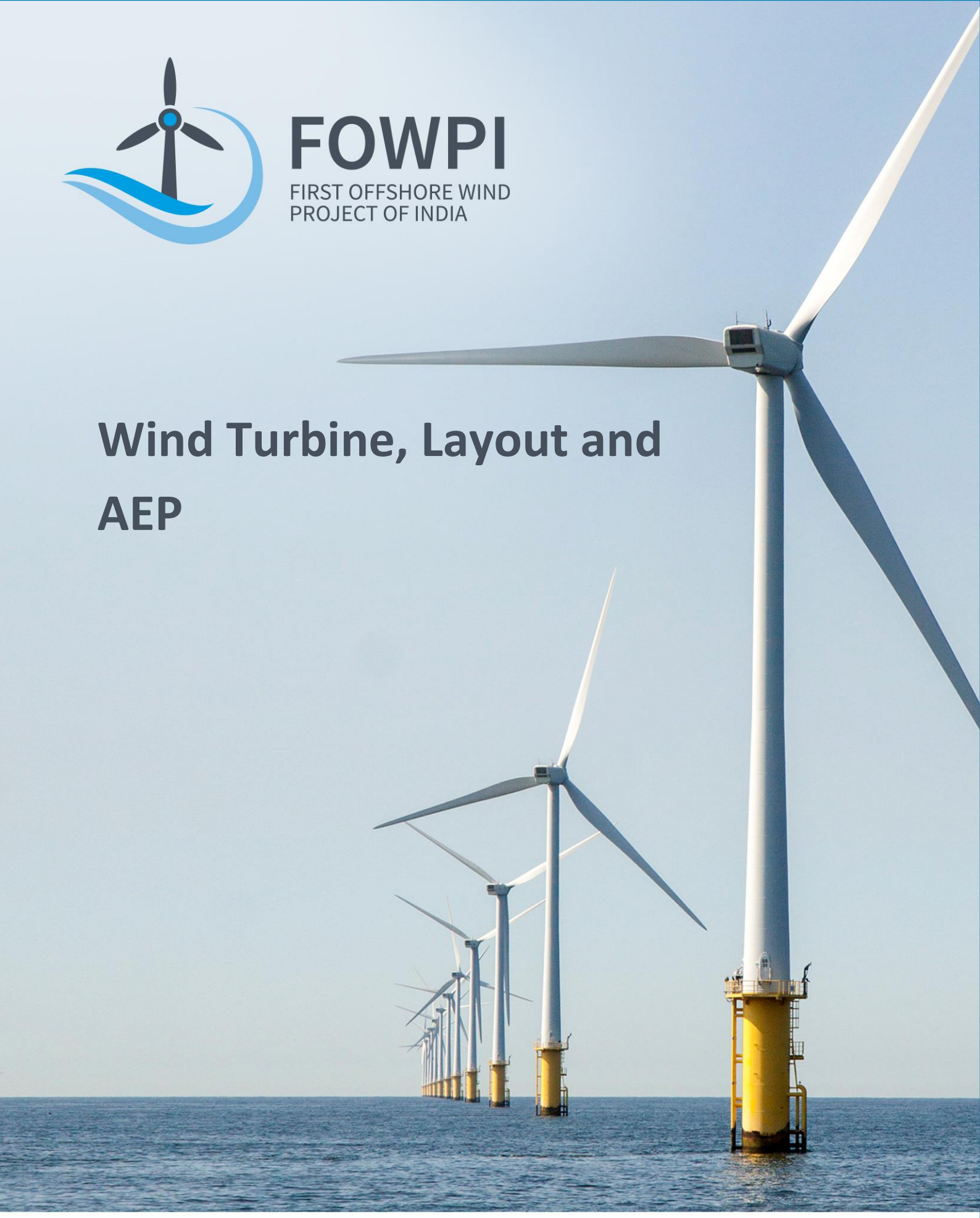
FOWPI

FIRST OFFSHORE WIND PROJECT OF INDIA

Wind Turbine, Layout and AEP



EUROPEAN UNION

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 conceptual offshore wind farm near the coast of Gujarat, 25 km off Jafarabad. The project scope focus is on preliminary investigations and advisory for the wind farm including wind turbine foundation, electrical network, metocean modelling, wind ressource, environmental scoping, financial modelling and others. 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 in the country.

FOWPI is led by COWI A/S (Denmark) with support from COWI Pvt Ltd India and 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

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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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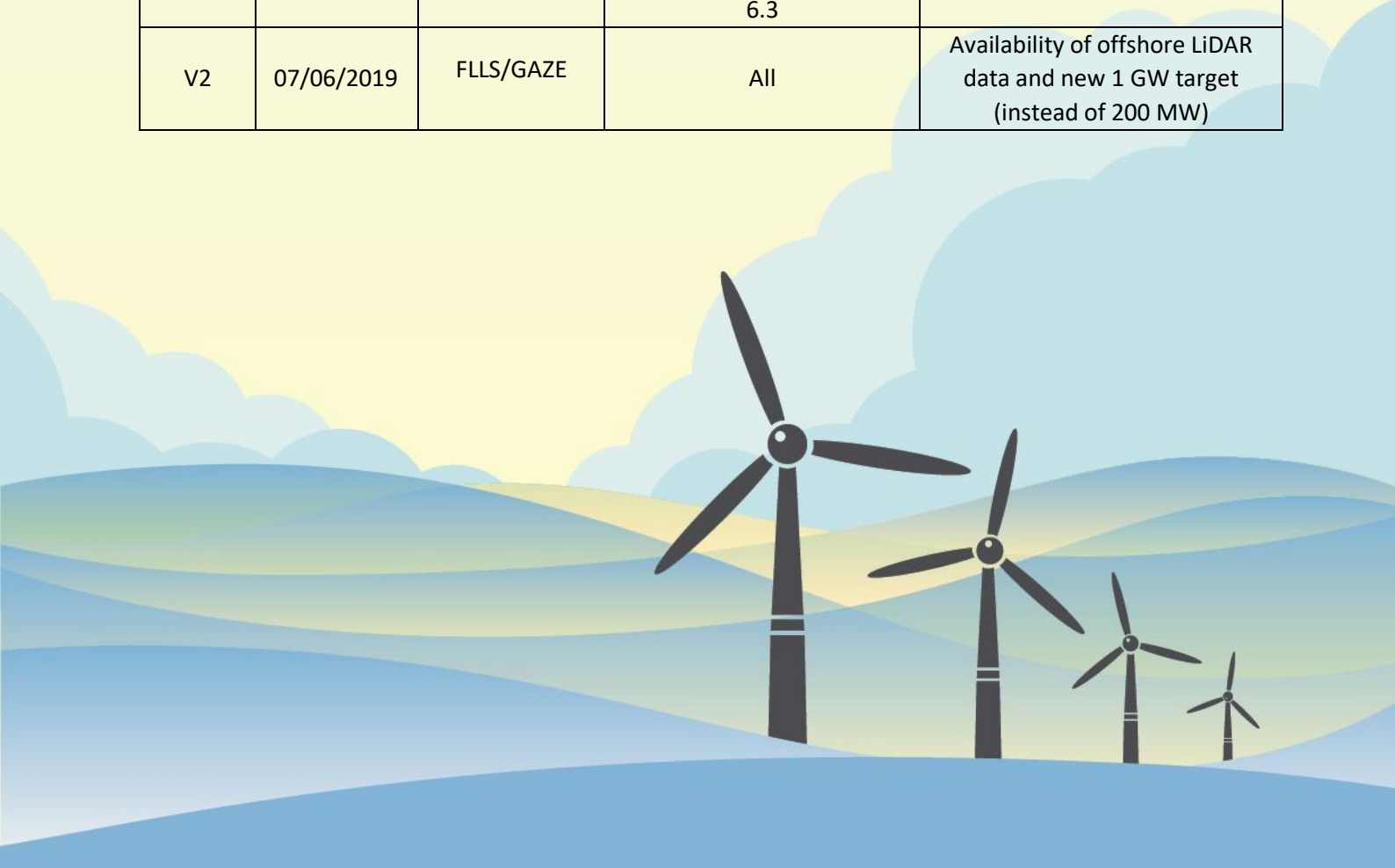
V2	07/06/2019	FLLS/GAZE	All	Availability of offshore LiDAR data and new 1 GW target (instead of 200 MW)



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FOWPI - WIND TURBINE, LAYOUT AND AEP

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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 plays an important role. At present levels, there are approximately 35 GWs of installed onshore wind power throughout the country. Numbers are quickly rising and by 2022 60 GWs of onshore wind is targeted to be installed 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 surpassed 18 GWs and numbers are continuously rising. Other countries that have installed offshore wind include China, USA and Taiwan. 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. After years of developments, offshore wind today can benefit from subsidy-free auctions in multiple mature markets.

This document, which is a revision of the previous report for a 200 MW offshore wind farm (Ref. /4/), has been prepared with the purpose of providing updated preliminary design and annual energy production estimates for the currently prospected 1 GW FOWPI offshore wind farm (OWF) near the coast of Gujarat. For such purpose, the report includes a wind resource study based on offshore LiDAR measurements and VORTEX synthetic data (Chapter 4), wind turbine technology and the definition of FOWPI reference 3 MW and 6 MW turbines (Chapter 5), the design of conceptual wind farm layouts for the 1 GW OWF and estimates of energy yield figures (Chapter 7) and economic optimization considerations of conceptual layouts (Chapter 8).

The currently presented preliminary study has been prepared by COWI for 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 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.

For the present study, 3 MW and 6 MW generic wind turbines have been used – as originally established during FOWPI inception. 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. It must be underlined, however, that these are only reference turbines, built based on commercially available models, and that the choice of the specific wind turbine is foreseen to rest as a choice of the project developer.

On-site LiDAR wind measurements have been carried out since November 2017, and in this report the wind resource at the FOWPI project area is assessed on the basis of the available LiDAR measurements published by NIWE and a 10 years VORTEX synthetic time series (virtual mast). Furthermore, wind data from the onshore Jafrabad coastal met mast has also been evaluated.

The analyses between the three sets of data shows that VORTEX ERA5 data reflects very well the LiDAR measurements. Thus, at this conceptual stage, it has been assessed that there is no need to carry out a (MCP) substitution of the missing LiDAR data by Jafrabad mast data or VORTEX data.

The LiDAR data has been primarily used to validate the VORTEX data, and based on this validation, the following corrections have been applied on the VORTEX data to comply with the wind speed measured at the LiDAR:

- VORTEX -> LiDAR:
  - 100 m AMSL: -0.7%
  - 80 m AMSL: -0.5%

Furthermore, a long-term correction of the 10 years VORTEX data has been carried out to obtain a wind distribution, which is representative for a 20 years period. The following long-term correction has been applied:

Long-term correction (10 -> 20 years): +0.9%

Consequently, the following combined correction has been applied on the 10 years VORTEX data extracted within the offshore site area:

- Combined correction on VORTEX wind speed:
  - 100 m AMSL: +0.2%
  - 80 m AMSL: +0.4%

Based on these corrected VORTEX data, the long-term average (arithmetic) wind speed at the offshore LiDAR position is given:

- Mean wind speed at 100 m ASL: 7.4 m/s

The wind resource horizontal distribution across the site based on VORTEX data is shown in Figure 2-1.

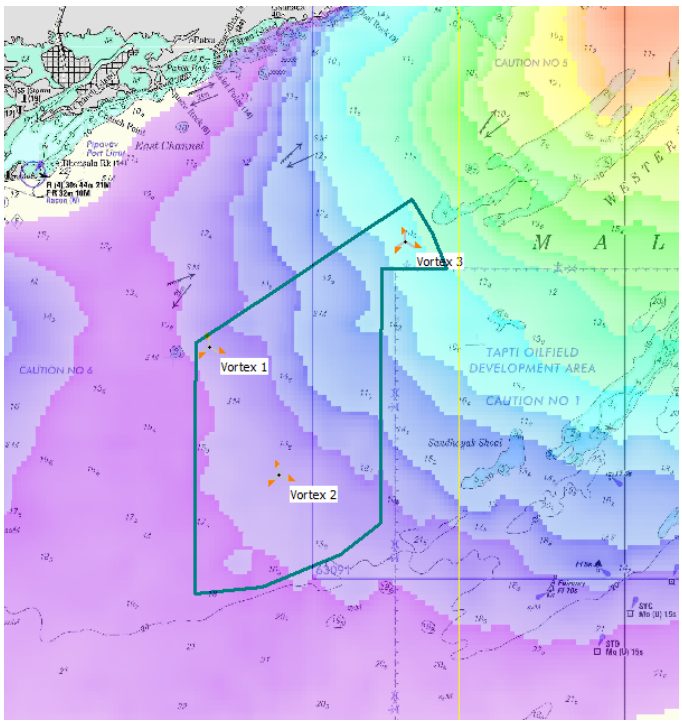


Figure 2-1 Wind resource distribution, site area/boundaries and VORTEX points. Wind speed is lowest in south-west and highest in north-east.

The corrected 10 years VORTEX data has been used to calculate the estimated long-term P50 net Annual Energy Production (AEP). Corresponding capacity factors based are for the 3 MW turbines 2868 GWh/y and 33% and for the 6 MW turbines 2327 GWh/y and 27%. Such results could be higher if e.g. point of coupling is assumed at offshore substation, instead of at onshore substation.

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. The base case wind turbine layouts are shown in Figure 2-2.

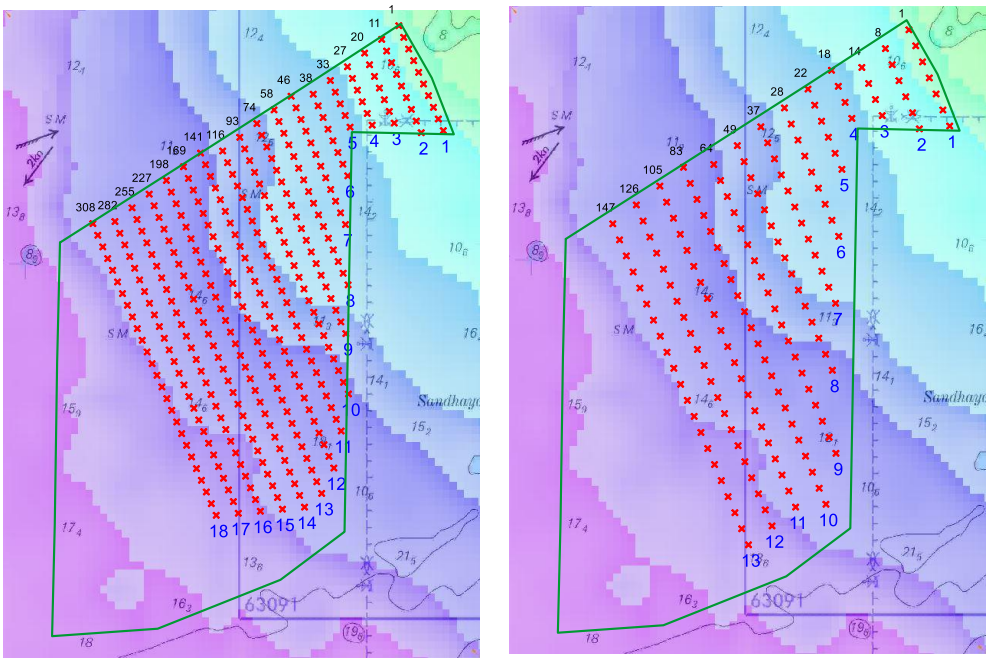


Figure 2-2 Base layouts: 333 x 3 MW (left) and 167 x 6 MW (right), base case. Site boundaries are illustrated by green polygon, turbine numbers by black digits and row numbers by blue digits. The background colours indicate the wind resource variation throughout the site – highest on north-easternmost corner.

An assessment has been carried out in order to evaluate possible economic gains/losses of alternatives to base layouts. Based on indicative electrical cabling & foundation costs, array losses and energy production estimates, it is found:

› No key advantages in shifting base layouts to the central area of the site, and thus eliminating the smaller rows of the north-east area.

› That the base case layout for the 6 MW turbine is fairly optimal. Results are nevertheless sensitive to the electricity tariff level and as the assumed tariff level increases, the economic benefit from larger spacings – in comparison to the base case - increases as well.

Soil conditions have not been considered in this report.

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, Version 1, September 2017. Report Nb. A073635-014-001

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

Ref. /4/ COWI, FOWPI - Wind Turbine, Layout and AEP, Version 1, September 2018. Report Nb. A073635-012-001

Ref. /5/ NIWE, Report on first LiDAR wind data analysis, December 2018.

Ref. /6/ NIWE, Report on data validation of offshore LiDAR, November 2016.

Ref. /7/ MeteoPole, LiDAR Installation and Maintenance report.
(merge of progress reports from May 2016 to September 2018)

Ref. /8/ Factual Report on Geotechnical Investigation for NIWE Project at Pipavav, 17th March 2017.

Ref. /9/ ERM, FOWPI – Environmental Scoping Report and Consent Register, Version 2, March 2019.

Ref. /10/ NIWE, EOI for Development of 1000 MW Offshore Wind Farm in Gujarat, 10.04.2018

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. 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 Expenditures
CRZ	Coastal Regulation Zone
D	Rotor diameter [m]
EU	European Union

FOWIND	Facilitating Offshore Wind in India
k	Form factor of the Weibull Distribution [-]
LAT	Low astronomical tide
MSL	Mean sea level (2.11 m LAT)
N.A.	Non available / Not applicable
NIWE	National Institute of Wind Energy
NM	Nautical Miles
NPV	Net Present Value
OWF	Offshore Wind Farm
O&M	Operations & Maintenance
WSW	West south west
WTG	Wind Turbine Generator

4 Site Boundaries and Wind Resource

Site boundaries have been defined by NIWE, in the call of Expressions of Interest (Ref. /10/), within the offshore development Zone B. The later, along with other offshore wind development zones in India, had been previously identified under the EU-funded FOWIND project (Ref. /3/).

For this study, wind speed data measured by the LiDAR measured from November 2017 to November 2018 has been made available. The LiDAR has been installed under the FOWIND project - by Meteopole - at the north-western corner of the proposed site area as shown Figure 4-1.

Furthermore, data from the onshore coastal Jafrabad met mast and VORTEX data have been made available for this study.

4.1 Site boundaries

Site boundaries are defined as shown in Figure 4-1, which also illustrates the LiDAR, the Jafarabad mast and VORTEX positions.

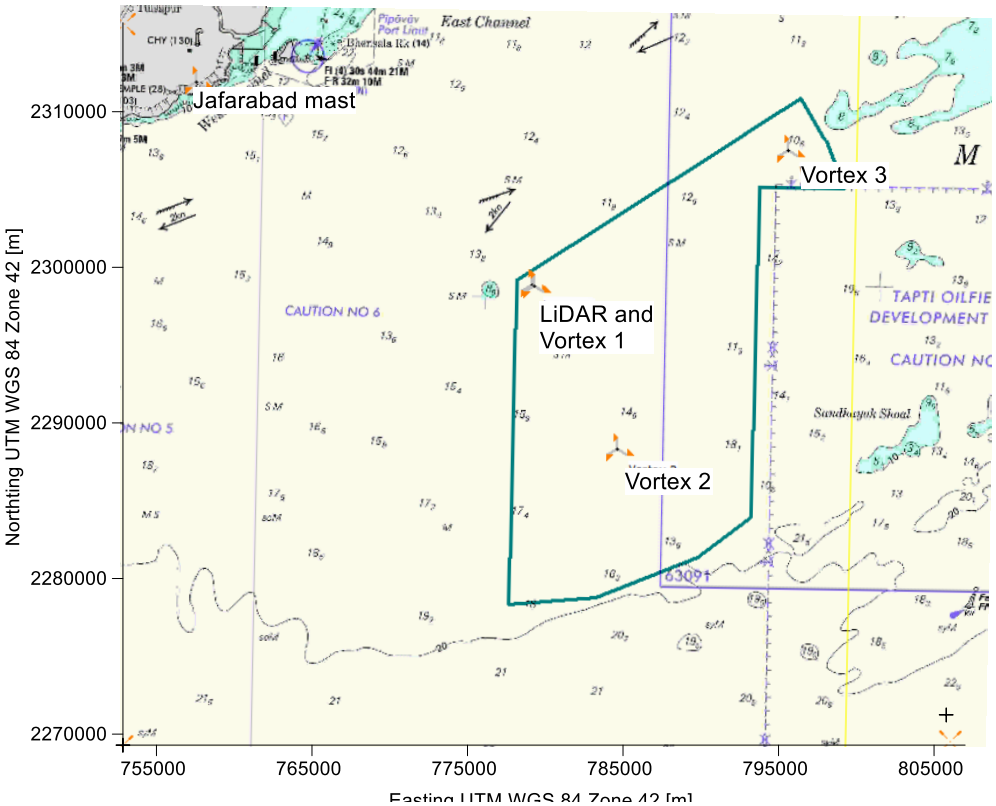


Figure 4-1 FOWPI site boundaries (green) and LiDAR, Jafarabad mast and VORTEX positions.

Site boundaries are further specified in Table 4-1.

SITE AREA POINT	EASTING	NORTHING
1	777274	2279026
2	782856	2279628
3	789276	2282462
4	792578	2285134
5	792365	2296266
6	792179	2306335
7	797594	2306419
8	796313	2309366
9	794566	2312172
10	789484	2308592
11	783647	2304548
12	776921	2299904
13	777004	2293591
14	777198	2284975

Table 4-1 Site boundaries coordinates (UTM WGS84, zone 42).

At the present stage, neither environmental and social impact assessments nor related surveys – such as for birds and marine mammals - have been carried out for the project. However, FOWPI Environmental and Social Screening and Scoping Study for the 1 GW area (Ref. /9/) has been performed to identify potential sensitivities associated with the site and project. Furthermore, it is expected that NIWE will carry out a Rapid EIA prior to the project tender.

It is noted that the site upper boundaries are at a distance closer than 12 Nautical Miles (NM) to the coastline, and thus CRZ clearance would be applicable for WTGs and associated components within the northern area of the site. Noting that CRZ clearance is in any case expected to be required for the wind farm subsea electrical cables and associated infrastructure, inclusion of WTGs within CRZ would not trigger significant additional requirements, if both the components are clubbed together. However, in case there are separate agencies involved for WTGs and power export infrastructure, then there may be a requirement of separate CRZ approvals which could impact project schedule. In this preliminary study, wind turbines are distributed both within and outside the CRZ area.

4.2 LiDAR Data

A Wind Cube LiDAR manufactured by Leosphere has been installed by Meteopole, under the FOWIND consortium, on an offshore platform located approx. 20 km from the coast as illustrated in Figure 4-1.

The Wind Cube LiDAR is a commonly used LiDAR for offshore and onshore wind resource measurements, and a validation report has been issued prior to the installation (Ref. /6/). The information about the LiDAR measurement has been provided by NIWE in its "Report on first LiDAR wind data analysis" Ref. /5/. Furthermore, an installation & maintenance report Ref. /7/ and a validation report Ref. /6/ have been made available.

The LiDAR position[1] is shown in Figure 4-1 and in Table 4-2. The measuring heights presented in Ref. /5/. refer to the platform, which is positioned 17 m above LAT and approx. 15 m above MSL. Since the turbine hub heights and VORTEX data heights refer to MSL, 15 m must be added to the provided LiDAR measuring heights in order to refer to MSL. The measuring heights are shown in Table 4-3.

EASTING	NORTHING
777858	2299719

Table 4-2 LiDAR position (UTM WGS84, zone 42) Ref. /8/.

MEASURING HEIGHTS (m)	
Above platform	MSL
40	55
60	75
70	85
80	95
87	102
100	115
107	122
120	135
140	155
160	175
180	195
200	215

Table 4-3 LiDAR measuring heights

[1] According to Ref. /8/. Please note that these coordinates deviate from the coordinates in Ref. /5/ by approx. 2.5 km, and Ref. /7/ does include information about the location.

The LiDAR data available for this study covers the period:

- LiDAR data period: 1 November 2017 to 30 November 2018

COWI's screening of the LiDAR data, the validation presented in Ref. /7/ and the comparison with VORTEX mesoscale data (section 4.5), indicates that the LiDAR wind speed data is of high quality. Nevertheless, it should be noted that COWI has not inspected the LiDAR. Furthermore, based on comparison with several re-analysis and mesoscale data sets, it has been revealed that the wind direction measured by the LiDAR most likely includes and offset error of approx. 20 degrees. This is probably due to a misalignment of the LiDAR north mark orientation. According to COWI's experience, the wind direction based on re-analysis and mesoscale data sets is normally in good agreement with the true (measured) wind direction.

Therefore, and since the received installation report does not include specific information about north mark alignment of the LiDAR, it has been decided for this study to use the VORTEX wind direction.

For further wind farm layout configuration studies, it is crucial to verify this potential misalignment of the LiDAR north mark orientation and to correct the LiDAR data accordingly. An inspection of the LiDAR to check the north mark is therefore strongly recommended.

The recovery of the LiDAR data is low during some periods as shown in Table 4-4 and therefore, wind data from the Jafarabad coastal mast and the VORTEX mesoscale data have been assessed for a possible substitution of the missing LiDAR data.

MONTH	MEASURING HEIGHTS (above platform)											
	40	60	70	80	87	100	107	120	140	160	180	200
Nov-17	68.3	68.3	68.3	68.3	68.3	68.3	68.3	68.3	68.3	68.3	68.3	68.3
Dec-17	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Jan-18	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8
Feb-18	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	99.8
Mar-18	97.1	96.9	96.9	96.9	96.8	96.6	96.3	95.8	95.4	95.1	94.5	93.9
Apr-18	100.0	100.0	100.0	99.9	99.9	99.8	99.8	99.7	99.7	99.7	99.1	98.0
May-18	100.0	100.0	100.0	99.9	99.9	99.9	99.9	99.9	99.8	99.7	99.2	98.6
Jun-18	99.9	99.5	99.3	98.9	98.6	98.3	98.3	97.6	97.4	97.2	97.0	96.9
Jul-18	38.7	38.2	37.6	37.0	36.6	36.2	35.7	35.3	34.8	34.4	34.1	34.1
Aug-18	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sep-18	35.4	35.4	35.4	35.4	35.4	35.4	35.4	35.4	35.4	35.4	35.4	35.4
Oct-18	96.7	96.6	96.5	96.5	96.5	96.4	96.4	96.4	96.4	96.3	96.3	96.3
Nov-18	97.9	97.7	97.5	97.5	97.4	97.4	97.3	97.3	97.3	97.3	97.2	97.1
All	71.2	71.1	71.0	70.9	70.8	70.8	70.7	70.6	70.5	70.4	70.2	70.0

Table 4-4 LIDAR data recovery in per cent

4.3 Jafrabad Coastal Mast

The Jafrabad coastal mast is located 28 km north west of the LiDAR position as shown in Figure 4-1 in Table 4-5. The measuring heights are shown in the last column in Table 4-5.

EASTING	NORTHING	MEASURING HEIGHTS
755899	2312112	20 m, 50 m, 80 m, 100 m

Table 4-5 Jafrabad mast position (UTM WGS84, zone 42) and measuring heights

Data from 1 November 2017 and up to 31 May 2018 has been available for this study.

4.4 VORTEX Data

The VORTEX data is 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 10 years. Output data are gathered with an hourly frequency sampling for different heights above the ground level (10 m intervals). The large-scale driver in the mesoscale calculation is data from Copernicus ERA5 (NEW) Reanalysis projects.

Initially, the data applied in the preliminary FOWPI AEP study (Ref. /4/) was based on VORTEX MERRA2 re-analysis data. However, for this study, a new set of VORTEX data based on ERA5 re-analysis data has been made available and applied. The analyses (elaborated in the subsequent Section 4.5) shows that

there is a much better correlation between the wind data measured by the LiDAR and the new set of VORTEX ERA5 data, than with the original MERRA2 VORTEX data. Therefore, as the new VORTEX ERA5 data is more representative than the original VORTEX MERRA2 data, VORTEX ERA5 is used throughout the analysis in this report.

The VORTEX ERA5 has been available covering the following 10 years and 9 months period for the subsequent analyses and AEP calculations:

- Basic wind data period: 01 January 2008 to 30 September 2018

To avoid seasonal bias, only 10 full years of data have been used.

4.5 Correlation between LiDAR data and Jafrabad mast data and VORTEX data

In order to assess whether the Jafrabad mast data and/or the VORTEX data (extracted at the LiDAR position) are applicable for substitution of the missing LiDAR data and also to assess if VORTEX data can be used as long-term reference, correlation analyses have been carried out between the three data sets.

The results are shown below presenting the correlation between the daily mean wind speeds at 100 m AGL (Jafrabad) and 100 MSL (VORTEX and LiDAR).

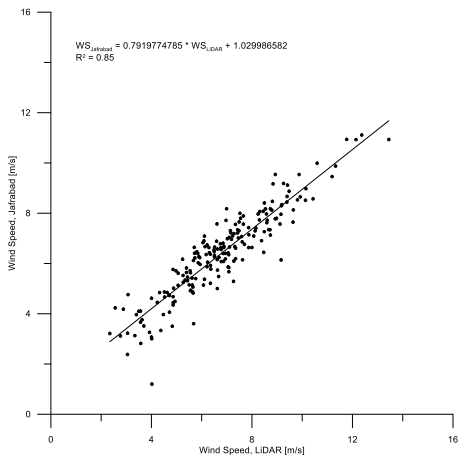


Figure 4-2 Correlation between daily mean wind speed, Jafrabad vs LiDAR

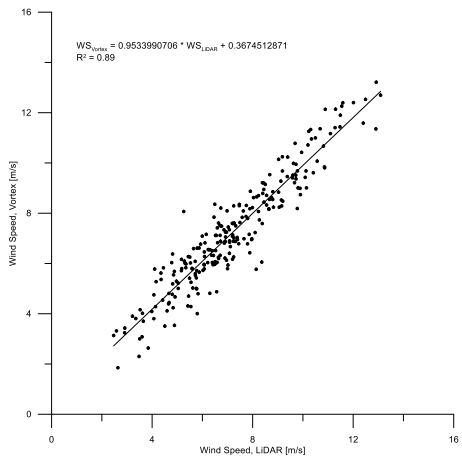


Figure 4-3 Correlation between daily mean wind speed, VORTEX vs LiDAR

It is seen that that there is slightly better correlation between the VORTEX data and LiDAR data than between the Jafrabad data and LiDAR data with the following correlation coefficients:

- Correlation coefficient Jafrabad /LiDAR, R^2: 0.85
- Correlation coefficient VORTEX / LiDAR, R^2: 0.89

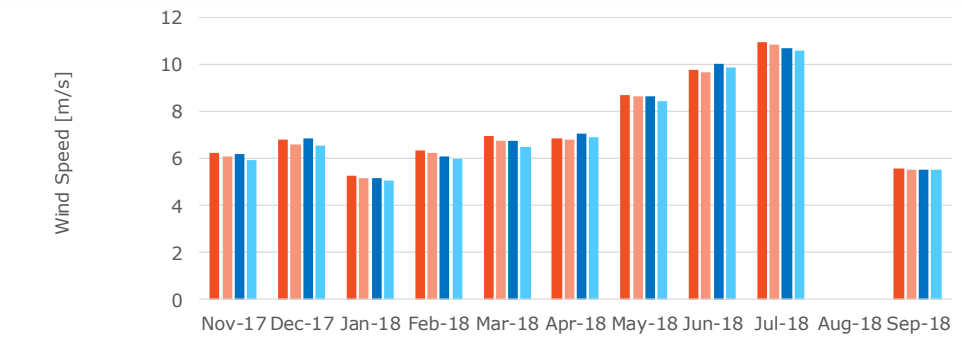
Furthermore, it is seen that the average wind speed based on the VORTEX data is only less than 1% higher than the averaged measured wind speed by the LiDAR for the overlapping period (not a full year):

- Average wind speed measured by the LiDAR at 100 m MSL: 7.34 m/s
- Average wind speed based on VORTEX data at 100 m MSL: 7.39 m/s
- Ratio LiDAR / VORTEX: 0.993

Similar results have been obtained at 80 m MSL:

- Average wind speed measured by the LiDAR at 80 m MSL: 7.19 m/s
- Average wind speed based on VORTEX data at 80 m MSL: 7.23 m/s
- Ratio LiDAR / VORTEX: 0.994

Figure 4-4 shows the monthly mean wind speeds and Figure 4-5 shows the measured wind distribution and Weibull fits based on respectively the LiDAR data and the VORTEX data. Only concurrent data is applied, i.e. gaps in LiDAR data are discarded in the VORTEX data.



	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Sep-18
LiDAR 100m	6.24	6.81	5.28	6.34	6.95	6.87	8.68	9.77	10.94	5.56
LiDAR 80m	6.07	6.59	5.18	6.26	6.78	6.81	8.63	9.69	10.86	5.54
Vortex ERA5 100m	6.21	6.86	5.17	6.11	6.75	7.08	8.63	10.05	10.69	5.54
Vortex ERA5 80m	5.96	6.55	5.04	5.99	6.49	6.93	8.45	9.88	10.59	5.52

Figure 4-4 Monthly mean wind speeds based on LiDAR and VORTEX data (concurrent)

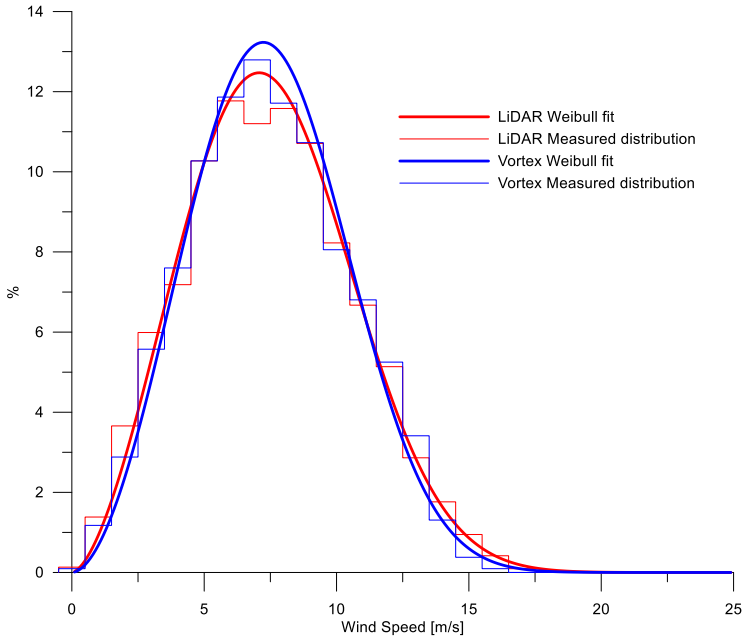


Figure 4-5 Measured distribution and Weibull fit, LiDAR and VORTEX data.

Results demonstrate that the VORTEX ERA5 data captures very well the actual wind speed measured by the LiDAR including the level, seasonal variations and distribution within one percent accuracy. Hence, based on the above results, it is decided not to carry out a (MCP) substitution of the missing LiDAR data. Instead, VORTEX data is directly used, after corrections (ref. section 4.13), to estimate the long-term wind resource at the FOWPI project site.

4.6 Basic wind distribution period

It is important that the basic wind distribution used for energy calculations represents a number of full years to avoid seasonal bias, and the following 10 years period has been applied as basic period for the further presented calculation results:

> Basic wind distribution period: 1 August 2008 to 31 July 2018

4.7 Wind Distribution

The wind distribution based on the 10 years VORTEX ERA5 data is presented in Table 4-6 and Table 4-7 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	8.49	2.722	100.0	7.56
N	7.91	3.590	9.5	7.13
NNE	8.23	3.709	15.7	7.43
ENE	5.86	2.566	7.1	5.21
E	3.95	2.220	2.2	3.50
ESE	3.54	1.748	1.1	3.15
SSE	3.60	1.260	1.0	3.34
S	5.41	1.839	1.9	4.80
SSW	8.08	3.119	7.6	7.23
WSW	10.53	3.913	28.6	9.54
W	9.01	3.106	14.2	8.06
WNW	6.82	2.748	5.9	6.07
NNW	7.10	2.832	5.4	6.32

Table 4-6: Wind distribution at 100 m ASL.

Sector	A-parameter [m/s]	k-parameter	Frequency [%]	Mean Wind Speed [m/s]
Mean	8.29	2.740	100.0	7.38
N	7.58	3.896	10.5	6.86
NNE	7.86	3.720	14.1	7.10
ENE	5.73	2.562	6.7	5.08
E	3.95	2.347	2.3	3.50
ESE	3.63	1.869	1.2	3.22
SSE	3.86	1.371	1.0	3.53
S	5.42	1.932	2.1	4.81
SSW	8.04	3.207	8.0	7.21
WSW	10.37	3.961	28.9	9.39
W	8.83	3.166	14.1	7.91
WNW	6.58	2.889	5.7	5.86
NNW	6.66	3.048	5.3	5.95

Table 4-7: Wind distribution at 80 m ASL.

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

- Weibull mean wind speed at 100 m AMSL, 10 years: 7.6 m/s
- Weibull mean wind speed at 80 m AMSL, 10 years: 7.4 m/s

The corresponding arithmetic mean wind speed are given by:

- Arithmetic mean wind speed at 100 m AMSL, 10 years: 7.4 m/s
- Arithmetic mean wind speed at 80 m AMSL, 10 years: 7.2 m/s

Figure 4-6 and Figure 4-7 show the all sector Weibull distributions. The red curves represent 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. In the AEP calculations the sector-wise Weibull distributions are used, and it is found that bias on the AEP due to the Weibull fits used corresponds to respectively -0.4% at 100 m and -0.8% at 80 m compared with using the time series data. Such bias is therefore corrected.

Figure 4-8 and Figure 4-9 show the wind (frequency) and energy roses. It is seen that the prevailing wind direction is WSW.

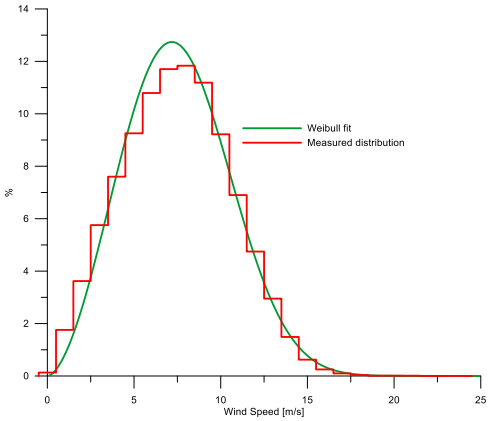


Figure 4-6: All sector Weibull distribution at 100 m ASL.

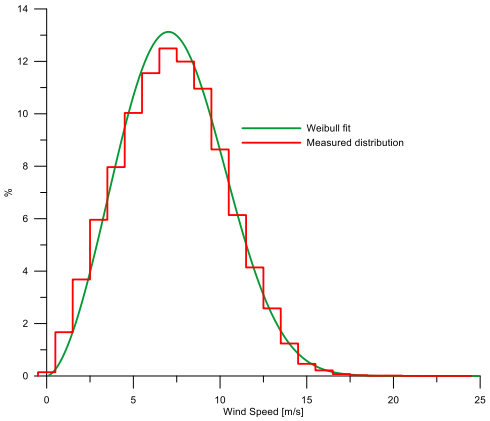


Figure 4-7: All sector Weibull distribution at 80 m ASL.

Frequency and Energy roses at 80 m are nearly identical to the roses at 100 m presented in Figure 4-8 and Figure 4-9.

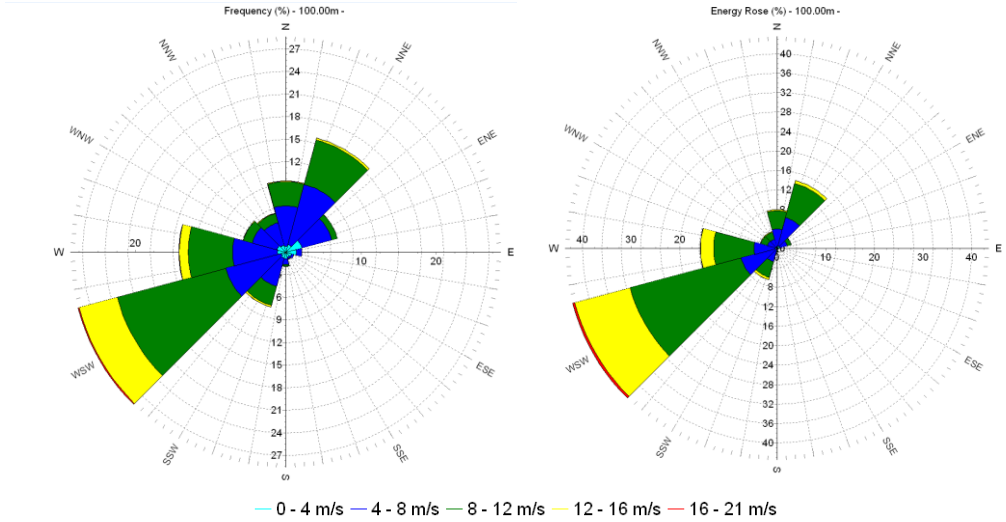


Figure 4-8 Frequency Rose at 100 m ASL. *Figure 4-9 Energy Rose at 100 m ASL.*

4.8 Daily Variations of Wind Speed

Figure 4-10 presents the average daily variations of the wind speed at 100 m and 80 m ASL based on the 10 years VORTEX ERA5 data. There is a significant diurnal variation between 6.2 m/s around noon and 8.1 m/s around midnight at 100 m.

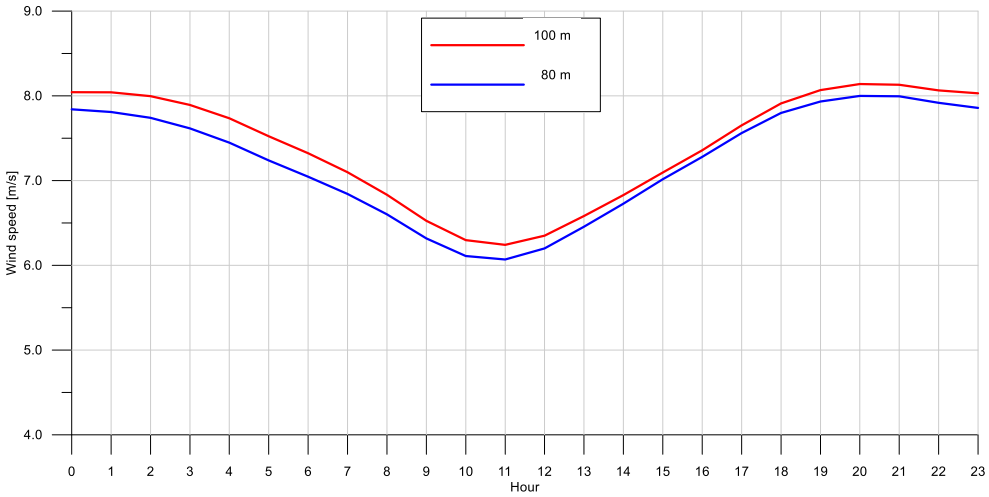


Figure 4-10: Average daily variation of the wind speed at 100 m and 80 m ASL.

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

4.9 Monthly variations of Wind Speed

Figure 4-11 presents the average monthly mean wind speeds at 100 m and 80 m ASL based on the 10 years VORTEX ERA5 data. The monsoon period is the high wind season from May to August. The lower wind season stretches from October to March.

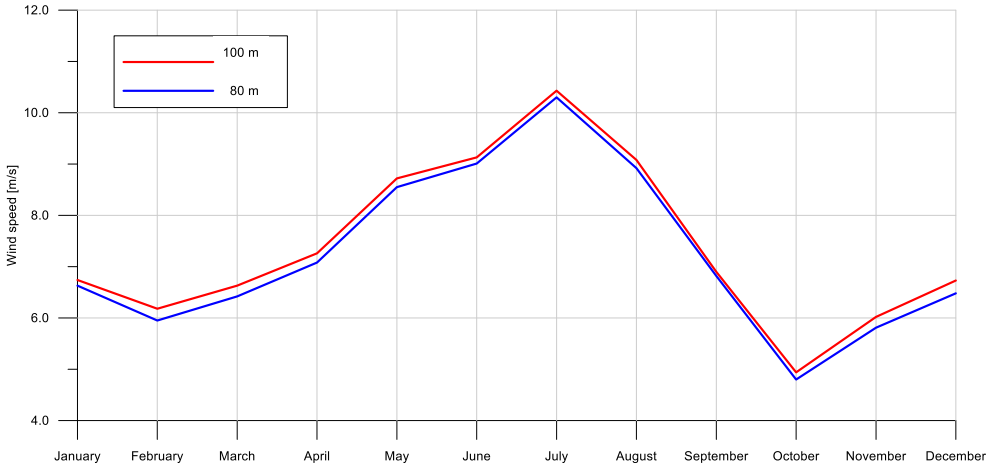


Figure 4-11 Monthly variation of wind speed.

4.10 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 1 year LiDAR data, for wind speeds measured from 55 m to 215 m ASL, the wind shear exponents are calculated and presented in Table 4-8 and Figure 4-12. The presented wind shear has not been used in the presented preliminary energy yield calculations, as the VORTEX data is available at 80 m and 100 m ASL, which is within 10 m of the reference turbine hub heights. Therefore, this section shall be considered as informative only.

It is seen that the wind shear exponent representing all directions and all day is 0.10, which is an expected value for offshore sites.

Sector	All	Day	Night
Mean	0.101	0.081	0.119
N	0.256	0.222	0.279
NNE	0.139	0.118	0.193
ENE	0.014	0.010	0.031
E	-0.029	-0.034	0.021
ESE	-0.070	-0.083	0.140
SSE	-0.130	-0.137	-0.056
S	-0.018	-0.026	0.019
SSW	0.062	0.048	0.075
WSW	0.049	0.017	0.053
W	0.025	0.109	0.008
WNW	0.283	0.352	0.281
NNW	0.176	0.214	0.152

Table 4-8 Wind shear exponents.

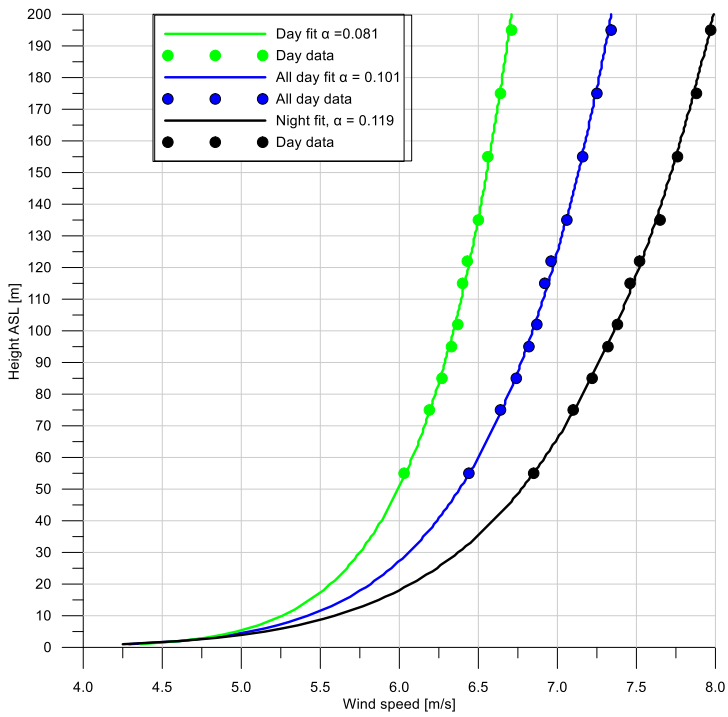


Figure 4-12: Wind shear based on LiDAR data and exponential fits.

It is seen that the day and night wind shear exponents are respectively lower and higher than the all-day wind shear exponent as expected.

4.11 Horizontal Wind Speed Distribution

The wind speed at offshore sites will vary depending on the distance to the coast due to e.g. land/see breeze effects but also parallel to the coast due to other thermal and topographic effect. Consequently, the wind resource will not necessarily be the same throughout the projected site area.

In order to assess this variation in the average wind speed, a 1 km resolution mesoscale modelling (VORTEX) has been carried out. The resulting resource map is shown in *Figure 4-13*[2].

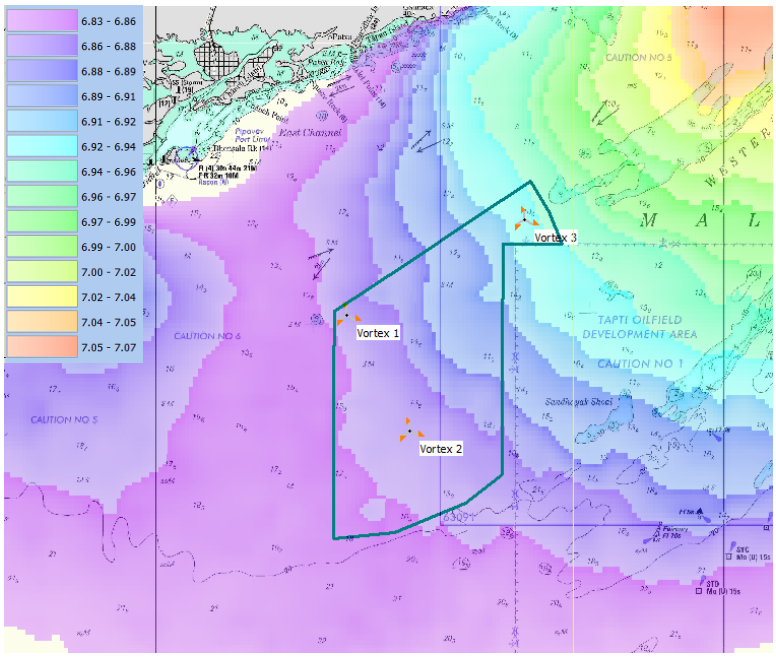


Figure 4-13 Wind resource distribution, site area and VORTEX points.

It is seen that the average wind speed varies a few per cent with the highest wind in the north-eastern part and the lowest wind in the south-western part.

As the map only includes information about the average wind speed and not the long-term wind distribution, two additional VORTEX time series (VORTEX 2 and 3) covering a short-term period representing the positions shown in Figure 4-1 have been used to the determine horizontal distribution of the wind resource throughout the proposed site. The three positions represented by the VORTEX data are shown together with the data heights in Table 4-9.

VORTEX SERIES	EASTING	NORTHING	HEIGHTS
1	777913	2299765	80 m and 100 m

[2] It should be noted that the presented wind resource map - produced to illustrate the horizontal wind distribution at the site - is based on a shorter data period and thus only representative of the distribution i.e. and not of the 20 years long-term average wind speed of the site.

2	783768	2289319	
3	793883	2308892	

Table 4-9 VORTEX positions (UTM WGS84, zone 42) and data heights

Correlations analyses between the wind speed representing respectively VORTEX position 1 and 2 and between 1 and 3 based on six months overlapping period covering 22 February to 22 August 2017, i.e. including both high and low wind periods, have been carried out. The result is presented by the weekly wind speeds at the two positions shown in Figure 4-14.

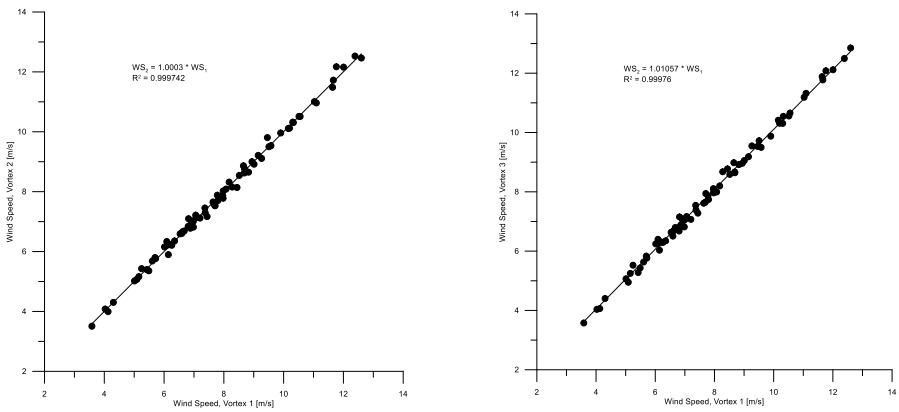


Figure 4-14 Correlations between the weekly average wind speed at VORTEX2 and VORTEX1 and between VORTEX3 and VORTEX1.

It is, as expected, seen that there are very good correlations and furthermore, it is seen that the wind speed at the VORTEX 2 point is almost identical with the wind the wind speed at the VORTEX 1 point, whereas the wind speed at VORTEX 3 point is approx. 1% higher than at VORTEX 1 point.

A sector-wise MCP analysis has been carried out to extend the short-term VORTEX 2 and VORTEX 3 time series to a 10 years basic period.

The resulting varying wind resource is applied and seen in the AEP calculations for the individual turbines shown in Table 8-4 and Table 8-5 in Appendix A.

4.12 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 applied wind data covers a sufficiently long period to represent the long-term average.

It is generally recommended to apply a reference period of 15 - 20 years for estimation of the long-term wind resource. Therefore, to assess whether the average wind speed based on the new 10 years VORTEX ERA5 period is representative for the long-term average, the originally sourced (Ref. /4/) VORTEX MERRA2 data covering a 20 years period is used.

To assess whether the VORTEX MERRA2 data is applicable as long-term reference for the VORTEX ERA5 data, a correlation analysis has been carried out between the two data sets. The results are shown in Figure 4-15 and Figure 4-16, and it is seen that there is a good correlation between the two data sets. Therefore, the 20 years VORTEX MERRA2 data can be used to assess to what extend the 10 years VORTEX ERA5 period is applicable as long-term reference.

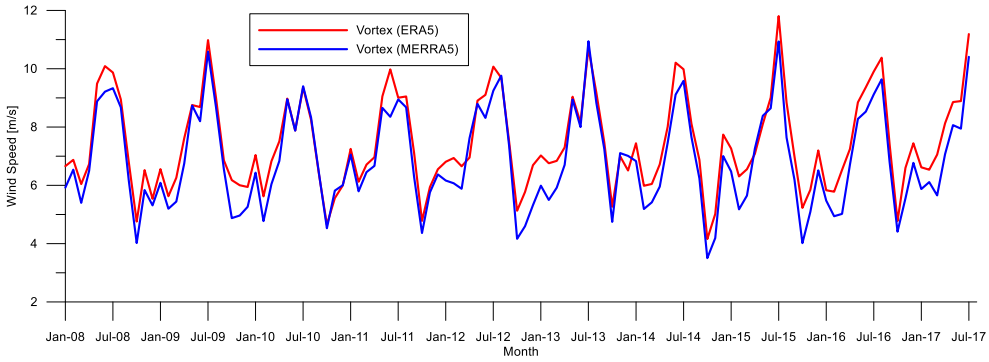


Figure 4-15 VORTEX monthly mean winds speed during the 10 years period January 2008 to December 2017

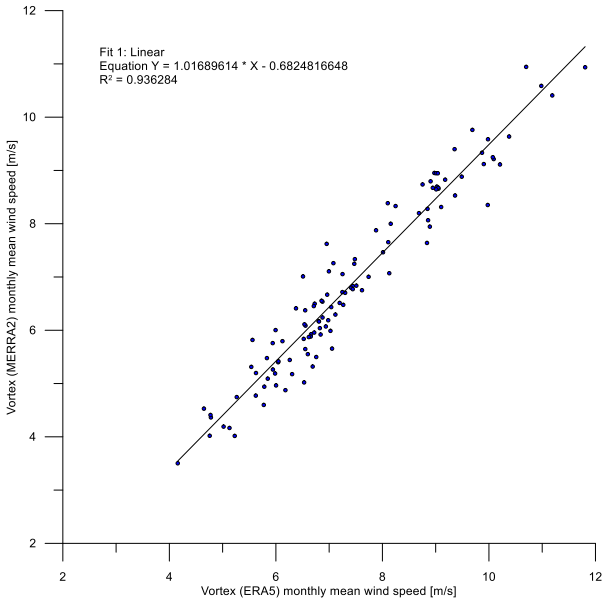


Figure 4-16 Correlation between monthly mean wind speeds based on VORTEX-MERRA2 and VORTEX-ERA5 data

However, re-analysis data must be handled carefully, as it is often seen that these 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 4-17 shows the VORTEX MERRA2 annual mean wind speeds during the period 1997 – 2016, and it is seen that there is no trend during the 20 years

[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

period. Therefore, it is assessed that a de-trending is not necessary before using the 20 years VORTEX MERRA2 data as long-term reference.

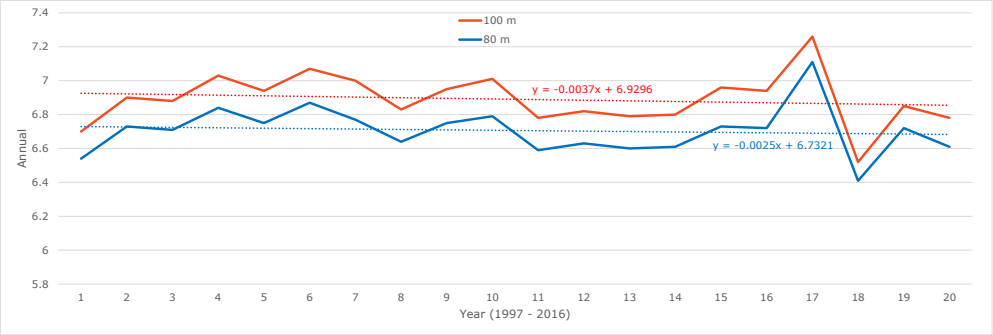


Figure 4-17: Annual mean wind speed based on VORTEX data.

The mean wind speed during respectively the 20 years period and the 10 years period based on the VORTEX MERRA2 data are given by:

- Mean wind speed, 10 years Jan 2008 - Dec 2007: 6.83
- Mean wind speed, 20 years Aug 1997 - Jul 2017: 6.89

This indicates that the mean wind speed has been 0.9% higher during the 20 years than during the 10 years. Therefore, the following long-term correction has been applied on the 10 years VORTEX ERA5 data:

- Long-term correction 20 / 10 years: 1.009

4.13 Combined correction on wind speed

Based on the results presented in sections 4.5, 4.7 and 4.12, the following corrections of the 10 years VORTEX wind speed used for the AEP calculations have been applied:

- VORTEX -> LiDAR:
  - 100 m AMSL: -0.7%
  - 80 m AMSL: -0.5%
- Long-term correction (10 -> 20 years): +0.9%
- Combined correction on VORTEX wind speed:
  - 100 m AMSL: +0.2%
  - 80 m AMSL: +0.4%

This correction on the wind speed is recalculated to a correction on the AEP based on the power curve and wind distribution.

5 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 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 5-1 (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 5-1 IEC design wind speed classes and turbulence categories.

It should be noted that the above IEC design classes in Table 5-1 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 and LiDAR data available, the annual average wind speed at the FOWPI site is very close class III (ref. section 4.7), and the turbulence intensity is expected to be low. Based on this, a class IIIB or IIB turbine with a relatively 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 specifically designed for typhoons may be required i.e. a so-called IEC class T[4].

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 5-1. 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. It should be noted 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. Therefore, the possibility of a turbine with a relatively large rotor suitable for the FOWPI site mean wind speed - but at the same time adapted for

[4] 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.

high extreme wind - should be evaluated so to maximize production. This could be obtained by increasing the strength of the components of a class II/III turbine, 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.

5.1 Definition of FOWPI Reference Wind Turbines

For FOWPI conceptual studies, 3 MW and 6 MW generic sample turbines have been defined upon project inception. 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, shall rest 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 5-2.

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

Table 5-2 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 5-1.

The power curves have been corrected according to the annual air density, which is estimated[5] 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.

[5] Based on long-term temperature and pressure data from Veraval met station. It should be verified by on-site measurement, when sufficient measurement data from the LiDAR platform is available.

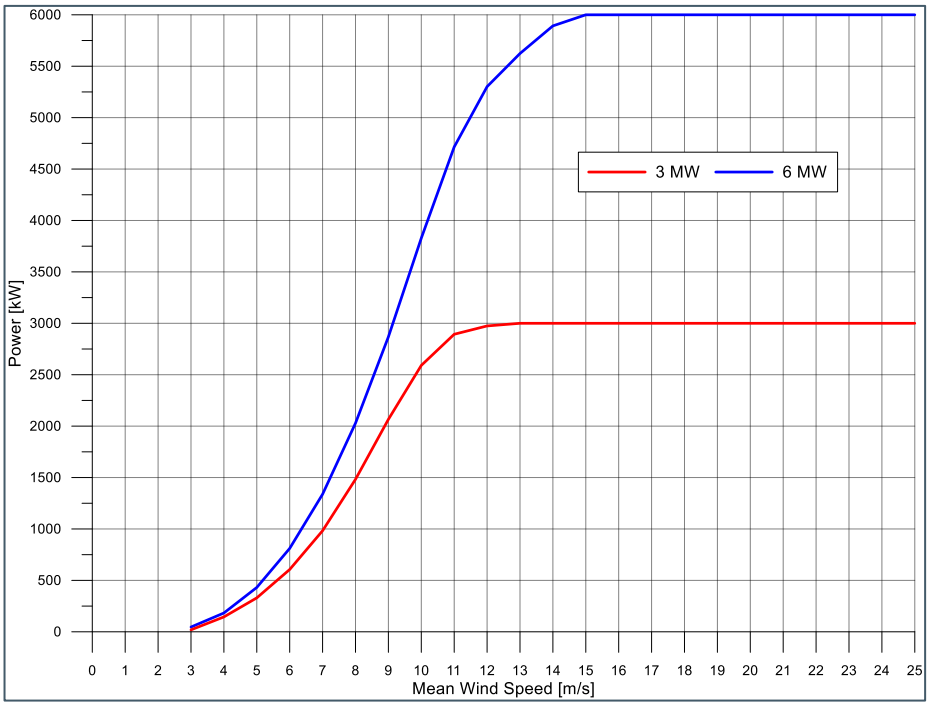


Figure 5-1 Generic 6 MW and 3 MW power curves.

It is noted that the normalized power curve for the generic 3 MW turbine, shown in Figure 5-2, is very comparable with more recently launched larger 4 MW platforms tailored designed handle high extreme wind in combination with relatively low mean wind speed. The normalized power curve for the 6 MW turbine, also shown in Figure 5-2, is more comparable with typical IEC Class I turbines designed for both high extreme and high mean wind speeds.

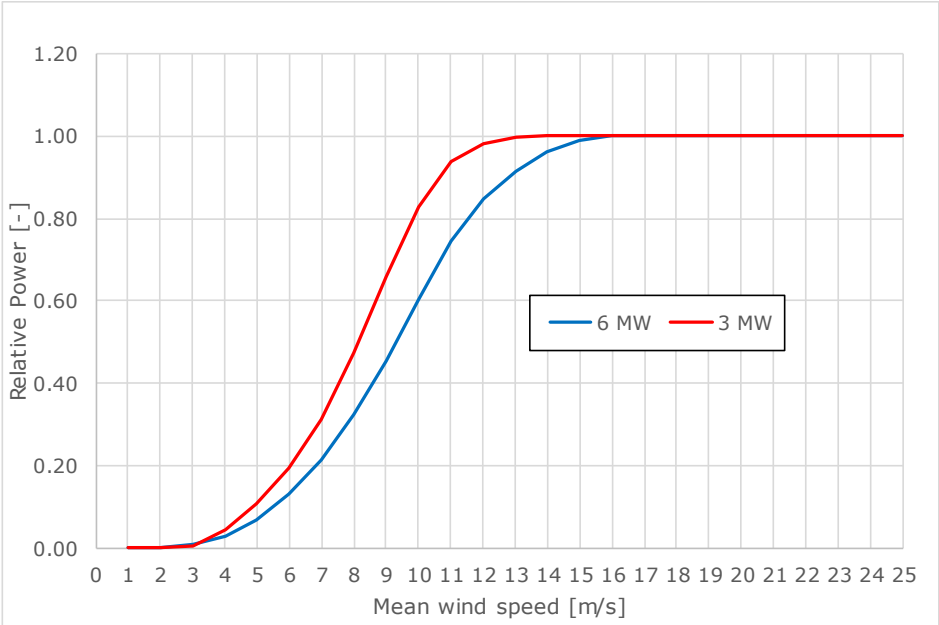


Figure 5-2 Normalized power curves for the generic 3 and 6 MW

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.

- 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.

6 Water Depth

Figure 6-1 (Ref. /2/) shows the water depths, and it is seen that within the projected site area the water depth varies from approx. 18 m to approx. 12 m, with the shallowest areas at the north-eastern corner of the projected site area.

The water depth has an influence on the foundation cost and therefore, indicate a benefit to locate as many turbines as possible in the north-eastern part of the projected site.

Fortunately, this supports that it would also be most feasible to exploit this part of the projected site due to the higher expected wind resource (see *Figure 4-13*).

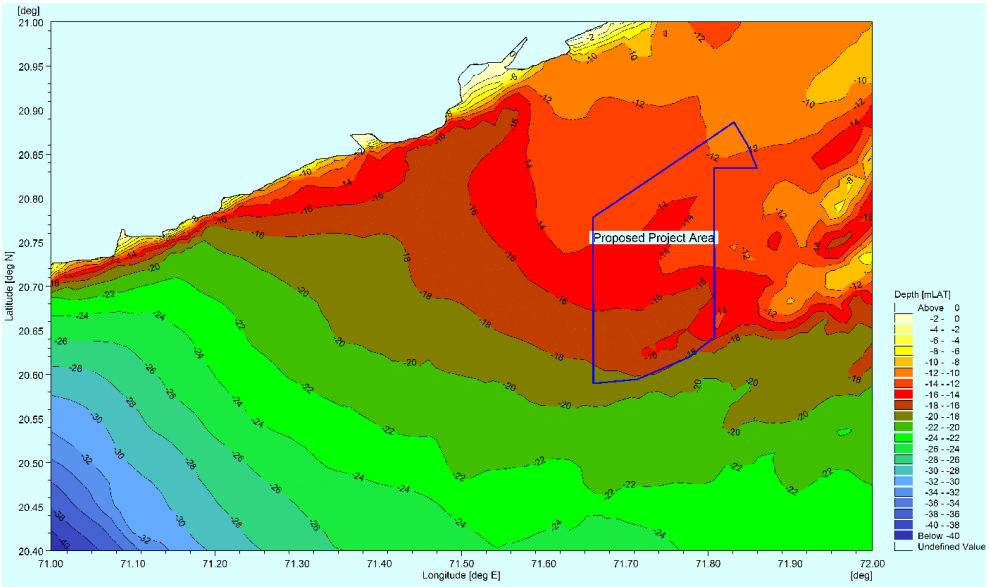


Figure 6-1 Water depths are extracted from MIKE C-Map and are given with respect to CD.

The average water depth is calculated for each of the layout scenarios considered in section 8.1.1 and 8.1.2

7 Base Layouts and Yield Estimates

In this chapter base layouts for both 3 MW and 6 MW reference turbines are defined. With an installed capacity of approx. 1 GW, the two layouts considered consist of respectively 333 3 MW turbines and 167 6 MW turbines.

Scenario	No of turbines	Size	Diameter	Hub height	In-row distance	Row Distance
1	333	3 MW	112 m	86 m	672 m	1120 m
2	167	6 MW	154 m	107 m	924 m	1540 m

Table 7-1: Wind farm layout scenarios, base case.

AEP estimates are thereafter calculated on the basis of VORTEX ERA5 10 years data validated against the on-site LiDAR data, the reference wind turbine models, the base layouts and the estimated corrections and losses.

7.1 Base layouts

In order to exploit the north-eastern part of the site, with the highest expected wind potential (section 4.11) and shallowest water (section 6), the base layouts are located as far as possible toward this part of the projected site area.

The base layouts within the site boundaries are shown in Figure 7-2 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 to minimize the wake loss. Furthermore, the layout is diagonal (i.e. in "zig-zag") so that e.g. the second row WTGs are not behind first row WTGs, downwind.

For the 3 MW and 6 MW FOWPI reference turbines this is translated into a 672 m x 1120 m and a 924 m x 1540 m spacing. For both reference turbines straight rows have been considered as shown in Table 7-1 and in Figure 7-2.

With a prevailing wind direction from WSW (see Figure 4-8 and Figure 4-9), the optimal row orientation will be approx. SSE – NNW. Based on an initial[6] optimization process, the wake loss has been calculated as a function of the row orientation. The result is shown in Figure 7-1, and it is seen that optimal row orientation is:

- Optimal row orientation: 156° / 336°

[6] Using a simple 3 x 21 turbine layout

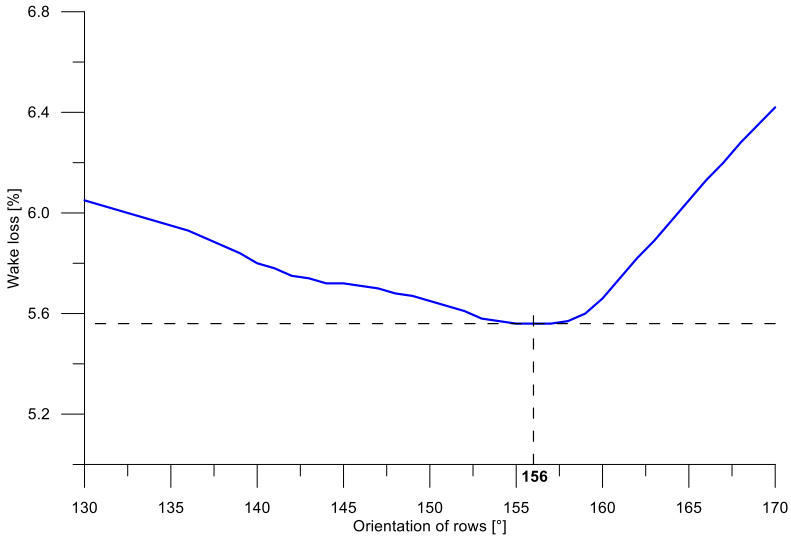


Figure 7-1 Wake loss as a function of the row orientation

The considered base layouts are shown in Figure 7-2.

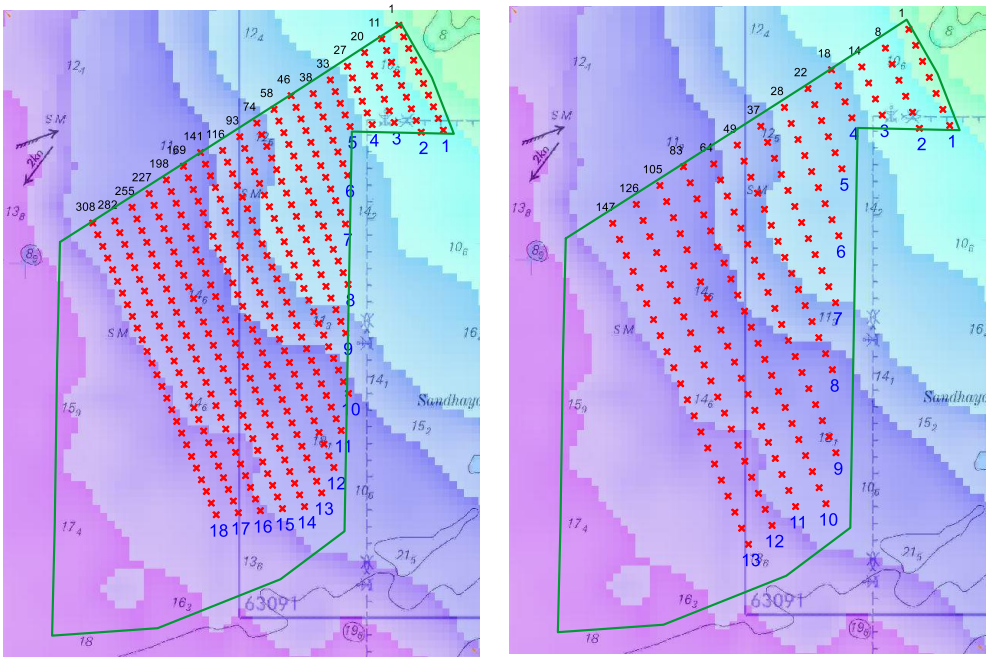


Figure 7-2 Base layouts: 333 x 3 MW (left) and 167 x 6 MW (right), base case. Site boundaries are illustrated by green polygon, turbine number by black digits and row number by blue digits. The background colours indicate the wind resource variation throughout the site.

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 8, further site investigations incl. geotechnical data and more detailed cost assessments.

7.2 Annual Energy Production

Based on the 10 years VORTEX synthetic data, 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 0.05[7] corresponding to offshore conditions has been applied in the calculations.

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. There hereby presented losses could be considerably lower if e.g. point of coupling is assumed at offshore substation, instead of at onshore substation.

The following combined corrections (see section 4.13) have been applied on the 10 years VORTEX wind speed:

- Combined correction on wind speed:
  - 80 m AMSL: +0.2%
  - 100 m AMSL: +0.4%

Depending on the power curve, this wind speed corrections are recalculated to the corresponding corrections on the AEP and combined with the Weibull fit correction (see section 4.7):

- Combined correction on AEP:
  - 3 MW turbines, 86 m hub height: -0.6%
  - 6 MW turbines, 107 m hub height: -0.2%

Table 7-2 and Table 7-3 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 VORTEX and LiDAR data.

[7] Default offshore wake decay constant. No deep array wake effect has been taken into account.

333 x 3 MW Turbines with 86 m (MSL) Hub Height		
Annual Gross Production for the 333 WTGs		3808.9 GWh/y
Wake Loss	14.4%	547.4 GWh/y
Annual Park Production for the 333 WTGs		3261.5 GWh/y
Combined Corrections	-0.6%	-19.0 GWh/y
Combined Estimated Losses	11.5%	374.4 GWh/y
Net Annual Production for the 333 3MW WTGs (P50)		2868.2 GWh/y
Full load hours		2871 h/y
Capacity Factor		32.8 %

Table 7-2 Long-term average production estimate and other key figures for the 333 x 3 MW wind turbines.

167 x 6 MW Turbines with 107 m (MSL) Hub Height		
Annual Gross Production for the 167 WTGs		3030.0 GWh/y
Wake Loss	13.0%	392.5 GWh/y
Annual Park Production for the 167 WTGs		2637.5 GWh/y
Combined Corrections	-0.3%	-6.6 GWh/y
Combined Estimated Losses	11.5%	303.8 GWh/y
Net Annual Production for the 33 WTGs (P50)		2327.1 GWh/y
Full load hours		2322 h/y
Capacity Factor		26.5 %

Table 7-3 Long-term average production estimate and other key figures for the 167 x 6 MW wind turbines.

It is seen that the capacity factor for the 333 x 3 MW turbines is larger than the capacity factor for 167 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 5.1.

The AEP calculations for the individual turbines are shown in Table 8-4 and Table 8-5 in Appendix A, where the decreasing wind resource towards southwest is seen. For instance, the gross AEP for the northernmost 3 MW turbine is 2.3% higher than for the southernmost.

7.3 Yearly and Monthly Variation of Energy Production

The annual mean wind speed varies from year to year, as seen in Figure 4-17. Consequently, the annual energy production varies too. Based on the 10 years VORTEX data, the standard deviation of the inter-annual mean speed variation is given by:

- Inter-annual wind speed variation: 2.5%

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
  - 3 MW turbines: 4.7%
  - 6 MW turbines: 5.5%

The monthly mean wind speed varies significantly as shown in Figure 4-11 and consequently, the monthly energy production (MEP) will vary significantly too. Based on the 10 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 5-1) – 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 7-3 and Figure 7-4.

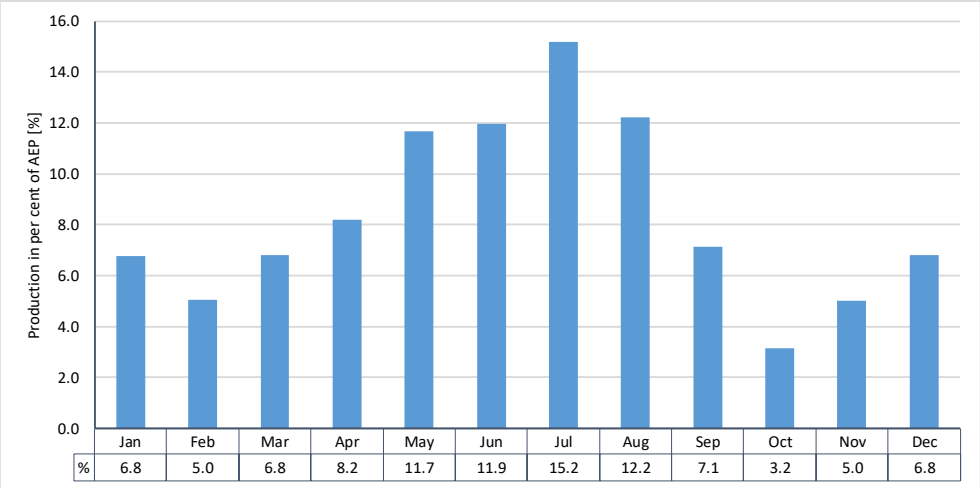


Figure 7-3 Average monthly production in percent, 333 x 3 MW turbines.

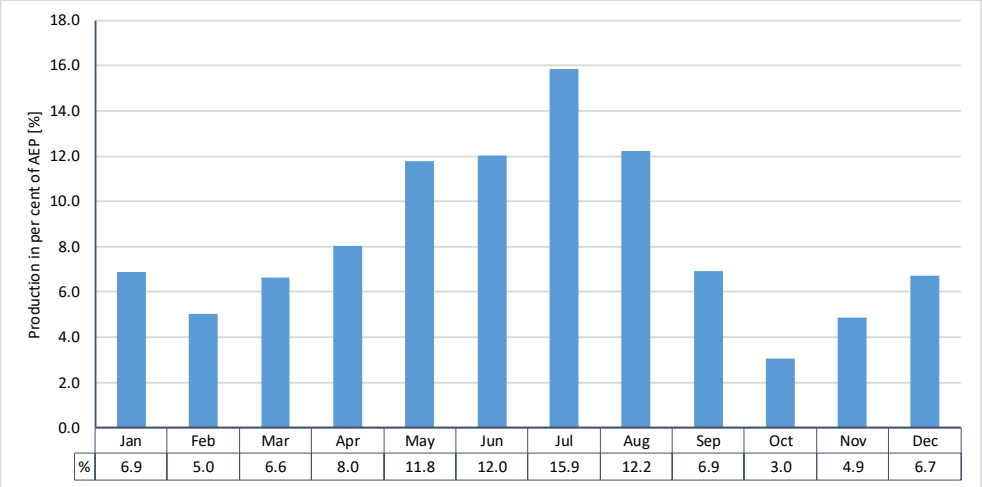


Figure 7-4 Average monthly production in percent, 167 x 6 MW turbines.

It is seen that – in average – respectively 51% and 52% of the AEP is produced during the four-month period from May to August by the 333 x 3 MW turbines and by the 167 x 6 MW turbines. This implicates, for instance, that O&M strategies could target low wind months to decrease wind turbine availability losses.

8 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 (e.g. due to more sea depth – if applicable), longer electrical cabling costs & losses and longer O&M routes.

In the following sections, alternatives to base layouts are explored. First, energy yield, water depth and array cabling length calculations are performed for multiple scenarios. Secondly, economic trade-offs are investigated based on various preliminary economic assumptions. Key results, which do not consider seabed conditions, are summarized in Table 8-3.

8.1 Technical considerations

8.1.1 Excluding small rows in base layout

For base layouts the most north-eastern part of the site - i.e. with the highest wind resource and shallowest water - was exploited resulting in relatively small rows of turbines in this part of the site (see Figure 7-2). This section estimates the impact on the energy level, water depth and array cabling by exploring the more central area of the site with longer and more symmetric rows as shown in Figure 8-1.

Two AEP calculations, similar to the ones presented for the base layouts in section 7.2, have been carried out, and the results are shown in Table 8-2 and Table 8-1 along with base cases.

It is seen that the AEP gross is reduced by respectively 0.2% and 0.5% for the 3 MW turbines and the 6 MW turbines. Furthermore, it is seen that the wake loss is increased by respectively 0.3% and 0.6% resulting in a reduction in the AEP Park[8] by respectively 0.6% and 1.1% compared with the base layouts.

The average water depths for the base layouts and the alternative layouts are shown in the last column of Table 8-2 and Table 8-1. It is seen that the average water depth of alternative layouts is less than 1 m larger than the average water depth of the base layouts. With regards to preliminary array cable length

[8] Including wake loss only

estimations, there is an increase in 26 km for the 6 MW turbines and a reduction of 2 km for the 3 MW.

Thus, based on such findings, it is demonstrated no potential benefit on shifting the base layouts to the more central area of the site - and thus excluding small rows of the base layouts.

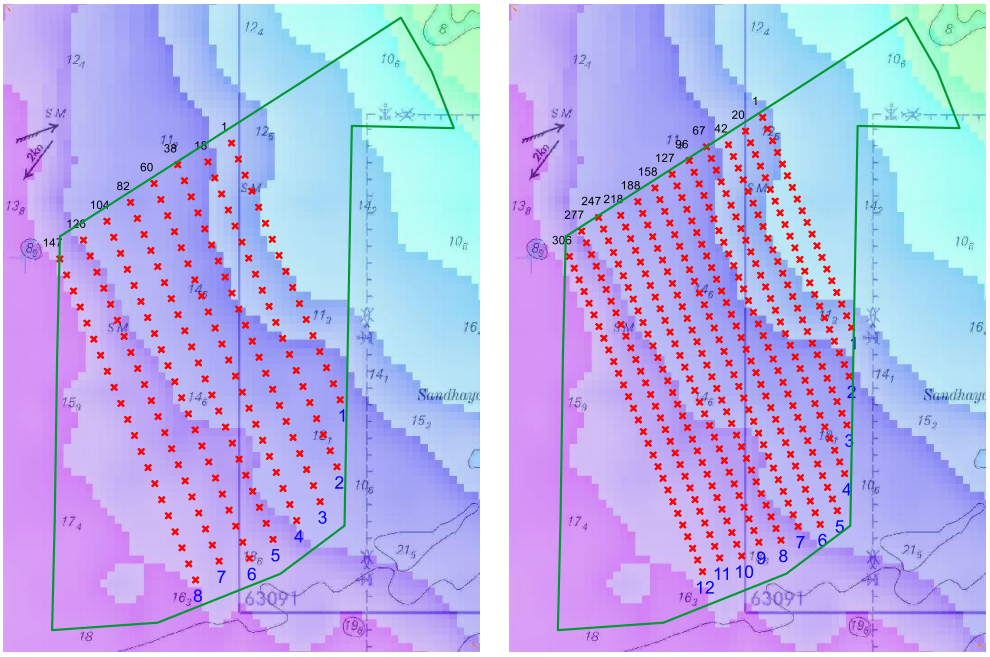


Figure 8-1 Alternative Layouts 2 i.e. smaller rows are excluded from north-eastern area of the site. 167 x 6 MW (left) and 333 x 3 MW (right).

	AEP Gross	Wake Loss	AEP Park	Average water depth	Cable Length
Base Layout	3030.0 GWh/y	12.95%	2637.5 GWh/y	14.1 m	161 km
Layout 2	3016.3 GWh/y	13.51%	2608.8 GWh/y	14.8 m	187 km
Difference	-0.5%	0.6%-point	-1.1%	0.7 m	26 km

Table 8-1 AEP Gross, wake loss, AEP Park, water depth and array cable lenght:167 x 6 MW turbines

	AEP Gross	Wake Loss	AEP Park	Average water depth	Cable length
Base Layout	3808.9 GWh/y	14.4%	3261.5 GWh/y	14.1 m	273 km
Layout 2	3801.2 GWh/y	14.7%	3243.2 GWh/y	14.7 m	271 km
Difference	-0.2%	0.3%-point	-0.6%	0.6 m	- 2 km

Table 8-2 AEP Gross, wake loss, AEP Park, water depth and array cable length: 333 x 3 MW turbines

8.1.2 Distances between WTGs

The wind farm internal wake loss is primarily dependent on the distances between the turbines in the wind farm layout and on the wind distribution at the site. In order to assess the impact of larger and smaller distances between turbines, this section considers the two alternative layout scenarios: 1) row distance and in-row distance increased to 12D x 7D and 2) row distance and in-row distance decreased to 9D x 5D. The layouts can be seen in Figure 8-2.

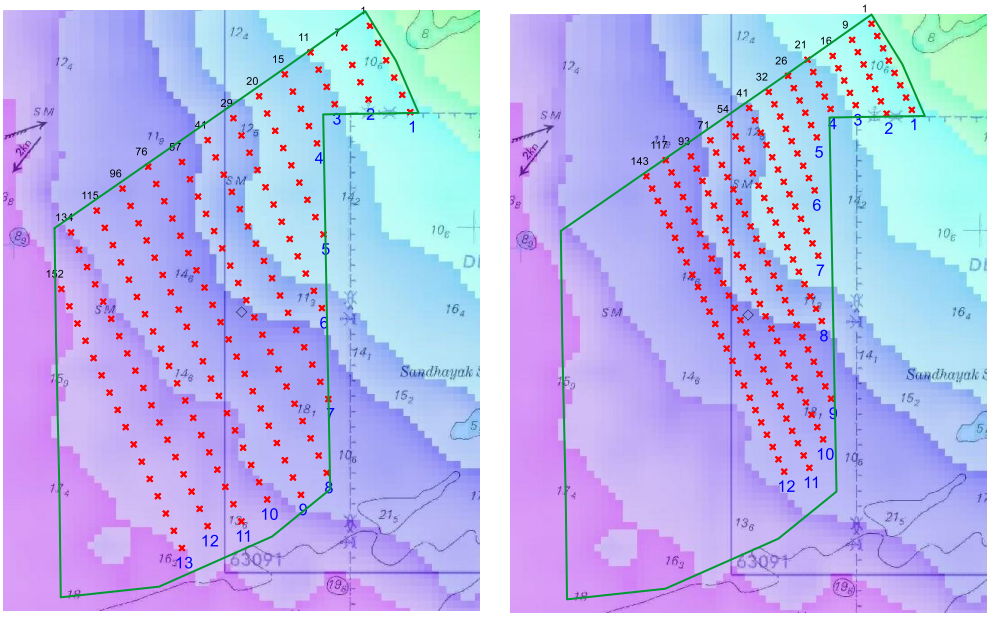


Figure 8-2 Layouts based on the 6 MW wind turbine with increased and decreased wind turbine spacing: 12D x 7D (left) and 9D x 5D (right).

The results are presented for the 167 6 MW turbines along with the results based on the base layout.

	AEP Gross	Wake Loss	AEP Park	Average water depth	Cable length
Base Layout	3030.0 GWh/y	13.0 %	2637.5 GWh/y	14.1 m	161 km
12D x 7D	3025.3 GWh/y	10.6 %	2705.4 GWh/y	14.4 m	221 km
9D x 5D	3034.6 GWh/y	15.0 %	2578.0 GWh/y	13.9 m	158 km

Tabel 8-1 AEP Gross, wake loss, AEP Park and water depth for 6 MW base, 12D x 7D and 9D x 5D layouts

It is seen that the wake loss decreases from 13.0% to 10.6% by increasing the turbines distances from 10D x 6D to 12D x 7D and consequently, the AEP Park increases by 2.6%. By decreasing the turbine distances to 9D x 5D, the wake

loss increases 2% and the AEP Park decreases by 2.3%. Similar results have been obtained for the 333 3 MW turbines.

One of the key disadvantages of increasing the wind turbine spacing in order to reduce the wake loss and consequently optimize the production is the longer array electrical cabling between the turbines. This will of course increase the investment costs, electrical losses and thus reduce the positive impact of increased spacing. Preliminary array cable lengths estimates are also illustrated in the results table, where it is indicated a substantial increase in required cabling for the layout with more spacing i.e. 12D x 7D.

8.2 Economic considerations

For an evaluation of possible economic gains/losses from alternative wind farm layouts with more or less spacing in between WTGs, with respect to the base case, the following assumptions are made:

- Marginal Foundation Cost incl. installation for entire farm: 15 m€/m
- Marginal Cable Cost incl. installation: 0.6 m€/km
- Marginal Electrical Cable Loss for entire farm: 400 MWh/km/year
- Tariff: 120 €/MWh[9]
- Economic lifetime: 25 years
- Discount rate: 12%
- O&M costs Not considered
- Soil conditions Not considered

The assumed foundation costs are the marginal costs, i.e. costs per additional meter of deployed foundation, assessed for the entire 1 GW wind farm. Likewise, the cable costs are also assessed in marginal terms, i.e. costs due to additional sub-sea cable length, for comparison with base case. 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.

8.2.1 Distances between WTGs

Table 8-3 includes a summary of results of two scenarios compared to each base layout: one with larger distances between turbines, designed to exploit a larger

[9] ≈9.4 INR/kWh.
N.B. This tariff is simply indicative and does not reflect any views on the expected tariff level.

extent of the site area, and another with smaller distances. 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, throughout the wind farm economic lifetime, which respect to the base scenario for the 6 MW WTG.

Scenario	Avg. Water depth [m]	Wake Loss [%]	AEP_{park}[10] [%]	Cable length[11] [km]	Energy Balance[12] [GWh/y]	ΔNPV [m€]
Base 6 MW	**0**	**13**	**100%**	**0**	**0.0**	0.0
12D x 7D	0.3	10.6	102.6	60	43.9	0.5
9D x 5D	-0.2	15.0	97.7	-3	-58.3	-44.3

Table 8-3: Water depth, wake loss, windfarm production, cable length and energy balance depending on layout configuration (base case shown in bold).

Based on the preliminary assumptions, the results presented in Table 8-3 suggest significant economic losses for 9D x 5D layout with less spacing and marginal economic gains for 12D x 7D layout with more spacing. Potential gains in NPV for the 12D x 7D scenario are however very small – i.e. in the order of 0.5 million euros – and within the uncertainty range of the input assumptions. The spacing of the base layout is thus found to be fairly optimal, although certainly subject to more detailed investigations and updates based on detailed project design.

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.
- The higher assumed the tariff level, the higher the economic benefit of the 12D x 7D layout. Conversely, the benefit of larger spacings in between turbines decreases as the assumed tariff level decreases.
- By increasing assumptions on marginal cabling costs and losses by 20%, the ΔNPV of the 6 MW 12D x 7D layout becomes negative by 10 m€.

[10] In per cent compared with base case

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

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

Further optimization exercises could consider scenarios with longer distances between rows – i.e. given the predominant wind direction at the site – in additional to soil conditions, more detailed economic estimates, etc.

Appendix A Layout and Energy Production

Table 8-4 and Table 8-5 present the results of the calculations of the energy production for respectively the 333 3 MW wind turbines and the 167 6 MW turbines. The coordinates (X, Y) are in UTM WGS 84 Zone 42.

WTG No.	X [m]	Y [m]	AEPGross [MWh]	Wake loss [%]	Loss & Correction [%]	AEPNet [MWh]
1	794462	2312069	11543.1	5.8	-12.1	9564.4
2	794748	2311460	11533.6	9.4	-12.1	9191.3
3	795033	2310852	11589.1	10.8	-12.1	9092.5
4	795318	2310243	11571.9	11.6	-12.1	8993.5
5	795603	2309635	11572.9	11.9	-12.1	8964.5
6	795888	2309026	11576.6	11.9	-12.1	8973.6
7	796173	2308418	11521.8	11.5	-12.1	8962.9
8	796458	2307809	11483.3	10.7	-12.1	9016.3
9	796744	2307201	11504.9	9.2	-12.1	9183.6
10	797029	2306592	11485.8	6.8	-12.1	9408.5
11	793582	2311309	11519.3	6.5	-12.1	9472.4
12	793867	2310701	11599.6	11.2	-12.1	9062.4
13	794152	2310092	11592.6	13.0	-12.1	8869.5
14	794437	2309484	11599.1	14.0	-12.1	8774.0
15	794722	2308875	11587.8	14.4	-12.1	8725.9
16	795007	2308266	11598.0	14.3	-12.1	8743.2
17	795292	2307658	11562.0	13.2	-12.1	8823.2
18	795577	2307049	11485.8	10.8	-12.1	9009.4
19	795862	2306441	11503.2	9.6	-12.1	9149.1
20	792701	2310549	11572.3	6.8	-12.1	9479.3
21	792986	2309941	11592.2	12.1	-12.1	8959.9
22	793271	2309332	11593.3	14.1	-12.1	8758.3
23	793556	2308724	11585.9	15.2	-12.1	8636.3
24	793841	2308115	11586.3	15.7	-12.1	8591.1
25	794126	2307506	11599.1	15.0	-12.1	8668.1
26	794411	2306898	11539.6	12.9	-12.1	8838.4
27	791820	2309789	11523.9	7.4	-12.1	9382.0
28	792105	2309181	11592.3	12.8	-12.1	8891.3
29	792390	2308572	11571.9	14.7	-12.1	8683.2
30	792675	2307964	11572.0	16.0	-12.1	8546.1
31	792960	2307355	11563.5	16.2	-12.1	8518.4
32	793245	2306746	11484.1	14.8	-12.1	8604.6
33	790939	2309029	11556.2	8.3	-12.1	9318.9
34	791224	2308421	11547.2	13.3	-12.1	8808.3
35	791509	2307812	11530.1	15.3	-12.1	8589.2
36	791794	2307204	11532.4	16.4	-12.1	8474.9
37	792079	2306595	11535.3	17.0	-12.1	8420.3
38	790058	2308269	11525.8	9.5	-12.1	9174.5
39	790343	2307661	11520.3	13.7	-12.1	8737.9

WTG No.	X [m]	Y [m]	AEPGross [MWh]	Wake loss [%]	Loss & Correction [%]	AEPNet [MWh]
40	790628	2307052	11523.0	15.6	-12.1	8550.1
41	790913	2306444	11531.0	16.7	-12.1	8448.7
42	791198	2305835	11524.7	17.3	-12.1	8382.8
43	791483	2305226	11523.8	17.2	-12.1	8386.3
44	791768	2304618	11518.2	16.6	-12.1	8444.0
45	792053	2304009	11494.9	16.2	-12.1	8474.4
46	788892	2308118	11502.2	6.3	-12.1	9479.7
47	789177	2307509	11510.3	10.4	-12.1	9065.0
48	789462	2306901	11518.0	14.0	-12.1	8712.0
49	789747	2306292	11499.1	15.8	-12.1	8518.5
50	790032	2305683	11507.7	16.8	-12.1	8416.9
51	790317	2305075	11506.2	17.3	-12.1	8362.8
52	790601	2304466	11529.9	17.6	-12.1	8356.0
53	790886	2303858	11526.1	17.5	-12.1	8360.8
54	791171	2303249	11528.1	17.2	-12.1	8389.8
55	791456	2302640	11482.4	16.7	-12.1	8414.6
56	791741	2302032	11478.1	15.7	-12.1	8512.5
57	792026	2301423	11466.8	15.1	-12.1	8556.2
58	788011	2307358	11521.5	6.9	-12.1	9434.7
59	788296	2306749	11522.7	11.7	-12.1	8943.0
60	788581	2306141	11523.8	14.4	-12.1	8670.0
61	788866	2305532	11520.1	16.1	-12.1	8504.3
62	789150	2304923	11514.5	17.0	-12.1	8405.5
63	789435	2304315	11506.5	17.5	-12.1	8344.1
64	789720	2303706	11484.9	17.8	-12.1	8300.5
65	790005	2303098	11453.7	17.9	-12.1	8267.3
66	790290	2302489	11444.8	17.8	-12.1	8275.7
67	790575	2301880	11452.3	17.6	-12.1	8294.5
68	790860	2301272	11456.7	17.2	-12.1	8340.3
69	791145	2300663	11405.0	17.1	-12.1	8316.7
70	791429	2300054	11391.1	16.4	-12.1	8373.8
71	791714	2299446	11427.1	15.2	-12.1	8517.3
72	791999	2298837	11418.9	14.8	-12.1	8557.3
73	792284	2298229	11403.0	14.4	-12.1	8582.6
74	787130	2306598	11455.0	7.3	-12.1	9335.6
75	787415	2305989	11455.1	12.7	-12.1	8797.2
76	787700	2305381	11454.4	14.8	-12.1	8582.6
77	787984	2304772	11441.8	16.4	-12.1	8410.5
78	788269	2304163	11443.9	17.2	-12.1	8333.4
79	788554	2303555	11445.3	17.7	-12.1	8285.4
80	788839	2302946	11446.3	18.0	-12.1	8255.9
81	789124	2302337	11447.2	18.1	-12.1	8246.8
82	789409	2301729	11419.1	18.2	-12.1	8214.4
83	789693	2301120	11394.9	18.3	-12.1	8191.4

WTG No.	X [m]	Y [m]	AEPGross [MWh]	Wake loss [%]	Loss & Correction [%]	AEPNet [MWh]
84	789978	2300511	11419.4	18.0	-12.1	8231.3
85	790263	2299903	11412.0	17.8	-12.1	8249.9
86	790548	2299294	11391.6	17.7	-12.1	8248.8
87	790833	2298686	11398.0	17.2	-12.1	8303.8
88	791118	2298077	11400.4	16.9	-12.1	8335.3
89	791403	2297468	11405.6	16.6	-12.1	8368.1
90	791687	2296860	11406.5	15.9	-12.1	8431.6
91	791972	2296251	11408.3	14.8	-12.1	8547.3
92	792257	2295642	11393.9	14.3	-12.1	8588.3
93	786249	2305838	11445.5	8.2	-12.1	9242.9
94	786534	2305229	11445.4	13.1	-12.1	8745.9
95	786818	2304621	11441.7	15.2	-12.1	8528.1
96	787103	2304012	11406.9	16.6	-12.1	8364.3
97	787388	2303403	11378.2	17.4	-12.1	8262.1
98	787673	2302795	11375.3	17.9	-12.1	8215.6
99	787958	2302186	11387.9	18.1	-12.1	8197.4
100	788242	2301577	11423.9	18.3	-12.1	8211.3
101	788527	2300969	11421.5	18.3	-12.1	8201.0
102	788812	2300360	11395.3	18.4	-12.1	8174.4
103	789097	2299751	11398.5	18.3	-12.1	8185.3
104	789382	2299143	11403.0	18.2	-12.1	8199.8
105	789666	2298534	11403.9	18.2	-12.1	8205.5
106	789951	2297925	11408.3	17.9	-12.1	8233.1
107	790236	2297317	11408.2	17.8	-12.1	8247.2
108	790521	2296708	11408.4	17.5	-12.1	8272.0
109	790806	2296099	11397.2	17.4	-12.1	8279.3
110	791090	2295491	11377.3	16.8	-12.1	8321.1
111	791375	2294882	11376.3	16.6	-12.1	8347.7
112	791660	2294273	11384.0	15.8	-12.1	8426.7
113	791945	2293665	11401.3	14.6	-12.1	8564.4
114	792230	2293056	11438.3	14.1	-12.1	8641.5
115	792514	2292447	11434.7	13.7	-12.1	8676.3
116	785368	2305078	11403.9	9.4	-12.1	9081.2
117	785652	2304469	11412.8	13.6	-12.1	8669.2
118	785937	2303860	11392.8	15.5	-12.1	8460.7
119	786222	2303252	11410.3	16.7	-12.1	8356.9
120	786507	2302643	11409.2	17.4	-12.1	8288.7
121	786791	2302034	11391.5	17.8	-12.1	8233.5
122	787076	2301426	11390.6	18.1	-12.1	8205.1
123	787361	2300817	11396.3	18.2	-12.1	8193.7
124	787646	2300208	11401.9	18.3	-12.1	8187.5
125	787931	2299600	11402.6	18.4	-12.1	8182.8
126	788215	2298991	11403.5	18.4	-12.1	8183.6
127	788500	2298382	11409.3	18.4	-12.1	8190.7

WTG No.	X [m]	Y [m]	AEPGross [MWh]	Wake loss [%]	Loss & Correction [%]	AEPNet [MWh]
128	788785	2297774	11411.0	18.3	-12.1	8194.8
129	789070	2297165	11412.4	18.3	-12.1	8202.4
130	789354	2296556	11386.8	18.2	-12.1	8195.1
131	789639	2295948	11369.3	18.0	-12.1	8194.3
132	789924	2295339	11379.5	17.9	-12.1	8210.8
133	790209	2294730	11425.3	17.7	-12.1	8272.7
134	790493	2294122	11437.5	17.4	-12.1	8309.4
135	790778	2293513	11436.2	17.2	-12.1	8325.7
136	791063	2292904	11448.3	16.6	-12.1	8395.7
137	791348	2292296	11452.0	16.3	-12.1	8427.6
138	791633	2291687	11451.0	16.0	-12.1	8455.3
139	791917	2291078	11450.7	15.4	-12.1	8521.2
140	792202	2290470	11451.3	14.0	-12.1	8659.9
141	784202	2304926	11433.6	5.9	-12.1	9458.0
142	784486	2304318	11398.7	10.2	-12.1	8997.1
143	784771	2303709	11385.9	13.7	-12.1	8636.2
144	785056	2303100	11387.7	15.5	-12.1	8457.7
145	785341	2302492	11384.9	16.6	-12.1	8346.0
146	785625	2301883	11390.9	17.3	-12.1	8285.7
147	785910	2301274	11395.5	17.7	-12.1	8249.9
148	786195	2300666	11405.7	18.0	-12.1	8229.1
149	786480	2300057	11408.3	18.1	-12.1	8215.0
150	786764	2299448	11408.7	18.2	-12.1	8205.8
151	787049	2298839	11405.7	18.3	-12.1	8198.8
152	787334	2298231	11409.9	18.3	-12.1	8200.6
153	787618	2297622	11399.1	18.3	-12.1	8191.3
154	787903	2297013	11386.7	18.3	-12.1	8180.9
155	788188	2296405	11397.1	18.2	-12.1	8193.6
156	788473	2295796	11406.7	18.1	-12.1	8210.2
157	788757	2295187	11423.7	18.1	-12.1	8229.3
158	789042	2294579	11425.9	18.0	-12.1	8234.0
159	789327	2293970	11452.4	17.9	-12.1	8267.7
160	789612	2293361	11451.7	17.8	-12.1	8282.5
161	789896	2292753	11453.2	17.7	-12.1	8291.5
162	790181	2292144	11450.0	17.4	-12.1	8315.6
163	790466	2291535	11443.3	17.3	-12.1	8326.1
164	790750	2290926	11436.8	17.0	-12.1	8349.4
165	791035	2290318	11434.8	16.8	-12.1	8368.7
166	791320	2289709	11435.0	16.0	-12.1	8443.3
167	791605	2289100	11434.5	15.0	-12.1	8546.8
168	791889	2288492	11434.4	13.1	-12.1	8737.8
169	783320	2304166	11406.0	6.4	-12.1	9388.5
170	783605	2303558	11402.6	11.3	-12.1	8897.7
171	783890	2302949	11408.0	14.0	-12.1	8626.6

WTG No.	X [m]	Y [m]	AEPGross [MWh]	Wake loss [%]	Loss & Correction [%]	AEPNet [MWh]
172	784175	2302340	11407.8	15.6	-12.1	8468.4
173	784459	2301732	11388.5	16.6	-12.1	8356.1
174	784744	2301123	11382.4	17.1	-12.1	8294.8
175	785029	2300514	11380.1	17.5	-12.1	8258.1
176	785313	2299905	11389.4	17.7	-12.1	8242.2
177	785598	2299297	11399.9	17.8	-12.1	8237.3
178	785883	2298688	11403.7	17.9	-12.1	8232.9
179	786167	2298079	11384.3	18.0	-12.1	8210.9
180	786452	2297471	11379.9	18.0	-12.1	8204.3
181	786737	2296862	11416.4	18.0	-12.1	8235.4
182	787022	2296253	11402.7	18.0	-12.1	8226.1
183	787306	2295644	11420.6	17.9	-12.1	8241.8
184	787591	2295036	11427.6	17.9	-12.1	8250.3
185	787876	2294427	11441.7	17.9	-12.1	8263.0
186	788160	2293818	11437.3	17.9	-12.1	8261.5
187	788445	2293210	11429.2	17.8	-12.1	8259.4
188	788730	2292601	11435.1	17.7	-12.1	8270.8
189	789014	2291992	11437.9	17.7	-12.1	8279.1
190	789299	2291383	11444.2	17.6	-12.1	8293.3
191	789584	2290775	11445.3	17.4	-12.1	8312.2
192	789868	2290166	11445.6	17.2	-12.1	8329.3
193	790153	2289557	11445.5	17.1	-12.1	8345.4
194	790438	2288948	11445.7	16.5	-12.1	8405.2
195	790722	2288340	11445.6	15.9	-12.1	8467.7
196	791007	2287731	11439.1	14.5	-12.1	8605.1
197	791292	2287122	11438.2	11.8	-12.1	8874.8
198	782439	2303406	11424.9	6.5	-12.1	9395.5
199	782724	2302798	11425.2	11.7	-12.1	8871.4
200	783009	2302189	11425.4	14.0	-12.1	8639.3
201	783293	2301580	11428.5	15.5	-12.1	8491.7
202	783578	2300971	11429.7	16.3	-12.1	8412.8
203	783863	2300363	11430.3	16.8	-12.1	8359.6
204	784147	2299754	11386.5	17.2	-12.1	8294.7
205	784432	2299145	11380.9	17.3	-12.1	8272.5
206	784717	2298536	11373.3	17.5	-12.1	8253.6
207	785001	2297928	11384.8	17.5	-12.1	8255.2
208	785286	2297319	11417.4	17.5	-12.1	8278.5
209	785571	2296710	11418.3	17.6	-12.1	8275.8
210	785855	2296102	11411.2	17.6	-12.1	8270.7
211	786140	2295493	11429.3	17.6	-12.1	8285.0
212	786425	2294884	11437.1	17.6	-12.1	8291.4
213	786709	2294275	11411.9	17.6	-12.1	8271.9
214	786994	2293667	11428.6	17.5	-12.1	8286.4
215	787278	2293058	11430.9	17.5	-12.1	8289.7

WTG No.	X [m]	Y [m]	AEPGross [MWh]	Wake loss [%]	Loss & Correction [%]	AEPNet [MWh]
216	787563	2292449	11444.2	17.5	-12.1	8301.7
217	787848	2291840	11442.1	17.5	-12.1	8303.7
218	788132	2291232	11442.7	17.4	-12.1	8308.0
219	788417	2290623	11443.8	17.4	-12.1	8316.1
220	788702	2290014	11443.6	17.3	-12.1	8326.0
221	788986	2289405	11442.7	17.1	-12.1	8339.1
222	789271	2288797	11443.3	16.9	-12.1	8363.8
223	789556	2288188	11444.6	16.4	-12.1	8415.5
224	789840	2287579	11444.1	15.6	-12.1	8495.8
225	790125	2286971	11443.9	13.4	-12.1	8716.8
226	790410	2286362	11445.9	9.1	-12.1	9146.4
227	781558	2302646	11421.1	6.5	-12.1	9387.5
228	781843	2302037	11420.4	11.7	-12.1	8866.9
229	782127	2301429	11421.1	13.6	-12.1	8680.8
230	782412	2300820	11426.0	15.0	-12.1	8539.8
231	782697	2300211	11428.1	15.7	-12.1	8473.5
232	782981	2299602	11406.3	16.1	-12.1	8413.7
233	783266	2298994	11401.1	16.4	-12.1	8382.7
234	783550	2298385	11377.8	16.6	-12.1	8347.4
235	783835	2297776	11405.3	16.6	-12.1	8363.3
236	784120	2297167	11420.1	16.7	-12.1	8367.2
237	784404	2296559	11420.8	16.7	-12.1	8362.8
238	784689	2295950	11423.2	16.8	-12.1	8361.5
239	784974	2295341	11426.3	16.7	-12.1	8365.6
240	785258	2294732	11415.8	16.8	-12.1	8354.7
241	785543	2294124	11414.9	16.8	-12.1	8353.3
242	785827	2293515	11432.0	16.8	-12.1	8367.1
243	786112	2292906	11436.1	16.8	-12.1	8371.0
244	786397	2292297	11454.0	16.7	-12.1	8385.9
245	786681	2291689	11387.7	16.9	-12.1	8326.2
246	786966	2291080	11391.6	16.8	-12.1	8331.7
247	787250	2290471	11392.8	16.8	-12.1	8335.0
248	787535	2289862	11391.8	16.8	-12.1	8339.5
249	787820	2289254	11393.9	16.7	-12.1	8349.6
250	788104	2288645	11392.6	16.5	-12.1	8365.7
251	788389	2288036	11412.0	16.2	-12.1	8406.9
252	788674	2287427	11478.7	15.5	-12.1	8534.1
253	788958	2286819	11442.9	13.8	-12.1	8677.4
254	789243	2286210	11444.2	9.7	-12.1	9087.5
255	780677	2301886	11368.4	6.5	-12.1	9346.4
256	780961	2301277	11370.3	10.7	-12.1	8924.3
257	781246	2300669	11359.5	12.6	-12.1	8728.9
258	781530	2300060	11389.0	13.6	-12.1	8656.6
259	781815	2299451	11396.8	14.2	-12.1	8603.7

WTG No.	X [m]	Y [m]	AEPGross [MWh]	Wake loss [%]	Loss & Correction [%]	AEPNet [MWh]
260	782100	2298842	11406.9	14.5	-12.1	8576.8
261	782384	2298233	11406.2	14.7	-12.1	8550.7
262	782669	2297625	11438.7	14.8	-12.1	8566.1
263	782953	2297016	11416.4	14.9	-12.1	8538.7
264	783238	2296407	11415.3	15.0	-12.1	8531.8
265	783523	2295798	11425.1	15.0	-12.1	8535.3
266	783807	2295190	11409.9	15.1	-12.1	8521.9
267	784092	2294581	11415.6	15.1	-12.1	8524.0
268	784376	2293972	11422.1	15.1	-12.1	8528.7
269	784661	2293363	11430.5	15.1	-12.1	8533.9
270	784946	2292755	11405.3	15.2	-12.1	8505.6
271	785230	2292146	11385.7	15.2	-12.1	8490.9
272	785515	2291537	11390.0	15.2	-12.1	8494.8
273	785799	2290928	11402.9	15.2	-12.1	8505.8
274	786084	2290320	11450.1	15.1	-12.1	8546.2
275	786368	2289711	11423.5	15.1	-12.1	8527.8
276	786653	2289102	11426.9	15.1	-12.1	8533.7
277	786938	2288493	11385.4	15.0	-12.1	8511.0
278	787222	2287884	11402.4	14.8	-12.1	8539.0
279	787507	2287276	11395.4	14.6	-12.1	8561.7
280	787791	2286667	11392.8	13.3	-12.1	8685.1
281	788076	2286058	11479.1	9.6	-12.1	9123.7
282	779795	2301126	11342.4	5.7	-12.1	9406.1
283	780080	2300517	11344.5	8.8	-12.1	9099.0
284	780364	2299908	11343.2	10.0	-12.1	8975.3
285	780649	2299300	11343.8	10.9	-12.1	8892.2
286	780934	2298691	11346.9	11.3	-12.1	8847.5
287	781218	2298082	11394.6	11.6	-12.1	8856.9
288	781503	2297473	11443.2	11.8	-12.1	8876.9
289	781787	2296864	11443.2	11.9	-12.1	8865.8
290	782072	2296256	11420.5	12.0	-12.1	8838.7
291	782356	2295647	11417.9	12.0	-12.1	8833.1
292	782641	2295038	11421.6	12.1	-12.1	8832.1
293	782925	2294429	11416.8	12.1	-12.1	8827.3
294	783210	2293821	11421.4	12.1	-12.1	8828.9
295	783495	2293212	11436.6	12.1	-12.1	8839.2
296	783779	2292603	11383.5	12.2	-12.1	8788.8
297	784064	2291994	11386.7	12.2	-12.1	8791.9
298	784348	2291385	11397.4	12.2	-12.1	8799.6
299	784633	2290777	11447.6	12.2	-12.1	8842.5
300	784917	2290168	11445.4	12.2	-12.1	8839.7
301	785202	2289559	11441.2	12.2	-12.1	8838.0
302	785486	2288950	11443.9	12.1	-12.1	8841.9
303	785771	2288342	11446.4	12.1	-12.1	8848.5

WTG No.	X [m]	Y [m]	AEPGross [MWh]	Wake loss [%]	Loss & Correction [%]	AEPNet [MWh]
304	786055	2287733	11432.5	12.0	-12.1	8844.0
305	786340	2287124	11426.1	12.0	-12.1	8844.5
306	786625	2286515	11372.3	11.5	-12.1	8852.9
307	786909	2285906	11389.3	8.9	-12.1	9124.9
308	778630	2300975	11350.3	0.7	-12.1	9912.9
309	778914	2300366	11355.4	2.2	-12.1	9769.8
310	779199	2299757	11344.7	4.1	-12.1	9567.3
311	779483	2299148	11336.8	5.0	-12.1	9469.4
312	779768	2298539	11345.5	5.7	-12.1	9408.5
313	780052	2297931	11349.3	6.1	-12.1	9373.2
314	780337	2297322	11397.7	6.3	-12.1	9390.3
315	780621	2296713	11439.9	6.5	-12.1	9405.4
316	780906	2296104	11451.4	6.6	-12.1	9406.1
317	781190	2295495	11421.5	6.7	-12.1	9373.7
318	781475	2294887	11412.8	6.7	-12.1	9362.9
319	781759	2294278	11412.6	6.7	-12.1	9362.3
320	782044	2293669	11419.7	6.7	-12.1	9364.8
321	782328	2293060	11420.9	6.8	-12.1	9363.2
322	782613	2292451	11384.9	6.8	-12.1	9329.1
323	782897	2291843	11391.0	6.8	-12.1	9334.2
324	783182	2291234	11398.5	6.8	-12.1	9338.3
325	783466	2290625	11443.4	6.8	-12.1	9377.8
326	783751	2290016	11477.6	6.8	-12.1	9409.8
327	784035	2289407	11458.1	6.7	-12.1	9395.8
328	784320	2288799	11477.9	6.8	-12.1	9411.8
329	784604	2288190	11468.9	6.7	-12.1	9405.2
330	784889	2287581	11437.5	6.8	-12.1	9374.6
331	785173	2286972	11435.8	6.8	-12.1	9376.9
332	785458	2286363	11412.9	6.7	-12.1	9360.9
333	785742	2285755	11372.3	6.6	-12.1	9337.5

Table 8-4 AEP Estimate for the 333 3 MW wind turbines.

WTG No.	X [m]	Y [m]	AEPGross [MWh]	Wake loss [%]	Loss & Correction [%]	AEPNet [MWh]
1	794707	2311667	18455.5	6.7	-11.8	15192.0
2	795099	2310830	18480.7	10.4	-11.8	14617.7
3	795491	2309993	18461.9	11.3	-11.8	14441.1
4	795883	2309157	18438.8	11.7	-11.8	14362.2
5	796275	2308320	18441.2	11.2	-11.8	14455.7
6	796667	2307483	18402.8	9.9	-11.8	14633.8
7	797059	2306647	18369.3	7.5	-11.8	14999.3
8	793496	2310622	18490.3	8.2	-11.8	14971.9
9	793888	2309785	18446.8	12.4	-11.8	14256.2
10	794280	2308949	18483.0	13.8	-11.8	14055.1

WTG No.	X [m]	Y [m]	AEPGross [MWh]	Wake loss [%]	Loss & Correction [%]	AEPNet [MWh]
11	794672	2308112	18409.9	13.5	-11.8	14044.5
12	795064	2307275	18422.0	11.5	-11.8	14388.0
13	795456	2306438	18402.9	10.4	-11.8	14548.7
14	792284	2309577	18482.8	9.5	-11.8	14752.1
15	792676	2308740	18442.7	13.7	-11.8	14038.6
16	793068	2307904	18442.7	15.0	-11.8	13831.3
17	793460	2307067	18446.6	13.9	-11.8	14013.7
18	790681	2309369	18420.1	6.2	-11.8	15243.2
19	791073	2308532	18435.4	10.6	-11.8	14542.7
20	791465	2307695	18441.6	14.3	-11.8	13946.4
21	791857	2306859	18433.6	15.9	-11.8	13681.4
22	789470	2308324	18426.6	6.7	-11.8	15161.6
23	789862	2307487	18440.4	11.9	-11.8	14334.4
24	790254	2306650	18443.6	14.8	-11.8	13871.6
25	790645	2305813	18409.6	16.4	-11.8	13585.8
26	791037	2304977	18236.1	17.1	-11.8	13341.6
27	791429	2304140	18142.0	16.7	-11.8	13335.6
28	788259	2307279	18295.9	7.1	-11.8	15004.4
29	788650	2306442	18232.2	12.8	-11.8	14033.2
30	789042	2305605	18185.4	15.3	-11.8	13596.0
31	789434	2304768	18170.8	16.8	-11.8	13345.7
32	789825	2303932	18113.5	17.5	-11.8	13190.5
33	790217	2303095	18106.9	17.6	-11.8	13167.6
34	790609	2302258	18163.5	17.1	-11.8	13290.8
35	791001	2301421	18173.3	16.1	-11.8	13454.9
36	791392	2300584	18182.5	15.6	-11.8	13544.2
37	787047	2306234	18233.9	7.5	-11.8	14884.0
38	787439	2305397	18213.6	13.3	-11.8	13925.1
39	787830	2304560	18215.6	15.3	-11.8	13607.5
40	788222	2303723	18216.3	16.9	-11.8	13362.2
41	788614	2302886	18173.1	17.5	-11.8	13223.2
42	789005	2302049	18168.9	17.7	-11.8	13191.4
43	789397	2301213	18136.4	17.8	-11.8	13160.0
44	789789	2300376	18128.2	17.4	-11.8	13215.2
45	790180	2299539	18130.3	17.1	-11.8	13256.1
46	790572	2298702	18138.1	16.4	-11.8	13375.8
47	790964	2297865	18133.9	15.2	-11.8	13560.1
48	791355	2297028	18178.4	14.7	-11.8	13680.1
49	785835	2305189	18199.8	8.4	-11.8	14714.1
50	786227	2304352	18165.2	13.5	-11.8	13859.9
51	786619	2303515	18161.2	15.6	-11.8	13520.5
52	787010	2302678	18169.8	16.8	-11.8	13342.0
53	787402	2301841	18137.9	17.4	-11.8	13215.0

WTG No.	X [m]	Y [m]	AEPGross [MWh]	Wake loss [%]	Loss & Correction [%]	AEPNet [MWh]
54	787793	2301004	18140.3	17.7	-11.8	13169.3
55	788185	2300167	18136.9	17.9	-11.8	13141.8
56	788577	2299330	18143.8	17.8	-11.8	13161.9
57	788968	2298493	18200.8	17.5	-11.8	13244.2
58	789360	2297657	18154.2	17.4	-11.8	13234.6
59	789751	2296820	18168.2	16.8	-11.8	13333.6
60	790143	2295983	18176.3	16.5	-11.8	13394.8
61	790535	2295146	18177.5	15.7	-11.8	13513.5
62	790926	2294309	18091.2	14.7	-11.8	13622.4
63	791318	2293472	18049.7	14.2	-11.8	13656.9
64	784624	2304144	18145.8	9.4	-11.8	14500.5
65	785015	2303307	18154.9	13.7	-11.8	13826.2
66	785407	2302470	18157.1	15.5	-11.8	13532.6
67	785798	2301633	18158.9	16.6	-11.8	13360.5
68	786190	2300796	18135.9	17.2	-11.8	13245.7
69	786581	2299959	18183.8	17.5	-11.8	13235.4
70	786973	2299122	18154.8	17.7	-11.8	13181.4
71	787365	2298285	18164.4	17.7	-11.8	13191.6
72	787756	2297448	18170.7	17.6	-11.8	13209.3
73	788148	2296611	18179.3	17.5	-11.8	13225.1
74	788539	2295774	18045.2	17.5	-11.8	13137.7
75	788931	2294937	18035.5	17.2	-11.8	13174.1
76	789322	2294100	18031.1	17.0	-11.8	13199.2
77	789714	2293263	17994.2	16.4	-11.8	13272.4
78	790105	2292426	17951.8	16.1	-11.8	13288.7
79	790497	2291589	17953.7	15.4	-11.8	13404.2
80	790888	2290752	18018.2	14.1	-11.8	13663.1
81	791280	2289916	18018.8	13.5	-11.8	13744.9
82	791671	2289079	18018.4	13.1	-11.8	13818.4
83	783021	2303936	18159.5	5.6	-11.8	15132.6
84	783412	2303099	18207.1	9.8	-11.8	14482.7
85	783804	2302262	18189.3	13.3	-11.8	13919.3
86	784195	2301425	18180.2	14.9	-11.8	13649.8
87	784587	2300588	18176.9	15.9	-11.8	13486.0
88	784978	2299751	18173.8	16.5	-11.8	13395.3
89	785369	2298914	18140.0	16.8	-11.8	13322.2
90	785761	2298077	18158.0	16.9	-11.8	13306.6
91	786152	2297240	18029.7	17.1	-11.8	13181.5
92	786544	2296403	18029.0	17.2	-11.8	13178.9
93	786935	2295566	18006.6	17.2	-11.8	13159.5
94	787327	2294729	17989.0	17.1	-11.8	13162.9
95	787718	2293892	18066.6	16.9	-11.8	13251.4
96	788110	2293055	18020.5	16.8	-11.8	13226.4
97	788501	2292218	18023.1	16.6	-11.8	13269.0

WTG No.	X [m]	Y [m]	AEPGross [MWh]	Wake loss [%]	Loss & Correction [%]	AEPNet [MWh]
98	788892	2291381	18022.3	16.3	-11.8	13311.5
99	789284	2290544	18039.8	16.1	-11.8	13355.6
100	789675	2289707	18050.8	15.4	-11.8	13472.9
101	790067	2288870	18039.2	15.0	-11.8	13528.2
102	790458	2288033	18024.6	14.6	-11.8	13583.3
103	790849	2287196	18022.8	13.2	-11.8	13797.3
104	791241	2286359	18025.6	8.2	-11.8	14606.9
105	781809	2302891	18181.9	5.5	-11.8	15158.9
106	782200	2302053	18175.5	10.0	-11.8	14425.8
107	782592	2301216	18176.8	12.2	-11.8	14080.2
108	782983	2300379	18197.4	13.6	-11.8	13870.9
109	783375	2299542	18205.0	14.4	-11.8	13755.8
110	783766	2298705	18161.7	14.8	-11.8	13655.1
111	784157	2297868	18001.9	15.2	-11.8	13474.2
112	784549	2297031	18030.3	15.3	-11.8	13474.6
113	784940	2296194	17996.6	15.4	-11.8	13438.4
114	785331	2295357	17989.2	15.4	-11.8	13426.5
115	785723	2294520	18069.2	15.4	-11.8	13494.8
116	786114	2293683	18057.2	15.3	-11.8	13490.0
117	786506	2292846	18032.4	15.3	-11.8	13476.5
118	786897	2292009	18026.4	15.3	-11.8	13476.2
119	787288	2291172	17995.2	15.1	-11.8	13475.5
120	787680	2290335	17997.8	15.0	-11.8	13502.5
121	788071	2289498	17997.5	14.9	-11.8	13515.0
122	788462	2288661	17998.1	14.6	-11.8	13560.4
123	788854	2287824	18007.4	14.4	-11.8	13605.6
124	789245	2286987	18036.9	14.0	-11.8	13690.9
125	789636	2286150	18034.2	13.1	-11.8	13828.1
126	780597	2301845	18166.4	4.4	-11.8	15322.3
127	780989	2301008	18144.7	8.3	-11.8	14684.8
128	781380	2300171	18101.8	9.8	-11.8	14400.7
129	781771	2299334	18023.8	10.8	-11.8	14177.5
130	782163	2298497	18041.7	11.4	-11.8	14105.7
131	782554	2297660	18058.9	11.7	-11.8	14064.3
132	782945	2296823	17995.7	11.9	-11.8	13981.2
133	783336	2295986	17966.2	12.1	-11.8	13938.7
134	783728	2295149	18058.3	12.1	-11.8	14005.6
135	784119	2294312	18069.1	12.1	-11.8	14010.1
136	784510	2293475	18037.0	12.2	-11.8	13980.1
137	784902	2292638	18001.6	12.1	-11.8	13953.2
138	785293	2291801	18009.4	12.1	-11.8	13965.5
139	785684	2290964	18083.2	12.0	-11.8	14035.7
140	786076	2290127	18079.8	12.0	-11.8	14040.5
141	786467	2289290	18082.6	11.9	-11.8	14051.1

WTG No.	X [m]	Y [m]	AEPGross [MWh]	Wake loss [%]	Loss & Correction [%]	AEPNet [MWh]
142	786858	2288452	18064.6	11.9	-11.8	14046.0
143	787249	2287615	18015.6	11.8	-11.8	14017.8
144	787641	2286778	17998.6	11.6	-11.8	14033.5
145	788032	2285941	17999.5	11.5	-11.8	14060.1
146	788423	2285104	18037.2	10.8	-11.8	14188.7
147	779385	2300800	18021.6	1.2	-11.8	15715.0
148	779777	2299963	18019.1	3.9	-11.8	15278.7
149	780168	2299126	18010.4	4.9	-11.8	15110.5
150	780559	2298289	18014.8	5.7	-11.8	14992.5
151	780950	2297452	18020.2	6.1	-11.8	14935.2
152	781342	2296615	18056.3	6.3	-11.8	14927.6
153	781733	2295778	17980.5	6.5	-11.8	14840.4
154	782124	2294941	18044.4	6.5	-11.8	14882.8
155	782515	2294103	18071.9	6.6	-11.8	14897.1
156	782907	2293266	18043.6	6.6	-11.8	14866.6
157	783298	2292429	18005.2	6.6	-11.8	14833.1
158	783689	2291592	18083.1	6.6	-11.8	14906.9
159	784080	2290755	18060.0	6.6	-11.8	14890.7
160	784472	2289918	18062.7	6.5	-11.8	14897.0
161	784863	2289081	18061.6	6.5	-11.8	14898.2
162	785254	2288244	18062.9	6.5	-11.8	14904.5
163	785645	2287407	18069.2	6.5	-11.8	14912.6
164	786036	2286570	18066.7	6.4	-11.8	14916.8
165	786428	2285733	18012.1	6.4	-11.8	14877.9
166	786819	2284896	17997.0	6.3	-11.8	14877.1
167	787210	2284058	18036.8	6.0	-11.8	14953.0

Table 8-5 AEP Estimate for the 167 6 MW wind turbines.

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FIRST OFFSHORE WIND
PROJECT OF INDIA