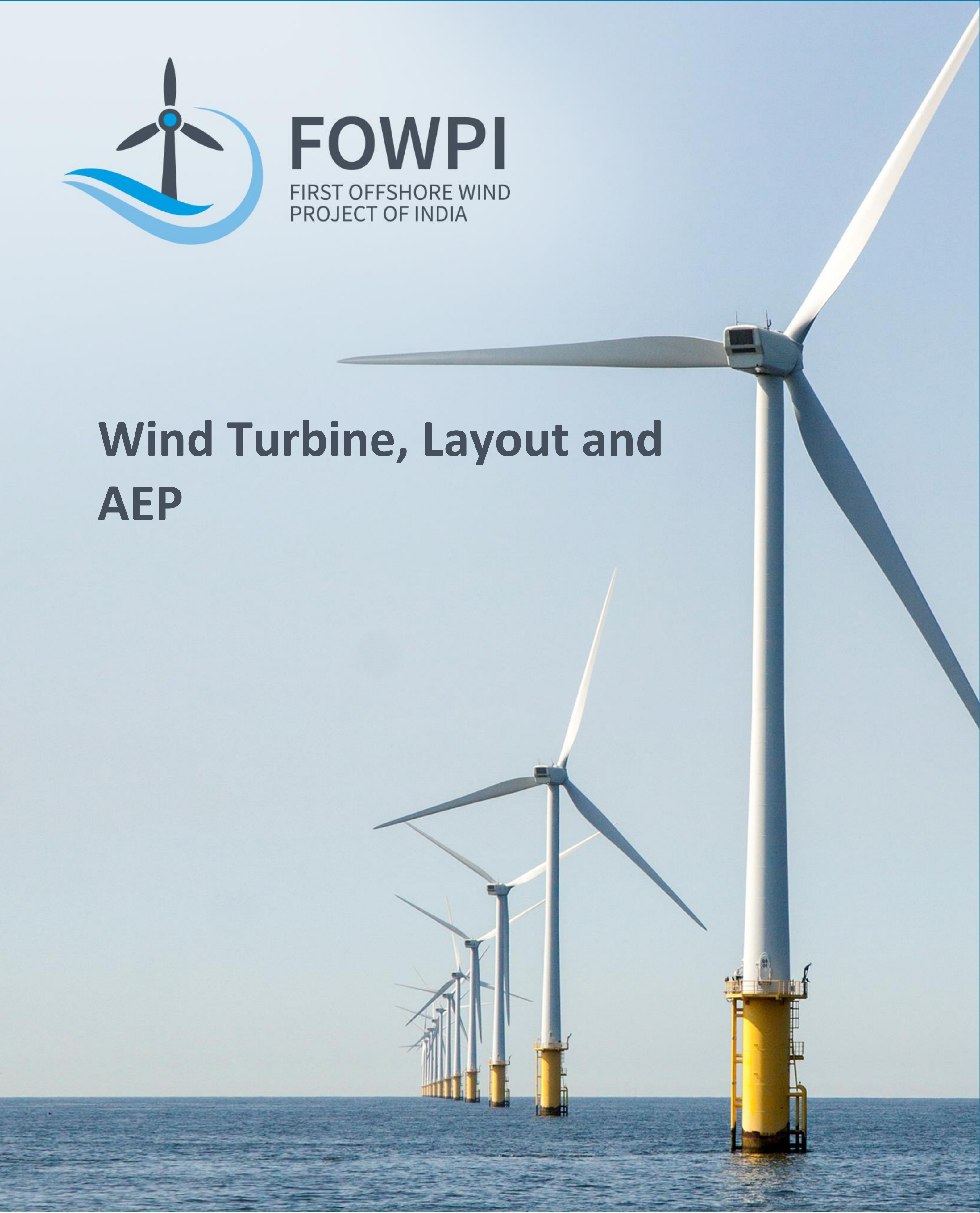
FOWPI

FIRST OFFSHORE WIND
PROJECT OF INDIA

Wind Turbine, Layout and AEP



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This Project is funded by The European Union

1 About FOWPI

The First Offshore Wind Project of India (FOWPI) is part of the “Clean Energy Cooperation with India" (CECI) programme, funded by the European Union (EU). The programme aims at enhancing India's capacity to deploy low carbon energy production and improve energy efficiency, thereby contributing to the mitigation of global climate change. Project activities will support India's efforts to secure the energy supply security, within a well-established framework for strategic energy cooperation between the EU and India.

FOWPI is defined as a 200MW offshore wind farm near the coast of Gujarat, 25km off Jafarabad. The project scope focus is on preliminary investigations and advisory for the windfarm including wind turbine foundation, electrical network, environmental scoping, financial modelling and other relevant studies. FOWPI uses the outputs from Facilitating Offshore Wind in India (FOWIND) project (2013-2018) also supported by the European Union. FOWIND and FOWPI bring the vast experience of European countries in offshore wind, to support India with the creation of a national knowledge centre and with technical support for setting up the first offshore wind-farms.

FOWPI is led by COWI A/S (Denmark) with key support from WindDForce Management Ltd. (India). The project is implemented in close collaboration with the European Union, the Ministry of New and Renewable Energy- India (MNRE) and National Institute of Wind Energy- India (NIWE).

Contract: No 2015/368469 Start 01-2016 Duration: 42 months

2 Disclaimer

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The 14th annual Summit between India and the European Union (EU) was held in New Delhi on 6 October 2017. Both sides adopted a Joint Statement on Clean Energy and Climate Change, reaffirmed their commitments under the 2015 Paris Agreement, and agreed to co-operate further to enhance its implementation. India and the EU noted that addressing climate change and promoting secure, affordable and sustainable supplies of energy are key shared priorities and welcomed the progress on the Clean Energy and Climate Partnership, adopted at the 2016 EU-India Summit, and reiterated their commitment to its implementation and further development. In particular the EU is committed to continue cooperation in view of the cost-effective development of offshore wind in India.

5 Acknowledgements

FOWPI is grateful for the support provided by European Union (EU), Ministry of New and Renewable Energy-India (MNRE), National Institute of Wind Energy- India (NIWE), and the Wind Industry.

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Wind Turbine, Layout and AEP

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FOWPI - WIND TURBINE, LAYOUT AND AEP

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APPENDICES

1 Introduction

India has one of the fastest growing economies in the world and, in order to meet with rising energy needs, new generation capacity must be implemented on a regular basis. Renewable energy has for many years been introduced in the Indian energy supply system and specifically onshore wind energy has been playing an important role with over 32 GWs of installed capacity throughout the country i.e. the fourth largest installed wind power capacity in the world. Numbers are quickly rising and by 2022 over 60 GWs of wind energy capacity is targeted to be operational in India.

In Europe, in addition to onshore wind, offshore wind has also become an important contributor to the regional sustainable energy mix. The total offshore wind farm installed capacity has already reached approximately 14 GWs and many more are expected to be installed within the next years. Given the required infrastructure and various challenges related to the offshore installation and operation, the costs for the first offshore wind farms were relatively high. However, thanks to market maturity and lessons learned in the design, manufacture, installation and O&M, the prices for new offshore wind projects are steeply declining and reaching record low levels. Besides the EU area, other countries that have already installed offshore wind include China, USA and Taiwan; whereas countries that have initiated planning activities include Australia and Malaysia.

This document has been prepared with the purpose of providing preliminary design and annual energy production estimates for the prospected 200 MW FOWPI offshore wind farm (OWF) near the coast of Gujarat. For such purpose, the reports includes wind turbine technology and definition of reference 3 MW and 6 MW turbines (Chapter 4), a wind resource study based on VORTEX synthetic data (Chapter 5), the definition of base wind farm layouts for the 200 MW OWF (Chapter 6), energy yield estimates (Chapter 7) and economic optimization considerations of base layouts (Chapter 8). The studies have been prepared by COWI on behalf of the National Institute of Wind Energy (NIWE) to support a call for tenders on a Build-Own-Operate basis.

2 Summary

The present report has been prepared by COWI on behalf of NIWE with the purpose to support a call for tenders on a Build-Own-Operate basis. The following sub-clauses summarize the presented information and main results.

A list of potential wind turbines for offshore projects is presented. For the present study, 3 MW and 6 MW generic wind turbines have been used. Whereas the 3 MW turbine is closer to an onshore and lower wind model, installed at many offshore sites in Europe and potentially manufactured in India, the 6 MW turbine is closer to a model designed for North Sea offshore wind conditions.

Wind measurements at site are still ongoing and in this report the wind resource at the FOWPI project area is assessed on the basis of a 20 years VORTEX synthetic time series (virtual mast). Based on these data, the long-term average wind speed at the position 20 km from the coast corresponding to the part of the site area closest to the coast is given by:

- Mean wind speed at 100 m ASL: 7.1 m/s

The estimated long-term P50 net AEP and corresponding capacity factors based on the VORTEX wind data are for the 3 MW turbines 518 GWh/y and 30% and for the 6 MW turbines 409 GWh/y and 24%. It should be noted that these results are closely connected to the non-validated VORTEX data.

For the AEP calculations, two base case wind turbine layouts have been defined in consideration of the wind resource across the site and experience in wind turbine spacing. Thereafter an assessment has been carried out in order to indicate possible economic gains/losses in function of more or less spacing in between turbines. Based on indicative electrical cabling costs, foundation costs and energy production estimates, it is concluded that the base case layouts are fairly optimal.

3 References and Abbreviations

3.1 References

Ref. /1/ IEC Standard 61400-1: Design requirements, third edition 2005-08.

Ref. /2/ COWI, FOWPI – Metocean Study, Rev. 1.0, September 2017.

Ref. /3/ FOWIND, Pre-Feasibility Study for offshore windfarm development in Gujarat. May 2015.

3.2 Abbreviations

The main abbreviations and symbols used in the present report are listed below.

A	Scale parameter of the Weibull Distribution [m/s]
AEP	Annual Energy Production
AEP_{gross}	Annual Energy Production without taken losses into account [Wh/year]
AEP_{net}	Annual Energy Production delivered to the grid, i.e. all losses taken into account [Wh/year]
AEP_{park}	Annual Energy Production with wake loss taken into account [Wh/year]
ASL	Above sea level
CAPEX	Capital Expenditure
D	Rotor diameter [m]
EU	European Union
FOWIND	Facilitating Offshore Wind in India
N.A.	Non available / Not applicable
NPV	Net Present Value
k	Form factor of the Weibull Distribution [-]
OWF	Offshore Wind Farm
TBC	To be confirmed
WSW	West south west
WTG	Wind Turbine

4 Wind Turbine Technology

Given the fast development of the wind industry, this chapter presents an updated version of the wind turbine survey carried out by FOWIND in May 2015 (Ref. /3/). Moreover, this chapter discusses the possibility of adapting onshore wind turbines for offshore use and defines reference 3 MW and 6 MW turbines to carry out annual energy production estimations.

4.1 Wind Turbine Supplier Survey

The updated wind turbine model survey carried out by FOWIND in May 2015 (Ref. /3/) is shown in Table 4-1 New/updated turbines, as of February 2018, are in blue.

Turbine Model	Rated Power (MW)	IEC Class	Rotor diameter (m)	Commercial Timeline
(Alstom/GE) Haliade 150-6	6	IEC IB	150	2014
AMSC 5.5 wt5500	5.5	TBC	140	TBC
AMSC Titan	10	TBC	190	TBC
Adwen AD5-132	5	TBC	132	TBC
Areva M5000-135 (Adewn AD 5-135)	5	Targeting IEC IB & S	135	2013
Areva M8000-180 (Adwen AD-180)	8	TBC	180	2018
CSIC HZ 127-5MW	5	Targeting IEC IA	127	2014
CSIC HZ 151-5MW	5	Targeting IEC IIIB	151	2015
CSR WT5000-D128	5	Targeting IEC IB	128	2014
DOOSAN WinDS3000/91	3	Targeting IEC IA	91.3	2012
DOOSAN WinDS3000/100	3	TBC	100	TBC
DOOSAN WinDS3000/134	3	Targeting IEC S	134	TBC
Gamesa G128-5.0	5	IEC IB	128	2013
Gamesa G132-5.0	5	Targeting IEC S	132	2013
Gamesa G14X-7.0	7	TBC	140	2015
Goldwind GW 6MW	6	TBC	TBC	2014
GUP6000-136	6	TBC	136	2012
Hitachi HTW 5.0-126	5	Targeting IEC S	126	2015
Huayi 6MW	6	TBC	TBC	TBC

Turbine Model	Rated Power (MW)	IEC Class	Rotor diameter (m)	Commercial Timeline
Hyundai HQ5500	5.5	IEC IB	127	2014
Hyundai/Dongfang 5.5	5.5	IEC I	140	2014
Mervento 3.6-118	3.6	IEC IIA	118	2012
Mervento 4.0-118	4	IEC IIB	118	2014
MHI Vestas V112-3.3MW	3.3	IEC IB	112	2014
MHI Vestas V116-3.3MW	3.3	IEC IIIB	126	2014
V117-4.2 MW™	4.2/4.0	IEC IB/IIA	117	2018
MHI Vestas V164-8.0MW	8	IEC S (based on IEC IB)	164	2015
MHI Vestas V164-9.5MW	9	IEC S	164	2018
Ming Yang 6MW SCD	6	TBC	140	TBC
Senvion 6M (6.2M 152)	6.15	IEC IB	126	2012
Senvion 6M+ (6.2M 152)	6.15	IEC S (based on IEC IB)	152	2014
Senvion 6.3 M152	6.33	IEC S	152	TBC
Shanghai electric SE 3.6MW	3.6	TBC	122	2010
Shanghai electric SE 5.0MW	5	TBC	TBC	TBC
Siemens SWT-3.6-120	3.6	IEC IA	120	2011
Siemens SWT-3.6-130	3.6	IEC IB	130	2015
Siemens SWT-4.0-120	4	IEC IA	120	2014
Siemens SWT-4.0-130	4	IEC IB	130	2014
Siemens SWT-6.0-154	6	IEC IA	154	2014
SGRE SWT-7.0-154	7	IEC IB	154	TBC
SGRE SWT-8.0-154	8	IEC IB	154	TBC
Sinovel SL3000/90	3	IEC I	90	TBC
Sinovel SL3000/105	3	IEC II	105	TBC
Sinovel SL3000/113	3	IEC III	113	TBC
Sinovel SL3000/121	3	IEC III	121	TBC
Sinovel SL6000/128	6	Targeting IEC I	128	2011
Sinovel SL6000/155	6	TBC	128	2011
XEMC Darwind DD115	5	Targeting IEC IC	115	2013
Yinhe Windpower	3.5	TBC	93.2	TBC
Zhejiang Windey WWD130/.5000	5	TBC	130	TBC

Table 4-1 Potential offshore wind turbines.

4.2 Possible use of Onshore Wind Turbine

None of the "standard" offshore wind turbines shown in Table 4-1 are manufactured in India. A possible alternative could be an onshore wind turbine adapted to offshore conditions. This approach was taken for some of the first offshore wind farms in Europe, e.g. Middelgrund Offshore Wind Farm where the Siemens 2.0 MW onshore wind turbine was adapted by improving the corrosion protection. For the OWF in question, in the Gulf of Khambhat, salinity is very high and therefore besides corrosion protection an airtight nacelle with recirculated dry and cooled air would be needed.

Given the high costs of offshore operations, whereas onshore turbines are typically designed to require two annual scheduled service visits, current European offshore wind turbines are typically designed to require only one annual scheduled service visit. This advantage may partly be reached by relatively simple adaptations of an onshore turbine.

Suzlon plans to introduce its new S128 machine — a 2.6 MW turbine with rotor diameter of 128 m and a tower height of 120 m to 140 m for low wind sites — during the 12 months following April 2018. This wind turbine, with the highest power rating so far produced by Suzlon, could potentially serve as the base platform for preparing an "onshore wind turbine adapted for offshore use".

It should be noted, however, that the use of proven wind turbine models are paramount for lowering the risk of offshore wind projects. Further, this is also an important point for the financing institutions/investors. For that reason, it is generally recommended to use specific wind turbines for offshore projects. As a matter of fact, not all adapted onshore turbines in offshore windfarms worked well. An example of this is the Ytre Stengrund OWF with 5 adapted 2MW turbines, which was decommissioned after less than 15 years of operation.

4.3 Wind Turbine Classes

The right choice of wind turbine for the project depends on the site conditions and the wind turbine design. Wind turbines are normally designed according to the IEC 61400-1 design classes I, II and III (ref. third column in Table 4-1) and turbulence categories A, B and C. The corresponding design extreme (50-years 10-minute) and annual average wind speeds and turbulence intensities at 15 m/s are shown in Table 4-2 (Ref. /1/).

Wind Turbine Classes (Wind)	I	II	III	S
Extreme Wind Speed (V_{ref}) [m/s]	50.0	42.5	37.5	Values specified by the designer
Annual Average Wind Speed (V_{ave}) [m/s]	10.0	8.5	7.5	
50-year Return Gust (1.4 V_{ref}) [m/s]	70.0	59.5	52.5	
Wind Turbine Categories (Turbulence Intensity)				
A (I_{ref})	0.16			
B (I_{ref})	0.14			
C (I_{ref})	0.12			

Table 4-2 IEC design wind speed classes and turbulence categories.

It should be noted that the above IEC design classes in Table 4-2 do not cover offshore areas nor where typhoons may occur. However, in northern Europe, offshore wind turbines are typically the equivalent of class IB, i.e. designed for high wind and medium turbulence intensity, which is representative for the European offshore sites.

Based on the VORTEX synthetic data available, the annual average wind speed at the FOWPI site is not higher than 7.5 m/s (ref. section 5.3). The turbulence intensity is expected to be low. Based on this, a class IIIB or IIB turbine with large rotor diameters could seem suitable. However, as typhoons are known to occur in the region with expected extreme 10-minutes wind speeds higher than the extreme IEC design wind speeds, a wind turbine especially designed for typhoons may be required i.e. a so-called IEC class T[1].

A standard wind turbine developed for a specific IEC class is designed for both the extreme wind speed and for the average wind speed specified in Table 4-2. E.g. an IEC class I turbine is designed for both large extreme loads caused by the high extreme wind and for large fatigue loads caused by the high average wind. Noting that for some parts of the wind turbine the extreme load is the design driver, whereas for other parts, the fatigue loads are the design driver, the possibility of a turbine with a relatively large rotor for the FOWPI site conditions - but at the same time adapted for high extreme wind - should be evaluated so to maximize production. This could be obtained by increasing the strength of the components of turbine with a class II/III rotor, for which the extreme load is the design driver e.g. tower.

A thorough site condition study – especially for determination of the extreme typhoon wind speeds - must be carried out for choosing the right wind turbine and furthermore, a site-specific design and approval of the chosen wind turbine is recommended.

4.4 Definition of FOWPI Reference Wind Turbines

For the present concept study, 3 MW and 6 MW generic sample turbines have been used based on the considerations from the previous sections. A generic 3 MW turbine represents a size close to available onshore turbines manufactured in India by e.g. Suzlon, and a 6 MW, represents a size closer to what is found in the European offshore market. Nevertheless, the size and model of the actually deployed turbine, which may certainly differ from the generic samples used for this study, rests as a decision of the wind farm developer based on further investigations.

The selected rotor diameters and hub heights for these two generic wind turbines are selected as being representative for the two sizes of wind turbines as shown in Table 4-3.

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[1] A class T is defined in the new version of the IEC 61400-1 standard for areas, which may experience very high extreme winds in an otherwise moderate wind climate. E.g. Vestas V117-4.2 and SWT-DD-120

Size (MW)	Rotor Diameter (m)	Hub Height (m)
3	112	86
6	154	107

Table 4-3 Generic wind turbines considered for the present study.

The power curves for the two generic wind turbines are calculated based on typical power coefficients for 'state of the art' and "off-the-shelf" wind turbines of the selected size and rotor diameters. The power curves are shown in Figure 4-1.

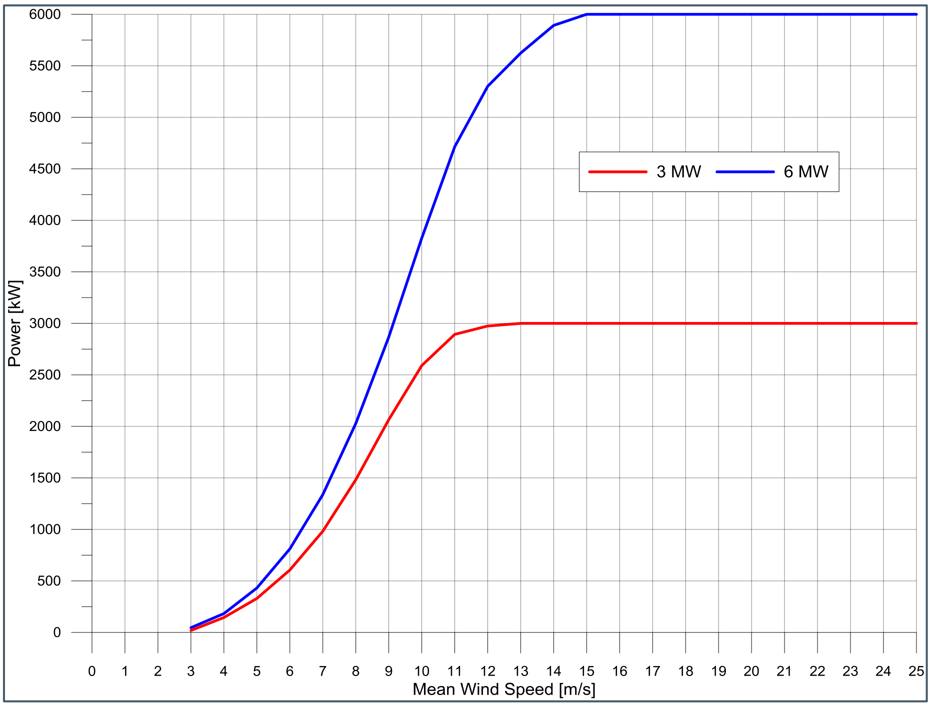

Figure 4-1 Generic 6 MW and 3 MW power curves.

The power curves have been corrected according to the annual air density, which is estimated[2] to respectively 1.167 kg/m^3 for the 86 m hub height and 1.165 kg/m^3 for the 107 m hub height, in the calculations of the AEP.

Given the conditions of offshore wind in Europe, incl. availability of purpose-made installation vessels and harbour infrastructure, larger turbines typically reduce the cost of energy. However, under the Indian context, using turbines of less than 5 MW could bring advantages for the demo project. For instance:

- Transportation of smaller components could be more easily performed by Indian based vessels and alternative installation options e.g. using a jack-up-barge with a mobile crane.

[2] Based on long-term temperature and pressure data from Veraval met station

- Smaller sized installation vessels are more available and have a relatively low cost as no new wind farms in Europe use wind turbines of less than 5 MW.

Specifically for the FOWPI site location, with relatively shallow waters and thus requiring smaller foundations, the use of smaller turbines can also bring economic advantages and more possibility of Indian made foundations.

5 Site Boundaries and Wind Resource

Site boundaries have been defined within a zone previously identified by FOWIND (Ref. /3/) and upon further consultations with the government of India. For a bankable wind resource assessment across the site area, site measurements for at least 1-year are typically required. Given unavailability of site measurements at present date, this section reports findings from a desktop study only. An on-site measurement might demonstrate significant differences and it is thus of very high importance. All assessments in this report should for this reason be used with precaution and are to be updated upon completion of the ongoing offshore measurements in the vicinity of the FOWPI site.

5.1 Site boundaries

Site boundaries are defined as shown in Figure 5-1, with a northerly border 12 nautical miles (NM) from the coast as per Coastal Regulation Zones (CRZ) notification.

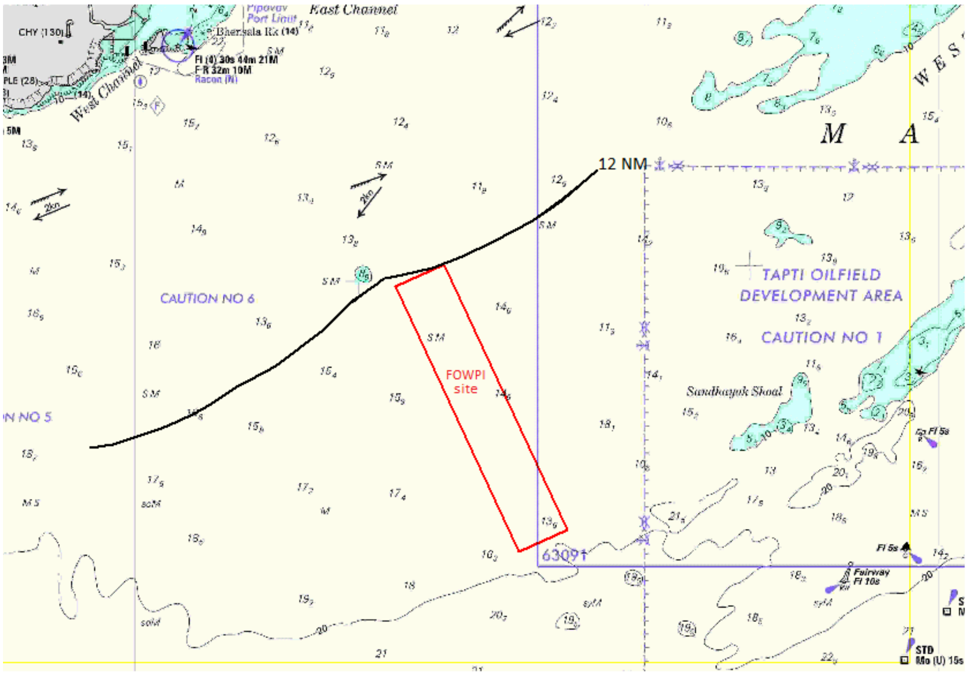

Figure 5-1 FOWPI site boundaries (red) 12 NM away from coast line.

Site boundaries are further specified in Table 5-1:

CORNER	LATITUDE	LONGITUDE
South-east	71°44'34.49"	20°36'38.21"
South-west	71°46'09.11"	20°37'17.69"
North-west	71°39'56.30"	20°45'57.05"
North-east	71°41'31.02"	20°46'36.53"

Table 5-1 Site boundaries coordinates.

At present, detailed environmental studies have not been carried out on the area. However, a number of preliminary considerations, detailed in Table 5-2, have been made for the designation of the site boundaries. Results from an environmental screening and scooping study implemented by FOWPI are expected during the second quarter of 2018.

Known protected habitats	No conflicts with known protected habitats have been identified. The closest protected area is Gir National Park.
Offshore infrastructure	No conflicts with offshore infrastructure have been identified. Tapti Oil Field Development Area is within 5 km from the site boundaries. Subsea infrastructure remains be assessed.
Marine archaeology	No conflicts with marine archelogy have been identified. The nearest is in Dwarka on the coast of Dwarka City. However it is to be noted that NIOT had discovered Harappa like civilization 20 km off the Surat shores in the early months of 2000.
Bird migratory routes	Gulf of Khambhat is part of migratory pathways and the Bhavnagar coast is known for the wide variety of migratory birds. The extent remains to be assessed e.g. through studies and consultations with coastal communities, fisherman and fisheries/forest department.
Shipping lanes	The project site does not intersect with recommended navigation routes on nautical charts.
Fishing activity	Fishing activity is undertaken in the area and the closest fish landing centres is Pipavav, Jafrabad (10km west) and Khera (18 km east). Consultations with local fisherman are needed to

	establish fishing routes and understand the extent of possible conflict. Based on secondary information however, the fishing seems to be largely focused within 5 km off the shore thus far from the site area.
Aviation radar	Information on aviation radar is not readily available, however there are two airports around the site i.e. Surat and Diu.

Table 5-2 Environmental pre-considerations within the site boundaries.

5.2 VORTEX Data

At the present stage, the wind resource at the prospected project site is based on a 20 years VORTEX time series (virtual mast) representing the wind at respectively 80 m and 100 m ASL at the position 20 km from the coast corresponding to the part of the site area closest to the coast as shown in Figure 5-2.

Figure 5-2 Prospected project site boundaries and VORTEX virtual mast position: Lat=20.776989 Lon=71.669414.

The VORTEX data are derived using the mesoscale model Weather and Research Model (WRF). WRF is a first-class atmospheric mesoscale model which has been imported to the wind industry by combining atmospheric modelling and wind engineering. The WRF model is used by VORTEX to generate time series of wind conditions and other meteorological variables for any site. The horizontal resolution of the model is 3 km and each run spans over a period of up to 20 years. Output data are gathered with an hourly frequency sampling for different heights above the ground level (10 m intervals). Large scale drivers are prescribed by data from Copernicus ERA5 (NEW), NCEP CFS, NASA MERRA2 and ECWMF ERA-Interim Reanalysis projects.

The VORTEX data shall at a later stage, e.g. after twelve months of measurements, be compared with Lidar measurements at the FOWPI site (same position as the reported VORTEX point), and based on that, the results shall be updated.

The following 20 years basic period has been chosen for the subsequent analyses and AEP calculations:

- Basic wind data period: 01 August 1997 to 31 July 2017

5.3 Wind Distribution

The wind distribution based on the VORTEX data is presented in Table 5-3 and Table 5-4 showing the sector-wise Weibull parameters, frequency distributions and mean wind speeds.

Sector	A-parameter [m/s]	k-parameter	Frequency [%]	Mean Wind Speed [m/s]
Mean	7.97	2.628	100.00	7.1
N	6.50	2.484	9.58	5.8
NNE	7.12	3.260	18.37	6.4
ENE	5.22	2.313	4.37	4.6
E	3.43	1.529	1.11	3.1
ESE	2.94	1.418	0.75	2.7
SSE	3.54	1.308	0.90	3.3
S	4.86	1.376	1.89	4.4
SSW	7.81	3.300	10.43	7.0
WSW	10.04	4.623	28.98	9.2
W	8.90	3.302	12.31	8.0
WNW	6.51	2.563	6.32	5.8
NNW	5.60	2.049	5.00	5.0

Table 5-3: Wind distribution at 100 m ASL.

Sector	A-parameter [m/s]	k-parameter	Frequency [%]	Mean Wind Speed [m/s]
Mean	7.76	2.641	100.00	6.9
N	6.29	2.653	10.21	5.6
NNE	6.85	3.332	17.57	6.1
ENE	5.00	2.158	3.97	4.4
E	3.35	1.528	1.10	3.0
ESE	2.99	1.472	0.76	2.7
SSE	3.44	1.305	0.97	3.2
S	4.79	1.411	2.04	4.4
SSW	7.68	3.388	11.41	6.9
WSW	9.87	4.692	28.81	9.0
W	8.64	3.382	12.03	7.8
WNW	6.18	2.704	6.23	5.5
NNW	5.28	2.220	4.91	4.7

Table 5-4: Wind distribution at 80 m ASL.

It is seen that the Weibull mean wind speeds at respectively 100 m and 80 m ASL are estimated to:

- Mean wind speed at 100 m ASL: 7.1 m/s
- Mean wind speed at 80 m ASL: 6.9 m/s

Figure 5-3 and Figure 5-4 show the all sector Weibull distributions. The red curves represents the measured distribution and the green curves, the all sectors Weibull fit. It is seen that the Weibull distributions do not perfectly fit the measured distributions. However, in the AEP calculations the sector-wise Weibull distributions are used, the Weibull fit method error is taken into account in the joint uncertainty of the AEP estimate.

Figure 5-5 and Figure 5-6 show the wind (frequency) and energy roses. It is seen than the prevailing wind direction is WSW.

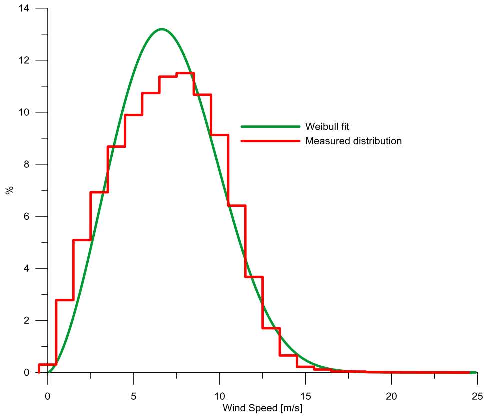

Figure 5-3: All sector Weibull distribution at 100 m ASL.

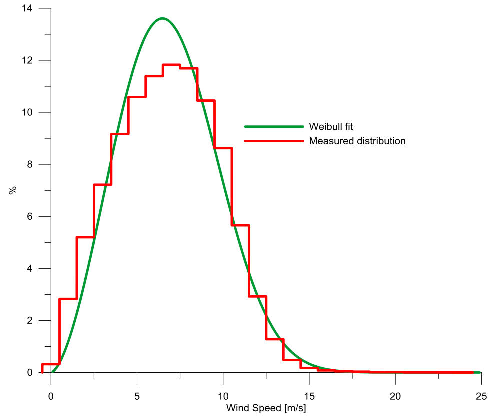

Figure 5-4: All sector Weibull distribution at 80 m ASL.

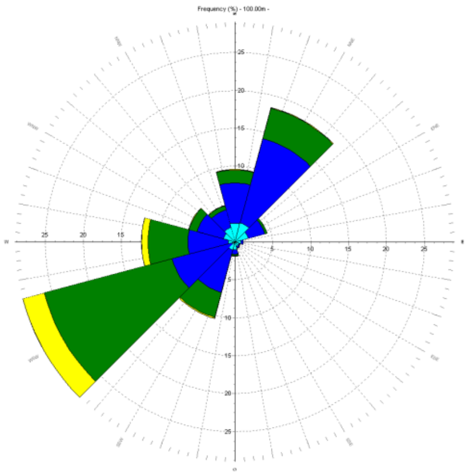

Figure 5-5 Frequency Rose at 100 m ASL.

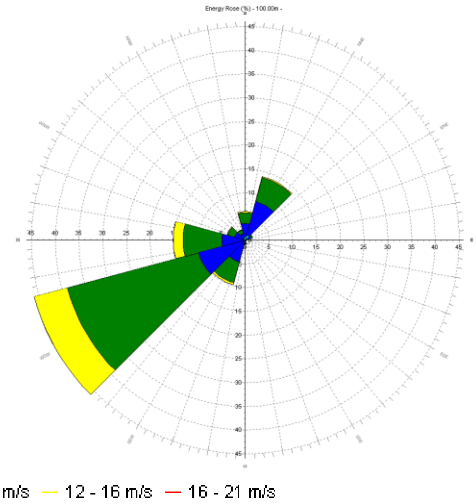

Figure 5-6 Energy Rose at 100 m ASL.

Frequency and Energy roses at 80 m are nearly identical to the roses at 100 m presented in Figure 5-5 and Figure 5-6 – as expected for offshore conditions.

5.4 Daily Variations of Wind Speed

Figure 5-7 presents the average daily variations of the wind speed at 100 m and 80 m ASL based on the 20 years VORTEX data. There is a significant diurnal variation between 5.7 m/s in the morning and 8.0 m/s around midnight.

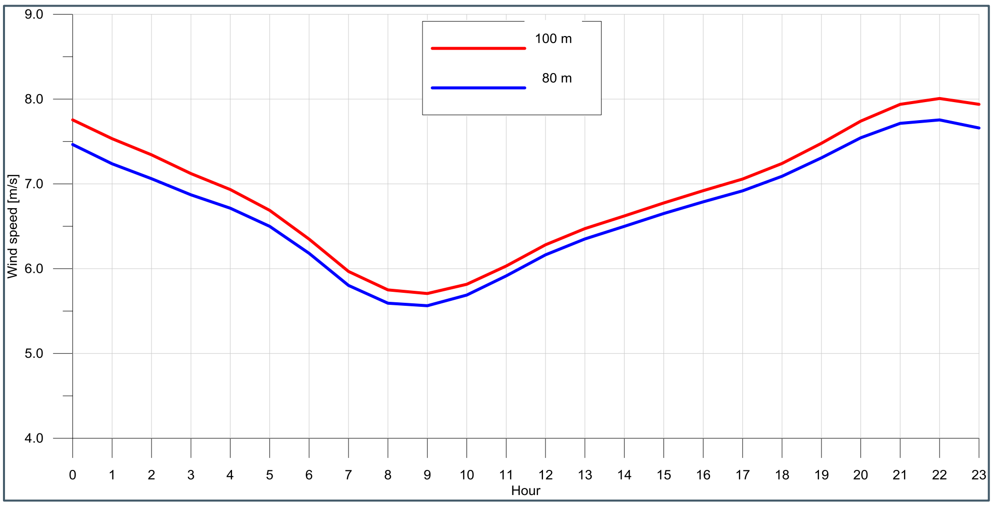

Figure 5-7: Average daily variation of the wind speed at 100 m and 80 m ASL.

Noteworthy is that this variation matches the expected consumption profile fairly well.

5.5 Monthly variations of Wind Speed

Figure 5-8 presents the average monthly mean wind speeds at 100 m and 80 m ASL based on the 20 years VORTEX data. The monsoon period is the high wind season from May to August. The lower wind season stretches from October to March.

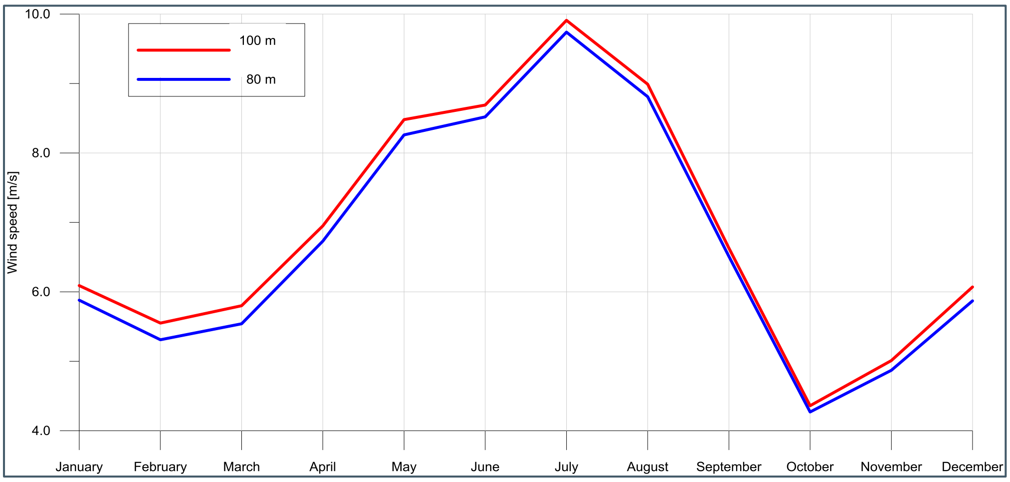

Figure 5-8 Monthly variation of wind speed.

5.6 Wind Shear

The wind shear expresses the ratio between the wind speeds at different heights and is part of the site characteristics related to the wind turbine specifications. The wind shear is an important parameter in the choice of the optimal hub height.

The wind shear depends on the wind direction due to the influence from land. When the wind is coming from North, i.e. from land, the wind shear is affected by the land/sea transition resulting in higher wind shear exponents.

Furthermore, the wind shear depends on the atmospheric stability conditions. During daytime, the atmospheric conditions are unstable resulting in lower wind shear exponents, whereas the atmospheric conditions during night are stable resulting in higher wind shear exponents.

The power law wind shear exponent, α is defined by:

$V_2 = V_1 (H_2 / H_1)^{\alpha}$,

where the shear exponent, α, is calculated between the respective heights H_1 and H_2 and their corresponding wind speed V_1 and V_2.

Based on the 20 years VORTEX time series including the wind speeds at respectively 100 m and 80 m ASL, the wind shear exponents are calculated and presented in Table 5-5 and Figure 5-9.

It is seen that the wind shear exponent representing all directions and all day is 0.13, which is as expected for offshore sites.

Sector	All	Day	Night
Mean	**0.13**	**0.10**	**0.15**
N	0.25	0.24	0.31
NNE	0.17	0.16	0.21
ENE	0.13	0.14	0.09
E	0.12	0.13	0.11
ESE	0.01	0.00	0.04
SSE	0.01	-0.05	0.13
S	0.03	-0.03	0.14
SSW	0.08	0.07	0.10
WSW	0.09	0.09	0.09
W	0.10	-0.01	0.11
WNW	0.19	0.18	0.21
NNW	0.25	0.27	0.29

Table 5-5 Wind shear exponents.

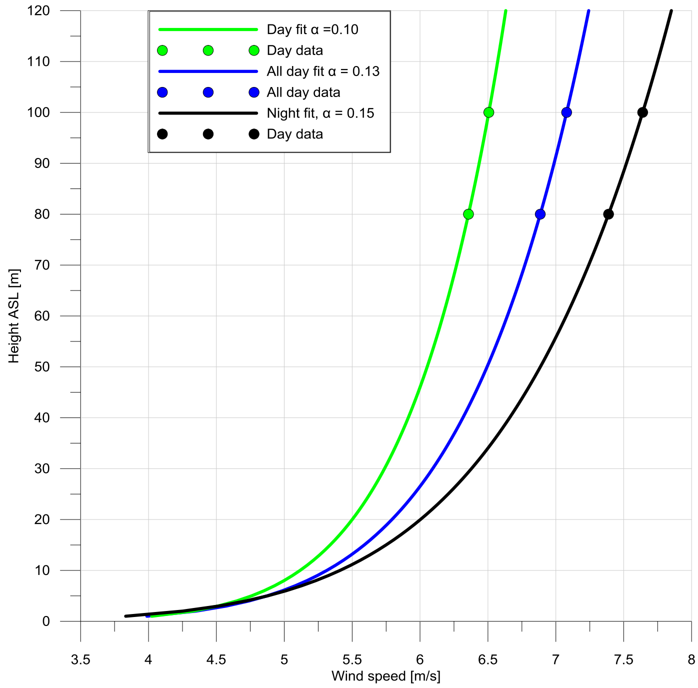

Figure 5-9: Wind shear based on VORTEX data and exponential fits.

The sector wise day/night wind shear exponents have been used to extrapolate the VORTEX wind speeds at respectively 100 m to the 107 m MSL and 80 m to 86 m MSL corresponding to the two hub heights considered.

5.7 Long-term Variation

It is a well-known fact that the annual mean wind speed at any given site varies over the years. It is therefore important that the wind data cover a sufficiently long period to represent the long-term average. A 20 years period is acknowledged as being applicable for this purpose and it is therefore not necessary to introduce additional long-term correction of the 20 years VORTEX data.

However, re-analysis data must be handled carefully, as it is often seen that the data includes a trend[3], which does not necessarily represent a real trend in the climate but is due to changes in the sources used for generating the data.

Figure 5-10 shows the VORTEX annual mean wind speeds during the period 1997 – 2016, and it is seen that there is no trend during the 20 years period. Therefore, it is assessed that a de-trending is not necessary before using the 20 years VORTEX data as long-term reference.

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[3] The use of NCEP/NCAR Reanalysis Data in MCP, Michael C. Brower, PhD, AWS Truewind, LLC, 255 Fuller Road, Albany, New York, 12203 USA

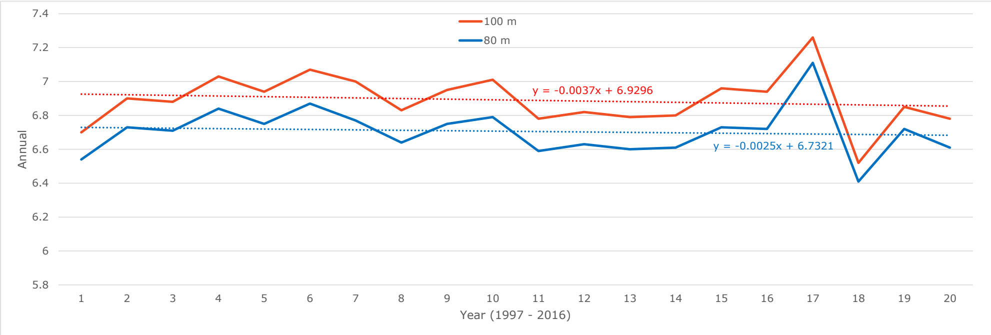

Figure 5-10: Annual mean wind speed based on VORTEX data.

5.8 Wind Speed Distribution throughout the Site

It is in general expected that the wind speed increases with the distance to the coast. However, due to e.g. land/see breeze effects, the wind speed might not continue to increase.

In order to assess how the average wind speed varies throughout the site, a 1 km resolution mesoscale modelling (VORTEX) has been carried out. The resulting resource map is shown in Figure 5-11[4] and it includes the boundaries for positioning wind turbines.

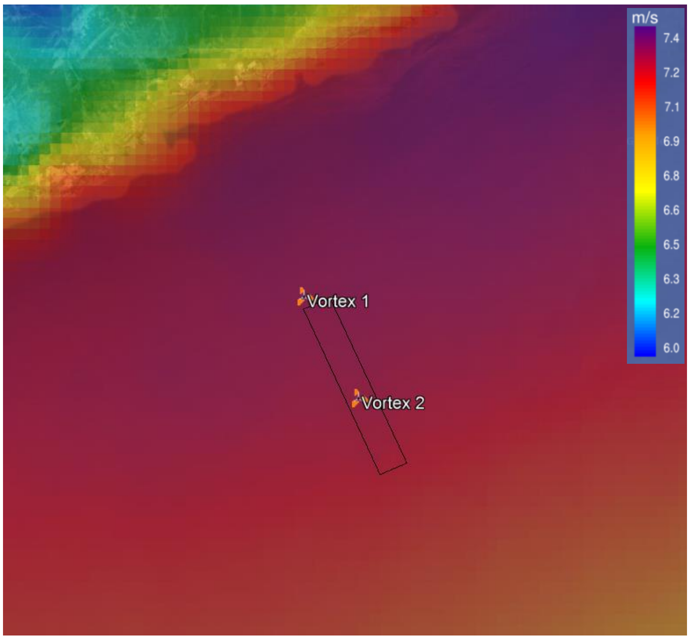

Figure 5-11 Wind resource distribution, site area and VORTEX points.

It is seen that the wind speed increases – as expected – when going offshore. Approx. 6 km off the coast, the wind speed reaches its maximum, and then it is almost constant the next approx. 20 km. After this point, the wind speed seems to decline.

[4] It should be noted that the wind resource map is based on a different period and therefore not representing exactly the 20 years long-term average wind speed applied

This means that the wind speed is highest in the northern part of the site. In order to determine this declining tendency from the northern to the southern part of the site, a VORTEX time series has been calculated representing the wind at the point *VORTEX 2* shown in Figure 5-11, which is approx. 12 km further off the coast compared with the VORTEX 1 point.

A correlation between the wind speed representing respectively VORTEX position 1 and 2 based on six months overlapping period covering 22 February to 22 August 2017, i.e. including both high and low wind periods, has been carried out. The result is presented by the weekly wind speeds at the two positions shown in Figure 5-12.

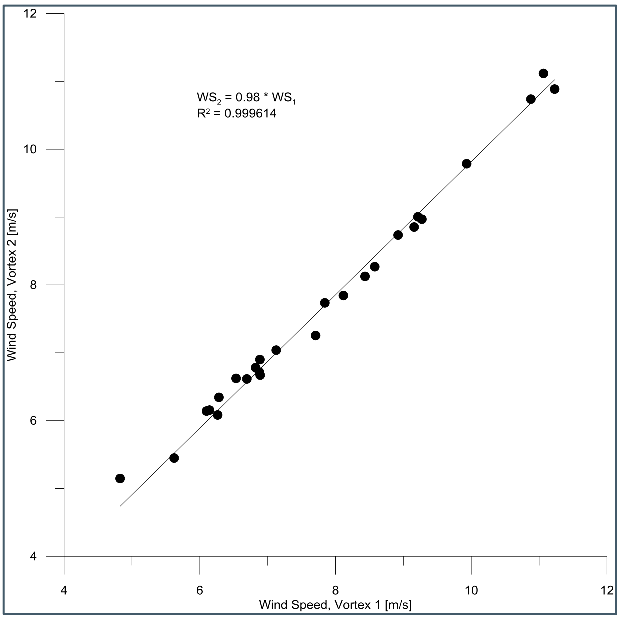

Figure 5-12 Correlation between the weekly average wind speed at VORTEX2 and at VORTEX1.

It is seen that as expected there is a very good correlation, and furthermore, it is seen that the wind speed is 2% lower at the VORTEX 2 point than the wind speed at the VORTEX 1 point.

This declining tendency of 2% in the wind speed over a distance of 12 km is taken into account in the AEP calculations.

It should be noted that it is not very unusual that the wind speed decreases with increasing distance to coast. The same is seen in some parts of the North Sea and in other regions. It is most likely due to the land/sea breeze driven wind, which effect decreases with the larger distance to shore.

The decreasing wind resource is seen in the AEP calculations for the individual turbines shown in Table 7-2 and Table 7-3 in Appendix A.

6 Base Layouts and Yield Estimates

In this chapter base layouts for both 3 MW and 6 MW reference turbines are defined. Yield Estimates are thereafter calculated on the basis of available synthetic modelled wind data, i.e. not site measurements, reference wind turbine models, base layouts and estimated losses.

6.1 Base layouts

Base layouts within the site boundaries are shown in Figure 6-1 and have been defined based on optimization experience and related rules of thumb. "Six-by-Ten" rotor-diameters is one such rule of thumb. Meaning that perpendicularly to the prevailing wind direction the wind-turbines should be spaced by approximately six rotor-diameters, and in the prevailing wind direction the distance should be approximately ten rotor-diameters. For the 6 MW FOWPI reference turbine this is translated into a 1000 m x 1500 m spacing i.e. respectively 6.5 and 9.7 rotor-diameters and thus very close to "Six-by-Ten". Post optimization in Section 7 might suggest slightly longer distance between rows as the prevailing wind at the prospected site is more dominant than in Northern Europe where the rule-of-thumb was developed.

In order to exploit the northern part of the site, with the highest expected wind potential, base layouts have wind turbines positioned in the northern end of the project site. For both reference turbines three straight rows have been considered, with 22 or 11 turbines in each row as shown in Table 6-1 and in Figure 6-1. The row orientation is perpendicular to the prevailing south-west wind direction, which minimizes the wake loss.

Further design should also consider displacing the middle north-south orientated row (see Figure 6-1) towards south corresponding to half the in-row turbine distance perpendicular to main wind direction. This will reduce the wake loss, but at the same time the gross production decreases slightly due to the declining wind resource towards south. Potential gains for the 33 x 6 MW layout shows that the combined net AEP increases by 1% when performing such design change, corresponding to an increase of the capacity factor from 23.6% to 23.8%. For the 66 x 3 MW turbines, the gain in net AEP is assessed to be less significant due to the denser layout.

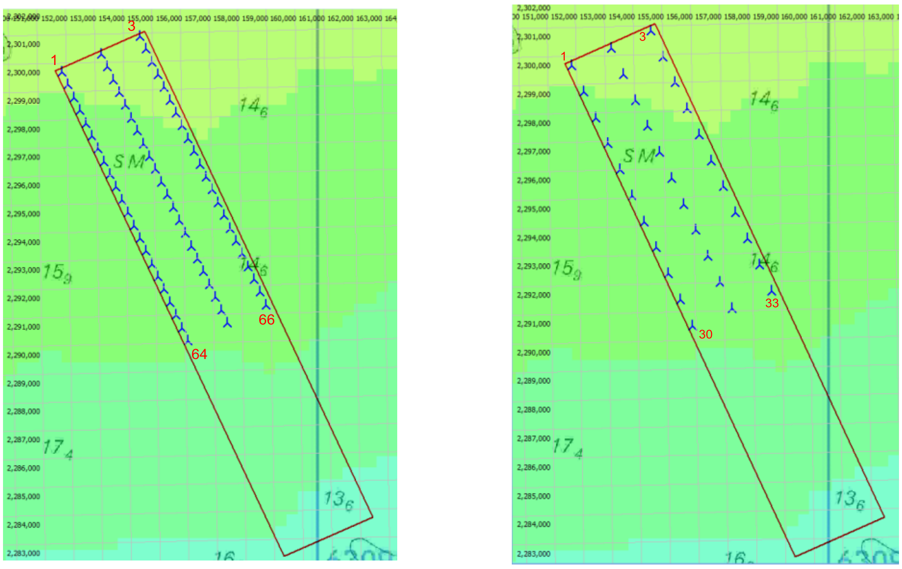

Figure 6-1 Base layouts: 66 x 3 MW (left) and 33 x 6 MW (right), base case. Site boundaries are illustrated by red rectangular perimeter surrounding wind turbine area. The background colours indicate the wind resource variation throughout the site. Turbine numbering related to Table 7-2 and Table 7-3 are shown for the corner turbines. The shown grid is UTM WGS 84 Zone 43

Scenario	No of turbines	Size	Diameter	Hub height	In-row distance	Row Distance
1	66	3 MW	112 m	86 m	500 m	1500 m
2	33	6 MW	154 m	107 m	1000 m	1500 m

Table 6-1: Wind farm scenarios, base case.

Noteworthy to mention is that the geophysical survey at FOWPI site included a grid of points across the site with 250 m x 1500 m resolution which brings much information on the area. For both base scenarios wind turbines are sited on grid points.

The coordinates of the individual turbines in the two base layouts used for the present study are presented in Appendix A and may be subject to post-optimization in consideration of findings from Section 7 and more detailed cost assessments.

6.2 Annual Energy Production

Based on the 20 years VORTEX synthetic data[5], the power curves and the considered layouts, the expected annual gross production (AEP_{Gross}) and annual PARK production (AEP_{PARK}), including wake loss, have been calculated using WAsP. The N. O. Jensen wake model with a wake decay constant of 0.041 corresponding to offshore conditions has been applied in the calculations.

[5] Extrapolated to the hub heights (ref. section 5.6). Furthermore, the tendency of declining wind speed (ref. section 5.8) from the northern part to the southern part of the site is taken into account

In order to obtain the estimated Net AEP delivered to the grid, technical losses must be taken into account. At this stage, the applied losses are assessed on the basis of experience with similar demonstration offshore projects. The following losses are assumed:

- Electrical loss: 5%
- Wind turbine availability loss: 5%
- Utility grid availability loss: 1%
- Power curve, blade contamination: 1%
- Resulting combined loss: 11.5%

At a later stage, the actual losses should be calculated on the basis of knowledge about the actual electrical configuration, the utility grid availability, the specific turbine, service contracts etc.

Table 6-2 and Table 6-3 show the resulting estimated long-term average Net AEP after applying the above assumed losses. Furthermore, the tables show the number of full load hours and the corresponding net capacity factors calculated based on synthetic and non-validated VORTEX data.

66 x 3 MW Turbines with 86 m (MSL) Hub Height			
Annual Gross Production for the 66 WTGs		652.3	GWh/y
Wake Loss	10.3%	67.2	GWh/y
Annual Park Production for the 66 WTGs		585.1	GWh/y
Combined Estimated Losses	11.5%	67.6	GWh/y
Net Annual Production for the 66 WTGs (P50)		517.6	GWh/y
Full load hours		2614.0	h/y
Capacity Factor		29.8	%

Table 6-2 Long-term average production estimate and other key figures for the 66 x 3 MW wind turbines.

33 x 6 MW Turbines with 107 m (MSL) Hub Height			
Annual Gross Production for the 33 WTGs		508.3	GWh/y
Wake Loss	9.0%	45.5	GWh/y
Annual Park Production for the 33 WTGs		462.8	GWh/y
Combined Estimated Losses	11.5%	53.4	GWh/y

Net Annual Production for the 33 WTGs (P50)	409.3	GWh/y
Full load hours	2067.0	h/y
Capacity Factor	23.6	%

Table 6-3 Long-term average production estimate and other key figures for the 33 x 6 MW wind turbines.

It is seen that the capacity factor for the 66 x 3 MW turbines is larger than the capacity factor for 33 x 6 MW turbines. The reason for the difference is the larger rotor swept area per installed capacity of the generic 3 MW turbine, in comparison to the rotor swept area per installed capacity of the generic 6 MW turbine. The generic 3 MW turbine used for this study reflects a design for a slightly lower wind than the design of the generic 6 MW turbine. Ref. section 4.3 and 4.4.

The AEP calculations for the individual turbines are shown in Table 7-2 and Table 7-3 in Appendix A, where the decreasing wind resource towards south is seen. For instance, the gross AEP for the northernmost 3 MW turbine is 5.5% higher than for the southernmost.

It is strongly recommended to re-recalculate production estimate figures when wind measurements at the site are available.

6.3 Yearly and Monthly Variation of Energy Production

The annual mean wind speed varies from year to year, as seen in Figure 5-10. Consequently, the annual energy production varies too. Based on the 20 years VORTEX data, the standard deviation of the inter-annual mean speed variation is given by:

- Inter-annual wind speed variation: 2.2%

This inter-annual variation of the wind speed will result in an inter-annual variation of the energy production of:

- Inter-annual energy production variation: 4.8%

The monthly mean wind speed varies significantly as shown in Figure 5-8 and consequently, the monthly energy production (MEP) will vary significantly too. Based on the 20 years VORTEX data, the average Weibull parameters for each calendar month are calculated representing the average monthly wind distribution. By combining these monthly wind distributions with the power curves (ref. Figure 4-1) – also taking the number of days per month into account - the average monthly energy productions in percent are calculated.

The result is shown as the Net Monthly Productions in percent in Figure 6-2 and Figure 6-3.

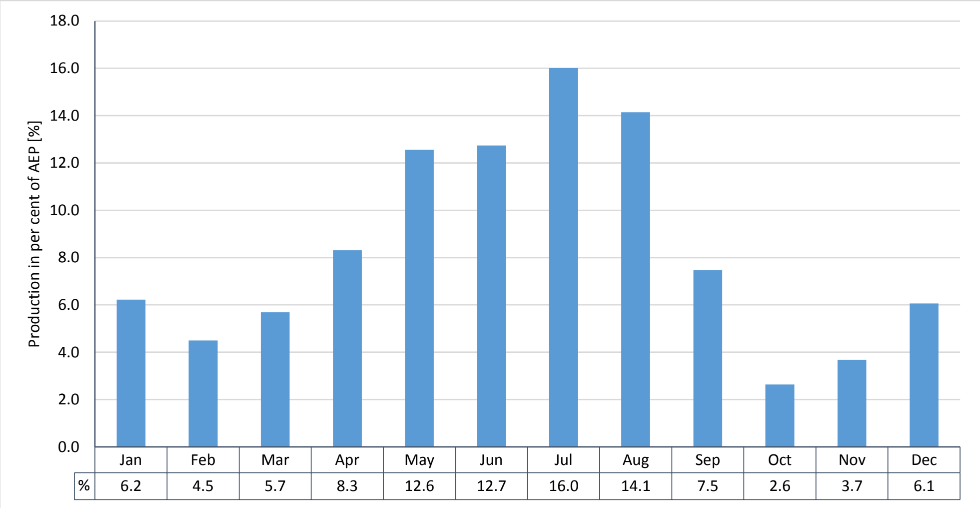

Figure 6-2 Average monthly production in percent, 66 x 3 MW turbines.

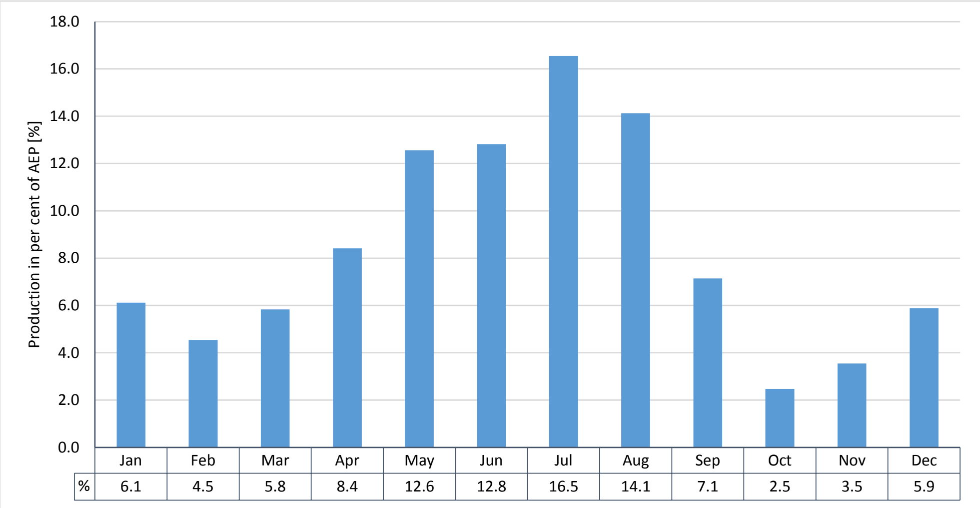

Figure 6-3 Average monthly production in percent, 33 x 6 MW turbines.

It is seen that – in average – respectively 55% and 56% of the AEP is produced during the four-month period from May to August by the 66 x 3 MW turbines and by the 33 x 6 MW turbines.

7 Layout Optimization

From an energy perspective the optimized wind farm layout should maximize energy production. For offshore wind farms this is mainly achieved by optimally distributing the spacing in between wind turbines within the available area taking most advantage of the wind resource available while minimizing the wake loss.

From an economic perspective, however, the optimized wind farm layout is the layout that minimizes the unit cost of produced energy. This is mainly achieved by investigating the trade-off between the energy yield gains from additional spacing between wind turbines and additional costs from foundation cost (i.e. due to more sea depth – if applicable), longer electrical cabling costs & losses and longer O&M routes.

In the following sections, the optimization of the base 3-row layouts is explored. First, energy yield calculations are performed for a multitude of scenarios. Secondly, economic trade-offs are investigated based on various preliminary economic assumptions. Results are summarized in Table 7-1.

7.1 Technical considerations

7.1.1 Wake Loss

The wind farm mutual wake loss is primarily dependent on wind farm layout and wind distribution at the site. This section considers the two main possibilities for evaluating the wake loss with respect to base scenarios: variations of in-row distance, i.e. wind turbine spacing perpendicular to the main wind direction, and variations of the row distance, i.e. wind turbine spacing across main wind direction. Calculations are performed for both 33 x 6 MW and 66 x 3 MW turbines based on N. O. Jensen wake model.

Variations in in-row distance

Figure 7-1 shows the total wake loss for the 33 x 6 MW wind turbines as a function of the in-row distance. Results indicate that the wake loss decreases from 9.1%, for an in-row distance of 1000 m or 6.5D (base case), to 5.9%, for an in-row distance of 1890 m or 12.3 D i.e. utilizing the entire site area as shown in Figure 8.1. Thus, utilizing the entire site area results in 3.2% of the

Gross AEP that is not lost due to wake losses. However, due to the lower wind resource in the southern part of the site (illustrated in Figure 6-1) the gross production is lower in this part and therefore, the resulting energy production increases by only 0.73% as shown in Figure 7-2.

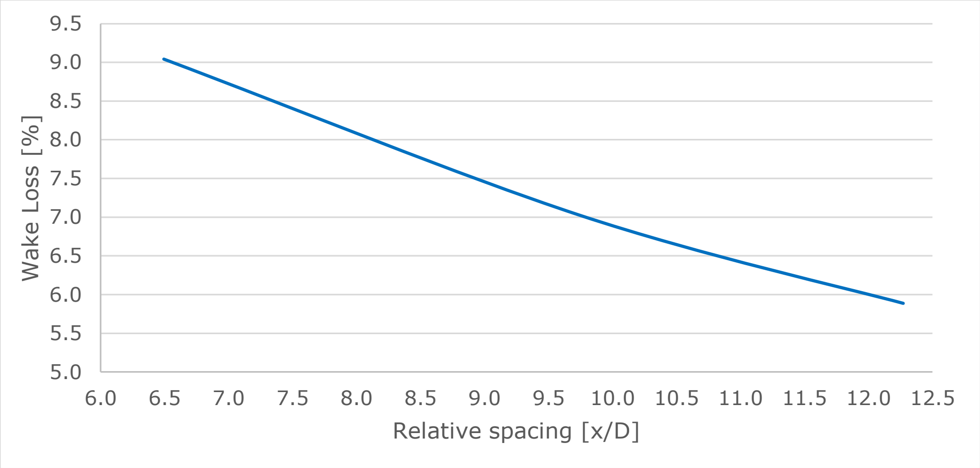

Figure 7-1 Total wake loss depending on in-row distance (33 x 6 MW turbines).

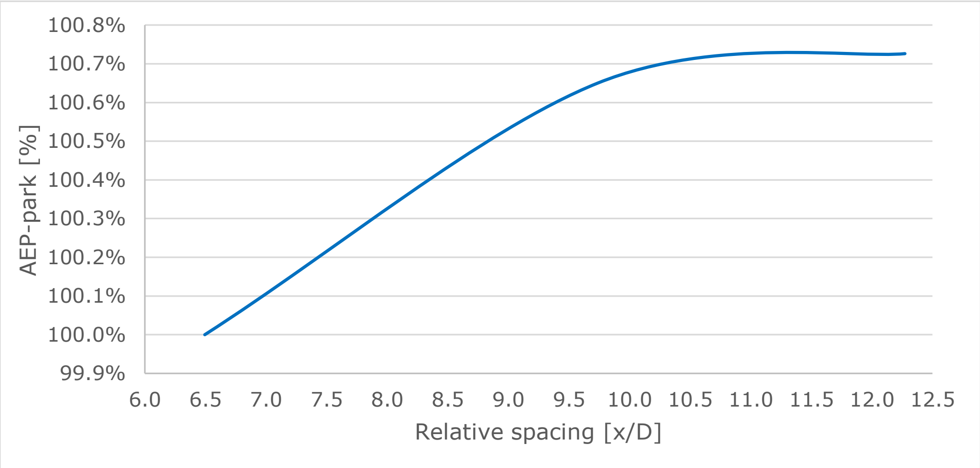

Figure 7-2 AEP-park (relative) depending on in-row distance (33 x 6 MW turbines).

Similar results are obtained for the 66 x 3 MW turbines. When increasing the in-row distance from 500 m or 4.5D (base case) to 900 m or 7.1D (utilizing the entire site area), the total wake loss is reduced from 10.3% to 6.6%. However the resulting energy production, after wake loss, increases by only 1.8%.

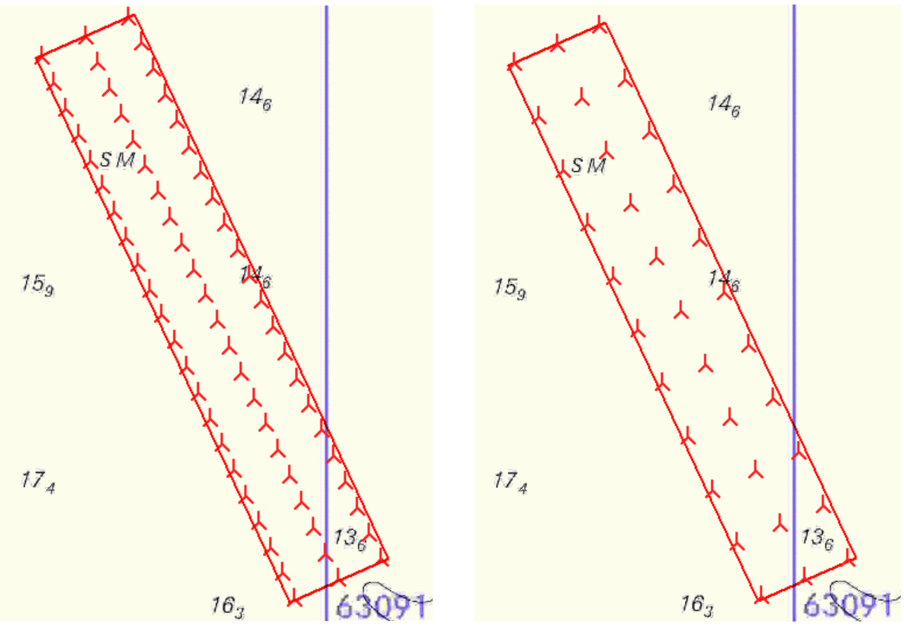

Figure 7-3 Larger in row distance between turbines, with WTGs covering the entire site area. Scenario 2 (Left) and 5 (Right).

Variations in row distance

In *Figure 7-4* the calculated wake loss for the individual 33 x 6 MW wind turbines is shown for the base case layout. It is clearly seen that the wake loss of the wind turbines in the row facing the prevailing wind direction (WTG no. 1, 4, 7, … 30)[6] is significantly lower than the wake loss of the wind turbines in the third row (WTG no. 3, 6, 9, … 33). For instance, the wake loss is only 0.4% for wind turbine 1, against 9% for wind turbine 3. This is due to the prevailing WSW wind direction, characteristic of the prospected site, and indicates that increasing row distances could bring more significant wake loss reductions.

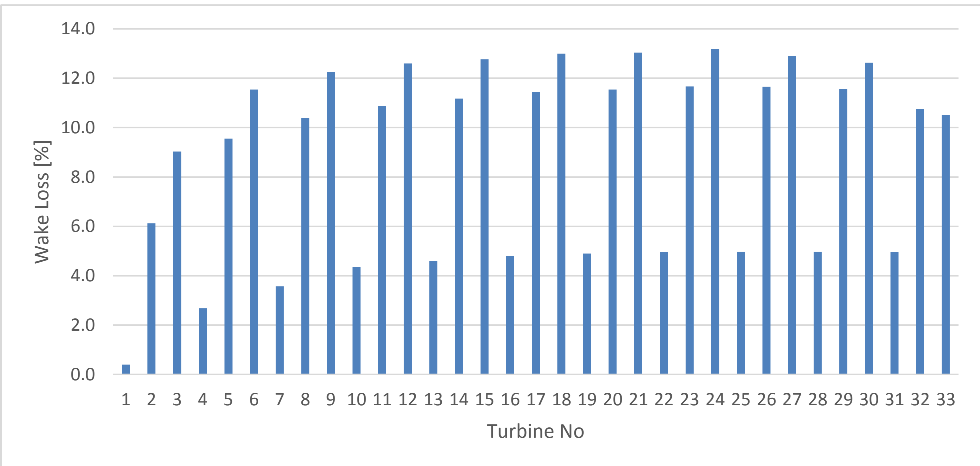

Figure 7-4 Wake loss for individual wind turbines (33 x 6 MW turbines).

[6] The WTG numbering is shown in Figure 6-1 and Table 7-2 and Table 7-3

In order to investigate larger row distances, a 2-row layout is considered – instead of 3 rows as in the base case - and the entire site area is utilized as shown in Figure 7-5.

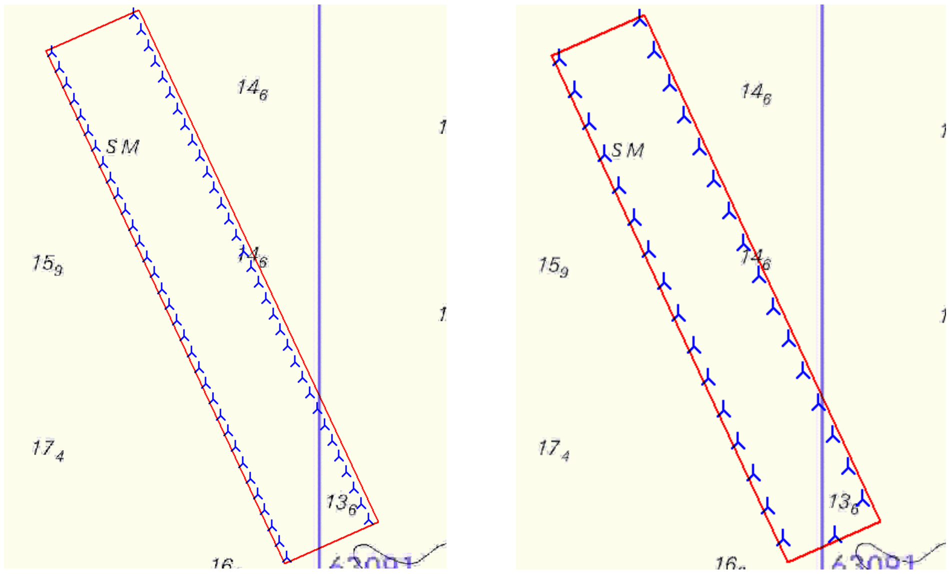

Figure 7-5 Wind turbine layouts: 2x33 3 MW to the left and 1x16+1 x 6 MW to the right. Scenario 3 (Left) and 6 (Right).

The wake loss for the 33 x 6 MW wind turbines in 2 rows with 16 wind turbines in each row plus one and a distance between the rows of 3000 m is reduced from 9.0% to 3.5% compared with the base case. Consequently, the energy production is increased by 3.2% despite of the lower wind resource available in the southern area within the site boundaries.

The wake loss for the 66 x 3 MW wind turbines in 2 rows with 33 in each row and a distance between the rows of 3000 m is reduced from 10.4% to 4.6% compared with the base case. Consequently, the energy production is increased by 3.9%.

7.1.2 Cable Length

One of the disadvantages of increasing the wind turbine spacing in order to reduce the wake loss and consequently optimize the production is the longer electrical cabling between the turbines. This will of course increase the investment costs and will reduce the positive result of increased spacing. In addition, the longer the cables the higher the electrical transmission losses.

The additional cable length for key scenarios, with respect to base scenarios, has been estimated and summarized in Table 7-1. The marginal electrical loss on the cables for the entire farm has been estimated at 100 MWh/km/year.

7.1.3 Water Depth

The water depth has an influence on the foundation cost, and by increasing the wind turbine spacing, some of the wind turbines may be located at greater water depth resulting in more costly foundations.

Figure 7-6 (Ref. /2/) shows the water depths, and it is seen that within the site area the water depth varies a few meters only, with an average depth of around 16 m.

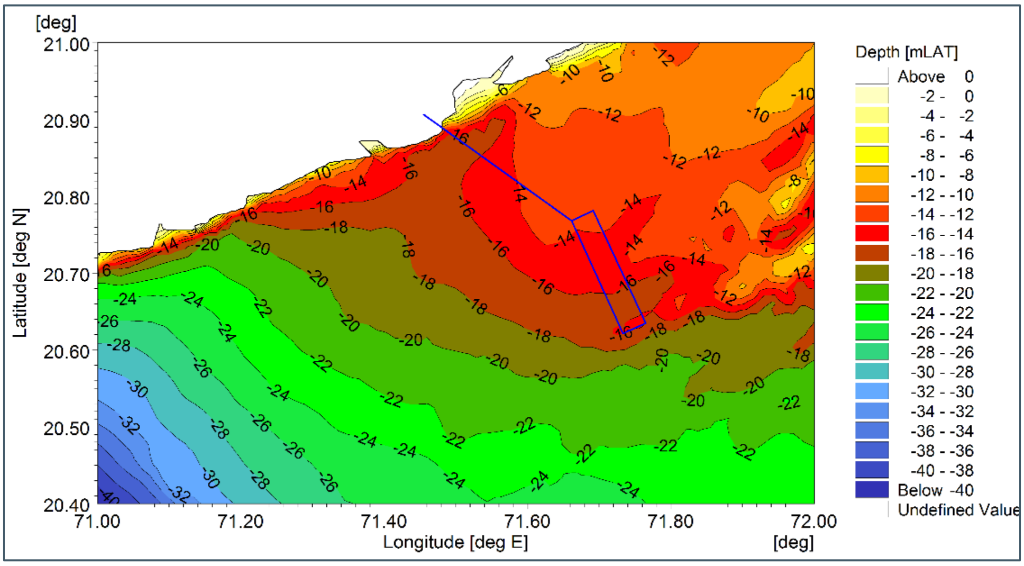

Figure 7-6 Water depths are extracted from MIKE C-Map and are given with respect to CD.

The average water depth is calculated for each of the layout scenarios considered in section 7.1.1, and the results are shown in Figure 7-7.

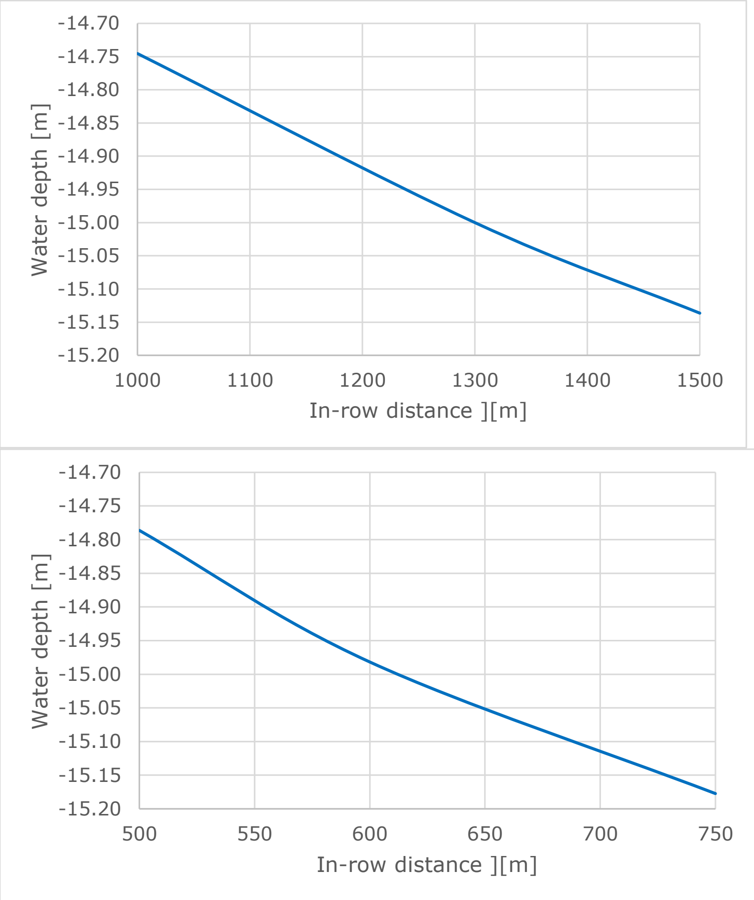

Figure 7-7 Water depth vs in-row WTG distance, 3 MW (bottom) and 6 MW (top).

7.2 Economic considerations

For a preliminary evaluation of possible economic gains/losses from alternative wind farm layouts, with respect to base cases, the following assumptions are made:

- Marginal Foundation Cost incl. installation for entire farm: 3 m€/m
- Marginal Cable Cost incl. installation for entire farm: 0.6 m€/km
- Marginal Electrical Cable Loss for entire farm: 100 MWh/km/year
- Tariff: 170 €/MWh[7]
- Economic lifetime: 25 years
- Discount rate: 12%
- O&M costs Not considered

[7] ≈13.5 INR/kWh

The assumed foundation costs are the marginal costs, i.e. costs per additional meter of deployed foundation, assessed as approximately 3%/m of the total average wind farm foundation costs including installation. Likewise, the cable costs are also assessed in marginal terms, i.e. costs due to additional sub-sea cable length, for comparison with base cases. Such marginal costs do not include start-up costs of mobilizing vessels, crew and manufacture or costs which do not significantly vary in function of the specific wind farm layout e.g. costs of pulling cables into foundations.

Table 7-1 includes a summary of results of two scenarios compared to each base layout: one with larger in-row distance, designed to exploit the entire extent of the site area, and another with two rows. All scenarios are illustrated in Figure 6-1, Figure 7-3 and Figure 7-5. Results consider changes in water depth, wake loss, cable length and cable losses for each configuration. The final economic gains are measured by the change in the Net Present Value (NPV) of the cash flows from each alternative layout, which respect to base scenarios 1 and 4.

Scenario	WTGs	In-row distance [m]	Row Distance [m]	Avg. Water depth[8] [m]	Wake Loss [%]	AEP_{park}[8] [%]	Cable length[9] [km]	Energy Balance [10] [GWh/y]	ΔNPV [m€]
1 base	33 x 6 MW	**1000**	**1500**	**0**	**9.1**	**100%**	**0**	**0.0**	0.0
2		1500	1500	0.4	7.0	100.6	16.5	1.0	-8.7
3		1200	3000[11]	0.7	3.5	103.2	17.4	11.3	2.1
4 base	66 x 3 MW	**500**	**1500**	**0**	**10.4**	**100%**	**0**	**0.0**	0.0
5		750	1500	0.4	7.6	101.8	23.3	6.9	-5.4
6		590	3000[11]	0.6	4.6	103.9	27.8	17.6	4.3

Table 7-1: Water depth, wake loss, windfarm production, cable length and energy balance depending on layout configuration (base cases shown in bold).

Based on the preliminary assumptions, the results presented in Table 7-1 suggest economic losses for three row layouts with more in-row spacing and potential economic gains for 2 row layouts. Gains for the 2 row layouts, scenarios 3 and 6, are in the order of 2 and 4 million euros for the 33 x 6 MW and 66 x 3 MW configuration, respectively. This represents less than 1% of the total project CAPEX, which falls within the uncertainty range of the input assumptions. The spacing of base layouts are thus found to be fairly optimal, although certainly subject to more detailed investigations and updates based on detailed project design.

[8] In per cent compared with base case

[9] Additional water depth / cable length compared with base case

[10] Gross AEP minus Wake loss and minus cable electrical loss

[11] Two rows spaced 3000 m

When performing a sensitivity analysis on the input assumptions, it is further observed that:

- The marginal foundation cost is nearly negligible for the economic optimization exercise since water depths do not vary significantly across the site area.
- Adding in-row spacing for the three row base layouts is very likely not to be economically beneficial.
- It is expected that the two row layouts could bring economic benefits to the project, especially if lower cable costs and/or higher tariffs are achieved.

Appendix A Layout and Energy Production

Table 7-2 and Table 7-3 present the results of the calculations of the energy production for respectively the 66 3 MW wind turbines and the 33 6 MW turbines. The coordinates (X, Y) are in UTM WGS 84 Zone 43.

WTG No.	X [m]	Y [m]	AEP_{Gross} [MWh]	Wake loss [%]	Loss [%]	AEP_{Net} [MWh]
1	152832	2299684	10252.2	0.4	-11.5	9031.4
2	154206	2300287	10251.6	6.3	-11.5	8499.6
3	155580	2300891	10252.2	8.7	-11.5	8277.5
4	153034	2299226	10251.2	1.9	-11.5	8896.9
5	154408	2299830	10250.7	8.6	-11.5	8286.4
6	155782	2300434	10251.6	11.2	-11.5	8050.5
7	153237	2298769	10250.8	3.1	-11.5	8781.8
8	154611	2299373	10084.4	10.8	-11.5	7960.9
9	155985	2299976	10084.3	12.6	-11.5	7795.4
10	153439	2298311	10084.5	4.4	-11.5	8528.1
11	154813	2298915	10084.5	11.9	-11.5	7861.8
12	156187	2299519	10083.6	13.2	-11.5	7745.9
13	153642	2297854	10084.2	4.8	-11.5	8487.8
14	155016	2298458	10084.1	12.3	-11.5	7820.5
15	156389	2299061	10083.7	13.5	-11.5	7714.0
16	153844	2297396	10083.7	5.2	-11.5	8452.5
17	155218	2298000	10083.6	12.6	-11.5	7791.3
18	156592	2298604	10083.0	13.8	-11.5	7691.6
19	154047	2296939	10083.1	5.5	-11.5	8429.0
20	155420	2297543	10083.2	12.9	-11.5	7770.4
21	156794	2298147	10082.5	13.9	-11.5	7679.6
22	154249	2296482	10083.0	5.6	-11.5	8414.9
23	155623	2297085	10082.4	13.1	-11.5	7754.3
24	156997	2297689	10082.4	14.0	-11.5	7671.3
25	154451	2296024	10082.7	5.8	-11.5	8404.5
26	155825	2296628	10082.2	13.2	-11.5	7742.9
27	157199	2297232	10082.4	14.1	-11.5	7665.2
28	154654	2295567	9955.1	5.9	-11.5	8288.2
29	156028	2296170	9954.8	13.5	-11.5	7620.8
30	157402	2296774	9954.6	14.3	-11.5	7545.5
31	154856	2295109	9954.2	5.9	-11.5	8281.9
32	156230	2295713	9954.3	13.5	-11.5	7615.3
33	157604	2296317	9954.2	14.3	-11.5	7542.4
34	155059	2294652	9954.2	6.0	-11.5	8278.5

WTG No.	X [m]	Y [m]	AEP_{Gross} [MWh]	Wake loss [%]	Loss [%]	AEP_{Net} [MWh]
35	156433	2295256	9954.1	13.5	-11.5	7612.1
36	157807	2295860	9954.5	14.4	-11.5	7541.3
37	155261	2294194	9954.0	6.0	-11.5	8275.7
38	156635	2294798	9954.1	13.6	-11.5	7610.3
39	158009	2295402	9954.4	14.4	-11.5	7540.3
40	155464	2293737	9953.9	6.0	-11.5	8273.9
41	156838	2294341	9951.6	13.6	-11.5	7607.7
42	158211	2294945	9952.1	14.4	-11.5	7537.9
43	155666	2293279	9846.9	6.1	-11.5	8182.0
44	157040	2293883	9847.1	13.7	-11.5	7514.6
45	158414	2294487	9847.1	14.5	-11.5	7442.8
46	155869	2292822	9846.6	6.1	-11.5	8181.1
47	157243	2293426	9846.9	13.7	-11.5	7515.0
48	158616	2294030	9847.1	14.5	-11.5	7445.3
49	156071	2292365	9846.8	6.1	-11.5	8180.9
50	157445	2292969	9847.0	13.7	-11.5	7516.2
51	158819	2293573	9847.2	14.4	-11.5	7452.7
52	156274	2291907	9846.6	6.1	-11.5	8180.7
53	157648	2292511	9846.8	13.7	-11.5	7517.8
54	159021	2293115	9847.0	14.3	-11.5	7463.8
55	156476	2291450	9846.5	6.1	-11.5	8180.8
56	157850	2292054	9846.6	13.7	-11.5	7520.5
57	159224	2292658	9847.0	14.2	-11.5	7475.2
58	156679	2290992	9846.3	6.1	-11.5	8181.4
59	158053	2291596	9846.6	13.2	-11.5	7562.7
60	159426	2292200	9720.0	13.7	-11.5	7416.1
61	156881	2290535	9719.4	6.1	-11.5	8075.1
62	158255	2291139	9719.5	12.8	-11.5	7500.6
63	159629	2291743	9719.9	12.6	-11.5	7514.1
64	157084	2290077	9719.3	6.0	-11.5	8082.7
65	158457	2290682	9719.3	10.5	-11.5	7692.1
66	159831	2291286	9719.7	9.4	-11.5	7790.7

Table 7-2 AEP Estimate for the 66 3 MW wind turbines.

WTG No.	X [m]	Y [m]	AEP_{Gross} [MWh]	Wake loss [%]	Loss [%]	AEP_{Net} [MWh]
1	152831	2299657	16104.9	0.4	-11.5	14188.1
2	154216	2300237	16103.6	6.1	-11.5	13382.2
3	155600	2300816	16104.8	8.9	-11.5	12973.0
4	153236	2298742	16100.3	2.7	-11.5	13863.0
5	154621	2299322	15788.6	9.5	-11.5	12644.6
6	156005	2299902	15788.6	11.5	-11.5	12366.6
7	153641	2297827	15785.4	3.5	-11.5	13471.2
8	155025	2298407	15784.9	10.3	-11.5	12526.8
9	156410	2298987	15784.2	12.1	-11.5	12265.8
10	154046	2296912	15782.4	4.3	-11.5	13361.9
11	155430	2297492	15782.3	10.8	-11.5	12456.7
12	156815	2298072	15781.3	12.5	-11.5	12214.4
13	154451	2295997	15778.8	4.5	-11.5	13324.0
14	155835	2296577	15778.5	11.1	-11.5	12414.0
15	157219	2297157	15778.8	12.7	-11.5	12189.5
16	154856	2295082	15539.7	4.7	-11.5	13095.7
17	156240	2295662	15539.4	11.3	-11.5	12185.6
18	157624	2296242	15539.0	12.9	-11.5	11968.3
19	155261	2294168	15537.5	4.8	-11.5	13080.2
20	156645	2294747	15537.3	11.4	-11.5	12172.3
21	158029	2295327	15537.8	13.0	-11.5	11961.7
22	155666	2293253	15338.8	4.9	-11.5	12906.1
23	157050	2293833	15339.0	11.6	-11.5	11998.0
24	158434	2294413	15339.4	13.1	-11.5	11788.0
25	156071	2292338	15337.5	4.9	-11.5	12902.5
26	157455	2292918	15337.9	11.6	-11.5	11999.0
27	158839	2293498	15337.8	12.8	-11.5	11825.2
28	156476	2291423	15336.9	4.9	-11.5	12902.2
29	157860	2292003	15336.9	11.5	-11.5	12009.2
30	159244	2292583	15337.5	12.6	-11.5	11860.7
31	156881	2290508	15103.3	4.9	-11.5	12708.6
32	158265	2291088	15103.1	10.7	-11.5	11930.9
33	159649	2291668	15103.8	10.5	-11.5	11958.4

Table 7-3 AEP Estimate for the 33 6 MW wind turbines.

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