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MASTER'S THESIS

Lifetime extension and Repowering of Offshore Wind Farm – Financial viability, GHG reduction, and Monopile reinforcement.

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WESTERN NORWAY UNIVERSITY OF APPLIED SCIENCES, HAUGESUND

MASTER OF SCIENCE IN MARITIME OPERATIONS

MMO5017: MASTER THESIS

LIFETIME EXTENSION & REPOWERING OF OFFSHORE WIND FARM

Financial viability, GHG reduction, and monopile reinforcement

Student Matriculation Number

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Preface

This is a 30-credit point Master thesis written as the final work for the award of Master of Maritime Operations degree with specialization in Offshore and Subsea Operations at the Western Norway University of Applied Science, Haugesund, Norway.

The thesis research was conducted as part of the DecomTools project which is funded by the EU in the programme “Interreg VB North Sea Region programme”. DecomTools is led by Marcus Bentin from the University of Applied Sciences Hochschule Emden/Leer, Germany. Jens Christian Lindaas is the lead person on the team from Western Norway University of Applied Sciences, Haugesund, Norway.

A decision tool for offshore wind farm lifetime extension/repowering from an energy production cost (financial viability) and a greenhouse gas (GHG) reduction perspective is presented. Also, an optimised design of monopile reinforcement for additional load support of offshore wind turbine was presented. The design concept used was the distribution of load and reinforcement clamp apparatus. It addresses the need to use the existing offshore wind turbine monopile foundation for a second lifetime (repowering). I hope that the offshore wind industry would find the optimised design in this thesis useful in her repowering decisions.

The work on this thesis has been mainly literature review and critical reasoning, however, a series of discussions with the DecomTools team and interviews with experts in the wind industry has also been a part of the process.

It has been fascinating and rewarding to be able to write a master's thesis on a new sector of the industry.

Abstract

Offshore wind is the fastest-growing sustainable energy source gradually replacing fossil fuels. Aside from addressing arising challenges like logistic, infrastructure, and recycling, there is the challenge of making the right end-of-life (EoL) decision. The discussion is whether these offshore wind turbines can last longer than their 20 to 25-year design life. At the end of the technical lifetime or economic lifecycle, their lifetime has to be extended, repowered or decommissioned. The decision to extend the lifetime or repower an offshore wind farm depends on several factors such as site conditions, regulations, technology, and profitability.

The core of this thesis is to compare several EoL options in terms of energy production costs and GHG reduction. The thesis includes a case study on Horns Rev 1 OWF, in which four distinct EoL scenarios are compared in terms of energy production cost and GHG reduction using technical and financial performance. RETScreen Expert software was used to analyse the feasibility of all scenarios.

The result of the case study shows that lifetime extension is more financially viable and has the highest gross annual GHG reduction. Next in line was partial repowering.

The optimised design shows theoretically that an installed monopile can be reinforced to carry a bigger turbine load by distributing the load to additional piles.

Dedication

to

God Almighty

for keeping me in divine health

to

my Dad & Mom

for giving me everything humanly possible

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A big thank you to my colleagues at HVL Haugesund and HS Emden/Leer. Johnbull Daere who is not only my house and classmate, but also did a good job in contributing to this thesis. Ahmed Askari who played a vital role in my research. And to my buddy Merle Nache, who has made my stay in Germany full of happy memories. Not only is our network a gathering of brilliant minds, but it's also a lot of fun.

My sincere thanks goes to Glad Nuhu, Duke Osain, Sagira Abdul, Marvlus Isreal, and Pst. Minika for making me feel at home in Norway. And to my friends in Nigeria, Philippines, Norway, Germany, and everywhere else. Thank you for the good times and the serious moments, and for constantly stretching my intellect.

Thank you! Salamat Po! Dankeschön! Tusen takk!

Nomenclature

Abbreviations

AEP Annual Energy Production

DECEX Decommissioning expenditure

EoL End of Life

IRR Internal Rate of Return

LCoE Levelized Cost of Energy

NPV Net Present Value

TSO Transmission System Operator

WACC Weighted Average Cost of Capital

ABEX Abandonment expenditure

CAPEX Capital expenditure

CB Cost breakdown structure

DEVEX Development expenditure

GW Gigawatt (1 GW = 1000 MW)

LCCA Life-cycle cost analysis

M€ Million Euro

MW Megawatt (1 MW = 1,000,000 W)

MWh Megawatt hour (1 MWh = 1,000,000 Wh)

OPEX Operating expenditure

OWF(s) Offshore Wind Farm(s)

OWT(s)	Offshore Wind Turbine(s)
SA	Sensitivity analysis
SOV	Service operation vessel
WACC	The weighted average cost of capital
Wh	Watt hour, one watt (1 W) of power expended for one hour (1 h) of time
WT(s)	Wind Turbine(s)
CE	Circular Economy
DEA	Danish Energy Agency
EU	European Union
GFRP	Glass-Fiber-Reinforced Polymer
GHG	Green House Gas
IRENA	International Renewable Energy Agency
LCA	Life Cycle Assessment
LCI	Life Cycle Inventory
LCIA	Life Cycle Impact Assessment
MCI	Material Circularity Index
MFA	Material Flow Analysis
OWF	Offshore Wind Farm
REE	Rare Earth Elements
REPA	Resource and Environmental Profile Analysis
SPIV	Self-propelled installation vessel
UNEP	United Nations Environmental Program

EEOI Energy Efficiency Operational Index

CO2 Carbon Dioxide

IMO International Maritime Organization

j the fuel type

i the voyage number

FCij the mass of consumed fuel j at voyage i

CFj the fuel mass to CO2 mass conversion factor for fuel j

m_{cargo} cargo carried (tonnes) or work done (number of TEU or passengers) or gross tonnes for passenger ships

D distance (in nautical miles) corresponding to the cargo carried or work done

TEU Twenty-foot Equivalent Unit

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INTRODUCTION

1.1. BACKGROUND OF STUDY

Wind energy continues to gain traction in the global energy mix, displacing long-established fossil fuels. Companies in the oil and gas sector are now looking for alternate methods to diversify their operations, embrace the fast moving energy transition, and expand investment in renewable energy projects as a result of mounting pressure to reduce their environmental effect and falling oil demand. Nonetheless, whether in oil and gas or renewable energy, all assets have one thing in common: they age, and the amount of assets and materials that must be safely disposed of at the end of their useful lives is staggering.

In 2019, Wind Europe set a goal of producing 450 GW from OWFs by 2050, which will cover 30% of Europe's power consumption (WindEurope, 2019). By 2035, more than 3.5GW of worldwide offshore wind power will have reached the end of its useful life. The wind industry's first aim in its efforts to produce an alternate source of energy to fossil fuels was to accelerate deployment and significantly cut energy prices (Spyroudi, 2021).

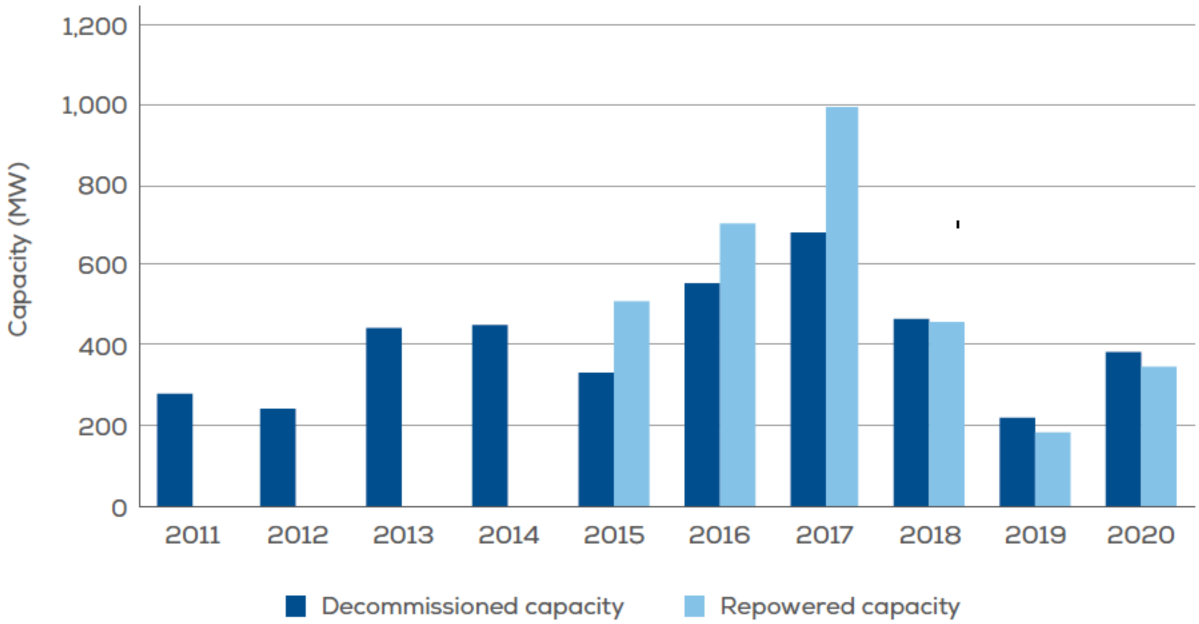
The default option is decommissioning, which requires developers to remove all wind farm components in order to return the seafloor to its original state. Besides that, because offshore wind growth is increasing and the present fleet is aging, it is now time to investigate alternate and more sustainable solutions for offshore wind sites beyond a 25-year lifetime. Increasing the lifetime of existing assets and repowering the farm preserves and enhances their utilization, frequently resulting in greater returns, cheaper maintenance and operation costs, and environmental advantages.

In the next decade, 2,624 wells, over 1.2 million tonnes of topsides, and about 675,000 tonnes of substructures will need to be repaired or replaced, removed, and sealed on offshore O&G sites (OGUK, 2019). Current techniques allow for the removal of 98% of the materials, with a little proportion being recycled; nonetheless, reuse and remanufacturing should be strongly regarded as the preferred choice. Decommissioning costs are expected to total 77.6 B€ over the next decade, with 7.61 B€ allocated to the UKCS alone (OGUK, 2019). The majority of these structures were erected in the 1970s with little thought given to disposal techniques at the end of their useful lives, and choices were made few years before production ended. The wind industry has set a goal to lower existing high decommissioning costs by about 35% while also improving awareness of current rules, updating law and relevant guidelines, and encouraging data exchange, best practices, and cost-effective conformity.

Because of economic restrictions, many projects are opting for life extension rather than repowering. Other considerations like as regulatory difficulties, the end of the subsidy period, environmental regulation, and public acceptability all play a role in determining the best choice for any wind farm project. Sharing knowledge and experiences acquired from the onshore wind and O&G industries will help offshore wind developers make better EoL decisions.

Emission reduction and sustainable energy drive has shone a spotlight on OWF EoL choices, which had previously received little attention. The sector has just a few years of experience, and the fast increase of installations and commissioning is bringing decommissioning and the need for alternative approaches closer together. There is presently no standard regulation that outlines the best procedures following the end of an operational life. The physical state of an asset and the theoretically permissible lifetime of the turbine, as well as the total cost and site characteristics, distinct country regulations, logistical constraints, and possible environmental impact, all influence decisions. The most well-known EoL alternatives to decommissioning are given in this thesis, nonetheless, overlaps can exist, allowing components of one plan to be merged with others for a specific wind farm.

In 2020, 388 MW of wind power was decommissioned. The breakdown is Germany 222 MW, Austria 64 MW, Denmark 61 MW, Belgium 25 MW, France 15 MW, Luxembourg 2 MW, and the United Kingdom UK 0.3 MW. Onshore wind provided all of the decommissioning capacity. Only 345 MW of the 14.7 GW of onshore wind added in 2020 came from repowering projects (Wind Europe, 2021).



Repowering terminology
Example

Old project		New project	
Number of turbines	13	Number of turbines	9
Turbine power rating	2	Turbine power rating	4
Capacity under repowering	26	Repowered capacity	36

Decommissioned capacity = Capacity under repowering + Fully decommissioned capacity
Repowered capacity = the final capacity in the new project

Figure 1: Decommissioned and Repowered capacity (Source: Wind Europe, 2021).

Offshore wind is like a marriage between onshore wind who have knowledge a lot about wind turbines and offshore oil and gas who have a lot of experience in building offshore structures. It strives to reduce LCoE, which is the total of all lifetime expenses divided by the amount of energy generated.

Since the original OWFs were created in the best sites, one of the key advantages of repowering OWFs is the ability to use offshore locations with abundant wind resources. Some of the existing OWF's components may be utilized, which is another advantage.

The case study in this thesis was conducted using RETScreen Expert, which allowed for comparisons between the EoL alternatives to decommissioning.

The scope of this thesis is the financial viability and gross GHG reduction in lifetime extension and repowering of OWF at shallow sea depth, near to shore and with a uniform layout. It includes reinforcement of installed monopiles for the purpose of additional load support from a theoretical perspective.

1.2. PROBLEM STATEMENT

Although offshore wind is a newer industry than onshore wind and O&G, there are obvious links in terms of decommissioning their infrastructures. If nothing is done, over 3.5GW of offshore wind will approach the end of its operational life by 2035, according to estimates. There is presently no established structure for the decommissioning process, making cost forecasting problematic and limiting future cost reduction opportunities. Even though decommissioning does get to be called reverse installation, installation is a costly process, and a lack of competence removing foundations might result in delays and consequently increased costs.

Today, the bulk of plants reaching their end of life are smaller turbines on small monopiles, near to coast and in shallow seas, but as the industry grows, new issues will emerge, such as tougher site conditions and available vessels being unable to satisfy decommissioning need, both in terms of size and standards. Because vessel expenses account for 60-80% of expected decommissioning expenses, project owners must promote flexibility in their timetables in part to escape peak demand seasons (Reuters Events Renewables, 2020). Modern vessels capable of operating in these bigger installations should be built at a rapid rate to keep up with the rate of turbine deployment. Furthermore, offshore Oil and Gas (O&G) expertise might be beneficial to offshore wind, as their projects have had to function in comparable hostile conditions, and lessons regarding the need of early planning could be derived.

Decommissioning is outside the scope of this thesis, hence, life extension and repowering are two of the potential options considered. Management and Developers will need to think about these possibilities more carefully throughout the design process, replacing old components with new ones when possible, in order to plan upfront and make the best cost-cutting, environmental friendly, and efficient technological modifications. EoL approaches are presently not completely defined until the project is nearing the end of its operational life (OPEX), and regulatory framework to assist and guide wind farm developers is minimal.

There is a need to build an industry-wide system to address not just the difficulties and common knowledge of what decommissioning, lifetime extension, and repowering entail, but also the larger circular economy (CE) implications of component reuse and material recycling.

This thesis demonstrates the financial viability, GHG reduction, and optimisation of monopiles for lifetime extension and repowering based on modelling the EoL scenarios Offshore Wind Farm (OWF) developers could employ with their aging assets. This thesis presents the results of an analysis evaluating several EoL scenarios for a Danish OWF by 2024 at the North Sea and gives clues from the designer's perspective on deciding the optimal approach, in terms of environment, finance, and technology.

Hence, the research questions are:

i. How can lifetime extension and repowering be optimised for increased financial return?
ii. What is the GHG reduction in extending the lifetime or repowering an existing wind farm?
iii. How can installed monopile foundation be reinforced for additional load support?

These three research questions form the grounds of the thesis.

1.3. RESEARCH AIMS AND OBJECTIVES

Centered on the problem statement and literature review, there is a need to reduce cost and CO_2 emissions, as well as further optimize monopiles for lifetime extension and repowering of offshore wind turbines (OWTs). Furthermore, a simplified knowledge of the life cycle assessment of wind turbines and monopiles for lifetime extension and repowering aids EoL decision. Based on the case study, the EoL scenarios of a selected OWF was analysed. Hence, the research aims and objectives is to:

i. Analyse which EoL scenario have the highest financial viability, aside from decommissioning.
ii. Analyse which EoL scenario have the highest GHG reduction, aside from decommissioning.
iii. Suggest a method for reinforcing installed monopiles

1.4. CLARIFICATION OF TERMS / DEFINITIONS

Balance of plant: Covers all wind farm components (including offshore substation, onshore substation, turbine foundation, transmission assets built for the purpose of the wind farm) excluding turbines.

Life extension: Upgrade of installed wind turbine components (e.g. gearbox, generator), without changing the overall external layout (e.g. hub height, siting, size) of the wind farm. It is distinct from normal routine operation and maintenance activities. This method can also be referred to as enhancement, reactivation, or refurbishment depending on the Member State.

Full Repowering: Complete dismantle of turbine (including nacelle, tower, rotor, foundation) and replace with new turbine in a brownfield and/or greenfield site. It may also include replacing balance of plant components and electrical infrastructure.

Partial Repowering: Replacement of an existing turbine (including nacelle, and/or tower and rotor) with a new turbine. It can make use of some of the old balance of plant components and electrical infrastructure (e.g. cables).

1.5. STRUCTURE OF THESIS

The structure of the thesis will follow:

Chapter 1 - Introduction: Setting the basis for the thesis and presenting the reader with a wider view of the topic, challenge, limitations, and aims and objectives of the thesis.

Chapter 2 – Literature review: A research on previous work on the theme and topic of the thesis.

Chapter 3 – Lifetime extension: An assessment of a 2 MW offshore turbine would be discussed.

Chapter 4 – Repowering: A bit of decommissioning and installation would be considered.

Chapter 5 – Reinforcement of monopiles for additional load support: An alternative repowering approach would be considered by strengthening existing monopile foundation. The vertical and horizontal loads would be theoretically analysed.

Chapter 6 – Case study: A case study for lifetime extension and repowering would be carried out for Horns Rev 1 OWF. The CAPEX would be analysed.

Chapter 7 – Results and Discussion: The results from the case study would be presented. And, a general discussion of the results, source of errors and uncertainties.

Chapter 8 – Conclusion and Recommendations: Contains the final thoughts on what is written in the thesis, summarizing the findings of the thesis. Followed by a list the recommendations and further research work.

Reference: Gives the comprehensive list of data source.

Appendix: Subsidiary material to back up the thesis would be included as attachments

2

LITERATURE REVIEW

Global warming is a threat to our existence. To meet a target of limiting global warming to 2°C over pre-industrial levels, we must urgently reduce CO_2 emissions (Ho & Mbistrova, 2017). In response to this, the European Union has set a binding target to cover 27% of our final energy consumption by renewable energy in 2030 (Vorpahl et al., 2013).

Vindeby, the first commercial offshore wind farm, which started operations in 1991 was only decommissioned last year (IEC, 2009).

The design lifetime has been quintessentially 20-25 years. Provided all load-carrying components have structural reserves left or can be replaced with reasonable effort, the assets can be operated beyond their design lifetime of 20-25 years (Pasamontes, 2014). The sructural reserves emanate if conditions on site are milder than design assumptions (Gentils, Wang, & Kilios, 2017).

Analytical assessment is based on a rerun of design simulations under precise site conditions (Pasamontes, 2014). Inspections and an evaluation of the maintenance history form the practical assessment (Pasamontes, 2014). Data driven assessment can be done by assessing fatigue loads during the service lifetime in place of using numerical models. In this thesis, this will be referred to as data-driven evaluations.

If wind farms are still profitable, extending their lives can boost their return on investment while also increasing the quantity of carbon-free electricity they generate.

Most of the available research focuses on the decommissioning of OWFs when they reach the maturity phase. There were no scientific publications prior to this thesis that actually explored the reinforcement of monopile foundation in the context of lifetime extension and repowering of OWT using a custom reinforcement apparatus creating an external framework of shaped steel rods and adjustable locking clamps directly in contact with the exterior of already installed monopole foundation to provide additional strength and resistance against deflection due to wave and wind forces and additional weight thereby enabling the placement of bigger wind turbines.

2.1. END-OF-LIFE SCENARIOS OF OFFSHORE WIND FARM

The final step of an offshore wind power project is decommissioning, with the goal of returning the site to its former form, or as near to it as feasible (Luengo and Kolios, 2015). Decommissioning often entails reversing the wind farm's commissioning and installation (Kerkvliet and Polatidis, 2016).

The initial stage is to disconnect the wind farm from the grid, then dismantle the individual turbines (Kaiser and Snyder, 2012a; Kerkvliet and Polatidis, 2016). To reduce the number of lifts, the blades, hub, and nacelle can be removed individually or combined (Kaiser and Snyder, 2012a).

To reduce the number of lifts, the blades, hub, and nacelle can be removed individually or combined (Kaiser and Snyder, 2012a). Disassembly of wind turbines should be done onshore to the greatest extent practicable due to the high expense and danger of offshore operations (Topham and McMillan, 2017).

Because of its size, penetration depth, and weight, removing a monopile foundation completely is challenging (Topham and McMillan, 2017). As a result, cutting the monopile a few meters beneath the seafloor are increasingly usual.

Internal cut, where dirt and muck from inside the monopile are pumped out so the monopile may be cut from the inside; or external cut, where excavation surrounding the monopile allows access to cut the pile from the outside (Kaiser and Snyder, 2012a). The excavation is refilled, concealing the foundation remnants, and the seabed is repaired once both processes have been used.

When subsea cables are dug and taken out of the seabed, they create trenches that must be rebuilt, resulting in greater decommissioning costs (Topham and McMillan, 2017).

The most often recommended strategy is to bury the inter-array and export cables underneath the seafloor (Topham and McMillan, 2017).

When the wind farm uses an offshore substation, it must be either emptied or sealed up prior to the removal to prevent the leakage of dangerous and damaging pollutants (Topham and McMillan, 2017).

According to several studies, complete decommissioning is associated with high expenditures and significant impacts to the maritime environment. As a result, the most usually advocated option is to bury most of the cables as well as the foundations' bottoms underneath the seabed at the construction site (Smyth et al., 2015).

When essential actions are conducted to enable an OWF to run for a longer period than the initial planned lifetime, the OWF's lifetime is extended. This is dependent on the OWF's structural strength remaining (Topham et al., 2019).

Installing strain gauges on foundations is already normal practice, and they can offer information regarding the monopile's structural strength. However, because most of the monopile lies below the seabed, assessing the monopile's structural strength is challenging (Ziegler et al., 2019).

Ziegler et al. (2019) developed a method for extrapolating the loads on monopile foundations using strain gauges to address this problem. Because most current foundations are over-dimensioned, replacing old wind turbines with the same kind may not result in higher foundation expenses (Hou et al., 2017, 2016). Because lifetime extension allows for a reduced LCoE, the offshore wind energy sector is planning for future OWFs to have longer lifespans (Ziegler et al., 2019).

Aside from decommissioning, lifetime extension, partial repowering, and full repowering are mentioned as three possible EoL scenarios for OWFs in this study. In the case study, there are more detailed explanations of the various EoL scenarios.

UK's first commercial wind farm Scroby Sands is an OWF in the North Sea, 2.5 km off the coast of Great Yarmouth. It is made up of 30 2 MW wind turbine generators built on monopile foundation, and has been active since 2004. Abfad Ltd was in charge of refurbishing the monopiles' steelwork from grating height to sea level. Abfad created the magnetic positioning device to enable their rope access sprayers and blaster to maintain a safe and secure position when dangling from the ropes. Because the sprayers and blaster are kept firmly in place by the magnetic clamps and do not have to “tie in” on challenging to access structures, this approach assures the maximum standards with precision. The magnetic positioning system has proven useful in locations where only a rope can be used to access the work platform and where a reliable technique of bringing the rope technician closer to the work platform and securely attaching them to enable them to carry out any essential work is necessary. By anchoring the rope technician to the steel substrate and enabling more accuracy of work, the user has a productivity advantage, boosting the pace of operations such as blasting, electromechanical surface preparation, welding, drilling, and inspections.

The work included refurbishing structural steel operations underneath the walkway gratings up to the monopile collar section, as well as all underneath the collar section to sea height. After completing the repair, the walkway gratings and davit arms were removed and later replaced. To remove all portions of corrosion, SA2.5 blasting was used, and a new protective coating was applied to the specified thickness with an airless spray machine. The project was a remarkable accomplishment, ensuring that the monopile was restored with maximum weather protection (Abfad, 2021).

Figure 2.1: Monopile refurbishment at Scroby Sands (Source: Abfad, 2021).

COMPONENTS OF OFFSHORE WIND FARM AND COSTS

COMPONENTS OF OFFSHORE WIND FARM AND COSTS

According to Klinge Jacobsen et al. (2019), if an OWF is more than 15 kilometers from the beach, visual impacts may essentially be ignored, resulting in the absence of trade-offs between public opposition and investment cost. The reduced investment costs of OWFs built closer to the coastline must be balanced against the less beneficial wind conditions and higher public opposition.

Total capital expenses for several OWFs may be identified and made public. The percentage of various cost components, on the other hand, is frequently kept a business secret. The overall investment cost for Horns Rev 1 and Nysted (Rdsand 1) is 2.146 M€ per MW, according to Morthorst and Kitzing (2016). The CAPEX for Kentish Flats and Lillgrund OWFs, according to Islam et al. (2014), were 1.95 M€ per MW and 2.09 M€ per MW, respectively.

2.2.1. WIND TURBINE

The cost of acquisition accounts for 85% of the entire cost of a wind turbine, while electrical installation, shipping, and assembly account for 10% and 5%, respectively (Douglas-Westwood, 2010; Gonzalez-Rodriguez, 2017). In the last three months of 2018, Siemens Gamesa reported an average selling price of 0.76 million euros per MW (Richard, 2019). A Vestas V47 refurbished turbine can be bought at Repowering Solutions for 365 k€ or 0.553 M€ per MW (Bergvall, 2019). The cost of offshore wind power is heavily influenced by the distance from shore and the depth of the sea, with nearshore facilities costing much less.

Table 2.1: Summary of wind turbine costs according to different references. Recreated from Bergvall, (2019).Table 2.2

Wind Turbine Cost Reference	Cost (€/MW)	Notes
Richard (2019)	0.780	SG Average Selling Price
BNEF (2018)	0.900	-
Krohn et al. (2009)	0.913	-
Gonzalez-Rodriguez (2017)	1.252	-

Gonzalez-Rodriguez (2017)	0.640	Nearshore average
Morthorst and Kitzing (2016)	1.040	Horns Rev I/Nysted
Repowering Solutions (2012)	0.553	Refurbished V47

2.2.2. TURBINE FOUNDATION

Monopile is the first type of foundation to support a turbine with a rated capacity of more than 3 MW and a rotor diameter of more than 100m. It was completed as part of the Arklow Bank project in 2003. Beyond monopiles, jackets are widely regarded as the best option. The Beatrice project in 2006 marked the beginning of their commercial use for offshore wind turbines.

Usually, the monopile is pushed into the seabed using a massive hydraulic hammer, and the transition piece is grouted or fixed to the top of the monopile during mounting.

Foundations should cost 0.46-0.75M€ per MW, since they account for around 20-30% of CAPEX for new constructions. Sun et al (2017) estimated that the cost of reinforcing existing foundations in order to commission new wind turbines on the foundations would be 10% of the installation cost, which was then assumed to be 80% of the wind turbine cost. It was predicted that the cost of foundation strengthening would be 8% of the cost of a wind turbine. Because most existing foundations are over-dimensioned, no extra strengthening costs were considered in the case study of Hou et al. (2017) when replacing existing wind turbines with ones of the same type.

Table 2. 3: Summary of wind turbine foundation costs according to different references. Recreated from (Bergvall, 2019).

Foundation Cost Reference	Cost (€/MW)	Depth	Notes
Gonzalez-Rodriguez (2017)	0.38	>20 m	GB (ex. seabed prep.)
Gonzalez-Rodriguez (2017)	0.60	>20 m	MP
Morthorst and Kitzing (2016)	0.43	6-9 m	Nysted GB
Morthorst and Kitzing (2016)	0.45	4-8 m	Lillgrund GB
Morthorst and Kitzing (2016)	0.43	6-14 m	Horns Rev I MP

2.3.3. BALANCE OF PLANT

CABLES

Horns Rev 1 export cable will be used for at least another 15 years. The export cable has the capacity to transmit a maximum of 200 MW. This is similar to the capacity of the export cable used for the Horns Rev 2 platform.

Cost of Transmission, substation and inter-array grid

Around 20% of the entire CAPEX is spent on substation, inter-array, and transmission cabling. The price of a meter of high-voltage transmission wire ranges from 520 to 1050 Euros (Morthorst and Kitzing, 2016). The cost of inter-array grid, substation, and export cable, according to Morthorst and Kitzing (2016), is 0.454 M€ per MW, based on Nysted (Rdsand 1) and Horns Rev 1. Wind power producers in Denmark must pay a balancing cost of around 2€ per MWh (Klinge Jacobsen et al., 2019). Denmark has a lower balancing cost than the rest of Europe (Klinge Jacobsen et al., 2019).

Substation, inter-array, and transmission cabling makes up about 20% of the total CAPEX. High voltage transmission cables cost about 520-1050 € per meter (Morthorst and Kitzing, 2016). Wind power producers in Denmark must pay a balancing cost of around 2€ per MWh (Klinge Jacobsen et al., 2019). Denmark has a lower balancing cost than the rest of Europe (Klinge Jacobsen et al., 2019).

Horns Rev 1 and Nysted (Rdsand 1) OWF design and project management accounted for 6% of CAPEX and 0.126 M€ per MW, respectively (Morthorst and Kitzing, 2016). Horns Rev 1 and Nysted (Rdsand 1) OWF accounted for 3% of CAPEX and a cost of 63 k€ per MW in the first environmental study (Morthorst and Kitzing, 2016). Installation and commissioning account for 20% of total CAPEX for European wind farms (Kaiser and Snyder, 2012).

DNV-GL estimates a decommissioning cost of 200-600 k€ per MW, or around 60-70 percent of the installation cost (Topham and McMillan, 2017).

O&M costs are of both fixed and variable types. Fixed costs are for example insurances, administration, salary, and regular maintenance. Variable costs are items such as repairs and spare parts. In 2015, O&M costs in Denmark were made up by 57.3 k€ per MW annually in fixed costs and 4.3 € per MWh in variable (Klinge Jacobsen et al., 2019).

According to IRENA (2012), O&M costs for European OWFs are 26-52 € per MWh, while the Danish Energy Agency in 2014 stated that the cost is 20 € per MWh for Danish OWFs (Morthorst and Kitzing, 2016).

Table 2.4: Summary of balance of plant costs according to different references. (Recreated from Bergvall, 2019).

Balance of plant	Cost (€/MW)	Cost reference	Notes
Electrical system	0.454	Morthorst and Kitzing (2016)	Horns Rev I/Nysted
Inter-array grid	0.970	Krohn et al. (2009)	Horns Rev I/Nysted
Transformer and export cable	0.322	Krohn et al. (2009)	Horns Rev I/Nysted
Design & Project Management	0.126	Morthorst and Kitzing (2016)	-
Design & Project Management	0.105	Gonzalez-Rodriguez (2017)	-
Environmental analysis	0.063	Morthorst and Kitzing (2016)	Horns Rev I/Nysted
Decommissioning	0.2-0.6	Topham and McMillan (2017)	-

2.4. ENVIRONMENT IMPACT

2.4.1. IMPACT OF WIND TURBINES ON THE ENVIRONMENT

The sensitive nature of the marine environment is a critical factor that must be respected even by offshore wind turbines despite how appealing renewable energy technology is. Denmark is a country with a lot of experience in dealing with offshore wind farms.

Offshore wind farms are an efficient source of renewable energy as shown by the Danish experience in the last 25 years. They have great environmental potentials because electricity produced from wind turbines can replace production based on fossil fuels. To the extent that fossil fuels are dislodged, there will be a cut down in the quota-covered CO_2 emissions, just as emissions of NOx and SO2, etc. will be cut down.

However, OWTs also pose challenges to the environment, and it is important that this type of offshore infrastructure respects the sensitive environment (Energistyrelsen, 2021).

EFFECTS OF ERECTING WIND TURBINES ON THE ENVIRONMENT

Programs to Monitor the Environment

Operators were sanctioned with performing intensive environmental monitoring programs during the construction of the Horns Rev 1 (2002) and Nysted (2003) OWFs, which should include an elaborate measurement of the environmental conditions before, during and after the construction of the two offshore wind farms.

In all, the environmental demonstration program by Horns Rev and Nysted proves that it is possible to construct OWFs in an environmentally sustainable way that does not cause nature significant damage. Below is a brief overview of the key findings from the monitoring program.

Main results from the monitoring program (Horns Rev OWF) include:

Bottom fauna and flora

Artificial habitats for animal and plant life, occasioned by the activities of wind turbine foundations and erosion protection has enhanced the diversity and biomass in the area. For other farms like the Nysted OWF, as a result of low salinity of the area and absence of predators, monocultures of mussels on wind turbine foundations and erosion protection have been developed.

Fish

The creation of new habitats can have good effects on the fishing communities after full development of the artificial reefs. No connection between the strength of the electromagnetic field and the motion patterns of the fish species looked at.

Marine mammals

Both at sea and on land, seals were basically undisturbed by the construction as well as the operation of the OWF. The Seals were only disturbed when the foundations had to be beaten. The number of guinea pigs reduced slightly during the construction work, but appreciated again after commissioning. For other farms like the Nysted OWF, the number of guinea pigs reduced markedly during the construction work and is only gradually returning after two years of operation.

Some species of birds have been displaced from previous foraging areas while majority just avoid the offshore wind farms completely. The possibility of colliding with the wind turbines is marginal. The effects at the population level are negligible as well.

Opinions

Over 80% of the respondents from the local areas are positive or very positive in embracing the OWFs. The majority believe that the resultant effect of OWFs on birds and the marine environment is neutral. About 2/3 believe that the effect of OWFs on the landscape is neutral or positive. There is a great deal of willingness to pay for the placement of wind turbines at distances where the visual disturbance is relatively low, say up to 18 km from the coast. At Horns Rev 1, there was no additional willingness to pay to get the turbines out of sight by raising the distance from 18 to 50 km from the coast.

The environmental monitoring program was carried out by the working group comprising of the Danish Forest and Nature Agency (presently the Danish Environmental Protection Agency), the Danish Energy Agency, Vattenfall and DONG Energy (now Ørsted). The work was continuously assessed by an international expert panel, The International Advisory Panel of Experts on Marine Ecology (IAPEME) with special skills within the various parts of the program.

There was an ongoing conversation with a green follow-up group comprising of representatives of the World Wide Fund for Nature (WWF), the Danish Society for Nature Conservation, the Outdoor Council, Greenpeace, the Danish Ornithological Society and the Organization for Renewable Energy. Also, the expert panel came at different intervals with recommendations for further work.

As a follow-up to the environmental monitoring program, an additional environmental monitoring program was set up which focuses on guinea pigs comprising the significance of noise from framing wind turbine foundations, waterfowl including sea lilies, pockets, black ducks, and fish including the parks' significance to fishing communities.

UNDERWATER NOISE FROM FRAMING OF WIND TURBINE FOUNDATIONS

Underwater noise has been linked to harmful impacts on aquatic life in recent years. When monopile foundations are used to build OWF, underwater noise occurs when the monopiles are framed in the seabed. This includes, for example, the possibility of coming into contact with marine animals such as guinea pigs and seals. In Denmark, an independent law for framing wind turbine foundations has been prepared to ensure that guinea pigs and seals do not sustain irreversible hearing loss during the framing of OWT foundations. The law consists of a number of standard provisions that are usually included in OWF establishment licenses, as well as a set of general guidelines. To protect marine mammals from the adverse effects of underwater noise in conjunction with the construction of foundations driven piles, the so-called combined Sound Exposure Level (SEL) from each installation chain must not exceed a level of 190 dB, according to the DEA's normative requirements for underwater noise from monopiles. It may be assumed that the use of pinger and seal scare away marine mammals up to 1.3 km. The total SEL from each construction activity causing underwater noise shall not exceed a threshold value of 190 dB for other installation activities causing underwater noise (Energistyrelsen, 2021).

2.4.2. THE USE OF A REFURBISHED OWTs REDUCES CO_2 EMISSIONS SIGNIFICANTLY

INTRODUCTION

In a Vestas publication by Elena (2021), there is a comprehensive sustainability strategy in Vestas where parts and repairs play an increasingly dominant role to become carbon free by 2030 without the use of offsets and building zero-waste wind turbines by 2040. It is paramount to scale reasonably in the near future where wind is set to grow exponentially.

There are primarily two big areas in the supply of parts that add to carbon footprint, they are production of materials and logistics. Of these, many people anticipate the logistics side of operation to have the biggest potential to reduce carbon footprint. Of course, there are savings to be made here, there is a sustainability collaboration with the supplier DSV Panalpina, working to cut down emissions from transport. But what holds an even bigger promise for reducing CO_2 is the materials used in the manufacture of the products themselves, particularly in the bigger components like gearboxes and generators. About 83% of the CO_2 emissions come from the manufacture of materials, while only 17% come from transport.

The Reduce – Reuse – Refurbish (3Rs) policy

Refurbished component at Vestas prevents on average 45% of CO_2 emissions in comparison to a new part, when reverse logistics are taken into consideration, that's the cost of conveying the object from the turbine to the factory for repairs. Primarily, by refurbishing components, CO_2 emissions is cut in half. So refurbishing cuts down the CO_2 effects of the materials used. Also, a refurbished component be can reused up to 70% of the materials in comparison to a new object. When there is a failure, we take the part out, convey it to the factory where we make it as good as new by fully refurbishing it, and give it a new guaranty. It's a fabulous solution in all respect, as in addition to being more sustainable, it's more competitive.

Nowadays, there is a high utilization and availability of refurbished parts. It is feasible to manufacture sustainable refurbished components by following the 3R's approach which adhere to very strict repair criteria in order to achieve the technical and quality criteria required to operate as new components.

Materials are given a second lifetime through recycling

For instance, in a generator, it is mostly the copper windings on the rotor and stator that needs to be changed. After which it is almost as good as new, and this gives a considerable CO_2 saving.

Craneless solutions, uptower repairs and a sustainable supply chain

Removing a major component like the generator from a tower, is costly and carbon intensive, considering the enormous crane that is necessary to carry these heavy pieces. These uptower repairs have led towards craneless maintenance wherever possible and keeps the attention on repairs which are possible in the nacelle, without having to take out parts to the repair factory. There is a transition from fueled vehicles to electrical vehicles or plug-in hybrids. The aim is to utilize zero emission vehicles by 2050.

2.4.3. REDUCING THE CARBON FOOTPRINT OF WIND ENERGY

According to Spyroudi (2021), the linear technique of product manufacture has been the standard practice for decades. However, rising demand and natural resource limitations have prompted the adoption of a more circular approach, which involves the reuse and recycling of valuable materials to decrease waste. As the industry and turbine sizes rise, the demand for efficient recycling solutions grows even more urgently, with 1.5GW of offshore wind estimated to be retired by 2030 and 13GW by 2040 worldwide. This has prompted scientists at ORE Catapult to investigate a variety of possibilities in establishing a circular economy within offshore wind in the recent past. The economic benefits of investing in such a plan cannot be overstated, with the newest analysis predicting that the industry may contribute 20,000 new employments by 2030.

In addition to the financial gain, the environmental impact of any EoL management plan should be considered when making a final decision. It's important to remember that every manufacturing process, including green manufacturing, produces some carbon emissions throughout the course of the product's lifetime. As a result, its activities may eliminate or even reduce the amount of carbon emitted. Wind power delivers zero-emission electricity and has one of the lowest carbon footprints of any energy source, but we can always do better. According to research, offshore wind power generation saves 143 ktCO2e per wind turbine compared to natural gas-generated electricity, which is comparable to the CO2e created by approximately 70,000 gasoline automobiles in a year. Recycling turbines at the end of their lifetimes might save at least 35 percent of carbon emissions equivalent per kWh when compared to producing components using primary raw materials.

However, when it comes to implementing a circular economy, recycling isn't the only option accessible to the wind business. Early on in the design process, it's critical to take a proactive approach to EoL management in offshore wind, developing a sustainable framework. Decommissioning is the most common option, though prolonging the product's life cycle and repowering enhancing elements of an existing asset are also being considered. These options can help to extend the life of existing assets by providing greater returns, cheaper maintenance costs, and environmental advantages by postponing and avoiding disposal. Carbon footprints are found in the turbine as well as the operation and maintenance containers for these technologies. To show how, to calculate the carbon footprint of boats used for decommissioning, extending the lifetime, and repowering for a sample UK windfarm with a 25-year history and plotted the findings below. Because only modest repairs necessitate inspection and staff transfer vessels, life extension had the lowest emissions. However, the carbon footprints of these end-of-life approaches are negligible when compared to the carbon saved by the wind farm's operation. When a wind farm is repowered, the 10MW larger turbines save an additional 110 $MtCO_2e$ per year, compared to the same energy provided by a typical natural gas plant.

Stretching the lifetime delivers more clean power and carbon savings from the same assets, resulting in a 1.45 MtCO2e gain in carbon savings over the following 10 years compared to the baseline scenario of 6.40 MtCO2e. Repowering for 25 years at the end of the original useful life by upgrading current assets with 10MW rated turbines (350MW) can boost savings (0.26 MtCO2e per year). Current carbon footprint predictions for wind turbines are roughly 0.011 kgCO2e/kWh (NREL, 2013), which is less than 2.5 percent of the estimated life cycle emissions from a natural gas plant. Extending the life of existing wind farms, whether by repowering or postponing decommissioning and material recycling, can result in higher levels of clean energy generation while consuming less primary resources per kWh generated.

To sum-up, changing from a linear to a circular economy would help the offshore wind sector minimize its carbon impact while simultaneously bringing major financial benefits. Recycling turbines at the end of their lifetimes may cut CO2 footprints by 35 percent when compared to producing components purely from original raw materials. Recycling isn't the only approach to lower the industry's carbon footprint; proactive operations and maintenance, as well as repowering, have been recommended as feasible methods to study further.

2.5. MONOPILE FOUNDATION

Turbine foundations such as the Horns Rev 1 turbine foundations used in the North Sea at a water depth of 5 to 20 m is made of a steel monopile foundation. The foundation is made up of two substructures, the topside is known as the transition piece while the lower section is the monopile. Monopiles are the most used foundations for OWT(s). The design and fabrication of monopiles and transition pieces is simple, time and cost effective. The steel sheets are prepared, a single sheet is up to 3 m wide, 40 to 82 mm thick. The individual steel sheets are bent into rims using rollers. The ends are joint together using state of the art robots to form rims. A rim weighs about 16 tons without base and limb (the rim is known as can). 11 to 15 cans are joined to make 1 monopile. The length of the monopiles varies between 28 and 40 m depending on location and water depth, with a diameter of 3.9 m and weigh up to 200 tons. 6 of the cans make up the transition piece. Each foundation is fitted with a boat landing, ladder, railings, frames, and navigation lights. It is coated with four layers of paint to protect it against water and the salt in the air. J-tubes are conduits inside the foundation that holds the turbine power cables, and they hold the turbine cables inside the foundation from the seabed up to the turbine tower (Aarsleff Biz, 2020).

Negro et al (2017) carried a research on monopiles in offshore wind. After his findings he came up with some useful simple formulas for estimating the main dimensions of monopiles as follows:

$L_T = 14D – 17$ (m)

L_T is the length of monopile

D is the diameter of monopile

Regression, $R^2 = 0.9148$

$L_D = 8D – 5$ (m)

L_D is the driving diameter

Regression, $R^2 = 0.8391$

$W = 16.5L_T – 392$ (t)

W is the weight, in tons, and

L_T is the total length, in meters.

Regression, $R^2 = 0.9418$

$t = 6.35 + D/100$ (mm)

t = thickness of monopile

Though the use of this formulars do not guarantee accuracy at all times since different foundation designers go with dynamic variations. However, it serves as useful guide to a simple equation to estimate the length and weight of large hollow steel monopiles, knowing its diameter.

2.6. REGULATORY FRAMEWORK FOR WIND FARM PERMITTING IN DENMARK

2.6.1. PERMITTING PROCEDURES

Citizens are included in the debates to select places suitable for wind turbines in an ideal scenario, reducing opposition. As a result, municipalities frequently designate suitable locations for the construction of wind turbines in their municipal plans. The procedure of obtaining a permit is depicted in the diagram below**.**

1. The developer submits a draft application to the municipality.
2. A minimum of two weeks is set aside for a public hearing on the draft application.
3. The municipality is responsible for the EIA process and report. Although, in actuality, the EIA is mostly created in collaboration with the project developer. For projects with more than three turbines and a length of more than 80 meters, an EIA is required.
4. The municipal-plan-supplement and EIA are brought up for public engagement for 8 weeks. A public meeting must be called no later than four weeks before the interface phase ends. It is worth noting the public meeting must be held within four weeks of the municipality's announcement that no EIA permission is required for wind turbines that do not require it.
5. Wind turbines are approved or rejected by the municipality. Documents are filed with the municipality for approved projects to ensure compliance with severe noise rules, and a construction permit is also submitted for at the same time.
6. The commissioning process: The Ministry of Environment is in charge of approving proposals for projects worth more than 122.6 M. The procedure is fairly similar to that which is approved by towns. Municipalities are only notified that projects under 25 kw are in accordance with the construction legislation. Small turbines, like big turbines, must be certified according to the technical approval

process and must conform to severe noise standards. A rural area permit would have to go along with the approval if the project is located in a rural region.

2.6.2. ACCEPTANCE CRITERIA FOR PROJECTS

In order to preserve public support, four new programs were introduced in 2009:
Alternatives for local residents to purchase wind turbine shares include - The Promotion of Renewable Energy Act (2009) requires developers to make a minimum of 20% of turbine ownership shares available for purchase.
Residents living within 4.5 kilometers of the nearest turbine must be the principal recipients of the purchasing offer.
If any shares remain unsold, the buying offer must be offered to inhabitants of the municipality where the turbine is located.
This clause does not apply to turbines that are erected for personal use or those that are required to be used as test turbines.

Property owners who believe the building of a wind turbine will result in a value loss in their property equal to or more than 1% can file a claim for compensation. Wind turbines under 25 meters are exempt from this requirement. The claim must be presented within four weeks of the public meeting. Resolutions of the valuation authority may be brought before the courts as civil legislation between the owner and the developer by the owner or the developer. If the developer has paid compensation in line with the valuation authority's determination, the action can only be brought to the courts within three months of the date of payment.

Provision of a green system to enhance the aesthetic and recreational possibilities of the surrounding area: As of October 2019, a new law was expected to be brought to the Senate for consideration. Resolutions provide conditions for developers to meet, such as providing free electricity to local communities and paying taxes directly in the neighborhood.

2.6.3. THE PROCEDURE FOR APPEAL

Rules of appeal: Regardless of the cause, approvals to begin a project that requires an EIA can be challenged to the Environmental Board of Appeal. If a resolution is in conflict with an existing law or if the board judges the resolution to be unreasonable or unsuitable, the board may arbitrate all issues and change it. Other local council resolutions made in accordance with the Planning Act can only be petitioned to the Board for legal review. The period for filing an appeal is four weeks from the day the resolution is published. The board is a self-contained quasi-judicial institution. It is made up of a chairperson, two Supreme Court judges, and one member nominated by each of the Folketing's Finance Committee's political parties.

Effects of an appeal: An appeal of an expropriation decision or a rural zone permission filed within the time frame allows the resolution's impact to be avoided. Unless the board decides differently, the resolution cannot be implemented until the appeal is determined. Other appeals normally do not exclude the resolution, but any action done on the basis of an appealed decision may have to be reversed if the Board overturns it.

Appeals to the courts: Legal action must be taken within six months following the Board's decision. As a result, the Board's decision can be challenged in court.

2.6.4. WIND FARM DEVELOPMENT OBSTACLES

Despite the fact that 80 percent of the Danish population supports wind power, the same amount opposes it being built near their houses (Rambøll, 2013). According to the Danish National Association of Neighbours against Giant Wind Turbines, there were roughly 120 protest organizations in the nation in 2016 (Gorroño Albizu et al, 2018). There are few statutory deadlines for building permit approval, which has an influence on lead times.

2.7. WIND ENERGY TODAY AND FUTURE PROJECTIONS

According to Wind Europe's 2020 data and the outlook for 2021-2025, the five-year market forecast for wind installations analyses and the development of wind power capacity, in her realistic expectation, which offers the best prediction of the installed capacity in Europe during the next five years, projects that there will be 318 GW of cumulative installed capacity in Europe, with an annual growth rate of 2%. The EU-27 will install 15 GW, however this is far less than the 18 GW required to meet the NECPs and the existing renewable energy target of 32% by 2030.

2.7.1. FOR DECOMMISSIONING AND LIFETIME EXTENSION

Over the next five years, 26 GW of projects are scheduled to reach their 20-year milestone. When 10 GW of projects reach 25 years of age and 1.5 GW of projects reach 30 years of age, we have 38 GW of projects that will need to decide whether to repower, prolong the asset's life, or decommission it entirely. We may witness negative wind capacity increases if governments do not step up their efforts. Austria had a net negative installation of -39 MW in 2020, due to the decommissioning of 64 MW and the commissioning of just 25 MW. It is anticipated that around 2.4 GW will be retired for repowering and 7 GW will be entirely retired, based on current trends and policy trust. Over the next five years, approximately 9.4 GW will be decommissioned. The remaining 29 GW will stay operational and will most likely be evaluated for life-extension services (perhaps with partial replacement of certain elements such as gearbox or blades).

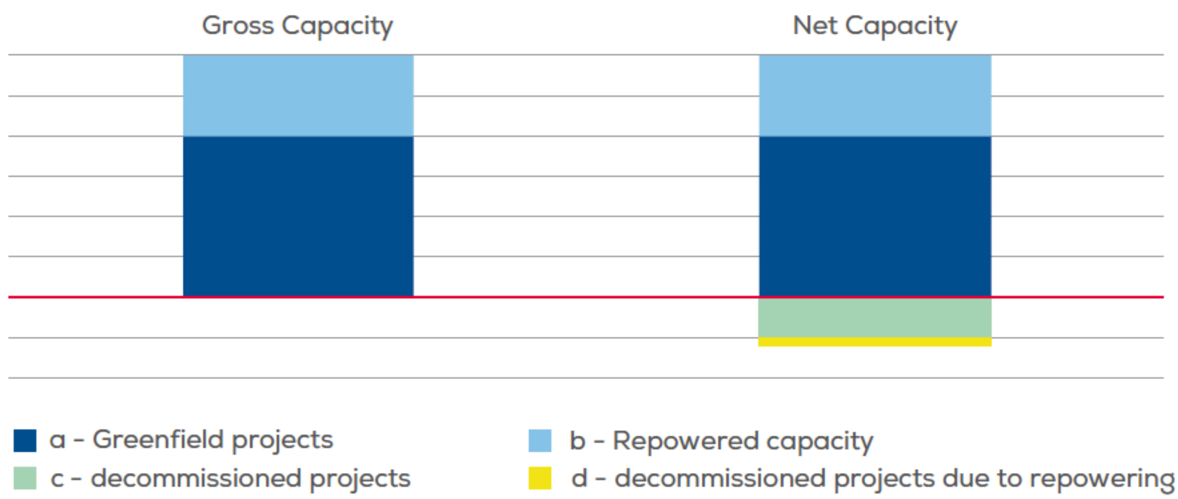


Figure 2.2: Gross vs. net added capacity accounting for decommissioning and repowering (Source: Wind Europe, 2021).

Note that gross added capacity = a + b, while net added capacity = (a + b) + (-c – d).

2.7.2. FOR REPOWERING

The most essential factors when opting to repower include existing incentives for repowering or lifetime extension, present and anticipated wholesale energy costs, and laws around the Environmental Impact Assessment and other environmental restraints that have changed in recent years. In the next five years, Europe is expected to have 4.4 GW of repowering projects. This means that around 2.4 GW will be decommissioned and later repowered, because the production capacity of repowered wind farms is increased by a factor of 1.8 on average.

2.7.3. PRDICTIONS IN OFFSHORE WIND

According to Quinn (2021), because of the pandemic's influence into the new year, 2021 may be a quieter year than many expected. Looking ahead, though, it will be a pivotal year. The COP26 meeting is on our minds both worldwide and locally, as revisions to the Paris Agreement are likely to be required to keep warming below 1.5°C.

The year 2020 was almost a watershed moment, with a lot of focus on green recovery and energy transition. On these subjects, a lot of talking, thinking, and writing has gone place. Governments, corporations, and people should mobilize and make substantial progress on high-impact projects in 2021, as well as push harder with current plans to bring good intentions to fruition.

2.7.3.1. OFFSHORE WIND IN THE UNITED STATES

Since the completion of the 30 MW Block Island project in 2016, the US offshore wind sector has been inactive. States have had to take the initiative due to a lack of clear, centralized policy and federal assistance, yet they have been unable to gain federal permissions and promote innovations due to the lack of clear, centralized policy and federal assistance. The Jones Act has made it difficult to find boats for the construction and maintenance of big wind farms, and the supply chain has been slow to develop. However, with the US reversing its stance on the Paris Agreement and Democrats in control of the House and Senate, we may expect more progressive energy policies to be implemented right away, and offshore wind might receive a significant boost. And with barriers lifted, the US can begin to build its 30GW pipeline of projects, and we can anticipate projects like Vineyard Wind (800MW) to make investment choices.

2.7.3.2. THE OFFSHORE PIPELINE IN THE UNITED KINGDOM IS EXPECTED TO EXPAND

The ScotWind leasing round in Scotland is slated to end applications in March. All projects granted by the end of the year are projected to total 10GW of new capacity, with several of them utilizing floating substructures. The 7 to 8.5 GW of seabed rights for additional capacity in the Offshore Wind Leasing Round 4 are unlikely to be awarded before 2022, so the rest of the UK will have to wait a little longer. In the short run, decisions on particular income support for tidal streams might be a deciding factor for the new technology. Rather than being entirely technology-neutral, Allocation Round 4 may probably include marine power minima in addition to all the offshore wind activity.

2.7.3.3. WIND BUBBLES FLOAT ALONG

The UK Government can be bolder with its floating wind ambitions, increasing them from 1GW to 2GW of installed turbines by 2030, according to the latest research from the Floating Offshore Wind Centre of Excellence, Floating Offshore Wind: Cost Reduction Pathways to Subsidy Free. However, big announcements are unlikely to be made this year as surveys and supply chain plans take the spotlight.

The 96MW Erebus project is now under development, which might provide the Celtic Sea a boost. More information may be found in the Benefits of Floating Offshore Wind to Wales and the South West Supply Chain Report, as well as the opportunities for floating offshore wind in the Celtic Sea. Leases for floating and fixed/floating hybrid projects will also be given as part of ScotWind. An oil and gas company making serious steps in the UK to power offshore installations with floating wind would be an unpredictable arrival. Total and Shell, with their Blue Gem Wind and TetraSpar initiatives, are already active players in the floating wind area. Equinor is busy issuing contracts for the 88MW Hywind Tampen project, which is expected to be completed by the end of next year.

2.7.3.4. GRID UPGRADES TO SUPPORT EXPANSION

Energy islands in the North Sea may be a long way off, but development starting this year might pave the way for more integrated, environmentally friendly international networks. Will a large scale electrolyser system be implemented into offshore wind action plan this year? Hydrogen continues to be a hot topic; will we see a large-scale electrolyser system implemented into offshore wind development plans this year? Simultaneously, technical testing of offshore hydrogen systems will gain traction on the way to a commercial project's approval. All of these developments will necessitate a significant increase in grid infrastructure. The Offshore Transmission Owner (OFTO) Regime is being examined, which might result in a more coherent response to transmission networks rather than single wind farm systems. In this sense, interconnectors will also contribute.

2.7.3.5. MAKING USE OF THE VALUE OF THE SUPPLIER CHAIN

By the end of 2020, the UK government has allocated 186 M€ in state financing for port expansion. This might result in a surge in new tower, monopile, and blade production facilities across the UK. In order to add more capacity, the renewable energy supply chain will need to expand. For the government to reach Sector Deal targets for local content and export success, massive private sector investment would be required. Meanwhile, a systematic program for skill transfers for workers transitioning from oil and gas and other sectors to renewable energy may be developed.

2.7.3.6. BETTER, QUICKER, AND MORE POWERFUL

As technical innovation strives to keep up with the popular thirst for bigger and better components, turbine producers may propose new designs, even greater than the recently planned 15MW from Siemens Gamesa. Larger turbines would necessitate larger array cables, and a plan should be in place this year to transition from 66 to 132 kV systems. The pandemic has put a halt to certain simulations of robotics for operations and maintenance, but we anticipate to see progress toward complete integration with wind farms. Experts using drone inspections may breathe easier now that the Civil Aviation Authority has increased the take-off mass, allowing for larger deliveries of roughly 12kg to be made this year. Although large components will not be handled in this manner, drones may bring spare parts or tools, reducing turbine downtime.

2.8. SUMMARY OF LITERATURE STUDY

The core objective has been to achieve the lowest possible LCoE and highest efficiency with well-tailored optimizations, but increased power production from an existing OWF has not been given adequate study.

There is indeed a noticeable divide between the meaning of lifetime extension and repowering in offshore wind. Though lifetime extension, partial repowering, refurbishment, and retrofitting is seen to having similar features, but it is unclear to differentiate them. As a result, by assembling these EoL options, this thesis attempts to simplify their meaning. According to some surveys, offshore wind turbine foundations are often over-designed with the intension to accommodate bigger loads in the future. Even so, while the sub structure could be capable of supporting a bigger wind turbine, it is uncertain if the design and dimensions are adequate for such change.

3

LIFETIME EXTENSION OF OFFSHORE WIND FARM

3.1 LIFE CYCLE ASSESSMENT

The wind farm in this study is the Horns Rev 1 OWF located in the North Sea 14 km from Blaavand, Denmark. In 2001, VWS A/S and Elsam Engineering A/S conducted and created a design scheme for the LCA of a Vestas V80 2.0 MW turbine. This forms the core source of this LCA, otherwise stated. According to Eslam (2004), the farm is made up of 80 Vestas V80 2 MW turbines that are arranged in a lattice pattern with a distance of 560 m between turbines. The tower is 140 tons and 60 m high, the nacelle is 64 tons, the rotor is 38 tons, and the foundation is 203 tons. The water depth ranges from 6.5 to 13.5 m. It has a monopile foundation rammed into its uniform sand bottom seabed. A 32 kV cable grid is installed on the transformer station and connects the turbines. The transformer foundation is made up of three monopiles, two of which have a diameter of 1.6 m and the other one is 2.3 m. They are connected by lattice girders.

A LCA is a tool for evaluating a product's environmental factors and future consequences. LCA is a technique that is used to provide a technical assessment of a product's or activity's environmental effects.

LCA carried out for OWF do not show much difference with the onshore counterpart. When an onshore wind turbine is placed optimally, the comparison reveals that power from an averagely sited onshore wind farm has a greater negative or equivalent environmental effect than power from an unfavorably located OWF.

Findings suggest that turbines have the greatest environmental impact, rather than the transmission grid, to a large degree. The most significant environmental impact from turbines comes from their manufacturing and removal, since it is the components that pose the greatest environmental adverse effect. The operation of wind turbines has a negligible effect on the overall environmental impact. OWF's foundations account for a significant portion of the overall environmental damage, since steel is a major component of the foundations, and some of it is left at the seabed after the farm is dismantled. As a result, the OWF's foundation is chosen as a priority field in relation to product optimization possibilities. It has been discovered that all foundation models have a nearly identical environmental effect. Despite the fact that the O&M has only little effect on the atmosphere, the environmental variations in using a helicopter or vessel for offshore turbine servicing should be investigated. However, regardless of the mode of transport, servicing would not have a significant effect on the overall impact of the farm over its lifetime.

Amongst the most important limitations of LCA is that it requires many arbitrary choices and decisions, and the precision of an LCA is dependent on access to or the availability of valid and reliable data.

The aim is to apply LCA to environmental improvement techniques in conjunction with product growth, as well as to use LCA-data to prepare an environmental declaration of contents for energy generated by turbines, as well as for lifetime extension and repowering. The objectives are to prepare an LCA for an offshore Vestas turbine, which includes grid connection, enhancement strategies for each life stage (manufacturing, usage, and removal), and the preparation of an environmental product declaration (EPD) and the electricity generated. This may serve as a modelling tool.

Turbines and internal cables have a lifetime of 20 to 25 years, while transmission cables, transformer stations, and cable transition stations have a 40-year lifetime. When the transmission grid is designed to have a 40-year lifetime, it means that after 20-25 years, a new farm will be built or the current farm will continue to operate.

The life cycle of a wind turbine is illustrated in figure 3.1.

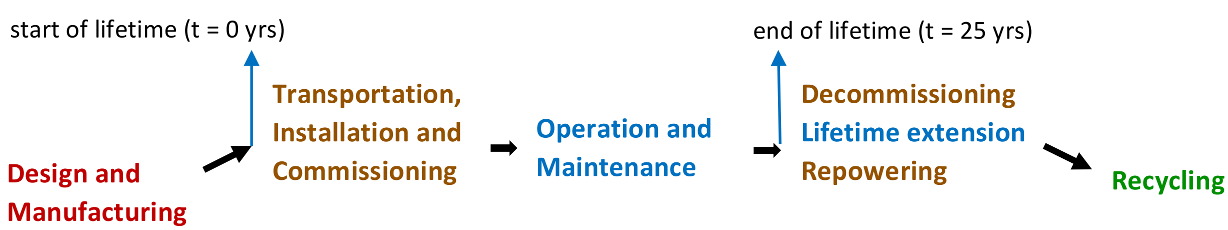


Figure 3.1: Life cycle of wind farm.

3.1.1 POWER GENERATION, OPERATION, AND LCA MODEL

The electric power output from Horns Rev 1 is estimated to be 647 GWh/year1, implying that each turbine generates 8.088 MWh/year, amounting to 4.044 full-loaded hours/year.

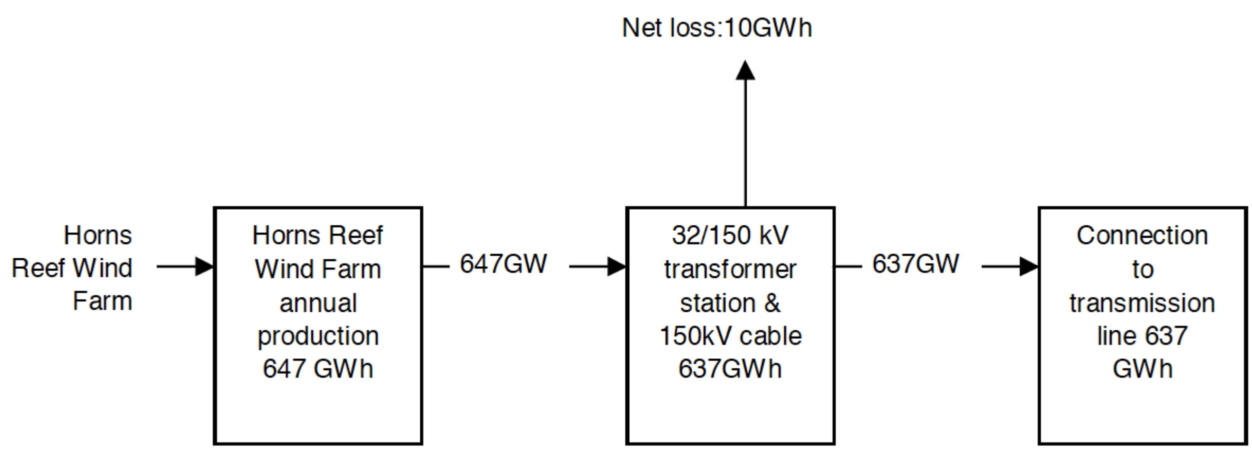


Figure 3.2: Power generation of LCA model of Horns Rev 1 (Source: Eslam, 2004).

Wear and tear, especially of the rotating components, will occur as a result of turbine operation. lifetime, one reconditioning/renewal of half of the gears and generators is expected to be performed, which will at the very least include bearing replacement. Just the gearboxes are used in the service plan to keep it simple, but in compensation, the model includes a complete replacement of half of the gearboxes sometime during the turbine's lifespan. As a result, the model should contain a large number of components, as most of the gears and generators would most likely be fixed rather than replaced.

Additionally, supplies for turbine maintenance, such as oil changes and lubrication of gear, generators, and other components, are used.

To prevent rust and corrosion, the foundations are given cathodic protection (e.g., aluminum) during their operating lifetime.

After 10-15 years of service, the transformer station must undergoe paint repairs and active anode renewal for cathode preservation. Inspections are expected to be carried out 12 times a year. 9 of these are likely to be carried out by helicopter, while the other 3 will be carried out by ship t is worthy of note that helicopters emit 5 times less CO2 per passenger compared to Crew transfer vessels. The inspection will cover about 2.400 kilometers a year by vehicle.

The inspection of the cables on a regular basis is not included. The turbines, on the other hand, will be serviced 5 times a year, 4 times by helicopter and ones by ship.

The LCA model comprises of turbines, internal cables, offshore transformer station, sea cable, onshore cable transmission station, and onshore cable to power grid. Materials, processing, transportation, installation, service, demolition, and scrapping are also used in each of these categories. The elements used in the LCA model for Horns Rev 1 are seen in Figure 3.3.

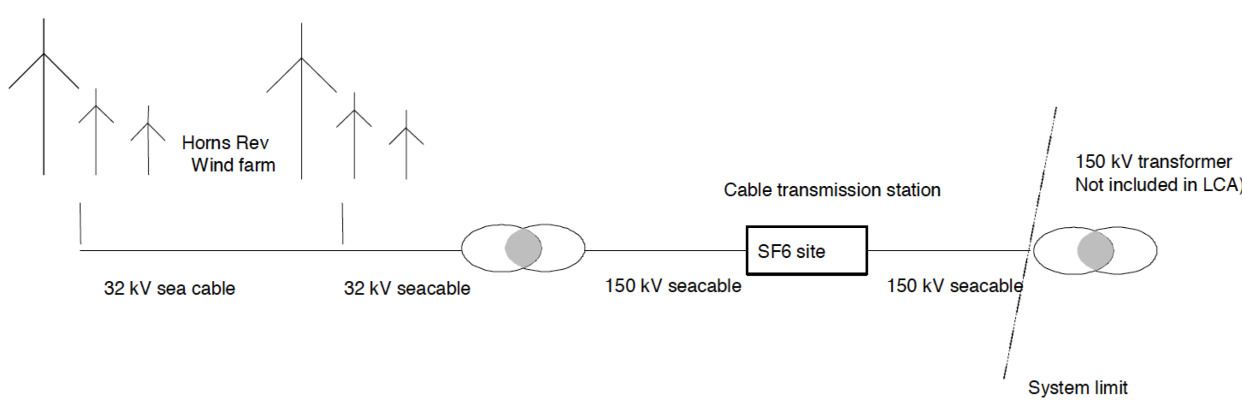


Figure 3.3: LCA model (Source: Eslam, 2004).

The tower is manufactured at VWS factory in Varde. The blades are manufactured at VWS A/S' factory in Nakskov. Plate foundations made of reinforced concrete serve as the base for the onshore turbine. The scale is about 15 x 15 m and 2 m wide. It consists of close to 350 m^3

concrete and nearly 27 tons of reinforcement. 32 kV PEX submarine cables are used for the internal farm cables, such as between turbines and between the 32/150 kV transformers. Oslofjorden manufactures the 95 and 150 mm2 cables, while Hanover manufactures the 400 mm2 cable. It is likely that 150 kV PEX submarine onshore cable and SF6-system for offshore wind farm I used. The platform's base, which is expected to last at least 40 years, is made up of three piles, two of which have a diameter of approximately 1.6 m and one with a diameter of 2.3 m. Lattice girders are used to connect the three foundation piles. The platform is about 14 m above mean sea level and stands at a height of approximately 7 m. The measurements of the ground are 20 m x 28 m. To have shelter on the foundation, the steel superstructure would be enclosed on both sides. A helicopter platform with a diameter of approximately 20 m is on top of the building, which is approximately 23 m above mean water level. Environment impact as a result of sea transportation is estimated to amount for less than 10%. Table 3.1 shows the material breakdown, Table 3.2 shows waste handling, and Table 3.3 estimates the energy consumption.

Table 3.1: Material breakdown (Source: Eslam, 2004).

Materials	**Offshore turbine** (kg/turbine)	**Transmission** (kg/farm)
Steel	349.240	1.488.186
High strength steel (stainless steel)	13.331	8.000
Cast iron	20.688	131.000
Glass fibre	21.842	0
Plastic	3.879	822.158
Lead	2	2.354.742
Cobber	2.958	858.237
Aluminium	3.545	364.450
Zinc	9.914	700
Concrete	0	1.375.000

Table 5: Waste handling at end of life (Source: Eslam, 2004).

Materials	Scenario
Steel blades	90% reuse
Stainless steel	90% reuse
Cast iron	90% reuse
Cobber	95% reuse
Aluminium	90% reuse
Plastic, PVC	100% deposit
Glass fibre	100% deposit
Oil	100% incineration
Lead	90% reuse
Zinc	90% reuse

Energy consumption [kJ/kWh]				
	Manufacturing/dismantling	Operation	Transport	Total
Fossil fuel				
Coal	26,48	1,58	0,003	28,07
Oil	42,33	8,15	1,09	51,56
Gas	17,51	1,18	0,07	18,77
Brown coal	3,59	0,41	1,45E-07	4,00
Renewable energy				
Water	25,93	0,96	0,002	26,89
Straw	8,28E-04	4,51E-08	0	8,28E-04
Wood	1,28E-06	1,98E-08	0	1,30E-06
Other biomass	0,58	0,03	7,52E-08	0,62
Nuclear power	4,90	0,38	7,29E-05	5,28
Wind power	3,60E-03	0	0	0,0036
Total (kJ/kWh)	**121,33**	**12,69**	**1,17**	**135,19**
Total (kJ/turbine)	19.626.195.279	2.053.516.004	189.050.162	21.868.761.445
Total (kWh/turbine) in the lifetime	**5.451.721**	**570.421**	**52.514**	**6.074.655**

Figure 3.4: Energy consumption (Source: Eslam, 2004).

3.2. ASSESSMENT OF MONOPILE FOUNDATION FOR LIFETIME EXTENSION AND REPOWERING OF OFFSHORE WIND TURBINES

To still ensure the profitability of wind parks, lifetime extension is essential to increasing the return on investment and also the amount of carbon-free emissions that existing assets produce. The life cycle of an offshore wind turbine comprises of different stages for design, manufacturing, transport and installation, operation, and potentially lifetime extension. Transport, installation, and waiting time until commissioning adds to the usage of the structure. This usage must be added on top of the structural reserves required for the planned service life. If the assets have structural reserves at the end of their design lifetime, then lifetime extension is possible. The operation of the wind turbines can then be driven until structural reserves are exhausted.

Monopiles are cylindrical objects made out of rolled steel plates. Plate segments are joined with longitudinal and circumferential double-sided butt welds. Welding inherently brings about small material defects which makes welds susceptible to initiation of fatigue cracks. The structure attains the fatigue limit state if the fatigue damage increases beyond 1 during the design lifetime and subsequently also during lifetime extension. The degree of fatigue damage is unrelated to an explicit physical state, apart from when fatigue damage equals 1, indicating failure. It hence cannot be determined directly during inspections. Only indirect measurements through a continuous fatigue load surveillance system are possible, which will keep track of the occurred stress distributions and number of cycles.

A damage equivalent load (DEL) is a constant-amplitude load that triggers the same amount of damage as a load time series with various amplitudes. Fracture mechanics models explains the spread of fatigue cracks in materials. The size of fatigue cracks is an unhidden phenomenon and can be determined. The Remaining Useful Life (RUL) is attained, once the crack got to a critical size.

Today's wind turbines use numerous sensors to adjust their operation to dynamic environmental conditions, to track their performance, and to observe selected components. Data is collated individually for every turbine as well as a group for the entire wind park. Environmental conditions are frequently collated on a wind park level using, for example, wave buoys, met masts, and measurement devices installed at the transformer platform.

Since offshore wind is a nascent industry, there is little body of knowledge with lifetime extension. Since the onshore and offshore wind industry are closely linked, it is necessary to examine which onshore practices can be adopted to offshore, and where new solutions are paramount.

Technical evaluations are necessary to prove that monopiles have enough structural reserves left for lifetime extension. Structural reserves remain if: constructed loads are less than design loads, built material resistances are more than design resistances, or when information on structural geometry, environment and operation, as well as increase accuracy of structural analysis models allows to cut down conservatism in safety factors. Numerical simulations, inspections, and measurements can be applied to evaluate structural reserves and the RUL of a monopile. Recommendations for technical lifetime extension evaluations are provided by Megavind (2016).

Analytical assessments are established in this thesis as a repetition of aero-hydro-servoelastic simulations from the design stage with new information brought in during the service life. Simulations should basically be carried out with the original design models. However, these are usually not provided for due to confidentiality of designers. Monopiles are quintessentially manufacturers near the upper bound of design allowances.

In the offshore environment, inspections are expensive because of crew transfer and risks for health and safety. In addition, offshore terrain and inherent difficult access reduce the probability to detect damages.

Lifetime extension has been researched widely for offshore oil & gas platforms, such as in [Ersdal, 2005), and (Ersdal, 2008). Jackets, mostly applied as support structures, are designed with redundancy. Their structural safety is not compromised even if some braces are missing. Monopiles do not have this redundancy. A crack in a cycle-like weld grows exponentially and can lead to catastrophic failure. As an example, the rotor-nacelle-assembly of a turbine in the Samso Offshore Wind Farm brokedown and fell into the sea in 2015 as a result of crack in the welding connection of the tower top flange (4C Offshore, 2015). The absence of redundancy and dynamic loading makes some basic assessment for lifetime extension, such as flooded member detection of fatigue cracks, unconducive for offshore wind turbines.

Lifetime extension is beneficial if operational costs (C/MWh) are less than the market price for electricity (C/MWh). In case of offshore wind, the RUL of monopiles defines the required time span for lifetime extension assuming that efforts to carry out major repair on monopiles are not cost-effective.

Repowering is profitable if sites are scarce and economic conditions support new investments. In comparison to new sites, repowering projects have the benefit of using existing infrastructure. Offshore infrastructure (e.g. cables, converter platform), however, is dimensioned for a specific power output. Repowering with bigger wind turbines will therefore require large-scale adjustments. Synergies may come up if decommissioning and installation of new turbines are carried out in one vessel operation to save logistic costs.

Technical, economic, or legal limitations might prevent lifetime extension and/ or repowering, which may make the decision simple. If both alternatives are feasible, repowering and lifetime extension projects are competing for the same site. It is then an optimization challenge to determine the best time to switch from lifetime extension to repowering.

3.3. STRATEGY FOR EXTENDING THE LIFETIME OF A WIND TURBINE

As wind turbines near the end of their operational lives, wind-turbine and wind-farm owners must make informed decisions about whether to continue operating the turbines, extend their lives, or decommission them. The different wind-turbine parts must be inspected to determine their functioning and the likelihood of failure during ongoing operation. Depending on the amount of operational data available and previous concerns with the turbine's components, the type of inspection may vary. Extending the life of a turbine beyond its typical design life necessitates the owner to verify by inspections, operational data, or both, that the yearly chance of structural component failure is still acceptable, taking into account maintenance history and component failure patterns.

The parts that follow describe how to determine prospective lifetime extension solutions using a component-by-component analysis, as well as important inspection requirements and suggestions that can demonstrate the feasibility of lifetime extension. The strategy is applicable to wind turbines towards the end of their design life and is based on the amount of operational data available, allowing for skilled choices. The current wind energy scenario in Denmark, as well as the legislative conditions for life extension, are described.

The interviews carried out by the author suggests that the approach to extend the lifetime of wind turbines given by MEGAVIND remains a useful guide for high performance. This guide together with the outcome of the interviews and research by the author form the basis of the strategy for extending the lifetime of a wind turbine presented as follows.

3.3.1. RECOMMENDATIONS

1) Begin research into repair procedures for each critical component of the turbine, including structural and non-structural components, for the purpose of extending the turbine's life and improving power generation and safety.

2) Develop a system for storing wind turbine failure records and underlying causes in a database structure.

3) Develop a method for approving lifetime extension requests.

4) Apply knowledge from other industries to the offshore wind energy business, such as the automotive, offshore, or civil engineering sectors.

5) Develop a new IEC TC88 standard for wind turbine lifetime extension to broaden the range of applications and requirements on a worldwide scale.

6) Develop a technique for measuring tension in prestresssed bolt connections.

7) Using operational and/or measurable data, develop standardized procedures for determining the remaining lifespan of important components.

3.3.2. METHODOLOGY

The current method focuses on extending the useful lifetime of wind turbines, including all

sizes and ratings, except those meant for households. The method is particularly helpful to wind turbines that are near the end of their design life and is based on the level of operational data accessable to make informed decisions.

WIND TURBINES INSTALLED IN DENMARK AND THEIR LEGAL BASIS

The order states that a wind turbine that has been in operation for longer than its design lifetime, as written in the manufacturer's manual or in the certificate issued, shall be subject to extended service. Extended service inspections of wind turbines must comprise the following basic requirements.

- Check for corrosion and wear on foundation bolts.
- Examine all bolted connections.
- Check for wear on the yaw bearing and measure the amount of play in the bearing. Examine critical components of the yaw system.
- Look for fractures in all welds on the tower.
- Look for fractures in the machine frame's heavy-load regions, as well as in all welds.
- Tighten nuts in joints according to the instruction, especially on blades.
- Look for concrete fractures in the foundation. Inspect and, if required, fix the foundation's sealing to keep water out.
- Look for dents and corrosion on the main shaft. This region must be free of dents and corrosion (no stress raisers).

• Perform a close visual check and subsequent evaluation of the blades, utilizing a camera or a picture drone/UAV. The aforementioned check must be carried out as a visual check of the components and things mentioned.

3.3.3. ESTIMATING THE LIFE EXPECTANCE OF WIND TURBINES

When no design specifications or measurements are provided, only estimates can be supplied. In the absence of such data, appropriate wind-climate-analysis tools might be utilized instead.

The structural design of the turbine is also based on a target yearly probability of failure or yearly reliability level, which means the structure fails when the design load, meaning the characteristic load multiplied by partial safety factor, reaches a limiting level in comparison to design-material resistance. The design load and material strength limits are frequently multiplied by partial safety factors, which are based on expected uncertainties in environmental circumstances, material properties, and design models, with a conservative cumulative result. Because the severity of the assumed uncertainties may be less than expected, this might allow turbine components to last longer. Failure in fatigue is defined as when the cumulative damage induced by stress cycle changes over time exceeds the material limit, as determined by the material's measured S-N curve15. It's worth noting that the IEC 61400 series of wind turbine standards doesn't include any requirements for assessing existing wind turbines. The following essential aspects should be considered while determining the RUL of wind turbines.

Lifetime extension procedure: In the context of continuing operation beyond the design life, evaluate the safety standards and integrity of key components and systems whose failure might result in damage, economic implications, or loss of life.

Failure modes: The common mechanisms of failure experienced by wind turbine components, as well as the repercussions of these failures, are determined by the dependability and deterioration of turbine components such as gearboxes, blades, bolts, and welded features, such as those found in the tower. A turbine's ability to operate is restricted by safety regulations, but it also depends on a cost–benefit analysis for the remaining lifetime. If the information from inspections, condition monitoring (CM), and structural-health monitoring (SHM) can be combined with suitable degradation models, it may be used to update the estimation of the turbine's reliability throughout its remaining lifetime.

3.3.4. COMPONENT ANALYSIS

Below are presented purpose-built criteria to decide the remaining life of wind turbine components, together with their probable failure modes and new technological areas of concentration to enhance condition monitoring and inspection. Rotor, nacelle, tower, offshore substructures, general issues, health & safety, economy and optimization of operation, and maintenance are subsections into which the analysis is divided.

1. ROTOR

The hub, blade root and hub connection, blades and the pitch actuators are analysed here.

Rotor, hub

Lifetime extension strategy: This is hinged on the handiness of a design basis. If it is handy, the load models and design threshold should be relooked at by the OEM or turbine owner and the required information updated. The updated results will show whether inspection or monitors are needed together with the standard service inspections carried out throughout the initial design life. The rotor's operating trajectory must be added in the assessment to make room for failure modes monitoring and prevention of future failure, so that the remaining design lifetime can be attained. A similar, turbine alternative can be used as a guide, if the load models or design threshold do not exist. If the load models or design baseline do not exist, a comparable, alternative turbine type can be used as a guide. To identify risk areas and probable failure modes by either inspection or monitoring, an FMEA can be carried out.

Failure modes and impact include:

• Broken and/or loose bolts in the joint between the hub and nascelle can lead to a collapse of the entire rotor and hub, damaging the tower in the process.

• Broken and/or loose bolts in the interface between the hub and blade/blade bearing can
lead to a collapse of the blade.

• Part of the hub as well as the blades can collapse to the ground as a result of general fatigue of the hub structure.

• Hub covers and other parts can collapse to the ground as a result of loose bolts or degraded materials.

Precautions During inspection:

• To prevent fatigue damage and maintain defined torque levels, replace old bolts.

• For cracks and corrosion, inspect the hub structure. Employ non-destructive testing (NDT).To identify the danger of premature fatigue failure, employ advanced load models using the design basis.

• Every component of the turbine shutdown system must be inspected and tested to curtail the danger of a runaway turbine.

• For cracks and degradation, hub cover parts must be inspected.

• Inside and outside the hub cover, components must be inspected to curtail the risk of parts falling.

Recommendations

• To determine the condition of mounted bolts, without dismounting them, create a dependable, cost effective and simple methods.

• To detect fatigue failures in the hub structure, create cost effective methods.

• To understand the prevailing weather conditions, create a site-specific wind and turbulence estimation tool.

Blade root and hub connection

Failure modes and impact: The structural strength of the joint between the blades and hub can be compromised by bolt failure. When deformation of the bolt's unthreaded shank occurs, it can cause an applied locking torsion that does not make for proper torqueing of the bolt's threaded section. Misleading pre-stress values can emanate from corrosion and rust in the threaded section. Displacement between the blade and hub and heightened vibration, which can result to fatigue damaged bolts and crack formations in blade rings, may arise from incorrect torsion. Bolts can fail either from fatigue or tension.

Precautionary measures: The detection of corrosion and rust, as well as deformation and fatigue damage can only be made possible after the removal of bolts to allow for visual inspection. In the bolt connection, greasing bolts must preceed retightening.

A recommendation is to detect pre-stress and crack formation, NDT methods should be created such as ultrasound and X-ray.

Blades

Lifetime extension strategy: The blades' operational trajectory should be scrutinized and all previous maintenance reporst evaluated. The cost of preventive repairs and maintenance should be calculated, if there is a likelihood of blade damage deterioration like cracks. The blade's remaining fatigue life can be determined, if the operational data and load models are available. The process is based on the damage trajectory by utilising design load calculations, acquired wind measurements, as well as previous operations' SCADA data. The blade surface must be subjected to aerodynamic evaluation in order to ascertain probable deterioration in power performance from worn surfaces. Design standards should be marked for change.

Failure modes and impact: The most common damages are cracks and debonding along the leading edge, trailing edge, and main load-bearing laminates. During extreme turbulence or negative wind shear, blade tower strike during operation can occur. Some frequent blade faults are failures from lightning strikes, failure of tip brakes, and erosion.

Precautionary measures: In recent times, most blade inspections are visual, and most visual inspections and repairs are carried out with rope access. This method is not only costly but may not often be accurate and may also pose a serious health and safety danger for the technicians involved in the inspection and repairs.

Recommendations: Recommend the use of drones implanted with thermal cameras, high resolution camera, NDT sensors, etc., to trace heat development in cracks. Visual inspection and drones can also be used to detect damage from the outside. While stiffness degradation monitoring can be used to detect inside cracks.

NACELLE

Failure modes and impact

A broken drive train is as a result of either a gearbox or main bearing failure. Such a failure can lead to the blades rupturing and falling to the ground. Overspeed can result from turbine safety system failure, thereby, leading to blades' collapse.

Precautionary measures

To identify failures, condition monitoring system (CMS) technology should be used. Utilising boroscope technology helps inspect gearbox.

Recommendations

CSM technology should be utilized, together with data analytics to predict the system's health for bearings and gears.

Nacelle: main bearing and shaft

Lifetime extension strategy

The gearbox, the main shaft as well as the main bearing should be looked at, leaving out none.

Failure modes and impact

Bending, torsion, and thrust result in the loads on the shaft.

The rotor can be lost due to a main shaft crack when overloaded. Welding can induce residual stresses in some areas, from which a crack can expand, leading to the breaking of the main shaft. The main shaft does not permit welding on it. The main bearing inner ring fit may experience wearing corrosion. If the wearing corrosion is not very serious, the shaft can be refurbished by metal spraying and grinding at the bearing fit.

Precautionary measures

The shaft must be repaired, if corrosion or deep scratches or cuts are detected by any tool. Paint or rust serve as protection, and so should be used.

Recommendations

Ultrasound testing on the section of the shaft inside the main bearing should be carried out. Testing and verification of material properties for fatigue resistance should be done.

Nacelle: frame

Lifetime extension strategy

An understanding of fatigue failures from cyclic loading is needed to forecast the lifetime of the mainframe. Cyclic loading occurs in phases, namely: the crack initiation phase, the crack growth phase and then rupture. The crack initiation phase is the interval leading up to the formation of surface cracks subject to fatigue loading. The crack growth phase comprises the remaining life until the crack gets to critical size. This second phase falls under the science of fracture mechanics, where a cardinal part is being played by both material properties and microstructure.

Failure modes and impact

When the turbine reaches its design lifetime, fatigue cracks can occur with a fairly high degree of certainty. In most instances, the effects of a large fatigue crack can lead to the nacelle's complete failure. Fatigue failure may be the product of a large crack together with an unstable crack as a result of extreme loading. Significant economic loss can emanate from the loss of the nacelle as a result of Fatigue failure of the nacelle frame.

Precautionary measures

An estimate of the anticipated fatigue damage can be calculated and compared with the requirements in the standards and design codes, if information is available about the wind climate and the turbine's operations during its lifetime. Information about the remaining fatigue life can be updated through inspections. Applications can be copied from other related industries.

Recommendations

Provision of multiyear data must be made ready concerning each important fatigue component in the frame, together with information about wind climate, condition monitoring and SCADA data, bringing about an up to date estimate of the design fatigue lifetime, in consonance with the design standards employed. The inspection planning should assess the authenticity of the inspection method employed, intervals between inspections, component criticality, and planned actions if cracks are discovered.

Nacelle: electrical components, including controller

Lifetime extension strategy

Each of these segments signifies a specific challenge during a WTG's lifetime. Fire or even an explosion can result from an uncontrolled combination of resistance and current flow within a high level challenge.

It is the attached electronic equipment converters that bring about the challenge, not the synchronous nor the asynchronous generator.

Failure modes and impacts

i. Electrical protection system including converter:

Total loss of WTG as a result of fire is a significant material damage emanating from electrical fault and has a major economic implication. Apart from the WTG's total loss, environmental damage as a result of spills from oil is common. Natural aging from wear and tear are less likely than electrical faults in converters, filters, and circuit breakers after the first decade of usage. Circuit breakers, which are designed at each start or stop, will experience wear and tear significantly more than circuit breakers only made for protection.

ii. Transformers in the nacelle

The windings in the coils can be connected internally. The high and low voltage terminals can also introduce arcing to ground.

Precautionary measures

i. Electrical protection system including converter

To measure wear and tear circuit breakers can be inspected.

ii. Transformers

It is important to look at for , dust in the cooling channels, bent connection rods between the taps, and connections, as well as partial discharge.

Recommendations

i. Converters, filters, and breakers

The replacement of capacitors and circuit breakers after a projected timeframe should be factored. The number of years before replacement is undertaken should be determined on a case by case basis, depending on the type of capacitors and electrical system's design. In addition, I recommend installation of an arc detection system.

ii. Transformers

Arc detection is essential to protect the transformer and the entire WTG.

2.4 Nacelle: yaw systems

Lifetime extension strategy

After replacement schedules during the turbine's lifetime and any life extension, the yaw-brake system, comprising the yaw-brake disc and yaw brake with brake calipers, needs renovation.

Failure modes and impact

Cracked yaw drive shafts, pitted yaw bearing races, fractured gear teeth, and failed bearing mounting bolts are all part of the yaw system failure. Yaw drives and yaw brake systems failure has only one economic consequence. Broken bolt interfaces can lead to the loss of the turbine if the nacelle or rotor falls to the ground.

Precautionary measures

Bolt connections should be inspected to prevent breakage.

Recommendations

To eradicate the possibility of worn out bolts resulting from fatigue loading, they should be changed regularly, unless available calculations or data show that inspections alone will be adequate. Also, to curtail yaw drive fatigue loading, employ hydraulic components in the yaw system design.

2. TOWER

Below are welds & flanges in the tower and doors examined.

Tower flanges and welds

Failure modes and impact

The impact of a huge fatigue crack in the peripheral weldings will lead to the tower's total failure. If the welding is subjected to corrosion, susceptibility will be increased. Fatigue failure can be a combination of a large crack and unstable crack propagation as a result of varying loads.

Precautionary measures

An estimate of the anticipated fatigue damage can be gotten and compared with the requirements in the standards and design codes, depending on inspections and analyses, together with wind climate data and the turbine's lifetime operational trajectory. Knowledge from other industries, like the offshore oil and gas platforms and bridges, can be incorporated, where needed.

Recommendations

First, an updated estimate of the design fatigue lifetime is made possible by updating the information about each critical fatigue in the tower with data from wind climate, condition monitoring, and SCADA data. Second, carry out the inspections, assess the periods between inspections, and the planned actions if cracks are noticed. A dependability level for an existing turbine tower lesser than for a new tower may then be factored in.

3.2 Tower: doors

Failure modes and impact

The implementation of a huge fatigue crack developing into the peripheral welding will lead to the tower's complete failure. For flange connections, fatigue, mostly, and incorrectly done or maintained bolted connections may lead to the tower's complete failure.

Precautionary measures

Inspections and analyses are both possibilities.

4. OFFSHORE SUBSTRUCTURES

Lifetime extension method

An offshore substructure is impacted by gravity, wind-propelled loads, and hydrodynamic loads, and also by marine growth and corrosion. Components erected on the substructure, like
boat landings, are subjected to impact loading from boats and vessels.

Failure modes and impact

Active cathodic protection, passive cathodic
protection as well as paint systems can protect the foundation from corrosion.

The grouted joint between the monopile and the transition piece, for monopile substructures, is a sensitive joint that must be inspected twice in a decade in order to gaurantee its reliability. The fatigue life of the steel parts and the wear of the grouting material between the steel shells are always impacted by the constantly varying loads. The static and fatigue strength of the structure's steel, including bolts, are reduced by corrosion.

Scour, is another common failure mode that brings about the removal of the soil around the foundation by the water currents, hence degrading the bearing capacity of the foundation support. Monitoring for the outset of scour is needed to make room for preventive action against undue vibration of the support structure as well as scour protection to prevent removal of the seabed.

Precautionary measures

Inspection of the structure's exterior and interior to detect corrosion in painted and unprotected areas, together with probable structural degradation with time is performed using Desktop analysis of critical stress faultlines.

Drones and unmanned underwater vehicles should be used for visual inspection of defects of the platform, boat landings, and J-tubes..

Where load measurements are possible, compare the real lifetime loads with the design loads. In the comparisons, both periods of idling and operational time should be accounted for, together with measurement of the soil and foundation's actual stiffness.

The cathodic system, scour, and grouting should be inspected during normal service work.

Recommendations

Partial safety factors and stress concentration factors employed in substructure design can reduce costs and be evaluated at the end of the design life to further assess repowering or decommissioning.

5. GENERAL ISSUES

Addressed below are issues that are critical to the structural integrity of the turbine, as well as the generic connectors that are not limited to any single turbine component.

5.1 General: bolts

Lifetime extension strategy

The turbine's hub are bolted with blades and their failure can either lead to throwing of a blade or total failure of the turbine. Inspection together with the component that is bolted are the prerequisites for calculating the lifetime of bolts and blades.

Failure modes and impact

Common failures include overload fracture, fatigue damage, and hydrogen embrittlement with manufacturing processes or corrosion as the supplier of hydrogen.

Bolt fatigue damage is also brought about by the presence of pre cracks in the galvanized layer or inside the source layer. Between the galvanized layer and the bolt's surface are the concentrated stresses. The pre crack penetrates into the material and instigates structural damage for many number of cycles.

The bolt's distortion triggers fatigue cracks, as do rust effects, corrosion, and removal of the painted thick layer, which all affect the pre stress condition and raise dynamic load. A determining factor in fatigue damage to bolts is the pre stress condition- under stress and over stress.

Crack growth results in bolt fatigue failure, which can further lead to a chain reaction on other bolts and significantly damage the entire bolted connection.

Precautionary measures

An evaluation of the bolts' RUL may comprise the remaining fatigue life and the level of corrosion protection.

Recommendations

For high fatigue and corrosion strengths, interrogate the coating of bolts. Use loads on bolts like load cells, strain gauges, and condition monitoring methods for pre stress condition.

5.3 General - corrosion

Lifetime extension strategy

If dehumidifiers or other means such as cathodic protection are not used, the degradation of paint systems on steel will give rise to corrosion. The internal and external components of substructures like monopiles must be inspected to ascertain the level of material damage resulting from corrosion and its effect on lifetime.

Failure modes and impact

Corrosion will degrade the thickness of steel and initiate notch factors. This will give rise to less static and fatigue strength of metallic structures, like the transition piece connecting the tower and offshore substructures. Higher maintenance costs can result from the corrosion of metallic structures. Corrosion can lead to significant wear on seals on surfaces such as blade bearings. High notch factors in the main shaft can be created by fretting corrosion at bearing seats. At main bearings, and in gearbox bearings, it can also cause enormous play in bearing seats.

Precautionary measures

To check for possible corrosion, bolts must be disassembled. For the turbine's disassembled components a database is needed. Use axial ultrasonic check into the main shaft to determine if cracks have occurred as a result of fretting corrosion.

Recommendations

The performance of the cathodic protection system and the coating condition determines the foundation's corrosion protection. This should be assessed employing cost effective surveys and/or a close review of historical data from inspections or monitoring devices to evaluate the probability of lifetime extension.

6. HEALTH AND SAFETY

6.1 Non Destructive Testing (NDT)

All measuring and inspection techniques that do not require the test specimens to be destroyed are known as NDT. Ultrasonic and eddy current are some of the best inspection methods for in service turbine inspection, and they are cost effective. Bolt cracks, delamination in the blade, and cracks in mainframes can be inspected using ultrasonic inspection method. They can be combined with other advanced methods like automatic inspection for data acquisition and storage, and phased array method. Acoustic emissions and infrared scanning are also other possible methods.

6.2 Risk assessment

For calculating the probability of complete or partial structural failure, the consequences, and acceptance criteria, together with the likelihood of an effect from the throw of debris from the failed turbine, all require advancing a proper risk evaluation methods.

6.3 Repair

To detect damages early, it is critical that decision rules are employed, and this would aid preventive maintenance to be carried out as well as meet the reliability requirements.

7. ECONOMY

Critical to both risk assessment and economic impact estimation are deterioration models for different components like uncertainty modelling. As a decision tool for repair and maintenance, models for damage accumulation with time must be created. Critical for setting up requirements for inspection intervals are specific models to represent the fatigue damage of different materials and their types of deterioration. Knowledge from bridges and the oil and gas industry can be employed.

Depending on the turbine's operation, a measurement that uses undisturbed wind quantity measurement for each turbine could be used to make for an environmental condition. A strategy could be evolved to bypass curtailment strategies or the load level to enhance the turbine's lifetime, depending on a combination of wind speed and turbulence intensity measurement.

8. OPTIMISATION OF OPERATION AND MAINTENANCE

Taking into consideration weather windows and revenue from electricity production to reduce operational costs, operation and maintenance can be predicated on condition monitoring data gotten from the wind turbines whereby required maintenance to different components can be planned long before failure of the component.

Condition monitoring

Systematic data collection and evaluation to identify changes in the turbine's structural parts is achievable through the installation of Condition Monitoring (CM). This is to enable remedial action to be planned in order to maintain reliability in a cost effective manner. If the measurement parameters are correctly chosen and measured with accurate sensors, CM can provide early warning of potential failure.

CM offers diagnostics, data, and information for root cause analysis and equipment redesign, together with verification of defects or design correction, when used to propel reliability improvement.

Life cycle asset (structural) integrity management

It would be a major driver to visualising the connectivity between system and component dependability and translate it into ongoing updates to: the anticipated RUL based on measured information; operating risks; changes in the inspection and condition monitoring as well as the maintenance programme; the need for new experiences across asset life cycles and performance standards together with operational changes. It would also be a key enabler to the governing technical requirements and legislation as well as the technical connectivity and visibility between the installation premises and the design and the operating condition; and provide the operator with the template for best practice design and sound operational performance standards.

Reliability based optimisation of O&M

Common failure mechanisms serve as a critical enabler for the CBM and inspections already proposed in this document, and they have identifiable and measurable characteristics that develop over time. Either in necessary planned repairs or in the design process, the reliability database provides insight into potential systemic failures and helps to account for that.

For the systematic utilisation of failure data from different turbine components to better identify commonalties of dominant degradation characters, a database could be installed, and so enables reliability dependent planning of inspection and monitoring activities. This database could become a major enabler for the optimisation of life cycle cost to life cycle time.

4

REPOWERING OF OFFSHORE WIND FARM

Currently, wind turbines are meant to have a 25-year technological life (Luengo and Kolios, 2015). Offshore wind turbines, on the other hand, are frequently approved for a lifespan expectancy of 25 to 30 years due to the lower fatigue loads on the wind turbines owing to less turbulent wind conditions (Carrasco et al., 2006). Wind turbines with gearboxes have a lower lifespan and require more maintenance (Islam et al., 2014). One of the major strengths of full repowering is that the site has been well-known to the developer for many years, and if the layout is well optimized, the repowered OWF can possibly guarantee extremely high performance (WindEurope, 2016).

Staffell and Green (2014) investigated how the performance of onshore wind farms in the United Kingdom varied over time, finding that wind turbine production fell by roughly 1.6 percent per year and that their capacity factor dropped significantly. Unless the deterioration gets too severe, it means that a wind turbine's economic lifespan is lower than its technical lifespan (Staffell and Green, 2014).

4.1. ASSESSMENT OF WIND RESOURCES AND POWER PRODUCTION

When it comes to the construction of a wind power project and determining its feasibility, energy output is perhaps the most important factor to consider. Accurate wind measurements are essential for a valid output estimation of an offshore wind power plant.

The yearly distribution of wind speeds and direction must be determined to determine how much energy a wind turbine produces over the course of a year (Sempreviva et al., 2008). The Weibull frequency distribution is the most appropriate for this application.

$$p(v) = \frac{k}{A}\left(\frac{v}{A}\right)^{k-1} e^{-}\left(\frac{v}{A}\right)^{k}$$

The scale parameter, A _is in m/s, and the shape factor, k _determines the distribution's breadth. The range of k _values is 1 to 3.5, with higher values indicating a narrower distribution (Brower, 2012).

Because wind speed in the atmospheric boundary layer changes with height, projecting the recorded wind speed to the right height is required, for example, if the hub-height of a planned wind turbine is different from the ones on which the wind measurements were taken (Arrambide et al., 2019). At a particular height, the wind speed v is calculated.

$$p(v) = v_0\left(\frac{h}{h_0}\right)^{n}$$

Where v0_ _is the average wind speed at the measured height, h _is the height to which the wind speed will be extrapolated, h0_ _is the measurement height, and n _is the wind shear factor. The fluctuation in wind speed with height is referred to as wind shear. A wind shear value of 0.10-0.15 is normal for offshore locations in a temperate environment (Brower, 2012).

Wind turbine energy output is determined by wind speed, rotor swept area, and air density (Sempreviva et al., 2008). The efficiency of the wind power system influences the amount of electricity produced. Equation 3 is used to calculate the power output (Arrambide et al., 2019; Islam et al., 2014).

$$P = \frac{1}{2}\rho A v^{3} n_{eff}$$

Where P _is the wind turbine's power output, _is the air density, A _is the rotor swept area, v _is the wind speed, and neff _is the wind turbine system's efficiency. Higher air density, wind speed, and rotor swept area, as well as enhanced efficiency, will all enhance the power generated by a wind turbine, according to this equation.

The electrical output of a wind turbine at various wind speeds is represented by a power curve (Sempreviva et al., 2008). When the wind turbine reaches its cut-in wind speed, the rotor produces enough power to compensate for drive train losses and cover the turbine's internal entropy.

The findings of the wind resource assessment are integrated with the wind turbine power curve to determine the annual energy production (AEP) of an OWF (Hasager and Giebel, 2015). Brower, 2012; Pérez et al., 2013) suggest using Equation 4 to calculate the AEP for the entire wind farm.

$$AEP = 8766 \sum_{s=1}^{N_s} \rho_s \sum_{i=1}^{N_T} \left[\int_{v_{out}}^{v_{in}} P_w(v_i) dv \right]$$

Where 8766 is the average number of hours per year, N s is the number of Weibull speed bins, and _s is the likelihood of the wind speed being in speed bin s. P w (v i) is the produced amount of power by wind turbine I for the corresponding wind speed at the hub height v, v in and v out are the cut-in and cut-out wind speeds as defined by the power curve, and P w (v i) is the produced amount of power by wind turbine I for the corresponding wind speed at the hub height v. Because of the wind speed at hub height, Equation 4 determines the gross AEP before losses for all wind turbines. There are various alternative ways to calculate the AEP, depending on whether wind direction is considered.

$$CF = \frac{Net\ annual\ energy\ production\ (MWh)}{Installed\ Power\ (MW) * Annual\ hours\ (h)}$$

Offshore wind has a capacity factor of 37 percent on average in Europe (WindEurope, 2019b). Some OWFs, on the other hand, have a capacity factor of up to 56%. (Arrambide et al., 2019). Horns Rev 1 and Horns Rev 2 have capacity factors of 41.9 and 49.2 percent, respectively (Rodrigues et al., 2015). Vesterhav Nord and Syd, both proposed OWFs on Denmark's west coast, are estimated to have a capacity factor of up to 52 percent (Nielsen, 2018).

Wake losses, availability losses, environmental losses, electrical losses, turbine performance, and curtailment losses are the different types of losses. The wake formed downwind of a wind turbine causes wake losses, also called array losses. The wind speed and turbulence are both reduced by these wakes. Pérez et al. (2013) found that all wind turbines downwind in the wake will produce less energy. Needs to wake from upstream wind turbines have a major influence on wind turbine performance, delivering 10-20% less power than an undisturbed wind turbine (Archer et al., 2018; Sun et al., 2017).

When the wind speed is sufficient, availability refers to the period that a wind turbine or an OWF is operationally capable of generating power at the rated capacity. For energy production estimates, availability losses of 2% to 3% are commonly estimated (Brower, 2012).

All electrical components of an OWF experience electrical losses. These losses add up to around 2% to 3% of total revenue (Brower, 2012). Serrano González et al. (2017) use Germany and Denmark as examples of countries where the TSO represents the cost of connecting an OWF to the onshore grid.

Turbine performance losses include all losses that can be derived from the wind turbine not operating under optimal conditions. This can be yaw misalignment, calibration errors, blade pitch inaccuracies, high turbulence, high wind control hysteresis, etc. Aggregated, the losses due to suboptimal operation of a wind turbine could reach 2-3% (Brower, 2012).

Environmental losses are things such as the accumulation of ice, soil or degradation of the blades. It can also be shutdown of a wind turbine due to lighting strikes or very high or low temperatures (Brower, 2012). Weather conditions is also something that can have double effect on the losses. For instance, if there is a breakdown of a wind turbine during bad weather, the conditions can also hinder the repair of the wind turbine (Petersen et al., 2015). Environmental losses are difficult to estimate, however losses between 1-6% are typical (Brower, 2012).

Curtailment losses occur when, for example, some wind turbines within an OWF are turned off during specified wind directions to reduce component wear caused by wake-induced turbulence. The TSO can also apply curtailments as part of grid balancing. Curtailment losses may not be a problem because they generally amount for 0-5 percent of total losses (Brower, 2012). Table 6.7 shows an overview of typical values for the kinds of losses.

Table 4.1: Typical production losses for wind farms. (Recreated with data from Brower, 2012; Bergvall, 2019).

Typical Production Losses		
Wake Losses	[%]	10-20
Environmental Losses	[%]	2-3
Electrical Losses	[%]	2-3
Turbine Performance	[%]	2-3
Curtailment Losses	[%]	0-5
Availability Losses	[%]	2-3

Replacement of essential components of the wind turbine, such as the powertrain, hub, and blades, is recommended for partial repowering, but the existing base and tower should be used (Topham and McMillan, 2017)

Existing wind turbines are replaced with new ones during a full repowering, which usually has a larger installed capacity (Topham and McMillan, 2017). If possible, new wind turbines are erected on existing foundations, either using the existing tower if it is strong and tall enough or installing new wind turbines with towers on the original foundations (Topham et al., 2019).

Individual wind turbine distances must be sufficient to ensure that wake losses and turbulence do not become unacceptably high, resulting in greater loads on the wind turbines and, as a result, shorter wind turbine lifetimes (Perez et al., 2013).

Repowering should be investigated before the ultimate decommissioning of the OWF if the location has shown to be suitable for wind energy extraction. There are currently no documented approaches available. Because every OWF is different in terms of size, foundation type, weather, seabed conditions, and distance to shore, it is impossible to propose a uniform process for repowering OWFs (Hou et al., 2017). The structural strength of the foundations, as well as the ability of reinforcing them, determines whether a complete repowering is possible.

4.2. LAYOUT OPTIMIZATION AND REPOWERING OPTIMIZATION

Energy output, wake effects, capital expenditure (CAPEX), and operating expenditure (OPEX) all play a role in determining how OWF projects should be laid out (Mytilinou and Kolios, 2019).

A appropriate spacing between wind turbines in the main wind direction for minimising wake losses has been determined to be between eight (8D) and twelve (12D) rotor diameters. Between three (3D) and five (5D) rotor diameters should be maintained in the crosswind direction (Mytilinou and Kolios, 2019). In Europe, the average distance between wind turbines in commissioned OWFs is 5.98D. (Enevoldsen and Valentine, 2016).

Particle Swarm Optimization (PSO) and Generic Algorithm are commonly used in these researches to optimize layout (GA). The algorithms will figure out where the most efficient wind turbines should be placed on a wind farm site.

Some research has been done on layout optimization, which allows for uneven wind turbine placement within the wind farm area. For example, Pérez et al. (2013) conducted a case study on the German wind farm Alpha Ventus in the North Sea, finding that the wind farm's AEP could rise by 3.52 percent when compared to its current structure.

Sun et al. (2017) investigated OWF layout optimization toward the end of their specified lifetime, where the foundations and grid are reused, and the wind turbines are replaced with new wind turbines with reduced capacity. The goal was to extend the life of the wind farm and lower the cost of decommissioning. After a 20-year service life, a wind farm with 40 2.5-MW wind turbines was replaced with 1.65-MW turbines in the case study. The results revealed that by reusing the foundations, the cost of electricity for the repowered wind farm could be decreased by 14%, compared to the initial wind farm's cost of double that (Sun et al., 2017).

4.3. INTER-ARRAY GRID, TRANSMISSION, AND SUBSTATION

Transmission cables link the OWFs to the grid (Kaiser and Snyder, 2012a). Medium voltage transmission cables can be utilized for short distances. The power ratings of these cables are typically between 24 and 36 kV. (Kaiser and Snyder, 2012a). Transmission cables connecting an OWF to shore often have twice the capacity of the OWF itself (Hau, 2013).

In an OWF, the inter-array grid collects power from all the farm's individual wind turbines and delivers it to the substation (Petersen et al., 2015). The cable is linked to the wind turbine's transformer, which boosts the voltage from the lower voltage output to 10-36 kV. (Kaiser and Snyder, 2012a).

For short transmission distances, medium voltage transmission cables can be used. Typically, these cables have voltage levels of between 24 and 36kV (Kaiser and Snyder, 2012a). The capacity of transmission cables from an OWF to shore usually have twice that of the OWF (Hau, 2013).

The inter-array grid in an OWF collects the power from all the individual wind turbines of the farm and transmits the power to the substation (Petersen et al., 2015). The cable is connected to the transformer of the wind turbine, which steps up the voltage to 10-36 kV from the lower voltage output from the wind turbine (Kaiser and Snyder, 2012a). The cable is typically buried 1-2 meters underneath the seafloor and links to the array's next wind turbine.

4.4. FINANCE OF OFFSHORE WIND POWER DEVELOPMENTS

Offshore wind power development necessitates large capital investments, which may account for up to 75% of an OWF's total lifespan cost (Morthorst and Kitzing, 2016). Because repowering is a cost-effective method of decreasing the LCOE of offshore wind power, it also necessitates large capital inputs.

The levelized cost of energy (LCoE) is a metric often used in wind power development and other power projects to assess the economics of a project and compare different options (Ioannou et al., 2017; IRENA, 2012; Klinge Jacobsen et al., 2019).

The sum of all expenditures incurred by an OWF during its lifespan, which includes both CAPEX and OPEX, as well as decommissioning and disposal expenses (DECEX), is used to determine the LCoE. (Mytilinou and Kolios, 2019). The expenses are levelized and discounted to the present using the OWF's computed AEP (INNWIND, 2015).

$$LCOE = \frac{\sum_{t=1}^{n} \frac{CAPEX_t OPEX_t DEVEX_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{AEP_t}{(1+r)^t}}$$

Where CAPEXt, OPEXt, and DECEXt _represent capital, operating, and decommissioning expenditures in year t, AEPt _represents annual energy production, n _represents the projected lifespan of the OWF, and r _represents the discount rate.

Staffell and Green (2014) estimate a 9 percent rise in LCOE throughout the life of a wind generating plant due to rising OPEX costs.

The net present value (NPV), weighted-average cost of capital (WACC), internal rate of return (IRR), and discount rate are a few financial factors that are important and widely utilized when analyzing the financial performance of an offshore wind power project. The cost of financing can make up as much as 27% of the entire cost of offshore wind power development, putting a project's sustainability in jeopardy. WACC is determined by the quantity of accessible equity as well as the investment's risks (Petersen et al., 2015). Wind power projects typically have a debt-to-equity ratio of 70-80% debt to 20-30% equity (WindEurope, 2019c).

The cost of energy production influences the price paid for electricity delivered to the grid and is an essential input component in calculating a power project's financial performance. In 2020, the average production cost is expected to be 78 euros per megawatt-hour (MWh) (EEA, 2009). 60.7 € per MWh is received by Horns Rev 1 and Nysted (Rdsand 1). (Energi Styrelsen, 2014; Power Technology, 2019). The electricity price for Horns Rev 3 has been set at 103.1 Euro per MWh under an agreement with the Danish government (Vattenfall, 2019b).

4.5. OFFSHORE FOUNDATION

The wind turbine's foundation, which also includes the transition piece and scour protection, is the most important part of the support structure. The transition piece connects the wind turbine to the foundation, providing both absorption and simpler tower attachment. The foundation is surrounded by scour protection to keep the support system from being harmed by the sea (Kaiser and Snyder, 2012a).

The foundations must be designed to withstand the complex combination of forces and loads of varying frequency, amplitude, and direction that cause long-term cyclic loads on the support structure, as well as the extreme loads exerted on the foundations by the harsh nature of the sea (Ziegler et al., 2019).

Monopiles, which operate as an extension of the tower into the seabed, are the most basic sort of foundation for offshore wind turbines (Lesny and Richwien, 2011).

Monitoring of installed monopiles has revealed that they are stiffer than envisaged by the design. As a result, new design approaches may be able to minimize the monopile's weight and the depth to which it is sunk into the seafloor (Wu et al., 2019). When evaluating the feasibility of repowering an OWF, the structural strength and performance of monopile foundations is a critical factor to examine, as Wu et al. (2019) and Ziegler et al (2019).

Currently it is uncertain how much larger a wind turbine and tower can be built on an existing monopile, and further study is needed.

5

REINFORCEMENT OF MONOPILES FOR ADDITIONAL LOAD SUPPORT

Monopile foundations are designed to carry a specific maximum load over a given period of time. In a scenario where the wind park is to be repowered with bigger turbines, the structural strength and integrity of the foundation has to be accessed thoroughly. If the results show that the current substructure cannot withstand the load of the bigger wind turbine, then the closest option is to dismantle the wind turbine including the foundation and install the chosen wind turbine on a new foundation close to the dismantled spot. Another option could be to remove the old wind turbine but keep the old foundation. The old foundation is then reinforced for the purpose of carrying a bigger load than its initial maximum design load. Considering the harsh terrain of offshore sites, this seems challenging but does not rule out its possibility. After drawing a good project development and management plan and assessment of the environmental and soil conditions of the site, the additional monopile would be designed onshore and transported to the offshore site. There are basically two ways to attach the additional monopile to the existing monopile foundation, by using concrete or through welding.

However, this thesis will explore the possibility of using clamps to attach the additional monopiles to the existing one. It will show theoretical analysis of the possibility of implementing the additional monopile and clamp to reinforce the old monopile installed at the offshore site.

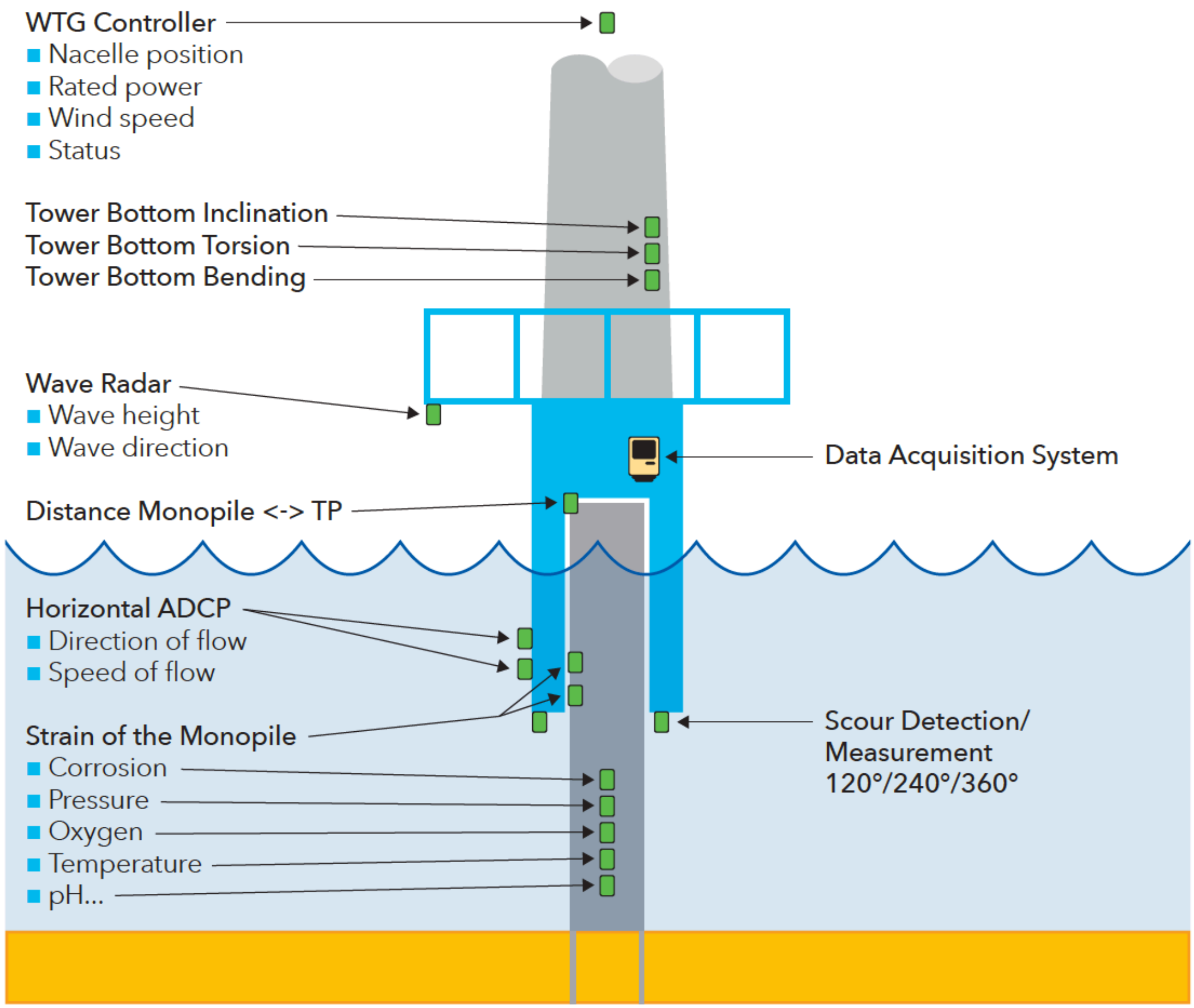


Figure 5.1: Substructure (Source: DNV)

5.1. THEORETICAL ASSESSMENT OF LOAD

To analyse if the an existing monopile foundation can carry additional load some calculations have been put together from a theoretical angle.

5.1.1. FAILURE DUE TO COMPRESSION AND BUCKLING

Monopiles are primarily made of steel, and as all steel when subject to greater load beyond their design capacity they experience failure. The two common failure modes as a result of wind turbine load is compression and buckling. The example below will try to calculate for compression and buckling of the base case that will be seen later in the next chapter.

Given the data below:

Mass of turbine = 764 t = 7494.84 kN

Mass of Monopile = 384 t = 348,000 kg

It is possible to calculate whether the monopile would be able to carry the wind turbine load or fail due to compression or buckling.

The area of the cylindrical monopile with regards to the outer and inner diameter is given as

$$A = 2\pi l(r_o + r_i\ ) \ + 2\pi(r_o^2 - \ r_i^2)$$

where:

$A =$ Area of the cylindrical monopile

$l = 39m =$ Length of the cylindrical monopile

$r_o =$ Outer diameter cylindrical monopile

$r_i =$ Inner diameter cylindrical monopile

But Outer diameter of monopile $D_o = 4\ m$

Inner diameter of monopile $D_i = 3.95\ m$

$$r_o = \frac{D_o}{2} = \frac{4}{2} = 2\ m$$

$$r_o = 2 \text{ ⍰}$$

Similarly,

$$r_i = \frac{D_i}{2} = \frac{3.95}{2} = 1.975\ m$$

$$r_i = 1.975 \text{ ⍰}$$

Substituting the values of r_o and r_i

$$A = 2\pi * 39(2 + 1.975\ ) \ + 2\pi(2^2 - \ 1.975^2)$$
$$A = (245.044 * 3.975) + 0.099 = 974.149\ m^2$$
$$A = 974.149\ m^2$$

For Compression: To check if the monopile would be able to carry the load of the wind turbine without failure due to compression, the applied stress exerted by the load should be less than the allowable stress for steel. The allowable stress for steel is 250,000KN/m^2.

Applied Stress = Applied Force / Cross sectional area.

Mathematically:

$$\sigma_a \ = \frac{F}{A}$$

$$\sigma_a \ = \frac{F}{A} = \frac{7494.84\ KN}{974.149\ m^2} = 7.7\ KN/m^2$$

From the calculation, the allowable stress is greater than the applied stress, which means that the monopile will be able to carry the load of the wind turbine without compression.

For Buckling: To check if the monopile will not fail due to buckling, the critical buckling load (P_{cr}) should be greater than the modulus of elasticity (E) of the monopile material. The modulus of elasticity of steel = $200 * 10^6\ KN/m^2$.

$$F\text{cr} \ = \frac{\pi^2 EI}{L^2}$$

where:

P_{cr} = Buckling Load

E = Modulus of Elasticity = 200 GN/m^2

L = Length of monopile = 39 m

I = Moment of Inertia of the monopile

For other given data:

Outer diameter of monopile $D_o \ = 4\ m$

Inner diameter of monopile $D_i = 3.95\ m$

$$r_o = \frac{D_o}{2} = \frac{4}{2} = 2\ m$$

$$r_o = 2\ m$$

Similarly,

$$r_i = \frac{D_i}{2} = \frac{3.95}{2} = 1.975\ m$$

$$r_i = 1.975\ m$$

Also,

$$I = \frac{\pi}{4}(r_o^4 - r_i^4)$$

Substituting the value of r_o and r_i

$$I = \frac{\pi}{4}(2^4 - 1.975^4) = 0.6166\ m^4$$

$$I = 0.6166\ m^4$$

Substituting the values of E, I and L

$$P_{cr} = \frac{\pi^2 * 200 * 10^9 * 0.6166}{39^2} = 800\ MN$$

$$P_{cr} = 800\ MN$$

5.1.2 CALCULATIONS OF WAVE AND WIND LOAD ON OFFSHORE TURBINE

The assessment, design, and construction of offshore structures are unquestionably difficult tasks for an engineer to do. Strong wave and wind loads become key factors in the construction of offshore infrastructures since they are positioned in a harsh environment (Haritos, 2007).

There are two types of loads that an offshore wind turbine is subjected to: those caused by the structure's function known as functional loads, and those caused by the environment known as environmental loads. The first group covers static or dynamic loads resulting from the turbines' functioning, as well as the its weight, buoyancy, and other factors. Wind load, wave load, earthquake load, current load, and other loads that result from the environment's direct or indirect contact with the structure are included in the second category (Mavrakos, 1999).

CALCULATION OF WIND LOAD ON MONOPILE

To compute the wind load on the turbine foundation, we assume it to be a cylindrical structure, despite the fact that the tower's diameter reduces as we go closer to the rotor.

The equations used were in accordance with DNV with respect to environmental conditions and environmental loads.

Given Data:

Velocity @ 10 m height of the tower at 1hour ($V_{1h/10}$) = 7.1 m / s

Diameter of monopile D = 4 m

Length of monopile Z = 39 m

The wind is acting perpendicular to the pile (tower) a = 90 ^{o}

Air density ρ = 1.225 kg / m^3

From DNV, the force due to wind can be calculated using the equation below:

$$F_W = CqAsina \tag{5.1}$$

The velocity @ the maximum length of the pile with respect to the assumed velocity at a given height 10 m @ 1hour can be calculated using the equation below:

$$\mathrm{V} = \alpha V_{1h10}\left(\frac{Z}{10}\right)^{\beta} \tag{5.2}$$

Where α and β are coefficients and their values are obtained @ 1hour from table 1 below

α = 1

β = 0.15

Table 5.1: α and β coefficients at different time (Mavrakos, 1999).

Coefficient	Average Measuring Time		
	1hour	10 Minutes	1 Minutes
α	1	1.06	1.18

β	0.15	0.13	0.133

By substituting values of Z, α, β and V_{1hh10} into equation (2) above

$V = 1 * 7.1 \left(\frac{39}{10}\right)^{0.15}$ = 8.7 m / s

V = 8.7 m / s

The shape coefficient C_∞ for elements with infinite length given in accordance with Reynolds number is given by the equation $Re = \frac{D*V_{1h10}}{V_{tZ}}$ (5.3)

Where V_{tz} = V = 8.7 m / s

By substituting the values of D, V_{1h10} and V_{tz} into equation (3)

Re= $\frac{4*7.1}{8.7}$ = 3.3

Re = 3.3

From the graph below when the Reynold`s number is 3.3 the corresponding value of C_D is 6.4

But also shape coefficient as a function of Reynold`s number is given as:

$C_\infty = \frac{C_D}{10} = \frac{6.4}{10} = 0.64$

C_∞ = 0.64

To calculate for k which is the reduction coefficient of shape coefficient, the ratio of the length of the monopile to the diameter of the monopile is considered.

$\frac{z}{D} = \frac{L}{D} = \frac{39}{4} = 9.75$

Note: Z = L = Length of monopile = 39 m

It is known that 9.75 falls between 5 and 10, hence the corresponding value of reduction coefficient k at 9.75 can be calculated by the method of interpolation where the corresponding values of reduction coefficients at 5 and 10 were taken alongside.

Table 5.2: Reduction coefficient k due to finite length of the element given as function of L/D (Mavrakos, 1999).

$\frac{Length}{Diamter}$	2	5	10

Circular cylinder supercritical flow (k)	0.8	0.8	0,82

Table 5.3: Reduction coefficient at 9.75

$\frac{Length}{Diamter}$	Reduction Coefficient
5	0.8
9.75	k
10	0.82

From table 3 by interpolation method

$$\frac{9.75-5}{10-5}=\frac{k\ -0.8}{0.82-0.8}$$

$$\frac{4.75}{5}=\frac{k\ -0.8}{0.02}$$

$$k-0.8=0.95*0.02$$

$$k=0.819$$

But the reduction coefficient is given by the equation

$$C=k*C_{\infty} \quad (5.4)$$

Where

C = Shape coefficient

Substituting the values of k and C_{∞} into equation (4)

$$C=0.819*0.64=0.524$$

$$C=0.524$$

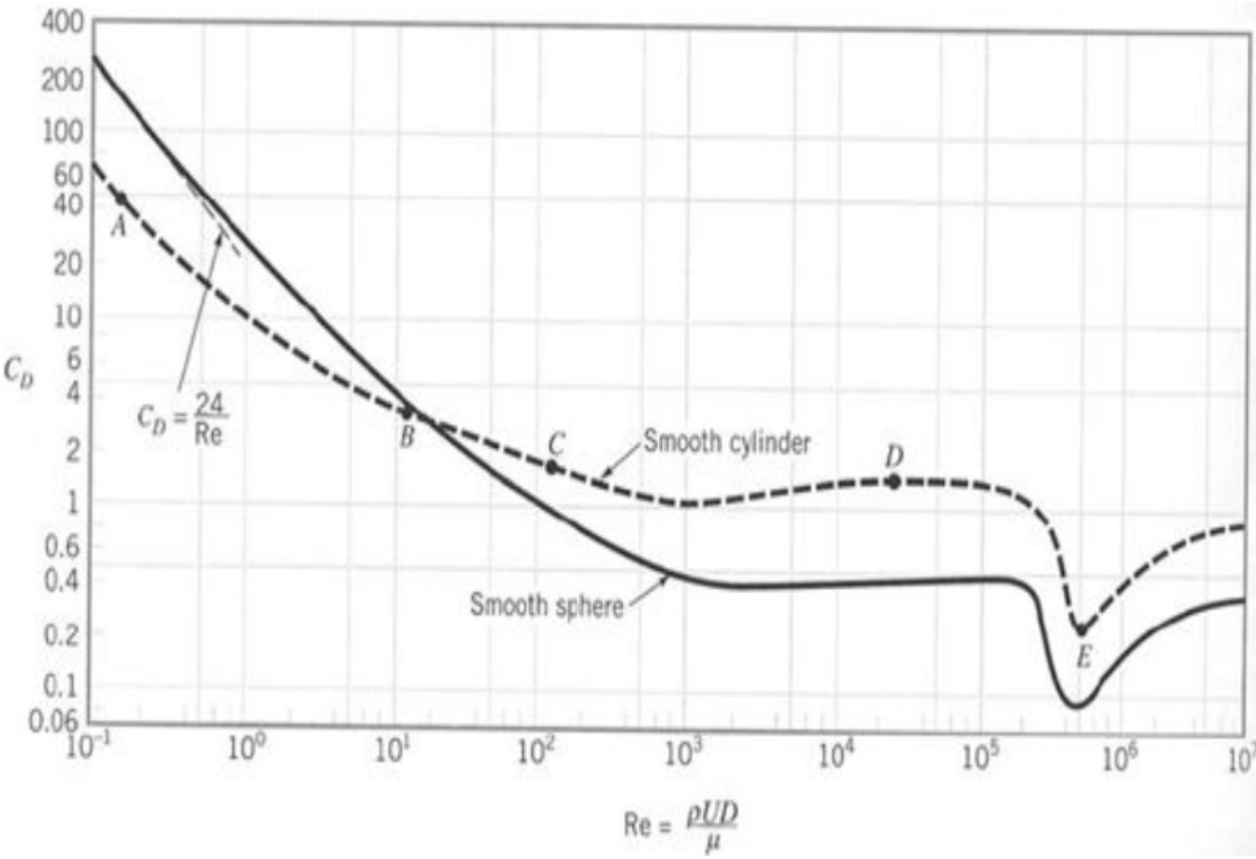


Figure 5.1: Graph: Shape coefficient C∞ as a function of Reynolds number (University of Waterloo, 2005).

To calculate the total wind load, we must consider the wind load when the assumed velocity and the calculated velocity are 7.1 m / s and 8.7 m / s at 10 m height with respect to the pressure formular in equation (5) below.

$$q_{7.1\, m/\, s} = \frac{\rho V^2}{2} \tag{5.5}$$

When v = 7.1 m / s and ρ = 1.225 kg / m^3 equation (5) becomes

$$q_{7.1\, m/\, s} = \frac{1.225 * 7.1^2}{2} = 30.88\ N/m^3$$

$$q_{7.1\, m/\, s} = 30.88\ N/m^3$$

The force when the assumed velocity (7.1 m / s) at 10 m height can be calculated by using the formular below

$$F_{7.1\, m\, /\, s} = \mathrm{C}q_{7.1\, m\, /s}\,\mathrm{Asina} \tag{5.6}$$

$$F_{7.1\, m\, /\, s} = \mathrm{C}q_{7.1\, m\, /s}\,\mathrm{Ddzsina} \tag{5.7}$$

Integrate the right-hand side of equation (7) with respect to z

$F_{7.1\ m\ /\ s} = \ \mathrm{C}q_{7.1\ m\ /s}\,\mathrm{Dzsina}$ (5.8)

But a = 90 °

Substituting the value of C, $q_{7.1\ m\ /\ s}$, D, z (10 m) and a into equation (8)

$F_{7.1\ m/\ s} = 0.524 * 30.88 * 4 * 10 * \sin 90^0 \ = 647.24\ N$

$F_{7.1\ m/\ s} = 647.24\ N$

Similarly, the same formulas and procedures were considered when the velocity is 8.7 m / at 10 m height

$$q_{8.7\ m/\ s} = \frac{1.225 * 8.7^2}{2} = 46.36\ N/m^3$$

$F_{8.7\ m\ /\ s} = \ \mathrm{C}q_{8.71\ m\ /s}\,\mathrm{Dzsina}$ (5.9)

$F_{8.7\ m/\ s} = 0.524 * 46.36 * 4 * 10 * \sin 90^0 \ = 647.24\ N$

$F_{8.7\ m/\ s} = 971.71\ N$

Total wave load $F_T = \ F_{7.1\ m\ /\ s} + F_{8.7\ m/\ s} = 647.24 + 971.71\ N$

$F_T = 1618.95\ N$

CALCULATION OF WAVE LOADS ON FOUNDATION

For the calculation of wave load on the pile Morison's equation is considered. The equation is given by the formular below:

$$F_X \ = C_{F_1} sin(\omega t) + \frac{C_{FD}}{Cos(\omega t)}$$

(5.10)

$$C_{F_1} \ = -\frac{C_{M\rho g\pi HD^2 sinh(kd)}}{8\cosh(kd)}$$

(5.11)

$$C_{F_D} \ = \frac{1}{16} c_D\ \rho g D H^2 2kd + 1$$

(5.12)

where:

C_M = inertia coefficient

ρ = Water density 1025 kg / m^3

g = Acceleration due to gravity = 9.81 m/s^2

D = cylinder diameter (m)

H = wave height (m)

k: Wave number

λ = Wavelength (m)

d = Water depth (m)

ω = Wave frequency (m/s)

t = T = wave period (s)

The wave height, wavelength, inertia coefficient and the drag coefficient were taken from South West of England Regional Development Agency, 2006 and Coastal engineering technical note, 1985. The values are given below:

Wave Height H = 5 m

Wavelength λ = 45.52m

Inertia coefficient C_M = 3

Drag Coefficient C_D = 1.5

The wave number k is given by the equation:

$$k = \frac{2\pi}{\lambda}$$

(5.13)

By substituting the value of wavelength into equation (13)

$$k = \frac{2\pi}{45.52} = 0.138$$

$$k = 0.138$$

Diameter of monopile D = 4 m

Water depth d = 9 m

But for shallow water the angular velocity $\omega^2 = k^2gd$

$$\omega = \sqrt{k^2}gd$$

(5.14)

Substituting the values of k, g and d into equation (14)

$\omega = \sqrt{(0.138^2 * 9.81 * 9)}$

$\omega = 1.68\, m/s$

Also wave period $T = \frac{2\pi}{\omega}$

(5.15)

Substituting the value of ω into equation (15)

$T = \frac{2\pi}{1.68} = 3.76\, s$

$T = 3.76\, s$

But $\sinh(kd) = \frac{1}{2}\left(e^{kd} - e^{-kd}\right)$

(5.16)

$\cosh(kd) = \frac{1}{2}\left(e^{kd} + e^{-kd}\right)$

(5.17)

Substituting the value of k and d as 0.138 and 9 m into equation (16) and (17)

$\sinh(0.138 * 9) = \frac{1}{2}\left(e^{0.138*9} - e^{-(0.138*9)}\right)$

$\sinh(1.242) = \frac{1}{2}\left(e^{0.138*9} - e^{-(0.138*9)}\right)$

$\sinh(1.242) = \frac{1}{2}(e^{1.242} - e^{-1.242})\, \sinh(1.242) = \frac{1}{2}(3.4625 - 0.28881)$

$\sinh(1.242) = \frac{1}{2}(3.17369) = 1.5868$

$\sinh(1.242) = 1.5868$

Similarly,

$\cosh(0.138 * 9) = \frac{1}{2}\left(e^{0.138*9} + e^{-(0.138*9)}\right)$

$\cosh(1.242) = \frac{1}{2}\left(e^{0.138*9} + e^{-(0.138*9)}\right)$

$\cosh(1.242) = \frac{1}{2}(3.4625 + 0.28881)$

$\cosh(1.242) = 1.8757$

Substituting the value of C_M, C_D, ρ, g, D, H, k, λ, sin(kd) and cos(kd), into equation (11) and (12)

$C_{F_1} = -\frac{C_M \rho g \pi H D^2 sinh(kd)}{8\cosh(kd)} = -\frac{3 * 1025 * 9.81 * \pi * 5 * 4^2 * 1.5868}{8 * 1.8757}$

$C_{F_1} = -801.7\ KN$

$C_{F_D} = \frac{1}{16} c_D\ \rho g D H^2 2kd + 1 = \frac{1.5 * 1025 * 9.81 * 4 * 5^2 * 2 * 0.138 * 9}{16} + 1$

$C_{F_D} = 234.1\ KN$

Substituting the value of C_{F_1}, C_{F_D}, ω, and t into equation (10)

$F_X = C_{F_1} sin(\omega t) + \frac{C_{FD}}{Cos(\omega t)} = -801.7 sin(1.68 * 3.76) + \frac{234.1}{Cos(1.68 * 3.76)}$

$F_X = -801.7 sin(1.68 * 3.76) + \frac{234.1}{Cos(1.68 * 3.76)}$

$F_X = -88.2 + 239.56 = 151.36\ KN$

$F_X = 151.36\ KN$

The wave force will act on the three monopile from any direction of the wave.

Therefore, the total wave load $F_T = 3\ F_X = 3 * 151.36\ KN = 454.08\ KN$

$F_T = 454.08\ KN$

The outcome of the results of the calculations show that the existing monopile that currently carries a load of a 2MW wind turbine would need some sort of reinforcement to be able to withstand the much bigger load of an 8MW wind turbine. In the abscene of commercial softwares capable of doing such modelling with much accuracy and reliability, a simple mathematical analogy is put forward. This brings us to the concept of distribution of load.

5.1.3. Load Distribution

Again, this is a simple anology.

From net force equation

$\sum F_y = 0$

That is $\sum F_y = \sum R_y$

$$R_1 + R_2 + R_3 + R_4 = 764 \qquad (1)$$

But $R_2 = R_3 = R_4$ and R_1 = Mass of the existing monopile = 384 tons

Substituting the value of R_1 into equation (1)

$384 + R_2 + R_2 + R_2 = 764$

$3R_2 = 764 - 383 = 380$

$R_2 = \frac{380}{3} = 126.67\ tons$

$R_2 = 126.67\ tons$ But $R_2 = R_3 = R_4$

Hence $R_1 = 384\ tons,\ R_2 = 126.67\ tons,\ R_3 = 126.67\ tons,\ and\ R_4 = 126.67\ tons$

From the calculation, it assumed that the existing foundation is 384 tons, and the weight of the 8 MW wind turbine is smaller than 764 tons. So, three small piles are added to existing one to help share the weight of the turbine. If this is done, it shows that the three other piles will carry 126.67 tons each assuming the total load is 764 tons. There may be some error analysis that might negate this approach, however, it should be noted that this is not a proven analysis and care should be observed while brainstorming in this line.

Going further, to reinforce the existing monopile, an idea is put forward in the next sub topic. However, the scope of the thesis will not cover further details, an explanation is presented only, with a bonus sketch. The highlight is the clamp design that is used in place of welds due to the offshore terrain and an alternative weld integrity issues over time.

5.3. REINFORCEMENT APPARATUS FOR MONOPILES

5.3.1. REINFORCING DESIGN

The optimized design is a reinforcement apparatus that is installed on the exterior of the monopile. It is made up of rods connected to adjustable brackets for providing additional strength along the length of the monopile. The base of the apparatus is embedded into the seabed to provide sufficient structural support to withstand the force moment from additional weight, waves, and wind shear.

Designers are challenged to optimize supporting structures in response to increasing turbine capacity. Building new foundations is one way to meet the need for mounting bigger turbines. Another possibility is to install the bigger turbine on top of an existing foundation. Since existing foundations were not designed to safely support much bigger turbine load, they must be reinforced to provide not only the needed support for the additional load, but also the additional forces that the wave, wind, and other environmental conditions will exert on the foundation because of the increased surface area presented by the much bigger turbine.

A method of reinforcing monopiles is by installing welding bars, angle or tubular steel sections to the exterior surface of the monopile. Though adding steel to the monopile increases its strength, the process is expensive, labour intensive, and significantly reduces the integrity of the galvanized steel in the monopile to resist rust, which will inevitably affect the strength of the monopile.

Another way monopiles can be reinforced is by overlaying a steel skin on the existing monopile. This method is expensive and labour intensive because the steel skin must be fabricated to fit the existing monopile with minor tolerances for dimensional error. The installation of this type of reinforcement is inefficient because the weight of the overlay pieces necessitates the use of large cranes to place the steel skin over the existing monopile.

Also, existing monopiles can be strengthened by constructing metal lattice-work structures around the existing monopile. But the downside is that such lattice structures are costly and takes longer time to install.

As a result, there is a need in the field of monopile reinforcement for a cost-effective, conceptually satisfying, long-lasting, and simple method of reinforcing and strengthening monopile foundations.

5.3.2. DESIGN IN BRIEF

The design is a reinforcement apparatus that forms a partial exo-skeletal frame for support directly on the surface of an existing monopile to provide additional strength and stability to resist the force moment from wind resistance resulting from increased surface area and additional load via the use of adjustable mounting clamps and accompanying circumference support rods.

The design is intended to provide resistance and stability to deflection to existing monopile foundations in a cost-effective and efficient manner by constructing a simple and less expensive reinforcement apparatus bounding the monopile at various heights from the base and having adjustable mounting clamps and support rods positioned on and along the outer skin of the monopile. The mounting clamps have adjustable spacings, allowing them to easily fit around the monopile at any point along its entire length. A set of support rods run along the length of the monopile, along the pile's surface, and connects the adjustable mounting clamps.

The reinforcement apparatus consists of several support rods and adjustable mounting clamps with guide tubes extending along and close to the pile's outer surface. The plurality of support rods each have two ends, with each end receiving one of the pluralities of guide tubes. The adjustable mounting clamps are made up of a series of interconnecting brackets that are linked together by length adjustable attachment members. Threaded rods and nuts of sufficient strength are used in this design.

The connecting brackets consist of a steel plate with a flat central section with both ends placed at angles to the flat central section, and the guide tube is fixed to the flat central section. The exterior dimensions of the of guide tubes are the same or marginally smaller than the inner dimensions of the support rods, resulting in a tight fit as the guide tube is inserted into the support rod. Since the guide tubes can only reach from the bracket in a single direction, guide tubes that stretch in opposite directions are used along the monopile.

By circumscribing the monopile structure with several support rods with opposing ends and extending along the monopile to at least three adjustable mounting clamps at either end of the guide tubes, the apparatus will provide additional reinforcement. The adjustable mounting clamps are made up of a series of interconnecting brackets that are linked together by length adjustable attachment members.

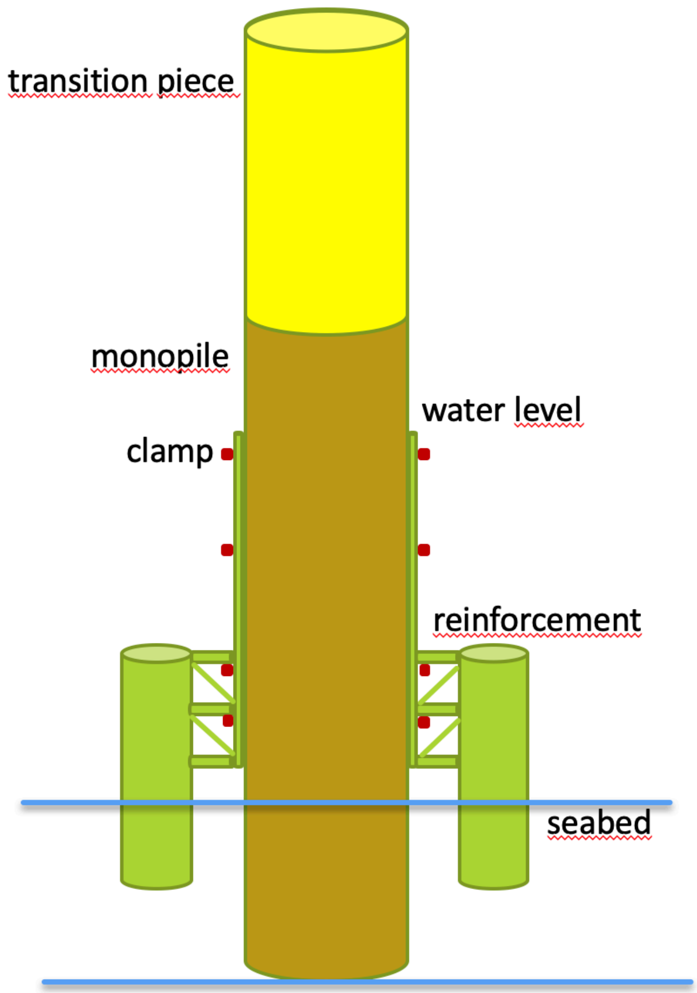


Figure 5.2: Drawing of the reinforced design.

6

CASE STUDY

6.1. INTRODUCTION

Horns Rev 1 is used for the case study. The study consists of four scenarios, namely, lifetime extension, partial repowering, full repowering, and retrofitting scenario. The aim of the case study is to show the cost viability and CO_2 calculations. The technical and operability of the different scenarios will be considered. RETScreen software is used to analyse the feasibility of the location, facility, energy, cost, CO_2 emission, cost, finance, and risk of the project.

Horns Rev 1 was built in the North Sea by the Danish energy company Eslam. The company was formerly known as DONG, then Eslam, and now Ørsted. Horns Rev 1 was the world's first large scale OWF inaugurated in 2002, with a capacity of 160 MW, four times that of the previous largest OWF, the Middelgrunden. It was the first time monopile foundation was used, and the first time the transformer is mounted on an adjacent platform on the turbine rather than onshore. Horns Rev 1 is 14 to 20 km from shore.

In 2002, the Danish OWF services provider A2SEA installed a total of 80 Vestas V80-2.0 MW turbines. It got a price of 453 DKK/KWh for the first 42,000 hours, which is paid for by energy consumers (PSO-udgifter, p. 4). In 2005, 60% of the wind farm was sold for €270 m to Vattenfall, who is in charge of operations (Power Technology). HR1's AEP in 2014 was 658 GWh, and 613 GWh in 2015 (DEA, 2017).

The park has a 96-97% availability, and a gearbox can be replaced in a single day. An optimized Eurocopter EC-135 helicopter is the primary mode of transport to the WP (Wittrup, 2015). The favourable weather condition for transportation to the WP is when winds are less than 19 m/s. Out of the 80 turbines, unfortunately, turbine 79 and 80 are burnt out and are unprofitable to replace with new ones because they have less than 10 years remaining to run. The staff are hoisted to and from a small platform on turbines, allowing entry to the park despite sea conditions, that would otherwise restrict navigation in the location for most of the year. HR1 has an expected lifetime of 22 years which elapse in 2024 (Wittrup, 2015).

Horns Rev 1's turbines have a unique power curve that is tailored to the site (Morales, 2015). The turbines are arranged in an oblique rectangle shape 5 km x 3.8 km comprising of 8 horizontal and 10 vertical rows. The distance between turbines is 560 m in each direction. The radar at sea report shows a measurement of the wind patterns (Pinson, 2011). The wind turbines have an 80 m diameter rotor and a 70 m hub height, and the diagonal distance between rotor diameter of the turbines is either 9.4D or 10.4D (Hasager and Giebel, 2015). The average distance between rotor diameter of turbines is approximately 560 m. In the case of HR1, the turbines have a spacing of seven (7D) rotor diameters between columns and columns (Hou et al., 2017). This suggests that it is possible to marginally reduce the spacing between turbines without significantly increasing wake losses.

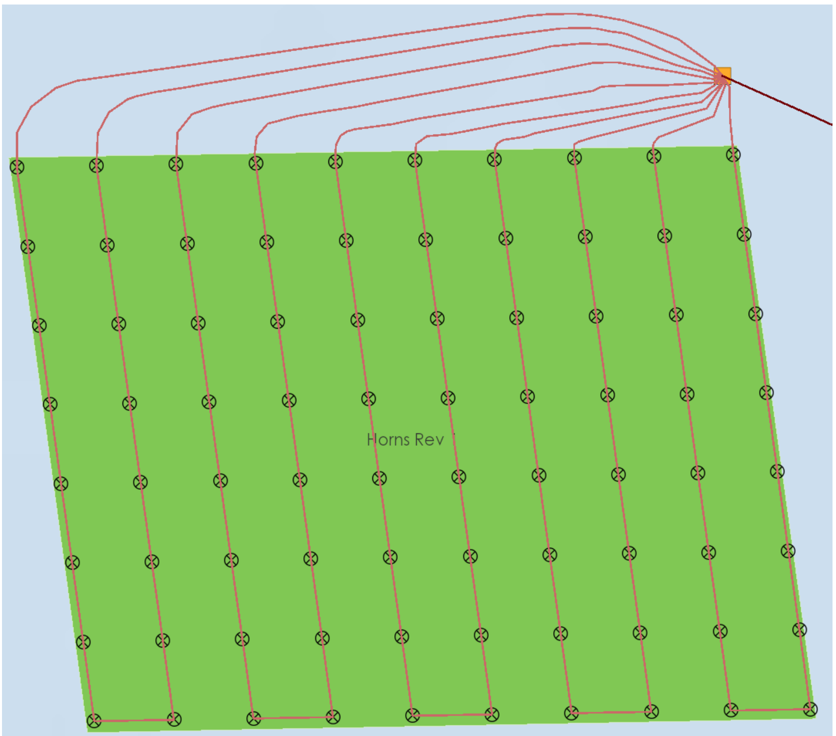


Figure 6.1: Existing inter-array grid of Horns Rev 1

Table 6.1: Horns Rev 1 data

Country	Denmark
Location	Horns Rev, East North Sea
Coordinates	55°31′47″N 7°54′22″E
Status	Operational
Commission date	2002
Owner(s)	Vattenfall (60%); Ørsted (40%)
Operator	Vattenfall
Type	Offshore
Max. water depth	6–14 m
Distance from shore	14–20 km
Units operational	80
Make and model	Vestas Wind Systems: V80-2.0

Nameplate capacity	160 MW
Annual net output	600 GWh
Hub height	70 m
Rotor diameter	80 m
Rated wind speed	9.7 m/s
Speed	8-18 rotations per minute
Start wind speed for electricity production	4 m/s
Stop wind speed for electricity production	13 m/s
Turbine weight including foundation	500 t
Turbine weight	439-489 t
Distance between turbines	560 m
Rotor length	40 m
Length of monopile imbedded beneath seabed	22-24 m
Water depth	6-14 m
Water surface to service crane platform	9 m
Monopile diameter	4 m
Monopile thickness	0.06 m
Monopile length	37-47 m
Transition piece length	18 m
Length of monopile from transition to seabed	5 m

As Horns Rev 1 approach its end of life, a decision will be made to either decommission, extend the lifetime or repower the wind farm. One important driver would be the findings from the assessment of the remaining life and usability of the components. Trusted assessments are carried out by experts such as Energinet.

Every four years, Energinet (Danish TSO) inspects the electrical structures in Horns Rev 1 OWF. According to the most recent inspections, all structures seem to be working normally. It is expected that the substation will continue to operate for at least 15 years, and the transformers can continue to work for up to 10 mores years without defects, which with adequate maintenance, will continue to operate for 15 years or more in addition to the 20 to 25 year design lifetime.

According to HSM offshore (2002), the transformer platform for 160 MW capacity consist of topsides and support frame on three supporting piles in 8 m water depth, a tripod with 5 x 36 kV J-tubes and independent boat landing structure. The dimension is 28 x 19 x 11 m, and the weight of topside is 1100 t.

The topside of the substation weighs 900 t, jacket and crane weigh 100 t. While the platform consists of three 60 m monopile foundations and a 100 t frame is placed on top of the three monopiles. The transformer of weighs 250 t, which includes 80 t of oil and 100 t of copper in it. The maximum capacity of the substation is a 160 MW, which is also the capacity of the transformer in place. The estimated cost of installing a new substation, including foundations will be about 200 million Danish Kroner. The substation is supported by three monopile foundations (tripod structure); the substation foundations could be in operation for another 20 years of service.

From the interviews done in the course of this research it was mentioned that the foundations of Horns Rev 1 are overdesigned having an additional 15 mm thickness to their diameters. In the substation, the main materials used are aluminium, concrete, copper, and steel. The substructure is mostly made of steel, the frame is made of aluminium, while copper is used in cables and transformer, and concrete is used under the transformer box. The materials that make up the platform can be split into 10 % aluminium, 10 % concrete, and 80 % steel.

The substations, export cables, transformers, and foundations have a construction lifetime of 25 years. The new substations that are being built now have a design lifetime of 25 years. It is anticipated that lifetime extension could be the favoured alternative for new wind farms.

The export cable will be used for at least another 15 years. The export cable has the capacity to transmit a maximum of 200 MW. This is similar to the capacity of the export cable used for the Horns Rev 2 platform.

In most countries, there are no standard procedures for extending the lifetime of the wind park and electrical infrastructure. The common practise is inspection of components, followed by replacement of defective equipment. Substation upgrades are usually based on the state of the transformer. A transformer replacement could cost at about 20 million Danish Kroner. Other key components are the turbines and foundations.

However, the focus here will be on lifetime extension and repowering of Horns Rev 1. Four scenarios are presented which are:

Scenario 1: lifetime extension (using 80 refurbished V80-2.0 MW wind turbines, 160 MW)

Scenario 2: partial repowering (50 new V90-3.0 MW wind turbines, 150 MW)

Scenario 3: full repowering (40 V164-8.0MW wind turbines, 320 MW)

Scenario 4: reinforcement (40 V164-8.0MW wind turbines, 320 MW)

6.2. END-OF-LIFE SCENARIOS AND COST ASSUMPTIONS

6.2.1. SCENARIO 1: LIFETIME EXTENSION

In this scenario, refurbished Vestas V80 2MW wind turbines will be used to replace the existing Vestas V80 2MW wind turbines. The existing turbine foundations, transition pieces, towers, inter-array cables, and substation would be reused. Only the blades and nacelle will be replaced, which is similar to

Bockstigen OFW repowering case. Since the existing turbines are all Vestas V80 2MW, it is assumed that the refurbished turbines would have the same power curve as the existing turbines.

The extended lifetime of the OWF is estimated to be 15 years. This assumption is because the lifetime of the refurbished wind turbines may be less than that of the new wind turbines. The wind turbine layout will remain the same, and no extra cables would be needed. This is in line with the premise that the inter-array grid and substation would have a lifetime of at least 40 years (Hou et al., 2017).

The layout and wake losses is considered to remain unchanged given that the refurbished wind turbines have the same hub height and rotor diameter as the existing turbines. Pena and Rathmann (2014) calculated that average wake losses at Horns Rev 1 to be between 9 and 14%, with an average of 9.8%.

COST ASSUMPTIONS

Similar to Gonzalez-Rodrigues (2017), the cost of project development and management is estimated to be 0.105 M€ per MW.

Assessment of the remaining structural strength of the monopile foundation and transition piece was assumed to be 0.043 M€ per MW (Morthorst and Kitzing, 2016), which is equivalent to 10% of the cost of a new turbine foundation and transition piece.

The cost of wind turbine acquisition was estimated to be 0.553 M€ per MW. This assumption was made with a clue from the cost of a refurbished turbine including tower from Repowering Solutions (2012).

Installation cost is estimated to be 0.18 M€ per MW. The cost assumes the installation cost account for about 20.43% of this scenario's CAPEX. This assumption is tailored from a combination of the cost guide for OWF (BVG Associates, 2019) and the cost comparison of repowering (Bergvall, 2019). The CAPEX used for the cost feasibility analysis of this scenario is shown in Table 6.2.

Table 6.2: Capital expenditure (80 Refurbished V80-2.0MW wind turbines = 160 MW)

	Cost per MW (M€)	**Cost of 160 MW (M€)**
Project Development and Management	0.105	16.8
Assessment of Structural Strength	0.043	6.88
Wind Turbine Acquisition	0.553	88.48
Turbine Installation	0.18	28.8
CAPEX	**0.881**	**140.96**

6.1.2. SCENARIO 2: PARTIAL REPOWERING

This scenario consists of 50 new Vestas V90 3MW wind turbines giving a total capacity of 150 MW. The new turbines with design life of 25 years would be used, and since the existing foundation is assumed to have a lifetime of about 50 years, hence, the expected lifetime of the partially repowered park is 25 years. It may be possible to use the existing towers after assessment because the difference in hub height between the 2 MW and 3 MW turbine is an increase of 10 m, hence this scenario will use the existing towers. The existing export cable, inter-array grid, and substation will be used since it is assumed to have an expected lifetime of 50 years as suggested by Topham and McMillan (2017). The RETScreen software was used to generate the power curve for the selected turbines.

Findings from the interviews carried out in this thesis states that the Horns Rev 1 turbine foundations are overly designed, and is capable of supporting a 3 MW turbine weight since the slight increase from 2 MW to 3 MW turbine load effect is below the design resistance of the foundation. It is also assumed that even if the degradation rate of the foundation is factored-in, it would still have enough structural strength to safely carry the load increment for the entire lifetime of this partially repowered scenario. In addition, the current foundations are expected to be able to carry the loads of the slightly bigger wind turbines. This assumption is based on the knowledge from the Kentish Flats OWF. At Kentish Flats OWF, Vestas V90 3MW wind turbines are used, with a row and column spacing of 700 m (7.78D) (Vattenfall, 2019). It has the same monopile foundation diameter and approximately the same length and piling depth as Horns Rev 1 (Negro et al., 2017). The V90 3MW wind turbine hub height is 70 m which is the same hub height used in this scenario. The wind farm consists of eight rows and ten columns. The first and last rows will have ten turbines each, while the middle rows will have five turbines each. In the base case, which is the existing scenario at Horns Rev 1, it can be observed from the turbine layout that one inter-array cable is used to connect 16 2MW turbines amounting to 32 MW. This means that the same cable can be used to connect 10 3MW turbines amounting to 30MW. The new design has more overall spacing between turbines. The first and last rows have a 6.22D turbine spacing, while the middle rows have 12.44D turbine spacing. The offsetting of every second column and row between the turbines in the middle rows will have a favourable impact on wake losses. Hence, 8.4% is assumed for the array losses.

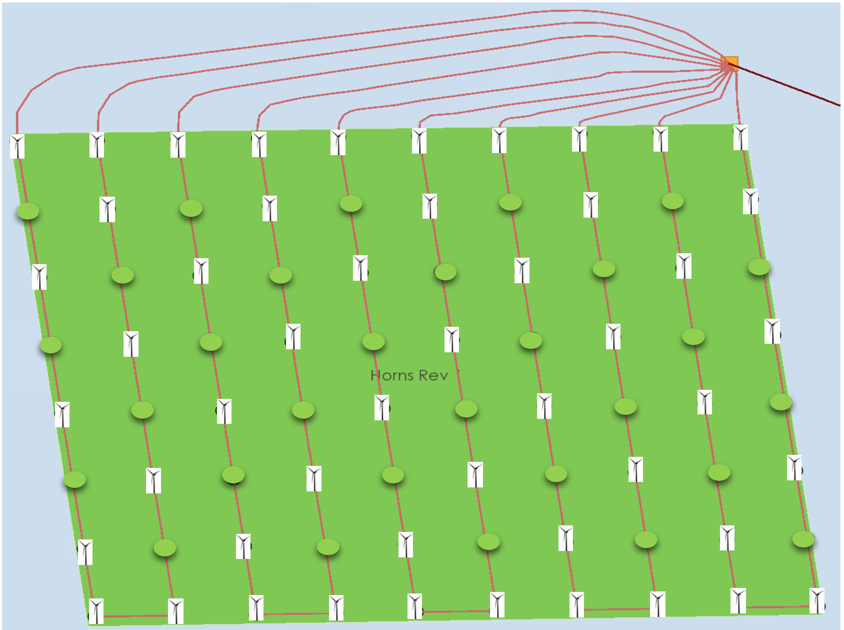


Figure 6.2: Layout of scenario 2.

COST FEASIBILITY

The project development and management is estimated to cost 0.105 M€ per MW (Gonzalez-Rodriguez, 2017).

Similar to Bergvall (2019), the cost of environmental analysis was estimated to be 0.020 M€ per MW. Due to previous knowledge of the site and a small amount of sub-surface work for this scenario, the cost per MW is lower than the 0.063 M€ per MW reported for the initial environmental review of Horns Rev 1 by Morthorst and Kitzing (2016).

The cost of assessing the structural integrity of the foundations, substructures, and towers, was estimated to be 0.043 M€ per MW, same as in scenario 1.

Based on DNV-GL mid-range decommissioning cost estimate, a cost of 0.3 M€ per MW is projected for the decommissioning of 30 existing 2MW wind turbines including foundations which amounts to 18 M€. The cost per MW assumption is also in line with Topham and McMillan (2017). A smaller cost of 0.1 M€ per MW was assumed for the removal of the nacelle and rotor of the remaining 50 2MW turbines which amounts to 10 M€. Hence, the average decommissioning cost in this scenario is calculated to be 0.175 M€ per MW.

The cost of wind turbine, including installation and transportation was estimated to be 1.040 M€ per MW (Morthorst and Kitzing, 2016). This is also in close comparison with the cost of the London Arrays Siemens 3.64 MW wind turbine that is assumed to be 1.17 M€ per MW.

The return from recycling 30 decommissioned wind turbines including foundation is 0.04 M€ per MW (Bergvall, 2019) which amounts to 2.4 M€. But the return from recycling only the nacelle and rotor of the remaining 50 turbines would be much smaller. Though, Vestas recently in May 2021 made a breakthrough in her quest to completely recycle turbine blades, the return from blades would slightly increase. Hence, the return from recycling 50 turbine nacelles and rotors is assumed to be 0.004 M€ per MW which amounts which amounts to 0.4 M€. Hence, the average return from recycling in this scenario is calculated to be 0.0175 M€ per MW. Table 6.3 shows the CAPEX for scenario 2.

Table 6.3: Capital expenditure for scenario 2 (50 new V90-3.0 MW wind turbines = 150 MW)

	Cost per MW (M€)	Cost of 150 MW (M€)
Project Development and Management	0.105	15.75
Environmental Analysis	0.020	3.0
Assessment of structural strength	0.043	6.45
Decommissioning	0.175	28
Wind Turbine Acquisition (including transport and installation)	1.040	156.0
Return from recycling	-0.0175	-2.8
CAPEX	**1.3655**	**206.4**

6.1.3. SCENARIO 3: FULL REPOWERING (40 V164-8.0MW wind turbines, 320 MW)

In this scenario, HR1 WF will be decommissioned and a new WF will be built on the same site. The new WF will consist of 40 new Vestas V164 8.0 MW WTs amounting to a 320 MW WF. The expected lifetime of the new WF is 25 years. The rotor diameter of the V164 8.0 MW WT is 164 m, and the hub height is 105 m (Vestas, 2014). The space between the rotor diameter of turbines is 6.8D in the new configuration. Although the diagonal space will be limited to 5.1D and 4.5D, the offsetting of every second column and row will have a positive effect on wake losses. And a wake loss of 12% is presumed.

Table 6.4: MHI Vestas V164-8MW parameters (Source: Vattenfall, 2021).

Annual production	1.700.000.000 kWh
Maximum height	187,1 meter
Rotor blade length	80 metres
Rotor diameter	164 metres
Nacelle	20.7 metres long 9.3 metres high 8.7 metres wide
Rotor blade weight	33 tonnes
Nacelle weight	381 tonnes
Tower weight	350 tonnes
Foundation weight	420–706 tonnes
Total weight per turbine	1,184–1,470 tonnes
Cut-in wind speed	4 m/s
Nominal speed	approx. 14 m/s
Cut-out wind speed	25 m/s
Water depth	11–19 metres
Distance from shore	29–44 kilometres
Distance between turbines	1,1–1,5 kilometres
Wind farm area	88 km^2

The power curve for the V164 8.0 MW WT could not be found in the RETScreen database, so it was collected from the Vesta 8 MW platform brochure which can be found in figure 5.3. LEANWIND 8.0 MW reference wind turbine also provides a similar power curve (LEANWIND, 2013). The parameters of the new turbine are given in table 6.4, while the layout of the turbines is shown in figure 6.3.

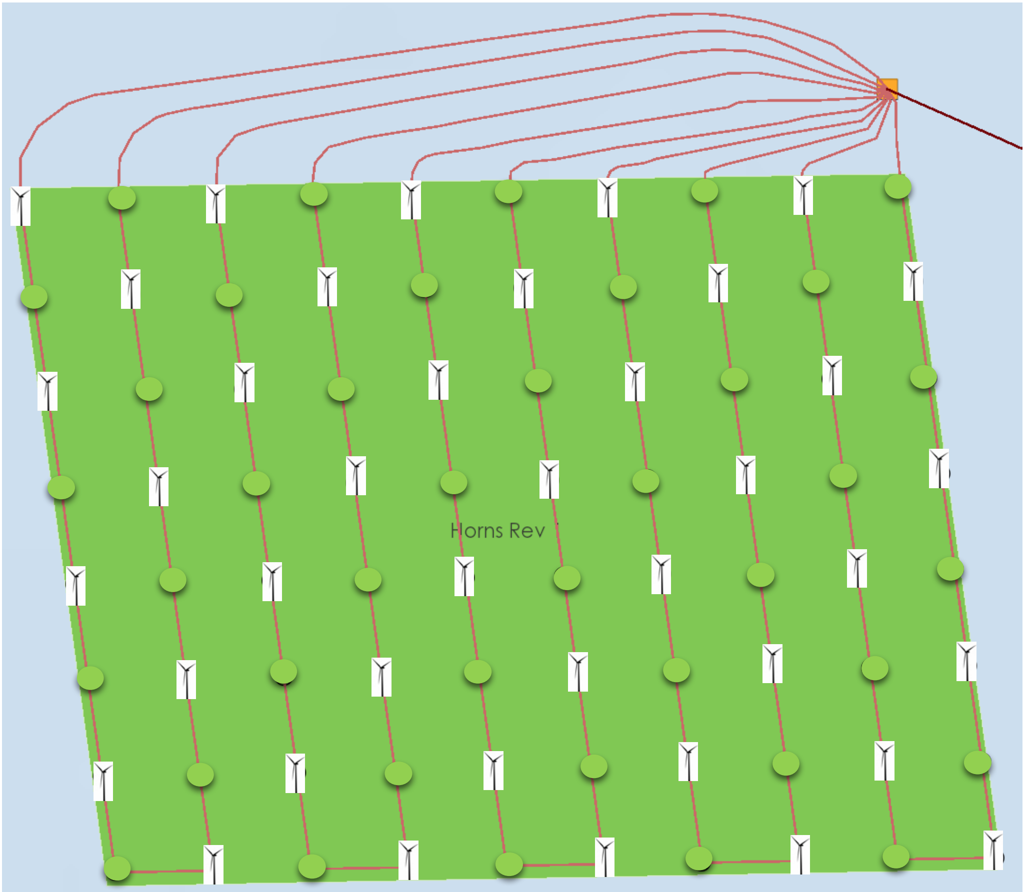


Figure 6.3: Layout of scenario 3.

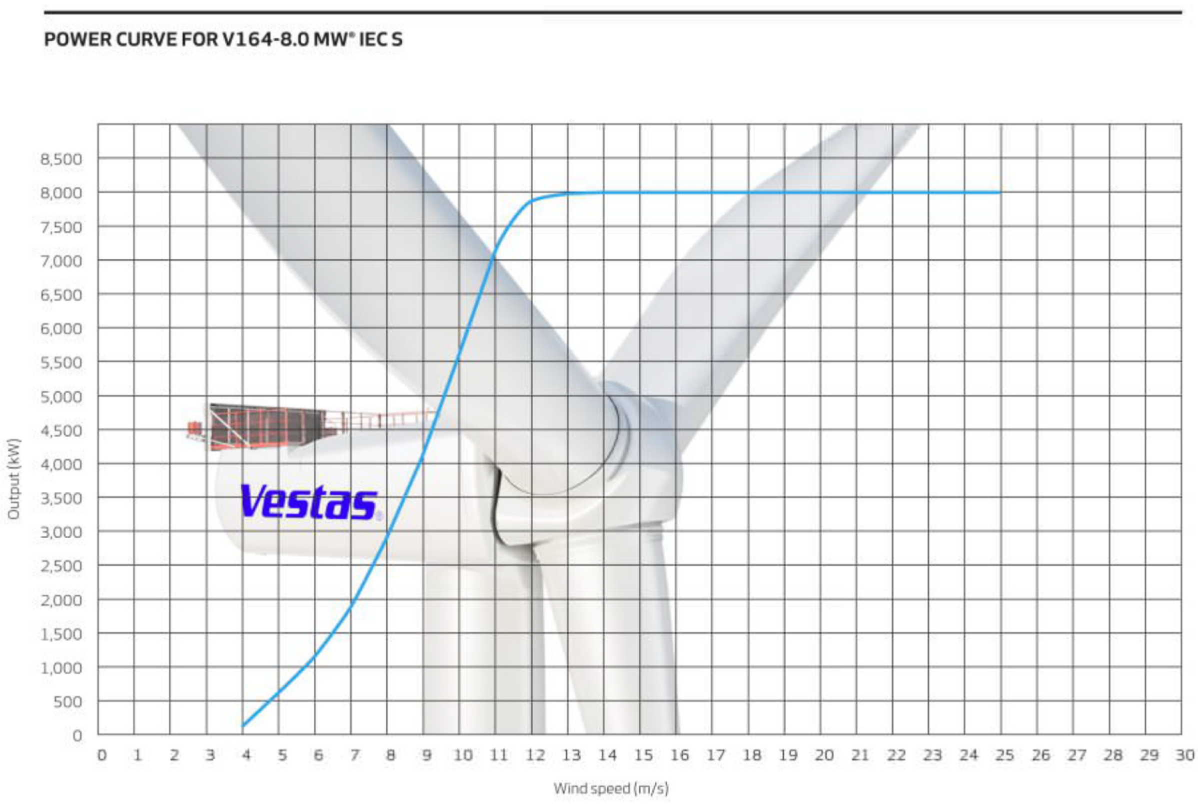


Figure 6.4: Power curve for V164-8.0 MW wind turbine (Source: Vestas, 8 MW platform brochure)

COST FEASIBILITY

0.105 M€ per MW is estimated for project development and management. Environmental analysis is estimated to 0.063 M€ per MW (Morthorst and Kitzing, 2016). This analysis will entail a substantial subsea work and major upgrade in the layout.

Based on DNV's average cost data, the cost of decommissioning installed WTs and foundations is estimated to be 0.2 M€ per MW (Bergvall, 2019), which is also the assumption in this scenario.

In line with the figures from the literature findings the new foundation is estimated to cost 0.43 M€ per MW (Morthorst and Kitzing, 2016). And the average cost of wind turbine, including installation and transportation is estimated to be 1.252 M€ per MW Gonzalez-Rodriguez (2017).

Morthorst and Kitzing (2016) suggests that electrical system costs 0.454 M€ per MW. Though new cables will be added to the inter-array grid where necessary, but the existing inter-array grid will be reused as much as possible. However, the electrical system upgrade is estimated to be 0.0908 M€ per MW. It assumes that the cost of upgrade is 20% of a completely new electrical system.

According to Krohn et al. (2009), transformer and export cable amounts to 0.322 M per MW, but it is assumed that about 50% of the cost of the new substation and export cable would later be gotten from recycling the decommissioned ones, hence, the new substation and export cable cost was estimated to be 0.161 M€ per MW for this scenario.

In 2006, the lifetime assessment of a V80-2.0 MW onshore wind turbine carried out by Vestas show a recyclability of up to 80%. It also stated that 100% of the iron and steel could be recycled when the turbine is dismantled. Recently, 85% of turbine components can be recycled (Vestas, 2021). However, with DNV's latest breakthrough in May 2021 in recycling 100% of turbine blades, the overall recyclability percentage of the turbine is expected to increase. Also, DNV states a decommissioning cost of 0.2 to 0.6 M€ per MW, which is roughly 60 to 70% of the initial installation cost (Topham and McMillan, 2017). And 10 to 20% of the decommissioning cost can be returned by proper recycling (Topham et al., 2019). Hence, the return from recycling is assumed to be 0.04 M€ per MW which is in line with Bergvall (2019). Table 6.5 shows the CAPEX for the feasibility analysis.

Table 6.5: Capital expenditure (40 V164-8.0MW Turbines = 320 MW)

	Cost per MW (M€)	Cost of 320 MW (M€)
Project Development and Management	0.1050	33.6
Environmental Analysis	0.063	20.16

Decommissioning of 160 MW	0.2	32
Monopile Foundation	0.43	137.6
Wind Turbine Acquisition including transportation and installation	1.252	400.64
Electrical System Upgrade	0.0908	29.056
Substation and export cable	0.161	51.52
Return from recycling (160 MW)	-0.04	-6.4
CAPEX	**2.2618**	**698.176**

6.2.4. SCENARIO 4: REINFORCEMENT

Like scenario 3, the wind farm will be decommissioned, and a new wind farm will be built on the same location. All 80 existing turbines including rotor, nacelle, and tower will be decommissioned. Half of the existing foundations will be decommissioned, while the rest will be optimised to enable them carry bigger wind turbines. This optimisation will entail constructing additional parts of the foundation on land, then it will be transported to the facility location where the retrofitting will take place. Several methods on how to join the additional parts to the existing foundation was considered, including welding and the use of concrete. However, after many explorations, the preferred choice was to employ the clamp apparatus discussed in chapter 5. The clamp was used to bolt the additional parts to the existing foundation. Though this technique has not been used in OWF to perform such operations, hence it is not proven. Nevertheless, similar technique has been used on land especially in the telecommunications industry. Similar clamp design is used to strengthen telecommunication mast and for additional load support. It is also used to other foundations made primarily of metal parts. So far, this clamp system has been successful, cost effective and efficient. It is on this premise, that the idea is birth and adapted to analyse the feasibility of incorporating the clam apparatus technique to the OWF industry.

This reinforcement scenario is a form of offshore repowering whereby the capacity of the wind farm is increased with fewer but bigger wind turbines. In this case, the new wind farm will consist of 40 new Vestas V164-8.0 MW wind turbines amounting to a 320 MW OWF. The expected lifetime of the new wind farm is 25 years. The rotor diameter of the V164-8.0 MW wind turbine the hub height, the space between the rotor diameter of turbines, the wake loss, and optimised layout will be the same as in scenario 3.

The power curve for the V164 8.0 MW WT could not be found in the RETScreen database, so it was collected from the wind power wind energy market intelligence (Wind Power, 2021) which can be found in figure 5.1. LEANWIND 8.0 MW reference wind turbine also provides a similar power curve (LEANWIND, 2013). The parameters of the 8 MW wind turbine can be seen in Table 6.4, while the layout of the turbines is shown in Figure 6.3.

COST ASSUMPTIONS

Project development and management is estimated to be 0.105 M€ per MW. While environmental analysis is estimated to cost 0.063 M€ per MW. Same as in scenario 3.

Based on DNV-GL mid-range decommissioning cost estimate, a cost of 0.3 M€ per MW is expected for the decommissioning of 30 existing 2MW wind turbines including foundations which amounts to 18 M€. A smaller cost of 0.2 M€ per MW was assumed for the removal of the turbine excluding foundation of the remaining 50 2MW turbines which amounts to 20 M€. Hence, the average decommissioning cost in this scenario is calculated to be 0.175 M€ per MW.

In accordance with the values from the literature review, a new foundation is estimated to cost 0.43 M€ per MW. However, the cost associated with reinforcing of monopile foundation is assumed to be about 65% of the cost of building a completely new monopile foundation. The assumed percentage results from the fact that the additional parts built would make use of less production materials and would have a smaller weight to be transported in comparison with that of a completely new monopile foundation. Hence, the cost of reinforcing an existing monopile foundation is 0.2795 M€ per MW. It should be noted that this technique has not been performed in the OWF industry, therefore the assumption regarding reinforcing the foundation may not be accurate, in order words it may cost less or more than the assumed 65%.

Same as scenarios 3, the cost of a wind turbine, including installation and transportation is estimated to be 1.252 M€ per MW, the electrical system upgrade is assumed to be 0.0908 M€ per MW, and the new substation and export cable cost is assumed to be 0.161 M€ per MW.

The return from recycling 30 decommissioned wind turbines including foundation is 0.04 M€ per MW (Bergvall, 2019) which amounts to 2.4 M€. But the return from recycling only the turbine excluding foundation of the remaining 50 turbines would be much smaller. Hence, the return from recycling the 50 turbines is assumed to be 0.012 M€ per MW which amounts which amounts to 1.2 M€. Hence, the average return from recycling in this scenario is calculated to be 0.0225 M€ per MW. Table 6.5 shows the CAPEX for scenario 4.

Table 6.6: Capital expenditure (40 V164-8.0MW Turbines = 320 MW)

	Cost per MW (M€)	Cost of 320 MW (M€)
Project Development and Management	0.105	33.6
Environmental Analysis	0.063	20.16
Decommissioning (160 MW)	0.175	28
Retrofitting of Monopile Foundation (160 MW)	0.2795	89.44
Wind Turbine Acquisition including transportation and installation	1.252	400.64
Electrical System Upgrade	0.0908	29.056
Substation and export cable	0.161	51.52
Return from recycling (160 MW)	-0.0225	-3.6
CAPEX	**2.1038**	**648.816**

6.3. OFFSHORE WIND RESOURCE ASSESSMENT USING RETSCREEN

RETScreen Expert was used for the wind power project feasibility analysis to investigate the financial viability. The software was configured for appropriate currency, language, and other settings necessary for the analysis. The inbuilt virtual energy analyzer was used for the pre-feasibility analysis to create a wind power archetype, with the input cells already entered with reasonable values. Architype refers to a set of default values describing a typical project. The virtual energy analyzer generates the archetype based on four key information, which includes the location, type of facility, project size, and technology.

Horns Rev 1 data was manually entered in the location, facility, energy, cost, emission, finance, and risk modules.

6.3.1. SITE ANALYSIS

Location module: In the site reference conditions, the climate data location was taken from measuring station at Blaavand, Denmark, and wind measurements was taken from the facility location at latitude 55.31°N longitude 7.54°E, and the climate data location was taken from latitude 55.55°N longitude 8.08°E. It was done at an elevation of 18 m, and earth temperature amplitude of 13.7°C. The source of the data is a combination of Ground and NASA.

The source of data of monthly and annual measurements of air temperature, relative humidity, wind speed, heating degree-days, and cooling degree-days was from Ground. While the source of data of monthly and annual precipitation, daily solar radiation – horizontal, atmospheric pressure, and earth temperature was from NASA. For each month, the measured average monthly wind speed was inserted.

In May 1999 to November 2002, a met mast was erected at the facility location to record the wind direction and wind speed above sea level at 15 m, 30 m, 45 m, and 62 m respectively. The measurements had a coverage rate of approximately 99% (Sommer and Hansen, 2002). The measurements show that the dominant wind direction is 254°, with a peak wind speed of 45.4 m/s and an average wind speed of 9.46 m/s at 62 m. The wind shear exponent between 62 and 45 m was 0.16, with a Weibull scale value of 10.59 m/s and a Weibull shape value of 2.3. Table 5.4 shows a rundown of the facility observations from each of the estimated altitudes.

Table 6.7: Horns Rev 1 wind measurements from May 1999 – November 2002. Recreated from Bergvall, (2019)

Height above sea level	15 m	30 m	45 m	62 m
Predominant Wind Direction (°)		254	254	254
Max Wind Speed (m/s)	39.5	40.7	43.1	45.4
Mean Wind Speed (m/s)	7.89	8.51	8.85	9.46
Weibull Scale Parameter (m/s)	8.98	9.64	10.05	10.59
Weibull Shape Parameter	2.2	2.3	2.3	2.3
Wind Shear Exponent		0.10	0.10	0.16

The above parameters were used in RETScreen.

Facility module: For the facility information, power plant was chosen as the facility type, and wind turbine was specified. The energy production cost central grid range for the technology was generated with the software. A lot of thought was put into deciding the benchmark electricity price for all scenarios. Firstly, in 2009, the European Environment Agency (EEA) estimated an average production price of 78 €/MWh for 2020. Energistyrelsen in 2014, and Power Technology in 2019 has stated that Horns Rev 1 receives 60.7 €/MWh. Also, the IRENA power generation projected cost for 2023 is 61.77 €/MWh. However, since the scenarios are planned to commence from 2024, and are expected to have an additional lifetime of 15 to 25 years, it seems more accurate to use a price benchmark that envisions this timeline. To achieve this, the author made a price benchmark calculation with the help of data from the basic projection of electricity prices, electricity and district heating capacities and emission factors provided by Energistyrelsen (2020). This projection states the electricity price for every hour from 2021 to 2030. The average price was calculated and the result is 50.37 €/MWh. This price was used as the electricity price benchmark for all scenarios and was manually inputted in the RETScreen software. Other details can be seen in the Appendix C-F.

6.3.2. ENERGY MODELLING

Energy module: All scenarios were generated using a level 3 simulation in the energy menu with the following criteria: wind turbine model, capacity, number of turbines, hub height, rotor diameter, losses and energy curve shape factor. The data for the power curve was either inserted manually or imported from the RETScreen product database.

The RETScreen measures the average gross energy output of a single WT based on wind speed at hub height, atmospheric pressure, and temperature levels at the farm. Array losses, availability, airfoil losses, and miscellaneous losses are all excluded from the annual gross energy generation as a percentage.

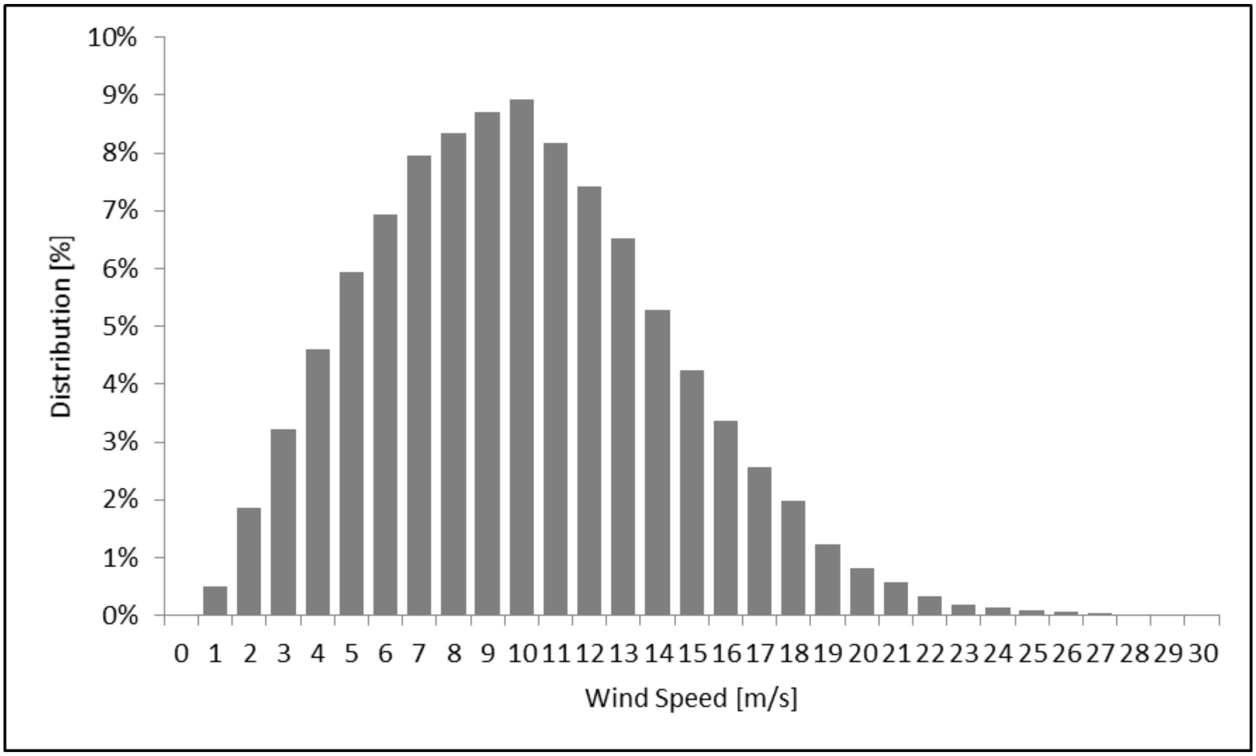


Figure 6.5: Wind speed distribution at Horns Rev, measured at a height of 62 meters. (Retrieved from Bergvall, 2019).

The frequency distribution of wind speeds was determined from the data collection of wind speeds from the met mast, as seen in Figure 5.5. Monthly variations of mean wind speed were measured from the data set and used as input parameters in RETScreen for calculating annual power generation. Figure 5.6 depicts the monthly variation in mean wind speed measured at the met mast. In a standard grid WF, the predominant wind direction is useful for determining the orientation of rows and columns. That being said, owing to the configuration of the WF and the location of new WTs being dictated by the current configuration, wind direction was not taken into account in this study.

Short-time measurements are not as accurate as long-time measurements, and the data used in this study has not been long-time corrected (Brower, 2012; Sommer and Hansen, 2002). But the wind measurements were long-time updated with the land based meteorological station Hvide Sande from 1989-2002 in the study by Sommer and Hansen (2002). The updated long-time measurements revealed an improved average wind speed of 9.67 m/s, a Weibull scale value of 10.8 m/s, and a Weibull shape value of 2.5. (Sommer and Hansen, 2002). This suggests that wind resources, and therefore electricity generation, may have been underrated. The energy analysis for all scenarios is in Appendix C-F.

Table 6.8: Mean monthly wind speed from Horns Rev met mast May 1999 – November 2002. Climate data from Blaavand meteorological station. Coordinates: 8,0799999237°E 55,5499992370605°N. (Retrieved from Bergvall, 2019).

Month	Wind Speed (m/s)	Atmosphere Pressure (kPa)	Air Temperature (°C)
January	10.96	101.1	1.9
February	11.76	101.2	1.2
March	10.09	101.2	2.6
April	8.39	101.2	6.3
May	8.19	101.4	10.5
June	8.60	101.3	13.3
July	7.56	101.2	16.3
August	7.41	101.2	16.1
September	9.17	101.2	16.7
October	11.12	101.1	13.9
November	10.84	101.0	10.2
December	10.50	101.1	3.5

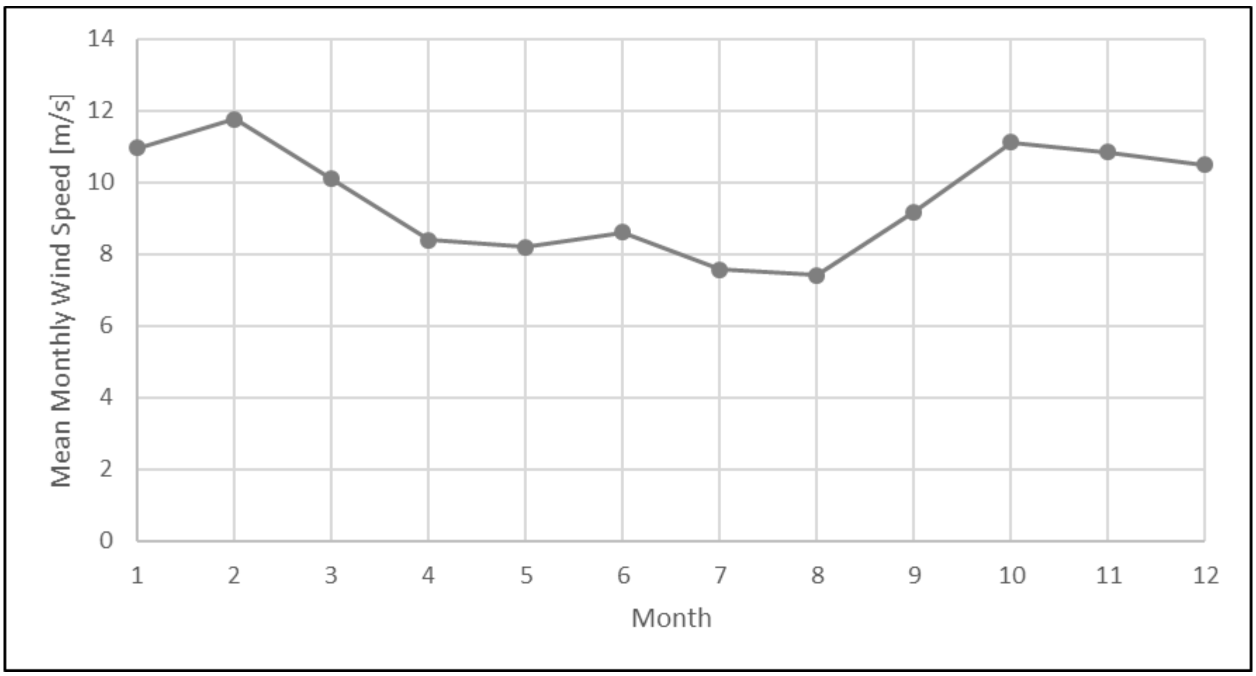


Figure 6.6: Seasonal variations of mean wind speed from the measurement period May 1999 –November 2002. (Retrieved from Bergvall, 2019).

6.3.3. COST AND TARIFF ANALYSIS

Cost module: For each scenario, the projected CAPEX and assumed OPEX were inserted. The study used level 1 cost estimation in RETScreen because the original investment cost was measured outside of the software. The financial factors were eventually inserted using a level 2 examination in the financial menu. RETScreen divides production losses into four distinct divisions, namely: availability, miscellaneous losses, airfoil losses, and array (wake) losses are the four types of losses. The availability was presumed to be 98%, airfoil and miscellaneous losses each at 2%.

A fixed cost of 20 € per MWh for O&M was assumed for all scenarios, which is the cost for Danish OWFs given by the DEA. Thus, the OPEX cost is 22 € per MWh.

6.3.5. RISK ANALYSIS

Risk module: The feasibility of a project can be assessed using RETScreen's built-in risk and sensitivity feature if, for example, electricity demand is reduced or the original expenditure is increased. In a sensitivity analysis, the LCoE and NPV findings were compared to shifts between 10% and 20% in the original expenditure expense and energy efficiency. The index for energy output price was also compared to a lower production price. This was done to determine the lowest price at which the various outcomes will have a beneficial NPV.

7

RESULTS AND DISCUSSIONS

7.1. RESULTS

The energy production cost is sometimes referred to as the LCoE. The benchmark electricity price was set at 50.37 € per MWh.

The gross GHG reduction for scenario 1,2,3, and 4 is 206,504 tCO_2/yr, 181,849 tCO_2/yr, 448,095 tCO_2/yr, 448,095 tCO_2/yr.

The energy production cost for scenario 1, 2, 3, and 4 is 43.83 € per MWh, 50.26 €/MWh, 59.72 €/MWh, and 57.26 €/MWh, respectively.

The total CAPEX for scenario 1, 2, 3, and 4, is 140.96 M€, 206.4 M€, 698.176 M€, and 648.816 M€, respectively.

The initial investment cost for scenario 1, 2, 3, and 4 is 0.8810 M€/MW, 1.3655 M€/MW, 2.2618 M€/MW, and 2.1038 M€/MW respectively.

From the results, it seen that due to the decommissioning of obsolete infrastructure as well as the installation of an entirely new wind farm, the full repowering scenario has the highest investment cost. Table 7.1 provides a comprehensive summary of the results of the four scenarios.

Table 7.1.: Financial results of all scenarios

	UNIT	SCENARIO 1	SCENARIO 2	SCENARIO 3	SCENARIO 4
Wind Turbine					
Wind Turbine Model	-	Vestas V80	Vestas V90	MHI Vestas V164	MHI Vestas V164
Wind Turbine Rated Capacity	MW	2	3	8	8
Rotor Diameter	m	80	90	164	164
Rotor Swept Area	m^2	5,027	6,362	21,124	21,124
Hub Height	m	70	70	105	105
Wind Speed at Hub Height	m/s	9.74	9.74	10.39	10.39
Number of Wind Turbines	pcs	80	50	40	40
Total Installed Capacity	MW	160	150	320	320
Weibull Shape Factor	-	2.3	2.3	2.3	2.3
Performance					
Array Losses	%	9.8	9	12	12
Airfoil Losses	%	2	2	2	2
Miscellaneous Losses	%	1	1	1	1
Availability	%	98	98	98	98
Capacity Factor	%	46.7	43.9	50.7	50.7
Financial Parameters					
General					
Inflation rate	%	2	2	2	2
Discount rate	%	5	5	5	5
Reinvestment rate	%	9	9	9	9
Project life	yr	15	25	25	25
Finance					
Debt ratio	%	70	70	70	70
Debt	€	98,672,000	144,480,000	488,723,200	454,171,200
Equity	€	42,288,000	61,920,000	209,452,800	194,644,800
Debt interest rate	%	5	5	5	5
Debt Term	yr	15	15	15	15
Debt Payments	€/yr	9,506,286	13,919,534	47,084,711	43,755,892
Annual revenue					
Electricity export revenue					
Electricity exported grid	MWh	655,129	576,914	1,421,575	1,421,575
Electricity export rate	€/MWh	50.37	50.37	50.37	50.37

Electricity export revenue	€	32,998,866	29,059,146	71,604,723	71,604,723
Electricity escalation rate	%	1	1	1	1
GHG reduction revenue					
Gross GHG reduction	**tCO_2/yr**	**206,504**	**181,849**	**448,095**	**448,095**
Gross GHG reduction - 15 yrs	tCO_2	3,097,553	4,546,229	11,202,376	11,202,376
Costs					
Initial Investment Cost	M€/MW	0.8810	1.3655	2.2618	2.1038
Total CAPEX	€	140,960,000	206,400,000	698,176,000	648,816,000
Yearly cash flows – Year 1					
Annual costs/Debts payments					
O&M	€/MWh	20	20	20	20
O&M costs (savings)	€	13,102,587	11,538,275	28,431,496	28,431,496
Dept payments – 15 yrs	€	9,506,286	13,919,534	47,084,711	43,755,892
Total OPEX	€	22,608,873	25,457,809	75,516,207	72,187,389
Annual savings and revenue					
Total annual savings and revenue	€	32,998,866	29,059,146	71,604,723	71,604,723
Net yearly cash flow – Year 1	€	10,389,992	3,601,337	-3,911,484	-582,665
Financial Viability					
Pre-tax IRR - equity	%	24.3	9.3	3	4.3
Pre-tax MIRR	%	14.4	9.1	4.3	5.3
Pre-tax IRR – assets	%	1.8	0.95	-2.4	-1.7
Pre-tax MIRR – assets	%	5.5	4	-0.25	0.35
Simple Payback Time	yr	7.1	11.8	16.2	15
Equity Payback Time	yr	4	15.1	20.6	19.2
Net Present Value (NPV)	€	69,866,859	47,229,633	-73,206,499	-23,846,499
Annual life cycle savings	€/yr	6,731,133	3,351,059	-5,194,181	-1,691,968
Benefit-Cost (B-C) ratio	-	2.7	1.8	0.65	0.88
Debt service coverage	-	2.1	1.3	0.92	0.99
GHG reduction cost	€/tCO_2	-32.60	-18.43	11.59	3.78
Energy production cost (LCoE)	**€/MWh**	**43.83**	**50.26**	**59.72**	**57.26**

7.2. DISCUSSIONS

In the case study, several feasibility analysis including risk analysis, but they are not included in the discussion because they are outside the scope of this thesis. Emission and financial analysis are covered here.

7.2.1. EMISSION ANALYSIS

The Emission Analysis worksheet calculates the proposed facility's GHG emission reduction (mitigation) potential.

GHG global warming potential parameters at Level 1 were employed. It is divided into three sections: Base case electricity system (Baseline), GHG emission and GHG reduction revenue. The Base case electricity system and Base case system GHG summary sections provide a description of the emission profile of the baseline system. The Proposed case system GHG summary section provides a description of the emission profile of the proposed facility. The GHG emission reduction summary section provides a summary of the estimated GHG emission reduction based on the input parameters. Results are calculated as equivalent tonnes of CO_2 avoided per annum. Inputs entered in the worksheet did not affect results reported in other worksheets, except for the GHG related items that appear in the Financial Analysis and Risk Analysis worksheets. Figure 7.1: shows a screenshot of the GHG reduction for scenario 1. The GHG emission reduction for other scenarios can be seen in Appendix C-F.

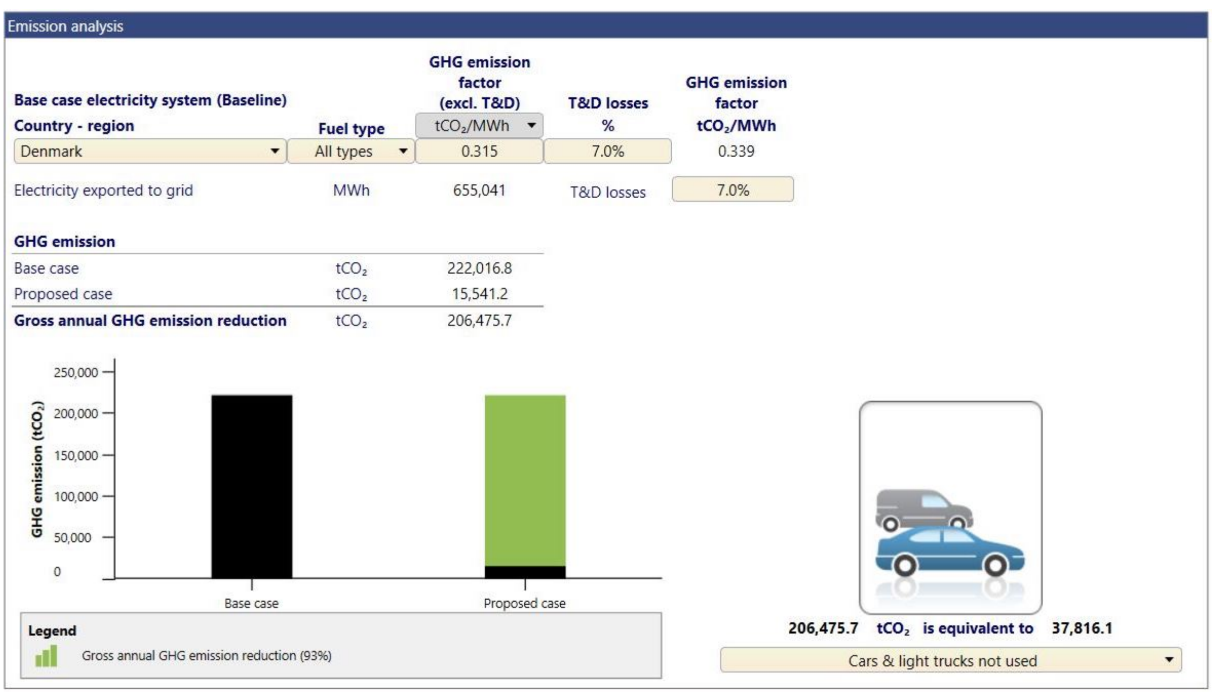


Figure 7: GHG emission analysis for scenario 1 (screenshot from RETScreen Expert).

GHG emission: When the base case is replaced with the proposed example, the model estimates the yearly decrease in GHG emissions.

Show graph: In the graph legend, the percentage of the gross yearly GHG emission decrease over the base case GHG emission is also estimated.

Show GHG equivalence: It compares the gross yearly GHG emission reduction with units that are simpler to comprehend (e.g. cars and light trucks not utilized).

Gross annual GHG emission reduction: The model determines the expected gross yearly decrease in GHG emissions if the scenario is executed. The computation is based on yearly emissions from both the base case and recommended case systems. The units are in tCO2/yr (equivalent tonnes of CO2 emissions per year).

GHG emission factor: The GHG emission factor for the power system given is calculated by the model. The value is derived using the T&D losses and the GHG emission factor (excluding T&D).

7.2.2. FINANCIAL ANALYSIS

Finance module: All financial conditions used in the analysis were the same for all scenarios, with the exclusion of the project lifetime. The discount rate was set at 5%, a little more than the DEA's recommendation of 4% (Klinge Jacobsen et al., 2019). The rate of inflation was estimated to be 2%. The debt interest rate was set at 5% for a 15-year duration. A debt-to-equity ratio of 70% to 30% was assumed. An escalation rate of 1% a year was estimated for electricity exports, which is the price rise of electricity.

The present value of all future cash flows, discounted at the discount rate, is the Net Present Value (NPV). The NPV is computed at a time 0 that corresponds to the intersection of year 0's end and year 1's commencement. The present value of all cash inflows is compared to the present value of all cash outflows connected with an investment project using the NPV technique. The NPV, or the difference between the present value of these cash flows, establishes whether the project is a financially suitable investment in general. Positive NPV numbers indicate a project that may be viable.

The model determines the cost of producing energy (electricity) per kWh (or MWh). This number (also known as the Levelized Cost of Power or LCOE) shows the needed rate of electricity export to achieve a Net Present Value (NPV) of zero. This computation excludes money from GHG reduction, customer premium income (rebate), Other revenue (cost), and revenue from Clean Energy (CE) generation.

Figure 7.1: shows a screenshot of the GHG financial analysis for scenario 1. The financial analysis for other scenarios can be seen in Appendix C-F.

Financial parameters

General		
Fuel cost escalation rate		
Inflation rate	%	2%
Discount rate	%	5%
Reinvestment rate	%	9%
Project life	yr	15
Finance		
Incentives and grants	€	
Debt ratio	%	70%
Debt	€	98,672,000
Equity	€	42,288,000
Debt interest rate	%	5%
Debt term	yr	15
Debt payments	€/yr	9,506,286
Income tax analysis		☐

Annual revenue

Electricity export revenue		
Electricity exported to grid	MWh	655,129
Electricity export rate	€/MWh	50.37
Electricity export revenue	€	32,998,866
Electricity export escalation rate	%	1%
GHG reduction revenue		
Gross GHG reduction	tCO_2/yr	206,504
Gross GHG reduction - 15 yrs	tCO_2	3,097,553
GHG reduction revenue	€	0
Other revenue (cost)		☐
Clean Energy (CE) production revenue		☐

Costs | Savings | Revenue

Initial costs			
Initial cost	100%	€	140,960,000
Total initial costs	**100%**	**€**	**140,960,000**
Yearly cash flows - Year 1			
Annual costs and debt payments			
O&M costs (savings)		€	13,102,587
Debt payments - 15 yrs		€	9,506,286
Total annual costs		**€**	**22,608,873**
Annual savings and revenue			
Electricity export revenue		€	32,998,866
GHG reduction revenue		€	0
Other revenue (cost)		€	0
CE production revenue		€	0
Total annual savings and revenue		**€**	**32,998,866**
Net yearly cash flow - Year 1		**€**	**10,389,992**

Financial viability

Pre-tax IRR - equity	%	24.3%
Pre-tax MIRR - equity	%	14.4%
Pre-tax IRR - assets	%	1.8%
Pre-tax MIRR - assets	%	5.5%
Simple payback	yr	7.1
Equity payback	yr	4
Net Present Value (NPV)	€	69,866,859
Annual life cycle savings	€/yr	6,731,133
Benefit-Cost (B-C) ratio		2.7
Debt service coverage		2.1
GHG reduction cost	$€/tCO_2$	-32.60
Energy production cost	€/MWh	43.83

Yearly cash flows

Year	Pre-tax	Cumulative
#	€	€
0	-42,288,000	-42,288,000
1	10,457,929	-31,830,071
2	10,523,925	-21,306,146
3	10,587,908	-10,718,238
4	10,649,804	-68,433
5	10,709,538	10,641,105
6	10,767,034	21,408,138
7	10,822,210	32,230,349
8	10,874,988	43,105,337
9	10,925,283	54,030,619
10	10,973,010	65,003,630
11	11,018,084	76,021,713
12	11,060,413	87,082,126
13	11,099,908	98,182,034
14	11,136,474	109,318,508
15	11,170,015	120,488,523

Figure 7.2: Financial analysis of scenario 1 (screenshot from RETScreen Expert).

7.2.3. MONOPILE REINFORCEMENT

For a single monopile installation, calculations for compression, thermal stress and buckling were all done, and the results show that the weight of the turbine is acting as an overload on the single monopile. Hence an additional three monopile were installed to support the existing monopile as to enable it function effectively. Furthermore, calculations on wind load and wave force were also carried out and the results show that the installation of the three monopiles can withstand and resist the external forces due to environmental conditions and environmental loads. The assumed velocity at 10 m is a fundamental parameter that must be considered when calculating for environmental load such as wind load. This is because, the wind velocity at the maximum height of the monopile can be ascertained from the assumed velocity thereby determining the pressure and the wind load at the maximum height of the monopile

The strength of the three additional monopile with each monopile withstanding up to 126.67 tons resist the existing monopile from breakdown. Hence installation of the three additional monopile that weighs up to 384 tons is also desired to support the weight of the existing monopile breakdown due to due to the weight of the turbine as an external load.

7.2.4. RESEARCH LIMITATIONS

Gathering reliable data from experts in the industry was challenging due to stiff commercial confidentiality rules and as a result of the competitive business environment. Some of the relevant data used was from reliable online sources, but not from the chosen wind farm operators, hence a minor gap for error. Another limiting factor was the COVID 19 pandemic situation which made it challenging to access some informants. Also, the research is centered only on lifetime extension and repowering at the North Sea, shallow depth, close to shore, and with regular layout, hence, it may not be applicable to other cases.

Many tasks of various kinds had to be completed in order to achieve the thesis's objectives. Selecting which theories to apply, analyzing all of the material from various sources, and deciding which sources of information to employ was the most challenging aspect.

To determine the strength of the foundation, a theoretical approach does not fulfill the requirements because they do not provide sufficient results.

8

CONCLUSION

The goal of this thesis was to theoretically analyse the possibility of reinforcing installed offshore monopile foundation for additional load support and to compare the financial viability and gross GHG reduction of lifetime extension and repowering scenarios at the EoL of an OWF.

The results of the case study show that the lifetime extension scenario has a solid business case with the highest financial viability.

The full repowering scenario has the highest gross GHG reduction of 0.45 $MtCO_2e$ per year.

The lowest LCoE was achieved from the lifetime extension scenario whereby refurbished wind turbines (i.e. nacelle and rotor) of similar size replaces the existing ones. This low LCoE is possible because the existing foundation, tower, substation, electrical infrastructure, etc. is reused, hence require the least CAPEX. In summary, the lifetime extension scenario has the lowest energy production cost and financial risk, highest GHG reduction and NPV.

Presently, there is no standard regulation defining optimal procedures following EoL. Financial constraints, as well as other factors such as available technology, country regulations, logistics challenges, environmental impact, and site condition, all influence decisions.

However, decommissioning can be postponed to keep obsolete fleet turbines and their components from becoming waste. Extending the life of important assets through life extension and repowering is presently being investigated as an alternate strategy.

Early in the design stage, adopting a proactive plan to EoL and developing a sustainable framework can help to reduce the environmental impact of turbine assets and lead to a change from linear to circular economic activities

From the calculations, wave and wind loads on the pile are fairly small, and do not create large bending moments, hence, they are not a key design consideration. On the hand, the turbine load has more effect on the existing monopile, therefore should be given more attention. The calculations show that the existing monopile could not carry the bigger turbine, but after distributing the load to the additional piles, it shows theoretically that the reinforced foundation is able to carry the additional load.

Finally, the objective of the reinforcement is accomplished. The reinforced monopile is calculated to resist the additional turbine load.

8.1. RECOMMENDATION

The concept of early repowering in order to considerably improve renewable energy generation is one suggestion for additional research on the issue.

The assessment of the structural strength and size of foundations, as well as the financial implications of installing bigger wind turbines and towers on existing foundations, are more significant at this point.

For environmental purposes, painting wind turbine blades with a darker colour e.g. black may reduce bird deaths.

Net zero emission pledges have can help to drive the industry forward. There should be Federal energy policy such as implementation of carbon tax.

The main recommendation is to make sure that cables have gold-plated reliability.

8.2. FURTHER STUDIES

Enthusiastic researches can look further into reinforcing or retrofitting existing offshore foundations.

Secondly, lifetime extension needs to be assessed further to come up with a decision tool on when exactly to make the switch from lifetime extension to repowering in the offshore context.

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APPENDIX

The section helps to show further details on how the thesis was done. It contains:

A: Interviews

B: Horns Rev 1 data

C: Scenario 1 Analysis

D: Scenario 2 Analysis

E: Scenario 3 Analysis

F: Scenario 4 Analysis

G: Other useful information

A. INTERVIEWS

A.1. Email to companies for interview

Dear Madam/Sir,

I'm a master student in a joint master's programme in Maritime Operations, major in Offshore and Subsea Operations at Western Norway University of Applied Sciences in Haugesund, Norway, and University of Applied Sciences Hochschule Emden/Leer in Germany.

I'm writing my master thesis on the area *Lifetime extension / Repowering of offshore wind farm*.

I have respect for your many years of experience in performing technical consultancy and assessment of the technical standard on existing turbines operating onshore in Denmark, thus, I believe a discussion with you would enrich my knowledge of lifetime extension / repowering operations and help tailor my research with relevant and reliable initiatives. Please, can you be so kind to grant me an online interview?

Thank you for your anticipated cooperation and I look forward to receiving your positive response.

See below the contact detail of my project supervisors:

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Best regards,

Biobele Oborie

A.2. Minutes of meeting, Wind Estate

This document is a summary of minutes of meeting (via online audio/video interview) on the 10th and 27th of November 2020.

Present:
Person 1 (Wind Estate)
Person 2 (Wind Estate)
Person 2 (Wind Estate)
Jens Christian Lindaas (HVL, Haugesund)
Marcus Bentin (HS Emden/Leer)
Biobele Oborie (HVL, HS Emden/Leer)

The questions/answers are presented as follows:

What part is more challenging: technical, financial, or environmental?
The Financial part is more challenging. It is not difficult to change a spare part, but it has to be financially feasible first.

In order to extend the lifetime for few more years, are there some standard permit requirements or thickness measurements for the foundations?
As of date, most of the lifetime extension operations in Denmark have been onshore, and it is allowed to operate the turbines for as long as it is technically possible without an additional permit for the purpose of lifetime extension. For offshore, there is no stipulated requirement yet. Though, to extend for five years or more there may be some sort of prove that the structure is fit and capable.

What is the key difference between Lifetime extension and Repowering in offshore wind?
In Denmark, replacing an old nacelle with a new one is not considered repowering, speaking from the Danish market perspective, repowering is to dismantle the old turbines and erect new ones. While

lifetime extension is to make minor replacement/refurbishment and keep the turbine running for longer than the design lifetime.

What end-of-life option is projected to dominate offshore wind in the nearest future?

Every maintenance carried out by the technicians is meant to increase the lifetime of the components which will translate to lifetime extension.

In summary, the limitation of the lifetime of the turbine is only financial reasons, so you can speak about a financial lifetime, once is no longer feasible, no matter how good the spare parts or whichever shape they might be in doesn't matter because once it is not feasible from a financial point of view then there would be no need to extend the lifetime, the only option would be to dismantle the turbine. For example, if from a technical point of view, it is feasible to change a generator to extend the turbine lifetime, however it would not be done if it's not feasible from a financial point of view. So, when you look at lifetime intensions, it is not just based sole on the technical point of view but rather it is based primarily on the financial point of view. And off course, as much as possible it has to be green energy.

A.3. Minutes of meeting, Owner of the substation of the base case (Feb. 2021)

The following are the answers to the questions about the electrical infrastructure. Only the questions for which the answers were given are presented here.

1. What is the typical lifetime of a substation, inter array cable and export cables? Values for Horns Rev 1 OWF

   The design lifetime of the substations, transformers and foundations is 25 years. Energinet (Danish TSO) conducts inspection of the electrical structures in Horns Rev 1 Offshore Wind Farm every 4 years.
   With respect to the recent inspections, all the structures seem to be operating as expected. It is estimated that as of now substation can function for 15 more years, transformers can operate for 10 more years without faults. Some components on the substation were replaced in the last few years.
   HR1 substation is supported by 3 monopile foundations (tripod structure), the substation foundations could be safe in operation for 20 more years.
   Export cable has a design lifetime of at least 25 years. HR1 export cable can be operational for another 15+ years. Inter array cable is owned by Vattenfall (OWF Owner)

2. Any typical methods for extending the lifetime of the electrical infrastructure?

   There are no standard steps carried to extend the lifetime of the electrical infrastructure. Inspection of components is required and then replacing the faulty equipment is required. Normally upgrading of the substations depends on the condition of the transformer. Replacing a transformer would cost at least 20 Million Danish Kroner.

3. What are the weights of the main materials (eg. Iron, copper, steel….) used in the substations and grid cables for HR1? Possible percentage split into different components (eg. Transformer, foundation, cables..)

   Topside weighs 900 tons, Jacket and crane weigh 100 tons

   Platform: There are 3, 60m monopile foundations and on top of that a 100-ton frame. The foundations of the HR1 are overdesigned, with an additional 15mm thickness to their diameters.
   Main materials used in the structure are steel, aluminium in frame, copper in transformer and cable, concrete under the transformer box.

   The split of the materials in platform can be as 80% steel, 10% concrete, 10% aluminium. Transformer of HR1 weighs 250 tons, which includes 80 tons of oil and 100 tons of copper in it.

4. What are the upper limits in terms of max capacity, max voltage, max current and max Power that can be handled by the existing offshore substation platform of HR1? And the specification ratings of existing transformer, inter array and export cable?

   The maximum capacity of the substation is with a 160MW transformer, export cable capacity at 200MW, similar export cable is used for the Horns Rev 2 platform.

5. What is the maximum power that can be transmitted by the existing cable network?

   The export cable can transmit maximum power of 200MW

6. What changes in the electrical infrastructure will be required if all the present Wind turbines (2MW) are replaced with new 3MW WTG?

   The HR1 is connected with 5 arrays with inter-array cables. If all the 2MW WTs are replaced with new 3MW WTG, then there will be a need of a bigger transformer and to build a new substation. The current substation will not be refurbished to accommodate the increase in capacity. The current switch gear will be changed. Also, all the inter-array will have to be changed and even the export substation will not be sufficient. Perhaps the onshore substation will also not be sufficient for this capacity change.
   The rough cost of building of a new substation including its foundations would be around 200 Million Danish Kroner.

   50 WTs of 3MW capacity can be installed, keeping the same electrical infrastructure of the HR1 OWF. Note: Same power rating in each array results in NO Change in the electrical infrastructure required.

7. What do you believe could happen to the substations that are developed now?

The new substations being developed now are still with a design lifetime of 25 years.
For the future wind farms, it is estimated that lifetime extension could be the preferred option, and not a lot of repowering would take place.
The rules regarding the ownership of the substation have been changed now. The upcoming Offshore Wind Farm Thor will have the wind farm developer owning the substation. The ownership of the connection (export cable) and onshore substation will still be kept with the Energinet (TSO).

Energinet directly could reuse the 150kV switch gear as a spare part for another offshore wind farm in one case. Other components from the substation are sold as a scrap material.

A.4. Minutes of meeting, Nordic Wind Consultants

This is the list of questions that was discussed with Nordic Wind Consultants shows the questions only (via online audio) on the 17th of December 2020.

Present:
Person 1 (Nordic Wind Consultant)
Biobele Oborie (HVL, HS Emden/Leer)

The questions as follows:

Is there a regulatory framework in Denmark governing Lifetime extension and Repowering of Offshore Wind Farm? What are the key areas worthy of note?

TECHNICAL ASPECT

1. What lifetime extension and/or repowering projects have you been involved in? What was your scope of work?
2. Which tools, equipment, vessels, and methods were used for cutting, dismantling, lifting, installation, and towing?
3. What is the scope of lifetime extension in offshore wind farm?
4. What is the scope of repowering in offshore wind farm?
5. How many weeks will the repowering process take?
6. What is the life span of the foundation, transition piece, tower, rotor, blades, hub, nacelle, generator, gearbox, shaft, brake, yaw motor, yaw drive, and other vital components?
7. What is the likelihood that the transition piece would be suitable enough to serve the purpose of repowering?
8. How can you replace the turbine? What processes are involved?
9. Which are the suitable and best time/cost efficient vessels will you use at the dismantling phase, Installation phase, and Towing phase? And why?
10. Considering all factors, which will you subscribe to, lifetime extension or repowering? And Why?

B. HORNS REV 1 DATA

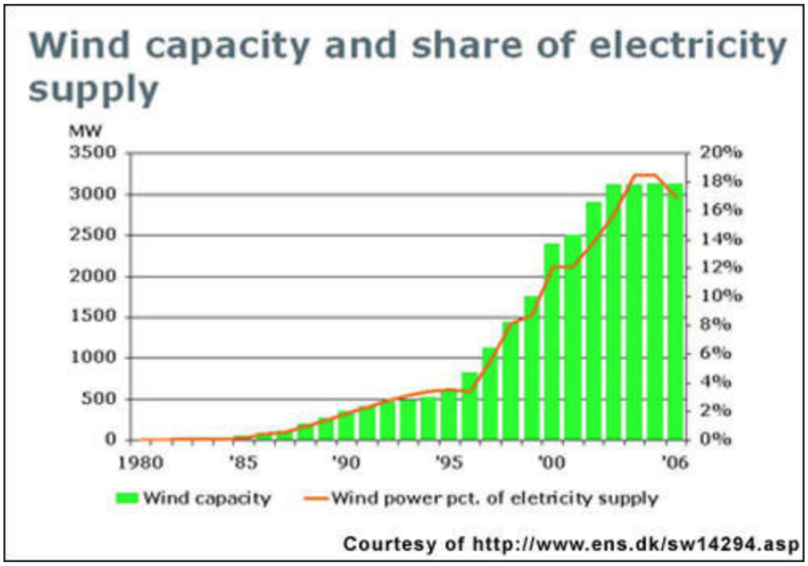


Fig. A.1: Wind capacity and share of electric supply (Source: Power Technology)

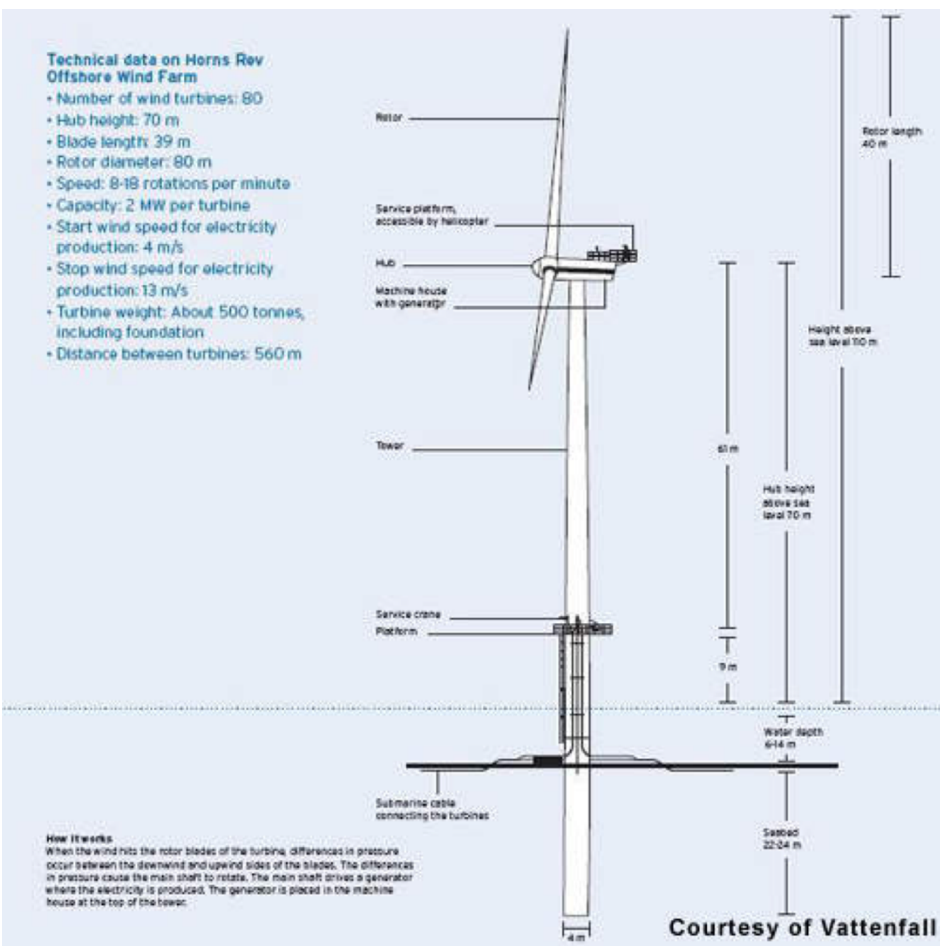
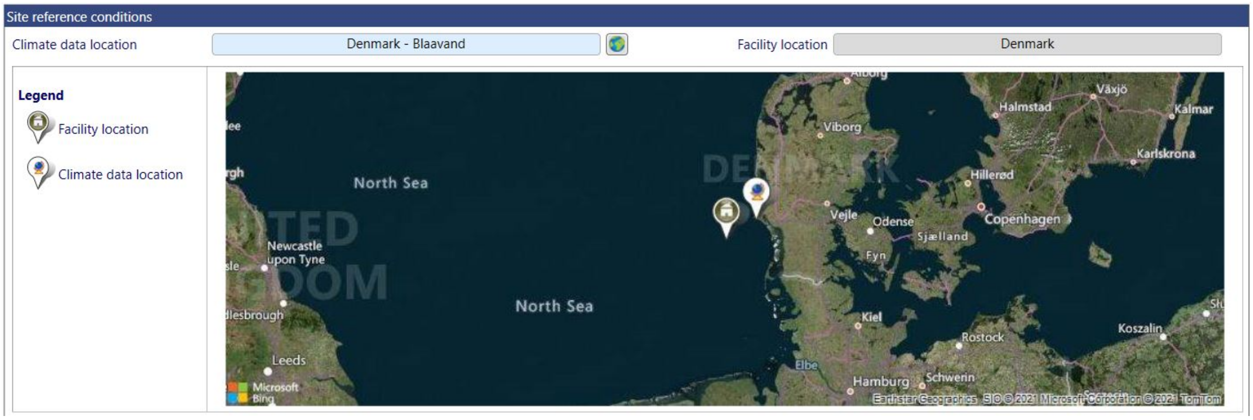
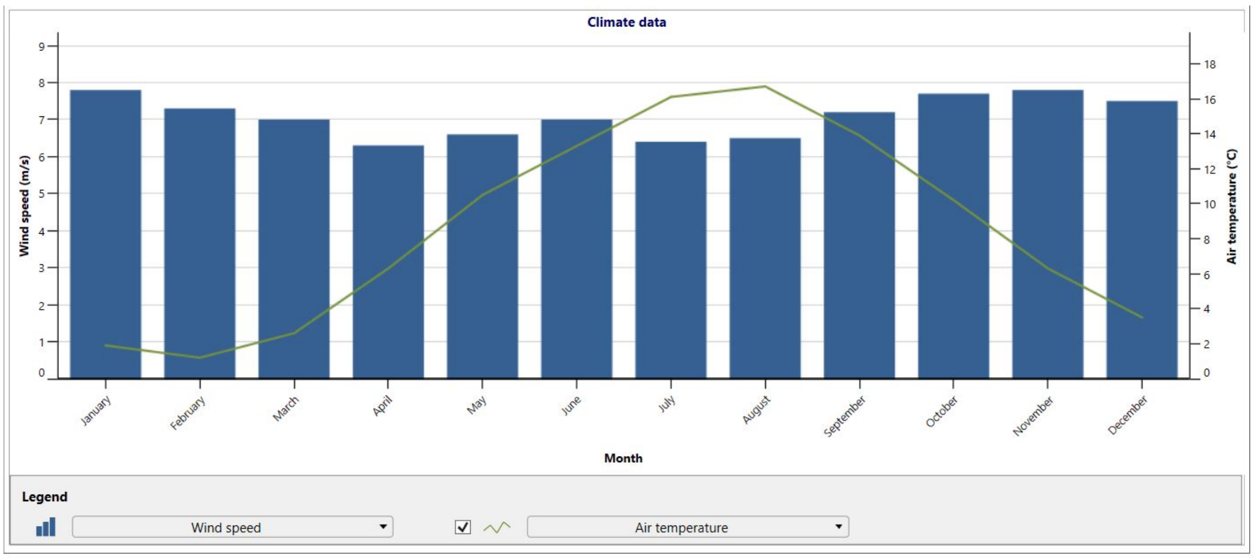


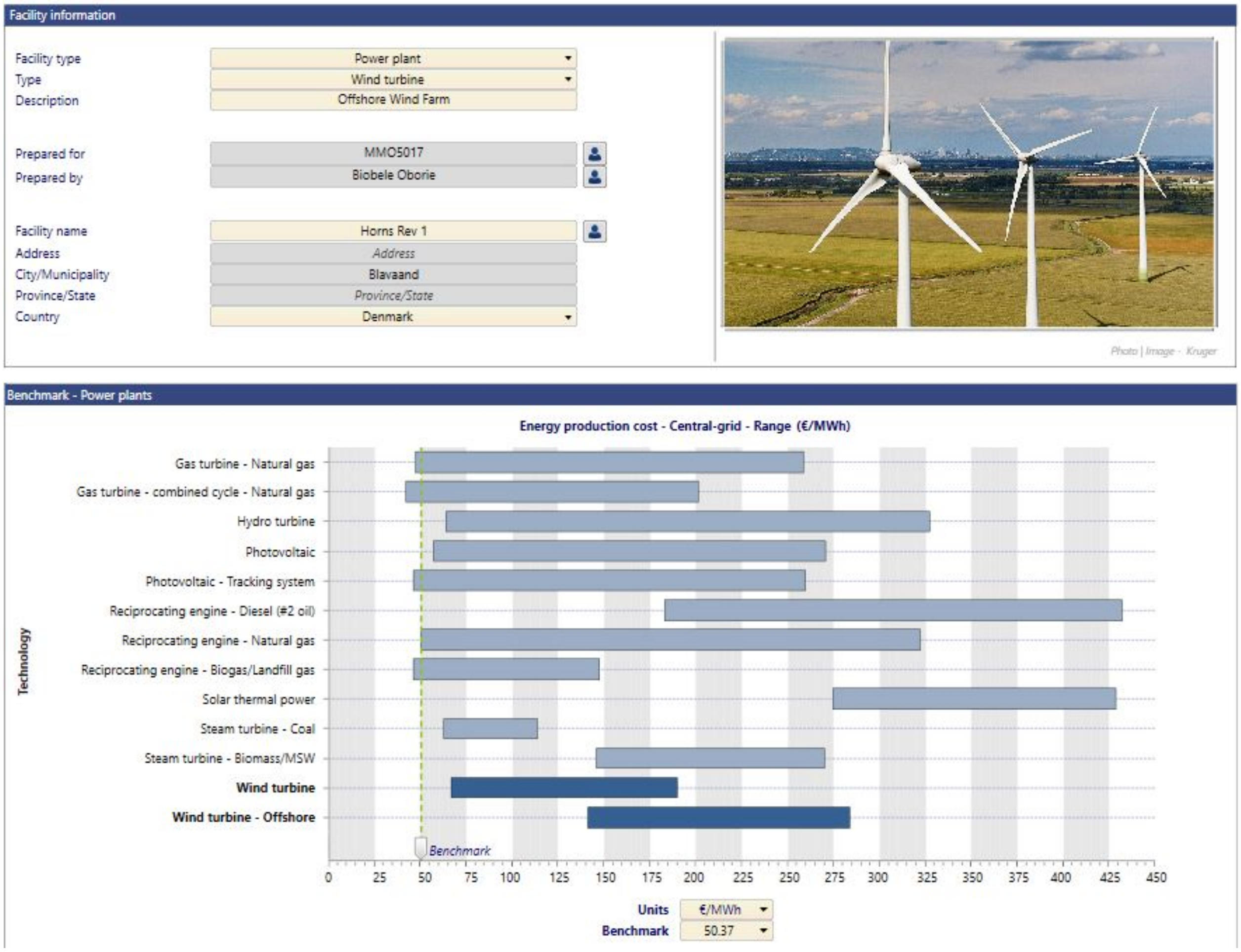
Fig. A.2: Horns Rev 1 Wind Turbine Parameters (Source: Power Technology)

Fig. A.3: Horns Rev 1 Substation a, b, and c (Source: HSM Offshore, 2002)

A.3: SCENARIO 1






Facility information
Facility type
Power plant
Type
Wind turbine
Description
Offshore Wind Farm
Prepared for
MMO5017
Prepared by
Biobele Oborie
Facility name
Horns Rev 1
Address
Address
City/Municipality
Blavaand
Province/State
Province/State
Country
Denmark
Photo | Image - Kruger
Benchmark - Power plants
Energy production cost - Central-grid - Range (€/MWh)
Gas turbine - Natural gas
Gas turbine - combined cycle - Natural gas
Hydro turbine
Photovoltaic
Photovoltaic - Tracking system
Reciprocating engine - Diesel (#2 oil)
Reciprocating engine - Natural gas
Reciprocating engine - Biogas/Landfill gas
Solar thermal power
Steam turbine - Coal
Steam turbine - Biomass/MSW
Wind turbine
Wind turbine - Offshore
Technology
Benchmark
0 25 50 75 100 125 150 175 200 225 250 275 300 325 350 375 400 425 450
Units
€/MWh
Benchmark
50.37

Power plant - Offshore Wind Farm - Wind turbine

Fuels & schedules
- Electricity and fuels

Technology
- Power
  - Wind turbine - 100000 kW - Offshore (6.1m/s @10m)
  - Wind turbine - 100000 kW - Offshore (7.1m/s @10m)
  - Wind turbine - 100000 kW - Offshore (8.1m/s @10m)
  - Wind turbine - 100000 kW - Offshore (9.1m/s @10m)
  - Offshore

Summary
- Include system?
- Comparison

Wind

Description: Offshore

Note

Level: Level 1 Level 2 Level 3

eLearning

Wind - Level 3

Resource assessment

Resource method: Wind speed

Month	Wind speed m/s	Atmospheric pressure kPa	Air temperature °C	Climate Data Denmark - Blaavand m/s	kPa	°C	Electricity export rate €/MWh	Electricity exported to grid MWh
January	11.0	101.1	1.9	7.8	101.1	1.9	50.37	67,825
February	11.8	101.2	1.2	7.3	101.2	1.2	50.37	65,505
March	10.1	101.2	2.6	7.0	101.2	2.6	50.37	62,066
April	8.4	101.2	6.3	6.3	101.2	6.3	50.37	46,009
May	8.2	101.4	10.5	6.6	101.4	10.5	50.37	45,205
June	8.6	101.3	13.3	7.0	101.3	13.3	50.37	46,799
July	7.6	101.2	16.1	6.4	101.2	16.1	50.37	38,430
August	7.4	101.2	16.7	6.5	101.2	16.7	50.37	36,873
September	9.2	101.2	13.9	7.2	101.2	13.9	50.37	51,197
October	11.1	101.1	10.2	7.7	101.1	10.2	50.37	66,705
November	10.8	101.0	6.3	7.8	101.0	6.3	50.37	63,900
December	10.5	101.1	3.5	7.5	101.1	3.5	50.37	64,527
Annual	**9.5**	**101.2**	**8.6**	**7.1**	**101.2**	**8.6**	**50.37**	**655,041**

Measured at	m	62	10
Wind shear exponent		0.16	

Wind turbine

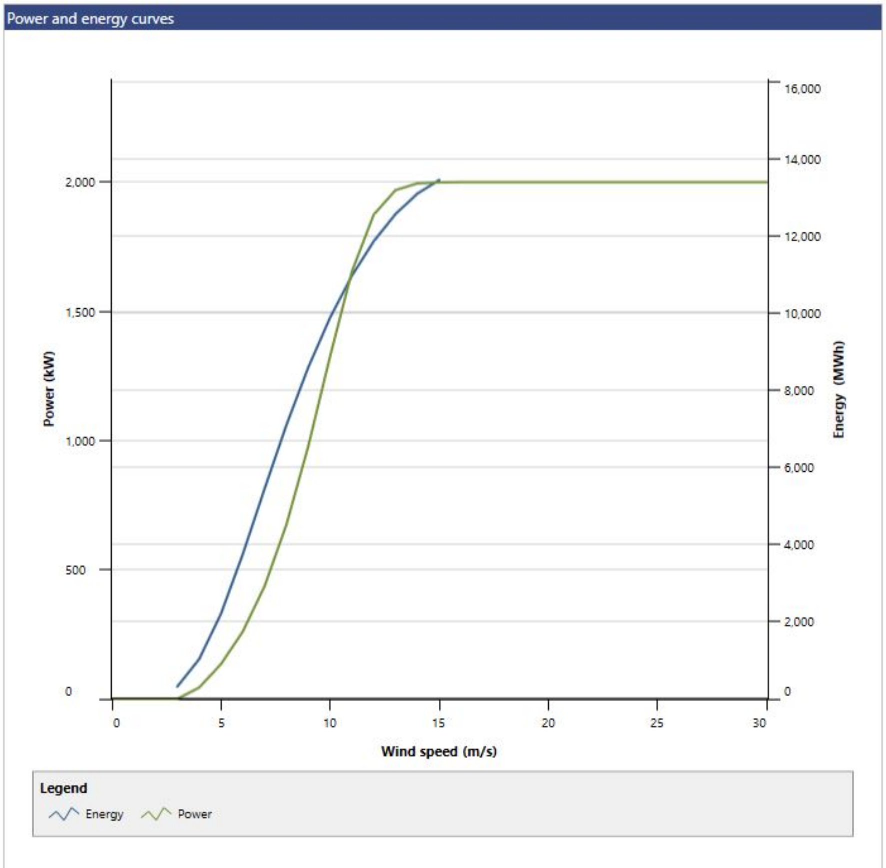
Power capacity per turbine	MW	2	
Manufacturer		Vestas	
Model		VESTAS V80-2.0 MW OFFSHORE	
Number of turbines		80	
Power capacity	MW	160	
Hub height	m	70	9.7 m/s
Rotor diameter per turbine	m	80	
Swept area per turbine	m²	5,026.55	
Energy curve data		Custom	
Shape factor		2.3	

Power and energy curves

Data

Wind speed m/s	Power curve data kW	Energy curve data MWh
0	0	
1	0	
2	0	
3	0	322
4	44.1	1,034
5	135	2,211
6	261	3,756
7	437	5,455
8	675	7,107
9	978	8,598
10	1,326	9,888
11	1,654	10,974
12	1,874	11,866
13	1,969	12,574
14	1,995	13,101
15	1,999	13,455
16	2,000	
17	2,000	
18	2,000	
19	2,000	
20	2,000	
21	2,000	
22	2,000	
23	2,000	
24	2,000	
25	2,000	
26	2,000	
27	2,000	
28	2,000	
29	2,000	
30	2,000	

Power and energy curves



Losses

Array losses	%	9.8%
Airfoil losses	%	2%
Miscellaneous losses	%	1%
Availability	%	98%

Summary

Capacity factor	%	46.7%
Initial costs	€/kW	881
	€	140,960,000
O&M costs (savings)	€/MWh	20
	€	13,100,820
Electricity export rate		Electricity export rate - annual
	€/MWh	50.37
Electricity exported to grid	MWh	655,041
Electricity export revenue	€	32,994,415

Other information

		Per turbine
Unadjusted energy production	MWh	9,314
Pressure coefficient		0.999
Temperature coefficient		1.023
Gross energy production	MWh	9,547
Losses coefficient		0.86
Specific yield	kWh/m²	1,629

Initial costs (credits)	Unit	Quantity	Unit cost		Amount
Initial cost				€	140,960,000
Show data					
User-defined	cost			€	-
Total initial costs				**€**	**140,960,000**

Annual costs (credits)	Unit	Quantity	Unit cost		Amount
O&M costs (savings)	project			€	13,100,820
Show data					
User-defined	cost			€	-
Total annual costs				**€**	**13,100,820**

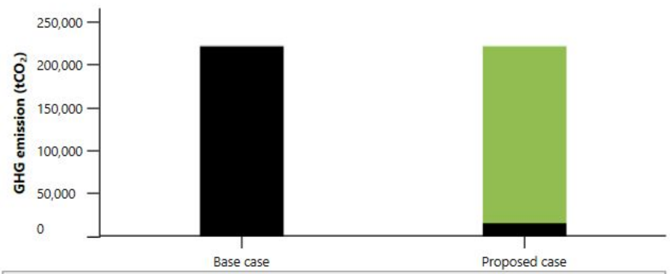
Annual savings	Unit	Quantity	Unit cost		Amount
User-defined	cost			€	-
Total annual savings				**€**	**-**

Emission analysis

Base case electricity system (Baseline)		GHG emission factor (excl. T&D)	T&D losses	GHG emission factor
Country - region	Fuel type	tCO₂/MWh	%	tCO₂/MWh
Denmark	All types	0.315	7.0%	0.339
Electricity exported to grid	MWh	655,041	T&D losses	7.0%

GHG emission

Base case	tCO_2	222,016.8
Proposed case	tCO_2	15,541.2
Gross annual GHG emission reduction	tCO_2	206,475.7



Legend
Gross annual GHG emission reduction (93%)

206,475.7 tCO_2 is equivalent to 37,816.1 Cars & light trucks not used

GHG reduction revenue

GHG reduction credit rate €/tCO_2

Financial parameters

General		
Fuel cost escalation rate		
Inflation rate	%	2%
Discount rate	%	5%
Reinvestment rate	%	9%
Project life	yr	15
Finance		
Incentives and grants	€	
Debt ratio	%	70%
Debt	€	98,672,000
Equity	€	42,288,000
Debt interest rate	%	5%
Debt term	yr	15
Debt payments	€/yr	9,506,286
Income tax analysis		

Annual revenue

Electricity export revenue		
Electricity exported to grid	MWh	655,129
Electricity export rate	€/MWh	50.37
Electricity export revenue	€	32,998,866
Electricity export escalation rate	%	1%
GHG reduction revenue		
Gross GHG reduction	tCO_2/yr	206,504
Gross GHG reduction - 15 yrs	tCO_2	3,097,553
GHG reduction revenue	€	0
Other revenue (cost)		
Clean Energy (CE) production revenue		

Costs | Savings | Revenue

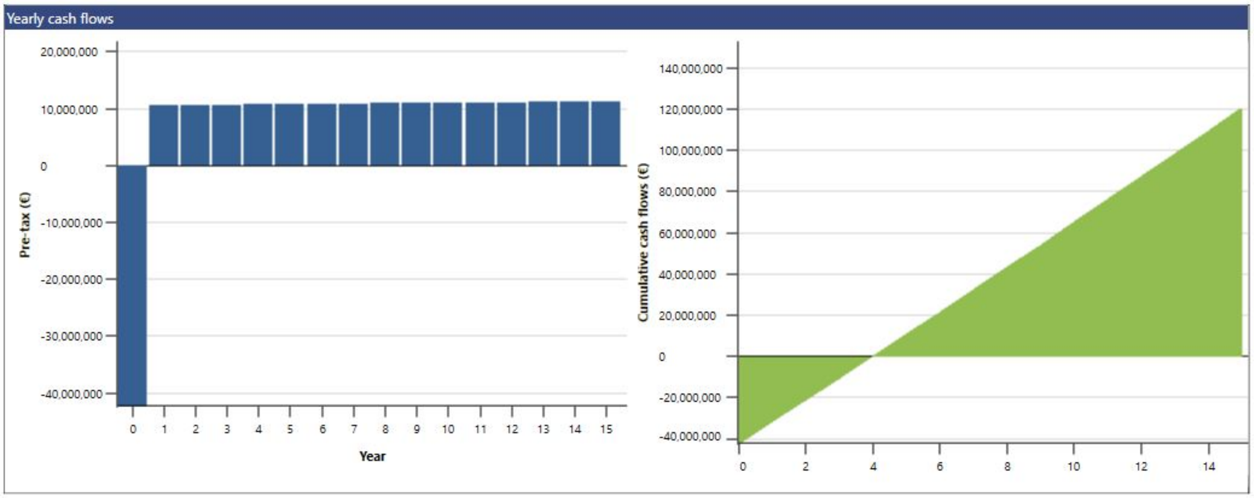
Initial costs			
Initial cost	100%	€	140,960,000
Total initial costs	**100%**	€	**140,960,000**
Yearly cash flows - Year 1			
Annual costs and debt payments			
O&M costs (savings)		€	13,102,587
Debt payments - 15 yrs		€	9,506,286
Total annual costs		€	**22,608,873**
Annual savings and revenue			
Electricity export revenue		€	32,998,866
GHG reduction revenue		€	0
Other revenue (cost)		€	0
CE production revenue		€	0
Total annual savings and revenue		€	**32,998,866**
Net yearly cash flow - Year 1		€	**10,389,992**

Financial viability

Pre-tax IRR - equity	%	24.3%
Pre-tax MIRR - equity	%	14.4%
Pre-tax IRR - assets	%	1.8%
Pre-tax MIRR - assets	%	5.5%
Simple payback	yr	7.1
Equity payback	yr	4
Net Present Value (NPV)	€	69,866,859
Annual life cycle savings	€/yr	6,731,133
Benefit-Cost (B-C) ratio		2.7
Debt service coverage		2.1
GHG reduction cost	€/tCO_2	-32.60
Energy production cost	€/MWh	43.83

Yearly cash flows

Year	Pre-tax	Cumulative
#	€	€
0	-42,288,000	-42,288,000
1	10,457,929	-31,830,071
2	10,523,925	-21,306,146
3	10,587,908	-10,718,238
4	10,649,804	-68,433
5	10,709,538	10,641,105
6	10,767,034	21,408,138
7	10,822,210	32,230,349
8	10,874,988	43,105,337
9	10,925,283	54,030,619
10	10,973,010	65,003,630
11	11,018,084	76,021,713
12	11,060,413	87,082,126
13	11,099,908	98,182,034
14	11,136,474	109,318,508
15	11,170,015	120,488,523

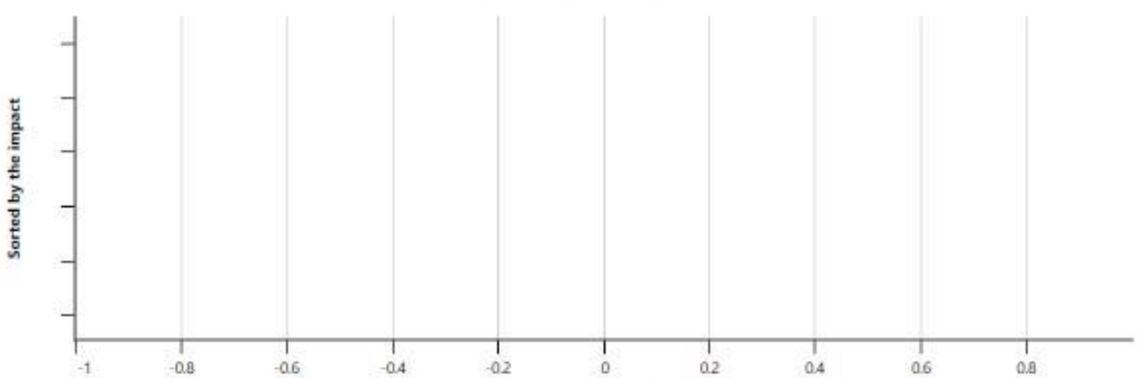

Yearly cash flows
20,000,000
10,000,000
0
-10,000,000
-20,000,000
-30,000,000
-40,000,000
Pre-tax (€)
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15
Year
140,000,000
120,000,000
100,000,000
80,000,000
60,000,000
40,000,000
20,000,000
0
-20,000,000
-40,000,000
Cumulative cash flows (€)
0 2 4 6 8 10 12 14

Risk analysis

Perform analysis on	Equity payback
Number of combinations	500
Random seed	No

Parameter	Unit	Value	Range (+/-)	Minimum	Maximum
Initial costs	€	140,960,000	25%	105,720,000	176,200,000
O&M	€	13,100,820	25%	9,825,615	16,376,025
Electricity exported to grid	MWh	655,040.99	25%	491,280.74	818,801.24
Electricity export rate	€/MWh	50.37	25%	37.78	62.96
Debt ratio	%	70.0%	25%	52.5%	87.5%
Debt interest rate	%	5.00%	25%	3.75%	6.25%
Debt term	yr	15	25%	11	19

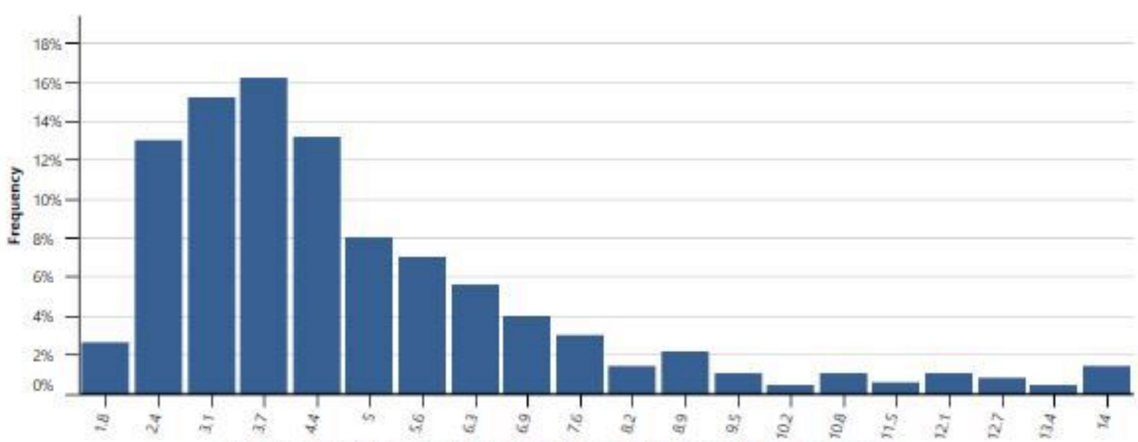
Impact - Equity payback



2% of cases have an equity payback either immediate or greater than the project life.

Median	yr	4.2
Level of risk	%	10%
Minimum within level of confidence	yr	2.3
Maximum within level of confidence	yr	10.8

Distribution - Equity payback



2% of cases have an equity payback either immediate or greater than the project life.

Sensitivity analysis

Perform analysis on	Net Present Value (NPV)	
Sensitivity range	20%	
Threshold	50.37	€

- Remove analysis

Electricity export rate		Initial costs (€)				
		112,768,000	126,864,000	140,960,000	155,056,000	169,152,000
€/MWh		-20.0%	-10.0%	0.0%	10.0%	20.0%
40.30	-20.0%	24,457,888	10,361,888	-3,734,112	-17,830,112	-31,926,112
45.33	-10.0%	61,244,155	47,148,155	33,052,155	18,956,155	4,860,155
50.37	0.0%	98,030,422	83,934,422	**69,838,422**	55,742,422	41,646,422
55.41	10.0%	134,816,689	120,720,689	106,624,689	92,528,689	78,432,689
60.44	20.0%	171,602,955	157,506,955	143,410,955	129,314,955	115,218,955

- Remove analysis

O&M		Initial costs (€)				
		112,768,000	126,864,000	140,960,000	155,056,000	169,152,000
€		-20.0%	-10.0%	0.0%	10.0%	20.0%
10,480,656	-20.0%	129,443,271	115,347,271	101,251,271	87,155,271	73,059,271
11,790,738	-10.0%	113,736,846	99,640,846	85,544,846	71,448,846	57,352,846
13,100,820	0.0%	98,030,422	83,934,422	**69,838,422**	55,742,422	41,646,422
14,410,902	10.0%	82,323,997	68,227,997	54,131,997	40,035,997	25,939,997
15,720,984	20.0%	66,617,573	52,521,573	38,425,573	24,329,573	10,233,573

- Remove analysis

Debt ratio		Debt interest rate (%)				
		4.00%	4.50%	5.00%	5.50%	6.00%
%		-20.0%	-10.0%	0.0%	10.0%	20.0%
56%	-20.0%	75,083,204	72,483,661	69,838,422	67,148,257	64,413,966
63%	-10.0%	75,738,802	72,814,316	69,838,422	66,811,987	63,735,909
70%	0.0%	76,394,400	73,144,971	**69,838,422**	66,475,716	63,057,852
77%	10.0%	77,049,998	73,475,626	69,838,422	66,139,445	62,379,795
84%	20.0%	77,705,596	73,806,281	69,838,422	65,803,175	61,701,738

- Remove analysis

O&M		Electricity exported to grid (MWh)				
		524,032.79	589,536.89	655,040.99	720,545.09	786,049.19
€		-20.0%	-10.0%	0.0%	10.0%	20.0%
10,480,656	-20.0%	27,678,737	64,465,004	101,251,271	138,037,538	174,823,805
11,790,738	-10.0%	11,972,313	48,758,580	85,544,846	122,331,113	159,117,380
13,100,820	0.0%	-3,734,112	33,052,155	**69,838,422**	106,624,689	143,410,955
14,410,902	10.0%	-19,440,536	17,345,730	54,131,997	90,918,264	127,704,531
15,720,984	20.0%	-35,146,961	1,639,306	38,425,573	75,211,839	111,998,106

- Remove analysis

Initial costs		O&M (€)				
		10,480,656	11,790,738	13,100,820	14,410,902	15,720,984
€		-20.0%	-10.0%	0.0%	10.0%	20.0%
112,768,000	-20.0%	129,443,271	113,736,846	98,030,422	82,323,997	66,617,573
126,864,000	-10.0%	115,347,271	99,640,846	83,934,422	68,227,997	52,521,573
140,960,000	0.0%	101,251,271	85,544,846	**69,838,422**	54,131,997	38,425,573
155,056,000	10.0%	87,155,271	71,448,846	55,742,422	40,035,997	24,329,573
169,152,000	20.0%	73,059,271	57,352,846	41,646,422	25,939,997	10,233,573

Sensitivity analysis

Perform analysis on	Energy production cost	
Sensitivity range	20%	
Threshold	50.37	€/MWh

- Remove analysis

Electricity export rate		Initial costs (€)				
		112,768,000	126,864,000	140,960,000	155,056,000	169,152,000
€/MWh		-20.0%	-10.0%	0.0%	10.0%	20.0%
40.30	-20.0%	39.69	41.76	43.83	45.91	47.98
45.33	-10.0%	39.69	41.76	43.83	45.91	47.98
50.37	0.0%	39.69	41.76	**43.83**	45.91	47.98
55.41	10.0%	39.69	41.76	43.83	45.91	47.98
60.44	20.0%	39.69	41.76	43.83	45.91	47.98

- Remove analysis

O&M		Initial costs (€)				
		112,768,000	126,864,000	140,960,000	155,056,000	169,152,000
€		-20.0%	-10.0%	0.0%	10.0%	20.0%
10,480,656	-20.0%	35.07	37.14	39.21	41.29	43.36
11,790,738	-10.0%	37.38	39.45	41.52	43.60	45.67
13,100,820	0.0%	39.69	41.76	**43.83**	45.91	47.98
14,410,902	10.0%	42.00	44.07	46.14	48.22	50.29
15,720,984	20.0%	44.31	46.38	48.45	50.53	52.60

- Remove analysis

Debt ratio		Debt interest rate (%)				
		4.00%	4.50%	5.00%	5.50%	6.00%
%		-20.0%	-10.0%	0.0%	10.0%	20.0%
56%	-20.0%	43.06	43.44	43.83	44.23	44.63
63%	-10.0%	42.97	43.40	43.83	44.28	44.73
70%	0.0%	42.87	43.35	**43.83**	44.33	44.83
77%	10.0%	42.77	43.30	43.83	44.38	44.93
84%	20.0%	42.68	43.25	43.83	44.43	45.03

- Remove analysis

O&M		Electricity exported to grid (MWh)				
		524,032.79	589,536.89	655,040.99	720,545.09	786,049.19
€		-20.0%	-10.0%	0.0%	10.0%	20.0%
10,480,656	-20.0%	49.02	43.57	39.21	35.65	32.68
11,790,738	-10.0%	51.90	46.14	41.52	37.75	34.60
13,100,820	0.0%	54.79	48.70	**43.83**	39.85	36.53
14,410,902	10.0%	57.68	51.27	46.14	41.95	38.45
15,720,984	20.0%	60.57	53.84	48.45	44.05	40.38

- Remove analysis

Initial costs		O&M (€)				
		10,480,656	11,790,738	13,100,820	14,410,902	15,720,984
€		-20.0%	-10.0%	0.0%	10.0%	20.0%
112,768,000	-20.0%	35.07	37.38	39.69	42.00	44.31
126,864,000	-10.0%	37.14	39.45	41.76	44.07	46.38
140,960,000	0.0%	39.21	41.52	**43.83**	46.14	48.45
155,056,000	10.0%	41.29	43.60	45.91	48.22	50.53
169,152,000	20.0%	43.36	45.67	47.98	50.29	52.60

A.4: SCENARIO 2

Power plant - Offshore Wind Farm - Wind turbine

Fuels & schedules
- Electricity and fuels

Technology
- Power
  - Wind turbine - 100000 kW - Offshore (6.1m/s @10m)
  - Wind turbine - 100000 kW - Offshore (7.1m/s @10m)
  - Wind turbine - 100000 kW - Offshore (8.1m/s @10m)
  - Wind turbine - 100000 kW - Offshore (9.1m/s @10m)
  - Offshore

Summary
- Include system?
- Comparison

Wind
Description: Offshore
Note:

Level: Level 1 | Level 2 | Level 3

eLearning

Wind - Level 3

Resource assessment

Resource method: Wind speed

Month	Wind speed m/s	Atmospheric pressure kPa	Air temperature °C	Climate Data Denmark - Blaavand m/s	kPa	°C	Electricity export rate €/MWh	Electricity exported to grid MWh
January	11.0	101.1	1.9	7.8	101.1	1.9	50.37	60,302
February	11.8	101.2	1.2	7.3	101.2	1.2	50.37	58,621
March	10.1	101.2	2.6	7.0	101.2	2.6	50.37	54,753
April	8.4	101.2	6.3	6.3	101.2	6.3	50.37	39,984
May	8.2	101.4	10.5	6.6	101.4	10.5	50.37	39,229
June	8.6	101.3	13.3	7.0	101.3	13.3	50.37	40,733
July	7.6	101.2	16.1	6.4	101.2	16.1	50.37	33,250
August	7.4	101.2	16.7	6.5	101.2	16.7	50.37	31,900
September	9.2	101.2	13.9	7.2	101.2	13.9	50.37	44,783
October	11.1	101.1	10.2	7.7	101.1	10.2	50.37	59,388
November	10.8	101.0	6.3	7.8	101.0	6.3	50.37	56,752
December	10.5	101.1	3.5	7.5	101.1	3.5	50.37	57,141
Annual	**9.5**	**101.2**	**8.6**	**7.1**	**101.2**	**8.6**	**50.37**	**576,834**

Measured at	m	62	10
Wind shear exponent		0.16	

Wind turbine

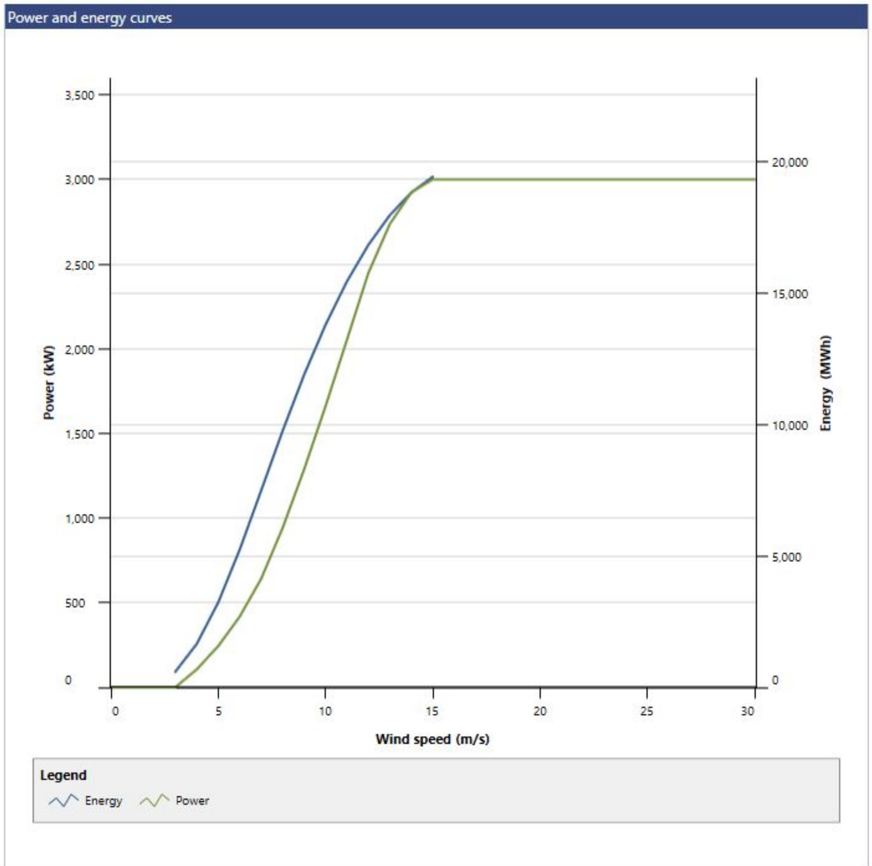
Power capacity per turbine	MW	3	
Manufacturer		Vestas	
Model		VESTAS V90-3.0 MW - 80m	
Number of turbines		50	
Power capacity	MW	150	
Hub height	m	70	9.7 m/s
Rotor diameter per turbine	m	90	
Swept area per turbine	m²	6,361.73	
Energy curve data		Custom	
Shape factor		2.3	

Power and energy curves

Data

Wind speed m/s	Power curve data kW	Energy curve data MWh
0	0	
1	0	
2	0	
3	0	591
4	106	1,651
5	243	3,227
6	417	5,234
7	640	7,482
8	940	9,753
9	1,285	11,886
10	1,659	13,795
11	2,052	15,450
12	2,447	16,842
13	2,736	17,971
14	2,923	18,834
15	3,000	19,434
16	3,000	
17	3,000	
18	3,000	
19	3,000	
20	3,000	
21	3,000	
22	3,000	
23	3,000	
24	3,000	
25	3,000	
26	3,000	
27	3,000	
28	3,000	
29	3,000	
30	3,000	

Power and energy curves



Losses

Array losses	%	9%
Airfoil losses	%	2%
Miscellaneous losses	%	1%
Availability	%	98%

Summary

Capacity factor	%	43.9%
Initial costs	€/kW	1,366
	€	204,825,000
O&M costs (savings)	€/MWh	20
	€	11,536,681
Electricity export rate		Electricity export rate - annual
	€/MWh	50.37
Electricity exported to grid	MWh	576,834
Electricity export revenue	€	29,055,132

Other information

		Per turbine
Unadjusted energy production	MWh	13,006
Pressure coefficient		0.999
Temperature coefficient		1.023
Gross energy production	MWh	13,334
Losses coefficient		0.87
Specific yield	kWh/m^2	1,813

Initial costs (credits)	Unit	Quantity	Unit cost		Amount
Initial cost				€	204,825,000
Show data					
User-defined	cost	1	€ 1,575,000	€	1,575,000
Total initial costs				**€**	**206,400,000**

Annual costs (credits)	Unit	Quantity	Unit cost		Amount
O&M costs (savings)	project			€	11,536,681
Show data					
User-defined	cost			€	-
Total annual costs				**€**	**11,536,681**

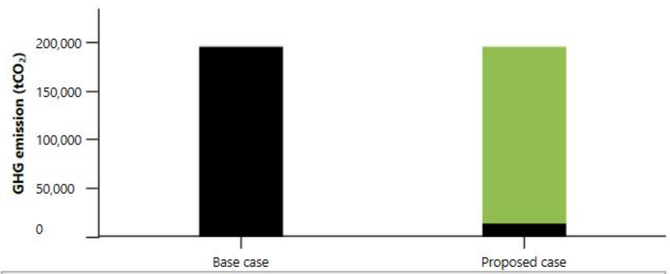
Annual savings	Unit	Quantity	Unit cost		Amount
User-defined	cost			€	-
Total annual savings				**€**	**-**

Emission analysis

Base case electricity system (Baseline)		GHG emission factor (excl. T&D)	T&D losses	GHG emission factor
Country - region	Fuel type	tCO_2/MWh	%	tCO_2/MWh
Denmark	All types	0.315	7.0%	0.339
Electricity exported to grid	MWh	576,834	T&D losses	7.0%

GHG emission

Base case	tCO_2	195,509.7
Proposed case	tCO_2	13,685.7
Gross annual GHG emission reduction	tCO_2	181,824.0



Legend

Gross annual GHG emission reduction (93%)

181,824.0 tCO_2 is equivalent to 33,301.1

Cars & light trucks not used

GHG reduction revenue

GHG reduction credit rate	€/tCO_2	

Financial parameters

General		
Fuel cost escalation rate		
Inflation rate	%	2%
Discount rate	%	5%
Reinvestment rate	%	9%
Project life	yr	25
Finance		
Incentives and grants	€	
Debt ratio	%	70%
Debt	€	144,480,000
Equity	€	61,920,000
Debt interest rate	%	5%
Debt term	yr	15
Debt payments	€/yr	13,919,534
Income tax analysis		☐

Annual revenue

Electricity export revenue		
Electricity exported to grid	MWh	576,914
Electricity export rate	€/MWh	50.37
Electricity export revenue	€	29,059,146
Electricity export escalation rate	%	1%
GHG reduction revenue		
Gross GHG reduction	tCO_2/yr	181,849
Gross GHG reduction - 25 yrs	tCO_2	4,546,229
GHG reduction revenue	€	0
Other revenue (cost)		☐
Clean Energy (CE) production revenue		☐

Costs | Savings | Revenue

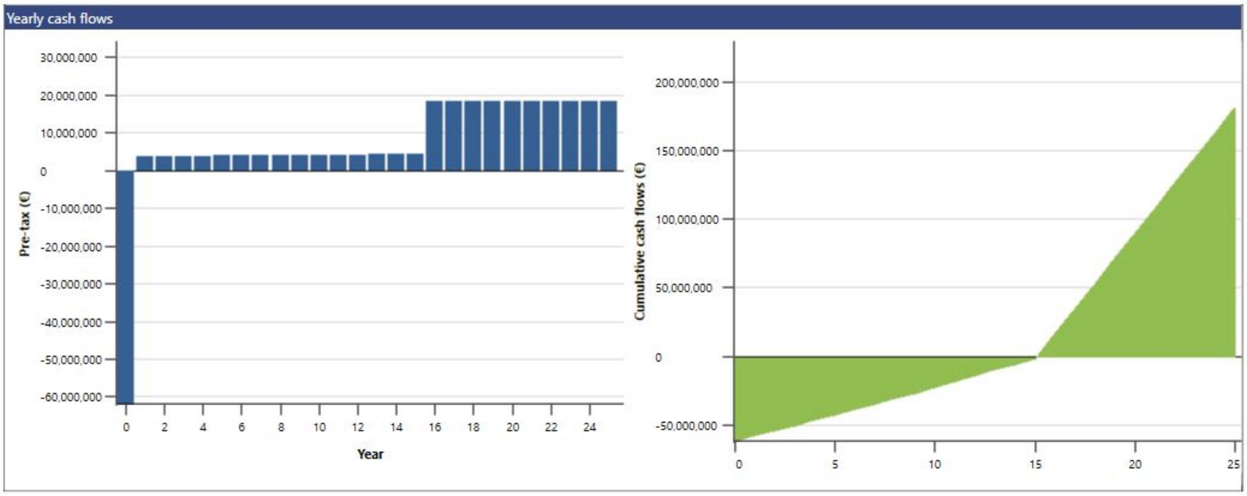
Initial costs			
Initial cost	99.2%	€	204,825,000
User-defined	0.76%	€	1,575,000
Total initial costs	**100%**	€	**206,400,000**
Yearly cash flows - Year 1			
Annual costs and debt payments			
O&M costs (savings)		€	11,538,275
Debt payments - 15 yrs		€	13,919,534
Total annual costs		€	**25,457,809**
Annual savings and revenue			
Electricity export revenue		€	29,059,146
GHG reduction revenue		€	0
Other revenue (cost)		€	0
CE production revenue		€	0
Total annual savings and revenue		€	**29,059,146**
Net yearly cash flow - Year 1		€	**3,601,337**

Financial viability

Pre-tax IRR - equity	%	9.3%
Pre-tax MIRR - equity	%	9.1%
Pre-tax IRR - assets	%	0.95%
Pre-tax MIRR - assets	%	4%
Simple payback	yr	11.8
Equity payback	yr	15.1
Net Present Value (NPV)	€	47,229,633
Annual life cycle savings	€/yr	3,351,059
Benefit-Cost (B-C) ratio		1.8
Debt service coverage		1.3
GHG reduction cost	€/tCO_2	-18.43
Energy production cost	€/MWh	50.26

Yearly cash flows

Year	Pre-tax	Cumulative
#	€	€
0	-61,920,000	-61,920,000
1	3,661,163	-58,258,837
2	3,719,279	-54,539,558
3	3,775,623	-50,763,934
4	3,830,130	-46,933,805
5	3,882,732	-43,051,072
6	3,933,363	-39,117,709
7	3,981,952	-35,135,757
8	4,028,429	-31,107,328
9	4,072,719	-27,034,609
10	4,114,749	-22,919,860
11	4,154,441	-18,765,420
12	4,191,716	-14,573,703
13	4,226,496	-10,347,208
14	4,258,696	-6,088,512
15	4,288,233	-1,800,279
16	18,234,555	16,434,276
17	18,258,504	34,692,780
18	18,279,526	52,972,306
19	18,297,526	71,269,832
20	18,312,410	89,582,242
21	18,324,082	107,906,324
22	18,332,441	126,238,765
23	18,337,386	144,576,151
24	18,338,813	162,914,963
25	18,336,615	181,251,578



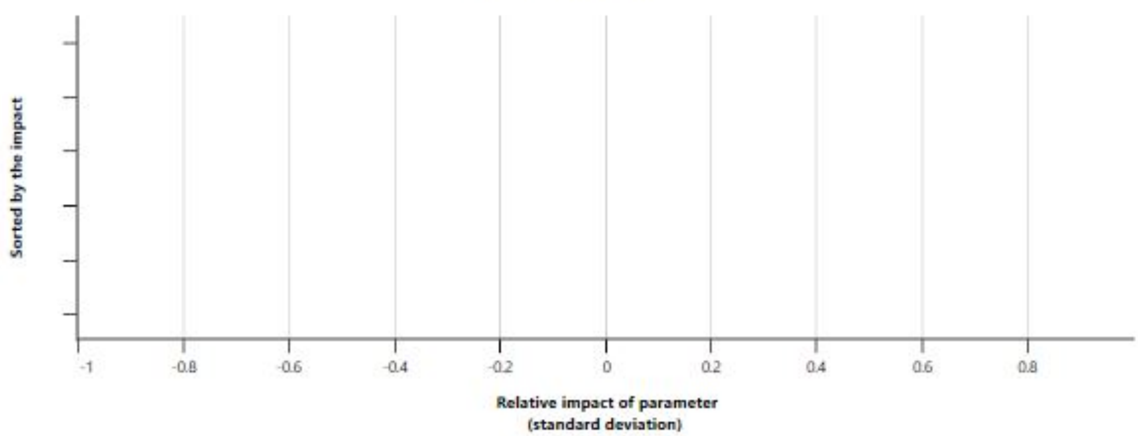
Yearly cash flows
Pre-tax (€)
30,000,000
20,000,000
10,000,000
0
-10,000,000
-20,000,000
-30,000,000
-40,000,000
-50,000,000
-60,000,000
0 2 4 6 8 10 12 14 16 18 20 22 24
Year
Cumulative cash flows (€)
200,000,000
150,000,000
100,000,000
50,000,000
0
-50,000,000
0 5 10 15 20 25

Risk analysis

Perform analysis on	Equity payback
Number of combinations	500
Random seed	No

Parameter	Unit	Value	Range (+/-)	Minimum	Maximum
Initial costs	€	206,400,000	25%	154,800,000	258,000,000
O&M	€	11,536,681	25%	8,652,511	14,420,852
Electricity exported to grid	MWh	576,834.07	25%	432,625.55	721,042.59
Electricity export rate	€/MWh	50.37	25%	37.78	62.96
Debt ratio	%	70.0%	25%	52.5%	87.5%
Debt interest rate	%	5.00%	25%	3.75%	6.25%
Debt term	yr	15	25%	11	19

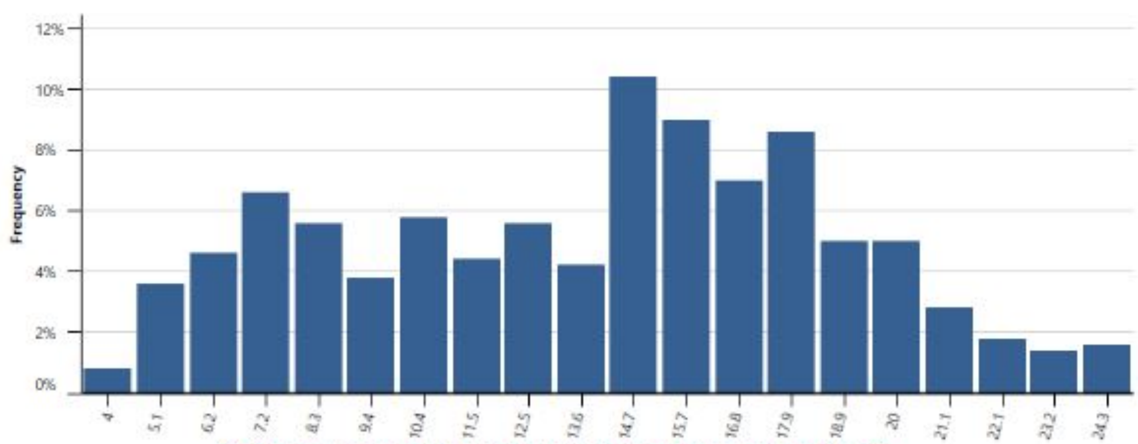
Impact - Equity payback



2.4% of cases have an equity payback either immediate or greater than the project life.

Median	yr	14.6
Level of risk	%	10%
Minimum within level of confidence	yr	5.9
Maximum within level of confidence	yr	21.6

Distribution - Equity payback



2.4% of cases have an equity payback either immediate or greater than the project life.

Sensitivity analysis

Perform analysis on	Net Present Value (NPV)
Sensitivity range	20%
Threshold	50.37 €

- Remove analysis

Electricity export rate		Initial costs (€)				
		165,120,000	185,760,000	206,400,000	227,040,000	247,680,000
€/MWh		-20.0%	-10.0%	0.0%	10.0%	20.0%
40.30	-20.0%	-2,686,922	-23,326,922	-43,966,922	-64,606,922	-85,246,922
45.33	-10.0%	42,893,841	22,253,841	1,613,841	-19,026,159	-39,666,159
50.37	0.0%	88,474,604	67,834,604	**47,194,604**	26,554,604	5,914,604
55.41	10.0%	134,055,367	113,415,367	92,775,367	72,135,367	51,495,367
60.44	20.0%	179,636,129	158,996,129	138,356,129	117,716,129	97,076,129

- Remove analysis

O&M		Initial costs (€)				
		165,120,000	185,760,000	206,400,000	227,040,000	247,680,000
€		-20.0%	-10.0%	0.0%	10.0%	20.0%
9,229,345	-20.0%	128,917,209	108,277,209	87,637,209	66,997,209	46,357,209
10,383,013	-10.0%	108,695,906	88,055,906	67,415,906	46,775,906	26,135,906
11,536,681	0.0%	88,474,604	67,834,604	**47,194,604**	26,554,604	5,914,604
12,690,350	10.0%	68,253,301	47,613,301	26,973,301	6,333,301	-14,306,699
13,844,018	20.0%	48,031,998	27,391,998	6,751,998	-13,888,002	-34,528,002

- Remove analysis

Debt ratio		Debt interest rate (%)				
		4.00%	4.50%	5.00%	5.50%	6.00%
%		-20.0%	-10.0%	0.0%	10.0%	20.0%
56%	-20.0%	54,874,251	51,067,883	47,194,604	43,255,543	39,251,870
63%	-10.0%	55,834,207	51,552,043	47,194,604	42,763,160	38,259,028
70%	0.0%	56,794,163	52,036,202	**47,194,604**	42,270,778	37,266,186
77%	10.0%	57,754,119	52,520,362	47,194,604	41,778,395	36,273,345
84%	20.0%	58,714,075	53,004,522	47,194,604	41,286,013	35,280,503

- Remove analysis

O&M		Electricity exported to grid (MWh)				
		461,467.26	519,150.66	576,834.07	634,517.48	692,200.88
€		-20.0%	-10.0%	0.0%	10.0%	20.0%
9,229,345	-20.0%	-3,524,317	42,056,446	87,637,209	133,217,972	178,798,735
10,383,013	-10.0%	-23,745,620	21,835,143	67,415,906	112,996,669	158,577,432
11,536,681	0.0%	-43,966,922	1,613,841	**47,194,604**	92,775,367	138,356,129
12,690,350	10.0%	-64,188,225	-18,607,462	26,973,301	72,554,064	118,134,827
13,844,018	20.0%	-84,409,528	-38,828,765	6,751,998	52,332,761	97,913,524

- Remove analysis

Initial costs		O&M (€)				
		9,229,345	10,383,013	11,536,681	12,690,350	13,844,018
€		-20.0%	-10.0%	0.0%	10.0%	20.0%
165,120,000	-20.0%	128,917,209	108,695,906	88,474,604	68,253,301	48,031,998
185,760,000	-10.0%	108,277,209	88,055,906	67,834,604	47,613,301	27,391,998
206,400,000	0.0%	87,637,209	67,415,906	**47,194,604**	26,973,301	6,751,998
227,040,000	10.0%	66,997,209	46,775,906	26,554,604	6,333,301	-13,888,002
247,680,000	20.0%	46,357,209	26,135,906	5,914,604	-14,306,699	-34,528,002

Sensitivity analysis

Perform analysis on	Energy production cost
Sensitivity range	20%
Threshold	50.37 €/MWh

- Remove analysis

Electricity export rate		Initial costs (€)				
		165,120,000	185,760,000	206,400,000	227,040,000	247,680,000
€/MWh		-20.0%	-10.0%	0.0%	10.0%	20.0%
40.30	-20.0%	45.18	47.72	50.26	52.80	55.34
45.33	-10.0%	45.18	47.72	50.26	52.80	55.34
50.37	0.0%	45.18	47.72	**50.26**	52.80	55.34
55.41	10.0%	45.18	47.72	50.26	52.80	55.34
60.44	20.0%	45.18	47.72	50.26	52.80	55.34

- Remove analysis

O&M		Initial costs (€)				
		165,120,000	185,760,000	206,400,000	227,040,000	247,680,000
€		-20.0%	-10.0%	0.0%	10.0%	20.0%
9,229,345	-20.0%	40.21	42.75	45.29	47.82	50.36
10,383,013	-10.0%	42.70	45.23	47.77	50.31	52.85
11,536,681	0.0%	45.18	47.72	**50.26**	52.80	55.34
12,690,350	10.0%	47.67	50.21	52.75	55.29	57.83
13,844,018	20.0%	50.16	52.70	55.24	57.77	60.31

- Remove analysis

Debt ratio		Debt interest rate (%)				
		4.00%	4.50%	5.00%	5.50%	6.00%
%		-20.0%	-10.0%	0.0%	10.0%	20.0%
56%	-20.0%	49.32	49.78	50.26	50.75	51.24
63%	-10.0%	49.20	49.72	50.26	50.81	51.36
70%	0.0%	49.08	49.67	**50.26**	50.87	51.48
77%	10.0%	48.96	49.61	50.26	50.93	51.60
84%	20.0%	48.84	49.55	50.26	50.99	51.73

- Remove analysis

O&M		Electricity exported to grid (MWh)				
		461,467.26	519,150.66	576,834.07	634,517.48	692,200.88
€		-20.0%	-10.0%	0.0%	10.0%	20.0%
9,229,345	-20.0%	56.61	50.32	45.29	41.17	37.74
10,383,013	-10.0%	59.72	53.08	47.77	43.43	39.81
11,536,681	0.0%	62.83	55.85	**50.26**	45.69	41.88
12,690,350	10.0%	65.94	58.61	52.75	47.95	43.96
13,844,018	20.0%	69.04	61.37	55.24	50.21	46.03

- Remove analysis

Initial costs		O&M (€)				
		9,229,345	10,383,013	11,536,681	12,690,350	13,844,018
€		-20.0%	-10.0%	0.0%	10.0%	20.0%
165,120,000	-20.0%	40.21	42.70	45.18	47.67	50.16
185,760,000	-10.0%	42.75	45.23	47.72	50.21	52.70
206,400,000	0.0%	45.29	47.77	**50.26**	52.75	55.24
227,040,000	10.0%	47.82	50.31	52.80	55.29	57.77
247,680,000	20.0%	50.36	52.85	55.34	57.83	60.31

A.5. SCENARIO 3

Power plant - OWF - Wind turbine

Fuels & schedules
- Electricity and fuels

Technology
- Power
  - Wind turbine - 100000 kW - Offshore (6.1m/s @10m)
  - Wind turbine - 100000 kW - Offshore (7.1m/s @10m)
  - Wind turbine - 100000 kW - Offshore (8.1m/s @10m)
  - Wind turbine - 100000 kW - Offshore (9.1m/s @10m)
  - Offshore (10.1m/s @10m)

Summary
- Include system?
- Comparison

Wind

Description: Offshore (10.1m/s @10m)

Note:

Level: Level 1 | Level 2 | Level 3

eLearning

Wind - Level 3

Resource assessment

Resource method: Wind speed

Climate Data: Denmark - Blaavand

Month	Wind speed m/s	Atmospheric pressure kPa	Air temperature °C	m/s	kPa	°C	Electricity export rate €/MWh	Electricity exported to grid MWh
January	11.0	101.1	1.9	7.8	101.1	1.9	61.75	143,604
February	11.8	101.2	1.2	7.3	101.2	1.2	61.75	136,738
March	10.1	101.2	2.6	7.0	101.2	2.6	61.75	133,567
April	8.4	101.2	6.3	6.3	101.2	6.3	61.75	102,922
May	8.2	101.4	10.5	6.6	101.4	10.5	61.75	101,668
June	8.6	101.3	13.3	7.0	101.3	13.3	61.75	103,834
July	7.6	101.2	16.1	6.4	101.2	16.1	61.75	87,916
August	7.4	101.2	16.7	6.5	101.2	16.7	61.75	84,938
September	9.2	101.2	13.9	7.2	101.2	13.9	61.75	112,355
October	11.1	101.1	10.2	7.7	101.1	10.2	61.75	140,944
November	10.8	101.0	6.3	7.8	101.0	6.3	61.75	135,351
December	10.5	101.1	3.5	7.5	101.1	3.5	61.75	137,580
Annual	**9.5**	**101.2**	**8.6**	**7.1**	**101.2**	**8.6**	**61.75**	**1,421,417**

Measured at	m	62	10
Wind shear exponent		0.16	

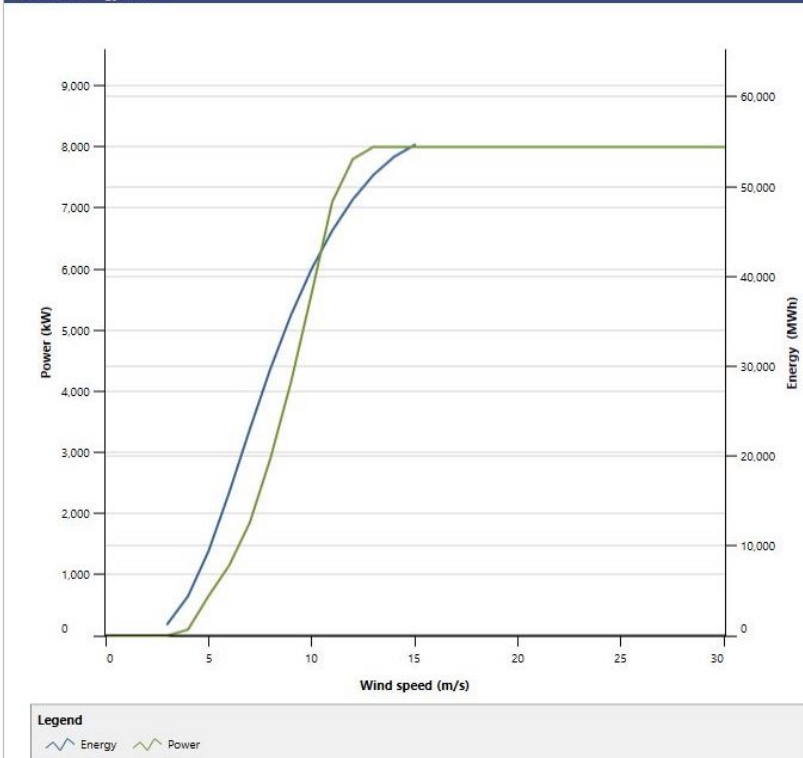
Wind turbine

Power capacity per turbine	MW	8	
Manufacturer		Vestas	
Model		V164-8.0 MW - 105m	
Number of turbines		40	
Power capacity	MW	320	
Hub height	m	105	10.4 m/s
Rotor diameter per turbine	m	164	
Swept area per turbine	m²	21,124	
Energy curve data		Custom	
Shape factor		2.3	

Data

Wind speed m/s	Power curve data kW	Energy curve data MWh
0		
1		
2		
3		1,300
4	100	4,388
5	650	9,424
6	1,150	15,940
7	1,850	22,983
8	2,900	29,721
9	4,150	35,715
10	5,600	40,833
11	7,100	45,098
12	7,800	48,573
13	8,000	51,304
14	8,000	53,320
15	8,000	54,645
16	8,000	
17	8,000	
18	8,000	
19	8,000	
20	8,000	
21	8,000	
22	8,000	
23	8,000	
24	8,000	
25	8,000	
26	8,000	
27	8,000	
28	8,000	
29	8,000	
30	8,000	

Power and energy curves



Initial costs (credits)	Unit	Quantity	Unit cost		Amount
Initial cost				€	723,776,000
Show data					
User-defined	cost	1	€ (25,600,000)	€	(25,600,000)
Total initial costs				**€**	**698,176,000**

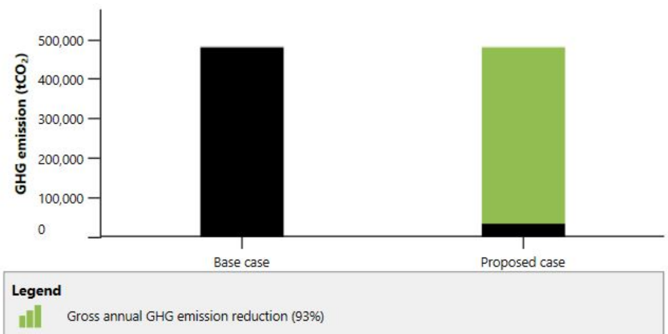
Annual costs (credits)	Unit	Quantity	Unit cost		Amount
O&M costs (savings)	project			€	28,428,340
Show data					
User-defined	cost			€	-
Total annual costs				**€**	**28,428,340**

Annual savings	Unit	Quantity	Unit cost		Amount
User-defined	cost			€	-
Total annual savings				**€**	**-**

Emission analysis

Base case electricity system (Baseline) **Country - region**	**Fuel type**	**GHG emission factor (excl. T&D)** tCO₂/MWh	**T&D losses** %	**GHG emission factor** tCO₂/MWh
Denmark	All types	0.315	7.0%	0.339
Electricity exported to grid	MWh	1,421,417	T&D losses	7.0%

GHG emission		
Base case	tCO_2	481,769.1
Proposed case	tCO_2	33,723.8
Gross annual GHG emission reduction	tCO_2	448,045.3



448,045.3 **tCO_2** **is equivalent to** **82,059.6**

Cars & light trucks not used

GHG reduction revenue

GHG reduction credit rate	€/tCO_2	

Financial parameters

General		
Fuel cost escalation rate		
Inflation rate	%	2%
Discount rate	%	5%
Reinvestment rate	%	9%
Project life	yr	25
Finance		
Incentives and grants	€	
Debt ratio	%	70%
Debt	€	488,723,200
Equity	€	209,452,800
Debt interest rate	%	5%
Debt term	yr	15
Debt payments	€/yr	47,084,711
Income tax analysis		☐

Annual revenue

Electricity export revenue		
Electricity exported to grid	MWh	1,421,575
Electricity export rate	€/MWh	50.37
Electricity export revenue	€	71,604,723
Electricity export escalation rate	%	1%
GHG reduction revenue		
Gross GHG reduction	tCO_2/yr	448,095
Gross GHG reduction - 25 yrs	tCO_2	11,202,376
GHG reduction revenue	€	0
Other revenue (cost)		☐
Clean Energy (CE) production revenue		☐

Costs | Savings | Revenue

Initial costs			
Initial cost	104%	€	723,776,000
User-defined	-3.7%	€	-25,600,000
Total initial costs	**100%**	€	**698,176,000**
Yearly cash flows - Year 1			
Annual costs and debt payments			
O&M costs (savings)		€	28,431,496
Debt payments - 15 yrs		€	47,084,711
Total annual costs		€	**75,516,207**
Annual savings and revenue			
Electricity export revenue		€	71,604,723
GHG reduction revenue		€	0
Other revenue (cost)		€	0
CE production revenue		€	0
Total annual savings and revenue		€	**71,604,723**
Net yearly cash flow - Year 1		€	**-3,911,484**

Financial viability

Pre-tax IRR - equity	%	3%
Pre-tax MIRR - equity	%	4.3%
Pre-tax IRR - assets	%	-2.4%
Pre-tax MIRR - assets	%	-0.25%
Simple payback	yr	16.2
Equity payback	yr	20.6
Net Present Value (NPV)	€	-73,206,499
Annual life cycle savings	€/yr	-5,194,181
Benefit-Cost (B-C) ratio		0.65
Debt service coverage		0.92
GHG reduction cost	$€/tCO_2$	11.59
Energy production cost	€/MWh	59.72

Yearly cash flows

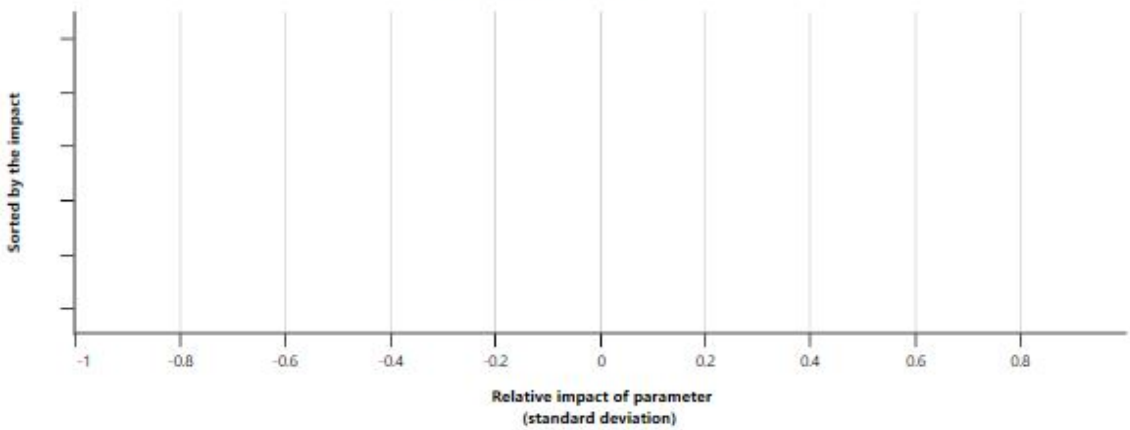
Year	Pre-tax	Cumulative
#	€	€
0	-209,452,800	-209,452,800
1	-3,764,067	-213,216,867
2	-3,620,862	-216,837,728
3	-3,482,024	-220,319,753
4	-3,347,715	-223,667,467
5	-3,218,096	-226,885,564
6	-3,093,337	-229,978,901
7	-2,973,608	-232,952,509
8	-2,859,086	-235,811,594
9	-2,749,950	-238,561,544
10	-2,646,385	-241,207,929
11	-2,548,580	-243,756,509
12	-2,456,728	-246,213,237
13	-2,371,029	-248,584,266
14	-2,291,684	-250,875,949
15	-2,218,901	-253,094,850
16	44,931,818	-208,163,032
17	44,990,832	-163,172,200
18	45,042,631	-118,129,569
19	45,086,986	-73,042,583
20	45,123,662	-27,918,921
21	45,152,422	17,233,501
22	45,173,020	62,406,521
23	45,185,205	107,591,726
24	45,188,721	152,780,446
25	45,183,305	197,963,751

Risk analysis

Perform analysis on	Equity payback
Number of combinations	500
Random seed	No

Parameter	Unit	Value	Range (+/-)	Minimum	Maximum
Initial costs	€	698,176,000	25%	523,632,000	872,720,000
O&M	€	28,428,340	25%	21,321,255	35,535,425
Electricity exported to grid	MWh	1,421,416.99	25%	1,066,062.74	1,776,771.24
Electricity export rate	€/MWh	50.37	25%	37.78	62.96
Debt ratio	%	70.0%	25%	52.5%	87.5%
Debt interest rate	%	5.00%	25%	3.75%	6.25%
Debt term	yr	15	25%	11	19

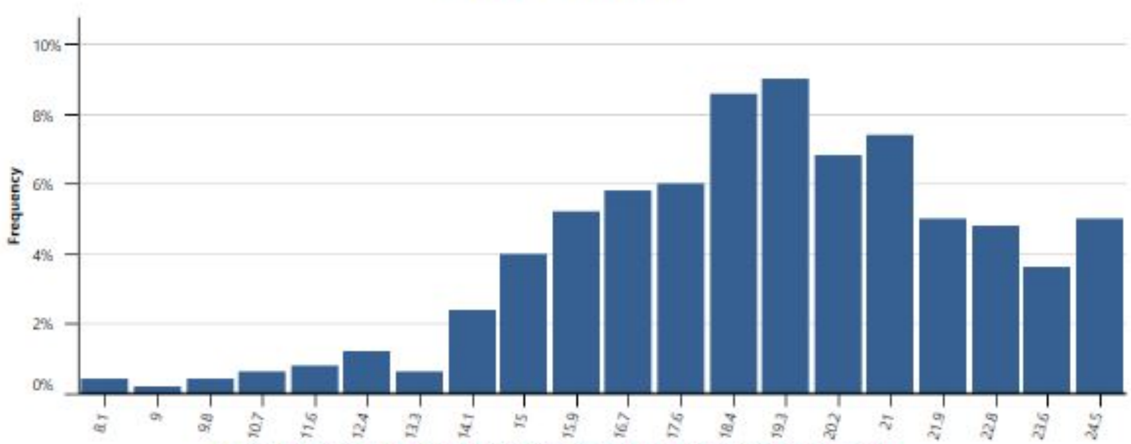
Impact - Equity payback



22.2% of cases have an equity payback either immediate or greater than the project life.

Median	yr	19.3
Level of risk	%	10%
Minimum within level of confidence	yr	13.3
Maximum within level of confidence	yr	24.2

Distribution - Equity payback



22.2% of cases have an equity payback either immediate or greater than the project life.

Sensitivity analysis

Perform analysis on	Net Present Value (NPV)
Sensitivity range	80%
Threshold	50.37 €

- Remove analysis

Electricity export rate		Initial costs (€)				
		139,635,200	418,905,600	698,176,000	977,446,400	1,256,716,800
€/MWh		-80.0%	-40.0%	0.0%	40.0%	80.0%
10.07	-80.0%	-413,284,933	-692,555,333	-971,825,733	-1,251,096,133	-1,530,366,533
30.22	-40.0%	35,989,992	-243,280,408	-522,550,808	-801,821,208	-1,081,091,608
50.37	0.0%	485,264,918	205,994,518	**-73,275,882**	-352,546,282	-631,816,682
70.52	40.0%	934,539,843	655,269,443	375,999,043	96,728,643	-182,541,757
90.67	80.0%	1,383,814,768	1,104,544,368	825,273,968	546,003,568	266,733,168

- Remove analysis

O&M		Initial costs (€)				
		139,635,200	418,905,600	698,176,000	977,446,400	1,256,716,800
€		-80.0%	-40.0%	0.0%	40.0%	80.0%
5,685,668	-80.0%	883,894,674	604,624,274	325,353,874	46,083,474	-233,186,926
17,057,004	-40.0%	684,579,796	405,309,396	126,038,996	-153,231,404	-432,501,804
28,428,340	0.0%	485,264,918	205,994,518	**-73,275,882**	-352,546,282	-631,816,682
39,799,676	40.0%	285,950,039	6,679,639	-272,590,761	-551,861,161	-831,131,561
51,171,012	80.0%	86,635,161	-192,635,239	-471,905,639	-751,176,039	-1,030,446,439

- Remove analysis

Debt ratio		Debt interest rate (%)				
		1.00%	3.00%	5.00%	7.00%	9.00%
%		-80.0%	-40.0%	0.0%	40.0%	80.0%
14%	-80.0%	-48,704,852	-60,517,124	-73,275,882	-86,924,031	-101,395,918
42%	-40.0%	437,209	-34,999,607	-73,275,882	-114,220,328	-157,635,991
70%	0.0%	49,579,270	-9,482,091	**-73,275,882**	-141,516,625	-213,876,063
98%	40.0%	98,721,331	16,035,426	-73,275,882	-168,812,922	-270,116,135
126%	80.0%					

- Remove analysis

O&M		Electricity exported to grid (MWh)				
		284,283.40	852,850.19	1,421,416.99	1,989,983.79	2,558,550.58
€		-80.0%	-40.0%	0.0%	40.0%	80.0%
5,685,668	-80.0%	-573,195,976	-123,921,051	325,353,874	774,628,799	1,223,903,724
17,057,004	-40.0%	-772,510,855	-323,235,929	126,038,996	575,313,921	1,024,588,846
28,428,340	0.0%	-971,825,733	-522,550,808	**-73,275,882**	375,999,043	825,273,968
39,799,676	40.0%	-1,171,140,611	-721,865,686	-272,590,761	176,684,165	625,959,090
51,171,012	80.0%	-1,370,455,489	-921,180,564	-471,905,639	-22,630,713	426,644,212

- Remove analysis

Initial costs		O&M (€)				
		5,685,668	17,057,004	28,428,340	39,799,676	51,171,012
€		-80.0%	-40.0%	0.0%	40.0%	80.0%
139,635,200	-80.0%	883,894,674	684,579,796	485,264,918	285,950,039	86,635,161
418,905,600	-40.0%	604,624,274	405,309,396	205,994,518	6,679,639	-192,635,239
698,176,000	0.0%	325,353,874	126,038,996	**-73,275,882**	-272,590,761	-471,905,639
977,446,400	40.0%	46,083,474	-153,231,404	-352,546,282	-551,861,161	-751,176,039
1,256,716,800	80.0%	-233,186,926	-432,501,804	-631,816,682	-831,131,561	-1,030,446,439

Sensitivity analysis

Perform analysis on	Net Present Value (NPV)
Sensitivity range	50%
Threshold	50.37 €

- Remove analysis

Electricity export rate (€/MWh)		Initial costs (€)				
		349,088,000	523,632,000	698,176,000	872,720,000	1,047,264,000
€/MWh		-50.0%	-25.0%	0.0%	25.0%	50.0%
25.19	-50.0%	-285,781,539	-460,325,539	-634,869,539	-809,413,539	-983,957,539
37.78	-25.0%	-4,984,711	-179,528,711	-354,072,711	-528,616,711	-703,160,711
50.37	0.0%	275,812,118	101,268,118	**-73,275,882**	-247,819,882	-422,363,882
62.96	25.0%	556,608,946	382,064,946	207,520,946	32,976,946	-141,567,054
75.56	50.0%	837,405,774	662,861,774	488,317,774	313,773,774	139,229,774

- Remove analysis

O&M (€)		Initial costs (€)				
		349,088,000	523,632,000	698,176,000	872,720,000	1,047,264,000
€		-50.0%	-25.0%	0.0%	25.0%	50.0%
14,214,170	-50.0%	524,955,715	350,411,715	175,867,715	1,323,715	-173,220,285
21,321,255	-25.0%	400,383,916	225,839,916	51,295,916	-123,248,084	-297,792,084
28,428,340	0.0%	275,812,118	101,268,118	**-73,275,882**	-247,819,882	-422,363,882
35,535,425	25.0%	151,240,319	-23,303,681	-197,847,681	-372,391,681	-546,935,681
42,642,510	50.0%	26,668,520	-147,875,480	-322,419,480	-496,963,480	-671,507,480

- Remove analysis

Debt ratio (%)		Debt interest rate (%)				
		2.50%	3.75%	5.00%	6.25%	7.50%
%		-50.0%	-25.0%	0.0%	25.0%	50.0%
35%	-50.0%	-33,769,501	-53,070,132	-73,275,882	-94,350,601	-116,254,878
53%	-25.0%	-14,016,311	-42,967,258	-73,275,882	-104,887,961	-137,744,376
70%	0.0%	5,736,880	-32,864,383	**-73,275,882**	-115,425,320	-159,233,874
88%	25.0%	25,490,070	-22,761,508	-73,275,882	-125,962,679	-180,723,372
105%	50.0%					

- Remove analysis

O&M (€)		Electricity exported to grid (MWh)				
		710,708.50	1,066,062.74	1,421,416.99	1,776,771.24	2,132,125.49
€		-50.0%	-25.0%	0.0%	25.0%	50.0%
14,214,170	-50.0%	-385,725,941	-104,929,113	175,867,715	456,664,543	737,461,372
21,321,255	-25.0%	-510,297,740	-229,500,912	51,295,916	332,092,745	612,889,573
28,428,340	0.0%	-634,869,539	-354,072,711	**-73,275,882**	207,520,946	488,317,774
35,535,425	25.0%	-759,441,338	-478,644,509	-197,847,681	82,949,147	363,745,975
42,642,510	50.0%	-884,013,136	-603,216,308	-322,419,480	-41,622,652	239,174,176

- Remove analysis

Initial costs (€)		O&M (€)				
		14,214,170	21,321,255	28,428,340	35,535,425	42,642,510
€		-50.0%	-25.0%	0.0%	25.0%	50.0%
349,088,000	-50.0%	524,955,715	400,383,916	275,812,118	151,240,319	26,668,520
523,632,000	-25.0%	350,411,715	225,839,916	101,268,118	-23,303,681	-147,875,480
698,176,000	0.0%	175,867,715	51,295,916	**-73,275,882**	-197,847,681	-322,419,480
872,720,000	25.0%	1,323,715	-123,248,084	-247,819,882	-372,391,681	-496,963,480
1,047,264,000	50.0%	-173,220,285	-297,792,084	-422,363,882	-546,935,681	-671,507,480

A.6: SCENARIO 4

Losses		
Array losses	%	12%
Airfoil losses	%	2%
Miscellaneous losses	%	1%
Availability	%	98%
Summary		
Capacity factor	%	50.7%
Initial costs	€/kW	2,104
	€	673,216,000
O&M costs (savings)	€/MWh	20
	€	28,428,340
Electricity export rate		Electricity export rate - annual
	€/MWh	50.37
Electricity exported to grid	MWh	1,421,417
Electricity export revenue	€	71,596,774
Other information		**Per turbine**
Unadjusted energy production	MWh	41,452
Pressure coefficient		0.999
Temperature coefficient		1.023
Gross energy production	MWh	42,471
Losses coefficient		0.84
Specific yield	kWh/m^2	1,682

Financial parameters

General		
Fuel cost escalation rate		
Inflation rate	%	2%
Discount rate	%	5%
Reinvestment rate	%	9%
Project life	yr	25
Finance		
Incentives and grants	€	
Debt ratio	%	70%
Debt	€	454,171,200
Equity	€	194,644,800
Debt interest rate	%	5%
Debt term	yr	15
Debt payments	€/yr	43,755,892
Income tax analysis		

Annual revenue

Electricity export revenue		
Electricity exported to grid	MWh	1,421,575
Electricity export rate	€/MWh	50.37
Electricity export revenue	€	71,604,723
Electricity export escalation rate	%	1%
GHG reduction revenue		
Gross GHG reduction	tCO_2/yr	448,095
Gross GHG reduction - 25 yrs	tCO_2	11,202,376
GHG reduction revenue	€	0
Other revenue (cost)		
Clean Energy (CE) production revenue		

Costs | Savings | Revenue

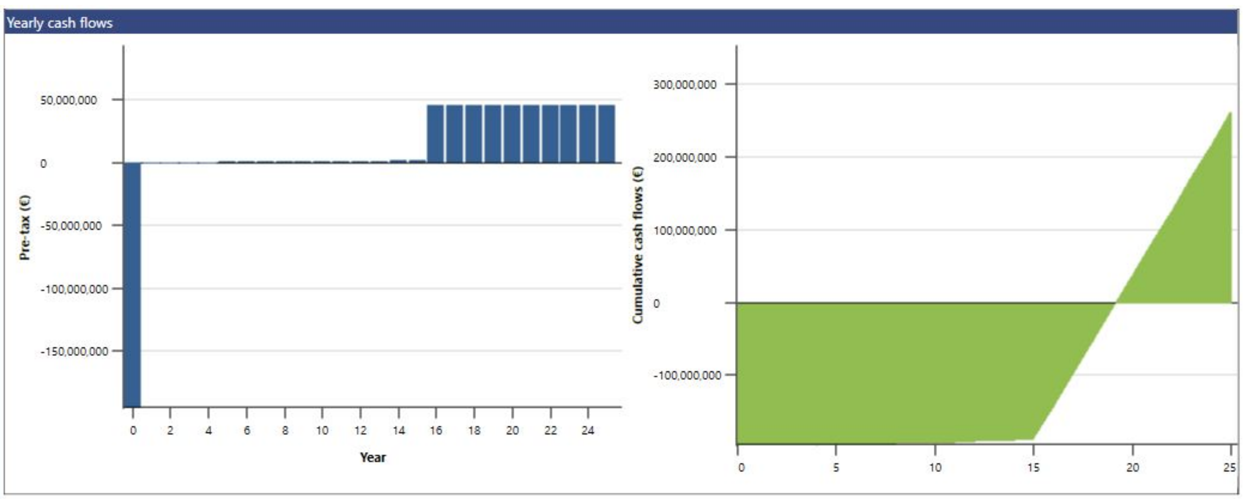
Initial costs			
Initial cost	104%	€	673,216,000
User-defined	-3.8%	€	-24,400,000
Total initial costs	**100%**	€	**648,816,000**
Yearly cash flows - Year 1			
Annual costs and debt payments			
O&M costs (savings)		€	28,431,496
Debt payments - 15 yrs		€	43,755,892
Total annual costs		€	**72,187,389**
Annual savings and revenue			
Electricity export revenue		€	71,604,723
GHG reduction revenue		€	0
Other revenue (cost)		€	0
CE production revenue		€	0
Total annual savings and revenue		€	**71,604,723**
Net yearly cash flow - Year 1		€	**-582,665**

Financial viability

Pre-tax IRR - equity	%	4.3%
Pre-tax MIRR - equity	%	5.3%
Pre-tax IRR - assets	%	-1.7%
Pre-tax MIRR - assets	%	0.35%
Simple payback	yr	15
Equity payback	yr	19.2
Net Present Value (NPV)	€	-23,846,499
Annual life cycle savings	€/yr	-1,691,968
Benefit-Cost (B-C) ratio		0.88
Debt service coverage		0.99
GHG reduction cost	$€/tCO_2$	3.78
Energy production cost	€/MWh	57.26

Yearly cash flows

Year	Pre-tax	Cumulative
#	€	€
0	-194,644,800	-194,644,800
1	-435,248	-195,080,048
2	-292,043	-195,372,091
3	-153,206	-195,525,296
4	-18,896	-195,544,192
5	110,722	-195,433,470
6	235,482	-195,197,988
7	355,211	-194,842,778
8	469,733	-194,373,045
9	578,869	-193,794,176
10	682,434	-193,111,742
11	780,239	-192,331,503
12	872,090	-191,459,412
13	957,790	-190,501,622
14	1,037,135	-189,464,487
15	1,109,918	-188,354,569
16	44,931,818	-143,422,752
17	44,990,832	-98,431,919
18	45,042,631	-53,389,288
19	45,086,986	-8,302,302
20	45,123,662	36,821,360
21	45,152,422	81,973,782
22	45,173,020	127,146,802
23	45,185,205	172,332,006
24	45,188,721	217,520,727
25	45,183,305	262,704,032



Initial costs (credits)	Unit	Quantity	Unit cost		Amount
Initial cost				€	673,216,000
Show data					
User-defined	cost	1	€ (24,400,000)	€	(24,400,000)
Total initial costs				**€**	**648,816,000**

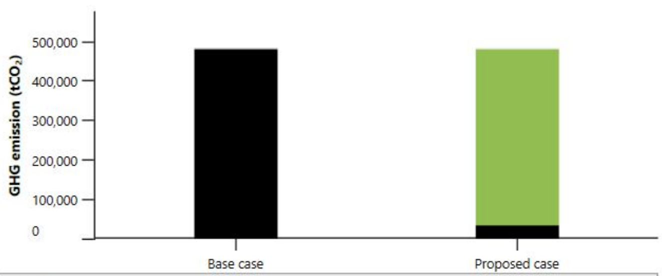
Annual costs (credits)	Unit	Quantity	Unit cost		Amount
O&M costs (savings)	project			€	28,428,340
Show data					
User-defined	cost			€	-
Total annual costs				**€**	**28,428,340**

Annual savings	Unit	Quantity	Unit cost		Amount
User-defined	cost			€	-
Total annual savings				**€**	**-**

Emission analysis

Base case electricity system (Baseline) **Country - region**	**Fuel type**	**GHG emission factor (excl. T&D)** tCO_2/MWh	**T&D losses** **%**	**GHG emission factor** **tCO_2/MWh**
Denmark	All types	0.315	7.0%	0.339
Electricity exported to grid	MWh	1,421,417	T&D losses	7.0%

GHG emission		
Base case	tCO_2	481,769.1
Proposed case	tCO_2	33,723.8
Gross annual GHG emission reduction	tCO_2	448,045.3



Legend
Gross annual GHG emission reduction (93%)

448,045.3 tCO_2 is equivalent to 82,059.6
Cars & light trucks not used

GHG reduction revenue

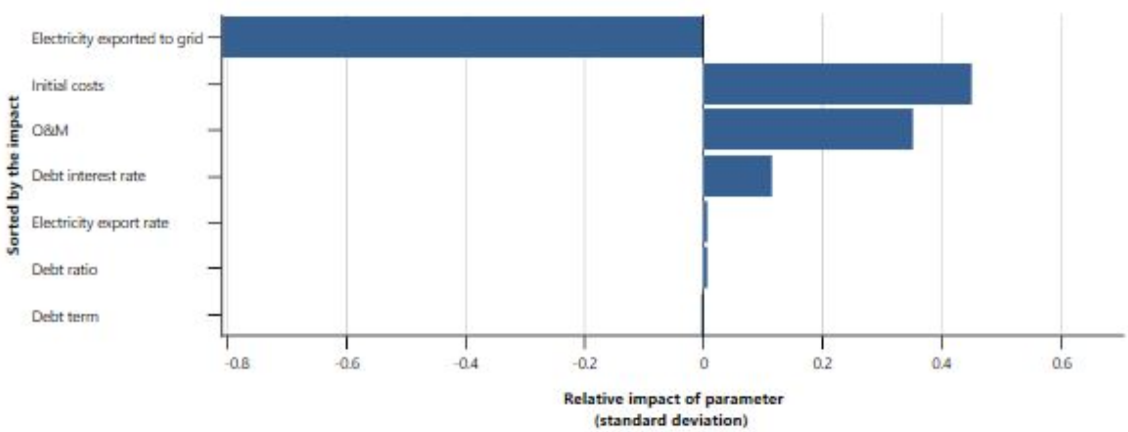
GHG reduction credit rate	€/tCO_2	

Risk analysis

Perform analysis on	Energy production cost
Number of combinations	500
Random seed	No

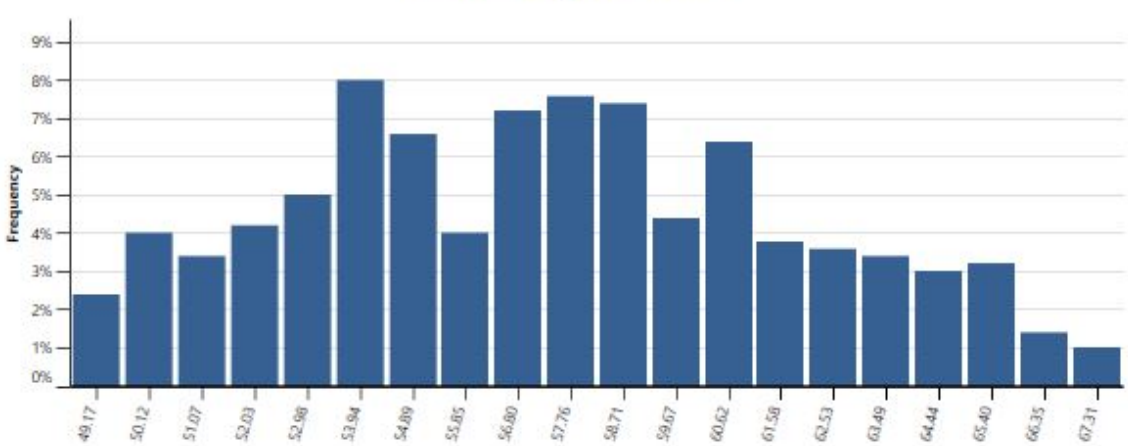
Parameter	Unit	Value	Range (+/-)	Minimum	Maximum
Initial costs	€	648,816,000	25%	486,612,000	811,020,000
O&M	€	28,428,340	25%	21,321,255	35,535,425
Electricity exported to grid	MWh	1,421,416.99	25%	1,066,062.74	1,776,771.24
Electricity export rate	€/MWh	50.37	25%	37.78	62.96
Debt ratio	%	70.0%	25%	52.5%	87.5%
Debt interest rate	%	5.00%	25%	3.75%	6.25%
Debt term	yr	15	25%	11	19

Impact - Energy production cost



Median	€/MWh	57.34
Level of risk	%	10%
Minimum within level of confidence	€/MWh	48.69
Maximum within level of confidence	€/MWh	67.79

Distribution - Energy production cost



Sensitivity analysis

Perform analysis on	Net Present Value (NPV)	
Sensitivity range	50%	
Threshold	50.37	€

- Remove analysis

Electricity export rate		Initial costs (€)				
		324,408,000	486,612,000	648,816,000	811,020,000	973,224,000
€/MWh		-50.0%	-25.0%	0.0%	25.0%	50.0%
25.19	-50.0%	-261,101,539	-423,305,539	-585,509,539	-747,713,539	-909,917,539
37.78	-25.0%	19,695,289	-142,508,711	-304,712,711	-466,916,711	-629,120,711
50.37	0.0%	300,492,118	138,288,118	**-23,915,882**	-186,119,882	-348,323,882
62.96	25.0%	581,288,946	419,084,946	256,880,946	94,676,946	-67,527,054
75.56	50.0%	862,085,774	699,881,774	537,677,774	375,473,774	213,269,774

- Remove analysis

O&M		Initial costs (€)				
		324,408,000	486,612,000	648,816,000	811,020,000	973,224,000
€		-50.0%	-25.0%	0.0%	25.0%	50.0%
14,214,170	-50.0%	549,635,715	387,431,715	225,227,715	63,023,715	-99,180,285
21,321,255	-25.0%	425,063,916	262,859,916	100,655,916	-61,548,084	-223,752,084
28,428,340	0.0%	300,492,118	138,288,118	**-23,915,882**	-186,119,882	-348,323,882
35,535,425	25.0%	175,920,319	13,716,319	-148,487,681	-310,691,681	-472,895,681
42,642,510	50.0%	51,348,520	-110,855,480	-273,059,480	-435,263,480	-597,467,480

- Remove analysis

Debt ratio		Debt interest rate (%)				
		2.50%	3.75%	5.00%	6.25%	7.50%
%		-50.0%	-25.0%	0.0%	25.0%	50.0%
35%	-50.0%	12,797,456	-5,138,649	-23,915,882	-43,500,650	-63,856,327
53%	-25.0%	31,154,126	4,249,968	-23,915,882	-53,293,034	-83,826,550
70%	0.0%	49,510,795	13,638,585	**-23,915,882**	-63,085,418	-103,796,772
88%	25.0%	67,867,465	23,027,202	-23,915,882	-72,877,802	-123,766,995
105%	50.0%					

- Remove analysis

O&M		Electricity exported to grid (MWh)				
		710,708.50	1,066,062.74	1,421,416.99	1,776,771.24	2,132,125.49
€		-50.0%	-25.0%	0.0%	25.0%	50.0%
14,214,170	-50.0%	-336,365,941	-55,569,113	225,227,715	506,024,543	786,821,372
21,321,255	-25.0%	-460,937,740	-180,140,912	100,655,916	381,452,745	662,249,573
28,428,340	0.0%	-585,509,539	-304,712,711	**-23,915,882**	256,880,946	537,677,774
35,535,425	25.0%	-710,081,338	-429,284,509	-148,487,681	132,309,147	413,105,975
42,642,510	50.0%	-834,653,136	-553,856,308	-273,059,480	7,737,348	288,534,176

- Remove analysis

Initial costs		O&M (€)				
		14,214,170	21,321,255	28,428,340	35,535,425	42,642,510
€		-50.0%	-25.0%	0.0%	25.0%	50.0%
324,408,000	-50.0%	549,635,715	425,063,916	300,492,118	175,920,319	51,348,520
486,612,000	-25.0%	387,431,715	262,859,916	138,288,118	13,716,319	-110,855,480
648,816,000	0.0%	225,227,715	100,655,916	**-23,915,882**	-148,487,681	-273,059,480
811,020,000	25.0%	63,023,715	-61,548,084	-186,119,882	-310,691,681	-435,263,480
973,224,000	50.0%	-99,180,285	-223,752,084	-348,323,882	-472,895,681	-597,467,480

Sensitivity analysis

Perform analysis on	Energy production cost	
Sensitivity range	50%	
Threshold	50.37	€/MWh

- Remove analysis

Electricity export rate		Initial costs (€)				
		324,408,000	486,612,000	648,816,000	811,020,000	973,224,000
€/MWh		-50.0%	-25.0%	0.0%	25.0%	50.0%
25.19	-50.0%	41.07	49.16	57.26	65.36	73.45
37.78	-25.0%	41.07	49.16	57.26	65.36	73.45
50.37	0.0%	41.07	49.16	**57.26**	65.36	73.45
62.96	25.0%	41.07	49.16	57.26	65.36	73.45
75.56	50.0%	41.07	49.16	57.26	65.36	73.45

- Remove analysis

O&M		Initial costs (€)				
		324,408,000	486,612,000	648,816,000	811,020,000	973,224,000
€		-50.0%	-25.0%	0.0%	25.0%	50.0%
14,214,170	-50.0%	28.63	36.73	44.82	52.92	61.02
21,321,255	-25.0%	34.85	42.94	51.04	59.14	67.23
28,428,340	0.0%	41.07	49.16	**57.26**	65.36	73.45
35,535,425	25.0%	47.28	55.38	63.48	71.57	79.67
42,642,510	50.0%	53.50	61.60	69.70	77.79	85.89

- Remove analysis

Debt ratio		Debt interest rate (%)				
		2.50%	3.75%	5.00%	6.25%	7.50%
%		-50.0%	-25.0%	0.0%	25.0%	50.0%
35%	-50.0%	55.43	56.32	57.26	58.24	59.25
53%	-25.0%	54.51	55.85	57.26	58.73	60.25
70%	0.0%	53.59	55.39	**57.26**	59.21	61.25
88%	25.0%	52.68	54.92	57.26	59.70	62.24
105%	50.0%					

- Remove analysis

O&M		Electricity exported to grid (MWh)				
		710,708.50	1,066,062.74	1,421,416.99	1,776,771.24	2,132,125.49
€		-50.0%	-25.0%	0.0%	25.0%	50.0%
14,214,170	-50.0%	89.65	59.76	44.82	35.86	29.88
21,321,255	-25.0%	102.08	68.06	51.04	40.83	34.03
28,428,340	0.0%	114.52	76.35	**57.26**	45.81	38.17
35,535,425	25.0%	126.96	84.64	63.48	50.78	42.32
42,642,510	50.0%	139.39	92.93	69.70	55.76	46.46

- Remove analysis

Initial costs		O&M (€)				
		14,214,170	21,321,255	28,428,340	35,535,425	42,642,510
€		-50.0%	-25.0%	0.0%	25.0%	50.0%
324,408,000	-50.0%	28.63	34.85	41.07	47.28	53.50
486,612,000	-25.0%	36.73	42.94	49.16	55.38	61.60
648,816,000	0.0%	44.82	51.04	**57.26**	63.48	69.70
811,020,000	25.0%	52.92	59.14	65.36	71.57	77.79
973,224,000	50.0%	61.02	67.23	73.45	79.67	85.89

G: OTHER USEFUL INFORMATION

RECOMMENDATION FOR CABLES

Neumann (2021), discussed that one of offshore wind's biggest difficulties remain subsea cable failures and this continues to make up for the most insurance claims in the sector. Failure can result in massive financial consequences, as well as a lack of generation, inquiry, and repair work for months, even if the problems are minor. Induced currents and water infiltration, for example, can speed up the aging of components in cable systems, resulting in untimely cable breakdown. A problem, such as a cable short-circuit, might put developers at danger because the cost of repairing a single subsea cable can reach 2.9 M€ per kilometer.

When a cable fails a test in a warm, dry laboratory after being subjected to a variety of stressors, it will not be able to endure the tremendous pressures and severe temperatures found subsea. My team at our UKAS-accredited facility in ORE Catapult's National Renewable Energy Centre in Blyth is responsible for ensuring that concealed design or material faults in cables are identified prior to installation.

Research and Development must recognize that it's involvement is critical in bringing new products to market. Customers should be aware that it is their responsibility to identify acceptable test techniques that go beyond the requirements of the standards. Following that, studies undertaken for owners/operators provide insight into the primary reasons of failures, as well as directly supplying intelligence to support insurance claims of payment.

It may be insinuated that a cable can only be gold-plated for offshore installation if it has gone through a series of tests. As a result, the process of determining whether a cable is acceptable for usage must go beyond official criteria and criteria. Adherence to these is, in my opinion, a basic minimum.

It is impossible to overstate the benefits of information exchange in the sector. Individual cable designs should be tested, but the industry will not progress unless there is more transparency about why cables fail in the field.

VESSEL SELECTION

The Jack-up installation vessels Brave Tern and Bold Tern are state of the vessels for the decommissioning and installation operations. The Brave Tern and Bold Tern jack-up vessels are self-propelled and self-elevated vessels, developed by Gusto MSC and adapted by Fred.Olse. Windcarrier for high efficiencies and economical installations planned to satisfy the highest possible operational and safety requirements. They can perform offshore operations include installation, decommissioning, and O&M of OWF. It has been used in several offshore sites including Horns Rev 3 that is within the terrain of Horns Rev 1. It is a Gusto MSC NG9000C-HPE vessel type, with class DNV + 1A1, CLEAN DESIGN NAUT-OSV(A) OPP-F DYNPOS-AUTR EO HEL DK Class. The cargo capacity has a maximum variable load of 9500 t, deck area of 3200 m2, uniform deck loading of 5-10 t/m2, and WTG capacity (typical) of 8 x 3,6 MW or 4 x 8.0 MW. It has a maximum speed of 12 knots and DP2 positioning system. Its operation water depth range is 5.5 - 60, which is well suited for the Horns Rev 1 case. The vessel is powered by 4 diesel electric Wartsila generators (1 x 12v32 5760kW, 1 x 6L32 2880kW, 2 x 9L32 4230kW), a Harbour emergency generator, CAT 3512B 1400kW, with output range of 60 Hz, 230-690V 50 Hz on-deck power supply. In terms of fuel consumption, for transit speed of 10 knots it consumes 45 t/24h, at elevated standby it consumes 5-6 t/24h, during elevated crane work the fuel consumption is 6-8 t/24h. It can install four turbines per cycle like the Horns Rev 3 case, likewise four turbines in four days like the case of Borkum Riffgrund 2. (Fred. Olsen Windcarrier, 2021).

INFLUENCE OF FUEL IN CO_2 EMISSION

The Energy Efficiency Operational Index (EEOI) was created to aid in the process of determining and reducing pollution from ships in service. EEOI is a measurement instrument that represents the mass of CO_2 emitted per unit of transportation work.

Marine pollution encompasses both water and air pollution. The IMO has listed CO2, SOx, and NOx as main pollutants and has established a system of emission monitoring steps in order to regulate and reduce air pollution (IMO, 2011). When it comes to CO_2, the tests are divided into management, technical and operational categories, namely:

Ship Energy Efficiency Management Plan;

Energy Efficiency Design Index;

Energy Efficiency Operational Index.

EEOI:

EEOI is a concept introduced by the IMO to provide ship managers, shipowners, stakeholders and other parties with a system to assess the amount of greenhouse gas emissions from ships in service. The IMO's concerns on EEOI were put into consideration in the Guidelines for voluntary use of the ship energy efficiency operational indicator MEPC.1/Circ.684 (IMO, 2009), that advocate the EEOI as a useful instrument for limiting the effect of shipping on global climate change. These Guidelines are meant to provide an example of a measurement tool that may be used to monitor the effectiveness of a ship's service in an analytical, performance-based manner.

$$EEOI = MCO_2/Transport\ Work$$

where CO2 emissions are calculated using fuel consumption and transportation work is calculated using cargo mass (T) multiplied by distance travelled in nautical miles (Nm). The following are the terms of the equation:

- ★ Cargo mass: quantity as per Bill of Lading and Deck Log Book given in tonnes; for other types of vessels the work done will be expressed in a different manner: for turbine ferries – number of turbines, for crew vessels – number of crew.
- ★ Distance Sailed: the real distance travelled in nautical miles for each voyage, as recorded in the ship's Bridge Log Book;
- ★ Fuel consumption is the total amount of fuel used by main and auxiliary engines, boilers, and other equipment when at sea and in port, as reported in the Engine Log Book.

The following formula is used to compute the EEOI for a voyage, with a lower EEOI value indicating a more energy efficient ship:

$$EEOI = \sum_j FC_j * C_{Fj} \ / \ m_{cargo} * D$$

The indicator is expressed as follows for several voyages or voyage legs:

$$Average\ EEOI = \sum_j \sum_j FC_{ij} * C_{Fj} \,/\, \sum_j m_{cargo,i} x D_i$$

Types of marine fuel

The correlation between the fuel usage and CO_2 mass stems from the fuel's chemical composition, comprising mostly of hydrocarbons such as $C_{15}H_{32}$. The atomic weights of carbon (C) and hydrogen (H) are 12.011 and 1 respectively. This results in C with a mass fraction of 85.0-87.5 %, with diesel oil in the upper percent range and heavy fuel in the smaller percent range (IMO, 2005). If combusted hydrocarbons are reacted with oxygen (O), which is 15,9994 in atomic weight, then one C is required for each CO_2. The ratio of CO_2 to C is 3,664 by atomic weights. The specific CO_2 emission (CF) is calculated by multiplying the mass fraction of carbon in the fuel. We have different carbon contents for various types of fuel and thus several correction factors (IMO, 2009), see Table 6.7.

Table 6.7. Carbon content per fuel type (Recreated from Acomi & Acomi, 2014).

Type of fuel	**Reference**	**Carbon content**	**CF (t-CO_2/t-fuel)**
Diesel / Gas Oil	ISO 8217 Grades DMX through DMC	0.875	3.206000
Heavy Fuel Oil (HFO)	ISO 8217 Grades RME through RMK	0.85	3.114400
Light Fuel Oil (LFO)	ISO 8217 Grades RMA through RMD	0.86	3.151040
Liquefied Natural Gas (LNG)		0.75	2.750000
Liquefied Petroleum Gas (LPG)	Propane; Butane	0.819 0.827	3.000000 3.030000

BEAM/COLUMN ENGINEERING

The main difference between a column and a beam is how the load is applied. Columns experience compressive force where the load is applied parallel to the axis. In beams, the load is applied perpendicular along the axis of the member. It can result to deformation. A beam is a long, slender horizontal element of structure that resist perpendicular loads primarily through bending. Factors that affect the shear force and bending moment in a beam are length, load, material, and shape.

Simply supported beams have support on each end. In a simply supported beam, when load is applied at the top of a beam, it experiences compression at the top and tension at the bottom. This is applicable to trusses also. Over the years, lots of designs as has been put forward to enhance beam design. Concrete is strong under compressive forces but performs poorly under tension. This is one reason why in recent times most structures including turbine foundation have been made of steel. Furthermore, an applied force cause compression and tension pair that are equal and opposite forming an equilibrium, generating the moment which is sometimes referred to as the couple or bending moment. Bending moment is described as a tendency for a force to cause something to bend or rotate

Cantilever beams are beams with primarily only one support. It tends to be fixed support. The monopile can be considered as cantilever beam. The greater the length of the monopile between the nacelle and the seabed, the greater the chances of bend and rotation. Hence, the moment of the force exerted by the load about an axis or point would give a measure of the tendency of the force to cause the column to rotate about the axis or point. This is in somewhat applicable to the part of the monopile beneath the seabed as well. Moment is force multiplied by the perpendicular distance.

$$M = P * d$$

Shear force is the presence of two parallel forces acting at a distance. Considering a monopile as beam, failure due to shear force can occur as a result of forces from wave and wind. But this is highly unlikely given that the distance between the top of the monopile and the seabed is usually small around 20 m in some cases depending on the water depth.

Another type of beam is the Propped cantilever beam, which is a beam with one supported end and another support along the length of the beam.

All three beams, simply supported, cantilever and propped cantilever beams are all statically determinate. This means that the math governing them fairly is straight forward unlike statically independent beams.