INSTITUTE FOR SUSTAINABLE ENERGY, UNIVERSITY OF MALTA

SUSTAINABLE ENERGY 2014:
THE ISE ANNUAL CONFERENCE

Thursday 20th March 2014, Dolmen Hotel, Qawra, Malta

ISBN 978-99957-0-668-5

COST MODELLING OF FLOATING WIND FARMS WITH UPSCALED ROTORS IN MALTESE WATERS

M. Aquilina, [1], T. Sant, [1] and R. N. Farrugia, [2]
[1]Department of Mechanical Engineering, University of Malta, Msida, MSD2080, Malta.
[2]Institute for Sustainable Energy, University of Malta, Triqil-Barrakki, Marsaxlokk MXK1531, Malta.
Tel: (+356) 23402023, (+356) 23402437
Corresponding Author E-mail: matteo.aquilina.07@um.edu.mt

ABSTRACT: The technical viability of offshore wind projects depends upon a number of factors such as the site-specific wind resource, sea depth, seabed composition, distance to the shore and climatic conditions amongst others. The Mediterranean is characterised by deep seas relatively close to the shore and only a reasonable wind climate if compared to conditions in countries that are forerunners in the offshore wind sector. The development of floating wind turbine support structures will allow wind farms in deeper waters and will be a catalyst for the wider diffusion and larger-scale implementation of offshore wind farms on a global level. This study investigates the prospects for a hypothetical 100 MW floating offshore wind farm well to the west of the island of Malta. The study models three upscaled turbines having rotor diameters of 126, 145 and 170 m. The study shows that the rotor upscaling process can improve the economic viability of offshore wind turbines with the improved energy yield counterbalancing the higher investment costs required for such a project and thus resulting in a lower cost of energy. The levelised cost of electricity is estimated to be in the 21.0 to 23.6 €cent/kWh range which, although still well above the current market prices of electricity generated by conventional means, is expected to drop considerably over the coming years as new international players enter the offshore wind market. Increasing levels of competition, new concepts coming to fruition and wider and larger-scale diffusion of new technologies will help bring down costs of energy for the offshore wind farms of the future.

Keywords: Floating wind turbines, Deep offshore wind, Maltese waters, Cost of energy

1 INTRODUCTION

1.1 Background

Located in the Central Mediterranean Sea, the Maltese islands' characteristics offer a plethora of challenges to the development of offshore wind farms using existing commercial technologies. One of the foremost challenges is due to the relatively deep waters and lower wind speeds when compared to other locations such as the North Sea which benefit from large shallow areas with very good wind conditions.

Offshore wind turbines need to be supported on floating structures if installed at deep water sites. A depth of 60 metres is usually considered as the economic threshold for seabed mounted turbines **[1]**. The waters surrounding the Maltese islands are generally deeper than 100 metres, with the exception of a few sites with depths of 70 metres or less. Additionally, these latter sites lie close to shore, in areas in which environmentally protected habitats exist and where commercial and leisure maritime activities are typically more intense. Floating wind turbine technology would offer Malta the opportunity to exploit offshore wind at sites further away from the shore where environmental and planning issues related to wind farm developments are not expected to be as problematic.

1.2 Motivation

In the recent years, there has been an increased interest among industry and academia to research and develop floating wind turbine technologies **[2]**. A number of scaled and full-scale prototypes have already been deployed off Norway **[3, 4]**, Portugal **[5]**, Italy **[6]**, the USA **[7]** and Japan **[8]**. While some floating wind technologies are approaching commercialisation status, further developments would be necessary to optimise them for low-to-medium wind resource sites such as in the Central Mediterranean basin. Aerodynamic theory shows that the wind power available across a rotor increases with the square of the diameter. The use of upscaled rotors with a higher rotor area-to-generator capacity ratio (m^2/W) is one option proven to improve economic viability in onshore low-wind sites. In fact, various turbine manufacturers nowadays supply onshore turbines with a high rotor area-to-generator capacity ratio tailored for sites with a low long-term average wind speed. Increasing the rotor size demands taller towers to ensure that adequate clearance between the blade tips and the ground. The offshore wind sector is expected to follow the same path. The generator capacity for most offshore wind farm projects in shallow waters has increased from 3 MW to 5 MW in the past five years, with rotor diameters increasing from 90 m to 126 m **[9]**. Wind turbines with a capacity of 6 – 8MW and a diameter of 150 – 164 m are already in development (for example the Alstom HaliadeTM 150-6MW **[10]**, the Siemens SWT-154-6MW **[11]**, the Gamesa G145-7MW **[12]** and the Vestas V-164-8MW **[13]**). Maximum wind turbine hub heights are being increased from around 80 m to over 100 m above mean sea level. While increasing the tower height is unavoidable for large rotors, it also allows the exploitation of more favourable wind conditions available at higher altitudes. There is no doubt that such developments would naturally facilitate the introduction of low-wind speed turbines in the offshore market (as for example a 150 m turbine with a capacity of 5MW). Apart from increasing the energy generated at a particular wind speed, wind turbine up-scaling results in higher capital costs in terms of Euro per Megawatt investment.

1.3 Objectives of Study

The main scope of this study was to evaluate the impact of wind turbine rotor up-scaling on the costs of energy from floating wind farms in Maltese waters where wind conditions are inferior to those in the North Sea. The study only focused on one floating structure type, the Tension Leg Platform (TLP), installed at a sea depth of 200 metres.

2 METHODOLOGY

The study involved the analysis of three different hypothetical Floating Offshore Wind Turbine (FOWT) models referred to Models 1, 2, and 3; each having a generator capacity of 5 MW and a rotor diameter of 126, 145 and 170 m respectively. Model 1 was the baseline FOWT model, from which Models 2 and 3 were upscaled. The upscaling process was restricted to the rotor and tower only, with all remaining design parameters, including the generator capacity and TLP, kept unchanged. Model 1 had the design parameters of the NREL 126 m diameter 5MW reference offshore wind turbine with the MIT floating TLP. Further details about the NREL[1] 5 MW wind turbine and the MIT[2] TLP may be found in **[14, 15]**, respectively.

An engineering analysis was undertaken on the three FOWT models through a numerical simulation with GH BLADED™**[16]**, an integrated design tool for modelling the performance, loads and dynamic response of wind turbines. More information about this design tool may be found in **[17, 18]**. The FOWT models were simulated under Central Mediterranean Metocean conditions, Table 1, with various design load conditions (DLCs) analysed in accordance with the IEC 61400-3 offshore wind turbine standard **[19]**. The analysis was however restricted to an Ultimate Limit Strength (ULS) with DLCs limited to those concerning power production. The extreme loads predicted by GH Bladed for the different DLCs were used in a simplified stress analysis to ensure that the three wind turbine models could safely withstand the environmental conditions in Maltese waters.

Table 1: Metocean conditions for Central Mediterranean region (BMT Argoss data base).

Sea Depth		200 m
Average Wind Speed at 90m above mean sea level		7.50 m/s
10 min average extreme wind speed		37.5 m/s
Wind speed/ms^{-1}	**Wave height/m**	**Tp/s**
7.3	0.8	5.8
8.4	1	5.8
9.4	1	5.8
9.3 (rated 170m)	1	5.8
10.4 (rated 145m)	1.2	6.48
11.4 (rated 126m)	1.4	7.1
11.3	1.3	7.1
12.4	1.5	7.1
13.4	1.7	7.2
25 (cut out)	4.5	11

Three wind farms composed of the three different FOWT models were modelled for a deep offshore site located off the west coast of Malta. Estimates for the long term wind conditions for this site were derived by extrapolating wind measurements at two land-based monitoring by means of Measure Correlate Predict (MCP) routines available in the WindPRO**[20]** software. Long-term wind data collected at a height of 10 metres a.g.l. at WiedRini was correlated to shorter term wind data measured on the 80 metre wind mast at Aħrax Point, Marfa. The 80 metre level wind parameters time series was then used as a climatological input to the CFD wind flow modelling software WindSim**[21]**. Estimates for

[1]National Renewable Energy Laboratory, USA.

[2]Massachusetts Institute of Technology, USA.

the average wind speed and the Weibull parameters for this offshore site corresponding to a 90 metre hub height were derived. A cost model was developed to estimate the levelised cost of electricity (LCOE) over a 20 year lifetime. The various cost elements were mainly based on literature research and included costs related to project development, hardware, construction, operation and maintenance as well as decommissioning. The LCOE figures from the three independent wind farms were compared to determine the impact of rotor up-scaling on the economic feasibility of floating wind energy generation technology.

3 DESIGN PARAMETERS OF THE BASELINE FOWT MODEL (Model 1)

3.1 Wind Turbine Model

The design parameters of the NREL 5MW turbine used for FOWT Model 1 and implemented in GH BLADED are summarised in Tables 2 and 3. More details about this wind turbine model may be found in **[14]**. The tower diameter and material thickness varies linearly along the whole length. This results in a tapered structure with the widest diameter and thickest material at the tower base. A value of 8500 kg/m^3 for density was applied to compensate for the paint, bolts, flanges and any other parts which are not mentioned.

Table2: NREL offshore wind turbine details.

Parameter	Value
Rating	5 MW
Rotor Orientation, Design	Upwind, 3 Blades
Control	Pitch varied Speed
Drive-train ratio	97:1
Rotor Diameter	126 m
Hub Diameter, Height	3 m, 90 m
Cut-In, Rated, Cut-Out Wind Speed	3 m/s, 11.4 m/s, 25 m/s
Rated Tip Speed	80 m/s
Overhang, Shaft Tilt	5m, 5º
Pre-cone	2.5º upwind
Rotor Mass	110,000 kg
Nacelle Mass	240,000 kg
Tower Mass	347,460 kg

The blades have a controller to regulate the pitch angle of the blade depending on the rotor and wind speed. An external controller written by NREL was implemented in the simulations in GH BLADED [16]. For low wind speeds up to the rated wind speed, the blade pitch angle is maintained fixed with the rotor assuming variable speed operation to optimise the tip speed ratio. For wind speeds higher than the rated wind speed, the controller regulates the pitch angle of the blades to maintain rated power at 5MW with a constant rotor speed.

Table 3: Turbine details for 126 m diameter rotor.

Parameter	Value
Blade	
Mass per blade	17,740kg
Inertia Mass Moment	11,776,047kgm^2
Nacelle and Hub	
Hub Mass	56,780kg
Hub Inertia	115,926kgm^2
Nacelle Inertia	2,607,890kgm^2
Tower	
Height above Ground	87.6m
Base diameter, thickness	6m, 35.1mm
Top diameter, thickness Density	3.87m, 24.7mm 8500kg/m^3

3.2 Model for the Floating Platform

The design parameters for the MIT tension leg platform assumed in the present study are presented in Table 4. The platform data used was based on that presented in **[15]**. The floating support used for this study was a hybrid between a TLP design and a ballast stabilized system. This requires displacement of a large volume of water through a cylindrical platform beneath the turbine. Furthermore, mooring lines are employed to fix the turbine to the seabed and offer a stabilizing force. Concrete placed at the base of the platform was used as ballast in this turbine.

Table 4: Design properties of the TLP

Diameter	18 m
Platform wall thickness	0.015 m
Height of platform	47.89 m
Water displacement	12,180 m^3
Mass, including ballast	8,600,000 kg
Ballast (concrete) mass	8,216,000 kg
Ballast (concrete) height	12.6 m
Number of mooring lines	8 (4 pairs)
Depth to fairleads	47.89 m
Depth to sea bed	200 m
Radius to fairleads	27 m,
Radius to anchors	27 m
Un-stretched line length	151.7 m
Line diameter	0.127 m
Line mass density	116 kg/m
Line extensional stiffness	1,500,000,000 N
Average steel density	7850 kg/m^3
Average concrete density	2562.5 kg/m^3

The moorings should always be under tension in order to avoid failure **[15]**. This is because once they are slack they will undergo a sudden shock load once they placed under tension again. During initial simulations under Central Mediterranean conditions, several simulations had instances of slack moorings. Thus it was decided to alter the platform design in such a way as to increase the mooring tension. It was decided to reduce the concrete ballast at the base of the platform. The ballast weight that ensured proper behaviour of the moorings was 3,600,000 kg as opposed to the published 8,216,000 kg. Fig. 1 illustrates a 3D model of Model 1 as simulated in GH BLADED.

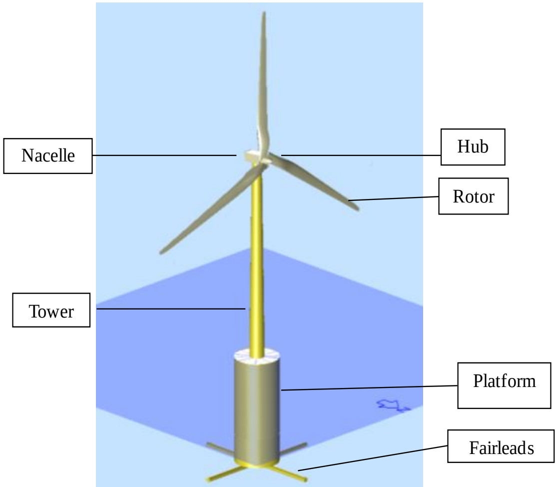

Figure 1: FOWT consisting of NREL wind turbine supported on a TLP as modelled in GH BLADED

4 UP-SCALING OF THE FLOATING WIND TURBINES

The up-scaling process used in this study involved only the wind turbine rotor and tower. It started by setting a reference rotor diameter of 126 m and two up-scaled rotor diameters (145 m and 170 m), for FOWT Models 2 and 3, respectively. The hub and tower were up-scaled in relation to the rotor diameter. Upscaling was done according to scaling rules determined from various literature findings. Linear scaling was applied to determine the geometry of the rotor and tower.

The radii and thicknesses along the tower length were also up-scaled linearly using the height as reference. The tower weight was calculated through volume and density relationships. On the other hand, the blade and hub weights were scaled according to $S_{blade}^{2.87}$, as suggested by **[22]**. An important distinction is that the tower height is scaled with different scaling factors to the blade and hub. This meant that two sets of scaling factors had to be used. S_{blade} was used for the blade and hub scaling process and was the ratio of the up-scaled to reference blade length. S_{tower} represented the scaling of the tower height and was the proportion of the up-scaled to reference tower height. Some properties after up-scaling are shown inTable 5. Here it should be pointed out that a property defined as a function of other properties is scaled using a scaling rule defined by the function of the corresponding scaling factors. Hence, as an example, the scaling rule of blade inertia in kgm^2 is the scaling rule of mass ($S_{blade}^{2.87}$) multiplied by the square of scaling rule of length (S_{blade}), effectively $S_{blade}^{4.87}$.The control parameters of the turbines had to change with the upscaling process. This is necessary to keep an optimum Tip Speed Ratio (TSR), calculated from Eqn. 1.

Table 5: Selected Parameters for Three FOWT Models

Tower properties	***Model 1***	***Model 2***	***Model 3***
Height, m	87.6	97.1	109.6
S_{tower}	1.000	1.108	1.251
Base/top diameter, m	6.00/3.87	6.65/4.29	7.51/4.84
Base/top thickness, mm	35.10/24.7	38.91/27.4	43.92/30.9
Blade properties	***Model 1***	***Model 2***	***Model 3***
Radius, m	63.0	72.5	85.0
S_{blade}	1.000	1.151	1.349
Mass, kg	17725	26524	41870
Inertia, kgm^2	1.29E7	2.56E7	5.55E7
Hub Properties	***Model 1***	***Model 2***	***Model 3***
S_{blade}	1.000	1.151	1.349
Root/Spinner Diameter, m	2/3	2.30/3.45	2.70/4.05
Mass, kg	56780	84968.53	134128.3

$$TSR = R\Omega/\bar{U}$$
$$\Omega_2 = R_1\Omega_1\bar{U}_2/\bar{U}_1R_2 \quad \text{Eqn. 1}$$

As can be observed as the radius, R, or the wind speed, $\bar{U}$, change a corresponding change in the rotational speed, Ω, is mandatory if the TSR is to be kept constant. The rated rotational speed changed according to the rated wind speed and the rotor diameter. However since the cut-in wind speed was kept the same at 3m/s for all sizes the cut-in rotational speed varied only depending on the rotor diameter.

Depending on the turbine specifications GH BLADED^{TM} can calculate the optimal TSR for below rated wind speeds. This function was used for both up-scaled sizes.The power is the product of the rotational speed and the torque. Thus to keep the rated power constant the rated toque had to be inversely proportional to the rotational speed. The parameters discussed above are shown in Table 6.

5 STEADY-STATE CHARACTERISTICS OF THE MODELLED WIND TURBINES

The performance characteristics for the three FOWT Models were generated using GH BLADED for steady state conditions, with the floater assumed fixed.

Table 6: Control Parameters of Turbine Models

Diameter, m	126	145	170
Rated wind speed, m/s	11.4	10.3	9.4
Minimum generator speed, rpm	670	582	496.59
Rated generator speed, rpm	1173.7	921.49	717.3
Rated torque, kNm	43.09	54.89	70.51

Fig. 2 presents the rotor power coefficient (C_P) versus tip speed ratio for the three rotors. The curves are identical for all three rotors given that linear up scaling was assumed and the influence of the flow Reynolds Number on the aerofoil characteristics of the rotor blades was neglected in the modelling.

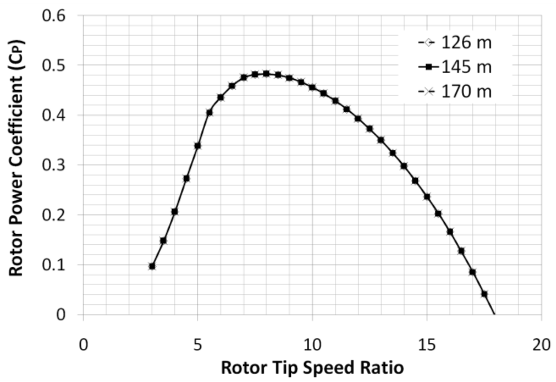

Figure 2: Variation of rotor aerodynamic power coefficient with tip speed ratio for an optimal pitch angle (0 deg).

The power curves for the three modelled FOWTs are presented in Fig. 3. It may be observed that all three wind turbine models have a common rated power. However the rated wind speed is lower for larger rotors, resulting in a higher energy capture at lower wind speeds. The variation of the rotor power coefficient (C_P) with wind speed is shown in Fig. 4. At low wind speeds between 5 m/s and the rated value, the controller maintains a constant C_P.

At higher wind speeds up to the cut-out value, the wind turbine controller regulates the pitch angle to keep the generated power output fixed. Consequently the C_P value decreases gradually. Ineffect, rotor up-scaling results in a more inefficient operation of the wind turbine at such high wind speeds when the generator rating is kept fixed. However, this will not impact the overall energy yield significantly at sites where the probability of having high wind speeds is very low. Fig. 5 plots the variation of the rotor speed with wind speed. As may be noted, larger rotors operate at lower speeds.

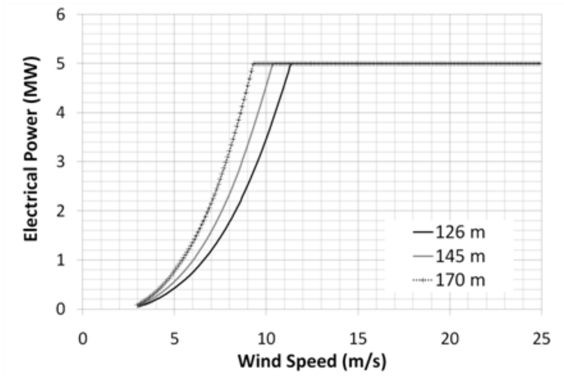

Figure 3: Power curves for the wind turbine models.

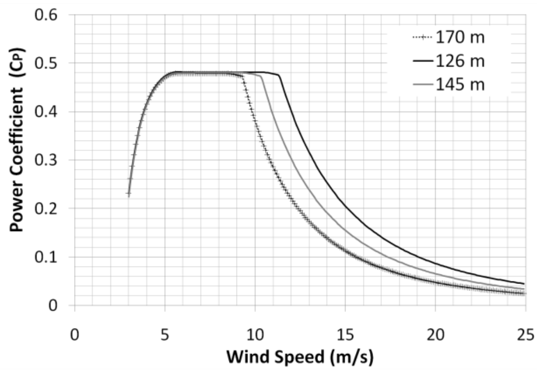

Figure 4: Variation of rotor aerodynamic power coefficient with wind speed.

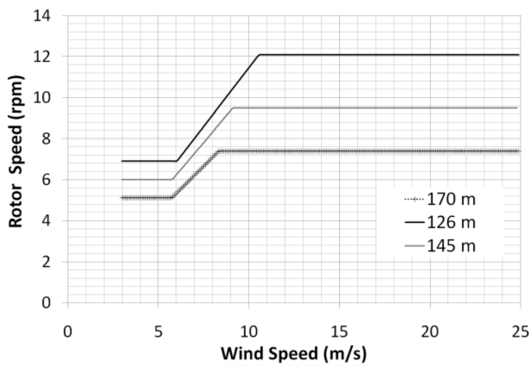

Figure 5: Variation of rotor speed with wind speed.

The rotor axial thrust is dominant load acting on the entire FOWT and therefore has a major influence on the floater design and stability. This load is counteracted by the buoyant forces of the floating structure and the moorings. The latter need be maintained continuously under tension to keep the entire floating platform stable. The influence ofrotor upscaling on the aerodynamic thrust may be observed in Fig. 6. It can be observed that the peak thrust acting on a rotor occurs at the rated wind speeds. It is also being predicted that upscaling the rotor from 126 m to 170 m does not increase the peak axial thrust significantly (by 9.4%).

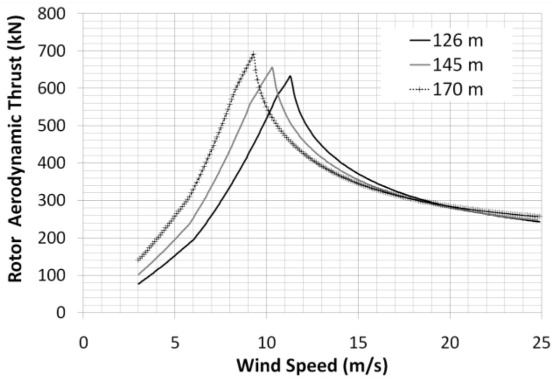

Figure 6: Variation of rotor aerodynamic thrust with wind speed

6 WIND FARM PERFORMANCE ANALYSIS

6.1 Wind Farm Layout

The case study presented in this paper assumes a floating wind farm located around 10 km off the west coast of the Maltese Islands where the sea depth is of about 200 m. The area is very well exposed to the prevailing North Westerly winds. The wind farm is assumed to consist of twenty floating 5MW turbines, reaching a total installed capacity of 100MW.

Fig. 7 shows the location of the wind farm, where the turbines are placed in two rows of ten turbines each. A staggered turbine arrangement is adopted to minimise array losses, with the two rows aligned perpendicularly to the North Westerly direction.

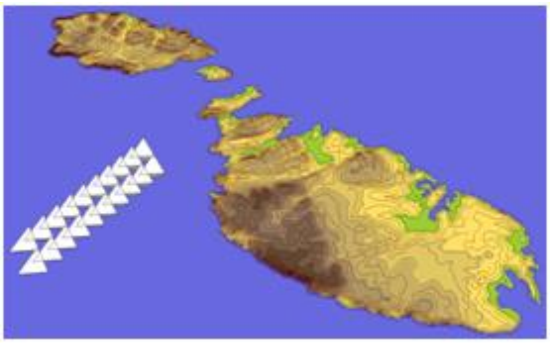
Figure 7: Perspective view of the 20x5MW floating wind turbines in Maltese waters

Three different wind farm options were investigated, with three different rotor diameters (FOWT Models 1, 2 and 3). Turbine spacing is set to 6D x 9D, where D is the rotor diameter. 9D is the perpendicular distance between the two turbine rows.

Hence, the turbine spacing is increased proportionally in the case of the two upscaled rotors (Models 2 and 3), at the expense of a larger wind farm area. The turbines across each row are assumed to be interconnected by electrical power cables lying on the sea-bed, with the last turbines from each row connected to an offshore floating transformer platform. This sub-station increases the voltage from 33kV to 132kV to minimise losses in power transmission. It is projected that the 132 kV undersea cable connecting the sub-station to the onshore grid is landed at Gnejna Bay, on the west coast. This will be connected to the Mosta Distribution Centre through a 10 km underground cable. The electricity will then be distributed to the islands accordingly. The undersea cable length varies from 7.6 down to 5.5km according to the rotor size, the smaller sized turbines will be placed further offshore and hence require a longer cable length.

6.2 Energy Yield Analysis

The gross annual energy yield from a single FOWT operating at the offshore site is computed from knowledge of the wind speed probability distribution and the turbine power curve:

$$\boldsymbol{E = \eta \times Y \int_{cut\ in}^{cut\ out} P(V)\, f(V)\, dV} \qquad \text{Eqn. 2}$$

where:

Y	is the number of operational turbine hours;
$P(V)$	is the Power at a given wind speed;
$f(V)$	is the Probability distribution of wind speed;
η	Efficiency of the wind farm.

GH BLADED was utilised applying a Weibull probability distribution at the rotor hub height in conjunction with the power curve for the turbine under consideration. The Weibull distribution was defined by two parameters: the shape parameter k and the long term average wind speed $\bar{U}$. Fig. 8 presents the Weibull distribution assumed for a 90 metre hub height above mean sea level.

The above method was applied to each of the three rotor models, applying the power curves presented in Fig. 3 and correcting the Weibull fit to the respective hub height assuming a wind shear exponent of 0.11. The net electricity yield from the entire wind farm was computed by multiplying the gross energy yield from a single turbine by the total number of turbines and an efficiency factor (η) which accounts for losses incurred due to turbine downtime, turbine array wakes, electricity transmission and grid connection.

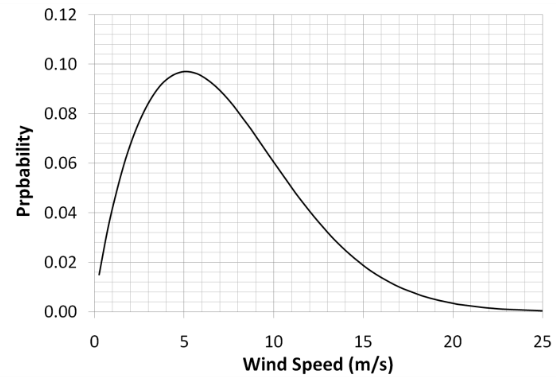

Figure 8: Weibull distribution for long-term wind conditions at 90amsl; k=1.76, Average wind speed=7.3 m/s

The values for the parameters assumed in the energy yield analysis are presented in Tables 7 and 8.

Table 7: Weibull parameters at 90 m above m.s.l. and wind farm efficiency

k, Weibull shape parameter	1.763
average wind speed,$\overline{U}$, m/s	7.30
Overall farm efficiency (η)	0.78

Table 8: Wind Farm Efficiency Assumptions

Wind Farm Availability	0.90
Array Efficiency	0.92
Efficiency of Electricity Transmission	0.95
Efficiency of Grid Connection	0.99
Overall farm efficiency (η)	**0.78**

The net annual energy yields from the three wind farm models are given in Table 9. It can be noted that rotor up-scaling improves the energy yield considerably, with an augmentation of 15% and 32% when up-scaling the rotor from 126 m to 145 m and 170 m diameter respectively.

Table 9: Energy Yield and Capacity Factor

Model	Rotor Diameter (m)	Annual Energy Yield (GWh/a)	Net Capacity Factor (%)
1	126	247	28.2
2	145	284	32.4
3	170	325	37.1

7 COST OF ENERGY ANALYSIS

This section describes the cost model developed to derive the levelised cost of energy (LCOE) for the three 100 MW wind farm options operating in Maltese waters. It is assumed that the operational lifetime of each wind farm is 20 years. Estimates for the various costs are mainly based on literature findings.

7.1 Design and Consenting Costs

Design and consenting costs include (1) the installation of an offshore-based wind monitoring mast to capture wind and Metocean data; (2) geophysical and geotechnical studies on the sea-bed; (3) Front End Engineering Design (FEED); (4) environmental impact assessment studies and (5) detailed engineering work. The development costs assumed in the present model are presented in Table 10. A cost for management was also included. This was taken as 3% of the total costs. These costs were taken as suggested by **[23]** after accounting for inflation. A rate of 1.18% was used for inflation while the rate of exchange from GBP to Euro was taken to be 1.206. This resulted in a total rate of 1.423.

Table 10: Design and Consenting Costs

Consenting costs (incl. met mast), M€	11.58
Contingency, M€	2.85
Management, M€	0.433
Total development cost, M€	**11.8**

7.2 Hardware Costs

The capital cost for a 5MW, 126 m turbine was taken to be 5.575M€, **[23]** after accounting for inflation. The cost of a particular component of the wind turbine was derived by assuming the percentage breakdown of wind turbine costs presented by IRENA, **[24].** The cost of upscaled rotors and towers was derived through linear relationships with weight. Such relationships were derived by dividing the component costs for the 126 m diameter turbine by the respective weight. The resulting component costs are shown in Table 11.

Table 11: Cost distribution for turbine sizes

Model	1	2	3
Rotor diameter, m	126	145	170
Tower, M€	1.32	1.80	2.59
Blades, M€	1.12	1.67	2.64
Hub, M€	0.28	0.42	0.66
Personal access, k€	62.96	62.96	62.96
Nacelle, M€	0.11	0.11	0.11
Transformer, M€	0.22	0.22	0.22
Gearbox, M€	0.84	0.84	0.84
Generator, M€	0.22	0.22	0.22
Controller, M€	0.56	0.56	0.56
Other, M€	0.84	0.84	0.84
Total, M€	5.57	6.74	8.73

The cost for the floating TLP structure supporting each wind turbine was based on component costs presented in **[25, 26]** after accounting for inflation where necessary with a rate of 0.832%. The labour hours needed for the manufacture of the platform were increased from what was suggested since this study's platform has a bigger displaced volume. The cost of the piles was calculated as 3.5€/kg, taken from **[27]**. The total cost of single floating TLP structure, including the moorings and anchors was estimated to be equal 2.28M€ for the support system for every turbine. This excludes the installation costs which are discussed later on. As already discussed earlier, the same floating structure is being adopted for all the three wind turbine models considered in this study.

Table 12 lists other hardware costs assumed in order to develop each wind farm. The costs for the sub-station and the electrical cables were taken from **[27]** while the other costs are as given in **[23]**. Care was taken to account for inflation where required with the rates discussed earlier. A cost of 3% was also included over the sum of all these hardware costs to take account of management costs.

Table 12: Other costs

Offshore transformer station, M€	12
SCADA, M€	1.43
Interconnecting cables, €/m	400
Offshore transmission cables, €/m	800
Onshore cables, €/m	250

7.3 Transportation, Assembly and Installation

The wind farm components are assumed to be transported by sea from Northern Europe to a port in the Central Mediterranean where they would be assembled before being towed to the offshore site in Malta. It is assumed that all wind farm components are shipped from Northern Germany, where the majority of offshore wind manufacturers are located. The parts are shipped on a barge and pulled by a tugboat to the port of Palermo, Sicily. The cost model is based on the proviso that the barge is sufficiently large to accommodate the parts for three wind turbines of any upscaled size. Three turbines would still allow for some additional free space on the barge which can be used to transport other materials needed such as the cables. It is estimated that seven round trips are required to transport all wind farm components, including the cables and offshore substation. The estimated cost to transport all of the turbine parts from North Germany to Sicily is estimated to be 6.11M€.

The turbine parts will be shipped from Northern Germany to a port in Sicily, where they will be assembled on the floating platform which will be manufactured in situ. The offshore substation is also assumed to be supported on a floating TLP structure similar to that of the wind turbines.

The turbines and substation are to be assembled on their TLP structures at the port and then towed to the wind farm site and installed. To increase stability during the towing operation and in order to aid installation of the mooring lines, the TLP floaters should be temporarily ballasted with sea water **[25, 26]**. Once the mooring lines are attached the water ballast is removed and the moorings will be tensioned appropriately. The costs for the assembly of the turbine/sub-station onto the platform were based on those published in **[25, 26]** after accounting for inflation with a rate of 0.832. Given that in the present study a bigger platform is being considered, the installation work is increased appropriately by increasing the man hours required. This resulted in a cost of 7301€ per turbine/sub-station assembly.

The sea-bed conditions in Maltese waters are generally rocky in nature. Hence to be able to install the four anchor piles per turbine, pre-drilling is required. This will allow the anchor piles to be inserted into the seabed, following which a grout is applied between the anchor and the hole to ensure that the piles are firmly installed in the sea-bed. A secondary vessel is to be used during this operation to transport crew members, supply consumables and perform other ancillary tasks. The costs involved for the drilling and pile driving operations are estimated to equal 1,286.2k€ per platform, [27]. Once the turbine has been assembled in the Sicilian port it will be towed out to sea by a tugboat stationed in Malta. It was estimated that three tugboats and a secondary vessel would be required for this operation. The cost to transport and install a turbine/sub-station is estimated to be equal to 669.8k€.

Other installation costs were calculated for electrical connection and laying the required cables. The onshore cables will run a distance of about 10 km along the road network. The undersea cables will be laid by an offshore cable laying vessel. These cable laying costs were estimated from **[27]** and are presented in Table 13. The costs for electric connection, commissioning and onshore grid connection were estimated from **[23]**.

It is expected that the turbine parts will have to be stored at the port during the transitional period spanning from the unloading at Sicilian port until they are assembled. It is expected that the storage space required will not exceed 8,571.4 m^2 and will be used for a whole year resulting in an expected cost of 3.13M€.

The cost model for every sea vessel covered expenses for mobilisation and demobilisation as well as operational costs based on an hourly rate. Operational costs were corrected for possible downtime resulting from excessive significant wave heights encountered in rough weather conditions.

In addition to these transportation, assembly and installation costs another cost for management was included. This was calculated as 3% of all the transportation, assembly and installation costs.

Table 13: Other costs for installation

Electric connection, k€/turbine		192.7
Maximum operational wave height, m		2
Commissioning, k€/turbine		95.6
Maximum operational wave height, m		2
Offshore cable laying vessel	Mob & demob, k€	400
	Price, €/m	230
	Operational wave height, m	2
Onshore cable laying price, €/m		90
Onshore grid connection, k€/MW		264.1

Table 14 compares the estimated capital expenditure (CAPEX) in Euro/KW for the three wind farm models. These include costs for wind farm consenting and design, hardware, transport, installation and commissioning.

Table 14: Wind farm initial capital costs

Model	Rotor Diameter (m)	CAPEX (€million)	CAPEX (k€/MW)
1	126	282	2823
2	145	306	3055
3	170	346	3464

7.4 Operating and Maintenance Costs (OPEX)

The operational and maintenance costs considered for the 100MW farm are listed in Table 15. The O&M cost was taken from **[28]** and the LRC and Lease cost were taken from **[29]**. Inflation and conversion was accounted for as necessary with rates of 1.09% and 0.734% respectively.

Table 15: Operating & Maintenance Costs

Levelised Replacement Costs, €/MW	30,000
Other O&M costs per MW, €/MW	84,000
Lease Costs, €/MW	15,417
Total O&M cost, €/MW	129

7.5 Decommissioning

The costs for decommissioning are assumed to be 1,110k€ per turbine/substation, following **[23]** after accounting for inflation. The values were increased by 18% for inflation while the rate of exchange from GBP to Euro was taken to be 1.206. This resulted in a total rate of 1.423.

7.6 Levelised Cost of Electricity (LCOE)

The Levelised Cost of Electricity (LCOE) for the three wind farm models was computed from the following equations:

$$\mathbf{1+r=\frac{1+i}{1+v}} \qquad \text{Eqn. 3}$$

$$\boldsymbol{COE=\frac{\sum_{t=0}^{T} C(1+r)^{-t}}{\sum_{t=0}^{T} E(1+r)^{-t}}} \qquad \text{Eqn. 4}$$

where*r*, *i* and *v* denote the discount, interest and inflation rates respectively. The assumed values are listed in Table 16. *C* denotes the annualised cost including CAPEX and OPEX while *E* denotes the annual net electricity production in GWh per annum. *T* is the total lifetime of the project, from inception to decommissioning; spanning over 26 years. The first five years are assumed to be required to develop the project up to the commissioning stage while the final year is allowed for decommissioning. Annual O&M costs will start at the expected value, go down to 90% and gradually up to 130% of the expected value. A cost of 0.5€cents/kWh was added to the LCOE values obtained from Eqn. 4 to cater for spinning reserve costs **[28]**. The results are shown in Table 17.

Table 16: Financial Parameters

Interest Rate (i)	11%
Inflation (v)	2%
Discount Rate (r)	9%
Developer Profit Margin	15%

Table 17: Levelised Cost of Electricity

Model	Rotor Diameter (m)	LCOE (€cents/KWh)
1	126	23.6
2	145	21.8
3	170	21.0

Only the installation and hardware costs increase as the turbine size is changed while the other cost components remain invariant. The costs for the turbine parts were represented by percentages of the total cost for every model as shown in Fig. 9. The percentage for the hardware cost increases with the upscaling process while the other percentages decrease along the up-scaling process. This is a consequence of the fact that the increase in the hardware cost is much greater than that of installation.

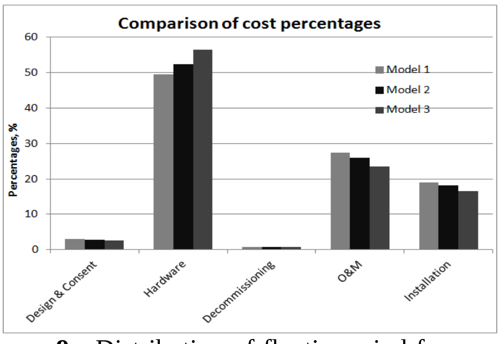

Figure 9: Distribution of floating wind farm costs for the three wind turbine models

8 CONCLUSIONS

The study has shown how rotor upscaling can potentially improve the economic viability of offshore floating wind farms operating in Maltese conditions. The improved energy yield from larger rotor diameters outweighs the higher investment costs, resulting in a lower cost of energy.

The levelised cost of electricity from a 100 MW floating wind farm with present infrastructural costs was found to be in the region of 21.0 – 23.6 €cent/KWh. Although this is well above the current market prices of electricity generated by conventional means, it is anticipated that the cost of offshore wind will decrease considerably over the coming years as new international players are entering the offshore wind market, thereby increasing the level of competition.

Further work will involve a more detailed engineering design optimisation exercise intended to further reduce material costs associated with the construction of the upscaled wind turbine rotors and towers.

9 ACKNOWLEDGEMENTS

The authors would like to thank the Malta Resources Authority that provided wind data from the 80 metre wind monitoring mast at Aħrax Point, Malta.

10 REFERENCES

[1] J.M. Jonkman, "Dynamics Modeling and Loads Analysis of an Offshore Floating Wind Turbine," NREL, Golden, Colorado, NREL/TP-500-41958 2007

[2] European Wind Energy Association (EWEA), "Deep Water – The Next Step for Offshore Wind Energy," July 2013.

[3] www.statoil.com

[4] www.sway.no

[5] www.principlepowerinc.com

[6] www.bluehgroup.com

[7] www.deepcwind.org

[8] www.mes.co.jp

[9] The UK Crown Estate, *Offshore Wind Cost Reduction – Pathways Study*, May 2012.

[10] www.alstom.com/power/renewables/wind/

[11] www.energy.siemens.com

[12]www.gamesacorp.com

[13]http://www.vestas.com

[14] J. Jonkman et al., "Definition of a 5-MW Reference Wind Turbine for Offshore System Development," National Renewable Energy Laboratory, NREL/TP-500-38060 2009.

[15] Denis Matha et al., "Model Development and Loads Analysis of an Offshore Wind Turbine on a Tension Leg Platform, with a Comparison to Other Flaoting Turbine Concepts," NREL, Golden, Colorado, NREL/SR-500-45891 2010.

[16] GL Garrard Hassan Bladed Version 4.4.0.67, St. Vincent Works, Silverthorne Lane, Bristol BS2 0QD, England.

[17] GL Garrard Hassan, "Bladed user manual V4.3," Garrard Hassan & Partners Ltd., Bristol, England, 2012.

[18] GL Garrard Hassan, "Bladed theory manual V4.3," Garrard Hassan & Partners Ltd., Bristol, England, 2012.

[19] "Wind Turbines-Part 3: Design requirements for offshore wind turbines," IEC 61400-3, 2009.

[20] WindPRO Ver. 2.7, EMD International A/S NielsJernesVej 10, 9220 Aalborg Ø, Denmark

[21] WindSim Ver. 5.1, WindSim AS, Tønsberg, Norway

[22] Dayton A. Griffin, "WindPACT Turbine Design Scaling Studies Technical Area 1-Composite Blades for 80-to 120-Meter Rotor," NREL, Golden, Colorado, NREL/SR-500-29492 2001.

[23] "Study of the Costs of Offshore Wind Generation," DTI, 07/779, 2007.

[24] "Renewable Energy Technologies: Cost Analysis Series," IRENA, Working Paper June 2012.

[25] E.N. Wayman et al., "Coupled Dynamic Modelling of Floating Wind Turbine Systems," in *Offshore Technology Conference*, Houston, 2006.

[26] Elizabeth Wayman, "Coupled dynamics and economic analysis of floating wind turbine analysis," Dept. Mech. Eng., MIT, Cambridge, Massachusetts, MSc Thesis 2006.

[27] "Feasibility Study for Developing a 350 MW Offshore Wind Farm at the South East Offshore Zone," University of Malta, Unpublished Report, R&I-2009-003.

[28] "Feasibility Study for Increasing Renewable enregy Credentials," Malta Resource autority-Mott Mc Donald, January 2009.

[29] S. Tegen, E. Lantz, M. Hand, B. Maples, A. Smith, P. Schwabe, "2011 Cost of Wind Energy Review," NREL, March 2013.