Feasibility Study of the Hub and Spoke Concept in the North Sea

Developing a Site Selection Model to Determine the Optimal Location

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MASTER THESIS

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PREFACE

This report is the final thesis of my master program Hydraulic Engineering at Delft University of Technology. The research has been conducted in cooperation with engineering and consulting agency Witteveen+Bos and will be publicly defended on Wednesday October 4^th, 2017.

First, I would like to thank Witteveen+Bos for giving me the opportunity to investigate such a revolutionary new idea like the Hub and Spoke concept. Offshore wind energy is still in its early stages and developments go very rapid, thereby making it difficult to investigate but at the same time very interesting. I want to thank the sustainable energy development department at Witteveen+Bos and in particular my daily supervisor, Emiel van Druten. Your enthusiasm and large amount of recommendations kept me always thinking of the bigger picture and gave me some valuable insights.

Secondly, I would like to thank all members of my graduation committee who have supported me in writing this thesis. Especially at the start of my research it was very difficult to determine the right research framework, because the Hub and Spoke concept is such a new concept. It contains many uncertainties and is dependent on so many variables. Even TenneT, the initiator of the concept, could not always answer my questions. The reflection moments with Tiedo Vellinga, Coen Kuiper and Peter Quist however always pointed me in the right direction and helped me in achieving this thesis.

And last, but certainly not least, I would like to thank all industry experts who where willing to be interviewed. It was very helpful to hear all kinds of different motives and be able to derive a general consensus on some aspects. Thank you Jaap de Boer and Hans Scholten (Energy Watch) for giving me a first acquaintance with offshore wind energy, Mart van der Meijden (TenneT) who introduced me to the Hub and Spoke concept, Maarten Schäffner (Witteveen+Bos) who advised me on ecological impact and sustainable design, Teun van Breukelen (Witteveen+Bos) who was my sparring partner on offshore wind energy and gave me some very helpful documents, Romke Bijker (Advanced Consultancy Romke Bijker) who gave me practical information on subsea interconnector cables based on over two decades of experience and finally Gerard van Bussel (TU Delft) and Jos Beurskens (ECN), who are experts in the field of offshore wind energy and challenged some of my thoughts on the Hub and Spoke concept. All your input is very much appreciated and everyone's enthusiasm made my last year of being a student very pleasant.

Stefan Gerrits
Delft, October 2017

ABSTRACT

The European energy system is significantly changing to restrict the rise in global average warming. There is a shift from fossil fuels to renewable energy sources, which resulted in an exponential growth of offshore wind energy capacity in the North Sea. However, the North Sea is already one of the most intensively used sea basins in the world and space is limited. Offshore wind farms are therefore increasingly constructed under less favourable conditions. On the one hand the industry is rapidly developing and the cost of offshore wind energy goes down, but on the other hand offshore wind farms are constructed at greater water depths and further from shore. This latter development counteracts the cost reduction achieved by the industry, but countries are forced to construct offshore wind farms under less favourable conditions in order to achieve the climate agreements.

In June 2016, Dutch transmission system operator TenneT proposed the Hub and Spoke concept. It is an alternative method to connect offshore wind farms with the onshore grid and makes the parameter distance to shore far less important. Basically, the concept combines offshore wind farms with interconnector cables. An artificial island is created somewhere in the centre of the North Sea which is surrounded by offshore wind farms, thereby being far away from the crowded coastlines while profiting from near shore conditions. The interconnector cables subsequently transport the generated electricity to shore.

Dogger Bank is the envisioned location for the Hub and Spoke concept. The area contains strong winds, shallow water conditions and is centrally located. However, the unique characteristics of the shallow sandbank make it also very favourable to a variety of species. The area is therefore appointed Natura 2000 territory and could cause major resistance from environmental organisations. The general consensus amongst environmental organisations is not yet known, but industry experts indicate this as the major reason which could stop the Hub and Spoke concept from being realised on Dogger Bank.

The objective of this research is to determine the optimal location for the Hub and Spoke concept in the North Sea. The concept feasibility has never been determined and it is not even certain if Dogger Bank is the most beneficial location, while the location contains a very large risk. Therefore, the site selection model is created. The model contains input data from metocean conditions and electricity markets, which makes it possible to calculate the feasibility of the Hub and Spoke concept for every location in the North Sea. The result is a contour plot with the net present value of the Hub and Spoke concept, which shows the optimal location in the North Sea.

The Hub and Spoke concept is divided into five components to determine the influence of certain conditions on cost or revenue and to compare the components between each other. The artificial island and offshore wind turbines are primarily influenced by water depth, while the subsea interconnector cost is mainly influenced by the cable capacity and length of the cable. The optimal location for the island and offshore wind farms with respect to cost is thus along the shallow coastlines or at Dogger Bank, while the optimal location for the subsea interconnector cables is determined by the minimum total cable length. This point is equal to the centre of gravity of the countries surrounding the North Sea and is located just above the Netherlands and Germany.

In terms of revenue, the wind conditions are normative for the production and revenue of offshore wind farms and interconnectors derive their congestion rents from electricity price differences between countries. Offshore wind farms generate most electricity in the northeastern part of the North Sea where the wind conditions are strongest. This negatively impacts the generated revenue from subsea interconnectors as the cable is used more often for offshore wind energy. Interconnector revenue of the Hub and Spoke concept is therefore lowest at locations with the strongest wind speed, but in total the highest revenue is generated. A comparison between these components for four various locations is presented in Figure 0.1.

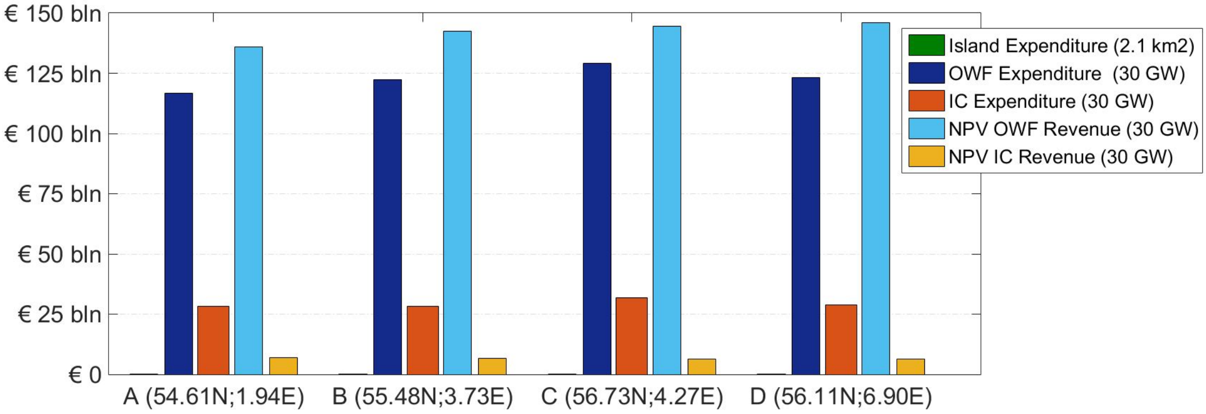

Figure 0.1

Offshore wind farms are both in cost and revenue the major component in the Hub and Spoke concept. The optimal location is thus expected to be found in areas with shallow water depths and high wind speeds. Finally, each component with its cost and revenue has been determined and can be merged in the site selection model to determine the feasibility of the Hub and Spoke concept in the North Sea. See Figure 0.2.

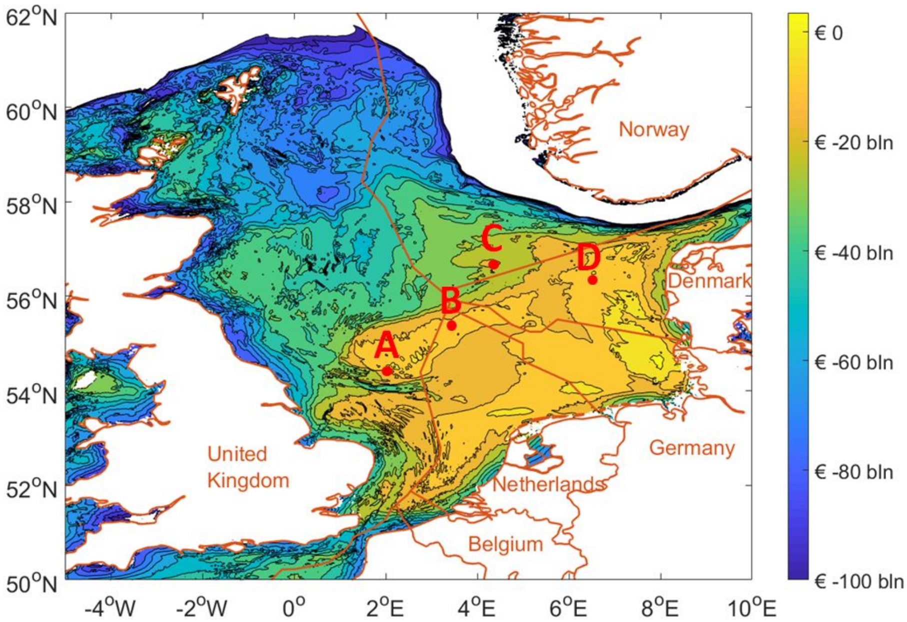

Figure 0.2: NPV Hub and Spoke Concept with 30 GW Capacity

It can be concluded that the highest net present value for the Hub and Spoke concept is situated along the coastline of Denmark and Germany. However, these locations are known to be very crowded and the reason to investigate alternative locations in the first place. Dogger Bank and the northwest of Denmark are two very interesting alternatives. Dogger Bank is very shallow with depths of 10 m, while the northwest of Denmark is slightly deeper with 20 m but contains roughly 10% higher wind speeds. Both locations are primarily free from other marine uses, although Dogger Bank is protected Natura 2000 territory and therefore contains a very large risk. It is therefore advised to construct the Hub and Spoke island at the northwest side of Denmark.

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ACRONYMS AND ABBREVIATIONS

AC	alternating current
CAPEX	capital expenditure
CFSv2	climate forecast system version 2
DC	direct current
DTM	digital terrain model
EEZ	exclusive economic zone
EC	European Commission
EU	European Union
GHG	greenhouse gasses
HV	high voltage (> 100 kV)
HVDC	high voltage direct current
IEM	internal energy market
LCoE	levelized cost of electricity
NGO	non-governmental organisation
NPV	net present value
MoU	memorandum of understanding
O&M	operation & maintenance
OPEX	operational expenditure
OWF	offshore wind farm
POT	Peaks-Over-Threshold
RES	renewable energy source
TSO	transmission system operator
WACC	weighted average cost of capital

UNITS OF MEASUREMENT

bln	billion
DKK	Danish Krone
EUR	Euro
GBP	Great Britain Pound
GW	gigawatt
GWh	gigawatt hour
ktoe	thousand tonnes of oil equivalent
mln	million
Mtoe	million tonnes of oil equivalent
MW	megawatt
MWh	megawatt hour
NOK	Norwegian Krone
SEK	Swedish Krona
TW	terawatt
TWh	terawatt hour
USD	United States Dollar

EUROPEAN MEMBER STATES

EU-28 The 28 Member States of the European Union from 1 July 2013 (Belgium, Bulgaria, Czech Republic, Denmark, Germany, Estonia, Ireland, Greece, Spain, France, Croatia, Italy, Cyprus, Latvia, Lithuania, Luxembourg, Hungary, Malta, Netherlands, Austria, Poland, Portugal, Romania, Slovenia, Slovakia, Finland, Sweden, *United Kingdom)

**On the 29th of March 2017 Prime Minister Theresa May triggered Article 50, meaning the United Kingdom has 2 years to agree on terms to split and is thus scheduled to leave the EU on the 29th of March 2019.*

1 INTRODUCTION

"Preservation of our environment is not a liberal or conservative challenge, it's common sense."
- Ronald Reagan, 1984

The recent Paris Agreement reminded us of the need to address climate change. The rise in global average temperature is caused by the emission of greenhouse gasses and since the industrial revolution humans are adding enormous amounts of it to the atmosphere. Action must be taken in order to prevent "dangerous and possibly catastrophic changes in the global environment." (EC, 2016a) One of the measures taken by the European Union is to reduce the amount of fossil fuels and make a shift towards renewable energy.

1.1 Offshore Wind Energy

The shift from fossil fuels to renewable energy sources resulted in an exponential growth of offshore wind energy capacity in the North Sea. Europe contains by far most of the offshore wind energy capacity in the world, but the associated cost is still a point of discussion. It is on average one of the most expensive forms of renewable energy and relies heavily on subsidies. (Capros, 2016) The cost need to come down drastically as competitiveness with other forms of energy is found increasingly important. Public and political support must be maintained or developments might be interrupted before the technology has reached its full potential. (Megavind, 2010; Hobohm et al., 2013)

There are two very dominant trends visible. On the one hand the industry is rapidly developing. The first offshore wind farm was installed only two decades ago in Denmark and the industry is thus very immature compared to other energy sources. There is much technological progress and cost are going down rapidly. On the other hand offshore wind farms are being installed under less favourable conditions. Especially along the coastline space in the North Sea is limited and offshore wind farms are therefore constructed further from shore and at greater water depths. (Megavind, 2010) This development counteracts the cost reduction achieved by the industry and can be seen in Figures 1.1 and 1.2. In previous years the average cost even increased, but it stabilised around the year 2012 and has been decreasing from there on. (The Crown Estate, 2012) However, countries have no other choice as the North Sea is one of the most intensively used sea basins and new offshore wind farms need to be installed in order to achieve the climate agreements.

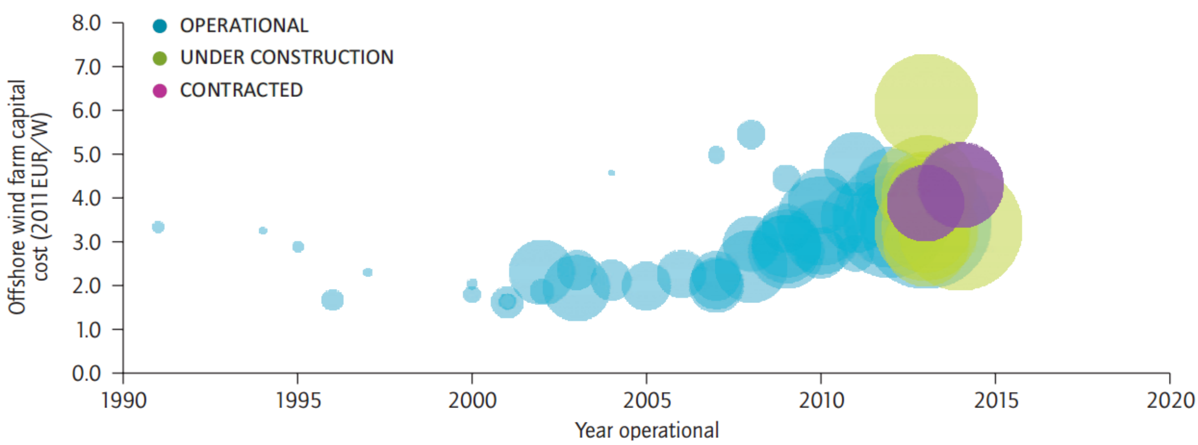


Figure 1.1: EU Offshore Wind Farm Capital Cost (source: Garrad Hassan, 2013)

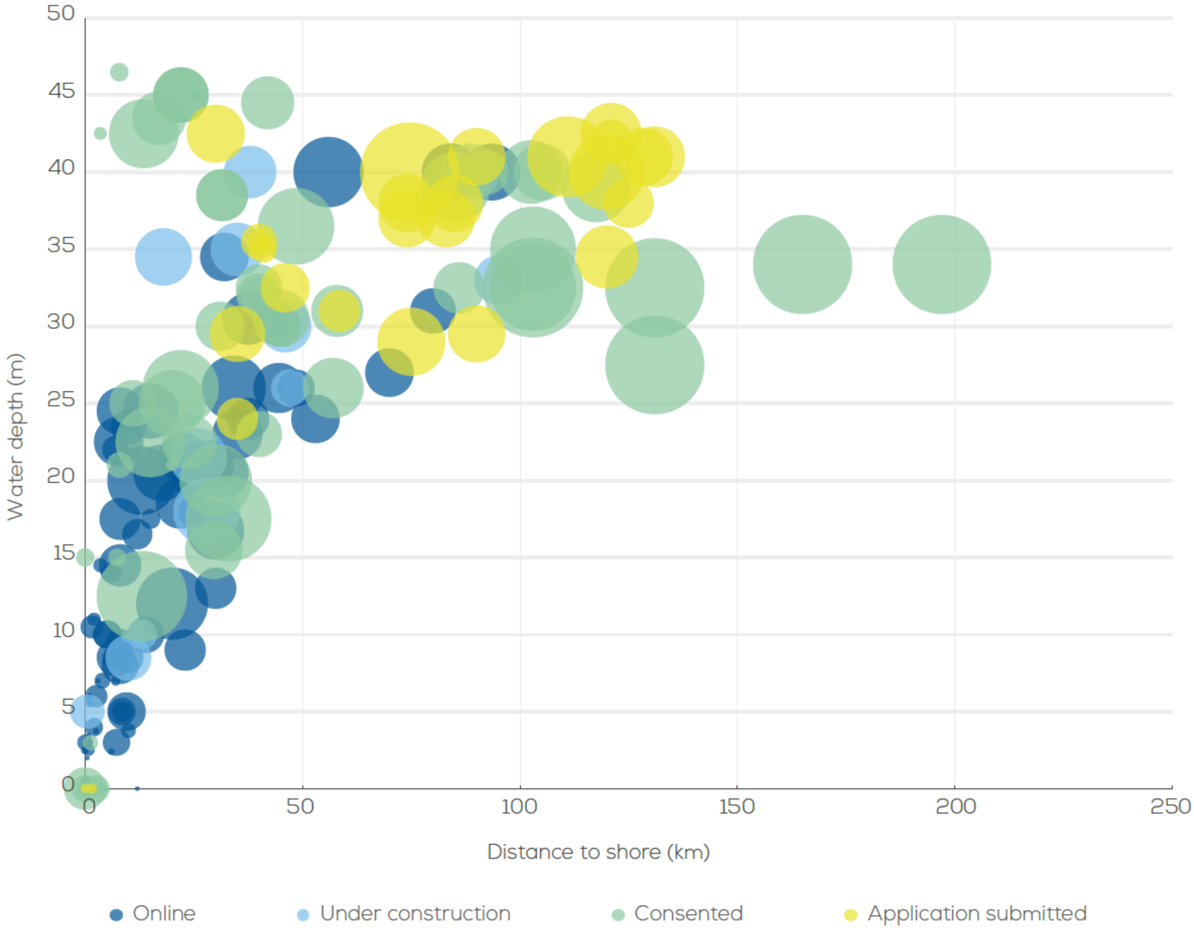


Figure 1.2: EU Offshore Wind Farm Water Depth and Distance to Shore by Development Status. Total Capacity Indicated by Circle Size. (source: WindEurope, 2017b)

1.2 Hub and Spoke Concept

In June 2016, Dutch transmission system operator TenneT proposed the Hub and Spoke concept. The Hub and Spoke concept is an alternative method to connect offshore wind farms with the onshore grid. An island in the centre of the North Sea is created, enabling offshore wind farms far away from the national coastlines to profit from near shore conditions. The parameter distance to shore is now much less relevant as the island could potentially be built everywhere in the North Sea and this could lead to a significant cost reduction in offshore wind energy. An artist impression of the Hub and Spoke concept is presented in Figure 1.3.

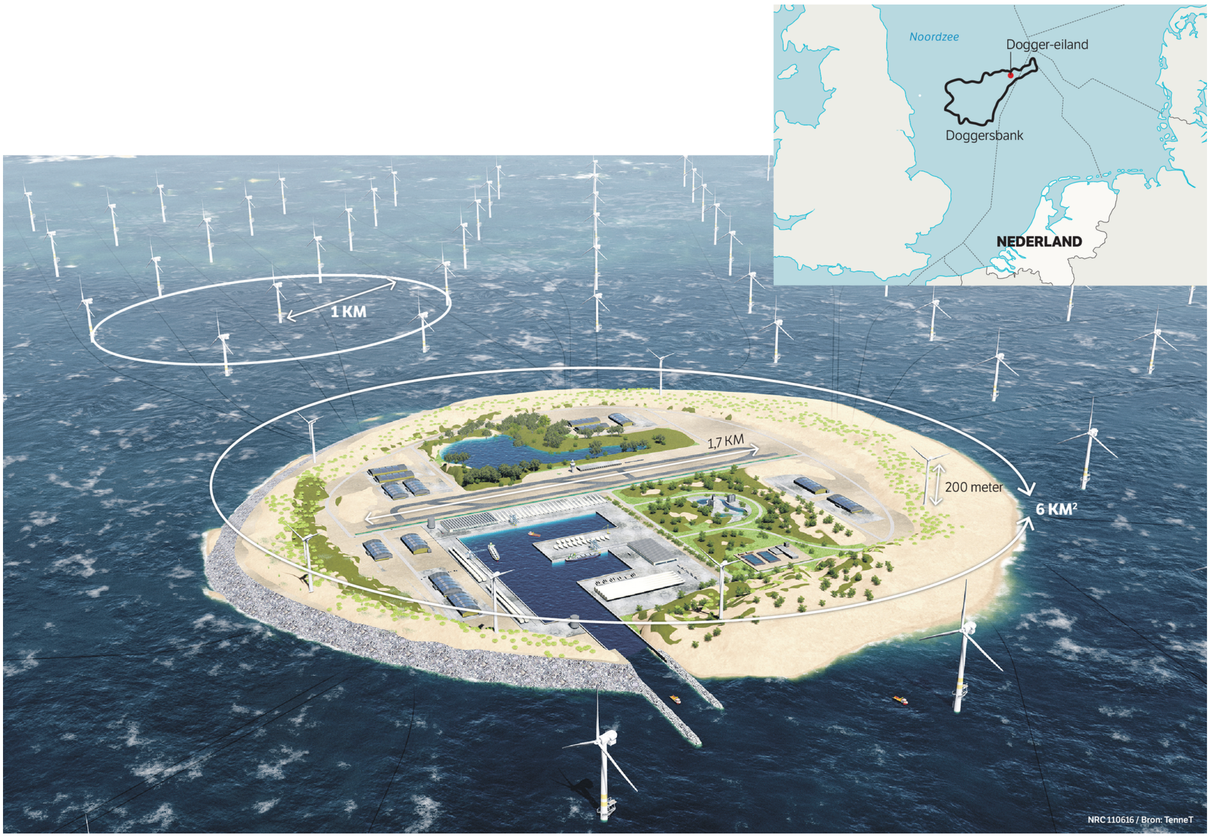


Figure 1.3: Artist Impression of the Hub and Spoke Concept (source: TenneT, 2016)

One of the reasons why offshore wind farms closer to shore are cheaper is because of the type of infrastructure. Electricity generated by offshore wind turbines is transported to shore with cables, but the cable loss increases with distance. At some point, usually between 60 - 100 km ABB, 2012, the cable losses in common alternating current infrastructure (henceforth AC) become unacceptably high and more expensive direct current infrastructure (henceforth DC) is required. The construction of an artificial island in the middle of the North Sea would make it possible to install far offshore wind farms with common and cheaper AC infrastructure.

However, the generated electricity still needs to be transmitted from the artificial island to the surrounding countries. This is done with DC infrastructure and may sound devious, but it contains two major advantages. First, the equipment to convert electricity from AC to DC can be installed on the artificial island instead of offshore and this leads to considerable cost savings. Offshore jackets are no longer needed, the structures do no longer have to comply with strict offshore regulations, it is much easier to access by personnel and expensive offshore operations are no longer needed. The second advantage is the connecting function between electricity markets. Utilisation of offshore wind farm infrastructure is roughly 40% as the wind conditions are not always optimal and time is needed for maintenance and repairs on the offshore wind turbines. The artificial island will however become a hub and facilitates electricity trade to multiple countries as well. The utilisation of DC cables thereby increases from roughly 40% towards 100% and additional revenue is being generated.

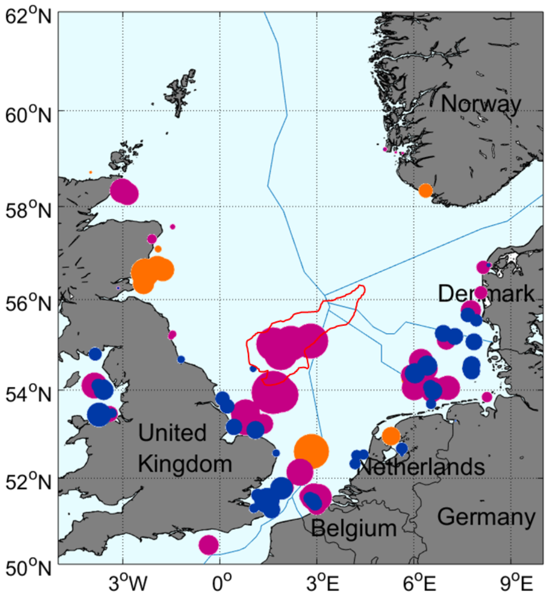


Figure 1.4: North Sea Offshore Wind Farms: Operational (blue), Under Construction or Consented (purple), Consent Application Submitted (orange)

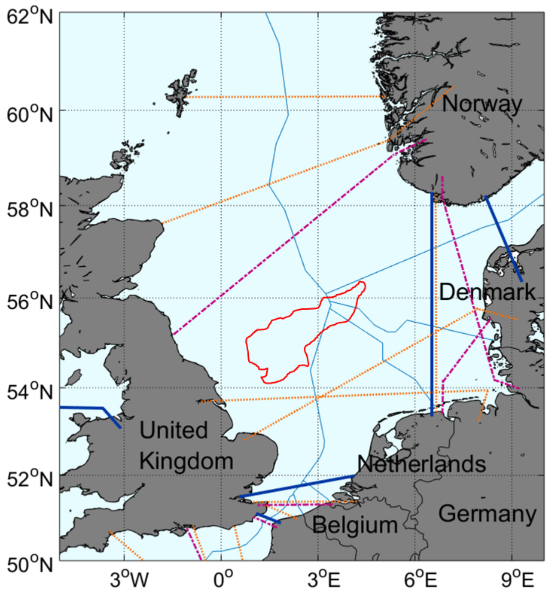


Figure 1.5: North Sea Subsea Interconnector Cables: Operational (blue), Under Construction or Consented (purple), Concept (orange)

The development of offshore wind farms and subsea interconnector cables is presented in Figures 1.4 and 1.5. It can be noticed that there is a very national approach. Offshore wind farms are installed close to shore and the development of interconnection cables looks very chaotic and inefficient. The installation of both types of structures are relatively new developments of the last two decades and are a result of the climate agreements. The infrastructure is essentially equal and it is therefore very logical to examine the possibility of combining offshore wind farms with interconnector cables. Synergies could possibly lead to a cost reduction in offshore wind energy, while simultaneously accelerating the development of a more integrated electricity grid. Furthermore, areas which were previously seen as unavailable for offshore wind farms have now become available as distance to shore is much less relevant. The Hub and Spoke concept could lead to a more coordinated approach and on top of all the associated advantages mentioned in this section it could also possibly achieve efficiency gains. The upper part of Figure 1.6 presents the current situation with individual offshore wind farms in a national approach, while the lower part of the figure depicts the underlying idea of the Hub and Spoke concept.

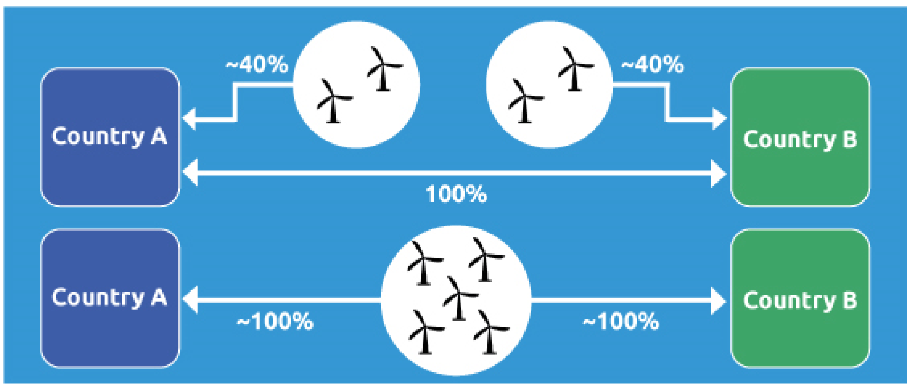


Figure 1.6: Synergy between Offshore Wind Farms and Interconnectors

1.3 Problem Definition

"The location for the Hub and Spoke concept must satisfy a number of suitability requirements. There must be a lot of wind, it must be centrally located and it must be in relatively shallow water. These criteria qualify Dogger Bank as a suitable location. " - TenneT, 2016

TenneT envisions the Hub and Spoke concept to be realised on Dogger Bank. This is a very large and shallow sandbank located in the centre of the North Sea. The location therefore fulfils the criteria and seems perfect for the Hub and Spoke concept. However, the unique characteristics of the sandbank make it also very favourable to a variety of species and the region is therefore appointed Natura 2000 territory. Human activities are still allowed, but the present ecological state must be preserved at all times and this severely complicates the project. The general consensus of environmental organisations is not yet clear, but according to industry experts opposing environmental organisations could completely stop the Hub and Spoke concept from being realised on Dogger Bank.

"Technically there are some uncertainties, but no big problems are expected. The major reason which could stop the Hub and Spoke concept from being realised on Dogger Bank is resistance from environmental organisations."
- Meijden, 2016; De Boer and Scholten, 2016

1.4 Research Objectives

The objective of this research is to determine the optimal location for the Hub and Spoke concept in the North Sea. At first sight, Dogger Bank seems the most suitable location due to its shallow water conditions and central position in the North Sea, but the location also contains a large risk as opposing environmental organisations could stop the project from being realised. The feasibility of the Hub and Spoke concept has however never been quantified and it is not even certain that Dogger Bank is the most beneficial location.

Therefore, the site selection model is constructed to determine the feasibility of the Hub and Spoke concept for every location in the North Sea. A thorough literature study is performed to indicate the dominant parameters influencing the feasibility of the concept and to determine cost and revenue of offshore wind farms and subsea interconnector cables. Furthermore, multiple interviews are conducted with industry experts to validate assumptions and to gain a general consensus on the advantages and disadvantages of the Hub and Spoke concept. Based on this research it can be concluded if Dogger Bank is indeed the most favourable location and the consequence of changing the concept to a different location is known.

1.5 Research Questions

Main Research Question

"What is the optimal location for the Hub and Spoke concept in the North Sea?"

Sub-Questions

The following sub-questions need to be answered to be able to form a well-argued advise on the feasibility and optimal location of the Hub and Spoke concept in the North Sea.

1. *"How is the European energy market developing and is there a certain capacity gap on which the Hub and Spoke concept can anticipate?"*
2. *"What are the major marine uses in the North Sea and how will they be affected by the Hub and Spoke concept?"*
3. *"What are the major metocean conditions influencing the feasibility of the Hub and Spoke concept?"*
4. *"How to determine cost and revenue of offshore wind farms and subsea interconnectors?"*
5. *"How is the price of electricity expected to develop in the future?"*

1.6 Overview

A brief overview is given on the chapters in this thesis. In the second chapter, 'European Energy Market Analysis', the transition of the energy system is analysed and future offshore wind farm and interconnection capacities are determined. The third chapter, 'Environmental Analysis', identifies the major marine uses in the North Sea and shows the possibilities of co-existence with offshore wind farms. The fourth chapter entitled 'Metocean Analysis' presents all meteorological and oceanographic conditions in the North Sea. The conditions with the most significant influence on the feasibility of the Hub ans Spoke concept are used as input for the site selection model. The site selection model is explained in chapter five, together with a validation of the input data with multiple physical measurements. In chapter six, 'Expenditure', the site selection model is used to determine the cost of the artificial island, surrounding offshore wind farms and interconnector cables for every location in the North Sea. In chapter seven, 'Production and Revenue', the expected revenue from generated wind energy and electricity trade is determined. In chapter eight, 'Model Results', cost and revenue from all individual components are combined and the feasibility of the Hub and Spoke for every location in the North Sea can be determined. Chapter nine, 'Conclusions and Recommendations', presents the optimal location for the Hub and Spoke concept in the North Sea and is used to reflect on the performed study.

2 EU ENERGY MARKET ANALYSIS

In this chapter the relation between renewable energy sources and interconnector capacity is explained, which forms the basis of the Hub and Spoke concept. The European energy system is changing significantly over the next coming decades due to a shift from fossil fuels to renewable energy sources. It is important to know how this affects the current energy system and the Hub and Spoke concept might even play a crucial part in this transition. The required offshore wind farm capacity and interconnector capacity in order to meet the climate goals is determined and compared with current developments, thereby addressing the need for the Hub and Spoke concept in the North Sea.

2.1 Offshore Wind Energy

In this section the development of offshore wind energy in the European Union is treated. The exponential rise in offshore wind energy capacity is explained, together with current project developments and future capacity requirements. There might be a capacity mismatch on which the Hub and Spoke concept could anticipate, thereby strengthening its business case.

2.1.1 Climate Goals

The EU energy system is changing significantly over the next decades due to a shift from fossil fuels to renewable energy sources (henceforth RES). Climate agreements are in force to restrict the rise in global average temperature and one of the possibilities to reach the agreements is by reducing the emission of greenhouse gasses (henceforth GHG). Humans are adding enormous amounts of it to the atmosphere by amongst others burning fossil fuels. The United Nations Framework Convention on Climate Change was the first step to restrict the rise in global average temperature, followed by the legally binding Kyoto Protocol (2005) and recently the Paris Agreement (2016). Countries promised to reduce GHG emissions and restrict the rise in global average temperature to well below 2°C relative to pre-industrial levels of 1990. Furthermore, efforts are pursued to limit the rise in global average temperature even further to 1.5°C. The EU has translated these climate agreements into energy strategies and published "Energy Roadmaps" to guide their Member States in achieving these goals. The European Energy Strategies and their corresponding targets are presented in Table 2.1.

Table 2.1: EU Energy Strategies resulting from Paris Climate Agreement with Targets Compared to Pre-Industrial Levels of 1990

EU 2020 Energy Strategy	20% reduction in GHG emissions
	20% share of renewable energy in final energy consumption
	20% reduction in primary energy consumption
EU 2030 Energy Strategy	40% reduction in GHG emissions
	At least 27% renewable energy in final energy consumption
	At least 27% reduction in primary energy consumption
EU 2050 Energy Strategy	80-95% reduction in greenhouse gas emissions

Between 1990 and 2014, the EU has already reduced its GHG emissions by 22.9% and the target for 2020 has already been met. The total share of RES is steadily growing and is also expected to reach the target for 2020. Energy efficiency is however expected to increase by only 18 - 19%, which means the target would barely be missed. There is still time available for Member States to improve efficiency even further and meet the target. The outlook on the nearest environmental targets looks promising, but future targets are more ambitious and harder to achieve. Larger efforts are required to keep up with the coming climate targets. (EC, b)

2.1.2 EU Energy Flow

The climate goals have a significant influence on the European energy production and consumption. The reduction of GHG emissions is realised in two ways: shifting from fossil fuels to renewable energy and increasing energy efficiency. The GHG emissions are thus being reduced by adjusting both energy supply and demand. The share of RES should become 20% of final energy consumption in 2020 and at least 27% in 2030. Primary energy consumption must be 20% more efficient in 2020 and at least 27% more efficient in 2030 compared to pre-industrial levels. It is good to be aware of the difference between final energy consumption and primary energy consumption, because these are not the same. Final energy consumption is the total amount of energy reaching the consumer, while primary energy consumption covers the total energy demand of Member States including consumption of the energy sector itself, transformation losses and distribution losses. The different kinds of energy consumption are visualised in the EU-28 energy flow over the year 2014, which is presented in Figure 2.1. Energy is expressed in million tonnes of oil equivalent (Mtoe), which is equal to 11,630 gigawatt hour (GWh).

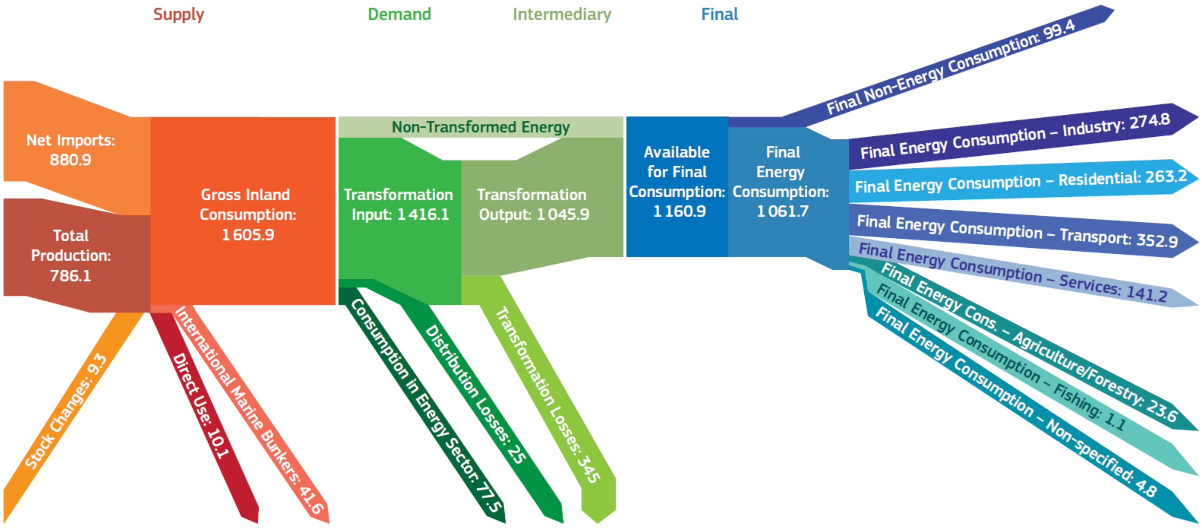


Figure 2.1: EU-28 Energy Flow 2014 in Mtoe (source: EC, 2016b)

The European Commission (henceforth EC) made the "Energy Model" for the energy system of their 28 Member States, which acts as a benchmark of current policy and market trends. The model shows the long-term influence of current policies and provides information on whether additional measures need to be taken. It is based on the assumption that all climate goals for the year 2020 are achieved and agreed policies at European and Member State level are all implemented. (Capros, 2016) The development of final energy consumption and primary energy consumption is presented in Figure 2.2. Reference is made to Appendix A for the full Energy Model output.

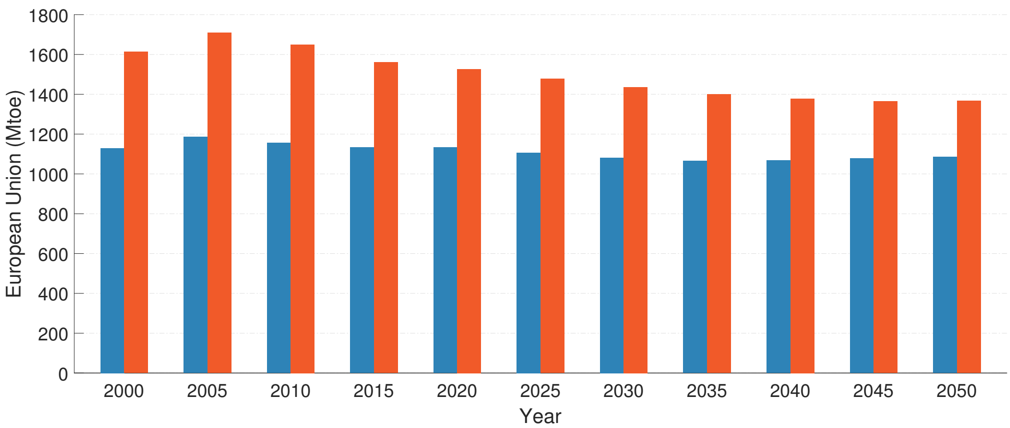


Figure 2.2: EU-28 Primary Energy Consumption (red) and Final Energy Consumption (blue) in Mtoe (source: Capros, 2016)

The above prediction helps to understand what the future energy demand will be and how much of this amount must be generated by RES. The climate goals for 2020 and 2030 are intermediate steps towards a low-carbon economy. These goals contain specific targets for RES and energy efficiency. The climate goal for the year 2050 is however not very specific and only mentions a reduction in GHG emissions by 80 - 95%, without the corresponding measures to achieve this goal. Therefore, the report “Energy Roadmap 2050” is written to identify the challenges for the energy system posed by this decarbonisation objective. Achieving the 2020 climate goals is not enough as this will only reduce GHG emissions by about 40%. Additional measures will thus be needed. Several decarbonisation scenarios have been examined which required 40 - 61% RES in primary energy consumption in order to achieve an 80% reduction in GHG emissions by 2050. (EC, 2012)

In 2050 the EU-28 primary energy consumption is estimated to be 1,367 Mtoe, which is equal to 15,904 TWh. The generated amount of electricity by RES should than be somewhere in the range of 6,362 - 9,701 TWh per year. This is based on the 80% lower limit of the decarbonisation objective, but it must be noted that the long term model forecast covers a very long period with consequently large uncertainties. Social, technological and behavioural changes can cause the energy system to alter significantly and predictions must therefore be updated regularly. (EC, 2012)

“Electricity production needs to be almost emission-free, despite higher demand. Our energy system has not yet been designed to deal with such challenges. By 2050, it must be transformed. Only a new energy model will make our system secure, competitive and sustainable in the long-run.”
- G.H. Oettinger, European Commissioner for Energy

2.1.3 EU Energy Mix

The composition of the EU energy mix must significantly change in order to reach the climate goals. The amount of renewable energy should increase, whilst simultaneously the use of fossil fuels should decrease. Renewable energy is generated from natural processes which are continuously replenished. It is an eternal form of energy and limits the impact on the environment with lower GHG emissions. The types of RES defined by the EC are hydropower (excluding pumping), wind energy, solar energy, geothermal energy, biofuels, renewable municipal waste and “others”. (EC, b) The class others contains RES with a negligible amount of generated energy, consisting of tidal-, wave- and ocean energy. Non-renewable energy sources are classified by the very long time it takes to be created or if the creation happened a long time ago and is unlikely to happen again. Fossil fuels like oil, coal, natural gas and nuclear power are examples of non-renewable energy. The Energy Model from the EC does not only indicates future energy demand and consumption, but also predicts the corresponding energy mix based on the assumption that all climate targets for the year 2020 are achieved. The predicted change of the EU-28 energy mix is presented in Figure 2.3.

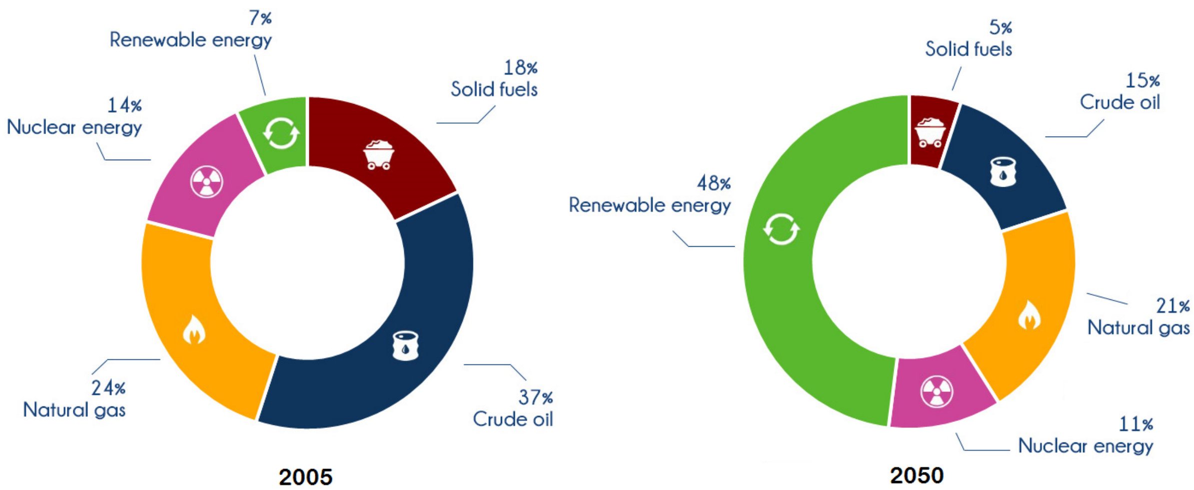


Figure 2.3: EU-28 Primary Energy Consumption by Source (source: EC, 2012)

2.1.4 Offshore Wind Energy Capacity

Part of the energy transition and contributing to the rise in RES is the installation of offshore wind turbines. By the end of 2016, Europe contained 3,589 operational offshore wind turbines with a cumulative capacity of 12.6 GW. This is however only the beginning as offshore wind energy is growing exponentially. There is currently 4.8 GW capacity under construction and another 24.2 GW of offshore wind farms has been consented by national governments to be developed in the near future. Contractors furthermore have submitted an additional 7.0 GW of projects about which national governments still need to make a decision and enough area is reserved to develop another 65.6 GW of offshore wind farms. The North Sea contains the majority of installed turbine capacity in Europe with 69.4% and also future capacity is expected to be mainly realised in this region. (WindEurope, 2017a) The development phases related to offshore wind energy capacity in Europe are shown in Figure 2.4.

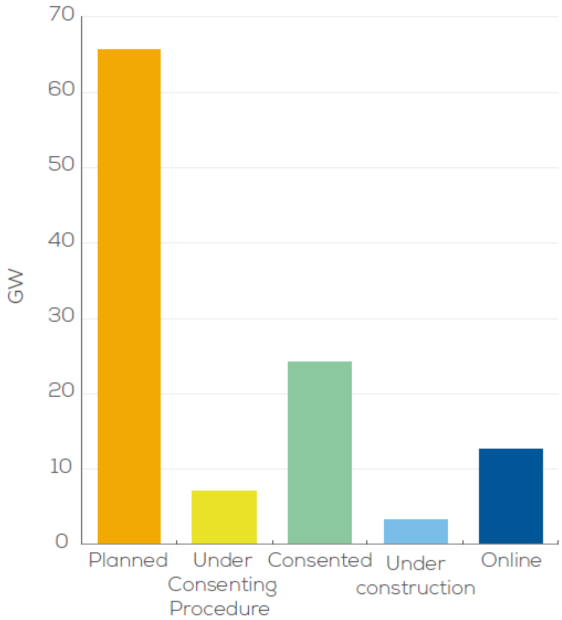


Figure 2.4: Development Phases of EU-28 Offshore Wind Energy Capacity (source: WindEurope, 2017a)

Installed capacity does however not say anything on the amount of generated electricity. The relation between capacity and amount of generated electricity is expressed with the capacity factor. The capacity factor is the ratio of actual electricity output over the maximum possible electricity output and this can be significantly different between various energy sources. In Figure 2.5 general capacity factors per energy source are presented. Energy sources which are constantly producing under optimal conditions achieve a maximum output with a capacity factor of 100%, but this is almost never achieved on a yearly basis as there is always time required to perform maintenance and repairs. Furthermore, supply must meet demand. Electricity is simply not always needed and this reduces the average capacity factor. Renewable energy sources however have a much lower capacity factor compared to common energy sources, because these forms of energy are dependent on local conditions. For example wind speed and sun intensity is variable and thus not always optimal, leading to lower capacity factors. More RES capacity is thus required to achieve the same amount of generated electricity by fossil energy sources. Between wind turbines there can also be significant differences. Offshore wind turbines have a higher capacity factor compared to onshore turbines, because the wind conditions offshore contain a higher- and more consistent wind speed. The annual capacity factor of offshore wind turbines in the EU ranges between 33 - 43%. (WindEurope, 2017a)

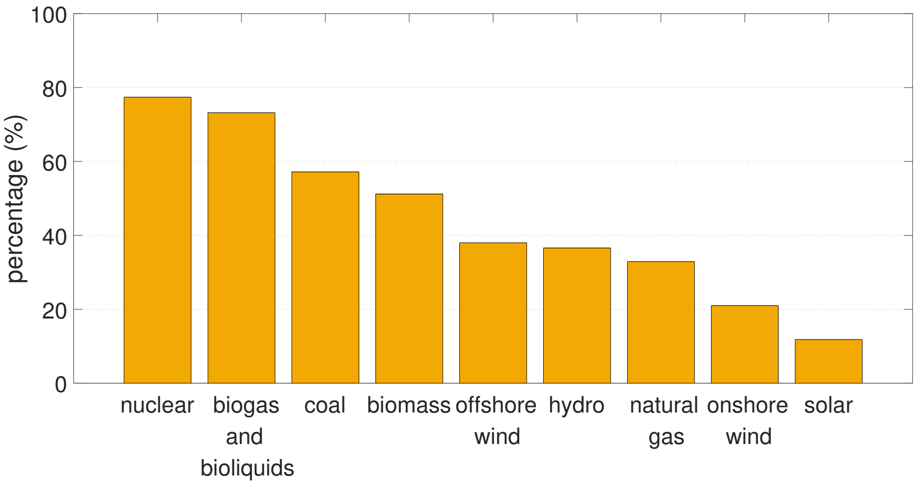


Figure 2.5: EU-28 Capacity Factors (source: EURELECTRIC, 2015)

The developments in installed capacity and capacity factor make it possible to approximate the future amount of generated electricity by offshore wind turbines. By the end of 2016, offshore wind farms with a total capacity of 12.6 GW were operational and generated a yearly output of 37 TWh. (WindEurope, 2017b) Assuming all projects are realised by the year 2050, this would lead to 114.2 GW operational offshore wind farms producing a yearly output of 335 TWh.

With the Energy Model it was already derived that 6,362 - 9,701 TWh per year must be generated by RES in order to achieve a low-emission economy by the year 2050. In 2015, wind energy accounted for 12% of RES in primary energy consumption and is predicted to rise to 23% by 2050. (Capros, 2016) The Energy Model does however not make a distinction between onshore and offshore wind energy. To determine the required amount of generated electricity by offshore wind turbines in 2050 the current ratio between onshore and offshore wind energy capacity is used and assumed to stay constant in time. This is a conservative assumption as onshore wind energy is a more mature industry, while offshore wind energy is a development of the last two decades and capacity is increasing exponentially. By the end of 2016, a total of 296 TWh was generated by all wind turbines in Europe of which 259 TWh onshore (87.5%) and 37 TWh offshore (12.5%). (WindEurope, 2017b) Assuming this ratio will stay constant in time, Europe would require 183 - 279 TWh electricity per year generated with 62.3 - 95.0 GW offshore wind farms in order to meet the decarbonisation objective by the year 2050.

2.1.5 Conclusion

It can be concluded that Europe has already reserved enough space to install the required offshore wind energy capacity for a low carbon economy by 2050. The fixed ratio between onshore and offshore wind energy capacity is unlikely, but even if this percentage would shift towards offshore wind energy there is not a large capacity gap which the Hub and Spoke concept could fill. The development of the Hub and Spoke concept would thus increase the total offshore wind energy capacity or be at the expense of already planned offshore wind farms. However, the majority of offshore wind farms still needs to be constructed. If the concept proves to be more efficient compared to "business-as-usuall" it could lead to considerable cost savings, thereby making it more competitive with common energy sources and accelerating the development of RES.

2.2 Integrated EU Electricity Grid

The production of RES is dependent on the local conditions and this makes their energy output less predictable compared to fossil fuels. The increase of RES in the energy mix will thus lead to a more unstable energy system where electricity demand is harder to match with supply. Currently, the energy system is designed to match consumer demand at all times, but additional infrastructure measures need to be taken when more and more energy is being generated with less predictable RES in order to avoid insufficient electricity generation.

2.2.1 RES Causing Black-Outs

The need for additional infrastructure measures to RES was clearly illustrated in Southern Australia in February 2017. A heat wave caused a lot of people to simultaneously turn on their airconditioning and this resulted in a major black-out for approximately 40.000 people. It was already the third black-out of the year. The country is subsidising renewable energy to such extent that wind energy became cheaper compared to conventional energy sources like coal and gas plants. Last year another coal plant was shut down and wind energy is now responsible for one third of the electricity production in Southern Australia. Due to the recent black-outs the question now arises if there is still enough back-up capacity in times when there is hardly any wind blowing and insufficient energy is being generated. According to prime minister Malcolm Turnbull the "ideological obsession with renewable energy" is at the expense of security of supply and caused the recent black-outs. This is contradictory to his earlier statement in 2010, where he advocated Australia to "head for a situation where all, or at least almost all of our energy should come from sources which do not or barely emit GHG". This event is also relevant to Europe as it strives to significantly reduce its GHG emissions by increasing its share of RES. The incident shows the vulnerability of a large share RES in the energy mix and expresses the need for additional infrastructure measures in order to cope with the greater volatility in production. (Grol, 2017)

2.2.2 Measures to Mitigate Generation Peaks

There are various methods to increase grid stability. The three most commonly used methods to provide a more constant power output are:

- Fossil Back-Up Capacity
- Interconnection Capacity
- Energy Storage

The black-outs in Southern Australia were caused by a combination of insufficient back-up capacity and insufficient connection capacity to neighbouring parts of the grid. In case the coal and gas plants would have been kept idle instead of completely closed, these polluting energy sources could kick-in with a constant electricity supply and anticipate on the shortcomings of RES. In a "capacity market" polluting energy sources with a constant output should be compensated for the time they do not produce electricity, but provide electricity in times of need to maintain a stable grid.

Another method to flatten generation peaks is to increase interconnection capacity with neighbouring markets. In times of insufficient generation, electricity can be imported from neighbouring markets which results in a more reliable and stable grid.

It is also possible to store energy in times of abundant supply and release it back to the grid in times of higher demand. Energy storage can be done in many different forms of which stored hydro power is the most well known and large scale example. An additional advantage of energy storage is the price difference. Energy is stored in times of abundant supply when prices are low, while the energy is released back to the grid in times of high demand and when prices are higher. However, the structures to store energy cost money as well. Large hydro storage in Norway makes use of natural geographic elevations and can therefore be constructed relatively cheap, but other storage methods like physical batteries, compressed air tanks, thermal pumps or flywheels can not yet be used on such a large scale and are too expensive.

Other methods to increase grid stability and sustainably implement RES are also possible, but these are less likely to become the dominant solution and will be applied in combination with one or several of the above mentioned methods. Smart grids is one of these solutions. Implementing sensors to different parts of the grid give information on energy use to home owners, factories and energy producers. Consumers get insight to their consumption pattern and can change their behaviour to save on electricity and expenses. Charging electric vehicles can for example be done during the evening when electricity demand and prices are lower, thereby adjusting electricity demand to the prevailing supply. Energy producers on the other hand get better feedback from their consumers and can anticipate more rapidly on changing demand or failing power lines. Micro grids can also be used to increase security of supply. Generation sources are applied on a much smaller scale, which are decentralised and operate independently from the larger grid.

This is basically a form of small scale back-up capacity and is already applied to important buildings like hospitals, but it will not provide a structural solution to the increasing volatility caused by RES.

2.2.3 Internal Energy Market

The EU is choosing completely for the development of additional connection capacity. The envisioned energy system is called the Internal Energy Market (henceforth IEM), where all Member States are sufficiently connected and backed-up by rapid and predictable gas fired plants. The IEM is created because of two reasons. First, the electricity markets are liberalised to achieve an overall welfare gain by increased competition, trade and lower electricity prices. Historically, countries have developed their electricity grid to become self sufficient and this has led to the very fragmented European energy system as we know it today. The second reason is the rise of RES in the energy mix. The fragmented national markets can be compared with the event in South Australia and additional infrastructure investments need to be made to strengthen security of supply.

Previously, connections with neighbouring electricity markets were primarily being made to increase security of supply. In case of a sudden drop in production, electricity could be imported from neighbouring markets to keep the grid stable and prevent black-outs. The development of RES is done on a much larger scale and the current interconnection capacity with neighbouring countries is no longer sufficient. Electrical infrastructure is high on the European agenda as it is crucial for a carbonised economy with increasing levels of RES. (Jacottet, 2012; EC, 2015)

"There cannot be an increase in renewables without an increase in interconnections."
- Miguel Arias Cañete, EU Climate and Energy Commissioner

2.2.4 Required Interconnector Capacity

The European Commission has introduced interconnection targets to realise the IEM. By 2020, every Member State should have at least an interconnection capacity of 10% of its installed electricity production capacity. Furthermore, the European Council encourages their Member States to continue new installations and achieve at least 15% interconnection capacity by the end of 2030. (EC, a) An overview of the interconnection capacities for countries surrounding the North Sea is presented in Table 2.2. Information on the interconnection capacity of Norway is not included as the country is not a Member State of the EU.

Table 2.2: Interconnection Capacity and Share of RES of North Sea Countries (sources: EC, 2016b, 2015)

Country	**Installed Electricity Capacity (MW)**	**Interconnection Capacity (MW)**	**Share of RES (%)**
Belgium	20,919	3,500 (17%)	8%
Denmark	13,655	6,000 (44%)	29%
Germany	198,416	19,800 (10%)	14%
Netherlands	31,762	5,400 (17%)	6%
Norway	-	-	-
United Kingdom	97,009	5,800 (6%)	7%

It can be seen in Table 2.2 that almost all Member States surrounding the North Sea have already achieved the interconnection target by the end of 2014. Only the United Kingdom is not yet satisfying the target, but several projects are still under construction and they are expected to reach it as well. (EC, 2015) However, it must be noted that the interconnection target was initially supposed to be met by the end of 2005. Experts furthermore question the height of the target itself. The European Commission was not able to provide reports which indicate the required interconnection capacity for a functional IEM and it is furthermore questionable if the same level of interconnection capacity should apply for every Member State. Geographical location and the national energy mix would suggest a different percentage interconnection capacity per Member State. The defined goals are rather arbitrary, but experts do agree on additional investments in the electricity grid. There is however no consensus on the most suitable solution and which part of the energy grid should get priority. (Jacottet, 2012; Van Renssen, 2015)

Interesting to notice is the high percentage interconnection capacity and share of RES in Denmark. The black-outs in Southern Australia were caused by a combination of limited infrastructure and high share of RES. This coherence is clearly visible for Denmark, which contains a relatively higher share of RES compared to the other countries and the interconnection capacity is therefore also higher in order to balance the grid. In times of plentiful supply the electricity is sold to neighbouring countries and electricity is imported when the RES do not generate sufficient electricity to meet demand. Denmark can be seen as a forerunner in the energy transition and shows the importance of sufficient interconnection capacity.

The Lappeenranta University of Technology created the "Internet of Energy Model", which simulates a global energy system running on 100% RES. The goal of the model is to find the most economically beneficial energy mix and presents the corresponding storage and transmission capacity to match demand with supply. The storage- and interconnection capacities for the countries surrounding the North Sea are shown in Table 2.3.

Table 2.3: Energy System Simulation with 100% RES (source: Berrill et al., 2015)

Region	**Installed Electricity Capacity (GW)**	**Energy Storage (GW)**	**Interconnection Capacity (GW)**
BeNeLux	77.0	21.3 (28%)	29.1 (38%)
British Islands	186.6	25.1 (13%)	39.7 (21%)
Denmark	24.6	3.7 (15%)	20.5 (83%)
Germany	249.1	60.0 (24%)	77.8 (31%)
Norway	79.9	11.5 (14%)	21.9 (27%)

Comparing the results of the Internet of Energy Model with the interconnection targets set by the EC directly shows a different outcome. As already expected by industry experts, the Internet of Energy Model shows different percentages of interconnection capacity per country in combination with energy storage. It must be noted that energy storage is at the expense of interconnection capacity, but will only become attractive when the share of RES reaches levels of roughly 70%. (Beurskens, 2017) The goals set by the EC can not be directly compared with the Internet of Energy Model as they include different infrastructure solutions and are based on different future scenarios. However, it can still be concluded that countries need to install additional interconnection capacity in order to reach a low carbon economy.

2.3 Conclusion

The European energy system is significantly changing the next coming decades. There is a shift from fossil fuels to RES in order to reduce the rise in global average temperature and to achieve the climate agreements. Offshore wind energy is one of these RES, which is being increasingly installed in the North Sea. It can however be concluded that there is not a large capacity gap in offshore wind energy in order to reach a low carbon economy by 2050. Europe has already reserved enough space to install the required capacity. Assuming all future projects are realised this would lead to a total of 114.2 GW offshore wind farms, while it is estimated that only 62.3 GW to 95.0 GW is required. The development of the Hub and Spoke concept would thus increase the total offshore wind energy capacity or be at the expense of already planned offshore wind farms.

The rising share of RES in the energy mix is however also causing problems. Renewable energy is dependent on local conditions like sunlight and wind speed, but these conditions are not always optimal and the energy production is therefore becoming increasingly unstable. The current energy system is designed to match consumer demand at all times, but additional infrastructure must be created in order to avoid insufficient electricity production and prevent any black-outs. The main three methods to keep energy production stable are fossil back-up capacity, interconnection capacity and energy storage. The EU fully chooses to increase interconnection capacity and achieve a European wide Internal Energy Market. This aspect of renewable energy is getting little media attention, but it is very high on the European agenda and as the EU Climate and Energy commissioner Miguel Arias Cañete already stated: "There cannot be an increase in renewables without an increase in interconnections." The EC has therefore introduced targets. By 2020, every Member State should have at least an interconnection capacity of 10% of its installed electricity production capacity and Member States are furthermore encouraged to achieve at least 15% interconnection capacity by the end of 2030. Most Member States have already met the targets, although experts question if these percentages are sufficient and if the same level of interconnection capacity should apply for every Member State. The “Internet of Energy Model” from the Lappeenranta University of Technology proved that interconnection capacity is a function of geographical location and the national energy mix. The percentage interconnection capacity is thus varying between countries, although absolute interconnection capacities could not be provided as the “Internet of Energy Model” is not based on the European climate agreements or Internal Energy Market.

The installation of RES and electrical infrastructure are two very important goals of the EU. Despite the lack of a direct need for additional capacity, the vast majority of offshore wind farms still needs to be constructed and it is very likely that additional interconnection capacity is required. The Hub and Spoke concept combines these functions and if it proves to be less expensive compared to “business-as-usuall” it could still be the preferred method and possibly accelerate the realisation of an Internal Energy Market.

3 ENVIRONMENTAL ANALYSIS

In this chapter an overview is given of the major marine uses in the North Sea. The activities are explained, their respective area's in the North Sea are visualised and their co-existence with offshore wind farms and other marine uses is determined. Dogger Bank will be treated in more detail, because this region is seen as the most suitable location for the Hub and Spoke concept. The required area for the Hub and Spoke concept is determined and conflicting interests with other marine uses are qualitatively described. Finally, expert opinions are included and a general consensus is derived on the spatial integration of the Hub and Spoke concept in the North Sea.

3.1 Exclusive Economic Zones

Territorial waters extend to 12 nautical miles (19.3 km) from the coastline in which national laws apply. Further from shore countries still have rights to for example mine for resources or generate electricity with RES. This region is called the Exclusive Economic Zone (henceforth EEZ) and extends to 200 nautical miles (370.4 km) from the coastline. However, the North Sea is a relatively small sea basin and these zones would overlap each other. The Exclusive Economic Zones in the North Sea have therefore been determined by the surrounding countries and are laid down in multiple treaties. These zones are presented in Figure 3.1. (Noordzeeloket, 2017)

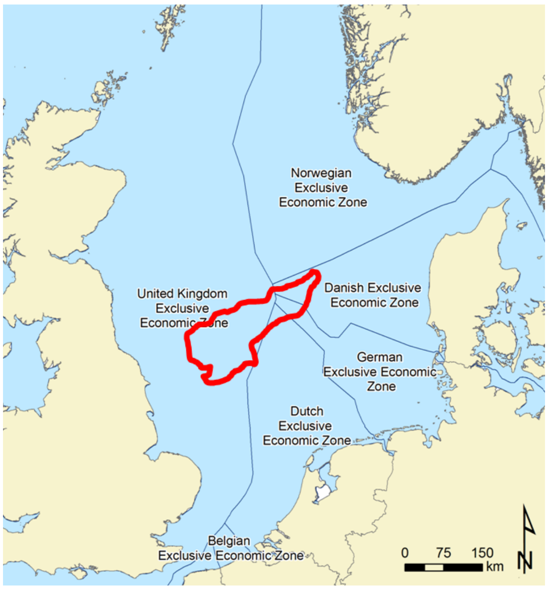


Figure 3.1: North Sea Exclusive Economic Zones with Dogger Bank (red)

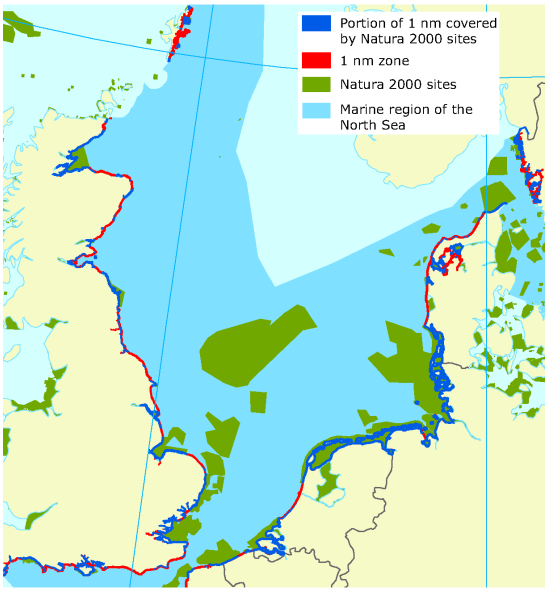


Figure 3.2: North Sea Natura 2000 Areas

3.2 Dogger Bank

Dogger Bank is mentioned several times as a possible location for the Hub and Spoke concept, because the area contains shallow water conditions and is centrally located in the North Sea. Dogger Bank is a sandbank which was formed during the last glacial period when large sheets of ice coming from the north pushed forward and deposited sediment. In time the sediment has been reshaped due to various environmental conditions, leading to a complex geography both in vertical and lateral direction. Archaeologists have found mammal remains and evidence of human activity at this location, indicating Dogger Bank was formerly situated above sea level and connected the United Kingdom with Europe. After the last glaciation the sea level gradually rose and completely covered the area with water.

The sandbank as we know it today covers around 17,600 km^2 and is roughly 20 m higher compared to the surrounding seabed. Dogger Bank is presented in Figure 3.1. The depth varies between 15 - 35 m and is shallowest at the western side located in the EEZ of the United Kingdom. Most area of Dogger Bank is also situated in the EEZ of the United Kingdom, after which it extends to the Netherlands, Germany and a small part of Denmark. The region is also very popular amongst fishermen as the shallow water depth and hydrodynamic conditions result in a rich biodiversity. Fishermen have already used this location for centuries and eventually got the sandbank its name after the Dutch fishing boats called *doggers*, which were used in the 17th century. The area is a geological anomaly with special hydrodynamic processes, causing the region to house a variety of species and making it an important location due to its high ecological value. Dogger Bank has therefore been appointed Natura 2000 territory. (Britannica, 2016)

3.3 Natura 2000

Natura 2000 is a European network of protected areas with high ecological value. These areas are presented in Figure 3.2. The goal is to stop the loss in flora and fauna and prevent nature becoming increasingly uniform. Threatened species and their natural habitat are preserved to remain the biodiversity in the region. The responsible authority for the region, which may be a province or ministry, determines the management plan for the area in cooperation with all involved stakeholders. These regions are however not nature reserves in which any human activity is forbidden. Certain activities like fishing are allowed, although it must be done in a sustainable manner and the present ecological state must be preserved at all times. The conservation of Natura 2000 areas is combined with sustainable use of space. Sea basins need to be managed sustainably, both ecologically and economically. (EC, 2017)

Developers often avoid Natura 2000 areas as these zones bring along many additional project requirements and demand a lot of studies on the ecological impact. It is however not forbidden to construct something in Natura 2000 areas as long as the present ecological state is conserved. Recently, four offshore wind farms have been consented on Dogger Bank in the EEZ of the United Kingdom. The project areas Teesside A, Teesside B, Creyke Beck A and Creyke Beck B are each 500 to 600 km2 large. These zones are much larger than the offshore wind farms eventually require, but this concept allows developers to select the most beneficial location and construct the offshore wind farm with the highest economical value. After construction has finished, the remainder of the project area is handed back to the government and might be used for additional offshore wind farms in the future. It is thus possible for offshore wind farms to be constructed on Dogger Bank, but simultaneously it may impact the feasibility and necessity of the Hub and Spoke concept at this location.

3.4 Spatial Integration of the Hub and Spoke Concept

The Hub and Spoke concept concentrates offshore wind farms and becomes a central hub for electricity trade between countries surrounding the North Sea. Offshore wind farms already require a lot of space and the concept will thus have a very significant impact on marine uses in the area. The size of the project can be determined by the limiting length of AC infrastructure. One of the major advantages of the Hub and Spoke concept is being able to use common and cheaper AC infrastructure for offshore wind farms, while being far away from the national coastlines. The concept increases available area for offshore wind energy and will lead to considerable cost savings. AC Infrastructure is used up to distances of 60 - 100 km (ABB, 2012), above which the cable losses become unacceptably high and more expensive DC infrastructure would be required. The latter type of infrastructure is however much more expensive and one of the reason to develop the Hub and Spoke concept in the first place. The offshore wind farms are thus limited to a 60 - 100 km radius around the artificial island and the whole project could potentially cover 11,300 km2 to 31,400 km2. The spatial integration of the Hub and Spoke concept located on Dogger Bank is presented in Figure 3.3. It does however not mean that the entire area will be used for offshore wind farms and should be kept free from any other activities.

In the media offshore wind farm capacities for the Hub and Spoke concept are mentioned between 30 GW and 100 GW. (TenneT, 2016; Energinet.dk, 2017) The total capacity can be converted to number of wind turbines and subsequently converted to area. Technological developments in offshore wind turbine design go very rapid and there is a trend of installing ever larger wind turbines with higher capacities. The same amount of electricity can be generated with fewer turbines, but it must be noted that the amount of installed capacity per area stays roughly equal as the intermediate distance between turbines must increase as well. In Figure 3.4 the wake effect behind offshore wind turbines at Horns Rev II is visualised due to low laying fog. Wind turbines extract energy from the passing air flow and disturb the flow pattern behind the turbine. Wind speed in this wake is reduced and the flow is very turbulent.

The turbines located in the second and following rows will face these wakes and generate less electricity. Turbines with a higher capacity contain larger rotors and thus create larger wake fields. The effect of wakes must be kept as small as possible and larger turbines are therefore positioned further from each other. Therefore, the amount of installed capacity per area remains roughly constant at 7 MW / km^2 despite the turbine capacity. (Meijden, 2016) The required area for the Hub and Spoke with 30 GW to 100 GW capacity is therefore approximately 4,300 km2 to 14,300 km2.

Wake effects strongly influence the energy production of the entire offshore wind farm. The wake spreads as the disturbed flow moves further downstream and will change back to the main steam conditions, but this disturbance can be felt even 100 to 200 km downstream. On the long term the decrease in wind speed caused by wakes could reduce the total wind farm production with up to 50%. (Beurskens, 2017) More and more offshore wind farms are being build in the North Sea and it is also happens that multiple offshore wind farms are being constructed next to each other. This is for example the situation between the EEZ border of the Netherlands and Belgium. There is a lot of knowledge on single offshore wind farms, but the cumulative effect of multiple offshore wind farms close to each other has never been experienced in practice. The Hub and Spoke concept will develop offshore wind farms on an even larger scale and the cumulative wake effects have to be included in the design. Several corridors must very likely be included to reduce the impact of wake effects and give the wind pattern the ability to get back to its original state. (Beurskens, 2017) This might explain the difference between the possible area following from the limiting length of AC infrastructure and the area following from the Hub and Spoke capacities mentioned in the media. Building the entire site with offshore wind turbines would be very uneconomical due to the large cumulative wake effects. Corridors must likely be included and this makes it possible to combine the Hub and Spoke concept with other marine uses in the North Sea.

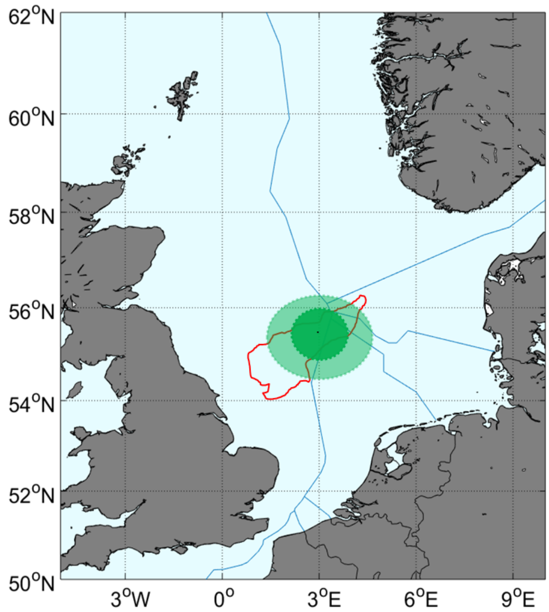


Figure 3.3: Area Indication of the Hub and Spoke Concept: 60 km Radius (dark green) to 100 km Radius (light green)

Figure 3.4: Wind Turbine Wake Effect at Horns Rev 2 (source: Vattenfall, 2017)

3.5 Marine Uses

The Hub and Spoke concept covers a very large area of approximately 4,300 km2 to 14,300 km2. The North Sea is however already one of the most intensively used sea basins in the world with a variety of marine uses. Offshore wind farms require relatively a lot of space and the construction is not only limited to cost and revenue. Other activities must be included in the design in order to achieve a sustainable marine spatial planning. This requires a thorough understanding of all other marine uses in the area. An overview of the major uses in the North Sea is presented in Figure 3.5.

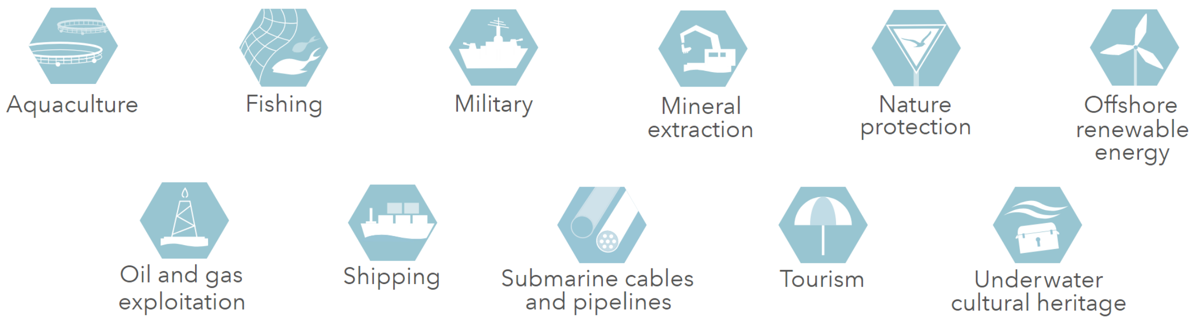


Figure 3.5: North Sea Marine Uses

Aquaculture
Available fishing areas in the North Sea are declining due to amongst others the development of offshore wind farms and assigned Natura 2000 territories. Furthermore, there is a lot of public pressure on the industry. Waters all around the world are systematically subject to overfishing to meet the global rising demand for food. The marine ecosystem is negatively impacted and ways are being sought to make the industry more sustainable. Aquaculture might be a solution which is the breeding, rearing and harvesting of plants and animals in water. At the moment aquaculture is not yet being performed in the North Sea, but governments are already looking for possibilities to combine it with offshore wind farms. Over the next few years the first pilot projects are expected to start and this will prove the technical and economical viability of aquaculture in the North Sea. (Dutch Ministry of Infrastructure and Environment; and Dutch Ministry of Economic Affairs, 2015)

Fishing
Fishermen on the North Sea must comply with EU regulations. The Common Fisheries Policy is active to maintain a sustainable fish population and prevent overfishing. These regulations include permitted locations to fish, amounts of fish to be caught, the period and/or fishing days, permitted engine capacity, fishing gear and techniques. In the Dutch EEZ fishing activity is furthermore not allowed in offshore wind farms, shipping routes, approach areas, clearways, closer than 500 m from oil or gas platforms, above ammunition dumps and partly or completely in Natura 2000 areas. (Noordzeeloket, 2016) On a national level there are however still some significant differences. The fishing industry in the Netherlands is complaining, because more and more area is used for offshore wind farms while it is forbidden to fish at these locations. Fishing nets drag along the seabed and could damage the cables. This results in a structural loss of fishing territory. In France and the United Kingdom it is however allowed to fish between offshore wind turbines. Fishing activity is included in the design and cables are buried to greater depths. It is thus possible to combine fishing activity with offshore wind farms, although this must be included in the design and would require greater investments. Eventually it is a political decision between the risk of damage to offshore wind farms and increased investments. (Berends, 2016)

Military
The North Sea contains several reserved areas for military activities, including flight exercises, artillery exercises and exercises in mine disposal. During military exercises these zones are restricted to all other users, but otherwise the area is open to other activities. The North Sea is getting more intensively used and multifunctional use of military zones is becoming more relevant. These areas can possibly be combined with other functions like temporary sand extraction, although co-existence with permanent structures like oil and gas platforms or offshore wind farms is not possible and would require a permanent change in function of the area. (Noordzeeloket, 2016)

Mineral Extraction
Surface mineral extraction in the North Sea is done for sand, gravel and shells. Sand extraction in specified areas is very common and is used for coastal replenishment and filling material. Extraction of sand to maintain the coast is expected to increase in the coming decades due to sea level rise. Shell and gravel extraction is much less common and does not have appointed areas. The morphological and ecological effects of surface mineral extraction must be determined for the specific location and negative consequences on nature and other uses must be mitigated as much as possible. Before extraction starts, the area is scanned for cultural, historical and archaeological objects which could hinder extraction ac-

tivities in case of their presence. Sand extraction in the appointed areas is given priority, but other uses in the area are in general also possible. Fixed structures like oil and gas platforms, offshore wind farms and cables and pipelines can however not be combined. Planning and granting of permits for cables or pipelines in surface mineral extraction areas must therefore be done in cooperation with the mineral extraction industry. An overview of the extraction areas in the North Sea is presented in Figure 3.6, although these locations can easily change over time. (Noordzeeloket, 2016)

Nature Protection
The North Sea is home to a variety of organisms with vast areas of importance to birds, fish and marine mammals. The suitable living environment is created by the water depth differences, food availability, salinity conditions, currents and seabed material. The ecosystem in the North Sea functions properly. It is resilient, the water is clean and space is used sustainably. Regulations are in force to maintain these beneficial conditions and areas with high ecological value get appointed Natura 2000 territory. Habitats and species in these regions are protected to stop the loss in flora and fauna and maintain the present biodiversity. These areas are not forbidden to other marine uses, but the present ecological state must be preserved at all times. (Noordzeeloket, 2016)

Offshore Renewable Energy
The European Union is shifting towards renewable energy sources to reduce the rise in global average temperature, anticipate on depleting fossil fuel sources and become less dependent on energy from other countries. Offshore wind energy is a very important part in this transition and it is the main renewable energy source in the North Sea. With 69.4% the North Sea contains the majority of installed offshore wind energy capacity in the European Union and it is also the main location for future offshore wind farms. (EWEA, 2016) Offshore wind farms require however a lot of space, while other marine uses in the area are most of the times forbidden to reduce the risk on damage. There are plans to make offshore wind farms accessible to other activities and achieve multifunctional use of space, but until then offshore wind farms require a lot of area which is not available to other marine uses.

Oil and Gas Exploitation
The first license to extract oil and gas in the North Sea was issued in 1964, followed by decades of new discoveries of oil and gas fields. Nowadays, the North Sea is dotted with offshore oil and gas platforms and reached a total of 1,420 platforms by the end of 2015. This makes it one of the regions with the highest density offshore platforms in the world. However, according to the United Kingdom and Norway more than half of the North Sea oil reserves have been extracted and production is expected to drop. The recent drop in oil prices in combination with the depletion of oil and gas fields causes the amount of operational platforms to decline. It is obligated by law to remove out of service platforms and it is estimated that over 500 platforms need to be removed in the next few decades, although it is very uncertain when exactly these platforms are going to be removed. (Callahan) Other marine uses should be outside a 500 meters radius from offshore oil and gas platforms to prevent any possible damages. Installing new offshore platforms therefore affects all other uses, although offshore wind farms are most conflicting as they require a lot of space and are often overlapping with oil and gas fields. Permits granted for offshore wind farms include a provision on oil and gas extraction, making close cooperation between these industries an absolute necessity. (Noordzeeloket, 2016)

Shipping
The North Sea contains multiple major harbours and is one of the busiest sea basins regarding shipping traffic. Specific routes are constructed to connect these harbours to the rest of the world, while taking obstacle areas and caution zones into consideration. This has led to an international system of shipping routes and separation zones governed by the International Maritime Organisation (IMO). The shipping routes are maintained to certain depths and provided with aids to navigation to ensure a safe environment for ships. Shipping routes are available to all kinds of vessels including fishing boats, pleasure crafts and mineral extraction vessels. Shipping traffic gives little nuisance to other activities and most marine uses can easily be combined. Fixed structures must however be avoided and shipping traffic is therefore conflicting with oil and gas platforms and offshore wind farms. The planning of new offshore wind farm areas and oil and gas platforms is therefore done in close cooperation with the shipping industry. Especially wind farms use a lot of space and just like offshore platforms they stay at the same location for decades. Permits for offshore wind farms are therefore granted while taking into account future shipping developments as much as possible. (Noordzeeloket, 2016)

Submarine Cables and Pipelines

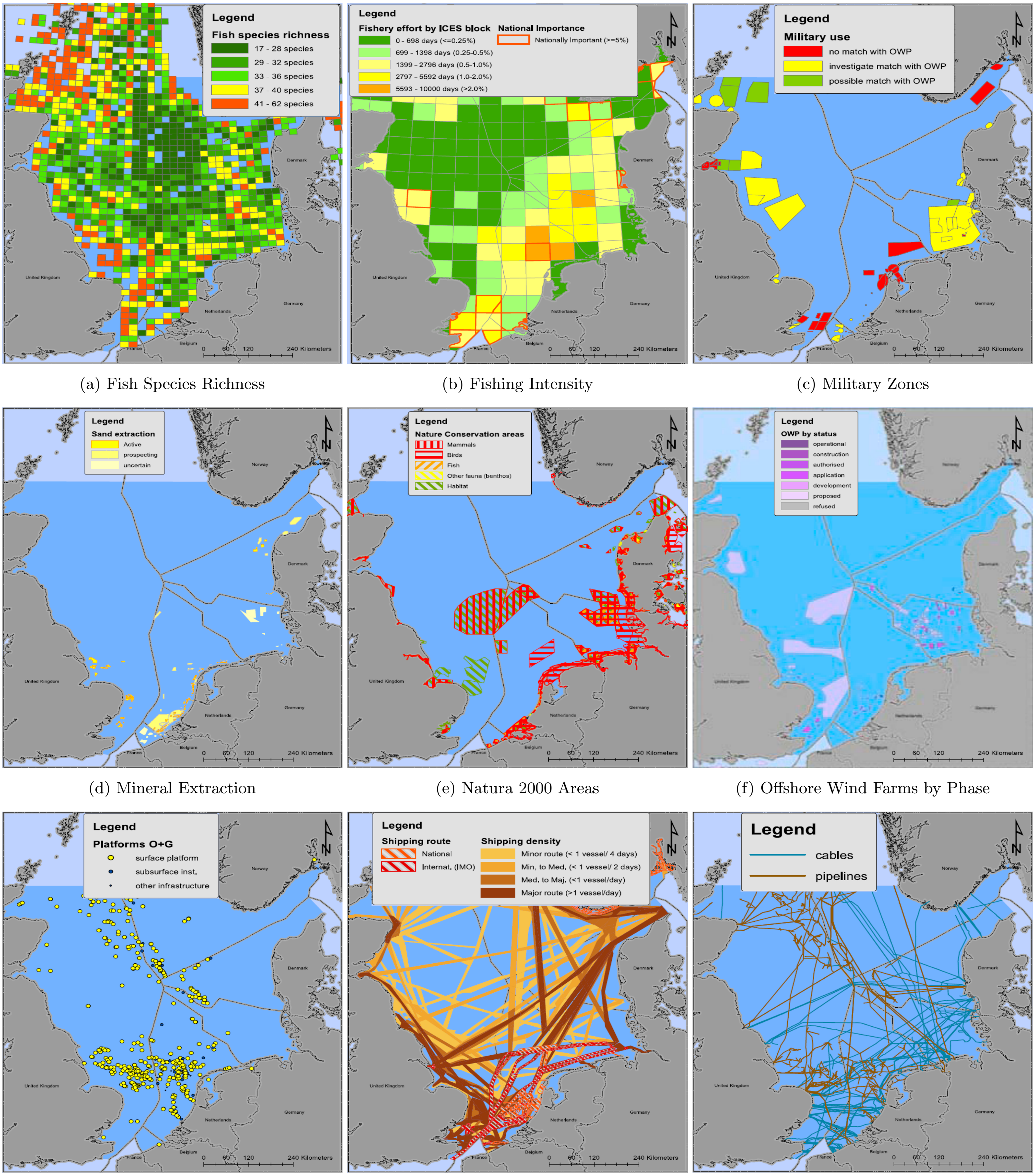
Vast amounts of cables and pipelines are situated on the bottom of the North Sea and this is expected to further increase due to growing telecommunication needs and the large scale development of offshore wind farms. Their function varies from telecommunication to the transportation of oil, gas or electricity. Cables and pipelines in the North Sea consisted of 2,500 individual connections which covered over 45,000 km by the end of 2013. (Oil & Gas UK, 2013) Cables and pipelines are almost always buried to avoid interaction with other uses like equipment from fishing boats dragged along the seabed or dropped anchors from shipping traffic. It is a trade-off between increased installation cost and the consequence of failure. Cables and pipelines furthermore contain a 500 m to 1,000 m free zone on both sides of the cable in which offshore wind farms, sand extraction and anchoring areas are forbidden. These zones might give some nuisance to other marine uses, but are enforced to prevent any damage to the cable and new cable zones are updated on maritime navigation maps as soon as possible. (Noordzeeloket, 2016)

Tourism and Recreation

The North Sea and its coastline is also used for recreational purposes. Amongst others tourists, bathers, surfers, sailers and fishermen are active in this region and governments are responsible to provide safe recreational areas. Recreation is allowed in military zones when no exercises are performed and shipping routes are open to all vessel types, although pleasure craft usually choose to avoid these busy shipping routes. In the Netherlands it is forbidden to sail through offshore wind farms, although the Dutch government is making this possible in the near future and in some other countries like the United Kingdom and France it is already allowed. Recreation is often located in natural areas and this could have a negative impact on flora and fauna. This problem can however be mitigated by for example closing off certain areas during breeding, spawning or migrating seasons. The key is to find a good balance between economic interests and natural values, but in general it is possible to combine nature with other marine uses. (Noordzeeloket, 2016)

Underwater Cultural Heritage

Some then thousand years ago the North Sea consisted of land which was used by our remote ancestors. They used the land to hunt and collect items of which remains are still conserved on the seabed. These objects contain valuable information about our past and have social, cultural and historical significance. Eventually the land flooded and the North Sea was created as we know it today. For centuries these waters have also been used by fishing boats and transportation vessels. The conditions at sea could be very harsh and in time many ships have sunk, leaving even more objects from the past laying on the seabed. However, increasing use of the North Sea makes the conservation of archaeological values ever more important. Known locations of valuable objects can possibly be combined with other functions or else the objects can be retrieved to surface. Known archaeological values are incorporated in marine spatial planning and should be taken into account with the planning of other marine uses. (Noordzeeloket, 2016)



(a) Fish Species Richness (b) Fishing Intensity (c) Military Zones

(d) Mineral Extraction (e) Natura 2000 Areas (f) Offshore Wind Farms by Phase

(g) Oil and Gas Platforms (h) Shipping Routes and Density (i) Cables and Pipelines

Figure 3.6: North Sea Marine Uses (source: Jongbloed et al., 2014)

3.6 Interaction between Marine Uses

The interaction between offshore wind farms and other marine uses is schematised in Figure 3.7. The functions can either exclude each other, are possibly compatible or have a positive effect in which one function improves the condition for other uses. Arrowheads indicate the function with a stronger claim on space in case a trade-off needs to be made. It can be seen that offshore wind farms are difficult to combine with other functions and contain a weaker claim on space compared to shipping routes, oil and gas platforms and cables and pipelines. The limited possibility of co-existence is unfortunate as most of the other activities are compatible with each other or contain possibilities to do so. The Hub and Spoke concept is very big in size and will thus have a significant impact on the other marine uses in the North Sea. The North Sea is already one of the most intensively used sea basins and all affected activities must be included in the design in order to maintain sustainable use of area.

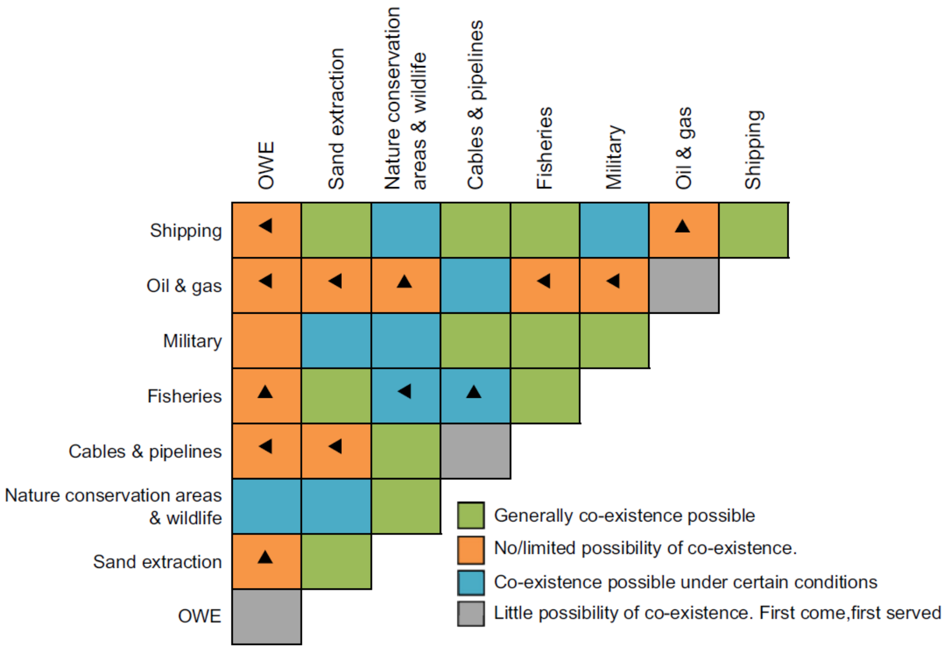


Figure 3.7: Interaction between Marine Uses (source: Jongbloed et al., 2014)

3.7 Conclusion

It can be concluded that the North Sea is already an intensively used sea basin with a variety of human and ecological activities. The Hub and Spoke concept requires a very large area of approximately 4,300 km2 (30 GW) to 14,300 km2 (100 GW) and the integration with other marine uses will thus be extremely complex, especially because the interaction between offshore wind farms and other marine uses is often limited or not even possible at all. However, at the moment there are already locations reserved for offshore wind farms which would become free to other marine uses. (Gotje, 2017)

Dogger Bank contains an additional complication. The Hub and Spoke concept is envisioned to be realised on this very large sandbank due to the shallow water conditions and central location in the North Sea, but its unique characteristics make it also very favourable to a variety of species. The high ecological value made the region Natura 2000 territory. Human activities are however still allowed in the region and just recently four offshore wind farms have been consented by the United Kingdom, but it severely complicates projects as the present ecological state must be preserved at all times. The general consensus of environmental organisations is not yet known, but experts are assuming that opposing environmental organisations could completely stop the realisation of the Hub and Spoke concept on Dogger Bank. (De Boer and Scholten, 2016; Meijden, 2016)

4 METOCEAN ANALYSIS

The meteorological and physical oceanographic conditions in the North Sea are presented in this chapter. Marine uses have been qualitatively described, but the meteorological and physical oceanographic conditions are quantified as they will form most of the input for the site selection model. Based on these conditions the feasibility and optimal location of the Hub and Spoke concept in the North Sea is determined. Meteorological and physical oceanographic conditions are abbreviated and referred to as metocean conditions in the remainder of this thesis.

4.1 Bathymetry

The North Sea is a relatively shallow sea basin located in the northwest part of Europe. It covers approximately 750,000 km^2 and is connected to the North Atlantic Ocean and the Baltic Sea. At the northern boundary the continental shelf quickly rises from roughly 2 km depth to 200 meters. At this point the North Sea starts and the seabed is gradually rising towards the south up to 80 meters depth in front of Dogger Bank. Dogger Bank is a large and shallow sandbank with water depths up to only 10 meters. Further down south the gradual slope of the seabed is continuing, after which is stays equal at roughly 30 meters deep near the English Channel. The deepest part of the North Sea is located in the Norwegian trench, which is an elongated depression along the Norwegian coastline. It is 50 to 100 km wide and reaches depths down to 700 meters, but strongly deviates from the average bathymetry and is only relevant in the northwest part of the North Sea. (EMODnet, 2016) In Figure 4.1 an overview of the North Sea bathymetry is presented.

Bathymetry is the distance between water level and the seabed, but the water level at each location is changing in time and mean sea level is different per location. The bathymetry is therefore presented relative to the fixed worldwide coordinate system WGS84. This datum is a spheroidal reference surface which approximates mean sea level and thus contains a small error of less than one meter everywhere on earth. (GeoNet, 2014) The error is different per location, but on the North Sea the WGS84 datum approaches mean sea level very close and the bathymetry data is therefore not adjusted.

4.2 Geology

The current topography of the North Sea has originated from basin subsidence, uplift and hydraulic conditions influencing sediment input. Glacial periods resulted in high rates of sediment input by eroding the mainland and seabed. Ice sheets carried these sediments along and deposited them again at other locations on the seabed. The changes from arctic to moderate climates were the dominant factor in determining the sediment type and input rate. It caused the North Sea basin to be filled with sediment in times of rapid basin subsidence. Nowadays, the North Sea nearly has any sediment input and the seabed mainly consists of sand and gravel. Local currents subsequently formed sandbanks and ridges. Many nearshore sandbanks are mobile, although there are also various sandbanks which have been stable for longer periods of time. Some deeper parts of the North Sea may also consist of muddy sand. (Balson et al., 2002) An overview of the current North Sea geology is presented in Figure 4.5.

4.3 Wind Conditions

The average wind condition at the North Sea are presented in Figure 4.2. The wind comes mainly from the southwest and is responsible for the general circulation pattern and sea wave spectrum in the North Sea. (Sündermann and Pohlmann, 2011) The presented wind speed is at 10 meters altitude and is thus strongly influenced by ground surface friction from local topography. It can be seen that the United Kingdom is lowering the wind speed, after which it faces less resistance from the sea surface and increases in speed. The North Sea is enclosed from thee sides and this causes the average wind speed to be lower compared to the top left part in the figure. Over here, the wind conditions coming from the North Atlantic Ocean have not been influenced by land and the lower friction from the sea surface makes it possible to achieve higher average wind speeds. The wind conditions are very important to the significant wave height, surge levels and generated revenue by offshore wind turbines.

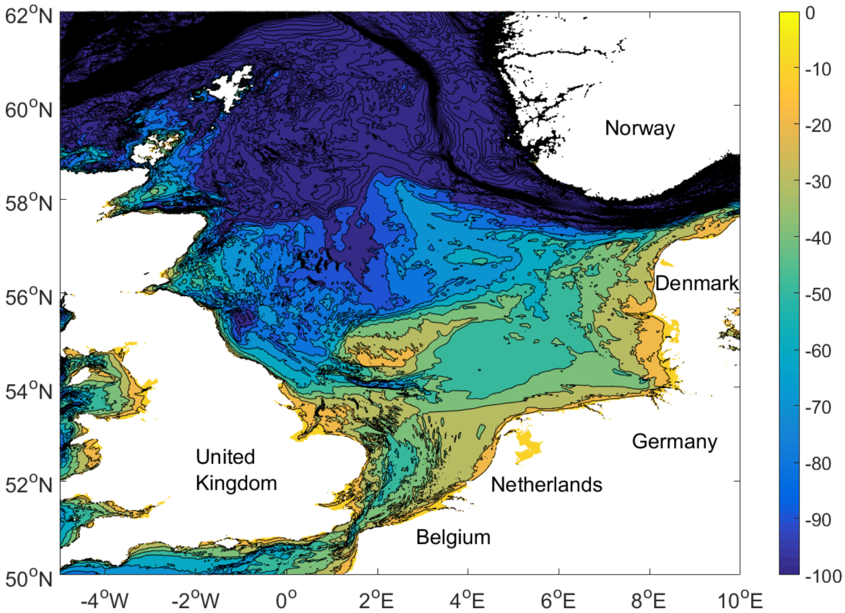


Figure 4.1: North Sea Bathymetry (m) Relative to WGS84 Datum (source: EMODnet, 2016)

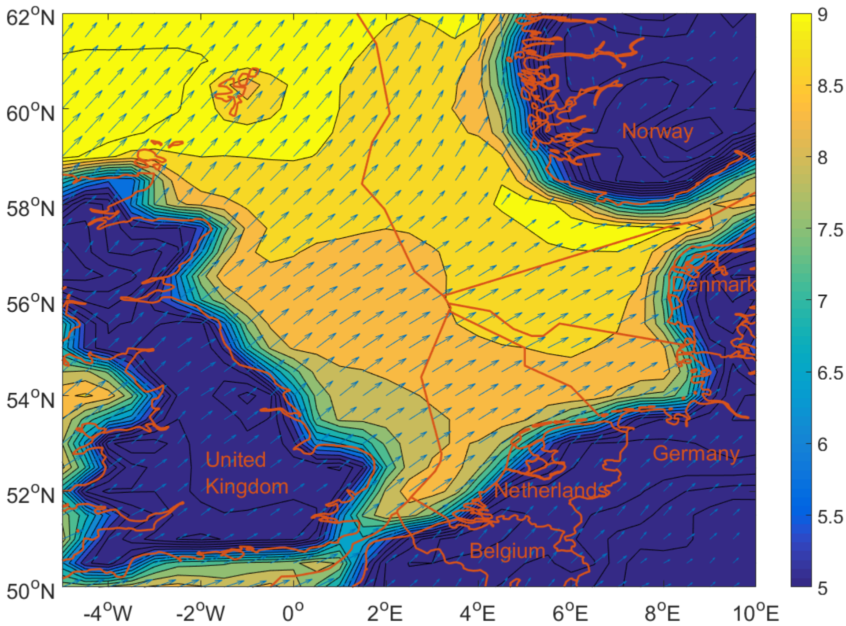


Figure 4.2: North Sea Average Wind Speed (m/s) at 10 m Altitude in Period 2012 - 2016

4.4 Wave Conditions

The average significant wave height in the North Sea is presented in Figure 4.3. The significant wave height H_s is the highest one-third of waves and can be divided into sea waves and swell. Sea waves are caused by wind blowing over a smooth water surface. The friction between wind and water causes small ripples and when the wind speed is high enough these ripples become large enough for the wind to be pushed along and create sea waves. The wave grows in size with increasing wind speed and eventually breaks when the wave becomes too steep with respect to its wavelength. Swell waves are waves moving away from their source of origin. Stronger wind speeds or storms create higher swell waves which are able to travel longer distances. Along the way the wave changes shape from high frequency peaked waves to longer waves with a lower frequency. The North Sea usually contains a combination of sea waves and swell. (Bosboom and Stive, 2015) It can be seen that the average significant wave height becomes higher towards the northeast, which corresponds to the average wind direction. The significant wave height is very important to determine the coastal protection of the artificial island, determine the location of the harbour and to give an indication of the available dredging window.

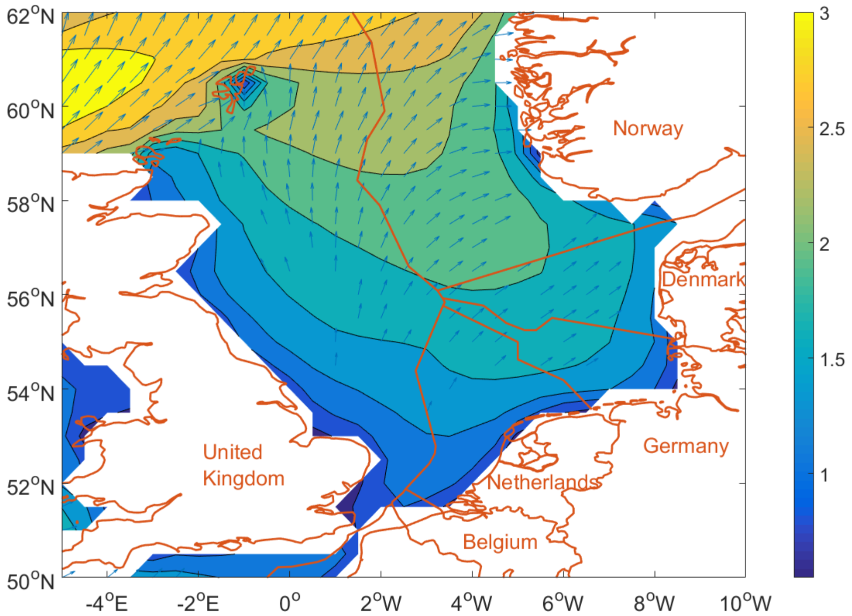


Figure 4.3: North Sea Average Significant Wave Height (m) in Period 2012 - 2016

4.5 Currents

The currents in the North Sea are primarily determined by the tidal movements. The sea basin is in contact with the Atlantic Ocean and the Baltic Sea and gains additional water from debouching rivers of the surrounding countries. The majority of water entering the North Sea comes from the Atlantic Ocean and flows around the northern tip of the Shetland Islands down south. A smaller volume of water subsequently enters through the English channel, after which the current continues to move counter-clockwise in the basin and leaves the North Sea through the Norwegian trench up north. An overview of the mean depth average current velocity in the North Sea during winter (1961 - 2000) is presented in Figure 4.4. The strongest average currents are observed along the coastline from the English Channel to the north of Denmark. The mean average current velocity at these locations is less than 1.0 m/s. On average the current velocities in the North Sea are very small due to the broad connection with the Atlantic Ocean. The maximum current velocities will be higher and certain specific locations along the coastline might experience strong tidal currents, although the Hub and Spoke concept is likely to be located somewhere in the middle of the North Sea where average current velocities are negligible. Currents are therefore not included in the initial design and site selection of the Hub and Spoke concept. (SEOS, 2017)

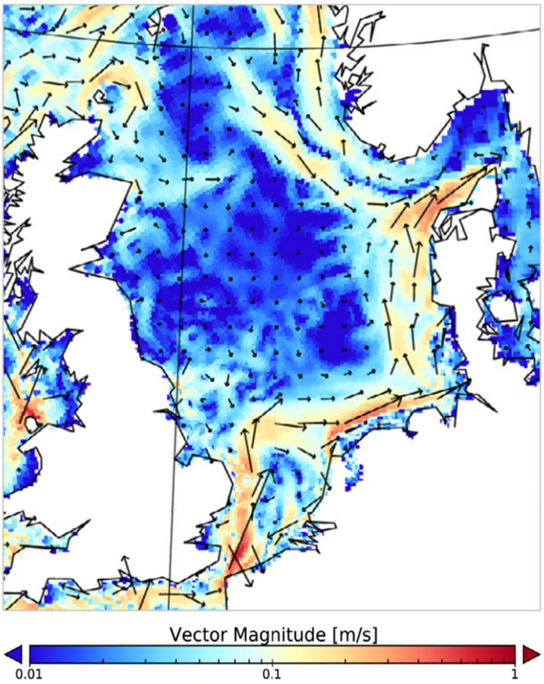


Figure 4.4: North Sea Mean Depth Average Current Velocity (m/s) in Winter (1961 - 2000) (source: Mathis et al., 2015)

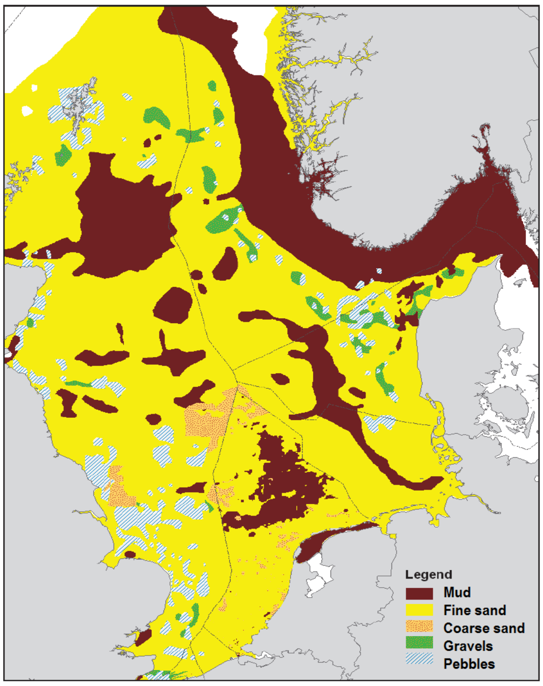


Figure 4.5: North Sea Geology: Mud (red), Fine Sand (yellow), Coarse Sand (brown), Gravel (green), Pebble (blue) (source: EMODnet, 2016)

4.6 Tidal Range

The tidal conditions in the North Sea are presented in Figure 4.6. The solid co-phase lines indicate simultaneous high water at a certain time and the dashed co-range lines indicate equal tidal elevation in meters. Especially along the coastline significant tidal ranges can be observed, but the Hub and Spoke concept will be located somewhere in the middle of the North Sea and experience tidal differences in the range of 2.0 meters or less. At the amphidromic points the tidal elevation is equal to zero. Tidal elevation influences the height of the artificial island, but compared to bathymetry the effect of tidal ranges is only marginal. Accurately determining the tidal conditions for every location in the North Sea is therefore not relevant to the scope of this research.

A general indication of mean high water and mean low water is now known. The tide is semi-diurnal which means that high and low water is present twice a day, but there is also a longer period trend when the sun, earth and moon are all aligned. The attracting forces on water bodies are amplified were high tides become higher and low tides become lower. This is referred to as spring tide. On the other hand the gravitational forces on the water body can also achieve a minimum when the sun and moon are 90 degrees out of phase. This results in a decreased range of tidal amplitude with lower high tides and higher low tides, which is called neap tide. The highest high tide is called highest astronomical tide (HAT) and is the largest tidal elevation under average meteorological conditions, respectively for the lowest astronomical tide (LAT). (Bosboom and Stive, 2015) The height of the artificial will be designed to HAT elevations and physical measurements in the North Sea are therefore compared to give a general indication. The measurements are presented in Table 4.1 with mean sea level is used as reference at +0.0 meters.

Table 4.1: Tidal Range Based on Physical Measurements (2016) (source: Rijkswaterstaat, 2017)

Code	Coordinates	LAT	MLW	MSL	MHW	HAT
K13A	53.2N 3.2E	-1.06 m	-0.52 m	0 m	+ 0.40 m	+ 1.10 m
Euro platform	52.0N 3.3E	-1.08 m	- 0.75 m	0 m	+ 0.75 m	+ 1.34 m
Aukfield	56.4N 2.1E	-0.76 m	-0.44 m	0 m	+ 0.32 m	+ 0.77 m

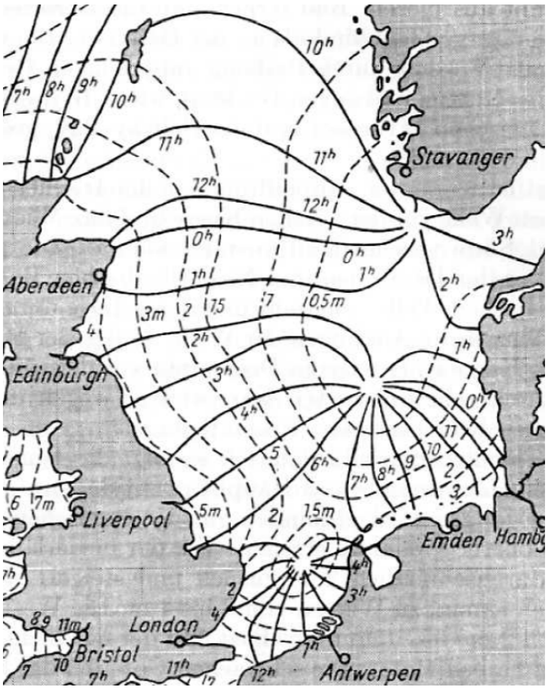


Figure 4.6: North Sea Semi-Diurnal Tide (m) Indicated with Co-Phase Lines (solid, hours) and Co-Range Lines (dashed, meters) (source: Sager, 1959)

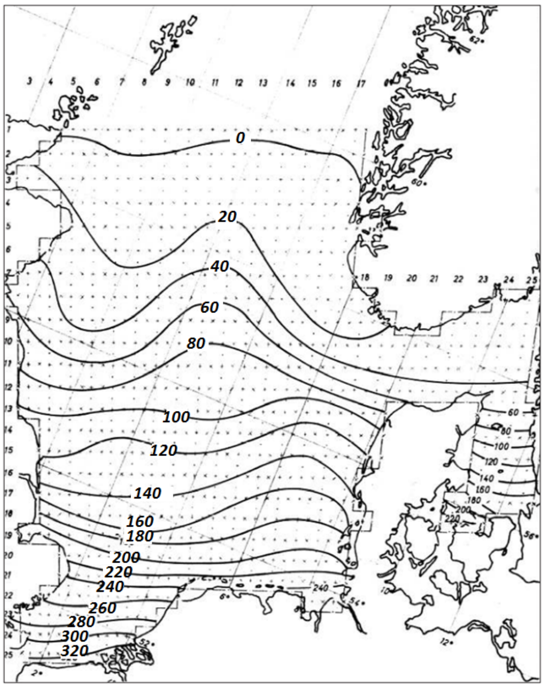


Figure 4.7: North Sea Storm Surge (cm) for Constant Northerly Wind Speed of 23.2 m/s (source: Sündermann, 1966)

The tidal conditions are based on one full year, although actually an epoch of 19 years should be used to determine the datum levels. (NOAA, 2017) The actual datum levels will therefore have greater deviations from mean sea level. Rijkswaterstaat mentions the highest astronomical tide to be +1.10 m for platform K13A, +1.34 m for the Euro platform and +0.77 m for the Aukfield platform. The semi-diurnal tide in the centre of the North Sea has a maximum range of approximately 2.0 meters. Combined with the physical measurements in Table 4.1 the highest astronomical tide in the centre of the North Sea can be approximated. The physical measurements show that highest astronomical tide is for all three platforms not more than three times mean high water. An upper limit of 3.0 m HAT is therefore used as a safe simplification for the tidal elevations in the centre of the North Sea.

4.7 Storm Surge

The water level fluctuates with tidal movements, but storm surges can increase the water level elevation even further. Storm surges are abnormal elevations of the water surface caused by low atmospheric pressures in combination with high wind speeds pushing a water body towards the coastline. The water piles up and can cause major floodings like the flood of 1953 in the Netherlands or more recently the flooding of New Orleans in 2005. The amplitude of the storm surge is dependent on local bathymetry, orientation of the coastline relative to the storm path, size, speed and intensity of the storm. The storm surge levels in the North Sea for a constant northerly wind speed of 23.2 m/s are presented in Figure 4.7. From north to south the basin is getting shallower and this increases the danger of storm surges with increased water levels up to 3.20 meters in the southern parts of the North Sea. The highest water levels are however achieved when a storm surge coincides with the highest astronomical tide. The sun, moon and earth are then all aligned and the pulling forces on the water body are amplified. (NOAA; Bosboom and Stive, 2015) Storm surge is relevant to the height of the artificial island, but negligible compared to bathymetric elevations. Accurately determining storm surge levels is therefore not relevant to the scope of this research and will be included as static data presented in Figure 4.7.

4.8 Sea Level Rise

The design life of the artificial island is likely to be multiple decades and the long-term changes in sea level therefore need to be included. Sea level rise is primarily caused by the rise in global average temperature. Over the last century global mean sea level has risen 1.7 mm/year on average, but the last two decades experienced a higher rate of 3.0 mm/year and is expected to go even faster in the near future. Projections for the 21st century estimate a global mean sea level rise at a rate between 8 - 16 mm/year.

More relevant is the relative sea level rise, which is the absolute sea level rise combined with land rise or subsidence. This directly impacts coastal protections and makes the consequences of sea level rise different per region. Over the next century the North Sea is estimated to subside 2 mm/year. In combination with a sea level rise of 8 - 16 mm/year this leads to a relative sea level rise of 10 - 18 mm/year. (European Environment Agency, 2016; Balson et al., 2002)

4.9 Earthquakes

The North Sea is not located on a geological fault line, but earthquakes do occur. The strongest known earthquake in the North Sea was located at Dogger Bank in 1931. It had a magnitude of 6.1 on Richter scale and could be felt by all surrounding countries. The earthquake even caused damage to multiple buildings in the United Kingdom and was reported to create a small nondestructive tsunami. (British Geological Survey, 2017) Over the last 40 years the ten most significant earthquakes in the centre of the North Sea contained magnitudes between 4.0 and 4.4 on Richter scale and even more earthquakes have occurred with smaller magnitudes. (USGS, 2017) For the entire North Sea an earthquake with magnitude 4.0 is expected approximately every 2 years and an earthquake with magnitude 5.0 is expected every 14 years. (Balson et al., 2002) Although the North Sea region is not seen as an earthquake prone area, the earthquakes that do occur could cause significant damage to the artificial island or the electrical infrastructure on top. Earthquakes must be included in the design of the Hub and Spoke concept, although it is too specific for the scope of this study and will therefore not be included.

5 SET-UP SITE SELECTION MODEL

In this chapter the site selection model is explained, which determines the feasibility of the Hub and Spoke concept for every location in the North Sea. The metocean models which form the input of the site selection model are discussed and furthermore validated with multiple physical measurements to give an indication of the associated input errors.

5.1 Model Setup

The site selection model determines the feasibility of the Hub and Spoke concept for every location in the North Sea and can be used to determine the optimal location.

The dominant parameters regarding the feasibility of the concept have been derived from literature and serve as input to the site selection model. The type of artificial island is mainly dependent on the local water depth and wave conditions, thereby determining to a large extent the corresponding investment. The cost of offshore wind farms is mainly influenced by water depth and distance to shore and the cost of subsea interconnector cables is primarily determined by distance. Wind conditions, electricity prices and subsidies are the dominant parameters with respect to the revenue generated by offshore wind farms and subsea interconnectors primarily derive their revenue from electricity price differences. An overview of the input and output of the site selection model is presented in Figure 5.1. Intermediate steps to determine the output are more detailed and are schematised in the following chapters.

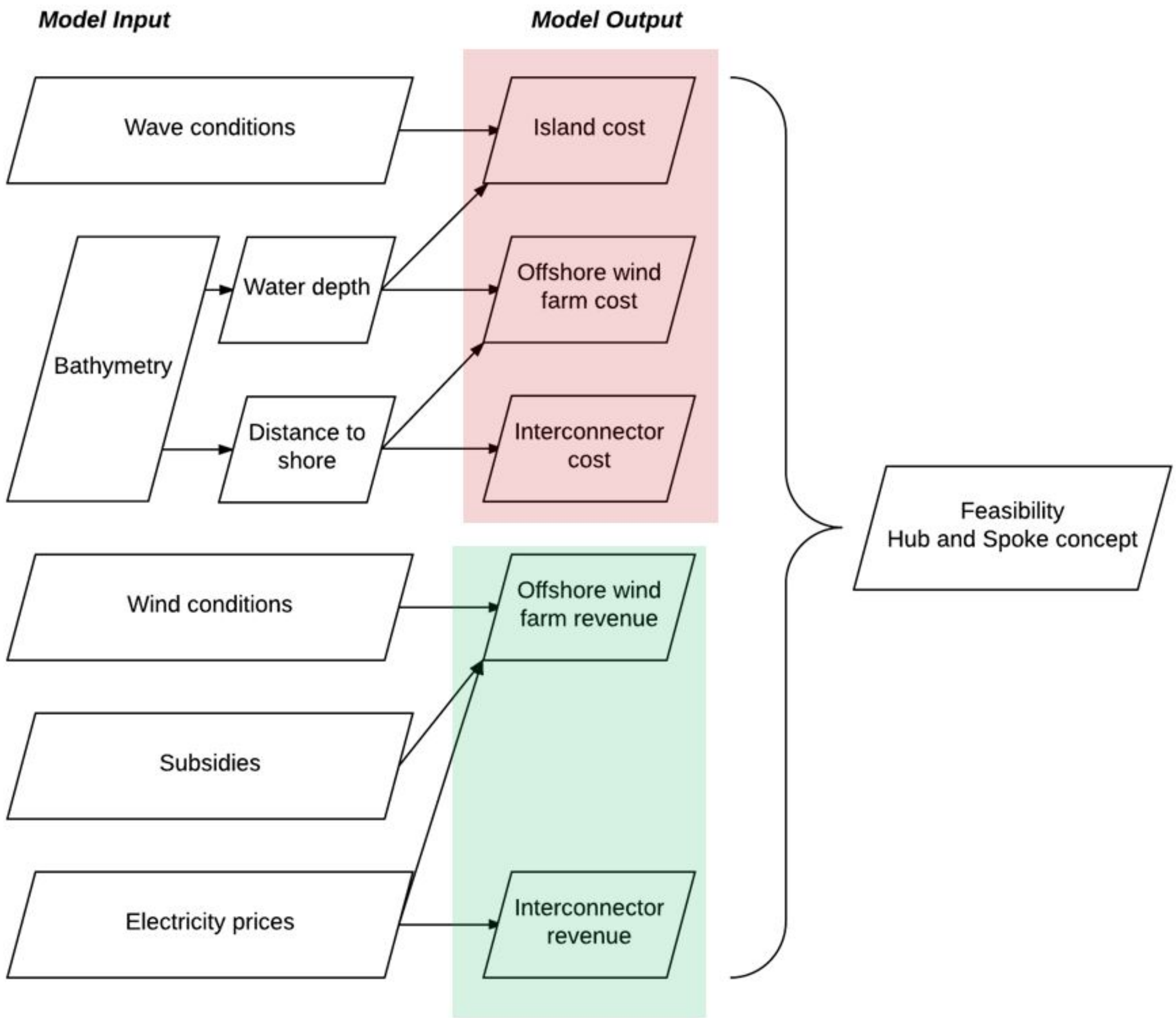


Figure 5.1: Flowchart of Site Selection Model Input and Output

The site selection model is created within the programming language Matlab. The input conditions are inserted and the North Sea region is specified by the author to be 5.0E to 10.0W longitude by 50.0N to 62.0N latitude, after which the site selection model calculates the cost and revenue of the artificial island, offshore wind farms and subsea interconnectors. The grid point at the top left is calculated first, after which the computing power of Matlab is used to calculate the remaining grid points in the specified area. The grid resolution follows from the input data and is 0.5 by 0.5 degrees (approximately 50 km by 50 km). More information on the input conditions is given in the remainder of this chapter. The set of calculation points is visualised in Figure 5.2.

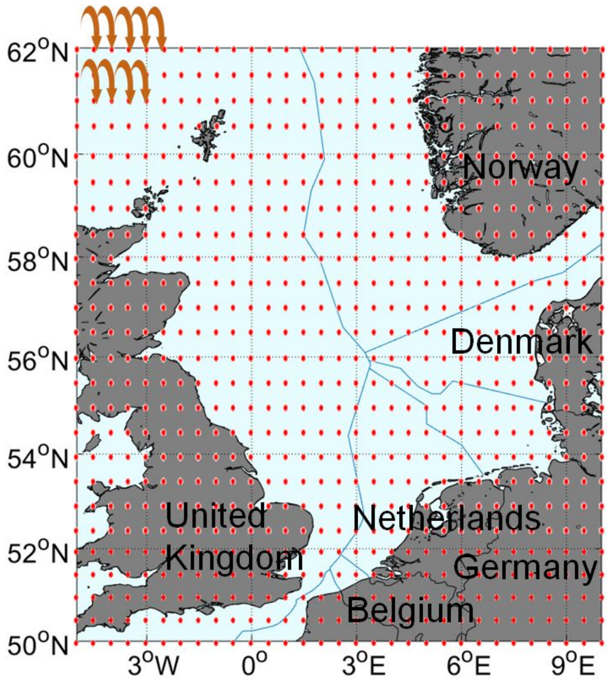


Figure 5.2: Site Selection Model Grid Resolution

The cost and revenue of the artificial island, offshore wind farms and interconnector cables are determined by the site selection model. The model output consists of contour plots showing the feasibility as a function of location. Finally, these individual contour plots are added together as layers to form one single contour plot. This is visualised in Figure 5.3. The final contour plot indicates the feasibility of the Hub and Spoke concept for every location in the North Sea, which can be used to determine the optimal location.

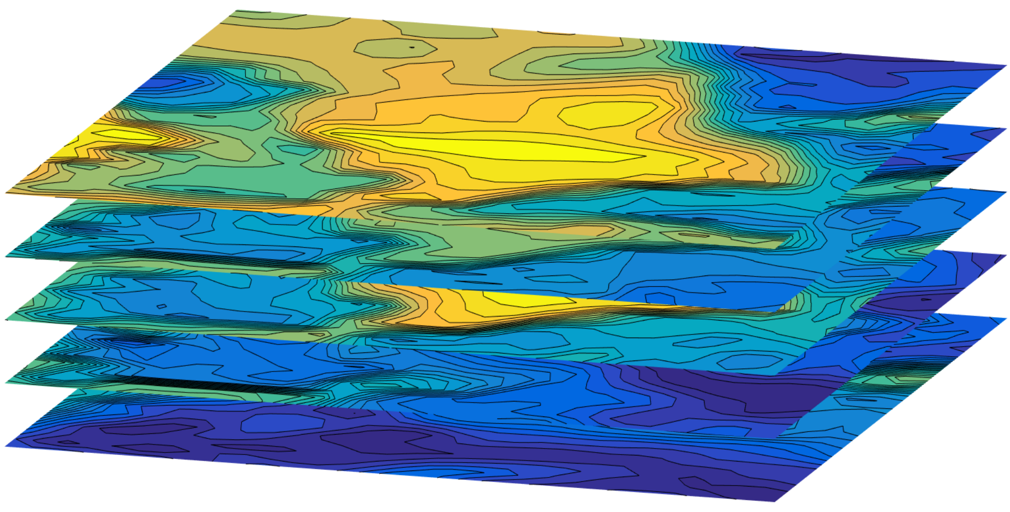
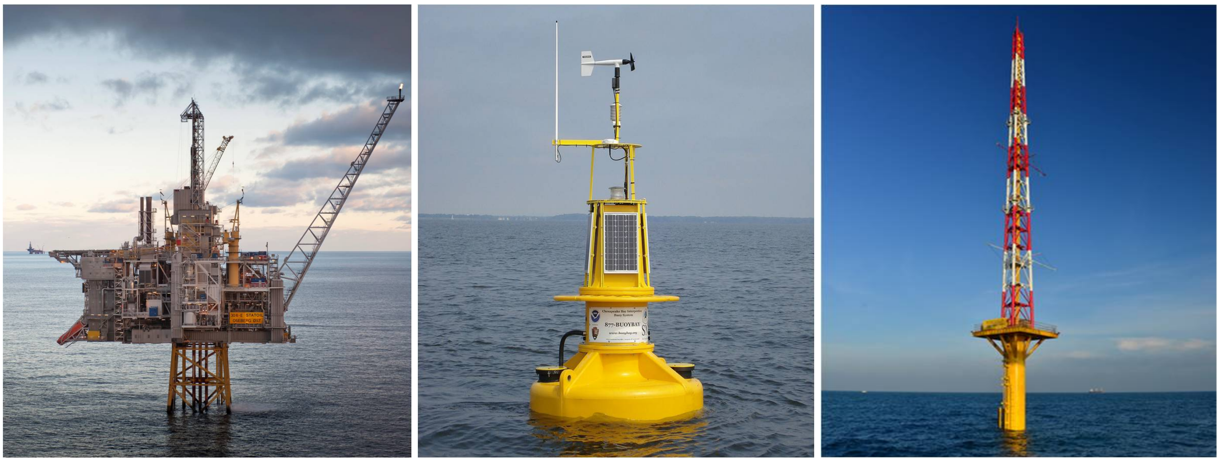


Figure 5.3: Merge of Cost and Revenue Output Layers

5.2 Selection of Metocean Data Type

Information on local conditions can be collected from measuring equipment or from models. Offshore measurements can be performed with amongst others buoys, measuring platforms or private platforms from the oil and gas industry which contain measuring equipment. Measured data is probably more accurate and better resembling the actual conditions compared to metocean models, but these measurements also have some disadvantages. Measuring local conditions offshore is expensive, which makes the amount of measurement locations and the period of measured data often limited. The measurement sources are scattered across the North Sea and have different periods of measured data in time. Furthermore, data gaps at irregular intervals are present due to equipment failure. The information coming from measuring equipment is therefore not evenly distributed in space and time, leading to differences in uncertainty and errors. The accuracy of measurement sources between each other might also be different as some structures are specifically designed for measuring purposes, while others like oil and gas platforms have a different primary function which could interfere with measuring accuracy. The large surface of oil and gas platforms could influence the wind profile, while towers specifically designed for measuring wind conditions contain much less surface and therefore lead to more accurate measurements. Each measurement source is unique and this makes its use on a large scale like the North Sea not very practical.



(a) Oil and Gas Platform (b) Mooring Buoy (c) Offshore Met Mast

Figure 5.4: Metocean Measurement Sources

Models use physically measured data and extrapolate this information in space and time with algorithms. Models approach reality based on measurements and the error is therefore likely to be bigger, but the major advantage of models is the continuous output over a very large and evenly distributed area. The goal of this thesis is to determine the feasibility and optimal location of the Hub and Spoke concept in the North Sea. The space and time characteristics of models are better fitting the scope of this research and metocean models are therefore used as input to the site selection model. In the following sections the metocean models are elaborated and validated on errors by comparing the results with physical measurements.

5.3 Metocean Sources

The selection of metocean models is based on grid size, grid resolution, period of data and expert judgement. Engineers from Witteveen+Bos, Rijkswaterstaat and Svašek Hydraulics were consulted to confirm the selected metocean models for water depth, distance to shore, significant wave height and wind conditions in the North Sea. The following metocean models were selected, which are also commonly used by engineering firms:

Digital Terrain Model
Bathymetry data of the North Sea is collected from the European Marine Observation and Data Network (EMODnet). The major problem of retrieving bathymetry data on such a large scale is the fragmented data storage and accessibility. Data in Europe is published by various public and private organisations,

but often only accessible at very specific locations and geographically limited. EMODnet is a network of organisations supported by the EU with the goal to process and offer all known data on European seas and oceans at one central location. The bathymetric data consists of surveys, composite data sets and GEBCO 2014 30" gridded data which are combined into a Digital Terrain Model (henceforth DTM). Bathymetry is the distance between water level and the seabed, although the water level at a specific location varies in time. The presented bathymetry levels are therefore relative to the WGS84 Datum, which is the worldwide reference coordinate system. Another very important parameter is distance to shore, which is derived from the DTM as the distance between positive and negative values (below water and above water). The DTM covers the entire North Sea region with a very detailed grid resolution of 1/8 by 1/8 arc minutes (approx. 100 m by 100 m) and will therefore be used as input for the site selection model. (EMODnet, 2016)

WaveWatchIII
Wave conditions in the North Sea are approached with the WaveWatchIII model. The model is developed by the National Oceanic and Atmospheric Administration (NOAA) in combination with the National Centers for Environmental Prediction (NCEP) and provides information on amongst others the significant wave height H_s, mean wave period T_p and wave direction (deg.). The selected model grid spans the entire globe and contains a grid resolution of 1/2 by 1/2 degrees (approx. 50 km by 50 km). The model is however only being used for the North Sea conditions and the area is therefore limited to 5.0E to 10.0W longitude by 50.0N to 62.0N latitude. The wave conditions are required to determine the type and height of the artificial island. The artificial island needs to be designed for extreme events. The wave data is therefore extrapolated in time and the period of data needs to be taken as long as possible in order to most accurately approximate the extreme wave conditions. The WaveWatchIII model goes back to 2006. The selected period of wave conditions covers 11 years with 3-hourly averages.

CFSv2
Wind data above the North Sea is collected from the Climate Forecast System Version 2 (henceforth CFSv2) model. The model is created by the National Centers for Environmental Prediction (NCEP) and provides information on amongst others hourly wind speed and wind direction at 10 meters altitude. The model is initialised with measured data every six hours and subsequently produces one- to five-hour forecasts. According to literature, at least five full consecutive years of wind data are required to evaluate a region and locate promising areas for offshore wind energy. (Serri et al., 2012) Wind conditions contain a yearly variation. The average wind speed between two years might differ 3-5%, leading to roughly 10-15% difference in turbine output. (van Bussel, 2017) It is thus important to use multiple years of wind data and the selected period therefore ranges from January 2012 to January 2017 (5 years). The model grid spans the entire globe, but again the North Sea region is specified by the author to 5.0E to 10.0W longitude by 50.0N to 62.0N latitude with a spatial resolution of 1/2 by 1/2 degrees (approx. 50 km by 50 km).

In Chapter 4 more metocean conditions have been discussed, although their spatial or temporal variation proved to be negligible or the impact on the feasibility of the Hub and Spoke concept is expected to be limited. Tidal variation, storm surge and sea level rise is still included in the site selection model, but this will be done with static and highly simplified values. Geology, currents and earthquakes are only of minor importance to the scope of this research and are therefore disregarded.

5.4 Validation of Metocean Data

Models approach the actual conditions and are therefore likely to contain a larger error compared to physical measurements. To give an indication of the error in metocean models, the wind and wave conditions are validated with physical measurements from buoys, measurement platforms and private platforms from the oil and gas industry equipped with measuring tools. In Figures 5.5 to 5.8 the wind speed data from the CFSv2 model is visually compared with physical measurements from Oil Platform 62164 and Mooring Buoy TWEms over the month July 2016.

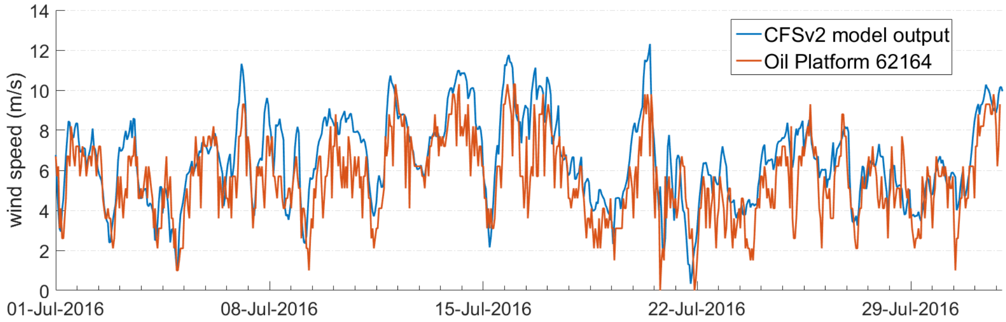


Figure 5.5: Wind Speed Data from CFSv2 Model and Oil Platform 62164

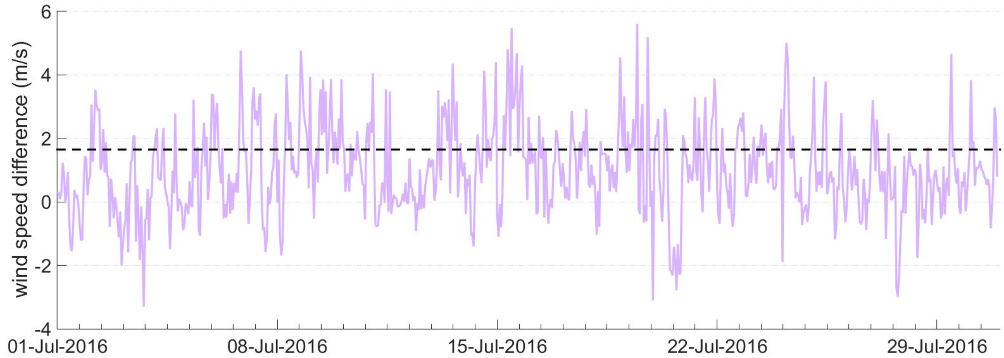


Figure 5.6: Wind Speed Difference between CFSv2 Model and Oil Platform 62164

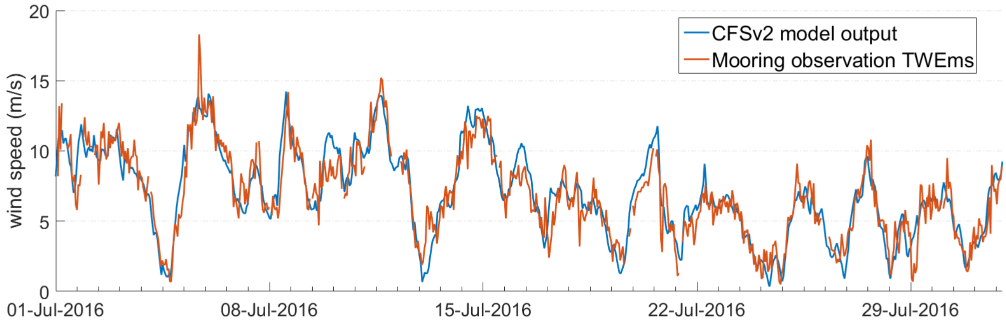


Figure 5.7: Wind Speed Data from CFSv2 Model and Mooring Buoy TWEms

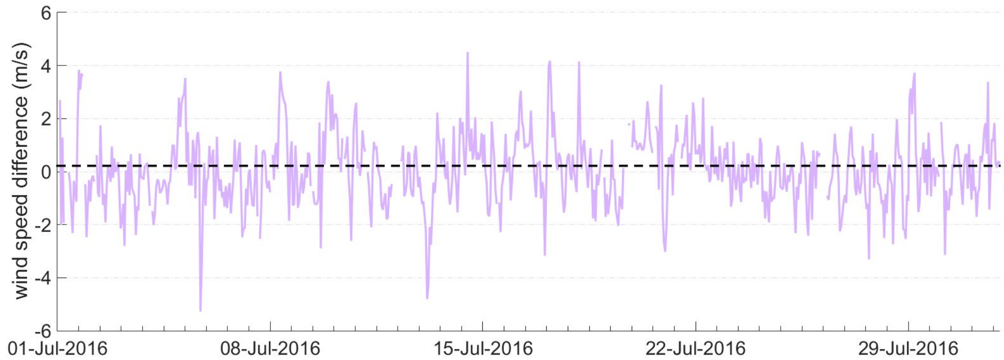


Figure 5.8: Wind Speed Difference between CFSv2 Model and Mooring Buoy TWEms

The CFSv2 model data has a better fit with Mooring Buoy TWEms. It can be seen by the purple lines that the standard deviation of the wind speed difference is approximately equal for both physical measurements, but the mean wind speed difference for Mooring Buoy TWEms is close to zero while Oil Platform 62164 presents a structural lower wind speed. Theoretically, the standard deviation and mean wind speed difference must be zero as both sources provide information on one single condition at the same location and at the same moment in time. Assuming the physical measurements are an exact representation of the local conditions, the standard deviation and mean wind speed difference between the model and physical measurements must be as small as possible to most accurately approximate the actual conditions. The figures above show a visual comparison over one single month. In Table 5.1 and Table 5.2 the wind model CFSv2 and wave model WaveWatchIII are validated with multiple physical measurements over a period of respectively 5 years and 11 years. The physical measurement sources are selected on geographical location and platform type, trying to cover most of the North Sea area and to simultaneously check on differences between physical measurement sources.

Table 5.1: Wind Speed Validation CFSv2 Model with Physical Measurement Sources (Jan. 2012 to Jan. 2017)

Code	**Type**	**Source**	**Coordinates**	**Mean diff.**	**Standard dev.**
62145	Mooring time series	Private	53.1N 2.8E	1.17 m/s	1.86 m/s
62146	Mooring time series	Private	53.8N 2.8E	1.65 m/s	4.20 m/s
62164	Mooring time series	Private	57.2N 0.5E	1.35 m/s	1.80 m/s
NsbII	Mooring time series	BSH	55.0N 6.3E	- 4.48 m/s	3.38 m/s
TWEms	Mooring time series	BSH	54.2N 6.4E	0.22 m/s	1.44 m/s

As could already be visually observed in Figure 5.6 and 5.8, the standard deviation between the CFSv2 model and the physical measurements from Oil Platform 62164 and Mooring Buoy TWEms are fairly similar with respectively 1.80 m/s and 1.44 m/s. The mean wind speed difference with Mooring Buoy TWEms is very close to zero with 0.22 m/s, while Oil Platform 62164 provides a structurally lower wind speed of 1.35 m/s. The standard deviation must be as small as possible to most accurately resemble the local conditions, but especially a mean wind speed difference is troublesome as this would lead to a wrong estimation of future wind energy generation. One physical measurement, Mooring Buoy NsbII, strongly deviates from the CFSv2 model. This is strange, especially because the data is provided by the Bundesamt für Seeschifffahrt und Hydrographie (BSH) which is seen as a respected data provider of metocean conditions. Large outliers are more likely to be expected from private companies who measure local conditions only as a secondary function of the platform and to which the platform is not designed to provide the most accurate data. It is possible that the CFSv2 model contains a large error at this location, but based on the other four physical measurements it is more likely that the error comes from the mooring buoy itself. On average the CFSv2 wind model is accurate enough to select potential locations for the Hub and Spoke concept and will be used as input for the site selection model.

Table 5.2: Significant Wave Height Validation WaveWatchIII Model with Physical Measurements Sources (Jan. 2006 to Jan. 2017)

Code	**Type**	**Source**	**Coordinates**	**Mean diff.**	**Standard dev.**
62145	Mooring time series	Private	53.1N 2.8E	0 m	0.90 m
62146	Mooring time series	Private	53.8N 2.8E	- 0.48 m	1.22 m
62164	Mooring time series	Private	57.2N 0.5E	- 0.19 m	1.26 m
A121	Mooring time series	Deltares	55.4N 3.8E	0.21 m	0.85 m

The standard deviation of the difference between the WaveWatchIII model and the physical measurements is fairly constant with on average 1.06 m/s, although there is some variation in mean significant wave height difference. Three out of four physical measurements are in good agreement with the WaveWatchIII model with mean significant wave height differences smaller than 0.21 meters. The mean difference of - 0.48 meters with Oil Platform 62146 is quite significant, especially when these wave conditions are extrapolated to design storms once every thousands of years, but on average the WaveWatchIII model is accurate enough for the preliminary design of the artificial island and will be used as input for the site selection model.

The EMODnet bathymetry data is combined into the Digital Terrain Model and consists of surveys, composite data sets and the GEBCO 2014 model. Just like the CFSv2 and WaveWatchIII model it is a collection of multiple data sources with different accuracy and from various locations. It is good to be aware of these differences when using bathymetric information. Echosounders are the most accurate method to determine water depth. An echosounder hangs below a vessel and sends a sound signal to the bottom of the sea bed. The sound signal reflects and the echo is picked up again by the equipment. The time it takes for the sound signal to travel back is multiplied with the speed of sound in water and this determines twice the distance to the sea bed. The speed of sound in water depends on temperature, salinity and depth and the measuring error of echosounders is dependent on the soil type, current velocity, wave height and size of the vessel. The measuring error is however usually not larger than 0.50 meters. (Schrieck, 2015) The GEBCO 2014 30 arc second bathymetric model is used to complete area coverage when surveys or composite data sets are not available for certain locations. The grid resolution of the GEBCO model is more detailed compared to the Digital Terrain Model of EMODnet, but this does not say anything about accuracy or validation. The GEBCO model is based on echosoundings which are accurate, but measuring the entire topography of all oceans with echosounding equipment would take a lot of time and money. Satellite-derived gravity data is therefore used to be able to cover the bathymetry of all oceans, but this method is especially beneficial to determine the bathymetry of deep ocean basins several kilometres deep. Basic shapes like ridges can be observed, but the vertical error is approximately 250 m and gravity-based measurements are therefore not suitable to the bathymetry of the smaller and shallower North Sea. Under these conditions echosounding measurements are simply interpolated to estimate the bathymetry for areas with missing data. Especially at shallow areas GEBCO is therefore not be very accurate, but to what extent is difficult to determine and differs per location. (GEBCO, 2016) It may however be concluded that the most accurate measurements are included in the Digital Terrain Model and the less accurate GEBCO data is used to fill the data gaps. The Digital Terrain Model indicates for every location which data source is used and based on this information the error can be estimated. The most accurate measurements with echosoundings are primarily located along the coastline and at certain interesting locations like Dogger Bank. On these locations the measurements are in general already accurate, but when the artificial island is located in other regions it is advised to perform additional bathymetric surveys. For the purpose of this study the resolution and accuracy of the Digital Terrain Model is sufficient enough to give a general cost indication of the Hub and Spoke concept in the North Sea.

6 EXPENDITURE

In this chapter the total expenditure of the Hub and Spoke concept is determined, which is divided into three main components: the artificial island, offshore wind farms and subsea interconnector cables. Each component is elaborated and the most influential conditions on expenditure are highlighted. Furthermore, expenditure between these components can be compared and the optimal location of the Hub and Spoke concept with respect to cost can be determined.

6.1 Artificial Island

The novel aspect of the Hub and Spoke concept is to construct an artificial island in the middle of the North Sea and provide near shore conditions, while being far away from the national coastlines. In this section the design criteria for the island are determined, after which the best suitable island type is chosen and the corresponding dimensions are determined. A preliminary design is made according to the local conditions and a cost indication is given for constructing the island at various locations in the North Sea. The flowchart diagram to determine the artificial island cost is presented in Figure 6.1.

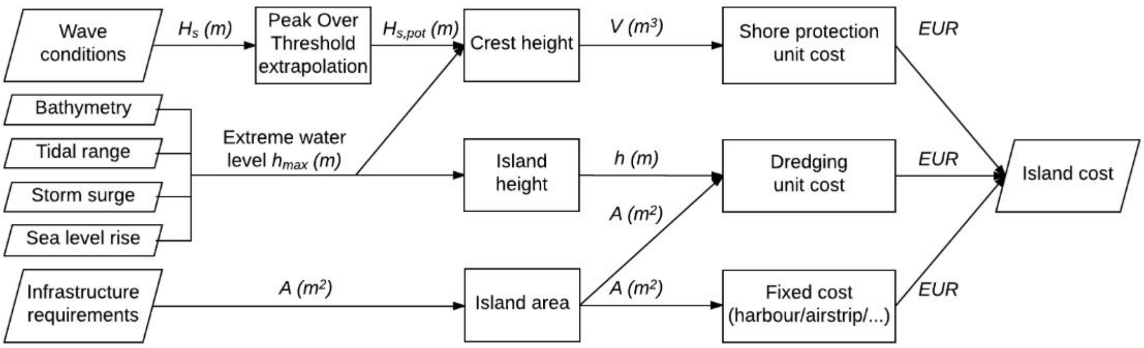


Figure 6.1: Flowchart Artificial Island Cost

6.1.1 Design Criteria

The type and dimensions of the artificial island have to fulfil certain design criteria. These criteria consist of regulation, physical limitations, design lifetime, metocean conditions and required area, which are elaborated in this section.

Regulation and Physical Limitations
There can be large differences in regulation between countries facing the North Sea. Regulation is however outside the scope of this study and will therefore not be included to determine the type or dimensions of the artificial island. In Chapter 3 an overview of the major marine uses in the North Sea was presented, which could pose physical limitations to the artificial island and surrounding offshore wind farms. Physical limitations are however more relevant in the design phase of the concept. It is too specific for the goal of this research and is therefore also not included.

Design Lifetime
The design lifetime of the artificial island is based on the construction-, operational- and decommissioning period of the offshore wind farms and subsea interconnector cables. This is summarised in Table 6.1.

Table 6.1: Design Life Offshore Wind Farms and Subsea Interconnectors

	Offshore Wind Farm	Interconnector
Construction period	3 years	0.25 years
Operational lifetime	25 years	40 years
Decommissioning period	1 years	0.25 years

Each offshore wind farm is unique with different conditions like water depth, distance to shore, soil conditions and weather conditions, but also in terms of wind farm characteristics like the number of turbines, offshore substations and possibly converter stations. Construction of a small offshore wind farm with 30 to 50 turbines takes approximately one and a half to two years, including the time required for manufacturing the structures. Larger projects may require several years in total with offshore construction activities spanning two to three years. (Bean, 2013) The design life of offshore wind farms is in general 20 years, with some exceptions to 25 years. The offshore wind turbines are the critical component with the shortest design life, but more and more turbine models are being delivered with a guaranteed operational lifetime of 25 years. (Smith, 2014) The decommissioning period is also dependent on the metocean conditions and offshore wind farm characteristics. This period may range from 100 days up to almost 4 years, although a significant period is for project management which can take up to 3 years for large offshore wind farms. The actual decommissioning activities take 6 to 12 months. Expressed per turbine this is on average 2 days to decommission, load and transport the turbine to shore while taking weather downtime into account. (Topham and McMillan, 2017)

Subsea interconnectors are mainly influenced by the seabed conditions and cable length. The installation period is dependent on the laying rate of cable vessels, which is approximately 200 m per hour and largely depends on the seabed conditions. (Ardelean and Minnebo, 2015) The North Sea mainly consists of sand and the cable can easily be buried. The Norwegian trench is the only part which is making installation more difficult due to the great water depths and rock bottom. Subsea interconnector cables in the North Se range between 50 and 700 km and the installation period might therefore take up to 150 days. However, the artificial island is likely to be constructed somewhere in the middle of the North Sea which makes the cable length and installation period twice as short. The financial investments related to construction and installation are very high and the demand for electricity is a long-term event. It is furthermore difficult to perform offshore repairs and the cables are therefore designed to withstand harsh conditions and achieve long operational lifetimes. The expected operational lifetime of subsea interconnector cables is 40 years. (Ardelean and Minnebo, 2015) Decommissioning will require a comparable amount of time as installation.

Based on the construction-, operation- and decommissioning period of offshore wind farms and interconnector cables the artificial island should get a design lifetime of at least 40 years. It is however very likely that the island will facilitate consecutive cycles of offshore wind farms as the total installed capacity of RES must continue to increase in the coming decades. The climate goals focus on the year 2050, but even further in time there will not be an abrupt change in energy sources. Furthermore, the island will become a hub in energy trade and it is likely to remain fulfilling this function over a longer period of time. The artificial island is therefore designed to an operational lifetime of 100 years.

Return Period of Extreme Events

The most important criteria to the artificial island is the very high degree of security. According to TenneT, the Hub and Spoke concept should be "always operational". In January 2017, a power outage in and around Amsterdam caused over 360,000 household to be without electricity for several hours. The power outage was caused by a failure in one of the substations and resulted in amongst others major congestion in transportation, supply of stores and failure of electronic payments. The economical damage is estimated to be tens of millions of euros and even caused one possible fatality as the emergency number could not be reached. The question arose if there should always be back-up infrastructure to anticipate on major power failures like the one in Amsterdam. This would lead to an increase in electricity cost, but the damage is also significant and the chance on power outage has to be compared with the consequences. (Couzy et al., 2017) This incident illustrates the consequences of power failure on a single big city. The Hub and Spoke concept will become a power hub for countries surrounding the North Sea. The consequences would be even larger and the artificial island should therefore get the highest degree of security possible.

However, it is statistically impossible to design the artificial island to be always operational. There is always a certain return period of extreme events, which results in a specific failure probability. The probability of an event during the design lifetime of the island can be determined with the Poisson distribution. The occurrence in a certain time interval λ and the number of events k are used in the cumulative inverse Poisson distribution (eq. 6.1) to determine the probability of events on the artificial island. The island will be designed to a probability which is adopted to be safe enough and this probability determines the allowable return period of extreme events like water level and significant wave height. The cumulative probability of occurrence during a design lifetime of 100 years is presented in Table 6.2.

$$P(k) = 1 - \sum_{k=0}^{k} \frac{\lambda^k}{k!} e^{-\lambda} \tag{6.1}$$

Table 6.2: Cumulative Probability of Occurrence During Island Design Lifetime of 100 years

Return period	**Number of events k**				
(years)	1	2	3	4	5
1/1	1.00	1.00	1.00	1.00	1.00
1/10	1.00	1.00	0.99	0.97	0.93
1/100	0.26	0.08	0.02	3.66E-03	5.94E-04
1/1,000	4.68E-03	1.55E-04	3.85E-06	7.67E-08	1.27E-09
1/10,000	4.97E-05	1.65E-07	4.13E-10	8.25E-13	1.33E-15
1/100,000	5.00E-07	1.67E-10	4.17E-14	<4.17E-14	<4.17E-14

It is not easy to determine an acceptable return period of events as the Hub and Spoke concept has never been realised before. However, the consequence of failure is very high and can be compared to other structures with similar consequences. Nuclear power plants for example must prevent a core meltdown at all times, although these incidents do occur and makes these structures comparable. The design lifetime of nuclear power plants is on average 60 years and contains a core meltdown probability of 5.57E-05. (Voosen, 2009) Accepting similar failure probabilities for the Hub and Spoke concept would lead to a design based on extreme conditions with a return period of 1/10,000 years.

Significant Storm Wave Height

The significant wave height in a specified design storm H_{ss} is determined with the Peaks-Over-Threshold (henceforth POT) method. Observations with the greatest significant wave height and a minimum duration are defined as storms. These events are the peaks above a certain threshold value, which are approximated by multiple distributions to most accurately extrapolate the significant wave height with very low return periods. The wave conditions are collected from the WaveWatchIII model over a period as long as possible to include most extreme events. The latest version of the model dates back to January 2006 and the wave conditions for the POT method are retrieved up to December 2016 (11 years). First, the wave conditions are filtered in directional ranges as the physical processes which influence the waves are likely to be different per incoming direction. Usually a range of 30 degrees to the normative incoming direction is assumed with most and highest waves. The minimum storm duration is normally chosen to be 6 hours and the defined number of storms is usually between 3 and 10 storms per year. (Bodde, 2017; Kaji, 2017) The significant wave heights fulfilling these criteria are fitted with the Exponential-, Gumbel- and Weibull distribution. The distribution with the best fit is subsequently being used to extrapolate the significant wave height in time.

In Figure B.3 the wave rose of the significant wave heights at Dogger Bank is presented. The waves with the greatest height and frequency come from the north and the wave conditions from the WaveWatchIII model are therefore filtered to the normative incoming direction between 335 and 5 degrees north.

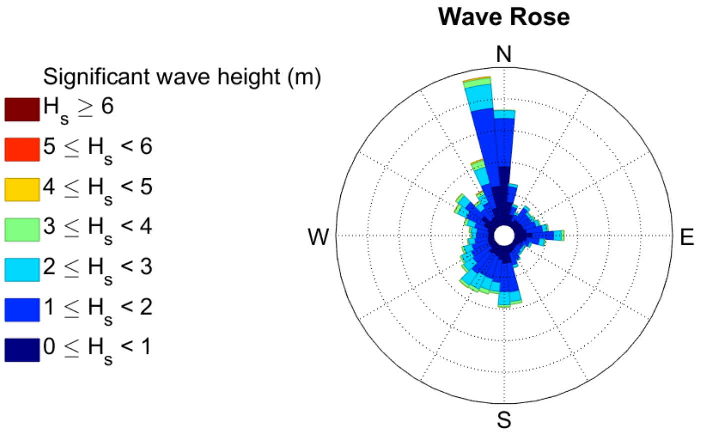


Figure 6.2: Wave Rose with Significant Wave Height H_s on Dogger Bank (54.5N 2.0E)

Subsequently, the storms at Dogger Bank are defined as the 10 greatest significant wave heights per year with a minimum duration of 6 hours. These peaks are fitted with the Exponential, Gumbel and Weibull distribution. The parameters of the distributions are determined by the best fit, leading to a minimum sum of squared residuals. The goodness of fit is expressed with the coefficient of determination, also known as the R-Squared value. This coefficient expresses how well the peaks are replicated by a trend line or distribution. R-Squared values range between zero and one, where values closer to one indicate a better fit. The results are presented in Table B.7 and visualised in Figure B.4.

Table 6.3: Significant Wave Height Extrapolation on Dogger Bank (54.5N 2.0E)

Distribution Type	α	β	γ	**1/100 year** H_s	**1/1,000 year** H_s	**1/10,000 year** H_s	**R-Squared**
Extrapolation	- 0.50	4.40	x	6.71 m	7.87 m	9.03 m	0.9815
Gumbel	x	0.47	2.24	6.58 m	7.66 m	8.74 m	0.9896
Weibull	1.43	1.02	1.64	6.21 m	6.99 m	7.72 m	0.9943

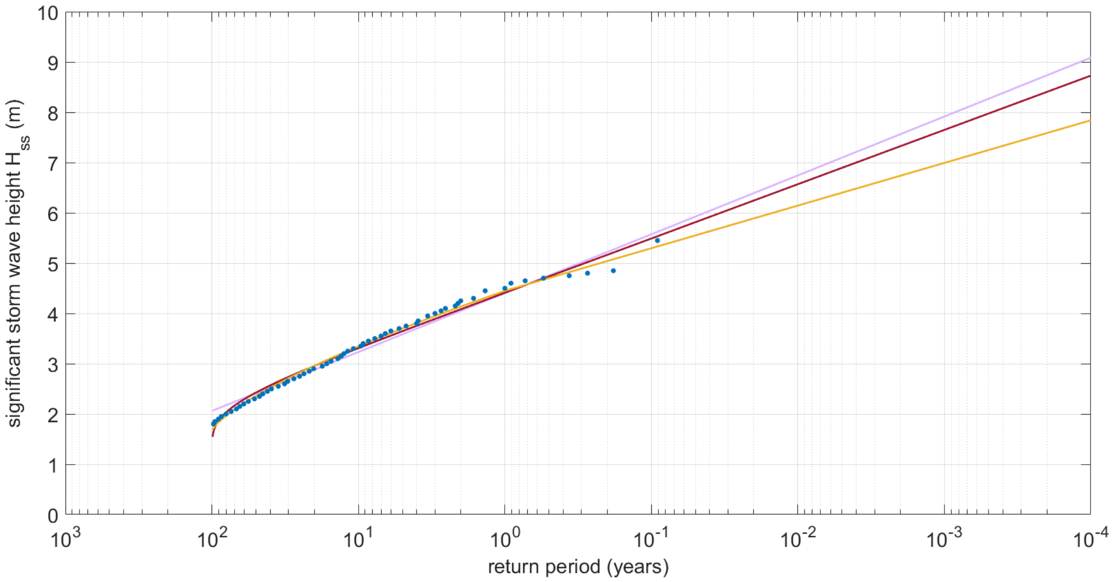


Figure 6.3: POT Distribution Comparison for H_{ss} on Dogger Bank (54.5N 2.0E)

In literature, the Weibull distribution most often contains the best fit with observed extreme wave conditions. (Far et al., 2016) The extreme wave height analysis on Dogger Bank also contains the best fit and R-Squared values closest to one for the Weibull distribution, which is therefore used to determine the significant design storm wave height for the entire North Sea.

There are however some uncertainties in the POT method as some parameters are rather arbitrary, there is not one distribution always fitting the data best, several methods can be used to determine the best fit and there is not some kind of "rule of thumb" to determine the number of storms per year or the threshold level. In practice, a 30 degrees range and 6 hour storms are commonly assumed, after which the number of storms per year is based on the best fit between the distributions and the significant wave height peaks. (Bodde, 2017; Kaji, 2017) In Appendix B.2 the storm duration, number of storms per year and the range of incoming waves have been varied to gain insight into the influence of these parameters. It proved that the commonly used values perform very well. The effect of storm duration is negligible, although the number of storms and the range of incoming waves proved to have a noticeable effect. More defined storms per year resulted in a better fit and higher significant wave heights. The number of storms has therefore been increased from 10 storms per year to 100 storms per year. A narrower range of incoming waves did not lead to a noticeable change with the standard values, although a wider range caused the fit to become much worse with lower significant wave heights. This can be explained by the different physical processes which influence waves coming from different directions and is the reason why the wave conditions are filtered. Especially for longer return periods these effects are amplified. The biggest deviation with the standard values was caused by an increase of the range of incoming waves to 90 degrees. The Weibull distribution resulted in a 15% lower significant wave height with 1/10,000 years return period.

Other important aspects to notice are the limited period of wave data and the application of the POT method on the WaveWatchIII model. The wave conditions represent an 11 year period and for extreme value analysis this is very short, especially when extrapolating these conditions to 1/10,000 years return periods. The measured period can be extrapolated roughly 3 times to achieve an accurate prediction and the 1/1,000 years and 1/10,000 years return periods are much less accurate. However, there are no wave condition measurements covering thousands of years and therefore there will always be some uncertainty. The second important aspect to notice is the application of the POT method on model data. Extreme value analysis uses the extremes in measured data and it might be possible that models are less accurate in resembling these extreme conditions.

The extrapolated wave conditions with a return period of 1/10,000 years are presented in Figure 6.4. The extreme wave conditions determined with the Exponential and Gumbel distribution are presented in Appendix B.2.

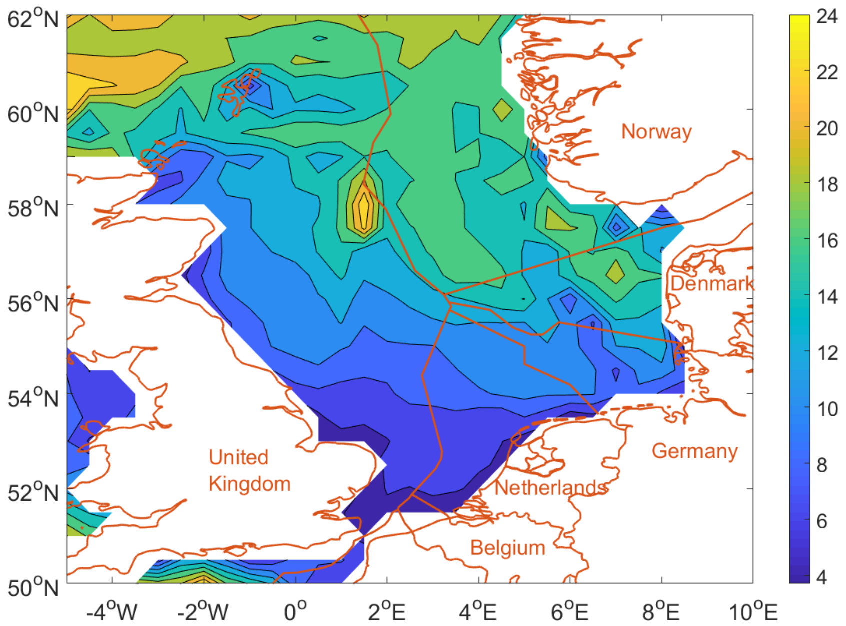


Figure 6.4: Significant Storm Wave Height H_{ss} in m (Weibull, return period 1/10,000 years)

Extreme Water Level
The water level is determined by bathymetry, tidal elevations, storm surge and on the long term sea level rise. Apart from bathymetry, these metocean conditions are however not included by means of a model as they have a smaller influence on the dimensions and type of artificial island. It is therefore not possible to perform the POT method on tidal elevations and storm surges for the entire North Sea. The extreme water level with 1/10,000 years return period is therefore simplified to still include these conditions in the site selection model. In Chapter 4, the tidal elevation, storm surge and sea level rise have already been determined. The storm surge for a constant northerly wind speed of 23.2 m/s was presented in Figure 4.7. The tidal elevation for highest astronomical tide was determined to be +3.0 m. The relative sea level rise in the North Sea was expected to be 10 to 18 mm/year, which leads to a water level increase of +1.0 m to +1.8 m over the 100 year design lifetime of the artificial island. Combining these extreme conditions leads to a rough approximation of the extreme water level with 1/10,000 years return period. This is presented in Figure 6.7.

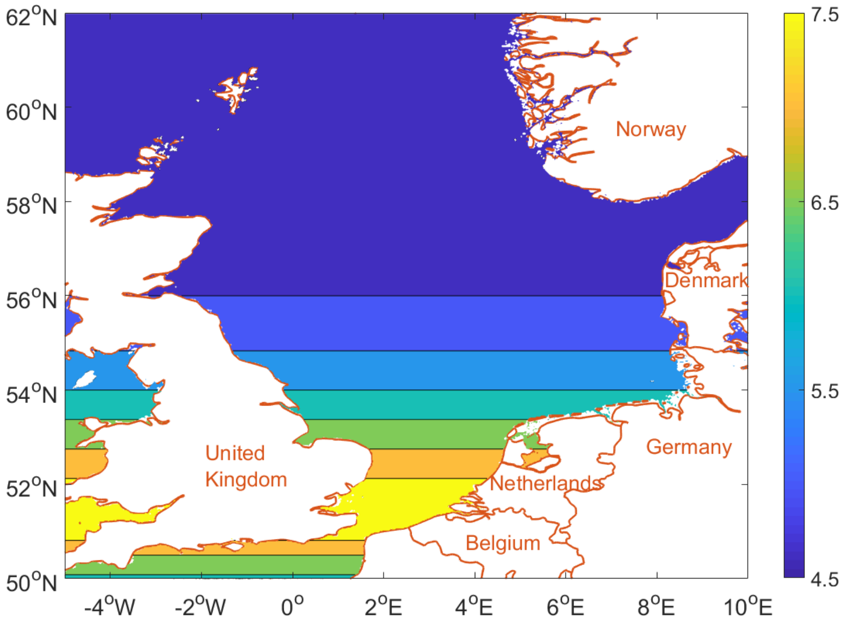


Figure 6.5: Extreme Water Level (m, return period 1/10,000 years)

Required Island Area
The main function of the island is to facilitate far offshore wind energy under near shore conditions. More offshore wind farms and interconnectors thus lead to more infrastructure and would require a larger island. It will become a working island with factories, warehouses, permanent accommodation for personnel and transportation facilities in the form of a harbour, airstrip and helipads. Large components are shipped to the island where the turbines will be finished inside complete assembly lines, after which installation vessels will be working full-time to install the turbines at the desired location. The harbour is also used in combination with the helipads for operation and maintenance on the wind turbines and the airstrip is constructed to transport personnel to and from the island.

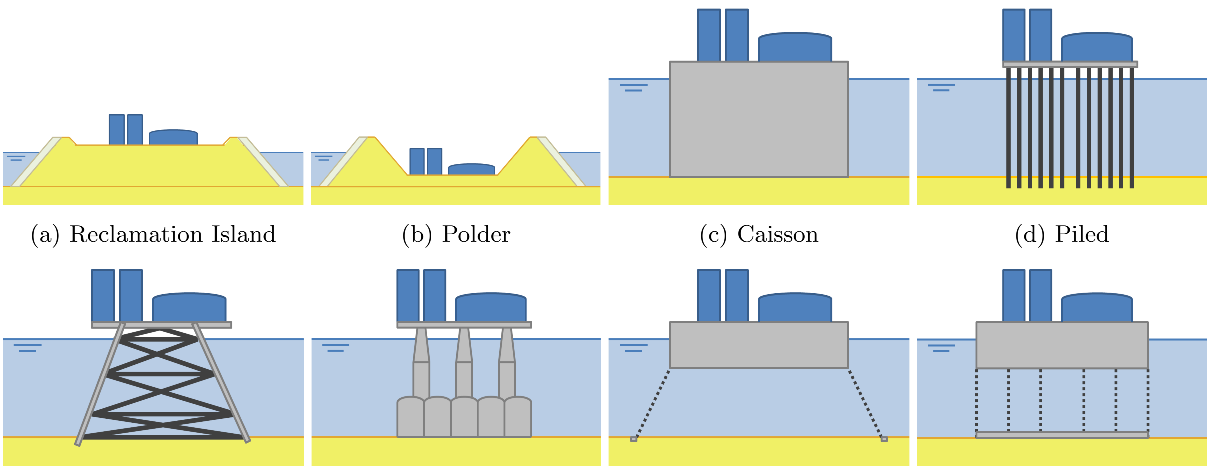
The area of the artificial island is determined by the capacity of surrounding offshore wind farms and subsea interconnectors. Transmission system operators TenneT (Netherlands, Germany) and Energinet (Denmark) are mentioning 30 GW to 100 GW installed capacity. (TenneT, 2016; Energinet.dk, 2017) These capacities are used as lower and upper boundaries to determine the required island area as presented in Table 6.4. Reference is made to Appendix B.1 for the determination of the required areas.

Table 6.4: Required Island Area

Function	**Required island area (m2) for 30 GW capacity**	**Required island area (m2) for 100 GW capacity**
HVDC Converters (2 GW)	540,000	1,800,000
Switchyard area HVDC converters	405,000	1,350,000
Cables	77,250	253,500
Factories	180,000	600,000
Warehouses	90,000	300,000
Refuelling-, bunker- and waste deposit station	45,000	135,000
Accommodation (1,500 to 5,000 persons)	45,000	150,000
Recreational area	60,000	200,000
Harbour (1,850 - 5,350 m quay length)	55,000	160,000
Airstrip (light weight aircraft)	225,000	250,000
Helipads (6 to 18 helidecks + hangar)	45,000	135,000
Other (roads, etc.)	20%	20%
Total	**2,120,000**	**6,400,000**

6.1.2 Types of Island

Multiple island alternatives are possible. Each island type has its own pros and cons and some are thus more suitable to meet the determined criteria. The various island types can be roughly divided into three groups. Reclamation islands and polders can be summarised as “fill islands”. Caissons, piled platforms, jackets and gravity based structures are classified as “fixed islands”. Moored platforms and tension leg platforms are classified as “floating islands”. An overview of these island types is presented in Figure B.1.



(a) Reclamation Island (b) Polder (c) Caisson (d) Piled

(e) Jacket (f) Gravity Based (g) Moored (h) Tension leg

Figure 6.6: Overview of Artificial Island Types

Fill islands are not subject to movement or vibrations caused by wind and wave loads. Furthermore, the consequences of a collision or sabotage are smaller compared to fixed or floating concepts. Artificial islands are cheap, easier to maintain and are better accessible during bad weather conditions. Disadvantages are however the in-situ construction under less favourable conditions and removal of the island might require large efforts. Shore protection is often applied to prevent the island from eroding.

Fixed islands can be prefabricated and mass produced under a controlled environment, with the additional advantage that they are more stable compared to floating islands. These structures are however vulnerable to collisions and sabotage and are difficult to access during bad weather conditions. The soil condition for fixed islands is important and requires preparation of the seabed.

Floating islands can also be prefabricated and mass produced under controlled conditions. The floating island can be placed in very deep waters and stability is not much affected by poor soil conditions. At the end of its operational lifetime the structure can be easily moved back to shore where it will be dismantled. There are however also some disadvantages. Floating structures have a higher risk on failure as they can sink and are vulnerable to ship collisions and sabotage. There are high maintenance cost due to anchoring, accessibility is poor during bad weather conditions and the floating island is furthermore subject to movements caused by wind and wave loads.

There are also various hybrid island types which combine the mentioned characteristics, but for simplicity these hybrids will not be treated. The most common island types have been elaborated and a quantitative comparison of these islands is presented in Table 6.5.

Table 6.5: Comparison of Island Type Characteristics (source: Sincoff and Dajani, 1976)

	Structural type	**Typical water-depth (m)**	**Relative cost**	**Design life (years)**	**Annual maintenance (% of capital expenditure)**
Fill island	Reclamation	0 - 30	28 - 100%	50 - 100	1 - 2%
	Polder	0 - 20	0.8 - 16%	50 - 100	2 - 5%
Fixed island	Piled	0 - 90	144 - 1,440%	25 - 50	5 - 10%
	Jacket	30 - 250	2,000 - 20,000%	20 - 30	5 - 10%
	Gravity based	100 - 300	2,000 - 20,000%	25 - 40	0 - 5%
Floating island	Moored platform	15 - 300	480 - 1,200%	20 - 40	5 - 10%
	Tensioned to base	300 - 600	1,200 - 48,000%	20 - 30	5 - 15%
	Moored to anchors	150 - 6000	1,200 - 48,000%	20 - 40	5 - 10%

The characteristics of fill islands are best suiting the determined criteria for the Hub and Spoke concept. The most important criteria is the very high degree of security. Fill islands are not subject to vibrations or movements and are the most rigid solution with respect to ship collisions and sabotage. The typical water depth of 0 - 30 m is similar to the typical water depth of offshore wind turbines and the design lifetime is equal to the determined lifetime of 100 years. A fill island is furthermore the cheapest solution for these local conditions and is therefore used for the Hub and Spoke concept. There are two types of fill islands: reclamation islands and polders. Polders contain a higher risk of failure and therefore a reclamation island is used for the Hub and Spoke concept.

6.1.3 Island Design

The main variables in the design of reclamation islands are the shape of the island, required area, island height, crest height and the slope of the shore protection.

- Island Shape
- Required Area
- Island Height
- Crest Height
- Slope of Shore Protection

A circle is the most efficient shape in terms of surface area to perimeter and results in most island area to shore protection surface. The shape of the island does however not necessarily have to be circular and it might be more beneficial to follow the shape of the seabed. The island will get a more natural shape and is likely to have a smaller impact on currents and morphology. Another shape might also follow some of the structural criteria like the elongated shape of the airstrip. This structure must face the dominant wind direction to limit cross-winds and reduce runway length, while the harbour is beneficially positioned on the lee side of the island with lowest wave heights. Another aspect which could be incorporated in the design is a modular approach. This increases the flexibility of the island in time and increases value on the long term. The consequence of choosing a non-circular island shape is the increased sediment volume and coastal protection surface for the same usable island area, but the design and cost of a reclamation island are dependent on more variables and a different shape might be more beneficial. The detailed design will be based on the local conditions and design criteria of the structures on the island, but for the scope of this thesis it is too specific and the island is therefore simplified to a conical shape with coastal protection as presented on the cover.

The dredging volume of the reclamation island is calculated with the formula of a conical volume. The radius of the island surface r follows from the required area A. The slope of the island and local water depth determine the radius of the island on the seabed r_0. The volume of the reclamation island V can be determined with eq. 6.4:

$$r_0 = r + \frac{h}{slope} \tag{6.2}$$

$$V = V_{total} - V_{top} \tag{6.3}$$

$$V = (1/3) \cdot slope \cdot \pi \cdot r_0^3 - (1/3) \cdot slope \cdot \pi \cdot r^3 \tag{6.4}$$

Figure 6.7: Reclamation Island Visualisation

The required weight and volume of the shore protection is determined by the height, slope and armour unit elements of the reclamation island in combination with the design wave conditions. The slope surface SA which needs to be protected is calculated with eq. 6.5:

$$SA = \pi r_0^2 + \pi r_0 \sqrt{r_0^2 \left(1 + slope^2\right)} - \pi r^2 - \pi r \sqrt{r^2 \left(1 + slope^2\right)} \tag{6.5}$$

In Figures 6.8 and 6.9 the influence of area, slope and height on the reclamation volume is presented. It can be seen that the island volume increases significantly and as good as linear with the required area, whereas the slope of the reclamation island contains a much smaller influence on the total island volume.

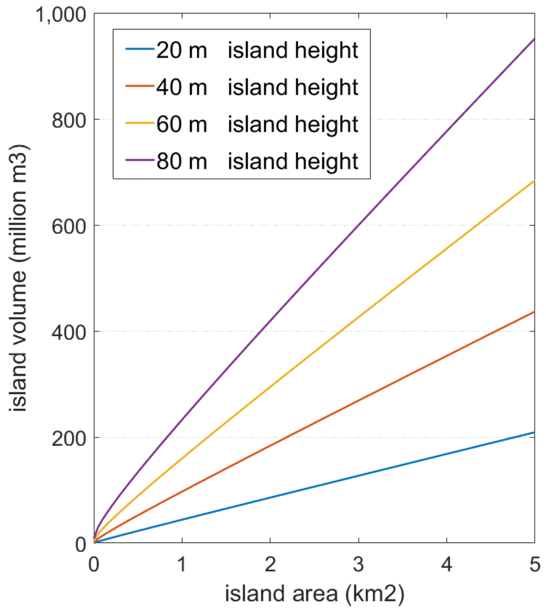


Figure 6.8: Island Volume as a Function of Area and Height (slope 1V:4H)

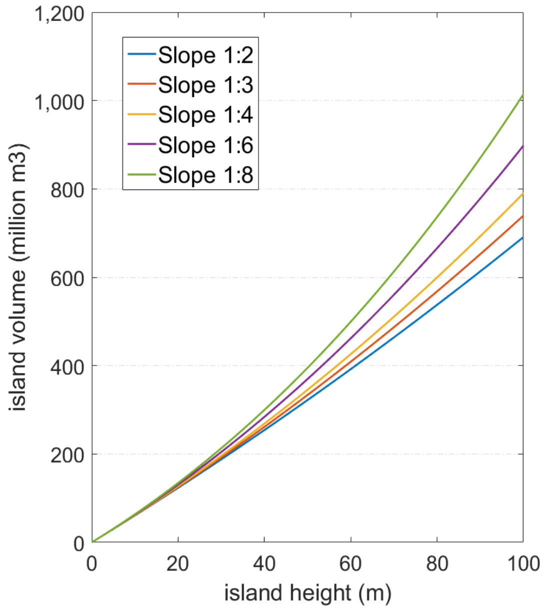


Figure 6.9: Island Volume as a Function of Height and Slope (area 6km2)

6.1.4 Island Expenditure

The cost of constructing the reclamation island is determined by the unit cost of shore protection and dredging operations, multiplied with the respective island volume and surface.

Unit Cost Shore Protection

The island can be protected with various methods. One extreme is the use of a gravel beach with very shallow slope. The profile will be continuously changing due to the changing wave characteristics and longshore transport. The other extreme is a statically stable shore protection where the weight of the elements in the armour layer is high enough to withstand the forces of incoming waves. Stable shore protections can be constructed under much steeper slopes and thus require less dredged material. Minimum island expenditure is achieved by the optimal balance of cost between dredged volume and the cost of shore protection. However, the island must be always operational and it is therefore chosen to construct a stable shore protection.

The island should be able to resist a 1/10,000 years storm. The armour layer of the shore protection can be constructed with natural rocks or concrete elements. The design wave conditions in the North Sea have been determined in Figure 6.4 and range between approximately $H_s = 6 - 16\ m$ and exert considerable forces on the shore protection. The standard grading of natural rock is however limited to 6-10 tons and heavier elements are likely required. The armour layer is therefore constructed with concrete Xbloc elements and the minimum unit weight is determined with the Hudson formula presented in eq. 6.6.

$$M = \frac{\rho_s\ H_s^3}{K_D\ \Delta^3\ cot\ \alpha} \tag{6.6}$$

The minimum element mass M (kg) for a stable shore protection is dependent on the element density ρ_s (kg/m^3), significant wave height H_s, damage coefficient K_D $(-)$, relative density Δ $(-)$ and slope angle α $(deg.)$. The slope correction term $cot\ \alpha$ is however simplified to such extent that the validity of Hudson's formula is limited to $1.5 < cot\ \alpha < 4.0$. Furthermore, the formula is based on experiments with a permeable breakwater. Despite the shore protection being very permeable, the sand body behind it is much less permeable and this has to be kept in mind when applying the Hudson formula. The permeability of the core is accounted for by a correction factor, but the Van der Meer formula could also be applied which is valid for multiple permeabilities.

Delta Marine Consultants (henceforth DMC) is the producer of Xblocs and advises to apply the elements between slopes of 1V:2.25H and 3V:4H, which is equal to $1.33 < cot\ \alpha < 2.25$. This falls partly outside the applicable range of Hudson, but the minimum weight of Xblocs is always determined for $cot\ \alpha = 1.33$ with a damage coefficient $K_D = 16$. According to Hudson a milder slope would lead to lighter elements, but this reduces the interlocking forces of the elements and the unit weight of Xblocs is therefore not reduced. The steepest slope of 3V:4H is therefore used to maximise interlocking forces and to minimise the required dredging volume. Although the minimum unit size is mainly determined by the design wave conditions, there are also a number of conditions which may require the application of larger unit sizes. These conditions are presented in Table 6.6. The greatest correction factor should be used when multiple correction factors are applicable, although it must be noted that these factors only give a first indication on the required element size. It is always advised to perform physical model tests for detailed designs.

Table 6.6: Correction Factors for Xbloc Protection

Condition	**Criteria**	**Correction factor**
Steep foreshore	Steepness between 1:30 and 1:20	1.1
	Steepness between 1:20 and 1:15	1.25
	Steepness between 1:15 and 1:10	1.5
	Steepness greater than 1:10	2
Large water depth	Water depth $>2.5\ H_s$	1.5
	Water depth $>3.5\ H_s$	2
Low core permeability	Low core permeability	1.5
	Impermeable core	2

The use of correction factors differs per location. A steep foreshore may lead to adverse wave impact against the shore protection, although the steepness is very site specific and must therefore be determined in the detailed design. Larger water depths reduce overall stability as the largest waves in the spectrum exert the highest loads on the shore protection. In shallow waters the ratio between the highest waves in the spectrum and the significant wave height is around 1.2 - 1.4, while for larger water depths this ratio can be up to 1.8 - 2.0. Furthermore, shore protections at large water depths often contain a high rock toe which can affect wave breaking and leads to rocking of the concrete elements. Lastly, a correction factor is applied for the permeability of the core as the formula of Hudson is only valid for permeable breakwaters. Low- and impermeable cores can lead to large pressures in the armour layer which reduce stability. Wave penetration in sand is almost negligible (Schiereck and Verhagen, 2012) and the core is therefore considered impermeable with a correction factor of 2.0.

Another restriction is the maximum number of rows. Long slopes with Xbloc shore protection could result in considerable settlements and therefore no more than 20 rows should be used. When the slope is longer than $0.5 \cdot D + 19 \cdot D_y$ there are two possible solutions: the unit size can be increased or the toe level can be raised by applying a rock berm. However, the second solution might alter the incoming wave characteristics and could still result in larger unit sizes. The largest possible Xbloc contains a diameter $D = 3.91\ m$ with an up-slope length $D_y = 2.47\ m$. Under a maximum slope of $cot\ \alpha = 1.33$ this leads to the greatest vertical height difference of 29.3 m. Offshore wind farms in the North Sea are however also constructed in deeper waters and part of the shore protection also rises above mean sea level. The maximum water depth is therefore even lower and the application of rock berms is often necessary.

The rock toe is designed to support the armour layer and prevent sliding down of the elements. The North Sea mainly consists of sand and the toe is therefore designed based on a sandy seabed. From bottom to top the toe starts with a granular filter with minimum height of 0.5 m, possibly in combination with geotextile. Rocks are subsequently dumped on top of the filter to form the foundation layer for the Xbase element. The Xbase elements are slightly different from Xbloc elements and flat on the bottom, which increases stability and makes it more easy to install the first row of Xblocs. The rock size in the foundation layer usually contains a median weight W_{50} equal to one-thirtieth of the Xbloc unit weight, which corresponds to 1.8 - 2.4 t. It must be noted that Xblocs are often applied to breakwaters with a permeable core where the interaction between the under layer and core is usually not a problem, but in this case the Xblocs and under layer are resting on a core made out of sand. The difference between the nominal diameter of sand and 1.8 - 2.4 t rocks is very high and a filter must be applied to protect the core from erosion, but the situation is simplified and the filter is not included. Finally, rocks are dumped in front of the Xbase to create a toe and prevent the armour units from sliding down. The size of these rocks depends on the water depth and wave height and can be calculated with eq. 6.7.

$$D_{n50} = \frac{H_s}{\left(2 + 6.2\left(\frac{h_t}{h}\right)^{2.7}\right) N_{od}^{0.15} \Delta} \tag{6.7}$$

The median nominal rock diameter D_{n50} (m) is dependent on the significant design wave height H_s (m), water depth above toe h_t (m), water depth in front of toe h (m), number of displaced units N_{od} and the relative concrete density Δ $(-)$. The number of displaced units is set to $N_{od} = 0.5$ which indicates the start of damage. The rock berm must furthermore be at least $2 \cdot D_{n50}$ high and $3 \cdot D_{n50}$ wide. It must be noted that the shore protection is designed to the design wave conditions from the normative direction. It is possible to use smaller elements for the remaining parts of the shore protection which face smaller wave heights. The maximum transition should however not be larger than two times the unit size.

The material dimensions have been determined and the toe is designed. The last part of the shore protection to design is the crest with required crest height, crest width, access to the breakwater and the allowable overtopping volume. The crest height is determined by the allowable overtopping discharge which can be calculated with eq. 6.8. The crest height $R_c =$ should be at least one time the design wave height H_s and a crown element will be installed on top of the crest. The shore protection is designed to very high waves and it will therefore rise considerably above mean water level. Without a crown element the crest would be inaccessible to people or equipment, but now it is accessible and equipment can be used to construct and maintain the upper part of the shore protection. Next to the crown element at least two Xblocs should be installed and the island must furthermore always be operational. Damage to the electrical infrastructure should be prevented at all times, but the essential infrastructure will not be installed near the shore protection to reduce the risk of failure. Instead, the essential infrastructure will be situated somewhere in the middle of the island and possibly on an elevation, thereby allowing some overtopping. A mean overtopping discharge of $q = 0.4\ l/m/s$ leads to some damage of equipment and is allowed to be the maximum overtopping volume.

$$\frac{q}{\sqrt{g\ H_{m0}^3}} = 0.2\ exp\left(-2.3\ \frac{R_C}{H_{m0}\ \gamma_f\ \gamma_\beta}\right) \tag{6.8}$$

The overtopping discharge q $(l/s/m)$ is dependent on the acceleration of gravity g $(9.81\ m/s^2)$, wave height calculated from the zero th moment from the spectrum H_{m0} (m), crest level above still water level R_c (m), roughness coefficient γ_f $(-)$ and angle of attack coefficient γ_β $(-)$. The wave height H_{m0} is an estimate of the significant wave height H_s, but generally the estimation is accurate and especially for deep waters the difference is very small. The situation is therefore simplified and the significant wave height H_s in front of the shore protection is used. The roughness correction factor γ_f is equal to 1.00 for smooth slopes like asphalt or concrete blocks, but for permeable slopes the wave run-up and overtopping discharge is reduced. The roughness coefficient factor for single layer Xblocs is $\gamma_f = 0.44$. (Bruce et al., 2009) The correction factor for angle of attack is applied to waves coming from other angles than the perpendicular direction with the shore protection. The artificial island can however be attacked from all directions and there is always a part of the shore protection with incoming waves under the perpendicular direction. The correction factor for the angle of attack is therefore $\gamma_\beta = 1.00$. Schiereck and Verhagen, 2012

The cross-section of a Xblocs shore protection is presented in Figure 6.10. Dimensions and stone gradings are not included as this will vary across the North Sea.

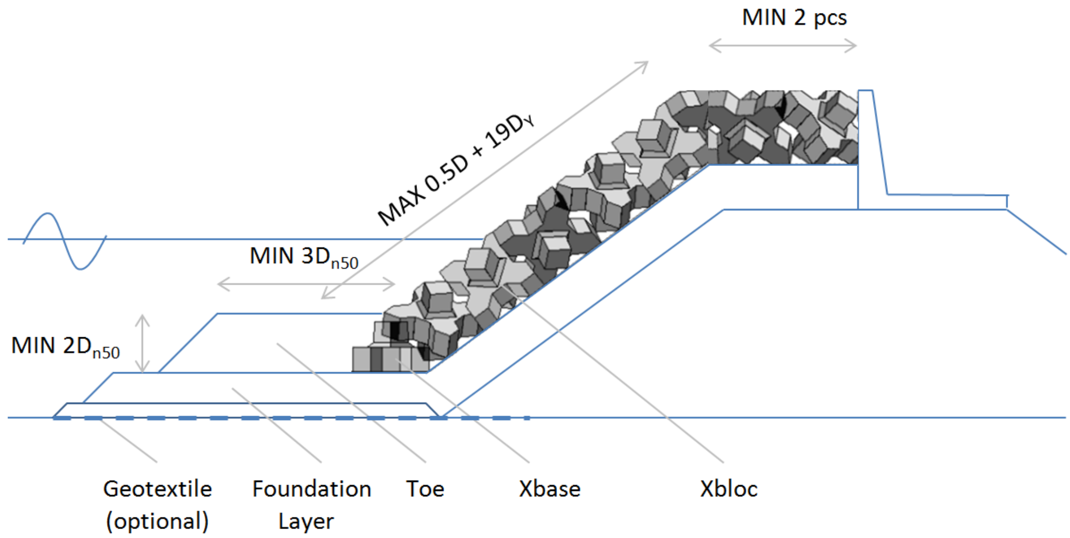


Figure 6.10: Cross-Section Xbloc Shore Protection (Not On Scale)

The method elaborated above is used to design the shore protection for Dogger Bank. The local water depth is assumed to be 20 m with a sandy seabed and a design wave height of $H_s = 7.72\ m$. Using the Hudson formula the minimum Xbloc unit weight with $\rho_s = 2,400\ kg/m^3$ is 22.1 t. The standard Xbloc constructed by Delta Marine Consultants fulfilling this criteria weighs 24.0 t and will be used in further calculations. The steepness is very site specific and will not be included in the preliminary design. The water depth is however meeting the criteria $20 > 2.5 \cdot H_s$ and the core made out of sand contains a low permeability, with respectively correction factors of 1.5 and 1.5. Only the greatest correction factor needs to be included and results in a higher minimum Xbloc unit weight of 33.1 t. The first standard Xbloc meeting this criteria weighs 33.6 t and will be used in further calculations. The unit weight is determined for a slope of 3V:4H and is not reduced by applying a milder slope. The amount and associated expenditure of shore protection is thus increasing for milder slopes as more surface needs to be protected. The maximum slope of 3V:4H is therefore applied, which contains maximum interlocking forces of the Xblocs and also reduces the required amount of dredged material. The foundation layer underneath the Xblocs usually contains a median weight of one-thirtieth the unit weight of the applied Xblocs, which is equal to rocks of 1.12 t in the standard grading 1-3 tons. The toe rock size is calculated with the Van der Meer formula and is equal to $D_{n50} = 1.00\ m$, which falls is the standard rock grading 3-6 tons. The granular filter is assumed to be 0.5 m and the under layer is advised by DMC to be 1.8 m thick. The Xbase and Xblocs are installed above this material at 17.7 m water depth and should reach up to one significant design wave height above mean sea level. The unit height and up-slope distance of 33.6 t Xblocs is respectively 3.48 m and 2.19 m. Above the Xbase there should be 11 Xblocs to reach a crest height of 7.72 m. On top of the crest 2 additional Xblocs and a crown element are installed to reduce the core volume and provide access to onshore equipment to construct the upper part of the shore protection. Finally, the design is checked for overtopping. The shore protection contains a mean overtopping discharge of $q = 0.07\ l/s/m$ which is safe enough for the buildings and personnel behind the shore protection. The required shore protection volume and corresponding expenditure are presented in Table 6.7 with unit costs provided by engineers from Witteveen+Bos. Construction of the shore protection contains a considerable part of total expenditure and is assumed to be equal to material expenditure.

Table 6.7: Xbloc Shore Protection Expenditure at Dogger Bank (27.7 m high, 100 m wide, slope 3V:4H)

Component	**Weight**	**Unit Cost**	**Volume (m2)**	**Weight (m2)**	**Total Cost (m2)**
Xbloc	33.6 t	€2,600/pcs	0.108 pcs	-	€280,-
Foundation Layer	1 - 3 t	€25/t	2.670 m3	4.400 t	€110,-
Toe	3 - 6 t	€25/t	0.290 m3	0.480 t	€12,-
Rock Berm	-	€25/t	-	-	-
Total Material					€402,-
Installation Cost					+100%
Total Cost					**€804,-**

The water depth and wave conditions are different across the North Sea and the shore protection is therefore unique for each location. The water depth and significant design wave height at Dogger Bank are not exceptional compared to other locations in the North Sea, but the shore protection already requires very large and heavy Xblocs while there is a limit to the unit size. The concrete elements are not reinforced with steel to prevent corrosion. The maximum unit size is therefore completely dependent on the tensile strength of concrete and limits the production of Xblocs to 48.0 t. Some locations in the North Sea might however require heavier elements. Possible solutions to reduce the required unit weight of Xblocs is to use a permeable core of rock or the application of a rock berm. The latter option is especially used for greater water depths and breaks the incoming waves before the shore protection is reached, thereby reducing the wave forces and enabling lighter Xbloc elements. The method followed above needs to be applied for every location in the North Sea, but the design is simplified and the cost per square meter shore protection is assumed to be constant with €804.00/m2.

Unit Cost Dredging

The price per cubic meter of dredged sediment is dependent on multiple factors like the soil characteristics, dredging vessel type, vessel capacity, number of operational hours per week and the distance between dredging and unloading. There are multiple dredging vessel types suitable for different kinds of conditions. The two main types are Trailing Suction Hopper Dredgers (henceforth TSHD) and Cutter Suction Dredgers (henceforth CSD). TSHD's can suck up sand, clay, silt or even gravel from the seabed with one or two drag heads mounted on suction tubes. The vessel sails slowly while the drag heads suck up sediment with powerful pumps, after which the sediment is collected in the "hopper" of the vessel. Once the hopper is filled it can be emptied in multiple ways. The bottom doors can be opened, the sediment can be transported with pipelines or it can be blown away by a powerful nozzle located on the front of the ship. It is also possible to dredge sediment with CSD's. These vessels have a rotating cutter head mounted on a ladder in front of the ship. The cutter head contains a suction mouth and the dredged material is sucked up along the ladder with powerful pumps. The sediment is however not stored on the vessel like with TSHD's, but directly loaded onto barges or transported to the destination with pipelines. On the back of the ship there are two poles. One is the spud pole which is penetrated into the seabed to create a stable position. By pulling on steel wires connected to anchors on either side of the cutter head the vessel is able to exert lateral forces and dredge sediment in an arc around the spud pole. After the cutter head made a full swing and dredged all sediment the CSD uses its poles to move forward. The auxiliary pole is penetrated into the seabed and the spud pole is lifted, enabling the vessel to push itself forward with some meters. The spud pole is penetrated into the seabed again and the auxiliary pole is lifted, after which the cutter head can make a new swing and the whole process is repeated.

Figure 6.11: Trailing Suction Hopper Dredger

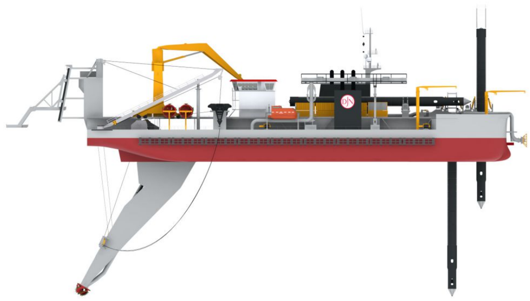


Figure 6.12: Cutter Suction Dredger

TSHD's have their own propulsion leading to a great manoeuvrability without the need of anchor wires. They furthermore have a high level of seaworthiness, can work independently from other equipment, have a high productivity and can discharge their load in multiple ways. This makes TSHD's especially suitable for deepening and maintaining channels and harbours, execute beach nourishments and hydraulic filling of new harbours and reclamation islands. These dredging vessels are however less suitable for harder soil types as the limited weight of the drag head prevents large cutting forces. CSD's are more suitable for the harder soil types as they can exert stronger forces with their heavy ladder and great cutter power. They are however also used for softer soils like sand and clay and have a higher accuracy.

The reclamation island requires a very large amount of dredged sand and the open conditions on the

North Sea with sea and swell waves cause TSHD's to be more suitable for the project. The North Sea contains several areas which are appointed for sand extraction. These locations are presented in Chapter 3 in Figure 3.6d, but the function of these areas might change over time and the scale and location of the artificial island could make an alternative location for the extraction of sediment desirable. The reclamation island is envisioned to be constructed on Dogger Bank. The Hub and Spoke concept would benefit most from the shallow water conditions if the island is constructed somewhere in the middle of Dogger Bank, where offshore wind turbines would have the greatest area with shallow water conditions. However, dredging operations create local turbidity as sediment is separated from the seabed and mixes with the surrounding water. The turbidity reduces sunlight reaching the seabed and this negatively affects the prevailing ecology. The level of turbidity varies with the dredging method, but it may be expected that the sediment extraction area will lie outside the Natura 2000 territory to minimise the impact on ecology. Both desires cause the sailing distance for the dredging vessels to increase. Dogger Bank is approximately 100 km wide and the maximum sailing distance is thus 50 km. The cycle time of dredging vessels can now be determined in combination with the hopper capacity, sailing speed and (un)loading rate. The first part of the island is created with dredging vessels unloading their capacity through the bottom doors. This process is vary rapid and takes only 5 to 10 minutes. At some point the minimum water depth has been reached and unloading through the bottom doors is no longer possible. At this point the sediment is unloaded by a powerful nozzle on front of the vessel, which blows the sediment through the air and lets the island rise above the water level. This process called rainbowing is often applied to finish the island without the need of costly pipelines and tug boats. Both methods require however a longer period to unload compared to discharging through bottom doors. The vessels are furthermore assumed to work with multiple shifts continuously 168 hours a week, although the actual operational hours will be somewhat lower due to mechanical and operational downtime. With these parameters and the characteristics of the dredging vessel the cycle time can now be calculated.

The cost and productivity is based on a TSHD with 35,000 m^3 hopper volume. The chosen dredging vessel is in the higher range regarding capacity, because the reclamation island requires a vast amount of sediment and economies of scale is also present in the dredging industry which reduces the cost per cubic meter. It is assumed that 6 TSHD's with a large hopper volume are working around the clock for 4 years straight, although this is a trade off between project duration and the number and capacity of dredging vessels which is largely dependent on the availability of vessels in the region. The assumptions are based on the Port of Rotterdam extension called Maasvlakte 2. The first phase required approximately 275 million cubic meters of sand, which took roughly 4 years to dredge with on average 10 TSHD's. The reclamation island of the Hub and Spoke concept is comparable. The volume is largely dependent on the water depth, but ranges roughly between 50 and 500 million cubic meters of sand for respectively 2.1 km^2 to 6.4 km^2 surface as can be seen in Figure 6.8. The weekly expenditure of dredging equipment is explained in more detail in Appendix B.5. The vessel characteristics, cycle time and weekly expenditure on dredging equipment are presented in Table 6.8, leading to the unit cost per cubic meter dredged sand of €3.26 / m^3.

Table 6.8: Trailing Suction Hopper Dredger (TSHD) Productivity and Expenditure

		Trailing Suction Hopper Dredger
Productivity	Hopper volume	35,000 m3 (24,000 m3 sand)
	Loading rate	24,000 m3 / hour
	Unloading rate	instant / 12,000 m3 / hour
	Sailing speed	17 km / hour
Cycle Time	Pumping time	60 min.
	Sailing (full)	180 min.
	Unloading	10 min. / 120 min.
	Sailing (empty)	180 min.
		+
	Total cycle time	430 min. / 540 min.
	Working schedule	168 hours
	Mechanical downtime (3%)	- 5 hours
	Operational downtime (15%)	- 25 hours
		+
	Operational hours / week	138 hours
	Cycles per week	15 to 19
	Weekly production	**360,000 m3 to 456,000 m3**
Weekly Expenditure	Depreciation and Interest $(D + i)$	€619,040
	Maintenance and Repairs $(M + R)$	€200,220
	Salary	€61,000
	Fuel and Lubricants	€182,160
	Insurance	€148,400
		+
	Subtotal	€1,210,820
	Overhead (20%)	€242,164
		+
		€1,452,984
Total Project Expenditure	Number of vessels	6
	Mobilisation (1.0 week)	6 x €1,210,820
	Project duration (4 years)	6 x €251,850,560
	Demobilisation (0.5 week)	6 x €605,410
		+
		€1,522,000,740
Indexation	TSHD +7.0%	**€1,628,540,792**
Dredged Volume		**500 million m3**
Unit Cost		**€3.26**

As can be seen in Table 6.8 there are a lot of parameters influencing the unit cost of dredged material. One of the assumptions is the 50 km distance between the extraction and reclamation area. Reducing the distance by half would result in a dredging unit cost of €2.05 / m^3 (-37%), although the location of the sediment extraction area is dependent on factors like Natura 2000 territory, soil conditions and the maximum dredging depth. TSHD's can dredge up to depths of 50 m and and it is even possible to dredge till greater depths with offshore suction dredgers (Vlasblom, 2003), although it is unlikely that the optimal location for the reclamation island is situated at such great water depths as this would also increase the cost of surrounding offshore wind turbines. Sediment would have to be collected further from the reclamation island, leading to an increased cycle time and higher unit cost of dredging.

Another assumptions is the 15% downtime in operational hours caused by the wave conditions at Dogger Bank. TSHD's can work up to significant wave heights of $H_s = 2.0 - 4.0$ m (Schrieck, 2015), while the wave conditions and thus the percentage operational hours are different across the North Sea. In Figure

6.13 the percentage operational hours under $H_s = 3.0$ m is presented. It can be seen that the southern and shallow parts of the North Sea contain a higher percentage of operational hours up to 95%, while further north in the deeper parts the percentage decreases to 80%. The production and unit cost are linearly affected, hereby changing the dredging unit cost to respectively €2.93 / m^3 (-10%) and €3.42 / m^3 (+5%) compared to dredging operations at Dogger Bank. Each significant wave height in Figure 6.13 is averaged over a 3-hour period. The time interval of measurements should become shorter and subsequently be matched with the dredging vessel cycle time in order to gain a more accurate percentage of operational hours.

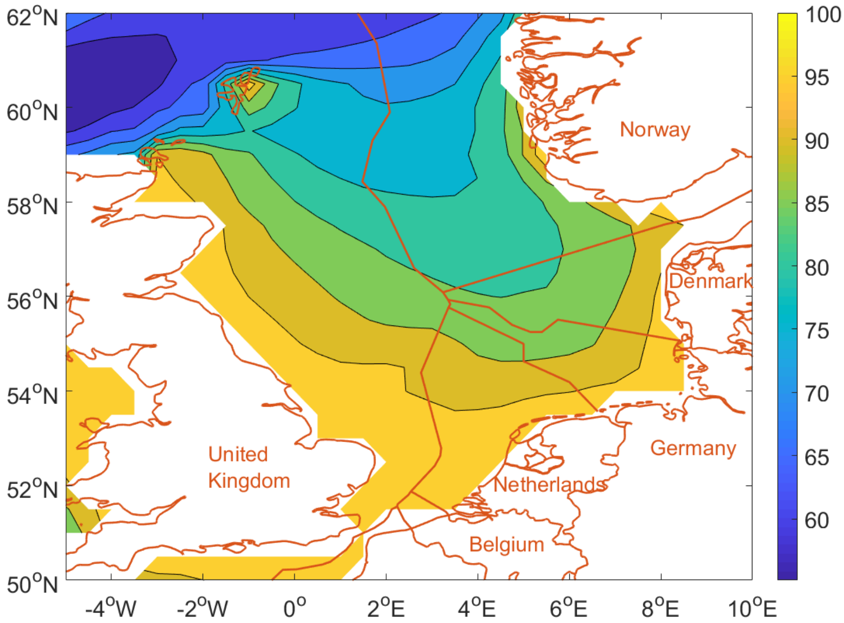


Figure 6.13: TSHD Percentage Operational Time as a Function of $H_s <= 3.0$ m (2012 - 2016)

There is also a seasonal variation in significant wave heights. In Figure 6.14 the wave conditions at Dogger Bank for the year 2016 are presented and it can be seen that during winter the significant wave heights are on average higher compared to summer. Dredging operations are therefore preferred to be done in summer to maximise the operational hours. However, this is conflicting with ecology as the summer period is primary production season for various species. Certain locations like the Western Scheld forbid dredging operations during summer (Arcadis, 2015) and other Natura 2000 areas might also have such a restriction. This could have a significant influence on logistics and the unit cost of dredged material if the reclamation island is going to be built on Dogger Bank. The situation is however simplified and time restrictions are not included in the calculation. Locations without significant ecological value have no restrictions with regard to dredging windows. Small dredging operations could possibly benefit from seasonal influences to maximise operational hours, but the reclamation island requires such a large amount of sediment that dredging operations will span multiple years and the seasonal influence is therefore less of a concern.

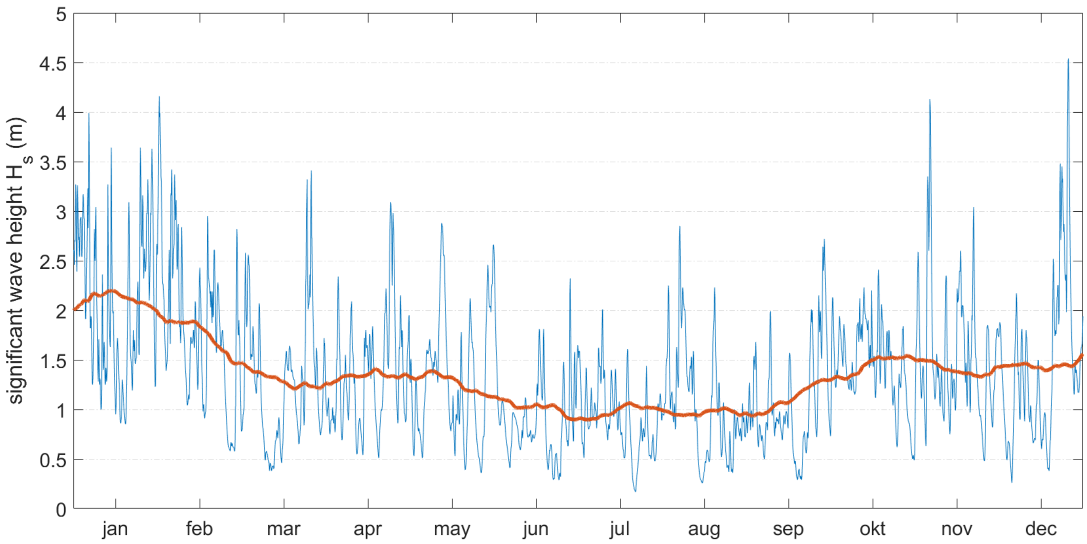


Figure 6.14: Significant Wave Height H_s per Month on Dogger Bank (2016)

Fixed Cost
The fixed costs consist of amongst others the harbour and airstrip on the island. These structures do not change for different locations in the North Sea, but are based on the requirements from the Hub and Spoke concept. The amount of structures which is included is however rather arbitrary and expenditure is not influenced by location. It will always be a fixed value and is therefore not included in the model.

Conclusion
The cost to construct a reclamation island with 2.1 km2 area and slope 3V:4H is presented in Figure 6.15. The determined unit cost of dredging is €3.26 / m3 and the unit cost of shore protection is calculated to be €804.00/m2. Fixed costs of for example the harbour or airstrip are not included. It is clearly visible that island expenditure is mainly determined by water depth. Along the coastlines and at Dogger Bank the reclamation island costs roughly EUR 200 mln, which increases up to EUR 500 mln for greater water depths.

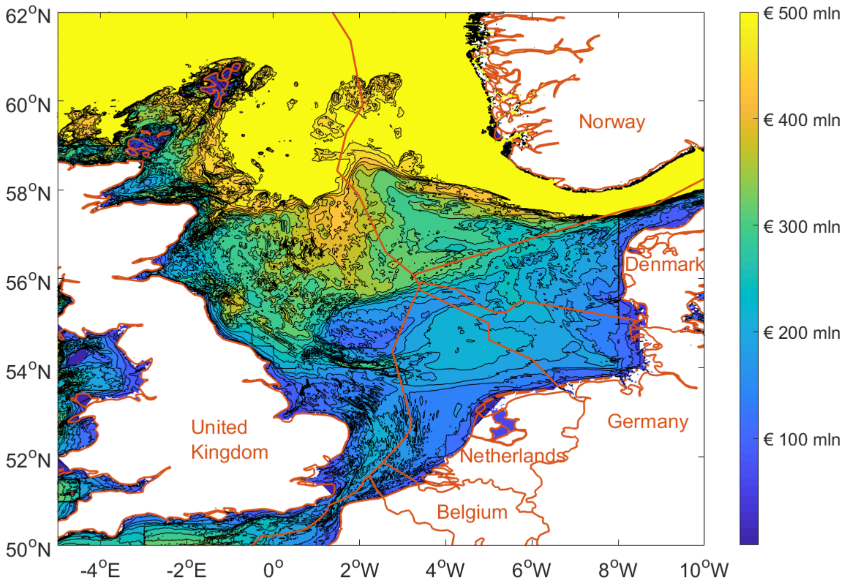


Figure 6.15: Total Expenditure for 2.1 km2 Island with Slope 3V:4H

6.2 Offshore Wind Farm

Offshore wind farms are constructed under different conditions and in a variety of configurations, thereby making the cost of offshore wind farms dependent on many variables. The corresponding cost per component is however not easy to obtain as there is a lack of public information and producers do not share information as the industry contains a high level of knowledge and competition. (Rosenauer, 2014) In literature, the common methodology to determine the cost of offshore wind farms is either by applying simple regression analysis on executed projects or the costs are determined by industry experts based on a fictional offshore wind farm with common project characteristics.

6.2.1 Literature Methodology

In Appendix C the cost per component determined by various sources is presented, but the differences are very large and most of the times only expressed per capacity or per distance. These relations are highly simplified and the cost of components is in reality dependent on more variables. For example, the cost of monopile turbine foundations is not only dependent on the weight of the turbine on top of it, which is strongly correlated to turbine capacity, but it is also a function of water depth. Two identical wind turbines require different monopile foundations for different water depths. A greater water depth requires a greater foundation and if the monopile needs to be penetrated to greater depths this could also increase the cost of installation. A possible reason for the single dependency with capacity could be the correlation between capacity and water depth. Turbine capacity could have a strong correlation with water depth and this would implicitly result in a good fit between foundation cost and turbine capacity, although in reality this dependency is not true and could lead to large errors. This phenomenon is called collinearity and might explain the very large differences in cost per component mentioned in literature.

However, despite these very large differences which can even deviate a factor two to three, offshore wind farm expenditure is primarily determined by the cost per component. Technological developments in offshore wind energy go very rapid, but a trend in time could also not be observed. To still give an indication on offshore wind farm expenditure, the costs per component determined by various sources are averaged and based on the "law of large numbers" one might assume that reality is approached reasonably. Some sources first had to be converted to Euro's and all sources have subsequently been adjusted for inflation to the year 2017. The offshore wind farm characteristics were collected from the company website of consultancy firm *4C Offshore*, which is also frequently used for scientific papers (Voormolen et al., 2016; Rosenauer, 2014). From this data base 20 offshore wind farms were selected to approximate total expenditure with the cost per component and compared with the stated project cost. The comparison is presented in Figure 6.18, although this method contains a very large average error of 50.1%. Reference is made to Appendix C.2 and F for the average cost per component and the offshore wind farm data base.

6.2.2 Adjusted Literature Methodology

The cost per component is often presented as a function of capacity, but several sources also mention the respective cost breakdown of offshore wind farms. Offshore wind farms can be divided into five phases: development & consent, production, installation & commissioning, operation & maintenance, and decommissioning. The distribution of costs over the design lifetime of offshore wind farms is presented in Table 6.9.

Table 6.9: Offshore Wind Farm Cost Breakdown (sources: We@Sea, 2009; The Crown Estate, 2010; TKI Wind op Zee, 2015)

	Reference OWF's	**We@Sea (2009)**	**The Crown Estate (2010)**	**TKI Wind op Zee (2015)**
Development and Consent	3%	1%	3%	2%
Production	43%	49%	52%	67%
Installation and Commissioning	12%	24%	20%	11%
Operation and Maintenance	37%	23%	24%	19%
Decommissioning	5%	3%	1%	1%

It can be seen that there are also some very large differences between the published reports, but other phases correspond quite well with each other. The reports published by We@Sea (2009) and The Crown Estate (2010) present a very equal distribution, while the report by TKI Wind op Zee (2015) published five years later deviates on some phases. This might be due to a number of reasons. One possible explanation could be the development in time. It can be seen that production cost is relatively increasing. The cost per component is expected to contain the strongest relation with this phase. Total offshore wind farm expenditure is therefore determined with the cost per component and production is subsequently scaled to the cost breakdown of the latest report from TKI Wind op Zee. The total expenditure approximation now contains a much better fit with the 20 selected reference projects and the average error is reduced to 24.7%.

6.2.3 Simple Regression Analysis

The previous method completely excludes local conditions, while the cost increase in offshore wind energy between 2000 and 2010 was primarily attributed to the construction of offshore wind farms in deeper waters and further from shore. It is strange that these variables are not included, because it is generally known that these variables have an influence on total expenditure. The industry is however not transparent and it is very challenging to acquire detailed cost information as almost all contracts are confidential. (Esteban et al., 2011; Voormolen et al., 2016) Therefore, another simple method often used in literature is to perform simple regression analysis on publicly available information. Basic variables like distance to shore and water depth can not be kept secret and the total project cost is often publicly available. This makes it possible to express certain characteristics as a function of total expenditure.

In Figures 6.16 and 6.17 the relation between total expenditure per installed MW with respect to water depth and distance to shore are presented. The Coefficient of Determination R^2 shows how much variation in one variable is caused by the variation in the other variable. Roughly stated, a change in expenditure per MW is thus directly related to 47.5% change in water depth and 20.1% change in distance to shore. These variables are influencing offshore wind farm expenditure, although simple regression can only include one independent variable and this is insufficient to achieve an accurate prediction.

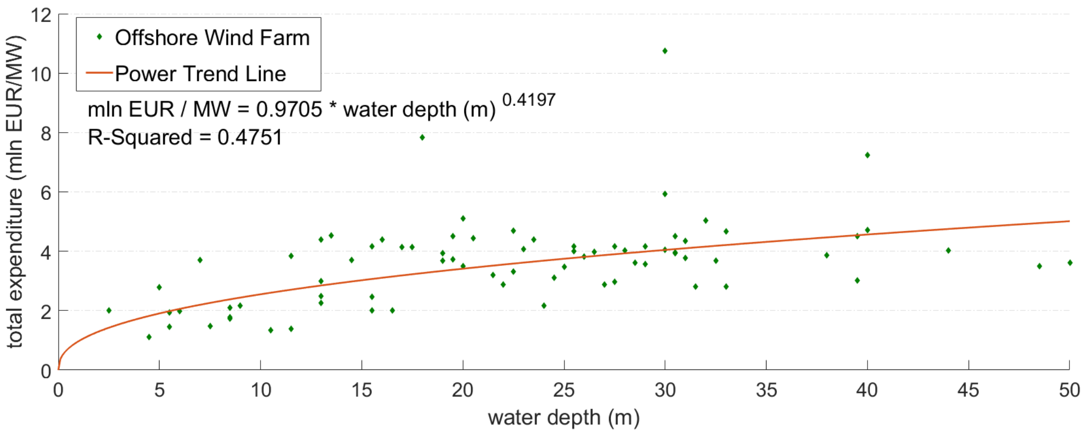


Figure 6.16: Simple Regression Analysis of Total Offshore Wind Farm Expenditure to Water Depth

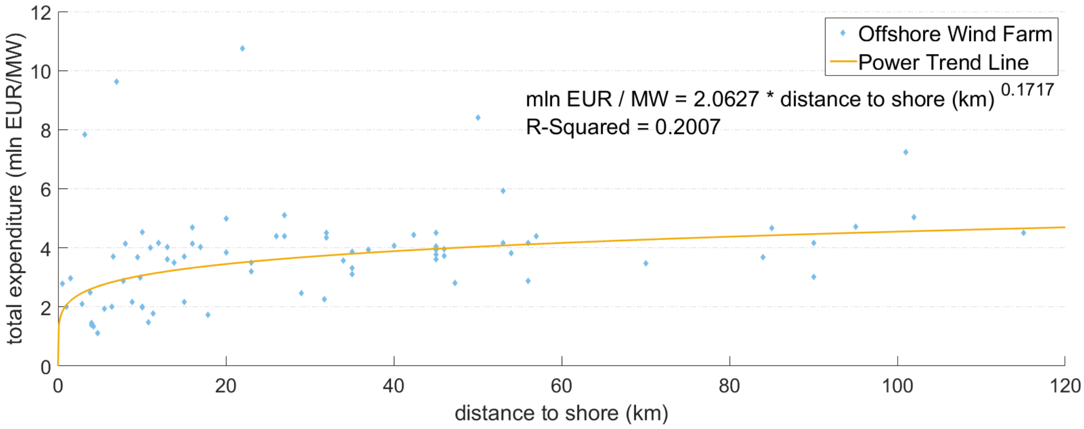


Figure 6.17: Simple Regression Analysis of Total Offshore Wind Farm Expenditure to Distance to Shore

6.2.4 Multiple Regression Analysis

Multiple variables influence offshore wind farm expenditure. A multiple regression analysis is therefore performed to examine how these independent variables influence a dependent variable. The influence of every variable can be combined and much more accurate predictions can be made. This may seem straightforward, although in literature multiple regression analysis on offshore wind farms has never been performed and the influencing variables have never been combined into a formula to predict offshore wind farm expenditure.

First, a multiple correlation analysis is performed to see how close every variable is related to the other variables. These correlations indicate how much one variable is likely to change by the change of another variable. In Table 6.10 the correlations are presented between total offshore wind farm cost, turbine capacity, offshore wind farm capacity, water depth, distance to shore and year of operation.

Table 6.10: Multiple Correlation Analysis of Offshore Wind Farms

	Cost	**Turbine Capacity**	**OWF Capacity**	**Water Depth**	**Distance to Shore**	**Year of Operation**
OWF Cost	1.00					
Turbine Capacity	0.36	1.00				
OWF Capacity	0.93	0.26	1.00			
Water Depth	0.50	0.47	0.38	1.00		
Distance to Shore	0.60	0.25	0.52	0.65	1.00	
Year of Operation	0.88	0.27	0.96	0.38	0.48	1.00

The first column of Table 6.10 shows the correlation of every investigated variable with total offshore wind farm expenditure. Offshore wind farm capacity and year of operation have a very strong relation with total expenditure, which can be seen by the correlation coefficient r close to 1.00. Water depth and distance to shore have a moderate relation. The correlation coefficient between turbine capacity and offshore wind farm expenditure is lowest but still above zero, indicating a weak relation between these variables.

The variables with the strongest correlations should be used to approximate offshore wind farm expenditure, although these variables might contain collinearity. In this situation two or more independent variables in the multiple regression contain a strong correlation with each other and may give invalid results. The remaining columns of Table 6.10 show that offshore wind farm capacity is strongly correlated to the year of operation with $r = 0.96$. One of these variables must therefore be disregarded in the multiple regression. The year of operation contains a slightly lower correlation with offshore wind farm expenditure and will therefore not be used. This results in the following variables for multiple regression in order of importance: offshore wind farm capacity, distance to shore, water depth and turbine capacity.

The objective is to gain the most accurate approximation of offshore wind farm expenditure, while using statistically significant variables. The trend line accuracy in multiple regression is expressed with the adjusted r square R^2_{adj} instead of R^2 for simple regression, because the latter value tends to automatically and spuriously increase in value when more variables are added. More variables are however not necessarily leading to more accurate predictions. The adjusted r square is adjusted for the number of independent variables in the regression. It will be always lower than or equal to R^2 and will only increase when new variables have an actual significant relation with offshore wind farm expenditure. Influencing variables are introduced in order of importance and the value for R^2_{adj} is calculated. The optimal selection of variables without any redundant terms is reached when the value for R^2_{adj} is maximum, after which it decreases when more variables are included. The maximum adjusted r square is however reached for including all investigated variables, thereby proving that all variables have a significant contribution in the approximation of total expenditure. The most accurate approximation is achieved by including the independent variables offshore wind farm capacity, water depth and turbine capacity and contains $R^2_{adj} = 0.9167$. The year of operation was already excluded as it contained a very strong collinearity with offshore wind farm capacity and could lead to invalid results. Characteristics of this regression are presented in Table 6.11 and reference is made to Appendix C.3 for the other less accurate regressions with different variable combinations.

The independent variables must also be statistically significant in order to be certain that a change in the independent variable will cause a change in the dependent variable. This is determined with the p-value for each independent variable which tests the null hypothesis of zero correlation. A low p-value means the null hypothesis can be rejected, because there is a significant correlation between the independent and dependent variable. These parameters are contributing to the accuracy of the regression and must therefore be included. In literature, it is generally accepted to use $p < 0.05$ for variables to be statistically significant and the regression must therefore meet this criteria. (Higgins, 2005) The most accurate regression with offshore wind farm capacity, water depth and turbine capacity contains a p-value which is lower than 0.05 for every variable. The derived formula is therefore statistically significant and will be used to approximate offshore wind farm expenditure.

Table 6.11: Multiple Regression Analysis of Offshore Wind Farms

	Regression Statistics
R Square	0.920
Adjusted R Square	0.917
Standard Error	297
Observations	88

	Coefficients	**P-value**
Intercept	- 129	0.1590
OWF Capacity	4.1754	3.17E-40
Water Depth	14.1526	0.0001
Turbine Capacity	-52.5587	0.0209

The standard formula for multiple regression is presented in eq. 6.9. It consists of the dependent variable which is tried to be predicted Y', the Y intercept a and the independent variable coefficients $b_{1,2,n}$ which indicate the change in Y for each unit of change in the independent variables $X_{1,2,n}$.

$$Y' = a + b_1X_1 + b_2X_2 + b_nX_n \tag{6.9}$$

The determined coefficients in Table 6.11 for offshore wind farm capacity, water depth and turbine capacity can now be applied to the standard formula for multiple regression. Total offshore wind farm expenditure can be approximated with eq. 6.10 and contains a multiple correlation coefficient of $R = 0.959$. The combined correlation between the independent variables and offshore wind farm expenditure is thus very strong and leads to accurate predictions. The formula is applied to the 20 reference projects in Figure 6.18 and contains an average error of 23.5%.

$$\begin{aligned} cost_{OWF}\ (mln\ EUR)\ &=\ -\ 129\ +\ 4.1754 \cdot OWF\ capacity\ (MW) \\ &+ 14.1526 \cdot water\ depth\ (m)\ -\ 52.5587 \cdot turbine\ capacity\ (MW) \end{aligned} \tag{6.10}$$

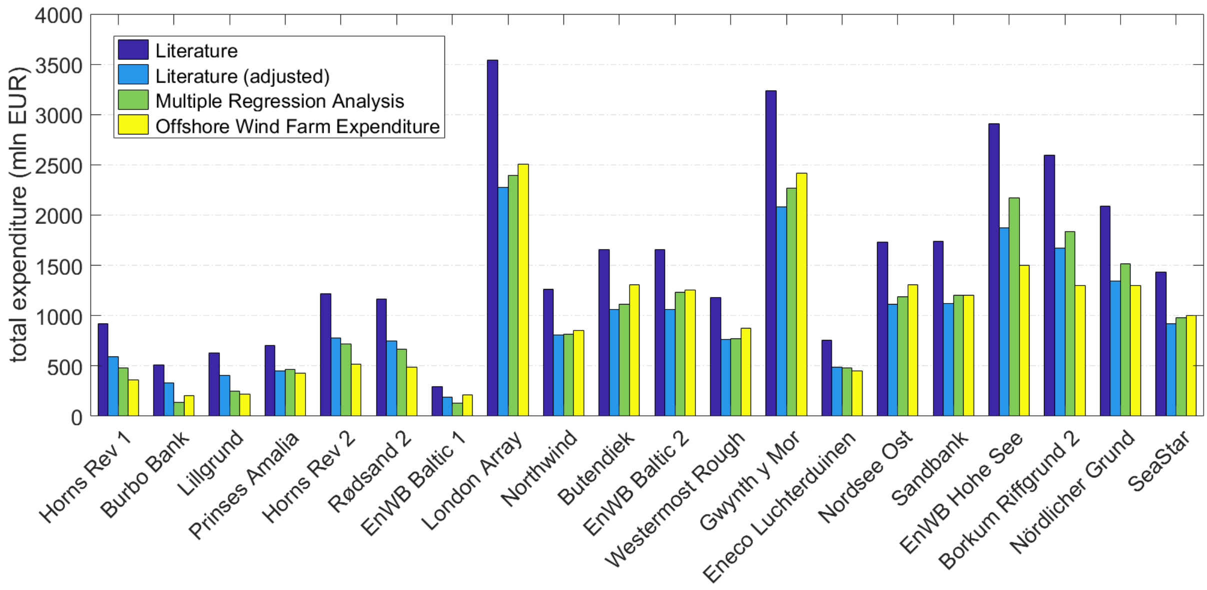


Figure 6.18: Total Expenditure Approximation of Offshore Wind Farms

There are several reasons why there is still a considerable error in determining offshore wind farm expenditure. Stated project costs for example are often rounded to €100 mln and the definition of stated project costs even differs per country. Capital expenditure in the United Kingdom, the Netherlands and Belgium includes all components up to the onshore substation, while in Germany only the components up to the offshore substation are included and in Denmark only the offshore wind turbines and their foundations are included. The reason for these differences is the division in responsibility between the offshore wind farm developer and the national TSO. It is difficult to retrieve offshore wind farm characteristics and even more difficult to adjust the stated costs per project, although it is mentioned in literature that Germany and Denmark would have higher capital expenditures of respectively 20% and 18% when the same definition of capital expenditure is used as in the United Kingdom, the Netherlands and Belgium. (Voormolen et al., 2016) Taking these factors into consideration makes it understandable why the average regression error is still considerable with 23.5%. Based on publicly available information this is however the best possible approximation on offshore wind farm expenditure and a significant improvement compared to the methodologies used in literature. The average error is still considerable and the industry needs to become more transparent in order to make more accurate predictions.

In Figure 6.19 the approximated offshore wind farm expenditure is presented for the entire North Sea, based on the determined multiple regression formula.

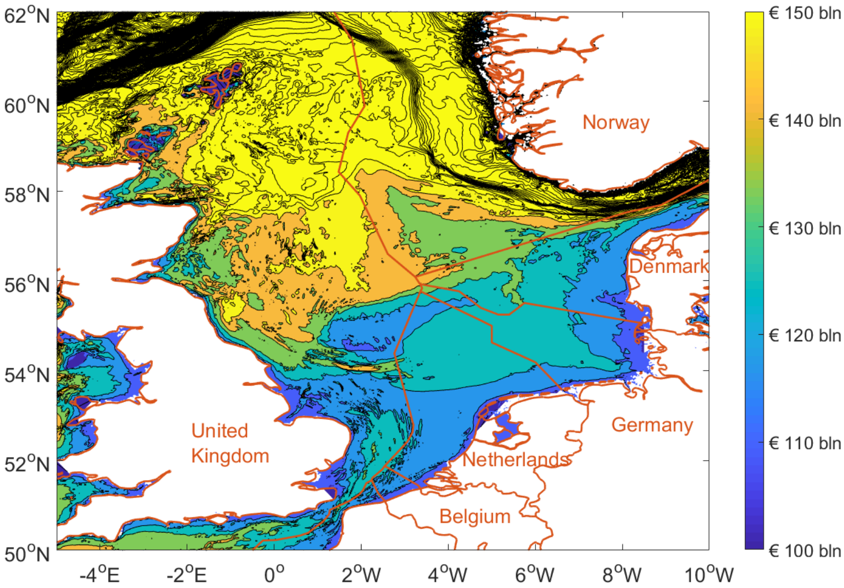


Figure 6.19: Total Expenditure 30 GW Offshore Wind Farms with 10.0 MW Turbines in the North Sea

6.3 Subsea Interconnector

Subsea interconnector cables are also constructed under different conditions and in a variety of configurations. In literature, total expenditure is often determined based on rules of thumb, but there rules are different between sources and contain a large average error. Multiple regression is therefore performed to approximate total subsea interconnector expenditure. The correlations between the investigated variables is presented in Figure 6.12.

Table 6.12: Multiple Correlation Analysis of Subsea Interconnectors

	Cost	**Capacity**	**Distance (onshore)**	**Distance (offshore)**	**Distance (total)**	**Year of Operation**
IC Cost	1.00					
Capacity	0.73	1.00				
Distance (onshore)	0.14	- 0.10	1.00			
Distance (offshore)	0.68	0.18	- 0.01	1.00		
Distance (total)	0.70	0.16	0.19	0.98	1.00	
Year of Operation	0.52	0.41	0.21	0.16	0.20	1.00

The strongest relations with total expenditure are capacity and distance. The distance is divided in an onshore and offshore part, because some interconnectors covered a significant onshore distance as well. This contributes to the stated project cost, although this effect proves to be very small. Total distance contains a slightly higher correlation with subsea interconnector expenditure and is therefore used in combination with capacity. The year of operation would lead to a p-value higher than 0.05. The variable is therefore not statistically significant and is excluded from the multiple regression formula. The multiple regression characteristics are presented in Table 6.13.

Table 6.13: Multiple Regression Analysis of Subsea Interconnectors

	Regression Statistics		**Coefficients**	**P-value**
R Square	0.8736	Intercept	- 596	0.00447
Adjusted R Square	0.8555	Capacity	0.952	1.3486 E-05
Standard Error	227.9	Distance (total)	1.589	2.2901 E-05
Observations	17			

$$cost_{subsea\ interconnector}\ (mln\ EUR) \ = \ -\ 596 \ + \ 0.952 \cdot capacity\ (MW) \ + \ 1.589 \cdot total\ distance\ (km) \tag{6.11}$$

In Figure 6.20 the approximated expenditure of subsea interconnector cables is presented, which contains an average error of 24.1%. Reference is made to Appendix G for an overview on all subsea interconnectors in the North Sea region.

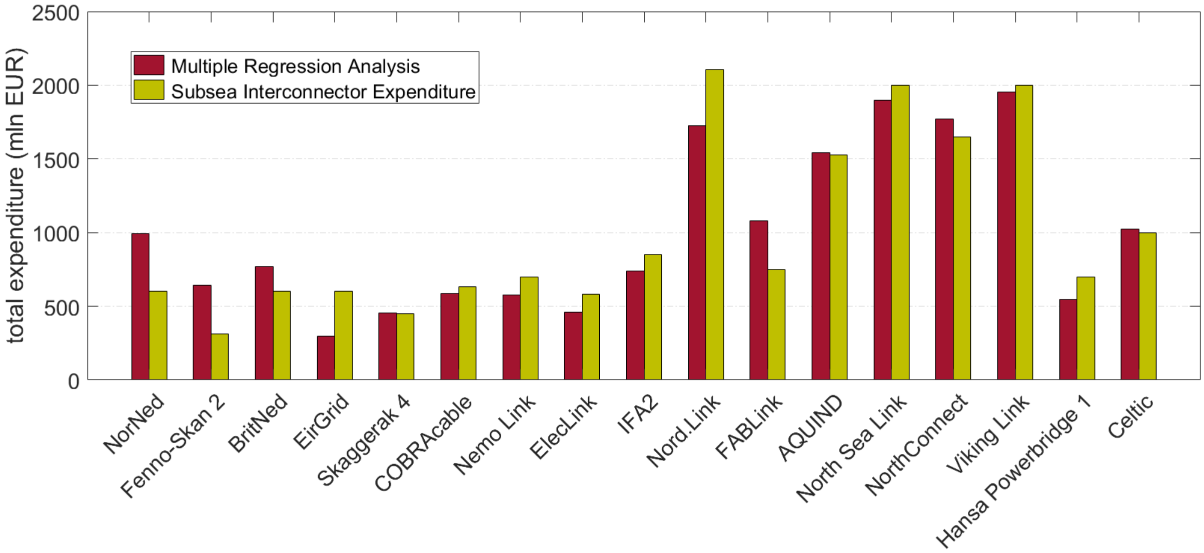


Figure 6.20: Total Expenditure Approximation of Subsea Interconnectors

The derived formula is based on interconnector projects with capacities ranging between 500 and 2,000 MW and cable lengths ranging between 65 and 766 km. TenneT proposed to use 2 GW cables as higher capacity cables profit from economies of scale. However, these cables are still under development and the capacity is included only once in the data set. The 2 GW cables are on the boundary of the investigated projects in the data set and might therefore contain a larger error. The optimal location of the Hub and Spoke concept must still be determined, but the island is envisioned to be constructed somewhere in the centre of the North Sea and will thus be roughly half the distance between countries surrounding the North Sea. Cable distance is therefore certainly in the range of other interconnector projects included in the data set.

Total subsea interconnector expenditure is calculated by finding the shortest distance between the artificial island and the selected landing points of the surrounding countries, after which these distances are inserted in eq. 6.11 to determine the corresponding expenditure. It is not possible to simply come ashore at any location and plug-in to the onshore grid, because the interconnector cable contains a very large volume of electricity at high voltage. The onshore grid must be capable to process these large volumes of electricity near the landing point or the location must be suitable for a future connection with subsea interconnectors. The landing points used in the calculation are based on operational and future interconnector projects. An overview of 30 GW subsea interconnector expenditure in the North is presented in Figures 6.21 and 6.22. Reference is made to Appendix **??** for an overview of the landing points and the total subsea interconnector expenditure for 100 GW capacity.

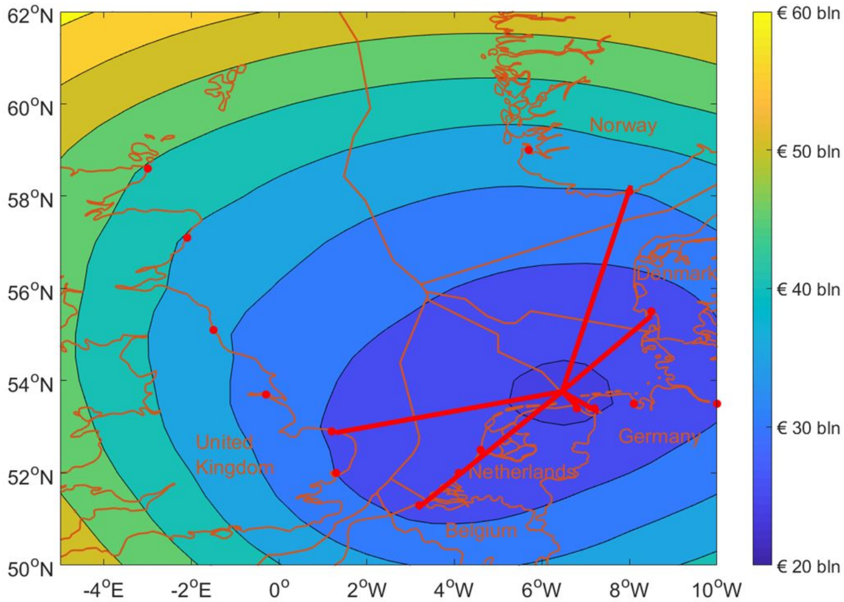


Figure 6.21: Total Expenditure 30 GW Subsea Interconnectors with Equal Distribution

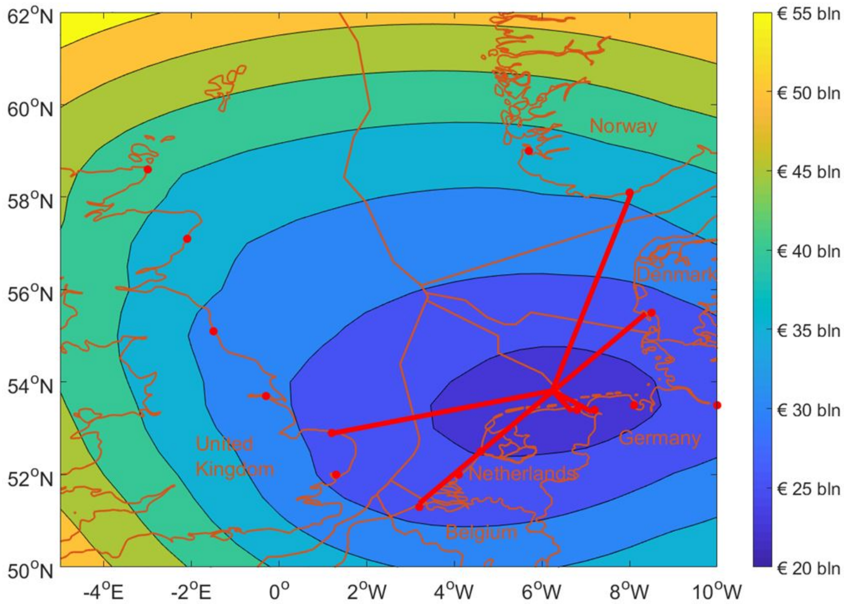


Figure 6.22: Total Expenditure 30 GW Subsea Interconnectors with "Fair" Distribution

The difference in total expenditure between an equal distribution and a "fair" distribution of interconnector capacity is not that big. The centre of gravity of the lowest interconnector expenditure is located just above the Netherlands and Germany and left from Denmark, which can be explained by the close proximity of these countries and results in the shortest total cable length. The lowest interconnector expenditure is achieved by constructing the artificial island at 53.44N 6.79E, which requires a total interconnector cable length of 4,202 km for 30 GW capacity and would cost approximately €24.1 bln. Adjusting cable capacity to the generating capacity of the surrounding countries does not significantly change the optimal location, because Germany contains by far the highest share of generating capacity with 50.2%. The attraction of Germany becomes stronger, but the centre of gravity was already located very close to the German shoreline and the location with the lowest interconnector expenditure is therefore barely shifting. The total interconnector expenditure is lower with the'fair distribution as more capacity is installed over a shorter distance. The lowest interconnector expenditure is now achieved by constructing the artificial island at 53.40N 7.19E, with a total cable length of 3,630 km for 30 GW capacity and a total expenditure of approximately €22.2 bln. The fair interconnector capacity distribution thus requires 13.6% less cable length and is 7.9% cheaper compared to the equal distribution of capacity between the connected countries.

The expenditure difference between an equal distribution and fair distribution of capacity becomes greater with 100 GW interconnector capacity. The lowest interconnector expenditure for an equal distribution requires 14,000 km cable and cost €80.2 bln, while the fair distribution requires 10,488 km cable and cost €69.0 bln. The fair distribution uses 25.1% less cable length and is 14.0% cheaper for 100 GW interconnector capacity.

6.4 Conclusion

The Hub and Spoke concept will be constructed with a reclamation island, because the probability of failure must be as low as possible and this island type is best suiting the criteria. The design lifetime is determined to be 100 years and the island should be able to resist extreme events with a return period of 1/10,000 years. The normative condition to island expenditure proved to be water depth. The optimal location for the reclamation island is therefore situated along the coastlines or on Dogger Bank and would cost approximately EUR 200 mln, which can increase up to EUR 500 mln when the island is constructed at greater water depths. These expenditures include the filling material and coastal protection. Fixed investments like the harbour and airstrip are not included.

Multiple variables influence offshore wind farm expenditure and therefore a multiple regression analysis was performed. The determining parameters (offshore wind farm capacity, water depth, turbine capacity) can now all be included and the average error for determining offshore wind farm expenditure is reduced to 23.5%. This is still a very significant error, but the best possible method with the available information. The industry should become more transparent if the error wants to be further reduced. Offshore wind farm expenditure is also primarily influenced by water depth and the optimal location is situated along the coastlines or on Dogger Bank. Total expenditure at these locations would be in the order of EUR 110 bln for 30 GW capacity, which increases up to EUR 150 bln for locations at greater water depths.

Subsea interconnectors are comparable to offshore wind farms and contain only limited information. Once again, a multiple regression analysis was performed to approximate total expenditure. The derived formula contained the dominant parameters cable capacity and cable length, which resulted in an average error of 24.1%. The optimal location with respect to subsea interconnector expenditure is just above the Dutch and German coast. In this situation minimum cable length is required and resulted in just under EUR 25 bln of expenditure. At Dogger Bank it would cost roughly EUR 30 bln.

Finally, the cost of these components are compared. It can be seen that the cost of the reclamation island is negligible and offshore wind farms take up the majority of expenditure.

7 PRODUCTION & REVENUE

In this chapter the production and total revenue of the Hub and Spoke concept is determined. Total revenue is divided between offshore wind farm revenue and interconnector trade. Both are elaborated and the most influencing variables are determined, after which the revenue potential is presented for every location in the North Sea.

7.1 Offshore Wind Farm Production

The revenue generated by offshore wind turbines is discussed in three steps. First, the conversion from wind energy to electrical turbine output is elaborated. Secondly, the electricity prices of the countries surrounding the North Sea are coupled to the turbine output. Both wind data and electricity prices consist of hourly data and thus produce an hourly revenue. Thirdly, national subsidies are added to the generated revenue as offshore wind energy is at the moment not yet competitive with other more common sources of energy. A flowchart of offshore wind farm revenue is presented in Figure ??.

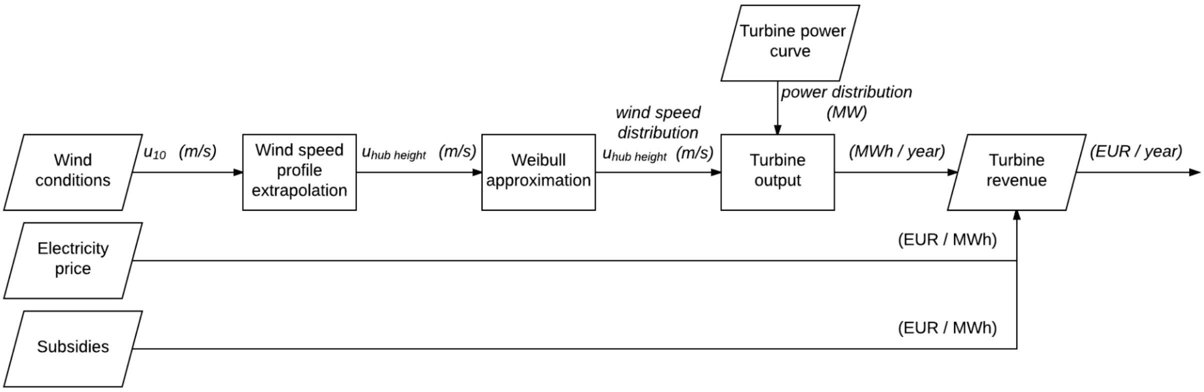


Figure 7.1: Flowchart of Offshore Wind Turbine Revenue

The power produced by an individual offshore wind turbine is calculated with eq. 7.1:

$$P = 0.5\ c_p\ \rho\ A\ v^3 \tag{7.1}$$

The generated power P (W) is determined by the power coefficient c_p $(-)$, air density ρ $(kg/m3)$, sweep area A $(m2)$ and wind speed v (m/s). The power coefficient is simply the ratio of generated power over the available wind power. The sweep area is determined by the length of the turbine blades and equals the circular surface from which wind energy can be extracted. The power coefficient and sweep area are mainly a result of the chosen turbine model. Air density and wind speed are the local parameters which determine the amount of available wind energy.

Air density is linearly influencing the amount of generated power. The parameter is dependent on temperature, relative humidity and altitude, although the differences in air density are negligible. The lowest air density at sea level in the North Sea region is 1.232 kg/m3 at the Strait of Dover up to 1.242 kg/m3 in front of the Norwegian coast. Air density is however also changing with altitude and offshore wind turbines can deviate strongly in size. The smallest operational 2.3 MW turbine contains 80 m hub height and the largest operational 8.0 MW turbine contains 110 m hub height. Temperature decreases with increasing altitude, causing the pressure and air density to decrease from 1.216 kg/m3 to 1.212 kg/m3. The changes in air density are very small with respectively 0.8% for horizontal differences and 0.3% for vertical difference. Reference is made to Appendix D.1 for the corresponding calculations. The influence on generated power is however so small that air density is assumed constant at 1.225 kg/m3 in further calculations.

Wind speed is influencing the amount of generated electricity to the power third. In Chapter 4 it could already be seen that the average wind conditions are considerably different across the North Sea and the parameter is thus expected to have a strong influence on the amount of generated power. The effect of wind speed is elaborated in the following sections and the yearly production is calculated for the offshore wind turbines presented in Table 7.1. The turbines are selected to give a complete overview of the current and future characteristics. Operational offshore wind turbines range from 2.3 MW to 8.0 MW, although Siemens has already mentioned to start delivering 10.0 MW models in the coming years (WEC, 2017) and early research is being done to 20.0 MW turbines. Some industry experts question if turbines larger than 10.0 MW are technically possible and economically beneficial (van Bussel, 2017; Beurskens, 2017), but industry developments go very rapid and the characteristics of a 20.0 MW turbine are therefore used for the upper limit.

Table 7.1: Offshore Wind Turbine Model Characteristics (sources: Siemens, Gamesa, Aerodyn, AMSC & ECN)

Turbine type	**Capacity**	**Rotor diameter**	**Hub height**	**Cut-in speed**	**Nominal power**	**Cut-out speed**
SWT-2.3-93	2.3 MW	93 m	80 - 101 m	3.5 m/s	13 m/s	25 m/s
SWT-3.6-120	3.6 MW	120 m	90 m	3.5 m/s	14 m/s	25 m/s
Gamesa G128-5.0MW	5 MW	128 m	80 - 94 m	2 m/s	14.5 m/s	27 m/s
Aerodyn SCD 8.0/168	8 MW	168 m	110 m	3.5 m/s	13 m/s	24 m/s
SeaTitan 10MW	10 MW	190 m	125 m	4 m/s	11.5 m/s	30 m/s
Upwind 20MW	20 MW	252 m	153 m	3 m/s	10 m/s	25 m/s

7.1.1 Wind Speed Extrapolation

Wind speed is commonly measured at 10 m above surface. Some measurements are performed at multiples of 10 m, but these measurements are less common as the increased height makes measurements more difficult and thus more expensive. Offshore measurements are furthermore harder to obtain compared to onshore measurements and data is less available. However, the wind speed at turbine hub height is required to determine the power output. Directly measuring the wind conditions at turbine hub height is only being done for the more detailed design stages of offshore wind farms, but in preliminary stages extrapolation methods are used to determine the wind conditions at turbine hub height based on wind measurements closer to surface. The most often used methods to extrapolate wind speeds are the *Power Law* (eq. 7.2) and *Log Law* (eq. 7.3).

The Power Law determines the wind speed v (m/s) at height of interest z (m). To perform this calculation the wind speed v_{ref} (m/s) at height z_{ref} (m) and the friction coefficient α $(-)$ must be known. The friction coefficient is a function of topography and represents the surface roughness. The coefficient is empirically determined and for terrain type "*lake, ocean and smooth-hard ground*" equal to $\alpha = 0.10$. The values corresponding to other terrain types are presented in Appendix Table D.1. The Power Law extrapolates the wind speed reasonably well between 10 m and 100 - 150 m (Bañuelos-Ruedas et al., 2011) and is thus suitable to determine the wind speed at turbine hub height.

$$v = v_{ref} \left(\frac{z}{z_{ref}} \right)^{\alpha} \tag{7.2}$$

Another formula often used to extrapolate wind speed is the Log Law. The roughness coefficient length z_0 (m) is similar to the friction coefficient α used in the Power Law and indicates surface roughness. The roughness coefficient length is often taken from literature. The most referenced tables are presented in Appendix Table D.2, D.3 & D.4. Two tables are mentioning terrain type "*water surface*" with z_0 = 0.0002 m. The third table is more detailed and makes a distinction between "*calm open seas*" and "*chopped high seas*" with respectively $z_0 = 0.0002$ m and $z_0 = 0.0005$ m.

$$v = v_{ref} \frac{ln\,(z/z_0)}{ln\,(z_{ref}/z_0)} \tag{7.3}$$

An average hourly wind speed of 8 m/s at 10 m altitude is a common value for the North Sea region. The reference wind speed is extrapolated with the Power Law ($\alpha = 0.1$) and Log Law ($z_0 = 0.0002$ m and $z_0 = 0.0005$ m) and the corresponding wind speed profiles are presented in Figure 7.2.

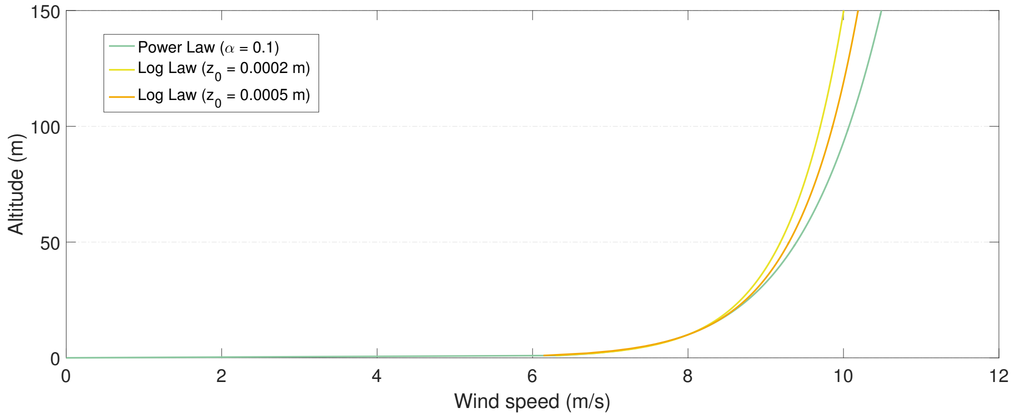


Figure 7.2: Wind Speed Extrapolation

The lowest extrapolated wind speed is gained with the Log Law ($z_0 = 0.0002$ m) and the highest extrapolated wind speed is gained with the Power Law ($\alpha = 0.1$). At 150 m hub height the wind speeds are respectively 10.0 m/s, 10.2 m/s and 10.5 m/s and differ 5% between the highest and lowest extrapolated wind speed. However, wind speed influences turbine production to the power third and the different extrapolation methods thus lead to an even greater production difference of 16%. This is the greatest deviation based on the upper limit of 20.0 MW turbines. The largest operational offshore wind turbines have lower hub heights of 110 m. At this altitude the maximum difference between extrapolation methods is lower with 4% in wind speed and 12% in turbine production. The smallest operational turbines have hub heights around 80 m with a wind speed difference of 3% and turbine production difference of 10%. Another reference wind speed leads to slightly different percentages, although this effect is only minor and will not exceed 1% variation in generated power.

The extrapolation error can be reduced in multiple ways. Wind measurements can be obtained closer to the turbine hub height or the friction coefficient α and roughness coefficient length z_0 can be determined for the specific conditions prevailing at the location. To determine the coefficients the wind speed at two or more altitudes needs to be known. The CFSv2 model only gives wind data at 10 m altitude, which makes the proposed reductions in extrapolation error not possible. If the wind speed on multiple altitudes at a specific location would be known, the friction coefficient can be calculated with eq. 7.4 and is subsequently used to determine the roughness coefficient in eq. 7.5:

$$\alpha = \frac{ln(v) - ln(v_{ref})}{ln(z) - ln(z_{ref})} \tag{7.4}$$

$$z_0 = exp\frac{z_{ref}^{\alpha} ln(z) - z^{\alpha} ln(z_{ref})}{z_{ref}^{\alpha} - z^{\alpha}} \tag{7.5}$$

Both the Power Law and Log Law are widely used to extrapolate wind speed for wind energy calculations. (Bañuelos-Ruedas et al., 2011) There is not a clear preference for one of these methods. The Log Law ($z_0 = 0.0005$) m lies between the Power Law ($\alpha = 0.1$) and Log Law ($z_0 = 0.0002$ m) and uses a roughness coefficient from a more detailed table in literature. Based on these considerations the wind speeds from the CFSv2 model are extrapolated with the Log Law ($z_0 = 0.0005$) m.

7.1.2 Wind Speed Approximation with Weibull Distribution

The local wind conditions are essential to determine the optimal turbine model, generated power output and revenues. Only knowing the mean wind speed at a certain location does however not tell anything about the average wind power. The relation between wind speed and power output is not linear but to the power third, thereby making the wind speed distribution essential to determine the mean wind power. High wind speeds occur less often compared to low wind speeds, but these high wind speeds contain relatively more energy and the bulk of wind energy will thus be found at wind speeds above the average wind speed. In literature the Weibull distribution is commonly used to represent the wind speed distribution. The Weibull probability density function is presented in eq. 7.6 with scale parameter

λ (m/s) and shape parameter k $(-)$. A higher value for λ stretches the distribution to higher wind speeds and a higher value for k makes the distribution more peaked.

$$f(v) = \left(\frac{k}{\lambda}\right) \cdot \left(\frac{v}{\lambda}\right)^{k-1} \cdot exp\left(-\left(\frac{v}{\lambda}\right)^{k}\right) \tag{7.6}$$

There are various methods to estimate the Weibull parameters λ and k from measured wind speeds. The most used methods are the empirical method and maximum likelihood method. The power density method is specifically created to determine the Weibull parameters more accurately for wind energy applications and this method is therefore compared as well. Reference is made to Appendix D.3 for the performance of these methods and their error with the wind speed data. All methods proved to resemble the wind speed data very accurately with only small differences between the used methods. The empirical method contained however the best fit for all reference locations at 100 m altitude and will therefore be used in further calculations. The formulas to determine λ and k with the empirical method are shown in eq. 7.10 & eq. 7.11.

$$\overline{v} = \left(\frac{1}{n}\sum_{i=1}^{n} v_i\right) \tag{7.7}$$

$$\sigma = \left(\frac{1}{n-1}\sum_{i=1}^{n}(v_i - \overline{v})\right)^{0.5} \tag{7.8}$$

$$\Gamma(v) = \int_0^{\infty} e^{-t} t^{v-1} dt \tag{7.9}$$

$$k = \left(\frac{\sigma}{\overline{v}}\right)^{-1.086} \tag{7.10}$$

$$\lambda = \frac{\overline{v}}{\Gamma(1+\frac{1}{k})} \tag{7.11}$$

In Figure 7.3 a histogram of the wind speed data and the corresponding Weibull probability density function are shown at 100 m altitude at Dogger Bank. It can be seen that the Weibull distribution approximates the wind speed distribution histogram very well as the peaks of the bins are located very close to the Weibull curve. Strong winds occur less often compared to moderate- and low wind speeds and the distribution is therefore skewed to the left. The area under the curve of the Weibull probability density function equals exactly 1, indicating the probability of wind blowing at one of these speeds is 100 percent.

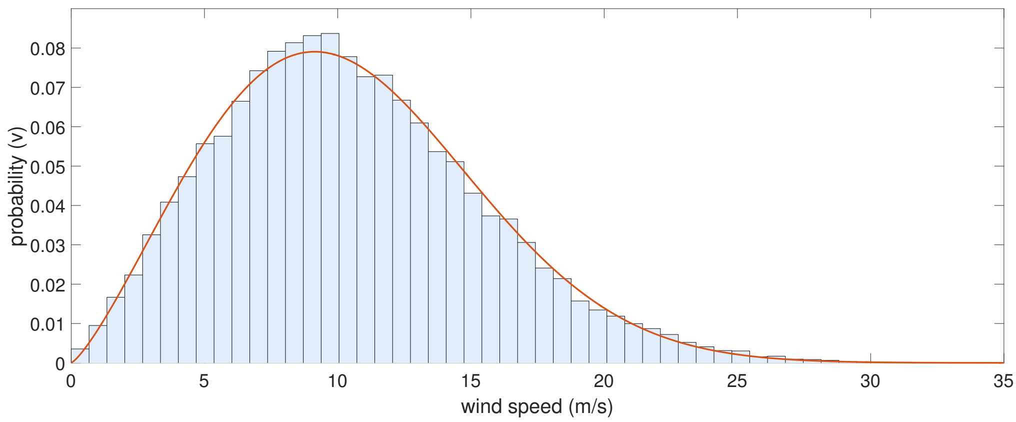


Figure 7.3: Normalised Histogram of Wind Speed Data with Weibull Curve Approximation at 100 m Altitude at Dogger Bank (54.5N 2.0E)

The wind speed conditions vary per location due to different landscapes and climate conditions. The Weibull approximation therefore varies both in shape and mean value. This is clearly visible in Figure 7.4 where the wind speed distributions at Dogger Bank, offshore wind farm Prinses Amalia and the city of Deventer (onshore) are presented. Furthest at sea the wind is least influenced by geographical variations, vegetation or any man made structures leading to the highest mean wind speed. Closer to shore the influence of wind coming from land is higher, leading to a slightly lower mean wind speed. The city of Deventer is located onshore and the greater ground roughness is clearly visible by the much lower mean wind speed. It must be noted that the roughness coefficient length for Deventer is set at z_0 = 0.2 m due to the much higher ground interference. The parameter value corresponds to terrain type "*agricultural land with many houses, shrubs and plants*" and is used in the wind speed extrapolation formula.

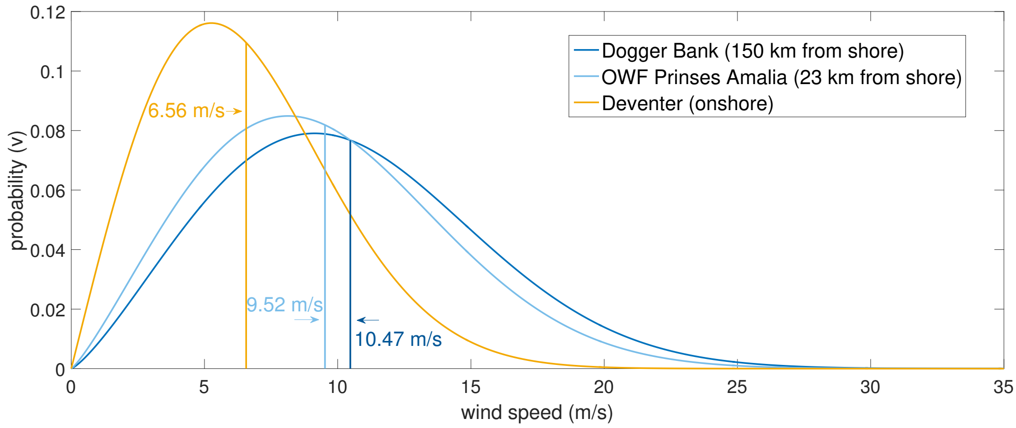


Figure 7.4: Weibull Wind Speed Approximations with Mean Wind Speed at 100 m Altitude at Dogger Bank (54.5N 2.0E), OWF Prinses Amalia (52.6N 4.2E) and the City of Deventer (52.3N 6.2E)

7.1.3 Betz Limit

Wind turbines convert kinetic wind energy to electricity. The extracted wind energy results in a slow down of the airflow behind the turbine. In order to reach 100% turbine efficiency all kinetic energy from the wind should be extracted and the air flow behind the turbine should be completely stopped. This could only be achieved if the blades were replaced by a solid disc, but in this scenario the disc will not rotate and no kinetic energy is converted. It is therefore not possible to reach full efficiency.

German physicist Albert Betz theoretically derived the maximum turbine efficiency. There must always be air flowing through the sweep area to spin the blades at which the highest possible efficiency was found to be $C_p = 16/27 \approx 59.3\%$. The maximum turbine efficiency is called the Betz limit or Betz' Law. It is not related to inefficiencies, but it is simply a result of how wind turbines work. At most 59.3% of the total kinetic wind energy can be used to spin the blades and generate electricity.

However, wind turbines have to be physically build and must meet structural requirements in terms of strength and durability. The theoretical maximum of Betz is therefore never reached. Efficiency of common wind turbines ranges between 35 - 45%, which is is roughly 60 - 75% of the Betz limit. Efficiency is reduced even further when looking at the complete wind farm. Only 10 - 30% of the total kinetic wind energy is converted into usable electricity. (Andres, 2010)

7.1.4 Turbine Power Curve

Offshore wind turbine power curves show production at different wind speeds. The power curve is determined by field measurements. An anemometer is placed on a mast close to the turbine and the measured wind speed is plotted against the turbine production. Wind speed is however always fluctuating and the exact column of air passing through the sweep area can therefore not be accurately measured. This results in a collection of measurements from which the average at each wind speed is taken and a smooth turbine power curve is created. Multiple wind turbine manufacturers were contacted to provide the power curves of their turbine models, but this information is confidential and would require a non-disclosure agreement. After extensive research on the internet it was however possible to collect some power curve graphs of different offshore wind turbine models. The corresponding values from these graphs were subsequently acquired with the free software *Engauge Digitizer*, which selects the axes and approximates graph data by reading the colour of the power curve. The retrieved power curve data is thus containing a very small error with the turbine performance as provided by the manufacturers, although it is accurate enough for the scope of this study. Furthermore, the power curve already includes an error with actual performance as it is based on field measurements. Measuring the exact wind speed is difficult and contains errors up to 3%, leading to a maximum error in certified power curves of 9%. (Danish Wind Industry Association, 2003) In Figure 7.5 the power curve of the Siemens SWT-2.3-93 turbine with 2.3 MW capacity is presented. Reference is made to Appendix D.4 for the power curve data of all offshore wind turbine models mentioned in Table 7.1.

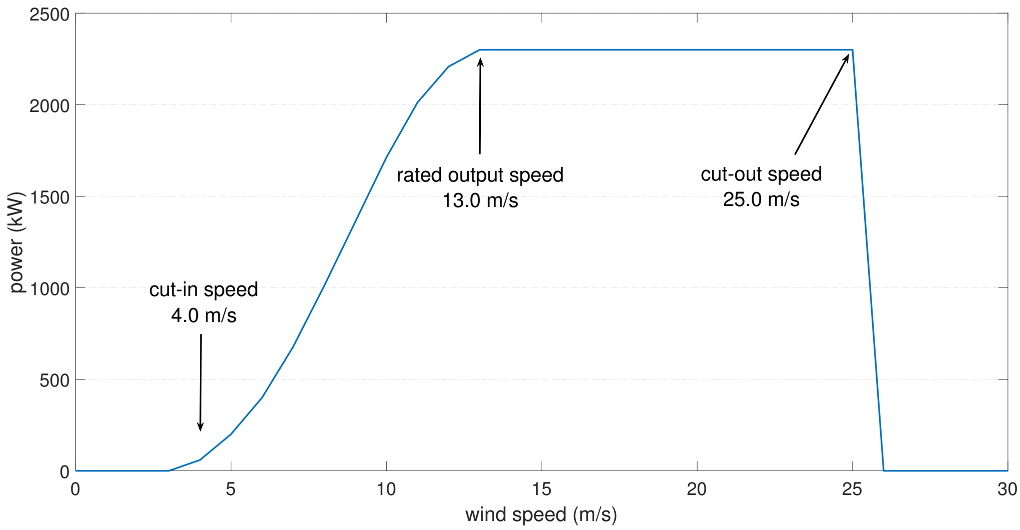


Figure 7.5: Offshore wind turbine power curve Siemens SWT-2.3-93 (source: (Siemens, 2009))

Wind turbines have cut-in, rated output and cut-out wind speeds. Below the cut-in wind speed not enough force is exerted on the turbine blades to make the rotor spin and generate electricity. At the cut-in wind speed which normally lies at 3 - 5 m/s the turbine starts to generate electricity. The power output rapidly increases with increasing wind speed and eventually reaches the point where the turbine contains its maximum generating capacity. The wind speed at this point usually lies somewhere between 12 - 17 m/s and is called the rated output speed. The turbine generates maximum output and remains constant up to the cut-out wind speed. The turbine limits the rotational speed and power output by adjusting the angle of the blades. The forces on the turbine increase with increasing wind speed and at some point the risk of damage to the turbine becomes too great. The braking system is enabled when the cut-out wind speed is reached and the turbine comes to a complete standstill. The cut-out wind speed is normally located at 25 m/s. (program)

7.1.5 Power Density Functions

The available wind power, maximum wind power according to Betz and the actual turbine production are visualised in Figure 7.6 for Dogger Bank at 100 m altitude. The wind power density curve is calculated with eq. 7.1 and multiplied with the Weibull probability density function of the wind speed shown in Figure 7.4. According to the Betz Limit only 16/27 of the wind power can theoretically be converted to electricity, which is visualised by the orange power density curve. In practice turbine efficiency is even lower due to efficiency losses and physical limitations in construction. The turbine power output is calculated by multiplying the turbine power curve shown in Figure 7.5 with the Weibull probability density function of the wind speed shown in Figure 7.4. These power density curves show the distribution of wind energy for different wind speeds and it can be seen that the majority of power is generated above the mean wind speed at Dogger Bank of 10.47 m/s.

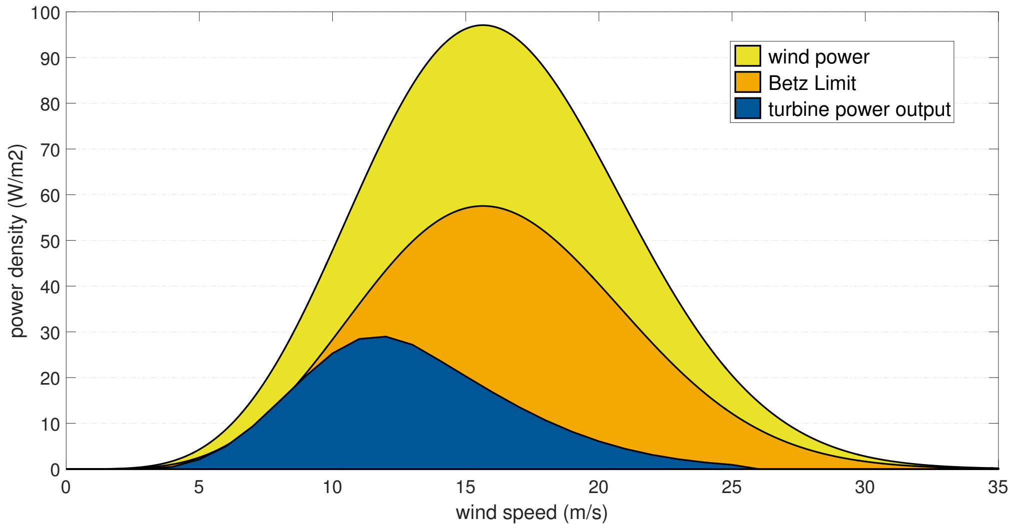


Figure 7.6: Power density function for wind speed, Betz' limit and turbine output (Siemens SWT-2.3-93) at 100 m altitude at Dogger Bank (54.5N 2.0E) (created by author)

The area under the curve equals the mean power in W/m^2 at 100 m altitude at Dogger Bank. The mean wind power at this location is 1,200 W/m2. The Betz Limit is 16/27th of the mean wind power with 711 W/m2 and the actual turbine production equals 273 W/m2.

7.1.6 Power Coefficient

Efficiency of the wind turbine is denoted with the power coefficient c_p. The coefficient is calculated by dividing the turbine power output by the wind power input. The power coefficient for the SWT-2.3-93 turbine at Dogger Bank equals the blue curve divided by the yellow curve in the previous figure and is presented in Figure 7.7.

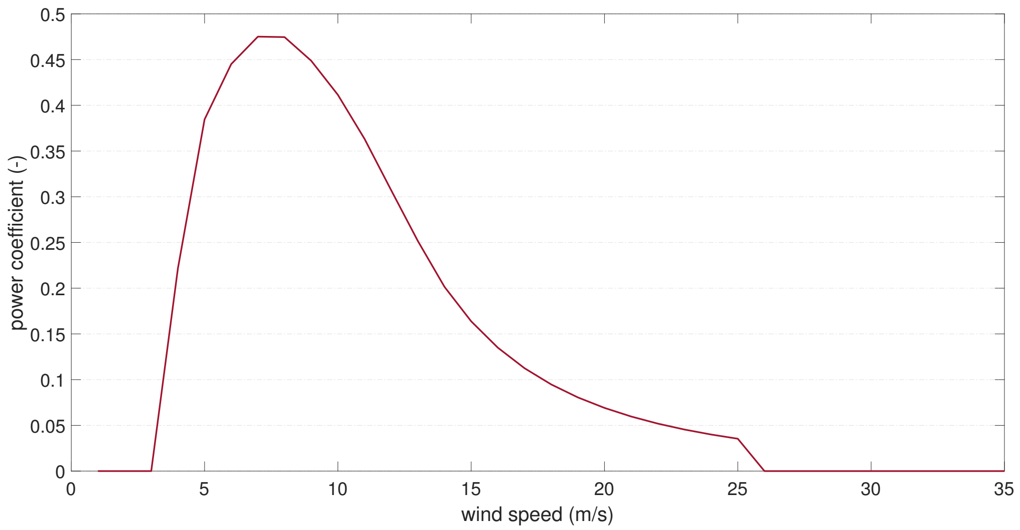


Figure 7.7: Power coefficient c_p (-) for Siemens SWT-2.3-93 at 100 m altitude at Dogger Bank (54.5N 2.0E) (created by author)

The Siemens SWT-2.3-93 turbine converts on average 22.8% of the total available kinetic wind energy. This is however much lower than the common 35 - 45% efficiency for offshore wind turbines stated earlier. The reason for this lower efficiency is the relatively small capacity of the Siemens SWT-2.3-93 turbine. The wind conditions at Dogger Bank contain much more power than the turbine can convert into electricity and there are therefore large losses. Nowadays, the average installed turbine capacity is 4.8 MW with the greatest turbines ranging up to 8.0 MW (WindEurope, 2017a), making it possible to convert more of the available wind power and thereby achieving higher efficiencies.

Turbine efficiency is also varying a lot with changing wind speeds. The maximum efficiency in Figure 7.7 is 47% at a wind speed of 7.5 m/s. For low and high wind speeds the efficiency is much lower, but this is not very troublesome as the amount of wind power at these wind speeds is also lower. Efficiency must be maximum at the wind speed where most wind power can be extracted. Maximum turbine efficiency is however not necessarily something which is strived for. Wind is a free resource and waste of this resource does not lead to economical losses. Instead, a trade-off is being made between the cost of the turbine and the generated revenue by power output. The optimal turbine is therefore not the one with the highest efficiency, but the one with the lowest cost per unit of output.

7.1.7 Capacity Factor

The annual turbine production can be expressed with the capacity factor. The capacity factor of wind turbines is the power output divided by the theoretical maximum power output. Each turbine contains a generator with a capacity which can be generated under optimal conditions. Wind conditions are however variable in time and thus not always optimal. In Figure 7.5 it was shown that the Siemens SWT-2.3-93 turbine contains a rated power output of 2.3 MW under an optimal wind speed between 13.0 - 25.0 m/s. Outside this wind speed range the turbine generates less electricity and the capacity factor decreases.

The capacity factor is however not an indication of the turbine performance. The factor is basically a design choice based on the trade-off between investment cost and power output. Offshore wind turbines can be designed with very long blades and low capacity turbines, leading to very high capacity factors but with a low total amount of generated electricity. It might be more beneficial to install higher capacity turbines. The investment cost will be slightly higher, but the total amount of produced electricity and corresponding revenue will be much higher despite the lower capacity factor. Maximising the capacity factor is thus not necessarily a good decision.

Other parameters influencing the capacity factor are down time and control decisions made by the wind farm operator. Wind speed is the primary parameter determining the power output, but the actual power output may be less due to frequency-control or other balancing services to stabilise the grid. These influences cannot be accurately predicted from day to day, but averaged over a few years these variations are averaged out and the designed capacity factor will be reached. Over the entire lifetime Danish offshore wind farms reached capacity factors between 22.2 - 48.1% and offshore wind farms in the United Kingdom reached capacity factors between 30.7 - 44.2%. (Andrew, 2017)

7.1.8 Offshore Wind Farm Production

The major influences on the amount of generated power have been explained and the annual turbine production can now be determined. The locations Dogger Bank (150 km from shore), offshore wind farm Prinses Amalia (23 km from shore) and the city of Deventer (onshore) have been highlighted to indicate the influence of location and the corresponding wind conditions on turbine production. The generated GWh / year for multiple turbine capacities is presented in Table 7.2 and it is clearly visible that further from shore turbine production is significantly higher (+10.6% to +12.4%).

Table 7.2: Average yearly turbine production (GWh/year) based on period 2012-2016

Turbine production (GWh/year)	**Deventer (onshore)**	**OWF Prinses Amalia (23 km from shore)**	**Dogger Bank (150 km from shore)**
Siemens SWT-2.3-93	3.4166	11.2139	12.6315
Siemens SWT-3.6-120	9.3998	17.7840	20.0285
Gamesa G128-5.0MW	11.9079	22.9593	26.0681
Aerodyn SCD 8.0/168	18.8638	36.2028	41.3455
SeaTitan 10MW	28.7177	51.1478	57.2311
Upwind 20MW	49.4029	91.1617	104.2741

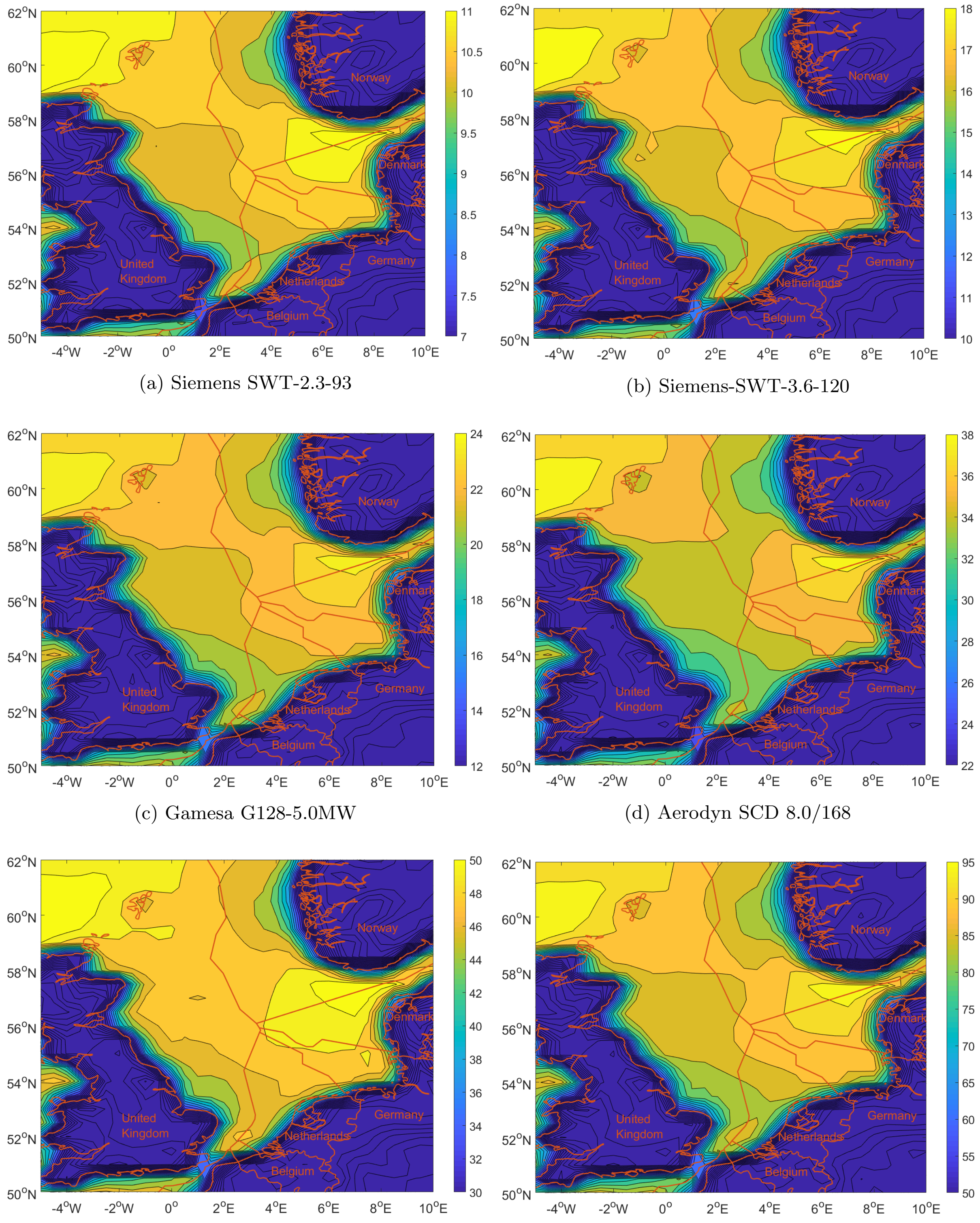
According to literature, at least five full consecutive years of wind data are required to evaluate a region and locate promising areas for offshore wind energy. (Serri et al., 2012) The average wind speed between two consecutive years might differ up to 3-5%, leading to roughly 10-15% difference in turbine output. (van Bussel, 2017) Therefore, the yearly turbine production is averaged over a 5-year period from 2012 - 2016 to flatten out yearly variations. These yearly variations can be seen in Appendix D.5, which presents the production for each individual year.

The annual turbine production is however not equal to the amount of generated electricity reaching the consumer. Offshore wind farms contain additional losses and more parameters need to be included to account for amongst others wake losses, transmission losses and downtime to perform maintenance and repairs. This is however too detailed and related to the design phase of offshore wind farms. The scope of this research is limited to the feasibility and optimal location of the Hub and Spoke concept and standard offshore wind farm losses are therefore assumed. These standard losses are presented in Table 7.3.

Table 7.3: Offshore Wind Farm Losses (source: Moné et al., 2015)

Offshore Wind Farm Generation Losses	**Percentage**
Environmental (icing, blade soiling, lightning)	1.59%
Technical (hysteresis, parasitic)	1.20%
Wake loss (site-specific loss)	5.14%
Electrical loss (site-specific loss)	3.30%
Availability loss (site-specific loss)	6.34%
Total losses	**16.30%**

The average yearly production for different turbine capacities in the North Sea are presented in Figure 7.8, including constant offshore wind farm losses of 16.3%.



(a) Siemens SWT-2.3-93

(b) Siemens-SWT-3.6-120

(c) Gamesa G128-5.0MW

(d) Aerodyn SCD 8.0/168

(e) SeaTitan 10MW (concept turbine)

(f) Upwind 20MW (concept turbine)

Figure 7.8: Average yearly offshore wind farm production (GWh/year/turbine)

It can be concluded that the spatial distribution of yearly production does not change for different turbine capacities. Turbine production further from shore is higher and turbines with a greater capacity generate more electricity, but the contour lines are fairly similar. The small spatial differences in yearly production can be explained by the power curves of the corresponding turbine models. These curves are presented in Figure 7.9. The shape of the power curves is almost identical with the only difference in maximum power output. The rated output speed and cut-out speed are all situated at the same location, causing all turbines to generate electricity under optimal conditions for the same wind speed range of roughly 12 m/s to 25 m/s. The optimal location for the Hub and Spoke concept is therefore not dependent on the turbine capacity.

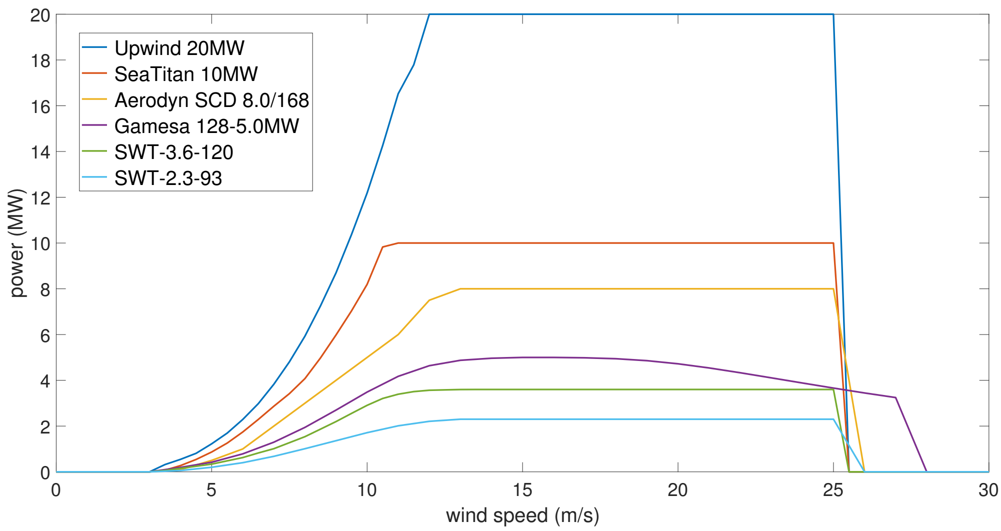


Figure 7.9: Offshore Wind Turbine Power Curves (sources: The Wind Power, 2017; Wind Turbine Models, 2017)

7.1.9 Turbine Model Selection

The turbine capacity to use for the Hub and Spoke concept is chosen based on the lowest cost per generated unit of wind power. In terms of power production it was concluded that turbine capacity is not relevant. There are no geographical differences between turbine capacities and the amount of generated electricity per installed MW is approximately equal. The multiple regression formula in the previous chapter however indicated lower offshore wind farm expenditure for higher turbine capacities. The production per installed MW is thus constant, while larger turbines are cheaper per installed MW. Therefore, the largest possible turbine capacity is used and this is in accordance with current industry developments. Operation and maintenance is the primary reason to use ever larger wind turbines as it takes up roughly a quarter of total expenditure. Offshore wind farms with larger turbine capacities require less turbines in total, thereby reducing the need for operation and maintenance and lowering total expenditure. The largest capacity offshore wind turbine currently in operation is 8.0 MW, but Siemens mentioned to be working on 10.0 MW turbines and expects these models to be delivering in the coming years. WEC, 2017 The Upwind 20.0 MW turbine is however still in the early research stage and industry experts question if this model will ever become technically and economically feasible. van Bussel, 2017; Beurskens, 2017 The SeaTitan 10.0 MW turbine is therefore chosen for the Hub and Spoke concept and its average yearly offshore wind turbine production is presented in Figure 7.10.

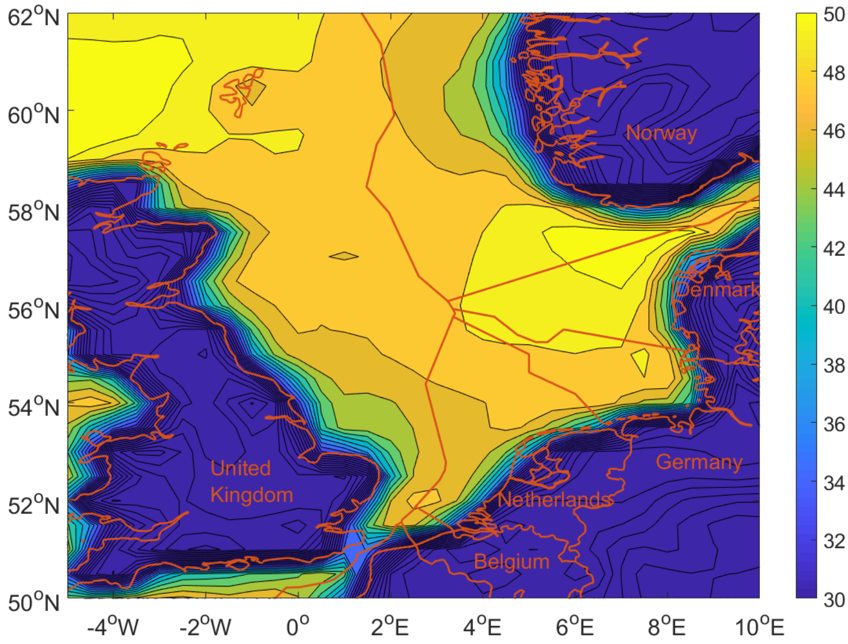


Figure 7.10: Average yearly turbine production (GWh/year) SeaTitan 10MW (concept turbine)

7.2 Interconnector Trade

Revenue generated with subsea interconnectors is dependent on the cable capacity and electricity price difference. However, the cable is used for both offshore wind energy and electricity trade. If this distribution is known, the generated revenue can be determine. A flowchart of interconnector revenue is presented in Figure 7.11.

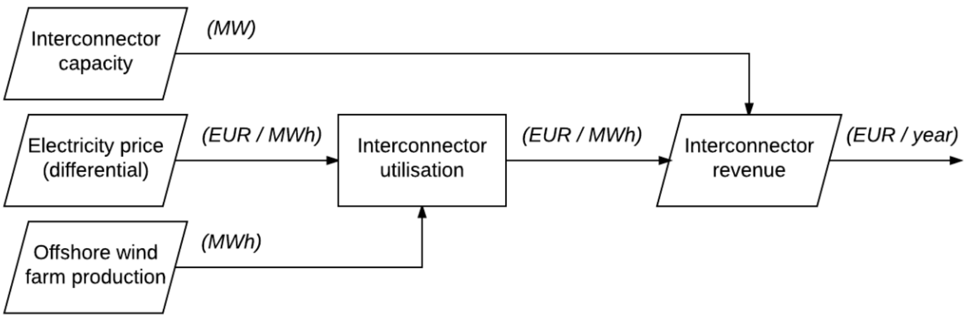


Figure 7.11: Flowchart of Interconnector Revenue

7.2.1 Influence on Energy Markets

The effect of an interconnector on electricity markets between country A and country B is illustrated in Figure 7.12. Country A has a break-even point with demand and supply and country B has a break-even point with demand and supply. The price of electricity in country A is however lower compared to country B. The installation of an interconnector with capacity K changes demand and supply for both countries. Country A can now export quantity K to country B and sell it at a higher price. Production in country A will thus increase and benefit with the area under the cost curve $a + b + c$. For consumers in Country A the interconnector is disadvantageous as the price increases and demand drops with $a + b$. Country B faces an opposite reaction as the country imports low cost electricity and the price drops. Producers will generate less electricity and lose d, while consumers benefit from the lower price with $d + e + f$. The result is a redistribution of benefits between producers and consumers of both countries, but in total there is a net benefit c for country A and $e + f$ for country B. (Turvey, 2006)

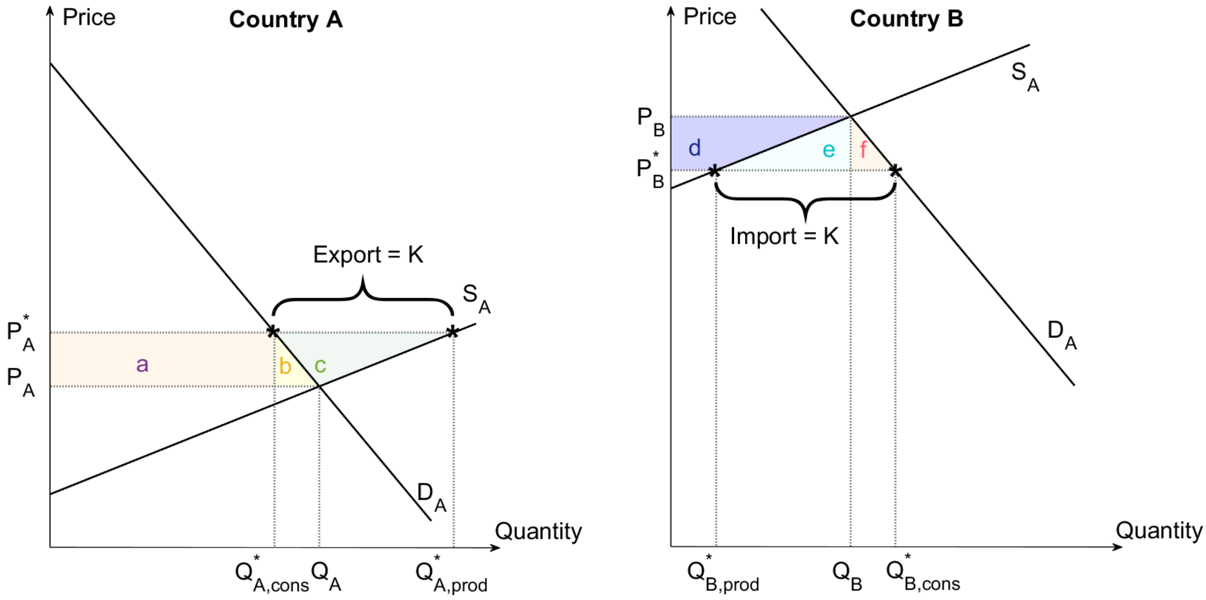


Figure 7.12: Redistribution and net benefits of interconnectors (source: Turvey, 2006)

Interconnectors provide overall welfare and the EC therefore strives for a more integrated energy market, although individual Member States might be against further integration as there is a redistribution of benefits amongst market participants. Some market participants are thus negatively affected. Especially low-cost generating countries might be against further integration as neighbouring consumer prices go down at the expense of price increases for their own citizens.

"The distribution of cost and benefits is seen as one of the largest barriers for the development of multi-national assets like interconnectors in meshed structures combined with offshore wind." - (PwC et al., 2016)

7.2.2 Interconnector Trade

Interconnectors change the national production- and consumption volumes and the electricity prices of the connected countries, but to what extent these parameters are influenced is different per country and too detailed for the scope of this study. It is therefore assumed that these parameters stay constant. However, the Hub and Spoke concept is very large with capacities mentioned to be ranging from 30 GW to 100 GW. The concept will therefore very likely influence energy markets and this needs to be investigated in further studies.

Furthermore, it is assumed that there is always full cable utilisation in case of electricity price differences between markets and transmission losses are neglected. With the latest technology, transmission losses have been reduced to less than 1% over 1,000 km. ABB, 2017 The average distance between countries surrounding the North Sea is even less and cable losses are therefore neglected.

7.2.3 Investment and Revenue Types

At the moment insufficient interconnectors are being constructed in Europe to realise an IEM. (Jacottet, 2012) The incentives for TSO's to construct interconnectors are lacking. Their task is to provide reliable and affordable electricity to consumers in the respective country, while interconnector projects contain high risks and are outside the responsibilities of TSO's. The IEM is however a prerequisite for the integration of renewable energy sources and the EC is therefore also encouraging private investors to realise interconnectors. This has resulted in two investment methods: regulated and private. Regulated investments by TSO's have always been the standard, but it is now also possible for private investors to construct and operate interconnectors. The two investment methods and their corresponding revenue schemes are explained below:

Regulated Investment
The interconnector is usually paid and operated by the TSO's of the connected countries. The cable owners have to comply with all aspects of European regulation with regards to cross border electricity trade and consists of amongst others full third party access, congestion management guidelines and the obligation to use generated revenues on the grid or reduce consumer prices. There is full up- and downside potential, but recently the "cap-and-floor" regime has been introduced which is a variant of the regulated investment. When revenues exceed the cap the excess is paid back to consumers and when revenues fall below the floor consumers will pay the interconnector owners extra to the level of the floor. This gives TSO's greater certainty the investment will pay off and increases the development of interconnections.

Private Investment
Interconnectors financed by private investors may seek exemptions from the regulatory requirements. The developer faces full up- and downside potential and does no longer have to comply with some or all aspects of European cross border electricity trade. The interconnector is a standalone project without regulatory uncertainty and the investors are allowed to keep all profits. (Norton Rose Fulbright, 2015)

Interconnector owners derive revenue through so called congestion rents. Price differences between markets are created when there is insufficient export capacity to optimally distribute all generated electricity. Areas with a production surplus get a lower electricity price and areas with a production shortage get a higher electricity price. The price difference $P_B - P_A$ (€/ MWh) multiplied with the amount of transmitted electricity through the interconnector cable V (MWh) results in revenue for the owners and is called congestion rent CR (€). In case the interconnector contains multiple owners the revenue is often distributed according to the share of investment, although this might deviate and is agreed between the owners. (Nord Pool, 2017) The congestion rent is calculated with eq. 7.12:

$$CR = (P_B - P_A) \cdot V \tag{7.12}$$

7.3 Electricity Prices

The presented prices in Figure 7.13 are day-ahead auction prices. The day-ahead market is the main location to trade electricity and in this market the price is determined between buyers and sellers. Buyers of electricity are usually utilities which need to estimate how much electricity they need the following day in order to provide sufficient electricity to their customers. Sellers are on the opposite side of the contract and agree on the amount of electricity they will deliver the next day. Both must determine this for every hour of the following day and at what price. After closure of the day-ahead bidding period the bids made by buyers and sellers are matched by the commodity exchange and the electricity price is determined. At the start of the next day the contract enters into force and the electricity is delivered.

There are two mayor commodity exchanges for electricity trade in the North Sea region. Nord Pool Spot is the largest market for electricity trade in Europe and offers trading services for amongst others Denmark, Norway and the United Kingdom. Information on day-ahead electricity prices and volume is publicly available hour-by-hour for the last four years. EPEX SPOT provides similar services for amongst others Belgium, the Netherlands and Germany. Information on this commodity exchange is however not freely accessible. Hourly price information of the Netherlands for the period 2013 - 2015 was obtained from Witteveen+Bos and the remaining missing prices are completed with quarterly average day-ahead prices presented in Electricity Market reports from the EC. (DG Energy) The solid lines in Figure 7.13 are monthly average day-ahead electricity prices and the dotted lines are quarterly average day-ahead prices published by the EC.

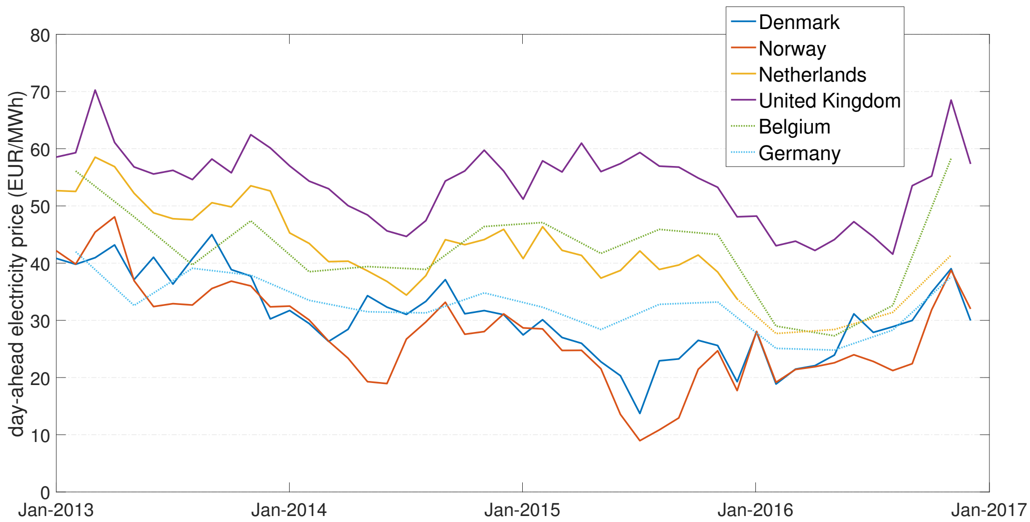


Figure 7.13: Monthly average (solid) and quarterly average (dotted) day-ahead electricity prices in EUR (sources: Nord Pool Spot, EC)

There are large differences and considerable fluctuations in national electricity prices. The United Kingdom contains by far the highest electricity price of the countries surrounding the North Sea and Norway contains the lowest electricity price, with a structural difference of 20 to 30 EUR / MWh. The price is dependent on various parameters influencing supply and demand, like the energy mix, import diversification, operation and maintenance cost of the grid and the cost of emission certificates. (Eurostat, 2017) Accurately determining the price of electricity is not the goal of this study and it is assumed as a given, although it is interesting to look at the correlation between offshore wind energy production and the price of electricity. Higher wind speeds lead to greater wind energy production and as the production is not coupled to consumer demand this may lower the electricity price. The EU is furthermore increasing its share of RES to meet the climate goals and the correlation is thereby expected to become even stronger. Denmark contains the highest percentage wind energy production of the presented countries surrounding the North Sea and the correlation is therefore expected to be strongest. In Figure 7.14 the hourly production of Danish offshore wind farms located in the North Sea are plotted against the national electricity price. It must be noted that the Danish offshore wind farms located in the Baltic Sea and the onshore wind farms are not included, although it may be expected that strong onshore and offshore winds occur simultaneously and the correlation between production and electricity price is therefore not affected.

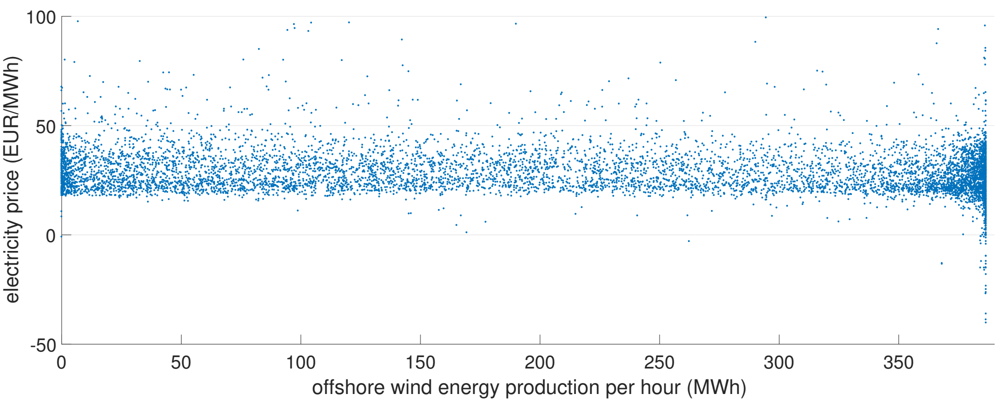


Figure 7.14: Danish Wind Energy Production versus Electricity Price

There is no correlation visible between offshore wind farm production and the electricity price in Denmark. Higher wind speeds and thus greater wind energy production do not reduce the price of electricity. The lowest electricity prices are however achieved under optimal wind conditions, although these moments are very sparse and likely coincide with other circumstances. The revenue per generated unit wind energy is thus constant and long-term price forecasts do not have to be adjusted for lower revenues at higher wind speeds.

On the long term there are also considerable differences and large movements expected in national electricity prices. In Figure 7.15 the expected cost of gross electricity generation is presented up to the year 2050, which is predicted by the Energy model from the EC. It was already mentioned that this model contains large uncertainties and future developments could significantly alter the predictions, but it clearly indicates the expected trend. Transforming the energy system costs money and energy prises will be rising worldwide. It is expected that electricity prices will rise in the EU until somewhere near 2025, after which new energy sources and an internal energy market bring down electricity prices in the long run. (EC, 2012) The expected cost of gross electricity generation is presented in Figure 7.15. Norway is not included as it is not part of the EU.

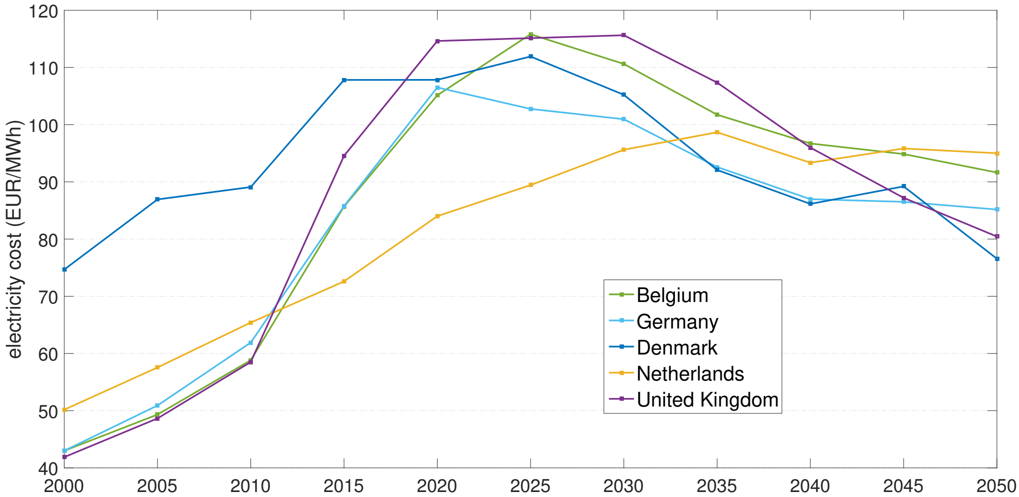


Figure 7.15: Average cost of gross electricity generation (source: EC Energy model, 2017)

7.4 Subsidies

Offshore wind energy is at the moment more expensive compared to common energy sources like coal- or gas plants. (Capros, 2016) Offshore wind farms are therefore consented with subsidies in order to make the projects profitable for developers and stimulate development. The operators of offshore wind farms are compensated for every produced MWh of electricity delivered to the grid, but there are several types of support schemes active and with different amounts. The most up to date support schemes are explained below and presented in Table 7.4, although these support schemes will be adjusted by national governments with time.

Feed-in Tariff
Guaranteed price for every MWh delivered to the grid. Time invariant and not dependent on market price.

Feed-in Premiums and Contracts for Difference
Guaranteed additional compensation for every MWh delivered to the grid. Under Contracts for Difference (henceforth CfD) the offshore wind farm operator is obligated to pay back the difference in times when the market price lies above the guaranteed price.

Quota System and Tradable Certificates
Tradable certificates are proof of a certain amount renewable energy production. These certificates contain a minimum price and can be traded separately from the produced electricity.

Table 7.4: National RES Support Schemes (source: PwC et al., 2016)

	Subsidy type	**Subsidy amount**	**Subsidy duration**
Belgium	Certificates	€90-107/MWh	20 years
Denmark	Feed-In Tariff	€33-141/MWh	11-12 years
Germany	Feed-In Tariff	€39-194/MWh	20 years
Netherlands	Feed-In Tariff	€87-187/MWh	15 years
Norway	Certificates	€22/MWh	15 years
United Kingdom	Certificates	€5/MWh	20 years
	or CfD	€184/MWh	15 years

The national approach in offshore wind energy development is clearly visible by the individual support schemes. It is however possible to harmonise these support schemes for multilateral projects like the Hub and Spoke concept as the legal framework is already present. Countries can develop offshore wind farms outside their own exclusive economic zone and add the production to their national climate goals, thereby stimulating the increase of renewable energy. However, to date no multilateral infrastructure projects have been planned or constructed so far (PwC et al., 2016) as it is uncertain how this regulation will work out. The required investments for offshore wind farms are very high and the legal uncertainty makes the regulatory risks of multilateral projects too high.

Furthermore, the first offshore wind farm without subsidies has recently been consented. In April 2017 the 900 MW German offshore wind farm "He Dreiht" was announced to be built without subsidies and must be operational by 2025. According to the wind farm developer the new project is situated close to other offshore wind farms which they operate and this leads to synergies with cost savings. (Van Dijk, 2017a) However, industry experts mention the large period between consenting and commissioning to be the main reason for the lack of subsidies. It takes years before construction starts and the project will benefit from rapid technological developments and the industry becoming more mature. Developers furthermore include rising electricity prices in their earnings model as shown in Figure 7.15 and this makes it possible to realise this specific project without any subsidies. (Van Dijk, 2017b) These conditions are very specific and do not represent the current average situation, but it does show the trend of declining cost and proves that future offshore wind farms can be realised without government contributions. The Hub and Spoke concept is expected to reduce the cost even more and will take at least multiple years or even decades to be realised. Subsidies are by that time probably no longer necessary and therefore not included in the feasibility study.

7.5 Net Present Value

The island of the Hub and Spoke concept is designed to be operational for 100 years and the future cost of electricity up to the year 2050 is presented in Figure 7.15. However, provided inflation and a positive interest rate the value of money in the future is worth less than the same amount of money in the present. Money can grow in a savings account with a certain interest rate and without any risk, while this is no longer possible when the money is invested in a project. Future cash flows must therefore be discounted with the interest rate to the present in order to determine the profitability of the project. The Net Present Value (henceforth NPV) is the difference between the present value of costs and revenues and can be calculated with eq. 7.13:

$$NPV = \sum_{t=1}^{T} \frac{C_t}{(1+r)^t} - C_0 \tag{7.13}$$

The NPV is dependent on the number of years t, discount rate r, net cash flow at the start of the project C_0 and the future net cash flows C_t. Projects contain however a certain level of risk and the discount rate is therefore often increased. In literature, the discount rate for offshore wind farm projects and interconnector projects is set equal to the Weighted Average Cost of Capital (henceforth WACC). The WACC expresses the financing cost of a project and is the weighted average of the required returns on debt and equity. The higher this value the less likely the project is creating value as it has to overcome more expensive borrowing cost in order to make a profit. The formula to calculate the WACC is shown in eq. 7.14, although these values have already been determined for offshore wind farms and the NorNed subsea interconnector which are presented in Figure 7.16 and Table 7.5.

$$WACC\ (\%) = share\ of\ equity\ \cdot\ cost\ of\ equity\ (\%)\ +\ share\ of\ depth\ \cdot\ cost\ of\ depth\ (\%) \qquad (7.14)$$

There are considerable differences in WACC for offshore wind farms between the North Sea countries. The ratio of debt to equity is typically around 70:30, but the cost of debt and equity is different due to economic-, technological- and political conditions. As a result of the economic crisis in 2008 all countries experienced a 1.5% increase in WACC, although unstable and unpredictable policy frameworks have a stronger influence and cause the WACC for the United Kingdom to be 4.5% higher compared to Denmark and Germany. Subsidy schemes in the United Kingdom are different from other countries and there is an additional currency risk, thereby increasing the project risk and leading to a higher WACC. The WACC is a very important parameter and strongly influences the business case. The discounted costs of offshore wind farms in the United Kingdom would reduce by 22% when the lower WACC of Denmark and Germany would be applied and this indicates the importance of a stable and predictable political framework. (Voormolen et al., 2016)

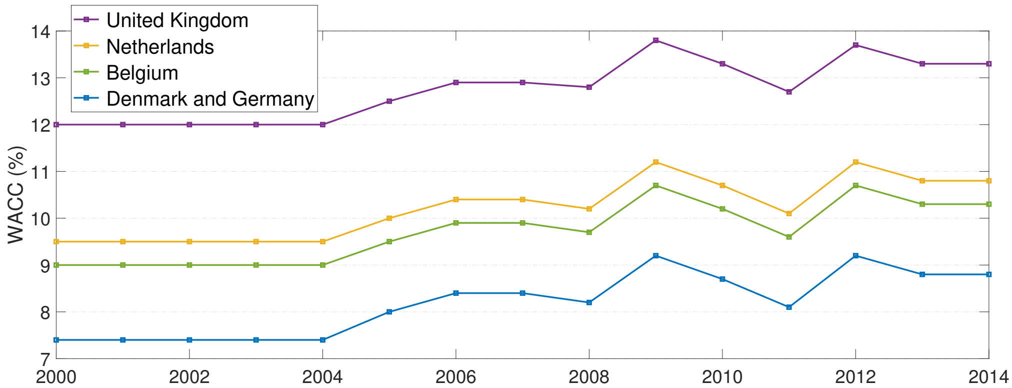


Figure 7.16: Offshore Wind Farm WACC per Country (source: Voormolen et al., 2016)

Besides national differences it also occurs that different WACC values are calculated for the same project. In Table 7.5 the calculated WACC for the NorNed subsea interconnector cable by each stakeholder is presented. The WACC can be determined with several methods and stakeholders can deviate in their assumptions. The Dutch government uses a standard calculation for the WACC of government investments: 4% plus a project specific risk premium, resulting in 8.9%. The Office of Energy Regulation (DTe), a department of the Dutch government, however deviates from the standard government approach and assumes a shorter interconnector design life of 25 years. According to the DTe there is not enough experience with subsea interconnectors being operational for 40 years and the revenue would be very uncertain over such a long period. It furthermore increased the predicted project cost by 20% as previous public investments were often over budget and this resulted in a slightly higher WACC of 9.00%. TenneT is providing two WACC values. The WACC before taxes indicates the actual risk and the required profitability of the project, but TenneT needs to pay taxes over the created revenue and the WACC is therefore increased to 9.65%. This situation clearly illustrates the different stakeholder motives and the influence of varying assumptions on the WACC. The NorNed subsea interconnector was eventually financed at a WACC of 9.00%.

The WACC of the EirGrid interconnector running between the United Kingdom and Ireland is known as well and serves as a second reference project. The EirGrid interconnector contains a pre-tax WACC of 4.92% and was financed at the after-tax WACC of 5.63%. This is lower compared to the WACC of the NorNed interconnector, but each project is unique and contains different risk premiums. The EirGrid interconnector became operational four years later, contained a smaller cable capacity, covered less than half the distance and furthermore profited from the favourable Irish tax regulations. (De Nooij, 2011)

Table 7.5: NorNed Subsea Interconnector WACC per Stakeholder (source: De Nooij, 2011)

Stakeholder	**Discount rate**
Dutch Government	8.90 %
DTe	9.00 %
TenneT (before tax)	6.31 %
TenneT (after tax)	9.65 %

The offshore wind industry is relatively immature compared to other electricity generation sources. This makes the technology as well as the regulatory framework new and uncertain, leading to high WACC levels. Industry developments go very rapid and countries surrounding the North Sea have stated in a Memorandum of Understanding to increase cooperation in the development of offshore wind energy. (Council of the EU, 2016) The WACC between countries is therefore expected to converge and will decrease in time. The rate of this development is however uncertain and the Hub and Spoke concept deviates from common offshore wind farms. The concept has never been constructed before and it thereby contains a higher risk. Taking all these factors into account the WACC for offshore wind energy in the Hub and Spoke concept is therefore set at 10%.

Subsea interconnectors are just like offshore wind farms a development of the last decades and average WACC values could not be found in literature. The WACC for the subsea interconnectors of the Hub and Spoke concept is therefore based on the two reference projects NorNed and Eirgrid. However, the subsea interconnector cables of the Hub and Spoke concept get double functionality as they export generated wind energy as well. This has never been done before and increases the risk. The WACC for subsea interconnector cables of the Hub and Spoke concept is therefore set equal to the higher WACC level of 9%.

7.6 Revenue

The double functionality, capacity and distribution of capacity of the subsea interconnector cables determines to a large extent the revenue of the Hub and Spoke concept. First, it must be determined which function gets priority. The interconnector cables export generated wind energy as well as trade electricity between connected countries. In Figure 7.17 the future cost of electricity is presented with the highest and lowest electricity prices of the North Sea countries indicated by the red-dotted lines. This is the range to which the generated offshore wind energy from the Hub and Spoke island can be sold. Interconnector revenue is based on the price difference between markets. The maximum price difference is achieved by subtracting the red-dotted lines from each other and this is indicated with the green line. The maximum market price difference is always lower than the lowest national electricity cost and generated offshore wind energy will therefore always get priority over trade in terms of revenue.

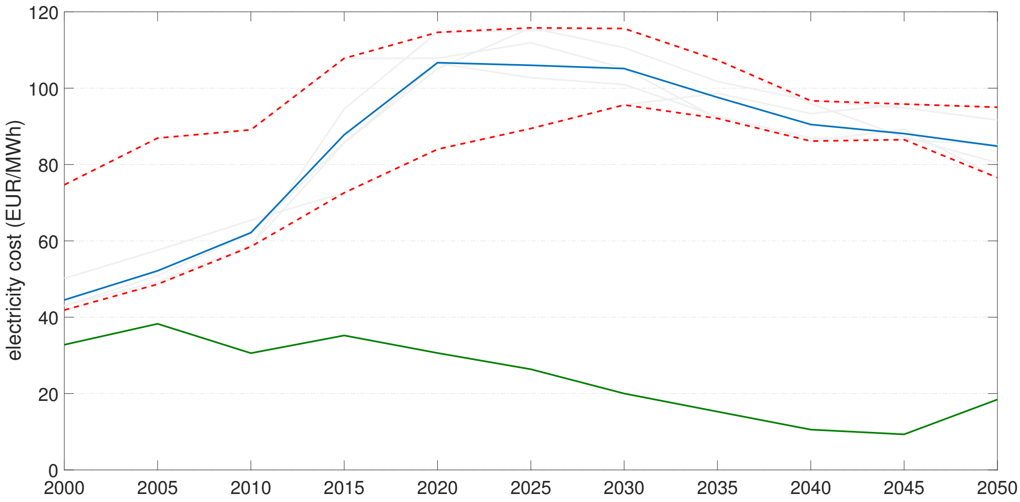


Figure 7.17: North Sea Countries Average Cost of Gross Electricity Generation: Maximum and Minimum Cost (red-dotted), Average Cost (blue) and Maximum Cost Difference (green)

However, the presented electricity costs are averaged over 5-year periods and it might happen that for certain hours the price difference would become bigger than the lowest national electricity price. It has even happened that electricity prices became negative. For some countries it would now be more profitable to trade electricity instead of exporting the generated offshore wind energy. The frequency of these situations has therefore been tested on the historical hourly electricity prices over the last four years. Over the period 2013 - 2016, the United Kingdom contained 2.58% of the time lower electricity prices compared to Denmark and 1.64% of the time compared to Norway. The frequency of these events is very small and will therefore not be included in the revenue calculations. Furthermore, the Hub and Spoke concept will be realised to help achieve the IEM and climate goals. Electricity trade might be more profitable at some times, but generated electricity by offshore wind turbines would be wasted and this would exceed the initial aim of the concept. Offshore wind energy is therefore always getting priority over electricity trade.

7.6.1 Offshore Wind Farm Revenue

Offshore wind energy revenue is determined by the production volume times electricity price. The wind conditions might fluctuate up to 3-5% per year and cause the production to fluctuate by 10-15% (van Bussel, 2017), although this is not possible to predict beforehand and the yearly average production is therefore used over the past 5-year period from 2012 - 2016. The yearly average production of SeaTitan turbines and the future cost of electricity have already been determined in previous sections and can be seen in Figures 7.10 and 7.15.

When the generated offshore wind energy would be sold at the highest price, all interconnector capacity would be allocated to one single country assuming the price stays constant. The country with the highest electricity price is however changing in time. Offshore wind farms have a design life of 20 years and are assumed to be operational from 2025 to 2045. The United Kingdom is expected to have the highest electricity price up to the year 2040, after which Belgium and the Netherlands will have higher prices.

The remaining surrounding countries might however experience this situation as unfair. Every connected country will financially contribute to the realisation of the Hub and Spoke concept and might demand a corresponding share of generated offshore wind energy. This would lower the revenue, but results in a more even distribution of the generated electricity. This “fair distribution” is based on the national electricity production capacity. The corresponding interconnector capacities with 2 GW cables are presented in Table 7.6.

Table 7.6: “Fair” Interconnector Capacity Distribution Hub and Spoke Concept

	Installed Electricity Capacity	**Interconnector Capacity 30 GW**	**Interconnector Capacity 100 GW**
Belgium	20.9 GW (5.3%)	2 GW	6 GW
Denmark	13.7 GW (3.5%)	2 GW	4 GW
Germany	198.4 GW (50.2%)	12 GW	48 GW
Netherlands	31.8 GW (5.3%)	2 GW	6 GW
Norway	33.8 GW (8.5%)	4 GW	10 GW
United Kingdom	97.0 GW (24.5%)	8 GW	26 GW

The distribution of interconnector capacity has considerable influence on future revenues. In Figure 7.18 the future cost of gross electricity generation is linearly interpolated to yearly values and discounted with 10.0% WACC for offshore wind energy. The orange/yellow bars indicate the maximum electricity price for each year and the blue bars indicate the “fair” electricity price when offshore wind energy is sold to countries corresponding to the distribution in Table 7.6.

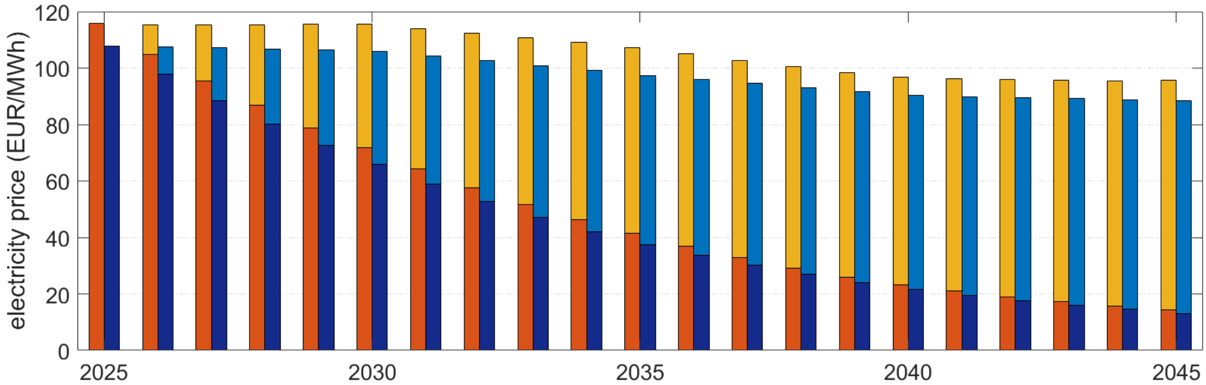


Figure 7.18: Absolute (yellow) and Discounted (orange) Maximum Electricity Price & Absolute (light blue) and Discounted (dark blue) “Fair” Electricity Price, both with 10.0% WACC

The fair distribution of interconnector capacity leads to 8.0% lower revenue as the offshore wind energy is now being sold proportionally to the national generating capacity and no longer at the highest electricity price, resulting in a lower average price of electricity. The NPV of maximum revenue and fair revenue are shown in eq. 7.17 and 7.18.

$$REV_{NPV,MAX} = EUR/MWh\ 52.46 \cdot yearly\ production\ (MWh/year)\ \cdot\ 20\ years \tag{7.15}$$

$$REV_{NPV,FAIR} = EUR/MWh\ 48.43 \cdot yearly\ production\ (MWh/year)\ \cdot\ 20\ years \tag{7.16}$$

The revenue generated from offshore wind energy can now be determined by multiplying the average yearly production of 30GW and 100 GW SeaTitan turbines with the NPV of future electricity prices. The fair distribution is much more likely to be developed and the corresponding revenues are presented in Figure 7.19 and 7.20.

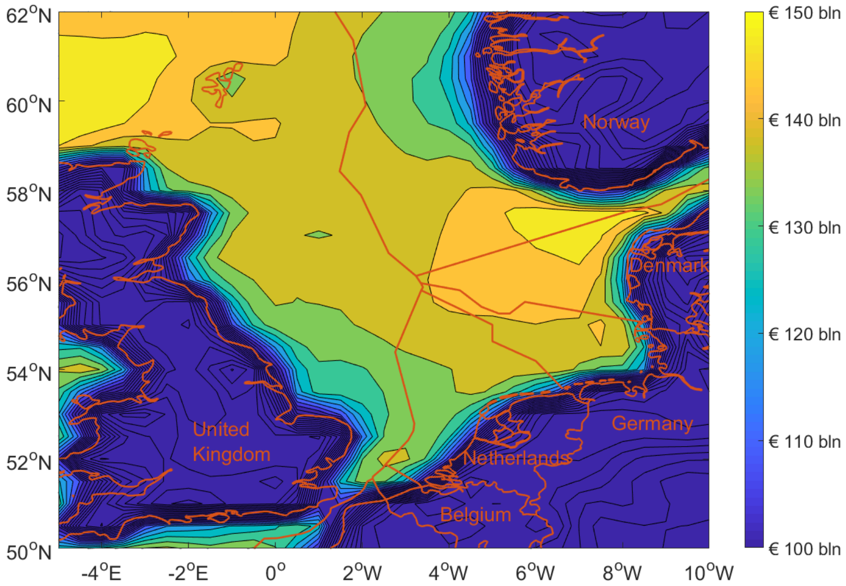


Figure 7.19: NPV Revenue for 30 GW SeaTitan Turbines (design life 2025 - 2045, WACC 10.0%)

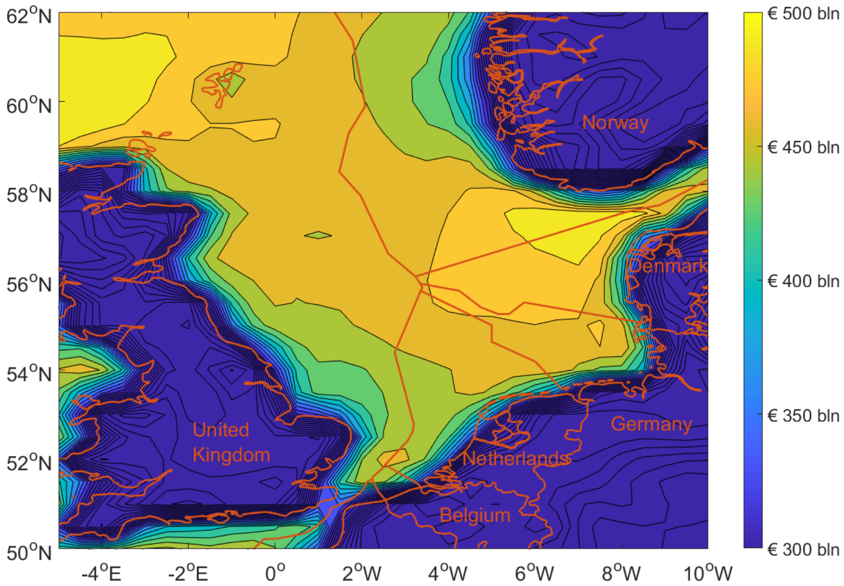


Figure 7.20: NPV Revenue for 100 GW SeaTitan Turbines (design life 2025 - 2045, WACC 10.0%)

7.6.2 Interconnector Revenue

The generated offshore wind energy is exported entirely to the surrounding countries, but wind is not always blowing under optimal conditions and the interconnector cable is thus not always used to its full potential. When the offshore turbines are not generating electricity at their rated power, the interconnector cable is not used to its maximum capacity and it is possible to trade electricity. The capacity factor is dependent on the local wind conditions and the turbine model. The capacity factor of the SeaTitan turbine is presented in Figure 7.21.

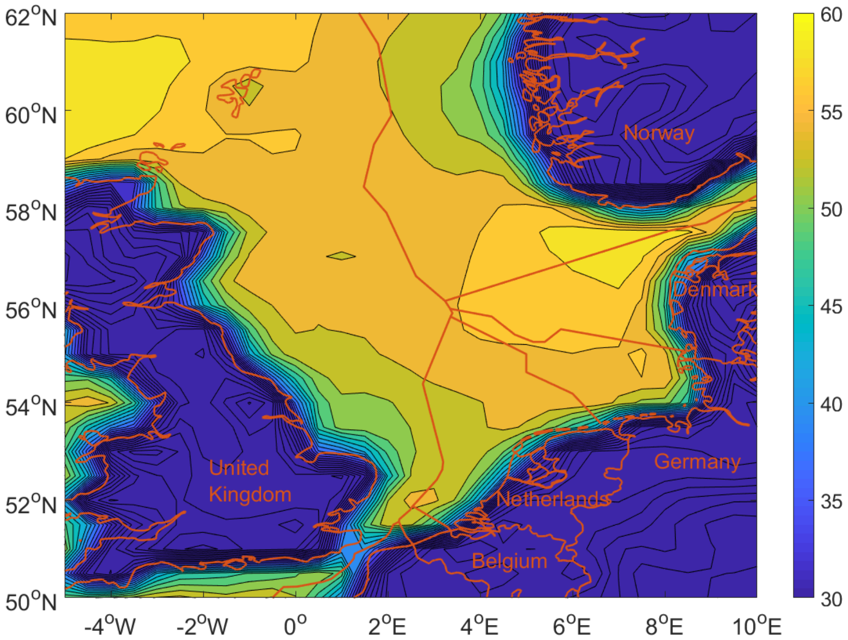


Figure 7.21: Capacity Factor SeaTitan 10.0MW (%)

It can be seen that the capacity factor of the SeaTitan turbine is strongly correlated with the average wind speed over the North Sea. In the northeastern part of the North Sea are the wind conditions strongest and the cable utilisation for offshore wind energy highest. This means less cable capacity available for electricity trade and therefore lower congestion revenues. In Figure 7.22 the future electricity price difference is linearly interpolated to yearly values and discounted with 9.0% WACC for subsea interconnector cables. The orange/yellow bars indicate the maximum electricity price difference for each year and the blue bars indicate the "fair" electricity price difference when interconnector capacity is distributed to the amount of generating capacity per country.

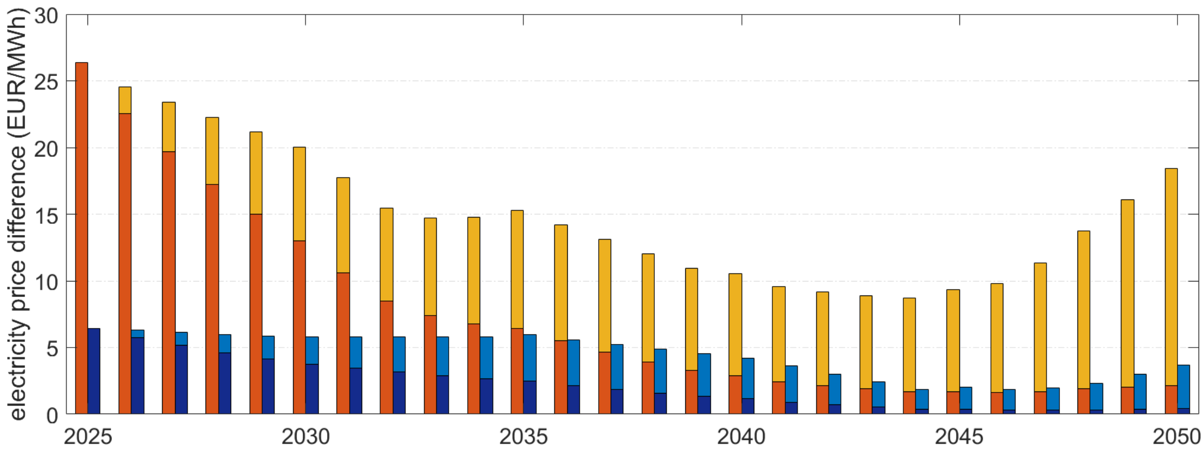


Figure 7.22: Absolute (yellow) and Discounted (orange) Maximum Electricity Price Difference & Absolute (light blue) and Discounted (dark blue) "Fair" Electricity Price Difference, both with 9.0% WACC

The fair distribution of interconnector capacity leads to 29.7% lower congestion rents. This percentages is much higher compared to offshore wind energy, but much lower in absolute amounts. The NPV of maximum revenue and fair revenue are shown in eq. 7.17 and 7.18.

$$REV_{NPV,MAX} = EUR/MWh\ 7.72 \cdot yearly\ production\ (MWh/year)\ \cdot\ 25\ years \tag{7.17}$$

$$REV_{NPV,FAIR} = EUR/MWh\ 2.29 \cdot yearly\ production\ (MWh/year)\ \cdot\ 25\ years \tag{7.18}$$

The revenue generated from congestion rents can now be determined by multiplying the average yearly transmission of 30GW and 100 GW interconnector cables with the NPV of future electricity prices. The fair distribution is much more likely to be developed and the corresponding revenues are presented in Figure **??** and **??**.

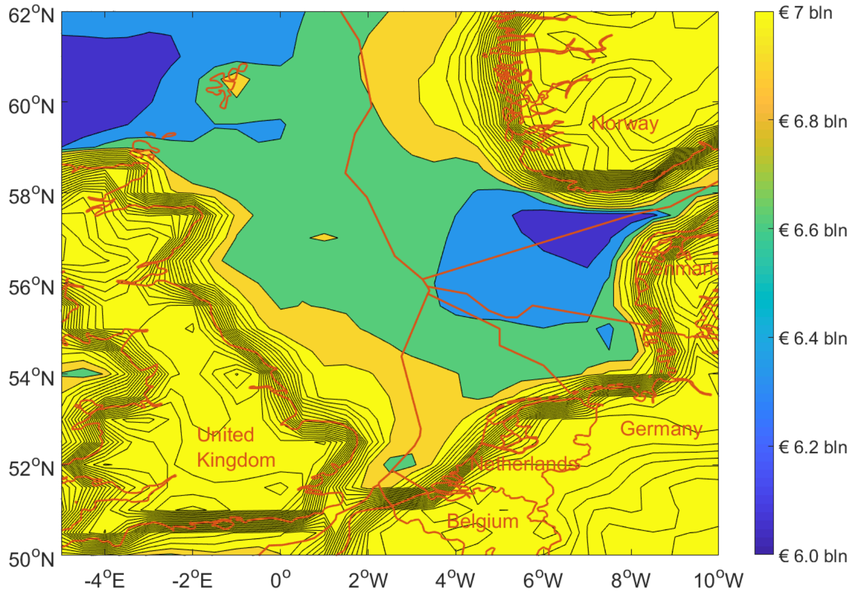


Figure 7.23: NPV Revenue for 30 GW Interconnector Capacity (design life 2025 - 2050, WACC 9.0%)

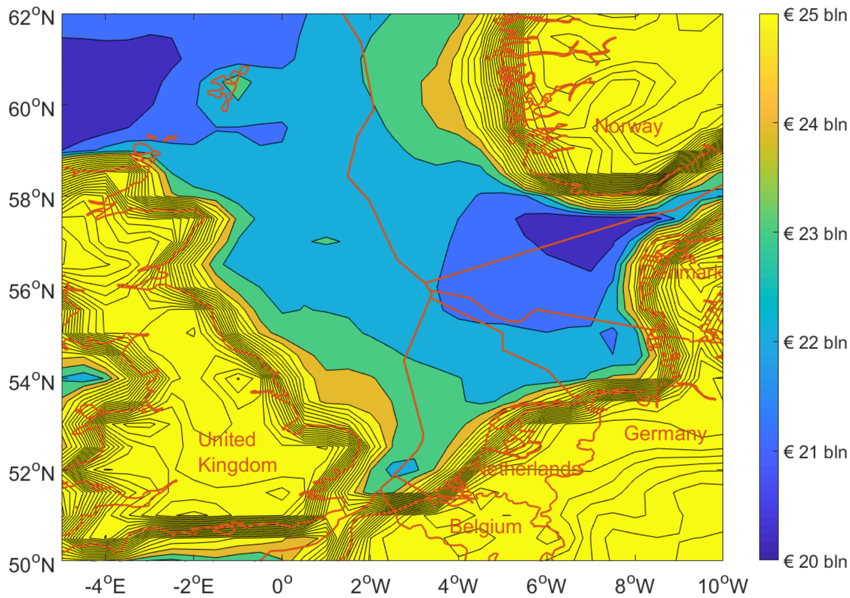


Figure 7.24: NPV Revenue for 100 GW Interconnector Capacity (design life 2025 - 2050, WACC 9.0%)

7.7 Conclusion

The turbine model selection is no relevant to production as the amount of generated electricity is roughly equal per installed MW. In terms of expenditure is does however make a difference. The multiple regression formula in the previous chapter indicated lower offshore wind farm expenditure for higher turbine capacities. The production per installed MW is thus constant, while larger turbines are cheaper per installed MW. Therefore, the largest possible turbine capacity is used and this is in accordance with current industry developments. Operation and maintenance is the primary reason to use ever larger wind turbines as it takes up roughly a quarter of total expenditure. Offshore wind farms with larger turbine capacities require less turbines in total, thereby reducing the need for operation and maintenance and lowering total expenditure. Siemens mentioned to be delivering 10.0 MW turbines in the coming years and this capacity is therefore used for the Hub and Spoke concept.

Offshore wind turbine generation is largest in the northwestern part of the North Sea. Over here, a 10.0MW turbine can produce on average 50 GWh/year, while at Dogger Bank this is only 46 GWh/year. The largest wind energy production does however also mean the largest cable utilisation for offshore wind energy. Less cable capacity is available for electricity trade and therefore lower congestion revenues are obtained.

For 30 GW offshore wind energy capacity the NPV revenue at Dogger Bank for offshore wind energy is EUR 135 bln and for interconnector revenue is EUR 7 bln At the northeastern part of the North Sea NPV revenue generated with offshore wind turbines is highest. This is equal to EUR 150 bln and EUR 6 bln is generated with electricity trade.

8 MODEL RESULTS

All layers indicating the cost and revenue of specific components of the Hub and Spoke concept have been determined. Finally, it is possible to merge these layers and create one single contour plot indicating the feasibility of the Hub and Spoke concept in the North Sea. A summary of the calculated layers from previous chapters is presented in the figures below:

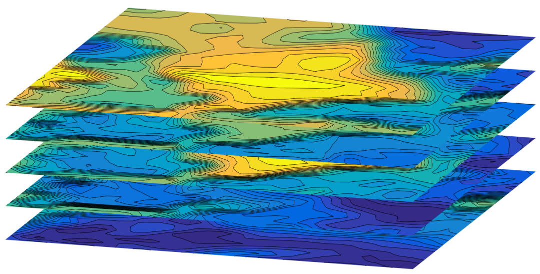


Figure 8.1: Site Selection Model Layers

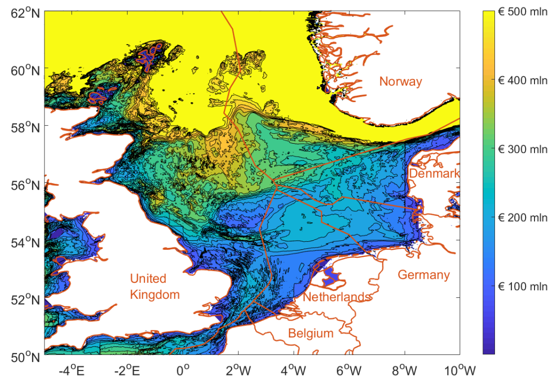


Figure 8.2: Expenditure Reclamation Island 2.1 km2

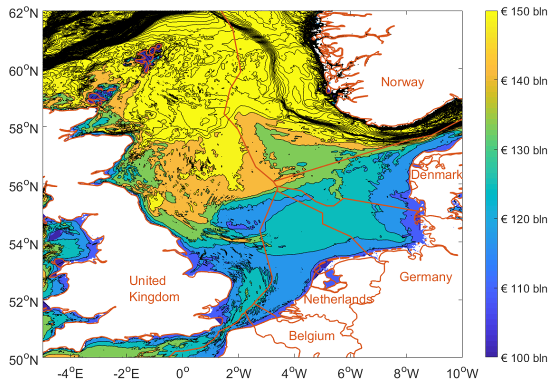


Figure 8.3: Expenditure 30 GW OWF's

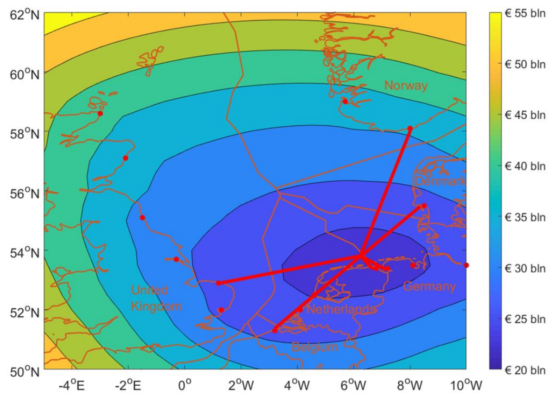


Figure 8.4: Expenditure 30 GW IC's

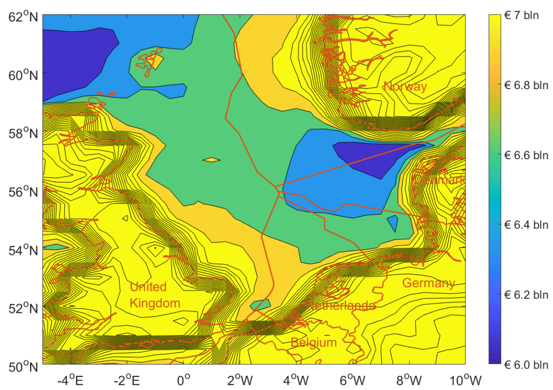


Figure 8.5: Revenue 30 GW OWF's

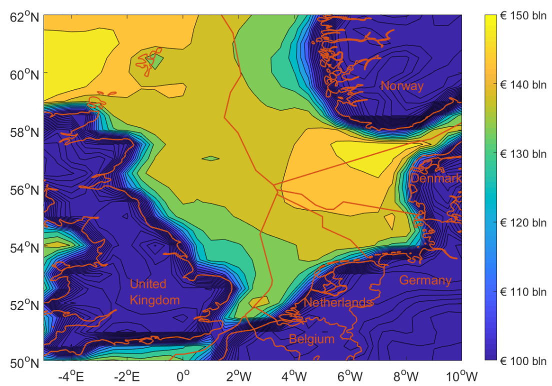


Figure 8.6: Revenue 30 GW IC's

It is now also possible to compare cost and revenue from the specified components. In Figure 8.7 an overview of cost and revenue is presented for four different locations. Location A and B are situated on the left and right side of Dogger Bank. Location C is situated more to the north and location D is in the centre of the Danish exclusive economic zone. It can be seen that offshore wind farms are both in cost as in revenue the dominant part in the Hub and Spoke concept. Subsea interconnector cables contain much smaller values and the artificial island is almost negligible.

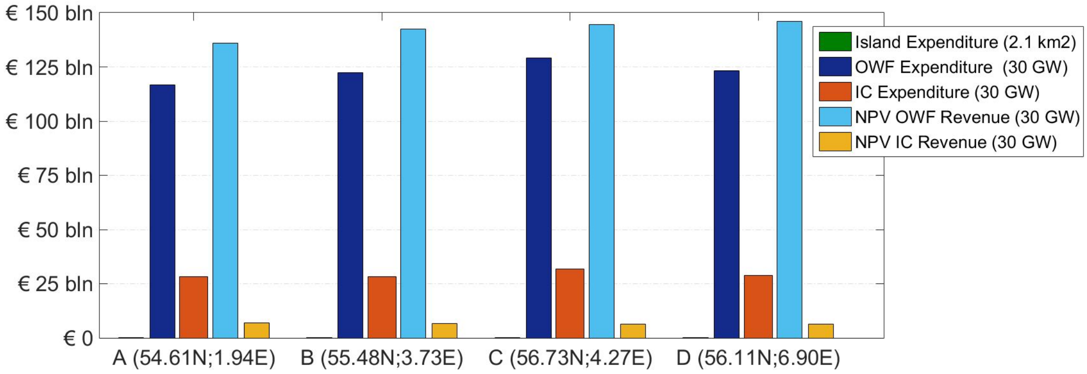


Figure 8.7

Merging these individual layers results in Figure 8.8, which presents the feasibility of the Hub and Spoke concept with 30 GW offshore wind energy capacity in the North Sea.

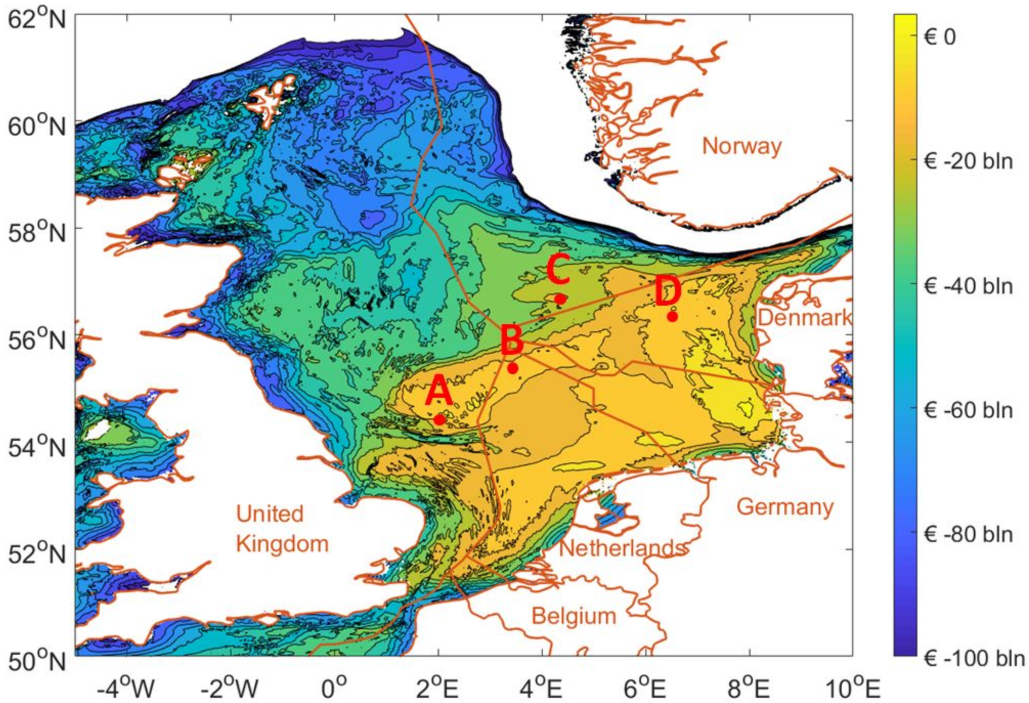


Figure 8.8: NPV Hub and Spoke Concept with 30 GW Capacity

It can be concluded that the highest net present value for the Hub and Spoke concept is situated along the coastline of Denmark and Germany. However, these locations are known to be very crowded and the reason to investigate alternative locations in the first place. Dogger Bank and the northwest of Denmark are two very interesting alternatives. Dogger Bank is very shallow with depths of 10 m, while the northwest of Denmark is slightly deeper with roughly 20 m but contains roughly 10% higher wind speeds. Both locations are primarily free from other marine uses, although Dogger Bank is protected Natura 2000 territory and therefore contains a very large risk. It is therefore advised to construct the Hub and Spoke island at the northwest side of Denmark.

9 CONCLUSIONS & RECOMMENDATIONS

9.1 Conclusions

The European energy system is significantly changing to restrict the rise in global average warming. There is a shift from fossil fuels to renewable energy sources, which resulted in an exponential growth of offshore wind energy capacity in the North Sea. It is estimated that 62.3 GW to 95.0 GW offshore wind energy capacity is needed in Europe in order to reach a low carbon economy by 2050. Europe has already reserved enough space for 114.2 GW offshore wind farms and the Hub and Spoke concept is therefore not needed in terms of offshore wind energy capacity.

The rising share of RES in the energy mix is however causing problems. Renewable energy is dependent on the prevailing local conditions and this makes the generation of electricity more volatile and independent from consumption. The EU is therefore strengthening the electricity grid with additional interconnection capacity. Demand and supply can be balanced with neighbouring countries, thereby increasing the stability of the energy system and enabling the integration of RES. By 2020, every Member State should have at least an interconnection capacity of 10% of its installed electricity production capacity and Member States are furthermore encouraged to achieve at least 15% interconnection capacity by the end of 2030. Most Member States have already met their targets and the Hub and Spoke concept is therefore also not needed in terms of interconnection capacity, although experts question if these percentages are sufficient and if all Member States should have the same level of interconnection capacity.

Despite the lack of a direct need for additional capacity, the Hub and Spoke concept does provide the functions which the EU so desperately strives for. Furthermore, the vast majority of offshore wind farms still needs to be constructed and it is very likely that additional interconnection capacity is required in the future.

The North Sea is already one of the most intensively used sea basins in the world with a variety of human and ecological activities. The Hub and Spoke concept requires a very large area of approximately 4,300 km2 to 14,300 km2 for respectively 30 GW and 100 GW capacity and the integration with other marine uses will thus be extremely complex, especially because the interaction between offshore wind farms and other marine uses is often limited or not even possible at all. The Hub and Spoke concept is envisioned to be realised on Dogger Bank, but this location contains a high ecological value and is therefore appointed Natura 2000 territory. Human activities are still allowed and recently four offshore wind farms have been consented at this location, but it severely complicates the project as the present ecological state must be preserved at all times.

The cost of the Hub and Spoke concept is divided into three components: artificial island, offshore wind farms and subsea interconnector cables. Water depth is the normative condition with respect to expenditure of the artificial island and offshore wind farms. The optimal location is therefore situated along the coastlines or at Dogger Bank. The reclamation island would cost approximately EUR 200 mln, which can increase up to EUR 500 mln when the island is constructed at greater water depths. These expenditures include the filling material and coastal protection. Fixed investments like the harbour and airstrip are not included. Offshore wind farms with a total capacity of 30 GW would cost approximately EUR 110 bln at these locations, which increases to EUR 150 bln for greater water depths. Subsea interconnector cables are mainly influenced by cable capacity and distance. The optimal location is situated just above the Dutch and German coastline. Expenditure is just under EUR 25 bln and increases to EUR 30 bln at Dogger Bank. Offshore wind farms are therefore the majority of the Hub and Spoke expenses.

Revenue is divided in offshore wind farm revenue and congestion rents derived from electricity trade. The Hub and Spoke concept is created to facilitate offshore wind energy and therefore wind energy always gets priority over electricity trade. The net present value of offshore wind energy revenue is approximately EUR 140 bln at Dogger Bank, which increases towards the northwest of Denmark to EUR 150 bln. Congestion rents derived from electricity trade are much lower. At Dogger Bank this is roughly EUR 10 bln and decreases towards the northwest of Denmark to EUR 6 bln. Once again, offshore wind farms are the dominant aspect of the Hub and Spoke concept and provide the majority of revenue.

With this information the main research question can be answered:

"What is the optimal location for the Hub and Spoke concept in the North Sea?"

Dogger Bank and northwest from Denmark are the optimal locations for the Hub and Spoke concept. There are some areas along the coastline of Denmark, Germany and the Netherlands which suggest an even better feasibility, but these locations are already very crowded and the reason for this research in the first place. Dogger Bank is very shallow with depths of 10 m. The northwest of Denmark is slightly deeper with 20 m, but contains wind speeds which are roughly 10% higher compared to Dogger Bank. Both locations are primarily free from other marine uses, although Dogger Bank is protected Natura 2000 territory and therefore contains a very large risk. It is therefore advised to construct the Hub and Spoke island at the northwest side of Denmark.

9.2 Recommendations

The recommendations from this research are as follows:

- Determine the **required interconnection capacity** of each country as a function of renewable energy. It was already stated that "there cannot be an increase in renewables without an increase in interconnections", but the targets set by the European Commission are rather arbitrary and the model from the Lappeenranta University of Technology only shows the upper limit for an energy system completely running on renewable energy. In this research the interconnector capacity is based on the installed offshore wind farm capacity, but the island will also function as a hub for electricity trade and could possibly provide additional benefits.
- Investigate opportunities to **combine offshore wind farms with other marine uses**. The Hub and Spoke concept requires a tremendous amount of space, while the interaction with other marine uses proved to be often limited or not even possible at all. The current approach of simply forbidding any other activity at offshore wind farms is already under discussion. The North Sea is one of the most intensively used sea basins and multifunctional use of space is therefore very important. Stakeholders have to be included in the design to enable multifunctional use of space.
- Further improve the **cost approximation of offshore wind farms** and subsea interconnectors. Multiple regression analysis improved the current methodology used in literature, although there is still a significant average error of respectively 23.5% and 24.1%. Offshore wind farms contain the major part of the Hub and Spoke concept expenses and more accurate predictions would lead to considerable gains in accuracy. There is however a lack of public information and the industry is not transparent, which makes it difficult to further reduce the error. Industry developments go however very rapid and more information will become available when the industry becomes more mature. Multiple regression can be improved by updating the data set with the most recent projects, although the biggest gain in accuracy is achieved by more accurate information.
- Use a **higher resolution wind model**. Bathymetry is the dominant condition with respect to cost and the EMODnet model contains a resolution of approximately 100 x 100 meters. The wind conditions are dominant to revenue, although the CFSv2 model contain a much lower resolution of approximately 50 x 50 km. Wind speed affects revenue to the power third and a higher resolution model, assuming the other characteristics are equal, can significantly increase the accuracy of revenue. It is advised to use the KNMI WindAtlas model which contains a resolution of 2.5 x 2.5 km, although this model is not publicly available for the entire North Sea and has to be purchased.

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APPENDICES

A - EU ENERGY MODEL

B - ARTIFICIAL ISLAND

C - EXPENDITURE

D - PRODUCTION AND REVENUE

E - INTERVIEWS

F - NORTH SEA OFFSHORE WIND FARMS

G - NORTH SEA SUBSEA INTERCONNECTORS

H - MATLAB CODE

A - EU ENERGY MODEL (2016)

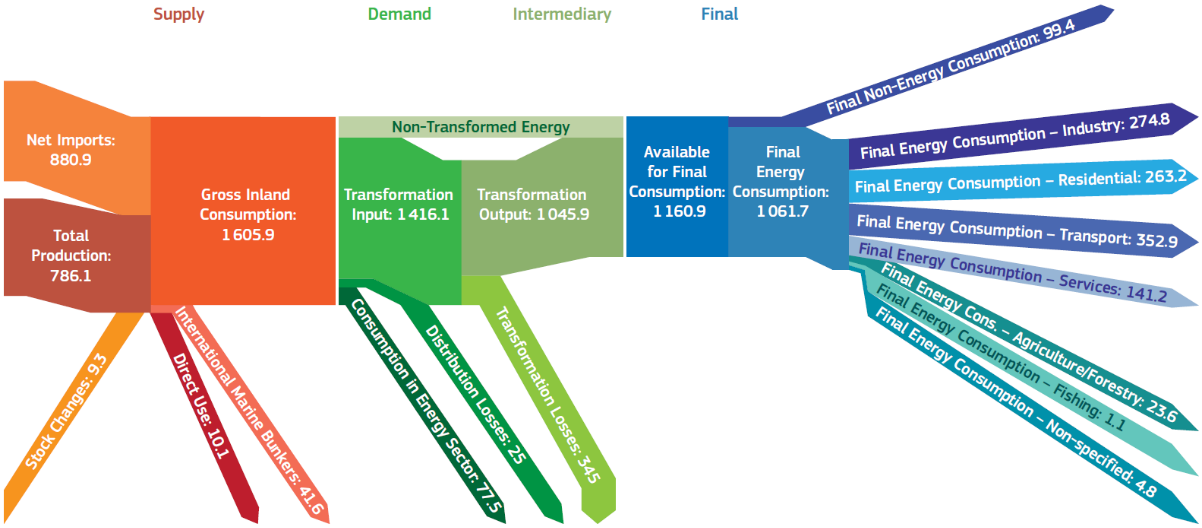


Figure A.1: EU-28 Energy Flow in 2014 in Mtoe (source: EC, 2016b)

EU Reference Scenario 2016 based on PRIMES, GAINS	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Net Imports (ktoe): EU28	**826,349**	**979,676**	**955,004**	**962,880**	**939,241**	**936,371**	**913,530**	**918,466**	**921,057**	**916,273**	**900,215**
Solids (ktoe): EU28	98,320	125,363	111,814	129,695	116,099	98,394	83,855	62,251	42,781	30,886	21,705
Oil (ktoe): EU28	532,226	597,491	558,847	556,140	532,001	529,826	523,615	525,540	528,066	532,091	536,465
Natural gas (ktoe): EU28	193,432	254,054	278,015	269,292	279,116	296,557	295,088	319,712	339,699	343,969	332,706
Electricity (ktoe): EU28	2,030	1,412	712	1,761	1,501	779	175	147	23	16	-21
Production (incl. recovery of products) (ktoe): EU28	**944,996**	**903,986**	**835,772**	**758,585**	**756,920**	**716,021**	**701,817**	**664,400**	**645,477**	**639,419**	**661,556**
Solids (ktoe): EU28	214,596	196,030	164,837	148,196	135,147	121,500	101,636	81,393	65,416	49,831	61,127
Oil (ktoe): EU28	173,901	135,553	100,408	78,529	69,728	58,085	48,211	36,781	28,798	21,092	14,028
Natural gas (ktoe): EU28	209,436	190,771	159,948	118,438	106,515	92,577	78,508	63,594	59,389	57,448	53,285
Nuclear (ktoe): EU28	243,841	257,516	236,562	213,043	188,974	174,739	187,232	187,748	171,124	165,795	163,825
Renewable energy (ktoe): EU28	103,222	124,116	174,017	200,379	256,556	269,120	286,231	294,883	320,751	345,252	369,291
Hydro (ktoe): EU28	30,703	26,859	32,312	31,168	32,301	32,291	32,592	33,261	34,005	35,117	36,215
Biomass & waste (ktoe): EU28	65,583	85,060	119,573	132,613	163,441	164,951	168,133	169,769	177,890	181,498	183,700
Wind (ktoe): EU28	1,913	6,058	12,836	23,588	39,794	45,356	52,328	53,251	59,502	70,648	84,280
Solar and others (ktoe): EU28	436	827	3,775	11,001	17,799	22,826	27,799	30,963	35,731	41,786	48,934
Geothermal (ktoe): EU28	4,587	5,312	5,521	2,009	3,221	3,695	5,379	7,639	13,624	16,203	16,162
Gross Inland Consumption (ktoe): EU28	**1,726,888**	**1,824,722**	**1,760,315**	**1,666,601**	**1,639,429**	**1,593,747**	**1,554,387**	**1,520,273**	**1,501,734**	**1,488,372**	**1,491,621**
Transformation Input (GWh): EU28	**1,456,240**	**1,532,105**	**1,414,476**	**1,260,792**	**1,199,162**	**1,163,728**	**1,123,962**	**1,093,336**	**1,058,978**	**1,020,958**	**997,750**
Energy branch consumption (ktoe): EU28	**86,261**	**91,922**	**86,455**	**81,624**	**75,821**	**70,778**	**66,909**	**64,147**	**61,392**	**59,425**	**60,637**
Available for Final Consumption	**1,242,533**	**1,302,450**	**1,266,109**	**1,240,167**	**1,246,313**	**1,222,124**	**1,199,686**	**1,185,941**	**1,190,858**	**1,200,586**	**1,210,023**
Final energy consumption (ktoe): EU28	**1,129,427**	**1,186,370**	**1,155,879**	**1,133,457**	**1,133,797**	**1,106,322**	**1,081,368**	**1,065,407**	**1,067,769**	**1,077,083**	**1,085,865**
Solids (ktoe): EU28	61,977	53,988	50,512	47,694	45,711	42,313	34,285	25,558	18,469	15,208	13,392
Oil (ktoe): EU28	487,065	502,509	455,207	437,598	405,293	390,260	373,318	365,300	358,889	355,261	352,635
Gas (ktoe): EU28	267,588	281,191	273,366	265,879	264,623	251,208	241,000	233,980	234,095	235,978	236,649
Electricity (ktoe): EU28	217,644	239,548	244,471	241,010	250,682	257,237	265,172	274,372	285,235	296,767	307,340
Heat (from CHP and district heating) (ktoe): EU28	46,044	52,425	52,875	49,062	50,935	52,357	54,346	54,510	56,136	56,253	56,700
Renewable energy (ktoe): EU28	49,109	56,708	79,448	92,104	116,178	112,396	112,458	110,598	113,098	115,086	115,912
Other (ktoe): EU28	-	-	-	111	375	550	787	1,089	1,847	2,530	3,237
Non-energy consumption (ktoe): EU28	**113,106**	**116,080**	**110,230**	**106,709**	**112,515**	**115,802**	**118,318**	**120,534**	**123,089**	**123,504**	**124,158**

Figure A.2: EU Energy Model - Reference Scenario 2016 (source: Capros, 2016)

B - ARTIFICIAL ISLAND

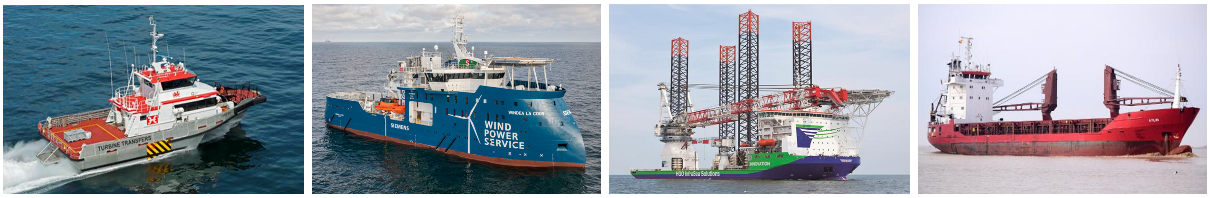
B.1 Required Island Area

Electrical Infrastructure
Onshore HVDC converters with 2 GW capacity cover in the order of 36,000 m2 with accompanying switch yards of 27,000 m2. (TenneT, 2016) Export cables from the surrounding offshore wind farms and interconnector cables coming from surrounding countries run to the HVDC converter stations and also require area. The cables are buried to reduce the risk on damage, but no structures are allowed on top as this increases risk on damage and the cables must be always accessible for repairs. The minimum intermediate distance between offshore power cables is 25 meters (Bijker, 2017) and reduces to 2.5 meters onshore from crossing the coastal protection to the converter station (Arcadis, 2015). The number of cables and the distance to the converter station determines the required area. The number of export cables is based on the Borssele offshore wind farm with 1,400 MW capacity and 4 export cables. Extrapolation to 30 GW and 100 GW capacity gives 88 to 288 export cables. TenneT assumes 2 GW interconnector cables which result in an additional 15 to 50 cables. The last parameter to determine is the distance to the HVDC converter stations. These are the most important structures on the island and it is therefore likely they will be constructed somewhere in the centre of the island, furthest away from sea water and possibly on an elevation. This will however limit optimal use of area on the island as cable pathways running to the converter stations must stay clear from structures and hinder the other activities on the island. The HVDC converter stations are therefore assumed to be constructed on average 300 meters from the coastal protection, which results in a total cable pathway area of 77,250 m2 to 253,500 m2. The area above the cable pathways might however serve a second function as recreational area for personnel or a place for nature with low growing vegetation.

Industrial Buildings
The required area of factories and warehouses is highly dependent on the activities taking place on the artificial island. TenneT is still researching the possibilities and benefits and the required area therefore contains a very high uncertainty. Maintenance and operation seems very advantageous to perform from the artificial island as distance is a very decisive parameter, although complete assembly lines are mentioned as well and would require additional factories. The area for warehouses, refuelling stations and waste deposit stations are based on information from TenneT. Factories are included to make a safe assumption with regards to island area and is assumed to require double the amount of area compared to the warehouses.

Accommodation and Recreational Space
Accommodation is based on estimates made by TenneT. Recreational space is based on standards for outdoor recreational areas. (Moeller, 1965) There is no simple method to determine an adequate level of recreational area, but based on rules of thumb and past experience 10 acres (40,000 m2) per 1,000 persons is reserved.

Harbour
The harbour on the artificial island is used for installation and maintenance on the offshore wind turbines. Large components and other supplies are shipped to the island with general cargo vessels where the turbines will be finished inside complete assembly lines, after which turbine installation vessels will be working full-time to install the turbines from the island at the desired location. The harbour is also used in combination with the helipads for operation and maintenance. Small crew transfer vessels (CTV's) are used to transfer personnel for turbine inspections, after which service operation vessels (SOV's) can be used to replace the larger components. Common vessel dimensions are presented in Table B.1. The dimensions of general cargo vessels can vary widely, although this is a common dimension for these types of vessel. The dimensions of the CTV and SOV vessels are based on information from TenneT and the dimensions of the turbine installation vessel are typical dimensions according to The Crown Estate. (TenneT, 2016; The Crown Estate, 2010)



(a) CTV (b) SOV (c) Installation vessel (d) General cargo vessel

Figure B.1: Harbour Vessel Types

The quay length is subsequently determined by multiplying the vessel lengths with 1.1 to gain the necessary space between vessels for mooring and safety. The small crew transfer vessels are very manoeuvrable and do not have to be individually berthed parallel to the quay. These vessels can be easily positioned abreast or with the slip/finger arrangement commonly applied in marinas, leading to a much lower quay length requirement. (Ligteringen and Velsink, 2014) The harbour must however be large enough to provide sufficient berthing capacity for all vessels in case they need to seek shelter during storms. Based on the vessel length, the number of vessels and the additional factor for mooring and safety the total required quay length becomes 1,850 m to 5,350 m. The terminal area including storage, internal roads and associated buildings is dependent on amongst others the annual throughput, dwell time and cargo density. These factors are however not yet known and will be determined in more detailed design studies. In this stage the terminal area is based on initial calculations made by TenneT and ranges between 55,000 m2 and 160,000 m2.

Table B.1: Harbour Dimensions (sources: TenneT, 2016; The Crown Estate, 2010; Ligteringen and Velsink, 2014)

Type	**Length**	**Width**	**Draft**	**No. of vessels (30 - 100 GW)**	**Quay length**
Crew transfer vessel (CTV)	25 m	10 m	1 m	75 - 225	2,100 - 6,200 m
Service operations vessel (SOV)	80 m	20 m	6 m	16 - 48	1,400 - 4,200 m
Turbine installation vessel	130 m	38 m	5 m	2 - 6	300 - 900 m
General cargo vessel	110 m	20 m	7 m	1 - 2	150 - 250 m

Airstrip

The design criteria for the airstrip are based on light weight aircraft and small jets. The size of the airstrip and its associated surrounding buildings is primarily determined by the size of calling aircraft. The required space is tried to be kept as small as possible, because this decreases the volume and cost of the reclamation island. Simultaneously, smaller aircraft increase utilisation and efficiency of the airstrip.

The estimates of 30 GW to 100 GW offshore wind energy capacity around the island would require approximately 1,500 to 5,000 people. (TenneT, 2016) The light weight aircraft shown in Figure B.2 can have a capacity around 10 - 12 persons and in combination with common leave regulations for expats of 2 months on the island and 1 month off this results in under 4 flights per day. Even when flights are only allowed during daylight the capacity of such an airstrip is more than sufficient and larger aircraft with a larger airstrip is not necessary. Another reason to choose for larger aircraft might be the reduced risk on collisions with surrounding offshore wind turbines, but this would have to be studied in more detail.

Figure B.2: Lightweight Aircraft with 12 Person Capacity (source: Royal Flying Doctor Service, 2016)

The airstrip for lightweight aircraft has to comply with certain design criteria. The following criteria are not strict formal regulations, but are rules of thumb of the Royal Flying Doctor Service based on light weight aircraft like in Figure B.2 for remote airstrips in Australia. The most important factor is good drainage with a slight cumber in the airstrip. The proposed runway length is 1,200 meters which makes landing and take off possible under almost all weather conditions. A reliable airstrip should be at least 1,000 meters and shorter is possible as well, but this restricts the use by the local conditions at that time. The width of the runway must be at least 90 meters to use the airstrip day and night, but might be reduced to 45 meters if used under solely daylight conditions. Additional free width of 45 meters on each side of the runway is required over which the aircraft can fly in case of a missed approach. The additional free width also reduces damage if the aircraft runs of the airstrip. These zones must stay clear from trees, rocks, fences or any other obstacles. The start and end of the airstrip must also stay clear from any obstructions as approaching and leaving aircraft fly over these areas. At least 900 meters in the runway direction should be clear from objects above a slope of 3.3%. Furthermore, terrain or man-made structures should not be higher than 45 meters in a 2,500 meters (preferably 4,000 meters) radius. The airstrip must be positioned in such a way that aircraft do not fly close to or over residential areas or other buildings. These criteria must also be ensured after construction of the airstrip.

The criteria mentioned above are based on the same type of light weight aircraft used for the Hub and Spoke airstrip. The airstrip conditions are however very different. The Royal Flying Doctor Service often faces remote airstrips with natural surfaces in mainland Australia. The airstrip length is very dependent on the surface, wind conditions, temperature, elevation above sea level and the weight of the aircraft. The Hub and Spoke island will contain a man-made airstrip with a bitumen surface. This reduces the required airstrip length considerably, although the North Sea faces much stronger winds compared to mainland Australia and this increases the required length and width. How much these factors influence the airstrip dimensions is not precisely known and the initial values of the Royal Flying Doctor Service are therefore applied. The final aspect to take into account is the free area on the start and end of the airstrip. The crest of the coastal protection and surrounding offshore wind turbines should stay for 900 meters under a slope of 3.3% from the airstrip and should not be higher that 45 meters in a radius of 2,500 meters. It may therefore be necessary to construct the airstrip at a higher level. The area for parking the aircraft in a hangar is estimated to be 10,000 m2. Royal Flying Doctor Service, 2016

Table B.2: Airstrip dimensions (source: Royal Flying Doctor Service, 2016)

Airstrip Dimensions	**Light weight aircraft**
Airstip length	1,200 m
Airstrip width	90 m
Additional free width	2 x 45 m
Parking + hanger	10,000 m2

Other

An additional 20% of island area is reserved for amongst others roads, the back slope of the coastal protection, unforeseen additional structures and other marine uses. The percentage is arbitrarily chosen, but it is wise to include additional area to be able to anticipate on unforeseen events. Expanding the island is a possibility, but this is a very expensive option if only a small amount of additional area would be needed.

B.2 Peaks-Over-Threshold method

There are several methods to perform extreme value analysis. One of the most common methods to determine extreme wave heights is the Peaks-Over-Threshold (henceforth POT) method. A threshold level is chosen above which storms of a certain duration are defined and these peaks are used to fit multiple distributions and extrapolate the wave heights. The Exponential, Gumbel and Weibull distributions are fitted, although in literature even more distributions have been used. The goal is to find a distribution with the best possible fit to the peaks, which resemble the extreme significant wave heights in the measured data set. The parameters of the distributions are determined with the Least Squares method and the distribution with the R-Squared value closest to one is fitting the data peaks best and is used to extrapolate the significant wave heights.

First, the significant wave heights H_s are filtered in directional ranges of usually 30 degrees because the physical processes which influence the waves are likely to be different per incoming direction. The artificial island is designed to the direction with the most and highest significant waves and the POT method is therefore only applied to waves coming from the normative direction. Storms are usually assumed to last for 6 hours and the number of storms per year is iteratively determined by the goodness of fit of the distributions. The number of assumed storms influences the number of peaks and the height of the threshold level. Usually 3 to 5 storms per year are assumed and these will form the peaks of the POT method. However, the measured data period to extrapolate extreme wave heights is often longer with measurement periods of 30 to 50 years. The retrieved wave conditions from the WaveWatchIII model only contain 11 years of data. The number of storms per year is therefore increased to 10 storms per year to achieve a comparable number of peaks. The values of these parameters have been verified by engineers from Witteveen+Bos and will form the base scenario for the extrapolation of the significant wave height on Dogger Bank (54.5N 2.0E). (Bodde, 2017; Kaji, 2017)

After filtering of the wave conditions the significant storm wave heights H_{ss} are sorted from low to high and divided into bins. The number of observations and the cumulative number of observations is presented, after which the probability P can be determined of wave heights smaller than the maximum measured wave height. The parameter Q is the inverse and presents the probability of wave exceedance. Multiplying the probability of wave exceedance with the number of storms per year N_s gives the probability of storm exceedance Q_s and with this information it is possible to fit the Exponential distribution.

$$P = P\left(H'_{ss} \leq H_{ss}\right) \tag{B.1}$$

$$Q = Q\left(H'_{ss} > H_{ss}\right) = 1 - P \tag{B.2}$$

$$Q_s = N_s \cdot Q \tag{B.3}$$

Exponential distribution
The parameters α and β of the Exponential distribution are determined with linear regression and the significant wave height in a design storm H_{ss} can now be calculated.

$$H_{ss} = \alpha \cdot ln\left(Q_s\right) + \beta \tag{B.4}$$

Gumbel distribution
The Gumbel distribution is another distribution commonly applied to extrapolate the significant wave height. The distribution is rewritten to get one side of the equation in the form $AH_{ss} + B$ and the remaining part of the equation is noted as G. Once again, linear regression is performed to determine the variables β and γ of the Gumbel distribution and the significant wave height in a design storm H_{ss} can be determined.

$$P = exp\left[-exp\left(-\frac{H_{ss} - \gamma}{\beta}\right)\right] \tag{B.5}$$

$$ln\ P = -exp\left(-\frac{H_{ss} - \gamma}{\beta}\right) \tag{B.6}$$

$$\underbrace{-ln\left(-ln\ P\right)}_{G} = \frac{H_{ss} - \gamma}{\beta} = \underbrace{\frac{1}{\beta}H_{ss} - \frac{\gamma}{\beta}}_{AH_{ss} + B} \tag{B.7}$$

$$H_{ss} = \gamma - \beta \cdot ln\left(ln\left(\frac{N_s}{N_s - Q_s}\right)\right) \tag{B.8}$$

Weibull distribution
The Weibull distribution is often mentioned in literature to have the best approach to extreme wave heights. However, the Weibull distribution contains three variables. The parameter α must be found first by means of iteration in order to determine the parameters β and γ. Just like the Gumbel distribution the formula is rewritten to gain one part of the equation in the form $AH_{ss} + B$ and the remaining part of the equation is noted as W. The parameter α is iteratively determined by approaching the highest correlation between the measured wave heights H_s and the values in column W. Once α is known the

remaining parameters can be determined with linear regression and the significant wave height in the design storm H_{ss} can be calculated.

$$Q = exp\left[-\left(\frac{H_{ss}-\gamma}{\beta}\right)^{\alpha}\right] \tag{B.9}$$

$$-ln\ Q = \left[\frac{H_{ss}-\gamma}{\beta}\right]^{\alpha} \tag{B.10}$$

$$\underbrace{(-ln\ Q)^{1/\alpha}}_{W} = \frac{H_{ss-\gamma}}{\beta} = \underbrace{\frac{1}{\beta}H_{ss} - \frac{\gamma}{\beta}}_{AH_{ss}+B} \tag{B.11}$$

$$H_{ss} = \gamma + \beta \cdot \left(-ln\left(\frac{Q_s}{N_s}\right)\right)^{1/\alpha} \tag{B.12}$$

In Table B.3 the measured wave data and calculation steps are presented. The data present 11 years of wave conditions from the WaveWatchIII model at Dogger Bank (54.5N 2.0E). The peaks are based on 10 defined storms per year with a duration of 6 hours, coming from the normative direction between 335 and 5 degrees north.

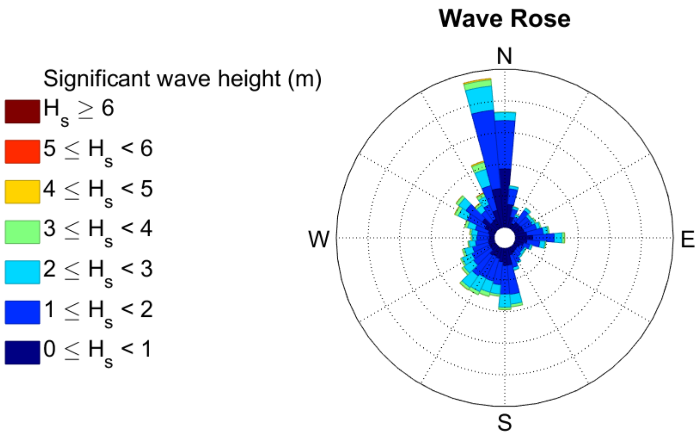


Figure B.3: Wave Rose with Significant Wave Height on Dogger Bank (54.5N 2.0E)

Table B.3: POT Calculation Sheet

H_s bins		Obs.	Cum.	P	Q	-ln(H_{ss})	Q_s	ln(Q_s)
3.25	3.50	20	20	0.19608	0.80392	-1.2528	7.4545	2.0088
3.50	3.75	31	51	0.50000	0.50000	-1.3218	4.6364	1.5339
3.75	4.00	19	70	0.68627	0.31373	-1.3863	2.9091	1.0678
4.00	4.25	11	81	0.79412	0.20588	-1.4469	1.9091	0.64663
4.25	4.50	10	91	0.89216	0.10784	-1.5041	1	-4.44E-16
4.50	4.75	7	98	0.96078	0.039216	-1.5581	0.36364	-1.0116
4.75	5.00	2	100	0.98039	0.019608	-1.6094	0.18182	-1.7047
5.00	5.25	0	100	0.98039	0.019608	-1.6582	0.18182	-1.7047
5.25	5.50	2	102	1	0	-1.7047	0	-Inf

Table B.4: Significant Storm Wave Height H_{ss} (m) Extrapolation on Dogger Bank (54.5N 2.0E, 9.27 storms per year, 3.25 m threshold)

Distribution Type				1/100 year H_s	1/1,000 year H_s	1/10,000 year H_s	R-Squared
Extrapolation	- 0.42	4.42	x	6.34 m	7.30 m	8.26 m	0.9755
Gumbel	x	0.37	3.66	6.17 m	7.02 m	7.86 m	0.9817
Weibull	1.34	0.65	3.28	6.02 m	6.69 m	7.31 m	0.9819

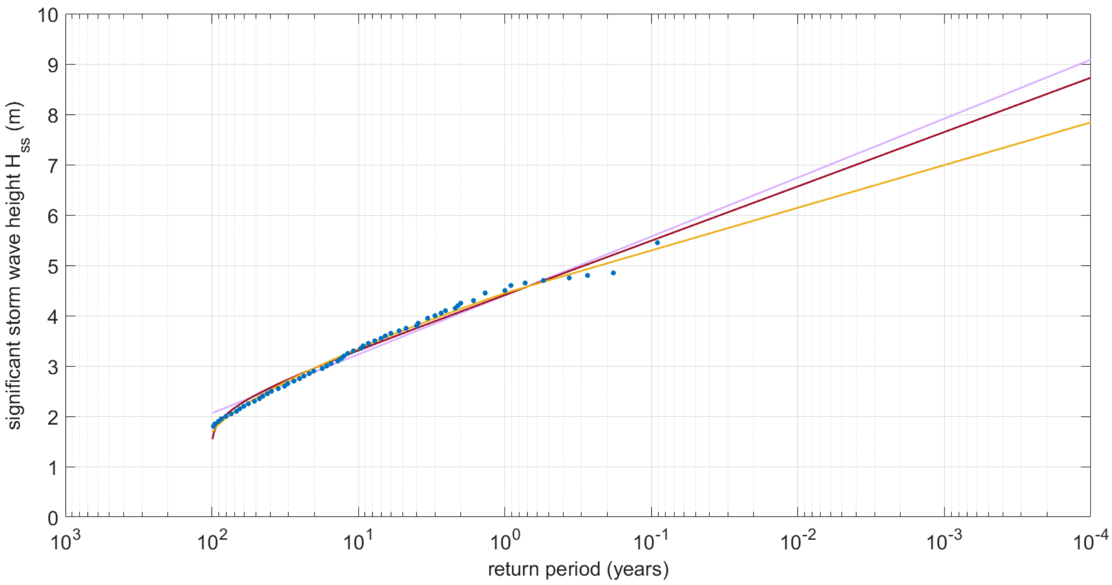


Figure B.4: POT Distribution Comparison for H_{ss} on Dogger Bank (54.5N 2.0E)

There are however some uncertainties in the POT method as some parameters are rather arbitrary, there is not one distribution always fitting the data best, several methods can be used to determine the best fit and there is not some kind of "rule of thumb" to determine the number of storms per year or the threshold level. Several factors are influencing the distribution parameters and their goodness of fit: the angle of incoming waves, number of storms and threshold level, storm duration and the period of measured data. The extrapolation shown in Figure B.4 is the base scenario and the parameters are varied in order to gain insight into their influence on the extrapolated values.

B.2.1 Storm duration

Storm duration is one of the parameters which is rather arbitrary. Normally a storm is assumed to last 6 hours, but the wave conditions in the WaveWatchIII model are averaged over 3-hour periods and it is thus possible to use shorter storms. By decreasing the storm duration the number of storms per year increases to 12.18, although the threshold level remains at 3.25 m. The influence is however rather small for all distributions as can be seen in Table B.5.

Table B.5: Significant Wave Height Extrapolation with Storm Duration of 3 Hours

Distribution Type				**1/100 year H_s**	**1/1,000 year H_s**	**1/10,000 year H_s**	**R-Squared**
Extrapolation	- 0.41	4.43	x	6.32 m	7.27 m	8.22 m	0.9753
Gumbel	x	0.38	3.53	6.21 m	7.08 m	7.95 m	0.9807
Weibull	1.40	0.72	3.10	6.00 m	6.65 m	7.25 m	0.9812

B.2.2 Number of storms per year

The number of storms per year and the subsequent height of the threshold level is another arbitrary parameter and usually chosen at 3 to 5 storms per year. The number of storms is usually iteratively determined by the R-Squared value of the distributions closest to one as this indicates the best fit. In Table B.6 the number of storms per year is lowered to 3 with a corresponding threshold level of 3.75 m and in Table B.7 the number of storms per year is increased to 100 with a corresponding threshold level of 1.75 m.

Table B.6: Significant Wave Height Extrapolation with ∼3 Storms per Year

Distribution Type				**1/100 year H_s**	**1/1,000 year H_s**	**1/10,000 year H_s**	**R-Squared**
Extrapolation	- 0.39	4.44	x	6.24 m	7.15 m	8.05 m	0.9521
Gumbel	x	0.33	4.16	6.05 m	6.80 m	7.55 m	0.9563
Weibull	1.26	0.53	3.87	6.00 m	6.65 m	7.26 m	0.9541

Table B.7: Significant Wave Height Extrapolation with ∼100 Storms per Year

Distribution Type				**1/100 year H_s**	**1/1,000 year H_s**	**1/10,000 year H_s**	**R-Squared**
Extrapolation	- 0.50	4.40	x	6.71 m	7.87 m	9.03 m	0.9815
Gumbel	x	0.47	2.24	6.58 m	7.66 m	8.74 m	0.9896
Weibull	1.43	1.02	1.64	6.21 m	6.99 m	7.72 m	0.9943

It can be seen that less storms result in lower R-Squared values indicating the fit of the distributions with the significant storm wave heights is less accurate. The opposite is true for more storms per year as the fit increases in accuracy compared to the base scenario. The difference between extrapolated significant wave heights is significant and especially for longer periods the difference becomes larger. The Gumbel distribution contains the largest difference of 1.19 m between 3 storms per year and 100 storms per year for a return period of 10,000 years.

B.2.3 Angle of incoming direction

The wave conditions are almost always filtered to a range of 30 degrees. In Table B.8 and Table B.9 the range of incoming direction is varied to 10 degrees and 90 degrees to see the influence of this assumption.

Table B.8: Significant Wave Height Extrapolation with 10 Degrees Angle of Incoming Waves

Distribution Type				**1/100 year H_s**	**1/1,000 year H_s**	**1/10,000 year H_s**	**R-Squared**
Extrapolation	- 0.42	4.42	x	6.35 m	7.32 m	8.28 m	0.9743
Gumbel	x	0.37	3.68	6.17 m	7.02 m	7.86 m	0.9816
Weibull	1.37	0.67	3.29	6.01 m	6.66 m	7.26 m	0.9818

Table B.9: Significant Wave Height Extrapolation with 90 Degrees Angle of Incoming Waves

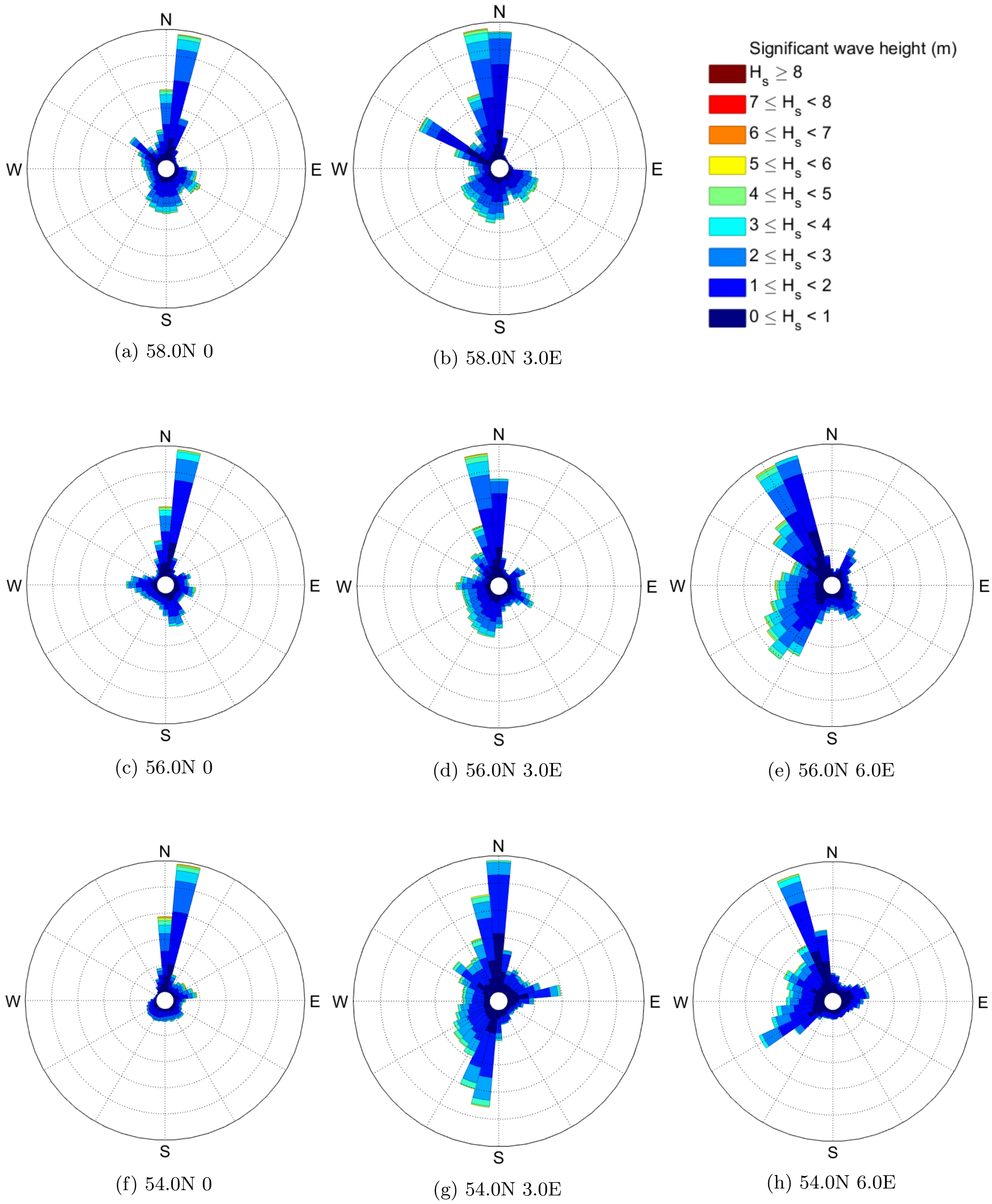
Distribution Type				**1/100 year H_s**	**1/1,000 year H_s**	**1/10,000 year H_s**	**R-Squared**
Extrapolation	- 0.30	4.94	x	6.32 m	7.01 m	7.69 m	0.8617
Gumbel	x	0.27	4.44	6.25 m	6.88 m	7.51 m	0.9034
Weibull	5.29	2.57	2.13	5.81 m	6.02 m	6.20 m	0.9685

It can be seen that a small range of directions has a much better fit with the significant storm wave heights. A consequence of smaller direction ranges is the lower threshold level at 3.25 m compared to 4.00 m for the 90 degrees range. The lower threshold level is caused by the constant number of storms per year criterion. The sample size is reduced by the direction constriction and the definition of a storm is thus lowered in terms of wave height. One could suggest this should lead to a less accurate fit as there are fewer peaks with great significant wave heights, but these extremes are likely to be influenced by different physical processes for different directions and the data set is thus more likely to be disturbed for greater ranges of incoming waves.

B.2.4 Conclusion

The chosen parameters of the base scenario perform very well compared to the various parameter variations. The effect of storm duration proved to be neglectable, although the number of storms and the range of incoming waves proved to have a noticeable effect. Especially for longer return periods the effects are amplified and even led to a 1.11 m deviation of the Weibull distribution with a once every 10,000 years storm, compared to the base scenario.

B.3 Wave Roses



(a) 58.0N 0

(b) 58.0N 3.0E

(c) 56.0N 0

(d) 56.0N 3.0E

(e) 56.0N 6.0E

(f) 54.0N 0

(g) 54.0N 3.0E

(h) 54.0N 6.0E

Figure B.5: North Sea Wave Roses with Significant Wave Height H_s

B.4 Significant Storm Wave Height H_{ss} - Exponential and Gumbel distribution

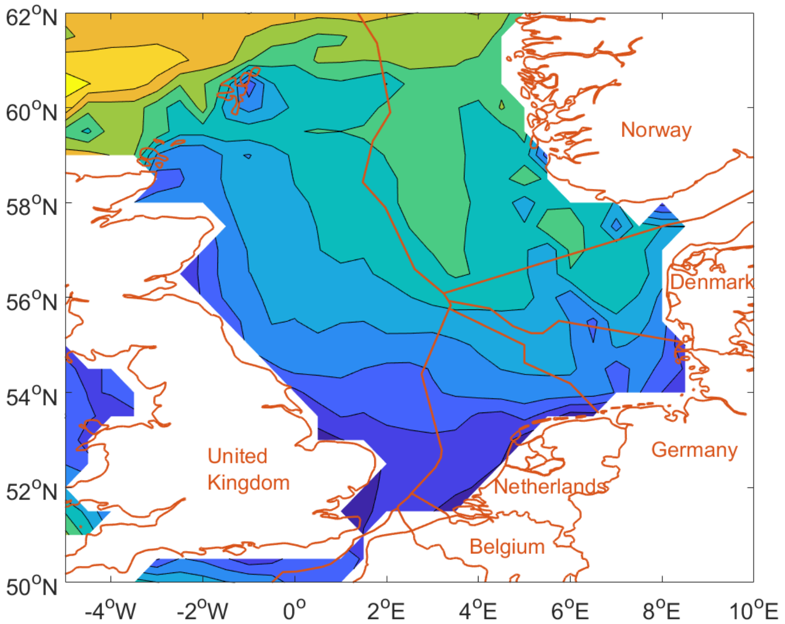


Figure B.6: Significant Storm Wave Height H_{ss} in m (Exponential, return period 1/10,000 years)

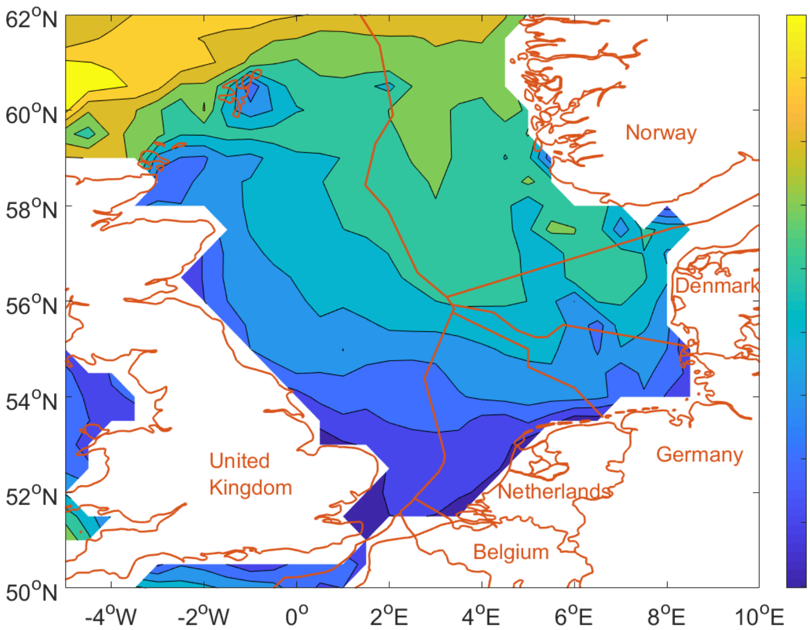


Figure B.7: Significant Storm Wave Height H_{ss} in m (Gumbel, return period 1/10,000 years)

B.5 Unit Cost of Dredging

The unit cost of dredging is determined with the course book "Dredging Technology" by G.L.M. van der Schrieck and the report "A guide to cost standards for dredging equipment 2009" by R.N. Bray, with cost standards indexation for 2016. The latter report provides a standard method to determine the cost of various dredging vessels and their related equipment. The unit cost of dredged material is determined by the following topics:

- Standard Value
- Depreciation and Interest
- Maintenance and Repair
- Salary
- Fuel and Lubricants Expenditure
- Insurance Expenditure
- (De)mobilisation
- General Overhead

Standard Value
The standard value V of the dredging vessel is equal to the replacement cost of the item. This value can be approximated by the major vessel characteristics. For TSHD's these characteristics consist of the weight of unloaded vessel W, power of dredge pumps during suction P_t, power of the drag head jet pumps J_t and the free sailing propulsion power S. For CSD's these characteristics consist of the cutter motor power C, weight of the cutter gearbox W_{cgb}, dredge and jet pump power $P + J$, weight of the unloaded vessel W and the propulsion power S. The formula's to approximate the vessel standard value based on these characteristics are expressed in eq. B.13 and B.14 and the values are shown in Figures B.8 and B.9. Only the standard value of self propelled CSD's are presented. Smaller CSD's are often not self propelled and have to be moved by tugs. These smaller vessels are often applied in sheltered regions with lower wave heights. The open conditions in the North Sea can however be rough and the smaller not self propelled CSD's are therefore disregarded.

$$V_{TSHD} = 6,000 \cdot W + 1,212,000 \cdot W^{0.35} - 6,464,000 + 1,900 \cdot P_t + 785 \cdot J_s + 910 \cdot S \quad \text{(B.13)}$$

$$V_{CSD,\ self\ propelled} = 2,000 \cdot C + 80,000 \cdot W_{cgb} + 1,400 \cdot (P+J) + 8,500 \cdot W + 141,000 \cdot W^{0.35} + 950 \cdot S \quad \text{(B.14)}$$

Depreciation and Interest
Depreciation and interest $(D + i)$ is dependent on the standard value, the depreciation period and the interest rate. This amount is often expressed per week as a percentage of the standard value V. Dredging vessels have an expected lifetime of 18 years, the interest rate is usually set at 7% and a residual value of 10% of the standard value is assumed.

Maintenance and Repairs
Maintenance and repairs $(M+R)$ consists of all cost to keep the dredging equipment working under optimal conditions. The percentage for maintenance and repairs is based on common project characteristics, equipment lifetime, yearly utilisation, depreciation and interest rates and the residual value. TSHD's have a typical yearly utilisation of 33 weeks / year and CSD's are used 26 weeks / year, leading to depreciation and interest rates $(D+i)$ of respectively 9.6% and 9.8%. These values are based on projects in Europe. Extreme conditions or projects in other continents could lead to higher cost in maintenance and repairs.

Salary
The salary of personnel also needs to be included and is influenced by the number and skill level of employees. Dutch crew members cost around EUR 3000,- per week and local crew members like seamen or welders cost approximately EUR 1000,- per week. These expenses include airplane tickets for leave, salary during leave, housing and medical care. The salary is also highly influenced by the allowable hours and the number of shifts on the vessel. In Europe this is more strict compared to the rest of the world. Over here, large CSD's would require around 17 people leading to a salary cost of €51,000 / week and large TSHD's require around 16 experienced people and 13 local crew members, leading to a salary cost of €61,000 / week.

Fuel and Lubricants Expenditure
Fuel expenditure is a direct consequence of the price of fuel and the amount of fuel used. The average price of marine diesel is approximately €0.25 / litre and 10% of these cost might be added to include lubricants. Modern diesel engines consume in the order of 0.2 litres / kW / hour. Based on a full work week of 168 hours minus the mechanical and operational downtime, it is possible to determine the weekly fuel- and lubricant expenses based on the power capacity of the dredging vessel. For a 6,000 kW CSD with 105 operational hours per week the fuel and lubricants expenditure is roughly €31,500 + €3,150 and for a 24,000 kW TSHD which has less downtime the fuel and lubricants expenditure is €165,600 + €16,560 based on 138 operational hours per week.

Insurance Expenditure
A common percentage for weekly insurance is 0.07% of the standard value.

(De)mobilisation
The dredging equipment needs to be collected, transported to the project destination and assembled on site. It is very well possible, especially for larger projects, that equipment is being transported across continents and this (de)mobilisation time is at the expense of dredging hours. Mobilisation and demobilisation is adopted to take respectively 1 and 0.5 week, while the weekly expenses are continuing. These expenses have to be multiplied with the number of vessels, although general overhead can be excluded as the risk in this period is very little compared to the production period.

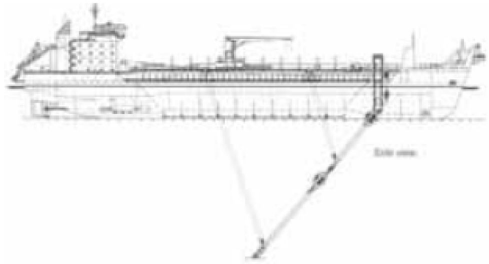
General Overhead
The cost-breakdown is increased with a percentage for general overhead to include profit and risks. Usually this is 20% of the expenditure, although this will vary from project to project.

Indexation
The standardised cost for dredging equipment is changing in time. The report "A guide to cost standards for dredging equipment 2009" is written based on price levels in 2009 and is indexed annually to stay up-to-date. In Table B.11 the cost standards indexation of TSHD's and CSD's for 2016 are presented.

Table B.11: Dredging Cost Standards Indexation 2016 (source: CIRIA, 2016)

Description	**Index 01-01-2016**
Trailing suction hopper dredgers	107
Cutter suction dredgers	109

Table 100 Trailing suction hopper dredgers



With certificate for unrestricted navigation area [a]

Unloading through bottom doors, valves or sliding doors with or without shore discharge

Service life	18 years
Service hours	168 hours per week
Residual value	10 % of V
Utilisation period	33 weeks
D+i	9.647 % of V per year or 0.292 % per week
Standard value	$V = 6000 \times W + 1\,212\,000 \times W^{0.35} - 6\,464\,000 + 1900 \times P_t + 785 \times J_t + 910 \times S$

Hopper volume	Displacement at dredging mark [b]	Lightweight (W)	Power dredge pumps during suction (P_t) [b]	Power jet pumps on draghead (J_t)	Free sailing propulsion power (S)	Value (V) [d]	Costs per week D+i	Costs per week M+R	M+R/ week
cu.m	t	t	kW	kW	kW	€	€	€	% of V
900	2000	635	350	220	950	10 600 000	30 952	21 917	0.2068
1300	3000	945	600	300	1550	15 300 000	44 676	30 508	0.1994
1800	4000	1260	880	360	2200	19 800 000	57 816	38 734	0.1956
2400	5200	1640	1000	660	2500	24 200 000	70 664	42 625	0.1761
2700	5800	1800	1250	660	3550	27 200 000	79 424	45 142	0.1660
3500	7600	2400	1550	760	4000	33 600 000	98 112	50 513	0.1503
4700	9900	3050	1950	800	5100	40 900 000	119 428	56 639	0.1385
6200	13 000	3925	2400	850	6450	50 100 000	146 292	64 359	0.1285
7700	16 000	4780	2600	1000	7350	58 100 000	169 652	71 072	0.1223
9100	19 000	5635	3500	1600	9400	68 700 000	200 604	79 967	0.1164
11 000	23 000	6830	4320	1600	10 800	80 400 000	234 768	89 786	0.1117
12 500	26 000	7610	5200	1600	13 000	89 800 000	262 216	97 674	0.1088
13 500	29 000	8685	5200	1800	13 000	97 700 000	285 284	104 303	0.1068
18 000	40 000	12 100	6680	2000	16 700	128 000 000	373 760	129 730	0.1014
19 000	42 000	13 750	7000	2000	17 500	141 000 000	411 720	140 639	0.0997
22 500	48 000	15 950	7200	3000	18 000	157 000 000	458 440	154 066	0.0981
24 000	60 000	18 250	9600	4000	24 000	184 000 000	537 280	176 723	0.0960
35 000	83 000	22 440	9600	4000	24 000	212 000 000	619 040	200 220	0.0944
45 000	105 000	27 000	13 000	4500	38 000	261 000 000	762 120	241 339	0.0925

a For trailing suction hopper dredgers without a certificate for unrestricted navigation area, V should be decreased by 10 per cent. For further explanation about class, see Section A1.3.

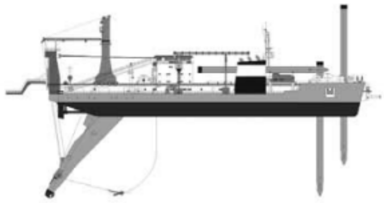
b Displacement on dredging mark = lightweight W + deadweight.

c Unless dredge pumps during trailing have their own power supply that cannot be used for other applications, P_t is defined as 40 per cent of the main engine power but not exceeding the mechanical limitation of the dredge pump drive.

d Standard values for large TSHDs exhibit a different trend to the smaller vessels because of the inclusion of extra equipment, such as extended pipes and submerged dredge pumps.

Figure B.8: Trailer Suction Hopper Dredger Expenditure related to Vessel Characteristics (source: Bray, 2009)

Table 200 Cutter suction dredgers, self propelled



With certificate for unrestricted navigation area [a]

Service life 18 years

Service hours 168 hours per week

Residual value 10 % of V

Utilisation period 26 weeks

D+i 9.647 % of V per year or 0.371 % per week

Standard value $V = 2000 \times C + 80\,000 \times W_{cgb} + 1400 \times (P + J) + 8500 \times W + 141\,000 \times W^{0.35} + 950 \times S$

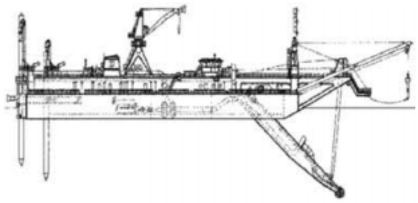
Power cutter motors (C)	Weight of cutter gearbox (W_{cgb})	Power dredge and jet pumps (P+J)	Lightweight (W)	Propulsion power (S)	Remarks	Value (V)	Costs per week D+i	Costs per week M+R	M+R/ week
kW	t	kW	t	kW		€	€	€	% of V
1750	50	8000	4300	1750		59 500 000	220 745	79 351	0.1334
2000	55	8500	4700	2000		64 900 000	240 779	84 198	0.1297
2500	75	8000	5100	3500		71 700 000	266 007	90 302	0.1259
3000	80	7000	6250	3000		81 200 000	301 252	98 830	0.1217
4000	105	9600	6050	7400	FSC [b]	93 100 000	345 401	109 512	0.1176
6000	145	16 000	10 650	7400	FSC [b]	150 000 000	556 500	160 588	0.1071
6000	150	15 000	11 000	7000	DE [c]	158 000 000	589 890	168 667	0.1068
7600	220	16 000	13 700	7600	DE [c]	194 000 000	727 160	201 880	0.1041

a For cutter suction dredgers without a certificate for unrestricted navigation area, V should be decreased by 10 per cent. For explanation about class, see Section A1.3.

b In cases where the dredger is equipped with a flexible spud carrier, two per cent is added to the value derived from the equation.

c In cases where the dredgers' main drives are diesel-electric, six per cent is added to the value derived from the equation.

Table 201 Cutter suction dredgers, not self propelled



With certificate for unrestricted navigation area [a]

Dredgers with a lightweight >250 tons and cutter power >200 kW

Service life 18 years

Service hours 168 hours per week

Residual value 10 % of V

Utilisation period 26 weeks

D+i 9.647 % of V per year or 0.371 % per week

Standard value $V = 3800 \times C + 20\,000 \times W_{cgb} + 1400 \times (P + J) + 9050 \times W + 15\,000 \times W^{0.35}$

Power cutter motors (C)	Weight of cutter gearbox (W_{cgb})	Power dredge and jet pumps (P+J)	Lightweight (W)	Remarks	Value (V)	Costs per week D+i	Costs per week M+R	M+R/ week
kW	t	kW	t		€	€	€	% of V
250	8	850	360	–	5 680 000	17 882	20 786	0.3660
250	10	1000	380	–	6 110 000	20 405	22 026	0.3605
350	0	1675	400	–	7 420 000	27 528	25 567	0.3446
550	0	1700	520	–	9 310 000	34 540	30 103	0.3233
750	0	3300	1050	–	17 100 000	63 441	40 830	0.2388
750	30	4100	1370	–	21 800 000	80 878	46 580	0.2137
900	33	4000	2000	–	28 000 000	103 880	53 400	0.1907
1100	34	6000	2500	–	36 100 000	133 931	61 517	0.1704
1300	44	6400	2650	–	39 000 000	144 690	64 330	0.1649
1500	50	6500	2850	–	41 800 000	155 078	66 923	0.1601
1700	55	7000	3200	–	46 600 000	172 886	71 250	0.1529
2500	57	7000	3400	–	51 500 000	191 065	75 667	0.1469
3000	80	7000	4900	–	67 400 000	250 054	90 000	0.1335
3300	90	9600	6000	FSC [b]	84 040 000	311 788	104 999	0.1249
3700	100	9000	6340	DE [c]	91 540 000	342 804	112 535	0.1229

a In cases where the dredger has a certificate for restricted navigation area (coastal), V should be decreased by five per cent. Without a class certificate, V must be decreased by 10 per cent. For explanation about class, see Section A1.3.

b In cases where the dredger is equipped with a flexible spud carrier, two per cent is added to the value V.

c In cases where the dredgers' main drives are diesel-electric, six per cent is added to the value V.

Figure B.9: Cutter Suction Dredger Expenditure related to Vessel Characteristics (source: Bray, 2009)

C - EXPENDITURE

Offshore wind farms can be constructed in a variety of configurations. The configuration is primarily based on local conditions and it is therefore essential to gain insight into the most influencing parameters. The corresponding cost per component is however not easy to obtain as there is a lack of public information and producers do not share information as the industry contains a high level of knowledge and competition. The cost per component is therefore determined based on multiple scientific articles in combination with experience from industry experts. The common methodology in literature to determine offshore wind farm cost is either by applying regression analysis on executed projects or based on a fictional wind farm with common project characteristics. Every source is briefly explained with the adopted methodology and characteristics.

Sources

The report “A Guide to an Offshore Wind Farm” (2010) by the Crown Estate is based on expected offshore wind farm characteristics in the Round 3 development phase in the United Kingdom. The offshore reference wind farm contains 500 MW capacity with AC technology and is located 80 km from shore. The turbines are 5 MW each and founded on monopiles. (The Crown Estate, 2010)

The report “Offshore Wind Assessment for Norway” (2010) by Douglas-Westwood contains a cost breakdown for a 600 MW HVDC offshore wind farm located 15 km from shore. Monopile foundations are used at 20 m water depth and the project lifetime is assumed to be 20 years. (Douglas Westwood, 2010)

Greenpeace published a report on an integrated European offshore electricity grid. “A North Sea Electricity Grid [R]evolution” (2008) specifies the cost per component to construct a DC interconnector. Interconnector infrastructure largely overlaps with offshore wind farm infrastructure and can thus also be applied. A point of attention is the year of publication. In the summer of 2008, interconnectors with a capacity above 500 MW were not yet executed and validation on projects with higher capacities was not possible. Today it is however possible to use single interconnector cables with capacity up to 3,000 MW. (Greenpeace, 2008)

The scientific article “Levelised Cost of Energy for Offshore Floating Wind Turbines in a Life Cycle Perspective” (2014) by A. Myhr et al. presents a comparison of floating offshore wind farms with common bottom-fixed offshore wind farms. The offshore DC reference wind farm consists of 100 turbines with 5 MW capacity, located 200 km from shore and at 30 m water depth. The project lifetime is assumed to be 20 years. (Myhr et al., 2014)

The scientific article “Guidelines for Assessment of Investment Cost for Offshore Wind Generation” (2011) by M. Dicorato et al. is specifically written to gain insight into every cost component of an offshore wind farm. The goal of the article is to formulate a general model which can determine the total investment cost depending on wind farm configuration. The model is validated on an AC reference wind farm with 150 MW capacity, although the component costs are often expressed per MW or per km and can thus be applied to a broad range of wind farm characteristics. (Dicorato et al., 2011)

The technical report “Cost of Wind Energy Review” (2015) published by NREL, a national laboratory of the U.S. Department of Energy, compares the cost of onshore turbines with offshore turbines. The report is based on a 4.14 MW offshore turbine, although all cost are expressed per MW. (Moné et al., 2015)

“Optimisation of the Coupled Grid Connection of Offshore Wind Farms” was presented by D. Schoenmakers on the 29th of October, 2008. His master thesis results at the Technical University of Eindhoven are based on multiple cost values which complement the above mentioned sources. (Schoenmakers, 2008)

Finally, experience from industry experts is included by means of interviews. Mart van der Meijden is employed at TenneT and actively involved with the Hub and Spoke concept. Romke Bijker is an offshore- and coastal morphologist with more than 30 years of experience in subsea cables and pipelines. (Meijden, 2016; Bijker, 2017)

Currency Conversion and Inflation Rate
The cost of offshore wind farm components are given for different years and in various currencies. To make the previously mentioned sources comparable with each other, every component is expressed in Euro's and adjusted for inflation to the year 2017. The currency exchange rates per year are presented in Table C.1 and EU inflation rates are shown in Figure C.2.

Table C.1: Historic Average Annual Exchange Rates (source: OFX Group, 2017)

Exchange rate	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
	1.4618	1.2595	1.1225	1.1657	1.1526	1.2333	1.1780	1.2405	1.3780	1.2248
	0.7308	0.6831	0.7190	0.7549	0.7188	0.7783	0.7530	0.7536	0.9017	0.9042
	0.1248	0.1219	0.1145	0.1249	0.1282	0.1337	0.1282	0.1197	0.1119	0.1076

Table C.2: Historic EU Inflation Rates (source: StatBureau, 2017)

Inflation rate	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
EU	1.1480	1.1139	1.0965	1.0864	1.0630	1.0345	1.0120	1.0035	1.0052	1.0029

C.1 Offshore Wind Farm Expenditure

The project lifetime of offshore wind farms can be divided into five main phases: development & consent, production, installation & commissioning, operation & maintenance, and decommissioning. Expenditure is presented according to these phases and presented in:

- Table C.3 Development and Consent
- Table C.4 Production
- Table C.5 Installation and Commissioning
- Table C.6 Operation and Maintenance
- Table C.7 Decommissioning

Table C.3: Offshore Wind Farm Expenditure - Development and Consent

	Development and Consent	Source
4% of CAPEX	€152,000/MW	Crown Estate, 2010
	€366,400/MW	Douglas-Westwood, 2010
2% - 4% of CAPEX	€50,000/MW	M. Dicorato et al., 2011

Table C.4: Offshore Wind Farm Expenditure - Production

Component	**Production**	**Source**
Monopile	€644,000/MW	Crown Estate, 2010
Monopile	€583,000/MW	Douglas-Westwood, 2010
Monopile		M. Dicorato et al., 2011
Monopile		M. Dicorato et al., 2011
Monopile	€482,000/MW	A. Myhr et al., 2014
Monopile	€615,000/MW	NREL, 2015
Monopile	€640,000/MW	Ballast Nedam, 2009
Jacket	€638,000/MW	A. Myhr et al., 2014
Jacket	€(420,000 to 630,000)/MW	Ballast Nedam, 2009
Jacket		A. Borgen, 2010
Gravity based	€(440,000 to 490,000)/MW	Ballast Nedam, 2009
Turbine	€1,520,000/MW	Crown Estate, 2010
Turbine	€1,615,000/MW	Douglas-Westwood, 2010
Turbine	€1,584,000/MW	DTI, 2007
Turbine	€935,000/MW	M. Dicorato et al., 2011
Turbine	€1,500,000/MW	A. Myhr et al., 2014
Turbine	€1,329,000/MW	NREL, 2015
Array cable AC	€317,000/km	Crown Estate, 2010
Array cable AC 240mm2	€190,000/km	Douglas-Westwood, 2010
Array cable AC 630mm2	€516,000/km	Douglas-Westwood, 2010
Array cable AC		M. Dicorato et al., 2011
Array cable AC 300mm2	€282,000/km	A. Myhr et al., 2014
Offshore substation	€228,000/MW	Crown Estate, 2010
Offshore HVDC VSC converter	€312,000/MW	Douglas-Westwood, 2010
Offshore HVDC VSC converter	€123,000/MW	Greenpeace, 2008
Offshore HVDC VSC converter ± 150 kV	€223,000/MW	Schoenmakers, 2008
Offshore HVDC VSC converter ± 300 kV	€245,000/MW	Schoenmakers, 2008
Offshore HVDC VSC converter 320 kV	€(236,000 to 287,000)/MW	A. Myhr et al., 2014
Export cable AC	€950,000/km	Crown Estate, 2010
Export cable AC 630 mm2	€716,000/km	M. Dicorato et al., 2011
Export cable AC 630 mm2	€(479,000 to 533,000)/km	NREL, 2007
Export cable DC 1600 mm2	€448,000/km	Douglas-Westwood, 2010
Export cable DC	€(1,213/MW + 71,580)/km	Greenpeace, 2008
Export cable DC 1500mm2	€445,000/km	A. Myhr et al., 2014
Export cable DC	€1,000,000/km	R. Bijker, 2017
Onshore HVDC VSC converter ± 150 kV	€95,000/MW	Schoenmakers, 2008
Onshore HVDC VSC converter ± 300 kV	€103,000/MW	Schoenmakers, 2008
Onshore HVDC VSC converter 320 kV	€144,000/MW	A. Myhr et al., 2014
Onshore HVDC VSC converter	€251,000/MW	TenneT, 2016
Onshore substation	€101,000/MW	Crown Estate, 2010

Table C.5: Offshore Wind Farm Expenditure - Installation and Commissioning

	Installation	**Source**
Monopile	€253,000/MW	Crown Estate, 2010
Monopile	€244,000/MW	Douglas-Westwood, 2010
Monopile	€580,000/foundation	M. Dicorato et al., 2011
Monopile	€192,500/MW	A. Myhr et al., 2014
Jacket	€275,400/MW	A. Myhr et al., 2014
Turbine	€355,000/MW	Crown Estate, 2010
Turbine	€312,000/MW	Douglas-Westwood, 2010
Turbine	€116,200/MW	A. Myhr et al., 2014
Array cable AC	€253,300/km	Crown Estate, 2010
Array cable AC	€135,700/km	Douglas-Westwood, 2010
Array cable AC	€388,000/km	M. Dicorato et al., 2011
Array cable AC	€191,000/km	A. Myhr et al., 2014
Offshore substation	€25,300/MW	Crown Estate, 2010
Offshore HVDC VSC converter	€51,600/MW	Douglas-Westwood, 2010
Offshore HVDC VSC converter	€(36,700 to 47,800)/MW	A. Myhr et al., 2014
Export cable AC	€1,267,000/km	Crown Estate, 2010
Export cable AC	€765,000/km	M. Dicorato et al., 2011
Export cable AC	€306,000/km	Schoenmakers, 2008
Export cable AC	€84,000/km	NREL, 2007
Export cable DC	€407,000/km	Douglas-Westwood, 2010
Export cable DC	€111,400/km	Greenpeace, 2008
Export cable DC	€278,500/km	Schoenmakers, 2008
Export cable DC	€(355,200 to 829,000)/km	A. Myhr et al., 2014
Export cable AC (onshore)	€195,000/km	Schoenmakers, 2008
Export cable DC (onshore)	€167,000/km	Schoenmakers, 2008

Table C.6: Offshore Wind Farm Expenditure - Operation and Maintenance

	Operation & Maintenance	**Source**
Offshore wind farm	€63,300 - 101,300/MW/year	Crown Estate, 2010
Offshore wind farm	€95,000/MW/year	Douglas-Westwood, 2010
Offshore wind farm	€115,400/MW/year	A. Myhr et al., 2014
Offshore wind farm	€162,200/MW/year	NREL, 2015

Table C.7: Offshore Wind Farm Expenditure - Decommissioning

	Decommissioning	**Source**
Turbine + monopile	€247,000/MW	A. Myhr et al., 2014
Turbine + monopile	€215,000/MW	NREL, 2015
Array cable	€19,000/km	A. Myhr et al., 2014
Export cable	€(35,500 to 82,900)/km	A. Myhr et al., 2014
Offshore HVDC VSC converter	€(33,000 to 43,000)/MW	A. Myhr et al., 2014

C.2 Average Cost per Component

Table C.8: Average Cost per Offshore Wind Farm Component

		Average Expenditure	Expenditure Range
Development and Consent		€190,000/MW	€(50,000 to 366,400)/MW
Production			
Foundation	Monopile	€592,800/MW	€(583,000 to 644,000)/MW
	Jacket	€638,000/MW	-
	Gravity Based	€465,000/MW	€(440,000 to 490.000)/MW
Turbine		€1,414,000/MW	€(935,000 to 1,615,000)/MW
Array Cable		€326,300/km	€(190,000 to 516,000)/km
Offshore Substation	Jacket	-	-
	Substation	€126,600/MW	-
Offshore Converter	Jacket	€139,000/MW	€(111,000 to 167,000)/MW
	Converter	€238,000/MW	€(123,000 to 312,000)/MW
Export Cable	AC	€669,500/km	€(479,000 to 950,000)/km
	DC	€631,000/km	€(445,000 to 1,000,000)/km
Onshore Converter		€148,300/MW	€(95,000 to 251,000)/MW
Onshore Substation		€176,000/MW	€(101,000 to 251,000)/MW
Installation and Commissioning			
Foundation	Monopile	€230,000/MW	€(192,500 to 253,000)/MW
	Jacket	€275,400/MW	-
Turbine		€261,000/MW	€(116,200 to 355,000)/MW
Array Cable		€242,000/km	€(135,700 to 388,000)/km
Offshore Substation		€25,300/MW	-
Offshore Converter		€45,400/MW	€(36,700 to 51,600)/MW
Export Cable	AC	€780,000/km	€(306,000 to 1,267,000)/km
	DC	€396,200/km	€(111,400 to 829,000)/km
Operation and Maintenance		€107,500/MW/year	€(63,300 to 162,200)/MW/year
Decommissioning			
Turbine + Monopile		€231,000/MW	€(215,000 to 247,000)/MW
Array Cable		€19,000/km	-
Offshore Converter		€38,000/MW	€(33,000 to 43,000)/MW
Export Cable		€59,200/km	€(35,500 to 82,900)/km

C.3 Offshore Wind Farm Regression Analyses

The best regression fit contains the highest value for R^2_{adj}, while every variable should be statistically significant and meet the criteria $p < 0.05$.

Table C.9: Regression Analysis: OWF Capacity and Distance to Shore

	Regression Statistics		**Coefficients**	**P-value**
R Square	0.9094	Intercept	- 136	0.0200
Adjusted R Square	0.9072	OWF Capacity	4.054	8.61 E-41
Standard Error	314	Distance to Shore	3.203	0.0217
Observations	88			

Table C.10: Regression Analysis: OWF Capacity, Distance to Shore and Water Depth

	Regression Statistics		**Coefficients**	**P-value**
R Square	0.9150	Intercept	-251	0.0011
Adjusted R Square	0.9119	OWF Capacity	3.968	7.89 E-40
Standard Error	306	Distance to Shore	1.314	0.4013
Observations	88	Water Depth	9.258	0.0210

Table C.11: Regression Analysis: OWF Capacity, Distance to Shore, Water Depth and Turbine Capacity

	Regression Statistics		**Coefficients**	**P-value**
R Square	0.9200	Intercept	- 126	0.1688
Adjusted R Square	0.9162	OWF Capacity	4.1428	2.03 E-38
Standard Error	298	Distance to Shore	1.0462	0.4944
Observations	88	Water Depth	12.7186	0.0028
		Turbine Capacity	- 51.3745	0.0247

The adjusted r square keeps increasing when independent variables are added, although the p-value of distance to shore is much of the times not statistically significant and the regressions are therefore disregarded. The variable distance to shore is therefore excluded and the regressions analyses are performed again.

Table C.12: Regression Analysis: OWF Capacity and Water Depth

	Regression Statistics		**Coefficients**	**P-value**
R Square	0.9143	Intercept	- 258	0.0008
Adjusted R Square	0.9122	Capacity	4.004	1.32 E-41
Standard Error	305	Water Depth	10.969	0.0016
Observations	88			

Table C.13: Regression Analysis: OWF Capacity, Water Depth and Turbine Capacity

	Regression Statistics		**Coefficients**	**P-value**
R Square	0.9196	Intercept	- 129	0.1590
Adjusted R Square	0.9167	OWF Capacity	4.1754	3.17 E-40
Standard Error	297	Water Depth	14.1526	0.0001
Observations	88	Turbine Capacity	- 52.5587	0.0209

It can be seen that all variables are now statistically significant and $R^2_{adj} = 0.9167$ is even higher than the previous regressions including distance to shore. The last multiple regression analysis with offshore wind farm capacity, water depth and turbine capacity approximates offshore wind farm expenditure best and is therefore used in further calculations.

C.4 Subsea Interconnector Regression Analyses

Table C.14: Regression Analysis: IC Capacity and Total Distance

	Regression Statistics		Coefficients	P-value
R Square	0.8736	Intercept	- 596	0.0045
Adjusted R Square	0.8555	IC Capacity	0.9525	1.35 E-05
Standard Error	228	Total Distance	1.5886	2.29 E-05
Observations	17			

Table C.15: Regression Analysis: IC Capacity, Total Distance and Year of Operation

	Regression Statistics		Coefficients	P-value
R Square	0.8977	Intercept	- 41,100	0.0992
Adjusted R Square	0.8741	IC Capacity	0.8515	6.69 E-05
Standard Error	213	Total Distance	1.5265	2.67 E-05
Observations	17	Year of Operation	20.1288	0.1037

The latter regression contains a higher R^2_{adj} value, but the year of operation is not statistically significant due to the p-value of 0.1037 and the regression is therefore disregarded. The first regression with independent variables interconnector capacity and total cable length is therefore used to approximate total interconnector expenditure.

C.5 Subsea Interconnector Expenditure

Subsea interconnector cables coming from the Hub and Spoke island can not simply plug-in to the existing onshore grid of surrounding countries. The onshore grid must be capable to process these large volumes of electricity at high capacity or must be suitable for a future connection with subsea interconnectors. The landing points used in the calculation to determine the lowest interconnector expenditure are based on operational and future interconnector projects, which are presented in Table C.16.

Table C.16: Selected Landing Points Subsea Interconnectors

Belgium	Denmark	Germany	Netherlands	Norway	United Kingdom
Blankenberge (51.3N 3.2E)	Esbjerg (55.5N 8.5E)	Emden (53.4N 7.2E)	Hoek van Holland (52.0N 4.1E)	Kristiansand (58.1N 8.0E)	Duncansby (58.6N 3.0W)
-	-	Bremerhaven (53.5N 8.1E)	Ijmuiden (52.5N 4.6E)	Stavanger (59.0N 5.7E)	Aberdeen (57.1N 2.1W)
-	-	Hamburg (53.5N 10.0E)	Eemshaven (53.4N 6.8E)	-	Blyth (55.1N 1.5W)
-	-	-	-	-	Kingston upon Hull (53.7N 0.3W)
-	-	-	-	-	Sheringham (52.9N 1.2E)
-	-	-	-	-	Felixstowe (52.0N 1.3E)

The expenditure difference between an equal distribution and fair distribution of capacity becomes greater with 100 GW interconnector capacity. The lowest interconnector expenditure for an equal distribution requires 14,000 km cable and cost €80.2 bln, while the fair distribution requires 10,488 km cable and cost €69.0 bln. The fair distribution thus uses 25.1% less cable length and is 14.0% cheaper for 100 GW interconnector capacity. An overview of the total subsea interconnector expenditure for 100 GW capacity in the North is presented in Figures C.1 and C.2.

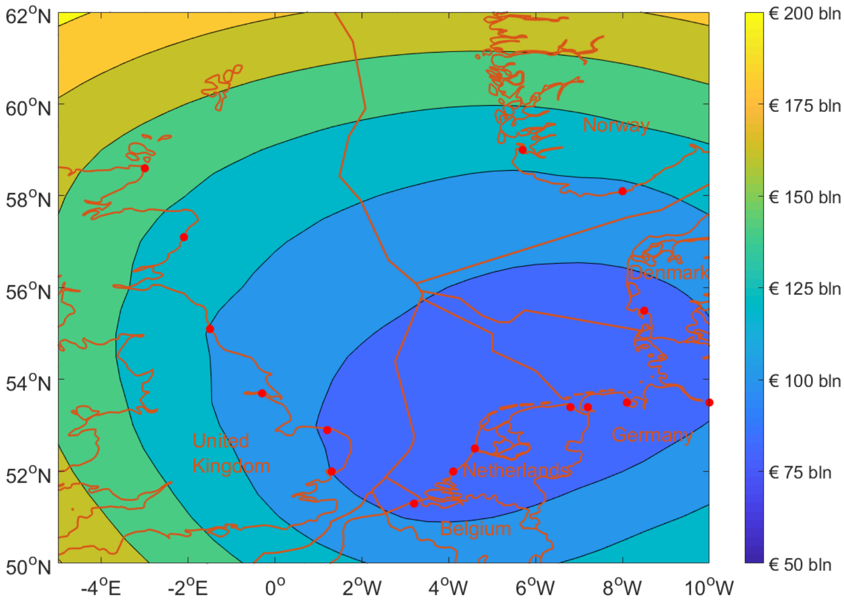


Figure C.1: Expenditure 100 GW Subsea Interconnectors with Equal Distribution

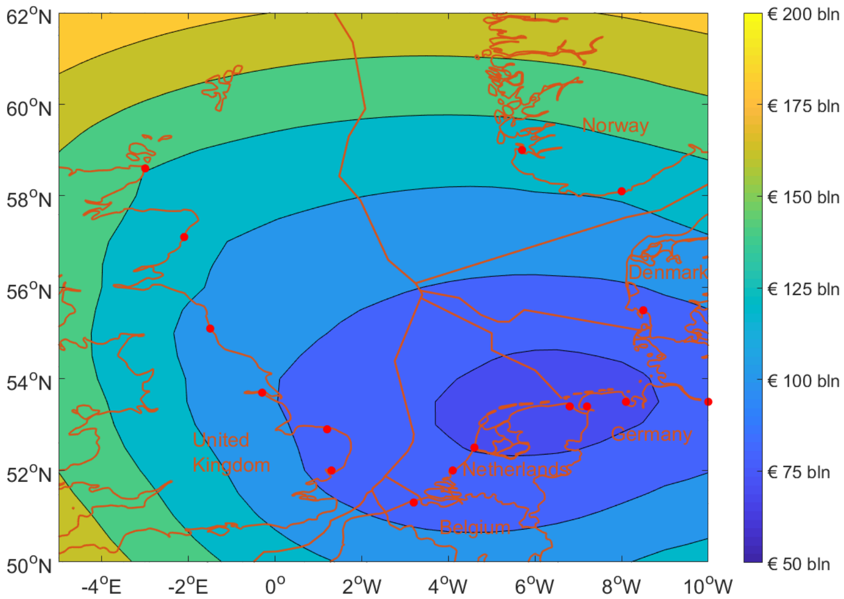


Figure C.2: Expenditure 100 GW Subsea Interconnectors with “Fair” Distribution

D - PRODUCTION AND REVENUE

D.1 Influence of Air Density

The air density ρ_{air} can be calculated with temperature, pressure and relative humidity. The formula consists of two parts and is a summation of dry air density and water vapour density.

$$\rho_{air} = \frac{p_d}{R_d T_K} + \frac{p_v}{R_v T_K} \tag{D.1}$$

The left part of the formula is the *ideal gas law* and calculates the air density for completely dry air. This is done with the dry air pressure p_d (Pa), specific gas constant for dry air R_d (287.05 J/(kg · K)) and temperature T_K (Kelvin). In reality air always contains some water which influences the air density. The water vapour density is expressed on the right side of the equation and consists of the water vapour pressure p_v (Pa), specific gas constant for water vapour R_v (461.495 J/(kg · K)) and temperature T_K (Kelvin).

The gas constants R_d and R_v indicate the weight of the gas molecules. Air is actually a mixture of nitrogen, oxygen and roughly one percent of other gasses. Water consists of hydrogen and oxygen. The molecular weight of water is less than the average molecular weight of gasses present in the air. This causes a higher water vapour content to reduce the air density and thus the gas constant in the denominator is greater for water vapour.

The maximum amount of water vapour in air is dependent on temperature. Warmer air can contain more water. The temperature at which the maximum water vapour content is reached is called the dew point temperature. The air at this point is saturated and on the boundary of condensation. The saturation vapour pressure p_{sat} (kPa) is calculated with the following formula:

$$p_{sat} = 0.61\ exp\left(\frac{17.3\ T_C}{237 + T_C}\right) \tag{D.2}$$

Be aware of the different units for temperature. Equation D.1 calculates air density and uses temperature in Kelvin, while equation D.2 calculates saturation vapour pressure and uses temperature in degrees Celsius. The temperature in Kelvin is expressed with a greater constant value of 273.15 compared to degrees Celsius.

$$T_K = T_C + 273.15 \tag{D.3}$$

The relative humidity (%) expresses the ratio of actual vapour pressure over the saturation vapour pressure. The temperature, pressure and relative humidity in the North Sea region are all available in the CFSv2 model and the averages are presented in Figures D.1, D.2 and D.3. With this information the water vapour pressure p_v can be calculated by multiplying the saturation vapour pressure with the relative humidity. The dry air pressure can subsequently be determined by subtracting the actual vapour pressure from the total pressure.

$$p_v = p_{sat} \cdot RH \tag{D.4}$$

$$p_d = p - p_v \tag{D.5}$$

All parameters are now known and the air density can be calculated with eq. D.1. The average air density is presented in Figure D.4. It can be seen that the differences in air density on the North Sea are very small, ranging from 1.232 kg/m3 at the Strait of Dover to 1.236 kg/m3 at Dogger Bank and 1.242 kg/m3 in front of the Norwegian coast. However, the Norwegian trench is located at the latter where depths are increasing very rapid up to 800 m and making bottom founded structures for offshore wind energy very unfavourable. The difference between the upper and lower limit of air density on the North Sea is 0.8%. Excluding the Norwegian trench with the highest air densities on the North Sea leaves suitable areas for bottom founded offshore wind energy in terms of depth. This makes the air density difference even smaller with 1.232 kg/m3 at the Strait of Dover and 1.237 kg/m3 just South of the Norwegian trench, resulting in a difference of 0.4%.

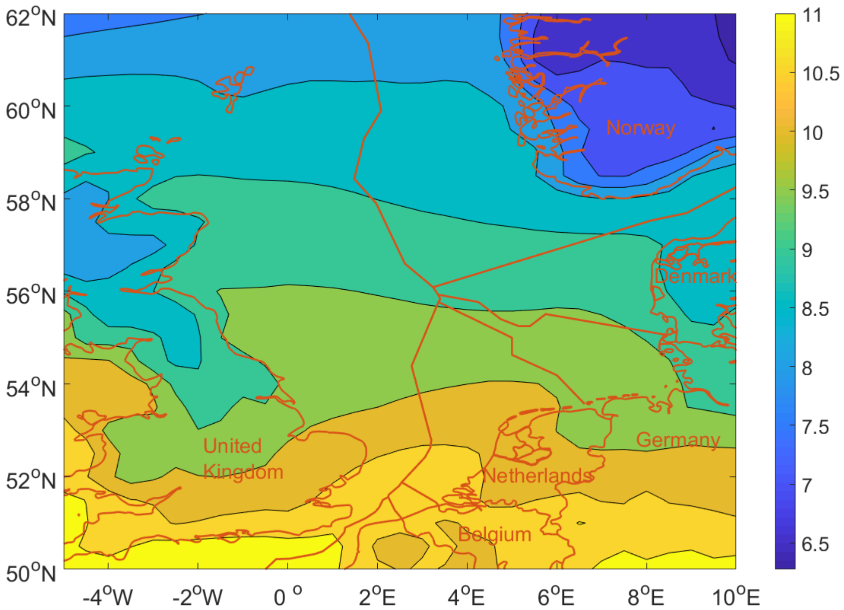


Figure D.1: Average Temperature (Celcius) at 100 kPa (2012 - 2016)

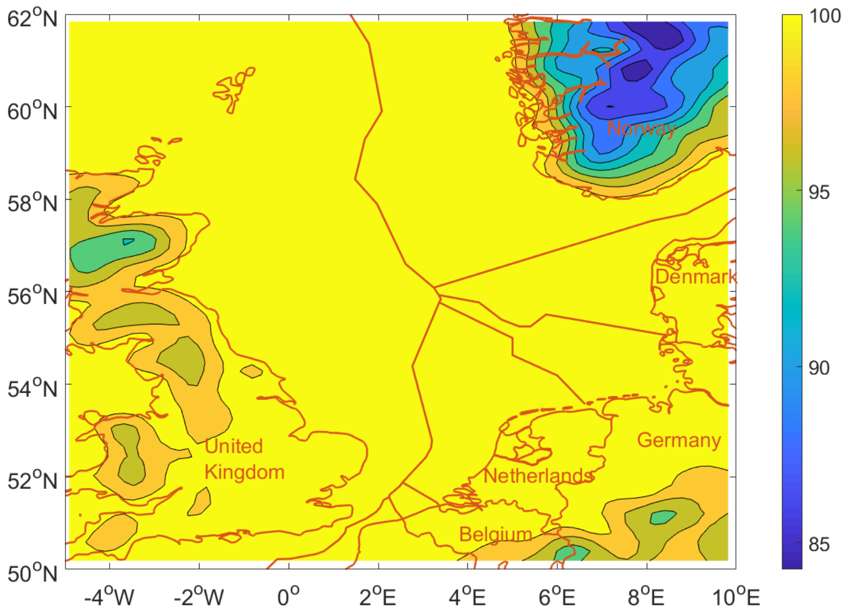


Figure D.2: Average Air Pressure (kPa) at Water Surface (2012 - 2016)

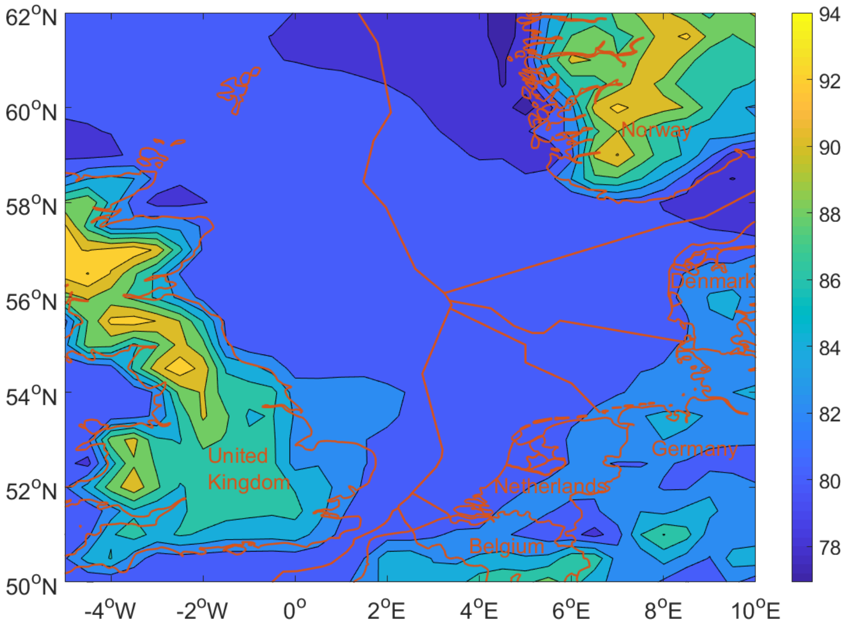


Figure D.3: Average Relative Humidity (%) at 2 m Above Water Surface (2012 - 2016)

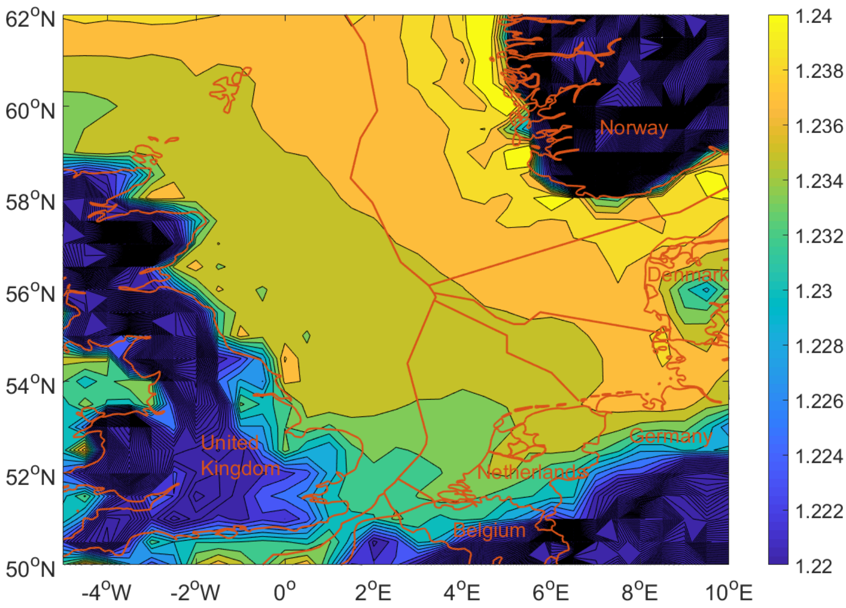


Figure D.4: Average Air Density (kg/m^3) at Water Surface (2012 - 2016)

The previous calculations proved the air density differences over the North Sea at water level to change barely in terms of location. However, the air density also changes with altitude. The temperature decreases with increasing altitude and thus the pressure and air density decrease. The pressure at altitude h is calculated with the standard atmospheric pressure at sea level p_0 (101.325 kPa), the standard temperature at sea level T_0 (288.15 K), earth's gravitational acceleration g (9.81 m/s^2), the universal gas constant R (8.31447 J/(mol $\cdot$ K), the molecular weight of dry air M (0.0289644 kg/mol) and the change of temperature as a function of altitude L (0.0065 K/m).

$$p = p_0 \left(1 - \frac{Lh}{T_0}\right)^{gM/RL} \tag{D.6}$$

The temperature changes with altitude and is calculated in the troposphere with the following formula:

$$T_K = T_0 - Lh \tag{D.7}$$

The air density can now be calculated with the pressure p from eq. D.6 and temperature T_K from eq. D.7:

$$\rho_{air} = \frac{pM}{RT_K} \tag{D.8}$$

The wind condition at turbine hub height is used to determine the power output. There are various turbine models with capacities ranging from 2.3 MW turbines up to 8.0 MW turbines currently operational. The hub height and other turbine dimensions increase with capacity, ranging from 80 m hub height to 110 m. The 10.0 MW turbine is still under development, but is expected to reach the market in the coming years with a hub height around 125 m. Research is also being done to 20.0 MW turbines. Experts question the technical and economical viability of such high turbine capacities (van Bussel, 2017; Beurskens, 2017), but the expected hub height of 150 m is taken as an upper limit to investigate the altitude effect on air density.

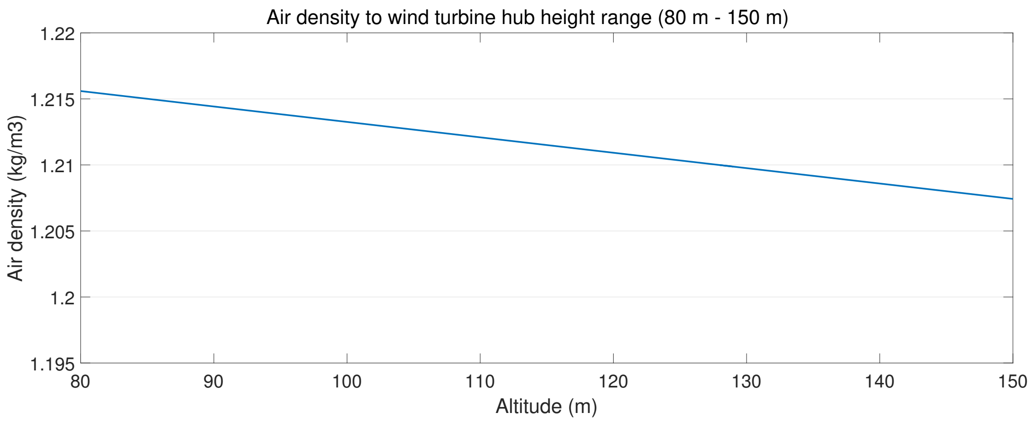


Figure D.5: Air Density to Hub Height

The change of air density over this altitude range is small. At 80 m altitude the air density is 1.216 kg/m3 and at 150 m altitude the air density is 1.207 kg/m3. The influence of air density on turbine power output is linear. The 0.7% difference in air density thus leads to a 0.7% lower power output at 150 m hub height when the remaining parameters are constant. The highest turbine capacity currently operational only reaches a hub height of 110 m. The air density at this height is 1.212 kg/m3 and the difference would be even smaller with 0.3%.

The air density variation in location and altitude for the entire spectrum of offshore wind turbine models proved to be small, existing of 0.8% respectively 0.7%. Looking only at the operational turbine models the variation in air density is even smaller with 0.4% respectively 0.3%. The air density influences the turbine power output linearly and the effect is only very small. The CFSv2 model data will therefore not be checked against direct meteorological measurements as the benefits in increased accuracy would be minor.

D.2 Wind Speed Friction Coefficient & Roughness Length

Table D.1: Wind Friction Coefficient per Terrain Type (source: Masters, 2004)

Terrain type	**Friction**
Lake, ocean and smooth-hard ground	0.10
Foot-high grass on level ground	0.15
Tall crops, hedges, and shrubs	0.20
Wooded country with many trees	0.25
Small town with some trees and shrubs	0.30
City area with tall buildings	0.40

Table D.2: Wind Speed Roughness Length (source: Borja et al., 1998)

Landscape type	**Roughness length z_0 [mm]**
Very soft ice or mud	0.01
Calm open seas	0.20
Chopped high seas	0.50
Snow surface	3.00
Grassland and green areas	8.00
Pasture areas	10.00
Arable land	30.00
Annual crops	50.00
Scant trees	100.00
Heavily forested areas and few buildings	250.00
Forest land covered with large-size trees	500.00
City outskirts	1500.00
Downtown city areas with many high rise buildings	3000.00

Table D.3: Wind Speed Roughness Classes and Roughness Lengths (source: European Wind Atlas)

Roughness class [-]	**Roughness length z_0 [m]**	**Energy Index [%]**	**Landscape type**
0	0.0002	100	Water surface.
0.5	0.0024	73	Completely open terrain with smooth surface.
1	0.03	52	Open agricultural area with softly rounded hills.
1.5	0.055	45	Agricultural land with some housing. Approx. 1250 m apart.
2	0.1	39	Agricultural land with some housing. Approx. 500 m apart.
2.5	0.2	31	Agricultural land with many houses, shrubs and plants.
3	0.4	24	Villages, small towns, forests and very rough uneven terrain.
3.5	0.8	18	Larger cities with tall buildings.
4	1.6	13	Very large cities with tall buildings and sky scrapers.

Table D.4: Wind Speed Roughness Classes and Roughness Lengths (source: (Masters, 2004))

Roughness class [-]	**Description**	**Roughness length z_0 [m]**
0	Water surface	0.0002
1	Open areas dotted with some objects	0.03
2	Farmland dotted with some objects more than 1 km apart	0.1
3	Urban districts, farmland with many objects	0.4
4	Densely populated urban districts, forest areas	1.6

D.3 Methods to determine Weibull parameters

The Weibull distribution is commonly used in literature to express the wind speed distribution (Akdağ and Dinler, 2009). There are however multiple methods to determine the Weibull parameters from the measured wind data. The most used methods are the empirical method and the maximum likelihood method. The power density method is specifically made to determine the Weibull parameters more accurately for wind energy applications and will be compared as well. Performance of these methods is tested for various geographical locations with the coefficient of determination (R^2) and Root Mean Square Error ($RMSE$).

The empirical method, maximum likelihood method and power density method are applied to Dogger Bank (54.5N 2.0E), offshore wind farm Prinses Amalia (52.6N 4.2E) and the city of Deventer (52.3N 6.2E) at 100 m altitude. The equations to determine the Weibull scale parameter λ (m/s) and shape parameter k $(-)$ are presented below:

Empirical method

$$\overline{v} = \left(\frac{1}{n}\sum_{i=1}^{n} v_i\right) \tag{D.9}$$

$$\sigma = \left(\frac{1}{n-1}\sum_{i=1}^{n}(v_i - \overline{v})\right)^{0.5} \tag{D.10}$$

$$\Gamma(v) = \int_0^\infty e^{-t}t^{v-1}dt \tag{D.11}$$

$$k = \left(\frac{\sigma}{\overline{v}}\right)^{-1.086} \tag{D.12}$$

$$\lambda = \frac{\overline{v}}{\Gamma(1+\frac{1}{k})} \tag{D.13}$$

Maximum Likelihood method

$$k = \left(\frac{\sum_{i=1}^{n} v_i^k ln(v_i)}{\sum_{i=1}^{n} v_i^k} - \frac{\sum_{i=1}^{n} ln(v_i)}{n}\right)^{-1} \tag{D.14}$$

$$\lambda = \left(\frac{1}{n}\sum_{i=1}^{n} v_i^k\right)^{1/k} \tag{D.15}$$

Power Density method

$$E_{pf} = \frac{\overline{v^3}}{(\overline{v})^3} \tag{D.16}$$

$$k = 1 + \frac{3.69}{(E_{pf})^2} \tag{D.17}$$

$$\lambda = \frac{\overline{v}}{\Gamma(1+\frac{1}{k})} \tag{D.18}$$

The formulas of the goodness of fit tests coefficient of determination (R^2) and root mean square error ($RMSE$) are presented below. The parameters consist of the total number of intervals N, the frequency of measured wind speed y_i, the mean wind speed or in other words average of y_i and the wind speed frequency value from the Weibull distribution x_i. The best performing methods have a coefficient of determination (R^2) closest to 1.0 and root mean square error ($RMSE$) closest to zero.

$$R^2 = 1 - \frac{\sum_{i=1}^{N}(y_i - x_i)^2}{\sum_{i=1}^{N}(y_i - \overline{y})^2} \tag{D.19}$$

$$RMSE = \left(\frac{1}{N} \sum_{i=1}^{N} (y_i - x_i)^2 \right)^{0.5} \tag{D.20}$$

The estimated Weibull parameters for Dogger bank, offshore wind farm Prinses Amalia and the city of Deventer at 100 m altitude, together with the coefficient of determination (R^2) and root mean square error ($RMSE$), are summarised in Table D.5:

Table D.5: Method Comparison of Weibull Parameter Estimation at 100 m Altitude: Empirical Method (EM), Maximum Likelihood Method (MLM), Power Density Method (PDM)

Region	**Parameters**	**EM**	**MLM**	**PDM**
Dogger Bank	k $(-)$	2.2615	2.2363	2.2424
(54.5N 2.0E)	λ (m/s)	11.8240	11.8205	11.8248
	R^2	0.9961	0.9956	0.9957
	$RMSE$	0.0018	0.0019	0.0019
OWF Prinses Amalia	k $(-)$	2.1891	2.1727	2.1495
(52.6N 4.2E)	λ (m/s)	10.7525	10.7622	10.7526
	R^2	0.9870	0.9861	0.9852
	$RMSE$	0.0037	0.0038	0.0039
Deventer (onshore)	k $(-)$	2.0086	2.0134	1.9283
(52.3N 6.2E)	λ (m/s)	7.4074	7.4287	7.4007
	R^2	0.9628	0.9622	0.9546
	$RMSE$	0.0087	0.0087	0.0096

In literature several methods have been proposed to estimate the Weibull parameters, but with various results and recommendations in previous studies. It might therefore be concluded that suitability of the method varies with geographical location and size of data (Akdağ and Dinler, 2009). It can be seen in Table D.5 that the empirical method resembles the model data best as the coefficient of determination (R^2) is closest to 1.0 and root mean square error ($RMSE$) closest to zero. This is true for all three locations, although the differences between the parameter estimation methods are very small. The error is greatest for Deventer, but all locations have goodness of fit values very close to an optimal fit and the error caused by the Weibull wind speed distribution is thus small. The empirical method will be used for further calculations as it is easy to compute and best resembles the model data at the three reference locations.

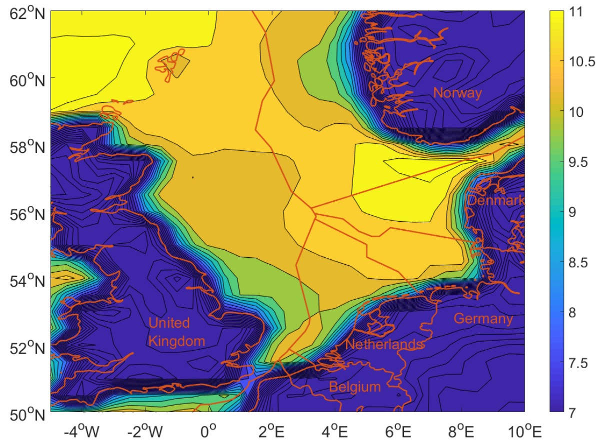
D.4 Turbine Power Curve Data

The power curves of offshore wind turbine models show production at different wind speeds. Multiple wind turbine manufacturers were contacted to provide data or graphs of their turbine models, but this information is confidential and would require a non-disclosure agreement. After extensive research on the internet it was however possible to collect some power curve graphs of different offshore wind turbine models. Information from these graphs was subsequently acquired with the free software *Engauge Digitizer*, which selects the axes and approximates graph data by reading the colour of the power curve. The power curve data is thus containing a very small error with the actual turbine performance, but it is accurate enough for the scope of this study and indicates the production differences between various turbine capacities.

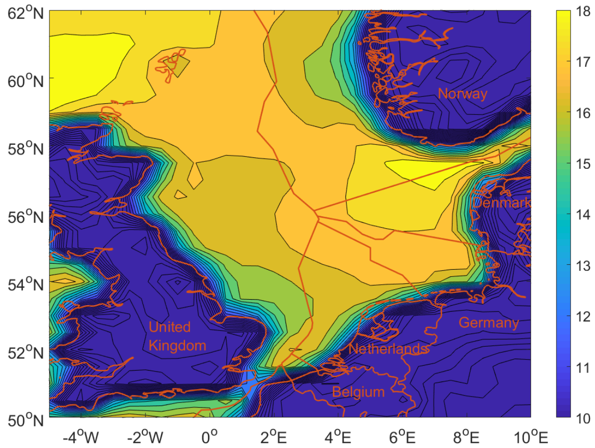
Table D.6: Turbine Power Curve Data (sources: The Wind Power, 2017)

Wind Speed	**SWT-2.3-93**	**SWT-3.6-120**	**Gamesa G128-5.0MW**	**Aerodyn SCD 8.0/168**	**SeaTitan 10MW**	**Upwind 20MW**
0 m/s	0 kW	0 kW	0 kW	0 kW	0 kW	0 kW
1 m/s	0 kW	0 kW	0 kW	0 kW	0 kW	0 kW
2 m/s	0 kW	0 kW	0 kW	0 kW	0 kW	0 kW
3 m/s	0 kW	0 kW	0 kW	0 kW	0 kW	0 kW
4 m/s	59 kW	150 kW	195 kW	100 kW	275 kW	547 kW
5 m/s	200 kW	337 kW	420 kW	500 kW	867 kW	1225 kW
6 m/s	400 kW	624 kW	786 kW	1000 kW	1741 kW	2290 kW
7 m/s	678 kW	1012 kW	1296 kW	2000 kW	2869 kW	3829 kW
8 m/s	1011 kW	1537 kW	1943 kW	3000 kW	4075 kW	5930 kW
9 m/s	1361 kW	2197 kW	2699 kW	4000 kW	5983 kW	8698 kW
10 /ms	1712 kW	2907 kW	3487 kW	5000 kW	8194 kW	12187 kW
11 m/s	2012 kW	3393 kW	4174 kW	6000 kW	10000 kW	16524 kW
12 m/s	2208 kW	3566 kW	4639 kW	7500 kW	10000 kW	20000 kW
13 m/s	2300 kW	3597 kW	4875 kW	8000 kW	10000 kW	20000 kW
14 m/s	2300 kW	3600 kW	4965 kW	8000 kW	10000 kW	20000 kW
15 m/s	2300 kW	3600 kW	5000 kW	8000 kW	10000 kW	20000 kW
16 m/s	2300 kW	3600 kW	5000 kW	8000 kW	10000 kW	20000 kW
17 m/s	2300 kW	3600 kW	4984 kW	8000 kW	10000 kW	20000 kW
18 m/s	2300 kW	3600 kW	4944 kW	8000 kW	10000 kW	20000 kW
19 m/s	2300 kW	3600 kW	4859 kW	8000 kW	10000 kW	20000 kW
20 m/s	2300 kW	3600 kW	4722 kW	8000 kW	10000 kW	20000 kW
21 m/s	2300 kW	3600 kW	4541 kW	8000 kW	10000 kW	20000 kW
22 m/s	2300 kW	3600 kW	4331 kW	8000 kW	10000 kW	20000 kW
23 m/s	2300 kW	3600 kW	4108 kW	8000 kW	10000 kW	20000 kW
24 m/s	2300 kW	3600 kW	3883 kW	8000 kW	10000 kW	20000 kW
25 m/s	2300 kW	3600 kW	3661 kW	8000 kW	10000 kW	20000 kW
26 m/s	0 kW	0 kW	3447 kW	8000 kW	0 kW	0 kW
27 m/s	0 kW	0 kW	3247 kW	0 kW	0 kW	0 kW
28 m/s	0 kW	0 kW	0 kW	0 kW	0 kW	0 kW
29 m/s	0 kW	0 kW	0 kW	0 kW	0 kW	0 kW
30 m/s	0 kW	0 kW	0 kW	0 kW	0 kW	0 kW

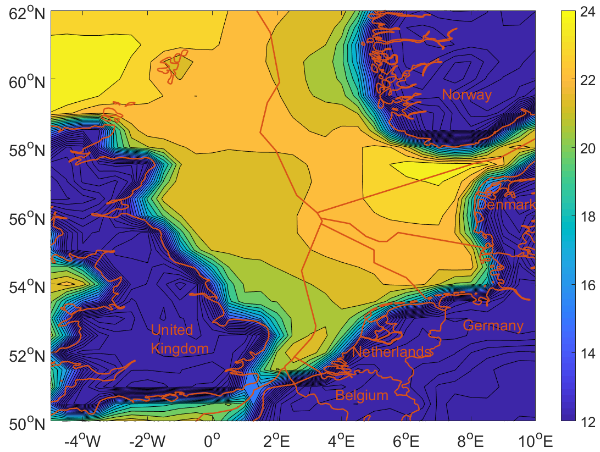
D.5 Yearly Average Turbine Production



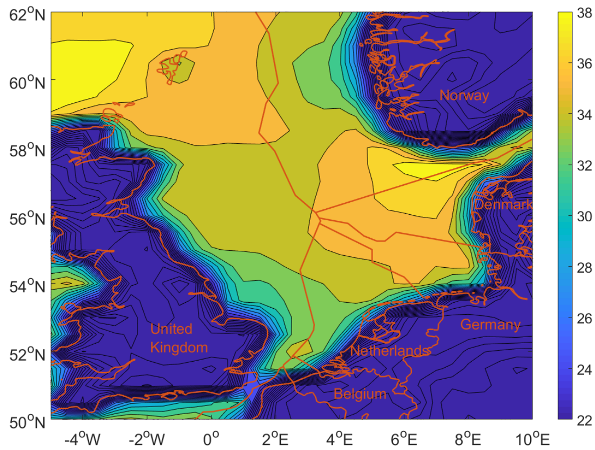
(a) Siemens SWT-2.3-93



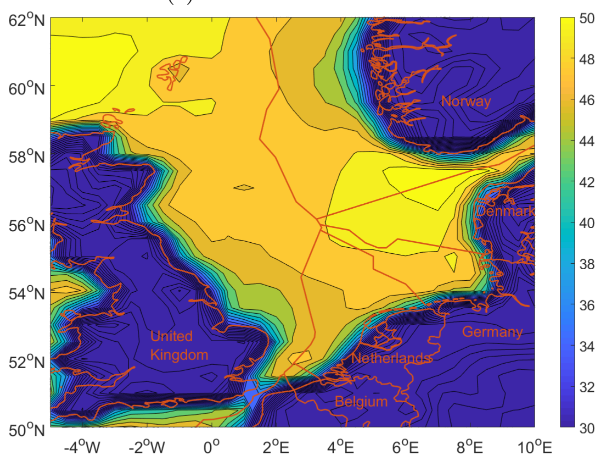
(b) Siemens-SWT-3.6-120



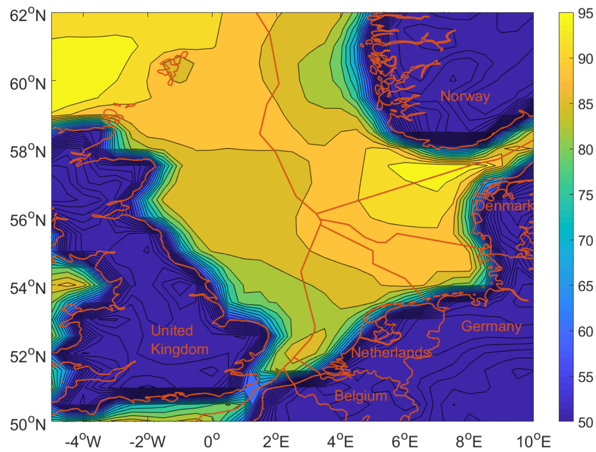
(c) Gamesa G128-5.0MW



(d) Aerodyn SCD 8.0/168



(e) SeaTitan 10MW (concept turbine)



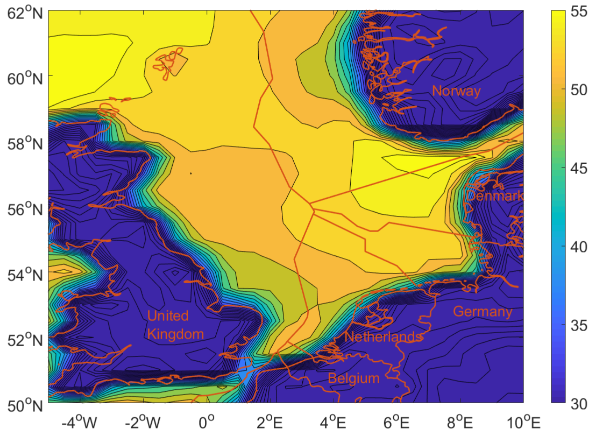
(f) Upwind 20MW (concept turbine)

Figure D.6: Average Yearly Turbine Production (GWh/year)

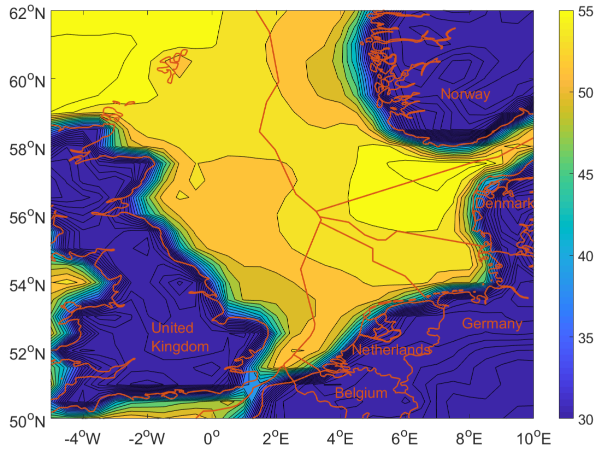
Table D.7: Yearly Average Turbine Production

Power output (GWh/year)	**Deventer (onshore)**	**OWF Prinses Amalia (23 km from shore)**	**Dogger Bank (150 km from shore)**
Siemens SWT-2.3-93			
2012	3.2593	11.1595	12.6463
2013	3.4963	11.3194	12.5389
2014	3.4775	11.1106	12.3464
2015	3.9078	11.8762	13.1552
2016	2.9421	10.6037	12.4708
Siemens SWT-3.6-120			
2012	9.2624	17.7259	20.0746
2013	9.5806	17.9769	19.8589
2014	9.3781	17.6109	19.5693
2015	10.3374	18.7903	20.8501
2016	8.4404	16.8161	19.7895
Gamesa G128-5.0MW			
2012	11.6864	22.8869	26.1157
2013	12.1449	23.2112	25.8275
2014	11.9208	22.7927	25.4694
2015	13.1480	24.2517	27.2357
2016	10.6393	21.6538	25.6921
Aerodyn SCD 8.0/168			
2012	18.4932	35.9658	41.3834
2013	19.2792	36.5364	40.9598
2014	18.8914	36.0033	40.3880
2015	20.8954	38.4794	43.3150
2016	16.7598	34.0293	40.6813
SeaTitan 10MW			
2012	28.4258	51.0179	57.4375
2013	29.2875	51.7894	56.7941
2014	28.5381	50.5649	55.8276
2015	31.3929	53.8621	59.3321
2016	25.9442	48.5047	56.7640
Upwind 20MW			
2012	48.4481	90.9444	104.7405
2013	50.3060	92.3501	103.0048
2014	49.4875	90.7158	101.6309
2015	54.6558	96.1884	109.0962
2016	44.1171	85.6099	102.8983

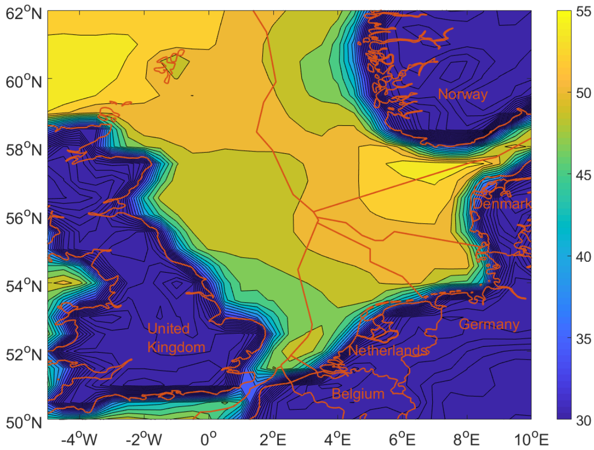
D.6 Offshore Wind Farm Capacity Factor



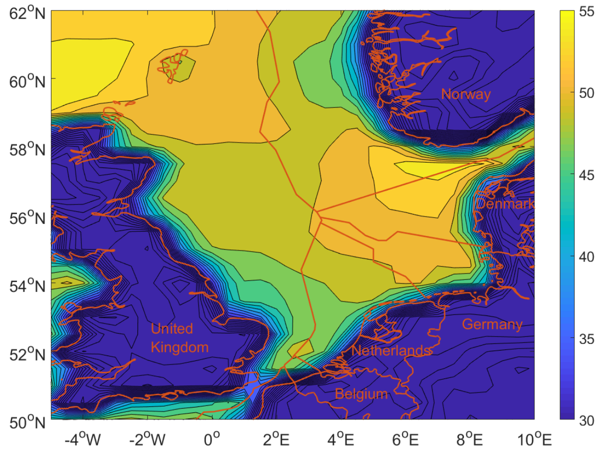
(a) Siemens SWT-2.3-93



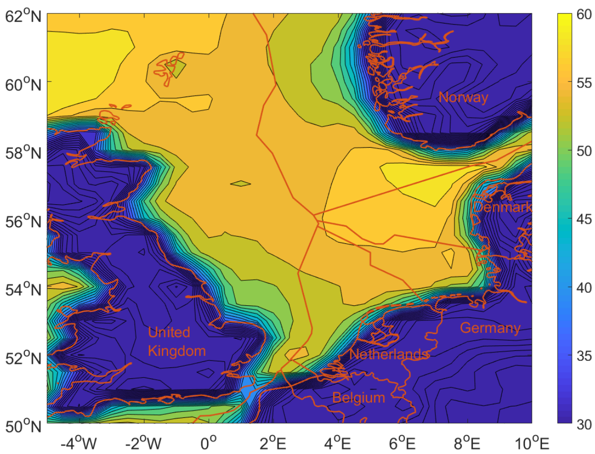
(b) Siemens-SWT-3.6-120



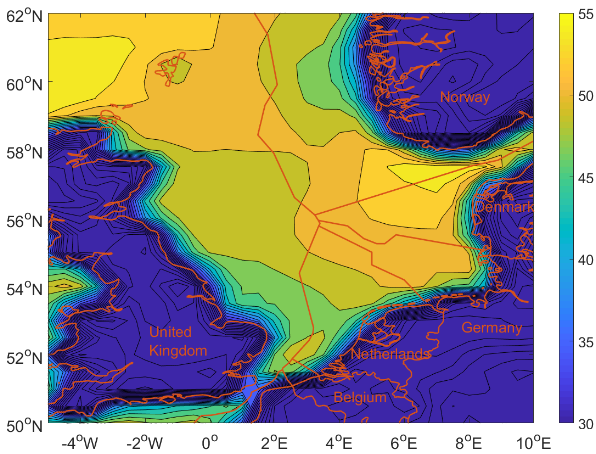
(c) Gamesa G128-5.0MW



(d) Aerodyn SCD 8.0/168



(e) SeaTitan 10MW (concept turbine)



(f) Upwind 20MW (concept turbine)

Figure D.7: Offshore Wind Farm Capacity Factor (%)

D.7 Maximum NPV Revenue Offshore Wind Energy

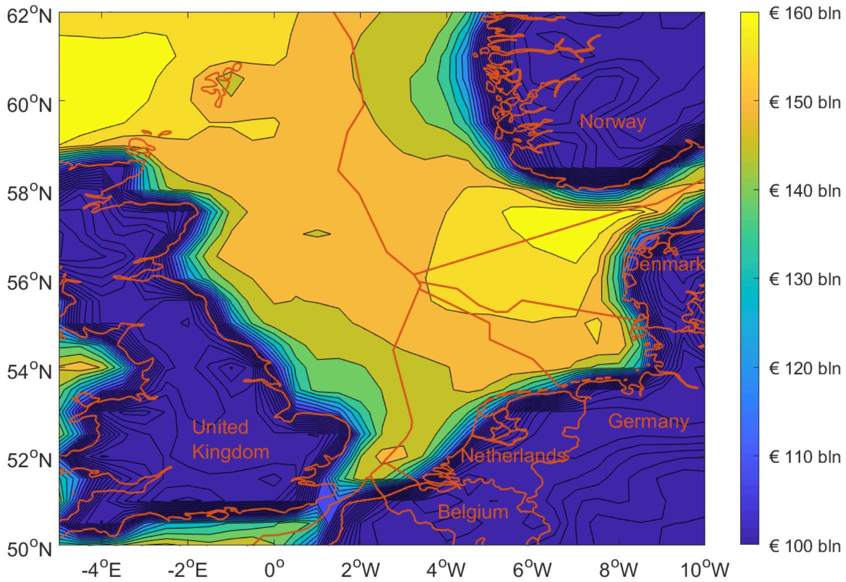


Figure D.8: Maximum NPV Revenue for 30 GW SeaTitan Turbines (design life 2025 - 2045, WACC 10.0%)

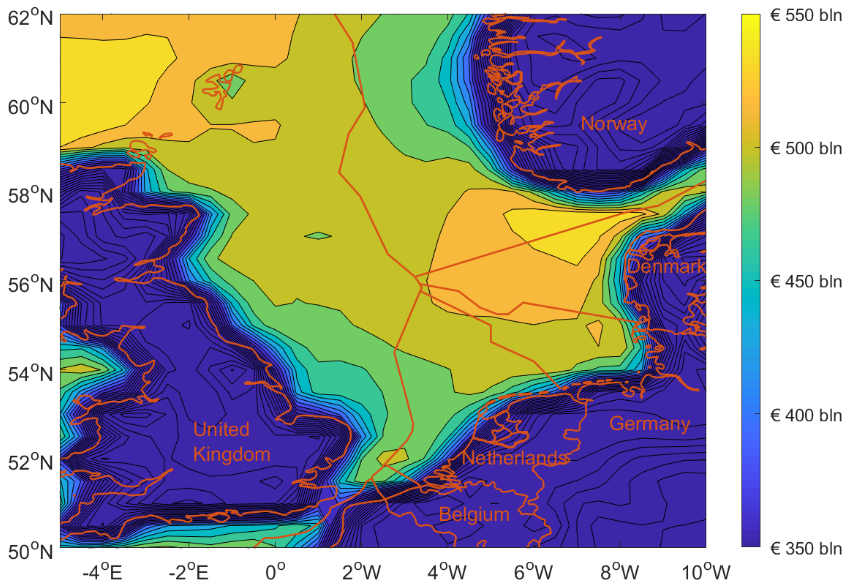


Figure D.9: Maximum NPV Revenue for 100 GW SeaTitan Turbines (design life 2025 - 2045, WACC 10.0%)

D.8 Maximum NPV Revenue Subsea Interconnectors

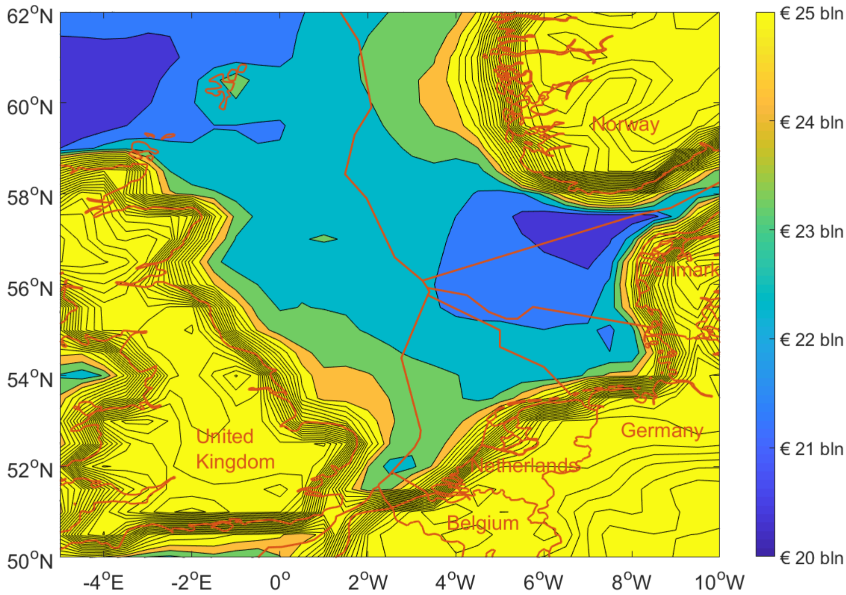


Figure D.10: Maximum NPV Revenue for 30 GW Interconnector Capacity (design life 2025 - 2050, WACC 9.0%)

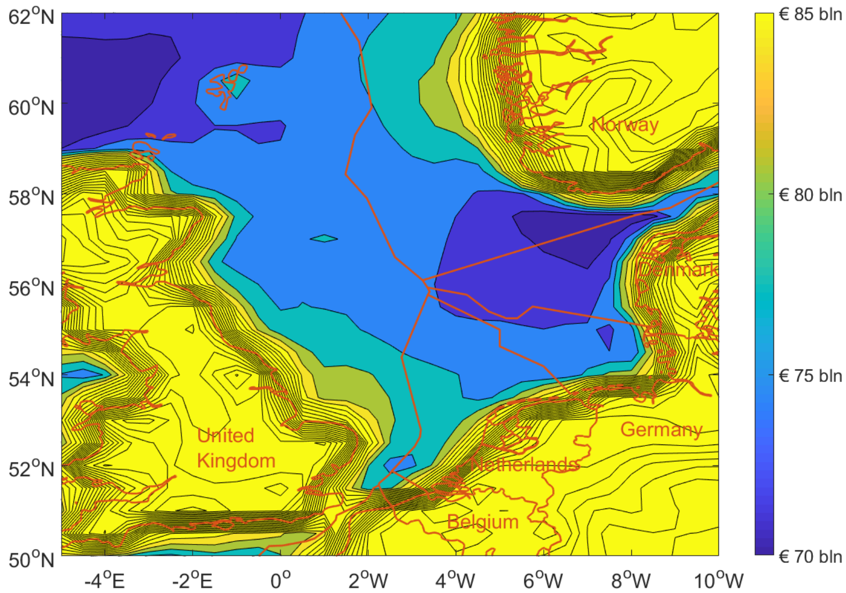


Figure D.11: Maximum NPV Revenue for 100 GW Interconnector Capacity (design life 2025 - 2050, WACC 9.0%)

E - INTERVIEWS

E.1 Interview Jaap de Boer & Hans Scholten (Energy Watch)

Who:	Jaap de Boer & Hans Scholten
Company:	Energy Watch
When:	26th September 2016
Where:	Twentepoort Oost 27-61, Almelo

This is a summary of the conversation with Jaap de Boer and Hans Scholten. Together they manage Energy Watch; a consultant company in the field of wind energy. Energy Watch was involved in the development of the TenneT island concept.

The problem of far offshore wind farms
The cheapest location for wind energy is on land, but this often results in hinder for local residents. The Netherlands is a densely populated country and there is not much space available for large wind turbines. The alternative is to place wind turbines offshore in relatively shallow waters and close to shore. However, these locations are also limited and are starting to be saturated. Wind farms are shifting to deeper waters further from the coast, which is more expensive. Germany already faces this problem. It has to construct wind farms further offshore and in deeper waters to realise the amount of wind energy mentioned in the climate agreements. When wind farms are located further than roughly 50 km from the coast, electricity losses in the standard AC cable become too high during transmission. DC cables need to be used between the wind farm and the coast to limit the electricity losses over greater distances. In addition, HVDC-converters need to be constructed. The generated AC wind electricity is converted to DC by an offshore HVDC-converter, after which it is transmitted through the more efficient DC cable. At the coast the electricity is converted back again from DC to AC by an onshore HVDC-converter, to be able to deliver the electricity to the AC grid.

Why construct an island in the North Sea?
The island concept of TenneT has two advantages. On the one hand it reduces the costs of far offshore wind farms. Far shore becomes near shore and jackets with offshore HVDC-converters are no longer needed. Instead, only onshore HVDC-converters on the island are needed to transmit the electricity over the great distances to the surrounding North Sea countries. Costs in O&M (Operation and Maintenance) are also reduced due to the closer distance to shore. The island can result in considerable cost savings as O&M is responsible for a large part of wind energy costs. Very expensive boats with stabilising techniques are currently being used to transport personnel to offshore wind farms. This prevents the people on the boat from getting seasick and they are immediately able to work on arrival. Transport is furthermore restricted to daytime, wave heights exceeding 2.5 m and shifts of maximum 6 hours straight. It has disadvantages the further wind farms are from shore. With an island the crew can be closer to the wind farms in the middle of the North Sea.

The second advantage is better integration of the electricity markets. The island functions as a hub; increasing electricity trade and creating a more stable grid. Renewable energy is variable and dependent on environmental circumstances which makes a greater market beneficial. Expensive HVDC-converters on land are still needed, but compared to current far offshore wind farms it leads to cost reduction.

Why did TenneT publish their concept?
TenneT published its concept for other companies and governments to anticipate.

(i) At the moment interconnectors are being placed between individual countries. This increases electricity trade opportunities and stabilises the grid, but a cooperative approach would be even more beneficial. By creating a hub in the middle of the North Sea, less cable is needed in total and a greater market is reached. Furthermore, variable renewable energy generated on the island can be better distributed, thereby better anticipating on supply and demand. A rule of thumb is 1% electricity loss per 100 km of DC interconnector cable.

(ii) The TenneT island would reduce costs of far offshore wind farms and thereby stimulate offshore wind energy. The Netherlands would particularly benefit from the island, as the country still has much wind turbines to place if it wants to realise the amount of renewable energy mentioned in the climate agreements.

(iii) The project is very expensive and can only succeed if multiple countries cooperate. It takes time for governments to make decisions, so TenneT already proposed a future scenario to which governments and companies can anticipate. There has never been cooperation in the field of wind energy. To change this TenneT presented their view on a future with more renewable energy.

What are the consequences if a country would not connect?
"Every country will connect, there are only advantages!" The largest consequences for the island would be if the United Kingdom or Norway would not connect. The United Kingdom would primarily buy electricity (currently high price) and Norway would primarily sell electricity (currently low price). The countries both have an anti-European sentiment and an individual cable between these countries would smoothen the largest mismatch in electricity supply and demand. Energy Watch could not answer with certainty what the consequences would be for the TenneT North Sea island if the United Kingdom and Norway would not connect. From another point of view; once the island is constructed both the United Kingdom and Norway would still benefit from connecting to the island and reach a greater market. This is probably one of the reasons TenneT published their concept, as the benefits of the island would reduce if countries keep placing individual interconnectors.

Is it possible to use Norway as a giant battery in a European electricity grid?
Witteveen+Bos proposed to construct the TenneT island in combination with an artificial hydro storage basin. The plan has been previously worked out in another setting by Dutch engineer Lievense. Hydro storage could lead to benefits in terms of dredging costs per cubic meter and the variable supply of wind energy could be used more efficiently, based on consumer demand. The reactions from Energy Watch on the TenneT island combined with Plan Lievense were not very positive. The storage basin would have too little capacity and cost a lot of money. Natural basins in Norway could be used, which have a much higher capacity. Furthermore, storage is not seen as the problem by Energy Watch. *"If every country facing the North Sea would connect to the TenneT island, wind energy can always be transmitted to places with demand."* In case wind energy supply would be higher than demand, research can be done to hydro storage in Norway. Up till now the basins in Norway are used as a back-up instead of a battery. Pumping up water to release it in times of demand is not being done. Water is only released in times of urgent electricity demand and nature refills the basin in time. However, Norway has done several studies to use hydro storage as an export product to replace the export of oil once the reservoirs have been emptied. Norway has much more potential storage capacity, but Energy Watch could not go further into detail about this subject. TenneT has not much demand for energy storage, but would rather have means to provide additional services. A giant lithium-ion battery would be more effective, as this could serve for frequency support by its rapid release of large amounts of electricity. The storage basin of Plan Lievense has already been discussed by the concept project group, but was not seen as promising. However, TenneT is willing to look at additional features for the island!

Energy Watch asked if Plan Lievense would add value to the project. It can complicate the original business case. TenneT likes to see additional features to the island, but at the same time it is convinced the island is already financially sustainable without extra features. Furthermore, Plan Lievense has been already discussed and at the time it was not seen as added value. It can impede the decision to construct the basic island.

Were there any engineering problems that came up during the concept phase?
Technically there are no big problems expected. The concept has been worked out very roughly and there are a lot of assumptions. There are assumptions in investment costs, maintenance costs and economies of scale (investment and maintenance). The location of the island is highly influencing all these parameters. Dogger Bank came up as a central location in the North Sea with shallow waters, but other locations are also possible. There was not an extensive site selection and further investigation could deliver possibly far better results. Factors that have not been taken into account are the oil- and gas industry, fishing areas, military areas, shipping routes, Natura 2000 and other environmental areas, country territory and possibly other stakeholders. Concluding, there is still a lot to be done. Research into these aspects would therefore greatly benefit TenneT.

What are the requirements of the island?

(i) Harbour

(ii) Airstrip

(iii) Accommodation with corresponding activities for roughly 5,000 employees

(iv) Cable routing

The investment costs of the island are relatively low compared to the complete project. The island was estimated at EUR 500 mln by Energy Watch, but if the costs for the island would double it would not substantially alter the business case. The design of the island is therefore not determinative for the investment costs, but should adapt to the wind farm requirements. However, the costs of the island should be justified to the person making the investment. Also important to mention are the O&M costs. For offshore wind farms this contributes for 15-25% of total project costs. If O&M could be reduced with 1% by adapting the island design, this would already make a huge difference. Such a feature of the island would create lots of positive reactions, as it would easily compensate for the possible extra costs of the island.

Cable routing
Cable routing concerns the minimal distance between cables. Till now it has not been addressed enough, while it is a very important aspect. All cables come together on a small piece of land. The island design should possibly be adjusted to comply with regulations.

Environmental organisations
There have already been conversations with environmental organisations. Greenpeace has a neutral opinion. They agree with the plan, because nature makes place for renewable energy. It is a consideration and as long as Greenpeace can contribute to the project major obstructions are not expected.

E.2 Interview Mart van der Meijden (TenneT)

Who:	Mart van der Meijden
Company:	TenneT
When:	5th October 2016
Where:	EWI building room LB03.244, Delft

This is a summary of the conversation with Mart van der Meijden. Mister Van der Meijden is working for TenneT and part time professor at the Delft University of Technology. TenneT is an electrical grid operator and proposed the concept of an artificial island in the North Sea. Mister Van der Meijden was involved in the concept development. Via the Delft University of Technology it was possible to ask several questions about the assumptions, considerations and difficulties of the project.

What are the advantages of the TenneT island?
The island is not a goal, but a means to lower wind energy cost and increase EU wind energy generation. Alternatives to the island are also possible. In the future gas can also become a part of the distribution hub, but at the moment this is not relevant as electricity has a much higher value compared to gas. Energy storage is also not relevant as the costs are too high.

(i) The main advantage of the island is available area located near many wind farm sites, making serial wind farm production possible which drastically reduces costs.

(ii) Due to variable wind energy roughly 50% of cable capacity is used from wind farm to shore. With the TenneT island concept DC cables also serve as interconnector and cable utilisation increases towards 100% by international trade.

(iii) The island needs less cable length in total to connect the surrounding North Sea countries in comparison to individual interconnections.

(iv) Offshore jackets are no longer needed.

(v) Offshore HVDC-converters are no longer needed. Wind farms are closer to shore and can use AC cables.

(vi) Personnel can be stationed on the island under better circumstances. This is better for both personnel as construction and maintenance. Personnel can stay on the island comparable to ex-pats. Accommodation is easier and safer, because it is placed away from the HVDC converters. Furthermore, space is available for extra functions like entertainment.

(vii) Construction and maintenance can be done more easily as the distance to the wind farms is closer. Furthermore, there is completely no hinder to surrounding civilisation.

(viii) Air planes and ships can be used instead of expensive and unreliable helicopters for transport of personnel, goods and equipment.

At the moment wind farms are not constructed in serial production, but often from project to project. A change in this approach could lead to the biggest cost reduction in wind energy. Factories need to be placed close to the wind farms for construction and maintenance and the amount of to be installed wind turbines should be high enough to allow serial production. Space on the island is required. Wind farm Borssele has proven that serial production drastically reduces investment costs.

Are there other concepts that were disregarded?
In the current situation countries are laying DC interconnector cables for individual purposes. These cables allow national electricity trade between two countries or connect far offshore wind farms to shore.

One alternative was to extend DC cables from far offshore wind farms further inland to reduce cable losses over the onshore grid. However, the capacity of the cable would be roughly 50% and people are not supportive of such a cable running near their homes.

Another idea was to combine the COBRA cable (interconnector The Netherlands – Denmark) with offshore wind energy in Germany. A converter station roughly halfway the cable would be needed to insert the generated wind electricity, but due to problems with different benefits and national subsidy regulations the concept was not executed.

In another project, between the Netherlands and the United Kingdom, the approach is the other way around and interconnector functions are possibly added to far offshore wind farms. Cooperation between the future East Anglia wind farm (United Kingdom) and Ijmijden Ver wind farm (The Netherlands) could create an interconnection between the two countries. The experience of this project could give valuable information to the business case of the TenneT North Sea island.

The oil and gas industry proposed to use existing platforms for renewable wind energy. What are the thoughts on this plan from the wind industry?
The oil and gas industry is obligated to remove jackets and platforms once they stop pumping up resources. The removal of all these platforms in the North Sea will cost the oil and gas industry billions of euro's. If the function of the platforms can be converted to wind energy, the platforms are no longer obsolete and are more likely to stay .The platforms could serve as major foundations to bigger wind turbines, HVDC converters or for wind farm substations. However, the oil and gas industry mentions the possibilities for wind energy without backing calculations. The function of the existing platforms is to pump up resources and the wind industry questions if the foundations could bear the weight of wind energy infrastructure.

Will the combination of electricity trade and variable wind energy give problems regarding the cable capacity?
The capacity of DC cables to connect far offshore wind farms to shore are roughly being used 50%. With the addition of electricity trade the capacity is being used up to 100%. This way the cable is used to its maximum potential. However, wind energy is variable. There can be a situation that the electricity coming from Norway is cheaper than the generated wind energy near the island and trade will get the upper hand. The cable is fully used for electricity trade and the wind turbines need to be turned off. Renewable energy is being wasted and the whole concept is being misused. Firm agreements would need to be made by governments and companies to prevent renewable energy waste.

What are the main challenges and uncertainties of the North Sea island?
Technology, both from a civil engineering as electrical perspective, is not the problem. The biggest challenge is to gather all surrounding North Sea countries and create the willingness to cooperate in offshore wind energy. Without shared goals and ambitions the island will not be feasible. Furthermore, regulations and subsidies are currently not based on cooperative wind energy generation. This will have to change. Agreements need to be made on the amounts of wind energy use per country and how this influences the national climate goals.

Furthermore, the concept will also be disregarded if NGO's are against the artificial island. TenneT does not expect positive reactions. It is a trade-off for environmental organisations and it is expected they will not give major resistance as long as they can contribute. Creating added value to the environment is therefore a very important aspect of the project.

What if a country does not want to connect to the island?
This is not the situation. VikingLink, an interconnector between the United Kingdom and Denmark, is going to be constructed and the investors are already afraid that it becomes not profitable once the TenneT island is constructed. Seeing this situation suggests countries will connect to the island.

What are the island requirements?

(i) Harbour

(ii) Airstrip

(iii) Accommodation for roughly 4,000 employees

(iv) Workspace for construction and maintenance

(v) Creating added value to the ecology

(vi) (wish) Maritime research centre

The size of the harbour or the size of the berthing ships is not specified. It is up to the wind industry to determine specific requirements for activities on the island.

What is the opinion of TenneT on energy storage?
Energy storage is seen as a future scenario and will probably not be part of the initial island construction. Wind energy will be better distributed due to the interconnector-hub function of the island and future consumers are expected to store more energy themselves. Electricity storage could become interesting if wind energy capacity on the island would become more than 30 GW. The most promising storage methods mentioned during the concept were power to gas located on the island, hydro storage in Norway and electricity storage in warm water basins. For now, energy storage is seen as too expensive and it is not a requirement of TenneT. Energy storage must create additional value to the island and it must be completely independent of subsidies to be considered.

The island is a future concept and is expected to be constructed somewhere in 2030-2050. How is the rapid increase in wind energy developments incorporated in the business case?
The amount of generated electricity per square kilometre stays constant at roughly 6 MW / km^2 despite the rapid increase in larger wind turbine capacity. Calculations on the North Sea island concept have been done with 7 MW / km^2 to include technological progress, though this is an optimistic figure.

Economies of scale lead to cost reduction, but it is unknown to what extent. HVDC converters will also reduce in costs per MW when higher converter capacities are installed.

Cable routing is a very important aspect to the island design, but not discussed during the concept. Could you mention the cable routing requirements?
Ships can drop their anchor and rip cables. Cables therefore need to be positioned with some safe intermediate distance. It can always happen that cables are ripped by anchors, but the consequences are now limited. Mostly professional ships are working around the island and anchors are less likely to be randomly dropped. Pleasure vessels or vessels not related to the wind industry are more likely to cause cable ripping, although these vessels have less reason to sail around the island. However, it is still an

important aspect and it could happen. Especially for interconnectors it can have major consequences. Till now, cable routing was not much of a problem due to the individual placement of wind farms. Multiple wind farms connecting to the same area cause cables running close to each other. The requirements need to be emphasised and incorporated in the island design.

Estimated cost figures

EUR 100 - 150 mln	Offshore jacket foundation for HVDC converter.
EUR 300 mln	900 MW, 4 ha and 20 tonnes weight HVDC converter. Current price. The price for onshore and offshore HVDC converters is roughly equal.
EUR 500 mln	2 GW HVDC converter station. Economies of scale and technological improvements are incorporated, HVDC converters are currently more expensive.
EUR 2.1 mln/km	2 GW DC interconnector cable. There is not much difference in investment and maintenance costs between AC and DC cable.

Estimated energy losses

2%	Total electricity loss with converters and cable combined. Assumption with 30 GW capacity and 320 km cable on average. Most losses occur in the converter stations.

The break-even distance between offshore AC and offshore DC cables is in the range of 50 km to 80 km, but this is dependent on the electricity current level. Project exceptions exist. Onshore the break-even distance in cable types is around 500 km. The problem with AC is the declining current with increasing distance. DC cables do not have this problem.

E.3 Interview Maarten Schäffner (Witteveen+Bos)

Who:	Maarten Schäffner
Company:	Witteveen+Bos
When:	12th October 2016
Where:	Hoogoorddreef 15, Amsterdam

This is a summary of the conversation with Maarten Schäffner. He is a sustainability professional working for engineering consultant Witteveen+Bos in Amsterdam. Sustainable design is a relatively new concept and information is collected by interviewing experts in their field.

How is sustainable design being developed?
Sustainable design is pioneers work. Around 10 years ago sustainability became a hot topic, but the companies did not know how to incorporate this in their work. At the moment there are still different approaches to sustainable design and environmental impact. The concept is new and is still in its infancy. There is no standard framework that companies and governments can use, although sustainable design is an important aspect and now mostly required for large engineering projects.

Knowledge is shared by a network of sustainability professionals working at engineering firms like Arcadis, Sweco, Antea Group and Royal HaskoningDHV. Progress has been made in the reduction of carbon footprint of companies. This has been achieved by amongst others using the train more often and reducing the number of air plane flights to clients. The next step is to make projects more sustainable. What for impact do the proposed measures really have? Every firm calculates sustainability in their own way. The measures being taken right now are good for awareness, but it is impossible to draw conclusions. There needs to come a standard framework with uniformity to be able to compare results.

How is sustainable design being integrated in projects?
Sustainability in projects is expressed in comparison with the base case. The project is designed like a normal contractor would do (materials, CO2 emissions, environment, social aspects) and sustainable alternatives are designed. This way the differences in scenarios are more explicit. The benefits are still hard to monetise, but a rough decision on the best design can be made.

How is sustainable design being valued?
It is always difficult to value sustainable design and the contribution it has to society is very hard to determine. What is society; the surrounding people, the region, the world? Preventing climate change is good to the world, but often expensive to a company like for example TenneT.

There are Social Cost Benefit Analyses to value and monetise sustainable design. At the moment SCBA's are only being done for large engineering projects. Different designs are compared (base case, energy efficient, environmental friendly, etc.) and the added value is determined. This can be in the form of job creation, tourism or an iconic status to the Netherlands. Although everything is being monetised, some aspects are hard to express in value and explanation in words is still very important to create awareness.

A SCBA is more difficult to perform on smaller projects. There is less possibility for improvement, making a comparison between alternatives less distinctive.

Is there a list of effective sustainable measures?
No, sustainable design is custom. The possibilities of adding value to a project differ and need to be investigated, while values of stakeholders are also different and need to be made clear for support. Sustainability to a project is never completely the same, while an engineering consultant still needs to make profit on its projects. However, a shift can be seen to sustainable design and it keeps getting more important to contractors and relevant stakeholders. Support for sustainable design is increasing. Everybody finds it important and it will become a standard aspect to create sufficient support.

Values of relevant stakeholders are being analysed and the project is being designed to these values as much as possible. Working this way creates the most support amongst stakeholders and makes it more likely to execute the project.

What is the environmental impact of offshore wind farms?
Wind turbines are disadvantageous to birds, but you have to present the complete picture and emphasise the positive conditions it creates. Especially at the foundation of wind turbines a suitable environment is created for marine life and wind farms could increase fish population.

Maarten Schäffner has no experience in sustainability of offshore wind farms, but Rob Nieuwkamer can be contacted who has made a SCBA for offshore wind turbines near the city of Urk. He can tell me about the stakeholder involvement and ecological impact.

What is the environmental impact of existing jackets in the North Sea?
This is not specifically known by Maarten Schäffner. The oil and gas industry needs to remove their jackets and platforms if resources are no longer pumped up. There is a connection with the oil fields which has to be cut off in a proper manner to prevent environmental disasters. It must never go wrong. Furthermore, the removal of existing platforms makes it now possible to construct wind farms on these locations. "The North Sea has the potential to solve our energy problem. In the past, energy was delivered by the oil and gas industry and now this is going to shift to wind energy."

Plugging the wells and restoring the area is good, but with the removal of the jackets there is also nuisance and destruction of surrounding life. Compare the scenarios of doing nothing versus removal by environmental effects, important aspects and sensitivity. Check all relevant criteria and make a decision. Find out who the relevant stakeholders of the jackets are. What are their values and motives? There are many public documents of environmental studies, also from Witteveen+Bos, which can be used for reference and to support proposed measures.

Furthermore, the offshore industry is lagging with sustainability. This applies to contractors, but also to the clients who less frequently include sustainability in their contracts. There is a large potential to increase sustainability in the offshore industry.

E.4 Interview Teun van Breukelen (Witteveen+Bos)

Who:	Teun van Breukelen
Company:	Witteveen+Bos
When:	13th October 2016
Where:	Leeuwenbrug 27, Deventer

This is a summary of the conversation with Teun van Breukelen. He is working at Witteveen+Bos and is involved with the VikingLink project; an interconnector between the United Kingdom and Denmark, crossing Dutch territory. Cable routing will become an important aspect as the number of wind farms in the North Sea is increasing. This interview gave good insight and relevant information about safe intermediate cable distances.

Current offshore wind farm development in the Netherlands

In the Netherlands there is a unique approach to offshore wind farm development. Companies need to compete in a tender to win the bid and construct the project. The process is coordinated by the government who takes care of permits, location and connection to the grid. There is less uncertainty for developers, leading to lower risk and enabling lower bids. Electrical grid operator TenneT provides the wind energy substations and cables to shore, leaving the developer only with the construction and maintenance of wind turbines and array cables. This prevents unstructured cable placement. Wind farms are placed in previously selected areas at least 12 miles from the coast. Closer to shore would reduce costs, but increases the resistance amongst politicians and people living near the coastline. Currently there are discussions to reduce the boundary for offshore wind farms to 10 miles from the coast.

All offshore wind farms in the Netherlands use the same construction method. Information from one offshore wind project, like Borssele 1 and 2, is therefore representative to all offshore wind projects in the Netherlands. The Dutch Ministry of Economic Affairs is the client of offshore wind energy and is more comfortable with proven technology. A standard approach reduces risks and project delays. Especially offshore wind projects in the near future will use proven technology due to the time pressure.

Countries surrounding the North Sea each have their own approach in offshore wind energy development regarding regulations and subsidy arrangements. However, the differences in wind farm design and safety margins will not be large, if there are any.

Future offshore wind farm design

The wind energy industry is searching for improvements in wind farm design, support structures, turbine development and grid integration. Technological developments are going fast. The artificial island of TenneT is a new concept and implies large benefits, but the ecological impact on the Doggersbank could be too severe and stop the project. Other concepts like floating wind farms could also be a future scenario with probably less environmental impact. With the construction of an island wind farms can be constructed closer to shore while being located in the middle of the North Sea. There is no resistance by surrounding residents, only employees are working at the island. Placing wind turbines closer to shore is cheaper, but vessels still need to have sufficient depth to place the turbines and helicopters and airplanes need free space to manoeuvre. In case of airplanes there needs to be a lane of free space. The safe distance and nuisance to employees has to be determined, but keep in mind the farmers in the Netherlands who own wind turbines on their land. This example can be used for reference.

Cable routing will become an important aspect due to the increase in project numbers and size. In case of an artificial island there are many cables running to the same central point. Safe distance between cables needs to be maintained to prevent damage by dropped anchors or construction and maintenance of other cables. For array cables between wind turbines the consequences of damage are less severe than for interconnector cables and consequently the intermediate distances are also less. One cable owner does not want to have damage caused by another cable owner and intermediate distances of 500 m are common. Especially in the TenneT concept the Dutch offshore wind energy development approach is recommended. There will be one central organisation responsible for wind farm development and cable placement. Due to the size of the TenneT concept intermediate cable distances could increase due to the much larger consequences. Cable management becomes more important. Intermediate cable distances of the Borssele wind farm project are not representative for future larger concepts. Safety contours are designed on damage and consequences. The capacity connected to the artificial island is higher and the risks are greater, leading to more intermediate cable distance. Wind farm Borssele can be used as a lower boundary.

A lot of research has been done to economies of scale. Amongst others research programme FLOW (Far and Large Offshore Wind), a combination of Dutch companies and knowledge institutions, does research to cost reduction in offshore wind energy.

E.5 Interview Romke Bijker (Advanced Consultancy Romke Bijker)

Who:	Romke Bijker
Company:	Advanced Consultancy Romke Bijker
When:	26th January 2017
Where:	Leeuwenbrug 27, Deventer

This is a summary of the conversation with Romke Bijker. Mister Bijker is an offshore- and coastal morphologist with more than 30 years of experience. Witteveen+Bos and mister Bijker often work together on offshore cable and pipeline projects. Recently he contributed to the Viking Link interconnector project and can give valuable information on interconnector cables.

Is there a rule of thumb to quickly determine the required cable length for interconnectors?
Using the distance between point A and B and subsequently adding 10% is a good conservative rule of thumb for interconnector cable length. The first thing you do when determining the cable route is to draw a straight line between point A and B. This is however always impossible do to objects or activities crossing the line and the cable route has to be redirected. Bathymetry and sandbanks are responsible for an additional 2 to 3% to the cable length, but also including anchoring areas, shipwrecks, cable and pipeline crossings, navigation channels, offshore platforms, sand mining areas, protected environmental areas and possible cable bundling makes an additional 10% a good conservative estimate.

If you look at the North Sea special attention needs to be paid to the Norwegian trench. This area is up to 800 m deep and the rule of thumb is no longer applicable. Cable length needs to be added for a proper estimate of required cable length.

What is a good estimate for the cable cost?
I do not have sufficient experience on this topic to answer this question. Offshore interconnector cables are per definition DC due to their long distance. DC cables have lower transmission losses compared to standard AC cables, but they are also more expensive and you need a converter station on both sides of the cable. As a rough estimate I use EUR 1.0 mln per km, but this is dependent on amongst others cable capacity, burial depth, soil conditions and day rate of the lay-vessel. EUR 1.4 mln per km is relatively expensive, but could also certainly be true for some projects. TenneT assumes EUR 2.1 mln per km for 2 GW interconnector cables with EUR 500 mln converter stations on each side of the cable. The day rate of cable-laying vessels ranges between EUR 200,000 - 300,000 per day to which EUR 250,000 per day is a good estimate. Maintenance on offshore cables and pipelines is very expensive and is therefore reduced to a minimum. Currently there is strong competition between cable and pipeline installation companies due to the low oil prices, which causes the day rates to be somewhat lower than average. The laying speed to average depths of 1.5 m is 200 m per hour. The cost of the cable and the converter stations on both sides of the cable also needs to be included in the calculation to come to a total cost estimate.

Is the interconnector industry rapidly developing and are costs decreasing?
Especially in cable design there has been a lot of progress. A few years ago DC cables could not be buried too deep as the heat of the cable could not be sufficiently emitted to its surrounding. Nowadays this problem has been resolved and interconnector cables are buried to depths of 1.0 - 1.5 m. I do not know how cable capacity or the investment cost over years is developing, but the Viking Link interconnector I am currently working on has a cable capacity of 1,400 MW.

Does a port on the artificial island create additional value to the installation and operation process of interconnector cables?
Not at all. At the factory the interconnector cable is being loaded onto the cable-laying vessel and sails, possibly in combination with a trenching vessel, day and night while installing the cable. A port on the artificial island does not have additional value to the installation process of interconnector cables.

Offshore interconnector cables are designed to prevent any maintenance. The only time work is performed on the cables is during failure. Repairs are very expensive as the cable does not function during this period and no income is being generated. Downtime frequency for offshore wind farm export cables and interconnector cables is once per 50 years. The period which it takes to perform the repair is in the order of weeks to months. The time it takes for repair vessels to sail to a specific location and the cost of the repair itself is therefore negligible. A port on the artificial island does not have additional value to maintenance and repair of interconnector cables.

What is the intermediate distance between interconnector cables?
At first, an intermediate distance of 500 m is used. Companies with existing cables or pipelines have no problem with the construction of new cables or pipelines outside this area. The risk of damage on the existing cable or pipeline during construction is very low. This distance is however very safe. From a technical point of view the intermediate distance can be 10 - 20 m. These values can be seen as the upper and lower limit. For the Borssele wind farm TenneT used 100 - 200 m intermediate distance between the cables and 200 - 500 m on the outer sides of the route, but in my opinion this is still too much. In case one of the cables is damaged and needs to be repaired, TenneT wants to keep the risk on damaging neighbouring cables during repairs very low. It restricts the use of other activities in the area and the intermediate distance could be lower. The cables are buried and you know very precisely where they are as they do not or barely move in time. Even if the cables are placed on the seabed it would be unlikely they will move due to their large weight and fixed connections.

Energy Watch mentioned the high concentration of cables to become a possible problem. Do you think this will become a problem?
If you mention this problem to engineers they will come up with a solution. Keep in mind that the North Sea is very big and a cable is a relatively small object. Maybe the intermediate distance of 500 m per cable could become a problem, but as already mentioned this intermediate distance for every cable is overestimated. Keep in mind that TenneT is already bundling cables and uses 100 - 200 m intermediate distance for the Borssele wind farm. The distance is basically a function of risk and in my opinion this can become much less. The large amount of cables would require some management, but this is not a showstopper and I assume this "problem" can be solved. Cable bundling justifies amongst others the rule of thumb with 10% additional cable length for the distance between point A and B.

To which depth are interconnector cables being buried?
Export cables for offshore wind farms and interconnector cables are not placed on the seabed as the chance on damage is too high. The cables are currently being buried at 1.0 m below the seabed to reduce the risk on damage. Trenching to deeper depths means more soil excavation and the laying vessel needs to sail slower, leading to a longer installation period. Furthermore, the chance on encountering less erodible soil becomes higher and the chance on bad weather conditions increases. The laying vessel may have to seek shelter and come back one or more times. Some people proposed to bury the Viking Link interconnector at 2.0 m depth instead of 1.0 m, which reduces the risk of damage to the cable but is estimated to increase the installation cost with 10 - 30%. In morphologically dynamic areas the cable is often already trenched somewhat deeper. Giant sand ripples can move along the cable with lengths of 10 - 20 m and heights of 0.5 - 1.0 m. Once the cable is buried less than 30 cm additional measures need to be taken.

In case of the Borssele wind farm the first 32 km of the export cable on the shore side is buried at a minimum depth of 3.0 m and the remaining 35 km of cable at the seaside is installed at a minimum depth of 1.0 m. At some locations like anchoring areas and shipping channels the chance on damage is higher and the cable is buried to greater depths. It can be seen that TenneT and mister Bijker do not agree on burial depth. According to mister Bijker offshore cables are buried too deep and money is being waisted.

What is the ecological impact of interconnector cables?
Interconnector cables are almost always buried to reduce the risk of damage. Trenching the cable will lead to some local turbidity. Especially during winter seasons, close to shore and during high wind speeds the North Sea is very turbid. The Dogger Bank has due to its shallow water conditions relatively clear water and construction in this area will therefore lead to a relatively greater impact on the environment. The location is home to lots of species and it is therefore appointed Natura 2000 area. Plans to construct something in these areas often leads to overreactions, but it is allowed if the natural habitat at this location is conserved. Interconnector cables emit heat to its surroundings and this attracts animals, but the level of environmental impact is still unknown. If cables are trenched to greater depths the heat emitted to the surface also becomes less. Burial depth is however at the moment a trade off between installation cost and risk of damage, environmental impact is not yet specifically incorporated in the cost calculation. You could bury the cable very deep to prevent the emitted heat from reaching the surface or you could simply place the cable on the seabed, but trenching the cable at for example 0.5 m would from an ecological point of view be least attractive. The cable needs to be designed for a situation where it cannot emit all of its generated heat and trenching equipment is needed during the installation process, while animals are still being attracted. The level of environmental impact is still unknown.

Do you think the island proposed by TenneT will be viable?
One of the biggest problems for offshore wind farms is maintenance. On land you can simply take a van and ride to the turbine, while at sea you have to wait for good weather conditions and even then it is still difficult to reach the turbine. The further wind turbines are located from a port the longer it takes to reach them. The chance on rough weather conditions during this longer maintenance period increases, resulting in longer downtime of the turbine and higher operation and maintenance cost. In my opinion a port is the biggest benefit of the artificial island due to the shorter distance, availability of spare parts and maintenance facilities.

I think that the artificial island will be both technically and economically viable. The biggest problem is probably politics. There is very little cooperation in the EU and cooperative projects are going very slow. Every country has already projected their future offshore wind energy projects and this was done without any cooperation with neighbouring countries. Combining offshore wind energy with interconnectors is only viable when multiple countries participate and getting all countries on the same level will be very difficult. I think politics will prevent the concept from being realised or there should be a significant need that the concept fulfils.

Resistance from environmental organisations will be severe. Maybe it is also sufficient to create a ring dike. You would than have a much smaller impact on the environment, while creating far better and calmer offshore conditions. Be aware that TenneT is not an expert on this topic. The company gets a lot of media attention lately, but the concept has been proposed before and historically TenneT was only active on land. With the rise of offshore wind energy they have also become offshore players, but this does not make them experts. During conferences companies like Alliander and ECN came with innovative ideas, while TenneT was most of the times absent.

F - NORTH SEA OFFSHORE WIND FARMS

Table F.1: North Sea Region Offshore Wind Farms (1 to 35) (source: 4coffshore)

	Status	Offshore wind farm	Year	Turbine [MW]	Capacity [MW]	Investment [mln EUR]	Depth	range [m]	Distance to shore [km]
BE01	operational	Belwind		3	165	614	15	24	46
BE02	operational	Northwind	2014	3	216	851	15	23	37
BE03	operational	Thornton Bank phase I	2009	5	30	153	20	20	27
BE04	operational	Thornton Bank phase II	2012	6.2	184.5	812.5	6	20	27
BE05	operational	Thornton Bank phase III	2013	6.2	110.7	487.5	10	22	26
BE06	under constr.	Nobelwind		3.3	165	655	20	33	45
BE07	under constr.	Norther		8	370		13	26	23
BE08	under constr.	Rentel		7	309	1100	24	34	34
BE09	consented	Mermaid			274		26	26	54
BE10	consented	SeaStar		7	246	1000	20	26	40
BE11	appl. submitted	Northwester 2		6.5	253	1000	24	37	46
DK01	operational	Anholt	2013	3.6	400		12	19	15
DK02	operational	Avedøre Holme	2009	3.6	10.8		2	2	0
DK03	operational	Frederikshavn	2003	2.3	7.6		1	4	3.2
DK04	operational	Horns Rev 1	2002	2	160	278	6	11	17.9
DK05	operational	Horns Rev 2	2009	2.3	209.3	475	9	17	31.7
DK06	operational	Middelgrunden	2000	2	40	44.89	3	6	4.7
DK07	operational	Nysted	2003	2.3	165.6	245	6	9	10.8
DK08	operational	Rødsand 2	2010	2.3	207	450	6	12	8.8
DK09	operational	Rønland	2003	2.3	17.2		0	2	0.1
DK10	operational	Samsø	2003	2.3	23	31.97	10	13	4
DK11	operational	Sprogø	2009	3	21		6	16	10.6
DK12	operational	Tunø Knob	2013	0.5	5	9.75	4	7	5.5
DK13	operational	Vindeby	1991	0.45	4.95		2	4	1.8
DK14	under constr.	Horns Rev 3	2019	8	406.7	1000	11	20	29
DK15	under constr.	Nissum Bredning Vind		7	28		1	6	2.5
DK16	consented	Vesterhav Nord		9	180		17	24	4
DK17	consented	Versterhav Syd		9	170		16	23	4
DK18	appl. submitted	Jammerland Bugt		5	180		5	24	7.6
DK19	appl. submitted	Kriegers Flak	2021	9	600	1300	18	30	15
DK20	appl. submitted	Mejlflak		9	180		17	24	4
DK21	appl. submitted	Omø Syd		5.5	260		6	13	11.3
FI01	operational	Reposaaren Tuulipuisto		2.3	2.3	8.5	10	19	6.6
FI02	under constr.	Aajos		3.3	42.4		0	8	5.2
FI03	under constr.	Tahkuluoto		4	40	120	0	26	9.8

Table F.2: North Sea Region Offshore Wind Farms (36 to 70) (source: 4coffshore)

	Status	**Offshore wind farm**	**Year**	**Turbine [MW]**	**Capacity [MW]**	**Investment [mln EUR]**	**Depth**	**range [m]**	**Distance to shore [km]**
FI04	appl. submitted	Suurhiekka		5.5	480		2	16	25
FI05	appl. submitted	Tornion Röyttän		4	70		2	10	5
FR01	operational	D'Experimentation en Mer			8		33	33	24
FR02	under constr.	Floatgen Project		2	2	21.5	30	30	22
FR03	consented	Nenuphar MISTRAL			10		52	63	5
FR04	consented	Nenuphar TWINFLOAT		2	2	16.8	97	97	50
FR05	appl. submitted	Eoliennes Hautes Falaises		6	498	2000	25	31	13
FR06	appl. submitted	Eoliennes de Calvados		6	450	1800	21	30	11
FR07	appl. submitted	Parc du Banc de Guerande		6	480	2000	10	21	12
FR08	appl. submitted	Eolien en Mer		8	496	2500	28	36	102
DE01	operational	Alpha Ventus		5	60	250	28	30	56
DE02	operational	Amrumbank West	2015	3.6	302	1000	20	25	35
DE03	operational	BARD Offshore 1	2013	5	400	2900	39	41	101
DE04	operational	Borkum Riffgrund 1	2015	4	312	1190	23	29	54
DE05	operational	Breitling	2006	2.5	2.5		0	0	0.3
DE06	operational	Butendiek	2015	3.6	288	1300	18	21	32
DE07	operational	DanTysk	2015	3.6	288	1000	21	29	70
DE08	operational	EnBW Baltic 1	2011	2.3	48.3	200	16	19	16
DE09	operational	EnWB Baltic 2	2015	3.6	288	1250	20	42	32
DE10	operational	Ems Emden	2004	4.5	4.5		0	2	0.6
DE11	operational	Global Tech I	2015	5	400	1800	38	41	115
DE12	operational	Meerwind Süd/Ost	2015	3.6	288	1200	24	27	53
DE13	operational	Nordsee Ost	2015	6.15	295.2	1300	22	25	57
DE14	operational	Riffgat	2014	3.6	108	480	18	23	42.4
DE15	operational	Sandbank	2017	4	288	1200	26	29	90
DE16	operational	Borkum I	2015	5	200	900	28	33	45
DE17	under constr.	Veja Mate	2017	6	402	1900	39	41	95
DE18	under constr.	Gode Wind 1 and 2	2016	6	582	2200	28	34	45
DE19	under constr.	Nordergründe		6.15	110.7	410	3	11	15
DE20	under constr.	Nordsee One	2017	6.15	332.1	1200	28	29	45
DE21	under constr.	Wikinger	2017	5	350	1350	36	40	35
DE22	under constr.	Arkona		6	385	1200	21	28	35
DE23	under constr.	Borkum Riffgrund 2		8	450	1300	25	29	56
DE24	under constr.	Schwimmendes Fundament		2.3	2.3	18	18	18	3.2
DE25	under constr.	Merkur		6	396	1600	27	33	45

Table F.3: North Sea Region Offshore Wind Farms (71 to 105) (source: 4coffshore)

	Status	Offshore wind farm	Year	Turbine [MW]	Capacity [MW]	Investment [mln EUR]	Depth	range [m]	Distance to shore [km]
DE26	consented	Arcadis Ost 1		6	348	1400	43	45	17
DE27	consented	Borkum Riffgrund West I		6	270	1600	29	31	53
DE28	consented	Delta Nordsee 1		6	210		26	34	50
DE29	consented	Delta Nordsee 2		6	192		29	33	51.1
DE30	consented	Deutsche Bucht		8	252		38	40	87
DE31	consented	EnBW He Dreiht			732		37	40	85
DE32	consented	EnWB Hohe See	2019	7	497	1500	39	40	90
DE33	consented	Gode Wind 3		6	90		30	34	39
DE34	consented	Gode Wind 4		6	252		30	34	42.4
DE35	consented	Kaikas		7	581		41	41	110
DE36	consented	Nördlicher Grund		5.5	352	1300	27	38	84
DE37	consented	Nordsee Three			369	1037.4	33	33	47.3
DE38	consented	Nordsee Two			295.2	829.63	29	34	47.3
DE39	consented	OWP Albatros Phase 1		7	116.8		39	41	100
DE40	consented	OWP Albatros Phase 2			278		39	41	100
DE41	consented	OWP West		6.5	267		29	31	58
DE42	consented	Sandbank Plus		9	184		26	34	95.3
DE43	consented	Borkum II		6.15	203	800	28	33	45
DE44	appl. submitted	Adlergrund 500		3.6	72		34	37	40
DE45	appl. submitted	Adlergrund GAP		5	155		29	36	36
DE46	appl. submitted	Adlergrund Nordkap		4.3	134		36	41	36
DE47	appl. submitted	Atlantis I		8	584		35	39	83
DE48	appl. submitted	Baltic Eagle		6	500		40	44	28
DE49	appl. submitted	Baltic Power		4	108		43	47	33.4
DE50	appl. submitted	Beta Baltic		3	150		21	22	15.8
DE51	appl. submitted	Borkum Riffgrund West II		6	236		29	31	67
DE52	appl. submitted	Gennaker		8	865				15
DE53	appl. submitted	Global Tech II		5	474		39	39	85
DE54	appl. submitted	He Dreiht II		5	195		37	39	46
DE55	appl. submitted	Kaskasi II			272		22	26	47.6
DE56	appl. submitted	Ostseeperle		6	245		39	41	25
DE57	appl. submitted	Ostseeschatz		6	252		44	44	30
DE58	appl. submitted	Sandbank extension		4	190		25	37	90
DE59	appl. submitted	Strom-Nord		4.8	216		43	45	30
DE60	appl. submitted	Wikinger Nord		5	40		40	40	40

Table F.4: North Sea Region Offshore Wind Farms (106 to 140) (source: 4coffshore)

	Status	Offshore wind farm	Year	Turbine [MW]	Capacity [MW]	Investment [mln EUR]	Depth	range [m]	Distance to shore [km]
DE61	appl. submitted	Windanker		6	252		41	41	41.9
IR01	operational	Arklow Bank phase 1		3.6	25.2	50	2	10	10
IR02	consented	Arklow Bank phase 2			495		1	35	10
IR03	appl. submitted	Dublin Array		4.5	442	2000	2	25	10
IR04	appl. submitted	Oriel Wind Farm		6	330	950	17	27	7.8
IR05	appl. submitted	Sceirde Rocks		5	100		8	27	5.9
IT01	consented	Gulfo de Gela		3.6	137		17	21	3
IT02	consented	Porto di Taranto		3	30	63	3	14	2.9
NL01	operational	Egmond aan Zee	2008	3	108	217	15	18	10
NL02	operational	Eneco Luchterduinen	2015	3	129	450	18	22	23
NL03	operational	Irene Vorrink	1996	0.6	16.8		2	3	0.8
NL04	operational	Prinses Amaliawindpark	2008	2	120	383	19	24	23
NL05	operational	Westermeerwind		3	144	400	3	7	0.5
NL06	under constr.	Gemini	2017	4	600	2800	32	34	85
NL07	consented	Borssele 1 and 2		8	722		16	38	22
NL08	consented	Borssele 3 and 4		8	702		14	38	40.3
NL09	consented	Borssele 5			16		22	24	75
NL10	appl. submitted	Windpark Fryslan	2021	4	338		3	6	5.6
NO01	operational	Hywind - Metcentre	2009	2.3	2.3		220	220	10
NO02	consented	Kvitsøy			8		0	50	1
NO03	consented	Marine Energy Test Centre			20		0	200	1
NO04	consented	Rennesøy			8		0	55	1
NO05	consented	SWAY 2.6 MW Test		2.6	2.6	25	210	210	7
NO06	appl. submitted	Siragrunnen		5.5	200	400	11	20	1
PL01	appl. submitted	Baltyk Srodkowy III		6	600		25	34	23
PT01	consented	WindFloat Atlantic		8	25	125	100	100	20
SP01	under constr.	Mario Luis Romero Torrent		5	5	14.8	25	30	1.5
SP02	under constr.	PLOCAN		3	15		5	500	1.1
SP03	appl. submitted	FLOCAN 5		6.5	25		50	200	2
SW01	operational	Bockstigen	1998	0.55	2.75	4	5	6	4
SW02	operational	Karehamn	2013	3	48	120	6	20	3.8
SW03	operational	Lillgrund	2008	2.3	110.4	197	4	13	11.3
SW04	operational	Utgrunden I		1.5	10.5	14	6	15	4.2
SW05	operational	Vindpark Vänern	2010	3	30		1	18	3.5
SW06	consented	Kattegatt Offshore		4.8	282		20	26	8.9

Table F.5: North Sea Region Offshore Wind Farms (141 to 175) (source: 4coffshore)

	Status	**Offshore wind farm**	**Year**	**Turbine [MW]**	**Capacity [MW]**	**Investment [mln EUR]**	**Depth**	**range [m]**	**Distance to shore [km]**
SW07	consented	Kriegers Flak II		5	640		16	39	32.7
SW08	consented	Stenkalles grund		5	100		2	18	4.5
SW09	consented	Stora Middelgrund		7	756		10	36	25
SW10	consented	Storgrundet		4.5	420		1	25	11
SW11	consented	Taggen Vindpark		5.8	300		12	20	19
SW12	consented	Trolleboda		5	150		11	22	2.3
SW13	appl. submitted	Marviken		4	43		0	15	1.2
SW14	appl. submitted	Södra Midsjöbanken		7	2100		14	25	70
SW15	appl. submitted	Svenska Björn Offshore					7	20	48.8
UK01	operational	Barrow	2006	3	90		12	16	7.5
UK02	operational	Burbo Bank	2007	3.6	90	181	0	5	6.4
UK03	operational	Greater Gabbard	2012	3.6	504		4	37	36
UK04	operational	Gunfleet Sands	2010	3.6	172.8		0	13	7
UK05	operational	Gunfleet Sands 3	2013	6	12		5	12	8
UK06	operational	Gwynt y Mor	2015	3.6	576	2700	13	32	16
UK07	operational	Humber Gateway	2015	3	219		10	18	10
UK08	operational	Inner Dowsing	2009	3.6	97.2		6	8	5
UK09	operational	Kentisch Flats	2005	3	90		3	4	8.5
UK10	operational	Kentisch Flats Extension		3.3	49.5		1	4	8.5
UK11	operational	Levenmouth		7	7		5	5	0
UK12	operational	Lincs	2013	3.6	270		8	16	8
UK13	operational	London Array	2012	3.6	630	2420	0	23	20
UK14	operational	Lynn	2009	3.6	97.2		7	11	5
UK15	operational	North Hoyle	2003	2	60		5	12	7.2
UK16	operational	Ormonde	2012	5.075	150	552	17	21	9.5
UK17	operational	Rhyl Flats	2009	3.6	90		4	11	8
UK18	operational	Robin Rigg	2010	3	174		0	12	11
UK19	operational	Scroby Sands	2004	2	60		0	10	2.3
UK20	operational	Sheringham Shoal	2012	3.6	316.8		14	23	23
UK21	operational	Teesside	2013	2.3	62.1		6	18	1.5
UK22	operational	Thanet	2010	3	300		14	23	12
UK23	operational	Walney Phase 1	2011	3.6	183.6		19	23	14
UK24	operational	Walney Phase 2	2012	3.6	183.6		24	30	14
UK25	operational	Wave hub			30		42	53	16
UK26	operational	West of Duddon Sands	2014	3.6	389		17	21	15

Table F.6: North Sea Region Offshore Wind Farms (176 to 205) (source: 4coffshore)

	Status	Offshore wind farm	Year	Turbine [MW]	Capacity [MW]	Investment [mln EUR]	Depth	range [m]	Distance to shore [km]
UK27	operational	Westermost Rough	2015	6	210	870	12	22	8
UK28	under constr.	Burbo Bank Extension	2017	8	254.2		3	14	6
UK29	under constr.	Dudgeon	2017	6	402		12	24	35
UK30	under constr.	Galloper		6	336		27	36	27
UK31	under constr.	Race Bank	2018	6	573.3		6	23	27
UK32	under constr.	Rampion	2018	3.45	400.2		19	39	13
UK33	under constr.	Aberdeen		8	92.4		20	30	2.4
UK34	under constr.	Beatrice	2007	7	588		35	50	18.4
UK35	under constr.	Blyth - Array 2		8	41.5		29	39	5.7
UK36	under constr.	East Anglia ONE		7	714		30	41	45.4
UK37	under constr.	Hornsea Project One		7	1218		24	37	120
UK38	under constr.	Hywind Scotland Pilot Park		6	30		96	110	25
UK39	under constr.	Walney Extension		8	659		20	54	19
UK40	consented	Blyth - Array 3A and 4		8.5	58.4	205	43	54	13.8
UK41	consented	Dogger Bank - Creyke Beck A		10	1100		18	25	131
UK42	consented	Dogger Bank - Creyke Beck B		10	1100		20	33	131
UK43	consented	Dogger Bank - Teesside A		10	1200		21	30	196
UK44	consented	Dogger Bank - Teesside B		10	1200		21	33	165
UK45	consented	ForthWind Phase 1		6	12		10	14	1.5
UK46	consented	Hornsea Project Two		10.5	1800		30	40	99.5
UK47	consented	Moray Firth Eastern Area 1		8	504		39	50	22
UK48	consented	Moray Firth Eastern Area 2		8	496		39	52	22
UK49	consented	Triton Knoll		8	825		12	30	33
UK50	appl. submitted	Dounreay Tri		5	10		74	76	6
UK51	appl. submitted	East Anglia THREE		9.5	1200		24	48	74.6
UK52	appl. submitted	Inch Cape		7.5	784		36	54	22
UK53	appl. submitted	Kincardine		6.15	50		62	62	15
UK54	appl. submitted	Neart na Gaoithe		7	448	1614	44	56	13
UK55	appl. submitted	Seagreen Alpha		7	525		39	61	27
UK56	appl. submitted	Seagreen Bravo		7	525		42	58	38

G - NORTH SEA SUBSEA INTERCONNECTORS

Table G.1: North Sea Region Subsea Interconnectors (1 to 25) (source: 4coffshore)

	Name	Status	Year of operation	Country 1	Country 2	Capacity [MW]	Onshore [km]	Offshore [km]	Total [km]	Cost [€ mln]
IC01	IFA	decomm.	1961	FR	UK	160	?	?	65	?
IC02	Skagerrak 4	operational	2015	NO	DK	700	104	138	242	449
IC03	IFA2000	operational	1986	FR	UK	2000	27	46	73	?
IC04	BritNed	operational	2011	UK	NL	1000	9	250	259	600
IC05	East West	operational	2012	UK	IR	500	75	186	261	600
IC06	Norned	operational	2008	NO	NL	700	1.6	578.4	580	600
IC07	Baltic Cable	operational	1994	DE	SW	600	12	250	262	?
IC08	Fenno-Skan	operational	1989	FI	SW	550	33	200	233	?
IC09	Fenno-Skan 2	operational	2011	FI	SW	800	103	196	299	315
IC10	Kontek	operational	1995	DE	DK	600	119	52	171	?
IC11	Skagerrak 1 and 2	operational	1977	NO	DK	500	32.5	42.5	75	?
IC12	Skagerrak 3	operational	1993	NO	DK	440	38	42	80	?
IC13	Konti-Skan 1	operational	1965	DE	SW	380	86	87	173	?
IC14	Konti-Skan 2	operational	2030	DE	SW	360	61	88	149	?
IC15	Bornholm	operational	1980	DK	SW	60	6.3	43.5	49.8	?
IC16	Oresund 132kV	operational	1963	DK	SW	1350	?	5.5	?	?
IC17	COBRAcable	under constr.	2019	NL	DK	700	26	299	325	631
IC18	Nemo Link	under constr.	2019	UK	BE	1000	10	130	140	700
IC19	Nord.Link	under constr.	2020	DE	NO	1400	107	516	623	2104
IC20	North Sea Link	under constr.	2021	NO	UK	1400	10	720	730	2000
IC21	ElecLink	under constr.	2020	UK	FR	1000	14	51	65	580
IC22	Oresund 400kV	cons. authorised	1973	DK	SW	?	1.2	7.3	8.5	34
IC23	Oresund 132kV	cons. authorised	2018	DK	SW	?	6	5.5	11.5	?
IC24	IFA2	appl. submitted	2020	FR	UK	1000	32	208	240	850
IC25	Channel Cable	concept	2018	FR	UK	1400	?	?	130	580

Table G.2: North Sea Region Subsea Interconnectors (2 to 50) (source: 4coffshore)

	Name	**Status**	**Year of operation**	**Country 1**	**Country 2**	**Capacity [MW]**	**Onshore [km]**	**Offshore [km]**	**Total [km]**	**Cost [€ mln]**
IC26	NorthConnect	concept	2022	UK	NO	1400	2.6	647.4	650	1651
IC27	FABLink	concept	2021	UK	FR	1400	45	171	216	750
IC28	Celtic Interconnector	concept	2025	IR	FR	700	100	500	600	1000
IC29	IceLink	concept	2030	UK	IC	1000	?	?	1000	3500
IC30	Viking Link	concept	2023	UK	DK	1400	131	635	766	2000
IC31	Greenlink	concept	2020	UK	IR	500	30	180	210	?
IC32	NorNed 2	concept	2030	NO	NL	700	?	?	570	?
IC33	NorGer	concept	2028	NO	DE	1400	?	630	?	?
IC34	Hansa Powerbridge 1	concept	2025	SW	DE	700	100	200	300	700
IC35	Greenwire North	concept	2021	UK	IR	1000	?	?	262	?
IC36	Greenwire South	concept	2022	UK	IR	1500	?	?	288	?
IC37	Greenconnect	concept	2022	UK	IR	700	?	?	155	?
IC38	Maali	concept	2023	UK	NO	900	?	?	380	?
IC39	AQUIND Interconnector	concept	2021	UK	FR	2000	55	90	145	1529
IC40	MAREX	concept	2020	UK	IR	1500	?	?	?	?
IC41	Hansa Powerbridge 2	concept	2030	DE	SW	700	?	?	?	700
IC42	Britib	concept	2020	FR	UK	2400	?	650	?	3300
IC43	Gridlink	concept	2022	UK	FR	1500	?	?	?	?
IC44	UK Belgium	concept	2025	UK	BE	1000	?	?	?	?
IC45	Kontek 2	concept	2030	DK	DE	600	?	?	?	?
IC46	Kontek 3	concept	2035	DK	DE	?	?	?	?	?
IC47	Denmark Poland	concept	2035	DK	PO	500	?	?	?	?
IC48	COBRA 2	concept	2035	DK	DE	700	?	?	?	?
IC49	UK Netherlands	concept	2030	UK	NL	1000	?	?	?	?
IC50	NeuConnect	concept	2022	UK	DE	1400	?	?	650	?

H - MATLAB CODE

H.1 Bathymetry

```
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%% EUROPE %%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
depthB2 = rot90(ncread('B2.mnt','DEPTH')); % 90 deg. rotation to get x = lon
depthB3 = rot90(ncread('B3.mnt','DEPTH'));
depthC2 = rot90(ncread('C2.mnt','DEPTH'));
depthC3 = rot90(ncread('C3.mnt','DEPTH'));

latB2 = flipud(ncread('B2.mnt','LINES'));
latB3 = flipud(ncread('B3.mnt','LINES'));

lonB2 = ncread('B2.mnt','COLUMNS');
lonC2 = ncread('C2.mnt','COLUMNS');

% bathymetry = [depthB2, depthC2; depthB3, depthC3];
% Calculation time (~25 sec.) and plotting (> 2 min.)

i = 1:9480;
j = 10:10:9480;
i([j])=[]; % Horizontal reduction by factor 10
depthB2(:,[i]) = [];
depthB3(:,[i]) = [];
depthC2(:,[i]) = [];
depthC3(:,[i]) = [];
lonB2([i],:) = [];
lonC2([i],:) = [];

k = 1:7200;
l = 10:10:7200;
k([l])=[]; % Vertical reduction by factor 10
depthB2([k],:) = [];
depthB3([k],:) = [];
depthC2([k],:) = [];
depthC3([k],:) = [];
latB2([k],:) = [];
latB3([k],:) = [];

bathymetry = [depthB2, depthC2; depthB3, depthC3]; % Reduced resolution
lat = [latB2; latB3];                               % lat = 69.999 to 40.001
lon = [lonB2; lonC2];                               % lon = -16.249 to 23.249

bathymetry(bathymetry>=0) = NaN; % Remove positive values, only 'depth'

%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%%%%%%%%%%%%%%%%%%%%%%%%%%%%% ENTIRE NORTH SEA %%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
[diff latminvec] = min(abs(lat-62));
[diff latmaxvec] = min(abs(lat-50));
[diff lonminvec] = min(abs(lon+5));
[diff lonmaxvec] = min(abs(lon-10));

```

```
latmindeg = lat(latminvec);
latmaxdeg = lat(latmaxvec);
lonmindeg = lon(lonminvec);
lonmaxdeg = lon(lonmaxvec);

nslat = lat(latminvec:latmaxvec,1);
nslon = lon(lonminvec:lonmaxvec,1);

nsbathymetry = bathymetry(latminvec:latmaxvec,lonminvec:lonmaxvec);

nsbathymetry(nsbathymetry>=0) = NaN;

% save('nsbathymetry.mat','nsbathymetry')
% save('nslon.mat','nslon')
% save('nslat.mat','nslat')

l = linspace(0,-1800,181)';
contourf(nslon,nslat,nsbathymetry,l)% X, Y, Z
caxis([-100,0]) % change this value to set range colorbar
colorbar
```

H.2 Wind Conditions

```
%%% CREATING SINGLE VECTOR FROM MUTLTIPLE FILES (monthly) %%%
% date vector for calling data from multiple files
monthyears = 201201:201612; % 5 years
m = 1:12;
month = 1:12;
for i = 1:5-1; % number of years (2012 - 2016)
    month = [month, m + i*100];
end
monthyears = monthyears(month);

% merging information (v) from every file into one variable
east5years = [];
north5years = [];
time = [];
for k = monthyears; %200601:200602;
  myfilename = sprintf('wnd10mx0.5.cdas1.%d.grb2.nc',k);
  east = double(ncread(myfilename,'U_GRD_L103'));
  north = double(ncread(myfilename,'V_GRD_L103'));
  east5years = cat(3,east5years,east);
  north5years = cat(3,north5years,north);
end

save('east5years.mat','east5years');
save('north5years.mat','north5years');

lat = double(ncread('wnd10mx0.5.cdas1.201201.grb2.nc','lat'));
lon = double(ncread('wnd10mx0.5.cdas1.201201.grb2.nc','lon')); % Equal for
    every file

save('lat.mat','lat')
save('lon.mat','lon')
```

```
%%% WIND SPEED MOVIE %%%
DROPBOX = tempname;
mkdir(DROPBOX, 'images')
date_vec = 736665:(1/24):736668-(1/24);

for i = 43105:43272; % 01 December 2016 - 03 December 2016      (168 frames)
    contourf(lon,lat,squeeze(windspeed5years(:,:,i)));
    hold on
    q = quiver(lon,lat,east5years(:,:,i),north5years(:,:,i));
    c = q.Color;
    q.Color = 'yellow';
    hold on
    plot(borders(:,1),borders(:,2),'r','linewidth',1)
    hold on
    plot(EEZ(:,1:6),EEZ(:,7:12),'--r','linewidth',1)
    xlabel('longitude')
    ylabel('latitude')
    title({'North Sea hourly wind speed (m/s)',datestr(date_vec(i-43104))})
    axis([-5 10 50 62])
    caxis([0,15]) % change this value to set range colorbar
    colorbar
    name = [sprintf('%03d',i) '.png'];
    fullname = fullfile(DROPBOX,'images',name);
    saveas(gcf,fullname)
end
```

H.3 Wave Conditions

```
% Edit '/...Path/...to/nctoolbox' to call nctoolbox directory
addpath('D:/Users/GERS5/Desktop/MATLAB/Waves/nctoolbox-1.1.3');
setup_nctoolbox;
% You need to add these lines to your XXXXXXXXXXX.m file if you
% want to use nctoolbox when starting Matlab. The toolbox is required
% to read GRIB2 data format. (http://nctoolbox.github.io/nctoolbox/)

% creating date vector for retrieving data from multiple files
monthyears = 201201:201612;
m = 1:12;
month = 1:12;
for i = 1:5-1; % number of years (2012 - 2016)
    month = [month, m + i*100];
end
monthyears = monthyears(month);

% merging information (hs) from every file into one 'matlab'.mat file
hs = [];
hs_sub = [];
for k = monthyears; %201201:201612;
  myfilename = sprintf('multi_1.glo_30m.hs.%d.grb2',k);
  ds = ncgeodataset(myfilename);
  hs_sub = ds.geovariable('Significant_height_of_combined_wind_waves_and_swell_surface');
  hs_1 = double(hs_sub.data(:,32:56,711:720)); %Dimension: time, lat, lon
  hs_2 = double(hs_sub.data(:,32:56,1:21));
  hs_sub = cat(3,hs_1,hs_2); % Due to difference in 180W 180E and 0E 360E
  hs = [hs; hs_sub];
```

```
end

save('hs.mat','hs')

lat = ds.geovariable('lat');
lon = ds.geovariable('lon');
lat = double(lat(32:56)); %North Sea (area specified by author) 50.0N 62.0N
lon = double([lon(711:720)-360;lon.data(1:21)]); %                    5.0W 10.0E

save('lat.mat','lat')
save('lon.mat','lon')
```

H.4 Wind Turbine Revenue

```
load('lat.mat')
load('lon.mat')
load('east5years.mat')
load('north5years.mat') %hourly data, jan. 2012 - dec. 2016 in lon, lat,
    time
load('bordersNS.mat')
load('EEZ.mat')

east5years = permute(east5years,[2 1 3]);
north5years = permute(north5years,[2 1 3]); % To get lat, lon, time
windspeed5years = sqrt((east5years.^2)+(north5years.^2));

% Power Law
v1 = 5;          % windspeed [m/s]
z1 = 10;         % height [m]
z2 = 0:1:150;    % ...
alpha = 0.1;     % wind shear exponent
v2 = v1*(z2/z1).^alpha;

% Log Law
v1 = 5;                % windspeed [m/s]
z1 = 10;               % height [m]
z2 = 0:1:150;          % ...
z_0 = 0.0005;          % roughness length [m]
v2 = v1 * log(z2/z_0) / log(z1/z_0);

% Further calculations done with Log Law
v1 = windspeed5years;
z1 = 10;
z2 = 100; % --> input value
z_0 = 0.0005;
v2 = v1 * log(z2/z_0) / log(z1/z_0);
v2 = squeeze(v2);

% Weibull approximation
mu = mean(v2,3);
sigma = std(v2,0,3);
k = (sigma ./ mu).^(-1.086);
lambda = mu ./(gamma(1+(1./k)));

weib_emp = makedist('Weibull','a',lambda,'b',k)
x = 0:0.1:35;
prob_emp = pdf(weib_emp,x);
```

```

% Air power density (W/m2)
rho = 1.225; %kg/m^3
E = 0.5 .* rho .* lambda.^3 .* gamma(1 + (3./k));

%%% Turbine power curves %%%
% SWT-2.3-93 Power curve
SWT23 = [0,0,0,0,59,200,400,678,1011,1361,1712,2012,2208,2300,2300,2300,2300,2300,
2300,2300,2300,2300,2300,2300,2300,2300,0,0,0,0,0,0,0,0,0,0]/1000;

% SWT-3.6-120
SWT36 = [0,0,0,0,0,0,0,62,150,246,337,481,624,825,1012,1274,1537,1866,2197,2555,
2907,3207,3393,3507,3566,3582,3597,3600,3600,3600,3600,3600,3600,3600,3600,
3600,3600,3600,3600,3600,3600,3600,3600,3600,3600,3600,3600,3600,3600,3600,
3600,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0]/1000;

% Gamesa 128-5.0MW
gamesa = [0,0,0,0,195,420,786,1296,1943,2699,3487,4174,4639,4875,4965,5000,5000,
4984,4944,4859,4722,4541,4331,4108,3883,3661,3447,3247,0,0,0,0,0,0,0,0]/1000;

% Aerodyn SCD 8.0/168
aerodyn = [0,0,0,0,100,500,1000,2000,3000,4000,5000,6000,7500,8000,8000,8000,8000,
8000,8000,8000,8000,8000,8000,8000,8000,8000,0,0,0,0,0,0,0,0,0,0]/1000;

% SeaTitan 10MW Power curve
sea_titan = [0,0,0,0,0,0,0,0.0723,0.2746,0.5419,0.8671,1.2572,1.7413,2.2905,2.8685,
3.4176,4.0751,4.9783,5.9827,7.0376,8.1936,9.8269,10,10,10,10,10,10,10,10,10,
10,10,10,10,10,10,10,10,10,10,10,10,10,10,10,10,10,10,10,10,0,0,0,0,0,0,0,0,
0,0,0,0,0,0,0,0,0,0,0,0];

% Upwind 20MW Power curve
upwind = [0,0,0,0,0,0,0,0.3192,0.5471,0.8101,1.2253,1.6932,2.2899,2.9803,3.8288,
4.8061,5.9298,7.2525,8.6981,10.378,12.1867,14.2588,16.5241,17.786,20,20,20,
20,20,20,20,20,20,20,20,20,20,20,20,20,20,20,20,20,20,20,20,20,20,20,20,
0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0];

x = 0:1:35;
x2 = 0:0.5:35;

plot(x,SWT23)
hold on
plot(x2,SWT36)
hold on
plot(x,gamesa)
hold on
plot(x,aerodyn)
hold on
plot(x2,sea_titan)
```

```
hold on
plot(x2,upwind)

% Power density curves
P_max_pdf = prob_emp .* (0.5 .* rho .* x.^3); % W/m2, A = 1.0 m^2
P_betz_pdf = P_max_pdf .* (16/27);
A = pi * (diameter/2)^2; % turbine sweep area <-- input
P_real_pdf = 1e6 * prob_emp2 .* SWT23 ./ A; % W/m2

area(x,P_max_pdf)
hold on
area(x,P_betz_pdf)
hold on
area(x2,P_real_pdf)

% Power coefficient c_p
P_max = (0.5 .* rho .* x2.^3); % W/m2, A = 1.0 m^2
P_max_pdf = P_max .* prob_emp2; % kW/m2
c_p = P_real_pdf ./ P_max_pdf; % different per turbine (specific power curve)

% Yearly turbine generation (GWh/year)
overview = [];
overview_row = [];
for i = 1:25;
    for k = 1:31;
        turbine_power = interpn(x,sea_titan,v2(i,k,:),'cubic'); % MW
        GWh_year = nansum(turbine_power)/(5*1e3);
        overview_row = cat(2,overview_row,GWh_year);
    end
    overview = cat(1,overview,overview_row);
    overview_row = [];
end

% Yearly turbine revenue (EUR/year)
revenue = overview.*price;

contourf(lon,lat,revenue,30)
hold on
plot(borders(:,1),borders(:,2),'r','linewidth',2)
hold on
plot(EEZ(:,1:6),EEZ(:,7:12),'--r','linewidth',1)
xlabel('longitude')
ylabel('latitude')
axis([-5 10 50 62])
caxis([2e6,5e6]) % change this value to set range colorbar
colorbar
```

H.5 Subsea Interconnector Revenue

```
%% EC Energy model forecast %%
x = 2000:5:2050;
BE = [42.99203926; 49.32307082; 58.81675741; 85.68096207; 105.1305568; 115.8082676; 110.6122676; 101.7385592; 96.70667764; 94.86221848; 91.63586891];
DE = [42.99188963; 50.9063581; 61.91091864; 85.77180467; 106.5088022; 102.7509304; 100.9519177; 92.59609967; 86.97486835; 86.50993364;
```

```
    85.16659331];
DK = [74.67157; 86.92810601; 89.09373654; 107.8183044; 107.8324192; 111.9129848; 105.2203253; 92.08685386; 86.14281552; 89.20804401; 76.56489722];
NL = [50.16813226; 57.55497305; 65.41114134; 72.59678553; 84.00475571; 89.43401815; 95.61592298; 98.67025338; 93.35129765; 95.8325576; 95.00775141];
UK = [41.87944806; 48.64966772; 58.5066032; 94.55394438; 114.6286858; 115.1247407; 115.63096; 107.3574549; 95.98449301; 87.21035953; 80.44052072];

% Extrapolating to yearly values (linear)
x2 = 2000:1:2050;
BE2 = interpn(x,BE,x2,'linear');
DE2 = interpn(x,DE,x2,'linear');
DK2 = interpn(x,DK,x2,'linear');
NL2 = interpn(x,NL,x2,'linear');
UK2 = interpn(x,UK,x2,'linear');

matrix = [BE DE DK NL UK];
upper = max(matrix,[],2);
lower = min(matrix,[],2);
max_difference = upper - lower;

x3 = 2025:1:2050; % 25 years design life, longer information not available
WACC = 0.09; % discount rate 9%
t = 0:length(x3)-1;
NPV = (1 + WACC).^t;
price_short_mat = matrix(26:end,:);
NPV_price_mat = price_short_mat ./ NPV';

capacity = 30e3; % 30 GW
fair_price = (cap./capacity).*NPV_price_mat;
fair_price_sum = sum(fair_price,2);
revenue = sum(fair_price_sum).*overview;

revenue_max_IC = (upper(26:end)-lower(26:end))./NPV';
absolute_revenue_max_IC = upper(26:end)-lower(26:end);
difference = (cap./capacity).*(NPV_price_mat - fair_price_sum);
revenue_fair_IC = sum(abs(difference),2);
absolute_revenue_fair_IC = revenue_fair_IC.*NPV';

% UTILISATION
x = 0:0.5:35;
overview = [];
overview_row = [];
for i = 1:25;
    for k = 1:31;
        turbine_power = interpn(x,sea_titan,v2(i,k,:),'cubic'); %MW
        MWh_year = nansum(turbine_power.*(1.00-0.163))/5; % 5 year wind conditions
        capacity = 100*MWh_year / (max(sea_titan)*365*24);
        overview_row = cat(2,overview_row,capacity);
    end
    overview = cat(1,overview,overview_row);
    overview_row = [];
end

```

```
capacity = 30e3; % 30 GW
NPV_IC_max = sum(revenue_max_IC);
NPV_IC_fair = sum(revenue_fair_IC);
IC_capacity = (100 - overview)/100;
IC_revenue = 365*24*capacity.*IC_capacity.*NPV_IC_fair;
```

H.6 Significant Storm Wave Height H_{ss}

```
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%%%%%%%%%%%%%%%%%%%%%%%%%% ENTIRE NORTH SEA %%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
load('lat.mat')             % lat = 50:0.5:62;
load('lon.mat')             % lon = -5:0.5:10;
load('hs11years.mat')       % Data from WaveWatchIII
load('dp11years.mat')       % http://polar.ncep.noaa.gov/waves/index2.shtml
load('tp11years.mat')
load('bordersNS.mat')       % borders and EEZ lines for plotting
load('EEZ.mat')


% Significant Storm Wave Height H_ss
num = 1100; % Determining number of storms
acc = 0.01; % Accuracy [m]
period = 11; % Years of collected data
return_period = 1e4;
ex_Hs = [];
ex_Hs_sub = [];
gum_Hs = [];
gum_Hs_sub = [];
weib_Hs = [];
weib_Hs_sub = [];

for q = 1:25;
    for z = 1:31;
        hs = hs11years(:,q,z);
        if  isnan(mean(hs)) == 0;
        [a loc] = sort(hs,'descend'); % Select deg. range with highest
            waves
        deg = dp11years(:,q,z);
        b = deg(loc);
        deg_bins = 0:30:360;
        c = histogram(b,deg_bins);
        [d deg_loc] = max(c.Values);
        deg_range = 30*(deg_loc-1):30*deg_loc; % Deg. range selected
        e = find(deg >= min(deg_range)& deg <= max(deg_range));
        f = hs(e);
        g = sort(f,'descend'); % Selecting # of highest waves from 30 deg.
            range
        h = g(1:num);
        i = min(h); % Threshold value rounded to 0.01 m, else h = round(min
            (g)*4)/4 for 0.25 m;
        j = [diff(e(1:num)) == 1;0]; % Storm duration of 6 hours
        k = h.*j;
        k(k==0) = [];

        edges = i:acc:15; % Change the first value to set storm Hs
        l = histogram(k,edges);
```

```
        observations = l.Values;
        cumulative = cumsum(observations);
        P = cumulative / sum(observations);
        Q = 1 - P;
        min_ln_Hs = - log(edges(2:end));
        storms_year = sum(observations)/period;
        Qs = Q * storms_year;
        ln_Qs = log(Qs);

        % Extrapolation
        x = Qs;
        x(x == 0) = [];
        y = edges(2:length(x)+1);
        exponential_coefficients = [ones(1,length(y))' log(x)'] \ y';
        exponential_alpha = exponential_coefficients(2);
        exponential_beta = exponential_coefficients(1);
        exponential_Hs = exponential_alpha * log(1/return_period) + exponential_beta;
        ex_Hs_sub = cat(2,ex_Hs_sub,exponential_Hs);

        % Gumbel
        G = -log(log(1./P));
        x = G;
        x(x == Inf) = [];
        y = edges(2:length(x)+1);
        gumbel_coefficients = polyfit(x,y,1);
        gumbel_beta = gumbel_coefficients(1);
        gumbel_gamma = gumbel_coefficients(2);
        gumbel_Hs = gumbel_gamma - gumbel_beta * log(log(storms_year/(storms_year-(1/return_period))));
        gum_Hs_sub = cat(2,gum_Hs_sub,gumbel_Hs);

        % Weibull
        corr = [];
        step = 0.01;
            for weibull_alpha = 0:step:2; % initial values --> iterations needed
                W = log(1./Q).^(1./weibull_alpha);
                x = W;
                x(x == Inf) = [];
                y = edges(2:length(x)+1);
                c = corrcoef(x,y);
                correlation = c(1,2);
                corr = cat(2,corr,correlation);
            end
        [weibull_correlation vec] = max(corr);
        weibull_alpha = step*(vec-1); % iteration complete --> alpha
        W = log(1./Q).^(1./weibull_alpha);
        x = W;
        x(x == Inf) = [];
        y = edges(2:length(x)+1);
        weibull_coefficients = polyfit(x,y,1);
        slope = weibull_coefficients(1);
        intersection = weibull_coefficients(2);
        weibull_beta = slope;
        weibull_gamma = intersection;
        weibull_Hs = weibull_gamma + weibull_beta*(-log(1/(return_period*storms_year)))^(1/weibull_alpha);
```

```
            weib_Hs_sub = cat(2,weib_Hs_sub,weibull_Hs);

        else
            ex_Hs_sub = cat(2,ex_Hs_sub,NaN);
            gum_Hs_sub = cat(2,gum_Hs_sub,NaN);
            weib_Hs_sub = cat(2,weib_Hs_sub,NaN);
        end
    end
    ex_Hs = cat(1,ex_Hs,ex_Hs_sub);
    ex_Hs_sub = [];
    gum_Hs = cat(1,gum_Hs,gum_Hs_sub);
    gum_Hs_sub = [];
    weib_Hs = cat(1,weib_Hs,weib_Hs_sub);
    weib_Hs_sub = [];
end

% save('ex_Hs.mat','ex_Hs')
% save('gum_Hs.mat','gum_Hs')
% save('weib_Hs.mat','weib_Hs')

brown = [217 83 25]./255;
contourf(lon,lat,ex_Hs)
hold on
plot(borders(:,1),borders(:,2),'linewidth',2,'color',brown)
hold on
plot(EEZ(:,1:6),EEZ(:,7:12),'linewidth',2,'color',brown)
axis([-5 10 50 62])

brown = [217 83 25]./255;
contourf(lon,lat,gum_Hs)
hold on
plot(borders(:,1),borders(:,2),'linewidth',2,'color',brown)
hold on
plot(EEZ(:,1:6),EEZ(:,7:12),'linewidth',2,'color',brown)
axis([-5 10 50 62])

brown = [217 83 25]./255;
contourf(lon,lat,weib_Hs)
hold on
plot(borders(:,1),borders(:,2),'linewidth',2,'color',brown)
hold on
plot(EEZ(:,1:6),EEZ(:,7:12),'linewidth',2,'color',brown)
axis([-5 10 50 62])
```

H.7 Island Expenditure

```
load('lon')
load('lat')
load('nslon')
load('nslat')
load('nsbathymetry')

% Calculating island volume
A = 2.1e6; % [km2]   <—— input
r = sqrt(A/pi);

load('extreme_water_level') % 'h', extreme water level
```

```
depth = nsbathymetry; % [km]  <--- input

slope = 3/4; % V/H
r_0 = r + (h + abs(depth))/slope;
V_total = (1/3) * pi * slope * r_0.^3;
V_remove = (1/3) * pi * slope * r^3;
V = V_total - V_remove; % m3

unitcost_dredging = 3.26; % EUR 3.26 / m3, calculated in report
sand_cost = V*unitcost_dredging;

% Calculating shore protection surface
load('weib_Hs_FINAL.mat') % 'weib_Hs', extreme wave height

crest = h + weib_Hs;
r_crest = r - weib_Hs./slope;
SA = pi*r_0.^2 + pi*r_0.*sqrt(r_0.^2*(1+slope^2)) - pi.*r_crest.^2 - pi.*r_crest.*sqrt(r_crest.^2.*(1+slope^2));
unit_cost = 2236000/(100*28); % To get cost/m2
protection_cost = (r_0 + r_crest)*pi*(depth + crest)*unit_cost;

island_expenditure = sand_cost + protection_cost;
```

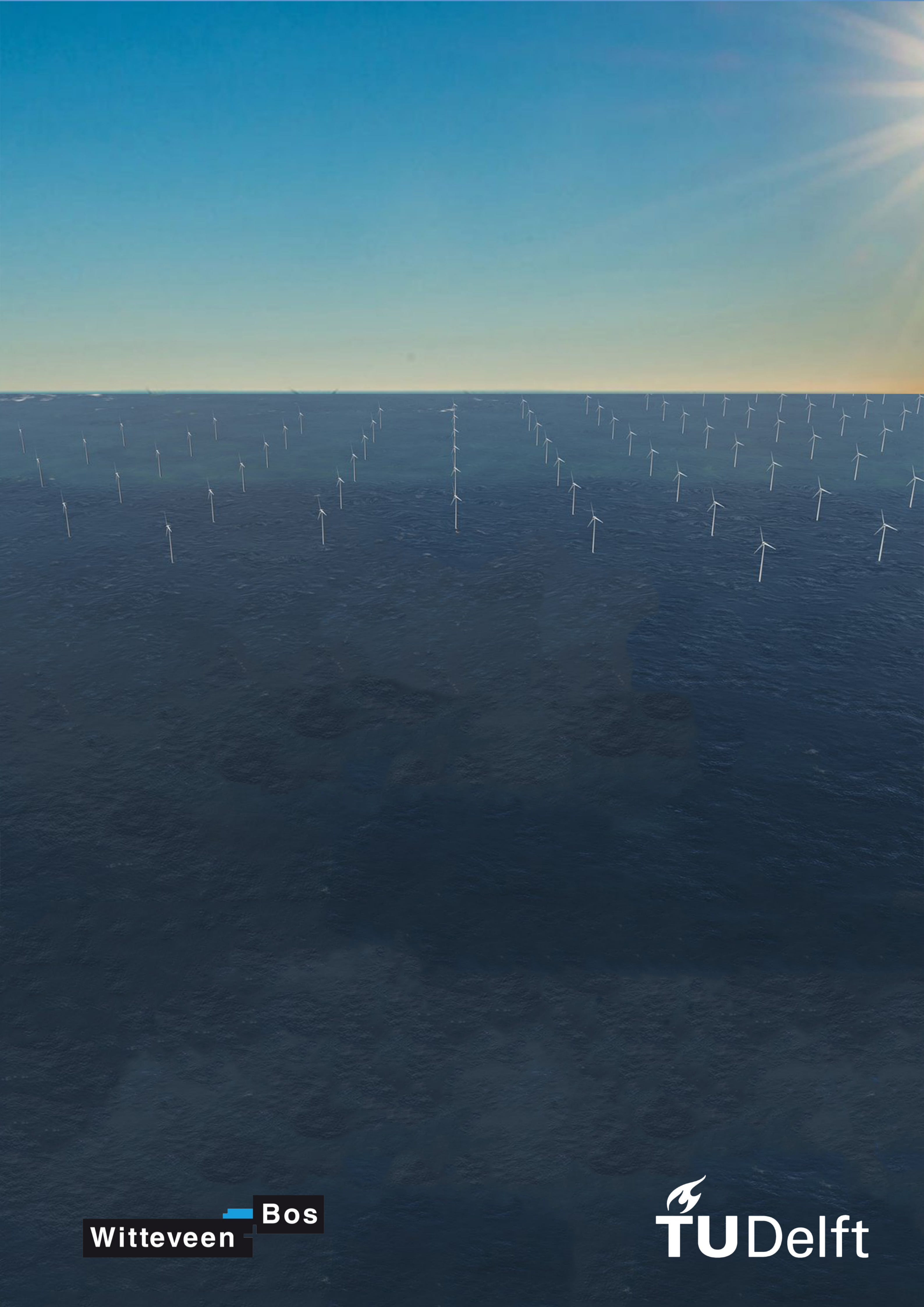
H.8 Expenditure Offshore Wind Farms

```
load('lat')
load('lon')
load('EEZ.mat')
load('bordersNS.mat')

load('nsbathymetry')
load('nslon')
load('nslat')

capacity = 30e3;
cost_OWF_single = -258.331620711705 + (4.00411777177956*700) + (10.9690280492503*-nsbathymetry);
cost_OWF = cost_OWF_single*(capacity/700);
```

H.9 Expenditure Subsea Interconnectors

```
% SELECTION OF LANDING POINTS
BE = [3.2 51.3; nan nan; nan nan; nan nan; nan nan; nan nan];
DK = [8.5 55.5; nan nan; nan nan; nan nan; nan nan; nan nan];
DE = [7.2 53.4; 8.1 53.5; 10.0 53.5; nan nan; nan nan; nan nan];
NL = [4.1 52.0; 4.6 52.5; 6.8 53.4; nan nan; nan nan; nan nan];
NO = [8.0 58.1; 5.7 59.0; nan nan; nan nan; nan nan; nan nan];
UK = [-3.0 58.6; -2.1 57.1; -1.5 55.1; -0.3 53.7; 1.2 52.9; 1.3 52.0];
matrix = [BE DK DE NL NO UK];

% HAVERSINE FUNCTION (SEPERATE MATLAB FILE)
function d = haversine(lat1,lon1,lat2,lon2)

r = 6371; %radius earth (km)
phi1 = lat1*pi/180; %Lat in formula (radians)
```

```
phi2 = lat2*pi/180;
lambda1 = lon1*pi/180; %Lon in formula (radians)
lambda2 = lon2*pi/180;
d = 2*r*asin(sqrt(sin((phi2-phi1)/2)^2 + cos(phi1)*cos(phi2)*sin((lambda2-
    lambda1)/2)^2)); %km
end

% distribution = [BE DK DE NL NO UK];
% 30 GW
distribution = [5 5 5 5 5 5]; % multiply with 1 GW
distribution = [2 2 12 2 4 8]; % ''fair'' distribution 30 GW capacity
% 100 GW
distribution = [16.6 16.6 16.7 16.7 16.7 16.7];
distribution = [6 4 48 6 10 26]; % ''fair'' distribution 100 GW capacity

IC = [];
IC_row = [];
dist_mat = [];
dist_mat_sub = [];
for i = 1:25;
    for j = 1:31;
        [a b] = size(matrix);
        for k = 1:2:b;
            for z = 1:a;
                dist = 1.1*haversine(matrix(z,k+1),matrix(z,k),lat(i),lon(j
                    )); % 10% extra length
                dist_mat_sub = cat(1,dist_mat_sub,dist);
            end
            dist_mat = cat(2,dist_mat,dist_mat_sub);
            dist_mat_sub = [];
        end
        shortest = min(dist_mat,[],1);
        cost_IC = -595.683561892483 + 0.952466809495687*1000 +
            1.58856099101832*shortest;
        total_cost = sum(distribution.*cost_IC); % to get 2 GW cables
        IC_row = cat(2,IC_row,total_cost);
        dist_mat = [];
    end
    IC = cat(1,IC,IC_row);
    IC_row = [];
end

[a b] = min(IC(:));
[I_row, I_col] = ind2sub(size(IC),b);
min_IC = IC(I_row,I_col)
min_length = length(I_row,I_col)
```


Witteveen
Bos
TUDelft