuned to fit requirements.

$$\mathrm{C}_{tower} = C\_C\_1 \cdot M_{tower}$$

The M_{tower} equals the volume of the tower wall times the density of the tower material.

The input paramters to determine the cost of the tower are:

C_C_1	cost of the tower material per kg.	4.
c_d_1	top diameter/rotor diameter fraction	0.03
C_buck	Buckling factor	175.
E_{tower}	Modulus of elasticity tower material	2.1E+11
ρ_{tower}	Density of tower material	7800.
σ_{ext}	Allowable extreme stress tower material	150.E+06
σ_{fat}	Allowable fatigue stress tower material	50.E+06
m	slope of SN curve tower material	5
σ_{yield}	Yield stress tower material	240.E+06

The constants to determine the allowable frequency ranges for the tower eigenfrequencies are:

a 0.85;

b 1.15;

c 0.99;

d 1.01.

A.10 Blade

The rotor blade cost model is like the tower model also an engineering model. An optimum blade is designed in such a way that for all cross sections the blade is sufficiently strong with respect to fatigue and extreme loads while the load reducing effect of centrifugal stiffening is taken into account.

The blade is described as a load carrying beam with:

- a circular outside cross section for the root part;

- an elliptical or box outside cross section for the aerodynamic part;

The blade is divided into the same number of elements as for the power curve and load calculations. At each cross section the extreme and fatigue loads in flatwise and edgewise direction are known.

For each cross section the wall thickness is determined with a minimization process. The target is a minimum cross section with while the following constraints are not violated.

- cross section sufficient strong against fatigue loads;
- cross section sufficient strong against extreme loads;

The required input parameters are:

C_C_1	: price per unit of mass	€/kg
C_C_2	: price per unit of mass of a moveable tip	€/kg
C_mass	: coefficient of mass of tip	-
$\mathrm{s}f_{cntr}$	: safety factor for control	-
lbox	: box or elliptical shape of load carring cross section	-
Espar	: Modulus of elasticity of spar material	-
ρ_{spar}	: density of spar material	$\mathrm{k}g/m^3$
ρ_{skin}	: density of skin material	$\mathrm{k}g/m^3$
σ_{fat}	: Allowable fatigue stress	N/m^2
m	: Slope of S–N curve	-
σ_{ext}	: Allowable extreme stress	N/m^2
t_{min}	: minimum shell thickness for skin and load carrying beam	-

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Abstract

In this report the work performed for task 12 of the Dowec concept study project is reported. Task 12 consisted of multidisciplinary optimisation of the complete wind energy conversion system, an off-shore wind farm, taking into account the wind turbines, the foundations, the electric infrastructure and the operations and maintenance. The aim of this optimisation was to find quantitative difference between 5 different wind turbine concepts.

Due to limited data for the foundation, electric infrastructure and O&M cost, optimisation was not very useful in the end. The work performed is a cost comparison between 5 different concepts of wind turbines applying the known differences to the cost of the foundations, electric infrastructure and O&M cost/availability.

All concepts had a cost of energy price level between 4.5 €ct/kWh (robust) and 5.5 €ct/kWh (Advanced stall). Recommendation for the further research are given, aiming at a more solid basis for the choice of the wind turbine concept.

Keywords Optimisation, Cost of Energy, Off-shore, Wind Energy Converter

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