Offshore Wind Planning in the New York Bight:

Offshore Wind Resource Assessment Zones 1 and 3

NEW YORK STATE | NYSERDA New York State Energy Research and Development Authority

NYSERDA Report 25-12
February 2025

NYSERDA's Promise to New Yorkers:

NYSERDA provides resources, expertise, and objective information so New Yorkers can make confident, informed energy decisions.

Our Vision:

New York is a global climate leader building a healthier future with thriving communities; homes and businesses powered by clean energy; and economic opportunities accessible to all New Yorkers.

Our Mission:

Advance clean energy innovation and investments to combat climate change, improving the health, resiliency, and prosperity of New Yorkers and delivering benefits equitably to all.

Cover Image Source: Getty Images

Offshore Wind Planning in the New York Bight: Offshore Wind Resource Assessment Zones 1 and 3

Final Report

Prepared for:

New York State Energy Research and Development Authority

Albany, NY

Prepared by:

DNV Energy USA Inc.

Medford, MA

NYSERDA Report 25-12 NYSERDA Contract 202229 February 2025

Notice

Preferred Citation

New York State Energy Research and Development Authority (NYSERDA). 2025. "Offshore Wind Planning in the New York Bight: Offshore Wind Resource Assessment Zones 1 and 3." NYSERDA Report Number 25-12. Prepared by DNV Energy USA Inc., Medford, MA. nyserda.ny.gov/publications

Abstract

The examination of meteorological data sets obtained from offshore wind buoys, which are used to simulate the long-term wind speeds of a specific area, is covered in this Wind Resource Assessment (WRA). The WRA helps the reader comprehend the relative wind flow across Zone 1 and Zone 3. Using a wind flow model and the third-party certified data, DNV Energy USA, Inc. (DNV) determined the potential power output of a wind farm. A net capacity factor (NCF) was the outcome.

Visuals of the wind flow model have been included as part of the WRA after the visuals were adjusted for future wakes from planned projects. New York State Energy Research and Development (NYSERDA) has endeavored to select DNV based on their expertise, not necessarily for an alignment of opinions with NYSERDA, or the State of New York. Please note that the opinions expressed in this WRA are those of DNV.

Keywords

Offshore Wind Development, Wind Energy Areas, Resource Assessment

Table of Contents

Acronyms and Abbreviations

ABL	Atmospheric Boundary Layer
AEP	Annual Energy Production
AoA	Area of Analysis
ASL	Above Sea Level
ASIT	Air-sea Interaction Tower
ASOS	Automatic Surface Observing Station
BOEM	Bureau of Ocean Energy Management
CFD	Computational fluid dynamics
CLCPA	Climate Leadership and Community Protection Act
CNR	Carrier-to-noise ratio
DNV	DNV Entity
ECMWF	European Centre for Medium-Range Weather Forecasts
ERA5	European Centre for Medium-Range Weather Forecasts Re-Analysis (fifth generation)
FAA	Federal Aviation Administration
GEOS-5	Goddard Earth Observing System Data Assimilation System, Version 5
IEC	International Electrotechnical Commission
MEASNET	Measuring Network of Wind Energy Institutes
MERRA-2	Modern-Era Retrospective analysis for Research and Applications, Version 2
MSL	Mean Sea Level
MW	Megawatt
NASA	National Aeronautics and Space Administration
NWS	National Weather Service
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and maintenance
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
RANS	Reynolds-averaged Navier-Stokes
RMS	Root-mean-square
SNR	Signal-to-noise ratio
TI	Turbulence intensity
TWG	Technical Working Groups
WEA	Wind Energy Areas
WHOI	Woods Hole Oceanographic Institution
WRF	Weather Research and Forecasting

Executive Summary

Offshore wind energy could become a major source of affordable, renewable power for New York State, particularly on Long Island and in the New York Metropolitan Area, where demand on the electric grid is greatest. Generating electricity with wind turbines located off New York State's Atlantic Coast has the potential to provide up to 39,000 megawatts (MW) of clean power for the State, enough to power 15 million homes.

A strong knowledge of meteorological and oceanographic—metocean—conditions is essential for the safe and efficient design and operation of offshore wind installations. Prior to this study, limited metocean data had been collected in the region and our knowledge of wind speeds and other conditions had been largely based on modeled data. This uncertainty in physical conditions increased development risk and offtake bid prices. By obtaining better metocean characterization of the wind, wave, and ocean current environment within the offshore wind study areas, certainty of development conditions increases, which is useful in planning activities such as the refinement of project layout and turbine siting, key variables in lease auctions, and offtake.

In 2019, the New York State Energy Research and Development Authority (NYSERDA), in collaboration with DNV and Ocean Tech Services, deployed two floating Lidar systems approximately 70 kilometers (km) off the Atlantic Coast of New York State, also known as the New York Bight. The floating Lidars have gathered data for approximately two years, which is used to better understand the metocean conditions for the development of future offshore wind farms in the area. The collection of the site data is part of the NYSERDA's wider initiative to encourage the development of offshore wind in a manner that is sensitive to environmental, maritime, economic, and social issues while addressing market barriers for offshore wind technology and aiming to lower electricity costs for consumers.

NYSERDA retained DNV Energy USA Inc. (DNV) to complete independent assessments of the wind climate and energy production for two indicative offshore wind farms on the East Coast Zone 1 as well as Zone 3 in the New York Bight. The following two chapters are the results of the wind resource and energy production analysis and are independent, third-party verified summaries.

.

1 Offshore Wind Resource Assessment Zone 1

Offshore Wind Resource Assessment:

Zone 1

Report

Prepared for:

New York State Energy Research and Development Authority

Albany, NY

Prepared by:

DNV Energy USA Inc.

Medford, MA

NYSERDA Report 25-12 NYSERDA Contract 123367A March 2025

IMPORTANT NOTICE AND DISCLAIMER

Preferred Citation

New York State Energy Research and Development Authority (NYSERDA). 2025. “Offshore Wind Planning in the New York Bight: Offshore Wind Resource Assessment Zones 1 and 3.” NYSERDA Report Number 25-12. Prepared by DNV Energy USA Inc., Medford, MA. nyserda.ny.gov/publications

Table of Contents

Appendices

List of Tables

List of Figures

List of Abbreviations

Abbreviation	Meaning
ABL	Atmospheric Boundary Layer
AEP	Annual Energy Production
AoA	Area of Analysis
ASL	Above Sea Level
ASIT	Air-sea Interaction Tower
ASOS	Automatic Surface Observing Station
BOEM	Bureau of Ocean Energy Management
CFD	Computational fluid dynamics
Climate Act	Climate Leadership and Community Protection Act
CNR	Carrier-to-noise ratio
DNV	DNV Energy USA Inc.
ECMWF	European Centre for Medium-Range Weather Forecasts
ERA5	European Centre for Medium-Range Weather Forecasts Re-Analysis (fifth generation)
FAA	Federal Aviation Administration
GEOS-5	Goddard Earth Observing System Data Assimilation System, Version 5
IEC	International Electrotechnical Commission
MEASNET	Measuring Network of Wind Energy Institutes
MERRA-2	Modern-Era Retrospective analysis for Research and Applications, Version 2
MSL	Mean Sea Level
MW	Megawatt
NASA	National Aeronautics and Space Administration
NWS	National Weather Service
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and maintenance
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
RANS	Reynolds-averaged Navier-Stokes
RMS	Root-mean-square
SNR	Signal-to-noise ratio
TI	Turbulence intensity
TWG	Technical Working Groups
WEA	Wind Energy Areas
WHOI	Woods Hole Oceanographic Institution
WRF	Weather Research and Forecasting

EXECUTIVE SUMMARY

Offshore wind energy could become a major source of affordable, renewable power for New York State, particularly on Long Island and in the New York City metropolitan area, where demand on the electric grid is greatest. Generating electricity with wind turbines located off New York's Atlantic Coast has the potential to provide up to 39,000 megawatts (MW) of clean power for the State, enough to power 15 million homes.

A strong knowledge of meteorological and oceanographic - metocean - conditions is essential for the safe and efficient design and operation of offshore wind installations. Prior to this study, limited metocean data has been collected in the region and our knowledge of wind speeds and other conditions has been largely based on modeled data. Uncertainty in physical conditions increases development risk and offtake bid prices. By obtaining better metocean characterization of the wind, wave, and ocean current environment within the offshore wind study areas, certainty of development conditions increases, which is useful in planning activities such as the refinement of project layout and turbine siting, key variables in lease auctions, and offtake.

In 2019, the New York State Energy Research and Development Authority, in collaboration with DNV and Ocean Tech Services, deployed two floating Lidar systems approximately 70 km off the Atlantic Coast of New York, also known as the New York Bight. The floating Lidars have gathered data for approximately two years, which is used to better understand the metocean conditions for the development of future offshore wind farms in the area. The collection of the site data is part of the New York State Energy Research and Development Authority’s wider initiative to encourage the development of offshore wind in a manner that is sensitive to environmental, maritime, economic, and social issues while addressing market barriers for offshore wind technology and aiming to lower electricity costs for consumers.

New York State Energy Research and Development Authority retained DNV Energy USA Inc. (DNV) to complete independent assessments of the wind climate and energy production for two indicative offshore wind farms in the East Coast Zone 1 in the New York Bight. The tables below summarize the projects and the results of the wind resource and energy production analysis.

Project Summary		
Indicative layout	01	02
Turbine make and model	Theoretical 15 MW	Theoretical 18 MW
Turbine hub-height [m]	140	155
Turbine rated power [kW]	15000	18000
Number of turbines	67	56
Installed capacity [MW]	1005	1008
Wind Resource Summary		
Average air density [kg/m^3]	1.22	1.22
On-site measurement period [years]	2.4	2.4
Long-term reference period [years]	23.1	23.1
Average turbine hub-height wind speed [m/s]	10.6	10.7
Energy Assessment Summary		
Evaluation period [years]	25	25
Gross energy [GWh/year]	5453.8	5387.4
P50 loss factors		
- Turbine interaction effects (wakes and blockage)	91.0%	91.2%
- Availability	94.1%	94.1%
- Electrical	97.5%	97.5%
- Turbine performance	96.7%	96.5%
- Environmental	100.0%	100.0%
- Curtailment	100.0%	100.0%
Total losses	80.6%	80.6%
Effect of asymmetric production	99.8%	99.8%
P50 Net Energy [GWh/year]	**4395.8**	**4341.5**
P50 Net Capacity Factor	**49.9%**	**49.1%**
1-year P99 Net Energy [GWh/year]	3455.0	3407.2
1-year P99 Net Capacity Factor	39.2%	38.6%

The key findings of the analysis and factors affecting the analysis results are summarized below:

- The wind resource campaign used two floating Lidar systems (FLSs) at three locations: two EOLOS FLS-200s each with one ZephIR ZX300M Lidar unit on-board. The FLS locations are not representative of the East Coast Zone 1 wind regimes as the measurements are approximately 270km or more away from the Zone 1 turbine locations. This energy assessment is based on approximately two years of measured wind data.
- DNV has derived hypothetical power curves based on current and expected trends in turbine technology.
- The sensitivity of energy due to changes in wind speed (sensitivity ratio) for offshore wind projects is typically lower due to the higher wind speeds, but is also dependent on the turbine characteristics such as swept rotor size and rated power. Given the high wind speeds in the East Coast Zone 1 site, and the assumed turbine characteristics of the hypothetical turbines modeled for this preliminary assessment, the net energy is less sensitive to changes in wind speed and the sensitivity ratio approaches unity for this preliminary assessment. DNV notes that the sensitivity ratio and therefore the project uncertainty may vary materially depending on the final commercially available turbines selected for the projects.
- The variation in wind speed over the East Coast Zone 1 Area of Analysis were predicted using Vortex mesoscale model. The wind speed variation across Zone 1 at 140 m is based on the Vortex mesoscale model and calibrated to the long-term mean wind speed at the floating lidar E05_N. The wind speed range is between 10.0 m/s and 10.8 m/s. Generally, the wind speed increases with the distance to shore with the highest wind speed to the east of the Area of Analysis.
- Based on publicly available information, DNV derived representative turbine layouts of neighboring wind farms for the sake of external wake modelling and estimation. Given the early stage of development of several of the neighboring projects, it is not possible to accurately model their wake effects on the East Coast Zone 1 project. DNV has estimated the wake effects of the neighboring projects assuming the same turbine model as the East Coast Zone 1 Wind Farm. The external wake effect range is 93.0% to 100.0% with the external wake effect being higher in areas close to neighboring wind farms.
- NYSERDA has requested that DNV design two indicative wind farm layouts. DNV notes that alternative, non-gridded layouts are possible within the Lease Areas and that gridded layouts have been assumed for this preliminary assessment for simplicity. The gridded layouts are not a reflection of New York State policy on preference for any predetermined layout or approach thereto. Project capacities for each indicative layout were maintained at approximately 1000 MW and are likewise generically identified for hypothetical purposes befitting a preliminary assessment and are not a reflection of DNV or New York State's opinions regarding project sizing.

  Based on water depth, wind speed variation and external wake effect across the Area of Analysis, DNV has chosen a Wind Turbine Area. For the indicative layouts used in this study, DNV did not perform detailed layout optimization and, as such, no environmental constraint analysis was done. DNV has not performed a site visit to determine site suitability nor micro sited the turbine locations. The layouts used in this analysis are indicative for wind resource characterization and preliminary energy assessments only and should not be considered as a recommendation.
- The potential external wake effects from five neighboring projects on the two indicative layouts have been considered in this assessment. These projects are at various stages of development and publicly available coordinates for project turbine locations are not available. However, based on publicly available information, DNV derived representative turbine layouts. Details of these neighboring wind farms are presented in Section 2.4. When additional information about these wind farms becomes available, it is recommended that the impacts of the proposed wind farms are reconsidered.

- No wind sector management strategy has been modeled, and DNV has not included any losses which may be associated with this. However, given the large inter-turbine spacings assumed, DNV considers it unlikely a wind sector management strategy would be required. For future projects, it is recommended that the turbine supplier be approached at an early stage to gain approval for the indicative layouts and that an Independent Engineer reviews the manufacturer's conclusions as part of a full due diligence exercise.
- Aside from inter-annual variability, the uncertainty in the analysis is driven by loss factor uncertainty and measurement uncertainty. Uncertainty in the analysis could be reduced by obtaining commercially available turbine power curves, assessing the electrical systems and access strategies to inform more refined estimates for electrical loss and turbine availability, and having a measurement location closer to East Coast Zone 1.

The preceding factors have all been considered in the analysis.

1 INTRODUCTION

In 2019, New York's historic Climate Leadership and Community Protection Act (Climate Act) was signed into law, requiring the State to achieve 100% zero-emission electricity by 2040 and to reduce greenhouse gas emissions 85% below 1990 levels by 2050. The law specifically mandates the development of 9,000 megawatts (MW) of offshore wind energy by 2035, building upon its previous goal of 2,400 MW of offshore wind energy by 2030. The New York State Energy Research and Development Authority (NYSERDA) is charged with advancing these goals.

For more than a decade, New York State has been conducting research, analysis, and outreach to evaluate the potential for offshore wind energy. New York State Energy Research and Development Authority (NYSERDA) led the development of the New York State Offshore Wind Master Plan (Master Plan), a comprehensive roadmap and suite of more than 20 studies for the first 2,400 megawatts (MW) of offshore wind energy. The Master Plan encourages the development of offshore wind in a manner that is sensitive to environmental, maritime, economic, and social issues while addressing market barriers and aiming to lower costs. The Master Plan included spatial studies to inform siting of offshore wind energy areas. Now, NYSERDA is undertaking new spatial studies to review the feasible potential for deep water offshore wind, at or exceeding depths of 60 meters in the New York Bight.

Planning processes considering the development of offshore wind in the deepwater areas examined in each of NYSERDA's spatial studies must consider these studies in the context of one another. Decision making must additionally consider different stakeholders and uses, and will require further adjusted approaches and offshore wind technologies to ensure the best outcome. Globally, deepwater wind technology is less mature and primarily concentrated on floating designs at the depth ranges being assessed through these spatial studies, while deepwater fixed-bottom foundations are at their upper technical limit within the Area of Analysis (AoA). Therefore, floating designs were predominantly considered since most, if not all, of the AoA would likely feature floating offshore wind. NYSERDA, along with other state and federal agencies, is developing research and analysis necessary to take advantage of opportunities afforded by deep water offshore wind energy by assessing available and emerging technologies, and characterizing the cost drivers, benefits, and risks of floating offshore wind. Findings from these studies and available datasets will be used to support the identification of areas that present the greatest opportunities and least risk for siting deep water offshore wind projects.

1.1 Benefits and Cost-Reduction Pathways

The State's Master Plan analysis concluded that offshore wind development will enhance the State's job market, supply chain, and economy; reduce the use of fossil fuels; and provide other public health, environmental, and societal benefits. While the State plans to continue procuring offshore wind projects within the existing lease areas, the timing is right to build a better understanding of the opportunities and challenges of projects farther offshore. Cost is a critical consideration for the State in the development of offshore wind. A focused study on the cost landscape and technological readiness for deepwater offshore wind of 60 to 3,000 meters in water depths in the Area of Analysis was conducted to help the State understand how floating offshore wind may fit in New York's renewable energy portfolio. Additional discussion of costs and cost-reducing strategies focusing on State options for contracting related to deep water offshore wind, job-training programs, and infrastructure investments will also be developed as part of future planning efforts.

The State will continue to undertake research and engage its established Technical Working Groups (TWGs) on key subjects of fishing, maritime commerce, the environment, environmental justice, jobs, and the supply chain. These TWGs will continue to inject expert views and the most recent information as an integral part of future decision-making.

When combined, the information assembled in these studies will empower New York State and its partners to take the informed steps needed to continue to capitalize on the unique opportunity presented by offshore wind energy.

1.2 Spatial Studies to Inform Lease Siting

- Benthic Habitat Study
- Birds and Bats Study
- Deepwater Wind Technologies – Technical Concepts Study
- Environmental Sensitivity Analysis
- Fish and Fisheries Data Aggregation Study
- Marine Mammals and Sea Turtles Study
- Maritime Assessment – Commercial and Recreational Uses Study
- Offshore Wind Resource Assessment Study Zones 1 and 3
- Technology Assessment and Cost Considerations Study

Each of the studies was prepared in support of a larger planning effort and shared with relevant experts and stakeholders for feedback. The State addressed comments and incorporated feedback received into the studies. Feedback from these diverse groups helps to strengthen the studies, and also helps ensure that these work products will have broader applicability and a comprehensive view

The Energy Policy Act of 2005 amended Section 8 of the Outer Continental Shelf Lands Act (OCSLA) to give BOEM the authority to identify offshore wind development sites within the Outer Continental Shelf (OCS) and to issue leases on the OCS for activities that are not otherwise authorized by the OCSLA, including wind development. The State recognizes that all development in the OCS is subject to review processes and decision-making by BOEM and other federal and State agencies. This collection of spatial studies is not intended to replace the BOEM Wind Energy Area identification process and does not commit the State or any other agency or entity to any specific course of action with respect to offshore wind energy development. Rather, the State's intent is to facilitate the principled planning of future offshore development off the New York coast, provide a resource for the various stakeholders, and encourage the achievement of the State's offshore wind energy goals.

1.3 Scope of Study

The spatial studies will evaluate potential areas for deep water offshore wind development within a specific geographic area of analysis (AoA) of approximately 35,670 square miles of ocean area extending from the coast of Cape Cod south to the southern end of New Jersey. It includes three zones extending outward from the 60-meter depth contour, which ranges between 15 and 50 nautical miles from shore to the 3,000-meter contour, which ranges from 140 to 160 nautical miles from shore.

The eastern edge of the AoA avoids Nantucket Shoals and portions of Georges Bank, since those areas are well known to be biologically and ecologically important for fish and wildlife, fisheries, and maritime activity. The AoA does include areas such as the Hudson Canyon, which is under consideration to be designated as a National Marine Sanctuary and thus unlikely to be suitable for BOEM site leases.

While offshore wind infrastructure will not be built across the entire AoA, the spatial studies analyze this broad expanse to provide a regional context for these resources and ocean uses.

- Zone 1 is closest to shore and includes a portion of the Outer Continental Shelf. It extends from the 60-meter contour out to the continental shelf break [60 meters (197 feet) to 150 meters (492 feet) deep]. Zone 1 is approximately 12,040 square miles.

- Zone 2 spans the steeply sloped continental shelf break, with unique canyon geology and habitats [150 meters (492 feet) to 2,000 meters (6,561 feet) deep]. Zone 2 is approximately 6,830 square miles.

- Zone 3 extends from the continental shelf break out to 3,000 meters (9,842 feet) depth. Zone 3 is approximately 16,800 square miles.

Zone 2, stretching across the steeply sloped continental shelf break with its distinctive canyon geology and unique habitats, was excluded from consideration for wind development research due to several compelling reasons. In the initial discussions of the spatial studies, members of the Technical Working Groups swiftly recognized the zone's extraordinary biodiversity and distinctive ecological attributes, leading to a consensus that it was ill-suited for development.

Additionally, the considerable variance in water depths within this zone posed potential engineering challenges for the installation of wind turbines along the shelf's precipice. These engineering hurdles would likely result in escalated development costs compared to alternative locations within the Area of Analysis.

The decision to forgo Zone 2 was a meticulously considered one, firmly aligned with two of NYSERDA’s Guiding Principles for Offshore Wind: the imperative to maximize cost-effectiveness for New York State ratepayers and the commitment to minimize environmental impacts. This strategic choice reflects a careful balance between offshore wind development and environmental responsibility, ultimately serving the best interests of both the industry and the State.

1.4 Study Objective

New York State Energy Research and Development Authority (NYSERDA) retained DNV Energy USA, Inc. (DNV) to provide ongoing data management and quality checking services for the on-site FLSs through DNV’s Resource Panorama service and complete independent analyses of the wind regime and energy production for two hypothetical offshore wind farms in the NY Offshore Wind Study Area in the New York Bight. This report is issued to NYSERDA pursuant to a written agreement arising from the Proposal for Energy Services 202229, dated 19 January 2023.

This report presents a description of the project site, turbine technology, and neighboring wind projects. It then describes the available measurements and analysis of the wind data followed by an evaluation of the expected project gross and net energy, as influenced by assumed losses and uncertainties. Finally, it presents DNV’s observations and recommendations.

2 PROJECT DESCRIPTION

As shown in Figure 2-1, the Area of Analysis is located in federal waters offshore of New York on the outer continental shelf and is approximately 460 km x 70 km. DNV has identified an Indicative Wind Turbine Area, approximately 190 km south-east of Long Island.

DNV has analyzed the following indicative layouts as seen in Table 2-1.

Table 2-1 Indicative layouts

Indicative layout	Number of turbines	Turbine type	Hub-height [m]
01	67	Theoretical 15 MW	140
02	56	Theoretical 18 MW	155

Measurements of the wind regime have been made at three locations using two EOLOS FLS-200s. These are described in more detail in Section 3.

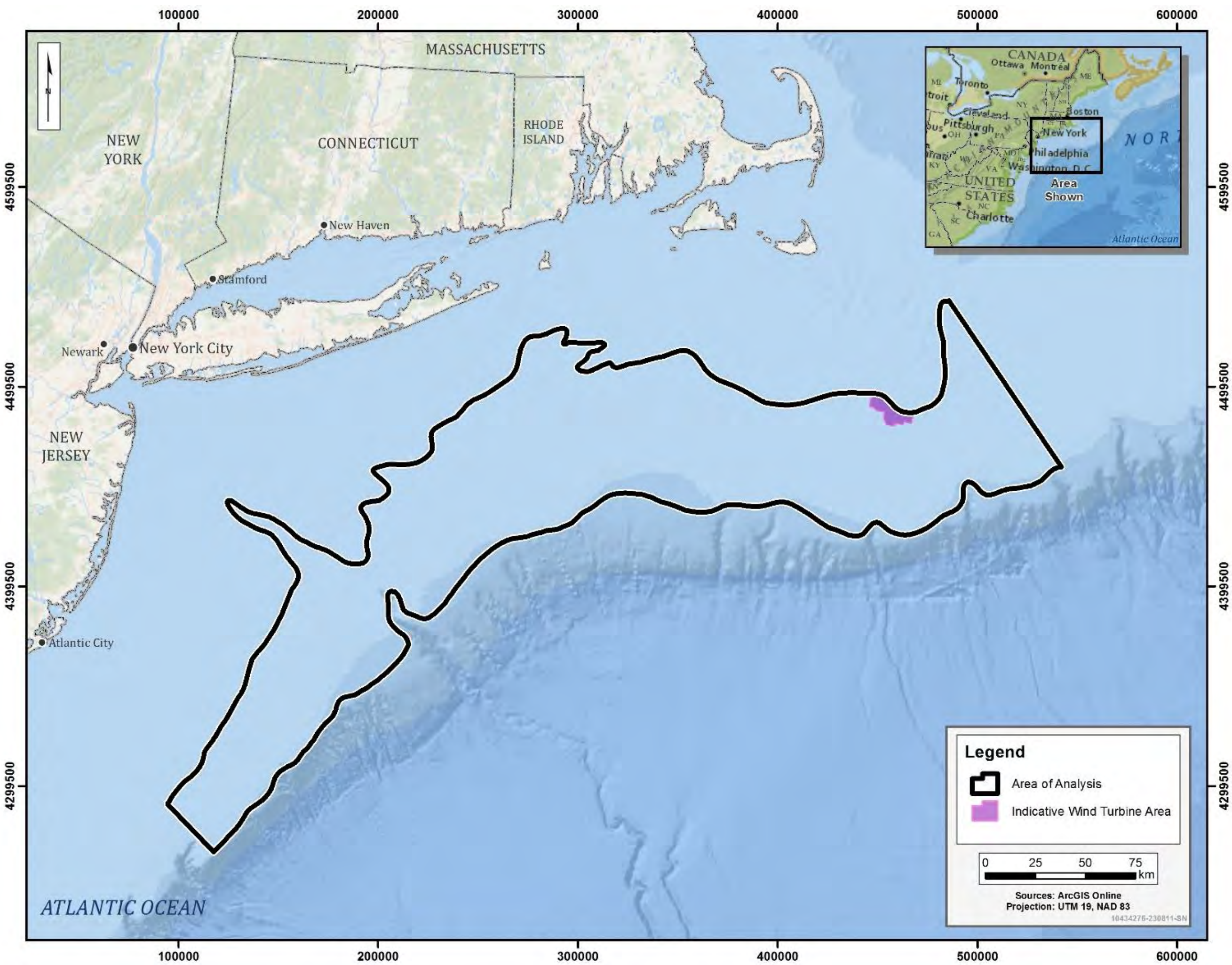


Figure 2-1 Project location

2.1 Site description

The Indicative Wind Turbine Area is located in federal waters offshore of New York, approximately 190 km south-east of Long Island.

Figure 2-2 is a map of the area showing the site measurement locations. Maps of each indicative layout for the East Coast Z1 Wind Farm are presented in Figure 2-3 and Figure 2-4, showing the proposed turbine locations.

Based on water depth, wind speed variation and external wake effect across the Area of Analysis, DNV has chosen a Wind Turbine Area as shown in Figure 2-2. DNV did not perform detailed layout optimization and, as such, no environmental constraint analysis was done. DNV has not performed a site visit to determine site suitability nor micro sited the turbine locations. The Wind Turbine Area chosen in this analysis is indicative for wind resource characterization and preliminary energy assessments only and should not be considered as a recommendation. More information about the wind speed variation across the Area of Analysis is shown in Section 4.3.

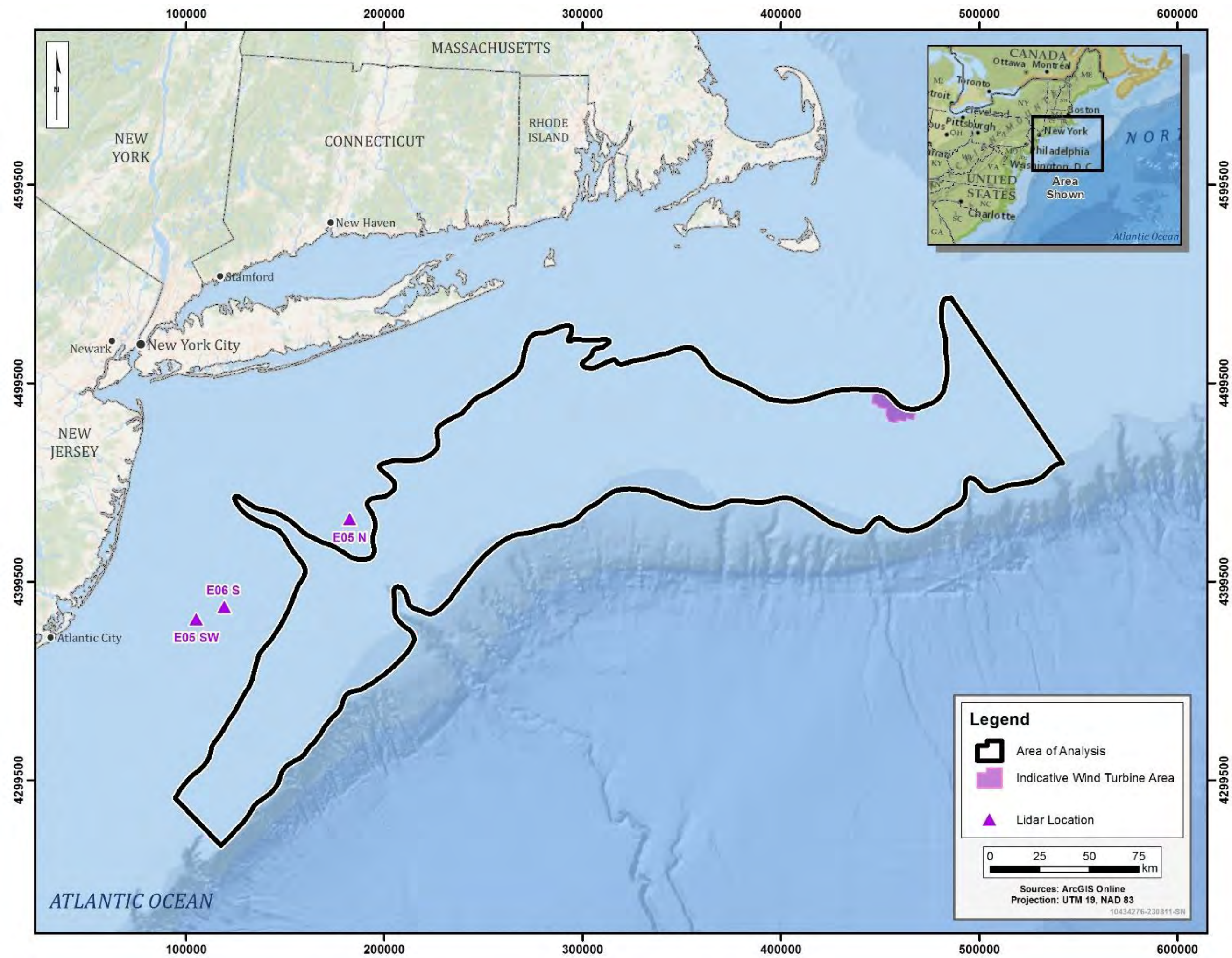


Figure 2-2 Map of the Measurement Locations

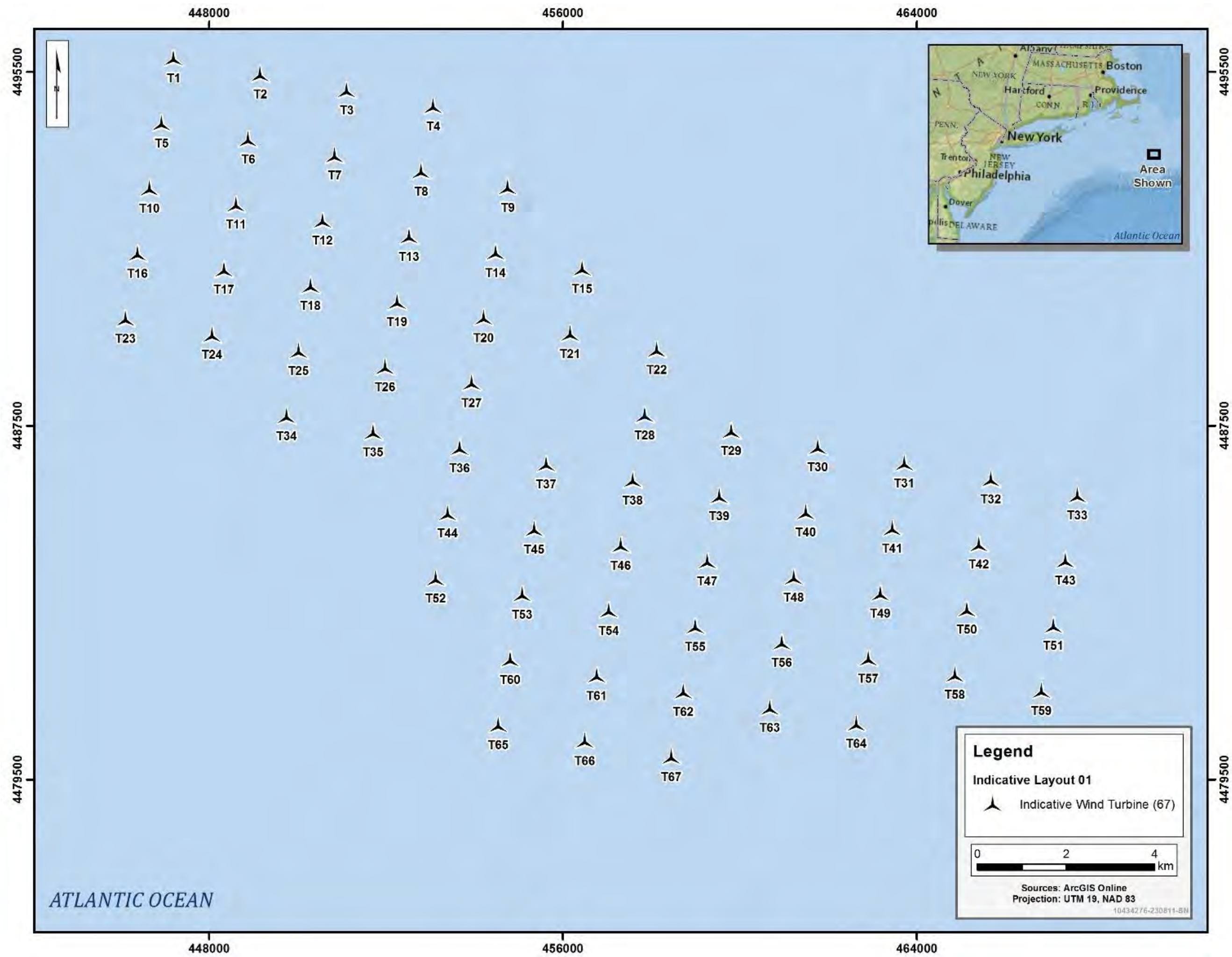


Figure 2-3 Map of the East Coast Z1 Wind Farm, Indicative layout 01

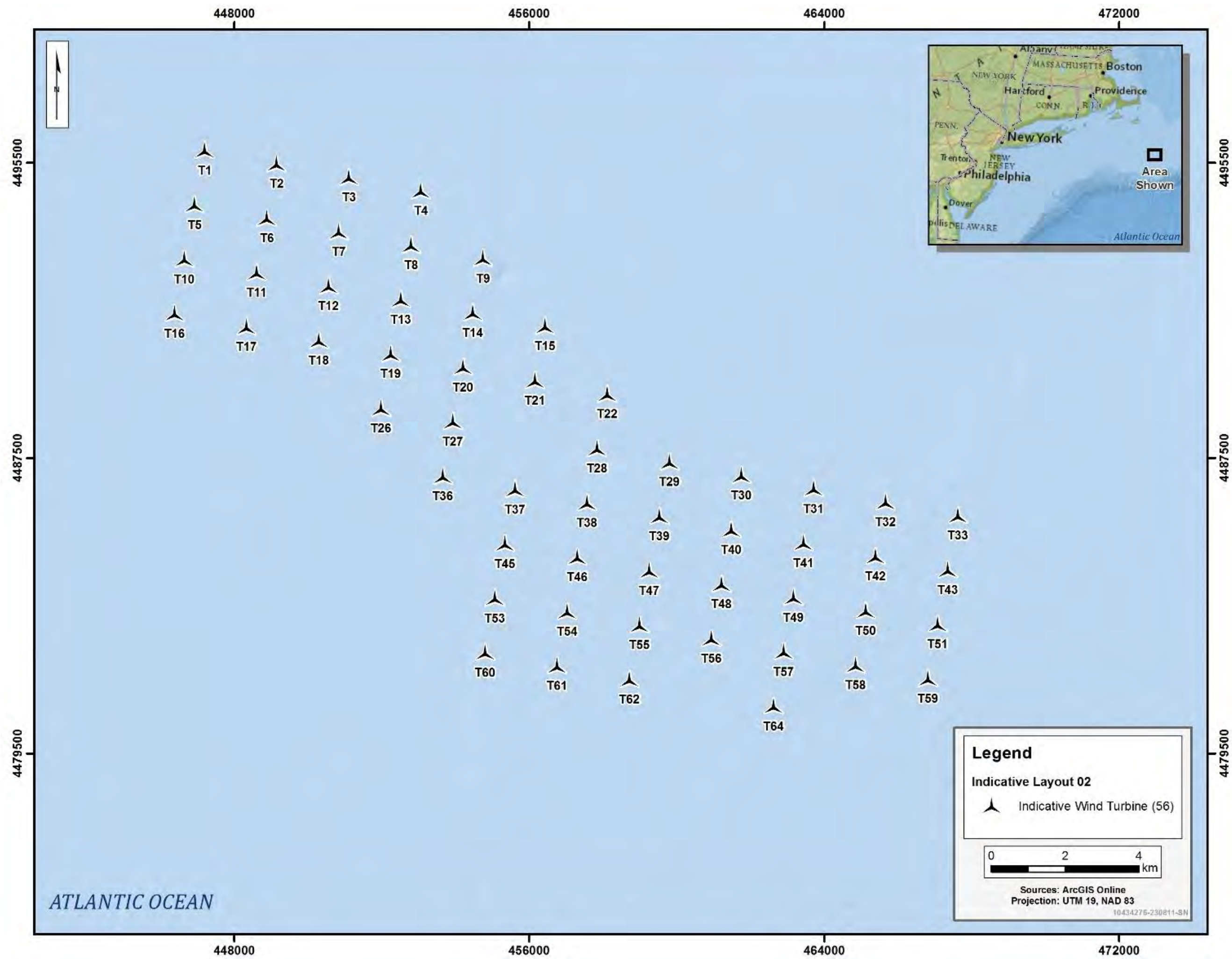


Figure 2-4 Map of the East Coast Z1 Wind Farm, Indicative layout 02

Although DNV has not visited the site, DNV visited the Ocean Tech Services shop in Avalon, NJ on 02 August 2019 to witness the Site Acceptance Test for the EOLOS FLS-200 buoys as reported in the Port Site Acceptance Test report [1]. Photos of the EOLOS FLS-200 buoys are shown in Figure 2-5.

Figure 2-5 E05 (left) and E06 (right) EOLOS FLS-200 buoys

2.2 Turbine technology

Table 2-2 summarizes the hypothetical turbine configurations under consideration for the East Coast Z1 project.

Table 2-2 Proposed turbine model parameters

Turbine	Rated power [MW]	Rotor diameter [m]	Hub-height [m MSL]	Peak power coefficient [Cp]	Valid power curve air density [kg/m^3]
Theoretical 15 MW	15	236	140	0.46	1.225
Theoretical 18 MW	18	250	155	0.46	1.225

NYSERDA has requested that DNV derive hypothetical power curves for the project. The power curves are based on air densities of 1.225 kg/m^3 and have been adjusted to the site density [3]. Although relatively high, the peak power coefficients are considered to be attainable. Based on DNV extensive review and experience in power performance measurements, the peak power coefficient are within a range of typical values.

2.3 Turbine layout

NYSERDA has requested that DNV design two indicative wind farm layouts with fixed bottom foundations within the boundaries of Zone 1. As requested by NYSERDA, the following constraints have been used for this design:

- DNV considered one turbine model and one hub-height for each indicative layout.
- Water depths of 65m or less were considered for turbine locations.

- Indicative layout 01 is considered the base case layout scenario. The base case layout was pared down for Indicative layout 02 to maintain project capacities of approximately 1000 MW by removing surplus turbine locations.

Figure 2-3 and Figure 2-4 show the turbine indicative layouts for East Coast Zone 1. The grid coordinates of the turbines are shown in Appendix C.

The following aspects of the indicative layouts are notable and have been considered in the analysis:

- The indicative layouts were orientated to maximize the turbines spacing in the prevailing wind direction to minimize the internal wake effect.
- The overall average spacing of the 15 MW indicative layout is 10.7 rotor diameters (D) in the prevailing direction and 6.4D in the non-prevailing direction. The overall average spacing of the 18 MW indicative layout is 10.1D in the prevailing direction and 6.0D in the non-prevailing direction.
- DNV notes that alternative, non-gridded layouts are possible within the Lease Areas and that gridded layouts have been assumed for this preliminary assessment for simplicity. The gridded layouts are not a reflection of New York State policy on preference for any predetermined layout or approach thereto.
- No wind sector management strategy has been modeled, and DNV has not included any losses which may be associated with one. However, given the large inter-turbine spacings assumed, DNV considers it unlikely a wind sector management strategy would be required. For future projects, it is recommended that the turbine supplier be approached at an early stage to gain approval for the indicative layouts and that an Independent Engineer reviews the manufacturer’s conclusions as part of a full due diligence exercise.

2.4 Neighboring wind farms

The indicative layouts are located near a region of significant wind farm development. DNV has identified five wind farms within approximately 100 km of the project. While there are additional Lease Areas further northwest of the project, DNV considers these will have a negligible wake impact on the project given their distance. These projects are at various stages of development and publicly available coordinates for project turbine locations are not available. However, based on publicly available information, DNV derived representative turbine layouts for the sake of external wake modelling and estimation [2]. The locations of these Lease Areas are illustrated in Figure 2-6, with the details considered for each project are outlined in Table 2-3.

When additional information about these wind farms becomes available, such as the final turbine model, layout and hub-height, it is recommended that this analysis is updated to reflect the impact of proposed wind farms.

Table 2-3 Summary of neighboring wind farms

Lease area number	Start of operation	Distance to site	Turbine configuration
OCS-A 0522	Proposed	35 km south-east	152 x Generic 15 MW-236 at 140 m
OCS-A 0521	Proposed	60 km south-east	146 x Generic 15 MW-236 at 140 m
OCS-A 0520	Proposed	70 km south-east	158 x Generic 15 MW-236 at 140 m
OCS-A 0501	Proposed	80 km south-east	62 x Generic 13 MW at 140m
OCS-A 0534	Proposed	85 km south-east	116 x Generic 15 MW-236 at 140 m

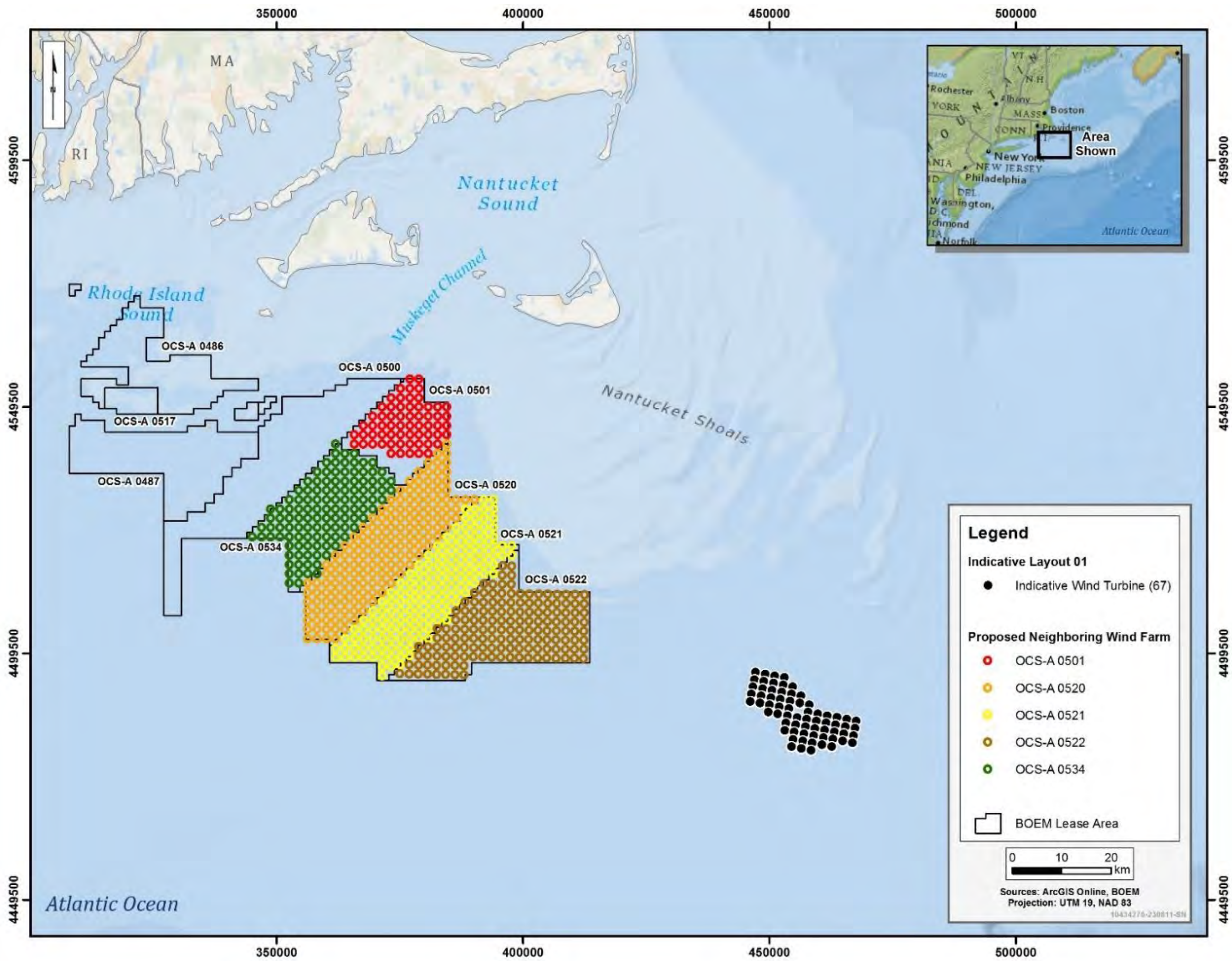


Figure 2-6 Map of Indicative layout 01 and surrounding projects

3 ON-SITE WIND MONITORING

3.1 Wind resource measurements

Wind resource measurements have been taken at three floating lidar systems across three locations over the period of August 2019 to January 2023.

The characteristics of the measurement campaign are summarized in Table 3-1.

Table 3-1 Remote sensing campaign summary

Lidar System	Buoy reference	Lidar	Measurement heights [m MSL]	Measurement period	Stage maturity according to the OWA Roadmap[a]
EOLOS FLS-200 FLiDAR	E05_N	ZephIR ZX300M	20, 40 ,60, 80, 100, 120, 140, 160, 180, 200	August 2019 - September 2021	Stage 2 / pre-commercial [b]
EOLOS FLS-200 FLiDAR	E05_SW	ZephIR ZX300M	20, 40 ,60, 80, 100, 120, 140, 160, 180, 200	January 2022 – January 2023	Stage 2 / pre-commercial [b]
EOLOS FLS-200 FLiDAR	E06_S	ZephIR ZX300M	20, 40 ,60, 80, 100, 120, 140, 160, 180, 200	September 2019 to March 2022	Stage 2 / pre-commercial [b]

a. Carbon Trust Offshore Wind Accelerator Roadmap [5].

b. DNV is aware that EOLOS FLS-200 has recently been independently verified as having reached stage 3 maturity status, however copies of the independent stage 3 validation reports have not been provided.

Full details of the history of each data source and its instrumentation are provided in Appendix B.

3.1.1 Floating Lidar System (FLS) deployments

DNV is aware that the EOLOS FLS-200 FLS has reached Stage 3 maturity according to the Carbon Trust OWA Roadmap for the Commercial Acceptance of Floating LiDAR Technology. DNV has not received copies of the independent stage 3 validation reports that include the classification uncertainty for the Fugro SWLB. Previously, a Stage 2 Type Verification of the EOLOS FLS-200 Buoy system against a tall offshore meteorological mast has previously been conducted at Mast Ijmuiden (MMIJ) [4] for a period of 6 months over the period March 2015 to October 2015. During this period the data recorded was compared to those recorded by Mast MMIJ. It was concluded the 'best practice' acceptance criteria and key performance indicators for accuracy were met at all comparable measurement heights. Details of this validation can be found in the offshore validation report [4].

Current industry guidance [5] recommends that independent pre-deployment verifications against a trusted reference should be undertaken as part of a wind resource assessment for lowest uncertainty. The E05 and E06 EOLOS FLS-200 Buoys underwent two-phase pre-validations, one onshore and one offshore, as reported in the pre-deployment offshore verification reports [6]. For the onshore validations, the units were deployed from 7 December 2018 - 18 December 2018 and the data were compared to a reference met mast. For the offshore validations, the FLSs were deployed from 12 April 2019 - 26 May 2019 and the data were compared to the Narec NOAH reference mast. All verifications concluded that the floating Lidar systems met the minimum key performance indicators and acceptance criteria for wind speed accuracy as defined by the Carbon Trust OWA Roadmap [5].

The floating Lidar units were set up to record data at the heights listed in Table 3-1. The height above sea level of the Lidars has been incorporated into the heights listed in Table 3-1. All floating Lidar heights are referred to as above MSL for the remainder of this report.

The floating Lidar systems were programmed to record mean wind speed, direction and turbulence components during each ten-minute interval.

3.2 Data processing

Data from the floating Lidar systems installed near the Project have been obtained from DNV's Resource Panorama service. The data supplied are already processed and compensated for motion using the manufacturer's algorithm; however, the processed remote sensing wind data have been subject to a further quality checking procedure by DNV to identify records which were affected by equipment malfunction and other anomalies.

Wind data coverage is generally good at the E05_N and E05_SW FLSs. There is lower data coverage at E06_S in 2020 and 2021 when the FLS was out of service or awaiting maintenance. Summarized data coverage levels for the key parameters and instruments on each remote sensing device are shown in Table 3-2.

Table 3-2 Summary of site data coverage

Location	Distance to site[a] [m]	Height [m]	Available period [years]	Valid period [years]	Measured wind speed [m/s]	Wind speed data coverage [%]
E05_N	270	140	2.1	1.9	10.2	92
		160	2.1	1.9	10.3	91
E05_SW	355	140	1.0	0.9	10.1	92
		160	1.0	0.9	10.3	92
E06_S	340	140	2.6	1.8	10.1	69
		160	2.6	1.8	10.2	68

a. The distance represents the distance between the floating Lidar systems and the indicative layouts.

3.3 Site measurement uncertainties

Table 3-3 presents the site measurement uncertainties estimated for the site.

Table 3-3 Site measurement uncertainties – E05_N

Uncertainty category	% wind speed
Measurement accuracy	3.3

Measurement uncertainty derived for the floating Lidars is based on the IEA Floating Lidar Recommended Practices [7] considering the following components:

- Classification uncertainty – DNV has not received classification trial results including classification uncertainty for the Stage 3 EOLOS FLS-200 buoy system; therefore, DNV has assumed a class number based on DNV's knowledge of Lidar and floating Lidar system classifications. DNV recommends that this uncertainty be updated once the classification uncertainty for the Stage 3 EOLOS FLS-200 buoy system is obtained.

- Verification uncertainty – this is based on the verification uncertainty analysis found in the pre-deployment offshore verification reports completed for the EOLOS FLS-200 Buoys deployed at the site [6].
- Based on the results of the metocean comparison performed in the pre-deployment offshore verification reports [6] for the EOLOS FLS-200 FLSs and additional checks conducted by DNV, the environmental conditions at the project site are considered slightly harsher than the environmental conditions during the trial campaigns. To account for the impact of environmental variables outside of the floating Lidar system verification envelope, an additional uncertainty has been applied.

4 WIND ANALYSIS

The analysis of the site wind regime involved several steps, which are summarized below:

- Data recorded at FLS E05_N were correlated to FLS E06_S on a 10-minute basis to recover missing and historical data. These correlations were used to derive the annual wind speeds at FLS E05_N for the period from August 2019 to March 2022.
- Data recorded at FLS E05_SW were correlated to FLS E06_S on a 10-minute basis to recover missing and historical data. These correlations were used to derive the annual wind speeds at FLS E05_SW for the period from September 2019 to January 2023.
- Data recorded at FLS E06_S were correlated to FLS E05_N and E05_SW on a 10-minute basis to recover missing and historical data. These correlations were used to derive the annual wind speeds at FLS E06_S for the period from August 2019 to January 2023.
- Reference data sources were correlated to the measured data at the FLS on a daily basis. These correlations were used to derive the long-term mean wind speeds at these measurement locations for the period from January 2000 to January 2023.
- In order to reference the site data to the period of January 2000 to January 2023, the adjustments determined between the E05_N, E05_SW and E06_S units and the reference data sources were applied independently to the annual wind speeds determined at the measurement locations for the full site period.
- Measured data recorded at the site masts were used to derive boundary layer power law wind shear exponents. These shear estimates were used to extrapolate the long-term mean wind regime at the site masts to the proposed 140 m and 155 m hub-heights.
- The hub-height wind speed and direction frequency distributions at the site masts were extrapolated from the measured data and subsequently adjusted to reflect the predicted long-term mean wind speed at each individual mast.
- Wind flow modeling was carried out to determine the hub-height wind speed variations over the site.

Results for each step of the process are provided in the following sections.

4.1 Measurement-height wind regime

4.1.1 Site-period wind speeds

As noted in Section 3.1, data were recorded near the East Coast Z1 site from August 2019 to January 2023.

In order to bring all the mast measurement periods to a consistent period of record, missing and historic wind speed and direction data at the upper measurement levels of each measurement location were synthesized from other sensors at that location, as well as from neighboring site Lidars, on a 10-minute directional basis. The specific correlations in order of priority are presented in Table 4-1. Summaries of the regressions as well as associated statistics and graphs are presented in Appendix C.

The site-period wind speeds are shown in Table 4-1 and include the synthesized data. Monthly average site-period wind speeds for each met mast are also presented in Appendix C.

Table 4-1 Site period wind speeds

Device	Height [m]	Reference device in order of priority	Site period [years]	Site period annual average wind speed [m/s]
E05_N	140	E06_S	2.4	10.1
E05_N	160	E06_S	2.4	10.2
E05_SW	140	E06_S	2.6	10.0
E05_SW	160	E06_S	2.6	10.2
E06_S	140	E05_SW, E05_N	3.2	9.9
E06_S	160	E05_SW, E05_N	3.2	10.1

4.1.2 Extension of the site period to the reference period

The inclusion of quality reference data can reduce the uncertainty in the estimate of the long-term wind regime at the site. When selecting appropriate reference data for this purpose, it is important that the reference data's wind regime is driven by similar factors as the site wind regime and the reference data are consistent over the measurement period being considered.

4.1.2.1 Reference data considered

DNV has undertaken an extensive review of the sources of reference data surrounding the East Coast Z1 project and near the measurement locations in order to identify appropriate long-term reference stations for this analysis. Table 4-2 summarizes the stations considered while Figure 4-1 shows their proximity to the Project site.

Table 4-2 Reference data sets considered for correlations to site data

Meteorological data source	Network	Start date	End date
ERA5 39.90N, 72.90W	ECMWF	January 2000	December 2022
ERA5 39.60N, 73.50W	ECMWF	January 2000	December 2022
MERRA-2 40.00N, 72.50W	NASA	January 2000	January 2023
MERRA-2 40.00N, 73.13W	NASA	January 2000	January 2023
MERRA-2 39.50N, 73.13W	NASA	January 2000	January 2023
MERRA-2 39.50N, 73.75W	NASA	January 2000	January 2023
Vortex ERA5 39.96N, 72.73W	Vortex	January 2000	March 2023
Vortex MERRA-2 39.96N, 72.73W	Vortex	January 2000	January 2023
Vortex ERA5 39.54N, 73.42W	Vortex	January 2000	March 2023
Vortex MERRA-2 39.54N, 73.42W	Vortex	January 2000	January 2023

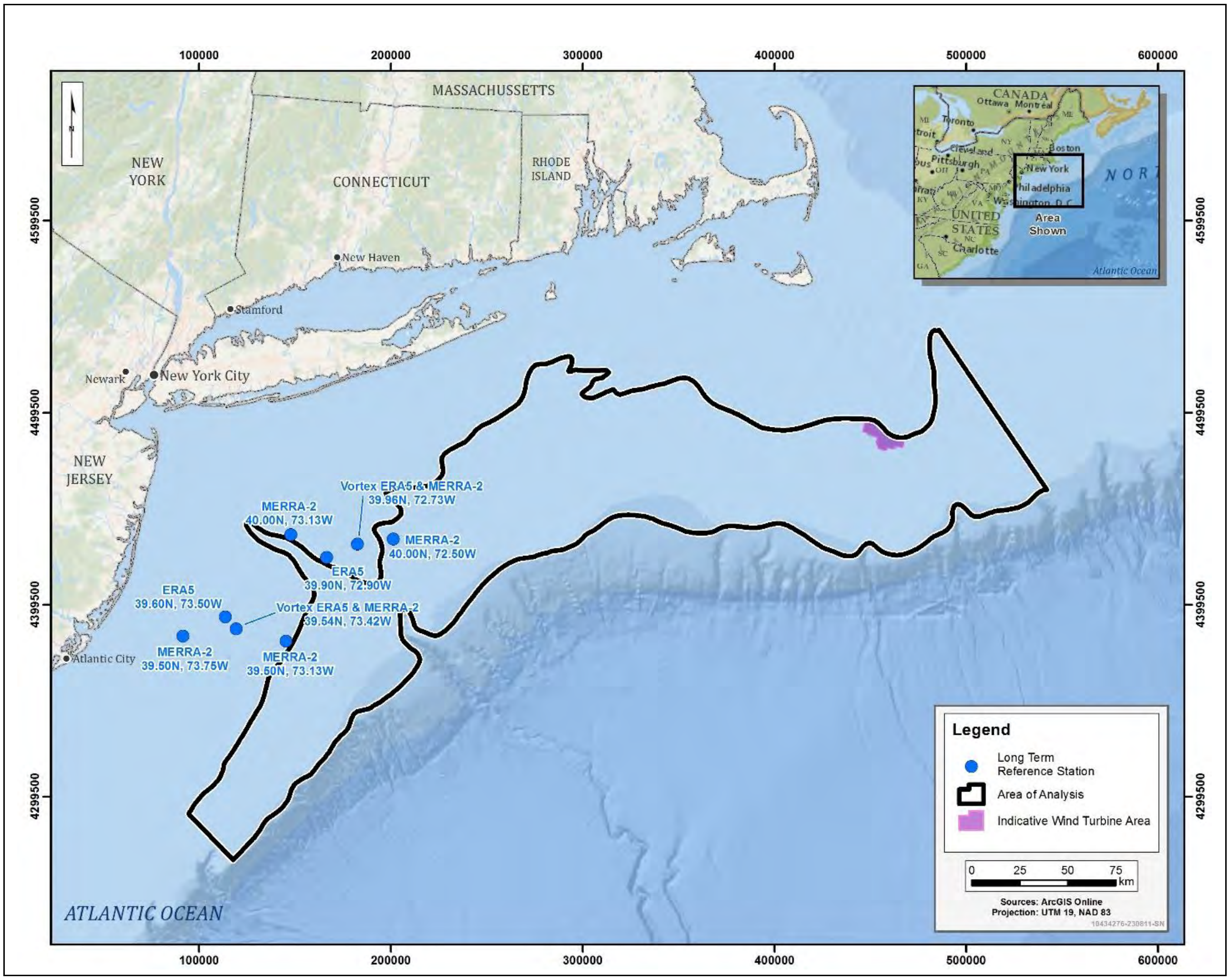


Figure 4-1 Location of the East Coast Z1 wind farm and potential reference data sources

Further information regarding long-term reference data sources typically used by DNV is included in Appendix B. A review of the suitability and use of these sources of data reference in the analysis is provided below.

4.1.2.2 Reference data consistency

The consistency of each source of reference data was evaluated through a comparison to the regional trends, a review of available station maintenance logs, and a statistical change point analysis.

Figure 4-2 shows a plot of seasonally-normalized 12-month moving average wind speeds for the reference data sources.

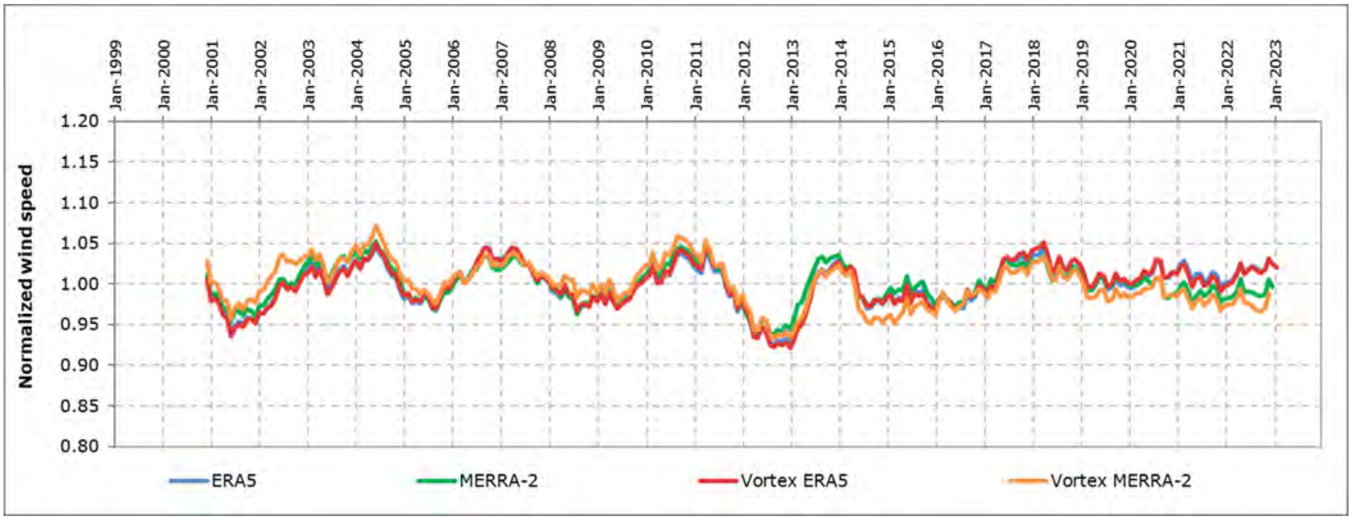


Figure 4-2 Reference data seasonally-normalized 12-month moving average wind speeds

The ERA5 data have inconsistent trend in this area in the later part of its period of record; therefore, ERA5 and Vortex ERA5 have not been considered further. The remaining stations appear suitable for consideration as long-term references in the analysis and have been correlated to the site data as reported in Section 4.2.2.

4.1.2.3 Quality of correlation

To determine whether use of the reference data will reduce uncertainty, a correlation of daily mean wind speeds between each consistent reference station and the site was completed. The results of this analysis are summarized in Table 4-3.

Table 4-3 Summary of correlations to 140 m site data

Device	Reference station	Coefficient of determination, R^2
E05_N	MERRA-2 40.00N, 72.13W	0.92
E05_N	MERRA-2 40.00N, 73.25W	0.91
E05_N	Vortex MERRA-2 39.96N, 72.73W	0.93
E05_SW	MERRA-2 39.50N, 73.13W	0.87
E05_SW	MERRA-2 39.50N, 73.75W	0.89
E05_SW	Vortex MERRA-2 39.54N, 73.42W	0.92
E06_S	MERRA-2 39.50N, 73.13W	0.88
E06_S	MERRA-2 39.50N, 73.75W	0.91
E06_S	Vortex MERRA-2 39.54N, 73.42W	0.93

DNV's analysis of these results and assessment of the uncertainties in the site period and reference period wind speeds concludes that the method with lowest uncertainty is to extend the site data to the 23.1-year period available from the MERRA-2 and Vortex MERRA-2 reference data.

For each of the selected reference data sources, independent correlations of daily data, binned by month, were used to synthesize reference period wind speeds at the FLSs. The resulting adjustments in the site period wind speeds and estimated long-term measurement height wind speeds at each of the measurement locations are shown in Table 4-4.

Table 4-4 Site period wind speed adjustments and estimated measurement height long-term wind speeds

Device	Height [m]	Long term adjustment	Wind speed [m/s]
E05_N	140	0.8%	10.2
E05_N	160	0.8%	10.3
E05_SW	140	-0.1%	10.0
E05_SW	160	-0.1%	10.1
E06_S	140	0.7%	10.0
E06_S	160	0.5%	10.1

4.1.3 Measurement-height wind speed uncertainties

Table 4-5 and Table 4-6 present the uncertainties in determining the long-term measurement-height wind speed for each of the measurement locations near the site.

Table 4-5 Long-term measurement-height wind regime uncertainties [% wind speed] at 140 m

Uncertainty sub-category	Lidar E05_N	Lidar E05_SW	Lidar E06_S
On-site data synthesis	0.2	1.8	0.8
Variability of 23.1 years of data	0.9	0.9	0.9
Correlation to reference station	1.4	1.2	0.9
Consistency of reference data	1.3	1.3	1.3
Wind frequency distribution - past[a]	1.3	1.2	1.1

a. Expressed as percent energy, not wind speed

Table 4-6 Long-term measurement-height wind regime uncertainties [% wind speed] at 160 m

Uncertainty sub-category	Lidar E05_N	Lidar E05_SW	Lidar E06_S
On-site data synthesis	0.2	1.9	0.8
Variability of 23.1 years of data	0.9	0.9	0.9
Correlation to reference station	1.6	1.3	0.8
Consistency of reference data	1.3	1.3	1.3
Wind frequency distribution - past[a]	1.3	1.2	1.1

a. Expressed as percent energy, not wind speed

4.2 Hub-height wind regime

4.2.1 Hub-height wind speed

To extrapolate the wind speed estimates from the measurement height to the 140 m and 155 m hub-heights, the average power law at each mast has been evaluated between all relevant measurement heights and applied to the upper-level measurements at each measurement location.

Table 4-7 Shear exponents and hub-height wind speeds

Device	Height [m]	Primary measurement height long-term wind speed [m/s]	Measured wind shear exponent	140 m wind speed estimate [m/s]	155 m wind speed estimate [m/s]
E05_N	140	10.2	0.09	10.2	-
E05_N	160	10.3	0.09	-	10.3
E05_SW	140	10.0	0.10	10.0	
E05_SW	160	10.1	0.10	-	10.1
E06_S	140	10.0	0.09	10.0	-
E06_S	160	10.1	0.09	-	10.1

Analysis of the shear data indicated that the seasonal and diurnal variations in the shear exponent are consistent with DNV's expectations for the region.

4.2.2 Hub-height wind speed and direction distributions

Hub-height wind speed and direction distributions were developed by extrapolating the measured wind speed data on a time series basis. The frequency distributions for each FLS were scaled to the representative, long-term, hub-height, mean wind speed at each FLS.

A representative, long-term, hub-height wind rose and wind speed histogram are shown in Figure 4-3 for E05_N. Additional representative long-term hub-height wind speed and direction frequency distributions are shown in Appendix C.

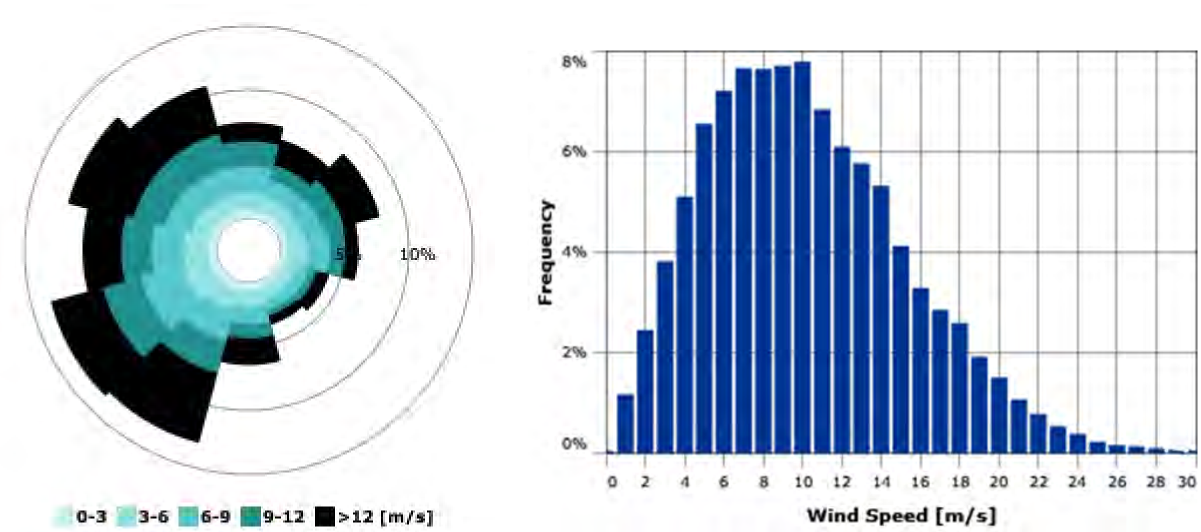


Figure 4-3 Lidar E05_N Long-term hub-height frequency distribution and wind rose at 140 m

4.2.3 Vertical extrapolation uncertainties

There is no material uncertainty at the FLS locations given the availability of measurements near hub-height.

4.3 Wind regime across the site

4.3.1 Modeling

The variation in wind speed over the East Coast Z1 sites were predicted using Vortex mesoscale model. E05_N has been used to initiate the wind flow modeling used to predict the long-term wind regimes at the Zone 1 turbine locations in Figure 4-3 shows the wind speed variation across East Coast Zone 1 at 140 m based on the Vortex mesoscale model and calibrated to the long-term mean wind speed at E05_N. The wind speed range is between 10.0 m/s and 10.8 m/s. Generally, the wind speed increases with the distance to shore with the highest wind speed to the east of the Area of Analysis.

Figure 4-5 shows the external wake effect caused by the neighboring wind farms across East Coast Zone 1. Based on publicly available information, DNV derived representative turbine layouts for the sake of external wake modelling and estimation. The locations of these representative turbine layouts and Lease Areas are illustrated in Figure 4-5. Given the early stage of development of several of the neighboring projects, some project information is missing such as the turbine layouts, the turbine types and hub heights. Therefore, it is not possible to exactly model their wake effects on the East Coast Z1 project. DNV has estimated the wake effects of the neighboring projects assuming the same turbine model as the East Coast Z1 Wind Farm. The external wake effect range is 93.0% to 100.0% with the external wake effect being higher in areas close to neighboring wind farms. When additional information about the neighboring wind farms becomes available, it is recommended that this analysis is updated to reflect the impact of the neighboring wind farms.

Based on water depth, wind speed variation and external wake effect across the Area of Analysis, DNV has chosen a Wind Turbine Area as shown in Figure 4-4 and Figure 4-5. DNV did not perform detailed layout optimization and, as such, no environmental constraint analysis was done. DNV has not performed a site visit to determine site suitability nor micro sited the turbine locations. The Wind Turbine Area chosen in this analysis is indicative for wind resource characterization and preliminary energy assessments only and should not be considered as a recommendation.

Uncertainty in the results was minimized in the analysis by initiating turbines from the most representative floating Lidar and using the Vortex mesoscale wind speed map to inform the wind speed variation across the site. The wind speed variation predicted by Vortex is generally consistent with measurements recorded near the site, showing an increase of the wind speeds moving northeast away from the shore. The initiation measurement location for each turbine is indicated in Appendix C. Through this approach, the predicted long-term mean wind speeds at each turbine at the proposed hub-heights were developed as shown in Appendix C. The average long-term wind speeds for the wind farms as a whole at each hub-height is 10.6 m/s for Indicative layout 01 (140 m hub-height) and 10.7 m/s for Indicative layout 02 (155 m hub-height).

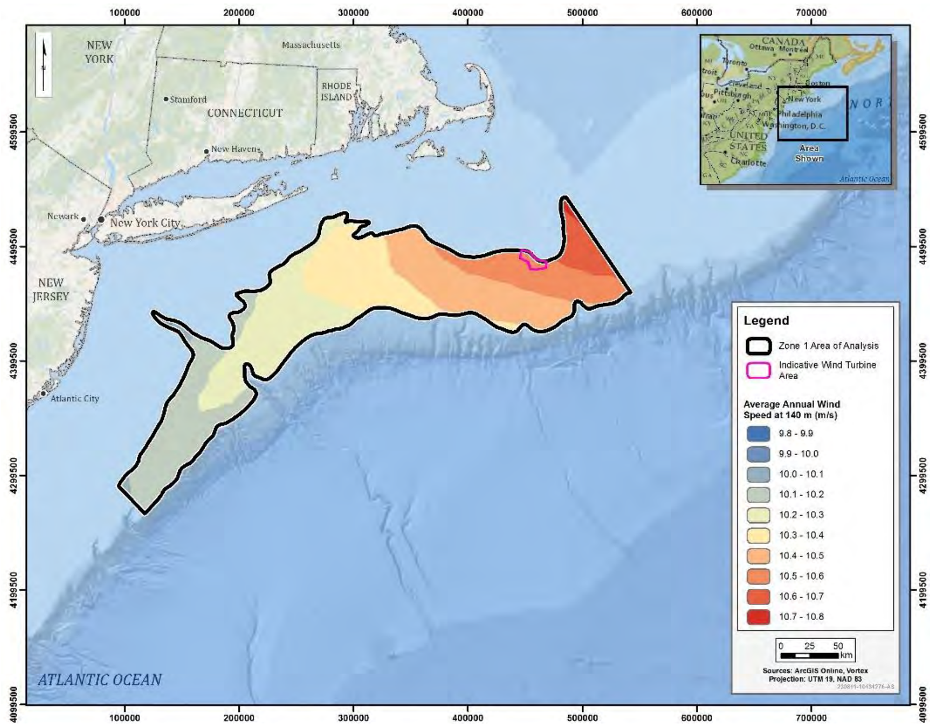


Figure 4-4 Long-term wind speed across East Coast Zone 1 at 140 m

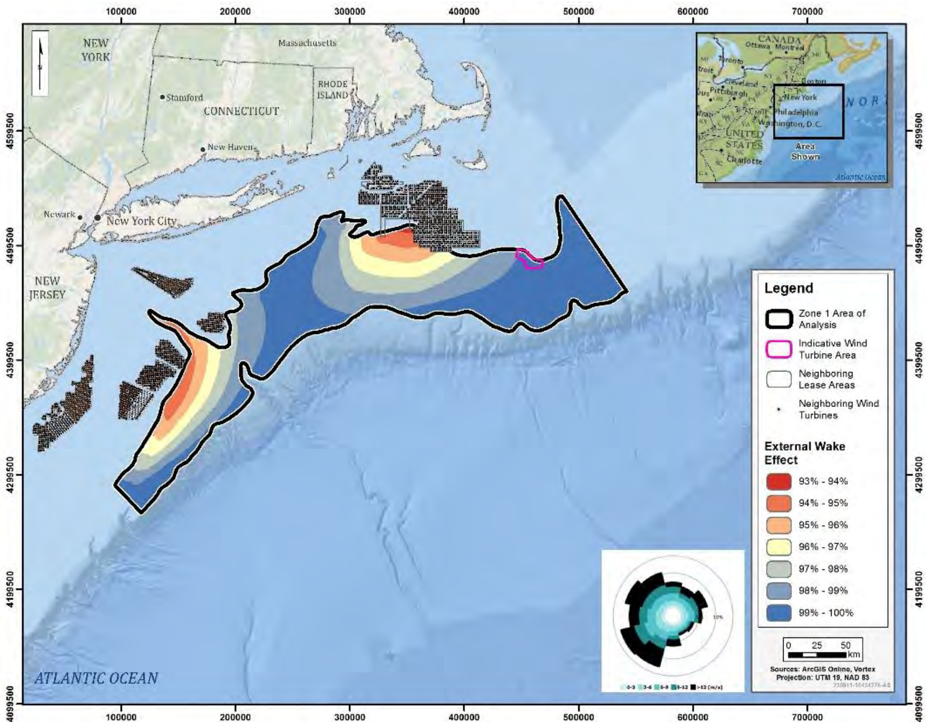


Figure 4-5 External wake effect across East Coast Zone 1 at 140 m

4.3.2 Spatial variation uncertainties

Table 4-8 quantifies the spatial variation uncertainty for the East Coast Z1 projects, given the following considerations:

- Wind speed variation for offshore projects is generally very low, and this is supported by Vortex, resulting in lowered uncertainty.
- The wind speed variation predicted by Vortex mesoscale model is generally consistent with measurements recorded near the site, resulting in lower uncertainty.
- The extrapolation distance from E05_N is significantly high, resulting in higher uncertainty. DNV would recommend having on-site measurements.

Table 4-8 Spatial extrapolation uncertainties [% wind speed]

Uncertainty category	Indicative layout 01	Indicative layout 02
Spatial extrapolation	2.0	2.0

4.4 Turbulence

Post-processed turbulence intensity measurements were available at the floating Lidars. However, it is widely accepted that turbulence intensity measurements (TI) from Lidar devices (volume measurements) are not directly comparable to turbulence intensity measurements from meteorological masts using cup anemometers (point measurements), which is currently the wind industry standard. DNV has reviewed the measured TI from the FLSs found the turbulence intensity to be higher than expected.

As no suitable measures of wind speed standard deviation were available at the sites, an assumption was made for ambient turbulence intensity, based on data from the Woods Hole Oceanographic Institution (WHOI) Air-sea Interaction Tower (ASIT) [8] and DNV’s experience of the regional offshore wind regime, using an IEC fit profile considering a turbulence intensity of 4.5% at 15m/s [3].

5 ENERGY ANALYSIS

5.1 Gross and net energy estimates

The gross energy production at the individual turbine locations have been calculated using the WindFarmer software, the results of the wind flow modeling and the hypothetical turbine power curves derived by DNV.

Table 5-1 and Table 5-2 provide the aggregated results for the projects.

The projected net energy production of the wind farms shown in and Table 5-1 and Table 5-2 were calculated by applying a number of energy loss factors to the gross energy production. The predictions represent the estimates of the annual production expected over the first 25 years of operation. Wind farms typically experience some time dependency in availability and other loss factors.

Table 5-1 Energy production summary – Indicative Layout 01

	Wind Farm Rated Power	**1005.0**	**MW**
	Gross Energy Output	**5453.8**	**GWh/annum**
1	**Turbine interaction effects**	**91.0**	**%**
1a	Internal wake and blockage effects	91.2	% Project specific
1b	External wake effect	99.7	% Project specific
1c	Future wake effect	100.0	% Project specific
2	**Availability**	**94.1**	**%**
2a	Turbine availability	95.2	% Project specific
2b	Balance of plant availability	99.0	% DNV standard
2c	Grid availability	99.8	% DNV standard
3	**Electrical efficiency**	**97.5**	**%**
3a	Operational electrical efficiency	97.5	% Project specific
3b	Wind farm consumption	100.0	% DNV standard
4	**Turbine performance**	**96.7**	**%**
4a	Generic power curve adjustment	100.0	% DNV standard
4b	High wind speed hysteresis	99.2	% Project specific
4c	Site-specific power curve adjustment	99.3	% DNV standard
4d	Sub-optimal performance	99.5	% DNV standard
4e	Blade and turbine degradation	98.7	% Project specific
4f	Aerodynamic device degradation	100.0	% Project specific
5	**Environmental**	**100.0**	**%**
5a	Performance degradation – icing	100.0	% Project specific
5b	Icing shutdown	100.0	% Project specific
5c	Temperature shutdown	100.0	% Project specific
5d	Site access	100.0	% Project specific
6	**Curtailments**	**100.0**	**%**
6a	Wind sector management	100.0	% Not considered
6b	Grid curtailment	100.0	% Not considered
6c	Noise, visual, and environmental curtailment	100.0	% Not considered
	Total Losses (%)	**80.6**	**%**
	Asymmetric production effect	**99.8**	**%**
	Net Energy Output	**4395.8**	**GWh/annum**
	Net Capacity Factor	**49.9**	**%**

Table 5-2 Energy production summary – Indicative Layout 02

	Wind Farm Rated Power	**1008.0**	**MW**
	Gross Energy Output	**5387.4**	**GWh/annum**
1	91.2	**91.2**	**%**
1a	Internal wake and blockage effects	91.4	% Project specific
1b	External wake effect	99.8	% Project specific
1c	Future wake effect	100.0	% Project specific
2	**Availability**	**94.1**	**%**
2a	Turbine availability	95.2	% Project specific
2b	Balance of plant availability	99.0	% DNV standard
2c	Grid availability	99.8	% DNV standard
3	**Electrical efficiency**	**97.5**	**%**
3a	Operational electrical efficiency	97.5	% Project specific
3b	Wind farm consumption	100.0	% DNV standard
4	**Turbine performance**	**96.5**	**%**
4a	Generic power curve adjustment	100.0	% DNV standard
4b	High wind speed hysteresis	98.9	% Project specific
4c	Site-specific power curve adjustment	99.3	% DNV standard
4d	Sub-optimal performance	99.5	% DNV standard
4e	Blade and turbine degradation	98.7	% Project specific
4f	Aerodynamic device degradation	100.0	% Project specific
5	**Environmental**	**100.0**	**%**
5a	Performance degradation – icing	100.0	% Project specific
5b	Icing shutdown	100.0	% Project specific
5c	Temperature shutdown	100.0	% Project specific
5d	Site access	100.0	% Project specific
6	**Curtailments**	**100.0**	**%**
6a	Wind sector management	100.0	% Not considered
6b	Grid curtailment	100.0	% Not considered
6c	Noise, visual, and environmental curtailment	100.0	% Not considered
	Total Losses (%)	**80.6**	**%**
	Asymmetric production effect	**99.8**	**%**
	Net Energy Output	**4341.5**	**GWh/annum**
	Net Capacity Factor	**49.1**	**%**

Table 5-1 and Table 5-2 includes potential sources of energy loss that have been either assumed to be the DNV standard values or estimated for this project. Project-specific aspects of the loss estimates are provided in the following bullets:

- 1a Internal wake and blockage effects – DNV has recently undertaken a validation of its offshore wake modeling methodology using operational data from a number of offshore wind farms in North Europe [9][10]. As a result of that work, DNV estimates offshore wake only turbine interaction effects using the DNV WindFarmer: Analyst Eddy Viscosity wake model with Large Wind Farm correction applied.

- 1b External wake effect – The effects of the neighboring wind farms from Leases OCS-A 0501, OCS-A 0520, OCS-A 0521, OCS-A 0522, and OCS-A 0534 have been considered in the wake modelling of this analysis.
- 1c Future wake effect – No future wake effects were considered in the analysis.
- 2a Turbine availability – For both indicative layouts, DNV has made a starting assumption for the turbine availability that could be expected from the project based on the wave climate, anticipated O&M access strategy and some assumptions regarding the reliability and track record of the turbine technology to be installed in the future, based on DNV experience.
- 3a Operational electrical efficiency – An electrical loss of 2.5% has been assumed for both indicative layouts assuming an offshore metering point. Details of the specific balance of plant infrastructure and grid connection point are not available at this stage given the preliminary nature of this assessment. As such, this estimate is not based on detailed modeling or project specific calculations.
- 4b High wind speed hysteresis – The 28.0 m/s turbine cut-out wind speed was reduced to 25.0 m/s to estimate this loss.
- 4c Site-specific power curve adjustment – It is assumed that there are no site-specific wind flow issues which will adversely affect the performance of the turbines. The loss includes a 0.75% loss to account for the average blockage effect inherent in power performance test measurements [10].
- 4d Sub-optimal performance – It is assumed that the loss associated with material performance deviations from the optimal power curve is 0.5%.
- 4e Blade and turbine degradation – This assumption is to account for the performance degradation of the turbine drivetrain and rotor assembly. The loss factor applied assumes that the future projects will have blade leading edge protection systems installed and that a proactive plan to manage leading edge erosion based on regular blade inspections and repair will be in place throughout the project lifetime. For future projects, it is recommended that an Independent Engineer reviews the plans to manage leading edge erosion as part of a full due diligence exercise.
- 4f Aerodynamic device degradation – DNV assumes that aerodynamic devices will not be used at the projects.
- 5a Performance degradation – icing – It has been assumed that ice accretion on the turbine casing is not applicable at these locations.
- 5b Icing shutdown – It has been assumed that ice accretion on the turbine casing is not applicable at these locations.
- 5c – Temperature shutdown – DNV has assumed the operating range is between -10°C and 35°C for all turbine models.
- 5d Site access – Site access due to the project being located offshore is accounted for as part of loss 2a – Turbine availability.
- 6a Wind Sector Management – No wind sector management has been considered.
- 6b Grid curtailment – No grid curtailment loss has been considered.
- 6c Noise, visual, and environmental curtailment – No studies were conducted by or supplied to DNV for consideration.

5.1.1 Uncertainty in loss factors

Table 5-3 quantifies this uncertainty for the East Coast Z1 project.

Table 5-3 Loss factor uncertainties

Uncertainty subcategory	% Energy: Indicative layout 01	% Energy: Indicative layout 02
Wakes	2.4	2.3
Availability	2.6	2.6
Electrical	0.6	0.6
Turbine performance	2.6	2.6
Environmental	0.0	0.0
Curtailment	0.0	0.0

5.2 Seasonal and diurnal distributions

The expected long-term average seasonal and diurnal variation in energy production has been approximately assessed from the available data at the project site. The long-term average seasonal and diurnal variation in air density was developed from temperature records and pressure records at MERRA-2 40.50N -69.38W and scaled to the site-predicted long-term annual site air density. The measured wind speeds extrapolated to hub-height at Lidar E05_N were adjusted to reflect the predicted long-term mean wind speeds and monthly profiles of each site mast.

A simulated time series of production data was produced using the time series of density, wind direction, and wind speed and the WindFarmer energy model developed for the East Coast Z1 project.

The resulting expected seasonal and diurnal variations in energy production at 140 m and 155 m are presented in Appendix C.6 in the form of a 12-month by 24-hour (12 x 24) matrix. It is noted that the uncertainty associated with the prediction of any given month or hour of day is significantly greater than that associated with the prediction of the annual energy production. It is also noted that the results presented are inclusive of wake and hysteresis losses only.

6 UNCERTAINTY

The main sources of deviation from the central estimate (P50) have been quantified and combined using a probabilistic model, assuming full independence between the sources. Additional details on this process are given below.

6.1 Inter-annual variability

Even if the central estimate was perfectly defined, wind farm energy production varies from year to year due to a number of factors, including natural variation in the wind regime, variations in system availability, and variations in environmental losses, categorized as inter-annual variability. Table 6-1 presents the inter-annual variability estimated for the site.

Table 6-1 Inter-annual variability uncertainty

Uncertainty subcategory	%	Unit
Wind frequency distribution - future	2.0	Energy
Inter-annual variability of the wind	4.5	Wind Speed
Availability	3.0	Energy

6.2 Converting wind speed uncertainties to energy uncertainties

Uncertainties in the estimate of the site wind speed were described in Section 3.3, Section 4.1.3, Section 4.2.3 and Section 4.3.2.

Wind speed uncertainties are converted to energy uncertainties using the sensitivity ratio. The sensitivity ratio shows how sensitive the net energy production is to changes in wind speed and is dependent mainly on the wind speed distribution and power curve of the turbine. For example, with a sensitivity ratio of 1.50, a 2.0% reduction in wind speed at all masts would lead to a 3.0% reduction in net energy production. The sensitivity ratio is non-linear over large ranges of wind speed, which has been accounted for in this analysis. The average calculated sensitivity ratios for the East Coast Z1 project for variations of 10% on wind speed are 0.98 for Indicative layout 01 and 0.97 for Indicative layout 02.

6.3 Project uncertainties

A summary of the project uncertainties considered as part of this analysis are show in Table 6-2 and Table 6-3. The 1-year numbers presented are representative of any individual year in the 25-year life of the project. The 10-year numbers are representative of the first 10 years of operation.

Table 6-2 Uncertainty in the projected energy output for East Coast Z1 – Indicative layout 01

Source of uncertainty/variability	[GWh/annum]	Equivalent standard deviation [%]
Measurement accuracy	151.8	3.5
Long-term measurement height wind regime	113.9	2.6
Vertical extrapolation	0.0	0.0
Spatial extrapolation	90.8	2.1
Loss factors	196.0	4.5
Inter-annual variability	225.6	5.1
Overall uncertainty		
Future period under consideration		
1-year	**398.1**	**9.1**
10-year	**290.6**	**6.6**
25-year	**281.5**	**6.4**

Table 6-3 Uncertainty in the projected energy output for East Coast Z1 – Indicative layout 02

Source of uncertainty/variability	[GWh/annum]	Equivalent standard deviation [%]
Measurement accuracy	148.1	3.4
Long-term measurement height wind regime	117.6	2.7
Vertical extrapolation	0.0	0.0
Spatial extrapolation	89.4	2.1
Loss factors	191.9	4.4
Inter-annual variability	220.7	5.1
Overall energy uncertainty		
Future period under consideration		
1-year	**394.2**	**9.1**
10-year	**290.4**	**6.7**
25-year	**283.7**	**6.5**

The results of the probabilistic simulation of net energy production are summarized in Table 6-4 and Table 6-5.

Table 6-4 Summary of project net average energy production – Indicative layout 01

Probability of exceedance	1 year in 25 [GWh/a]	10-year average [GWh/a]	25-year average [GWh/a]
50%	4403.9	4415.9	4395.8
75%	4139.1	4222.6	4206.4
90%	3893.7	4043.4	4035.0
95%	3744.2	3937.5	3929.1
99%	3455.0	3738.4	3741.3

Table 6-5 Summary of project net average energy production – Indicative layout 02

Probability of exceedance	1 year in 25 [GWh/a]	10-year average [GWh/a]	25-year average [GWh/a]
50%	4348.2	4362.0	4341.5
75%	4086.1	4168.4	4150.9
90%	3843.0	3989.8	3978.0
95%	3693.5	3884.8	3877.0
99%	3407.2	3693.9	3688.4

7 OBSERVATIONS AND RECOMMENDATIONS

DNV makes the following observations and recommendations regarding this analysis:

- DNV notes the following observations and opinions regarding uncertainty.

    a. Aside from inter-annual variability, the uncertainty in the analysis is driven by loss factor uncertainty and measurement uncertainty.

    b. Uncertainty in the analysis could also be reduced by obtaining commercially available turbine power curves and assessing the electrical systems and access strategies to inform more refined estimates for electrical loss and turbine availability.

    c. The extrapolation distance from E05_N is significantly high, resulting in higher spatial extrapolation uncertainty. DNV would recommend having on-site measurements.

- DNV has derived hypothetical power curves based on current and expected trends in turbine technology.

- The sensitivity of energy due to changes in wind speed (sensitivity ratio) for offshore wind projects is typically lower due to the higher wind speeds, but is also dependent on the turbine characteristics such as swept rotor size and rated power. Given the high wind speeds in the East Coast Zone 1 site, and the assumed turbine characteristics of the hypothetical turbines modeled for this preliminary assessment, the net energy is less sensitive to changes in wind speed and the sensitivity ratio approaches unity for this preliminary assessment. DNV notes that the sensitivity ratio and therefore the project uncertainty may vary materially depending on the final commercially available turbines selected for the projects.

- The variation in wind speed over the East Coast Zone 1 Area of Analysis were predicted using Vortex mesoscale model. The wind speed variation across Zone 1 at 140 m is based on the Vortex mesoscale model and calibrated to the long-term mean wind speed at the floating lidar E05_N. The wind speed range is between 10.0 m/s and 10.8 m/s. Generally, the wind speed increases with the distance to shore with the highest wind speed to the east of the Area of Analysis.

- Based on publicly available information, DNV derived representative turbine layouts of neighboring wind farms for the sake of external wake modelling and estimation. Given the early stage of development of several of the neighboring projects, it is not possible to accurately model their wake effects on the Zone 1 project. DNV has estimated the wake effects of the neighboring projects assuming the same turbine model as the Zone 1 Wind Farm. The external wake effect range is 93.0% to 100.0% with the external wake effect being higher in areas close to neighboring wind farms.

- NYSERDA has requested that DNV design two indicative wind farm layouts. DNV notes that alternative, non-gridded layouts are possible within the Lease Areas and that gridded layouts have been assumed for this preliminary assessment for simplicity. The gridded layouts are not a reflection of New York State policy on preference for any predetermined layout or approach thereto. Project capacities for each indicative layout were maintained at approximately 1000 MW and are likewise generically identified for hypothetical purposes befitting a preliminary assessment and are not a reflection of DNV or New York State's opinions regarding project sizing.

  Based on water depth, wind speed variation and external wake effect across the Area of Analysis, DNV has chosen a Wind Turbine Area. For the indicative layouts used in this study, DNV did not perform detailed layout optimization and, as such, no environmental constraint analysis was done. DNV has not performed a site visit to determine site suitability nor micro sited the turbine locations. The layouts used in this analysis are indicative for wind resource characterization and preliminary energy assessments only and should not be considered as a recommendation.

- The potential external wake effects from five neighboring projects on the two indicative layouts have been considered in this assessment. These projects are at various stages of development and publicly available coordinates for project turbine locations are not available. However, based on publicly available information, DNV derived representative turbine layouts. Details of these neighboring wind farms are presented in Section 2.4. When additional information about these wind farms becomes available, it is recommended that the impacts of the proposed wind farms are reconsidered.
- No wind sector management strategy has been modeled, and DNV has not included any losses which may be associated with this. However, given the large inter-turbine spacings assumed, DNV considers it unlikely a wind sector management strategy would be required. For future projects, it is recommended that the turbine supplier be approached at an early stage to gain approval for the indicative layouts and that an Independent Engineer reviews the manufacturer's conclusions as part of a full due diligence exercise.
- DNV has recently undertaken a validation of its offshore wake modeling methodology using operational data from a number of offshore wind farms in North Europe. As a result of that work, DNV estimates offshore wake only turbine interaction effects using the DNV WindFarmer: Analyst Eddy Viscosity wake model with Large Wind Farm correction applied.
- DNV has undertaken, and continues to undertake, extensive research into turbine interaction effects. Through this research, evidence suggests turbines cause lateral as well as upstream effects, which together contribute to a resistance, or blockage, on the wind flow, deflecting some of the flow above and around the wind farm. DNV has estimated the wind flow blockage effects based on the assumed project configurations and included any resulting loss in this analysis.
- DNV has applied standard assumptions for balance of plant and grid availability as a starting assumption.
DNV notes that they may vary materially from standard assumptions and can be mitigated to some extent, especially in early years of the project, through appropriate contractual provisions on a project-specific basis.
- This estimated operational electrical efficiency loss is not based on detailed modeling or project specific calculations given the preliminary nature of this assessment.

8 REFERENCES

[1] Port Site Acceptance Test of Two EOLOS FLS-200 Lidar Buoys in Avalon, NJ reported in DNV report dated 23 August 2019 for EOLOS FLS-200 buoy serial numbers ZX842 and ZX844.

[2] Federal Aviation Administration. Circle search for cases, retrieved March 2023, https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=showCircleSearchForm

[3] "Wind turbines – Part 12-1: Power performance measurements of electricity producing wind turbines, IEC 61400-12-1: 2005," International Electrotechnical Commission, Geneva, Switzerland, 2005.

[4] "Validation of EOLOS floating Lidar against Offshore Meteorological Mast Ijmuiden", ECN, March – October 2015.

[5] "Carbon Trust OWA Roadmap for the Commercial Acceptance of Floating Lidar Technology", Version 2.0, October 2018.

[6] Unit pre-deployment verifications at the Pershore UK remote sensing test site and against the Narec NOAH Offshore Met Tower reported in DNV reports dated 1 August 2019 and 3 September 2019 for EOLOS FLS-200 buoy serial numbers ZX842 and ZX844 (and a metocean comparison report against the Narec NOAH Offshore Met Tower reported in DNV report dated 24 July 2019 for EOLOS FLS-200 buoy serial numbers ZX842 and ZX844).

[7] IEA Wind. "18. Floating LiDAR Systems, First edition, 2017", Document: IEA Wind TCP RP 18. Floating LiDAR Systems, September 2017

[8] MassCEC MetOcean Data Initiative. https://www.masscec.com/masscec-metocean-data-initiative

[9] Beckford, T., "Offshore turbine interaction - wake validation and blockage", WindEurope Resource Assessment, June 2019.

[10] Papadopoulos, I., "Improving confidence in offshore wake and energy yield predictions through innovative, statistically meaningful and detailed operational validations", Global Offshore Wind, June 2019.

APPENDIX A – Wind farm site information

Figure A-1 E05 (left) and E06 (right) EOLOS FLS-200 buoys at port

APPENDIX B – Wind data measurement and analysis

B.1 E05_N floating Lidar location

Buoy floating Lidar device configuration

Site name	East Coast Z1	Elevation [m]	Eastings [m]	Northings [m]	Coordinate system	Datum	Zone
Device name	E05_N	0	695058	4426856	UTM	WS84	18N
Installation date	2019-08-12						

Device description

Device Model	EOLOS FLS-200
Lidar Type	ZephIR ZX300M
Scan Heights [m MSL]	20, 40, 60, 80, 100, 120, 140, 160, 180, 200
Averaging Period [min]	10

Note that the location given above is the initial deployment location. There was occasional movement of the device throughout the deployment period, but given the scale of the movements relative to the distance from the shore and the resolution of the wind maps which were used to model flow variation over the area, these changes in location were not considered to have a significant impact on the analysis and the location above has been used in the analysis.

B.2 E05_SW floating Lidar location

Buoy floating Lidar device configuration

Site name	East Coast Z1	Elevation [m]	Eastings [m]	Northings [m]	Coordinate system	Datum	Zone
Device name	E05_SW	0	621173	4371530	UTM	WS84	18N
Installation date	2022-01-28						

Device description

Device Model	EOLOS FLS-200
Lidar Type	ZephIR ZX300M
Scan Heights [m MSL]	20, 40, 60, 80, 100, 120, 140, 160, 180, 200
Averaging Period [min]	10

Note that the location given above is the initial deployment location. There was occasional movement of the device throughout the deployment period, but given the scale of the movements relative to the distance from the shore and the resolution of the wind maps which were used to model flow variation over the area, these changes in location were not considered to have a significant impact on the analysis and the location above has been used in the analysis.

B.3 E06_S floating Lidar location

Buoy floating Lidar device configuration

Site name	East Coast Z1	Elevation [m]	Eastings [m]	Northings [m]	Coordinate system	Datum	Zone
Device name	E06	0	634944	4378580	UTM	WGS84	18N
Installation date	2019-09-04						

Device description

Device Model	EOLOS FLS-200
Lidar Type	ZephIR ZX300M
Scan Heights [m MSL]	20, 40, 60, 80, 100, 120, 140, 160, 180, 200
Averaging Period [min]	10

Note that the location given above is the initial deployment location. There was occasional movement of the device throughout the deployment period, but given the scale of the movements relative to the distance from the shore and the resolution of the wind maps which were used to model flow variation over the area, these changes in location were not considered to have a significant impact on the analysis and the location above has been used in the analysis.

B.4 Device data coverage summary

Figure B-1 and Figure B-2 summarize data coverage by wind speed and wind direction. Sensor labels indicate the lidar, instrument type, height, and orientation.

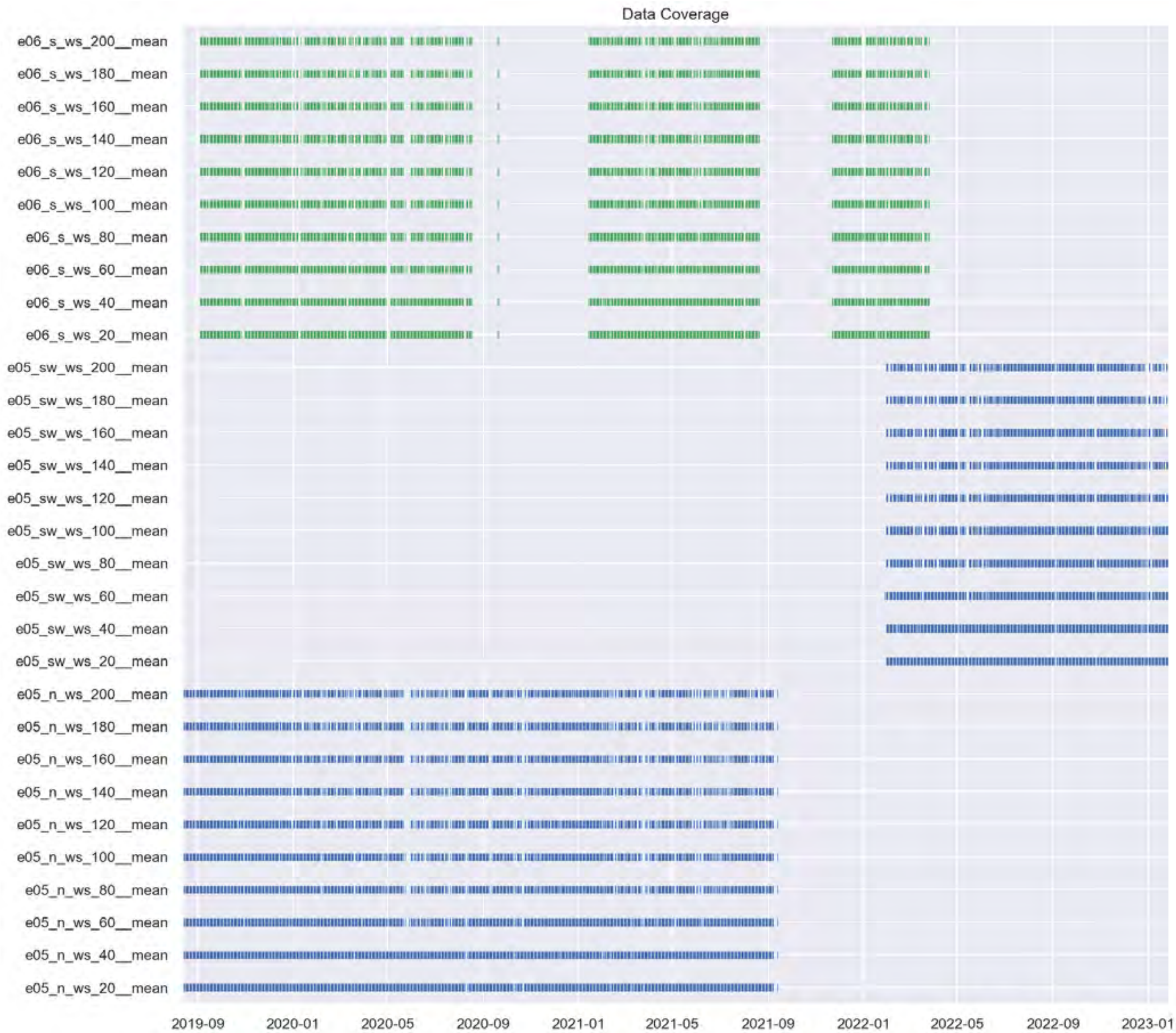


Figure B-1 Wind speed data coverage

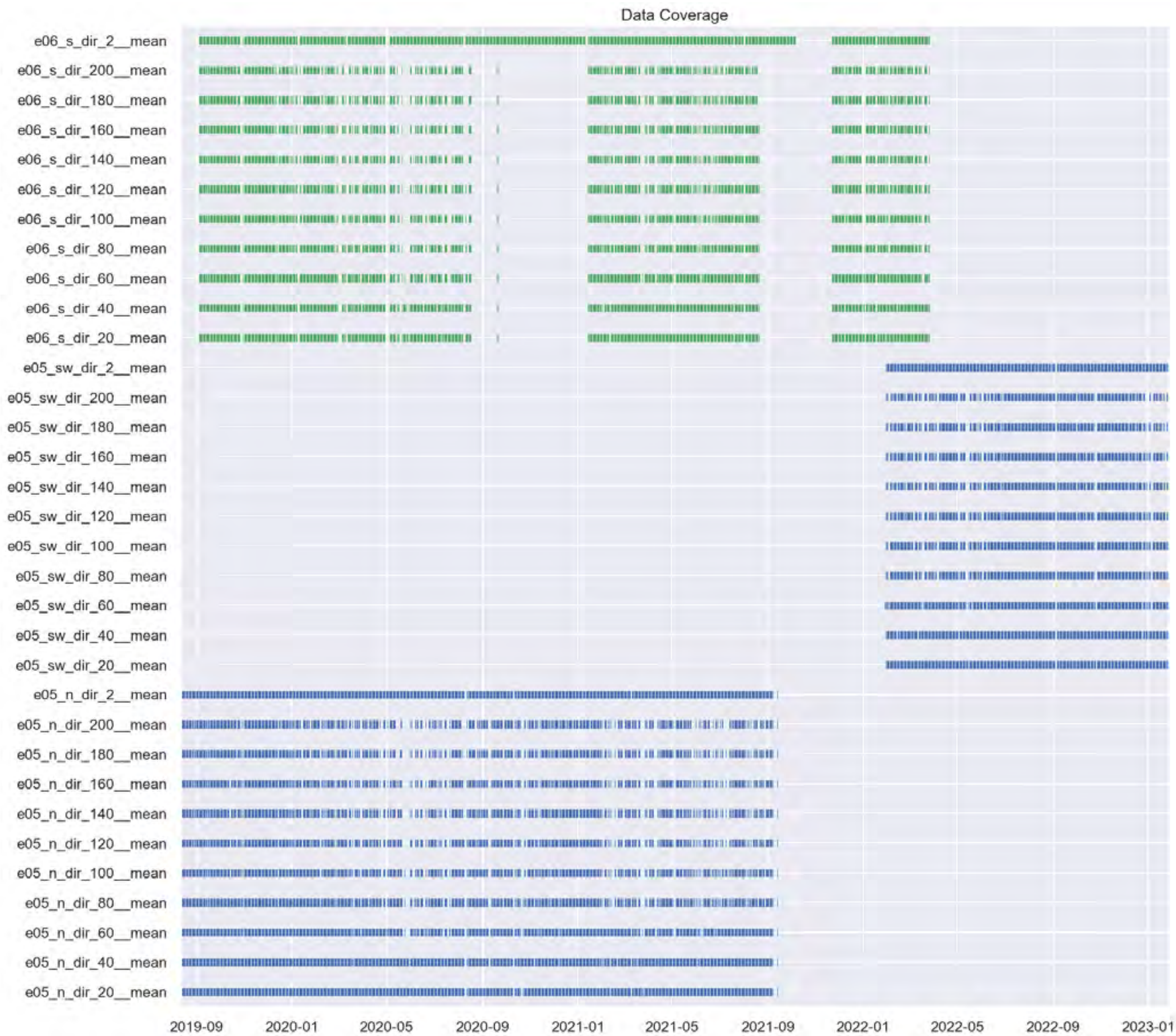


Figure B-2 Wind direction data coverage

B.5 Reference wind data

B.5.1 MERRA-2 data

The Modern Era Retrospective-analysis for Research and Applications, Version 2 (MERRA-2) data set has been produced by the National Aeronautics and Space Administration (NASA) by assimilating satellite observations with conventional land-based meteorology measurement sources using the Goddard Earth Observing System, Version 5.12.4 (GEOS-5.12.4) atmospheric data assimilation system. The analysis is performed at a spatial resolution of 0.625° longitude by 0.5° latitude. DNV typically procures hourly time series of two-dimensional diagnostic data, at a surface height of 50 m [B-1] for suitable grid cells near the project site.

B.5.2 ERA5 data

ERA5 is the fifth generation of European Centre for Medium-Range Weather Forecasts (ECMWF) atmospheric reanalysis of the global climate. It provides data at a considerably higher spatial and temporal resolution than its predecessor ERA-Interim: hourly analysis fields are available at a horizontal resolution of 31 km and include wind data at 100 m above ground level, as well as surface air temperature and air pressure. ERA5 incorporates vast amounts of historical measurement data, including satellite-, commercial aircraft-, and ground-based data [B-2][B-3].

B.5.3 Vortex Data

Vortex SERIES is a commercially-sold long-term reference data source, primarily based on the Weather Research and Forecasting (WRF) model, a mesoscale model developed and maintained by a consortium of more than 150 international agencies, laboratories, and universities. Its downscaling system uses a number of high-resolution inputs such as MERRA-2 or ERA5, as well as analyses of soil temperature and moisture, sea surface temperature, sea ice, and snow depth. Data are typically produced as a virtual hourly time series on a 3 km horizontal resolution, centered on the subject wind farm and at heights between 50 and 300 m above ground.

B.5.4 References

[B-1] National Aeronautics and Space Administration, MERRA-2, MDISC, https://disc.sci.gsfc.nasa.gov/mdisc/, MERRA-2 tavg1_2d_slv_Nx: 2d, 1-Hourly, Time-Averaged, Single-Level, Assimilation, Single-Level Diagnostics V5.12.4 (M2T1NXSLV), 1980-present.

[B-2] European Centre for Medium-Range Weather Forecasts, “ERA5 data documentation,” https://confluence.ecmwf.int/display/CKB/ERA5+data+documentation

[B-3] Copernicus, “Climate reanalysis,” https://climate.copernicus.eu/products/climate-reanalysis

B.5.5 Tables of monthly reference data

Table B-1 Wind speed statistics at the MERRA-2 40.00N, 73.13W

Month	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan	11.0	8.0	9.4	10.2	10.7	9.3	10.1	9.9	9.6	9.0	9.7	8.6	9.8	9.2	9.4	10.6	9.9	9.1	10.3	9.8	9.2	9.3	9.9	8.7
Feb	8.8	8.8	9.2	10.0	9.0	8.9	10.1	10.6	9.1	10.1	10.5	10.0	8.6	9.8	8.7	9.5	10.3	9.6	9.1	8.5	8.3	9.5	9.4	-
Mar	9.4	8.9	9.7	8.3	9.3	8.6	8.9	9.6	9.6	8.2	9.5	9.1	8.2	9.7	9.4	8.4	9.0	10.4	10.7	8.8	8.6	9.3	9.4	-
Apr	9.4	7.9	8.7	9.3	9.0	9.0	8.4	8.8	8.0	9.5	7.5	9.7	8.0	8.5	8.8	9.2	8.7	8.3	8.9	9.1	9.5	8.2	9.1	-
May	7.6	7.4	8.2	6.9	7.7	7.1	7.4	7.6	8.4	7.5	7.9	7.2	7.3	8.7	7.7	7.8	7.4	8.5	7.4	8.0	8.6	7.3	8.7	-
Jun	7.8	6.4	7.5	6.3	7.1	7.4	8.2	7.3	7.0	6.1	7.2	5.8	7.0	8.2	5.9	7.5	6.9	7.9	6.5	7.3	6.8	7.8	6.6	-
Jul	5.8	6.5	6.6	7.3	6.7	6.4	6.7	6.3	6.1	6.5	6.5	6.1	6.2	7.1	7.1	5.8	6.1	6.1	6.4	6.1	5.9	6.4	6.6	-
Aug	6.5	6.7	6.4	6.9	6.6	5.8	6.4	6.4	5.0	5.5	6.2	6.4	5.3	6.2	5.4	6.0	6.0	5.6	6.6	5.8	6.5	5.8	5.9	-
Sep	7.1	6.6	6.8	7.6	6.5	6.3	7.0	6.3	7.1	7.2	7.9	6.4	6.4	6.4	6.4	6.6	7.7	7.4	6.8	6.8	6.9	7.3	7.1	-
Oct	7.6	8.5	8.2	8.6	7.8	9.0	9.1	7.8	7.9	9.0	9.1	8.0	8.5	7.9	8.5	8.8	7.9	8.2	8.5	9.2	7.1	7.9	8.0	-
Nov	8.8	8.6	9.6	8.8	8.5	9.5	8.2	9.0	8.7	9.2	8.8	8.8	8.7	9.4	9.5	8.0	8.5	8.7	9.8	9.1	9.1	8.6	8.8	-
Dec	9.7	8.9	10.1	11.3	9.5	9.5	9.2	9.1	10.3	11.1	10.8	8.4	9.0	9.2	9.0	8.3	9.7	8.9	8.7	9.1	9.8	7.9	9.9	-
Annual	8.3	7.8	8.3	8.4	8.2	8.1	8.3	8.2	8.0	8.2	8.5	7.9	7.7	8.3	8.0	8.0	8.2	8.2	8.3	8.1	8.0	7.9	8.3	-

Table B-2 Wind speed statistics at the MERRA-2 40.00N, 72.50W

Month	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan	11.3	8.3	9.8	10.5	11.1	9.6	10.4	10.4	9.9	9.5	10.0	9.0	10.1	9.6	9.8	11.1	10.2	9.4	10.7	10.1	9.4	9.6	10.1	9.0
Feb	9.0	9.2	9.4	10.5	9.4	9.3	10.4	10.9	9.4	10.4	11.0	10.3	8.9	10.3	9.1	9.9	10.6	9.9	9.5	8.8	8.7	9.6	9.7	-
Mar	9.6	9.1	9.9	8.4	9.8	8.9	9.2	9.8	9.8	8.4	9.9	9.3	8.3	10.2	9.5	8.7	9.2	10.9	11.1	9.0	9.0	9.5	9.6	-
Apr	9.8	8.2	8.8	9.6	9.0	9.3	8.5	9.2	8.3	9.9	7.5	10.0	8.1	8.6	9.0	9.5	8.9	8.6	9.2	9.4	9.7	8.4	9.2	-
May	7.8	7.7	8.5	6.9	7.7	7.3	7.7	7.8	8.6	7.6	8.1	7.4	7.6	9.0	8.0	7.9	7.6	8.8	7.6	8.2	9.0	7.5	9.0	-
Jun	7.9	6.6	7.5	6.6	7.1	7.6	8.4	7.6	7.1	6.2	7.3	6.0	7.3	8.5	6.0	7.5	7.1	8.3	6.8	7.5	7.0	8.0	6.5	-
Jul	5.8	6.7	6.8	7.5	6.7	6.7	6.8	6.5	6.2	6.7	6.5	6.2	6.3	7.2	7.2	5.7	6.1	6.1	6.5	6.3	6.1	6.6	6.6	-
Aug	6.6	6.8	6.2	7.1	6.7	5.8	6.5	6.6	5.2	5.5	6.4	6.7	5.4	6.3	5.6	6.1	6.1	5.8	6.7	6.0	6.6	6.0	5.9	-
Sep	7.2	6.7	6.9	7.6	6.7	6.4	7.0	6.2	7.2	7.4	8.1	6.5	6.5	6.7	6.5	6.8	8.1	7.9	7.0	7.1	7.1	7.5	7.3	-
Oct	7.8	8.6	8.5	8.8	7.9	9.3	9.3	7.9	8.2	9.2	9.5	8.2	8.6	8.0	8.7	9.1	8.3	8.5	8.6	9.6	7.3	8.1	8.0	-
Nov	9.0	8.8	9.9	9.0	8.8	9.7	8.2	9.2	8.9	9.6	9.2	9.1	9.1	9.7	9.8	8.2	8.8	8.9	10.2	9.4	9.2	8.9	9.1	-
Dec	10.1	9.2	10.5	11.6	9.8	9.8	9.5	9.4	10.7	11.5	11.2	8.7	9.5	9.7	9.2	8.5	10.0	9.2	9.0	9.5	10.0	8.1	10.3	-
Annual	8.5	8.0	8.5	8.7	8.4	8.3	8.5	8.5	8.3	8.5	8.7	8.1	8.0	8.6	8.2	8.2	8.4	8.5	8.6	8.4	8.2	8.1	8.4	-

Table B-3 Wind speed statistics at the MERRA-2 39.50N, 73.13W

Month	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan	11.1	8.0	9.5	10.3	10.8	9.5	10.1	10.2	9.8	9.2	10.0	8.8	9.9	9.2	9.4	10.7	10.1	9.1	10.4	9.8	9.3	9.4	10.1	9.0
Feb	8.8	8.9	9.3	10.3	9.1	9.1	10.1	10.7	9.2	10.2	10.9	10.1	8.6	10.0	8.9	9.7	10.5	9.7	9.2	8.5	8.6	9.6	9.5	-
Mar	9.6	9.2	9.9	8.3	9.6	8.6	8.9	9.7	9.8	8.3	9.7	9.1	8.1	10.1	9.6	8.5	9.0	10.5	10.9	8.8	8.7	9.4	9.6	-
Apr	9.7	8.4	8.7	9.4	9.2	9.5	8.6	9.2	8.3	9.9	7.3	10.2	8.1	8.7	8.9	9.2	9.0	8.6	8.9	9.3	9.8	8.3	9.1	-
May	7.9	7.3	8.2	7.0	7.8	7.2	7.4	7.9	8.6	7.7	7.9	7.2	7.6	9.0	7.7	7.8	7.3	8.8	7.4	8.0	9.0	7.2	9.2	-
Jun	7.9	6.4	7.2	6.6	7.0	7.5	8.2	7.4	7.1	6.1	7.2	5.8	7.1	8.2	5.9	7.6	7.1	8.1	6.7	7.6	7.0	7.8	6.6	-
Jul	5.8	6.7	6.4	7.5	6.6	6.4	6.7	6.2	6.1	6.4	6.5	6.1	6.1	7.0	7.0	5.5	5.8	6.0	6.4	6.1	5.8	6.4	6.4	-
Aug	6.6	6.7	6.2	7.0	6.6	5.6	6.4	6.6	5.2	5.4	6.1	6.6	5.5	6.1	5.4	6.0	5.8	5.6	6.5	5.8	6.3	5.7	5.8	-
Sep	6.9	6.6	6.9	7.6	6.6	6.4	6.8	6.0	7.3	7.5	7.7	6.2	6.3	6.4	6.5	6.7	7.9	7.8	6.8	6.9	7.0	7.4	7.2	-
Oct	7.8	8.3	8.2	8.4	7.8	8.9	9.0	7.5	7.9	9.2	9.1	8.0	8.6	7.8	8.4	8.8	8.1	8.1	8.2	9.3	7.0	8.2	7.8	-
Nov	8.9	8.4	9.7	8.7	8.4	9.4	8.0	9.0	8.8	9.3	9.0	8.9	8.9	9.4	9.6	8.0	8.7	8.6	10.0	9.2	8.9	8.9	8.9	-
Dec	9.9	9.3	10.4	11.3	9.5	9.6	9.1	9.1	10.2	11.3	11.1	8.6	9.1	9.4	9.0	8.4	9.7	8.9	8.7	9.1	9.9	8.0	9.8	-
Annual	8.4	7.9	8.4	8.5	8.2	8.1	8.3	8.3	8.2	8.4	8.5	8.0	7.8	8.4	8.0	8.1	8.2	8.3	8.3	8.2	8.1	8.0	8.3	-

Table B-4 Wind speed statistics at the MERRA-2 39.50N, 73.75W

Month	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan	10.5	7.6	8.9	9.6	10.1	9.0	9.6	9.5	9.2	8.5	9.4	8.3	9.4	8.5	8.9	9.8	9.6	8.7	9.8	9.3	8.7	8.7	9.6	8.5
Feb	8.3	8.4	8.9	9.7	8.6	8.5	9.5	10.1	8.7	9.7	10.2	9.5	8.2	9.2	8.3	9.1	9.9	9.2	8.6	8.0	8.1	9.2	9.0	-
Mar	9.3	8.8	9.5	8.1	9.0	8.3	8.4	9.3	9.3	7.9	9.3	8.7	7.8	9.4	9.2	7.9	8.6	9.9	10.1	8.4	8.2	9.0	9.2	-
Apr	9.2	8.0	8.4	9.0	8.9	9.1	8.3	8.7	7.8	9.3	7.1	9.6	7.9	8.3	8.6	8.9	8.6	8.1	8.4	8.8	9.3	7.9	8.8	-
May	7.5	6.9	7.8	6.8	7.5	7.0	7.0	7.5	8.2	7.2	7.5	6.9	7.0	8.4	7.1	7.4	6.9	8.4	6.9	7.7	8.4	6.8	8.6	-
Jun	7.5	6.0	7.0	6.0	6.7	7.1	7.7	6.9	6.8	6.0	6.8	5.5	6.6	7.6	5.6	7.4	6.6	7.5	6.3	7.1	6.8	7.3	6.4	-
Jul	5.7	6.4	6.2	7.1	6.4	6.0	6.4	5.9	5.9	6.2	6.2	5.8	5.7	6.7	6.8	5.4	5.7	6.0	6.3	5.8	5.6	6.1	6.1	-
Aug	6.4	6.5	6.2	6.7	6.3	5.5	6.2	6.1	5.0	5.2	5.9	6.2	5.3	5.9	5.1	5.9	5.6	5.4	6.2	5.5	6.2	5.3	5.7	-
Sep	6.8	6.5	6.6	7.4	6.4	6.2	6.6	5.9	7.1	7.3	7.4	6.0	6.1	6.1	6.4	6.5	7.4	7.2	6.6	6.6	6.7	7.1	7.0	-
Oct	7.4	8.1	7.8	8.1	7.5	8.5	8.7	7.3	7.6	8.8	8.7	7.8	8.3	7.7	8.0	8.6	7.7	7.7	8.0	8.7	6.8	7.8	7.7	-
Nov	8.5	8.1	9.3	8.4	8.1	9.1	7.9	8.7	8.4	8.9	8.4	8.6	8.5	8.9	9.1	7.7	8.2	8.3	9.4	8.7	8.5	8.4	8.5	-
Dec	9.4	8.7	9.7	10.8	9.0	9.1	8.6	8.6	9.6	10.5	10.3	8.2	8.5	8.7	8.6	8.0	9.1	8.3	8.3	8.5	9.4	7.5	9.2	-
Annual	8.0	7.5	8.0	8.1	7.9	7.8	7.9	7.8	7.8	7.9	8.1	7.6	7.4	8.0	7.6	7.7	7.8	7.9	7.9	7.8	7.7	7.6	8.0	-

Table B-5 Wind speed statistics at the Vortex MERRA-2 39.96N, 72.73W

Month	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan	12.4	8.9	10.7	10.8	11.7	10.6	11.6	11.3	10.9	9.7	10.7	9.2	10.8	9.8	10.5	11.3	10.7	10.2	12.0	10.8	10.1	9.7	10.5	9.2
Feb	10.0	10.1	10.3	11.3	9.8	10.2	10.9	11.3	10.3	11.6	11.6	11.3	9.6	10.8	9.7	10.0	11.9	10.8	10.8	9.5	9.6	10.5	10.7	-
Mar	11.4	10.2	11.5	9.7	11.4	9.9	9.9	11.3	11.1	9.6	11.6	10.5	9.8	11.1	10.6	9.3	10.8	12.0	12.1	10.1	10.6	10.7	10.8	-
Apr	11.4	9.8	10.6	11.7	11.6	11.5	9.9	10.1	10.1	12.2	9.4	12.7	9.3	10.0	10.5	11.6	10.3	10.3	11.0	11.0	11.0	9.6	10.4	-
May	9.6	9.4	10.3	8.5	9.6	8.9	9.5	9.5	10.8	9.7	10.0	9.2	9.4	10.9	9.4	9.9	9.1	10.6	9.7	9.8	10.6	9.2	10.6	-
Jun	10.4	8.1	9.7	7.7	9.2	9.8	10.5	9.7	9.3	7.4	9.5	7.3	8.8	10.7	7.1	9.1	8.5	10.2	8.0	8.9	8.8	9.8	7.9	-
Jul	7.1	8.3	8.8	9.2	8.4	7.9	8.6	8.1	8.0	8.5	8.1	7.9	7.7	9.1	8.8	6.9	7.4	7.6	7.5	7.6	7.8	8.2	8.1	-
Aug	8.2	8.7	7.9	9.1	8.0	7.3	7.8	8.1	6.1	6.7	7.6	7.9	6.2	7.2	6.2	6.9	7.3	6.6	8.2	6.9	8.0	7.2	6.9	-
Sep	8.6	7.8	8.0	8.9	7.8	7.3	8.2	7.5	8.5	8.3	9.6	7.8	7.3	7.5	7.3	7.6	9.1	9.3	7.9	8.2	8.2	8.6	8.0	-
Oct	9.1	10.1	9.6	9.7	8.9	10.4	10.4	9.3	9.0	10.7	10.5	9.0	9.6	8.9	9.8	10.2	9.6	9.9	9.5	11.0	8.3	9.2	9.1	-
Nov	9.8	10.2	10.7	10.0	9.6	11.2	9.7	10.2	9.8	10.7	10.3	10.3	10.0	10.6	10.5	9.2	9.6	9.9	11.1	9.9	10.1	9.3	9.9	-
Dec	10.8	10.2	11.0	12.7	10.7	10.3	10.6	10.1	11.7	12.3	11.8	9.3	10.1	10.5	9.9	9.7	10.4	9.4	9.8	10.4	10.5	8.9	11.2	-
Annual	9.9	9.3	9.9	9.9	9.7	9.6	9.8	9.7	9.6	9.8	10.1	9.4	9.1	9.8	9.2	9.3	9.5	9.7	9.8	9.5	9.5	9.2	9.5	-

Table B-6 Wind speed statistics at the Vortex MERRA-2 39.54N, 73.42W

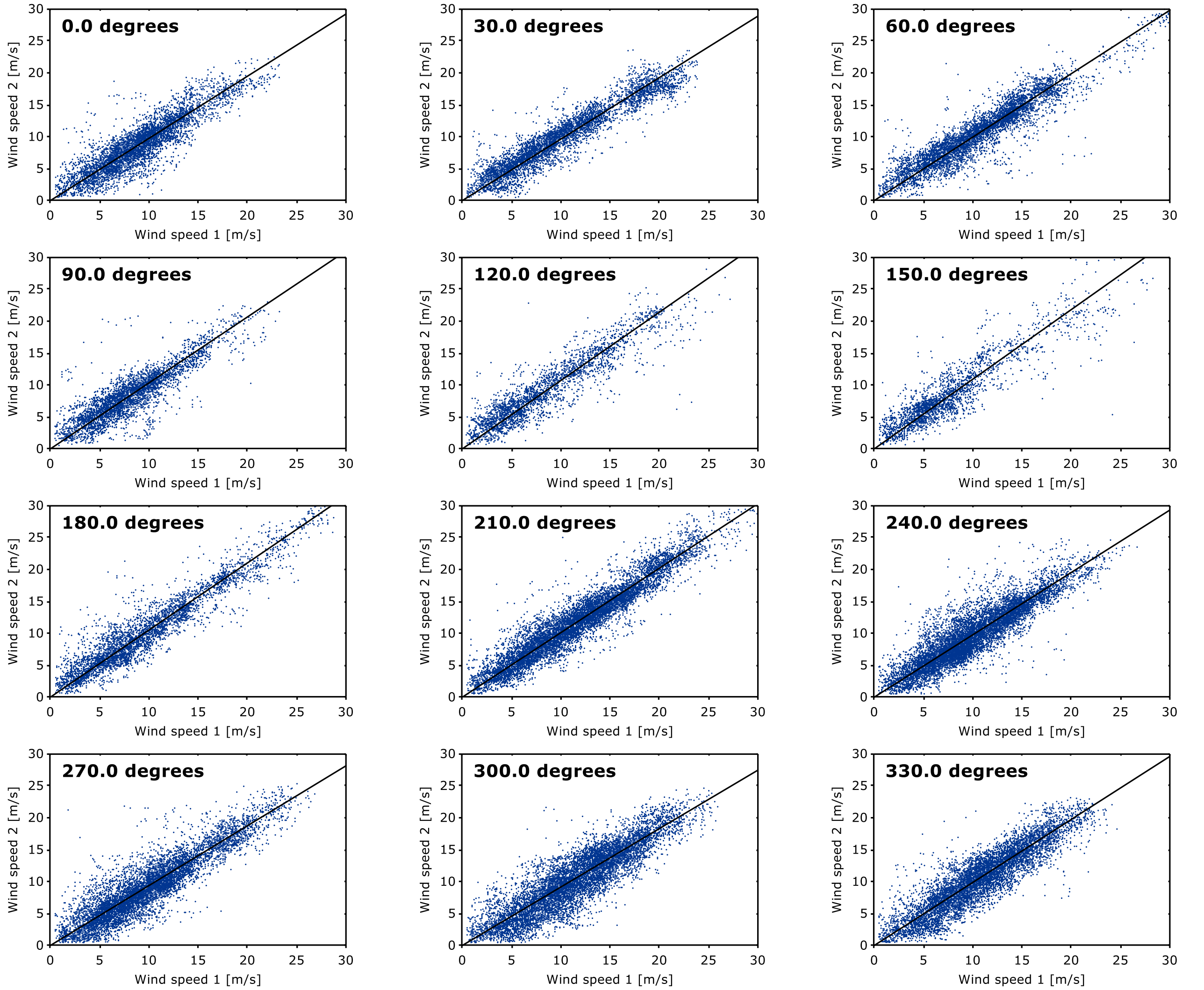
Month	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan	12.2	8.9	10.5	10.7	11.5	10.6	11.5	11.0	10.8	9.4	10.7	9.2	10.7	9.6	10.1	10.8	10.7	10.0	11.7	10.3	9.9	9.6	10.6	9.4
Feb	9.8	10.0	10.3	11.1	9.6	9.9	10.8	11.1	10.2	11.4	11.5	11.1	9.6	10.4	9.5	9.8	11.8	10.7	10.7	9.1	9.3	10.6	10.5	-
Mar	11.3	10.3	11.6	9.7	11.2	9.7	9.4	11.1	10.9	9.5	11.5	10.3	9.5	10.9	10.7	9.0	10.6	11.7	11.8	10.0	10.1	10.6	10.9	-
Apr	11.2	10.0	10.6	11.6	11.6	11.5	10.0	10.2	9.9	12.0	9.0	12.9	9.2	10.2	10.3	11.3	10.4	10.1	10.7	11.0	11.0	9.5	10.4	-
May	9.6	8.8	10.0	8.6	9.8	8.8	9.1	9.5	10.6	9.7	9.7	9.2	9.3	10.9	8.8	9.7	8.6	10.6	9.2	9.9	10.6	8.7	10.7	-
Jun	10.2	7.9	9.3	7.8	9.0	9.7	10.4	9.3	9.4	7.4	9.5	7.3	8.5	10.2	6.8	9.2	8.3	10.2	7.9	9.1	8.8	9.4	8.2	-
Jul	7.0	8.2	8.4	9.2	8.1	7.6	8.6	7.7	7.9	8.1	8.1	8.0	7.5	9.0	8.6	6.6	7.1	7.5	7.5	7.6	7.3	8.1	8.1	-
Aug	8.0	8.5	7.9	8.9	7.9	7.1	7.6	7.9	6.2	6.4	7.2	7.6	6.2	7.1	5.8	6.9	6.9	6.3	7.9	6.6	7.7	7.0	7.0	-
Sep	8.3	7.7	7.8	9.1	7.6	7.2	7.9	7.1	8.6	8.4	9.2	7.5	7.2	7.3	7.2	7.4	8.9	8.8	7.7	7.9	8.0	8.5	7.9	-
Oct	8.9	9.9	9.2	9.4	8.6	9.9	10.1	8.9	8.9	10.5	10.2	8.9	9.8	8.9	9.5	10.0	9.3	9.5	9.1	10.4	8.0	9.3	8.9	-
Nov	9.8	9.8	10.5	9.7	9.3	11.0	9.4	9.9	9.8	10.3	10.0	10.2	9.9	10.3	10.4	9.0	9.3	9.6	10.9	9.7	9.8	9.4	9.8	-
Dec	10.6	10.1	10.9	12.5	10.4	10.1	10.2	9.8	10.9	12.0	11.7	9.3	9.7	10.2	9.7	9.6	10.2	9.2	9.6	9.7	10.4	8.9	10.6	-
Annual	9.7	9.2	9.7	9.8	9.5	9.4	9.6	9.5	9.5	9.6	9.8	9.3	8.9	9.6	8.9	9.1	9.3	9.5	9.6	9.3	9.2	9.1	9.5	-

APPENDIX C – Wind farm analysis and results

C.1 Correlations
C.2 Site-period wind speeds
C.3 Mast long-term wind regime
C.4 Time-dependent loss factors
C.5 Energy results
C.6 Seasonal and diurnal variation

C.1 Correlations

Directional correlation of wind speeds recorded at [E05_N~WS140~Mean] (1) and [E06_S~WS140~Mean] (2)



Directional correlation ratios

Bin centers [degrees]	Wind speed ratio	Number of records
0.0	1.055	4034
30.0	1.047	4563
60.0	0.997	4865
90.0	0.954	3622
120.0	0.956	2565
150.0	0.924	2106
180.0	0.966	4122
210.0	0.995	10595
240.0	1.019	8673
270.0	1.070	6250
300.0	1.066	7577
330.0	1.017	6594
All directional	1.018	66452

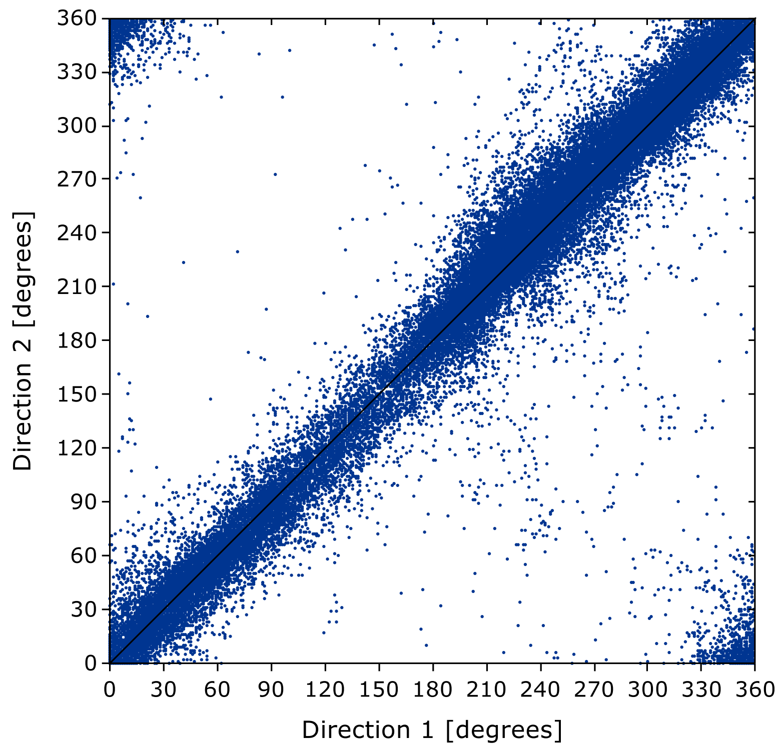
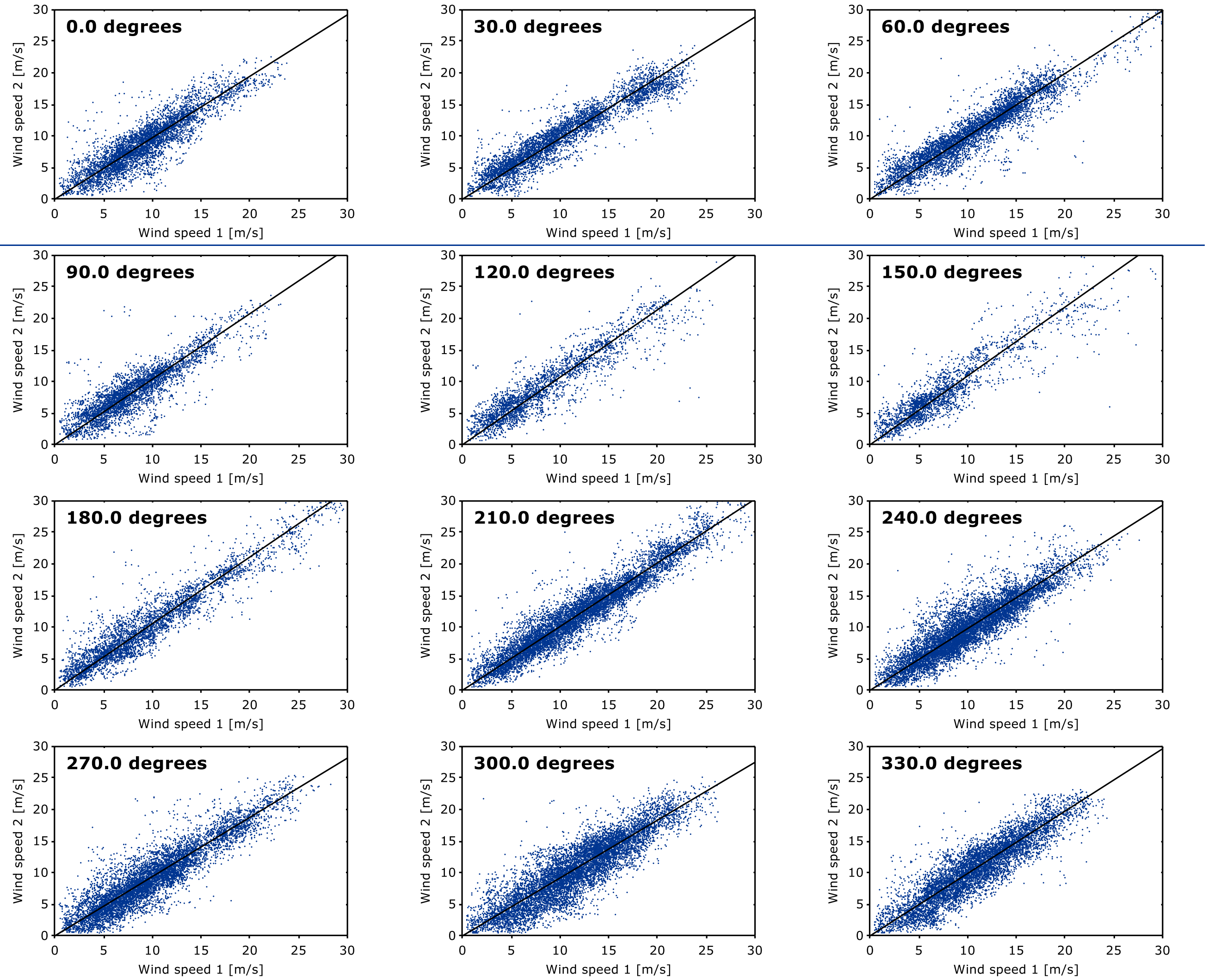


Figure C-1 Correlation of wind direction between [1] E06_S at 140 m and [2] E05_N at 140 m

Directional correlation of wind speeds recorded at [E05_N WS160~Mean] (1) and [E06_S ~WS160~Mean] (2)



Directional correlation ratios

Bin centers [degrees]	Wind speed ratio	Number of records
0.0	0.973	5129
30.0	0.961	4895
60.0	0.995	5627
90.0	1.037	3900
120.0	1.068	2720
150.0	1.089	2278
180.0	1.055	4050
210.0	1.008	9014
240.0	0.976	9604
270.0	0.938	7828
300.0	0.915	9097
330.0	0.987	7456
All directional	0.982	71942

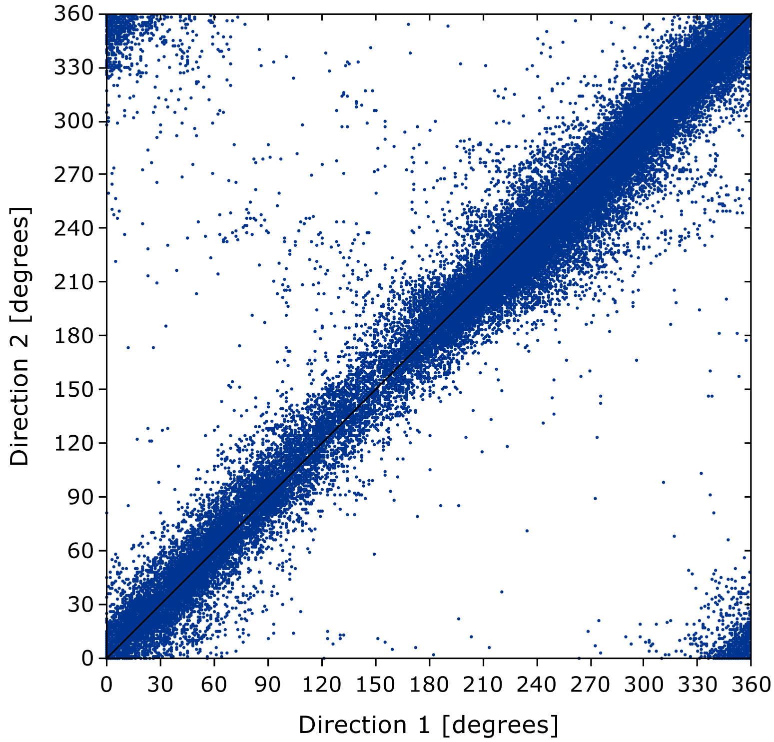


Figure C-2 orrelation of wind direction between [1] E06_S at 160 m and [2] E05_N at 160 m

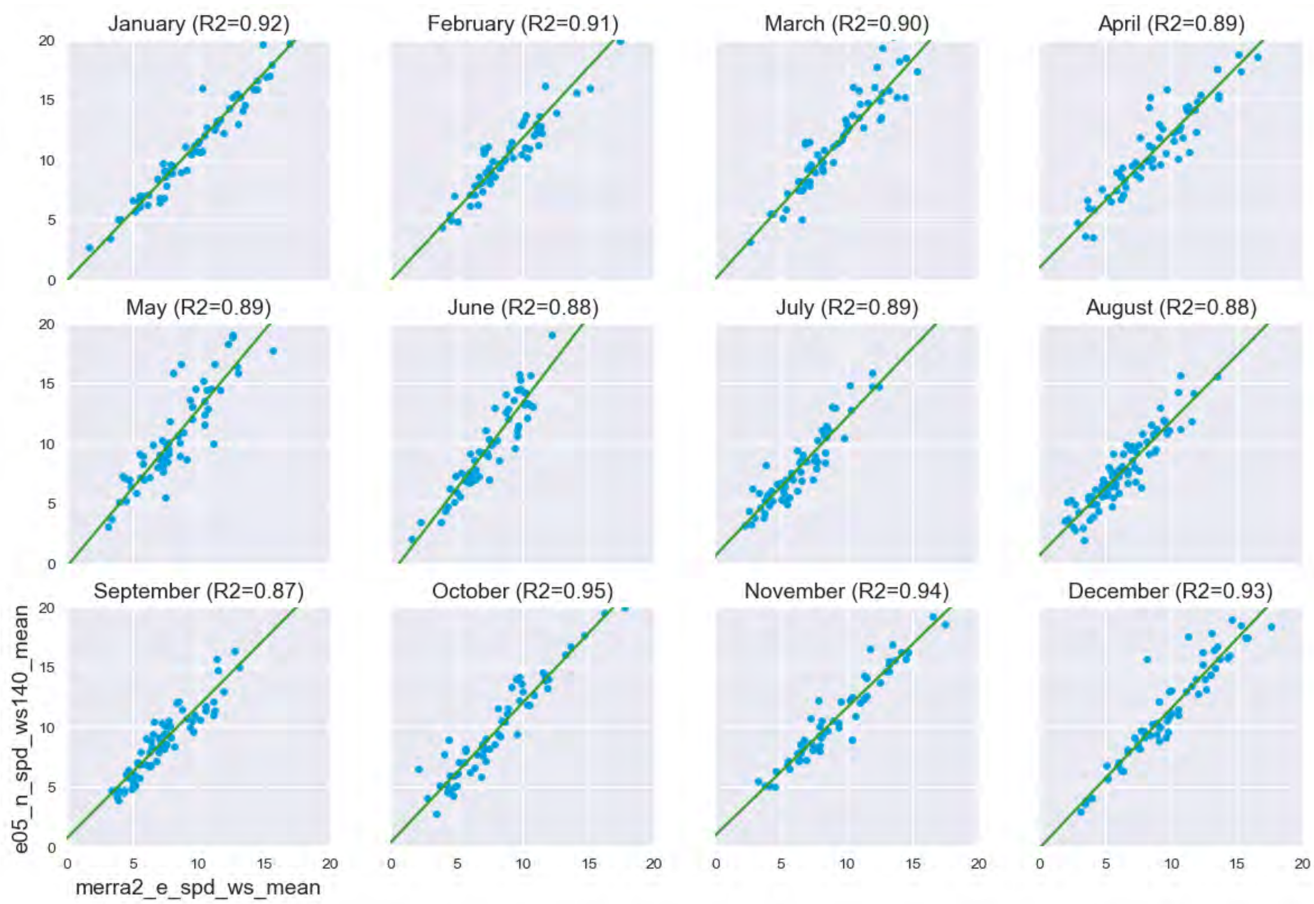


Figure C-3 Correlation of wind speed between E05_N at 140m and MERRA-2 40.00N, 72.50W

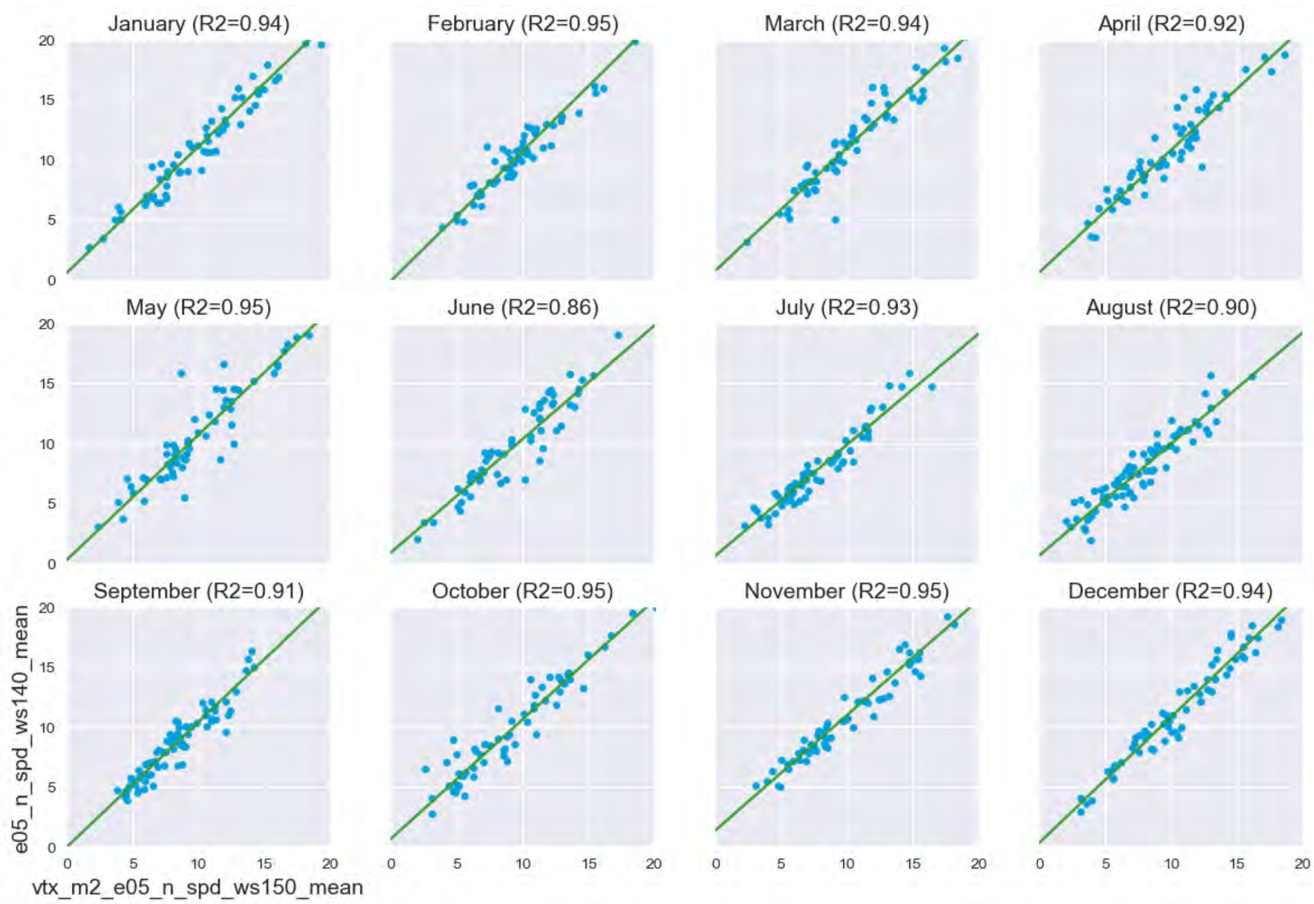


Figure C-4 Correlation of wind speed between E05_N at 140m and Vortex MERRA-2 39.96N, 72.73W

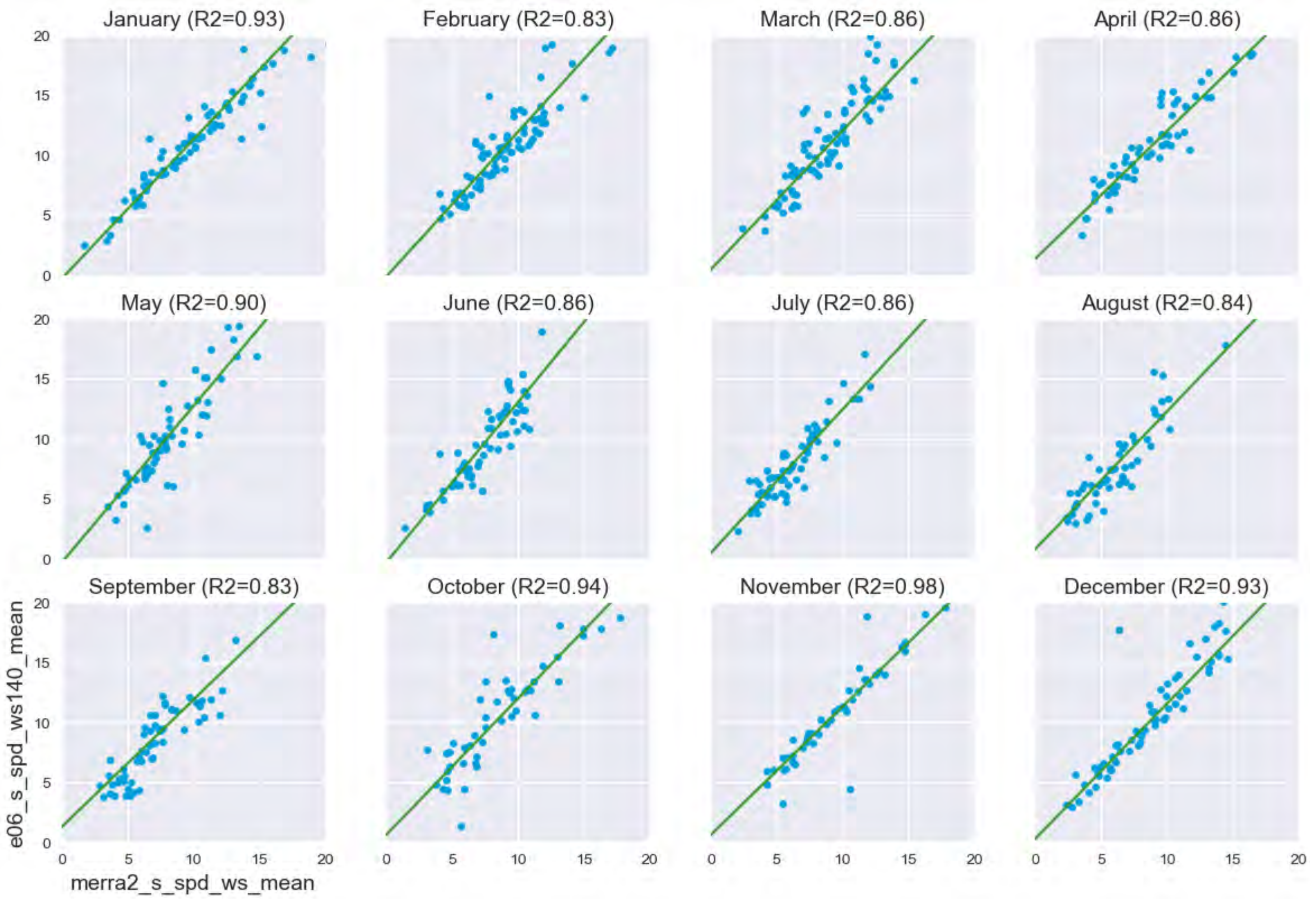


Figure C-5 Correlation of wind speed between E06_S at 140m and MERRA-2 39.50N, 73.13W

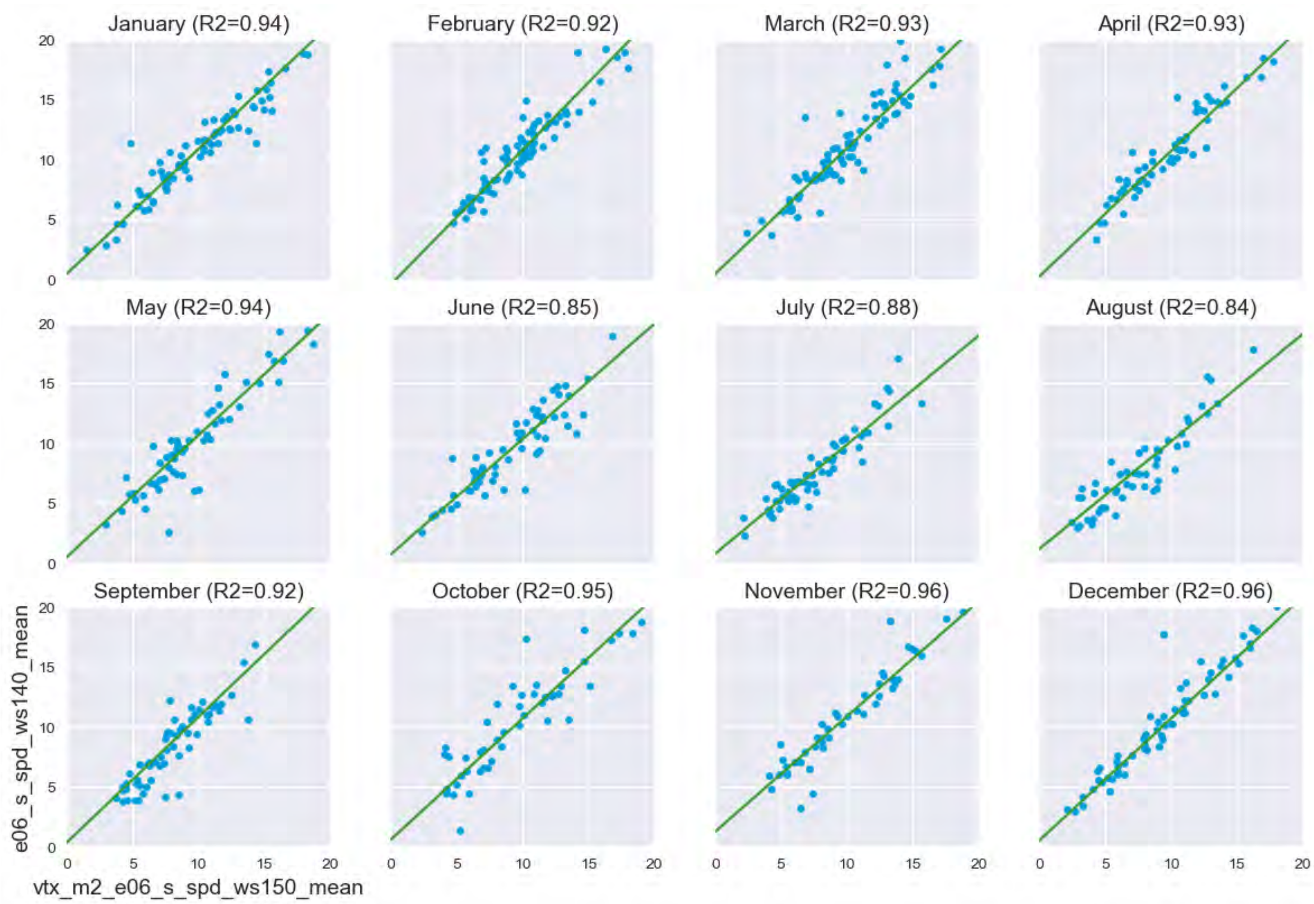


Figure C-6 Correlation of wind speed between E06_S at 140m and Vortex MERRA-2 39.96N, 72.73W

C.2 Site-period wind speeds

Table C-1 Site-period wind speeds

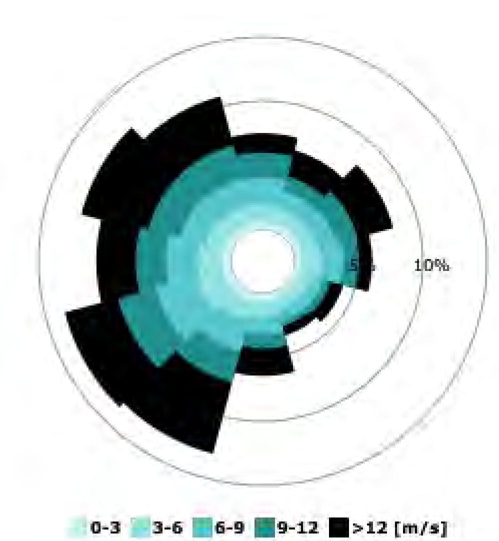
Month	E05_N 140 m	E05_N 160 m	E05_SW 140 m	E05_SW 160 m	E06_S 140 m	E06_S 160 m
January	11.0	11.1	11.0	11.1	10.8	10.9
February	11.1	11.2	11.0	11.1	11.0	11.1
March	11.6	11.7	11.6	11.7	11.5	11.7
April	11.2	11.4	11.1	11.2	11.1	11.2
May	10.6	10.7	10.7	10.8	10.8	10.9
June	9.6	9.7	9.2	9.3	9.1	9.2
July	7.9	8.0	8.1	8.3	7.9	8.1
August	7.8	7.9	7.6	7.7	7.5	7.6
September	8.5	8.6	8.8	8.9	8.5	8.6
October	10.1	10.2	10.5	10.6	10.0	10.1
November	11.0	11.1	10.6	10.7	10.6	10.7
December	10.8	10.9	10.4	10.5	10.5	10.6
Annual	**10.1**	**10.2**	**10.0**	**10.2**	**9.9**	**10.1**

Values include data synthesized from other site masts.

C.3 Mast long-term wind regime

Table C-2 E05_N long-term wind speed and frequency distribution at 155 m

Monthly	Wind speed [m/s]	Valid wind speed data [months]	Valid direction data [months]
January	11.0	1.9	1.9
February	10.8	1.8	1.8
March	11.9	1.8	1.8
April	11.5	1.9	1.9
May	10.8	1.6	1.6
June	9.7	1.7	1.7
July	8.1	1.8	1.8
August	7.9	2.5	2.5
September	8.7	2.2	2.2
October	10.5	1.8	1.8
November	11.0	2.0	2.0
December	11.3	1.9	1.9
Annual	10.3		



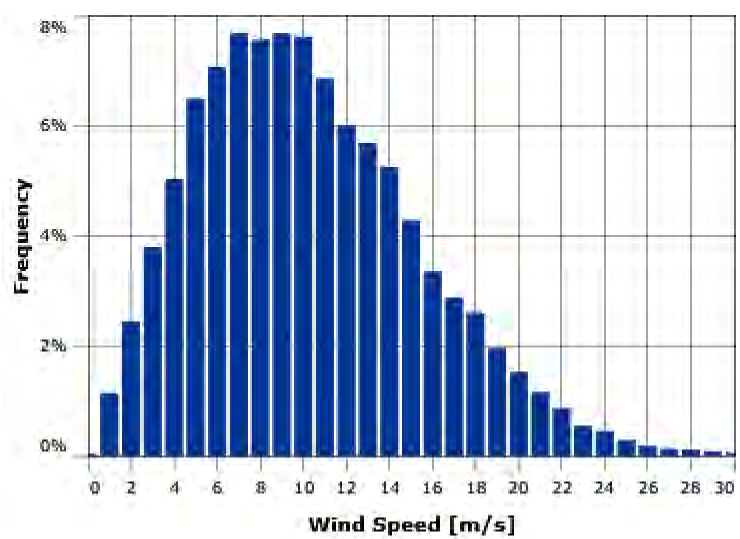


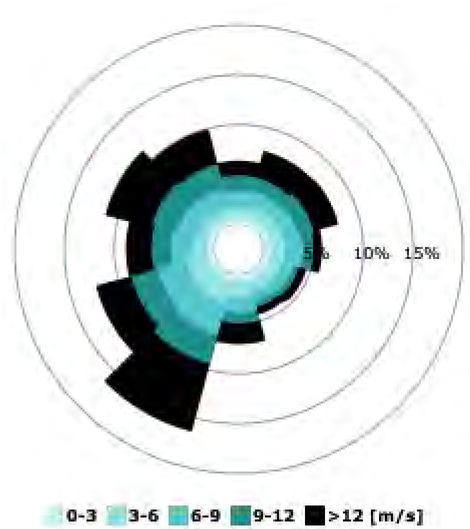
Table C-3 Wind speed and direction frequency distribution

Wind Speed [m/s]	0	30	60	90	120	150	180	210	240	270	300	330	No Direction	Total [%]
0	+	+	+		+	+	+		+	+	+	+		0.01
1	0.10	0.07	0.09	0.08	0.10	0.10	0.10	0.09	0.09	0.11	0.10	0.10		1.12
2	0.20	0.19	0.15	0.17	0.16	0.17	0.21	0.22	0.27	0.25	0.21	0.22		2.42
3	0.26	0.32	0.30	0.28	0.26	0.23	0.35	0.32	0.41	0.39	0.38	0.27		3.77
4	0.36	0.39	0.29	0.46	0.36	0.26	0.33	0.52	0.61	0.57	0.47	0.37		5.00
5	0.47	0.44	0.44	0.61	0.39	0.41	0.47	0.62	0.85	0.72	0.56	0.49		6.47
6	0.66	0.47	0.51	0.56	0.33	0.36	0.48	0.74	0.90	0.81	0.55	0.66		7.04
7	0.73	0.50	0.58	0.67	0.29	0.29	0.48	0.82	1.06	0.81	0.68	0.71		7.66
8	0.72	0.41	0.55	0.57	0.31	0.29	0.47	0.84	1.15	0.82	0.69	0.72		7.53
9	0.71	0.50	0.62	0.47	0.21	0.18	0.37	0.80	1.27	0.87	0.83	0.80		7.65
10	0.79	0.41	0.59	0.49	0.18	0.17	0.40	0.81	1.10	0.76	0.91	0.99		7.59
11	0.57	0.37	0.57	0.38	0.18	0.11	0.31	0.87	0.90	0.78	0.86	0.92		6.83
12	0.48	0.36	0.44	0.20	0.16	0.08	0.32	0.83	0.79	0.74	0.77	0.80		5.98
13	0.37	0.38	0.42	0.20	0.13	0.06	0.31	0.81	0.83	0.58	0.79	0.77		5.65
14	0.29	0.22	0.52	0.19	0.12	0.06	0.31	0.77	0.77	0.40	0.91	0.65		5.22
15	0.14	0.13	0.45	0.17	0.15	0.06	0.20	0.73	0.67	0.28	0.74	0.54		4.25
16	0.09	0.10	0.35	0.11	0.11	0.06	0.19	0.53	0.50	0.23	0.59	0.44		3.32
17	0.09	0.15	0.28	0.05	0.09	0.06	0.20	0.53	0.32	0.27	0.48	0.33		2.85
18	0.10	0.24	0.25	0.04	0.07	0.05	0.16	0.40	0.26	0.24	0.46	0.33		2.58
19	0.07	0.22	0.16	0.06	0.06	0.04	0.10	0.28	0.21	0.23	0.32	0.19		1.93
20	0.04	0.16	0.07	0.05	0.08	0.06	0.10	0.31	0.12	0.15	0.23	0.12		1.50
21	0.03	0.15	0.04	0.03	0.04	0.04	0.08	0.30	0.08	0.10	0.18	0.08		1.13
22	0.02	0.10	0.02	0.01	0.02	0.04	0.07	0.22	0.05	0.09	0.13	0.06		0.84
23	0.01	0.05	0.02	+	0.03	0.04	0.06	0.15	0.03	0.05	0.06	0.02		0.52
24	+	0.01	0.02	+	0.03	0.03	0.07	0.12	0.02	0.05	0.03	0.02		0.42
25	+	+	0.02	+	0.02	0.04	0.04	0.09	0.01	0.02	0.02	0.01		0.26
26	+	+	0.01	0.01	0.01	0.03	0.03	0.04	+	0.01	0.01	+		0.16
27	+	+	0.02	+	0.01	0.03	0.02	0.02	+	+	+	+		0.11
28	+		0.02	+	+	0.02	0.02	0.02	+	+				0.08
29	+		0.01	+		0.01	0.02	0.02	+	+				0.06
30			0.02	+		+	+	0.01	+					0.04
30+														
Total [%]	7.33	6.34	7.84	5.88	3.88	3.38	6.29	12.85	13.29	10.33	11.96	10.62		100.00
Mean Speed	8.97	10.16	10.60	8.38	9.01	8.91	10.26	11.67	10.01	9.90	11.33	10.63	-	10.26

Note: '+' indicates non-zero percentage <0.005%, blank indicates zero percentage

Table C-4 E06_S long-term wind speed and frequency distribution at 155 m

Monthly	Wind speed [m/s]	Valid wind speed data [months]	Valid direction data [months]
January	11.0	2.4	2.4
February	11.0	2.8	2.8
March	11.3	2.5	2.5
April	11.0	1.8	1.8
May	10.2	1.6	1.6
June	9.4	1.7	1.7
July	7.9	1.9	1.9
August	7.9	1.2	1.2
September	9.0	1.1	1.1
October	11.5	0.9	0.9
November	10.7	1.3	1.3
December	10.1	1.9	1.9
Annual	10.1		



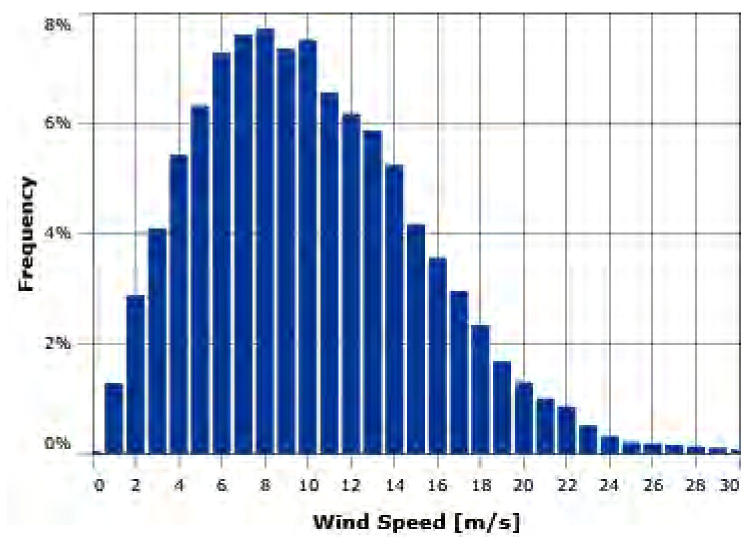


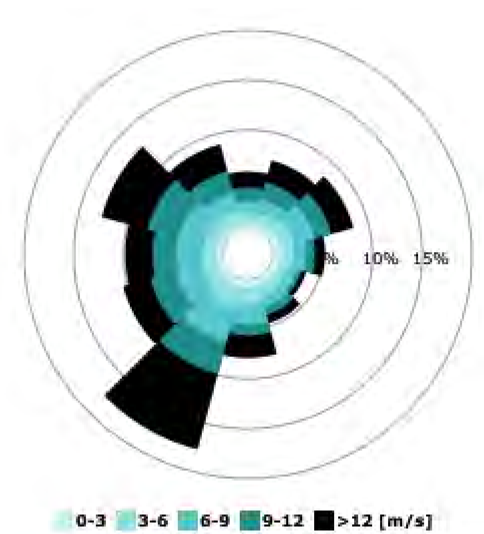
Table C-5 Wind speed and direction frequency distribution

Wind Speed [m/s]	0	30	60	90	120	150	180	210	240	270	300	330	No Direction	Total [%]
0	+	+	+	+	+	+	+	+	+	+	+	+		0.01
1	0.07	0.12	0.10	0.15	0.11	0.12	0.11	0.11	0.12	0.08	0.10	0.08		1.25
2	0.19	0.23	0.26	0.24	0.28	0.26	0.24	0.25	0.22	0.21	0.24	0.21		2.85
3	0.27	0.33	0.33	0.31	0.25	0.41	0.38	0.39	0.44	0.35	0.31	0.27		4.05
4	0.38	0.37	0.40	0.41	0.45	0.39	0.57	0.65	0.67	0.40	0.35	0.35		5.40
5	0.39	0.45	0.50	0.52	0.53	0.32	0.55	0.87	0.81	0.52	0.44	0.40		6.29
6	0.50	0.54	0.43	0.61	0.45	0.45	0.59	1.09	0.95	0.65	0.51	0.49		7.25
7	0.51	0.51	0.49	0.64	0.48	0.38	0.54	1.10	0.97	0.66	0.64	0.65		7.58
8	0.55	0.44	0.53	0.59	0.34	0.33	0.48	1.15	1.03	0.85	0.71	0.70		7.69
9	0.56	0.48	0.61	0.45	0.22	0.27	0.38	0.96	0.98	0.74	0.84	0.82		7.32
10	0.63	0.43	0.60	0.38	0.23	0.18	0.37	1.06	0.98	0.76	0.91	0.95		7.49
11	0.43	0.47	0.48	0.34	0.16	0.18	0.35	1.00	0.83	0.59	0.87	0.81		6.53
12	0.40	0.50	0.53	0.24	0.15	0.15	0.31	1.02	0.82	0.46	0.82	0.75		6.14
13	0.30	0.47	0.49	0.20	0.12	0.11	0.31	1.02	0.80	0.41	0.85	0.77		5.84
14	0.22	0.37	0.47	0.17	0.09	0.10	0.32	0.96	0.69	0.38	0.83	0.61		5.21
15	0.19	0.25	0.33	0.14	0.09	0.09	0.20	0.90	0.47	0.30	0.66	0.51		4.14
16	0.16	0.31	0.26	0.09	0.08	0.12	0.13	0.79	0.37	0.23	0.56	0.43		3.52
17	0.15	0.36	0.33	0.05	0.07	0.05	0.11	0.57	0.28	0.22	0.44	0.32		2.93
18	0.10	0.40	0.21	0.03	0.06	0.03	0.12	0.44	0.17	0.20	0.32	0.22		2.30
19	0.06	0.22	0.12	0.01	0.07	0.03	0.11	0.31	0.16	0.15	0.23	0.16		1.64
20	0.04	0.11	0.05	0.03	0.06	0.04	0.07	0.30	0.12	0.16	0.19	0.11		1.27
21	0.04	0.06	0.01	0.02	0.03	0.04	0.07	0.30	0.08	0.12	0.13	0.08		0.98
22	0.03	0.02	+	0.01	0.04	0.03	0.13	0.28	0.05	0.09	0.09	0.05		0.83
23	+	0.01	0.01	+	0.01	0.01	0.09	0.22	0.02	0.04	0.04	0.01		0.48
24		0.01	0.01	+	0.01	0.01	0.05	0.12	0.02	0.05	0.02	+		0.29
25	+		0.01	+	+	+	0.05	0.09	0.01	0.01	0.01			0.18
26	+		+	+	+	+	0.05	0.08	0.01	+				0.15
27	+		+	+		+	0.05	0.06	+	+				0.13
28			0.01	0.01		+	0.04	0.04	+					0.10
29			0.01			0.01	0.04	0.02	+					0.08
30			0.01			+	0.01	0.02	+					0.05
30+														
Total [%]	6.18	7.46	7.59	5.67	4.40	4.13	6.82	16.19	12.08	8.62	11.11	9.74		100.00
Mean Speed	9.19	10.36	9.95	7.99	7.95	7.90	9.95	11.53	9.73	10.02	11.13	10.60	-	10.08

Note: '+' indicates non-zero percentage <0.005%, blank indicates zero percentage

Table C-6 E05_SW long-term wind speed and frequency distribution at 155 m

Monthly	Wind speed [m/s]	Valid wind speed data [months]	Valid direction data [months]
January	10.9	0.9	0.9
February	11.7	0.9	0.9
March	11.8	0.9	0.9
April	11.0	0.9	0.9
May	12.1	0.8	0.8
June	8.8	0.9	0.9
July	8.5	1.0	1.0
August	7.2	1.0	1.0
September	8.4	0.9	0.9
October	9.6	0.9	0.9
November	10.5	1.0	1.0
December	10.9	0.9	0.9
Annual	10.1		



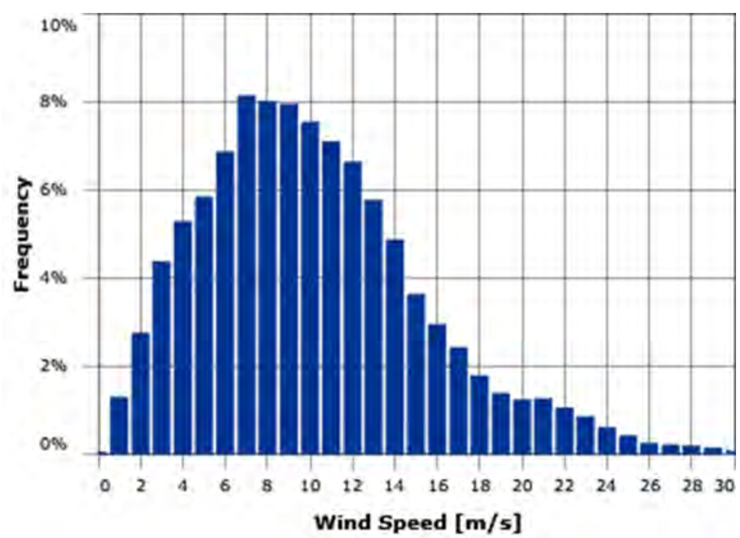


Table C-7 Wind speed and direction frequency distribution

Wind Speed [m/s]	0	30	60	90	120	150	180	210	240	270	300	330	No Direction	Total [%]
0	+	+	+	+	+	+	+	+	+	+	+	+		0.03
1	0.08	0.07	0.09	0.11	0.13	0.10	0.12	0.14	0.13	0.11	0.10	0.09		1.27
2	0.18	0.19	0.23	0.21	0.23	0.23	0.27	0.31	0.25	0.24	0.21	0.17		2.72
3	0.32	0.41	0.45	0.31	0.28	0.31	0.39	0.44	0.38	0.36	0.36	0.33		4.34
4	0.36	0.42	0.54	0.38	0.33	0.44	0.55	0.64	0.42	0.33	0.37	0.45		5.24
5	0.32	0.31	0.46	0.59	0.34	0.40	0.66	0.72	0.52	0.47	0.51	0.51		5.81
6	0.37	0.44	0.57	0.50	0.36	0.48	0.71	0.96	0.63	0.68	0.66	0.46		6.83
7	0.41	0.43	0.84	0.45	0.33	0.31	0.71	1.20	0.96	0.95	0.85	0.65		8.10
8	0.36	0.40	0.66	0.40	0.32	0.40	0.70	1.31	0.97	0.89	0.92	0.65		7.98
9	0.47	0.62	0.67	0.39	0.25	0.34	0.45	1.15	0.98	0.96	0.97	0.67		7.91
10	0.48	0.67	0.59	0.25	0.17	0.27	0.37	1.07	0.94	0.78	1.10	0.81		7.50
11	0.40	0.56	0.54	0.27	0.11	0.23	0.35	1.15	0.84	0.78	1.10	0.73		7.06
12	0.45	0.44	0.48	0.35	0.09	0.18	0.25	1.11	0.71	0.69	1.13	0.72		6.60
13	0.34	0.20	0.30	0.18	0.10	0.13	0.32	1.10	0.64	0.59	0.96	0.86		5.73
14	0.30	0.09	0.26	0.15	0.11	0.16	0.24	0.93	0.46	0.55	0.95	0.62		4.83
15	0.22	0.05	0.20	0.10	0.05	0.09	0.20	0.69	0.39	0.49	0.78	0.34		3.59
16	0.16	0.06	0.19	0.08	0.04	0.10	0.24	0.69	0.31	0.30	0.50	0.27		2.91
17	0.14	0.15	0.17	0.06	0.03	0.09	0.15	0.64	0.23	0.17	0.42	0.15		2.39
18	0.13	0.22	0.13	0.05	0.04	0.05	0.10	0.51	0.11	0.10	0.23	0.08		1.75
19	0.09	0.27	0.10	0.04	0.04	0.01	0.12	0.40	0.09	0.04	0.10	0.05		1.36
20	0.02	0.29	0.12	0.02	0.03	0.02	0.12	0.38	0.09	0.03	0.06	0.02		1.21
21	+	0.28	0.12	0.03	0.02	0.03	0.10	0.48	0.05	0.05	0.05	0.02		1.23
22	+	0.19	0.10	0.03	0.01	0.02	0.08	0.43	0.04	0.05	0.06	0.02		1.02
23	+	0.14	0.08	0.03	+	0.02	0.11	0.32	0.05	0.01	0.04	0.01		0.82
24	+	0.09	0.12	0.02	+	0.02	0.10	0.19	0.02	0.01	0.01			0.58
25	0.01	0.02	0.13	0.01		0.01	0.09	0.10	0.01		+	+		0.39
26	+	+	0.05	0.01		0.01	0.03	0.11	+			+		0.22
27		+	0.02	0.01		+	0.03	0.12	+	+				0.18
28				0.01		+	0.06	0.08	+	+				0.15
29				+		+	0.04	0.06	+					0.11
30				+			0.01	0.03	+					0.05
30+														
Total [%]	5.62	7.02	8.21	5.05	3.40	4.49	7.69	17.52	10.22	9.63	12.45	8.70		100.00
Mean Speed	9.44	10.91	9.98	8.39	7.32	8.24	9.96	12.00	9.70	9.63	10.60	9.78	-	10.12

Note: '+' indicates non-zero percentage <0.005%, blank indicates zero percentage

C.4 Turbine availability assumptions

For the purposes of this analysis, DNV has made the following preliminary assumptions to derive a starting assumption for the turbine availability loss profile (loss category 2a):

a) Projects with similar project characteristics and wave and wind conditions present similar availabilities in other regions in comparison with those experienced in the North Sea. Based on this assumption, the projected turbine availability is therefore based on North Sea experience. DNV considers this to be a reasonable starting assumption for projects in other regions in the absence of a more detailed project specific review of the O&M access strategy and metocean conditions at the site, as this is supported by previous experience and extensive modelling performed by DNV.

b) The project operates or is to operate with an optimal number of technicians, therefore values are only representative when the number of staff is well planned.

c) Main component replacements are performed using a Jack-Up vessel with an average lead time to get to the site of 45 days. This is the typical expected value based on operational experience in the North Sea, however this is expected to be different in the future and in different markets.

d) Turbine reliability is based on experienced turbine manufacturers therefore only valid for projects considering models from offshore experienced turbine suppliers. If the project is considering newer turbine models the validity of this projection is to be regarded with caution and a project specific review is recommended.

Based on these assumptions, DNV has estimated an indicative starting assumption for turbine availability for the following project characteristics:

Table C-8 Turbine availability loss assumptions

Project characteristic	Value assumed for modelling	Source of assumption
Distance to O&M port [nautical miles]:	N/A	DNV
Mean long-term significant wave height [m]:	1.7	DNV
Assumed Drive Train Concept:	Direct Drive	DNV
Ramp up expected [in increase of %]:	3%	DNV
Ramp up period [in years]:	5.0	DNV
Period evaluated [in years]:	See main body of report	Customer
Access strategy expected:	1 Service operations vessel, 1 crew transfer vessel, and 1 daughter craft	DNV

DNV has selected these values based on high-level assumptions. It is expected that these assumptions will change as the projects are developed further and a commercially available turbine model is identified for the site. At this later stage of the project, it is recommended that the estimated turbine availability for the project should be updated.

C.4.1 References

[C-1] Failure rate, repair time and unscheduled O&M cost analysis of offshore wind turbines, Carroll et al, https://pure.strath.ac.uk/portal/files/44298789/Carroll_etal_WE_2015_Failure_rate_repair_time_and_unscheduled_O_and_M_cost_analysis_of_offshore.pdf, University of Strathclyde, first published 6 August 2015.

C.5 Energy results

Table C-9 Energy results, Indicative layout 01 (25 years)

Turbine	Turbine model	Hub-height [m]	Initiation device	Easting[a] [m]	Northing[a] [m]	Elevation [m]	Long-term wind speed at hub-height[b] [m/s]	Energy output[c] [GWh/ annum]	Turbine interaction loss factor[d] [%]
T1	Generic 15 MW	140	E05_N	954,874	4,509,404	0	10.6	69.3	95.9
T2	Generic 15 MW	140	E05_N	956,855	4,509,174	0	10.6	67.6	93.6
T3	Generic 15 MW	140	E05_N	958,836	4,508,945	0	10.6	67.2	93.1
T4	Generic 15 MW	140	E05_N	960,817	4,508,715	0	10.6	67.0	92.8
T5	Generic 15 MW	140	E05_N	954,703	4,507,912	0	10.6	68.1	94.3
T6	Generic 15 MW	140	E05_N	956,684	4,507,682	0	10.6	66.3	91.8
T7	Generic 15 MW	140	E05_N	958,665	4,507,453	0	10.6	65.9	91.2
T8	Generic 15 MW	140	E05_N	960,646	4,507,223	0	10.6	65.5	90.7
T9	Generic 15 MW	140	E05_N	962,627	4,506,993	0	10.6	66.4	91.9
T10	Generic 15 MW	140	E05_N	954,533	4,506,420	0	10.6	67.9	94.1
T11	Generic 15 MW	140	E05_N	956,514	4,506,190	0	10.6	66.0	91.5
T12	Generic 15 MW	140	E05_N	958,495	4,505,960	0	10.6	65.7	91.0
T13	Generic 15 MW	140	E05_N	960,476	4,505,731	0	10.6	65.2	90.3
T14	Generic 15 MW	140	E05_N	962,457	4,505,501	0	10.6	65.0	90.1
T15	Generic 15 MW	140	E05_N	964,438	4,505,271	0	10.6	65.8	91.2
T16	Generic 15 MW	140	E05_N	954,362	4,504,928	0	10.6	67.6	93.8
T17	Generic 15 MW	140	E05_N	956,343	4,504,698	0	10.6	65.7	91.1
T18	Generic 15 MW	140	E05_N	958,324	4,504,468	0	10.6	65.4	90.6
T19	Generic 15 MW	140	E05_N	960,305	4,504,238	0	10.6	64.8	89.8
T20	Generic 15 MW	140	E05_N	962,286	4,504,009	0	10.6	64.9	90.0
T21	Generic 15 MW	140	E05_N	964,267	4,503,779	0	10.6	64.8	89.8
T22	Generic 15 MW	140	E05_N	966,248	4,503,549	0	10.6	66.1	91.6
T23	Generic 15 MW	140	E05_N	954,191	4,503,435	0	10.6	67.9	94.3
T24	Generic 15 MW	140	E05_N	956,172	4,503,206	0	10.6	66.5	92.2
T25	Generic 15 MW	140	E05_N	958,153	4,502,976	0	10.6	65.7	91.1
T26	Generic 15 MW	140	E05_N	960,134	4,502,746	0	10.6	65.0	90.2
T27	Generic 15 MW	140	E05_N	962,115	4,502,516	0	10.6	65.1	90.2
T28	Generic 15 MW	140	E05_N	966,078	4,502,057	0	10.6	64.8	89.8
T29	Generic 15 MW	140	E05_N	968,059	4,501,827	0	10.6	65.4	90.6
T30	Generic 15 MW	140	E05_N	970,040	4,501,597	0	10.6	65.6	91.0
T31	Generic 15 MW	140	E05_N	972,022	4,501,368	0	10.6	66.0	91.5
T32	Generic 15 MW	140	E05_N	974,003	4,501,138	0	10.6	66.2	91.8
T33	Generic 15 MW	140	E05_N	975,984	4,500,908	0	10.6	67.0	92.8

Turbine	Turbine model	Hub-height [m]	Initiation device	Easting[a] [m]	Northing[a] [m]	Elevation [m]	Long-term wind speed at hub-height[b] [m/s]	Energy output[c] [GWh/ annum]	Turbine interaction loss factor[d] [%]
T34	Generic 15 MW	140	E05_N	957,982	4,501,484	0	10.6	66.5	92.3
T35	Generic 15 MW	140	E05_N	959,963	4,501,254	0	10.6	65.6	90.9
T36	Generic 15 MW	140	E05_N	961,945	4,501,024	0	10.6	65.3	90.6
T37	Generic 15 MW	140	E05_N	963,926	4,500,794	0	10.6	64.8	89.9
T38	Generic 15 MW	140	E05_N	965,907	4,500,565	0	10.6	64.5	89.4
T39	Generic 15 MW	140	E05_N	967,888	4,500,335	0	10.6	64.1	88.8
T40	Generic 15 MW	140	E05_N	969,869	4,500,105	0	10.6	64.4	89.3
T41	Generic 15 MW	140	E05_N	971,851	4,499,875	0	10.6	64.6	89.6
T42	Generic 15 MW	140	E05_N	973,832	4,499,645	0	10.6	64.7	89.7
T43	Generic 15 MW	140	E05_N	975,814	4,499,415	0	10.6	65.8	91.2
T44	Generic 15 MW	140	E05_N	961,774	4,499,532	0	10.6	65.6	91.1
T45	Generic 15 MW	140	E05_N	963,755	4,499,302	0	10.6	64.4	89.3
T46	Generic 15 MW	140	E05_N	965,736	4,499,072	0	10.6	64.2	89.1
T47	Generic 15 MW	140	E05_N	967,717	4,498,843	0	10.6	64.0	88.7
T48	Generic 15 MW	140	E05_N	969,699	4,498,613	0	10.6	64.0	88.7
T49	Generic 15 MW	140	E05_N	971,680	4,498,383	0	10.6	64.6	89.5
T50	Generic 15 MW	140	E05_N	973,661	4,498,153	0	10.6	64.7	89.8
T51	Generic 15 MW	140	E05_N	975,643	4,497,923	0	10.6	65.9	91.4
T52	Generic 15 MW	140	E05_N	961,603	4,498,040	0	10.5	66.5	92.3
T53	Generic 15 MW	140	E05_N	963,584	4,497,810	0	10.5	65.2	90.4
T54	Generic 15 MW	140	E05_N	965,565	4,497,580	0	10.6	64.5	89.5
T55	Generic 15 MW	140	E05_N	967,547	4,497,350	0	10.6	64.3	89.2
T56	Generic 15 MW	140	E05_N	969,528	4,497,120	0	10.6	63.9	88.7
T57	Generic 15 MW	140	E05_N	971,509	4,496,890	0	10.6	64.4	89.4
T58	Generic 15 MW	140	E05_N	973,491	4,496,661	0	10.6	65.2	90.4
T59	Generic 15 MW	140	E05_N	975,472	4,496,431	0	10.6	66.7	92.5
T60	Generic 15 MW	140	E05_N	963,413	4,496,318	0	10.5	65.8	91.3
T61	Generic 15 MW	140	E05_N	965,394	4,496,088	0	10.5	64.6	89.7
T62	Generic 15 MW	140	E05_N	967,376	4,495,858	0	10.5	64.5	89.5
T63	Generic 15 MW	140	E05_N	969,357	4,495,628	0	10.5	64.7	89.8
T64	Generic 15 MW	140	E05_N	971,338	4,495,398	0	10.5	65.7	91.2
T65	Generic 15 MW	140	E05_N	963,242	4,494,826	0	10.5	66.8	92.8
T66	Generic 15 MW	140	E05_N	965,224	4,494,596	0	10.5	65.8	91.4
T67	Generic 15 MW	140	E05_N	967,205	4,494,366	0	10.5	66.1	91.7
Average						0	10.6	65.6	95.9
Total								**4395.8**	

a. Co-ordinate system is UTM 18N, NAD83.

b. Wind speed at the location of the turbine, not including wake effects.
c. Individual turbine output figures include all wind farm losses.
d. Individual turbine wake loss including all turbine interaction effects (wakes and blockage).

Table C-10 Energy results, Indicative layout 02 (25 years)

Turbine	Turbine model	Hub-height [m]	Initiation device	Easting[a] [m]	Northing[a] [m]	Elevation [m]	Long-term wind speed at hub-height[b] [m/s]	Energy output[c] [GWh/ annum]	Turbine interaction loss factor[d] [%]
T1	Generic 18 MW	155	E05_N	954,874	4,509,404	0	10.7	81.7	96.0
T2	Generic 18 MW	155	E05_N	956,855	4,509,174	0	10.7	79.7	93.7
T3	Generic 18 MW	155	E05_N	958,836	4,508,945	0	10.7	79.2	93.1
T4	Generic 18 MW	155	E05_N	960,817	4,508,715	0	10.7	79.3	93.1
T5	Generic 18 MW	155	E05_N	954,703	4,507,912	0	10.7	80.2	94.2
T6	Generic 18 MW	155	E05_N	956,684	4,507,682	0	10.7	77.9	91.6
T7	Generic 18 MW	155	E05_N	958,665	4,507,453	0	10.7	77.6	91.2
T8	Generic 18 MW	155	E05_N	960,646	4,507,223	0	10.7	77.4	91.0
T9	Generic 18 MW	155	E05_N	962,627	4,506,993	0	10.7	78.4	92.1
T10	Generic 18 MW	155	E05_N	954,533	4,506,420	0	10.7	79.9	94.0
T11	Generic 18 MW	155	E05_N	956,514	4,506,190	0	10.7	77.7	91.4
T12	Generic 18 MW	155	E05_N	958,495	4,505,960	0	10.7	77.2	90.8
T13	Generic 18 MW	155	E05_N	960,476	4,505,731	0	10.7	77.1	90.7
T14	Generic 18 MW	155	E05_N	962,457	4,505,501	0	10.7	76.8	90.3
T15	Generic 18 MW	155	E05_N	964,438	4,505,271	0	10.7	78.2	91.9
T16	Generic 18 MW	155	E05_N	954,362	4,504,928	0	10.7	80.2	94.4
T17	Generic 18 MW	155	E05_N	956,343	4,504,698	0	10.7	78.3	92.2
T18	Generic 18 MW	155	E05_N	958,324	4,504,468	0	10.7	78.0	91.8
T19	Generic 18 MW	155	E05_N	960,305	4,504,238	0	10.7	77.3	90.9
T20	Generic 18 MW	155	E05_N	962,286	4,504,009	0	10.7	76.8	90.3
T21	Generic 18 MW	155	E05_N	964,267	4,503,779	0	10.7	77.0	90.5
T22	Generic 18 MW	155	E05_N	966,248	4,503,549	0	10.7	78.4	92.2
T26	Generic 18 MW	155	E05_N	960,134	4,502,746	0	10.7	78.1	92.0
T27	Generic 18 MW	155	E05_N	962,115	4,502,516	0	10.7	77.1	90.7
T28	Generic 18 MW	155	E05_N	966,078	4,502,057	0	10.7	76.6	90.1
T29	Generic 18 MW	155	E05_N	968,059	4,501,827	0	10.7	77.4	91.0
T30	Generic 18 MW	155	E05_N	970,040	4,501,597	0	10.7	77.4	91.0
T31	Generic 18 MW	155	E05_N	972,022	4,501,368	0	10.7	77.9	91.7
T32	Generic 18 MW	155	E05_N	974,003	4,501,138	0	10.7	77.7	91.4
T33	Generic 18 MW	155	E05_N	975,984	4,500,908	0	10.7	78.9	92.8
T36	Generic 18 MW	155	E05_N	961,945	4,501,024	0	10.7	78.2	92.1
T37	Generic 18 MW	155	E05_N	963,926	4,500,794	0	10.7	77.1	90.8
T38	Generic 18 MW	155	E05_N	965,907	4,500,565	0	10.7	76.0	89.5
T39	Generic 18 MW	155	E05_N	967,888	4,500,335	0	10.7	75.5	88.8
T40	Generic 18 MW	155	E05_N	969,869	4,500,105	0	10.7	75.8	89.2
T41	Generic 18 MW	155	E05_N	971,851	4,499,875	0	10.7	76.1	89.5
T42	Generic 18 MW	155	E05_N	973,832	4,499,645	0	10.7	76.3	89.7

Turbine	Turbine model	Hub-height [m]	Initiation device	Easting[a] [m]	Northing[a] [m]	Elevation [m]	Long-term wind speed at hub-height[b] [m/s]	Energy output[c] [GWh/ annum]	Turbine interaction loss factor[d] [%]
T43	Generic 18 MW	155	E05_N	975,814	4,499,415	0	10.7	77.3	91.0
T45	Generic 18 MW	155	E05_N	963,755	4,499,302	0	10.6	77.5	91.2
T46	Generic 18 MW	155	E05_N	965,736	4,499,072	0	10.7	75.8	89.2
T47	Generic 18 MW	155	E05_N	967,717	4,498,843	0	10.7	75.6	89.0
T48	Generic 18 MW	155	E05_N	969,699	4,498,613	0	10.7	75.3	88.7
T49	Generic 18 MW	155	E05_N	971,680	4,498,383	0	10.7	76.3	89.9
T50	Generic 18 MW	155	E05_N	973,661	4,498,153	0	10.7	76.0	89.4
T51	Generic 18 MW	155	E05_N	975,643	4,497,923	0	10.7	77.7	91.4
T53	Generic 18 MW	155	E05_N	963,584	4,497,810	0	10.6	77.8	91.7
T54	Generic 18 MW	155	E05_N	965,565	4,497,580	0	10.6	76.2	89.8
T55	Generic 18 MW	155	E05_N	967,547	4,497,350	0	10.6	75.9	89.3
T56	Generic 18 MW	155	E05_N	969,528	4,497,120	0	10.6	76.1	89.6
T57	Generic 18 MW	155	E05_N	971,509	4,496,890	0	10.6	76.5	90.1
T58	Generic 18 MW	155	E05_N	973,491	4,496,661	0	10.6	77.0	90.6
T59	Generic 18 MW	155	E05_N	975,472	4,496,431	0	10.6	78.5	92.5
T60	Generic 18 MW	155	E05_N	963,413	4,496,318	0	10.6	78.8	92.9
T61	Generic 18 MW	155	E05_N	965,394	4,496,088	0	10.6	77.3	91.1
T62	Generic 18 MW	155	E05_N	967,376	4,495,858	0	10.6	77.6	91.5
T64	Generic 18 MW	155	E05_N	971,338	4,495,398	0	10.6	78.1	92.1
Average						0	10.7	77.5	96.0
Total								**4341.5**	

a. Co-ordinate system is UTM 18N, NAD83.
b. Wind speed at the location of the turbine, not including wake effects.
c. Individual turbine output figures include all wind farm losses.
d. Individual turbine wake loss including all turbine interaction effects (wakes and blockage).

C.6 Seasonal and diurnal variation

Table C-11 Relative hourly and monthly energy production [a] [%], Indicative layout 01

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0000	0.42	0.38	0.42	0.42	0.45	0.38	0.30	0.26	0.29	0.34	0.38	0.40
0100	0.42	0.40	0.42	0.41	0.45	0.37	0.29	0.25	0.29	0.34	0.37	0.39
0200	0.41	0.41	0.42	0.40	0.44	0.36	0.27	0.24	0.28	0.35	0.38	0.39
0300	0.40	0.41	0.42	0.40	0.43	0.35	0.26	0.24	0.28	0.35	0.37	0.39
0400	0.40	0.41	0.42	0.38	0.40	0.33	0.25	0.25	0.28	0.34	0.37	0.39
0500	0.40	0.41	0.42	0.37	0.38	0.33	0.26	0.25	0.27	0.33	0.36	0.39
0600	0.39	0.41	0.44	0.38	0.37	0.31	0.26	0.25	0.27	0.33	0.35	0.38
0700	0.39	0.41	0.45	0.39	0.35	0.30	0.25	0.25	0.27	0.34	0.34	0.38
0800	0.40	0.42	0.44	0.37	0.34	0.29	0.23	0.24	0.27	0.35	0.34	0.38
0900	0.41	0.42	0.42	0.36	0.33	0.27	0.22	0.24	0.28	0.36	0.35	0.38
1000	0.40	0.40	0.40	0.35	0.31	0.26	0.21	0.23	0.28	0.36	0.36	0.38
1100	0.40	0.38	0.38	0.35	0.30	0.26	0.21	0.23	0.27	0.34	0.35	0.37
1200	0.39	0.36	0.36	0.34	0.29	0.27	0.21	0.23	0.27	0.33	0.35	0.38
1300	0.39	0.34	0.35	0.34	0.29	0.27	0.21	0.23	0.27	0.33	0.36	0.39
1400	0.39	0.34	0.35	0.34	0.29	0.27	0.22	0.24	0.27	0.33	0.37	0.40
1500	0.40	0.35	0.36	0.36	0.31	0.29	0.24	0.25	0.27	0.33	0.37	0.40
1600	0.41	0.35	0.36	0.38	0.33	0.31	0.27	0.26	0.27	0.33	0.38	0.42
1700	0.40	0.35	0.36	0.38	0.34	0.33	0.28	0.27	0.28	0.33	0.39	0.43
1800	0.40	0.35	0.37	0.37	0.37	0.34	0.29	0.28	0.29	0.33	0.40	0.44
1900	0.40	0.35	0.38	0.38	0.40	0.37	0.30	0.30	0.30	0.34	0.40	0.44
2000	0.41	0.35	0.39	0.40	0.42	0.37	0.31	0.30	0.30	0.34	0.39	0.43
2100	0.43	0.37	0.40	0.40	0.43	0.37	0.32	0.30	0.31	0.34	0.39	0.43
2200	0.43	0.38	0.41	0.40	0.43	0.37	0.31	0.29	0.31	0.34	0.39	0.42
2300	0.42	0.38	0.41	0.41	0.45	0.37	0.30	0.27	0.29	0.34	0.39	0.41
All	9.72	9.13	9.54	9.10	8.91	7.74	6.32	6.16	6.76	8.14	8.88	9.61

a. Only wake and hysteresis are included in the calculation.

Table C-12 Relative hourly and monthly energy production [a] [%], Indicative layout 02

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0000	0.42	0.38	0.42	0.42	0.45	0.38	0.31	0.26	0.29	0.34	0.38	0.40
0100	0.42	0.41	0.42	0.41	0.45	0.38	0.29	0.25	0.29	0.34	0.37	0.39
0200	0.41	0.41	0.43	0.41	0.44	0.36	0.28	0.24	0.29	0.35	0.38	0.38
0300	0.40	0.41	0.43	0.40	0.43	0.35	0.26	0.25	0.28	0.35	0.37	0.39
0400	0.40	0.42	0.42	0.38	0.40	0.33	0.26	0.25	0.28	0.34	0.37	0.39
0500	0.40	0.41	0.43	0.37	0.37	0.32	0.26	0.26	0.28	0.34	0.36	0.39
0600	0.39	0.41	0.44	0.38	0.37	0.31	0.26	0.26	0.27	0.33	0.35	0.38
0700	0.39	0.41	0.45	0.38	0.35	0.30	0.25	0.25	0.27	0.33	0.34	0.38
0800	0.40	0.42	0.44	0.37	0.33	0.28	0.23	0.24	0.28	0.35	0.34	0.38
0900	0.40	0.42	0.43	0.36	0.31	0.26	0.22	0.24	0.28	0.36	0.35	0.38
1000	0.40	0.39	0.40	0.35	0.30	0.25	0.20	0.24	0.28	0.36	0.36	0.38
1100	0.39	0.38	0.38	0.35	0.30	0.26	0.21	0.23	0.27	0.34	0.35	0.38
1200	0.39	0.36	0.36	0.34	0.29	0.27	0.21	0.23	0.27	0.33	0.35	0.38
1300	0.39	0.34	0.35	0.34	0.29	0.27	0.21	0.23	0.27	0.33	0.36	0.39
1400	0.39	0.35	0.36	0.34	0.29	0.27	0.22	0.24	0.27	0.33	0.37	0.40
1500	0.39	0.35	0.35	0.36	0.30	0.29	0.25	0.26	0.27	0.33	0.37	0.41
1600	0.41	0.35	0.36	0.37	0.32	0.31	0.27	0.27	0.27	0.33	0.38	0.42
1700	0.40	0.35	0.36	0.38	0.35	0.32	0.28	0.27	0.28	0.33	0.39	0.43
1800	0.40	0.35	0.37	0.37	0.37	0.34	0.30	0.29	0.29	0.33	0.40	0.44
1900	0.40	0.35	0.37	0.37	0.40	0.37	0.31	0.30	0.30	0.34	0.40	0.44
2000	0.41	0.35	0.38	0.39	0.42	0.37	0.32	0.30	0.30	0.34	0.39	0.44
2100	0.42	0.37	0.39	0.40	0.43	0.38	0.33	0.30	0.31	0.34	0.38	0.43
2200	0.42	0.38	0.41	0.40	0.43	0.37	0.32	0.30	0.31	0.35	0.39	0.41
2300	0.42	0.38	0.41	0.41	0.44	0.37	0.31	0.28	0.30	0.35	0.39	0.41
All	9.66	9.14	9.55	9.06	8.83	7.70	6.36	6.24	6.81	8.17	8.88	9.59

a. Only wake and hysteresis are included in the calculation.

APPENDIX D – REVISIONS

Customer Name:	New York State Energy Research and Development Authority	DNV Entity:	DNV Energy USA Inc.
Customer Address:	1359 Broadway New York, NY 10018	DNV Address:	101 Station Landing, Suite 520 Medford, MA 02155 USA
Contact person:	Jessica Dealy	DNV Tel.:	781-273-5700
Project name:	East Coast Zone 1	DNV Enterprise No.:	23-2625724
Report title:	Offshore Wind Resource Assessment		
Date of issue:	7 April 2025		
Project No.:	10434276		
Document No.:	10434276-HOU-R-02-I		
Status:	Final		

Task and objective: To complete an independent assessment of the wind climate and energy production for the Project.

Prepared by:	Verified by:	Approved by:
Idalia Machuca Offshore Wind Analyst	Jessica Mason Senior Engineer	Elizabeth Traiger Team Leader, Wind Energy Assessment
Émilie Chénier Energy Wind Analyst	Arthur Burden Senior Wind Energy Analyst	Onur Kaprol Head of Section, Wind Energy Assessment

Distribution outside of DNV:

☐ Published	Available for information only to the general public (subject to the above Important Notice and Disclaimer).
☒ Customer's Discretion	Distribution for information only at the discretion of the Customer (subject to the above Important Notice and Disclaimer and the terms of DNV's written agreement with the Customer).
☐ Confidential	Not to be disclosed outside the Customer's organization.
☐ None	Not to be disclosed outside of DNV.

Issue	Date	Reason for Issue	Prepared by	Verified by	Approved by
A	11 April 2023	Initial issue for review	I. Machuca	J. Mason	E. Traiger, O. Kaprol
B	28 July 2023	Wind speed map added and text edits	É. Chénier	A. Burden	E. Traiger
C	14 August 2023	Text edits	É. Chénier	A. Burden	E. Traiger
D	3 November 2023	Text edits	É. Chénier	A. Burden	E. Traiger
E	9 February 2024	Text edits	É. Chénier	A. Burden	E. Traiger
F	8 March 2024	Text edits	É. Chénier	A. Burden	E. Traiger
G	25 March 2024	Accessibility Updates	É. Chénier	A. Burden	E. Traiger
H	2 April 2025	Text edits: No changes to methodology or analysis.	É. Chénier	A. Burden	E. Traiger
I	7 April 2025	Final Issue	É. Chénier	A. Burden	E. Traiger

ABOUT DNV

We are the independent expert in assurance and risk management. Driven by our purpose, to safeguard life, property and the environment, we empower our customers and their stakeholders with facts and reliable insights so that critical decisions can be made with confidence. As a trusted voice for many of the world's most successful organizations, we use our knowledge to advance safety and performance, set industry benchmarks, and inspire and invent solutions to tackle global transformations.

2 Offshore Wind Resource Assessment Zone 3

Offshore Wind Resource Assessment:

Zone 3

Report

Prepared for:

New York State Energy Research and Development Authority

Albany, NY

Prepared by:

DNV Energy USA Inc.

Medford, MA

NYSERDA Report 25-12 NYSERDA Contract 123367A March 2025

Preferred Citation

New York State Energy Research and Development Authority (NYSERDA). 2025. “Offshore Wind Planning in the New York Bight: Offshore Wind Resource Assessment Zones 1 and 3.” NYSERDA Report Number 25-12. Prepared by DNV Energy USA Inc., Medford, MA. nyserda.ny.gov/publications

Table of Contents

Appendices

List of Tables

List of Figures

List of Abbreviations

Abbreviation	Meaning
ABL	Atmospheric Boundary Layer
AEP	Annual Energy Production
AoA	Area of Analysis
ASL	Above Sea Level
ASIT	Air-sea Interaction Tower
ASOS	Automatic Surface Observing Station
BOEM	Bureau of Ocean Energy Management
CFD	Computational fluid dynamics
Climate Act	Climate Leadership and Community Protection Act
CNR	Carrier-to-noise ratio
DNV	DNV Energy USA Inc.
ECMWF	European Centre for Medium-Range Weather Forecasts
ERA5	European Centre for Medium-Range Weather Forecasts Re-Analysis (fifth generation)
FAA	Federal Aviation Administration
GEOS-5	Goddard Earth Observing System Data Assimilation System, Version 5
IEC	International Electrotechnical Commission
MEASNET	Measuring Network of Wind Energy Institutes
MERRA-2	Modern-Era Retrospective analysis for Research and Applications, Version 2
MSL	Mean Sea Level
MW	Megawatt
NASA	National Aeronautics and Space Administration
NWS	National Weather Service
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and maintenance
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
RANS	Reynolds-averaged Navier-Stokes
RMS	Root-mean-square
SNR	Signal-to-noise ratio
TI	Turbulence intensity
TWG	Technical Working Groups
WEA	Wind Energy Areas
WHOI	Woods Hole Oceanographic Institution
WRF	Weather Research and Forecasting

EXECUTIVE SUMMARY

Offshore wind energy could become a major source of affordable, renewable power for New York State, particularly on Long Island and in the New York City metropolitan area, where demand on the electric grid is greatest. Generating electricity with wind turbines located off New York's Atlantic Coast has the potential to provide up to 39,000 megawatts (MW) of clean power for the State, enough to power 15 million homes.

A strong knowledge of meteorological and oceanographic - metocean - conditions is essential for the safe and efficient design and operation of offshore wind installations. Prior to this study, limited metocean data has been collected in the region and our knowledge of wind speeds and other conditions has been largely based on modeled data. Uncertainty in physical conditions increases development risk and offtake bid prices. By obtaining better metocean characterization of the wind, wave, and ocean current environment within the offshore wind study areas, certainty of development conditions increases, which is useful in planning activities such as the refinement of project layout and turbine siting, key variables in lease auctions, and offtake.

In 2019, the New York State Energy Research and Development Authority, in collaboration with DNV and Ocean Tech Services, deployed two floating Lidar systems approximately 70 km off the Atlantic coast of New York, also known as the New York Bight. The floating Lidars have gathered data for approximately two years, which is used to better understand the metocean conditions for the development of future offshore wind farms in the area. The collection of the site data is part of the New York State Energy Research and Development Authority's wider initiative to encourage the development of offshore wind in a manner that is sensitive to environmental, maritime, economic, and social issues while addressing market barriers for offshore wind technology and aiming to lower electricity costs for consumers.

New York State Energy Research and Development Authority retained DNV Energy USA Inc. (DNV) to complete independent assessments of the wind climate and energy production for two indicative offshore wind farms in the East Coast Zone 3 in the New York Bight. The tables below summarize the projects and the results of the wind resource and energy production analysis.

Project Summary		
Indicative layout	01	02
Turbine make and model	Theoretical 15 MW	Theoretical 18 MW
Turbine hub-height [m]	140	155
Turbine rated power [kW]	15000	18000
Number of turbines	67	56
Installed capacity [MW]	1005	1008
Wind Resource Summary		
Average air density [kg/m^3]	1.22	1.22
On-site measurement period [years]	2.4	2.4
Long-term reference period [years]	23.1	23.1
Average turbine hub-height wind speed [m/s]	10.1	10.2
Energy Assessment Summary		
Evaluation period [years]	25	25
Gross energy [GWh/year]	5243.6	5174.2
P50 loss factors		
- Turbine interaction effects (wakes and blockage)	95.2%	95.3%
- Availability	92.9%	92.9%
- Electrical	97.5%	97.5%
- Turbine performance	96.0%	95.9%
- Environmental	100.0%	100.0%
- Curtailment	100.0%	100.0%
Total losses	82.7%	82.6%
Effect of asymmetric production	99.9%	99.9%
P50 Net Energy [GWh/year]	**4333.9**	**4275.6**
P50 Net Capacity Factor	**49.2%**	**48.4%**
1-year P99 Net Energy [GWh/year]	3406.5	3349.9
1-year P99 Net Capacity Factor	38.7%	37.9%

The key findings of the analysis and factors affecting the analysis results are summarized below:

- The wind resource campaign used two floating Lidar systems (FLSs) at three locations: two EOLOS FLS-200s each with one ZephIR ZX300M Lidar unit on-board. The FLS locations are not directly representative of the East Coast Zone 3 wind regime as the measurements are 120 km or more away from the Zone 3 turbine locations. This energy assessment is based on approximately two years of measured wind data.
- DNV has derived hypothetical power curves based on current and expected trends in turbine technology.
- The sensitivity of energy due to changes in wind speed (sensitivity ratio) for offshore wind projects is typically lower due to the higher wind speeds, but is also dependent on the turbine characteristics such as swept rotor size and rated power. Given the high wind speeds in the East Coast Zone 3 site, and the assumed turbine characteristics of the hypothetical turbines modeled for this preliminary assessment, the net energy is less sensitive to changes in wind speed and the sensitivity ratio approaches unity for this preliminary assessment. DNV notes that the sensitivity ratio and therefore the project uncertainty may vary materially depending on the final commercially available turbines selected for the projects.
- The variation in wind speed over East Coast Zone 3 were predicted using Vortex mesoscale model. The wind speed variation across East Coast Zone 3 at 140 m is based on the Vortex mesoscale model and calibrated to the long-term mean wind speed at floating lidar E05_N. Figure 4-5 shows the external wake effect caused by the neighboring wind farms across East Coast Zone 3. The wind speed range is between 9.8 m/s and 10.4 m/s. Generally, the wind speed increases with the distance to shore with the highest wind speed to the east of the Area of Analysis.
- Based on publicly available information, DNV derived representative turbine layouts of neighboring wind farms for the sake of external wake modelling and estimation. Given the early stage of development of several of the neighboring projects, it is not possible to accurately model their wake effects on the East Coast Zone 3 project. DNV has estimated the wake effects of the neighboring projects assuming the same turbine model as the East Coast Zone 3 Wind Farm. Due to the distance, the neighboring projects are considered to have negligible wake impacts across the whole area of the Area of Analysis.
- NYSERDA has requested that DNV design two indicative wind farm layouts. DNV notes that alternative, non-gridded layouts are possible within the Lease Areas and that gridded layouts have been assumed for this preliminary assessment for simplicity. The gridded layouts are not a reflection of New York State policy on preference for any predetermined layout or approach thereto. Project capacities for each indicative layout were maintained at approximately 1000 MW and are likewise generically identified for hypothetical purposes befitting a preliminary assessment and are not a reflection of DNV or New York State’s opinions regarding project sizing.

  Based on water depth, the distance to shore and the seabed variation across the Area of Analysis, DNV has chosen a Wind Turbine Area. The wind speed being fairly consistent within the Area of Analysis and the external wake effect being negligible across the Area of Analysis, those parameters were not determining criteria for the siting. For the indicative layouts used in this study, DNV did not perform detailed layout optimization and, as such, no environmental constraint analysis was done. DNV has not performed a site visit to determine site suitability nor micro sited the turbine locations. The layouts used in this analysis are indicative for wind resource characterization and preliminary energy assessments only and should not be considered as a recommendation.
- No wind sector management strategy has been modeled, and DNV has not included any losses which may be associated with this. However, given the large inter-turbine spacings assumed, DNV considers it unlikely a wind sector management strategy would be required. For future projects, it is recommended that the turbine supplier be

approached at an early stage to gain approval for the indicative layouts and that an Independent Engineer reviews the manufacturer's conclusions as part of a full due diligence exercise.

- Aside from inter-annual variability, the uncertainty in the analysis is driven by loss factor uncertainty and measurement uncertainty. Uncertainty in the analysis could be reduced by obtaining commercially available turbine power curves, assessing the electrical systems and access strategies to inform more refined estimates for electrical loss and turbine availability, and having a measurement location closer to East Coast Zone 3.

The preceding factors have all been considered in the analysis.

1 INTRODUCTION

In 2019, New York's historic Climate Leadership and Community Protection Act (Climate Act) was signed into law, requiring the State to achieve 100% zero-emission electricity by 2040 and to reduce greenhouse gas emissions 85% below 1990 levels by 2050. The law specifically mandates the development of 9,000 megawatts (MW) of offshore wind energy by 2035, building upon its previous goal of 2,400 MW of offshore wind energy by 2030. The New York State Energy Research and Development Authority (NYSERDA) is charged with advancing these goals.

For more than a decade, New York State has been conducting research, analysis, and outreach to evaluate the potential for offshore wind energy. New York State Energy Research and Development Authority (NYSERDA) led the development of the New York State Offshore Wind Master Plan (Master Plan), a comprehensive roadmap and suite of more than 20 studies for the first 2,400 megawatts (MW) of offshore wind energy. The Master Plan encourages the development of offshore wind in a manner that is sensitive to environmental, maritime, economic, and social issues while addressing market barriers and aiming to lower costs. The Master Plan included spatial studies to inform siting of offshore wind energy areas. Now, NYSERDA is undertaking new spatial studies to review the feasible potential for deep water offshore wind, at or exceeding depths of 60 meters in the New York Bight.

Planning processes considering the development of offshore wind in the deepwater areas examined in each of NYSERDA's spatial studies must consider these studies in the context of one another. Decision making must additionally consider different stakeholders and uses, and will require further adjusted approaches and offshore wind technologies to ensure the best outcome. Globally, deepwater wind technology is less mature and primarily concentrated on floating designs at the depth ranges being assessed through these spatial studies, while deepwater fixed-bottom foundations are at their upper technical limit within the Area of Analysis (AoA). Therefore, floating designs were predominantly considered since most, if not all, of the AoA would likely feature floating offshore wind. NYSERDA, along with other state and federal agencies, is developing research and analysis necessary to take advantage of opportunities afforded by deep water offshore wind energy by assessing available and emerging technologies, and characterizing the cost drivers, benefits, and risks of floating offshore wind. Findings from these studies and available datasets will be used to support the identification of areas that present the greatest opportunities and least risk for siting deep water offshore wind projects.

1.1 Benefits and Cost-Reduction Pathways

The State's Master Plan analysis concluded that offshore wind development will enhance the State's job market, supply chain, and economy; reduce the use of fossil fuels; and provide other public health, environmental, and societal benefits. While the State plans to continue procuring offshore wind projects within the existing lease areas, the timing is right to build a better understanding of the opportunities and challenges of projects farther offshore. Cost is a critical consideration for the State in the development of offshore wind. A focused study on the cost landscape and technological readiness for deepwater offshore wind of 60 to 3,000 meters in water depths in the Area of Analysis was conducted to help the State understand how floating offshore wind may fit in New York's renewable energy portfolio. Additional discussion of costs and cost-reducing strategies focusing on State options for contracting related to deep water offshore wind, job-training programs, and infrastructure investments will also be developed as part of future planning efforts.

The State will continue to undertake research and engage its established Technical Working Groups (TWGs) on key subjects of fishing, maritime commerce, the environment, environmental justice, jobs, and the supply chain. These TWGs will continue to inject expert views and the most recent information as an integral part of future decision-making.

When combined, the information assembled in these studies will empower New York State and its partners to take the informed steps needed to continue to capitalize on the unique opportunity presented by offshore wind energy.

1.2 Spatial Studies to Inform Lease Siting

- Benthic Habitat Study
- Birds and Bats Study
- Deepwater Wind Technologies – Technical Concepts Study
- Environmental Sensitivity Analysis
- Fish and Fisheries Data Aggregation Study
- Marine Mammals and Sea Turtles Study
- Maritime Assessment – Commercial and Recreational Uses Study
- Offshore Wind Resource Assessment Study Zones 1 and 3
- Technology Assessment and Cost Considerations Study

Each of the studies was prepared in support of a larger planning effort and shared with relevant experts and stakeholders for feedback. The State addressed comments and incorporated feedback received into the studies. Feedback from these diverse groups helps to strengthen the studies, and also helps ensure that these work products will have broader applicability and a comprehensive view

The Energy Policy Act of 2005 amended Section 8 of the Outer Continental Shelf Lands Act (OCSLA) to give BOEM the authority to identify offshore wind development sites within the Outer Continental Shelf (OCS) and to issue leases on the OCS for activities that are not otherwise authorized by the OCSLA, including wind development. The State recognizes that all development in the OCS is subject to review processes and decision-making by BOEM and other federal and State agencies. This collection of spatial studies is not intended to replace the BOEM Wind Energy Area identification process and does not commit the State or any other agency or entity to any specific course of action with respect to offshore wind energy development. Rather, the State's intent is to facilitate the principled planning of future offshore development off the New York coast, provide a resource for the various stakeholders, and encourage the achievement of the State's offshore wind energy goals.

1.3 Scope of Study

The spatial studies will evaluate potential areas for deep water offshore wind development within a specific geographic area of analysis (AoA) of approximately 35,670 square miles of ocean area extending from the coast of Cape Cod south to the southern end of New Jersey. It includes three zones extending outward from the 60-meter depth contour, which ranges between 15 and 50 nautical miles from shore to the 3,000-meter contour, which ranges from 140 to 160 nautical miles from shore.

The eastern edge of the AoA avoids Nantucket Shoals and portions of Georges Bank, since those areas are well known to be biologically and ecologically important for fish and wildlife, fisheries, and maritime activity. The AoA does include areas such as the Hudson Canyon, which is under consideration to be designated as a National Marine Sanctuary and thus unlikely to be suitable for BOEM site leases.

While offshore wind infrastructure will not be built across the entire AoA, the spatial studies analyze this broad expanse to provide a regional context for these resources and ocean uses.

- Zone 1 is closest to shore and includes a portion of the Outer Continental Shelf. It extends from the 60-meter contour out to the continental shelf break [60 meters (197 feet) to 150 meters (492 feet) deep]. Zone 1 is approximately 12,040 square miles.

- Zone 2 spans the steeply sloped continental shelf break, with unique canyon geology and habitats [150 meters (492 feet) to 2,000 meters (6,561 feet) deep]. Zone 2 is approximately 6,830 square miles.

- Zone 3 extends from the continental shelf break out to 3,000 meters (9,842 feet) depth. Zone 3 is approximately 16,800 square miles.

Zone 2, stretching across the steeply sloped continental shelf break with its distinctive canyon geology and unique habitats, was excluded from consideration for wind development research due to several compelling reasons. In the initial discussions of the spatial studies, members of the Technical Working Groups swiftly recognized the zone's extraordinary biodiversity and distinctive ecological attributes, leading to a consensus that it was ill-suited for development.

Additionally, the considerable variance in water depths within this zone posed potential engineering challenges for the installation of wind turbines along the shelf's precipice. These engineering hurdles would likely result in escalated development costs compared to alternative locations within the Area of Analysis.

The decision to forgo Zone 2 was a meticulously considered one, firmly aligned with two of NYSERDA’s Guiding Principles for Offshore Wind: the imperative to maximize cost-effectiveness for New York State ratepayers and the commitment to minimize environmental impacts. This strategic choice reflects a careful balance between offshore wind development and environmental responsibility, ultimately serving the best interests of both the industry and the State.

1.4 Study Objective

New York State Energy Research and Development Authority (NYSERDA) retained DNV Energy USA, Inc. (DNV) to provide ongoing data management and quality checking services for the on-site FLSs through DNV’s Resource Panorama service and complete independent analyses of the wind regime and energy production for two hypothetical offshore wind farms in the NY Offshore Wind Study Area in the New York Bight. This report is issued to NYSERDA pursuant to a written agreement arising from the Proposal for Energy Services 202229, dated 19 January 2023.

This report presents a description of the project site, turbine technology, and neighboring wind projects. It then describes the available measurements and analysis of the wind data followed by an evaluation of the expected project gross and net energy, as influenced by assumed losses and uncertainties. Finally, it presents DNV’s observations and recommendations.

2 PROJECT DESCRIPTION

As shown in Figure 2-1, the Area of Analysis is located in federal waters offshore of New York beyond the shelf break and is approximately 450 km x 100 km. DNV has identified an Indicative Wind Turbine Area, approximately 170 km south of Long Island.

DNV has analyzed the following indicative layouts as seen in Table 2-1.

Table 2-1 Indicative layouts

Indicative Layout	Number of turbines	Turbine type	Hub-height [m]
01	67	Theoretical 15 MW	140
02	56	Theoretical 18 MW	155

Measurements of the wind regime have been made at three locations using two EOLOS FLS-200s. These are described in more detail in Section 3.

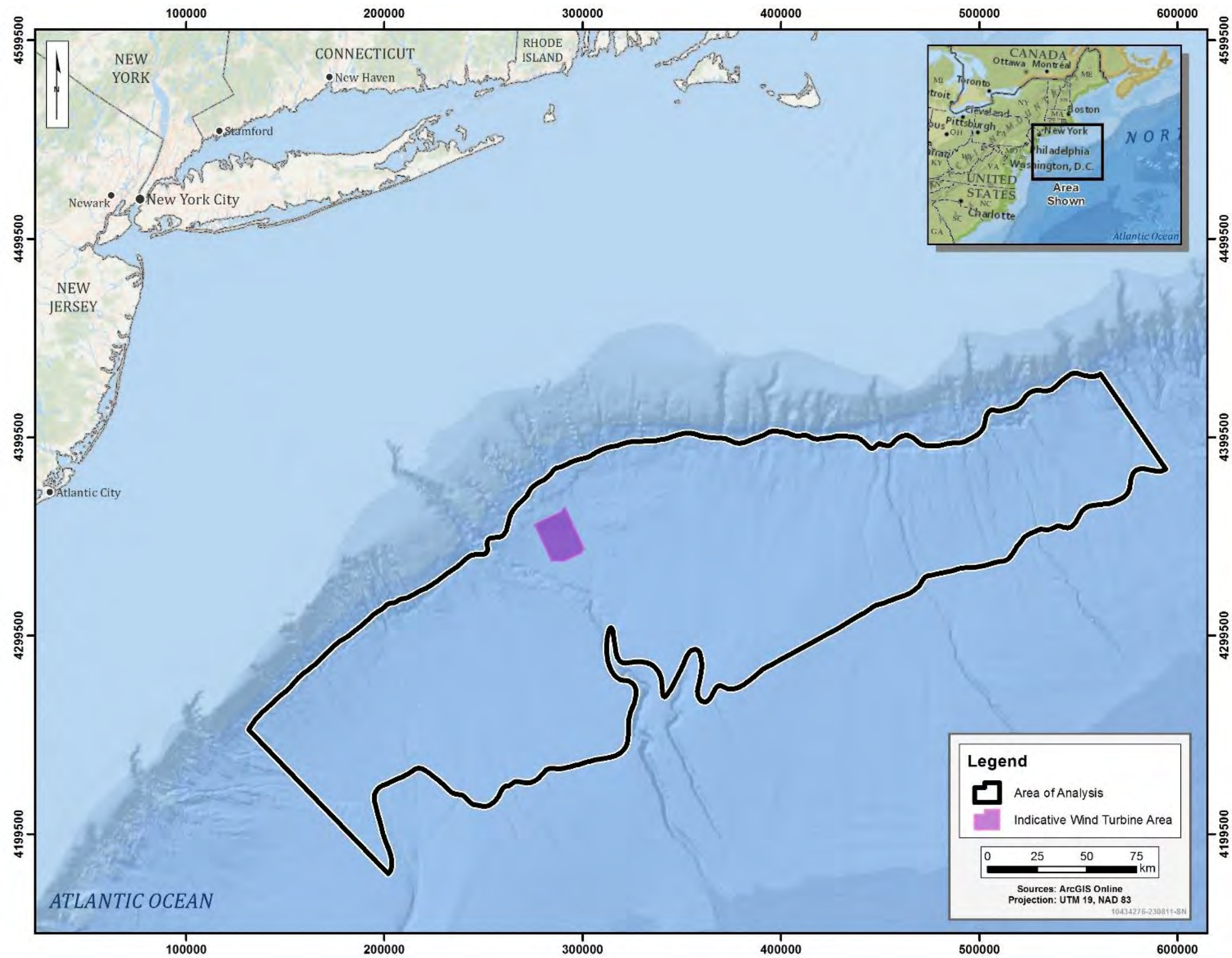


Figure 2-1 Project location

2.1 Site description

The Indicative Wind Turbine Area is located in federal waters offshore of New York, approximately 170 km south of Long Island.

Figure 2-2 is a map of the area showing the site measurement locations. Maps of each indicative layout for the East Coast Z3 Wind Farm are presented in Figure 2-3 and Figure 2-4, showing the proposed turbine locations.

Based on water depth, the distance to shore and the seabed across the Area of Analysis, DNV has chosen a Wind Turbine Area as shown in Figure 2-2. The wind speed being fairly consistent within the Area of Analysis was not a determining criterion for the siting. DNV did not perform detailed layout optimization and, as such, no environmental constraint analysis was done. DNV has not performed a site visit to determine site suitability nor micro sited the turbine locations. The Wind Turbine Area chosen in this analysis is indicative for wind resource characterization and preliminary energy assessments only and should not be considered as a recommendation. More information about the wind speed variation across the Area of Analysis is shown in Section 4.3.

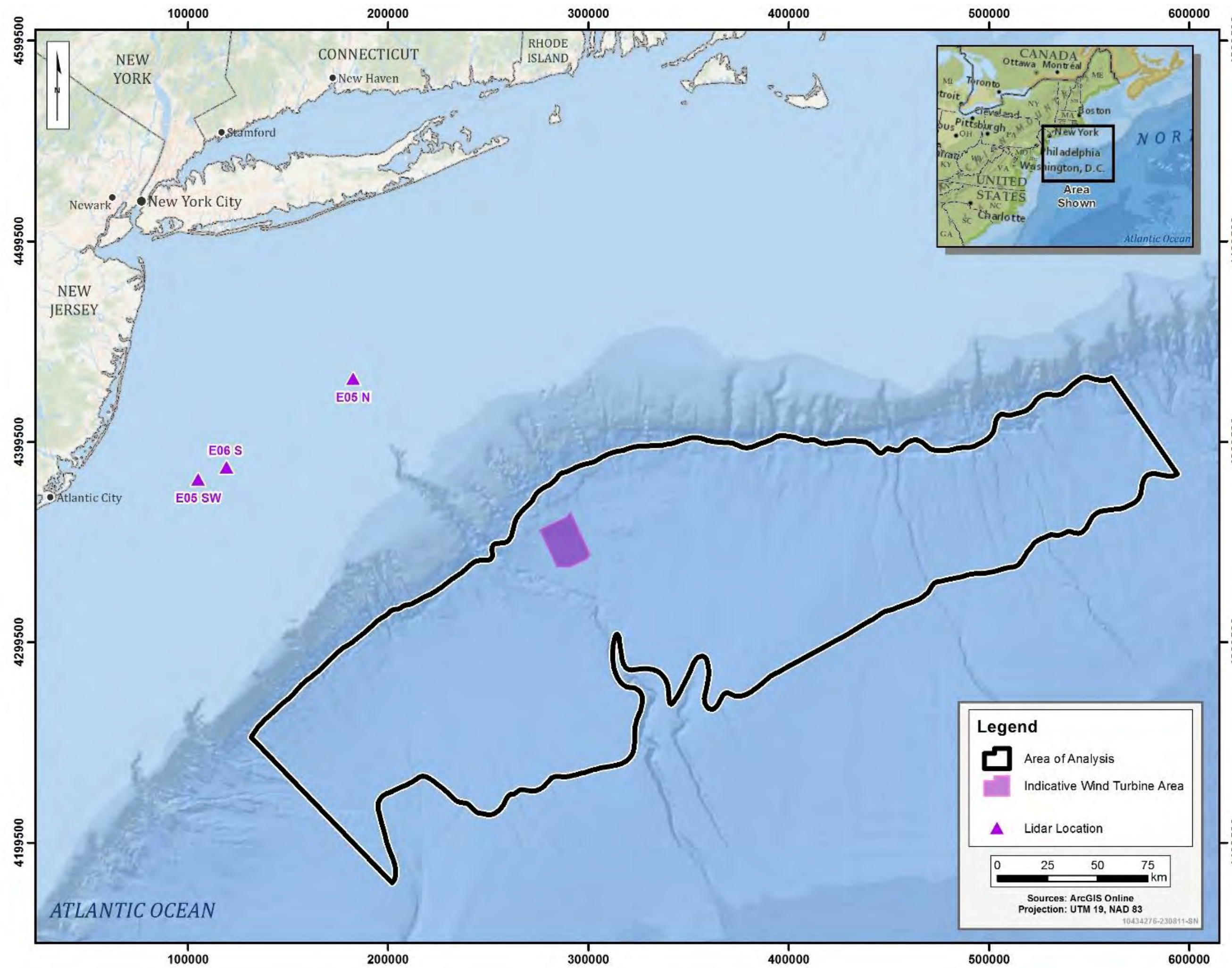


Figure 2-2 Map of the Measurement Locations

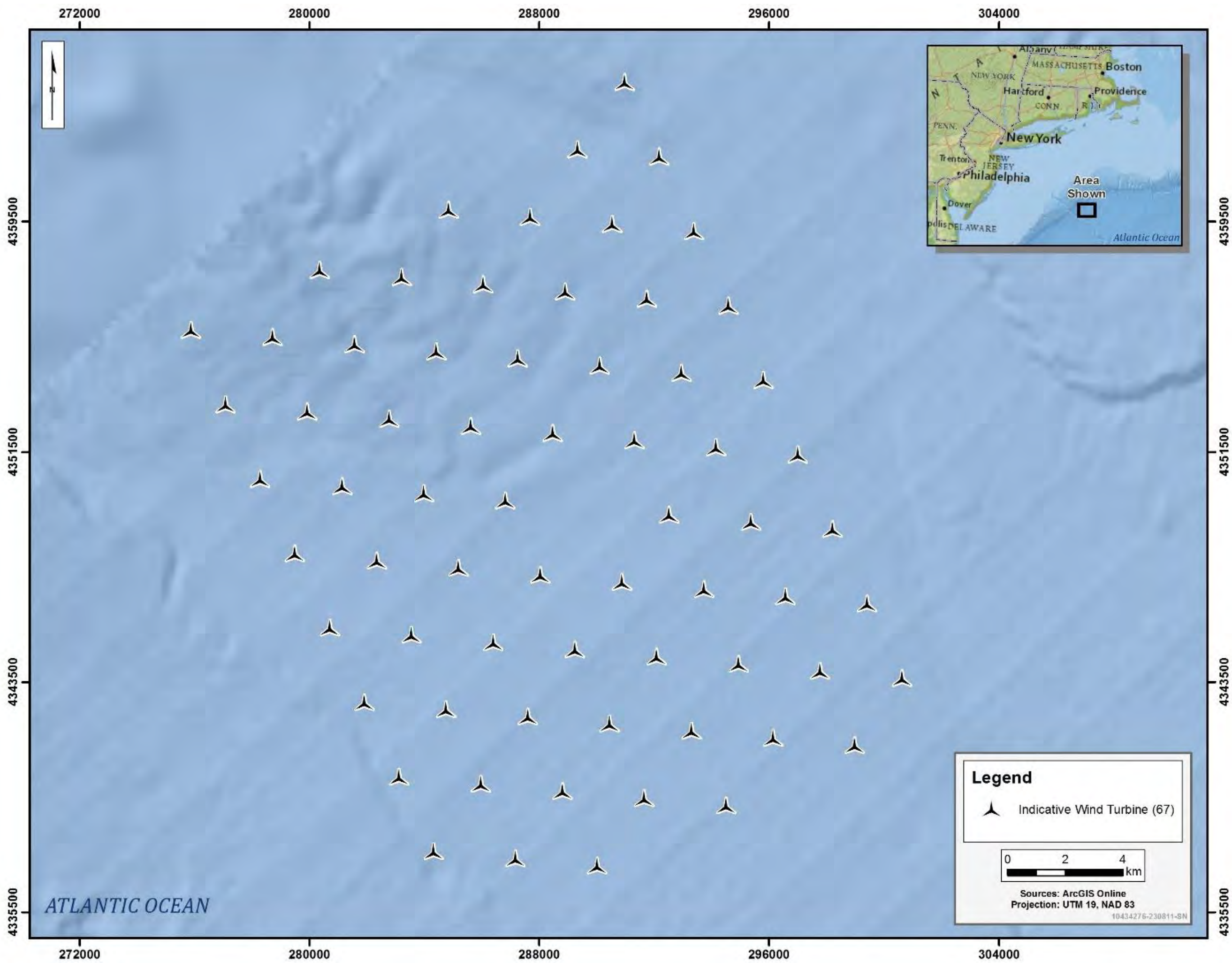


Figure 2-3 Map of the East Coast Z3 Wind Farm, Indicative layout 01

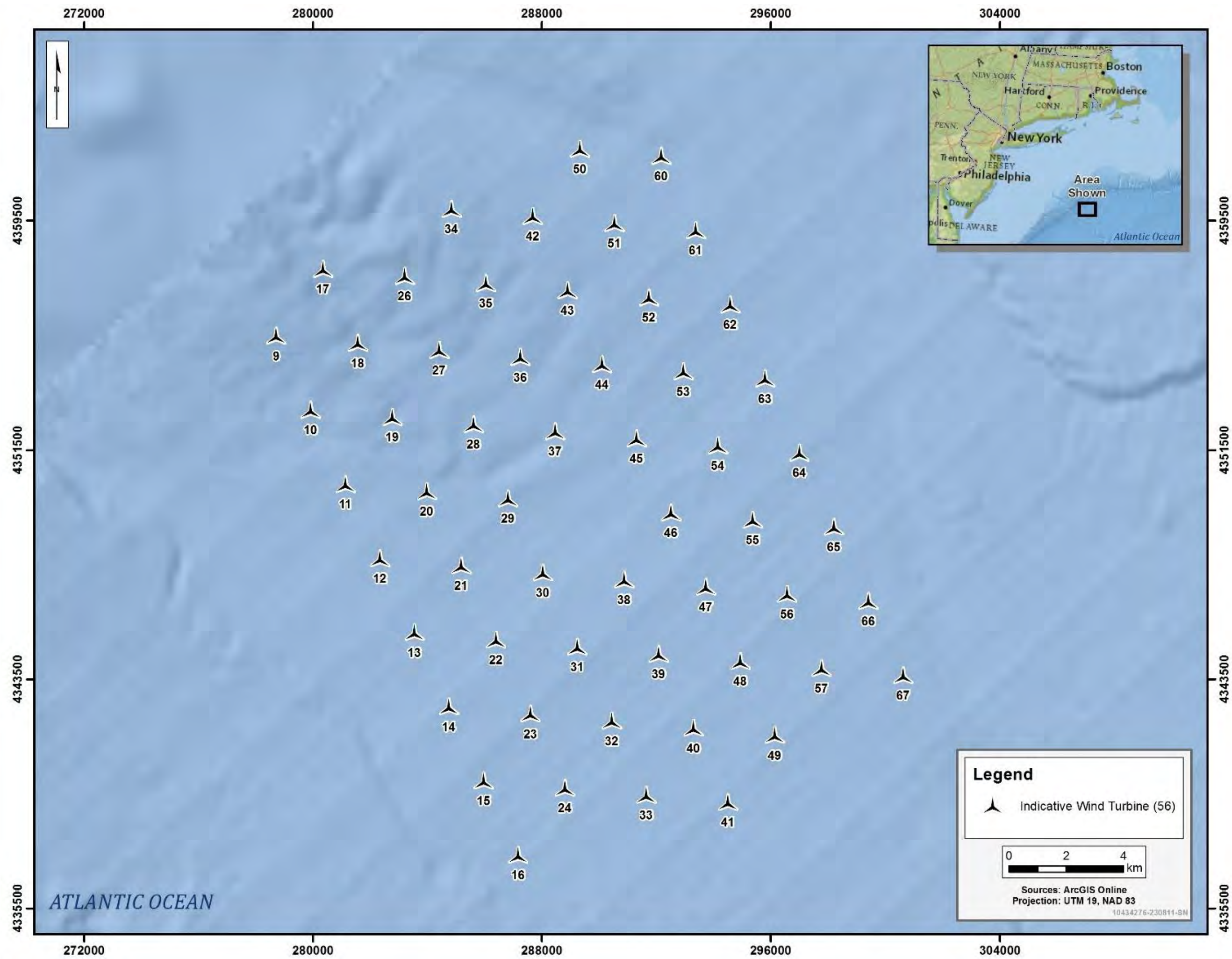


Figure 2-4 Map of the East Coast Z3 Wind Farm, Indicative layout 02

Although DNV has not visited the site, DNV visited the Ocean Tech Services shop in Avalon, NJ on 02 August 2019 to witness the Site Acceptance Test for the EOLOS FLS-200 buoys as reported in the Port Site Acceptance Test report [1].

Photos of the EOLOS FLS-200 buoys are shown in

Figure 2-5.

Figure 2-5 E05 (left) and E06 (right) EOLOS FLS-200 buoys

2.2 Turbine technology

Table 2-2 summarizes the hypothetical turbine configurations under consideration for the East Coast Z3 project.

Table 2-2 Proposed turbine model parameters

Turbine	Rated power [MW]	Rotor diameter [m]	Hub-height [m MSL]	Peak power coefficient [Cp]	Valid power curve air density [kg/m^3]
Theoretical 15 MW	15	236	140	0.46	1.225
Theoretical 18 MW	18	250	155	0.46	1.225

NYSERDA has requested that DNV derive hypothetical power curves for the project. The power curves are based on air densities of 1.225 kg/m^3 and have been adjusted to the site density [3]. Although relatively high, the peak power coefficients are considered to be attainable. Based on DNV extensive review and experience in power performance measurements, the peak power coefficients are within a range of typical values.

2.3 Turbine layout

NYSERDA has requested that DNV design two indicative wind farm layouts with floating foundations within the boundaries of Zone 3. As requested by NYSERDA, the following constraints have been used for this design:

- DNV considered one turbine model and one hub-height for each indicative layout.
- Indicative layout 01 is considered the base case layout scenario. The base case layout was pared down for Indicative layout 02 to maintain project capacities of approximately 1000 MW by removing surplus turbine locations.

Figure 2-3 and Figure 2-4 show the turbine indicative layouts for East Coast Zone 3. The grid coordinates of the turbines are shown in Appendix C.

The following aspects of the indicative layouts are notable and have been considered in the analysis:

- The mooring lines radius is considered equal to the water depth and the mooring system is made of 3 mooring lines.
- The indicative layouts were orientated to maximize the turbines spacing in the prevailing wind direction to minimize the internal wake effect.
- The overall average spacing of the 15 MW indicative layout is 21.0 rotor diameters (D) in the prevailing direction and 12.1D in the non-prevailing direction. The overall average spacing of the 18 MW indicative layout is 19.8D in the prevailing direction and 11.4D in the non-prevailing direction.
- DNV notes that alternative, non-gridded layouts are possible within the Lease Areas and that gridded layouts have been assumed for this preliminary assessment for simplicity. The gridded layouts are not a reflection of New York State policy on preference for any predetermined layout or approach thereto.
- No wind sector management strategy has been modeled, and DNV has not included any losses which may be associated with one. However, given the large inter-turbine spacings assumed, DNV considers it unlikely a wind sector management strategy would be required. For future projects, it is recommended that the turbine supplier be approached at an early stage to gain approval for the indicative layouts and that an Independent Engineer reviews the manufacturer’s conclusions as part of a full due diligence exercise.

2.4 Neighboring wind farms

DNV has reviewed the publicly-available data sources [2] and has identified no wind farms near the project. As shown in the Figure 2-6, the closest Lease Aera is approximately 80 km away from the Zone 3 Area of Analysis and approximately 110 km away from the Indicative layouts. Therefore, no neighboring wind farms have been considered in the analysis.

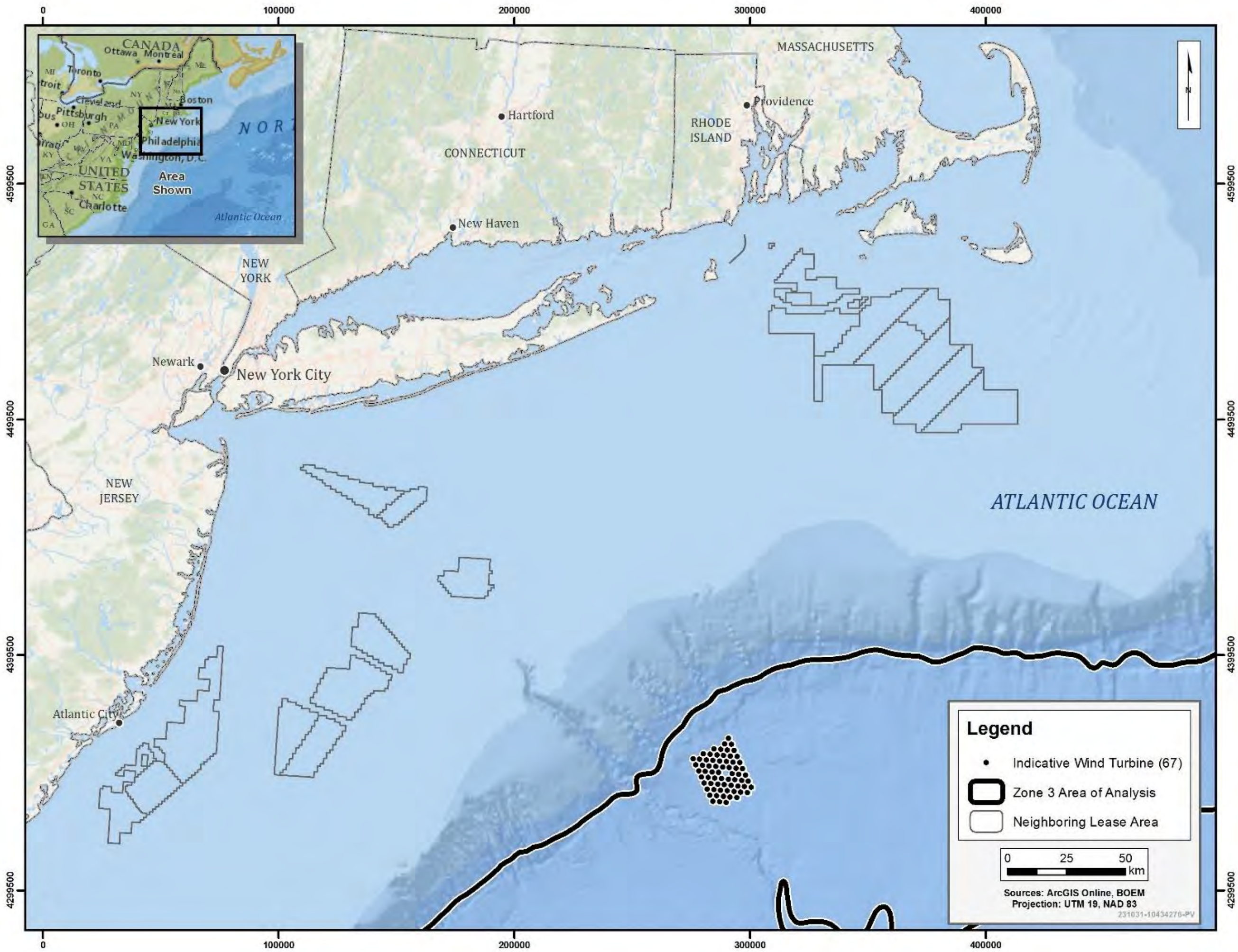


Figure 2-6 Map of Indicative layout 01 and surrounding Lease Areas

3 ON-SITE WIND MONITORING

3.1 Wind resource measurements

Wind resource measurements have been taken at three floating lidar systems across three locations over the period of August 2019 to January 2023.

The characteristics of the measurement campaign are summarized in Table 3-1.

Table 3-1 Remote sensing campaign summary

Lidar System	Buoy reference	Lidar	Measurement heights [m MSL]	Measurement period	Stage maturity according to the OWA Roadmap[a]
EOLOS FLS-200 FLiDAR	E05_N	ZephIR ZX300M	20, 40 ,60, 80, 100, 120, 140, 160, 180, 200	August 2019 - September 2021	Stage 2 / pre-commercial [b]
EOLOS FLS-200 FLiDAR	E05_SW	ZephIR ZX300M	20, 40 ,60, 80, 100, 120, 140, 160, 180, 200	January 2022 – January 2023	Stage 2 / pre-commercial [b]
EOLOS FLS-200 FLiDAR	E06_S	ZephIR ZX300M	20, 40 ,60, 80, 100, 120, 140, 160, 180, 200	September 2019 to March 2022	Stage 2 / pre-commercial [b]

a. Carbon Trust Offshore Wind Accelerator Roadmap [5].

b. DNV is aware that EOLOS FLS-200 has recently been independently verified as having reached stage 3 maturity status, however copies of the independent stage 3 validation reports have not been provided.

Full details of the history of each data source and its instrumentation are provided in Appendix B.

3.1.1 Floating Lidar System (FLS) deployments

DNV is aware that the EOLOS FLS-200 FLS has reached Stage 3 maturity according to the Carbon Trust OWA Roadmap for the Commercial Acceptance of Floating LiDAR Technology. DNV has not received copies of the independent stage 3 validation reports that include the classification uncertainty for the Fugro SWLB. Previously, a Stage 2 Type Verification of the EOLOS FLS-200 Buoy system against a tall offshore meteorological mast had been conducted at Mast Ijmuiden (MMIJ) [4] for a period of 6 months over the period March 2015 to October 2015. During this period the data recorded was compared to those recorded by Mast MMIJ. It was concluded the ‘best practice’ acceptance criteria and key performance indicators for accuracy were met at all comparable measurement heights. Details of this validation can be found in the offshore validation report [4].

Current industry guidance [5] recommends that independent pre-deployment verifications against a trusted reference should be undertaken as part of a wind resource assessment for lowest uncertainty. The E05 and E06 EOLOS FLS-200 Buoys underwent two-phase pre-validations, one onshore and one offshore, as reported in the pre-deployment offshore verification reports [6]. For the onshore validations, the units were deployed from 7 December 2018 - 18 December 2018 and the data were compared to a reference met mast. For the offshore validations, the FLSs were deployed from 12 April 2019 - 26 May 2019 and the data were compared to the Narec NOAH reference mast. All verifications concluded that the floating Lidar systems met the minimum key performance indicators and acceptance criteria for wind speed accuracy as defined by the Carbon Trust OWA Roadmap [5].

The floating Lidar units were set up to record data at the heights listed in Table 3-1. The height above sea level of the Lidars has been incorporated into the heights listed in Table 3-1. All floating Lidar heights are referred to as above MSL for the remainder of this report.

The floating Lidar systems were programmed to record mean wind speed, direction and turbulence components during each ten-minute interval.

3.2 Data processing

Data from the floating Lidar systems installed near the Project have been obtained from DNV's Resource Panorama service. The data supplied are already processed and compensated for motion using the manufacturer's algorithm; however, the processed remote sensing wind data have been subject to a further quality checking procedure by DNV to identify records which were affected by equipment malfunction and other anomalies.

Wind data coverage is generally good at the E05_N and E05_SW FLSs. There is lower data coverage at E06_S in 2020 and 2021 when the FLS was out of service or awaiting maintenance. Summarized data coverage levels for the key parameters and instruments on each remote sensing device are shown in Table 3-2.

Table 3-2 Summary of site data coverage

Location	Distance to site[a] [m]	Height [m]	Available period [years]	Valid period [years]	Measured wind speed [m/s]	Wind speed data coverage [%]
E05_N	120	140	2.1	1.9	10.2	92
		160	2.1	1.9	10.3	91
E05_SW	160	140	1.0	0.9	10.1	92
		160	1.0	0.9	10.3	92
E06_S	170	140	2.6	1.8	10.1	69
		160	2.6	1.8	10.2	68

a. The distance represents the distance between the floating Lidar systems and the indicative layouts.

3.3 Site measurement uncertainties

Table 3-3 presents the site measurement uncertainties estimated for the site.

Table 3-3 Site measurement uncertainties – E05_N

Uncertainty category	% wind speed
Measurement accuracy	3.3

Measurement uncertainty derived for the floating Lidars is based on the IEA Floating Lidar Recommended Practices [7] considering the following components:

- Classification uncertainty – DNV has not received classification trial results including classification uncertainty for the Stage 3 EOLOS FLS-200 buoy system; therefore, DNV has assumed a class number based on DNV's knowledge of Lidar and floating Lidar system classifications. DNV recommends that this uncertainty be updated once the classification uncertainty for the Stage 3 EOLOS FLS-200 buoy system is obtained.
- Verification uncertainty – this is based on the verification uncertainty analysis found in the pre-deployment offshore verification reports completed for the EOLOS FLS-200 Buoys deployed at the site [6].

- Based on the results of the metocean comparison performed in the pre-deployment offshore verification reports [6] for the EOLOS FLS-200 FLSs and additional checks conducted by DNV, the environmental conditions at the project site are considered slightly harsher than the environmental conditions during the trial campaigns. To account for the impact of environmental variables outside of the floating Lidar system verification envelope, an additional uncertainty has been applied.

4 WIND ANALYSIS

The analysis of the site wind regime involved several steps, which are summarized below:

- Data recorded at FLS E05_N were correlated to FLS E06_S on a 10-minute basis to recover missing and historical data. These correlations were used to derive the annual wind speeds at FLS E05_N for the period from August 2019 to March 2022.
- Data recorded at FLS E05_SW were correlated to FLS E06_S on a 10-minute basis to recover missing and historical data. These correlations were used to derive the annual wind speeds at FLS E05_SW for the period from September 2019 to January 2023.
- Data recorded at FLS E06_S were correlated to FLS E05_N and E05_SW on a 10-minute basis to recover missing and historical data. These correlations were used to derive the annual wind speeds at FLS E06_S for the period from August 2019 to January 2023.
- Reference data sources were correlated to the measured data at the FLS on a daily basis. These correlations were used to derive the long-term mean wind speeds at these measurement locations for the period from January 2000 to January 2023.
- In order to reference the site data to the period of January 2000 to January 2023, the adjustments determined between the E05_N, E05_SW and E06_S units and the reference data sources were applied independently to the annual wind speeds determined at the measurement locations for the full site period.
- Measured data recorded at the site masts were used to derive boundary layer power law wind shear exponents. These shear estimates were used to extrapolate the long-term mean wind regime at the site masts to the proposed 140 m and 155 m hub-heights.
- The hub-height wind speed and direction frequency distributions at the site masts were extrapolated from the measured data and subsequently adjusted to reflect the predicted long-term mean wind speed at each individual mast.
- Wind flow modeling was carried out to determine the hub-height wind speed variations over the site.

Results for each step of the process are provided in the following sections.

4.1 Measurement-height wind regime

4.1.1 Site-period wind speeds

As noted in Section 3.1, data were recorded near the East Coast Z3 site from August 2019 to January 2023.

In order to bring all the mast measurement periods to a consistent period of record, missing and historic wind speed and direction data at the upper measurement levels of each measurement location were synthesized from other sensors at that location, as well as from neighboring site Lidars, on a 10-minute directional basis. The specific correlations in order of priority are presented in Table 4-1. Summaries of the regressions as well as associated statistics and graphs are presented in Appendix C.

The site-period wind speeds are shown in Table 4-1 and include the synthesized data. Monthly average site-period wind speeds for each met mast are also presented in Appendix C.

Table 4-1 Site period wind speeds

Device	Height [m]	Reference device in order of priority	Site period [years]	Site period annual average wind speed [m/s]
E05_N	140	E06_S	2.4	10.1
E05_N	160	E06_S	2.4	10.2
E05_SW	140	E06_S	2.6	10.0
E05_SW	160	E06_S	2.6	10.2
E06_S	140	E05_SW, E05_N	3.2	9.9
E06_S	160	E05_SW, E05_N	3.2	10.1

4.1.2 Extension of the site period to the reference period

The inclusion of quality reference data can reduce the uncertainty in the estimate of the long-term wind regime at the site. When selecting appropriate reference data for this purpose, it is important that the reference data's wind regime is driven by similar factors as the site wind regime and the reference data are consistent over the measurement period being considered.

4.1.2.1 Reference data considered

DNV has undertaken an extensive review of the sources of reference data surrounding the East Coast Z3 project and near the measurement locations in order to identify appropriate long-term reference stations for this analysis. Table 4-2 summarizes the stations considered while Figure 4-1 shows their proximity to the Project site.

Table 4-2 Reference data sets considered for correlations to site data

Meteorological data source	Network	Start date	End date
ERA5 39.90N, 72.90W	ECMWF	January 2000	December 2022
ERA5 39.60N, 73.50W	ECMWF	January 2000	December 2022
MERRA-2 40.00N, 72.50W	NASA	January 2000	January 2023
MERRA-2 40.00N, 73.13W	NASA	January 2000	January 2023
MERRA-2 39.50N, 73.13W	NASA	January 2000	January 2023
MERRA-2 39.50N, 73.75W	NASA	January 2000	January 2023
Vortex ERA5 39.96N, 72.73W	Vortex	January 2000	March 2023
Vortex MERRA-2 39.96N, 72.73W	Vortex	January 2000	January 2023
Vortex ERA5 39.54N, 73.42W	Vortex	January 2000	March 2023
Vortex MERRA-2 39.54N, 73.42W	Vortex	January 2000	January 2023

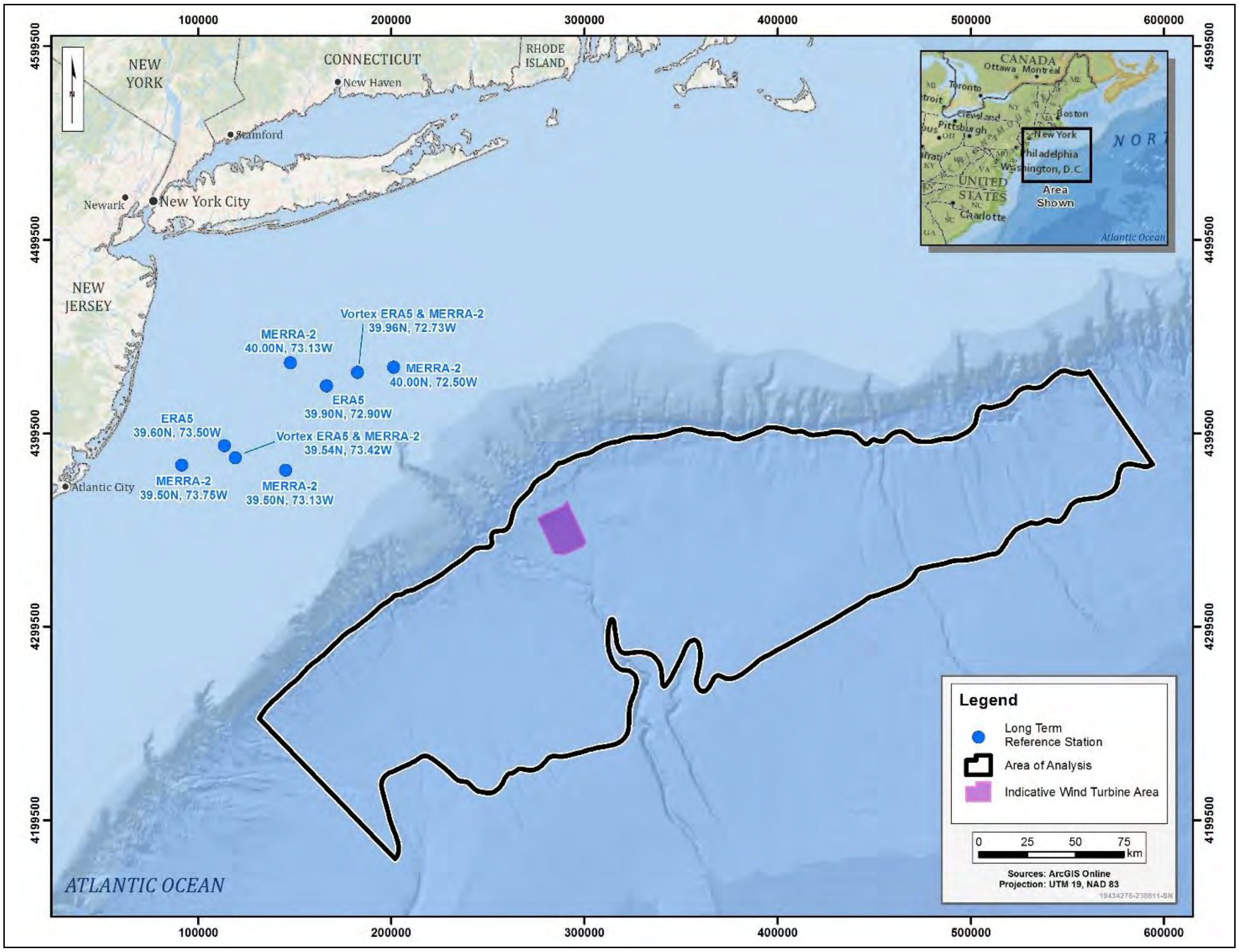


Figure 4-1 Location of the East Coast Z3 wind farm and potential reference data sources

Further information regarding long-term reference data sources typically used by DNV is included in Appendix B. A review of the suitability and use of these sources of data reference in the analysis is provided below.

4.1.2.2 Reference data consistency

The consistency of each source of reference data was evaluated through a comparison to the regional trends, a review of available station maintenance logs, and a statistical change point analysis.

Figure 4-2 shows a plot of seasonally-normalized 12-month moving average wind speeds for the reference data sources.

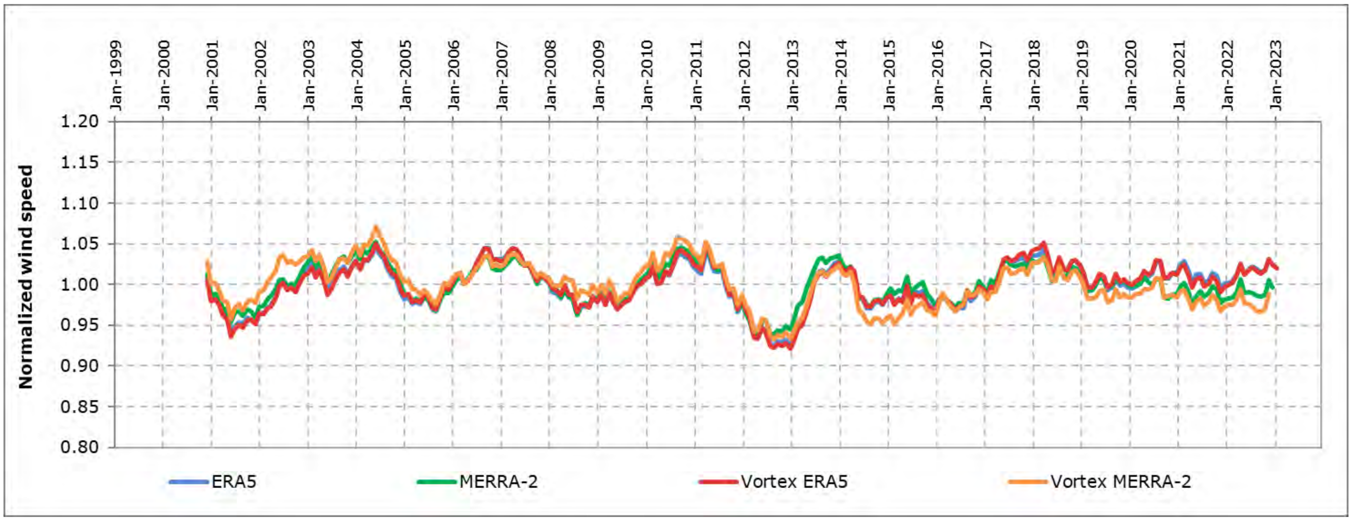


Figure 4-2 Reference data seasonally-normalized 12-month moving average wind speeds

The ERA5 data have inconsistent trend in this area in the later part of its period of record; therefore, ERA5 and Vortex ERA5 have not been considered further. The remaining stations appear suitable for consideration as long-term references in the analysis and have been correlated to the site data as reported in Section 4.2.2.

4.1.2.3 Quality of correlation

To determine whether use of the reference data will reduce uncertainty, a correlation of daily mean wind speeds between each consistent reference station and the site was completed. The results of this analysis are summarized in Table 4-3.

Table 4-3 Summary of correlations to 140 m site data

Device	Reference station	Coefficient of determination, R^2
E05_N	MERRA-2 40.00N, 72.13W	0.92
E05_N	MERRA-2 40.00N, 73.25W	0.91
E05_N	Vortex MERRA-2 39.96N, 72.73W	0.93
E05_SW	MERRA-2 39.50N, 73.13W	0.87
E05_SW	MERRA-2 39.50N, 73.75W	0.89
E05_SW	Vortex MERRA-2 39.54N, 73.42W	0.92
E06_S	MERRA-2 39.50N, 73.13W	0.88
E06_S	MERRA-2 39.50N, 73.75W	0.91
E06_S	Vortex MERRA-2 39.54N, 73.42W	0.93

DNV's analysis of these results and assessment of the uncertainties in the site period and reference period wind speeds concludes that the method with lowest uncertainty is to extend the site data to the 23.1-year period available from the MERRA-2 and Vortex MERRA-2 reference data.

For each of the selected reference data sources, independent correlations of daily data, binned by month, were used to synthesize reference period wind speeds at the FLSs. The resulting adjustments in the site period wind speeds and estimated long-term measurement height wind speeds at each of the measurement locations are shown in Table 4-4.

Table 4-4 Site period wind speed adjustments and estimated measurement height long-term wind speeds

Device	Height [m]	Long term adjustment	Wind speed [m/s]
E05_N	140	0.8%	10.2
E05_N	160	0.8%	10.3
E05_SW	140	-0.1%	10.0
E05_SW	160	-0.1%	10.1
E06_S	140	0.7%	10.0
E06_S	160	0.5%	10.1

4.1.3 Measurement-height wind speed uncertainties

Table 4-5 and Table 4-6 present the uncertainties in determining the long-term measurement-height wind speed for each of the measurement locations on the site.

Table 4-5 Long-term measurement-height wind regime uncertainties [% wind speed] at 140 m

Uncertainty sub-category	Lidar E05_N	Lidar E05_SW	Lidar E06_S
On-site data synthesis	0.2	1.8	0.8
Variability of 23.1 years of data	0.9	0.9	0.9
Correlation to reference station	1.4	1.2	0.9
Consistency of reference data	1.3	1.3	1.3
Wind frequency distribution - past[a]	1.3	1.2	1.1

a. Expressed as percent energy, not wind speed

Table 4-6 Long-term measurement-height wind regime uncertainties [% wind speed] at 160 m

Uncertainty sub-category	Lidar E05_N	Lidar E05_SW	Lidar E06_S
On-site data synthesis	0.2	1.9	0.8
Variability of 23.1 years of data	0.9	0.9	0.9
Correlation to reference station	1.6	1.3	0.8
Consistency of reference data	1.3	1.3	1.3
Wind frequency distribution - past[a]	1.3	1.2	1.1

a. Expressed as percent energy, not wind speed

4.2 Hub-height wind regime

4.2.1 Hub-height wind speed

To extrapolate the wind speed estimates from the measurement height to the 140 m and 155 m hub-heights, the average power law at each mast has been evaluated between all relevant measurement heights and applied to the upper-level measurements at each measurement location.

Table 4-7 Shear exponents and hub-height wind speeds

Device	Height [m]	Primary measurement height long-term wind speed [m/s]	Measured wind shear exponent	140 m wind speed estimate [m/s]	155 m wind speed estimate [m/s]
E05_N	140	10.2	0.09	10.2	-
E05_N	160	10.3	0.09	-	10.3
E05_SW	140	10.0	0.10	10.0	
E05_SW	160	10.1	0.10	-	10.1
E06_S	140	10.0	0.09	10.0	-
E06_S	160	10.1	0.09	-	10.1

Analysis of the shear data indicated that the seasonal and diurnal variations in the shear exponent are consistent with DNV's expectations for the region.

4.2.2 Hub-height wind speed and direction distributions

Hub-height wind speed and direction distributions were developed by extrapolating the measured wind speed data on a time series basis. The frequency distributions for each FLS were scaled to the representative, long-term, hub-height, mean wind speed at each FLS.

A representative, long-term, hub-height wind rose and wind speed histogram are shown in

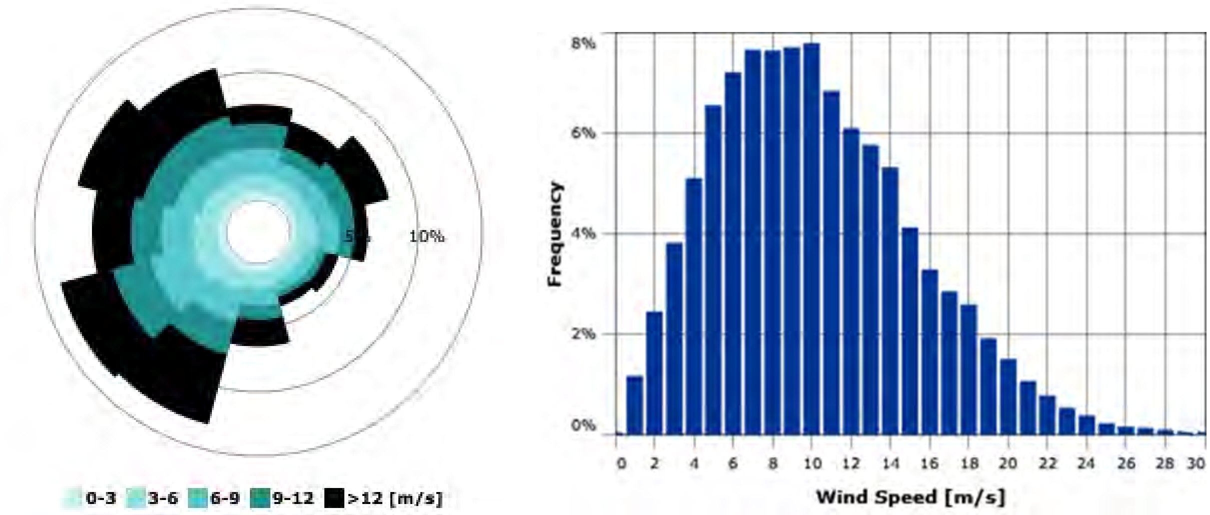


Figure 4-3 for E05_N. Additional representative long-term hub-height wind speed and direction frequency distributions are shown in Appendix C.

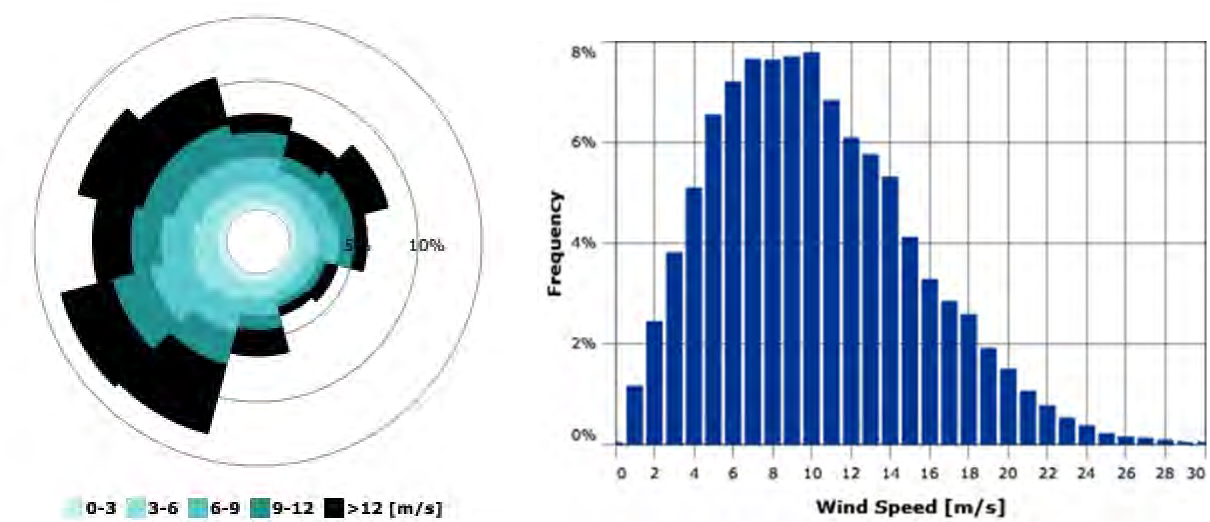


Figure 4-3 Lidar E05_N long-term hub-height frequency distribution and wind rose at 140 m

4.2.3 Vertical extrapolation uncertainties

There is no material uncertainty at the FLS locations given the availability of measurements near hub-height.

4.3 Wind regime across the site

4.3.1 Modeling

The variation in wind speed over the East Coast Z3 sites were predicted using Vortex mesoscale model. E05_N and E06_SW have been used to initiate the wind flow modeling used to predict the long-term wind regimes at the Zone 3 turbine locations, respectively. Figure 4-4 shows the wind speed variation across East Coast Zone 3 at 140 m based on the Vortex mesoscale model and calibrated to the long-term mean wind speed at E05_N. Figure 4-5 shows the external wake effect caused by the neighboring wind farms across East Coast Zone 3. The wind speed range is between 9.8 m/s and 10.4 m/s. Generally, the wind speed increases with the distance to shore with the highest wind speed to the east of the Area of Analysis.

Based on publicly available information, DNV derived representative turbine layouts for the sake of external wake modelling and estimation. The locations of these Lease Areas are illustrated in Figure 4-5. Given the early stage of development of several of the neighboring projects, some project information is missing such as the turbine layouts, the turbine types and hub heights. Therefore, it is not possible to exactly model their wake effects on the East Coast Z3 project. DNV has estimated the wake effects of the neighboring projects assuming the same turbine model as the East Coast Z3 Wind Farm. Due to the distance, the neighboring projects are considered to have negligible wake impacts across the whole area of the Area of Analysis. When additional information about the neighboring wind farms becomes available, it is recommended that this analysis is updated to reflect the impact of the neighboring wind farms.

Based on water depth, the distance to shore and the seabed variation across the Area of Analysis, DNV has chosen a Wind Turbine Area as shown in Figure 4-4 and Figure 4-5. The wind speed being fairly consistent within the Area of Analysis and the external wake effect being negligible across the Area of Analysis, those parameters were not determining criteria for the siting. DNV did not perform detailed layout optimization and, as such, no environmental constraint analysis was done. DNV has not performed a site visit to determine site suitability nor micro sited the turbine locations. The Wind Turbine Area chosen in this analysis is indicative for wind resource characterization and preliminary energy assessments only and should not be considered as a recommendation.

Uncertainty in the results was minimized in the analysis by initiating turbines from the most representative floating Lidar and using the Vortex mesoscale wind speed map to inform the wind speed variation across the site. The wind speed variation predicted by Vortex is generally consistent with measurements recorded near the site, showing an increase of the wind speeds moving northeast away from the shore. The initiation measurement location for each turbine is indicated in Appendix C. Through this approach, the predicted long-term mean wind speeds at each turbine at the proposed hub-heights were developed as shown in Appendix C. The average long-term wind speeds for the wind farms as a whole at each hub-height is 10.1 m/s for Indicative layout 01 and 10.2 m/s for Indicative layout 02.

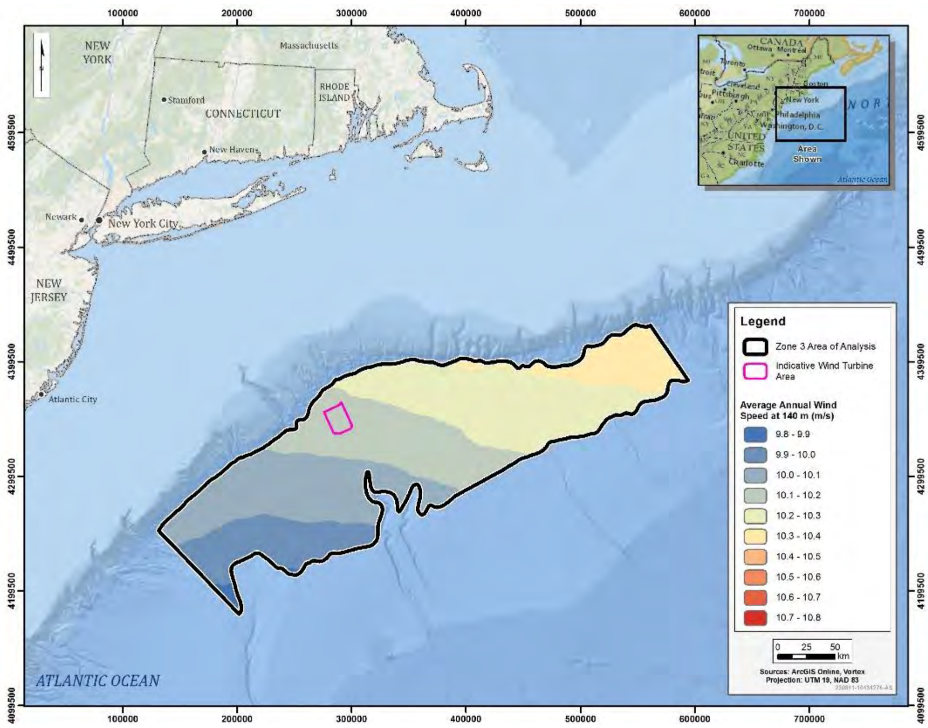


Figure 4-4 Long-term wind speed across East Coast Zone 3 at 140 m

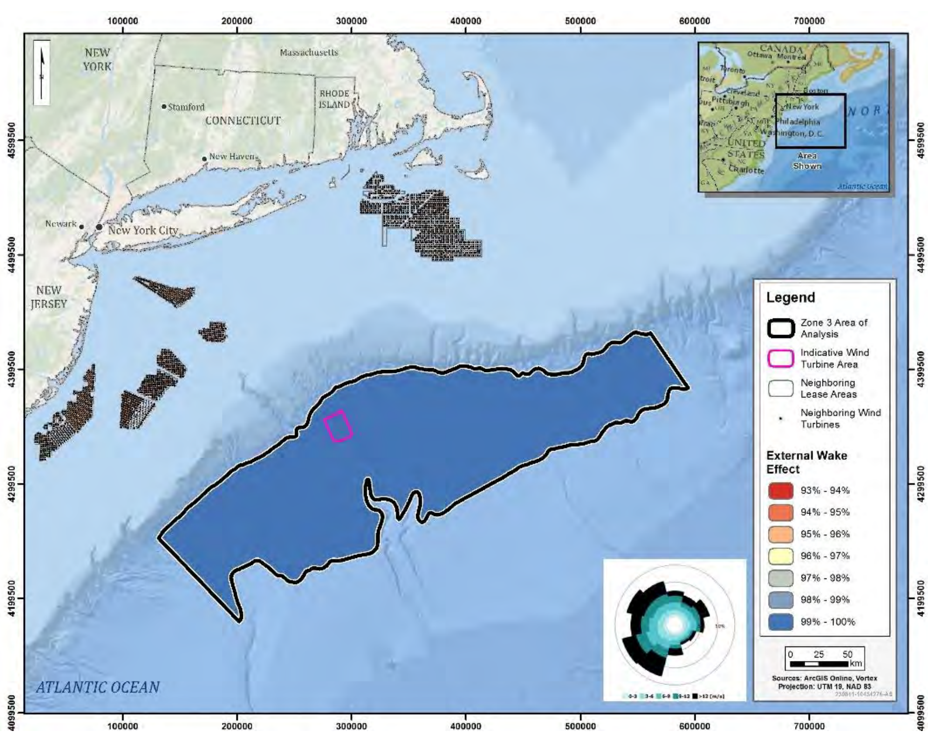


Figure 4-5 External wake effect across East Coast Zone 3 at 140 m

4.3.2 Spatial variation uncertainties

Table 4-8 quantifies the spatial variation uncertainty for the East Coast Z3 projects, given the following considerations:

- Wind speed variation for offshore projects is generally very low, and this is supported by Vortex, resulting in lower uncertainty.
- The wind speed variation predicted by Vortex mesoscale model is generally consistent with measurements recorded on site, resulting in lower uncertainty.
- The extrapolation distance from E05_N is significantly high, resulting in higher uncertainty. DNV would recommend having on-site measurements.

Table 4-8 Spatial extrapolation uncertainties [% wind speed]

Uncertainty category	Indicative layout 01	Indicative layout 02
Spatial extrapolation	2.0	2.0

4.4 Turbulence

Post-processed turbulence intensity measurements were available at the floating Lidars. However, it is widely accepted that turbulence intensity measurements (TI) from Lidar devices (volume measurements) are not directly comparable to turbulence intensity measurements from meteorological masts using cup anemometers (point measurements), which is currently the wind industry standard. DNV has reviewed the measured TI from the FLSs found the turbulence intensity to be higher than expected.

As no suitable measures of wind speed standard deviation were available at the sites, an assumption was made for ambient turbulence intensity, based on data from the Woods Hole Oceanographic Institution (WHOI) Air-sea Interaction Tower (ASIT) [8] and DNV’s experience of the regional offshore wind regime, using an IEC fit profile considering a turbulence intensity of 4.5% at 15m/s [3].

5 ENERGY ANALYSIS

5.1 Gross and net energy estimates

The gross energy production at the individual turbine locations have been calculated using the WindFarmer software, the results of the wind flow modeling and the hypothetical turbine power curves derived by DNV.

Table 5-1 and Table 5-2 provide the aggregated results for the projects.

The projected net energy production of the wind farms shown in and Table 5-1 and Table 5-2 were calculated by applying a number of energy loss factors to the gross energy production. The predictions represent the estimates of the annual production expected over the first 25 years of operation. Wind farms typically experience some time dependency in availability and other loss factors.

Table 5-1 Energy production summary – Indicative Layout 01

	Wind Farm Rated Power	**1005.0**	**MW**
	Gross Energy Output	**5243.6**	**GWh/annum**
1	**Turbine interaction effects**	**95.2**	**%**
1a	Internal wake and blockage effects	95.2	% Project specific
1b	External wake effect	100.0	% Project specific
1c	Future wake effect	100.0	% Project specific
2	**Availability**	**92.9**	**%**
2a	Turbine availability	94.0	% Project specific
2b	Balance of plant availability	99.0	% DNV standard
2c	Grid availability	99.8	% DNV standard
3	**Electrical efficiency**	**97.5**	**%**
3a	Operational electrical efficiency	97.5	% Project specific
3b	Wind farm consumption	100.0	% DNV standard
4	**Turbine performance**	**96.0**	**%**
4a	Generic power curve adjustment	99.0	% DNV standard
4b	High wind speed hysteresis	99.4	% Project specific
4c	Site-specific power curve adjustment	99.3	% DNV standard
4d	Sub-optimal performance	99.5	% DNV standard
4e	Blade and turbine degradation	98.7	% Project specific
4f	Aerodynamic device degradation	100.0	% Project specific
5	**Environmental**	**100.0**	**%**
5a	Performance degradation – icing	100.0	% Project specific
5b	Icing shutdown	100.0	% Project specific
5c	Temperature shutdown	100.0	% Project specific
5d	Site access	100.0	% Project specific
6	**Curtailments**	**100.0**	**%**
6a	Wind sector management	100.0	% Not considered
6b	Grid curtailment	100.0	% Not considered
6c	Noise, visual, and environmental curtailment	100.0	% Not considered
	Total Losses (%)	**82.7**	**%**
	Asymmetric production effect	**99.9**	**%**
	Net Energy Output	**4333.9**	**GWh/annum**
	Net Capacity Factor	**49.2**	**%**

Table 5-2 Energy production summary – Indicative Layout 02

	Wind Farm Rated Power	1008.0	**MW**
	Gross Energy Output	**5174.2**	**GWh/annum**
1	**Turbine interaction effects**	**95.3**	**%**
1a	Internal wake and blockage effects	95.3	% Project specific
1b	External wake effect	100.0	% Project specific
1c	Future wake effect	100.0	% Project specific
2	**Availability**	**92.9**	**%**
2a	Turbine availability	94.0	% Project specific
2b	Balance of plant availability	99.0	% DNV standard
2c	Grid availability	99.8	% DNV standard
3	**Electrical efficiency**	**97.5**	**%**
3a	Operational electrical efficiency	97.5	% Project specific
3b	Wind farm consumption	100.0	% DNV standard
4	**Turbine performance**	**95.9**	**%**
4a	Generic power curve adjustment	99.0	% DNV standard
4b	High wind speed hysteresis	99.3	% Project specific
4c	Site-specific power curve adjustment	99.3	% DNV standard
4d	Sub-optimal performance	99.5	% DNV standard
4e	Blade and turbine degradation	98.7	% Project specific
4f	Aerodynamic device degradation	100.0	% Project specific
5	**Environmental**	**100.0**	**%**
5a	Performance degradation – icing	100.0	% Project specific
5b	Icing shutdown	100.0	% Project specific
5c	Temperature shutdown	100.0	% Project specific
5d	Site access	100.0	% Project specific
6	**Curtailments**	**100.0**	**%**
6a	Wind sector management	100.0	% Not considered
6b	Grid curtailment	100.0	% Not considered
6c	Noise, visual, and environmental curtailment	100.0	% Not considered
	Total Losses (%)	**82.6**	**%**
	Asymmetric production effect	**99.9**	**%**
	Net Energy Output	**4275.6**	**GWh/annum**
	Net Capacity Factor	**48.4**	**%**

Table 5-1 and Table 5-2 includes potential sources of energy loss that have been either assumed to be the DNV standard values or estimated for this project. Project-specific aspects of the loss estimates are provided in the following bullets:

- 1a Internal wake and blockage effects – DNV has recently undertaken a validation of its offshore wake modeling methodology using operational data from a number of offshore wind farms in North Europe [9][10]. As a result of that work, DNV estimates offshore wake only turbine interaction effects using the DNV WindFarmer: Analyst Eddy Viscosity wake model with Large Wind Farm correction applied.

- 1b External wake effect – No external wake effects were considered in the analysis.
- 1c Future wake effect – No future wake effects were considered in the analysis.
- 2a Turbine availability – For both indicative layouts, DNV has made a starting assumption for the turbine availability that could be expected from the project based on the wave climate, anticipated O&M access strategy and some assumptions regarding the reliability and track record of the turbine technology to be installed in the future, based on DNV experience.
- 3a Operational electrical efficiency – An electrical loss of 2.5% has been assumed for both indicative layouts assuming an offshore metering point. Details of the specific balance of plant infrastructure and grid connection point are not available at this stage given the preliminary nature of this assessment. As such, this estimate is not based on detailed modeling or project specific calculations.
- 4a Generic power curve adjustment – Estimated energy loss due to the floating motion of the wind turbine, not inherent in the power curve, is 1.0%.
- 4b High wind speed hysteresis – The 28.0 m/s turbine cut-out wind speed was reduced to 25.0 m/s to estimate this loss.
- 4c Site-specific power curve adjustment – It is assumed that there are no site-specific wind flow issues which will adversely affect the performance of the turbines. The loss includes a 0.75% loss to account for the average blockage effect inherent in power performance test measurements [10].
- 4d Sub-optimal performance – It is assumed that the loss associated with material performance deviations from the optimal power curve is 0.5%.
- 4e Blade and turbine degradation – This assumption is to account for the performance degradation of the turbine drivetrain and rotor assembly. The loss factor applied assumes that the future projects will have blade leading edge protection systems installed and that a proactive plan to manage leading edge erosion based on regular blade inspections and repair will be in place throughout the project lifetime. For future projects, it is recommended that an Independent Engineer reviews the plans to manage leading edge erosion as part of a full due diligence exercise.
- 4f Aerodynamic device degradation – DNV assumes that aerodynamic devices will not be used at the projects.
- 5a Performance degradation – icing – It has been assumed that ice accretion on the turbine casing is not applicable at these locations.
- 5b Icing shutdown – It has been assumed that ice accretion on the turbine casing is not applicable at these locations.
- 5c – Temperature shutdown – DNV has assumed the operating range is between -10°C and 35°C for all turbine models.
- 5d Site access – Site access due to the project being located offshore is accounted for as part of loss 2a – Turbine availability.
- 6a Wind Sector Management – No wind sector management has been considered.
- 6b Grid curtailment – No grid curtailment loss has been considered.

- 6c Noise, visual, and environmental curtailment – No studies were conducted by or supplied to DNV for consideration.

5.1.1 Uncertainty in loss factors

Table 5-3 quantifies this uncertainty for the East Coast Z3 project.

Table 5-3 Loss factor uncertainties

Uncertainty subcategory	% Energy
Wakes	1.4
Availability	2.6
Electrical	0.6
Turbine performance	2.6
Environmental	0.0
Curtailment	0.0

5.2 Seasonal and diurnal distributions

The expected long-term average seasonal and diurnal variation in energy production has been approximately assessed from the available data at the project site. The long-term average seasonal and diurnal variation in air density was developed from temperature records and pressure records at MERRA-2 39.00N 71.25W and scaled to the site-predicted long-term annual site air density. The measured wind speeds extrapolated to hub-height at Lidar E05_N were adjusted to reflect the predicted long-term mean wind speeds and monthly profiles of each site mast.

A simulated time series of production data was produced using the time series of density, wind direction, and wind speed and the WindFarmer energy model developed for the East Coast Z3 project.

The resulting expected seasonal and diurnal variations in energy production at 140 m and 155 m are presented in Appendix C.6 in the form of a 12-month by 24-hour (12 x 24) matrix. It is noted that the uncertainty associated with the prediction of any given month or hour of day is significantly greater than that associated with the prediction of the annual energy production. It is also noted that the results presented are inclusive of wake and hysteresis losses only.

6 UNCERTAINTY

The main sources of deviation from the central estimate (P50) have been quantified and combined using a probabilistic model, assuming full independence between the sources. Additional details on this process are given below.

6.1 Inter-annual variability

Even if the central estimate was perfectly defined, wind farm energy production varies from year to year due to a number of factors, including natural variation in the wind regime, variations in system availability, and variations in environmental losses, categorized as inter-annual variability. Table 6-1 presents the inter-annual variability estimated for the site.

Table 6-1 Inter-annual variability uncertainty

Uncertainty subcategory	%	Unit
Wind frequency distribution - future	2.0	Energy
Inter-annual variability of the wind	4.5	Wind Speed
Availability	3.0	Energy

6.2 Converting wind speed uncertainties to energy uncertainties

Uncertainties in the estimate of the site wind speed were described in Section 3.3, Section 4.1.3, Section 4.2.3 and Section 4.3.2.

Wind speed uncertainties are converted to energy uncertainties using the sensitivity ratio. The sensitivity ratio shows how sensitive the net energy production is to changes in wind speed and is dependent mainly on the wind speed distribution and power curve of the turbine. For example, with a sensitivity ratio of 1.50, a 2.0% reduction in wind speed at all masts would lead to a 3.0% reduction in net energy production. The sensitivity ratio is non-linear over large ranges of wind speed, which has been accounted for in this analysis. The average calculated sensitivity ratios for the East Coast Z3 project for variations of 10% on wind speed are 1.03 for both indicative layouts.

6.3 Project uncertainties

A summary of the project uncertainties considered as part of this analysis are show in Table 6-2 and Table 6-3. The 1-year numbers presented are representative of any individual year in the 25-year life of the project. The 10-year numbers are representative of the first 10 years of operation.

Table 6-2 Uncertainty in the projected energy output for East Coast Z3 – Indicative layout 01

Source of uncertainty/variability	[GWh/annum]	Equivalent standard deviation [%]
Measurement accuracy	156.0	3.6
Long-term measurement height wind regime	115.9	2.7
Vertical extrapolation	0.0	0.0
Spatial extrapolation	93.3	2.2
Loss factors	174.7	4.0
Inter-annual variability	229.7	5.3
Overall energy uncertainty		
Future period under consideration		
1-year	**392.6**	**9.1**
10-year	**281.3**	**6.5**
25-year	**274.0**	**6.3**

Table 6-3 Uncertainty in the projected energy output for East Coast Z3 – Indicative layout 02

Source of uncertainty/variability	[GWh/annum]	Equivalent standard deviation [%]
Measurement accuracy	154.4	3.6
Long-term measurement height wind regime	121.0	2.8
Vertical extrapolation	0.0	0.0
Spatial extrapolation	93.2	2.2
Loss factors	171.9	4.0
Inter-annual variability	227.2	5.3
Overall energy uncertainty		
Future period under consideration		
1-year	**390.4**	**9.1**
10-year	**283.3**	**6.6**
25-year	**276.0**	**6.5**

The results of the probabilistic simulation of net energy production are summarized in Table 6-4 and Table 6-5.

Table 6-4 Summary of project net average energy production – Indicative layout 01

Probability of exceedance	1 year in 25 [GWh/a]	10-year average [GWh/a]	25-year average [GWh/a]
50%	4341.0	4354.8	4333.9
75%	4078.4	4167.4	4153.4
90%	3837.8	3994.3	3982.7
95%	3689.6	3886.2	3880.7
99%	3406.5	3697.1	3701.6

Table 6-5 Summary of project net average energy production – Indicative layout 02

Probability of exceedance	1 year in 25 [GWh/a]	10-year average [GWh/a]	25-year average [GWh/a]
50%	4279.7	4296.0	4275.6
75%	4019.3	4104.1	4091.6
90%	3779.4	3932.9	3921.9
95%	3632.0	3832.8	3825.6
99%	3349.9	3628.2	3632.0

7 OBSERVATIONS AND RECOMMENDATIONS

DNV makes the following observations and recommendations regarding this analysis:

- DNV notes the following observations and opinions regarding uncertainty.
    a. Aside from inter-annual variability, the uncertainty in the analysis is driven by loss factor uncertainty and measurement uncertainty.
    b. Uncertainty in the analysis could also be reduced by obtaining commercially available turbine power curves and assessing the electrical systems and access strategies to inform more refined estimates for electrical loss and turbine availability.
    c. The extrapolation distance from E05_N is significantly high, resulting in higher spatial extrapolation uncertainty. DNV would recommend having on-site measurements.
- DNV has derived hypothetical power curves based on current and expected trends in turbine technology.
- The sensitivity of energy due to changes in wind speed (sensitivity ratio) for offshore wind projects is typically lower due to the higher wind speeds, but is also dependent on the turbine characteristics such as swept rotor size and rated power. Given the high wind speeds in the East Coast Zone 3 site, and the assumed turbine characteristics of the hypothetical turbines modeled for this preliminary assessment, the net energy is less sensitive to changes in wind speed and the sensitivity ratio approaches unity for this preliminary assessment. DNV notes that the sensitivity ratio and therefore the project uncertainty may vary materially depending on the final commercially available turbines selected for the projects.
- The variation in wind speed over the East Coast Zone 3 Area of Analysis were predicted using Vortex mesoscale model. The wind speed variation across East Coast Zone 3 at 140 m is based on the Vortex mesoscale model and calibrated to the long-term mean wind speed at floating lidar E05_N. Figure 4-5 shows the external wake effect caused by the neighboring wind farms across East Coast Zone 3. The wind speed range is between 9.8 m/s and 10.4 m/s. Generally, the wind speed increases with the distance to shore with the highest wind speed to the east of the Area of Analysis.
- Based on publicly available information, DNV derived representative turbine layouts of neighboring wind farms for the sake of external wake modelling and estimation. Given the early stage of development of several of the neighboring projects, it is not possible to accurately model their wake effects on the East Coast Zone 3 project. DNV has estimated the wake effects of the neighboring projects assuming the same turbine model as the East Coast Zone 3 Wind Farm. Due to the distance, the neighboring projects are considered to have negligible wake impacts across the whole area of the Area of Analysis.
- NYSERDA has requested that DNV design two indicative wind farm layouts. DNV notes that alternative, non-gridded layouts are possible within the Lease Areas and that gridded layouts have been assumed for this preliminary assessment for simplicity. The gridded layouts are not a reflection of New York State policy on preference for any predetermined layout or approach thereto. Project capacities for each indicative layout were maintained at approximately 1000 MW and are likewise generically identified for hypothetical purposes befitting a preliminary assessment and are not a reflection of DNV or New York State's opinions regarding project sizing.

  Based on water depth, the distance to shore and the seabed variation across the Area of Analysis, DNV has chosen a Wind Turbine Area. The wind speed being fairly consistent within the Area of Analysis and the external wake effect being negligible across the Area of Analysis, those parameters were not determining criteria for the siting. For the indicative layouts used in this study, DNV did not perform detailed layout optimization and, as such, no environmental constraint analysis was done. DNV has not performed a site visit to determine site suitability nor micro sited the turbine locations. The layouts used in this analysis are indicative for wind resource characterization and preliminary energy assessments only and should not be considered as a recommendation.

- No wind sector management strategy has been modeled, and DNV has not included any losses which may be associated with this. However, given the large inter-turbine spacings assumed, DNV considers it unlikely a wind sector management strategy would be required. For future projects, it is recommended that the turbine supplier be approached at an early stage to gain approval for the indicative layouts and that an Independent Engineer reviews the manufacturer's conclusions as part of a full due diligence exercise.
- DNV has recently undertaken a validation of its offshore wake modeling methodology using operational data from a number of offshore wind farms in North Europe. As a result of that work, DNV estimates offshore wake only turbine interaction effects using the DNV WindFarmer: Analyst Eddy Viscosity wake model with Large Wind Farm correction applied.
- DNV has undertaken, and continues to undertake, extensive research into turbine interaction effects. Through this research, evidence suggests turbines cause lateral as well as upstream effects, which together contribute to a resistance, or blockage, on the wind flow, deflecting some of the flow above and around the wind farm. DNV has estimated the wind flow blockage effects based on the assumed project configurations and included any resulting loss in this analysis.
- DNV has applied standard assumptions for balance of plant and grid availability as a starting assumption. DNV notes that they may vary materially from standard assumptions and can be mitigated to some extent, especially in early years of the project, through appropriate contractual provisions on a project-specific basis.
- This estimated operational electrical efficiency loss is not based on detailed modeling or project specific calculations given the preliminary nature of this assessment.

8 REFERENCES

[1] Port Site Acceptance Test of Two EOLOS FLS-200 Lidar Buoys in Avalon, NJ reported in DNV report dated 23 August 2019 for EOLOS FLS-200 buoy serial numbers ZX842 and ZX844.

[2] Federal Aviation Administration. Circle search for cases, retrieved March 2023, https://oeaaa.faa.gov/oeaaa/external/searchAction.jsp?action=showCircleSearchForm

[3] "Wind turbines – Part 12-1: Power performance measurements of electricity producing wind turbines, IEC 61400-12-1: 2005," International Electrotechnical Commission, Geneva, Switzerland, 2005.

[4] "Validation of EOLOS floating Lidar against Offshore Meterological Mast Ijmuiden", ECN, March – October 2015.

[5] "Carbon Trust OWA Roadmap for the Commercial Acceptance of Floating Lidar Technology", Version 2.0, October 2018.

[6] Unit pre-deployment verifications at the Pershore UK remote sensing test site and against the Narec NOAH Offshore Met Tower reported in DNV reports dated 1 August 2019 and 3 September 2019 for EOLOS FLS-200 buoy serial numbers ZX842 and ZX844 (and a metocean comparison report against the Narec NOAH Offshore Met Tower reported in DNV report dated 24 July 2019 for EOLOS FLS-200 buoy serial numbers ZX842 and ZX844).

[7] IEA Wind. "18. Floating LiDAR Systems, First edition, 2017", Document: IEA Wind TCP RP 18. Floating LiDAR Systems, September 2017

[8] MassCEC MetOcean Data Initiative. https://www.masscec.com/masscec-metocean-data-initiative

[9] Beckford, T., "Offshore turbine interaction - wake validation and blockage", WindEurope Resource Assessment, June 2019.

[10] Papadopoulos, I., "Improving confidence in offshore wake and energy yield predictions through innovative, statistically meaningful and detailed operational validations", Global Offshore Wind, June 2019.

APPENDIX A – Wind farm site information

Figure A-1 E05 (left) and E06 (right) EOLOS FLS-200 buoys at port

APPENDIX B – Wind data measurement and analysis

B.1 E05_N floating Lidar device
B.2 E05_SW floating Lidar location
B.3 E06_S floating Lidar device
B.4 Mast data coverage summary
B.5 Reference wind data

B.1 E05_N floating Lidar location

Buoy floating Lidar device configuration

Site name	East Coast Z3	Elevation [m]	Eastings [m]	Northings [m]	Coordinate system	Datum	Zone
Device name	**E05_N**	**0**	**695058**	**4426856**	**UTM**	**WS84**	**18N**
Installation date	**2019-08-12**						

Device description

Device Model	EOLOS FLS-200
Lidar Type	ZephIR ZX300M
Scan Heights [m MSL]	20, 40, 60, 80, 100, 120, 140, 160, 180, 200
Averaging Period [min]	10

Note that the location given above is the initial deployment location. There was occasional movement of the device throughout the deployment period, but given the scale of the movements relative to the distance from the shore and the resolution of the wind maps which were used to model flow variation over the area, these changes in location were not considered to have a significant impact on the analysis and the location above has been used in the analysis.

B.2 E05_SW floating Lidar location

Buoy floating Lidar device configuration

Site name	East Coast Z3	Elevation [m]	Eastings [m]	Northings [m]	Coordinate system	Datum	Zone
Device name	E05_SW	0	621173	4371530	UTM	WS84	18N
Installation date	2022-01-28						

Device description

Device Model	EOLOS FLS-200
Lidar Type	ZephIR ZX300M
Scan Heights [m MSL]	20, 40, 60, 80, 100, 120, 140, 160, 180, 200
Averaging Period [min]	10

Note that the location given above is the initial deployment location. There was occasional movement of the device throughout the deployment period, but given the scale of the movements relative to the distance from the shore and the resolution of the wind maps which were used to model flow variation over the area, these changes in location were not considered to have a significant impact on the analysis and the location above has been used in the analysis.

B.3 E06_S floating Lidar location

Buoy floating Lidar device configuration

Site name	East Coast Z3	Elevation [m]	Eastings [m]	Northings [m]	Coordinate system	Datum	Zone
Device name	E06	0	634944	4378580	UTM	WGS84	18N
Installation date	2019-09-04						

Device description

Device Model	EOLOS FLS-200
Lidar Type	ZephIR ZX300M
Scan Heights [m MSL]	20, 40, 60, 80, 100, 120, 140, 160, 180, 200
Averaging Period [min]	10

Note that the location given above is the initial deployment location. There was occasional movement of the device throughout the deployment period, but given the scale of the movements relative to the distance from the shore and the resolution of the wind maps which were used to model flow variation over the area, these changes in location were not considered to have a significant impact on the analysis and the location above has been used in the analysis.

B.4 Device data coverage summary

Figure B-1 and Figure B-2 summarize data coverage by wind speed and wind direction. Sensor labels indicate the lidar, instrument type, height, and orientation.

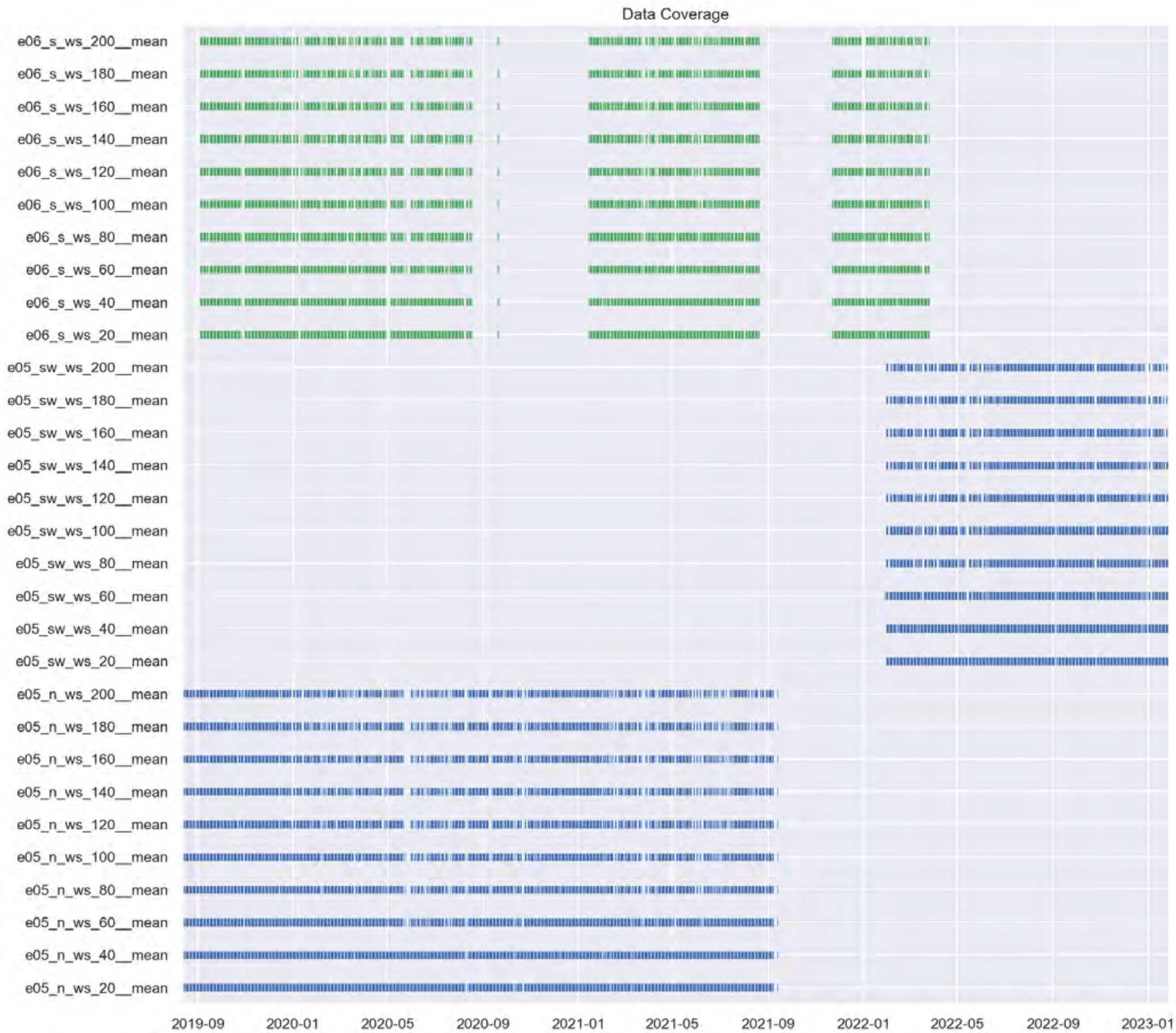


Figure B-1 Wind speed data coverage

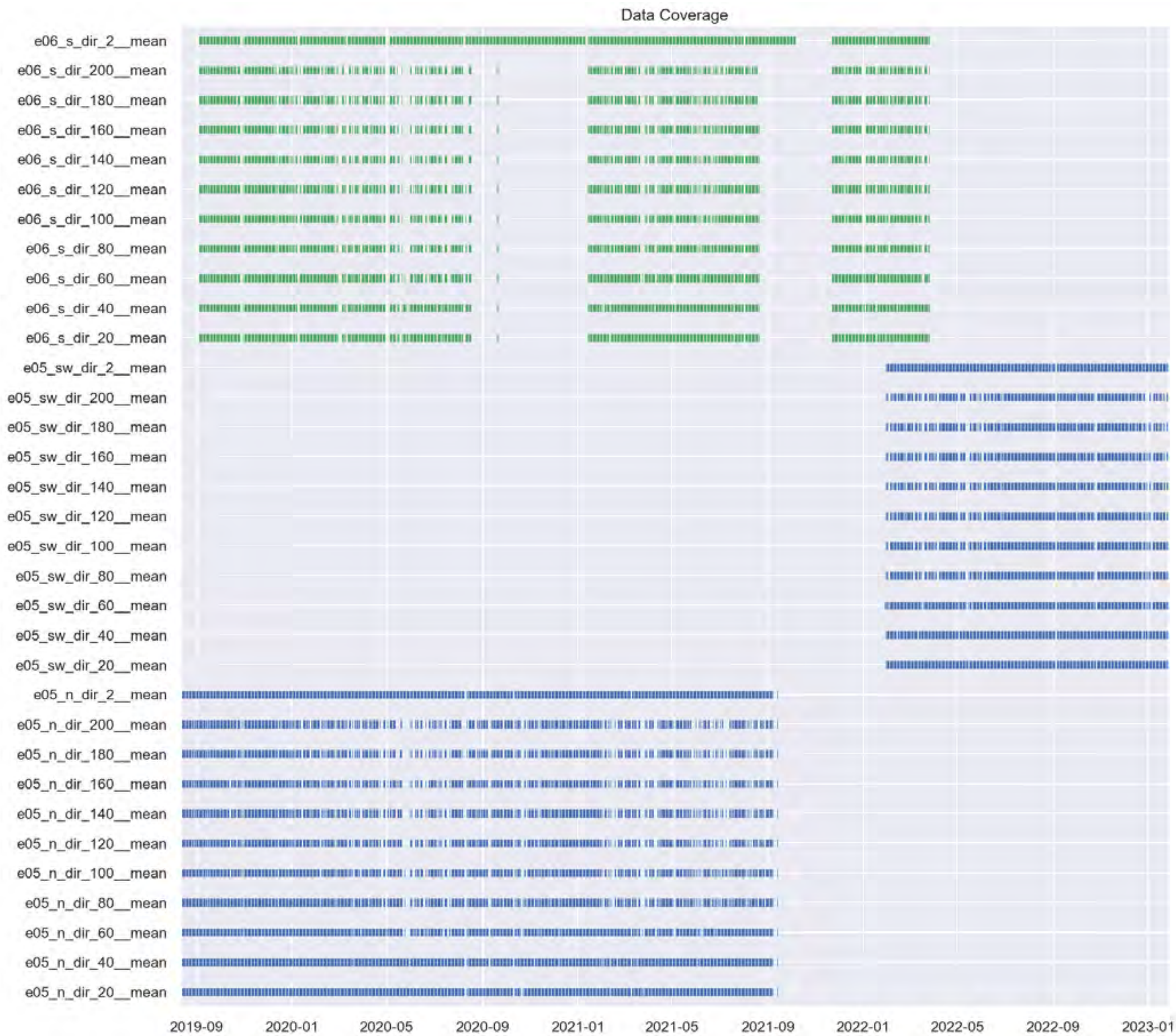


Figure B-2 Wind direction data coverage

B.5 Reference wind data

B.5.1 MERRA-2 data

The Modern Era Retrospective-analysis for Research and Applications, Version 2 (MERRA-2) data set has been produced by the National Aeronautics and Space Administration (NASA) by assimilating satellite observations with conventional land-based meteorology measurement sources using the Goddard Earth Observing System, Version 5.12.4 (GEOS-5.12.4) atmospheric data assimilation system. The analysis is performed at a spatial resolution of 0.625° longitude by 0.5° latitude. DNV typically procures hourly time series of two-dimensional diagnostic data, at a surface height of 50 m [B-1] for suitable grid cells near the project site.

B.5.2 ERA5 data

ERA5 is the fifth generation of European Centre for Medium-Range Weather Forecasts (ECMWF) atmospheric reanalysis of the global climate. It provides data at a considerably higher spatial and temporal resolution than its predecessor ERA-Interim: hourly analysis fields are available at a horizontal resolution of 31 km and include wind data at 100 m above ground level, as well as surface air temperature and air pressure. ERA5 incorporates vast amounts of historical measurement data, including satellite-, commercial aircraft-, and ground-based data [B-2][B-3].

B.5.3 Vortex Data

Vortex SERIES is a commercially-sold long-term reference data source, primarily based on the Weather Research and Forecasting (WRF) model, a mesoscale model developed and maintained by a consortium of more than 150 international agencies, laboratories, and universities. Its downscaling system uses a number of high-resolution inputs such as MERRA-2 or ERA5, as well as analyses of soil temperature and moisture, sea surface temperature, sea ice, and snow depth. Data are typically produced as a virtual hourly time series on a 3 km horizontal resolution, centered on the subject wind farm and at heights between 50 and 300 m above ground.

B.5.4 References

[B-1] National Aeronautics and Space Administration, MERRA-2, MDISC, https://disc.sci.gsfc.nasa.gov/mdisc/, MERRA-2 tavg1_2d_slv_Nx: 2d, 1-Hourly, Time-Averaged, Single-Level, Assimilation, Single-Level Diagnostics V5.12.4 (M2T1NXSLV), 1980-present.

[B-2] European Centre for Medium-Range Weather Forecasts, “ERA5 data documentation,” https://confluence.ecmwf.int/display/CKB/ERA5+data+documentation

[B-3] Copernicus, “Climate reanalysis,” https://climate.copernicus.eu/products/climate-reanalysis

B.5.5 Tables of monthly reference data

Table B-1 Wind speed statistics at the MERRA-2 40.00N, 73.13W

Month	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan	11.0	8.0	9.4	10.2	10.7	9.3	10.1	9.9	9.6	9.0	9.7	8.6	9.8	9.2	9.4	10.6	9.9	9.1	10.3	9.8	9.2	9.3	9.9	8.7
Feb	8.8	8.8	9.2	10.0	9.0	8.9	10.1	10.6	9.1	10.1	10.5	10.0	8.6	9.8	8.7	9.5	10.3	9.6	9.1	8.5	8.3	9.5	9.4	-
Mar	9.4	8.9	9.7	8.3	9.3	8.6	8.9	9.6	9.6	8.2	9.5	9.1	8.2	9.7	9.4	8.4	9.0	10.4	10.7	8.8	8.6	9.3	9.4	-
Apr	9.4	7.9	8.7	9.3	9.0	9.0	8.4	8.8	8.0	9.5	7.5	9.7	8.0	8.5	8.8	9.2	8.7	8.3	8.9	9.1	9.5	8.2	9.1	-
May	7.6	7.4	8.2	6.9	7.7	7.1	7.4	7.6	8.4	7.5	7.9	7.2	7.3	8.7	7.7	7.8	7.4	8.5	7.4	8.0	8.6	7.3	8.7	-
Jun	7.8	6.4	7.5	6.3	7.1	7.4	8.2	7.3	7.0	6.1	7.2	5.8	7.0	8.2	5.9	7.5	6.9	7.9	6.5	7.3	6.8	7.8	6.6	-
Jul	5.8	6.5	6.6	7.3	6.7	6.4	6.7	6.3	6.1	6.5	6.5	6.1	6.2	7.1	7.1	5.8	6.1	6.1	6.4	6.1	5.9	6.4	6.6	-
Aug	6.5	6.7	6.4	6.9	6.6	5.8	6.4	6.4	5.0	5.5	6.2	6.4	5.3	6.2	5.4	6.0	6.0	5.6	6.6	5.8	6.5	5.8	5.9	-
Sep	7.1	6.6	6.8	7.6	6.5	6.3	7.0	6.3	7.1	7.2	7.9	6.4	6.4	6.4	6.4	6.6	7.7	7.4	6.8	6.8	6.9	7.3	7.1	-
Oct	7.6	8.5	8.2	8.6	7.8	9.0	9.1	7.8	7.9	9.0	9.1	8.0	8.5	7.9	8.5	8.8	7.9	8.2	8.5	9.2	7.1	7.9	8.0	-
Nov	8.8	8.6	9.6	8.8	8.5	9.5	8.2	9.0	8.7	9.2	8.8	8.8	8.7	9.4	9.5	8.0	8.5	8.7	9.8	9.1	9.1	8.6	8.8	-
Dec	9.7	8.9	10.1	11.3	9.5	9.5	9.2	9.1	10.3	11.1	10.8	8.4	9.0	9.2	9.0	8.3	9.7	8.9	8.7	9.1	9.8	7.9	9.9	-
Annual	8.3	7.8	8.3	8.4	8.2	8.1	8.3	8.2	8.0	8.2	8.5	7.9	7.7	8.3	8.0	8.0	8.2	8.2	8.3	8.1	8.0	7.9	8.3	-

Table B-2 Wind speed statistics at the MERRA-2 40.00N, 72.50W

Month	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan	11.3	8.3	9.8	10.5	11.1	9.6	10.4	10.4	9.9	9.5	10.0	9.0	10.1	9.6	9.8	11.1	10.2	9.4	10.7	10.1	9.4	9.6	10.1	9.0
Feb	9.0	9.2	9.4	10.5	9.4	9.3	10.4	10.9	9.4	10.4	11.0	10.3	8.9	10.3	9.1	9.9	10.6	9.9	9.5	8.8	8.7	9.6	9.7	-
Mar	9.6	9.1	9.9	8.4	9.8	8.9	9.2	9.8	9.8	8.4	9.9	9.3	8.3	10.2	9.5	8.7	9.2	10.9	11.1	9.0	9.0	9.5	9.6	-
Apr	9.8	8.2	8.8	9.6	9.0	9.3	8.5	9.2	8.3	9.9	7.5	10.0	8.1	8.6	9.0	9.5	8.9	8.6	9.2	9.4	9.7	8.4	9.2	-
May	7.8	7.7	8.5	6.9	7.7	7.3	7.7	7.8	8.6	7.6	8.1	7.4	7.6	9.0	8.0	7.9	7.6	8.8	7.6	8.2	9.0	7.5	9.0	-
Jun	7.9	6.6	7.5	6.6	7.1	7.6	8.4	7.6	7.1	6.2	7.3	6.0	7.3	8.5	6.0	7.5	7.1	8.3	6.8	7.5	7.0	8.0	6.5	-
Jul	5.8	6.7	6.8	7.5	6.7	6.7	6.8	6.5	6.2	6.7	6.5	6.2	6.3	7.2	7.2	5.7	6.1	6.1	6.5	6.3	6.1	6.6	6.6	-
Aug	6.6	6.8	6.2	7.1	6.7	5.8	6.5	6.6	5.2	5.5	6.4	6.7	5.4	6.3	5.6	6.1	6.1	5.8	6.7	6.0	6.6	6.0	5.9	-
Sep	7.2	6.7	6.9	7.6	6.7	6.4	7.0	6.2	7.2	7.4	8.1	6.5	6.5	6.7	6.5	6.8	8.1	7.9	7.0	7.1	7.1	7.5	7.3	-
Oct	7.8	8.6	8.5	8.8	7.9	9.3	9.3	7.9	8.2	9.2	9.5	8.2	8.6	8.0	8.7	9.1	8.3	8.5	8.6	9.6	7.3	8.1	8.0	-
Nov	9.0	8.8	9.9	9.0	8.8	9.7	8.2	9.2	8.9	9.6	9.2	9.1	9.1	9.7	9.8	8.2	8.8	8.9	10.2	9.4	9.2	8.9	9.1	-
Dec	10.1	9.2	10.5	11.6	9.8	9.8	9.5	9.4	10.7	11.5	11.2	8.7	9.5	9.7	9.2	8.5	10.0	9.2	9.0	9.5	10.0	8.1	10.3	-
Annual	8.5	8.0	8.5	8.7	8.4	8.3	8.5	8.5	8.3	8.5	8.7	8.1	8.0	8.6	8.2	8.2	8.4	8.5	8.6	8.4	8.2	8.1	8.4	-

Table B-3 Wind speed statistics at the MERRA-2 39.50N, 73.13W

Month	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan	11.1	8.0	9.5	10.3	10.8	9.5	10.1	10.2	9.8	9.2	10.0	8.8	9.9	9.2	9.4	10.7	10.1	9.1	10.4	9.8	9.3	9.4	10.1	9.0
Feb	8.8	8.9	9.3	10.3	9.1	9.1	10.1	10.7	9.2	10.2	10.9	10.1	8.6	10.0	8.9	9.7	10.5	9.7	9.2	8.5	8.6	9.6	9.5	-
Mar	9.6	9.2	9.9	8.3	9.6	8.6	8.9	9.7	9.8	8.3	9.7	9.1	8.1	10.1	9.6	8.5	9.0	10.5	10.9	8.8	8.7	9.4	9.6	-
Apr	9.7	8.4	8.7	9.4	9.2	9.5	8.6	9.2	8.3	9.9	7.3	10.2	8.1	8.7	8.9	9.2	9.0	8.6	8.9	9.3	9.8	8.3	9.1	-
May	7.9	7.3	8.2	7.0	7.8	7.2	7.4	7.9	8.6	7.7	7.9	7.2	7.6	9.0	7.7	7.8	7.3	8.8	7.4	8.0	9.0	7.2	9.2	-
Jun	7.9	6.4	7.2	6.6	7.0	7.5	8.2	7.4	7.1	6.1	7.2	5.8	7.1	8.2	5.9	7.6	7.1	8.1	6.7	7.6	7.0	7.8	6.6	-
Jul	5.8	6.7	6.4	7.5	6.6	6.4	6.7	6.2	6.1	6.4	6.5	6.1	6.1	7.0	7.0	5.5	5.8	6.0	6.4	6.1	5.8	6.4	6.4	-
Aug	6.6	6.7	6.2	7.0	6.6	5.6	6.4	6.6	5.2	5.4	6.1	6.6	5.5	6.1	5.4	6.0	5.8	5.6	6.5	5.8	6.3	5.7	5.8	-
Sep	6.9	6.6	6.9	7.6	6.6	6.4	6.8	6.0	7.3	7.5	7.7	6.2	6.3	6.4	6.5	6.7	7.9	7.8	6.8	6.9	7.0	7.4	7.2	-
Oct	7.8	8.3	8.2	8.4	7.8	8.9	9.0	7.5	7.9	9.2	9.1	8.0	8.6	7.8	8.4	8.8	8.1	8.1	8.2	9.3	7.0	8.2	7.8	-
Nov	8.9	8.4	9.7	8.7	8.4	9.4	8.0	9.0	8.8	9.3	9.0	8.9	8.9	9.4	9.6	8.0	8.7	8.6	10.0	9.2	8.9	8.9	8.9	-
Dec	9.9	9.3	10.4	11.3	9.5	9.6	9.1	9.1	10.2	11.3	11.1	8.6	9.1	9.4	9.0	8.4	9.7	8.9	8.7	9.1	9.9	8.0	9.8	-
Annual	8.4	7.9	8.4	8.5	8.2	8.1	8.3	8.3	8.2	8.4	8.5	8.0	7.8	8.4	8.0	8.1	8.2	8.3	8.3	8.2	8.1	8.0	8.3	-

Table B-4 Wind speed statistics at the MERRA-2 39.50N, 73.75W

Month	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan	10.5	7.6	8.9	9.6	10.1	9.0	9.6	9.5	9.2	8.5	9.4	8.3	9.4	8.5	8.9	9.8	9.6	8.7	9.8	9.3	8.7	8.7	9.6	8.5
Feb	8.3	8.4	8.9	9.7	8.6	8.5	9.5	10.1	8.7	9.7	10.2	9.5	8.2	9.2	8.3	9.1	9.9	9.2	8.6	8.0	8.1	9.2	9.0	-
Mar	9.3	8.8	9.5	8.1	9.0	8.3	8.4	9.3	9.3	7.9	9.3	8.7	7.8	9.4	9.2	7.9	8.6	9.9	10.1	8.4	8.2	9.0	9.2	-
Apr	9.2	8.0	8.4	9.0	8.9	9.1	8.3	8.7	7.8	9.3	7.1	9.6	7.9	8.3	8.6	8.9	8.6	8.1	8.4	8.8	9.3	7.9	8.8	-
May	7.5	6.9	7.8	6.8	7.5	7.0	7.0	7.5	8.2	7.2	7.5	6.9	7.0	8.4	7.1	7.4	6.9	8.4	6.9	7.7	8.4	6.8	8.6	-
Jun	7.5	6.0	7.0	6.0	6.7	7.1	7.7	6.9	6.8	6.0	6.8	5.5	6.6	7.6	5.6	7.4	6.6	7.5	6.3	7.1	6.8	7.3	6.4	-
Jul	5.7	6.4	6.2	7.1	6.4	6.0	6.4	5.9	5.9	6.2	6.2	5.8	5.7	6.7	6.8	5.4	5.7	6.0	6.3	5.8	5.6	6.1	6.1	-
Aug	6.4	6.5	6.2	6.7	6.3	5.5	6.2	6.1	5.0	5.2	5.9	6.2	5.3	5.9	5.1	5.9	5.6	5.4	6.2	5.5	6.2	5.3	5.7	-
Sep	6.8	6.5	6.6	7.4	6.4	6.2	6.6	5.9	7.1	7.3	7.4	6.0	6.1	6.1	6.4	6.5	7.4	7.2	6.6	6.6	6.7	7.1	7.0	-
Oct	7.4	8.1	7.8	8.1	7.5	8.5	8.7	7.3	7.6	8.8	8.7	7.8	8.3	7.7	8.0	8.6	7.7	7.7	8.0	8.7	6.8	7.8	7.7	-
Nov	8.5	8.1	9.3	8.4	8.1	9.1	7.9	8.7	8.4	8.9	8.4	8.6	8.5	8.9	9.1	7.7	8.2	8.3	9.4	8.7	8.5	8.4	8.5	-
Dec	9.4	8.7	9.7	10.8	9.0	9.1	8.6	8.6	9.6	10.5	10.3	8.2	8.5	8.7	8.6	8.0	9.1	8.3	8.3	8.5	9.4	7.5	9.2	-
Annual	8.0	7.5	8.0	8.1	7.9	7.8	7.9	7.8	7.8	7.9	8.1	7.6	7.4	8.0	7.6	7.7	7.8	7.9	7.9	7.8	7.7	7.6	8.0	-

Table B-5 Wind speed statistics at the Vortex MERRA-2 39.96N, 72.73W

Month	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan	12.4	8.9	10.7	10.8	11.7	10.6	11.6	11.3	10.9	9.7	10.7	9.2	10.8	9.8	10.5	11.3	10.7	10.2	12.0	10.8	10.1	9.7	10.5	9.2
Feb	10.0	10.1	10.3	11.3	9.8	10.2	10.9	11.3	10.3	11.6	11.6	11.3	9.6	10.8	9.7	10.0	11.9	10.8	10.8	9.5	9.6	10.5	10.7	-
Mar	11.4	10.2	11.5	9.7	11.4	9.9	9.9	11.3	11.1	9.6	11.6	10.5	9.8	11.1	10.6	9.3	10.8	12.0	12.1	10.1	10.6	10.7	10.8	-
Apr	11.4	9.8	10.6	11.7	11.6	11.5	9.9	10.1	10.1	12.2	9.4	12.7	9.3	10.0	10.5	11.6	10.3	10.3	11.0	11.0	11.0	9.6	10.4	-
May	9.6	9.4	10.3	8.5	9.6	8.9	9.5	9.5	10.8	9.7	10.0	9.2	9.4	10.9	9.4	9.9	9.1	10.6	9.7	9.8	10.6	9.2	10.6	-
Jun	10.4	8.1	9.7	7.7	9.2	9.8	10.5	9.7	9.3	7.4	9.5	7.3	8.8	10.7	7.1	9.1	8.5	10.2	8.0	8.9	8.8	9.8	7.9	-
Jul	7.1	8.3	8.8	9.2	8.4	7.9	8.6	8.1	8.0	8.5	8.1	7.9	7.7	9.1	8.8	6.9	7.4	7.6	7.5	7.6	7.8	8.2	8.1	-
Aug	8.2	8.7	7.9	9.1	8.0	7.3	7.8	8.1	6.1	6.7	7.6	7.9	6.2	7.2	6.2	6.9	7.3	6.6	8.2	6.9	8.0	7.2	6.9	-
Sep	8.6	7.8	8.0	8.9	7.8	7.3	8.2	7.5	8.5	8.3	9.6	7.8	7.3	7.5	7.3	7.6	9.1	9.3	7.9	8.2	8.2	8.6	8.0	-
Oct	9.1	10.1	9.6	9.7	8.9	10.4	10.4	9.3	9.0	10.7	10.5	9.0	9.6	8.9	9.8	10.2	9.6	9.9	9.5	11.0	8.3	9.2	9.1	-
Nov	9.8	10.2	10.7	10.0	9.6	11.2	9.7	10.2	9.8	10.7	10.3	10.3	10.0	10.6	10.5	9.2	9.6	9.9	11.1	9.9	10.1	9.3	9.9	-
Dec	10.8	10.2	11.0	12.7	10.7	10.3	10.6	10.1	11.7	12.3	11.8	9.3	10.1	10.5	9.9	9.7	10.4	9.4	9.8	10.4	10.5	8.9	11.2	-
Annual	9.9	9.3	9.9	9.9	9.7	9.6	9.8	9.7	9.6	9.8	10.1	9.4	9.1	9.8	9.2	9.3	9.5	9.7	9.8	9.5	9.5	9.2	9.5	-

Table B-6 Wind speed statistics at the Vortex MERRA-2 39.54N, 73.42W

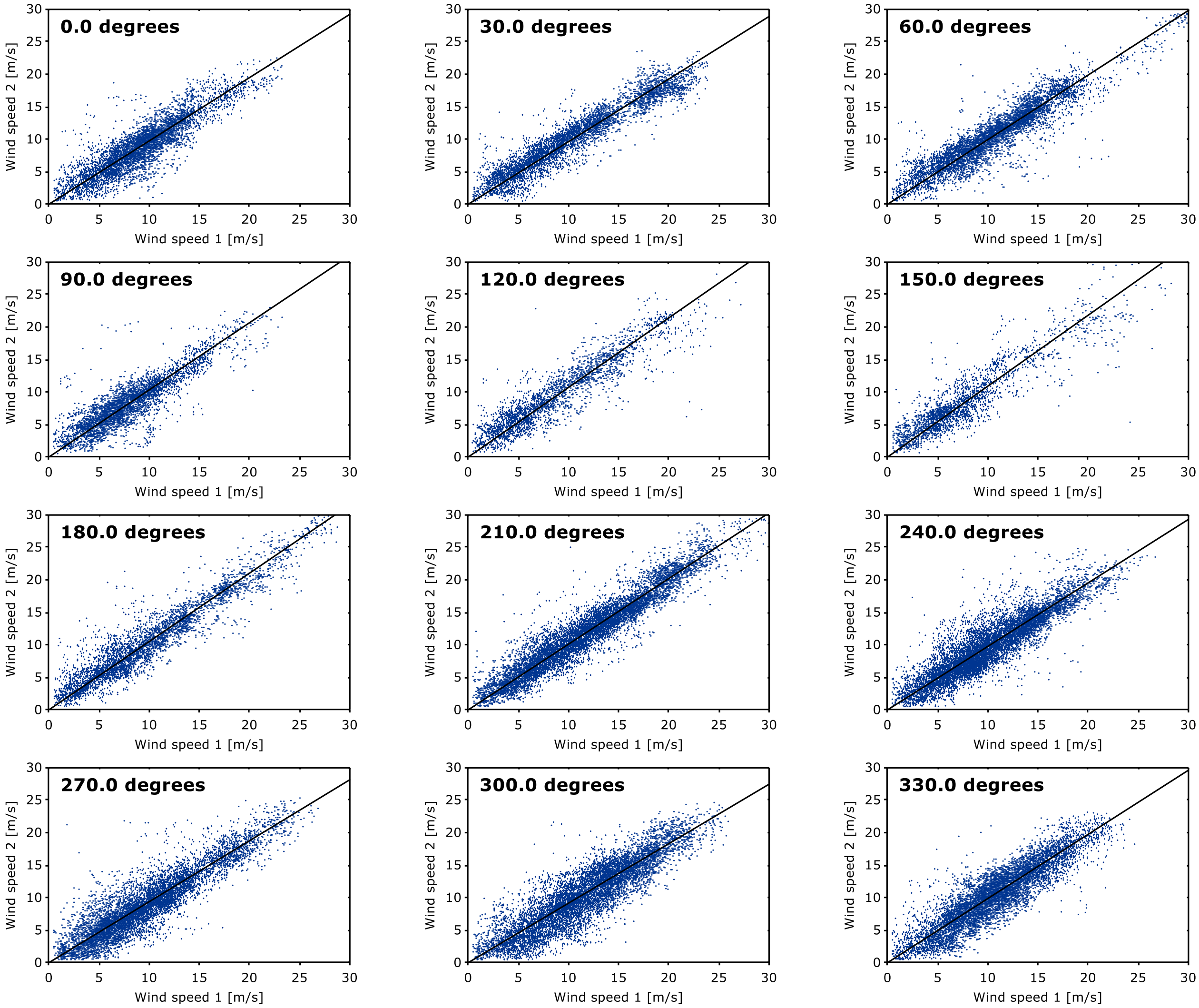
Month	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan	12.2	8.9	10.5	10.7	11.5	10.6	11.5	11.0	10.8	9.4	10.7	9.2	10.7	9.6	10.1	10.8	10.7	10.0	11.7	10.3	9.9	9.6	10.6	9.4
Feb	9.8	10.0	10.3	11.1	9.6	9.9	10.8	11.1	10.2	11.4	11.5	11.1	9.6	10.4	9.5	9.8	11.8	10.7	10.7	9.1	9.3	10.6	10.5	-
Mar	11.3	10.3	11.6	9.7	11.2	9.7	9.4	11.1	10.9	9.5	11.5	10.3	9.5	10.9	10.7	9.0	10.6	11.7	11.8	10.0	10.1	10.6	10.9	-
Apr	11.2	10.0	10.6	11.6	11.6	11.5	10.0	10.2	9.9	12.0	9.0	12.9	9.2	10.2	10.3	11.3	10.4	10.1	10.7	11.0	11.0	9.5	10.4	-
May	9.6	8.8	10.0	8.6	9.8	8.8	9.1	9.5	10.6	9.7	9.7	9.2	9.3	10.9	8.8	9.7	8.6	10.6	9.2	9.9	10.6	8.7	10.7	-
Jun	10.2	7.9	9.3	7.8	9.0	9.7	10.4	9.3	9.4	7.4	9.5	7.3	8.5	10.2	6.8	9.2	8.3	10.2	7.9	9.1	8.8	9.4	8.2	-
Jul	7.0	8.2	8.4	9.2	8.1	7.6	8.6	7.7	7.9	8.1	8.1	8.0	7.5	9.0	8.6	6.6	7.1	7.5	7.5	7.6	7.3	8.1	8.1	-
Aug	8.0	8.5	7.9	8.9	7.9	7.1	7.6	7.9	6.2	6.4	7.2	7.6	6.2	7.1	5.8	6.9	6.9	6.3	7.9	6.6	7.7	7.0	7.0	-
Sep	8.3	7.7	7.8	9.1	7.6	7.2	7.9	7.1	8.6	8.4	9.2	7.5	7.2	7.3	7.2	7.4	8.9	8.8	7.7	7.9	8.0	8.5	7.9	-
Oct	8.9	9.9	9.2	9.4	8.6	9.9	10.1	8.9	8.9	10.5	10.2	8.9	9.8	8.9	9.5	10.0	9.3	9.5	9.1	10.4	8.0	9.3	8.9	-
Nov	9.8	9.8	10.5	9.7	9.3	11.0	9.4	9.9	9.8	10.3	10.0	10.2	9.9	10.3	10.4	9.0	9.3	9.6	10.9	9.7	9.8	9.4	9.8	-
Dec	10.6	10.1	10.9	12.5	10.4	10.1	10.2	9.8	10.9	12.0	11.7	9.3	9.7	10.2	9.7	9.6	10.2	9.2	9.6	9.7	10.4	8.9	10.6	-
Annual	9.7	9.2	9.7	9.8	9.5	9.4	9.6	9.5	9.5	9.6	9.8	9.3	8.9	9.6	8.9	9.1	9.3	9.5	9.6	9.3	9.2	9.1	9.5	-

APPENDIX C – Wind farm analysis and results

C.1 Correlations
C.2 Site-period wind speeds
C.3 Mast long-term wind regime
C.4 Time-dependent loss factors
C.5 Energy results
C.6 Seasonal and diurnal variation

C.1 Correlations

Directional correlation of wind speeds recorded at [E05_N~WS140~Mean] (1) and [E06_S~WS140~Mean] (2)



Directional correlation ratios

Bin centers [degrees]	Wind speed ratio	Number of records
0.0	1.055	4034
30.0	1.047	4563
60.0	0.997	4865
90.0	0.954	3622
120.0	0.956	2565
150.0	0.924	2106
180.0	0.966	4122
210.0	0.995	10595
240.0	1.019	8673
270.0	1.070	6250
300.0	1.066	7577
330.0	1.017	6594
All directional	1.018	66452

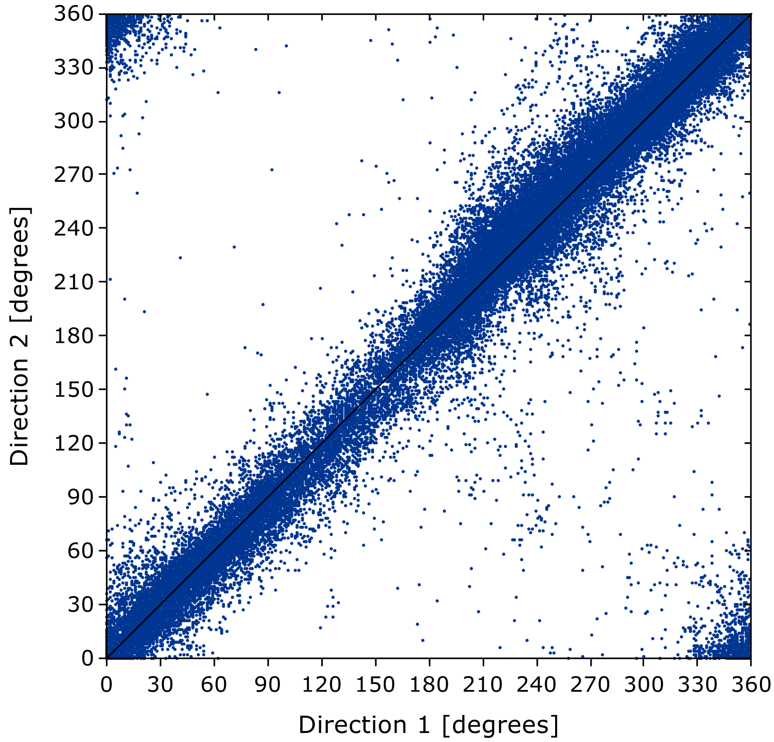
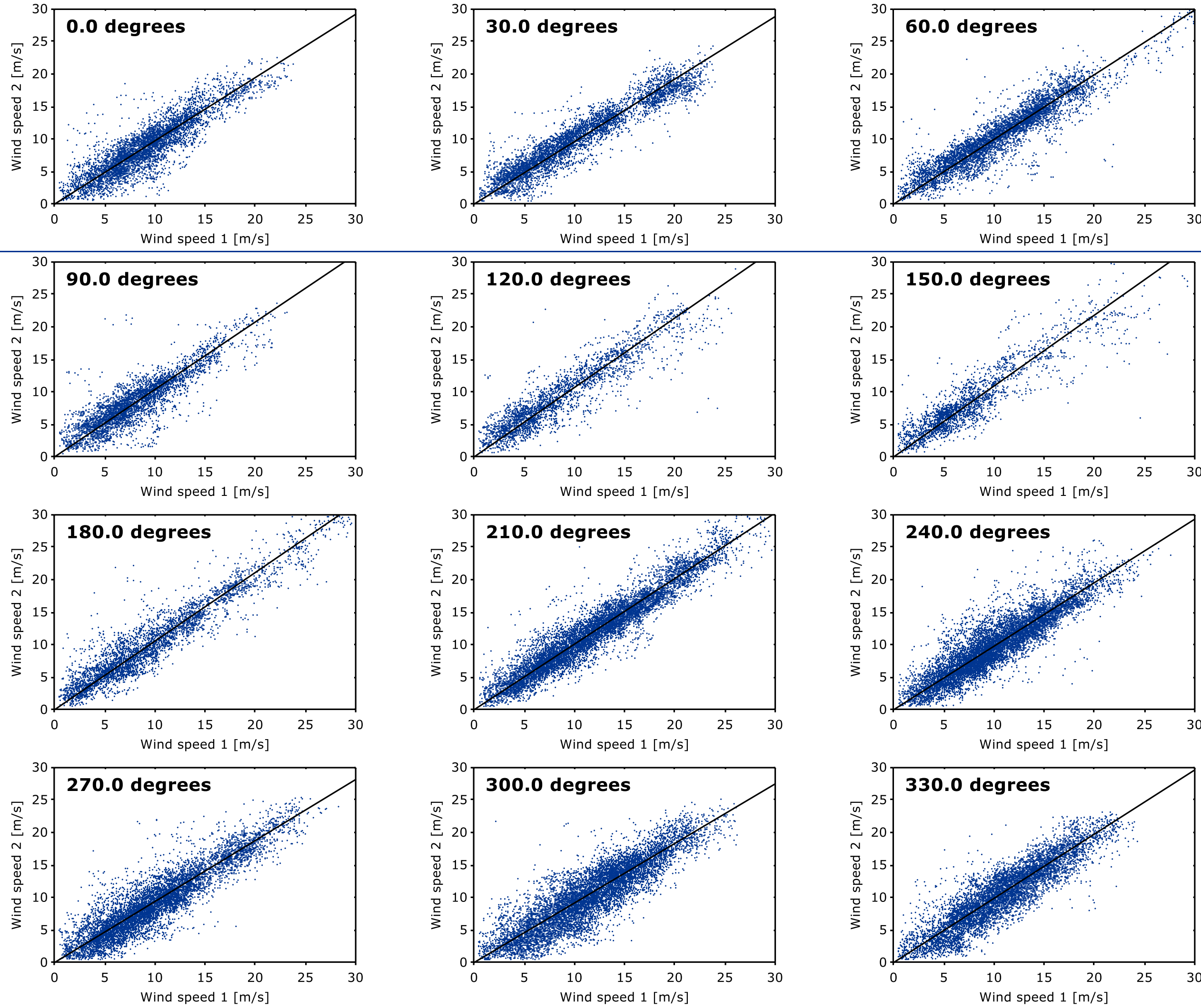


Figure C-1 Correlation of wind direction between [1] E06_S at 140 m and [2] E05_N at 140 m

Directional correlation of wind speeds recorded at [E05_N WS160~Mean] (1) and [E06_S ~WS160~Mean] (2)



Directional correlation ratios

Bin centers [degrees]	Wind speed ratio	Number of records
0.0	0.973	5129
30.0	0.961	4895
60.0	0.995	5627
90.0	1.037	3900
120.0	1.068	2720
150.0	1.089	2278
180.0	1.055	4050
210.0	1.008	9014
240.0	0.976	9604
270.0	0.938	7828
300.0	0.915	9097
330.0	0.987	7456
All directional	0.982	71942

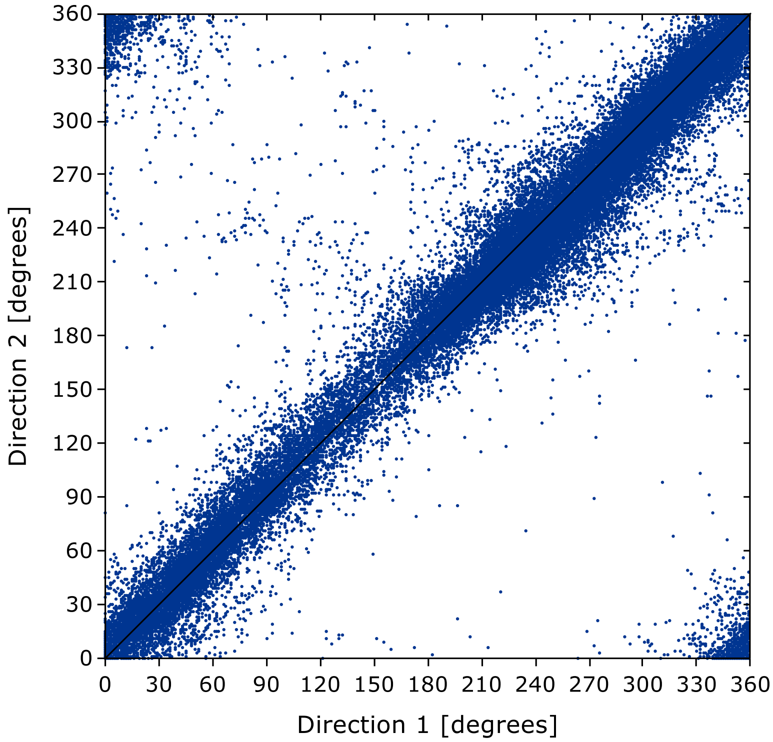


Figure C-2 Correlation of wind direction between [1] E06_S at 160 m and [2] E05_N at 160 m

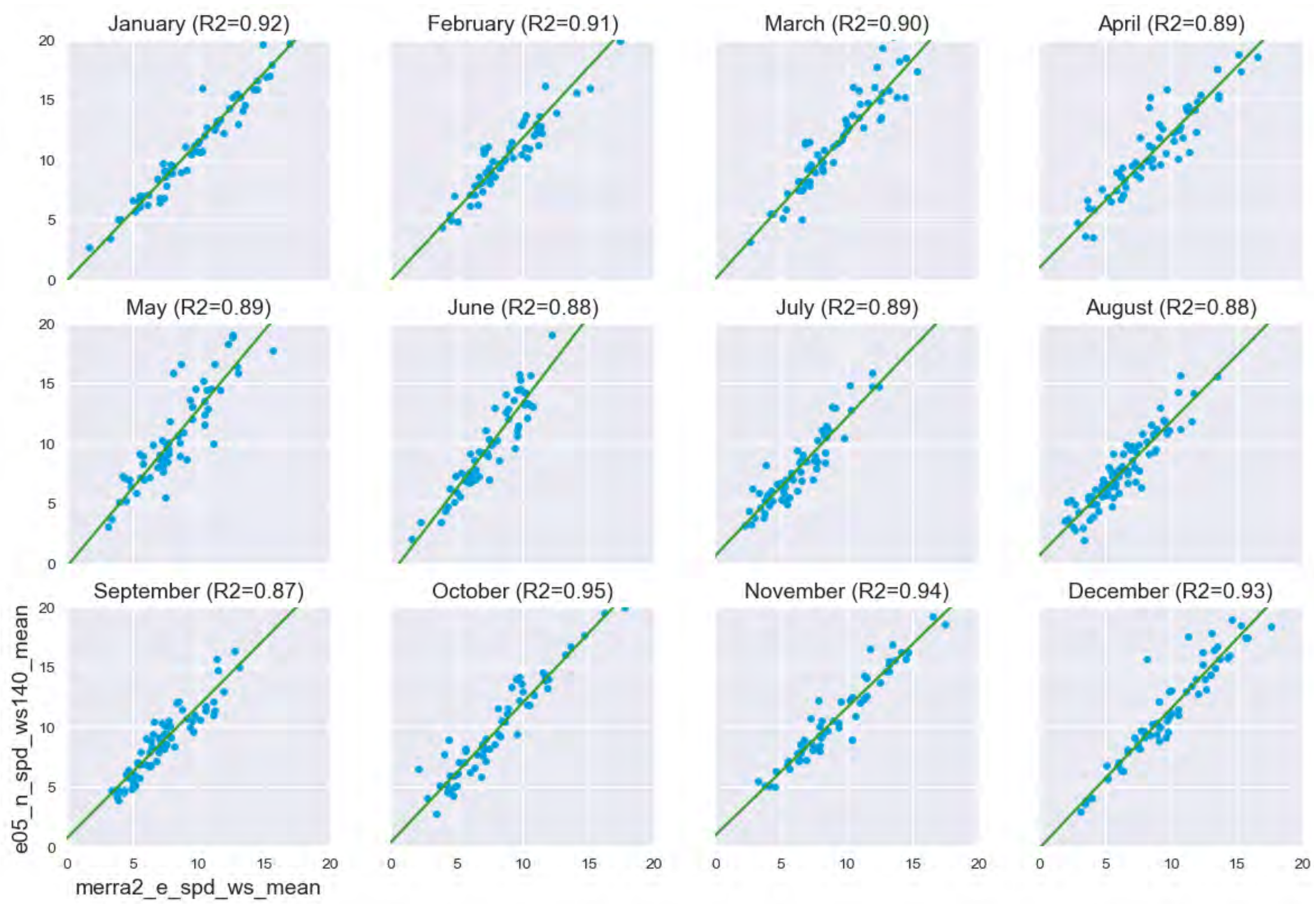


Figure C-3 Correlation of wind speed between E05_N at 140m and MERRA-2 40.00N, 72.50W

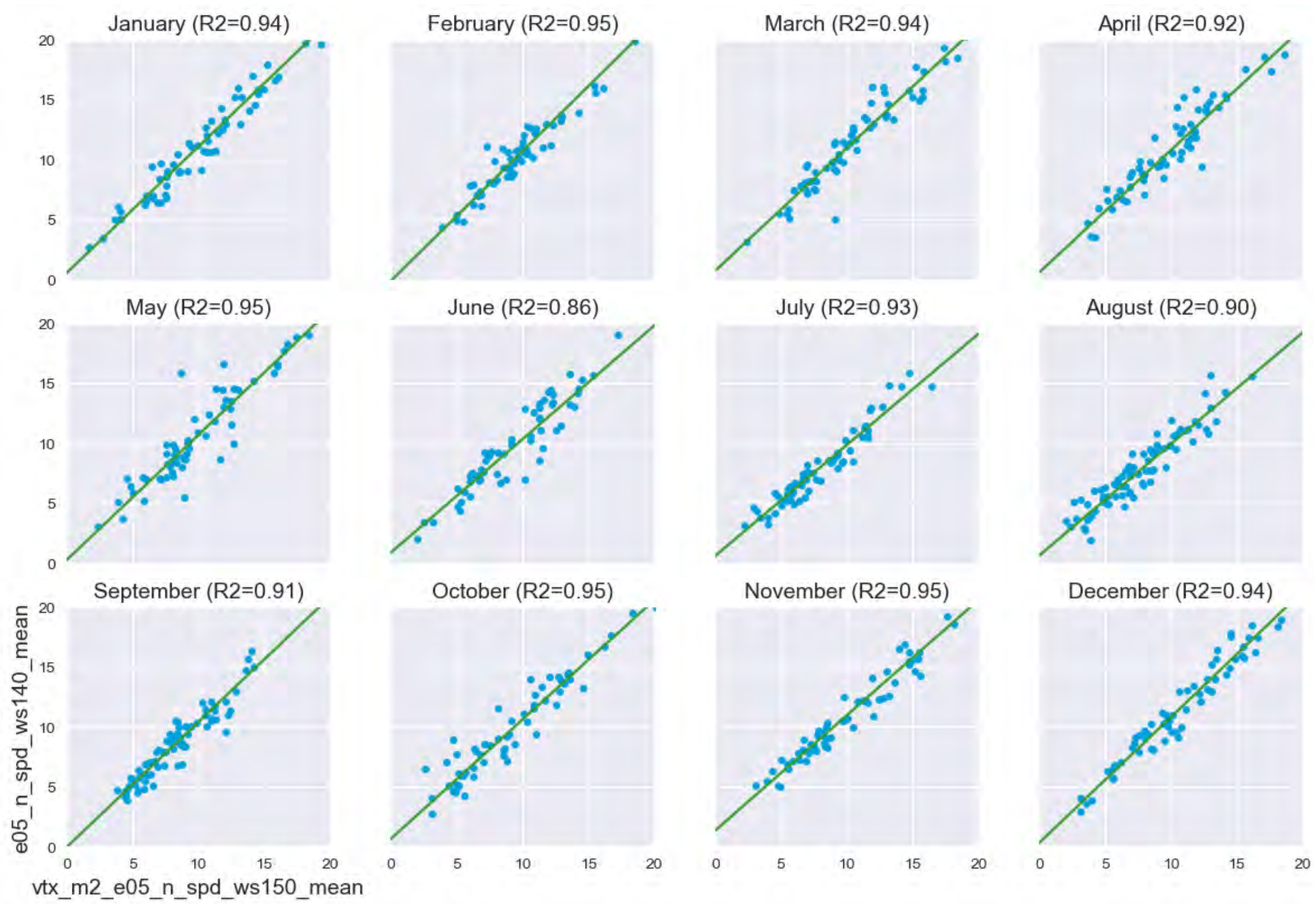


Figure C-4 Correlation of wind speed between E05_N at 140m and Vortex MERRA-2 39.96N, 72.73W

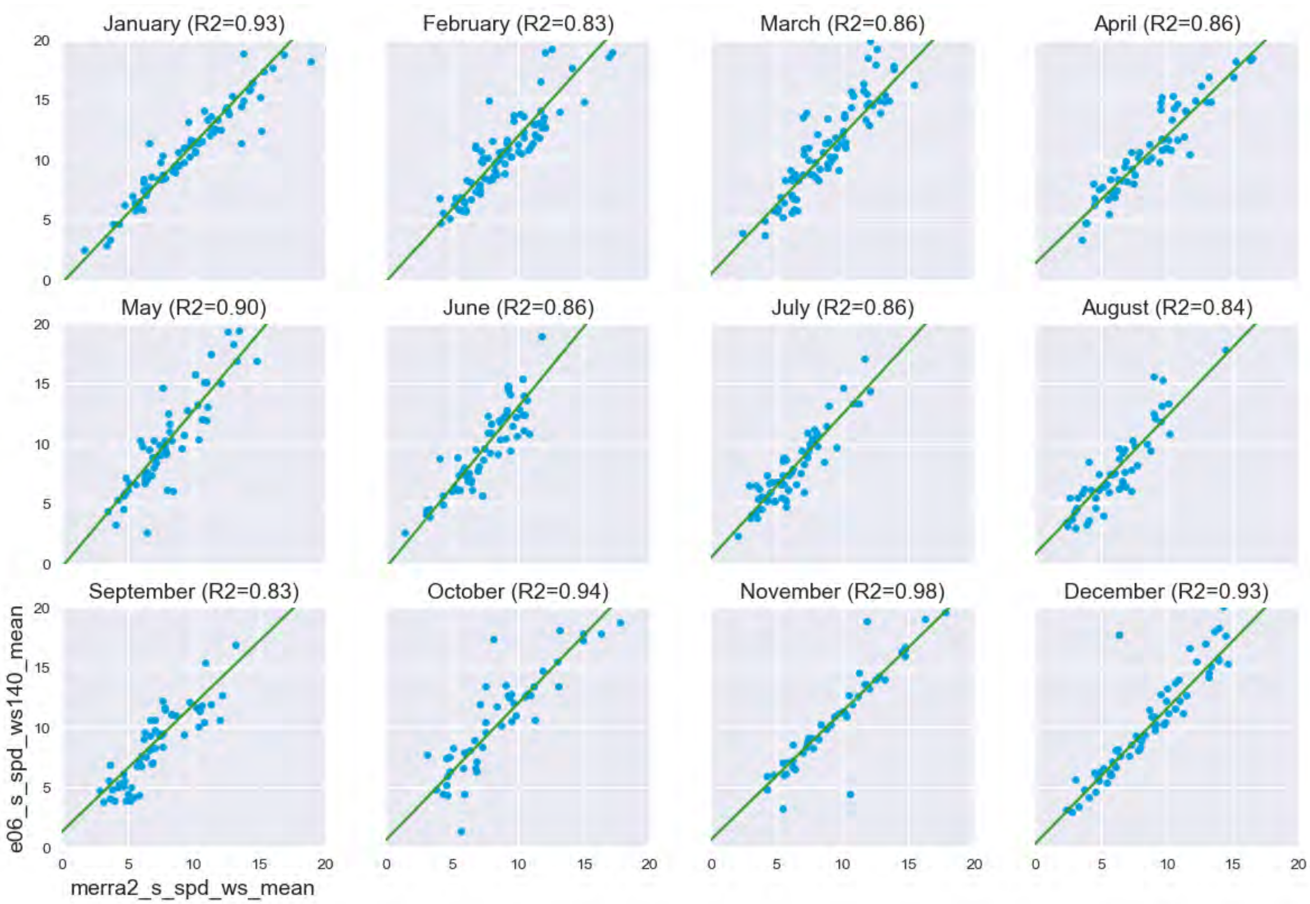


Figure C-5 Correlation of wind speed between E06_S at 140m and MERRA-2 39.50N, 73.13W

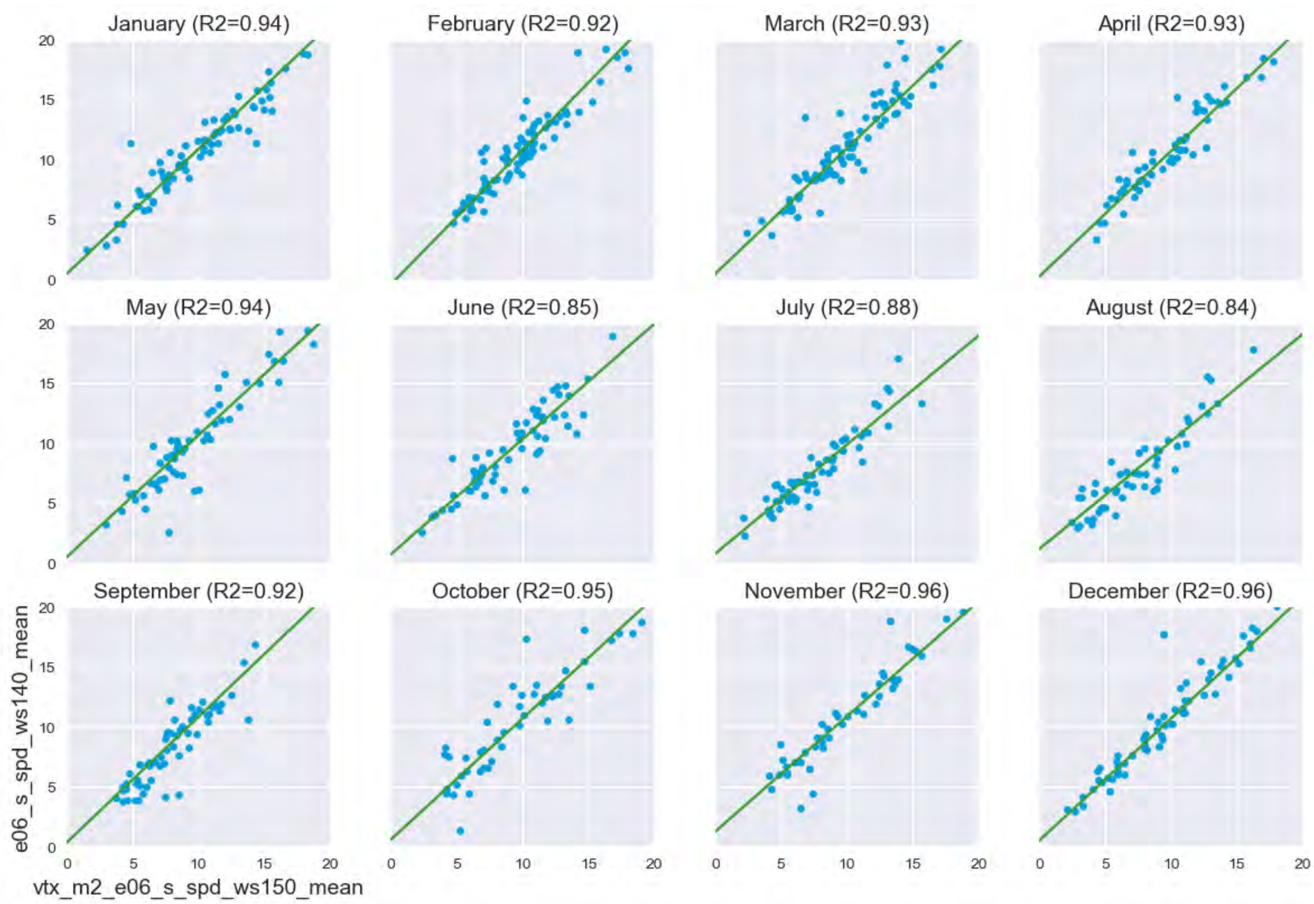


Figure C-6 Correlation of wind speed between E06_S at 140m and Vortex MERRA-2 39.96N, 72.73W

C.2 Site-period wind speeds

Table C-1 Site-period wind speeds

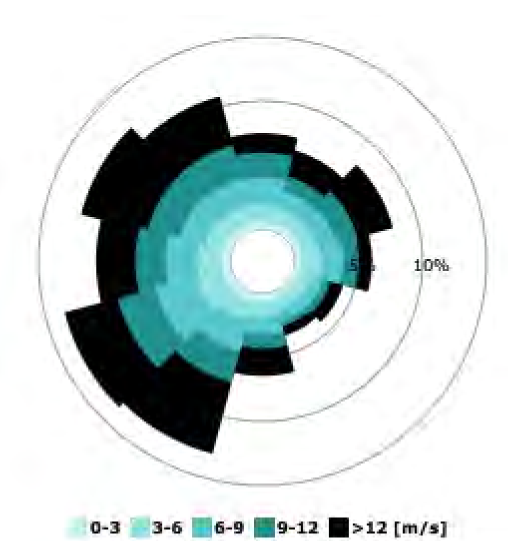
Month	E05_N 140 m	E05_N 160 m	E05_SW 140 m	E05_SW 160 m	E06_S 140 m	E06_S 160 m
January	11.0	11.1	11.0	11.1	10.8	10.9
February	11.1	11.2	11.0	11.1	11.0	11.1
March	11.6	11.7	11.6	11.7	11.5	11.7
April	11.2	11.4	11.1	11.2	11.1	11.2
May	10.6	10.7	10.7	10.8	10.8	10.9
June	9.6	9.7	9.2	9.3	9.1	9.2
July	7.9	8.0	8.1	8.3	7.9	8.1
August	7.8	7.9	7.6	7.7	7.5	7.6
September	8.5	8.6	8.8	8.9	8.5	8.6
October	10.1	10.2	10.5	10.6	10.0	10.1
November	11.0	11.1	10.6	10.7	10.6	10.7
December	10.8	10.9	10.4	10.5	10.5	10.6
Annual	**10.1**	**10.2**	**10.0**	**10.2**	**9.9**	**10.1**

Values include data synthesized from other site masts.

C.3 Mast long-term wind regime

Table C-2 E05_N long-term wind speed and frequency distribution at 155 m

Monthly	Wind speed [m/s]	Valid wind speed data [months]	Valid direction data [months]
January	11.0	1.9	1.9
February	10.8	1.8	1.8
March	11.9	1.8	1.8
April	11.5	1.9	1.9
May	10.8	1.6	1.6
June	9.7	1.7	1.7
July	8.1	1.8	1.8
August	7.9	2.5	2.5
September	8.7	2.2	2.2
October	10.5	1.8	1.8
November	11.0	2.0	2.0
December	11.3	1.9	1.9
Annual	10.3		



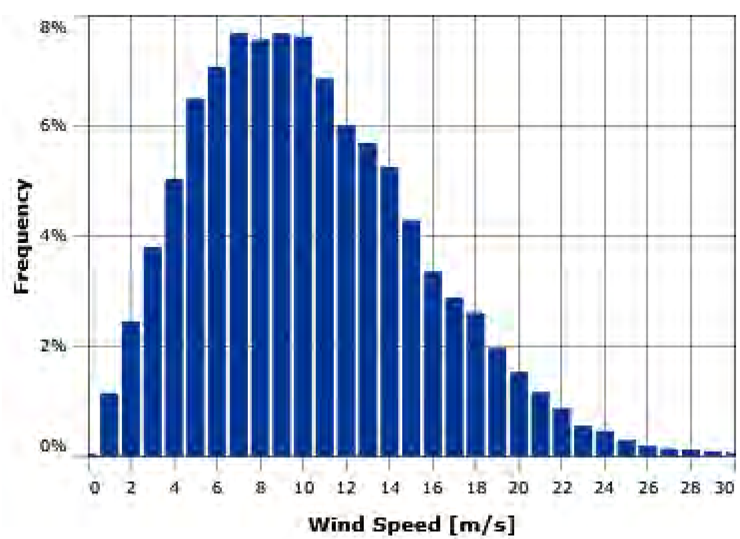


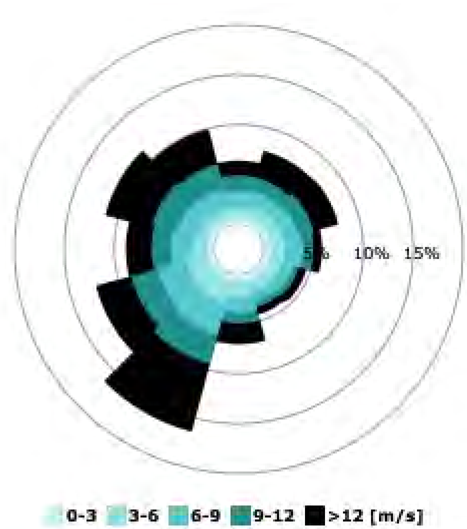
Table C-3 Wind speed and direction frequency distribution

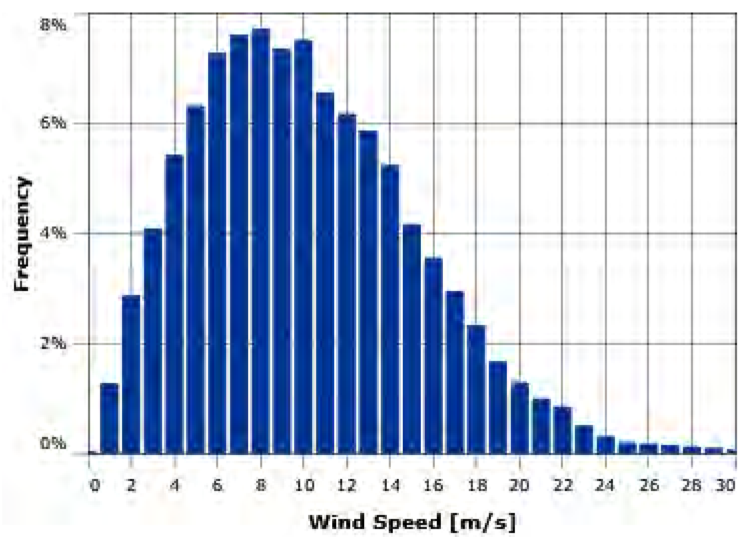
Wind Speed [m/s]	0	30	60	90	120	150	180	210	240	270	300	330	No Direction	Total [%]
0	+	+	+		+	+	+		+	+	+	+		0.01
1	0.10	0.07	0.09	0.08	0.10	0.10	0.10	0.09	0.09	0.11	0.10	0.10		1.12
2	0.20	0.19	0.15	0.17	0.16	0.17	0.21	0.22	0.27	0.25	0.21	0.22		2.42
3	0.26	0.32	0.30	0.28	0.26	0.23	0.35	0.32	0.41	0.39	0.38	0.27		3.77
4	0.36	0.39	0.29	0.46	0.36	0.26	0.33	0.52	0.61	0.57	0.47	0.37		5.00
5	0.47	0.44	0.44	0.61	0.39	0.41	0.47	0.62	0.85	0.72	0.56	0.49		6.47
6	0.66	0.47	0.51	0.56	0.33	0.36	0.48	0.74	0.90	0.81	0.55	0.66		7.04
7	0.73	0.50	0.58	0.67	0.29	0.29	0.48	0.82	1.06	0.81	0.68	0.71		7.66
8	0.72	0.41	0.55	0.57	0.31	0.29	0.47	0.84	1.15	0.82	0.69	0.72		7.53
9	0.71	0.50	0.62	0.47	0.21	0.18	0.37	0.80	1.27	0.87	0.83	0.80		7.65
10	0.79	0.41	0.59	0.49	0.18	0.17	0.40	0.81	1.10	0.76	0.91	0.99		7.59
11	0.57	0.37	0.57	0.38	0.18	0.11	0.31	0.87	0.90	0.78	0.86	0.92		6.83
12	0.48	0.36	0.44	0.20	0.16	0.08	0.32	0.83	0.79	0.74	0.77	0.80		5.98
13	0.37	0.38	0.42	0.20	0.13	0.06	0.31	0.81	0.83	0.58	0.79	0.77		5.65
14	0.29	0.22	0.52	0.19	0.12	0.06	0.31	0.77	0.77	0.40	0.91	0.65		5.22
15	0.14	0.13	0.45	0.17	0.15	0.06	0.20	0.73	0.67	0.28	0.74	0.54		4.25
16	0.09	0.10	0.35	0.11	0.11	0.06	0.19	0.53	0.50	0.23	0.59	0.44		3.32
17	0.09	0.15	0.28	0.05	0.09	0.06	0.20	0.53	0.32	0.27	0.48	0.33		2.85
18	0.10	0.24	0.25	0.04	0.07	0.05	0.16	0.40	0.26	0.24	0.46	0.33		2.58
19	0.07	0.22	0.16	0.06	0.06	0.04	0.10	0.28	0.21	0.23	0.32	0.19		1.93
20	0.04	0.16	0.07	0.05	0.08	0.06	0.10	0.31	0.12	0.15	0.23	0.12		1.50
21	0.03	0.15	0.04	0.03	0.04	0.04	0.08	0.30	0.08	0.10	0.18	0.08		1.13
22	0.02	0.10	0.02	0.01	0.02	0.04	0.07	0.22	0.05	0.09	0.13	0.06		0.84
23	0.01	0.05	0.02	+	0.03	0.04	0.06	0.15	0.03	0.05	0.06	0.02		0.52
24	+	0.01	0.02	+	0.03	0.03	0.07	0.12	0.02	0.05	0.03	0.02		0.42
25	+	+	0.02	+	0.02	0.04	0.04	0.09	0.01	0.02	0.02	0.01		0.26
26	+	+	0.01	0.01	0.01	0.03	0.03	0.04	+	0.01	0.01	+		0.16
27	+	+	0.02	+	0.01	0.03	0.02	0.02	+	+	+	+		0.11
28	+		0.02	+	+	0.02	0.02	0.02	+	+				0.08
29	+		0.01	+		0.01	0.02	0.02	+	+				0.06
30			0.02	+		+	+	0.01	+					0.04
30+														
Total [%]	7.33	6.34	7.84	5.88	3.88	3.38	6.29	12.85	13.29	10.33	11.96	10.62		100.00
Mean Speed	8.97	10.16	10.60	8.38	9.01	8.91	10.26	11.67	10.01	9.90	11.33	10.63	-	10.26

Note: '+' indicates non-zero percentage <0.005%, blank indicates zero percentage

Table C-4 E06_S long-term wind speed and frequency distribution at 155 m

Monthly	Wind speed [m/s]	Valid wind speed data [months]	Valid direction data [months]
January	11.0	2.4	2.4
February	11.0	2.8	2.8
March	11.3	2.5	2.5
April	11.0	1.8	1.8
May	10.2	1.6	1.6
June	9.4	1.7	1.7
July	7.9	1.9	1.9
August	7.9	1.2	1.2
September	9.0	1.1	1.1
October	11.5	0.9	0.9
November	10.7	1.3	1.3
December	10.1	1.9	1.9
Annual	10.1		





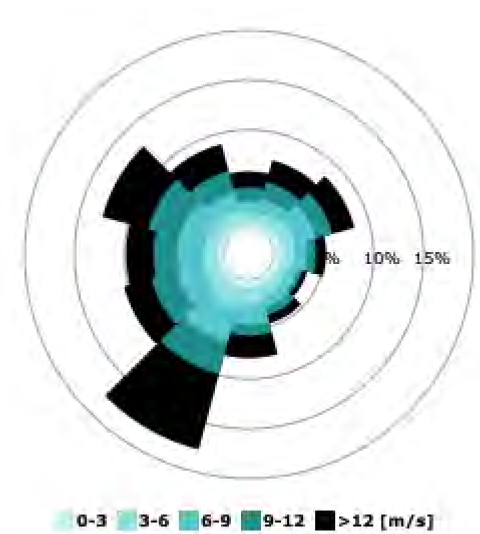
Wind speed and direction frequency distribution

Wind Speed [m/s]	0	30	60	90	120	150	180	210	240	270	300	330	No Direction	Total [%]
0	+	+	+	+	+	+	+	+	+	+	+	+		0.01
1	0.07	0.12	0.10	0.15	0.11	0.12	0.11	0.11	0.12	0.08	0.10	0.08		1.25
2	0.19	0.23	0.26	0.24	0.28	0.26	0.24	0.25	0.22	0.21	0.24	0.21		2.85
3	0.27	0.33	0.33	0.31	0.25	0.41	0.38	0.39	0.44	0.35	0.31	0.27		4.05
4	0.38	0.37	0.40	0.41	0.45	0.39	0.57	0.65	0.67	0.40	0.35	0.35		5.40
5	0.39	0.45	0.50	0.52	0.53	0.32	0.55	0.87	0.81	0.52	0.44	0.40		6.29
6	0.50	0.54	0.43	0.61	0.45	0.45	0.59	1.09	0.95	0.65	0.51	0.49		7.25
7	0.51	0.51	0.49	0.64	0.48	0.38	0.54	1.10	0.97	0.66	0.64	0.65		7.58
8	0.55	0.44	0.53	0.59	0.34	0.33	0.48	1.15	1.03	0.85	0.71	0.70		7.69
9	0.56	0.48	0.61	0.45	0.22	0.27	0.38	0.96	0.98	0.74	0.84	0.82		7.32
10	0.63	0.43	0.60	0.38	0.23	0.18	0.37	1.06	0.98	0.76	0.91	0.95		7.49
11	0.43	0.47	0.48	0.34	0.16	0.18	0.35	1.00	0.83	0.59	0.87	0.81		6.53
12	0.40	0.50	0.53	0.24	0.15	0.15	0.31	1.02	0.82	0.46	0.82	0.75		6.14
13	0.30	0.47	0.49	0.20	0.12	0.11	0.31	1.02	0.80	0.41	0.85	0.77		5.84
14	0.22	0.37	0.47	0.17	0.09	0.10	0.32	0.96	0.69	0.38	0.83	0.61		5.21
15	0.19	0.25	0.33	0.14	0.09	0.09	0.20	0.90	0.47	0.30	0.66	0.51		4.14
16	0.16	0.31	0.26	0.09	0.08	0.12	0.13	0.79	0.37	0.23	0.56	0.43		3.52
17	0.15	0.36	0.33	0.05	0.07	0.05	0.11	0.57	0.28	0.22	0.44	0.32		2.93
18	0.10	0.40	0.21	0.03	0.06	0.03	0.12	0.44	0.17	0.20	0.32	0.22		2.30
19	0.06	0.22	0.12	0.01	0.07	0.03	0.11	0.31	0.16	0.15	0.23	0.16		1.64
20	0.04	0.11	0.05	0.03	0.06	0.04	0.07	0.30	0.12	0.16	0.19	0.11		1.27
21	0.04	0.06	0.01	0.02	0.03	0.04	0.07	0.30	0.08	0.12	0.13	0.08		0.98
22	0.03	0.02	+	0.01	0.04	0.03	0.13	0.28	0.05	0.09	0.09	0.05		0.83
23	+	0.01	0.01	+	0.01	0.01	0.09	0.22	0.02	0.04	0.04	0.01		0.48
24		0.01	0.01	+	0.01	0.01	0.05	0.12	0.02	0.05	0.02	+		0.29
25	+		0.01	+	+	+	0.05	0.09	0.01	0.01	0.01			0.18
26	+		+	+	+	+	0.05	0.08	0.01	+				0.15
27	+		+	+		+	0.05	0.06	+	+				0.13
28			0.01	0.01		+	0.04	0.04	+					0.10
29			0.01			0.01	0.04	0.02	+					0.08
30			0.01			+	0.01	0.02	+					0.05
30+														
Total [%]	6.18	7.46	7.59	5.67	4.40	4.13	6.82	16.19	12.08	8.62	11.11	9.74		100.00
Mean Speed	9.19	10.36	9.95	7.99	7.95	7.90	9.95	11.53	9.73	10.02	11.13	10.60	-	10.08

Note: '+' indicates non-zero percentage <0.005%, blank indicates zero percentage

Table C-5 E05_SW long-term wind speed and frequency distribution at 155 m

Monthly	Wind speed [m/s]	Valid wind speed data [months]	Valid direction data [months]
January	10.9	0.9	0.9
February	11.7	0.9	0.9
March	11.8	0.9	0.9
April	11.0	0.9	0.9
May	12.1	0.8	0.8
June	8.8	0.9	0.9
July	8.5	1.0	1.0
August	7.2	1.0	1.0
September	8.4	0.9	0.9
October	9.6	0.9	0.9
November	10.5	1.0	1.0
December	10.9	0.9	0.9
Annual	10.1		



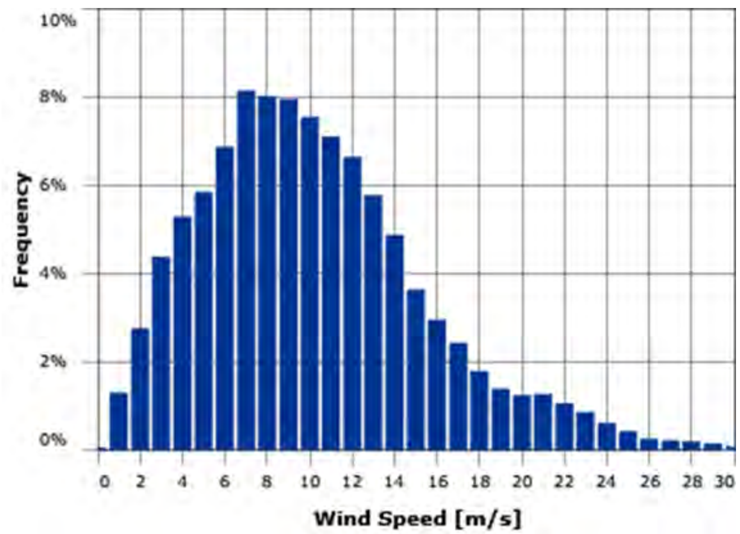


Table C-6 Wind speed and direction frequency distribution

Wind Speed [m/s]	0	30	60	90	120	150	180	210	240	270	300	330	No Direction	Total [%]
0	+	+	+	+	+	+	+	+	+	+	+	+		0.03
1	0.08	0.07	0.09	0.11	0.13	0.10	0.12	0.14	0.13	0.11	0.10	0.09		1.27
2	0.18	0.19	0.23	0.21	0.23	0.23	0.27	0.31	0.25	0.24	0.21	0.17		2.72
3	0.32	0.41	0.45	0.31	0.28	0.31	0.39	0.44	0.38	0.36	0.36	0.33		4.34
4	0.36	0.42	0.54	0.38	0.33	0.44	0.55	0.64	0.42	0.33	0.37	0.45		5.24
5	0.32	0.31	0.46	0.59	0.34	0.40	0.66	0.72	0.52	0.47	0.51	0.51		5.81
6	0.37	0.44	0.57	0.50	0.36	0.48	0.71	0.96	0.63	0.68	0.66	0.46		6.83
7	0.41	0.43	0.84	0.45	0.33	0.31	0.71	1.20	0.96	0.95	0.85	0.65		8.10
8	0.36	0.40	0.66	0.40	0.32	0.40	0.70	1.31	0.97	0.89	0.92	0.65		7.98
9	0.47	0.62	0.67	0.39	0.25	0.34	0.45	1.15	0.98	0.96	0.97	0.67		7.91
10	0.48	0.67	0.59	0.25	0.17	0.27	0.37	1.07	0.94	0.78	1.10	0.81		7.50
11	0.40	0.56	0.54	0.27	0.11	0.23	0.35	1.15	0.84	0.78	1.10	0.73		7.06
12	0.45	0.44	0.48	0.35	0.09	0.18	0.25	1.11	0.71	0.69	1.13	0.72		6.60
13	0.34	0.20	0.30	0.18	0.10	0.13	0.32	1.10	0.64	0.59	0.96	0.86		5.73
14	0.30	0.09	0.26	0.15	0.11	0.16	0.24	0.93	0.46	0.55	0.95	0.62		4.83
15	0.22	0.05	0.20	0.10	0.05	0.09	0.20	0.69	0.39	0.49	0.78	0.34		3.59
16	0.16	0.06	0.19	0.08	0.04	0.10	0.24	0.69	0.31	0.30	0.50	0.27		2.91
17	0.14	0.15	0.17	0.06	0.03	0.09	0.15	0.64	0.23	0.17	0.42	0.15		2.39
18	0.13	0.22	0.13	0.05	0.04	0.05	0.10	0.51	0.11	0.10	0.23	0.08		1.75
19	0.09	0.27	0.10	0.04	0.04	0.01	0.12	0.40	0.09	0.04	0.10	0.05		1.36
20	0.02	0.29	0.12	0.02	0.03	0.02	0.12	0.38	0.09	0.03	0.06	0.02		1.21
21	+	0.28	0.12	0.03	0.02	0.03	0.10	0.48	0.05	0.05	0.05	0.02		1.23
22	+	0.19	0.10	0.03	0.01	0.02	0.08	0.43	0.04	0.05	0.06	0.02		1.02
23	+	0.14	0.08	0.03	+	0.02	0.11	0.32	0.05	0.01	0.04	0.01		0.82
24	+	0.09	0.12	0.02	+	0.02	0.10	0.19	0.02	0.01	0.01			0.58
25	0.01	0.02	0.13	0.01		0.01	0.09	0.10	0.01		+	+		0.39
26	+	+	0.05	0.01		0.01	0.03	0.11	+			+		0.22
27		+	0.02	0.01		+	0.03	0.12	+	+				0.18
28				0.01		+	0.06	0.08	+	+				0.15
29				+		+	0.04	0.06	+					0.11
30				+			0.01	0.03	+					0.05
30+														
Total [%]	5.62	7.02	8.21	5.05	3.40	4.49	7.69	17.52	10.22	9.63	12.45	8.70		100.00
Mean Speed	9.44	10.91	9.98	8.39	7.32	8.24	9.96	12.00	9.70	9.63	10.60	9.78	-	10.12

Note: '+' indicates non-zero percentage <0.005%, blank indicates zero percentage

C.4 Turbine availability assumptions

For the purposes of this analysis, DNV has made the following preliminary assumptions to derive a starting assumption for the turbine availability loss profile (loss category 2a):

a) Projects with similar project characteristics and wave and wind conditions present similar availabilities in other regions in comparison with those experienced in the North Sea. Based on this assumption, the projected turbine availability is therefore based on North Sea experience. DNV considers this to be a reasonable starting assumption for projects in other regions in the absence of a more detailed project specific review of the O&M access strategy and metocean conditions at the site, as this is supported by previous experience and extensive modelling performed by DNV.

b) The project operates or is to operate with an optimal number of technicians, therefore values are only representative when the number of staff is well planned.

c) Main component replacements are performed using a Jack-Up vessel with an average lead time to get to the site of 45 days. This is the typical expected value based on operational experience in the North Sea, however this is expected to be different in the future and in different markets.

d) Turbine reliability is based on experienced turbine manufacturers therefore only valid for projects considering models from offshore experienced turbine suppliers. If the project is considering newer turbine models the validity of this projection is to be regarded with caution and a project specific review is recommended.

e) A turbine availability loss penalty of 1% is applied for floating turbine technology.

Based on these assumptions, DNV has estimated an indicative starting assumption for turbine availability for the following project characteristics:

Table C-7 Turbine availability loss assumptions

Project characteristic	Value assumed for modelling	Source of assumption
Distance to O&M port [nautical miles]:	N/A	DNV
Mean long-term significant wave height [m]:	1.8	DNV
Assumed Drive Train Concept:	Direct Drive	DNV
Ramp up expected [in increase of %]:	3%	DNV
Ramp up period [in years]:	5.0	DNV
Period evaluated [in years]:	See main body of report	Customer
Access strategy expected:	1 Service operations vessel, 1 crew transfer vessel, and 1 daughter craft	DNV

DNV has selected these values based on high-level assumptions. It is expected that these assumptions will change as the projects are developed further and a commercially available turbine model is identified for the site. At this later stage of the project, it is recommended that the estimated turbine availability for the project should be updated.

C.4.1 References

[C-1] Failure rate, repair time and unscheduled O&M cost analysis of offshore wind turbines, Carroll et al, https://pure.strath.ac.uk/portal/files/44298789/Carroll_etal_WE_2015_Failure_rate_repair_time_and_unscheduled_O_and_M_cost_analysis_of_offshore.pdf, University of Strathclyde, first published 6 August 2015.

C.5 Energy results

Table C-8 Energy results, Indicative layout 01 (25 years)

Turbine	Turbine model	Hub-height [m]	Initiation device	Easting[a] [m]	Northing[a] [m]	Elevation [m]	Long-term wind speed at hub-height[b] [m/s]	Energy output[c] [GWh/ annum]	Turbine interaction loss factor[d] [%]
T1	Theoretical 15 MW	140	E05_N	793,132	4,357,815	0	10.1	66.9	98.3
T2	Theoretical 15 MW	140	E05_N	794,508	4,355,311	0	10.1	66.3	97.5
T3	Theoretical 15 MW	140	E05_N	795,885	4,352,807	0	10.1	65.9	97.0
T4	Theoretical 15 MW	140	E05_N	797,261	4,350,304	0	10.1	65.8	96.8
T5	Theoretical 15 MW	140	E05_N	798,638	4,347,799	0	10.1	65.6	96.6
T6	Theoretical 15 MW	140	E05_N	800,014	4,345,295	0	10.1	65.5	96.5
T7	Theoretical 15 MW	140	E05_N	801,391	4,342,791	0	10.1	65.5	96.4
T8	Theoretical 15 MW	140	E05_N	802,767	4,340,287	0	10.1	65.6	96.7
T9	Theoretical 15 MW	140	E05_N	795,988	4,357,755	0	10.1	65.9	96.9
T10	Theoretical 15 MW	140	E05_N	797,365	4,355,252	0	10.1	65.2	95.9
T11	Theoretical 15 MW	140	E05_N	798,742	4,352,748	0	10.1	64.8	95.4
T12	Theoretical 15 MW	140	E05_N	800,118	4,350,244	0	10.1	64.6	95.1
T13	Theoretical 15 MW	140	E05_N	801,495	4,347,739	0	10.1	64.4	94.8
T14	Theoretical 15 MW	140	E05_N	802,871	4,345,235	0	10.1	64.3	94.7
T15	Theoretical 15 MW	140	E05_N	804,248	4,342,731	0	10.1	64.4	95.0
T16	Theoretical 15 MW	140	E05_N	805,624	4,340,227	0	10.1	64.8	95.6
T17	Theoretical 15 MW	140	E05_N	797,468	4,360,200	0	10.1	66.3	97.4
T18	Theoretical 15 MW	140	E05_N	798,845	4,357,696	0	10.1	65.3	96.0
T19	Theoretical 15 MW	140	E05_N	800,222	4,355,192	0	10.1	64.8	95.4
T20	Theoretical 15 MW	140	E05_N	801,599	4,352,688	0	10.1	64.5	94.9
T21	Theoretical 15 MW	140	E05_N	802,975	4,350,184	0	10.1	64.3	94.7
T22	Theoretical 15 MW	140	E05_N	804,352	4,347,679	0	10.1	64.1	94.3
T23	Theoretical 15 MW	140	E05_N	805,728	4,345,175	0	10.1	64.1	94.4
T24	Theoretical 15 MW	140	E05_N	807,105	4,342,671	0	10.1	64.2	94.6
T25	Theoretical 15 MW	140	E05_N	808,481	4,340,166	0	10.1	65.0	95.9
T26	Theoretical 15 MW	140	E05_N	800,325	4,360,140	0	10.1	65.4	96.2
T27	Theoretical 15 MW	140	E05_N	801,702	4,357,636	0	10.1	64.8	95.3
T28	Theoretical 15 MW	140	E05_N	803,079	4,355,132	0	10.1	64.3	94.6
T29	Theoretical 15 MW	140	E05_N	804,456	4,352,628	0	10.1	64.1	94.4
T30	Theoretical 15 MW	140	E05_N	805,832	4,350,124	0	10.1	63.9	94.0
T31	Theoretical 15 MW	140	E05_N	807,209	4,347,619	0	10.1	63.7	93.9
T32	Theoretical 15 MW	140	E05_N	808,585	4,345,115	0	10.1	63.8	94.0

Turbine	Turbine model	Hub-height [m]	Initiation device	Easting[a] [m]	Northing[a] [m]	Elevation [m]	Long-term wind speed at hub-height[b] [m/s]	Energy output[c] [GWh/ annum]	Turbine interaction loss factor[d] [%]
T33	Theoretical 15 MW	140	E05_N	809,962	4,342,611	0	10.1	64.1	94.5
T34	Theoretical 15 MW	140	E05_N	801,805	4,362,585	0	10.1	66.1	97.1
T35	Theoretical 15 MW	140	E05_N	803,182	4,360,081	0	10.1	65.0	95.6
T36	Theoretical 15 MW	140	E05_N	804,559	4,357,577	0	10.1	64.5	94.8
T37	Theoretical 15 MW	140	E05_N	805,936	4,355,072	0	10.1	64.1	94.4
T38	Theoretical 15 MW	140	E05_N	808,689	4,350,064	0	10.1	64.0	94.2
T39	Theoretical 15 MW	140	E05_N	810,066	4,347,559	0	10.1	63.7	93.8
T40	Theoretical 15 MW	140	E05_N	811,443	4,345,055	0	10.1	63.9	94.2
T41	Theoretical 15 MW	140	E05_N	812,819	4,342,550	0	10.1	64.6	95.2
T42	Theoretical 15 MW	140	E05_N	804,662	4,362,525	0	10.1	65.3	95.9
T43	Theoretical 15 MW	140	E05_N	806,039	4,360,021	0	10.1	64.5	94.7
T44	Theoretical 15 MW	140	E05_N	807,416	4,357,517	0	10.1	64.1	94.3
T45	Theoretical 15 MW	140	E05_N	808,793	4,355,013	0	10.1	63.9	94.0
T46	Theoretical 15 MW	140	E05_N	810,170	4,352,508	0	10.1	63.7	93.8
T47	Theoretical 15 MW	140	E05_N	811,547	4,350,004	0	10.1	63.6	93.6
T48	Theoretical 15 MW	140	E05_N	812,923	4,347,499	0	10.1	63.7	93.8
T49	Theoretical 15 MW	140	E05_N	814,300	4,344,995	0	10.1	63.9	94.1
T50	Theoretical 15 MW	140	E05_N	806,142	4,364,970	0	10.1	66.0	96.8
T51	Theoretical 15 MW	140	E05_N	807,519	4,362,466	0	10.1	64.8	95.2
T52	Theoretical 15 MW	140	E05_N	808,896	4,359,961	0	10.1	64.3	94.5
T53	Theoretical 15 MW	140	E05_N	810,273	4,357,457	0	10.1	64.0	94.1
T54	Theoretical 15 MW	140	E05_N	811,650	4,354,953	0	10.1	63.8	93.9
T55	Theoretical 15 MW	140	E05_N	813,027	4,352,448	0	10.1	63.6	93.6
T56	Theoretical 15 MW	140	E05_N	814,404	4,349,944	0	10.1	63.8	93.9
T57	Theoretical 15 MW	140	E05_N	815,781	4,347,439	0	10.1	63.9	94.1
T58	Theoretical 15 MW	140	E05_N	817,157	4,344,935	0	10.1	64.7	95.3
T59	Theoretical 15 MW	140	E05_N	807,622	4,367,414	0	10.1	66.6	97.7
T60	Theoretical 15 MW	140	E05_N	808,999	4,364,910	0	10.1	65.4	96.0
T61	Theoretical 15 MW	140	E05_N	810,377	4,362,406	0	10.1	65.2	95.7
T62	Theoretical 15 MW	140	E05_N	811,754	4,359,902	0	10.1	64.7	95.1
T63	Theoretical 15 MW	140	E05_N	813,131	4,357,398	0	10.1	64.5	94.8
T64	Theoretical 15 MW	140	E05_N	814,508	4,354,893	0	10.1	64.3	94.5
T65	Theoretical 15 MW	140	E05_N	815,884	4,352,389	0	10.1	64.3	94.6
T66	Theoretical 15 MW	140	E05_N	817,261	4,349,884	0	10.1	64.4	94.8
T67	Theoretical 15 MW	140	E05_N	818,638	4,347,379	0	10.1	64.7	95.2
Average						**0**	**10.1**	**64.7**	**95.2**
Total								**4333.9**	

a. Co-ordinate system is UTM 18N, NAD83.

b. Wind speed at the location of the turbine, not including wake effects.

c. Individual turbine output figures include all wind farm losses.

d. Individual turbine wake loss including all turbine interaction effects (wakes and blockage).

Table C-9 Energy results, Indicative layout 02 (25 years)

Turbine	Turbine model	Hub-height [m]	Initiation device	Easting[a] [m]	Northing[a] [m]	Elevation [m]	Long-term wind speed at hub-height[b] [m/s]	Energy output[c] [GWh/ annum]	Turbine interaction loss factor[d] [%]
T9	Theoretical 18 MW	155	E05_N	795,988	4,357,755	0	10.2	78.6	98.0
T10	Theoretical 18 MW	155	E05_N	797,365	4,355,252	0	10.2	77.9	97.2
T11	Theoretical 18 MW	155	E05_N	798,742	4,352,748	0	10.2	77.5	96.8
T12	Theoretical 18 MW	155	E05_N	800,118	4,350,244	0	10.2	77.4	96.6
T13	Theoretical 18 MW	155	E05_N	801,495	4,347,739	0	10.2	77.2	96.5
T14	Theoretical 18 MW	155	E05_N	802,871	4,345,235	0	10.2	77.0	96.3
T15	Theoretical 18 MW	155	E05_N	804,248	4,342,731	0	10.2	77.3	96.6
T16	Theoretical 18 MW	155	E05_N	805,624	4,340,227	0	10.2	77.6	97.1
T17	Theoretical 18 MW	155	E05_N	797,468	4,360,200	0	10.2	78.4	97.8
T18	Theoretical 18 MW	155	E05_N	798,845	4,357,696	0	10.2	77.1	96.2
T19	Theoretical 18 MW	155	E05_N	800,222	4,355,192	0	10.2	76.6	95.6
T20	Theoretical 18 MW	155	E05_N	801,599	4,352,688	0	10.2	76.2	95.2
T21	Theoretical 18 MW	155	E05_N	802,975	4,350,184	0	10.2	76.0	94.9
T22	Theoretical 18 MW	155	E05_N	804,352	4,347,679	0	10.2	75.8	94.7
T23	Theoretical 18 MW	155	E05_N	805,728	4,345,175	0	10.2	75.6	94.5
T24	Theoretical 18 MW	155	E05_N	807,105	4,342,671	0	10.2	76.0	95.0
T26	Theoretical 18 MW	155	E05_N	800,325	4,360,140	0	10.2	77.6	96.7
T27	Theoretical 18 MW	155	E05_N	801,702	4,357,636	0	10.2	76.7	95.7
T28	Theoretical 18 MW	155	E05_N	803,079	4,355,132	0	10.2	76.2	95.1
T29	Theoretical 18 MW	155	E05_N	804,456	4,352,628	0	10.2	76.1	94.9
T30	Theoretical 18 MW	155	E05_N	805,832	4,350,124	0	10.2	75.8	94.6
T31	Theoretical 18 MW	155	E05_N	807,209	4,347,619	0	10.2	75.6	94.5
T32	Theoretical 18 MW	155	E05_N	808,585	4,345,115	0	10.2	75.6	94.4
T33	Theoretical 18 MW	155	E05_N	809,962	4,342,611	0	10.2	76.2	95.3
T34	Theoretical 18 MW	155	E05_N	801,805	4,362,585	0	10.2	78.1	97.3
T35	Theoretical 18 MW	155	E05_N	803,182	4,360,081	0	10.2	76.7	95.6
T36	Theoretical 18 MW	155	E05_N	804,559	4,357,577	0	10.2	76.0	94.8
T37	Theoretical 18 MW	155	E05_N	805,936	4,355,072	0	10.2	75.7	94.4
T38	Theoretical 18 MW	155	E05_N	808,689	4,350,064	0	10.2	75.3	94.1
T39	Theoretical 18 MW	155	E05_N	810,066	4,347,559	0	10.2	75.1	93.8
T40	Theoretical 18 MW	155	E05_N	811,443	4,345,055	0	10.2	75.2	93.9
T41	Theoretical 18 MW	155	E05_N	812,819	4,342,550	0	10.2	76.6	95.7
T42	Theoretical 18 MW	155	E05_N	804,662	4,362,525	0	10.2	77.3	96.2
T43	Theoretical 18 MW	155	E05_N	806,039	4,360,021	0	10.2	76.4	95.3
T44	Theoretical 18 MW	155	E05_N	807,416	4,357,517	0	10.2	75.9	94.6
T45	Theoretical 18 MW	155	E05_N	808,793	4,355,013	0	10.2	75.8	94.6
T46	Theoretical 18 MW	155	E05_N	810,170	4,352,508	0	10.2	75.4	94.1

Turbine	Turbine model	Hub-height [m]	Initiation device	Easting[a] [m]	Northing[a] [m]	Elevation [m]	Long-term wind speed at hub-height[b] [m/s]	Energy output[c] [GWh/ annum]	Turbine interaction loss factor[d] [%]
T47	Theoretical 18 MW	155	E05_N	811,547	4,350,004	0	10.2	75.3	94.0
T48	Theoretical 18 MW	155	E05_N	812,923	4,347,499	0	10.2	75.3	94.0
T49	Theoretical 18 MW	155	E05_N	814,300	4,344,995	0	10.2	75.8	94.7
T50	Theoretical 18 MW	155	E05_N	806,142	4,364,970	0	10.2	78.0	97.1
T51	Theoretical 18 MW	155	E05_N	807,519	4,362,466	0	10.2	76.5	95.3
T52	Theoretical 18 MW	155	E05_N	808,896	4,359,961	0	10.2	75.9	94.6
T53	Theoretical 18 MW	155	E05_N	810,273	4,357,457	0	10.2	75.5	94.1
T54	Theoretical 18 MW	155	E05_N	811,650	4,354,953	0	10.2	75.3	93.9
T55	Theoretical 18 MW	155	E05_N	813,027	4,352,448	0	10.2	75.0	93.6
T56	Theoretical 18 MW	155	E05_N	814,404	4,349,944	0	10.2	75.0	93.6
T57	Theoretical 18 MW	155	E05_N	815,781	4,347,439	0	10.2	75.3	94.1
T60	Theoretical 18 MW	155	E05_N	808,999	4,364,910	0	10.2	77.5	96.5
T61	Theoretical 18 MW	155	E05_N	810,377	4,362,406	0	10.2	76.7	95.6
T62	Theoretical 18 MW	155	E05_N	811,754	4,359,902	0	10.2	76.3	95.1
T63	Theoretical 18 MW	155	E05_N	813,131	4,357,398	0	10.2	76.0	94.8
T64	Theoretical 18 MW	155	E05_N	814,508	4,354,893	0	10.2	75.9	94.7
T65	Theoretical 18 MW	155	E05_N	815,884	4,352,389	0	10.2	75.8	94.6
T66	Theoretical 18 MW	155	E05_N	817,261	4,349,884	0	10.2	76.2	95.1
T67	Theoretical 18 MW	155	E05_N	818,638	4,347,379	0	10.2	76.9	96.0
Average						**0**	**10.2**	**76.4**	**95.3**
Total								**4275.6**	

a. Co-ordinate system is UTM 18N, NAD83.
b. Wind speed at the location of the turbine, not including wake effects.
c. Individual turbine output figures include all wind farm losses.
d. Individual turbine wake loss including all turbine interaction effects (wakes and blockage).

C.6 Seasonal and diurnal variation

Table C-10 Relative hourly and monthly energy production [a] [%], Indicative layout 01

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0000	0.42	0.38	0.42	0.42	0.44	0.39	0.31	0.25	0.28	0.35	0.40	0.42
0100	0.42	0.40	0.42	0.41	0.44	0.37	0.29	0.24	0.28	0.34	0.39	0.40
0200	0.41	0.41	0.42	0.40	0.43	0.36	0.27	0.23	0.28	0.35	0.38	0.39
0300	0.40	0.41	0.42	0.40	0.43	0.35	0.26	0.24	0.28	0.35	0.38	0.40
0400	0.40	0.42	0.42	0.38	0.40	0.33	0.25	0.24	0.28	0.34	0.37	0.39
0500	0.40	0.42	0.42	0.37	0.37	0.33	0.26	0.24	0.27	0.34	0.36	0.39
0600	0.39	0.41	0.43	0.38	0.36	0.32	0.26	0.24	0.27	0.34	0.35	0.38
0700	0.39	0.42	0.45	0.38	0.34	0.30	0.25	0.24	0.27	0.34	0.35	0.38
0800	0.40	0.43	0.44	0.37	0.33	0.29	0.23	0.23	0.27	0.35	0.34	0.38
0900	0.40	0.42	0.42	0.36	0.32	0.27	0.22	0.23	0.28	0.36	0.35	0.38
1000	0.40	0.39	0.40	0.35	0.30	0.26	0.21	0.23	0.28	0.36	0.36	0.38
1100	0.40	0.38	0.38	0.35	0.29	0.26	0.21	0.23	0.27	0.34	0.35	0.38
1200	0.40	0.36	0.36	0.35	0.29	0.27	0.21	0.22	0.26	0.33	0.36	0.38
1300	0.40	0.35	0.35	0.34	0.28	0.27	0.21	0.22	0.26	0.33	0.36	0.39
1400	0.40	0.35	0.36	0.35	0.28	0.27	0.21	0.23	0.27	0.33	0.38	0.40
1500	0.40	0.35	0.36	0.37	0.30	0.29	0.24	0.25	0.27	0.34	0.38	0.41
1600	0.41	0.35	0.36	0.38	0.32	0.31	0.27	0.25	0.27	0.33	0.39	0.42
1700	0.41	0.35	0.36	0.37	0.33	0.33	0.28	0.26	0.28	0.33	0.40	0.43
1800	0.40	0.35	0.37	0.36	0.35	0.35	0.29	0.28	0.29	0.33	0.40	0.44
1900	0.41	0.35	0.38	0.37	0.39	0.37	0.30	0.29	0.30	0.34	0.41	0.45
2000	0.42	0.35	0.39	0.40	0.42	0.37	0.31	0.29	0.30	0.35	0.40	0.44
2100	0.43	0.38	0.41	0.40	0.42	0.38	0.32	0.29	0.30	0.35	0.40	0.43
2200	0.43	0.39	0.41	0.40	0.43	0.37	0.32	0.28	0.30	0.35	0.39	0.42
2300	0.43	0.38	0.41	0.41	0.44	0.38	0.31	0.27	0.29	0.35	0.40	0.42
All	**9.77**	**9.18**	**9.55**	**9.06**	**8.71**	**7.78**	**6.28**	**6.00**	**6.72**	**8.22**	**9.05**	**9.67**

a. Only wake and hysteresis are included in the calculation.

Table C-11 Relative hourly and monthly energy production [a] [%], Indicative layout 02

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0000	0.42	0.40	0.42	0.43	0.45	0.39	0.31	0.25	0.29	0.34	0.39	0.41
0100	0.42	0.41	0.42	0.42	0.44	0.38	0.29	0.24	0.29	0.35	0.39	0.40
0200	0.41	0.41	0.42	0.41	0.44	0.36	0.27	0.23	0.28	0.35	0.39	0.39
0300	0.41	0.42	0.43	0.40	0.43	0.35	0.26	0.23	0.28	0.35	0.38	0.40
0400	0.40	0.42	0.42	0.38	0.40	0.33	0.25	0.24	0.28	0.34	0.37	0.40
0500	0.40	0.42	0.43	0.37	0.37	0.32	0.26	0.24	0.27	0.34	0.36	0.39
0600	0.39	0.41	0.44	0.38	0.36	0.31	0.26	0.24	0.27	0.34	0.36	0.38
0700	0.39	0.42	0.45	0.38	0.34	0.30	0.25	0.24	0.27	0.34	0.35	0.38
0800	0.40	0.42	0.44	0.37	0.32	0.28	0.23	0.23	0.27	0.35	0.34	0.38
0900	0.40	0.42	0.43	0.36	0.31	0.26	0.22	0.23	0.28	0.36	0.35	0.38
1000	0.40	0.39	0.40	0.34	0.29	0.25	0.20	0.23	0.28	0.36	0.36	0.38
1100	0.40	0.38	0.39	0.35	0.29	0.26	0.20	0.23	0.27	0.34	0.35	0.38
1200	0.39	0.36	0.37	0.34	0.29	0.27	0.21	0.22	0.26	0.33	0.36	0.38
1300	0.40	0.35	0.35	0.34	0.28	0.27	0.20	0.22	0.26	0.32	0.36	0.39
1400	0.40	0.35	0.36	0.35	0.28	0.27	0.21	0.23	0.26	0.33	0.38	0.40
1500	0.40	0.35	0.36	0.36	0.30	0.29	0.24	0.25	0.27	0.34	0.38	0.41
1600	0.41	0.36	0.36	0.38	0.32	0.31	0.27	0.25	0.27	0.33	0.39	0.42
1700	0.40	0.35	0.37	0.38	0.33	0.32	0.28	0.26	0.28	0.34	0.40	0.43
1800	0.40	0.35	0.37	0.36	0.36	0.34	0.29	0.27	0.29	0.33	0.40	0.44
1900	0.41	0.35	0.38	0.37	0.40	0.37	0.30	0.28	0.30	0.34	0.41	0.45
2000	0.42	0.35	0.39	0.39	0.41	0.37	0.32	0.29	0.30	0.35	0.40	0.44
2100	0.43	0.38	0.40	0.40	0.43	0.38	0.32	0.29	0.30	0.35	0.39	0.43
2200	0.42	0.39	0.41	0.40	0.43	0.37	0.32	0.28	0.30	0.35	0.39	0.42
2300	0.42	0.39	0.41	0.41	0.44	0.38	0.31	0.27	0.29	0.35	0.40	0.41
All	**9.73**	**9.24**	**9.60**	**9.07**	**8.72**	**7.73**	**6.27**	**5.97**	**6.71**	**8.22**	**9.04**	**9.70**

a. Only wake and hysteresis are included in the calculation.

APPENDIX D – REVISIONS

Customer Name:	New York State Energy Research and Development Authority	DNV Entity:	DNV Energy USA Inc.
Customer Address:	1359 Broadway New York, NY 10018	DNV Address:	101 Station Landing, Suite 520 Medford, MA 02155 USA
Contact person:	Jessica Dealy	DNV Tel.:	781-273-5700
Project name:	East Coast Zone 3	DNV Enterprise No.:	23-2625724
Report title:	Offshore Wind Resource Assessment		
Date of issue:	7 April 2025		
Project No.:	10434276		
Document No.:	10434276-HOU-R-01-I		
Status:	Final		

Task and objective: To complete an independent assessment of the wind climate and energy production for the Project.

Prepared by:	Verified by:	Approved by:
Émilie Chénier Wind Energy Analyst	Jessica Mason Senior Engineer	Elizabeth Traiger Team Leader, Wind Energy Assessment
	Arthur Burden Senior Wind Energy Analyst	Onur Kaprol Head of Section, Wind Energy Assessment

Distribution outside of DNV:

☐ Published	Available for information only to the general public (subject to the above Important Notice and Disclaimer).
☒ Customer's Discretion	Distribution for information only at the discretion of the Customer (subject to the above Important Notice and Disclaimer and the terms of DNV's written agreement with the Customer).
☐ Confidential	Not to be disclosed outside the Customer's organization.
☐ None	Not to be disclosed outside of DNV.

Issue	Date	Reason for Issue	Prepared by	Verified by	Approved by
A	10 April 2023	Initial issue for review	É. Chénier	J. Mason	E. Traiger, O. Kaprol
B	28 July 2023	Wind speed map added and text edits	É. Chénier	A. Burden	E. Traiger
C	14 August 2023	Text edits	É. Chénier	A. Burden	E. Traiger
D	3 November 2023	Text edits	É. Chénier	A. Burden	E. Traiger
E	9 February 2024	Text edits	É. Chénier	A. Burden	E. Traiger
F	8 March 2024	Text edits	É. Chénier	A. Burden	E. Traiger
G	25 March 2024	Accessibility Updates	É. Chénier	A. Burden	E. Traiger
H	2 April 2025	Text edits: No changes to methodology or analysis.	É. Chénier	A. Burden	E. Traiger
I	7 April 2025	Final Issue	É. Chénier	A. Burden	E. Traiger

About DNV

We are the independent expert in assurance and risk management. Driven by our purpose, to safeguard life, property and the environment, we empower our customers and their stakeholders with facts and reliable insights so that critical decisions can be made with confidence. As a trusted voice for many of the world's most successful organizations, we use our knowledge to advance safety and performance, set industry benchmarks, and inspire and invent solutions to tackle global transformations.

NYSERDA, a public benefit corporation, offers objective information and analysis, innovative programs, technical expertise, and support to help New Yorkers increase energy efficiency, save money, use renewable energy, and reduce reliance on fossil fuels. NYSERDA professionals work to protect the environment and create clean-energy jobs. NYSERDA has been developing partnerships to advance innovative energy solutions in New York State since 1975.

To learn more about NYSERDA's programs and funding opportunities, visit nyserda.ny.gov or follow us on X, Facebook, YouTube, or Instagram.

New York State Energy Research and Development Authority

17 Columbia Circle
Albany, NY 12203-6399

toll free: 866-NYSERDA
local: 518-862-1090
fax: 518-862-1091

info@nyserda.ny.gov
nyserda.ny.gov

NYSERDA
New York State Energy Research and Development Authority

State of New York
Kathy Hochul, Governor

New York State Energy Research and Development Authority
Richard L. Kauffman, Chair | Doreen M. Harris, President and CEO