# *Driving Factors in the LCOE trend of Offshore wind power*

*Research Report regarding bachelor thesis commissioned by the research group Delta Power*

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# Abstract

From the start of the energy transition is has been believed that the development of wind power as a renewable source of electricity was vital for reaching the climate goals related to the decarbonization of the energy sector. The LCOE variable is globally applied when comparing the cost for the use of different technologies regarding renewable energy sources but is also used when determining price developments of electricity or energy production. It also highlights the viability of electricity or energy-producing technology. The cost development is driven by many factors influencing the 5 variables making up the LCOE value. Most of the LCOE's of renewable energy or electricity sources like geothermal, solar, water, and onshore wind follows a similar pattern, they become almost constantly cheaper over time. For offshore wind energy, the LCOE trend shows a different development over time compared to the LCOE values developments for other renewable sources that produce electricity. On average the price for the production of electricity per MWh by offshore wind only rose between 2000-2015 before dropping after 2015. This indicated that some driving factors behind offshore wind only made the technology on average more expensive as an electricity-producing technology. This non-adaption to wright's law has put extra pressure on the whole EU wide energy transition as offshore wind farms were either cancelled, postponed or reduced in size. All of these factors limit countries from reaching the climate goals they have set. The driving factors behind the LCOE trend of offshore wind are divided into two different categories namely; technology and infrastructure-based, and finance and risk-based. The variables of the LCOE can be influenced by either driving factors from one category or influenced by driving factors from both categories. The investment expenditures or non-recurring cost are influenced by driving factors from both categories while the Operations and maintenance expenditures or recurring cost and the electrical energy generated was just influenced by technology and infrastructure-based driving factors. In contrast, the variable of the discount rate was just influenced by finance and risk-based driving factors. The offshore wind energy sector in the search for more space to construct bigger offshore wind farms at a higher efficiency due to better wind conditions kept on being constructed further from shore. As a result of the increasing distance to shore and the increasing project size, the cost associated with individual offshore wind farms has increased substantially over the last two decades. This increase in cost was exponential due to the additional cost associated with the increase in foundation cost as a function of the water depth, the electrical infrastructure cost as a function of the distance to shore and the technological developments increasing the overall turbine cost by an increase in power size and corresponding turbine dimensions. This research clearly shows how the cost as a function of the substantive variables developed proportional to the supposed revenue increase as a function of those same substantive variables. As offshore wind was introduced it was believed that wind turbine just as their on-shore counterpart were almost maintenance-free. A unexpected amount of maintenance that needed to be conducted as a result of a underestimation in how the harsh weather conditions above the open sea could damage the turbine parts and subsea electrical cables being more frail than anticipated led to the use of inefficient maintenance strategies and an underdeveloped logistics aspect that had to deal with the decrease in accessibility as a function of the increasing distance to shore. These factors resulted in sub-par revenues from offshore wind farms motivated by additional and unexpected downtime which led to lower than expected capacity factors and availability percentages. With the distance to shore steadily increasing the influence on the numerator and denominator of the LCOE formula didn't develop parallel not maintaining a balance within the LCOE formula and thus increasing its value up till 2015. The decrease in the LCOE values after 2015 were initiated by a combination of a decreasing trend in the distance to shore resulting in a better balance between the numerator and denominator of the LCOE formula which was both consequence and cause for a more beneficial financing structure. The introduction of the auction-style process in combination with more beneficial risk assessments and more transparent manners of financing applied led to an EU wide drop in the WACC variable.

Possible future cost reduction possibilities should not be focused on the substantive variables of technology and infrastructure aspect. The offshore wind energy sector will keep on increasing its distance to shore in the search for more efficiency and revenue. The expected additions of floating foundations in the near future in combination with the increasing distance to shore indicates an increase in the LCOE values back to their 2015 values. Countering the downside of this development by having more efficient maintenance, monitoring and logistics strategies that could be adapted into clusters of offshore wind farms is the biggest cost reduction potential on this specific aspect. The financial structure needs to motivate these developments and not identify them as having additional risks. Without a beneficial financial structure and an increase in market competitivity the offshore wind energy sector will never be profitable without extensive subsidies and contingencies.

# Preface

This research has provided me to express my interest in a more sustainable future. It has led to me being able to add more knowledge about the subject of renewable energy and introduce me to the financial and governance aspect of the renewable energy sector and I am grateful for that. First of all, I want to thank Mr. Huibregste for recognizing this interest of mine and to connect and advocate for me in relation to this research and the lectureship of Delta Power. Second, I want to thank Mr. Rentier from the research group Delta Power for his guidance and advice he has provided me with during the writing of this thesis. I hope sincerely that the results of this research both in writing and in the made additions to the database help the research group in the future.

Under chapter 1 the research is introduced by formulating a problem analysis and problem statement. During the chapter, the background and cause for research are provided and described followed by the setting up and operationalization of the key-research question and the connected sub-questions. In the following chapter, the theoretical framework is stated as the 2nd chapter of this research report. In this chapter, the starting point of this research is further established by reviewing what is already known of the driving factors of the LCOE variable and what the LCOE trend of offshore wind looks like. In this chapter, the kind of driving factors will be described helping the researcher gather an understanding of their impact on the variables of the study and providing the researcher with context to the framework of the data analysis. In the next chapter, the research design and methods of research that are going to be used during the research will be given. This gives an overview of the proposed means of data collection and analysis. Chapter 3 furthermore gives insight into the used sources of the data and how this data will be analyzed per sub-question. The chapter is followed by providing the body of the report by stating the results, validation and discussion in chapters 4,5 and 6. The report is finished by providing a conclusion in chapter 7 before giving the used sources in the bibliography and the referred to information, figures and graphs in the different appendices.

The research report is written for students, researchers with presumed prior knowledge and interest in the subject of energy transition and renewable energy sources. The report will show how the LCOE trend of a renewable energy source can be divided into two different aspects and how these two aspects interact and influence each other. It also highlights how the eventual cost and revenues as dependent variables can be quantified by the use of intermediate variables. In case of questions, comments or request the researcher can be approached by using the contact information stated on the page above.

## List of Abbreviations

AEP: Annual Energy Production
AIC: Assembly, installation cost
PDSC: Permits, development and site assessment cost
CAPEX: Capital Expenditure
DECEX: Decommissioning Expenditure
CF: Capacity factor
CfD: Contracts for difference
CSC: Control system cost
CT: Turbine thrust coefficient
DtS: Distance to shore
DNC: Drive train and Nacelle cost
DOB: "De oude bibliotheek"
DOWA: Dutch offshore wind Atlas
EIA: Energy information administration
EIC: Electrical infrastructure cost
EWEA: Europe Wind Energy Association
HVDC: High Voltage direct current
F&R: Finance and Risk
FCC: Foundation capital cost
GT: Grounded theory
GW: Giga watt
LCOE: Levelized cost of Energy
IRENA: International Renewable Energy Agency
ITC: Installation and transportation cost
K: Entrainment constant
KWh: Kilowatt-hour
MA: Marinization
T&I: Technology and Infrastructure
MW: Megawatt
OFTO: Offshore transmission Owners
OPEX: Operational Expenditure
OWF: Offshore wind farm
OWC: Offshore warranty cost
OWE: Offshore wind electricity/energy
PS: Project size
R: Half of rotor diameter
RD: Rotor diameter
RE: Renewable Energy
SBC: Surety bond cost
SPC: Scour protection cost
TD: Technological developments
TC: Transportation cost
TCC: Turbine capital cost
TP: Turbine machine rating
TRC: Rotor cost
TS: Turbine size
TTAIC: Turbine Transportation, assembly and installation cost
TTC: Tower cost
TWh: Terra watt hour
T&I: Technology and Infrastructure
UR: Rated turbine wind speed
VO: Mean location wind speed
VW: Wake wind speed
WD: Water Depth
WACC: Weighted average cost of capital

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# 1. Introduction

The energy transition refers to the global energy sector shifting from fossil-based systems of energy production and consumption to the use of renewable sources like wind and solar. (S&P DOW Jones Indices, 2021) Back in 2015, a legally binding international treaty on climate change was adopted by 196 parties at COP 21 in Paris. (United Nations Climate Change, 2019) This agreement is formally known as the "Paris Agreement" signed by the parties on December 12th, 2015 and entering into force on November 4th of 2016. Its goal was to limit global warming to well below 2 degrees Celsius and preferably 1,5 degree Celsius on an annual basis compared to the "pre-industrial levels". The main driving force behind reaching this goal is severely reducing the amount of greenhouse gas emissions worldwide. The Netherlands as one of the parties involved in the agreement needed to reduce its emissions by 49% by the year 2030 before reducing its emissions by 95% in the year 2050 becoming almost climate neutral by this time. (Government of the Netherlands, 2021) The required actions that needed to be taken were introduced in the National Climate Agreement. The premise of these actions is based on the use and exploitation of renewable sources. The geographical location of the province of Zeeland gives excellent conditions for the use and exploitation of wind and water power as renewable sources.

The research group Delta Power allocated to the HZ University of Applied Sciences is located in the province of Zeeland. This location gives a great opportunity to monitor and contribute to the strengthening of a competitive position for water and wind energy in the Netherlands. (HZ University of Applied Sciences, 2021) The research group mainly performs research regarding innovation in sustainable energy systems particularly within the context of development within delta regions like the Dutch province of Zeeland worldwide. With the global energy transition in mind and the fact that 60% of the global population lives in delta regions like the province of Zeeland the research area is highly topical and drives the focus of the research group to co-develop relevant energy technology related to low carbon emissions. (Delta Power, 2021)

## 1.1 Research motivation

From the start of the energy transition is has been believed that the development of wind power as a renewable source of electricity was vital for reaching the climate goals related to the decarbonization of the energy sector. The conditions beneficial for onshore and offshore wind power development related to the Netherlands are excellent. (Ogg, 2018) Therefore, the Dutch National Climate Agreement also states that "Accelerating offshore wind power besides onshore wind and solar energy" is necessary for reaching the climate goals set for the energy transition. (Climate Agreement, 2019). Because of certain factors like exposure to the population and advantages in possible utilization time, the development of onshore wind power lowered over the years and the potential of offshore wind power grew. (P.E. Morthorst, 2016) The following upscaling in offshore wind capacity contribute to creating the "Green North Sea Powerhouse", aiming at a total EU offshore wind capacity of 230-450 GW[1] by 2050 to decarbonize the energy system and deliver to the goals set by the Paris agreement. Even with this positive development in total capacity, the trends regarding the cost developments of offshore wind around the Netherlands and the total EU has not been as positive.
For most of this decade, the average price of offshore wind energy per MWh[2] expressed in the LCOE[3] variable has risen as a renewable energy source in contrast to other renewables like solar and onshore wind. (IRENA, 2019) Appendix I and Appendix II show how the cost development of offshore wind differs from other renewable energy sources. The fact that the LCOE variable of offshore wind on average only rose since its implementation is an anomaly. Expected was that offshore wind just like any other renewable energy source would adapt to the law of technological maturity or the so-called Wright's law that states that a percental increase in production results in a fixed percentage improvement in production efficiency subsequently resulting in the reduction of production cost. (Ark-Invest, 2019) This adaption usually leads to a reduction in the LCOE as over time with the increase in production efficiency and the reducing cost that accommodate a growing market the price per MWh drops. The LCOE variable is globally used not only as an expression of the cost of electricity production by the use of renewable energy source but also as a market influencer.

[1] GW: Giga Watt
[2] MWh: Mega Watt hour
[3] LCOE: Levelized cost of energy (€/MWh)

Offshore wind farm developers require an accurate way of determining return on investments to attract more investors to the sector. The most common approach is using the LCOE as a function to determine the lifecycle cost relative to the amount of energy produced. (University of Belfast, Letterkenny Institute of technology, 2020) As stated by EIA[4] "For all forms of energy production renewable and not renewable the value of the LCOE is crucial to investment making decisions" (EIA, 2021) It can therefore be stated that the anomalies of the LCOE for offshore wind have at least had some influence in certain projects being cancelled, postponed or reduced in size eventually leading to not the projected amount of capacity being installed. This deviation combined with the increasingly higher goals set by the EU related to the amount of greenhouse gas emissions worldwide puts extra pressure on the energy transition and climate change as a whole. The great potential of offshore wind energy combined with the growing involvement of the province of "Zeeland" and the major role that Sloe area-based companies have in the further development is the main motivation for setting up this research. It is important for the province and the research group to identify what the driving factors of the cost development between 2000-2021 were and what innovations within offshore wind have harmed the progression of the energy transition.

## 1.2 Research Scope

The research is focused primarily on the driving factors behind the LCOE trend of offshore wind energy from the years 2000 to 2021. In this period the most representative data on the development of the driving factors behind the costs of offshore wind energy were generated. The development of offshore wind energy started before the year 2000 namely with a project called Vindeby in Denmark consisting of 11 turbines commissioned by Ørsted in 1991. (Ørsted, 2021) In the next 10 years only a few more offshore wind farms in Denmark, Sweden, The Netherlands and the UK were constructed. With the largest wind farm only producing 40MW[5] these farms can be considered as pilot projects. The political focus was on technical feasibility rather than on comparing the cost with the cost of other renewable energy. (Ørsted, 2021) Because of this statement, it is determined that these wind farms will not give representative data that can contribute to the results and the feasibility of the research results. A total of 12 countries that are a part of the EU including the UK[6] have placed offshore wind farms. In total the connected 5443 offshore wind turbines to the electrical grid having a total capacity of 25GW. (windeurope, 2021) If we purely look at the five biggest contributors, we can determine that they account for 97% of the total turbines connected and for 98,5% of the total capacity. This research is therefore focused on data regarding the offshore wind farms constructed in the UK, Germany, The Netherlands, Denmark and Belgium. One of the newest developments in offshore wind energy is the addition of "floating" offshore wind turbines. Because of the fact that the total capacity of these floating wind turbines at this point is just 24 MW or 0,096% of the total EU capacity and therefore the impact on capacity or cost developments regarding structures and foundations is deemed as minimal "floating" offshore wind falls outside the scope of this research. The LCOE variable has driving factors determining its value over time. This research will focus on the techno-economic driving factors. These are based either on the technology & infrastructure aspect or the finance & risk aspect. Within these two categories, individual trends of data related to specific driving factors will have differing scopes based on their contents. Just the driving factors of the LCOE trend are taken into account none of the market interactions deemed as an output of the LCOE trend or factors influenced by market forces like auction, strike and consumer prices is researched. The use of the LCOE value for financing capital and the influence of the LCOE variable on policy changes regarding the WACC[7] falls within the research scope. The use of the LCOE variable to compare cost developments of renewable energy sources becomes complex when comparisons are made between countries. Differences in policy among countries leads to different contents for the LCOE variable of a specific country. A set scope for the contents of the LCOE creates a demarcation that can be applied when comparing the LCOE values of different countries and thereby helps specify the effect of the driving factors. As the effects of the driving factors are expressed in the cost per KWh or MWh the definition of the CAPEX[8] applied in this research includes everything up to the 1st substation placed by the grid operator of the specific country. For the windfarms connected to the grid in the UK it applies that the operator of the offshore wind farms transfers its assets in the form of electricity to so called OFTO's[9], these assets are traded by so called transitional tenders to these private owned OFTO's.

[4] EIA: Energy information administration
[5] MW: Megawatt
[6] UK: United Kingdom
[7] WACC: Weighted average cost of capital
[8] CAPEX: Capital Expenditure
[9] OFTO: Offshore transmission Owners

This is in contrast to the other EU countries in which just one national government-owned company is the system operator of the entire national electricity transmission from the wind frames to households. (Weston, 2019) Transmission charges now set at 12-15% of the total yearly cost. (Offshore wind programme board, 2016) When levelized this means that the total CAPEX of OWFs[10] placed outside the UK increases with 18-20%. (Voormolen, 2015) The impact of this different approach by the UK are set to be minimal as the connection cost's influence on the total investment is set to be minimal. (Hans Cleijne, TENNET)

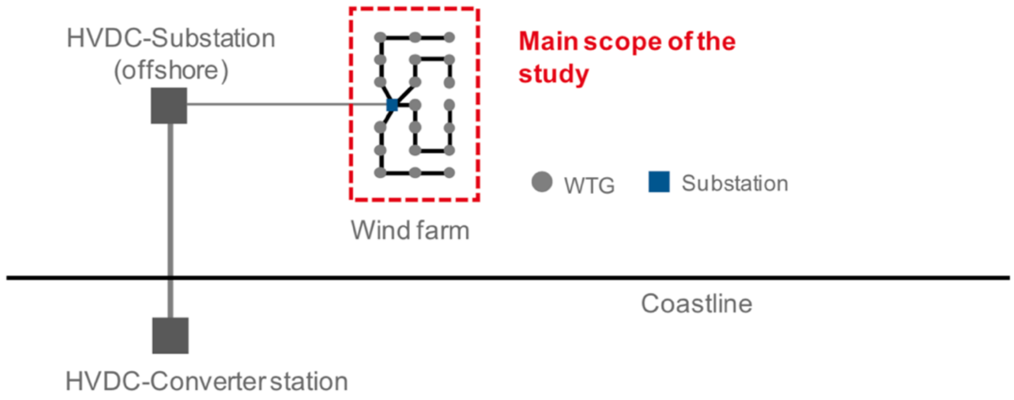


**Figure 1 Main Scope of research following demarcation (German offshore wind energy foundation, 2013)**

## 1.3 Significance

By identifying if T&I[11] based driving factors or F&R[12] based driving factors led to offshore wind not adapting to technological maturity the research group gets a better understanding of the cost development. This better understanding leads to more focused research in the future increasing efficiency and the overall results. Also, it makes it easier for the research group and thus the HZ to contribute or advise companies in the province of Zeeland that play a major part in the planned expansions of current OWFs on the North Sea and the construction of the planned new OWFs. The identification of the main techno-economic factors also has a significance for the future, an explanation of the rise in average levelized cost up to 2015 can help determine if a certain rise can happen again when certain factors are further developed. The rise in LCOE has possibly led to stagnation in the yearly scaling up of the entire offshore wind capacity as stagnation and the rise in LCOE are cause and consequence to each other. As the current climate goals keep rising, an understanding if certain political rulings, market characteristics or technological developments regarding this source of renewable energy have impacted the relative cost negatively is crucial. The outcome of this research could potentially point out flaws in these aspects, understanding these flaws now could lead to a prediction reaching the potential additional capacity of 33.844 TWh[13] now projected for the entire EU. (IEA, 2020)
It is known that policies regarding renewable energy vary heavily between EU countries, even though all countries have an obligation to reach climate goals set by the EU the manner in which they organize, motivate and finance these developments varies. There is still little understanding how these differences influenced the T&I and F&R based driving factors of specific countries and if developments in certain countries had such a negative impact on the LCOE it solely led to the rise of the LCOE variable consequently stagnating the entire sector.

By performing this research by means of the data collection that will be performed the opportunity is there to make additions to an existing OWF database owned by the research group. Owning an own database has significance for the research group because it makes it easier to share data among students and researchers. That same database also enables future automatization of data analysis and collection. This automatization could lead to creation of a digital platform that lets students or researcher access the database and easily take data and trends for the addressed offshore wind farms. It will help students and researchers to more easily construct graphs of certain factors all based upon representative data.

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[10] OWFs: Offshore wind farms
[11] T&I: Technology and Infrastructure
[12] F&R: Finance and Risk
[13] TWh: Terra watt hour

## 1.4 Problem statement

The fact that electricity generated by using offshore wind as a principle only became more expensive per KWh or MWh for most of this decade certainly had a negative impact on the entire energy transition. The rise in €/KWh or €/MWh is consequence, cause and overall inseparable from the fact that goals set by the EU related to total offshore wind capacity weren't achieved. (European Parliament for ITRE Committee, 2017) As the rollout of offshore wind energy was seen as a major contributor to reaching goals set in the Paris agreement by a lot of EU countries the cost development of offshore wind energy can be seen as a problem for accomplishing the energy transition. The objective of this research is a clear conclusion of how certain innovation(s) related to technology, infrastructure, finance and risk contributed to the LCOE trend of offshore wind between 2000-2021. The conclusion leads to provisional statements which factors can be identified as being the driving factors of the LCOE trend of offshore wind and how these factors contributed to the anomalies related to the LCOE trend of offshore wind. The research furthermore creates insight in the potential cost reductions possibilities and the probability of similar anomalies in the future with the further development of certain factors. At this moment it is still unknown how T&I and F&R based driving factors influence each other and to what extend they are influenced by specific country related policy and ruling. Country specific developments could have impacted the overall EU wide LCOE regarding offshore wind heavily. Because the LCOE value also has an impact as a market influencer country specific development could have influenced T&I and F&R based driving factors for other countries. This hypothesis is yet to be researched.

### *1.4.1 Research Intent*

The intent for this research is for the researcher to develop his aptitude and competence on the subject of performing research. By accomplishing this the research itself is structured better and this will enhance the research results besides the researcher accomplishing al the goals set by the institute and the research group.

### *1.4.2 Research objectieve*

The research is meant to create insight into which developments have led to the deviating LCOE trend related to offshore wind. The objective furthermore is that by the ramification into two categories this research will provide a clear conclusion on how both of these aspects of the energy sector have influenced each other. Also, it helps define how country specific developments as a consequence of geographic and policy have had an impact on the LCOE value of offshore wind.

### *1.4.3 Key - Research question*

*"What are the main techno-economic factors driving the LCOE of offshore wind?"*

### *1.4.4 Sub – research questions*

1. *What technology and infrastructure-based factors can be identified as the driving factor of the offshore wind LCOE variable between 2000-2021?*

2. *To what effect have the identified technology and infrastructure-based driving factors determined the LCOE trend and its anomalies and the overall non-adaption of offshore wind to wright's law?*

3. *What finance and risk-based driving factors can be identified as the driving factor of the offshore wind LCOE variable between 2000-2021?*

4. *To what effect have the identified finance and risk-based driving factors determined the LCOE trend and its anomalies and the overall non-adaption of offshore wind to wright's law?*

5. *What are the possible cost reductions and LCOE values regarding offshore wind energy from 2021-2050?*

    5.1. *What developments based on the technology and infrastructure aspect could contribute the most to future cost reduction of offshore wind?*
    5.2. *What developments based on the finance and risk-based aspect could impact future cost reductions of offshore wind the most?*

## 2. Theoretical background

The LCOE can be referred to as levelized cost of energy or levelized cost of electricity, it is globally applied when comparing cost for the use of different technologies regarding renewable energy sources but is also used when determining price trends of electricity or energy and calculating the viability of an energy or electricity producing technology. (University of Belfast, Letterkenny Institute of technology, 2020)
The LCOE variable applied to offshore wind energy can be defined by the following equation:

$$\mathrm{LCOE} = \frac{\text{Sum of cost over lifetime}}{\text{Sum of electrical energy produced over lifetime}} = \frac{\sum_{t=1}^{n} \frac{I_t + M_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \tag{1}$$

*With*:
$I_t = Investement\ expenditures\ in\ the\ year\ t$
$M_t = Operations\ and\ maintenance\ expenditures\ in\ the\ year\ t$
$E_t = Electrical\ energy\ generated\ in\ the\ year\ t$
$r = Discount\ rate$
$n = Expected\ lifetime\ of\ system\ or\ power\ station$
$t = Individual\ year\ of\ lifetime$

(eia U. S. Energy Information, 2020)

The results of the above standing equation can be given as a currency/KWh or MWh. The *sum of cost over lifetime* can be defined as containing non-recurring cost and recurring cost. It can be stated that the non-recurring cost can be defined as the *investment expenditures* variable in Eq. (1). The non-recurring cost are can be outlined as the CAPEX and DECEX[14] cost. The recurring cost on the other hand can be defined as the *operations and maintenance expenditures* variable in Eq. (1). These are well less defined then the non-recurring cost but are established to attribute 25-30% of the total offshore wind farm lifecycle cost. (P.E. Morthorst, 2016) This variable can be outlined as the OPEX[15] cost.
This *sum of cost over lifetime* is divided by the *Sum of electrical energy produced over lifetime,* this sum of electrical energy produced is dependent on different factors driving the technological developments. The lifetime factor or the variable *n* is set during the development stage and for most offshore wind farms is set at 25-30 years of production before decommissioning. (P.E. Morthorst, 2016) The *Sum of electrical energy produced over lifetime* is expressed as a total electricity produced in KWh or MWh from the initial *year 0* to the end of life *n*. (University of Belfast, Letterkenny Institute of technology, 2020)

The final variable in Eq. (2) is the *discount rate* or *r.* The discount rate can also be expressed as the WACC. The WACC in particular applies to capital-intensive technologies such as offshore wind power. The cost of capital or capital expenditures strongly affects energy production cost, the WACC discounts the annual operating cost and electricity generation thus providing the real calculatory financing rate. (Prognos AG & The Fichter Group, 2013).
The cost of capital over a project duration is estimated by using the following equation:

$$\mathrm{WACC} = \frac{E}{E+D} * R_E + \frac{D}{E+D} * R_D * (1-T) \tag{2}$$

*With*:
$E = Market\ value\ of\ Equity$
$D = Market\ value\ of\ Debt$
$R_E = Required\ rate\ of\ return\ on\ equity$
$R_D = Cost\ of\ debt$
$T = Applicable\ tax\ rate$

(German offshore wind energy foundation, 2013)

[14] DECEX: Decommissioning Expenditure
[15] OPEX: Operational Expenditure

## 2.1 Market interactions of the LCOE variable

Qualitative research preformed has led to the following qualitative overview of the market interactions surround the offshore wind energy and its LCOE. Figure 2 divides the driving factors of the LCOE variable in 2 separate categories namely: technological & infrastructure based and based on financing and risk aspect and shows the previously mentioned market influencing nature of the LCOE variable.

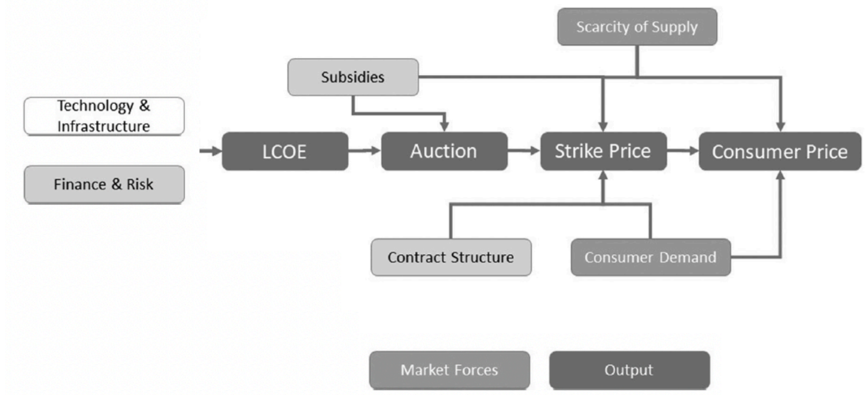



**Figure 2 Qualitative overview market interactions (University of Belfast, Letterkenny Institute of technology, 2021)**

## 2.2 The LCOE trend of offshore wind energy

Prior to the year 2000 determinations regarding the LCOE are not viable for this research as the LCOE variable tended to be very inconsistent due to the small number of projects and the major difference in installation and construction methods. From roughly the year 2000 we can review literature cohesive with the LCOE trend of offshore wind because of a rise in added capacity and made investments. On average between 2000-2015 the LCOE rose, while considering Wright's law[16] this is the first anomaly. The second anomaly is the price of electricity produced by offshore wind farms rising between 2012 and 2015 from 154 €/MWh to 183 €/MWh before dropping to 115 €/MWh in 2019. (Michael Taylor, 9 Juni 2020) Collection of data lead to the LCOE values of 86 offshore wind farms within the scope of this research. Figure 3 shows an own visualization of these data entry's and the consequencing LCOE trendline. The trendline indicates the before mentioned anomalies and confirms the consensus made in Appendix I and Appendix II. LCOE values shown as the blue data entries were estimated by N. Gomez based on stated project costs and revenues, calculations are based on data provided by 4C offshore. Information overview regarding used data points is shown in Appendix III.

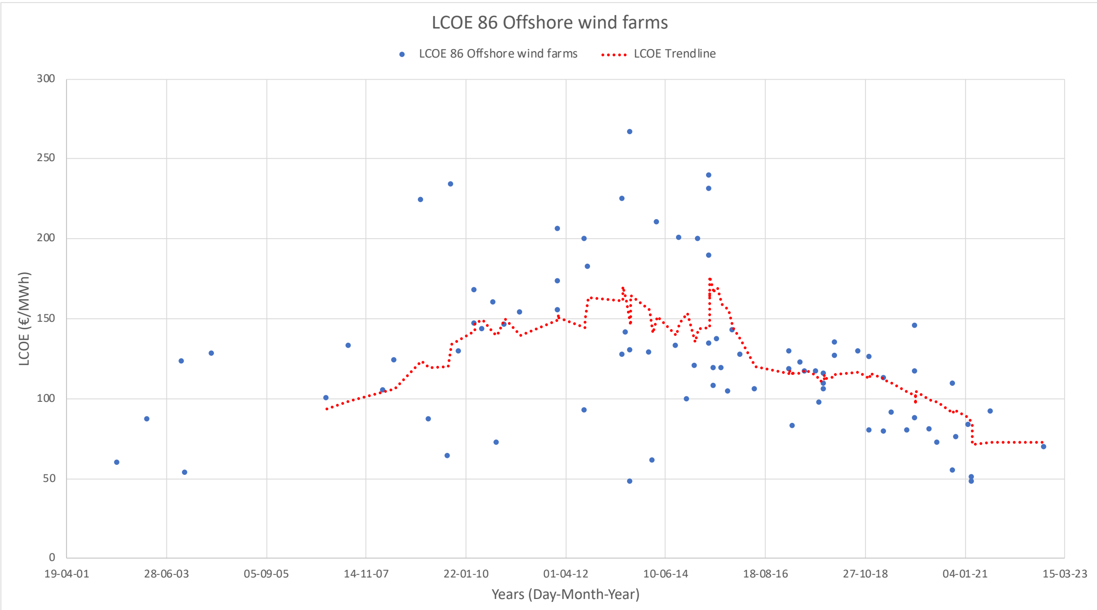



**Figure 3 LCOE trendline 2000-2021 (Own figure,2021 based on data 4Coffshore, Appendix III)**

[16] Wright's law: Progress increases with experience, Percental increase in production results in fixed percentage improvement in production efficiency subsequently resulting in reduction of production cost. (Ark-Invest, 2019)

## 2.3 Technology and infrastructure-based driving factors

The 3 variables of the LCOE that are influenced by driving factors based on the technology and infrastructure aspect (T&I) can defined as the non-recurring cost or $I_t$, the recurring cost or $M_t$ and the technological developments/ electrical energy generated or $E_t$. Each of the variables is influenced positively or negatively by certain T&I based driving factors. In the figure below the influence on the variables by 3 key developments in offshore wind between 2000-2021 is shown. As the $I_t$ and $M_t$ variables are placed in the numerator of the LCOE formula when they are negatively influenced, they rise in value. In contrast the $E_t$ variable as part of the denominator of the LCOE formula rises when influenced positively.

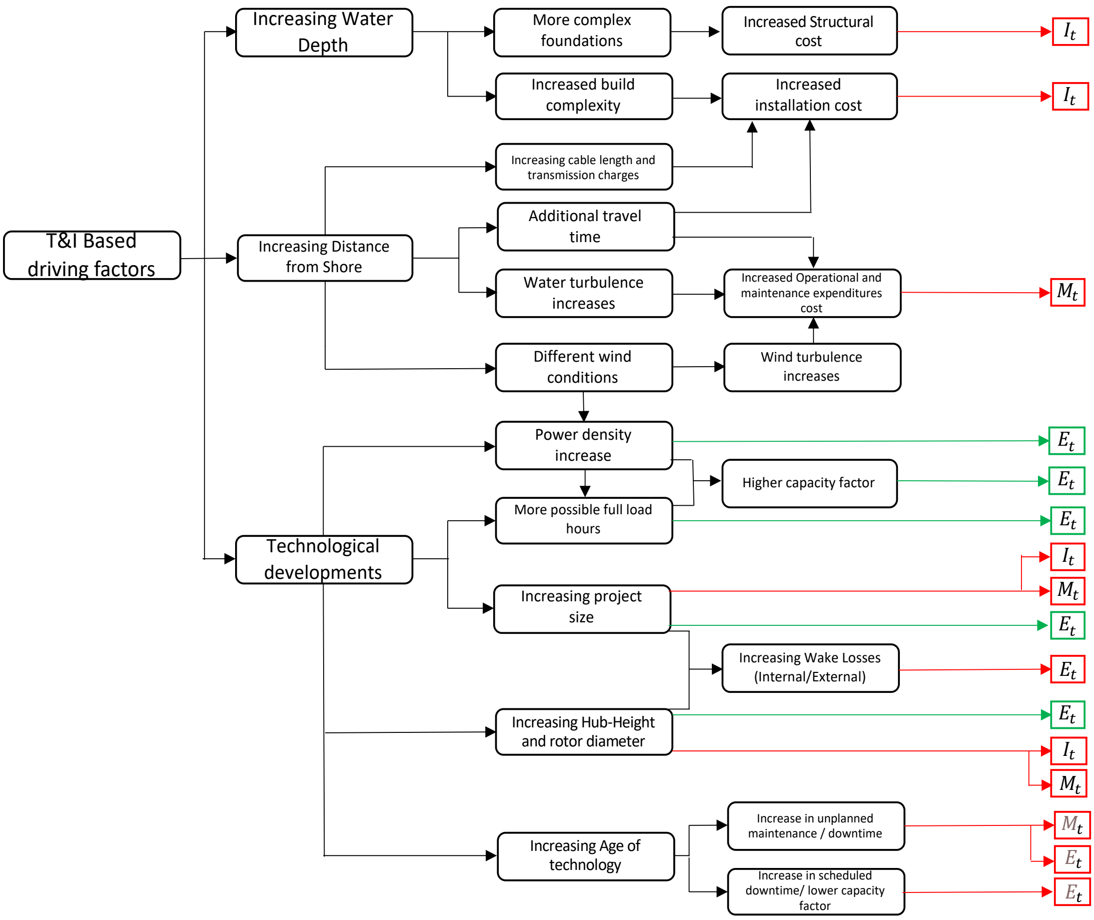



**Figure 4 Effect T&I based driving factors on the variables. (Red-> influenced negatively, Green-> influenced positively) (Own figure 2021, Based on quantitative research.)**

### 2.3.1 Non-recurring cost

The non-recurring cost or initial investment make up to about 70-80% of the total cost for an offshore wind farm as a renewable electricity source. (EWEA The economics of Wind Energy, 2009) The initial investments are not made up just from not just cost for materials, equipment, installation etc. A big part of this 70-80% roughly 35-40% is made from the cost associated with freeing up capital to invest and other economic factors regarding the financing and creating capital to invest. These costs are sometimes referred to as plain capital cost. (PWC, 2020) The non-recurring cost encompasses all cost related to the development of an offshore wind site. This includes feasibility and planning, certification and approval cost, project contingencies and provision cost related to the decommissioning or repowering. When the plain capital cost is put aside the international Renewable Energy Association or IRENA[17] has identified the five primary drivers of the remaining 35-40% as technology and installation cost. The wind turbine itself accounts for 44% of the non-recurring technological and installation-related cost. Cost for the turbine supply relay on rotor diameter and hub height in combination with technological developments to the nacelle. Besides the 44% allocated to the wind turbine cost also 37% of the technology cost and installation cost are allocated to the used foundation and the installation of these foundations and the adjunct turbines. (IRENA, 2016)

[17] IRENA: International Renewable Energy Association

The two main principles of foundation used are monopile and jacket foundations. These cost for foundations and instalment and the choice of foundation heavily rely on the used water depth and the kind of bedding of the sea. (Iberdrola, 2021) 16% of the non-recurring cost are cost associated to the cabling and transmission of electricity. (De oude Bibliotheek Academy, 2018) Most of the cabling and transmission cost are made with the connection from the wind farm substation to the separate offshore HVDC[18] transformer station and onshore HVDC convert station. The installation cost are considered as separate assumption that has to be made regarding the development of the investment cost. The single largest cost item is rental cost for the special ships that are required during different phases of the installation process. (German offshore wind energy foundation, 2013) Just as for the technology cost also for the installation and operation cost many of the same factors apply. When the distance to shore and water depth increases, besides the cost for larger foundations also so the installation cost will rise as the ships have to be rented for a longer time a maybe need adjusting to being able to transport larger foundations and turbines. As stated by P.E. Morthorst is that the construction of larger and faster ships besides the adoption of new installation processes could lead to a reduction of 5% on the total investment cost. (P.E. Morthorst, 2016) Some of the other cost that are also accounted for in the non-recurring cost are related to explosive ordnance clearance, Scour protection and environmental monitoring.

### *2.3.2 Recurring cost*

A wind farms has to be regularly maintained in order to be able to generate power efficiently over the expected lifetime of the system. Operation and maintenance cost (O&M) account for 25% of the total cost in M€/MW. (De oude Bibliotheek Academy, 2018) This percentage is deemed variable within the lifetime of the windfarm, it accounts for 20-25% of the LCOE when the turbine is new and 30-35% of the LCOE when the turbine is older. (P.E. Morthorst, 2016) It is stated that O&M cost have little impact as a driving factor for the LCOE for the fact that their share has remained almost constant from 2000-2021. (Voormolen, 2015) O&M cost increased in value, but that rise was countered by the increasing amount of electrical energy produced. There are operation and maintenance cost expenses allocated to the plain capital cost such as unplanned cost coming from downtime. In spite of all the regular planned maintenance and constant monitoring components may fail and these failures causes additional unplanned cost and so-called downtime of the system. (German offshore wind energy foundation, 2013) The overall downtime of offshore wind turbines consists of scheduled and unscheduled downtime. Scheduled downtime originated from choices in development and the freeing up of capital based on the projected capacity factor. Unscheduled downtime originates from unplanned maintenance impacting the potential full-load hours and the capacity factor. This unplanned downtime rises in the early years of the life cycle (<1 year of production) before stagnating during the useful years of production just before rising again in the so-called wear-out period. (>15 years of production). (De oude Bibliotheek Academy, 2018)

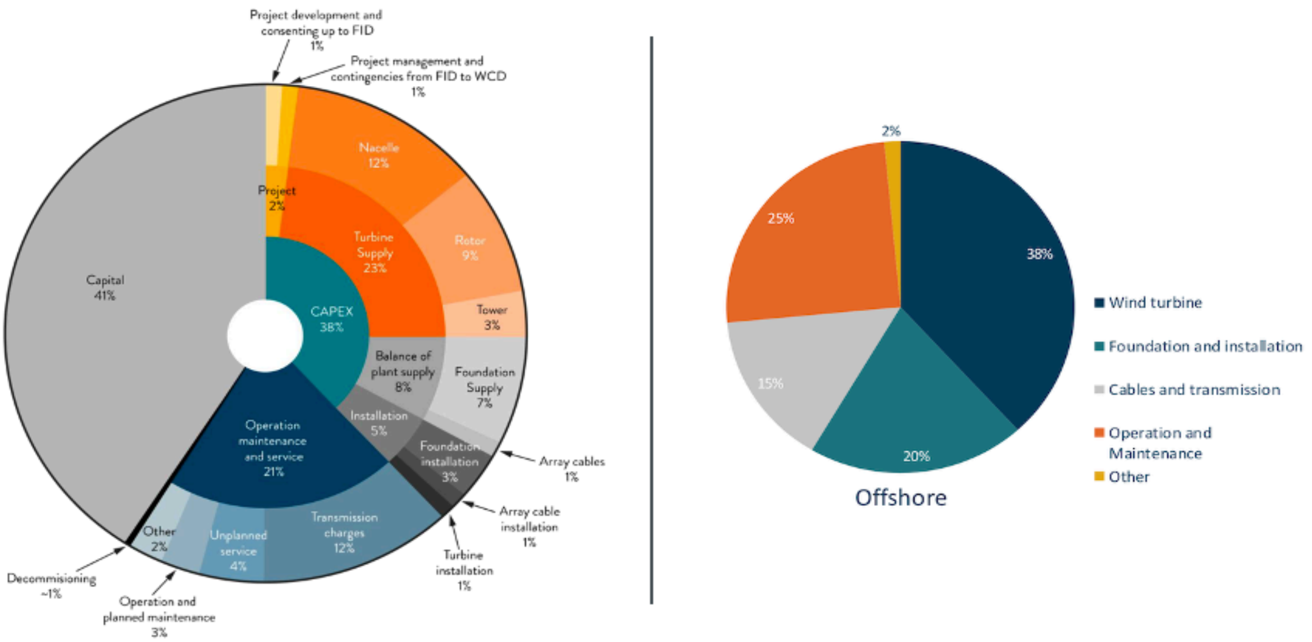



**Figure 5 Cost breakdown Numerator LCOE (L), Cost breakdown Recurring and non-Recurring cost (R) (De oude Bibliotheek Academy, 2018)**

[18] HVDC: High Voltage direct current

### 2.3.3 Technological developments

Technological maturity generally leads to lowering the non-recurring and recurring cost over time. In offshore wind production this is only deemed to be likely for some cost elements. (University of Belfast, Letterkenny Institute of technology, 2020) Technological developments and the hours of electricity production on yearly basis are the main driving factors behind impacting the $E_t$ variable or average gross and net electricity yield. The variable refers to the amount of electrical energy generated by one wind turbine or the entire wind farm per unit of time, usually given per year. Technological developments are driven by factors like; project size, rotor diameter, hub height, bigger drives and more technological and geographical factors like water depth and distance to shore. When turbines get larger and placed further from shore, they are able to access more stable wind flow, therefore the average gross and net electricity yield is benefited by technological developments as it is calculated based on empirical wind data. (University of Belfast, Letterkenny Institute of technology, 2020) Firstly, technological developments impact the overall site cost. It is stated that when technological developments lead to a rise of the $E_t$ variable the technological developments also lead to a rise in the site cost. (German offshore wind energy foundation, 2013) Furthermore, the technological developments have an impact on the $E_t$ variable itself. It is determined that the rise of the $E_t$ variable also leads to a rise in the power density and wake losses as a driving factor of the LCOE variable. The power density is defined in the unit $MW/km^2$ and gives the amount of electricity produced per area of the wind farm. Power density is used when determining the plain capital cost. (German offshore wind energy foundation, 2013) Wake losses make it so that when a single turbine extracts energy from the wind downstream there is a wake from the wind turbine in which the wind speed is reduced. The wake effect is essentially the aggregated influence on the energy production of the wind farm. The dropping of the wind speeds impacts the production rate of the entire wind farm. (F. Gonzalez-Longatt, 2012) The number of hours that electricity is produced is driven by the availability. The actual availability of offshore wind energy is set at between the 70-95%. (German offshore wind energy foundation, 2013) The availability is based upon wind conditions and planned and unplanned maintenance or summed up as downtime. When set out against the generated electricity it gives the capacity factor.

## 2.4 Finance and risk-based driving factors

35-40% of the non-recurring cost or $I_t$ are linked to freeing up of capital to invest and other economic factors regarding the financing and creating capital to invest. (PWC, 2020) This means that these plain capital costs are driven by factors based on finance and risk. Furthermore, the cost of money or variable *r* in Eq. (2) is driven by factors based upon finance and risk. The figure below visualizes the effects of certain F&R based driving factors. No concrete positive or negative influence is given as there is no clear pattern known.

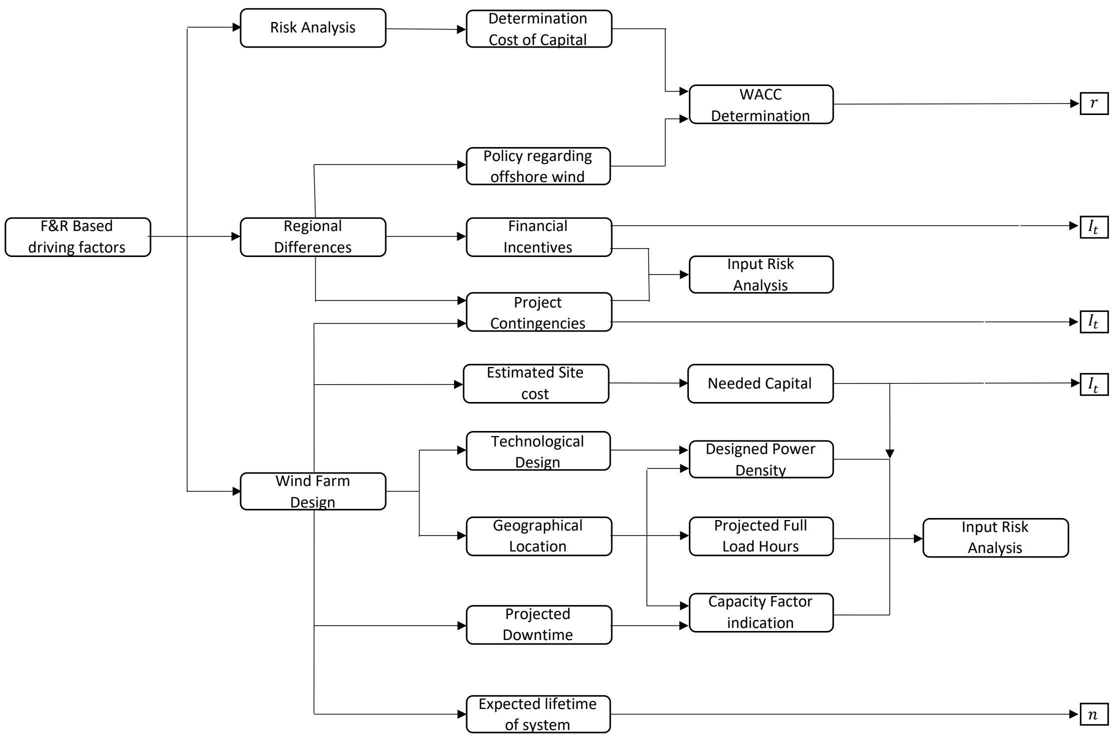



**Figure 6 Effect F&R based driving factors on the variables. (Own figure,2021 Based on quantitative research.)**

### 2.4.1 Plain Capital cost

The finance and risk-based driving factor help determine the plain capital cost. These plain capital costs differ in contents and value by regional differences that are often informed by geographical features, regulatory framework and ownership of seabeds. Because of these regional differences, some of the factors driving the plain capital cost create artificial regional variances in the LCOE values. (University of Belfast, Letterkenny Institute of technology, 2020) As visualized in figure 2 factors behind the plain capital cost like contract structures and subsidies are not deemed as driving factors behind the LCOE trend. Contract structures, subsidies but also factors like projected full-load hours and the capacity factor of offshore wind farms contribute and help determine the amount of plain capital cost. Factors like the capacity factor and projected full-load hours are initially primarily driven by the wheater conditions and downtime but over the total lifetime of the windfarm it is mostly an economic decision driven by the windfarm developer's trade-offs between the *sum of cost over lifetime* and the *Sum of electrical energy produced over lifetime*. (Energy Numbers, 2014) Because economic decisions are primarily based on market forces they are not deemed as a driving factor of the LCOE trend.

The site costs are deemed as a driving factor of the LCOE as it can be defined as the *sum of cost over lifetime* in Eq. (1). It contains the non-recurring cost and recurring cost of the wind farm. The site costs are established during development to help clear the finances and create the necessary capital. (University of Belfast, Letterkenny Institute of technology, 2020) However, the amount of site costs is determined by technology and infrastructure-based driving factors having their influence on the CAPEX and OPEX cost.

### 2.4.2 Cost of Money

In contrast to the site cost, the cost of money does have its own development over time. The cost of capital or cost of money is expressed as the discount rate or WACC and it strongly affects energy production cost, the WACC discounts the annual operating cost and electricity produced. All variables linked to the LCOE trend are impacted by the *discount rate* or *r*. The construction of offshore wind farms requires large amounts of equity. The risks related to the offshore wind projects are deemed higher than those for other investment projects like mature on-shore wind energy. These potential risk result in a higher requested rate of return. Factors like general economic welfare, technological related risks and policy risks affect the WACC. (PWC, 2020) Nearly half of the LCOE for completed projects is directly attributable to the CAPEX investment needed. Half of these CAPEX investments are attributed to project financing cost as "plain capital cost". This reflects how high capital-intensive offshore wind projects are, impacting the 41% capital cost can be done by impacting the discount rate or WACC. Improving the financial terms can significantly reduce the LCOE variable when for instance applying a 4% WACC the LCOE can drop by as much as 30% in advanced economies to which this research applies. (International Energy Agency, 2019)

### 2.4.3 Financial Incentives and project contingencies

Financial incentives are also seen as a driving factor for the LCOE variable as they provide funding and thereby a degree of security for the sector of offshore wind energy. Incentives can impact the financial conditions of renewable energy sources. This impact can lead to a substantial reduction in the realized cost of these wind farms. When the realized cost drop, in a sense that the site costs mentioned earlier are lower than expected when capital was financed the LCOE is impacted heavily. (Eia U.S. Energy Information Administration, 2021) Because the incentives have changed in the 2000-2021 scope by political and market related forces their impact is seen as a driving factor for the LCOE variable.

The technology and installation cost of a wind farm are usually fixed by contract and can be therefore planned ahead of construction. To cover unplanned issues like delays in installation because of weather or delays because of new turbine types being introduced certain provisions have to be made. (PWC, 2020)It is stated that these provisions can make up to 15% of the total investment cost. It has also been determined that over time by the commissioning of deemed successful projects these set provisions for new projects were reduced to making up 10% of the total investment cost. (German offshore wind energy foundation, 2013)

## 3. Research design & method

Especially in the early years of this century with the rapid rise of offshore wind energy as a renewable source of energy, their were a lot of studies and publications about offshore wind energy. Besides these countless studies as a source of data the more representative data is usually summed up in databases or so-called "wind atlas". These databases are usually set up by institutes or companies focused or somehow connected to this sector of renewable energy. The sources of data collection can be split up into primary data and secondary data. During this research, the majority of sources of data can be described as secondary data. This data in writing or raw data formatted in a database is either provided directly or indirectly by the organizations of the research group or via external credible sources. These external sources used preferably have backing from either government agency themselves or institutes connected to a government agency like IRENA. Furthermore, study's and sources of data affiliated with EWEA[19], the DOWA[20] or DOE[21] are be primarily used. The data relating to the substantive variables' development are collected to fit the applicability required to quantify the cost development by use of the so-called intermediate variables. The adaptation of the data collected therefore leads to differing demarcations within the already stated scope of this research. The intermediate variables help quantify how the development of substantive variables within the scope of this research impacted the dependent variables. The dependent variables therefore will be based on estimates as the used method or formula used for the intermediate variables is an approximation of quantifying the substantive variable's development.

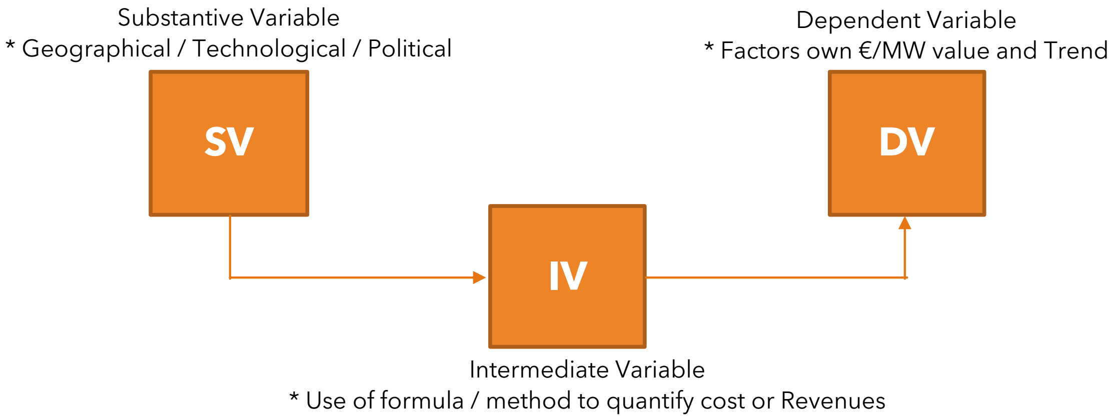



**Figure 7 Used methodology per driving factor (Own figure, 2021)**

### 3.1 Substantive variables data collection

The collection of data on the substantive variables is the basis of both methods of data analysis used. The data collection has focused on the substantive variables, these variables are set independent variables or factors. These independent variables have been collected to suit the needs of the method or formula used to quantify the development of the dependent variables by use of the intermediate variables. The substantive variables data collected originates from data presented by institutes related to offshore wind itself or other credible sources. The data itself is set out against the name of the offshore wind farm, date of commissioning and/or the country of placement. These set factors help cross-referencing data from different sources and the results of this cross-referencing supports the made additions to the existing database. The amount of data that was able to be collected determined the eventual applicability of the used method or formula and linear to this the eventual credibility of the used method on the eventual results. As the database present covers 184 OWF's within the scope of this research with commissioning dates ranging from the year 2000 to the year 2031 some substantive variables have lower coverage percentages as just the geographical location and planned commissioning date is known. An overview of the substantive variables used in this research is provided in appendix V while an overview of the coverage percentages of the substantive variables is shown in table 1.

[19] EWEA: Europe Wind Energy Association
[20] DOWA: Dutch offshore wind Atlas
[21] DOB: "De oude bibliotheek"

Table 1 Coverage percentages after data collection substantive variables (Own figure, 2021)

| Substantive variable | Coverage percentages | Notes |
|---|---|---|
| Water depth (m) | 98,9% | |
| Distance to shore (km) | 98,9% | |
| Wind speeds on location (m/s) | 93,5% | |
| Designed wind power density OWF (W/m2) | 76,6% | |
| Used foundation principle | 85,3% | * Includes combined foundation use |
| Turbine manufacturer | 90,2% | |
| Turbine type | 89,1% | |
| Turbine power (MW) | 89,1% | |
| Rated turbine wind speeds (m/s) | 75,6% | |
| Gearbox type | 85,9% | |
| Generator type | 79,9% | |
| Rotor diameter (m) | 85,9% | |
| Rotor power density (W/m2) | 89,1% | |
| Hub height (m) | 90,8% | * Includes site specific height |
| Number of turbines in OWF | 95,7% | |
| Total project size (MW) | 100% | * Includes scheduled project size |
| Stated average capacity factor (%) | 73,9% | |
| Stated average AEP per year (GWh) | 60,9% | |
| Applied WACC (%) | 67,4% | |
| Designed lifetime (yr) | 70,1% | |

## 3.2 Qualitative data analysis

The setting up of the theoretical framework has already contributed to the identifying of patterns and connections between certain variables. These patterns and connections contribute to the analyzing by means content analysis and the grounded theory analysis.(humans of data, 2018) The content analysis is used to analyze documented information mainly based on the content of the research question(s). (humans of data, 2018) The GT[22] analysis sets up the systematic inductive methods used for conducting qualitative research towards theory development. (SAGE Encyclopedia of science research methods, 2009) The method refers to using this method of data analysis to explain why certain patterns happen. The qualitative data analysis is mostly utilized when factors or patterns need elucidation and no quantitative data is present to support statements that are being made. The qualitative data analysis is present when researching the F&R based driving factors and certain T&I based driving factors as their development can't be expressed in data entries related to a specific OWF but rather scope wide observations and statements made in supporting literature.

## 3.3 Quantitative data analysis

The main focus of the quantitative part of the data analysis is the adaptation of trend analysis.
Trend analysis is defined as a statistical analysis method that provides the researcher with the ability to look at quantitative data collected over a longer period of time. (Streefkerk, 2020) This method helps collect feedback about data changes over time and aims for the researcher to be able to identify and understand the change in the LCOE variable. The trend analysis is based on key figures; this entails the analysis of average values taken from the intermediate or dependent variables. Using the average value over certain sets of data helps identify the trends and thus overall development of the intermediate and dependent variables over a standard set period of time. The period to which the data in the figures is set out against is depended on the overall coverage of the used methods and formulas in this entire research. In every figure, the average is taken over a set amount of data points determined by the amount of data present within the set period of time. This method of identifying the trend is partly based upon statistical correlation coefficient calculations.

[22] GT: Grounded theory

It's been adapted in every aspect of the results with means to visualize individual trends and the correlation between two set variables that eventually have been linked to the LCOE trend. Standard linear correlations between variables have not been adapted as the results are harder to link to the known anomalies of the LCOE trend.

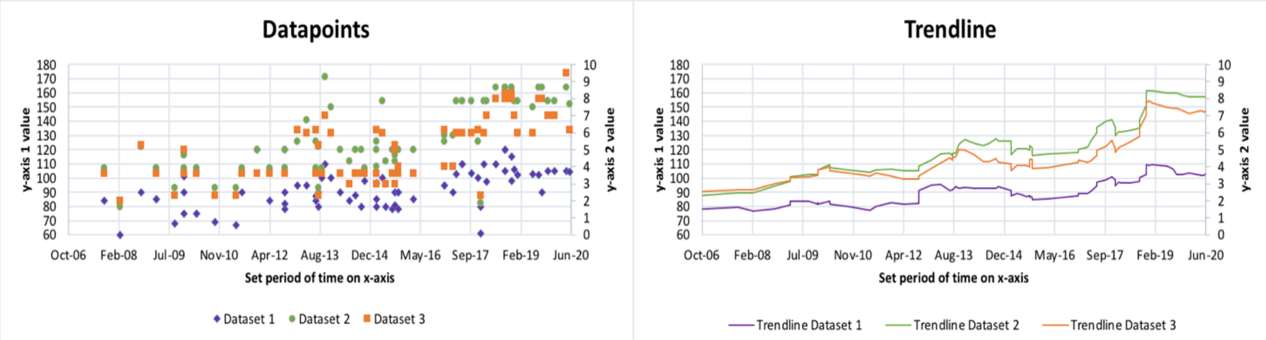



**Figure 8 Visual conversion datapoints into trendline (Own figure,2021)**

### 3.3.1 Intermediate variables

The methodology used incorporates the use of intermediate variables. The intermediate variables quantify the developments of the substantive variables into the estimated value of a specific cost or revenue aspect. The intermediate variables will be defined as the specific individual cost or revenue estimation of a single turbine. Before with taken project size/ number of turbines and turbine power size into account determines the eventual €/MW cost and revenue estimations, which are deemed as dependent variables. The driving factors that have been analyzed have differencing scopes and applicability. These are based on limitations when using a certain method for calculating the values. By generalizing the data within the scope set by the limitations of the intermediate variable's methods used the premise is that developments within the scope with a sufficient coverage percentage and the resulting development of the factor are deemed as credible. Validation between certain methods for calculations are based on the resemblances in characteristics in the trend and not necessarily the value. Intermediate variables are the results of the used equations in this research and their trend helps reason and visualize the driving factors of the overall cost and revenue trends. The intermediate variables will eventually provide answers to research questions 1 and 3.

**Table 2 Overview methodology Intermediate variables (Own figure,2021)**

| Intermediate variable | Source of method | Used in Equation | Shown in figure | Coverage Percentages | Notes on limitations |
|---|---|---|---|---|---|
| Individual FCC | (Center for Sustainable systems University of Michigan, 2014) | 3,4,5 | 11 | 85,3% | * No combined foundations/ No WD specified |
| Individual EIC | (Center for Sustainable systems University of Michigan, 2014) | 6 | 14 | 88,0% | * No mass calculation values/ No DtS specified |
| Individual TCC | (National Renewable Energy Laboratory, 2006) | 10 | 23 | 59,2% | * No mass calculation values |
| Individual TTAIC | (National Renewable Energy Laboratory, 2006) | 11 | 26 | 63,0% | * No mass calculation values |
| Individual Hub mass | (National Renewable Energy Laboratory, 2006) | Appendix XI | - | 59,2% | * No Site-specific height |
| Individual Nose cone mass | (National Renewable Energy Laboratory, 2006) | Appendix XI | - | 59,2% | * No machine rating specified |
| Individual Bearing mass | (National Renewable Energy Laboratory, 2006) | Appendix XI | - | 59,2% | * No machine rating specified |
| Individual Tower mass | (National Renewable Energy Laboratory, 2006) | Appendix XI | - | 59,2% | * No machine rating specified |
| Individual Single blade mass | (National Renewable Energy Laboratory, 2006) | Appendix XI | - | 59,2% | * No machine rating specified |
| Individual Swept area | (Make, 2014) | 9 | - | 85,9% | * No rotor diameter specified |
| Individual AEP | (Jensen, 2001) | 7/8 | 15 | 80,4%/71,2% | * eq. 7/8 factors not specified |
| Project O&M | (National Renewable Energy Laboratory, 2006)/ (IRENA, 2016) | 14/15 | 31 | 59,7% | * No Stated AEP specified |
| OWF Wake losses | (Norwegian University of Science and Technology, 2018) | 16 | 33 | 79,3% | * No Location wind speed specified |

### 3.3.2 Depended variables

To compare the impact of certain driving factors that have been analyzed all quantitative data is analyzed till an increase or decrease in the €/MW of a certain driving factor seen as a dependent variables for offshore wind is known. Besides the intermediate variables also the dependent variables will be analyzed quantitatively. The T&I based dependent variables will be expressed as either the €/MW cost development or the variables that are used as input for the eventual LCOE values calculation are expressed. The dependent variables are seen as a direct link to the LCOE value and trend. When the cost and revenues estimations are expressed in the €/MW unit their percentual increase in combination with the average value are the basis for the made comparison between each of the driving factors. Also, set deviations in the €/MW trend of a specific aspect can show resemblance to deviations in the LCOE trend. This can lead to an additional motivation of certain factors or aspects be the definitive driving factors. The dependent variables are furthermore used as the basis for the validation in section 5. For each of these driving factors appendix IV shows how they have been analyzed. Their initial scopes are given, and for the trend analysis, the alignment of the data is provided per driving factor. The dependent variables will eventually provide answers for the research question 2,4 and 5.

**Table 3 Overview methodology depended variables (Own figure,2021)**

| Depended variable | Source of method | Used in Equation | Shown in figure | Coverage Percentages | Notes on limitations |
|---|---|---|---|---|---|
| €/MW FCC | (Center for Sustainable systems University of Michigan, 2014) | 3,4,5 | 12 | 85,3% | * No combined foundations/ No WD specified |
| €/MW EIC | (Center for Sustainable systems University of Michigan, 2014) | 6 | - | 88,0% | * No mass calculation values/ No DtS specified |
| €/MW TCC | (National Renewable Energy Laboratory, 2006) | 10 | 25 | 59,2% | * No mass calculation values |
| €/MW TTAIC | (National Renewable Energy Laboratory, 2006) | 11 | 26 | 63,0% | * No mass calculation values |
| Project CAPEX | - | 13 | 30 | 56,5% | * Standard FCC used, no machine rating specified |
| Adjusted project CAPEX | - | - | - | 46,2% | * FCC is specified, no machine rating specified |
| Project OPEX | - | - | - | 46,2% | * No Stated AEP specified |
| Sum of cost over lifetime | - | - | - | 53,8% | * Not all CAPEX factors specified |
| Sum of electrical energy produced | - | - | - | 53,8% | * No Stated AEP specified |
| Windspeeds at hub height | (The swiss wind power data website, 2021) | 12 | 27 | 76,7% | * No hub height specified |
| Estimated AEP | (Jensen, 2001) | 7 | - | 80,4% | * No location wind speed, number of turbines, swept area specified |
| Estimated AEP | (Jensen, 2001) | 8 | - | 71,2% | * No CF, number of turbines, turbine power rating specified |
| Applied WACC | - | - | 35 | 67,4% | - |
| Designed lifetime | - | - | - | 70,1% | - |
| Estimated LCOE with standard depended variables | (eia U. S. Energy Information, 2020) | 1 | Appendix XIX, XX | 46,2% | - |
| Estimated LCOE with adjusted CAPEX | (eia U. S. Energy Information, 2020) | 1 | Appendix XIX, XX | 46,2% | - |

Table 3 shows that for eventually 46,2% of the initial scope all assets were able to be estimated with the used methodology. For this percentage of the scope all values with the used methods and formulas adapted by the use of the intermediate variables could be estimated.

## 4. Results

This section will highlight the results of the performed data analysis. The data analysis performed on the grounds of own data collection and data present in the existing OWF database provides a response to what substantive variables can be identified as being the main techno-economic driving factors of the LCOE of offshore wind. The results section is divided into WD, DtS, TD and PS as driving factors from the T&I aspects and the WACC as the sole driving factor from the F&R aspects. Per aspect the development of each relevant substantive variable will be provided after which the development of this particular factor is used to quantify its impact by describing the cost or revenues in the unit of €/MW over time.

### 4.1 Water Depth as a T&I Based driving factors

As is visualized in figure 9 the WD is identified as a T&I based driving factor for the foundation cost of OWF's. The WD has a significant impact on the construction and installation cost of offshore wind projects, the depth has that significant impact as greater water depths require more complex foundation principles that result in higher cost. (Marine Science and Engineering, 2016)

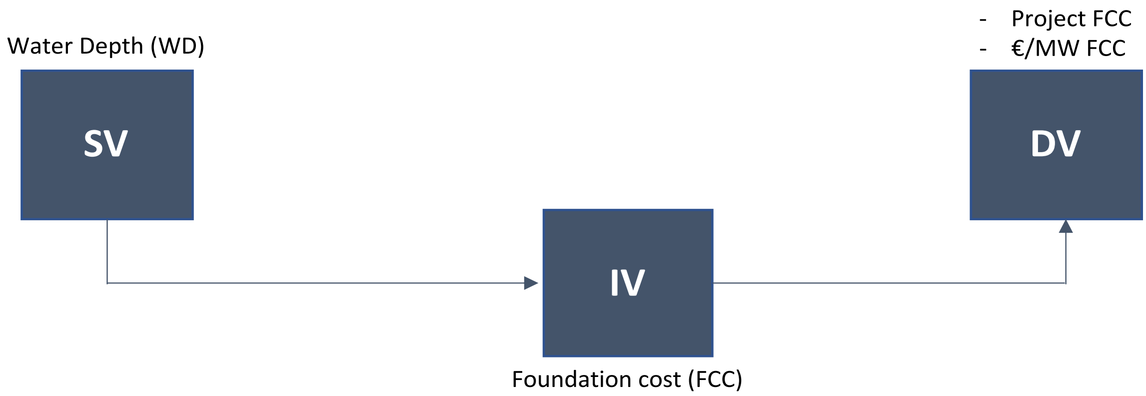



**Figure 9 Methodology Water Depth analysis (Own figure, 2021)**

The WD itself is mainly dependent on the DtS for a specific OWF. As one moves further from shore on average the WD also increases, as the OWE sector seeks for better wind conditions to boost annual production and the opportunity to build more turbines per OWF creating bigger wind farms the DtS has increased. Further from shore the wind conditions and available space for construction greatly improve. As a result of this development, the average WD in which OWF's are being constructed has also increased. Based on trend analysis we can state that within the scope for every Km that is moved further from shore the water depth increases by 2m. Overall the average WD has increased a 5-fold from 6m to 34m. The figure below shows the before mentioned correlation in the development of the WD and DtS.

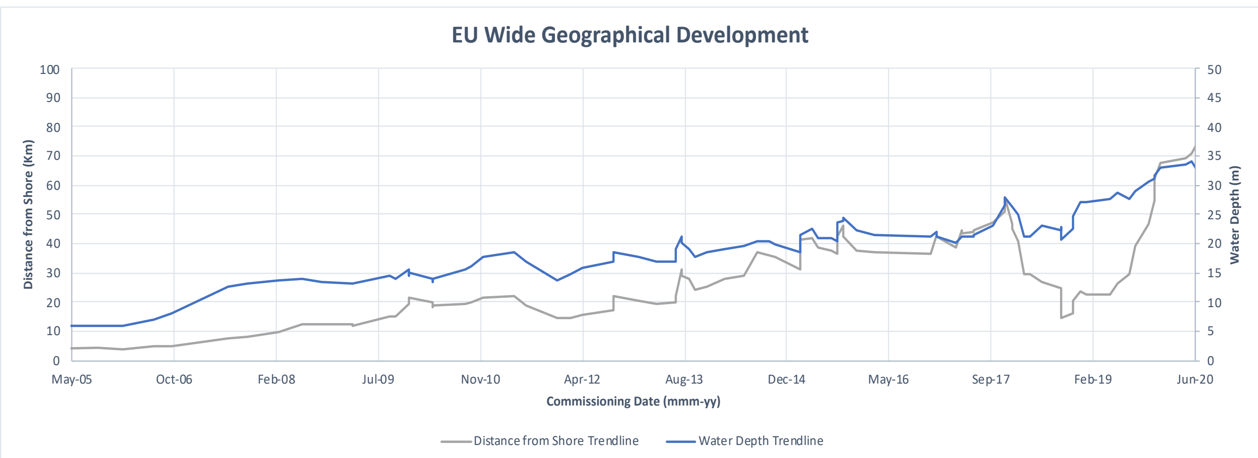



**Figure 10 WD & DtS trendline (Own figure,2021)**

The trend of the WD & DtS is impacted by country-specific developments. For instance, the WD trendline peaks around 2007 as at that time Germany commissioned its first big OWF's in relatively deep waters as a consequence of country-specific policy regarding the construction of OWF's close to shore. The WD trendline dips around 2018 as the commissioning of OWF's in the Netherlands, Belgium and UK could be performed in relatively shallow waters. The country-specific geographical developments are provided in appendix VI. The overtime increase in average WD has also led to innovations regarding the principle of foundations used. Within the scope of the study we can define the use of 4 principles of foundations, being; Jacket foundations, tripod foundations, Gravity based foundations (GBS) and the most commonly used monopile foundations. Of the OWF's from which the foundation principle could be defined 75,9% used monopile foundations. As the WD increases the share of monopile foundations in the OWE sector will steadily decrease as the monopile foundations are only applicable up to a water depth of 30m. (Marine Science and Engineering, 2016) Foundations principles like Jacket and tripod can be used up to a water depth of 50m. (Electrical and Energy Department Adana Vocationa Hogh School, 2010)

### 4.1.1 FCC

The WD is expressed as a function of the foundation cost. The impact of the WD of the FCC is defined by the use of formulas that use the WD or DtS as a variable. Each foundation principle is defined by a different formula as the applicability of each principle of foundations in relation to the WD differs. Foundation principles that are applicable for deeper waters have increased standard values in the formula as a consequence of increasing construction, transportation and installation cost.

$$\text{Monopile foundation cost } \left[\$^{23}/\text{MW}\right] = 986.059 * \exp(0{,}0182 * \text{WD}) \qquad (3)$$

$$\text{Gravity based foundation cost } [\$/\text{MW}] = 278{,}34 * \text{DtS} + 814.403{,}8 \qquad (4)$$

$$\text{Tripod foundation cost } [\$/\text{MW}] = 459{,}72 * \text{DtS} + 1.104.771 \qquad (5)$$

(Center for Sustainable systems University of Michigan, 2014)

The formulas as defined by researcher of the University of Michigan sometimes use the DtS as a variable. This development is as mentioned before cohesive with the WD development and therefore deemed credible for use. Moreover, the most communally used foundation principle can be defined as a direct function of the WD. Using the equations stated above the average individual foundations' cost per turbine has been defined. As a function of the WD, the individual foundation cost on average rose from €2.800.000 per foundation to €11.000.000 on average per foundation. This 292% increase is linear to the 466% increase in WD that was mentioned before. The scope wide average FCC cost per turbine is stated at roughly 6,8M€/turbine.

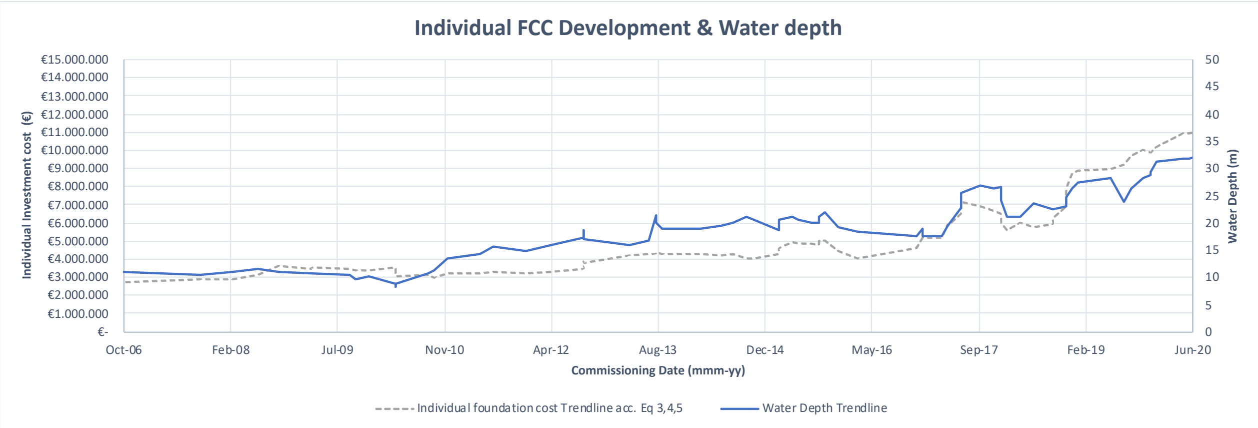



**Figure 11 Individual FCC development (Own figure,2021)**

The figure above highlights the correlation between the WD and the foundation cost estimation. As the average WD peaks around 2017 and from 2019 onwards the individual foundation cost estimations have increased the most. If we adapt the values per individual foundation to the number of turbines the total foundation cost per project can be assumed.

[23] Change rate 2014: 0,8237$/ Euro (Rateq, 2021)

The total amount of cost that can be allocated to the transportation, installation and construction of foundations increased from €80.000.000 per OWF to €390.000.000 per OWF. This is mainly driven by the increase in PS thus the number of turbines per OWF. The cost of the foundation rises as the WD in which they are placed determines the length of the foundation and the complexity of the structure. Besides the cost for the turbine foundations also the cost for the infrastructure surrounding the OWF like substations or worker platforms are driven by the WD as they also need foundation and thus rely on the present WD. These infrastructural costs however fall outside of the scope of this research. Besides making the foundations more expensive in construction as their length increases the installation and transportation expenses related to the foundations are a secondary driving factor. For example, bigger vessels with more deck capacity have been introduced over time as a consequence of the foundation becoming larger in size. (Panticon, 2016) Also, bigger cranes were introduced on installation vessels that had the lifting capacity that allowed them to install the bigger foundations. These cost however are hard to relate to an individual OWF's cost as the vessels are usually not constructed for a particular OWF. And even if so, the vessels construction cost are not allocated to the standard CAPEX or OPEX expenses of the OWF. But the foundations increasing in size has had a defining impact on the overall expenses made within the logistics aspect of the OWE sector. (Panticon, 2019)

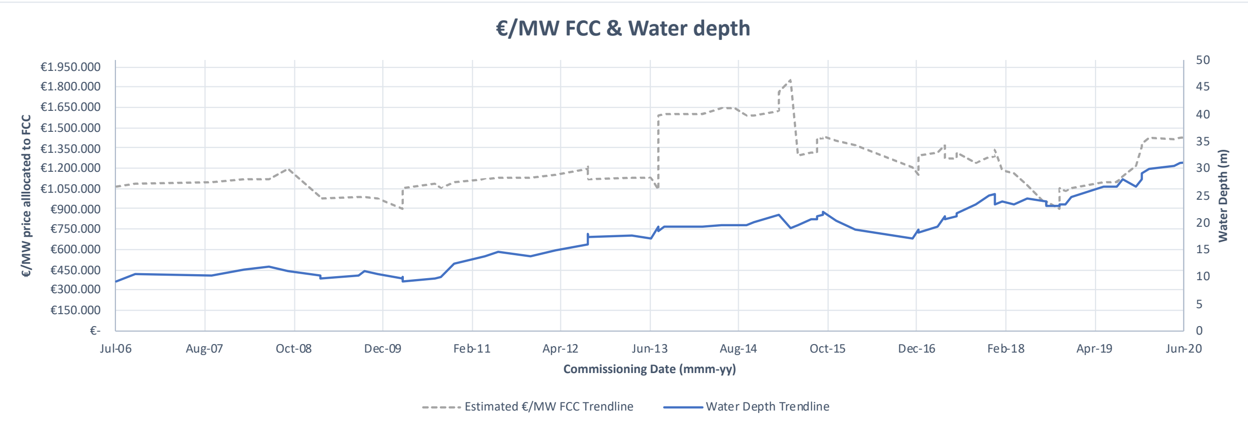



**Figure 12 €/MW FCC Trend (Own figure,2021)**

The figure above visualized the most important impact that the increasing WD has on the value of the LCOE variable being its individual impact on the €/MW price. The €/MW cost that can be allocated to the FCC has increased from €1.050.000/MW to €1.400.000/MW. This 33% increase defines that as a function of the WD the FCC which is part of the CAPEX has increased by 33% within the scope of this research and within the applicability of the used method. The €/MW price has increased by 71% from 2013 to 2016 due to the increasing WD of the commissioned OWF while the turbine power rating given in MW has stayed equal. The trend also shows that from 2015 the WD still increased but the €/MW significantly decreased as a consequence of increasing turbine power size. This turbine power size increase will be further discussed in the report but on the FCC, it had the effect that in countered the €/MW price even though the individual foundations themselves became more expensive during the same time as highlighted in figure 11.

From the data present in appendix VI it can be derived that countries with little or no differences in the averaged used WD and DtS have a completely linear total cost development trend to the PS trend. This indicates that the WD and DtS heavily impact and determine the relation and between the total cost of a project and the project size. As OWF's are placed further from shore in deeper waters the deviation between the project FCC cost and project size trendline increases indicating an increase in €/MW FCC cost in deeper waters.

## 4.2 Distance to shore as a T&I based driving factor

Besides the WD another geographical development is the development in the DtS. In figure 10 Just like the WD the DtS shows an on average increasing trend within the scope of this research. But unlike the WD the DtS is much more an engineering decision. As is shown in the figure below the DtS has an immediate impact on several different factors also including factors that influence the *Total sum of electrical energy produced over lifetime* as part of the LCOE equation.

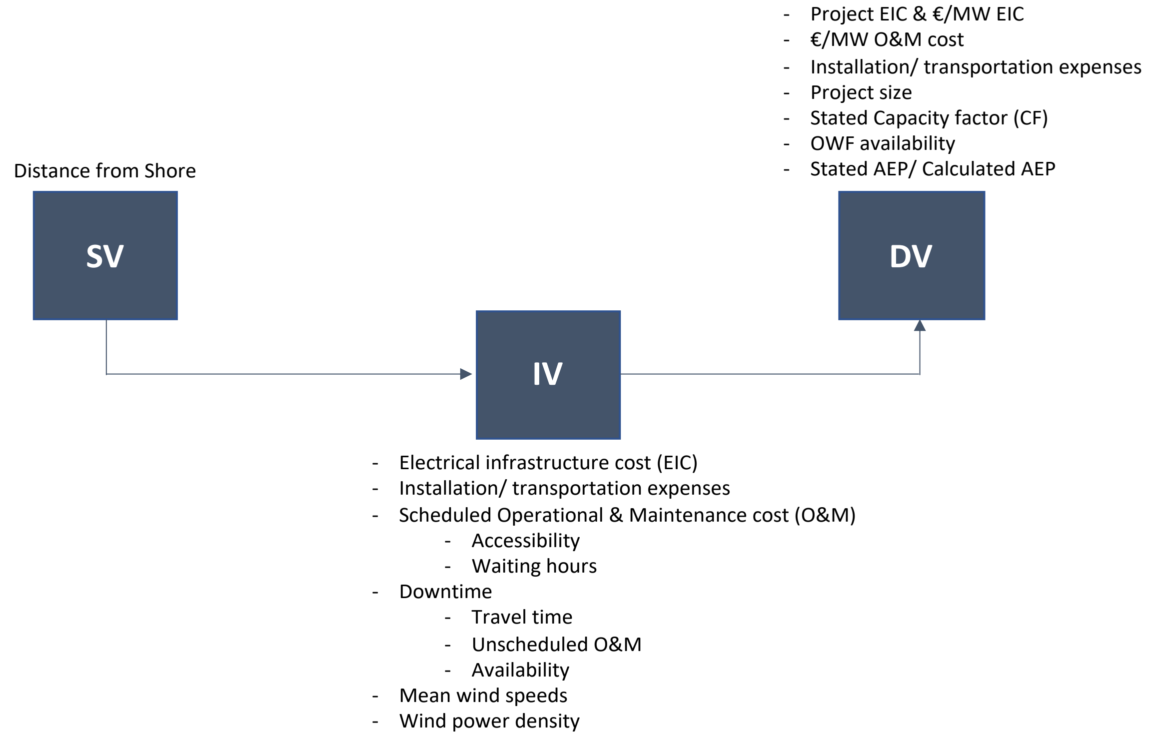



**Figure 13 Methodology Distance to shore Analysis**

As one moves further from shore the cost aspect related to the electrical infrastructure and installation & transportation are affecting de numerator of the LCOE formula. However, the increasing DtS also results in better wind conditions and more space to construct bigger OWF both positively impacting the denominator of the LCOE formula by increasing the AEP. Within the same scope as the WD it can be stated that the average DtS increased from 9 km on average at the beginning of the scope to 70 km in 2020.

### *4.2.1 EIC*

The electrical infrastructure cost or EIC can be derived as being a function of the DtS. As OWF's are placed further from shore the complexity of the electrical infrastructure increases. This complexity is defined by the increasing cable length necessary and the number of substations needed. At this stage in the OWE sector there are hardly any clusters of OWF's that would make it possible to in a way share the cost for the EIC and its transmission charges. To quantify these EIC cost Eq. (6) is used. The EIC cost are quantified per turbine, this entails that the total EIC cost are defined per turbine.

$$\text{Electrical infrastructure cost } [\$^{24}/\text{MW}] = 442.483{,}33 + 7.236 * \text{DtS} \tag{6}$$

(Center for Sustainable systems University of Michigan, 2014)

Figure 14 shows the individual value of the EIC related cost as mentioned before per turbine. The value of the cost is significantly lower than the FCC related cost. While the FCC cost accounted for roughly 6,8M€/turbine the EIC cost roughly accounts for 2M€/turbine. While the individual EIC cost trend shows the individual EIC cost more than double over time there is little resemblance to the DtS trend. The fact that the individual EIC cost doesn't seem to be influenced by its own variable can be allocated to the fact that the first standard value in Eq. (6) is not impacted by the DtS as a variable.

[24] Change rate 2014: 0,8237$/ Euro (Rateq, 2021)

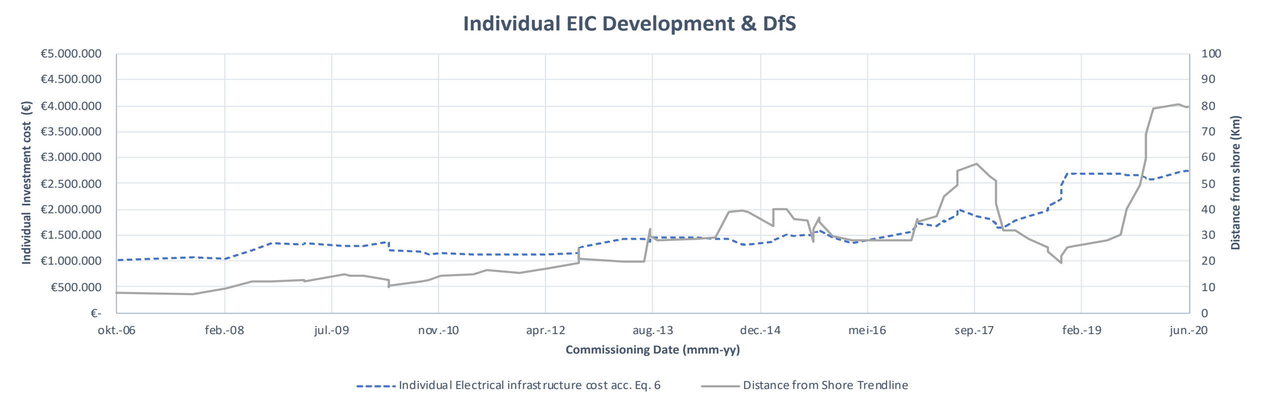



**Figure 14 Individual EIC development (Own figure,2021)**

The first standard value in equitation 6 defines the average standard cost of substations constructed. The use and cost of substations have stayed relatively similar over the scope of this research. The biggest increase in the cost aspect of the substations is the FCC as a function of the WD. The DtS as defined now does not impact the biggest contributor to the total cost of the Electrical infrastructure being the substations. As a result, the other standard value being the cable cost which does use the DtS as variables hardly impact the total cost in €/MW and thus the individual cost per turbine. This fact results in the €/MW trend even showing a decrease in value over time. With the cost of the substation assumed as standard, the additional cost for cables was countered completely by the introduction of bigger turbine sizes. The €/MW cost allocated to the EIC decrease from €405.000/MW to €320.000/MW. This results in a 21% decrease in €/MW price as a function of the DtS. However, the trend does show a similar 2015 peak to the €/MW WD trend. In this case, the €/MW price in this period rose by 80%.

### 4.2.2 ITC

The installation and transportation cost or ITC are affected by the increasing DtS. Defining the ITC cost as a function of the DtS centres around travel time and waiting hours. Both of these aspects also impact the scheduled and unscheduled O&M cost and the eventual downtime. All these aspects are discussed later in this report. As mentioned before the cost for installation and transportation centres around the use of vessels. As the DtS increases it is assumed that the travel time from shore to the OWF and from the OWF back to shore increases. When an OWF is constructed as part of the CAPEX cost a third party is hired to perform the transportation and installation of the foundation and turbine parts. This third party then charges the developers or owners of the OWF usually by a daily or hourly rate. As the travel time increases the vessels are used for a longer period of time thus the cost increase. The increase of the DtS can be seen as linear to the increase in travel time also increasing a 10-fold. The rates for vessels used in transportation and installation have also increased due to the technological developments resulting in the need for bigger vessels and the bigger OWF's resulting in a bigger fleet of vessels per OWF needed, consequently increasing the TIC.

Within the scope of this study the number of vessels used, the time needed for installation and the used rates were not part of the data collection. The impact these developments have made on the Total sum of cost over the lifetime and the eventual €/MWh price is hard to quantify. Based on qualitative research it can be stated that over time the larger turbine size has resulted in a reduced installation time per MW and thus a reduced €/MW. Also, a larger OWF generally speaking takes less time to install as the ratio between installed capacity and needed trips from and to the OWF decreases. The installation time per turbine has decreased from 7,6 days in 2000-2003 to 5.9 days in 2016-2017. (Joint Research Centre, European commission & Department of Electrical Engineering Universidad de Zaragoza, 2017)

### 4.2.2 O&M

In contrast to the ITC cost the operational and maintenance cost or O&M cost can be analyzed as a function of the DtS in a quantitative manner. From literature it is known that the O&M cost account for 20-30% of the total LCOE as part of the recurring cost. (Durham University, 2015) The recurring cost themselves are defined as the OPEX, the value of the OPEX is partly a function of the DtS besides being a function of the PS and TD. Especially the O&M cost are influenced by the DtS. As was stated in the ITC section, for O&M related works the same factors are accounted for as possible driving factors like travel time and waiting hours.

O&M can be divided into scheduled maintenance and unscheduled maintenance. Both are impacted by the DtS as when the DtS increases so does the travel time to and from the OWF. This also has its impact on the downtime of the OWF, a factor covered later in this report.

The scheduled maintenance is usually a set value of hours per year the turbine is switch off and the cost of the works themselves and the resulting revenue losses are calculated into the financing of the OWF. The scheduled maintenance is planned in advance and mostly scheduled in the summer months of the year as the waiting hours, working conditions and overall accessibility are most beneficial at this time. The un-scheduled maintenance however is not preliminary accounted for a can occur at any time and in any sort of severity. Both types of maintenance have the same driving factors. Besides failure rates another driving factor of the O&M cost can be summed up as the percentual accessibility of the OWF. This accessibility is defined as the percentages of hours on a yearly basis that the OWF is accessible and O&M works can be performed. This accessibility decreases as one moves further from shore, this is the result of factors like the wave height and average wind speeds increasing as the DtS increases. If the significant wave height surpasses the 2,5m no vessels can access the OWF as it is deemed too dangerous for the crew involved. Even if the wave height doesn't prohibit access to the OWF the wind speed still can. At wind speeds higher than 12 m/s all works related to climbing the rotor, an inspection of the tower and blades aren't allowed to be performed. (Enviromental Hydraulics Institute, 2016) The scheduled maintenance is structured in a way these conditions are always evaded, something that isn't possible for un-scheduled maintenance. The amount of time that is needed for the before mentioned conditions to revert back to acceptable is defined as the waiting hours. Waiting hours increase the O&M cost as the vessel charges are usually continued during these waiting hours. And these waiting hours can be defined as additional unscheduled downtime and revenue losses as a function of the DtS.

These waiting hours can increase up to 60 days for major replacements during the winter period. The average accessibility in the winter period is +-60% and +-80% in the summertime. (Enviromental Hydraulics Institute, 2016) Table 4 shows the average accessibility, waiting hours based on the average wind speeds and wave height that have been defined.

**Table 4 Overview Accessibility, Mean Waiting OWF's in the scope (Environmental Hydraulics Institute, 2016)**

| OWF | Dogger Bank (UK) | Gemini (NED) | Greater Gabbard (UK) | Butendiek (Ger) | Horns Rev II (Den) | Thortonbank III (Bel) |
|---|---|---|---|---|---|---|
| Distance to shore | 131 | 85 | 36 | 35 | 31,7 | 26 |
| Wind Speeds (m/s) | 10,33 | 10,13 | 9,66 | 10,17 | 10,21 | 9,58 |
| Wave Heights (m) | 1,54 | 1,59 | 1,06 | 1,4 | 1,38 | 1,07 |
| Accessibility (%) Summer | 69% | 71% | 82% | 73% | 73% | 82% |
| Accessibility (%) Winter | 47% | 48% | 67% | 52% | 51% | 66% |
| Mean Waiting period (hr) Summer | 5,95 | 5,22 | 2,51 | 4,71 | 4,79 | 2,47 |
| Mean Waiting period (hr) Winter | 16,16 | 14,66 | 6,04 | 11,99 | 12,55 | 6,23 |

Table 4 shows and supports the statement that as the DtS surpasses the 50Km mark the accessibility in the winter period and summer period is below the average values described before. Appendix VII shows visuals supporting this statement. Taking set known failure rates, repair time per type of reset, repair or replacement in combination with known vessel types for certain O&M activities and the number of required technicians collected by means of qualitative data collection. (Universitat Politecnica de Catalunya, 2020) The DtS in combination with known vessel costs is quantified till the increase in the €/MW price related to the O&M cost over two OWF's with strongly different distances to shore is known. Taking two different sets of data one specified at a DtS of 4Km of an OWF commissioned in 2006 and an OWF placed in 2020 at a DtS of 40,8Km the average yearly travel time increases from 0,3 hours to 2,6 hours. Besides the additional travel time also the average waiting hours per year doubles from 2,5hr to 5 hr. The total availability as a result of this drops from 75,8% in the 4Km case to 65,8% in the 100Km case additionally causing 10% more downtime.

Without taking the increasing turbine size into account solely the DtS as a result of waiting hours and travel time causes the O&M cost to rise by 4,4%. However, when we do take the greater turbine size that mitigates the greater distance to shore into consideration the O&M cost per MW drop by 65,2% essentially completely countering the additional cost as a function of the additional travel time and waiting hours. Appendix VIII shows the working sheet used for the calculations. In conclusion, the DtS does impact the total O&M cost making them rise in value, this is a motivation for statements from the literature indicating the overall increasing trend in OPEX cost/ MW that is discussed later in this report. However, just the extra cost of travel time and waiting hours related to the O&M cost has had little to no impact on the LCOE variable. The impact of the additional travel time and waiting hours on the extending of unscheduled downtime however seems to be much more of a driving factor of the LCOE.

### 4.2.3 AEP

The annual energy production or AEP defines the amount of electricity produced on a yearly basis. It is besides the WACC the sole variables that determines the value of the denominator. The AEP is both influenced by driving factors originating from technological developments and the DtS. The influence TD have had on the AEP value is discussed at a lateral stage. The AEP is the sum of the electricity that is actually produced, when divided by the possible amount of electricity that theoretically could be generated the capacity factor or CF can be estimated. The CF actually defines the usage rate of the OWF. The AEP is a value that can be linked to specific OWF's. For 49,5% of the OWF's in the scope of this research the AEP was stated and could be estimated with the use of Eq. (7) & Eq. (8).

$$AEP\ esitmation\ Wind\ speed\ based\ (1)[kWh] = k * v^3 * a_t * T \tag{7}$$

$With$:
$k = 3.2\ (Approximation\ factor\ depended\ on\ turbine\ size)$
$v = Mean\ (average) wind\ speed\ (m/s)$
$a_t = Swept\ area\ of\ the\ turbine\ in\ (m^2)$
$T = Number\ of\ Turbines$

(Jensen, 2001)

$$AEP\ estimation\ Capacity\ factor\ based\ (2)[kWh] = h * p_t * f * T \tag{8}$$

$With$:
$h = Number\ of\ hours\ per\ year\ (8760)$
$p_t = Rate\ power\ of\ each\ turbine\ (kW)$
$f = Annual\ capacity\ factor$
$T = Number\ of\ Turbines$

(Jensen, 2001)

With the stated AEP and the AEP's estimated with the adaptation of Eq. (7) & Eq. (8), figure 15 was constructed. To dismiss the overwhelming impact that PS has had on the AEP, the AEP has been estimated and visualized in figure 15 per turbine. It clearly shows the impact the DtS has on the individual AEP per turbines. As the DtS decreases around 2018 the stated AEP doubles, we assume that this fact is due to the lesser amount of downtime close to shore consequently boosting the CF. At the same time as the DtS decreases the estimated AEP based on windspeed just increases 4% most likely due to the lower wind speeds close to shore. On average the AEP per turbine still increases by 142% which is still a lower increase than was defined with the FCC increase of 249% and the EIC increase of 175%. Supporting the statement that the AEP hasn't increased linearly to the cost as should have been expected. Which would have led to overall reducing the €/MWh cost. Adapting Eq. (7) & Eq. (8), to the total OWF AEP the trend shows an increase in average AEP from 248.000 MWh to 1.175.000 MWh. This 373% increase in total AEP is driven by the increase in PS. The fact that the PS increases with an 8-fold and the AEP "just" triples highlights there have been developments within the driving factors of the AEP preventing the AEP to develop equally to the PS.

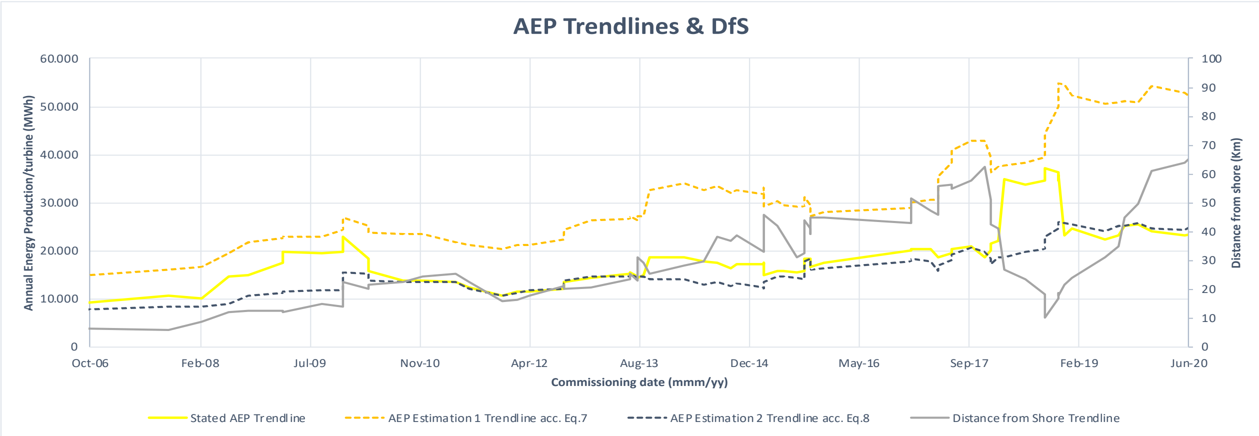



**Figure 15 Stated AEP and Calculated AEP per turbine (Own figure,2021)**

### 4.2.4 Mean Wind speeds

To determine which driving factors have contributed to the AEP's limited increase the factors used in Eq. (7) & Eq. (8) are discussed further. The mean (average) wind speed used in calculation 1 is defined by the DtS, as was stated before the average wind speeds tend to increase as the DtS increases. The mean wind speeds are dependent on the location of the OWF and the hub height of the turbine. For this section of the report the location thus DtS will only be taken into account as a driving factor.

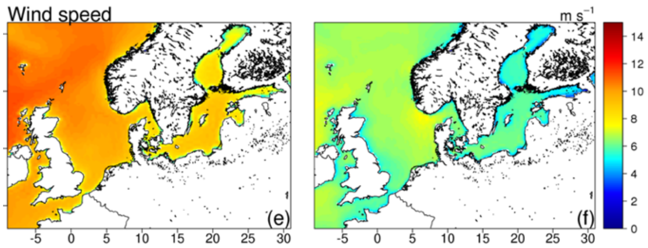



**Figure 17 Average Wind speeds. (L->Winter, R-> Summer) (MDPI, Wave climate changes in the North Sea and Baltic Sea,2019)**

Figure 16 visualizes the average wind speeds; it highlights the difference in windspeeds during seasons. In the winter windspeeds reach averages of +- 11m/s and in the summer +-7m/s. It also highlights that the differences in wind speeds as function of the DtS are minimal and don't deviate more than 2m/s. By means of data collection from 53,8% of the OWF's in the scope the stated mean wind speeds on location independent from the hub-height was collected. The figure below clearly shows the correlation between the DtS and the wind speed in the location.

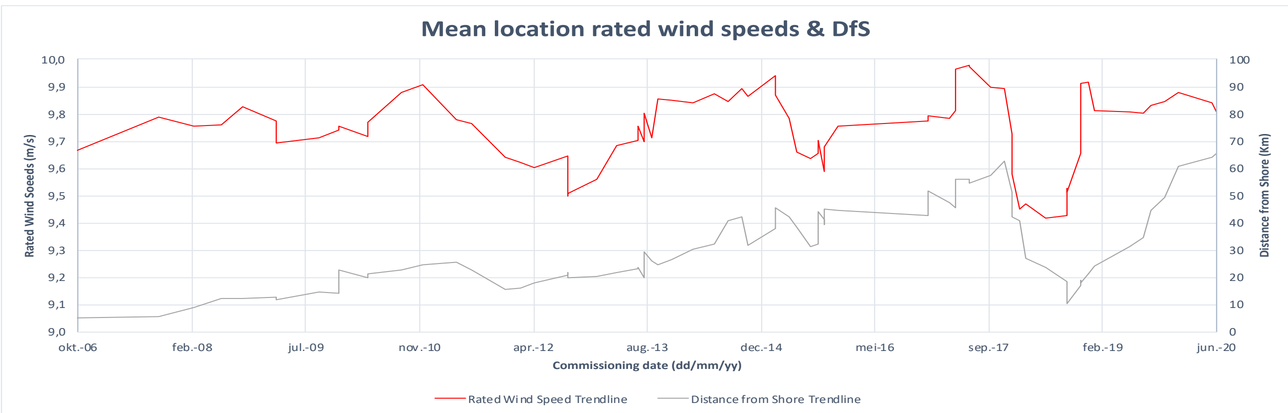



**Figure 16 Mean location-based wind speed Trendline (Own figure,2021)**

The trend showing the relatively small 5% decrease in average wind speeds around 2018 highlights that the wind speed on location isn't a driving factor behind the AEP. However, the 1,2% increase over the entire scope has led to the AEP rising with 3,8% on average. When the stated AEP trend of figure 15 is set out against the rated wind speed trendline it seems that when the stated average wind speed (thus the DtS) increases the AEP seems to decrease.

### 4.2.5 CF & Availability

Every type of turbine has its own turbine depended rated wind speed specified. This variable is defined as the needed windspeed interacting with the turbine so that the turbine produces a nominal power output. (Institute for Applied energy, 2017) The average rated turbine wind speed within the scope of this research is 13,4 m/s. There is a clear trend showing the TD of the turbines over time, before 2016 the average was still on 15,6 m/s. Over time turbines needed lower wind speeds to generate nominal or maximum power output. The number of hours on yearly basis a turbine produces a nominal power output are defined as so-called full load hours. The percentage of full load hours divided by the possible number of hours in a year generates the capacity factor or CF. Even though the turbine rated wind speed as a function of the TD matter, still the wind conditions on the location of the windfarm need to reach the rated turbine wind speeds at a sufficient level during the year.

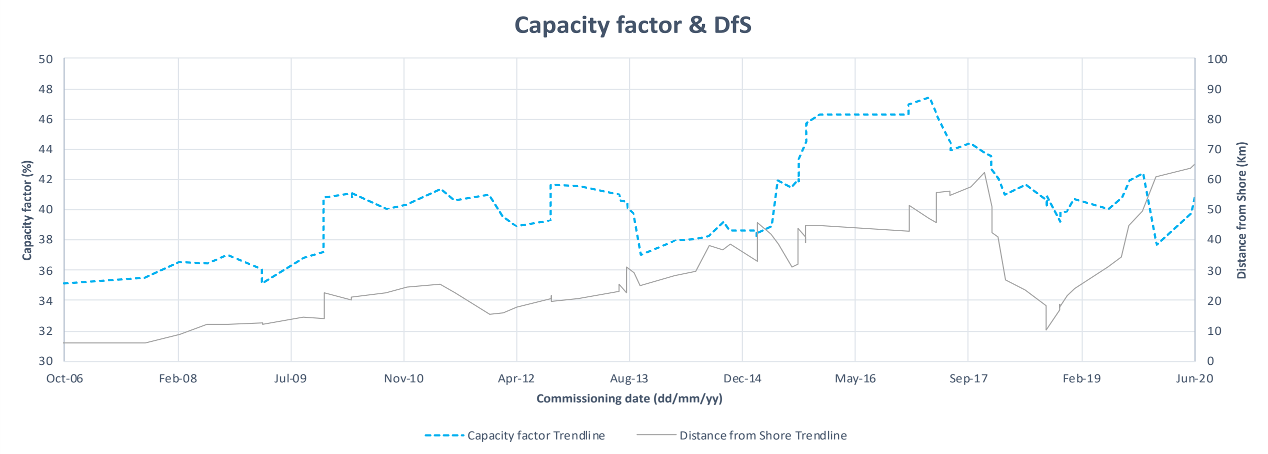



**Figure 18 Capacity factor Trendline (Own figure,2021)**

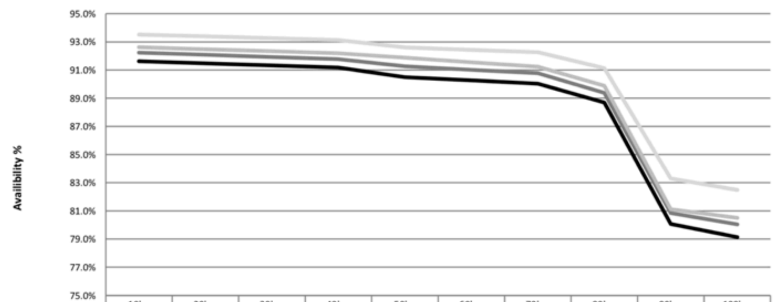
Definitions within literature related to the CF of OWF's differs heavily over time. Wind farms commissioned before 2010 had an average CF of about 30% while newer OWF's are projected to reach the 55-60% mark. (Voormolen, 2015) By taking the average of the stated CF's within the scope of this research the average CF is set at 40,4% which is cohesive with before known literature. Within the scope, the average CF increased from 36,2% to 40,7%. The trend also indicating a period between 2015 and the beginning of 2017 in which the average CF was stated at +- 47%. This increase in CF doesn't reflect itself in the AEP trend.

The CF defines the full-load hours, a wind turbine also has set cut-in and cut-out rated wind speeds. The cut-in wind speeds are defined as the minimal windspeed necessary to produce electricity at a sufficient efficiency rate and the cut-out wind speed as the maximum allowed wind speeds the turbine can endure before material damage can occur. Between the cut-in speeds and the rated wind speed and between the rated wind speed and the cut-out wind speed there are periods in which there is still electricity produced just not at the nominal rate. The percentage of time on a yearly basis within this entire period is known as the percentual availability of an OWF. In other words, the amount of time on a yearly basis the OWF produces electricity. In this research, it is assumed that the CF can be linked to the overall availability of the OWF. When a set assumed amount of yearly scheduled maintenance hours and a set assumed number of hours outside of the cut-in and cut-out wind speeds are added to the CF the average OWF availability can be stated. What remains is unscheduled downtime as the result of failures and malfunctions. The total set of scheduled maintenance was set at 15 hr/yr./turbine. (Power Engineering, 2021) While the number of hours outside of the cut-in and cut-out windspeeds is set at 8% on average. (ECN, 2010) As the hours between cut-in wind speeds and cut-out wind speeds are mostly defined within the CF percentage this was also assumed in this research. When estimating the working availability so without taking scheduled and un-scheduled maintenance into account on average the working availability is stated at 86% which is cohesive with literature stating availability of OWF's is 90-99%. (Windeurope, 2021) The remaining 10% is accounted for when scheduled maintenance is preformed or wind speeds fall outside of the utilization window thus below the cut-in windspeed or above the cut-out windspeed. When un-scheduled maintenance is defined the actual availability drops to an average of 70% over the entire scope. It is known that the actual availability of OWF hasn't been as expected. This is stated to be the result of an unexpected amount of un-scheduled maintenance.

When constructed it was deemed that offshore wind turbines just as its onshore counterpart were almost seen as maintenance free. (Fraunhofer Institute for Energy Economics and Energy system Technology, 2011) The extensive amount of un-scheduled maintenance partially originates from the existents of so-called “salty winds” caused by the extensive amount of salt in the wind above the European seas. These “salty winds” have had a huge impact on the amount of repair necessary to especially the rotor of the turbines due to the damage of the salt. (Discovery UK, 2019) Furthermore, an unexpected amount of cable failures increased downtime. (EAWE, 2020) As the cable length as a function of the distance to shore increased and the power that needed to be transported increased as a function of the turbine power size the failure rate for the subsea cable subsequently also increased leading to the assumption that the extensive amount of downtime also partially originates from these extensive cable failures.


**Figure 19 Working & Actual availability Trendline (Own figure,2021)**

Figure 19 clearly shows a decreasing trend in availability up to 2017. This decreasing trend shows the actual and working availability respectively dropping 17,7% and 17,4% until the beginning of 2017. Figure 19 furthermore indicates the before mentioned correlation between the DtS and the availability. It is clear that as the DtS decreases the availability and thus the CF increases even though the wind conditions are deemed to be less optimal. The initial statement made is validated by the figure below. In these sources of literature besides the increasing travel time and extending downtime impacting the availability, the increasing wind speeds and increasing failure rates as a consequence of these windspeeds are used as statements. The impact of the windspeeds on the OPEX cost will be discussed later in the report.




| | 10km | 20km | 30km | 40km | 50km | 60km | 70km | 80km | 90km | 100km |
|---|---|---|---|---|---|---|---|---|---|---|
| DFIG PRC | 91.6% | 91.5% | 91.3% | 91.2% | 90.5% | 90.3% | 90.0% | 88.7% | 80.1% | 79.1% |
| 3S PMG FRC | 92.2% | 92.1% | 91.9% | 91.8% | 91.3% | 91.0% | 90.8% | 89.4% | 80.8% | 80.0% |
| 2S PMG FRC | 92.6% | 92.5% | 92.3% | 92.2% | 91.9% | 91.6% | 91.2% | 89.9% | 81.1% | 80.5% |
| DD PMG FRC | 93.5% | 93.4% | 93.3% | 93.1% | 92.6% | 92.4% | 92.3% | 91.1% | 83.3% | 82.5% |

**Figure 20 Availability drops as function of the DtS with the use of different gearbox types. (Enviromental Hydraulics Institute, 2016)**

Country specific developments were also identified and are shown in appendix IX. These data clearly show that countries with little DtS influence such as Denmark have no clear difference in availability over time. UK has scope wide lows in CF and as a result scope wide lows in availability up till 2017. This is a believed combination between DtS development and known postponed OWF's commissioning and the resulting implementation of not up to par technology believed to contribute to the generally low CF in the UK. (Voormolen, 2015). From this data it can be stated that the CF is the main indicator of the AEP while the availability has been the main driving factor behind the AEP not increasing linear or relative to the PS or other researched cost aspect. Resulting in a negative impact on the correlation between de nominator and denominator of the LCOE formula.

## 4.3 Technological developments as a T&I based driving factor

Figure 21 shows how the technological developments or TD will be analyzed. The TD have their influence on the CAPEX and OPEX but also the AEP. The analysis is focused on the individual turbine cost and revenues and the €/MW variable focused on a singular turbine. During the entire analysis, no aspects of the foundation or electrical infrastructure will be taken into account as they are already defined as mostly being a cost function of the WD and DtS rather than cost resulting from the undergoing of massive technological developments over time.

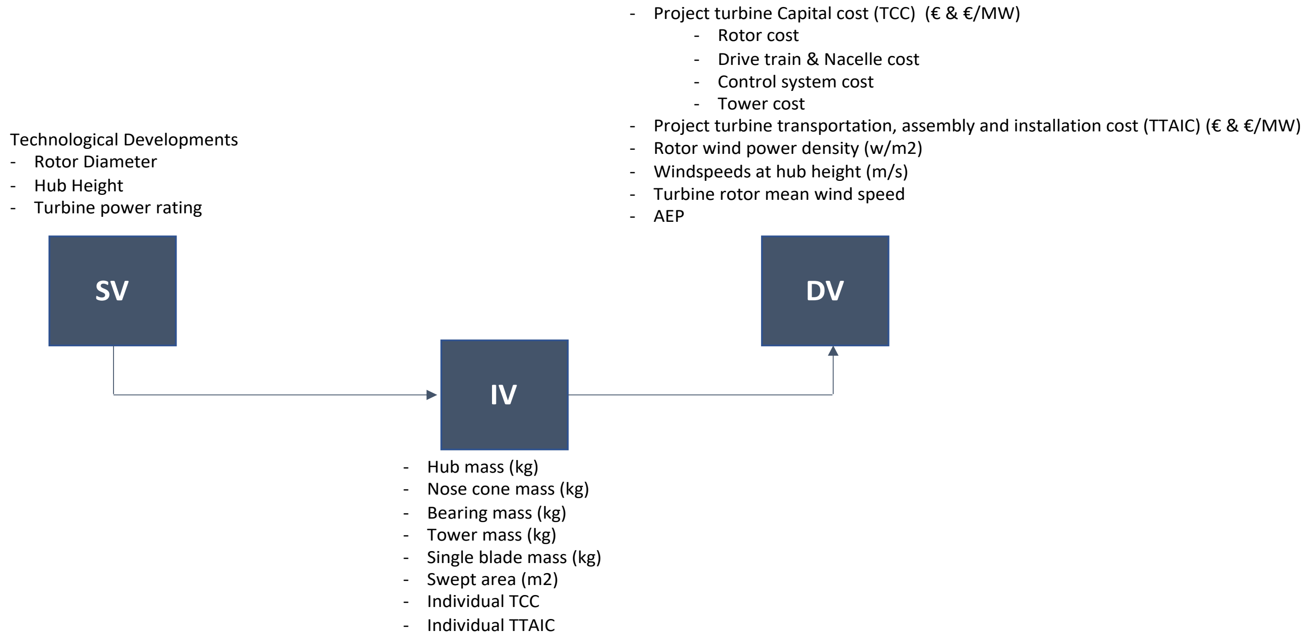



**Figure 21 Methodology TD analysis (Own Figure, 2021)**

The figure above highlights the development of the technological aspects of the wind turbine that are seen as the substantive variables. The hub height is defined as the total height in meters from the foundation to the top of the nacelle which has increased by 29,1%. The rotor diameter is defined as the distance from the tip of the rotor blade to the middle of the nose cone of the turbine which increased by 73,6%. The turbine size is defined as the power rating of the turbine usually given in KW or MW which increased by 126,7%.

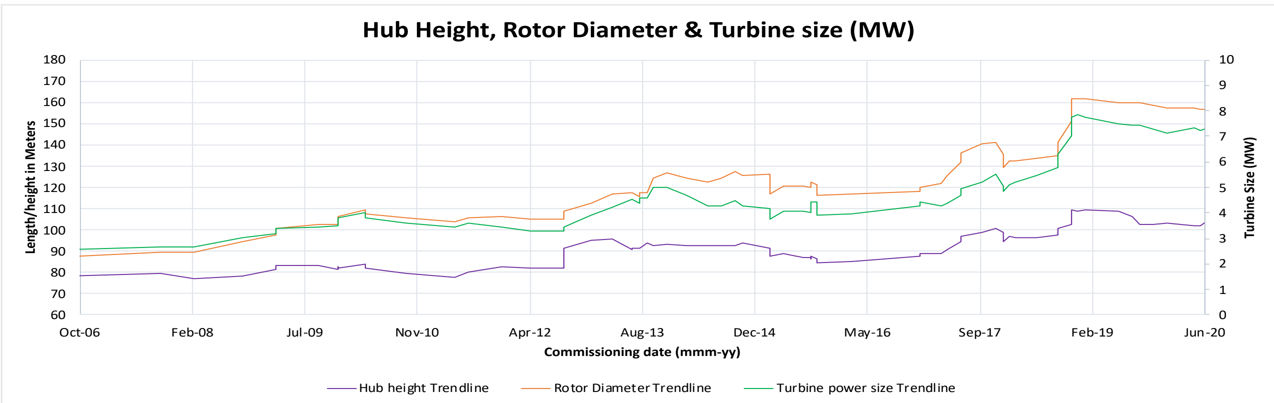



**Figure 22 Scope wide Trendlines of TD (Own figure, 2021)**

One semi-substantive variable is the swept area. The values of the swept area have been collected by means of data collection but can also be defined by the following equitation showing that its development is identical to the rotor diameter.

$$A = \pi r^2 \tag{9}$$

$With:$
$A = swept\ area\ (m^2)$
$\pi = \sim 3{,}14$
$r = half\ of\ rotor\ diameter\ (m)$
(Make, 2014)

### 4.3.1 TCC

To quantify how TD have impacted the cost associated with the construction of turbines the turbine capital cost or TCC is used. The TCC can be defined with the help of existing literature that uses the substantive variables applied in this research. (National Renewable Energy Laboratory, 2006) For the calculations certain general assumptions are made. These assumptions include that standard construction materials are used over time and these materials have set cost not varying over time. Appendix X shows these assumptions. The TCC is defined in Eq. (10).

$$Individual\ Turbine\ capital\ cost\ estimation\ [€^{25}] = (TR_c + DN_c + CS_c + TT_c) * ma \tag{10}$$

$With:$
$TR_c = Total\ individual\ rotor\ cost\ estimation\ [€]$
$DN_c = Total\ Drive\ train\ \&\ Nacelle\ cost\ estimation [€]$
$CS_c = Total\ Control\ systems\ cost\ estimation\ [€]$
$TT_c = Total\ tower\ cost\ estimation\ [€]$
$ma^{26} = Standard\ marinization\ factor\ (13{,}5\%)$

(National Renewable Energy Laboratory, 2006)

Eq. (10). consist of 4 separate variables. Each of the variables has its own dependent variables all defined as being functions of either the rotor diameter in meters, the rotor radius in meters, the hub height in meters, the swept area in m2 or the machine rating in KW. The used formulas for the TCC estimation are shown in appendix XI. The DOE/NREL scaling model used is a model able to express differing configurations of turbines to a total needed investment per turbine. The formulas in the model and thus adapted into this research are in definition all function of masses. The substantive variables are converted to the intermediate variables shown in figure 21. These intermediate variables are then used to express the total cost associated with that particular part. The formulas for the intermediate variables are not shown in appendix XI but rather already integrated in the shown formulas. The data collection prior to the adaptation of these formulas included the specification of used gearbox and generator types. Figure 23 shows how the estimated individual TCC has developed as function of the TD.

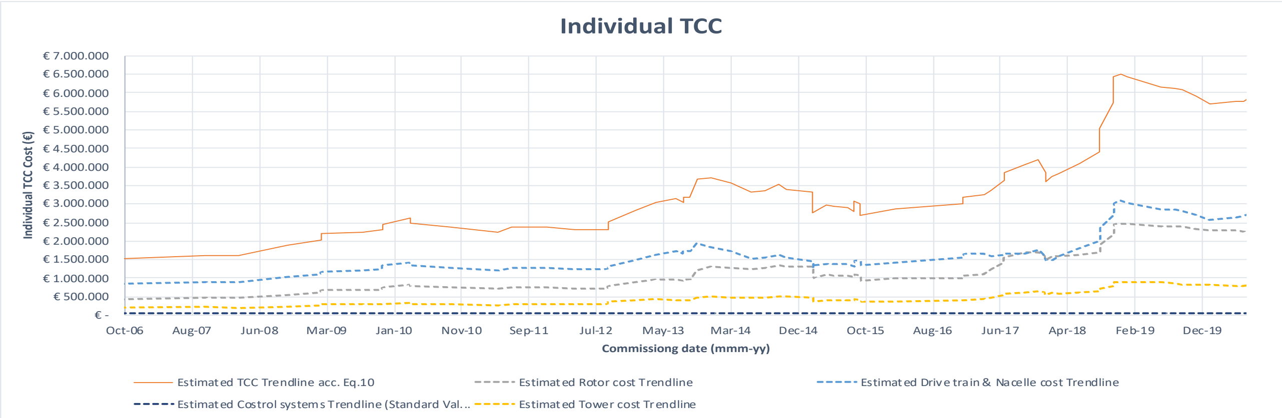



**Figure 23 TCC Trendline (Own figure,2021)**

[25] Original formules stated in $. Change rate 2006: 0,991$/ Euro (Rateq, 2021)
[26] MA = defined as the extra cost offshore turbine have in comparison to onshore wind turbines is set at 13,5% added to the TCC

The estimated TCC has increased from €1.500.000 per turbine on average to €5.750.000 per turbine on average. This 280% increased can be mostly accounted for by the increasing $R_c$ and $DN_c$ these two variables are influenced by the rotor radius/diameter and the power rating of the turbine. If we define those two variables further in their specific driving factors the following visuals show how the blade cost as a function of the rotor diameter has increased by 500% and the gearbox cost as function of the choice in gearbox and the machine rating has increased by 400%.

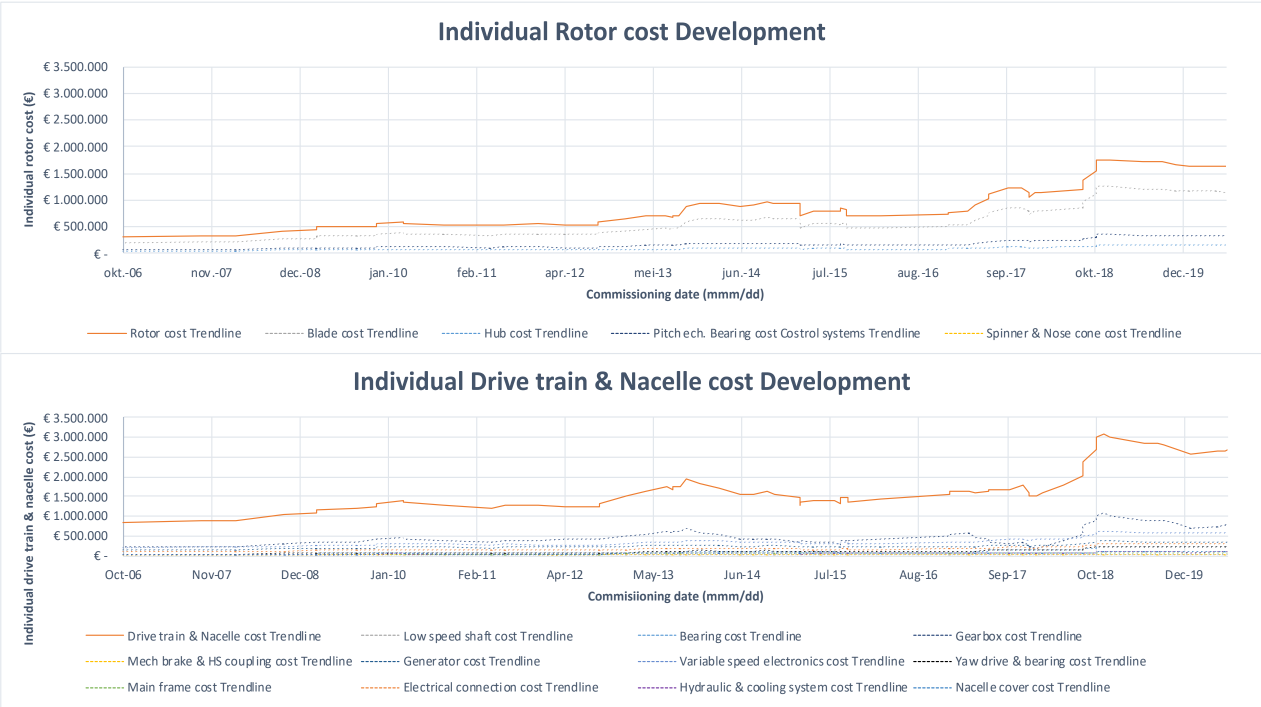



**Figure 24 Individual Rotor/ Drive train & Nacelle cost Trendline (Own figure,2021)**

In 2017 the gearbox cost decreased with 67% as a consequence of the adaptation of direct drive turbines which didn't use gearboxes. Interesting to note is during this period the $DN_c$ costs were hardly affected and even increased with 3%. Supporting the statement that the turbine size is the main driving factor of the TCC and the choices in gearbox and generator type have little to no influence.

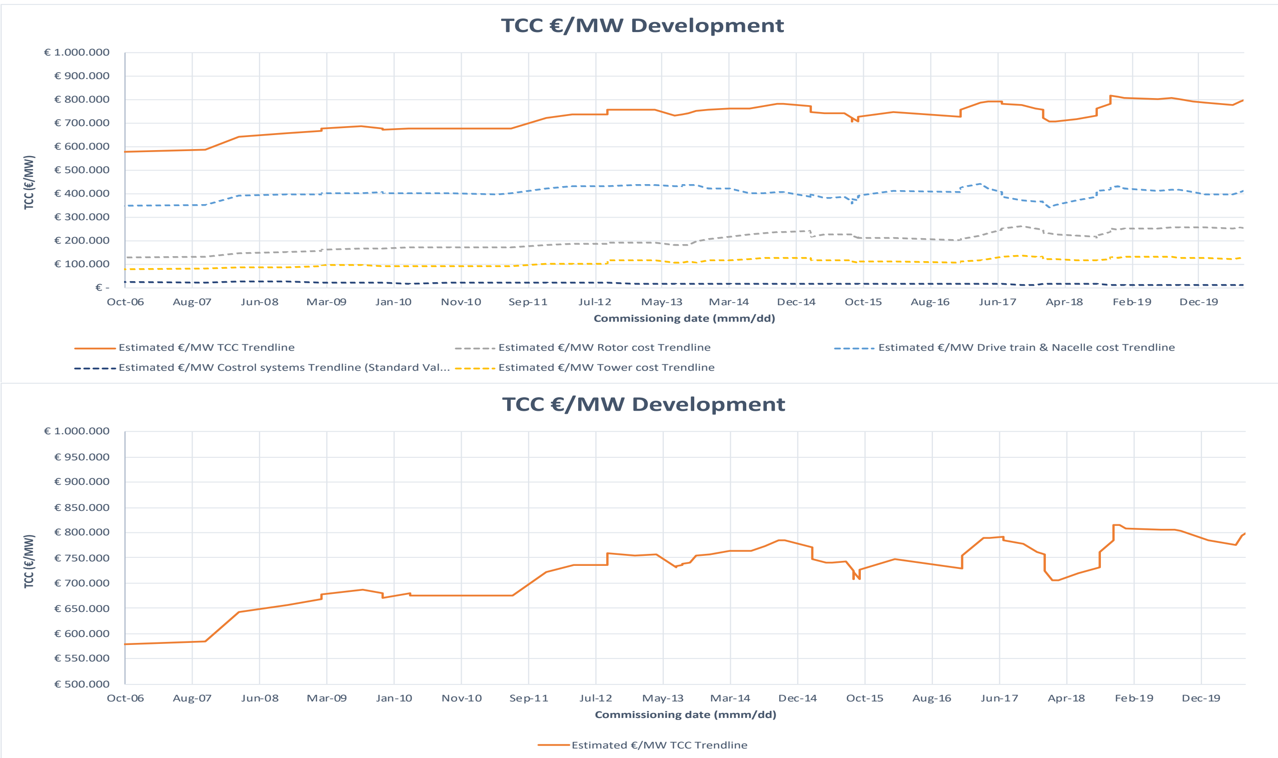



**Figure 25 TCC €/MW Trendlines (Own Figure,2021)**

Figure 25 indicate the impact of the TCC as €/MW cost. As mentioned before the turbine power size has been one of the main driving factors of the TCC. This fact also shows in figure 25. Even though the individual TCC has increased by 280% the impact of the TD on the €/MW is countered by the increasing turbine power size leading to the €/MW price increasing by 37,9% from 0,58M€/MW to 0,8M€/MW.

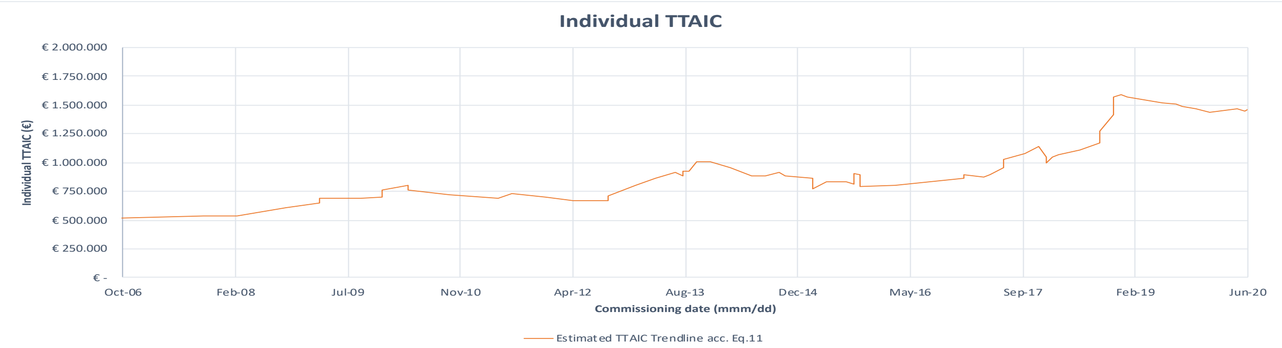
### 4.3.2 TTAIC

The turbine transportation, assembly and installation cost or TTAIC define the cost associated with the transportation, assembly and installation of turbines as a function of the increasing dimensions associated with the TD within the scope. As mentioned before the increasing dimensions of to be installed parts generates extra cost on the logistics aspect of the OWE sector. It is stated that the logistics aspect makes up at least 18% of the LCOE, 26% for the OPEX and 23% of the CAPEX associated with OWE showing its clear influence. (Panticon, 2019) To quantify the impact of TD on the CAPEX the development of the individual TTAIC cost and €/MW TTAIC cost were analyzed. As was the case for the FCC cost the defining of the installation cost is difficult as the vessel cost and fleet of vessels per OWF couldn't be specified. The TTAIC as quantified by the use of Eq. (11) counters this by stating that every individual turbine has its share in cost aspects like road and civil works needed to keep being able to transport turbine parts from the factory to the port and the acquisition of new port and staging equipment as function of the increasing turbine dimensions. Also, the increasing dimensions and masses and their relation with vessel cost is taken into account.

$$Individual\ Turbine\ transportation, assembly\ and\ installation\ cost\ estimation\ [€] = T_c + AI_c \qquad (11)$$

$With$:
$T_c = Transportation\ cost\ [€]$
$AI_c = Assembly\ and\ installation\ cost\ [€]$
(National Renewable Energy Laboratory, 2006)

Further formula deviation of the $T_c$ and $AI_c$ is shown in appendix XI. The individual estimated TTAIC development shows a very similar development to the TCC development increasing with 193% from €505.000 to €1.480.000 per turbine. This increase as was also the case for the TCC is countered by the increase in turbine power size so that the effective €/MW just increases with 6,8% from 0,18M€/MW to 0,2M€/MW. It shows that how lower the value of individual cost is how more impact the turbine size has in reducing the €/MW price.



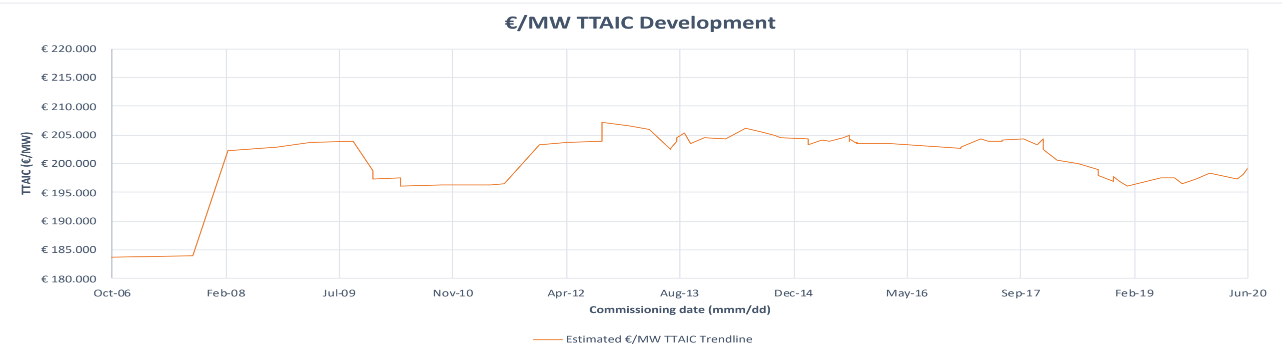




**Figure 26 Individual and €/MW TTAIC Trendlines (Own figure,2021)**

The estimated €/MW TTAIC trendline in contrast to the estimated €/MW TCC trendline does show a decreasing trend from 2017 onwards. Indicating that the turbine size increase has been higher than the increase in TTAIC cost the turbine size causes as function of the TD.

Using an average cost share for total logistical cost in the OWE sector per turbine as used in this research is not deemed as feasible. Literature clearly states that the logistics of OWF's have increased in efficiency by the maturing of the market and introduction of bigger vessel and their increased capacity reducing the installations days per turbine strongly reducing the installation and transportation cost per MW. (Panticon, 2019) The increasing individual TCC and TTAIC do clearly show how TD have had a contribution in the tripling of the CAPEX since the introduction of OWE till 2015 as stated in known literature. (Voormolen, 2015)

### 4.3.3 Estimated mean wind speed

As was mentioned before the TD also have had their impact on the total sum of electricity produced as part of the LCOE formula. The mean wind speeds on the location of the OWF and their impact on the AEP has already been discussed. However, the mean wind speeds aren't yet specified for a particular height. The wind speed in general is a function of the height measured from the earth surface. As the hub height has increased by 29,1% on average higher wind speeds were used leading to reaching the cut-in wind speeds and nominal wind speeds quicker and thus theoretically boosting the CF and AEP. By applying Eq. (12) the wind speeds were estimated at hub height.

$$Wind\ speed\ at\ hub\ height\ estimation\ [m/s] = \left( \frac{\ln \frac{H_2}{Z_0}}{\ln \frac{H_1}{Z_0}} \right) * V_1 \qquad (12)$$

$With:$
$H_1 = Reference\ height\ [m]$
$H_2 = Hub\ height\ [m]$
$Z_0 = Roughness\ length\ (Standard\ value\ of\ 0{,}0002\ above\ water\ surfaces)$
$V_1 = reference\ wind\ speeds\ (Average\ mean\ wind\ speed\ at\ location)$

(The swiss wind power data website, 2021)

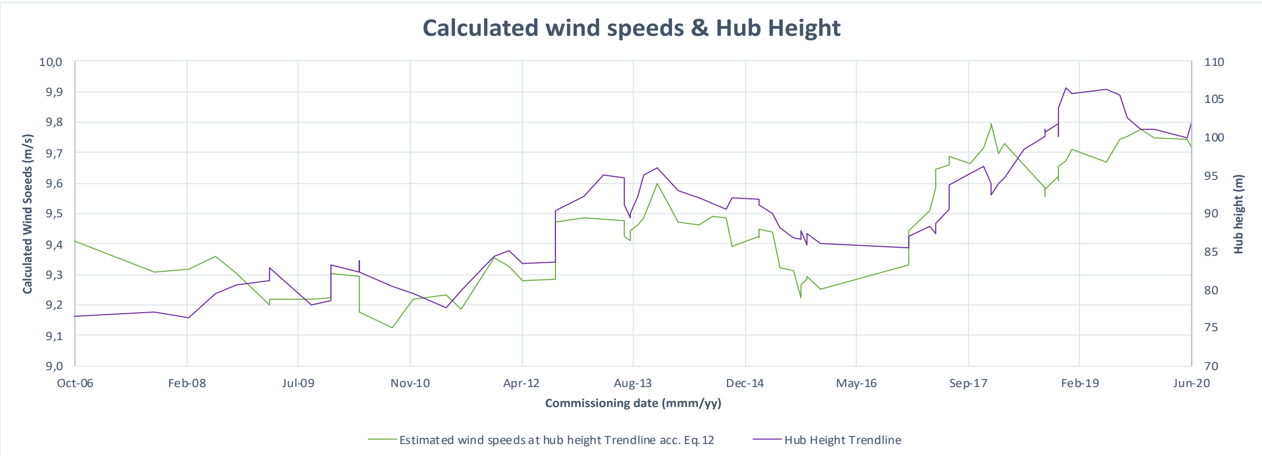



**Figure 27 Calculated wind speed at hub height Trendline (Own figure,2021)**

The figure above clearly shows how the development of the hub height has contributed to an assumed increasing wind speed at the hub height level. The wind speed as a function of the TD has increased by just 3,7%. This 3,7% has impacted the AEP in general increasing it by 11,6%, which is more than the stated increase of 3,8% as a function of the increase in mean average wind speeds as a function of the DtS defined before. Indicating that the hub height has had a more significant influence on the AEP and CF than the wind speeds as function of the DtS.

### 4.3.4 Rotor power density

The rotor power density is the amount of $watts/m^2$ the turbine is able to generate. This variable is driven by TD to the rotor and overall spacing within turbines in OWF's. Over the scope, the stated rotor density has decreased by 13% from 530$W/m^2$ to 460$W/m^2$. This shows how TD to the rotor and rotor spacing within OWF's over time decreased the efficiency needing more $m^2$ of swept area to produce a similar amount of electricity. Generally speaking, the rotor power density was decreased by the rotor diameter increasing by 73,6% while the density of the wind on location increased just slightly as a function of the increasing altitude and the resulting colder winds. Overall with the estimated wind speed and rotor power density statements, the TD seems to have more impact on the AEP then the similar factors as function of the DtS.

## 4.4 Project size as a T&I based driving factor

During the analysis of the T&I based driving factors it was deemed at an early stage to divide the cost and revenue aspects into 3 sperate categories being the individual cost and revenues per turbine, the €/MW cost including the power rating of the turbine and now also the project size or PS to determine the total cost and revenues over the entire lifetime of the OWF.

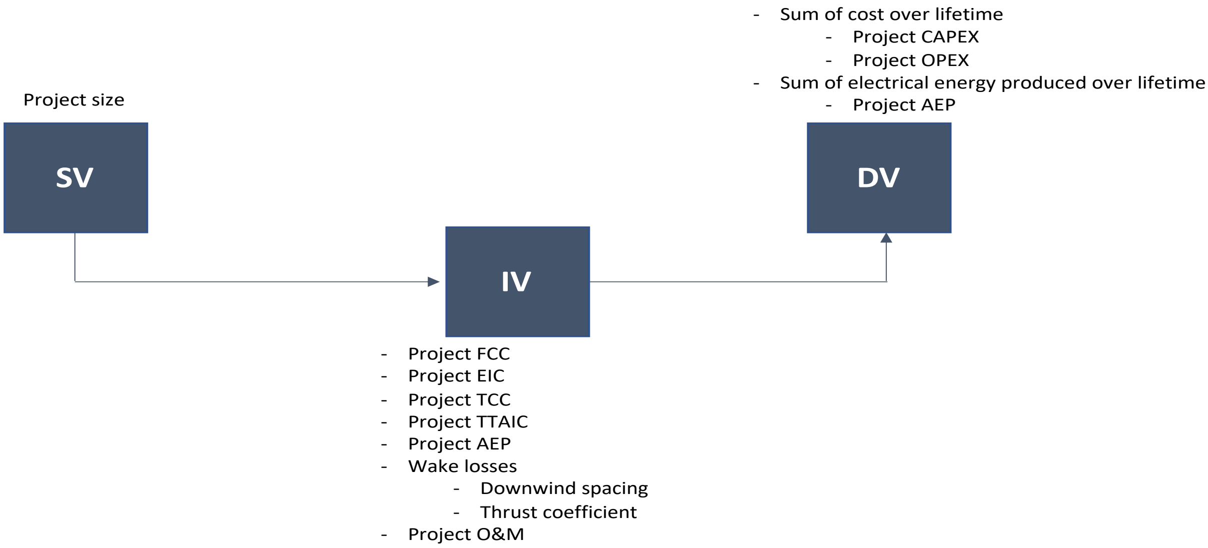



**Figure 28 Methodology Project size (Own figure,2021)**

The total CAPEX, OPEX and AEP have the project size as its main driving factor as the number of turbines or total project size in KW or MW eventual determine the total expenditures and revenues. The figure below suggests how the PS its main driving factor itself is the DtS.

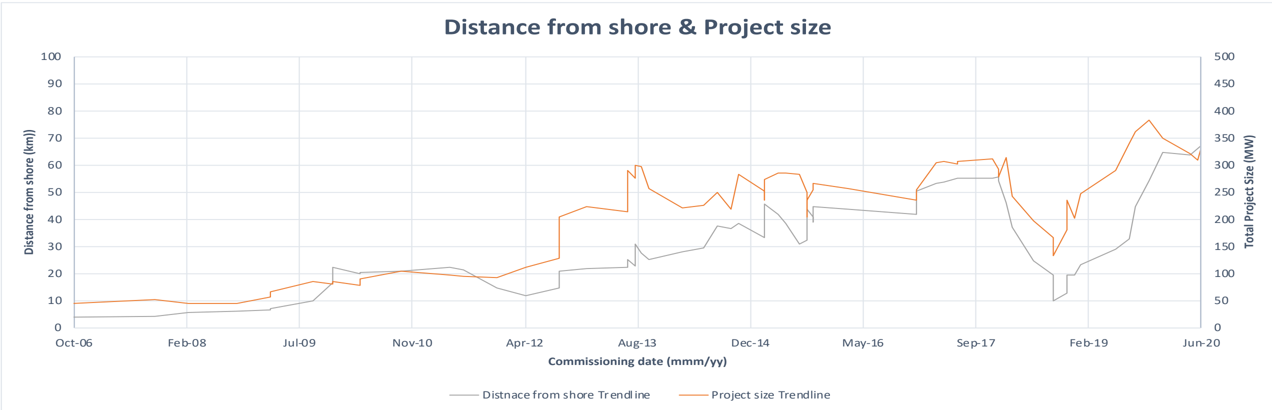



**Figure 29 Distance to shore & project size Trendline (Own figure,2021)**

### 4.4.1 CAPEX

The CAPEX or capital expenditures are defined as the non-recurring cost. The total CAPEX for an OWF in this research is defined by the following sum of aspects as defined in Eq. (13).

$$Project\ CAPEX\ estimation\ [€] = \left((FCC_i + EIC_i + TCC_i + TTAIC_i) * N_t\right) + PDS_c + SP_c + SB_c + OW_c \quad (13)$$

$With:$
$FCC_i = Individual\ foundation\ cost\ [€]$
$EIC_i = Indiviual\ electrical\ infrastructure\ cost\ [€]$
$TCC_i = Individual\ turbine\ capital\ cost\ [€]$
$TTAIC_i = Individual\ turbine\ transportation, assembly\ and\ installation\ cost\ [€]$
$N_t = Number\ of\ turbines\ in\ OWF$
$PDS_c = Permits, development\ and\ site\ assesment\ cost\ [€]$
$SP_c = Scour\ protetcion\ cost\ [€]$
$SB_c = Surety\ bond\ [€]$
$OW_c = Offshore\ warranty\ cost\ [€]$

Besides the already analyzed cost aspects, additional CAPEX cost includes the cost associated with the engineering and development of the OWF. The formulas used are discussed in appendix XII. The figure below shows the estimated CAPEX increasing a 7-fold from €100.000.000 to €700.000.000 on average. This increase is linear to the PS increase. This is the case for all CAPEX aspects.

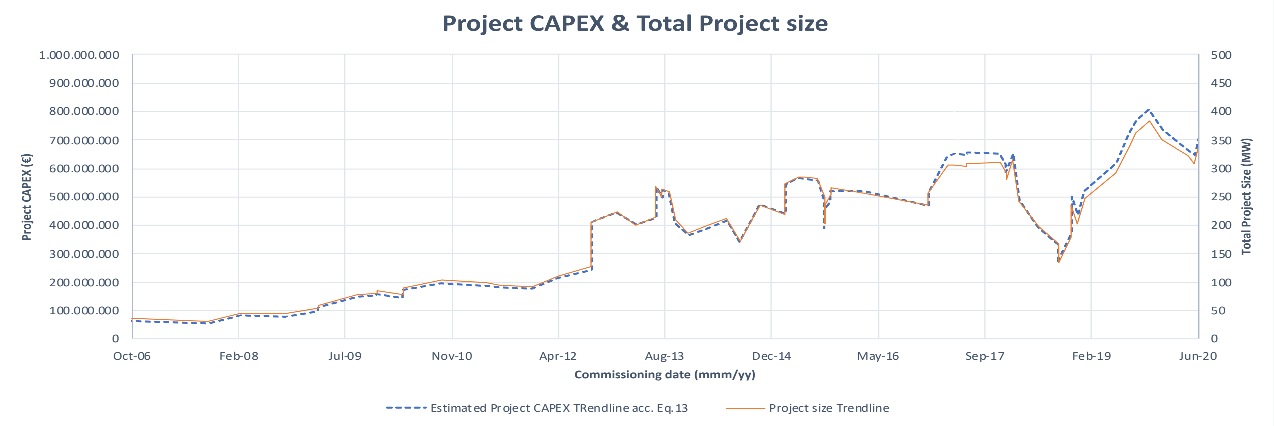



**Figure 30 Total CAPEX & Project size Trendline (Own figure,2021)**

### 4.4.2 OPEX

As was mentioned in the section specified to the O&M cost as a function of the DtS the OPEX is harder to quantify as a function of a substantive variable than that accounts for the CAPEX cost. The OPEX cost is usually defined as an average value in the unit of €/MW/Yr. The OPEX cost consists of multiple aspects with operational and maintenance (O&M) expenses being the majority part. Literature states that 60-70% of the total OPEX cost are related to the O&M expenses. (Voormolen, 2015) The O&M expenses are the expenses impacted by factors like travel time, accessibility, failure rates etc. To calculate the total lifetime expenses allocated to the OPEX of the OWF's average value in the unit of €/MW/Yr. are used. The OPEX its main driving factor is the probability of failure. This probability of failures is dependent mostly on the introduction of new technologies and available to use wind speeds. As the average wind speed increased over time as already defined in this study, it can be assumed that also the peaks and dips in the wind speed have increased. Especially the high peak wind speeds increase the load on internal parts of the turbine and the rotor itself. This load results in higher internal and external speeds, besides increasing internal temperatures just overall increases wear on the parts increasing the probability of a failure occurring or the so-called failure rates. (Universidad Pontificia Comillas, 2006) Appendix XIII and XIV shows the failure rates set out against the time of operation and internal temp. linked to the higher windspeeds.
With this research it is determined that due to the DtS increase and the resulting travel time and waiting hour increase the OPEX cost/yr. have been impacted. Furthermore, due to higher wind speeds associated with increasing hub height and mean average wind speeds on location in combination with TD leading to turbines with bigger dimensions all have led to an average increase in the OPEX cost per MW over time. Also, the sheer number of turbines has impacted the logistics behind the O&M and the overall probability of a failure occurring.

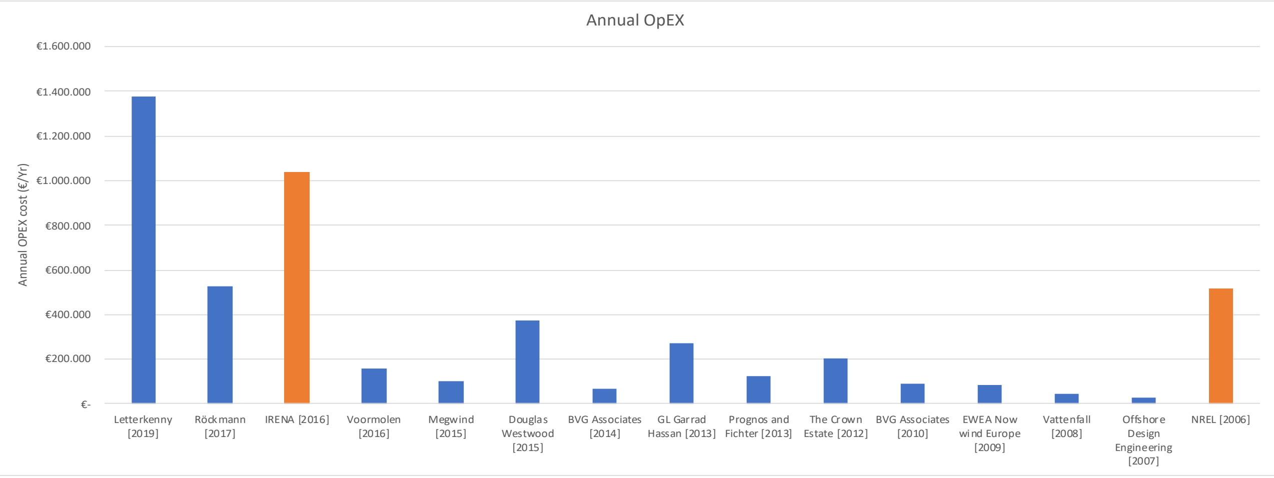



**Figure 31 Development of €/MW/Yr. OPEX cost as stated by literature (Own figure,2021)**

The figure above highlights how the stated OPEX cost in €/MW/Yr shown in blue has increased over time. By means of data collection on literature sources stating the €/MW/Yr the OPEX expenses are set out over time showing how the before mentioned factors have impacted the consensus on the OPEX cost and its impact on the LCOE. During this research two methods for calculating the average OPEX cost in €/MW/Yr were used shown in orange in figure 31.

$$OPEX\ Cost\ Estimation\ [(€/MW)/Yr] = (0{,}02108 * AEP) + (17 * T_p) \tag{14}$$

$With$:
$AEP = Anual\ Energy\ produced\ [MWh]$
$T_p = Turbine\ machine\ rating\ (MW)$

(National Renewable Energy Laboratory, 2006)

$$OPEX\ Cost\ Estimation\ [(€/MW)/Yr] = 17 * AEP \tag{15}$$

$With$:
$AEP = Annual\ Energy\ produced\ (MWh)$

(IRENA, 2016)

As there is an average cost/yr used the total OPEX over lifetime don't take decreasing OPEX during the peak operational years of the entire lifetime into account. (Centre for Doctoral training in Wind Energy systems, 2015) Furthermore, the total OPEX is defined by the amount of year that the OWF is operational. By means of data collection, the designed lifetime was determined for all OWF's in the scope of the research. Just 1 OWF that the LCOE could be estimated for surpassed its suspected lifetime. The amount of uncertainty and factors that couldn't be quantified in combination with statements made in literature stating the OPEX cost is a value per MW and has been countered by increasing project size and increased logistics. (Voormolen, 2015) Something also supported by trends constructed during this research all leads to the statement that certain factors related to DtS and TD have increased the €/MW OPEX cost but the OPEX isn't deemed as a driving factor of the LCOE.

### 4.4.3 AEP

The *total sum of electricity produced* is in this research defined by using the AEP. The AEP used is the stated AEP. By multiplying the AEP with the designed lifetime, the *total sum of electricity produced* is defined. Just as was the case for the OPEX just 1 OWF has a certified average stated AEP over its entire designed lifetime. All other OWF's in the scope of the research are assumed to produce a certain amount of electricity over its lifetime by means of maintaining the known average AEP over its actual lifetime.

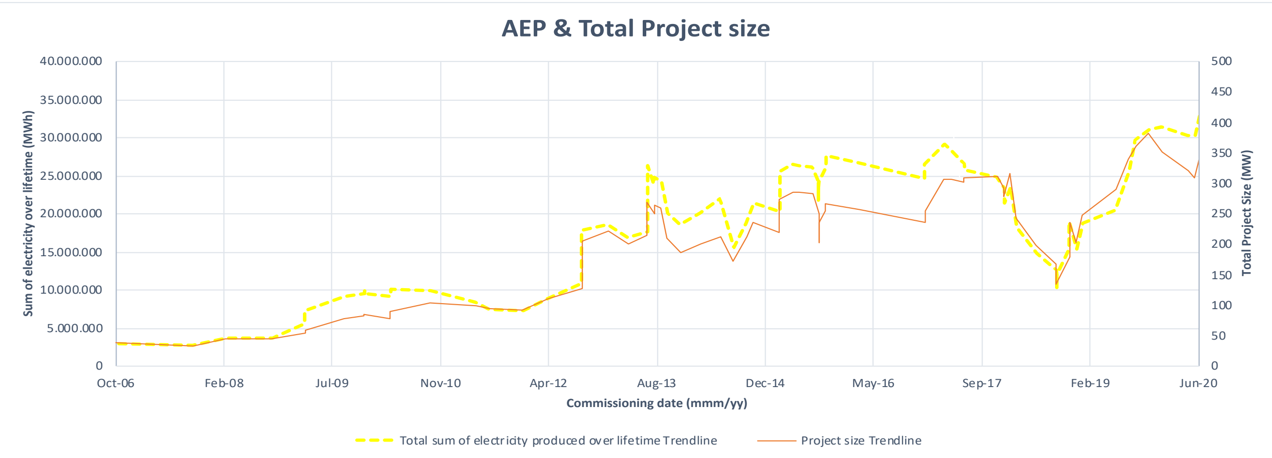



**Figure 32 Total sum of electricity produced over lifetime trendline (Own figure,2021)**

Figure 32 shows how the *total sum of electricity produced* is also mainly driven by the known project size. The fact remains however that the AEP per turbine hasn't increased as much as the cost related to the same turbine. The deviation in figure 32 between the two trends around 2016 are consistent with the increasing CF during that time.

### 4.4.4 Wake Losses

One driving factor impacting the AEP that is closely related to the project size are the so-called wake losses. Wake losses are created by the so-called "wake effect", this wake effect means that when a single turbine extracts energy from the wind downstream there is a wake from the wind turbine in which the wind speed is reduced. The wake effect is essentially the aggregated influence on the energy production of the wind farm. The dropping of the wind speeds impacts the production rate of the entire wind farm. (F. Gonzalez-Longatt, 2012) Eq. (7) uses the wind speeds to determine the AEP, in this research Eq. (16) is used to determine the wind speeds in the wake of the turbine. For these calculations no Weibull-coefficients, Wind direction or alignment of the OWF were used. Wake wind speeds were estimated for 1 row as is known that the wake effect hardly has any excessing impact after the wind passes the 1st row. (NYSERDA, 2018)

$$V_w(x)[m/s] = V_0\left[1 - (\frac{R}{kx + R})^2 * \left(1 - \sqrt{1 - C_T}\right)\right] \tag{16}$$

$With$:
$V_w = Wake\ wind\ speed\ over\ set\ downwind\ spacing\ (x)$
$V_0 = Mean\ location\ wind\ speed$
$R = Radius\ of\ the\ wind\ turbine\ [m]$
$k = Entrainment\ constant\ (Standard\ value\ offshore = 0{,}04)$
$C_T = Turbine\ thrust\ coefficient$

(Norwegian University of Science and Technology, 2018)

With the above standing equation, the wind speeds when affected by the wake effect were estimated. These wind speeds were estimated in the distance between the turbines or downwind spacing (in Eq. (16) defined as x). These downwind spacings were determined by means of data collection for 53,8% of the scope. For the remaining OWF's the method was applied that the downwind spacing generally is 7x the rotor diameter. (NYSERDA, 2018)

The thrust coefficient is dependent on the turbine type and can be defined as the unit of frontal area pressure that the turbine can convert into a thrust force.
(Georgia Tech College of Engineering, 2018)

$$C_T = \frac{3{,}5(2U_R + 3{,}5)}{U_R^2} \tag{17}$$

$With$:
$C_T = Thrust\ Coefficient$
$U_R = Rated\ turbine\ wind\ speed\ (m/s)$

(Georgia Tech College of Engineering, 2018)

When the AEP was estimated again with the differing wind speeds the difference between the two estimated AEP was seen as the wake losses. These wake losses, in general, were 11,9% which is cohesive with literature stating that wake losses of OWF's vary between 11 and 15%. (German offshore wind energy foundation, 2013) The average wake losses increased to 14,4% when just OWF's with 50+ turbines were taken into account and increased to 15,9% when OWF's with 80+ turbines were analyzed.

The trend clearly shows the wake losses increasing as the downwind spacing is reduced. The less downwind spacing the more wake losses have occurred. The downwind spacing itself is dependent on the number of turbines in the OWF. As the number of turbines decreases the downwind spacing increases. This is however only the case for OWF's close to shore. The fact that OWF's have become larger in the number of turbines has led to a reduction in downwind spacing. This is the result of the extensively increasing cost of enquiring such an extensive area of open sea to build in just to maintain the standard downwind spacing of 7 times the Rotor diameter. The increasing amount of wake losses have antagonized the AEP increase. The 11,9% wakes losses can be defined as 11,9% AEP losses.

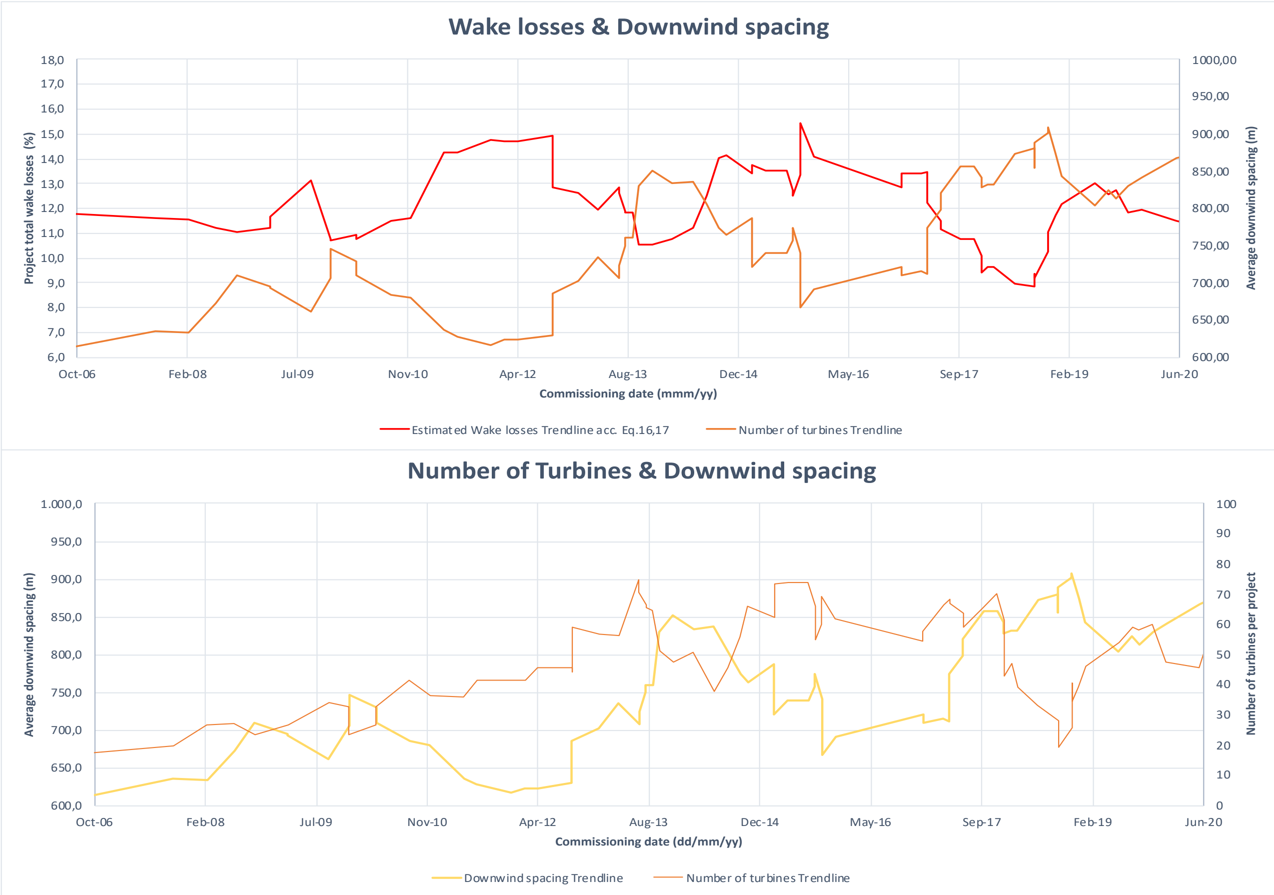



**Figure 33 Wake losses related Trendlines (Own figure, 2021)**

The AEP wake losses estimated are defined as internal wake losses. External wake losses from surrounding OWF's could drop the average windspeeds by as much as an additional 2,2 m/s. Increasing the overall wake losses to almost 20% if not managed correctly. External wake losses are in the current OWE sector not very common but as more OWF's are constructed clusters could start to form on locations with good wind conditions close to shore. (German offshore wind energy foundation, 2013)

## 4.5 WACC as a F&R based driving factor

Figure 34 highlights the sole methodology used to analyze the F&R aspect of this research. The discount rate or WACC is the only variable of the LCOE formula which is influenced by F&R based driving factors. The WACC can be defined as the cost of capital and seen as plane capital cost in figure 5. The substantive variables are not country-specific but rather specific to the OWE sectors development. The intermediate variables and dependent variables are country-specific and will be analyzed in such a matter.

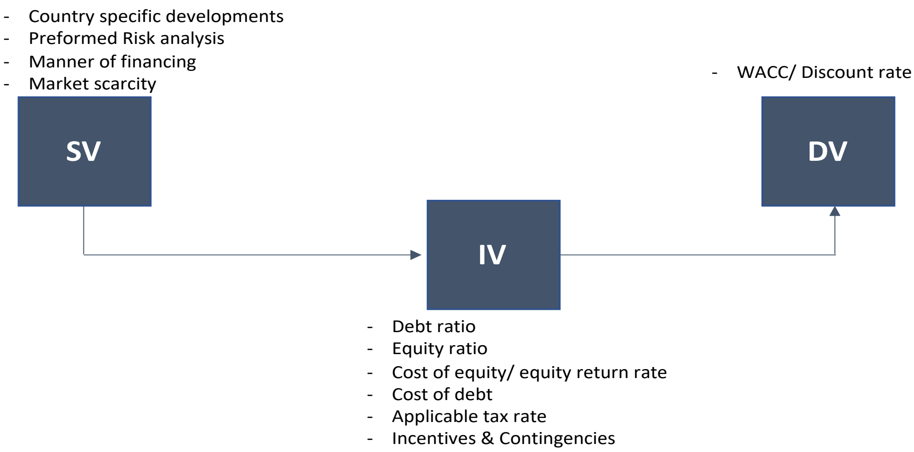



**Figure 34 Methodology F&R analysis (Own figure,2021)**

It is known that the WACC trend as shown in figure 35 per countries strongly differs and how impactful the WACC is to the overall LCOE. By means of data collection the figure below has been constructed. It shows how the UK has had a consequently EU wide high WACC up till 2017. (Voormolen, 2015) (PWC, 2020) (IEA Wind, 2018)

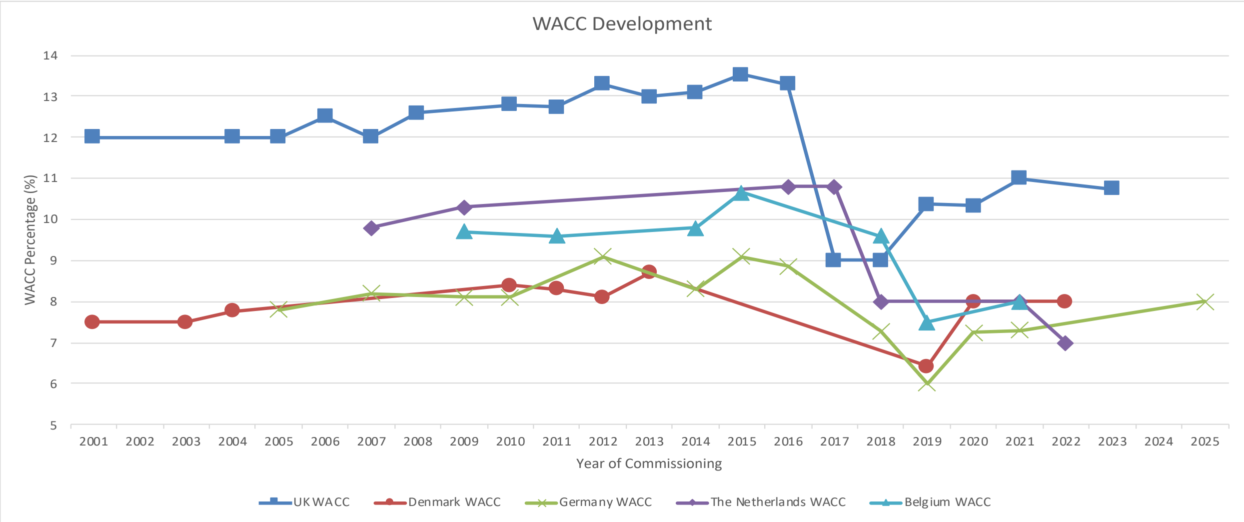



**Figure 35 WACC development of the countries within the scope (Own figure,2021)**

The WACC is mostly determined by country-specific political frameworks. To indicate the importance of the WACC, when the relatively low WACC of Denmark is applied to the OWF's in the UK their respective LCOE drops by approximately 22%. This indicates the big impact the political framework and long-term financial stability has is lowering the capital cost thus the LCOE. The eventual drop in WACC can be allocated to several market influences actual deemed as outside of the scope of this research. Auction-style processes to award projects to a developer have been more widely used since around 2017 in the OWE sector. The auction-style policy has been proposed by the EU because it helps guarantee the lowest possible price of electricity and increases the competitive nature of the market. (Energy Economics and System Analysis (EESA), 2021) The resulting bid of the developer is seen as the strike price. Strike prices for OWF's have decreased drastically over the years as an effect of developments within the variables of the WACC like results of risk assessments and manners of financing. (Energy Economics and System Analysis (EESA), 2021) Even some zero-bids were auctioned which has happened in 2020-2021 also influenced by the decrease in LCOE since 2017. Highlighting that the LCOE is also a market influencer and used in the financing aspect of the OWE sector. The auction-style process in combination with improvements in the risk assessments and stable revenues for the CfD since 2013 has led to a better balance between risk and return while simultaneously increasing debt capacity and lowering the WACC. (Energy Economics and System Analysis (EESA), 2021) (ARUP, 2018)

### *4.5.1 Manner of financing*

The equity ratio and debt ratio in Eq. (2) are influenced mostly by the manner of financing that is applied for the clearance of capital. For renewable energy or RE projects, two corporate finance structures are usually applied. These are balanced sheet financing and project financing. Project financing has since 2015 been used in more than half of the new investments related to new RE projects. (Energy Politics Group,2019, 2019) In balanced sheet financing the projects are funded by the developer themselves. This method includes financing through both equity and corporate debt. (TKI Wind op zee, 2019) The capital is raised at a company level through loans, bonds and share issues, the debt provider assesses whether the developer at the company level is able to repay their loans including interest payments. (PWC, 2020) The first OWF's were balanced sheet financed, the construction of OWF's was reserved for parties with a strong balance sheet and high liquidity[27]. When the understanding about construction and technological risks increased over time, project financing became the prominent financing structure in recent years. (PWC, 2020) In project financing itself, OWF projects are financed as stand-alone entities. The developer of the OWF provides equity to this entity and by doing this attracts equity investors and other lenders to the project. Then the providers of the equity and debt are repaid via cash flow generated by the project. (TKI Wind op Zee, 2015)

[27] i.e. good credit rating

The increasing trend of developers using the method of project financing suggests that project financing as a method could have among other benefits especially financial benefits. Project financing does increase the transparency of the investments for debt providers and provides them with a direct claim on assets in contrast to balanced sheet financing. (TKI Wind op zee, 2019) In theory, the manner of financing will have a limited effect on the cost of capital as the required return rate should not be differing as an effect of a used manner of financing. However, as project financing has become more widely adopted and in project financing the financial structure is dependent on tax optimization and financial gearing, the manner of financing has a hard to isolated impact on the cost of capital. The debt ratio is known to have increased from 60% to 75% due to the adaption of project financing, as debt is cheaper than equity the capital cost have been lowered as the before knowing equity; debt ratio was 40:60. (PWC, 2020) The impact of this on the LCOE is deemed as minimal and hard to quantify. (TKI Wind op zee, 2019)

### 4.5.2 Risk assessment

Generally speaking, the WACC is based on the amount of capital needed and the risk involved with the investment. The provider of the capital (debt provider) considers if the project's internal rate of return (IRR) is higher than the weighted average cost of the capital it is asked to provide. If the expected IRR exceeds the set WACC the debt provider declares the project financially viable. (PWC, 2020) When looking at other renewable energy sources historically speaking the WACC always decreases relatively quickly after its first years of known wide adoption and use. This is due to the fact that a new market related to some renewable energy sources always includes risks.(Westhoff, 2018) The WACC for solar PV has since its introduction fluctuated between the 2,5% and 5% on an EU average. Since 2018 the WACC is even stated around 2%. The EU wide average WACC for onshore wind has reached a high of 5% in 2015 but after this peak has dropped to 3,5% on average with a drop to 2,5% imminent for the future. The risk perception has its impact on the cost of equity/debt and the equity return rate in Eq. (2) Offshore wind historically speaking always had one of the highest WACC percentages in the RE market, this is mostly driven by the risk of investment as assessed by debt providers have not decreased as it has for other renewables. This is due to the fact that OWF's kept on being constructed in deeper waters, further from shore and had increasing dimensions raising the needed capital while the OWE sector itself showed lower CF than projected strongly reducing the AEP increasing the risk of investments. Besides this, the fact that wind turbines use rotating parts in contrast to solar PV has also increased the general risk of investment perceptions. (Energy Politics Group,2019, 2019) Investors when assessing the risk of investment consider country-level aspects as macro-economic stability and political uncertainties for long term commitments. We suspect that the political framework in the UK making the MWh tariff variable increases those uncertainties for long term commitments. The WACC decreases show in figure 35 can be mostly attributed to the decreasing required debt risk by introduction of risk premium cost of debt regulations in contrast to risk-free rate cost of debt besides the implementation of the auction process. The introduction of the cost of debt being dependent on the perceived risk, the liquidity risk and the margin of debt instead of the cost of debt with no risk for financial losses has dropped the cost of debt by 3% for OWF's commissioned after 2015. This implementation is due to the increasing competition on the market of debt providers and lowers perceived risks. (TKI Wind op zee, 2019) The cost of equity also reflects the risk perception but then accounted for by equity providers. The average cost of equity within the scope of this research is determined at 12,75%. Generally speaking, the risks related to the required return rate for OWF's are categorized into unsystematic risks and systematic risk.

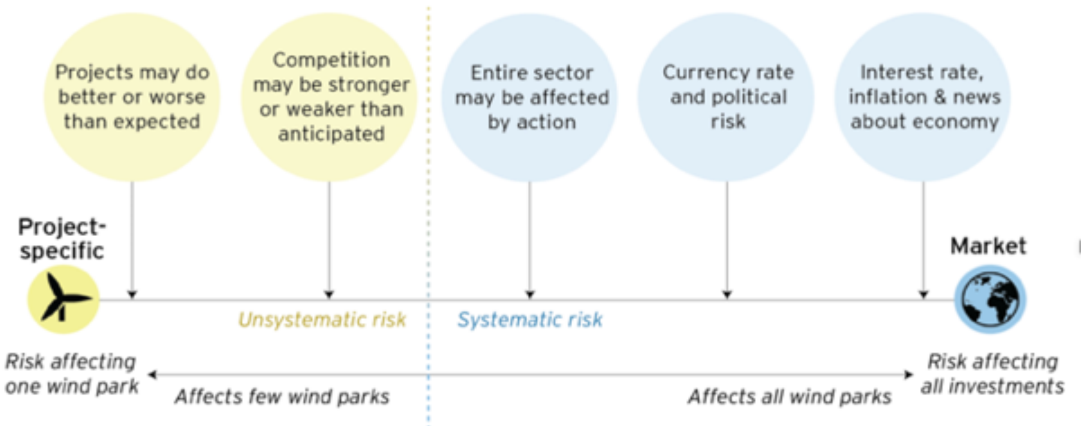



**Figure 36 Distinction between unsystematic and systematic risks (Westhoff, 2018)**

For balanced sheet financing risk assessment factors are seen as maturity risk, systematic risk and unsystematic risks. For project financing the commercial risk, macro-economic risk and political risk are also taken into account. The maturity risk is depended on the length of the project. The longer the term of an investment the more risk is associated with it. (Westhoff, 2018) With OWF having increasing lifetimes it can also be stated that the term of investment is starting to increase. The systematic risks driven by uncertainties in market movements is considered outside of the scope of this research. During this research, it was stated that several big delays in OWF commissioning happened especially in tender rounds 1 & 2 in the UK. (Voormolen, 2015) Some major OWF's were delayed by as much as 13 years, this delay was often coherent with a decrease in projects size that was going to be commissioned. Especially the delays lead to the implementation of outdated technology in the UK OWE. Contracts with manufacturers of turbines and cables were set at the official commissioning date and couldn't be adjusted to the implementation of up to date technology at the actual commissioning date. (Voormolen, 2015) In some cases, complete OWF's were cancelled and were never commissioned. These developments all lead to an increasing perception of unsystematic risks. Strongly preventing the WACC in the UK from dropping until 2017. The perceived risk in the other countries research already decreased significantly since 2011, however, the introduction of the auction-style process has contributed the most to the WACC. An overview of the risk assessment aspect and the main identified individual risk aspect is shown in appendix XV.

### 4.5.3 Market scarcity

A competitive market plays a vital role in the cost of offshore wind energy. Market scarcity has been a negative impactful factor. Market scarcity has mostly been focused on turbine manufacturers, cable manufacturers and debt providers. This scarcity has led to a less competitively market preventing the effective prices of certain parts to drop. The market scarcity has not been taken into account during this research as its impact is hard to quantify on a formula basis. According to the literature, a competitive market could lead to an overall cost reduction of upwards of 28% in the €/MW price. (Prognos AG & The Fichter Group, 2013)

### 4.5.4 Country specific developments

To quantify the impact of country-specific developments in appendix XVI & XVII an overview is given highlighting the average WACC variables for each of the specific countries related to this research. Also including incentives ruling. Incentive and contingencies ruling were not deemed as LCOE driving factors.

## 5. Validation

As this research is based upon the interpretation of substantive variables quantified by means of different methods into intermediate variables, during this research validations have been performed. The validations centre around the comparing of estimated values of the dependent variables and known values of these variables mentioned in other literature or previous studies. The comparisons are visualized in different appendixes.

- Appendix XVIII : CAPEX cost breakdown validation
- Appendix XIX : LCOE trend validation
- Appendix XX : Conclusion statements validation
- Appendix XXI : Country specific LCOE trends
- Appendix XXII : Table overview of additional validations

## 6. Discussion

The results of this study show what the driving factors in the LCOE of offshore wind power are. By indicating these driving factors, the study indicates how the cost and revenue aspects of offshore wind energy as a renewable energy sources have developed. The results indicate that the increase in expenditures as a result of an increase in WD, DtS, PS and TD couldn't be countered sufficiently due to a lesser increase in AEP as a result of the development of those same substantive variables. The findings surrounding the increase in expenditures are in line with those of previous studies. Also, the shortcomings in the AEP development based on the insufficient increase in the CF and the decrease in the availability of the OWF's are findings cohesive with known statements made in the existing literature. When the LCOE values are estimated based on the results of this study the values are 20-30% higher than known LCOE values related to offshore wind. The eventual LCOE trend does show a similar pattern to the known LCOE trend just with elevated values. These elevated values originate in the method used for calculating the FCC. The share of the FCC in the total CAPEX per OWF is not in line with the known total cost breakdown of an OWF. Based on the total FCC the share of the construction, transportation and installation of the foundations on the total cost becomes as substantial as the TCC. This deviation only becomes more distinct with large OWF, indicating that the used method for calculating the project FCC by multiplying the €/MW FCC with the project size can't be adapted. After readjusting the FCC to having the correct percentual share in the total cost the LCOE trend shows values and a trend cohesive with previous studies and literature.

The dependent variables besides the total cost of each of the aspects could all be validated with the initial results of the used calculations. The €/MW cost and individual turbine cost were all validated by data presented by previous studies and known literature. The deviations between the credibility of the dependent variables are due to the fact that the logistics aspect of the OWE isn't taken into account. As mentioned before the method of having each turbine and foundation individually have their share of the transportation and installation cost aspect is something that leads to the deviations especially at OWF's with a large number of turbines. The overall LCOE values must be interpreted with caution because of the use of average values directed at the OPEX aspect, the used CF and the used AEP. Further research could specify the LCOE values more by the use of actual known OPEX cost for each year of operation per OWF and the stated AEP of the OWF per individual year of operation. The fact that these averages are used leads to the fact that when in the LCOE calculations the designed lifetime is extended the LCOE values increase. Something that isn't cohesive with statements made in previous studies and known literature. The research has furthermore shown the importance of the WACC. The WACC that is used now in the calculations is country-specific based, there are deviations in the WACC not specified to the year of commissioning and the country of placement but rather the individual financial conditions of the owner/ developer. These deviations are deemed to be minimal, but these minimal deviations can still have their impact on the LCOE trend. Linking the WACC to individual OWF's is something that could be defined in further research.

# 7. Conclusion

This research has defined how certain developments within the OWE sector have led the certain anomalies in the LCOE trend of offshore wind energy in comparison to other renewable energy sources. What defines the average rise in the €/MWh price is the substantial increase in CAPEX expenditures due to the T&I based developments. At the centre of the T&I based driving factors is the distance to shore development, in search of better wind conditions and more available space to construct bigger OWF's the OWE sector moved further from shore. This increasing distance to shore was accompanied by an increase in water depth.
This increase in water depth led to the €/MW cost for foundations and installation to rise by 33% on a 1.4M€ average over the entire scope. The distance to shore itself increased the cost associated with the electrical infrastructure but was countered by the increasing project size and turbine size eventually decreasing the €/MW cost by 21% on a 0,5M€ average. The distance to shore has been the main driving factor behind the technological developments, as the wind conditions improved in combination with the available space for construction turbines kept getting larger in the search for more MWh produced per turbine. Technological developments like the increasing turbine power size, rotor diameter and hub height needed to accommodate this search for increased MWh produced per turbine. These technological developments lead to the €/MW cost for turbines to increase by 37,9% on a 0,8M€ average. The distance to shore besides being the driving factor of the CAPEX expenditures also had its impact on the total sum of energy produced. As the wind conditions improved the total sum of energy produced per turbines was deemed to increase as a function of the DtS and TD. However, due to this same distance to shore the unexpected amount of unscheduled maintenance as a result of a combination of the underestimation of the impact of salt in the wind on turbine parts and an extensive amount of failures in export cables extended the downtime of the turbines massively resulting in a subpar availability. The availability of OWF's within the scope of this research decreased from 95% to 77,5% due to the increasing travel time and waiting hours and the overall decreasing accessibility of the OWF's.

Together with the increasing wake losses, this has led to the increase in AEP over the entire scope being just 50% of the increase in total cost associated with the OWF's. The regularly scheduled maintenance was also impacted due to the increasing wind speeds associated with the increasing distance to shore resulting in higher internal speeds and temperatures consequently resulting in more wear and more need for preventive maintenance. These factors all centre around the subpar increase in the annual energy produced, highlighted by the average CF within the scope of this research being just 40,4% when a CF of 55-60% was expected for the OWE sector. The on average rising LCOE price un till 2015 as an anomaly is due to the overall investments made in the OWE sector. The substantial increase in the cost associated with the increase in project size growing exponentially due to the increasing cost associated with the water depth and distance to shore could have never been countered even with a 100% availability. Even with this 100% availability the sum of electricity produced as a function of the distance to shore and technological developments would have not increased linearly to the associated cost resulting in the overall LCOE still doubling from its initial value till 2015. All high LCOE OWF's have certain set similarities. firstly, they are constructed between 2012-2016 a period in which the market was still maturing resulting in an average WACC of 12,8% over these OWF's. The OWF's had an average availability of just 69% and an average CF of 40,5% due to their relatively high project size (228MW) and distance to shore (24,7Km). These similarities peak in value during 2013-2015, cohesive with the peak in the known LCOE trend. During this period 11 OWF's were commissioned of which 6 in the UK all having sub-par availabilities below 75% and CF's below 40,8% and most importantly an average WACC of 12,8%. The trend peak anomaly in the LCOE trend is due to some OWF's being commissioned with high WACC percentages that eventually delivered sub-par availabilities and thus revenues. This partly due to construction delays shortly before this period of time eventually leading to the placement of outdated technology and a subpar AEP during 2015 resulting in the peak anomaly in the LCOE trend. The increasing distance to shore and the factors that this substantive variable has negatively impacted prevented fixed percentage improvement in production efficiency and the non-adaption to Wright's law.

The WACC as an LCOE variable is both a consequence and a result of the increasing LCOE, the WACC is the sole variable influenced by the F&R based driving factors. Due to the sub-par revenues OWE projects were not deemed as less risk full investments over the years. The rising LCOE values due to the fact that bigger expenses in relation didn't lead to equally bigger revenues is used as main input for this risk assessment. Other factors that kept on increasing the risk of investments were the increasing water depths and distances to shore that led to consistently evolving risk and challenges within the sector. The results of these risk assessments led to a stable but high WACC. Especially the political framework in the UK led to scope wide high WACC values. The high WACC is the sole reason why even with 100% availability the LCOE would have still risen. The WACC values made big OWF's in especially the UK impossible to have lower or similar LCOE values than other OWF's at the time between 2012-2015. The WACC with the introduction of the auction-style process around 2017 has led to a better balance between risk and return while simultaneously increasing debt capacity and lowering the WACC substantially. The lowering of the WACC besides a decrease in distance to shore and a consequencing rise in availability leads to the LCOE dropping in value after 2015.

In the period between 2021 and 2050, the OWE sector will keep on developing. In the search for even better wind conditions, the distance to shore will keep on increasing. The introduction of the floating foundations will decrease the FCC cost in the future as the floating foundation principle isn't heavily dependent on the water depth anymore. The increasing distance to shore will put even more pressure on the logistics aspect of offshore wind. In order to counter the before mentioned impact of additional downtime and waiting hours as a function of the distance to shore on the offshore wind logistics, the logistics strategies and maintenance strategies will need to become more efficient to prevent excessive downtime. These improvements will need to centre around the monitoring aspect and the maintenance strategies applied to OWF. Sufficient maintenance strategies surrounding the subsea cable management and the impact of wind conditions on turbine parts is essential for countering the consequences of the increasing failure rates as a dependent variable. Furthermore, engineering innovations on the problematic aspects of those same factors could lead to technological innovations reducing the failure rates and reducing the extensive amount of downtime.

In the future due to the increasing number of OWF's naturally clusters of OWF's will start to form in places with good wind conditions relatively close to shore. These clusters allow the OWE sector to improve the logistics aspect, especially directed at the maintenance aspect by applying a joined maintenance strategy between OWF. The before mentioned clusters will in combination with increasing turbine size and decreasing spacing between turbines lead to wake losses both internal and external that could amount to 20% in the future. This 20% of AEP losses needs to be countered by accurate wind farm layout planning and reducing downtime by dealing with the logistics aspect. The projected LCOE values of offshore wind between 2021-2035 are with the applied CF and availability percentages known from the 2000-2020 period destined to rise again after 2021. Some major OWF's are constructed in the UK and Denmark that even with the lowered WACC with current data related to CF's and availability will ultimately rise the LCOE back to the 2016 values. By lowering the country-specific WACC by an additional 3% more the LCOE increase will be limited to just 46% and remain stable from 2020 onwards. For this to happen the market needs to remain and even increase in competitivity and the introduction of floating offshore wind should not impact the made risk assessment and not antagonize the strike prices in the future. One new challenge for the OWE sector will centre around the decommissioning or repowering of older OWF's. As time progresses the designed lifespan of OWF's will be reached and the OWF's will either be decommissioned or repowered. The repowering of OWF's by replacing older turbines with newer models has the absolute preference. The extending of the lifetime of an OWF will likely be more financially viable rather than decommissioning. Regular monitoring and maintenance and thereby extending the lifetime in combination with the repowering will eventually lead to an additional 5% lower LCOE. However, the expenses and new challenges of decommissioning/ repowering bring new uncertainties to this still-developing sector.

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## Appendix I: Cost development renewables based on Auction database and LCOE database

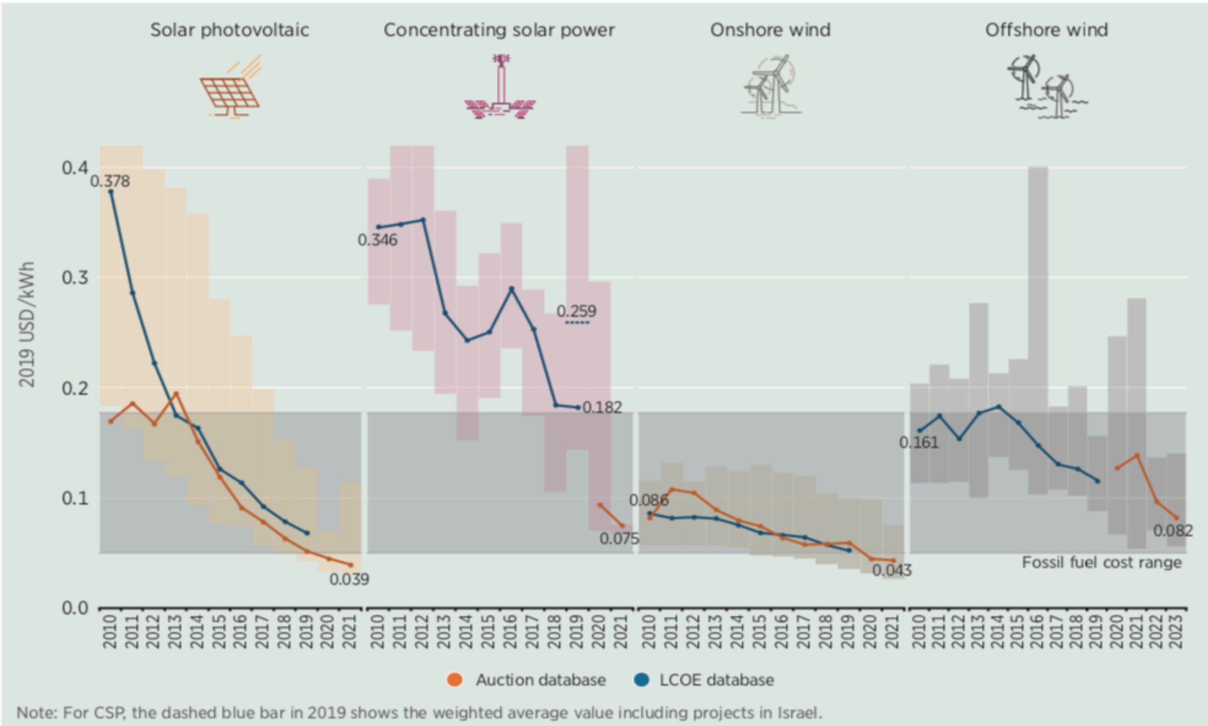
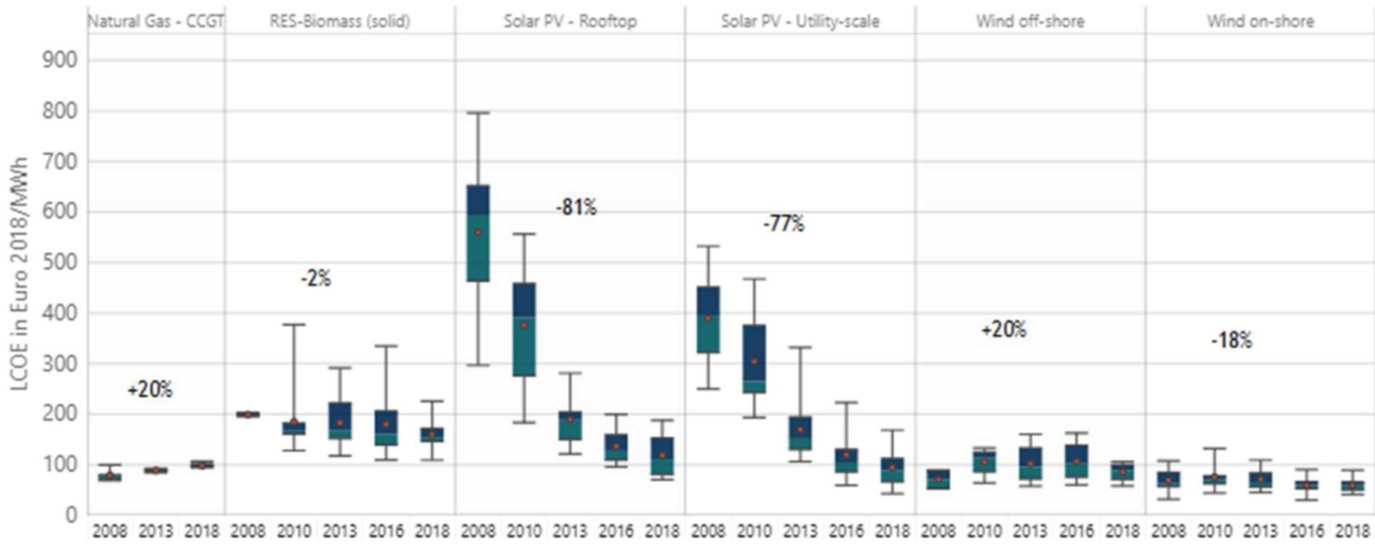



**Figure 37 Visual comparison LCOE trends RE sources (EWEA, 2019)**

## Appendix II: Changes in LCOE average from 2008-2018




Number of observations per year

| Country group | 2008 | 2010 | 2013 | 2016 | 2018 | Total |
|---|---|---|---|---|---|---|
| EU27 | 92 | 117 | 171 | 141 | 147 | 668 |

**Figure 38 Percentual development LCOE values 2008-2019 different RE sources (Trinomics, 2020)**

## Appendix III: Export initial LCOE

| Project | Country | Date | MW | Turbines (MW) | Foundation principle | CF | CAPEX | OPEX | Distance (km) | Depth (m) | Rotor Diameter (m) | life year projected | WACC | LCOE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Middelgrunden | DK | 01-04-01 | 40 | 2 | GravityBase | 25,5 | 1,52 | 4,29 | 4,7 | 4,5 | 76 | 25 | 7,5 | 93,12 |
| Horns Rev 1 | DK | 01-06-02 | 160 | 2 | Monopile | 42 | 2,3 | 9,98 | 18 | 10 | 80 | 25 | 7,5 | 59,32 |
| Samsø | DK | 01-02-03 | 23 | 2,3 | Monopile | 39,3 | 1,96 | 3,71 | 4 | 11,5 | 82 | 25 | 7,5 | 86,53 |
| North Hoyle | UK | 01-11-03 | 60 | 2 | Monopile | 31,8 | 2,51 | 5,4 | 8,7 | 9 | 80 | 25 | 12 | 122,8 |
| Nysted | DK | 01-12-03 | 165, 6 | | | 37,3 | 1,88 | 6,89 | 10,8 | 8 | 82 | 25 | 7,5 | 53,35 |
| Scroby Sands | UK | 01-07-04 | 60 | 2 | Monopile | 30,7 | 2,49 | 5,36 | 3,5 | 6 | 80 | 25 | 12 | 127,5 |
| Barrow | UK | 01-04-08 | 90 | 3 | Monopile | 36,1 | 2,4 | 7,06 | 9,8 | 17,5 | 90 | 20 | 12 | 105 |
| Egmond aan Zee | NL | 01-01-07 | 108 | 3 | Monopile | 33,1 | 2,35 | 7,7 | 10 | 16,5 | 59 | 20 | 9,8 | 99,77 |
| Burbo Bank | UK | 01-07-07 | 90 | 3,6 | Monopile | 34,1 | 2,86 | 6,77 | 6,4 | 4 | 107 | 20 | 12,5 | 132,76 |
| Prinses Amaliawindpark | NL | 01-07-08 | 120 | 2 | Monopile | 41,3 | 3,55 | 10,57 | 23 | 21,5 | 80 | 20 | 10,3 | 123,78 |
| Thornton Bank phase I | BE | 01-02-09 | 30 | 5 | GravityBase | 33 | 5,82 | 2,93 | 27 | 20 | 126 | 25 | 9,7 | 223,78 |
| Lynn & Inner Dowsing | UK | 01-04-09 | 190 | 3,6 | Monopile | 34,2 | 1,8 | 8,96 | 6,9 | 12 | 107 | 25 | 12,8 | 86,69 |
| Horns Rev 2 | DK | 01-09-09 | 209, 3 | 2,3 | Monopile | 48,1 | 2,43 | 12,63 | 32 | 13 | 93 | 25 | 8,4 | 63,55 |
| Sprogø | DK | 01-10-09 | 21 | 3 | GravityBase | 33,9 | 6,17 | 3,51 | 1 | 10 | 90 | 25 | 8,4 | 233,8 |
| Rhyl Flats | UK | 01-12-09 | 90 | 3,6 | Monopile | 33,1 | 2,62 | 5,57 | 10,7 | 9 | 107 | 25 | 12,8 | 129,3 |
| Alpha Ventus | DE | 01-04-10 | 60 | 5 | Jacket | 38 | 4,64 | 5,24 | 56 | 39 | 116 | 20 | 8,3 | 146,5 |
| Robin Rigg | UK | 01-04-10 | 174 | 3 | Monopile | 35,1 | 3,73 | 12,32 | 11,5 | 8,5 | 90 | 20 | 12,6 | 167,7 |
| Gunfleet Sands | UK | 01-06-10 | 172,8 | 3,6 | Monopile | 36,7 | 3,38 | 9,89 | 7 | 8,5 | 107 | 25 | 12,6 | 143,2 |
| Thanet | UK | 01-09-10 | 300 | 3 | Monopile | 32,6 | 3,37 | 15,49 | 17,7 | 22,5 | 90 | 25 | 12,6 | 159,6 |
| Rødsland 2 | DK | 01-10-10 | 207 | 2,3 | GravityBase | 44 | 2,41 | 13,98 | 7 | 9 | 90 | 20 | 8,3 | 71,72 |
| Belwind | BE | 01-12-10 | 165 | 3 | Monopile | 38,3 | 4,27 | 12,64 | 46 | 28,5 | 90 | 20 | 9,6 | 146,1 |
| EnBW Baltic 1 | DE | 01-04-11 | 48,3 | 2,3 | Monopile | 45 | 4,96 | 6,71 | 16 | 17,5 | 93 | 20 | 9,1 | 153,8 |
| Ormonde | UK | 01-02-12 | 150 | 5,075 | Jacket | 38,5 | 4,9 | 9,38 | 9,5 | 19 | 126 | 25 | 13,3 | 205,7 |
| Walney Phase 1 | UK | 01-02-12 | 183,6 | 3,6 | Monopile | 41 | 4,25 | 13,52 | 19,4 | 23,5 | 107 | 20 | 13,3 | 172,9 |
| Walney Phase 2 | UK | 01-02-12 | 183,6 | 3,6 | Monopile | 45,2 | 4,25 | 11,95 | 22,1 | 27,5 | 120 | 25 | 13,3 | 154,7 |
| Anholt | DK | 01-09-12 | 399,6 | 3,6 | Monopile | 49,4 | 3,56 | 26,56 | 15 | 17 | 120 | 20 | 8,7 | 92,34 |
| Sheringham Shoal | UK | 01-09-12 | 316, 8 | 3,6 | Monopile | 40,7 | 4,95 | 19,61 | 21,4 | 17,5 | 107 | 25 | 13,3 | 199,6 |
| Thornton Bank phase II | BE | 01-10-12 | 184, 5 | 6,15 | Jacket | 36 | 4,78 | 12,30 | 26 | 20 | 126 | 20 | 10,2 | 182,1 |
| Kentish Flats | UK | 01-07-13 | 90 | 3 | Monopile | 30,8 | 2,12 | 6,66 | 9,8 | 5 | 90 | 20 | 12,5 | 126,9 |
| London Array | UK | 01-07-13 | 630 | 3,6 | Monopile | 40,8 | 5,85 | 39,91 | 27,6 | 12,5 | 120 | 25 | 12,5 | 224,7 |
| Greater Gabbard | UK | 01-08-13 | 504 | 3,6 | Monopile | 42,1 | 3,7 | 27,30 | 36 | 26 | 107 | 25 | 12,5 | 141 |
| Thornton Bank | BE | 01-09-13 | 1244 | 6,4 | Jacket | 36,6 | 1,09 | 49,30 | 27 | 20 | 126 | 20 | 9,7 | 47,44 |
| BARD Offshore 1 | DE | 01-09-13 | 400 | 5 | Tripile | 34,5 | 7,85 | 33,50 | 101 | 40 | 122 | 25 | 8,3 | 266,1 |
| Lincs | UK | 01-09-13 | 270 | 3,6 | Monopile | 42,3 | 3,31 | 17,36 | 9,1 | 12,5 | 120 | 20 | 12,5 | 129,9 |
| Riffgat | DE | 01-02-14 | 108 | 3,6 | Monopile | 44,5 | 4,38 | 7,85 | 21,5 | 15 | 120 | 25 | 9,1 | 128,3 |
| Northwind | BE | 01-03-14 | 216 | 3 | Monopile | 42,9 | 1,62 | 11,02 | 37 | 25 | 112 | 25 | 10,65 | 61,05 |
| Teesside | UK | 01-04-14 | 62,1 | 2,3 | Monopile | 35,3 | 4,04 | 5,8 | 2,2 | 11 | 93 | 25 | 13,75 | 210,1 |
| Meerwind Süd/Ost | DE | 01-09-14 | 288 | 3,6 | Monopile | 42 | 4,34 | 17,32 | 23 | 24 | 120 | 25 | 9,1 | 132,5 |
| West of Duddon Sands | UK | 01-10-14 | 389 | 3,6 | Monopile | 45,4 | 5,31 | 25,23 | 14 | | 120 | 25 | 13,75 | 200 |
| DanTysk | DE | 01-12-14 | 288 | 3,6 | Monopile | 48,2 | 3,62 | 18,06 | 70 | 26,5 | 120 | 25 | 9,1 | 99,25 |
| EnBW Baltic 2 | DE | 01-02-15 | 288 | 3,6 | Monopile and jacked | 47,5 | 4,59 | 18,45 | 32 | 33,5 | 120 | 25 | 8,8 | 119,8 |
| Westermost Rough | UK | 01-03-15 | 210 | 6 | Monopile | 45,5 | 5,45 | 13,58 | 8 | 15 | 154 | 25 | 13,3 | 199,4 |
| Borkum riffgrund 1 | DE | 01-06-15 | 312 | 4 | Monopile | 39 | 4,15 | 17,64 | 40 | | 120 | 25 | 8,8 | 134 |
| Nordsee Ost | DE | 01-06-15 | 295, 2 | 6,15 | Jacket | 35 | 6,67 | 18,94 | 52 | 27 | 126 | 25 | 8,8 | 231,1 |
| Humber Gateway | UK | 01-06-15 | 219 | 3 | Monopile | 42,9 | 4,8 | 14,58 | 8 | 13 | 112 | 25 | 13,3 | 189,1 |
| Gwynt y Môr | UK | 01-06-15 | 576 | 3,6 | Monopile | 34,4 | 4,96 | 32,30 | 18 | 22,5 | 107 | 25 | 13,3 | 239,4 |
| Trianel windpark Borkum I | DE | 01-07-15 | 200 | 5 | Tripod | 49,7 | 4,7 | 13,05 | 45 | 30 | 116 | 25 | 8,8 | 118,5 |
| Global Tech I | DE | 01-07-15 | 400 | 5 | Tripod | 49,7 | 4,17 | 27,15 | 140 | 39 | 116 | 25 | 8,8 | 107,6 |
| Butendiek | DE | 01-08-15 | 288 | 3,6 | Monopile | 43 | 4,71 | 17,99 | 32 | 20 | 107 | 25 | 8,8 | 136,6 |
| Eneco luchterduinen | NL | 01-09-15 | 129 | 3 | Monopile | 46 | 3,64 | 8,98 | 23 | 20 | 112 | 25 | 10,8 | 118,5 |
| Amrumbank West | DE | 01-11-15 | 302 | 3,775 | Monopile | 42,4 | 3,45 | 16,70 | 35 | 22,5 | 120 | 25 | 8,8 | 104,1 |
| Kentish Flats Extension | UK | 01-12-15 | 49,5 | 3,3 | Monopile | 41,1 | 3,04 | 5,25 | 8,5 | 5 | 112 | 20 | 13,3 | 142,3 |
| Race Bank | UK | 01-02-16 | 573, 3 | 6,3 | Monopile | 44,7 | 3,37 | 30,11 | 33 | 18 | 154 | 24 | 13,3 | 126,8 |
| Westermeerwind | NL | 01-06-16 | 144 | 3 | Monopile | 42 | 2,88 | 8,94 | 0,5 | 7 | 108 | 25 | 10,8 | 105,2 |
| Burbo Bank Extension | UK | 01-04-17 | 254, 2 | 8 | Monopile | 39,1 | 2,42 | 11,00 | 7 | 10 | 164 | 25 | 9 | 82,79 |
| Veja Mate | DE | 01-03-17 | 402 | 6 | Monopile | 45,4 | 4,83 | 27,96 | 95 | 38 | 154 | 25 | 8 | 128,8 |
| Gemini | NL | 01-03-17 | 600 | 4 | Monopile | 49,3 | 4,77 | 42,88 | 55 | 32 | 130 | 20 | 8 | 117,7 |
| Gode Wind 1 and 2 | DE | 01-06-17 | 582 | 6,264 | Monopile | 37,8 | 3,87 | 29,29 | 45 | | 154 | 25 | 8 | 122,1 |
| Sandbank | DE | 01-07-17 | 288 | 4 | Monopile | 44,5 | 4,27 | 18,65 | 90 | 30 | 130 | 25 | 8 | 116,7 |
| Dudgeon | UK | 01-10-17 | 402 | 6 | Monopile | 48 | 4,34 | 23,54 | 32 | 21,5 | 154 | 25 | 9 | 116,9 |
| Wikinger | DE | 01-11-17 | 350 | 5 | Jacket | 51 | 4,08 | 21,06 | 35 | 40 | 135 | 25 | 8 | 97,34 |
| Nobelwind | BE | 01-12-17 | 165 | 3,3 | Monopile | 46,97 | 4,04 | 12,88 | 47 | 33 | 112 | 20 | 7,5 | 105,5 |
| Nordergründe | DE | 01-12-17 | 110, 7 | 6,15 | Monopile | 40 | 3,76 | 6,28 | 16 | 10 | 126 | 25 | 8 | 115,2 |
| Nordsee One | DE | 01-12-17 | 332, 1 | 6,15 | Monopile | 40,8 | 3,68 | 17,26 | 45 | 27,5 | 126 | 25 | 8 | 109,2 |
| Aberdeen offshore wind farm | UK | 01-03-18 | 93,2 | 8,2 | Jacket | 38 | 3,67 | 4,62 | 3,3 | 28 | 164 | 25 | 9 | 126,3 |
| Galloper | UK | 01-03-18 | 353 | 6 | Monopile | 47 | 4,84 | 22,62 | 27 | 31,5 | 154 | 23 | 9 | 134,4 |
| Walney Extension | UK | 01-09-18 | 659 | 8,25 | Monopile | 45,2 | 4,48 | 36,85 | 19 | | 154 | 25 | 9 | 128,9 |
| Borkum riffgrund 2 | DE | 01-12-18 | 450 | 8,3 | Various | 39 | 2,67 | 19,78 | 50 | 28 | 164 | 25 | 7 | 79,84 |
| Rampion | UK | 01-12-18 | 400, 2 | 3,45 | Monopile | 38,8 | 3,68 | 21,46 | 18 | | 112 | 25 | 9 | 125,8 |
| Arkona | DE | 01-04-19 | 385 | 6,417 | Monopile | 50 | 3,12 | 20,48 | 35 | 20 | 154 | 25 | 8 | 78,81 |
| Rentel | BE | 01-04-19 | 309 | 7 | Monopile | 48 | 4,53 | 20,94 | 40 | 30 | 154 | 20 | 7,5 | 112,7 |
| Merkur | DE | 01-06-19 | 396 | 6 | Monopile | 51 | 4,04 | 23,20 | 60 | 30 | 150 | 25 | 7 | 90,72 |
| Norther | BE | 01-10-19 | 369, 6 | 8,4 | Monopile | 54 | 3,52 | 23,19 | 23 | 24,5 | 164 | 20 | 7,5 | 79,97 |
| Deutsche Bucht | DE | 01-12-19 | 250 | 8,13 | Monopile | 51 | 5,2 | 19,11 | 80 | 39 | 164 | 25 | 7 | 116,9 |
| Hohe See | DE | 01-12-19 | 497 | 7 | Monopile | 49 | 3,62 | 31,45 | 95 | 35 | 154 | 25 | 7 | 87,14 |
| Beatrice | UK | 01-12-19 | 588 | 7 | Jacket | 49,4 | 5,54 | 37,58 | 13 | 42 | 154 | 25 | 9 | 145,1 |
| Hornsea Project One | UK | 01-04-20 | 1218 | 7 | Monopile | 52 | 2,6 | 70,6 | 110 | 27 | 154 | 25 | 11 | 80,54 |
| OWP Albatros | DE | 01-06-20 | 112 | 7 | Monopile | 49 | 2,72 | 5,98 | 60 | 40 | 154 | 25 | 8 | 71,87 |
| Kriegers Flak | DK | 01-10-20 | 590 | 8 | Various | 50 | 2,05 | 27,40 | 15 | 22 | 167 | 25 | 8 | 54,39 |
| East Anglia ONE | UK | 01-10-20 | 714 | 7 | Jacket | 55 | 3,96 | 38,21 | 50 | 35 | 154 | 30 | 11 | 108,7 |
| Horns Rev 3 | DK | 01-11-20 | 406, 7 | 8,3 | Monopile | 55 | 3,29 | 22,37 | 33 | 15 | 164 | 25 | 8 | 75,45 |
| Northwester 2 | BE | 01-02-21 | 219 | 9,5 | Monopile | 45 | 3,2 | 12 | 50 | 30 | 164 | 20 | 7 | 83,48 |
| Borssele 1 and 2 | NL | 01-03-21 | 752 | 8 | Monopile | 50 | 1,86 | 34,19 | 36 | 25 | 167 | 25 | 8 | 50,2 |
| Borssele 3 and 4 | NL | 01-03-21 | 731, 5 | 9,5 | Monopile | 47 | 1,78 | 31,46 | 42 | 25 | 164 | 25 | 7 | 47,49 |
| Triton Knoll | UK | 01-08-21 | 860 | 9,5 | Monopile | 44,6 | 2,63 | 39,63 | 33 | 21 | 164 | 25 | 11 | 91,79 |
| Hornsea Project Two | UK | 01-10-22 | 1386 | 8,4 | Monopile | 58 | 2,61 | 86,65 | 89 | 27 | 167 | 25 | 10 | 68,96 |

**Figure 39 Visual overview data set export made by (Gomez, 2020) made from (4C Offshore, 2021)**

**Table 5 Water depth data analysis overview (Own figure,2021)**

**Sub Question 1 T&I Based driving factors**

| Water Depth | Aspect of data collection | Scope of data collection | Grounded Theory analysis | Trend analysis Y-Axis | Trend analysis X-Axis | Nature of variables and correlation |
|---|---|---|---|---|---|---|
| | Water depth development | Demarcation EU offshore wind farms 2000-2021 | - | Water depth in meters | Commissioning date | Correlation |
| | Used foundation principle | Demarcation EU offshore wind farms 2000-2021 | - | Used foundation principle | Water depth | Correlation (Many to one) |
| | Increased Structural cost | Gravity based, monopile and jacket foundation | Foundation principle linked to structural cost | - | - | Causality |
| | Determination term build complexity | - | Quantifying term build complexity | - | - | Causality |
| | Increased installation cost | Demarcation EU offshore wind farms 2000-2021 | Impact build complexity on installation cost | Water depth & used foundation principle | Installation cost | Causality |

**Table 6 Distance to shore data analysis overview (Own figure,2021)**

**Sub Question 1 T&I Based driving factors**

| Distance to shore | Aspect of data collection | Scope of data collection | Grounded Theory analysis | Trend analysis Y-Axis | Trend analysis X-Axis | Nature of variables and correlation |
|---|---|---|---|---|---|---|
| | Development in distance to shore | Demarcation EU offshore wind farms 2000-2021 | - | Distance to shore in km | Commissioning date | Correlation |
| | Impact distance to shore on cable length and transmission charges | Demarcation EU offshore wind farms 2000-2021 | Quantifying impact on installation cost | Installation cost in euro/MW | Distance to shore in km | Causality |
| | Impact distance to shore on additional travel time | - | Quantifying term additional travel time | - | - | Correlation |
| | Impact on installation, operational and maintenance cost by additional travel time | Demarcation EU offshore wind farms 2000-2021 | - | Installation cost and operational and maintenance expenditures in euro/MW | Distance to shore & travel time | Causality |

**Table 7 Technological developments data analysis overview (Own figure,2021)**

**Sub Question 1 T&I Based driving factors**

| Technological developments | Aspect of data collection | Scope of data collection | Grounded Theory analysis | Trend analysis Y-Axis | Trend analysis X-Axis | Nature of variables and correlation |
|---|---|---|---|---|---|---|
| | Impact technological developments on power density and possible full-load hours | Demarcation EU offshore wind farms 2000-2021 | Quantifying increase in power density and possible full load hours | Power density and possible full load hours | Commissioning date | Causality |
| | Impact wind conditions on power density | Demarcation EU offshore wind farms 2000-2021 | Quantifying impact possible full load hours | Power density in MW/km2 | Distance to shore in km | Causality |
| | Power density and full load hour's impact on capacity factor | Demarcation EU offshore wind farms 2000-2021 | - | Capacity factor and power density | Commissioning date | Causality |

| | | | | | | |
|---|---|---|---|---|---|---|
| | Impact on Electrical energy generated | Demarcation EU offshore wind farms 2000-2021 | - | Electrical energy generated | Power density and capacity factor | Causality |
| | Increasing project size | Demarcation EU offshore wind farms 2000-2021 | - | Number of turbines, total MW, MW/turbine | Commissioning date | Correlation |
| | Increasing rotor diameter and hub-height | Demarcation EU offshore wind farms 2000-2021 | - | Hub-height and rotor diameter in Meters | Commissioning date | Correlation |
| | Impact on investment expenditures | Demarcation EU offshore wind farms 2000-2021 | Impact project size, rotor diameter and hub-height | MW/Turbine, Hub-height and rotor diameter | Investment expenditures | Causality |
| | Impact on Operational and maintenance expenditures | Demarcation EU offshore wind farms 2000-2021 | Impact project size, rotor diameter and hub-height | MW/Turbine, Hub-height and rotor diameter | Operational and maintenance expenditures | Causality |
| | Impact on Electrical energy generated | Demarcation EU offshore wind farms 2000-2021 | - | Electrical energy generated | MW/Turbine, Hub-height and rotor diameter | Causality |
| | Impact wake losses on electrical energy generated | - | Quantifying changes wake losses by TD | Electrical energy generated | Wake losses | Causality |
| | Amount of planned maintenance and scheduled downtime | - | Quantifying development in planned maintenance | Scheduled downtime | Commissioning date | Causality |
| | Amount of un-planned maintenance and un-scheduled downtime | - | Quantifying development in un- planned maintenance | Un-scheduled downtime | Commissioning date | Causality |

**Table 8 Analysis anomalies LCOE trend as function of T&I overview (Own figure,2021)**

**Sub Question 2 Effects T&I Based driving factors**

| **Anomalies LCOE trend** | **Aspect of data collection** | **Scope of data collection** | **Grounded Theory analysis** | **Trend analysis Y-Axis** | **Trend analysis X-Axis** | **Nature of variables and correlation** |
|---|---|---|---|---|---|---|
| | Influence on Investment expenditures | Sub-question 1 results | - | LCOE trend | Key Influences Investment expenditures | Correlation |
| | Influence on operational and maintenance cost | Sub-question 1 results | - | LCOE trend | Key Influences operational and maintenance cost | Correlation |
| | Influence on electrical energy generated | Sub-question 1 results | - | LCOE trend | Key Influences electrical energy generated | Correlation |

**Table 9 Risk analysis data analysis overview (Own figure,2021)**

**Sub Question 3 F&R Based driving factors**

| **Risk analysis** | **Aspect of data collection** | **Scope of data collection** | **Grounded Theory analysis** | **Trend analysis Y-Axis** | **Trend analysis X-Axis** | **Nature of variables and correlation** |
|---|---|---|---|---|---|---|
| | How risk analysis impacts determination cost of capital | - | Explanation how risk analysis is preformed | - | - | Correlation |
| | Cost of capital linked to WACC determination | - | Determination WACC from risk analysis | - | - | Correlation |
| | Impact wind farm design and reginal differences on WACC | | Quantification WACC | WACC (per country) | Year 2000-2021 | Correlation |

**Table 10 Regional differences data analysis overview (Own figure,2021)**

| Sub Question 3 F&R Based driving factors | | | | | | |
|---|---|---|---|---|---|---|
| **Regional differences** | **Aspect of data collection** | **Scope of data collection** | **Grounded Theory analysis** | **Trend analysis Y-Axis** | **Trend analysis X-Axis** | **Nature of variables and correlation** |
| | Difference in policy based on region/country | - UK<br>- The Netherlands<br>- Germany<br>- Denmark<br>- Belgium | Effects on WACC | - | - | Correlation |
| | Differences in financial incentives | - UK<br>- The Netherlands<br>- Germany<br>- Denmark<br>- Belgium | Impact financial incentives on investment expenditures | Incentives in €/MW (per country) | Year 2000-2021 | Correlation |
| | Differences in project contingencies | - UK<br>- The Netherlands<br>- Germany<br>- Denmark<br>- Belgium<br>- Group financing<br>- Project financing | Impact project contingencies on investment expenditures | Project contingencies in % on total investment (per country) | Year 2000-2021 | Correlation |
| | How financial incentives and project contingencies are used in the risk analysis | Demarcation EU offshore wind farms 2000-2021 | Use of incentives and project contingencies when determination of cost of capital | - | - | Causality |

**Table 11 Impact wind farm design data analysis overview (Own figure,2021)**

| Sub Question 3 F&R Based driving factors | | | | | | |
|---|---|---|---|---|---|---|
| **Wind farm design** | **Aspect of data collection** | **Scope of data collection** | **Grounded Theory analysis** | **Trend analysis Y-Axis** | **Trend analysis X-Axis** | **Nature of variables and correlation** |
| | Impact wind farm design on project contingencies | - UK<br>- The Netherlands<br>- Germany<br>- Denmark<br>- Belgium | Effects on investment expenditures | Project contingencies in % on total investment (per country) | Year 2000-2021 | Causality |
| | Development of estimated cost and needed capital | Demarcation EU offshore wind farms 2000-2021 | - | Total amount of needed capital | Year 2000-2021 | Causality |
| | Use of wind farm design as input risk analysis | - UK<br>- The Netherlands<br>- Germany<br>- Denmark<br>- Belgium | On:<br>- Needed capital<br>- Designed Power density<br>- Designed full load hours<br>- Designed capacity factor | - | - | Causality |
| | Changes in wind farm design on expected lifetime. | Demarcation EU offshore wind farms 2000-2021 | Possible impact of extended lifetime on LCOE | - | - | Correlation |

**Table 12 Analysis anomalies LCOE trend as function of F&R overview (Own figure,2021)**

**Sub Question 4 Effects F&R Based driving factors**

| Anomalies LCOE trend | Aspect of data collection | Scope of data collection | Grounded Theory analysis | Trend analysis Y-Axis | Trend analysis X-Axis | Nature of variables and correlation |
|---|---|---|---|---|---|---|
| | Influence on Investment expenditures | Sub-question 3 results | - | LCOE trend | Key Influences Investment expenditures | Causality |
| | Influence on discount rate | Sub-question 3 results | - | LCOE trend | Discount rate Or WACC (per country) | Causality |
| | Influence on expected lifetime of the system | Sub-question 3 results | - | LCOE trend | Expected lifetime of the system | Causality |

**Table 13 Analysis future LCOE values as function of T&I and F&R overview (Own figure,2021)**

**Sub Question 5 Possible cost reductions and LCOE values**

| Anomalies LCOE trend | Aspect of data collection | Scope of data collection | Grounded Theory analysis | Trend analysis Y-Axis | Trend analysis X-Axis | Nature of variables and correlation |
|---|---|---|---|---|---|---|
| | Deemed as significate Technology and infrastructure-based driving factors for the future | Demarcation EU offshore wind farms 2000-2021 | Possible cost reductions | Projected LCOE trend | Years 2021-2050 | Causality |
| | Possible significate Finance and risk-based driving factors | Demarcation EU offshore wind farms 2000-2021 | Possible cost reductions | Projected LCOE trend | Years 2021-2050 | Causality |

## Appendix V: Overview dataset used substantive variables

| ISO code | Name | Commissioning date | Sea name | Offshore Shore distance | Wind speeds on location | Designed wind power density | Used foundation principle | Turbine Manufacturer | Turbine Type | Turbine power |
|---|---|---|---|---|---|---|---|---|---|---|
| Code ISO 3166.1 | | yyyy/mm | | km | Yearly average (m/s) | W/m2 | | | | MW |
| GB | Blyth | 2000/12 | North Sea, Northern North Sea (Tyne) | 1 | 9,51 | 419,78 | Monopile | Vestas | V66/2000 | 2 |
| DK | Middelgrunden | 2000/12 | Øresund | 5 | #ND | 422,95 | Gravity-Base | Bonus | B76/2000 | 2 |
| DK | Horns Rev 1 | 2002/12 | North Sea | 18 | 9,88 | 431,98 | Monopile | Vestas | V80/2000 | 2 |
| DK | Frederikshavn Offshore | 2003/04 | Kattegat | 3 | 9,3 | 445,68 | Combined | Siemens | SWT-2.3-93 | 2,3 |
| DK | Frederikshavn Offshore | 2003/06 | Kattegat | 3 | 9,3 | 445,68 | Combined | Nordex | N90/2300 | 2,3 |
| DK | Frederikshavn Offshore | 2003/06 | Kattegat | 3 | 9,3 | 445,68 | Combined | Vestas | V90/3000 | 3 |
| DK | Nysted Offshore | 2003/11 | Baltic Sea | 11 | #ND | 430,52 | Gravity-Base | Bonus | B82/2300 | 2,3 |
| GB | North Hoyle | 2003/12 | Irish sea | 8 | 9,78 | 427,55 | Monopile | Vestas | V80/2000 | 2,3 |
| DK | Rønland | 2003/12 | Nissum Bredning | 0,1 | 10,2 | 444,38 | High-Rise Pile Cap | Vestas | V80/2000 | 2 |
| DK | Rønland | 2003/12 | Nissum Bredning | 0,1 | 10,2 | 445,68 | High-Rise Pile Cap | Bonus | B82/2300 | 2,3 |
| DK | Samso | 2003/12 | Kattegat | 4 | 8,78 | 418,16 | Monopile | Bonus | B82/2300 | 2 |
| GB | Scroby Sands | 2004/03 | North Sea, Southern North Sea (Thames) | 3 | 9,38 | 429,05 | Monopile | Vestas | V80/2000 | 2 |
| DE | Emden Offshore | 2004/10 | North Sea | 0,3 | 9,59 | 485,31 | Monopile | Enercon | E112/4500 | 4,5 |
| GB | Kentish Flats | 2005/10 | North Sea, Southern North Sea (Thames) | 10 | 9,81 | 431,98 | Monopile | Vestas | V90/3000 | 3 |
| DE | Breitling | 2006/02 | Breitling | 0,3 | #ND | 445,68 | Gravity-Base | Nordex | N90/2500 | 2,5 |
| GB | Barrow | 2006/07 | Irish sea | 10 | 9,79 | 439,02 | Monopile | Vestas | V90/3000 | 3 |
| NL | Egmond aan Zee | 2006/10 | North Sea | 14 | 9,56 | 431,98 | Monopile | Vestas | V90/3000 | 3 |
| GB | Beatrice Demonstration | 2007/07 | North Sea, Northern North Sea (Cromarty) | 25 | 9,97 | 465,95 | Jacket (Piled) | CSIC HZ Windpower | H151-5000 | 5 |
| GB | Burbo Bank | 2007/10 | Irish sea | 7 | 9,78 | 450,76 | Monopile | Vestas | V164/8000 | 3,6 |
| NL | Prinses Amalia | 2008/03 | North Sea | 25 | 9,94 | 416,52 | Monopile | Vestas | V80/2000 | 2 |
| BE | Thorntonbank | 2008/07 | North Sea | 27 | 10,21 | 462,61 | Gravity-Base | Repower | 5M | 5,08 |
| DE | Hooksiel | 2008/10 | North Sea | 3 | 9,94 | 458,00 | Tripile | Bard | BARD VM | 5,28 |
| GB | Lynn and Inner Dowsing | 2009/03 | North Sea, Southern North Sea (Humber) | 4,8 | 9,16 | 451,99 | Monopile | Siemens | SWT-3.6-107 | 3,6 |
| GB | Lynn and Inner Dowsing | 2009/03 | North Sea, Southern North Sea (Humber) | 4,8 | 9,16 | 451,99 | Monopile | Siemens | SWT-3.6-107 | 3,6 |
| DK | Horns Rev 2 | 2009/09 | North Sea | 32 | 9,94 | 429,05 | Monopile | Siemens | SWT-2.3-93 | 2,3 |
| DK | Sprogo | 2009/10 | Kattegat | 10 | #ND | 445,68 | Gravity-Base | Vestas | V90/3000 | 3 |
| DE | Alpha Ventus | 2009/12 | North Sea | 55 | 9,92 | 458,00 | Combined | Adwen | AD 5-116 | 5 |
| DE | Alpha Ventus | 2009/12 | North Sea | 45 | 9,92 | 470,28 | Combined | Adwen | AD 5-116 | 5 |
| GB | Rhyl Flats | 2009/12 | Irish sea | 9 | 9,78 | 439,02 | Monopile | Siemens | SWT-3.6-107 | 3,6 |
| GB | Gunfleet Sands 1 | 2010/04 | North Sea, Southern North Sea (Thames) | 7 | 9,93 | 439,02 | Monopile | Siemens | SWT-3.6-107 | 3,6 |
| GB | Gunfleet Sands 2 | 2010/04 | North Sea, Southern North Sea (Thames) | 7 | 9,93 | 439,02 | Monopile | Siemens | SWT-3.6-107 | 3 |
| GB | Robin Rigg | 2010/04 | Irish sea | 11 | 9,56 | 445,68 | Monopile | Vestas | V90/3000 | 3,6 |
| GB | Thanet | 2010/09 | North Sea, Southern North Sea (Thames) | 15 | 10,06 | 431,98 | Monopile | Vestas | V90/3000 | 3 |
| DK | Rodsand II | 2010/10 | Baltic Sea | 9 | #ND | 430,52 | Gravity-Base | Siemens | SWT-2.3-93 | 2,3 |
| GB | Wave Hub | 2010/11 | Celtic Sea (Lundy) | 33 | 9,94 | 469,21 | Floating | Alstom Power | Haliade 150 | 6 |
| BE | Belwind I | 2010/12 | North Sea | 46 | 10,16 | 440,38 | Monopile | Vestas | V90/3000 | 3 |
| DE | EnBW Baltic 1 | 2011/05 | Baltic Sea | 17 | 8,75 | 427,55 | Monopile | Siemens | SWT-2.3-93 | 2,3 |
| GB | Walney | 2011/07 | Irish sea | 22 | 9,79 | 458,00 | Monopile | Siemens | SWT-3.6-107 | 3,6 |
| DK | Avedøre Holme | 2011/12 | Øresund | 0,5 | 8,93 | 489,04 | Gravity-Base | Siemens | SWT-3.6-120 | 3,6 |
| GB | Ormonde | 2012/02 | Irish sea | 10 | 9,79 | 465,95 | Jacket (Piled) | Repower | 5M | 5,08 |
| GB | Walney | 2012/04 | Irish sea | 22 | 9,79 | 450,76 | Monopile | Siemens | SWT-3.6-107 | 3,6 |
| DK | Anholt | 2012/09 | Kattegat | 15 | 8,82 | 489,04 | Monopile | Siemens | SWT-3.6-120 | 3,6 |
| GB | Greater Gabbard 1 | 2012/09 | North Sea, Southern North Sea (Thames) | 34 | 9,88 | 458,00 | Monopile | Siemens | SWT-3.6-107 | 3,6 |
| GB | Greater Gabbard 2 | 2012/09 | North Sea, Southern North Sea (Thames) | 34 | 9,88 | 443,06 | Monopile | Siemens | SWT-3.6-107 | 3,6 |
| GB | Sheringham Shoal | 2012/09 | North Sea, Southern North Sea (Humber) | 22 | 9,17 | 448,24 | Monopile | Siemens | SWT-3.6-107 | 3,6 |
| BE | Thorntonbank | 2013/01 | North Sea | 27 | 10,21 | 463,73 | Jacket (Piled) | Senvion | 6.2M126 | 6,15 |
| GB | Gunfleet Sands 3 Demonstration | 2013/04 | North Sea, Southern North Sea (Thames) | 9 | 9,93 | 463,73 | Monopile | 2-B Energy | 2B6 | 6 |
| GB | London Array | 2013/07 | North Sea, Southern North Sea (Thames) | 22 | 9,95 | 454,43 | Monopile | Siemens | SWT-3.6-107 | 3,6 |
| BE | Thorntonbank | 2013/07 | North Sea | 26 | 10,21 | 450,76 | Jacket (Piled) | Senvion | 6.2M126 | 6,15 |
| DE | Bard Offshore 1 | 2013/08 | North Sea | 100 | 10,02 | 458,00 | Tripile | Bard | BARD VM | 2,3 |
| GB | Teesside | 2013/08 | North Sea, Northern North Sea (Tyne) | 2 | 9,4 | 445,68 | Monopile | Siemens | SWT-2.3-93 | 5,28 |
| GB | Lincs | 2013/09 | North Sea, Southern North Sea (Humber) | 8 | 9,16 | 469,21 | Monopile | Siemens | SWT-3.6-107 | 3,6 |
| GB | Fife Energy Park | 2013/10 | North Atlantic | 1 | 9,97 | 479,51 | Jacket (Piled) | Samsung | S7.0-171 | 7 |
| BE | Belwind Alstom Haliade Demonstration | 2013/12 | North Sea | 45 | 10,16 | 469,21 | Jacket (Piled) | Alstom Power | Haliade 150 | 6 |
| DE | Riffgat | 2014/03 | North Sea | 40 | 9,87 | 458,00 | Monopile | Siemens | SWT-3.6-120 | 3,6 |
| BE | Northwind | 2014/06 | North Sea | 37 | 10,21 | 450,76 | Monopile | Vestas | V112/3000 | 3 |
| DE | Dan Tysk | 2014/08 | North Sea | 92 | 9,97 | 455,63 | Monopile | Siemens | SWT-3.6-120 | 3,6 |
| GB | West of Duddon Sands | 2014/10 | Irish sea | 15 | 9,79 | 445,68 | Monopile | Siemens | SWT-3.6-120 | 3,6 |
| GB | Gwynt y Môr | 2014/11 | Irish sea | 17 | 9,78 | 467,05 | Monopile | Siemens | SWT-3.6-107 | 3,6 |
| DE | Meerwind Ost | 2015/03 | North Sea | 55 | 9,78 | 445,03 | Monopile | Siemens | SWT-3.0-108 | 3,6 |
| DE | Meerwind Süd | 2015/03 | North Sea | 55 | 9,78 | 451,99 | Monopile | Siemens | SWT-3.6-120 | 6,15 |
| DE | Nordsee Ost | 2015/03 | North Sea | 55 | 9,78 | 465,40 | Jacket (Piled) | Senvion | 6.2M126 | 3 |
| GB | Westermost Rough | 2015/05 | North Sea, Southern North Sea (Humber) | 10 | 9,19 | 469,21 | Monopile | Siemens | SWT-6.0-154 | 6 |
| GB | Humber Gateway | 2015/06 | North Sea, Southern North Sea (Humber) | 10 | 9,19 | 445,68 | Monopile | Vestas | V112/3000 | 3 |
| DE | Butendiek | 2015/08 | North Sea | 32 | 9,79 | 443,06 | Monopile | Siemens | SWT-3.6-120 | 3,6 |
| NL | Eneco Luchterduinen | 2015/09 | North Sea | 24 | 9,94 | 446,97 | Monopile | Vestas | V112/3000 | 3 |
| DE | Global Tech I | 2015/09 | North Sea | 110 | 10,05 | 458,00 | Tripod | Bard | BARD VM | 5 |
| DE | Trianel Borkum I | 2015/09 | North Sea | 55 | 9,92 | 458,00 | Tripod | Areva | M5000-116 | 5,28 |
| DE | Amrumbank West | 2015/10 | North Sea | 40 | 9,78 | 458,00 | Monopile | Siemens | SWT-3.6-120 | 4 |
| DE | Borkum Riffgrund I | 2015/10 | North Sea | 55 | 9,92 | 458,00 | Tripod | Siemens | SWT-4.0-120 | 3,6 |
| DE | EnBW Baltic 2 | 2015/10 | Baltic Sea | 33 | 8,83 | 443,06 | Combined | Siemens | SWT-3.6-107 | 3,6 |
| GB | Kentish Flats 2 | 2015/12 | North Sea, Southern North Sea (Thames) | 9 | 9,81 | 450,26 | Monopile | MHI Vestas Offshore | V112/3300 | 3,3 |
| NL | Westermeerdijk buitendijks | 2016/03 | #ND | 1 | #ND | 451,99 | Monopile | Siemens | SWT-3.6-120 | 3,6 |
| GB | Burbo Bank | 2016/12 | Irish sea | 9 | 9,78 | 491,77 | Monopile | Siemens | SWT-3.6-107 | 8 |
| DE | Nordergründe | 2017/01 | North Sea | 16 | 9,95 | 463,73 | Monopile | Senvion | 6.2M126 | 4 |
| DE | Sandbank | 2017/01 | North Sea | 95 | 10,09 | 463,73 | Monopile | Siemens | SWT-4.0-130 | 6,15 |
| NL | Gemini | 2017/04 | North Sea | 75 | 9,97 | 458,00 | Monopile | Siemens | SWT-4.0-130 | 4 |
| BE | Belwind II | 2017/05 | North Sea | 42 | 10,16 | 434,85 | Monopile | MHI Vestas Offshore | V112/3300 | 3,3 |
| DE | Veja Mate | 2017/05 | North Sea | 115 | 10,04 | 472,39 | Monopile | Siemens | SWT-6.0-154 | 6 |
| DE | Gode Wind I | 2017/07 | North Sea | 41 | 9,88 | 479,51 | Monopile | Siemens | SWT-6.0-154 | 6 |
| DE | Gode Wind II | 2017/07 | North Sea | 45 | 9,88 | 479,51 | Monopile | Siemens | SWT-6.0-154 | 6 |
| GB | Dudgeon | 2017/10 | North Sea, Southern North Sea (Humber) | 32 | 9,21 | 472,70 | Monopile | Siemens | SWT-6.0-154 | 5,08 |
| GB | Hywind Scotland Pilot Park | 2017/10 | North Sea, Northern North Sea (Cromarty) | 29 | 10,31 | 460,32 | Floating | Repower | 5M | 6 |
| DE | Nordsee One Offshore | 2017/12 | North Sea | 55 | 9,9 | 469,21 | Monopile | Senvion | 6.2M126 | 5,05 |
| DE | Wikinger Offshore | 2017/12 | Baltic Sea | 40 | 8,64 | #ND | Jacket (Piled) | Adwen | AD 5-135 | 6,15 |
| DK | Samso | 2018/01 | Kattegat | 4 | 8,78 | 418,16 | Monopile | Bonus | B82/2300 | 2,3 |
| DK | Samso | 2018/01 | Kattegat | 4 | 8,78 | 445,68 | Monopile | Bonus | B82/2300 | 2,3 |
| GB | Race Bank | 2018/02 | North Sea, Southern North Sea (Humber) | 32 | 9,12 | 479,51 | Monopile | Siemens | SWT-6.0-154 | 6 |
| DK | Nissum Bredning | 2018/03 | Nissum Bredning | 2 | 10,2 | 466,28 | Jacket (Gravity) | Siemens | SWT-7.0-154 | 7 |
| GB | Galloper | 2018/04 | North Sea, Southern North Sea (Thames) | 42 | 9,88 | #ND | Monopile | Siemens | SWT-6.0-154 | 6 |
| GB | Blyth Offshore | 2018/06 | North Sea, Northern North Sea (Tyne) | 14 | 9,46 | 479,51 | Gravity-Base | MHI Vestas Offshore | V164/8000 | 8 |
| GB | EOWDC | 2018/09 | North Sea, Northern North Sea (Cromarty) | 3 | 9,98 | 489,04 | Jacket (Suction Bucket) | MHI Vestas Offshore | V164/8300 | 8,3 |

**Figure 40 Substantive variable dataset 1 visual 1/2 (Own figure,2021)**

| ISO code | Name | Commissioning date | Sea name | Offshore Shore distance | Wind speeds on location | Designed wind power density | Used foundation principle | Turbine Manufacturer | Turbine Type | Turbine power |
|---|---|---|---|---|---|---|---|---|---|---|
| Code ISO 3166.1 | | yyyy/mm | | km | Yearly average (m/s) | W/m2 | | | | MW |
| GB | EOWDC | 2018/09 | North Sea, Northern North Sea (Cromarty) | 3 | 9,98 | 489,04 | Jacket (Suction Bucket) | MHI Vestas Offshore | V164/8300 | 8 |
| GB | Walney Extension | 2018/09 | Irish sea | 20 | 9,79 | #ND | Monopile | MHI Vestas Offshore | V164/8000 | 8,3 |
| GB | Walney Extension | 2018/09 | Irish sea | 20 | 9,79 | 474,47 | Monopile | Siemens | SWT-7.0-154 | 7 |
| GB | Kincardine Offshore Windfarm | 2018/10 | North Sea, Northern North Sea (Forth/Cromarty) | 15 | 9,84 | 474,47 | Floating | Vestas | MHI Vestas V164 | 8 |
| DE | Borkum Riffgrund II | 2018/11 | North Sea | 57 | 9,92 | 484,36 | Combined | MHI Vestas Offshore | V164/8000 | 3,45 |
| BE | Norther | 2018/11 | North Sea | 24 | 10,21 | 467,05 | Monopile | MHI Vestas Offshore | V164/8300 | 8 |
| GB | Rampion | 2018/11 | English Channel (Wight) | 19 | 9,77 | 450,76 | Monopile | Vestas | V112/3450 | 8,3 |
| BE | Rentel | 2018/12 | North Sea | 32 | 10,21 | 475,49 | Monopile | Siemens | SWT-7.0-154 | 7 |
| DE | Arkona | 2019/01 | Baltic Sea | 35 | 8,64 | 471,34 | Monopile | Siemens | SWT-6.0-154 | 6 |
| GB | Beatrice | 2019/05 | North Sea, Northern North Sea (Cromarty) | 13 | 10,06 | #ND | Jacket (Piled) | Siemens | SWT-7.0-154 | 7 |
| DE | Merkur Offshore | 2019/06 | North Sea | 60 | 9,92 | 472,39 | Monopile | GE Energy | Haliade 150 | 6 |
| DK | Horns Rev 3 | 2019/08 | North Sea | 30 | 9,95 | 471,34 | Monopile | MHI Vestas Offshore | V164/8000 | 8 |
| DE | Deutsche Bucht | 2019/09 | North Sea | 100 | 10,04 | 458,00 | Monopile | MHI Vestas Offshore | V164/8000 | 8 |
| DE | EnBW Hohe See | 2019/11 | North Sea | 95 | 10,01 | 474,47 | Monopile | Siemens | SWT-7.0-154 | 7 |
| GB | Hornsea Project One - Heron Wind | 2019/12 | North Sea, Southern North Sea (Humber) | 100 | 9,42 | #ND | Monopile | Siemens | SWT-7.0-154 | 7 |
| GB | Hornsea Project One - Njord | 2019/12 | North Sea, Southern North Sea (Humber) | 100 | 9,42 | #ND | Monopile | Siemens | SWT-7.0-154 | 7 |
| DE | Albatros | 2020/01 | North Sea | 110 | 10,05 | 474,47 | Monopile | Siemens | SWT-7.0-154 | 7 |
| BE | Northwester 2 | 2020/05 | North Sea | 50 | 10,16 | 657,27 | Monopile | MHI Vestas Offshore | V164/9500 | 9,5 |
| DE | Trianel Borkum II | 2020/06 | North Sea | 50 | 9,92 | 473,95 | Monopile | Senvion | 6.2M152 | 6,15 |
| GB | East Anglia One | 2020/07 | North Sea, Southern North Sea (Thames) | 50 | 9,73 | 489,04 | Jacket (Piled) | Siemens | SWT-7.0-154 | 7 |
| NL | Borssele I | 2020/11 | North Sea | 45 | 10,21 | #ND | Monopile | Siemens | SWT-8.0-154 | 8 |
| NL | Borssele II | 2020/11 | North Sea | 45 | 10,21 | #ND | Monopile | Siemens | SWT-8.0-154 | 8 |
| BE | Seamade (Mermaid) | 2020/12 | North Sea | 40 | 10,16 | #ND | Monopile | Siemens-Gamesa | SG 8.0-167 DD | 8 |
| BE | Seamade (SeaStar) | 2020/12 | North Sea | 48 | 10,16 | #ND | Monopile | Siemens-Gamesa | SG 8.0-167 DD | 8 |
| NL | Borssele III-IV | 2021/01 | North Sea | 45 | 10,21 | 507,89 | Monopile | MHI Vestas Offshore | V164/9500 | 9,5 |
| NL | Borssele V | 2021/01 | North Sea | 45 | 10,21 | 507,89 | Monopile | MHI Vestas Offshore | V164/9500 | 9,5 |
| GB | Kincardine Offshore Windfarm | 2021/06 | North Sea, Northern North Sea (Forth/Cromarty) | 15 | 9,84 | 474,47 | Floating | Vestas | MHI Vestas V164 | 4,3 |
| NL | Windpark Fryslân | 2021/06 | Ijsselmeer | 15 | 9,92 | 512,23 | Monopile | Siemens-Gamesa | SWT-DD-130 | 8 |
| DK | Kriegers Flak | 2021/12 | Baltic Sea | 20 | 8,94 | #ND | Monopile | Siemens-Gamesa | SG 8.0-167 DD | 8 |
| DE | Gicon SOF | 2022/01 | North Sea | 60 | 9,92 | 418,97 | Floating | Vestas | V80/2000 | 9,5 |
| DE | Gicon SOF | 2022/01 | North Sea | 60 | 9,92 | 443,06 | Floating | Siemens | SWT-2.3-93 | 9,5 |
| GB | Triton Knoll Wind Farm | 2022/01 | North Sea, Southern North Sea (Humber) | 35 | 9,16 | 506,24 | Monopile | MHI Vestas Offshore | V164/9500 | 2,3 |
| GB | Triton Knoll Wind Farm | 2022/01 | North Sea, Southern North Sea (Humber) | 35 | 9,16 | 506,24 | Monopile | MHI Vestas Offshore | V164/9500 | 2 |
| GB | Triton Knoll Wind Farm | 2022/01 | North Sea, Southern North Sea (Humber) | 35 | 9,16 | 506,24 | Monopile | MHI Vestas Offshore | V164/9500 | 9,5 |
| GB | Neart na Gaoithe | 2022/05 | North Sea, Northern North Sea (Forth) | 21 | 9,57 | #ND | Jacket (Piled) | Siemens-Gamesa | SG 8.0-167 DD | 8 |
| GB | Hornsea Project Two - Breesea and Optimus Wind | 2022/06 | North Sea, Southern North Sea (Humber) | 100 | 9,36 | #ND | Monopile | Siemens-Gamesa | SG 8.0-167 DD | 8 |
| DE | Kaskasi II | 2022/10 | North Sea | 48 | 9,78 | #ND | Monopile | Siemens-Gamesa | SG 8.0-167 DD | 9,5 |
| GB | Moray East | 2022/10 | North Sea, Northern North Sea (Cromarty) | 25 | 10,13 | 474,47 | Jacket (Piled) | MHI Vestas Offshore | V164/9500 | 8 |
| NL | Hollandse Kust Zuid Holland I - II | 2022/12 | North Sea | 26 | 9,97 | #ND | Monopile | Siemens-Gamesa | SG 11.0-200 DD | 11 |
| GB | Thanet 2 | 2023/04 | North Sea, Southern North Sea (Thames) | 15 | 10,06 | #ND | #NS (grounded) | #ND | #ND | #ND |
| NL | Hollandse Kust Zuid Holland III - IV | 2023/06 | North Sea | 26 | 9,97 | #ND | Monopile | Siemens-Gamesa | SG 10.0-193 DD | 10 |
| GB | Forthwind Offshore Wind Demonstration Project | 2023/10 | North Sea, Northern North Sea (Forth) | 1 | 9,05 | 450,76 | Jacket (Piled) | Siemens | SWT-6.0-120 | 6 |
| DK | Omo Syd | 2023/10 | Baltic Sea | 11 | #ND | #ND | #NS (grounded) | #ND | #ND | #ND |
| GB | Seagreen Alpha-Bravo | 2023/11 | North Sea, Northern North Sea (Forth) | 30 | 9,78 | #ND | Jacket (Suction Bucket) | Vestas | #ND | #ND |
| GB | Seagreen Charlie-Delta-Echo | 2023/11 | North Sea, Northern North Sea (Forth) | 60 | 9,78 | 474,47 | Jacket (Piled) | Vestas | V164/10000 | 10 |
| DE | Arcadis Ost 1 | 2023/12 | Baltic Sea | 19 | 8,7 | 531,60 | Monopile | MHI Vestas Offshore | V174/9500 | 12 |
| GB | Dogger Bank | 2023/12 | North Sea, Southern North Sea (Dogger) | 140 | 9,66 | 514,06 | Monopile | GE Energy | Haliade-X 12 MW | 8 |
| NL | Hollandse Kust Noord Holland I - II | 2023/12 | North Sea | 25 | 9,88 | #ND | Monopile | Siemens-Gamesa | SG 10.0-193 DD | 8 |
| DK | Vesterhavet Nord | 2023/12 | North Sea | 5 | 10,19 | #ND | Monopile | Siemens-Gamesa | SG 8.0-167 DD | 10 |
| DK | Vesterhavet Syd | 2023/12 | North Sea | 5 | 10,19 | #ND | Monopile | Siemens-Gamesa | SG 8.0-167 DD | 9,5 |
| DE | Gode Wind III | 2024/01 | North Sea | 42 | 9,88 | #ND | #NS (grounded) | Siemens-Gamesa | SG 11.0-200 DD | #ND |
| DE | Gode Wind III | 2024/01 | North Sea | 40 | 9,88 | #ND | #NS (grounded) | Siemens-Gamesa | SG 11.0-200 DD | 11 |
| DK | Jammerland Bugt | 2024/01 | Kattegat | 8 | #ND | #ND | #NS (grounded) | #ND | #ND | 5 |
| DK | Mejlflak | 2024/01 | Kattegat | 9 | 8,72 | 414,86 | #NS (grounded) | Vestas | V80/2000 | 2 |
| DE | Wikinger Süd | 2024/01 | Baltic Sea | 40 | 8,59 | 476,51 | #NS (grounded) | Repower | 5M | 11 |
| DE | Gennaker | 2024/06 | Baltic Sea | 15 | 8,43 | 515,34 | Monopile | Siemens | SWT-8.0-154 | 8 |
| DE | Baltic Eagle | 2024/08 | Baltic Sea | 30 | 8,7 | 531,60 | Monopile | MHI Vestas Offshore | V174/9500 | 8 |
| DK | Frederikshavn Offshore Demo | 2024/08 | Kattegat | 3 | 9,26 | 491,77 | Monopile | Vestas | V164/8000 | 9,5 |
| DK | Aflandshage | 2025/01 | Øresund | 4,8 | 8,93 | #ND | Gravity-Base | #ND | #ND | #ND |
| GB | Dogger Bank | 2025/01 | North Sea, Southern North Sea (Dogger) | 200 | 9,73 | 514,06 | Monopile | GE Energy | Haliade-X 12 MW | #ND |
| GB | East Anglia Three | 2025/01 | North Sea, Southern North Sea (Humber/Thames) | 70 | 9,57 | 511,76 | Monopile | #ND | #ND | 9,5 |
| GB | Hornsea Project Three | 2025/01 | North Sea, Southern North Sea (Humber) | 90 | 9,48 | #ND | #NS (grounded) | Siemens | #ND | 9,5 |
| GB | Inch Cape | 2025/01 | North Sea, Northern North Sea (Forth) | 20 | 9,63 | 474,47 | Monopile | MHI Vestas Offshore | V164/9500 | 12 |
| GB | Moray West | 2025/01 | North Sea, Northern North Sea (Cromarty) | 25 | 9,97 | 474,47 | #NS (grounded) | MHI Vestas Offshore | V164/9500 | 2 |
| DK | Nordre Flint | 2025/01 | Øresund | 11 | #ND | 431,98 | Gravity-Base | Vestas | V80/2000 | #ND |
| DE | EnBW He Dreiht | 2025/08 | North Sea | 95 | 10,01 | #ND | Monopile | #ND | #ND | #ND |
| DK | Lillebælt-Syd (Lillegrund) | 2025/08 | Baltic Sea | 11 | #ND | #ND | #NS (grounded) | Siemens-Gamesa | SG 8.0-167 DD | 8 |
| DE | Borkum Riffgrund III | 2025/12 | North Sea | 65 | 9,95 | 491,77 | #NS (grounded) | Vestas | V164/8000 | 8 |
| DE | Borkum Riffgrund III | 2025/12 | North Sea | 75 | 9,95 | 491,77 | #NS (grounded) | Vestas | V164/8000 | 8 |
| DE | Borkum Riffgrund III | 2025/12 | North Sea | 70 | 9,95 | 491,77 | #NS (grounded) | Vestas | V164/8000 | 8 |
| GB | Dogger Bank | 2026/12 | North Sea, Southern North Sea (Dogger) | 140 | 9,77 | 514,06 | Monopile | GE Energy | Haliade-X 12 MW | 12 |
| GB | Dudgeon Extension | 2026/12 | North Sea, Southern North Sea (Humber) | 36 | 9,17 | #ND | #NS (grounded) | Siemens | SWT-6.0-154 | 6 |
| GB | East Anglia Two | 2026/12 | North Sea, Southern North Sea (Thames) | 50 | 9,71 | #ND | Monopile | Siemens-Gamesa | SG 14-222 D | 14 |
| GB | Erebus (Demonstration) | 2026/12 | North Atlantic | 42 | 10,01 | #ND | Floating | #ND | #ND | #ND |
| GB | Hornsea Project Four | 2027/01 | North Sea, Southern North Sea (Humber) | 100 | 9,29 | #ND | #NS (grounded) | #ND | #ND | #ND |
| GB | East Anglia One North | 2027/04 | North Sea, Southern North Sea (Thames) | 50 | 9,6 | #ND | Monopile | #ND | #ND | #ND |
| GB | Norfolk Boreas | 2027/04 | North Sea, Southern North Sea (Humber/Thames) | 120 | 9,59 | 547,56 | #NS (grounded) | #ND | #ND | #ND |
| GB | Norfolk Vanguard | 2027/04 | North Sea, Southern North Sea (Humber/Thames) | 120 | 9,57 | 547,56 | #NS (grounded) | #ND | #ND | #ND |
| GB | Race Bank Extension | 2029/05 | North Sea, Southern North Sea (Humber) | 38 | 9,14 | #ND | #NS (grounded) | Siemens | SWT-6.0-154 | 6 |
| GB | Awel y Môr | 2030/01 | Irish sea | 16 | 9,78 | 467,05 | #NS (grounded) | Siemens | SWT-3.6-107 | 3,6 |
| GB | Blyth Offshore - 3A-4 | #ND | North Sea, Northern North Sea (Tyne) | 13 | 9,51 | 490,87 | Floating | Vestas | MHI Vestas V164 | #ND |
| GB | Dounreay Tri Offshore WDC | #ND | Scottish Continental Shelf (Fair Isle) | 9 | 11,19 | #ND | Floating | #ND | #ND | #ND |
| GB | Forthwind Offshore Wind Demonstration Project - 2 | #ND | North Sea, Northern North Sea (Forth) | 2 | 9,05 | 463,73 | Combined | 2-B Energy | 2B6 | #ND |
| GB | Galloper Extension | #ND | North Sea, Southern North Sea (Thames) | 42 | 9,88 | #ND | #NS (grounded) | #ND | #ND | 6 |
| GB | Greater Gabbard Extension | #ND | North Sea, Southern North Sea (Thames) | 34 | 9,88 | #ND | #NS (grounded) | Siemens | SWT-6.0-154 | #ND |
| GB | Ideol-Atlantis Energy Project 2 | #ND | #ND | #ND | 9,62 | #ND | Floating | #ND | #ND | 2 |
| DK | KadetBanke | #ND | Baltic Sea | 50 | 8,91 | #ND | #NS (grounded) | #ND | #ND | #ND |
| DK | Paludan Flak | #ND | Kattegat | 12 | #ND | #ND | #NS (grounded) | #ND | #ND | 8 |
| GB | Rampion Extension | #ND | English Channel (Wight) | 19 | 9,77 | 458,00 | #NS (grounded) | Areva | M5000-116 | #ND |
| GB | Seagreen Foxtrot-Golf | #ND | North Sea, Northern North Sea (Forth) | 40 | 9,78 | #ND | #NS (grounded) | #ND | #ND | #ND |
| GB | Sheringham Shoal Extension | #ND | North Sea, Southern North Sea (Humber) | 22 | 9,17 | #ND | #NS (grounded) | #ND | #ND | 6 |
| DK | Trea Mollebugt | #ND | #ND | #ND | #ND | 445,68 | #NS (grounded) | Vestas | V80/2000 | 5 |

**Figure 41 Substantive variable dataset 1 visual 2/2 (Own figure,2021)**

| ISO code | Name | Commissioning date | Rated Turbine wind speed | Gearbox type | Gearbox stages | Generator type | Rotor diameter | Swept area | Rotor power density | Rotor power density | Hub height |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Code ISO 3166.1 | | yyyy/mm | m/s | | | | m | m2 | W/m2 | m2/kW | m SS = Site Specific |
| GB | Blyth | 2000/12 | 17 | Step-planetary gear-helical | 3 | Induction with optispeed | 67 | 3421 | 584,6 | 1,7 | 62 |
| DK | Middelgrunden | 2000/12 | 15 | Planetary/helical | 3 | AMA 500L4/6A BAYH | 76 | 4500 | 444,4 | 2,3 | 64 |
| DK | Horns Rev 1 | 2002/12 | 16 | Spur/planetary | 3 | Asynchronous | 80 | 5027 | 397,9 | 2,5 | 70 |
| DK | Frederikshavn Offshore | 2003/04 | 14 | Spur/planetary | 3 | Asynchronous | 93 | 6800 | 338,2 | 3 | 80 |
| DK | Frederikshavn Offshore | 2003/06 | 12 | spur/planetary | 3 | Double fed Asyn | 90 | 6362 | 361,5 | 2,8 | 80 |
| DK | Frederikshavn Offshore | 2003/06 | 15 | Planetary/helical | (2/1) | #ND | 90 | 6362 | 471,5 | 2,1 | 80 |
| DK | Nysted Offshore | 2003/11 | 15 | spur/planetary | 3 | Asynchronous | 82,4 | 5300 | 434 | 2,3 | 69 |
| GB | North Hoyle | 2003/12 | 16 | Spur/planetary | 3 | Asynchronous | 80 | 5027 | 397,9 | 2,5 | 67 |
| DK | Rønland | 2003/12 | 15 | Spur/planetary | 3 | Asynchronous | 80 | 5027 | 434 | 2,3 | 80 |
| DK | Rønland | 2003/12 | 16 | spur/planetary | 3 | Asynchronous | 82,4 | 5300 | 397,9 | 2,5 | 79 |
| DK | Samso | 2003/12 | 15 | spur/planetary | 3 | Asynchronous | 82,4 | 5300 | 434 | 2,3 | 61 |
| GB | Scroby Sands | 2004/03 | 16 | Spur/planetary | 3 | Asynchronous | 80 | 5027 | 397,9 | 2,5 | 68 |
| DE | Emden Offshore | 2004/10 | 13 | Non-direct drive | 0 | Synchronus permanent | 114 | 10207 | 440,9 | 2,3 | 116 |
| GB | Kentish Flats | 2005/10 | 15 | Planetary/helical | (2/1) | #ND | 90 | 6362 | 471,5 | 2,1 | 70 |
| DE | Breitling | 2006/02 | 13,5 | spur/planetary | 3 | Double fed Asyn | 90 | 6362 | 393 | 2,5 | 80 |
| GB | Barrow | 2006/07 | 15 | Planetary/helical | (2/1) | #ND | 90 | 6362 | 471,5 | 2,1 | 75 |
| NL | Egmond aan Zee | 2006/10 | 15 | Planetary/helical | (2/1) | #ND | 90 | 6362 | 471,5 | 2,1 | 70 |
| GB | Beatrice Demonstration | 2007/07 | 10,5 | #ND | #ND | Synchronus permanent | #ND | #ND | 279,2 | 3,6 | 97 |
| GB | Burbo Bank | 2007/10 | 13,5 | #ND | #ND | PMG (permanent magnet) | #ND | #ND | 400 | 2,5 | 123 |
| NL | Prinses Amalia | 2008/03 | 16 | Spur/planetary | 3 | Asynchronous | 80 | 5027 | 397,9 | 2,5 | 60 |
| BE | Thorntonbank | 2008/07 | 14 | Planetary | 3 | #ND | 126 | 12469 | 407 | 2,5 | 94 |
| DE | Hooksiel | 2008/10 | 12,5 | spur/planetary | 3 | Double fed Asyn | 122 | 11690 | 451,3 | 2,2 | 90 |
| GB | Lynn and Inner Dowsing | 2009/03 | 13,5 | Planetary/helical | 3 | Asynchronous | 107 | 9000 | 400 | 2,5 | 85 |
| GB | Lynn and Inner Dowsing | 2009/03 | 13,5 | Planetary/helical | 3 | Asynchronous | 107 | 9000 | 400 | 2,5 | 85 |
| DK | Horns Rev 2 | 2009/09 | 14 | Spur/planetary | 3 | Asynchronous | 93 | 6800 | 338,2 | 3 | 68 |
| DK | Sprogo | 2009/10 | 15 | Planetary/helical | (2/1) | #ND | 90 | 6362 | 471,5 | 2,1 | 80 |
| DE | Alpha Ventus | 2009/12 | 12,5 | Step-planetary gear-helical | 1 | Synchronus permanent | 116 | 10568 | 473,1 | 2,1 | 101 |
| DE | Alpha Ventus | 2009/12 | 12,5 | Step-planetary gear-helical | 1 | Synchronus permanent | 116 | 10568 | 473,1 | 2,1 | 90 |
| GB | Rhyl Flats | 2009/12 | 13,5 | Planetary/helical | 3 | Asynchronous | 107 | 9000 | 400 | 2,5 | 75 |
| GB | Gunfleet Sands 1 | 2010/04 | 13,5 | Planetary/helical | 3 | Asynchronous | 107 | 9000 | 400 | 2,5 | 75 |
| GB | Gunfleet Sands 2 | 2010/04 | 13,5 | Planetary/helical | 3 | Asynchronous | 107 | 9000 | 400 | 2,5 | 75 |
| GB | Robin Rigg | 2010/04 | 15 | Planetary/helical | (2/1) | #ND | 90 | 6362 | 471,5 | 2,1 | 80 |
| GB | Thanet | 2010/09 | 15 | Planetary/helical | (2/1) | #ND | 90 | 6362 | 471,5 | 2,1 | 70 |
| DK | Rodsand II | 2010/10 | 14 | Spur/planetary | 3 | Asynchronous | 93 | 6800 | 338,2 | 3 | 69 |
| GB | Wave Hub | 2010/11 | 17,5 | non-direct drive | 0 | Synchronus permanent | 150 | 17860 | 335,9 | 3 | 100 |
| BE | Belwind I | 2010/12 | 15 | Planetary/helical | (2/1) | #ND | 90 | 6362 | 471,5 | 2,1 | 76 |
| DE | EnBW Baltic 1 | 2011/05 | 14 | Spur/planetary | 3 | Asynchronous | 93 | 6800 | 338,2 | 3 | 67 |
| GB | Walney | 2011/07 | 13,5 | Planetary/helical | 3 | Asynchronous | 107 | 9000 | 400 | 2,5 | 90 |
| DK | Avedøre Holme | 2011/12 | 12 | Planetary/helical | 3 | Asynchronous | 120 | 11300 | 318,6 | 3,1 | 120 |
| GB | Ormonde | 2012/02 | 14 | Planetary | 3 | #ND | 126 | 12469 | 407 | 2,5 | 97 |
| GB | Walney | 2012/04 | 13,5 | Planetary/helical | 3 | Asynchronous | 107 | 9000 | 400 | 2,5 | 84 |
| DK | Anholt | 2012/09 | 12 | Planetary/helical | 3 | Asynchronous | 120 | 11300 | 318,6 | 3,1 | 120 |
| GB | Greater Gabbard 1 | 2012/09 | 13,5 | Planetary/helical | 3 | Asynchronous | 107 | 9000 | 400 | 2,5 | 90 |
| GB | Greater Gabbard 2 | 2012/09 | 13,5 | Planetary/helical | 3 | Asynchronous | 107 | 9000 | 400 | 2,5 | 78 |
| GB | Sheringham Shoal | 2012/09 | 13,5 | Planetary/helical | 3 | Asynchronous | 107 | 9000 | 400 | 2,5 | 82 |
| BE | Thorntonbank | 2013/01 | 14 | Spur/planetary | 3 | Double fed Asyn | 126 | 12469 | 493,2 | 2 | 95 |
| GB | Gunfleet Sands 3 Demonstration | 2013/04 | 13 | spur/planetary | 3 | Double fed induction | 140,6 | 15526 | 386,4 | 2,6 | 95 |
| GB | London Array | 2013/07 | 13,5 | Planetary/helical | 3 | Asynchronous | 107 | 9000 | 400 | 2,5 | 87 |
| BE | Thorntonbank | 2013/07 | 14 | Spur/planetary | 3 | Double fed Asyn | 126 | 12469 | 493,2 | 2 | 84 |
| DE | Bard Offshore 1 | 2013/08 | 12,5 | spur/planetary | 3 | Double fed Asyn | 122 | 11690 | 451,3 | 2,2 | 90 |
| GB | Teesside | 2013/08 | 14 | Spur/planetary | 3 | Asynchronous | 93 | 6800 | 338,2 | 3 | 80 |
| GB | Lincs | 2013/09 | 13,5 | Planetary/helical | 3 | Asynchronous | 107 | 9000 | 400 | 2,5 | 100 |
| GB | Fife Energy Park | 2013/10 | 11,5 | Planet flexpin | 3 | PMG (permanent magnet) | 171,2 | 23020 | 304,1 | 3,3 | 110 |
| BE | Belwind Alstom Haliade Demonstration | 2013/12 | 17,5 | non-direct drive | 0 | Synchronus permanent | 150 | 17860 | 335,9 | 3 | 100 |
| DE | Riffgat | 2014/03 | 12 | Planetary/helical | 3 | Asynchronous | 120 | 11300 | 318,6 | 3,1 | 90 |
| BE | Northwind | 2014/06 | 11,5 | Non-direct drive | 0 | Synchronus permanent | 112 | 9940 | 301,8 | 3,3 | 84 |
| DE | Dan Tysk | 2014/08 | 12 | Planetary/helical | 3 | Asynchronous | 120 | 11300 | 318,6 | 3,1 | 88 |
| GB | West of Duddon Sands | 2014/10 | 12 | Planetary/helical | 3 | Asynchronous | 120 | 11300 | 318,6 | 3,1 | 80 |
| GB | Gwynt y Môr | 2014/11 | 13,5 | Planetary/helical | 3 | Asynchronous | 107 | 9000 | 400 | 2,5 | 98 |
| DE | Meerwind Ost | 2015/03 | 12 | Non-direct drive | 0 | Synchronus permanent | 108 | 9144 | 328,1 | 3 | 79,5 |
| DE | Meerwind Süd | 2015/03 | 12 | Planetary/helical | 3 | Asynchronous | 120 | 11300 | 318,6 | 3,1 | 85 |
| DE | Nordsee Ost | 2015/03 | 14 | Spur/planetary | 3 | Double fed Asyn | 126 | 12469 | 493,2 | 2 | 96,5 |
| GB | Westermost Rough | 2015/05 | 13 | Non-direct drive | 0 | Synchronus permanent | 154 | 18600 | 322,6 | 3,1 | 100 |
| GB | Humber Gateway | 2015/06 | 11,5 | Non-direct drive | 0 | Synchronus permanent | 90 | 9940 | 301,8 | 3,3 | 80 |
| DE | Butendiek | 2015/08 | 12 | Planetary/helical | 3 | Asynchronous | 120 | 11300 | 318,6 | 3,1 | 78 |
| NL | Eneco Luchterduinen | 2015/09 | 11,5 | Non-direct drive | 0 | Synchronus permanent | 112 | 9940 | 301,8 | 3,3 | 81 |
| DE | Global Tech I | 2015/09 | 12,5 | spur/planetary | 3 | Double fed Asyn | 122 | 11690 | 451,3 | 2,2 | 90 |
| DE | Trianel Borkum I | 2015/09 | 12,5 | step-planetary gear-helical | 1 | Synchronus permanent | 116 | 10568 | 473,1 | 2,1 | 90 |
| DE | Amrumbank West | 2015/10 | 12 | Planetary/helical | 3 | Asynchronous | 120 | 11300 | 318,6 | 3,1 | 90 |
| DE | Borkum Riffgrund I | 2015/10 | 13,5 | Planetary/helical | 3 | Asynchronous | 120 | 11300 | 354 | 2,8 | 90 |
| DE | EnBW Baltic 2 | 2015/10 | 13,5 | Planetary/helical | 3 | Asynchronous | 107 | 9000 | 400 | 2,5 | 78 |
| GB | Kentish Flats 2 | 2015/12 | 12,5 | Spur/planetary | 3 | #ND | 112 | 9852 | 335 | 3 | 83,6 |
| NL | Westermeerdijk buitendijks | 2016/03 | 12 | Planetary/helical | 3 | Asynchronous | 120 | 11300 | 318,6 | 3,1 | 85 |
| GB | Burbo Bank | 2016/12 | 13 | Planetary/helical | 3 | Asynchronous | 107 | 9000 | 378,7 | 2,6 | 84 |
| DE | Nordergründe | 2017/01 | 14 | Spur/planetary | 3 | Double fed Asyn | 126 | 12469 | 493,2 | 2 | 95 |
| DE | Sandbank | 2017/01 | 12 | Planetary/helical | 3 | Squirrel Cage Induction | 130 | 13273 | 301,4 | 3,3 | 95 |
| NL | Gemini | 2017/04 | 12 | Planetary/helical | 3 | Squirrel Cage Induction | 130 | 13273 | 301,4 | 3,3 | 90 |
| BE | Belwind II | 2017/05 | 12,5 | Spur/planetary | 3 | #ND | 112 | 9852 | 335 | 3 | 72 |
| DE | Veja Mate | 2017/05 | 13 | Non-direct drive | 0 | Synchronus permanent | 154 | 18600 | 322,6 | 3,1 | 103 |
| DE | Gode Wind I | 2017/07 | 13 | Non-direct drive | 0 | Synchronus permanent | 154 | 18600 | 322,6 | 3,1 | 110 |
| DE | Gode Wind II | 2017/07 | 13 | Non-direct drive | 0 | Synchronus permanent | 154 | 18600 | 322,6 | 3,1 | 110 |
| GB | Dudgeon | 2017/10 | 13 | Non-direct drive | 0 | Synchronus permanent | 154 | 18600 | 322,6 | 3,1 | 103,3 |
| GB | Hywind Scotland Pilot Park | 2017/10 | 14 | Planetary | 3 | #ND | 126 | 12469 | 407 | 2,5 | 92 |
| DE | Nordsee One Offshore | 2017/12 | 14 | Spur/planetary | 3 | Double fed Asyn | 126 | 12469 | 493,2 | 2 | 100 |
| DE | Wikinger Offshore | 2017/12 | 11,4 | step-planetary gear-helical | 1 | Synchronus permanent | 135 | 14326 | 352,5 | 2,8 | #SS |
| DK | Samso | 2018/01 | 15 | spur/planetary | 3 | Asynchronous | 82,4 | 5300 | 434 | 2,3 | 80 |
| DK | Samso | 2018/01 | 15 | spur/planetary | 3 | Asynchronous | 82,4 | 5300 | 434 | 2,3 | 61 |
| GB | Race Bank | 2018/02 | 13 | Non-direct drive | 0 | Synchronus permanent | 154 | 18600 | 322,6 | 3,1 | 110 |
| DK | Nissum Bredning | 2018/03 | 13 | Direct drive | 1 | Synchronus permanent | 154 | 18600 | 376,3 | 2,7 | 97,3 |
| GB | Galloper | 2018/04 | 13 | Non-direct drive | 0 | Synchronus permanent | 154 | 18600 | 322,6 | 3,1 | #SS |
| GB | Blyth Offshore | 2018/06 | 13 | Planetary | 3 | Synchronus permanent | 164 | 21164 | 378 | 2,6 | 110 |
| GB | EOWDC | 2018/09 | 13 | Planetary | 3 | Synchronus permanent | 164 | 21124 | 392,9 | 2,5 | 120 |

**Figure 42 Substantive variable dataset 2 visual 1/2 (Own figure,2021)**

| ISO code | Name | Commissioning date | Rated Turbine wind speed | Gearbox type | Gearbox stages | Generator type | Rotor diameter | Swept area | Rotor power density | Rotor power density | Hub height |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Code ISO 3166.1 | | yyyy/mm | m/s | | | | m | m2 | W/m2 | m2/kW | m SS = Site Specific |
| GB | EOWDC | 2018/09 | 13 | Planetary | 3 | Synchronus permanent | 164 | 21124 | 392,9 | 2,5 | 120 |
| GB | Walney Extension | 2018/09 | 13 | Planetary | 3 | Synchronus permanent | 164 | 21164 | 376,3 | 2,7 | 105 |
| GB | Walney Extension | 2018/09 | 13 | Direct drive | 1 | Synchronus permanent | 154 | 18600 | 378 | 2,6 | #SS |
| GB | Kincardine Offshore Windfarm | 2018/10 | 13 | Planetary | 3 | Synchronus permanent | 164 | 21164 | 378 | 2,6 | 105 |
| DE | Borkum Riffgrund II | 2018/11 | 13 | Planetary | 3 | Synchronus permanent | 164 | 21164 | 378 | 2,6 | 115 |
| BE | Norther | 2018/11 | 13 | Planetary | 3 | Synchronus permanent | 164 | 21124 | 392,9 | 2,5 | 98 |
| GB | Rampion | 2018/11 | 13 | Spur/planetary | 3 | #ND | 112 | 9852 | 350,2 | 2,9 | 84 |
| BE | Rentel | 2018/12 | 13 | Direct drive | 1 | Synchronus permanent | 154 | 18600 | 376,3 | 2,7 | 106 |
| DE | Arkona | 2019/01 | 13 | Non-direct drive | 0 | Synchronus permanent | 154 | 18600 | 322,6 | 3,1 | 102 |
| GB | Beatrice | 2019/05 | 13 | Direct drive | 1 | Synchronus permanent | 154 | 18600 | 376,3 | 2,7 | #SS |
| DE | Merkur Offshore | 2019/06 | 17,5 | direct drive | 1 | Synchronus permanent | 150 | 17860 | 335,9 | 3 | 103 |
| DK | Horns Rev 3 | 2019/08 | 13 | Planetary | 3 | Synchronus permanent | 164 | 21164 | 378 | 2,6 | 102 |
| DE | Deutsche Bucht | 2019/09 | 13 | Planetary | 3 | Synchronus permanent | 164 | 21164 | 378 | 2,6 | 90 |
| DE | EnBW Hohe See | 2019/11 | 13 | Direct drive | 1 | Synchronus permanent | 154 | 18600 | 376,3 | 2,7 | 105 |
| GB | Hornsea Project One - Heron Wind | 2019/12 | 13 | Direct drive | 1 | Synchronus permanent | 154 | 18600 | 376,3 | 2,7 | #SS |
| GB | Hornsea Project One - Njord | 2019/12 | 13 | Direct drive | 1 | Synchronus permanent | 154 | 18600 | 376,3 | 2,7 | #SS |
| DE | Albatros | 2020/01 | 13 | Direct drive | 1 | Synchronus permanent | 154 | 18600 | 376,3 | 2,7 | 105 |
| BE | Northwester 2 | 2020/05 | #ND | Planetary | 3 | PMG (permanent magnet) | 164 | 21124 | 449,7 | 2,2 | 105 |
| DE | Trianel Borkum II | 2020/06 | 11,5 | spur/planetary | 3 | Double fed Asyn | 152 | 18146 | 338,9 | 3 | 104,5 |
| GB | East Anglia One | 2020/07 | 13 | Direct drive | 1 | Synchronus permanent | 154 | 18600 | 376,3 | 2,7 | 120 |
| NL | Borssele I | 2020/11 | #ND | Direct drive | 1 | Synchronus permanent | 154 | 18600 | 430,1 | 2,3 | #SS |
| NL | Borssele II | 2020/11 | #ND | Direct drive | 1 | Synchronus permanent | 154 | 18600 | 430,1 | 2,3 | #SS |
| BE | Seamade (Mermaid) | 2020/12 | 12 | Direct drive | 1 | Synchronus permanent | 167 | 21900 | 365,3 | 2,7 | #SS |
| BE | Seamade (SeaStar) | 2020/12 | 12 | Direct drive | 1 | Synchronus permanent | 167 | 21900 | 365,3 | 2,7 | #SS |
| NL | Borssele III-IV | 2021/01 | #ND | Planetary | 3 | PMG (permanent magnet) | 164 | 21124 | 449,7 | 2,2 | 105 |
| NL | Borssele V | 2021/01 | #ND | Planetary | 3 | PMG (permanent magnet) | 164 | 21124 | 449,7 | 2,2 | 105 |
| GB | Kincardine Offshore Windfarm | 2021/06 | 13 | Planetary | 3 | Synchronus permanent | 164 | 21164 | 378 | 2,6 | 105 |
| NL | Windpark Fryslân | 2021/06 | #ND | Direct drive | 1 | Synchronus permanent | 130 | 13300 | 323,3 | 3,1 | 109 |
| DK | Kriegers Flak | 2021/12 | 12 | Direct drive | 1 | Synchronus permanent | 167 | 21900 | 365,3 | 2,7 | #SS |
| DE | Gicon SOF | 2022/01 | 14 | Spur/planetary | 3 | Asynchronous | 80 | 5027 | 338,2 | 3 | 78 |
| DE | Gicon SOF | 2022/01 | 16 | Spur/planetary | 3 | Asynchronous | 93 | 6800 | 397,9 | 2,5 | 61.5 |
| GB | Triton Knoll Wind Farm | 2022/01 | #ND | Planetary | 3 | PMG (permanent magnet) | 164 | 21124 | 449,7 | 2,2 | 140 |
| GB | Triton Knoll Wind Farm | 2022/01 | #ND | Planetary | 3 | PMG (permanent magnet) | 164 | 21124 | 449,7 | 2,2 | 140 |
| GB | Triton Knoll Wind Farm | 2022/01 | #ND | Planetary | 3 | PMG (permanent magnet) | 164 | 21124 | 449,7 | 2,2 | 140 |
| GB | Neart na Gaoithe | 2022/05 | 12 | Direct drive | 1 | Synchronus permanent | 167 | 21900 | 365,3 | 2,7 | #SS |
| GB | Hornsea Project Two - Breesea and Optimus Wind | 2022/06 | 12 | Direct drive | 1 | Synchronus permanent | 167 | 21900 | 365,3 | 2,7 | #SS |
| DE | Kaskasi II | 2022/10 | 12 | Direct drive | 1 | Synchronus permanent | 167 | 21900 | 365,3 | 2,7 | #SS |
| GB | Moray East | 2022/10 | #ND | Planetary | 3 | PMG (permanent magnet) | 164 | 21124 | 449,7 | 2,2 | 105 |
| NL | Hollandse Kust Zuid Holland I - II | 2022/12 | #ND | Direct drive | 1 | PMG (permanent magnet) | 200 | 31400 | 350,3 | 2,9 | #SS |
| GB | Thanet 2 | 2023/04 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| NL | Hollandse Kust Zuid Holland III - IV | 2023/06 | #ND | direct drive | 1 | Synchronus permanent | 193 | 29300 | 341,3 | 2,9 | #SS |
| GB | Forthwind Offshore Wind Demonstration Project | 2023/10 | 12 | Gearless | 0 | Synchronus permanent | 120 | 11500 | 521,7 | 1,9 | 84 |
| DK | Omo Syd | 2023/10 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Seagreen Alpha-Bravo | 2023/11 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Seagreen Charlie-Delta-Echo | 2023/11 | #ND | Planetary/helical | 3 | PMG (permanent magnet) | 164 | 21124 | 473,4 | 2,1 | 105 |
| DE | Arcadis Ost 1 | 2023/12 | #ND | Planetary (Torque split) | 3 | #ND | 174 | 23779 | 399,5 | 2,5 | 110 |
| GB | Dogger Bank | 2023/12 | #ND | Direct drive | 1 | Synchronus permanent | 220 | 38000 | 315,8 | 3,2 | 150 |
| NL | Hollandse Kust Noord Holland I - II | 2023/12 | #ND | direct drive | 1 | Synchronus permanent | 193 | 29300 | 341,3 | 2,9 | #SS |
| DK | Vesterhavet Nord | 2023/12 | 12 | Direct drive | 1 | Synchronus permanent | 167 | 21900 | 365,3 | 2,7 | #SS |
| DK | Vesterhavet Syd | 2023/12 | 12 | Direct drive | 1 | Synchronus permanent | 167 | 21900 | 365,3 | 2,7 | #SS |
| DE | Gode Wind III | 2024/01 | #ND | Direct drive | 1 | PMG (permanent magnet) | 200 | 31400 | 350,3 | 2,9 | #SS |
| DE | Gode Wind III | 2024/01 | #ND | Direct drive | 1 | PMG (permanent magnet) | 200 | 31400 | 350,3 | 2,9 | #SS |
| DK | Jammerland Bugt | 2024/01 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| DK | Mejlflak | 2024/01 | 16 | Spur/planetary | 3 | Asynchronous | 80 | 5027 | 397,9 | 2,5 | 59 |
| DE | Wikinger Süd | 2024/01 | 14 | Planetary | 3 | #ND | 126 | 12469 | 407 | 2,5 | 107 |
| DE | Gennaker | 2024/06 | #ND | Direct drive | 1 | Synchronus permanent | 154 | 18600 | 430,1 | 2,3 | 96 |
| DE | Baltic Eagle | 2024/08 | #ND | Planetary (Torque split) | 3 | #ND | 174 | 23779 | 399,5 | 2,5 | 110 |
| DK | Frederikshavn Offshore Demo | 2024/08 | 13 | #ND | #ND | PMG (permanent magnet) | #ND | #ND | 378,7 | 2,6 | 123 |
| DK | Aflandshage | 2025/01 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Dogger Bank | 2025/01 | #ND | Direct drive | 1 | Synchronus permanent | 220 | 38000 | 315,8 | 3,2 | 150 |
| GB | East Anglia Three | 2025/01 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | 147 |
| GB | Hornsea Project Three | 2025/01 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Inch Cape | 2025/01 | #ND | Planetary | 3 | PMG (permanent magnet) | 164 | 21124 | 449,7 | 2,2 | 105 |
| GB | Moray West | 2025/01 | #ND | Planetary | 3 | PMG (permanent magnet) | 164 | 21124 | 449,7 | 2,2 | 105 |
| DK | Nordre Flint | 2025/01 | 16 | Spur/planetary | 3 | Asynchronous | 80 | 5027 | 397,9 | 2,5 | 70 |
| DE | EnBW He Dreiht | 2025/08 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| DK | Lillebælt-Syd (Lillegrund) | 2025/08 | 12 | Direct drive | 1 | Synchronus permanent | 167 | 21900 | 365,3 | 2,7 | #SS |
| DE | Borkum Riffgrund III | 2025/12 | 13 | #ND | #ND | PMG (permanent magnet) | #ND | #ND | 378,7 | 2,6 | 123 |
| DE | Borkum Riffgrund III | 2025/12 | 13 | #ND | #ND | PMG (permanent magnet) | #ND | #ND | 378,7 | 2,6 | 123 |
| DE | Borkum Riffgrund III | 2025/12 | 13 | #ND | #ND | PMG (permanent magnet) | #ND | #ND | 378,7 | 2,6 | 123 |
| GB | Dogger Bank | 2026/12 | #ND | Direct drive | 1 | Synchronus permanent | 220 | 38000 | 315,8 | 3,2 | 150 |
| GB | Dudgeon Extension | 2026/12 | 13 | Non-direct drive | 0 | Synchronus permanent | 154 | 18600 | 322,6 | 3,1 | #SS |
| GB | East Anglia Two | 2026/12 | #ND | Direct drive | 1 | PMG (permanent magnet) | 222 | 39000 | 359 | 2,8 | #SS |
| GB | Erebus (Demonstration) | 2026/12 | #ND | #ND | #ND | #ND | #ND | #ND | #NIS | #NIS | #ND |
| GB | Hornsea Project Four | 2027/01 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | East Anglia One North | 2027/04 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Norfolk Boreas | 2027/04 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | 200 |
| GB | Norfolk Vanguard | 2027/04 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | 200 |
| GB | Race Bank Extension | 2029/05 | 13 | Non-direct drive | 0 | Synchronus permanent | 154 | 18600 | 322,6 | 3,1 | #SS |
| GB | Awel y Môr | 2030/01 | 13,5 | Planetary/helical | 3 | Asynchronous | 107 | 9000 | 400 | 2,5 | 98 |
| GB | Blyth Offshore - 3A-4 | #ND | 13 | Planetary | 3 | Synchronus permanent | 200 | 21164 | 378 | 2,6 | 122 |
| GB | Dounreay Tri Offshore WDC | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Forthwind Offshore Wind Demonstration Project - 2 | #ND | 13 | spur/planetary | 3 | Double fed induction | 140,6 | 15526 | 386,4 | 2,6 | 95 |
| GB | Galloper Extension | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Greater Gabbard Extension | #ND | 13 | Non-direct drive | 0 | Synchronus permanent | 154 | 18600 | 322,6 | 3,1 | #SS |
| GB | Ideol-Atlantis Energy Project 2 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #NIS | #NIS | #ND |
| DK | KadetBanke | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| DK | Paludan Flak | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Rampion Extension | #ND | 12,5 | step-planetary gear-helical | 1 | Synchronus permanent | 116 | 10568 | 473,1 | 2,1 | 90 |
| GB | Seagreen Foxtrot-Golf | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Sheringham Shoal Extension | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| DK | Trea Mollebugt | #ND | 16 | Spur/planetary | 3 | Asynchronous | 80 | 5027 | 397,9 | 2,5 | 80 |

**Figure 43 Substantive variable dataset 2 visual 2/2 (Own figure,2021)**

| ISO code | Name | Commissioning date | Number of turbines | Total power | Stated project size | Stated Capacity factor | Yearly hours of utilization | Stated AEP | AEP based on CF | Working availability | Applied WACC | Designed Lifetime |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Code ISO 3166.1 | | yyyy/mm | | kW | km2 | Average lifetime (%) | Average lifetime (hr) | GWh | GWh | % | % | yr |
| GB | Blyth | 2000/12 | 20 | 4000 | #ND | 44,0 | 3856,4 | 29,5 | 15,4 | 81,0 | 12,0 | 20 |
| DK | Middelgrunden | 2000/12 | 2 | 40000 | #ND | 25,2 | #ND | 100 | 88,3 | #ND | 7,5 | 25 |
| DK | Horns Rev 1 | 2002/12 | 80 | 160000 | #ND | 41,2 | 3611,2 | 600 | 577,5 | 63,0 | 7,5 | 25 |
| DK | Frederikshavn Offshore | 2003/04 | 1 | 2300 | #ND | 30,3 | 2656,1 | 4 | 6,1 | 82,0 | 7,8 | 20 |
| DK | Frederikshavn Offshore | 2003/06 | 1 | 3000 | #ND | 30,3 | 2656,1 | 4 | 6,1 | 82,0 | 7,8 | 20 |
| DK | Frederikshavn Offshore | 2003/06 | 1 | 2300 | #ND | 30,3 | 2656,1 | 4 | 8,0 | 82,0 | 7,8 | 20 |
| DK | Nysted Offshore | 2003/11 | 72 | 165600 | #ND | 43,5 | #ND | 540 | 631,0 | #ND | 7,5 | 25 |
| GB | North Hoyle | 2003/12 | 9 | 60000 | #ND | 32,5 | 2848,8 | 153 | 170,8 | 76,0 | 12,0 | 20 |
| DK | Rønland | 2003/12 | 1 | 9200 | #ND | 44,3 | 3883,1 | 55 | 35,7 | 80,0 | 7,8 | 20 |
| DK | Rønland | 2003/12 | 4 | 8000 | #ND | 44,3 | 3883,1 | 11 | 7,8 | 81,0 | 7,8 | 25 |
| DK | Samso | 2003/12 | 30 | 20700 | #ND | 39,1 | 3427,3 | 86 | 70,9 | 82,0 | 7,8 | 25 |
| GB | Scroby Sands | 2004/03 | 30 | 60000 | #ND | 31,3 | 2743,7 | 154 | 164,5 | 76,0 | 12,0 | 25 |
| DE | Emden Offshore | 2004/10 | 1 | 4500 | #ND | #ND | #ND | #ND | #ND | #ND | 7,8 | 20 |
| GB | Kentish Flats | 2005/10 | 30 | 90000 | #ND | 30,5 | 2673,2 | 280 | 240,5 | #ND | 12,5 | 20 |
| DE | Breitling | 2006/02 | 1 | 2500 | #ND | 21,3 | #ND | 17,5 | 4,7 | #ND | 8,2 | 20 |
| GB | Barrow | 2006/07 | 30 | 90000 | #ND | 35,7 | 3129,5 | 320 | 281,5 | 75,0 | 12,0 | 20 |
| NL | Egmond aan Zee | 2006/10 | 36 | 108000 | #ND | 33,3 | 2918,8 | 315 | 315,0 | 74,0 | 9,8 | 20 |
| GB | Beatrice Demonstration | 2007/07 | 2 | 10000 | #ND | 18,9 | #ND | #ND | 16,6 | #ND | 12,7 | 20 |
| GB | Burbo Bank | 2007/10 | 32 | 256000 | #ND | 34,0 | 2980,3 | 394 | 268,1 | 77,0 | 12,5 | 25 |
| NL | Prinses Amalia | 2008/03 | 60 | 120000 | #ND | 40,1 | 3515,1 | 422 | 421,5 | 68,0 | 10,3 | 20 |
| BE | Thorntonbank | 2008/07 | 6 | 30450 | #ND | 32,4 | 2840,0 | 290 | 86,5 | 81,0 | 9,7 | 25 |
| DE | Hooksiel | 2008/10 | 1 | 5000 | #ND | 44,0 | 3856,1 | 15 | 20,4 | 82,0 | 8,1 | 20 |
| GB | Lynn and Inner Dowsing | 2009/03 | 27 | 97200 | #ND | 35,1 | 3077,0 | 697 | 298,9 | 76,0 | 12,8 | 25 |
| GB | Lynn and Inner Dowsing | 2009/03 | 27 | 97200 | #ND | 35,1 | 3077,0 | 697 | 298,9 | 76,0 | 12,8 | 25 |
| DK | Horns Rev 2 | 2009/09 | 91 | 209300 | #ND | 48,0 | 4206,4 | 800 | 880,1 | 57,0 | 8,4 | 25 |
| DK | Sprogo | 2009/10 | 7 | 21000 | #ND | 33,5 | #ND | 61,5 | 61,6 | #ND | 8,4 | 25 |
| DE | Alpha Ventus | 2009/12 | 5 | 30000 | #ND | 52,5 | 4601,1 | 133,5 | 138,0 | 81,0 | 8,3 | 20 |
| DE | Alpha Ventus | 2009/12 | 6 | 30000 | #ND | 52,5 | 4601,1 | 133,5 | 115,0 | 80,0 | 8,3 | 20 |
| GB | Rhyl Flats | 2009/12 | 25 | 90000 | #ND | 34,2 | 2997,3 | 285 | 269,6 | 77,0 | 12,8 | 25 |
| GB | Gunfleet Sands 1 | 2010/04 | 30 | 108000 | #ND | 37,0 | 3243,3 | 300 | 350,0 | 75,0 | 12,6 | 25 |
| GB | Gunfleet Sands 2 | 2010/04 | 58 | 64800 | #ND | 37,0 | 3243,3 | 220 | 210,0 | 78,0 | 12,6 | 25 |
| GB | Robin Rigg | 2010/04 | 18 | 174000 | #ND | 35,7 | 3129,3 | 550 | 544,2 | 69,0 | 12,6 | 20 |
| GB | Thanet | 2010/09 | 100 | 300000 | #ND | 33,5 | 2935,9 | 822 | 880,4 | 61,0 | 12,6 | 25 |
| DK | Rodsand II | 2010/10 | 90 | 207000 | #ND | 43,5 | #ND | 830 | 788,8 | #ND | 8,3 | 20 |
| GB | Wave Hub | 2010/11 | #ND | 32000 | #ND | 57,0 | #ND | 15 | #ND | #ND | 13,3 | 20 |
| BE | Belwind I | 2010/12 | 50 | 165000 | #ND | 37,9 | 3321,7 | 530 | 498,0 | 71,0 | 9,6 | 20 |
| DE | EnBW Baltic 1 | 2011/05 | 21 | 48300 | #ND | 45,9 | 4024,1 | 185 | 194,2 | 77,0 | 9,1 | 25 |
| GB | Walney | 2011/07 | 51 | 183600 | #ND | 40,3 | 3533,1 | 650 | 648,2 | 70,0 | 13,3 | 20 |
| DK | Avedøre Holme | 2011/12 | 3 | 10800 | #ND | 38,1 | 3339,4 | 36 | 36,0 | 81,3 | 8,1 | 20 |
| GB | Ormonde | 2012/02 | 30 | 150000 | #ND | 37,9 | 3320,8 | 500 | 506,0 | 75,2 | 13,3 | 25 |
| GB | Walney | 2012/04 | 51 | 183600 | #ND | 45,9 | 4022,8 | 650 | 738,2 | 68,8 | 13,3 | 25 |
| DK | Anholt | 2012/09 | 111 | 399600 | #ND | 48,7 | 4267,0 | 1730 | 1704,7 | 67,7 | 8,7 | 25 |
| GB | Greater Gabbard 1 | 2012/09 | 80 | 288000 | #ND | 41,0 | 3592,4 | 875 | 1034,4 | 61,3 | 12,5 | 25 |
| GB | Greater Gabbard 2 | 2012/09 | 88 | 216000 | #ND | 41,0 | 3592,4 | 875 | 775,8 | 63,0 | 12,5 | 25 |
| GB | Sheringham Shoal | 2012/09 | 60 | 316800 | #ND | 40,2 | 3522,3 | 1165 | 1115,6 | 51,6 | 13,3 | 20 |
| BE | Thorntonbank | 2013/01 | 30 | 184500 | #ND | 36,8 | 3224,0 | 550 | 594,8 | 75,3 | 10,1 | 20 |
| GB | Gunfleet Sands 3 Demonstration | 2013/04 | 2 | 12000 | #ND | 31,3 | #ND | #ND | 32,9 | #ND | 12,6 | 20 |
| GB | London Array | 2013/07 | 175 | 630000 | #ND | 40,2 | 3523,8 | 3400 | 2218,6 | 40,9 | 12,5 | 20 |
| BE | Thorntonbank | 2013/07 | 18 | 110700 | #ND | 36,8 | 3225,7 | 348 | 356,9 | 78,0 | 9,7 | 25 |
| DE | Bard Offshore 1 | 2013/08 | 27 | 400000 | #ND | 34,5 | 3023,5 | 1134 | 1276,6 | 76,0 | 8,3 | 25 |
| GB | Teesside | 2013/08 | 80 | 62100 | #ND | 36,4 | 3190,0 | 120 | 198,0 | 64,9 | 13,8 | 25 |
| GB | Lincs | 2013/09 | 75 | 270000 | #ND | 42,5 | 3723,9 | 1250 | 1005,2 | 63,7 | 12,5 | 20 |
| GB | Fife Energy Park | 2013/10 | 1 | 7000 | #ND | 13,3 | 1165,5 | 40 | 8,2 | 81,8 | 13,6 | 20 |
| BE | Belwind Alstom Haliade Demonstration | 2013/12 | 1 | 6000 | #ND | #ND | #ND | #ND | #ND | #ND | 9,6 | 20 |
| DE | Riffgat | 2014/03 | 30 | 113400 | #ND | 50,0 | 4383,6 | 474 | 473,0 | 73,6 | 9,1 | 25 |
| BE | Northwind | 2014/06 | 72 | 216000 | #ND | 41,6 | 3646,2 | 875 | 787,1 | 64,7 | 10,7 | 25 |
| DE | Dan Tysk | 2014/08 | 80 | 302400 | #ND | 50,3 | 4408,5 | 1360 | 1269,0 | 59,4 | 9,1 | 25 |
| GB | West of Duddon Sands | 2014/10 | 108 | 388800 | #ND | 46,0 | 4031,4 | 1134 | 1566,7 | 53,9 | 13,8 | 25 |
| GB | Gwynt y Môr | 2014/11 | 160 | 576000 | #ND | 35,0 | 3066,6 | 1950 | 1766,0 | 47,4 | 13,3 | 25 |
| DE | Meerwind Ost | 2015/03 | 40 | 144000 | #ND | 37,1 | 3253,1 | 680 | 468,0 | 71,3 | 9,1 | 25 |
| DE | Meerwind Süd | 2015/03 | 48 | 144000 | #ND | 32,6 | 2858,5 | 680 | 411,2 | 73,7 | 9,1 | 25 |
| DE | Nordsee Ost | 2015/03 | 48 | 295200 | #ND | 35,7 | 3130,3 | 1000 | 923,2 | 71,5 | 8,8 | 25 |
| GB | Westermost Rough | 2015/05 | 35 | 210000 | #ND | 47,8 | 4191,1 | 800 | 879,3 | 72,6 | 13,3 | 25 |
| GB | Humber Gateway | 2015/06 | 73 | 219000 | #ND | 43,7 | 3830,6 | 803 | 838,4 | 63,8 | 13,3 | 25 |
| DE | Butendiek | 2015/08 | 80 | 288000 | #ND | 45,0 | 3944,3 | 1290 | 1135,3 | 61,6 | 8,8 | 25 |
| NL | Eneco Luchterduinen | 2015/09 | 43 | 129000 | #ND | 47,0 | 4118,5 | 531 | 531,1 | 70,6 | 10,8 | 25 |
| DE | Global Tech I | 2015/09 | 40 | 400000 | #ND | 48,6 | 4258,7 | 1400 | 1798,3 | 60,2 | 8,8 | 25 |
| DE | Trianel Borkum I | 2015/09 | 80 | 200000 | #ND | 61,6 | 5397,9 | 1200 | 1079,2 | 67,4 | 8,8 | 25 |
| DE | Amrumbank West | 2015/10 | 78 | 302400 | #ND | 44,0 | 3856,4 | 1190 | 1110,1 | 61,2 | 8,8 | 25 |
| DE | Borkum Riffgrund I | 2015/10 | 80 | 312000 | #ND | 38,5 | 3374,4 | 1063 | 1052,3 | #ND | 8,8 | 25 |
| DE | EnBW Baltic 2 | 2015/10 | 80 | 288000 | #ND | 45,9 | 4023,0 | 1350 | 1158,0 | #ND | 8,8 | 25 |
| GB | Kentish Flats 2 | 2015/12 | 15 | 49500 | #ND | 40,7 | 3567,0 | 280 | 176,5 | #ND | 13,3 | 20 |
| NL | Westermeerdijk buitendijks | 2016/03 | 40 | 144000 | #ND | 25,0 | #ND | 500 | 315,4 | #ND | 10,8 | 25 |
| GB | Burbo Bank | 2016/12 | 25 | 90000 | #ND | 41,0 | #ND | 1134 | 919,4 | #ND | 9,0 | 20 |
| DE | Nordergründe | 2017/01 | 72 | 110700 | #ND | 48,0 | 4203,0 | 639 | 465,5 | 77,1 | 8,0 | 25 |
| DE | Sandbank | 2017/01 | 18 | 288000 | #ND | 50,3 | 4404,4 | 1125 | 1269,0 | 61,7 | 8,0 | 25 |
| NL | Gemini | 2017/04 | 150 | 600000 | #ND | 49,4 | 4329,1 | 2600 | 2596,5 | 40,4 | 8,0 | 20 |
| BE | Belwind II | 2017/05 | 55 | 165000 | #ND | 37,9 | 3322,3 | 875 | 602,6 | 69,6 | 9,6 | 25 |
| DE | Veja Mate | 2017/05 | 67 | 402000 | #ND | 48,0 | 4207,7 | 1134 | 1690,3 | 63,9 | 8,0 | 20 |
| DE | Gode Wind I | 2017/07 | 42 | 344520 | #ND | 41,7 | 3655,1 | 1198 | 1205,5 | 68,8 | 8,0 | 20 |
| DE | Gode Wind II | 2017/07 | 55 | 263100 | #ND | 41,3 | 3620,0 | 914 | 911,7 | 72,0 | 6,0 | 20 |
| GB | Dudgeon | 2017/10 | 6 | 402000 | #ND | 48,1 | 4213,8 | 1499 | 1693,9 | 63,9 | 9,0 | 20 |
| GB | Hywind Scotland Pilot Park | 2017/10 | 67 | 30000 | #ND | 53,6 | 4695,7 | 150 | 143,1 | 81,0 | 9,0 | 25 |
| DE | Nordsee One Offshore | 2017/12 | 70 | 332100 | #ND | 32,0 | 2803,0 | 936 | 930,9 | 71,0 | 7,0 | 20 |
| DE | Wikinger Offshore | 2017/12 | 54 | 350000 | #ND | 76,0 | 6657,2 | 1820 | 2353,5 | 81,8 | 6,0 | 25 |
| DK | Samso | 2018/01 | 1 | 2300 | #ND | 39,1 | 3423,3 | 27,5 | 7,9 | 82,0 | 6,4 | 25 |
| DK | Samso | 2018/01 | 1 | 2300 | #ND | 39,1 | 3423,3 | 27,5 | 7,9 | 82,0 | 6,4 | 25 |
| GB | Race Bank | 2018/02 | 91 | 573300 | #ND | 43,5 | 3806,6 | 1870 | 2080,6 | 59,0 | 13,3 | 24 |
| DK | Nissum Bredning | 2018/03 | 4 | 28000 | #ND | 39,5 | 3463,7 | 480 | 96,9 | 81,0 | 6,4 | 20 |
| GB | Galloper | 2018/04 | 56 | 353000 | #ND | 47,0 | 4119,3 | 1750 | 1383,4 | 74,0 | 9,0 | 23 |
| GB | Blyth Offshore | 2018/06 | 5 | 41500 | #ND | 44,0 | 3855,9 | 67 | 154,2 | 81,0 | 11,0 | 20 |
| GB | EOWDC | 2018/09 | 9 | 75600 | #ND | 37,5 | 3283,9 | 55 | 54,5 | 82,0 | 11,0 | 20 |

**Figure 44 Substantive variable dataset 3 visual 1/2 (Own figure,2021)**

| ISO code | Name | Commissioning date | Number of turbines | Total power | Stated project size | Stated Capacity factor | Yearly hours of utilization | Stated AEP | AEP based on CF | Working availability | Applied WACC | Designed Lifetime |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Code ISO 3166.1 | | yyyy/mm | | kW | km2 | Average lifetime (%) | Average lifetime (hr) | GWh | GWh | % | % | yr |
| GB | EOWDC | 2018/09 | 40 | 17600 | #ND | 37,5 | 3283,9 | 260 | 245,4 | 80,0 | 11,0 | 20 |
| GB | Walney Extension | 2018/09 | 2 | 330000 | #ND | 49,1 | 4299,7 | 1300 | 1415,1 | 71,0 | 9,0 | 25 |
| GB | Walney Extension | 2018/09 | 47 | 329000 | #ND | 49,1 | 4299,7 | 1300 | 1376,4 | 71,0 | 9,0 | 25 |
| GB | Kincardine Offshore Windfarm | 2018/10 | 6 | 48000 | #ND | #ND | #ND | 218 | #ND | #ND | 11,0 | 20 |
| DE | Borkum Riffgrund II | 2018/11 | 116 | 448000 | #ND | 30,5 | 2670,3 | 1169 | 1197,0 | 71,0 | 6,0 | 20 |
| BE | Norther | 2018/11 | 56 | 369600 | #ND | 43,1 | 3773,5 | 1394 | 1378,8 | 71,0 | 7,5 | 25 |
| GB | Rampion | 2018/11 | 44 | 400200 | #ND | 34,7 | 3038,1 | 1400 | 1216,5 | 57,0 | 9,0 | 25 |
| BE | Rentel | 2018/12 | 42 | 309000 | #ND | 39,0 | 3416,1 | 804 | 1004,4 | 72,0 | 7,5 | 20 |
| DE | Arkona | 2019/01 | 60 | 384000 | #ND | 52,7 | 4612,9 | 1505 | 1661,9 | 64,0 | 8,0 | 25 |
| GB | Beatrice | 2019/05 | 84 | 588000 | #ND | 47,4 | 4157,9 | 1369 | 2441,5 | 63,0 | 9,0 | 25 |
| DE | Merkur Offshore | 2019/06 | 66 | 396000 | #ND | 32,1 | 2813,6 | 561 | 1113,5 | 68,0 | 7,0 | 25 |
| DK | Horns Rev 3 | 2019/08 | 49 | 406700 | #ND | 52,0 | 4557,0 | 1700 | 1785,6 | 68,0 | 8,0 | 25 |
| DE | Deutsche Bucht | 2019/09 | 31 | 252000 | #ND | 49,0 | 4290,0 | 1500 | 1064,5 | 73,0 | 7,0 | 25 |
| DE | EnBW Hohe See | 2019/11 | 71 | 497000 | #ND | 42,4 | 3710,8 | 1720 | 1846,0 | 65,0 | 7,0 | 25 |
| GB | Hornsea Project One - Heron Wind | 2019/12 | 87 | 609000 | #ND | 48,3 | 4230,4 | 2325 | 2576,7 | 59,0 | 11,0 | 25 |
| GB | Hornsea Project One - Njord | 2019/12 | 87 | 609000 | #ND | 48,3 | 4230,4 | 2325 | 2576,7 | 59,0 | 11,0 | 25 |
| DE | Albatros | 2020/01 | 16 | 112000 | #ND | 40,7 | 3560,4 | 5 | 399,3 | 80,0 | 8,0 | 25 |
| BE | Northwester 2 | 2020/05 | 23 | 218500 | #ND | 36,6 | #ND | 818 | 700,5 | #ND | 7,0 | 25 |
| DE | Trianel Borkum II | 2020/06 | 32 | 203200 | #ND | 51,6 | 4512,3 | 800 | 889,6 | 73,0 | 6,6 | 20 |
| GB | East Anglia One | 2020/07 | 102 | 714000 | #ND | 52,3 | 4579,0 | 2211 | 3271,2 | 52,0 | 11,0 | 30 |
| NL | Borssele I | 2020/11 | 47 | 376000 | #ND | 48,0 | #ND | 1523 | 1581,0 | #ND | 8,0 | 25 |
| NL | Borssele II | 2020/11 | 47 | 376000 | #ND | 48,0 | #ND | 1523 | 1581,0 | #ND | 8,0 | 25 |
| BE | Seamade (Mermaid) | 2020/12 | 30 | 235200 | #ND | #ND | #ND | #ND | #ND | #ND | 8,5 | 20 |
| BE | Seamade (SeaStar) | 2020/12 | 28 | 252000 | #ND | #ND | #ND | #ND | #ND | #ND | 8,5 | 20 |
| NL | Borssele III-IV | 2021/01 | 77 | 731500 | #ND | 54,0 | #ND | 3000 | 3460,3 | #ND | 7,0 | 25 |
| NL | Borssele V | 2021/01 | 2 | 19000 | #ND | 54,0 | #ND | #ND | 89,9 | #ND | 7,0 | 20 |
| GB | Kincardine Offshore Windfarm | 2021/06 | 89 | 50000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | 20 |
| NL | Windpark Fryslân | 2021/06 | 86 | 382700 | #ND | #ND | #ND | 1500 | #ND | #ND | #ND | 20 |
| DK | Kriegers Flak | 2021/12 | 72 | 605000 | #ND | #ND | #ND | #ND | #ND | #ND | 8,0 | 25 |
| DE | Gicon SOF | 2022/01 | 30 | 2300 | #ND | 66,0 | #ND | #ND | 13,3 | #ND | #ND | 20 |
| DE | Gicon SOF | 2022/01 | 30 | 8000 | #ND | 66,0 | #ND | #ND | 46,3 | #ND | #ND | 20 |
| GB | Triton Knoll Wind Farm | 2022/01 | 1 | 285000 | #ND | 48,0 | #ND | #ND | 1198,4 | #ND | 11,0 | 25 |
| GB | Triton Knoll Wind Farm | 2022/01 | 4 | 285000 | #ND | 48,0 | #ND | #ND | 1198,4 | #ND | 11,0 | 25 |
| GB | Triton Knoll Wind Farm | 2022/01 | 30 | 285000 | #ND | 48,0 | #ND | #ND | 1198,4 | #ND | 11,0 | 25 |
| GB | Neart na Gaoithe | 2022/05 | 54 | 432000 | #ND | 37,2 | #ND | #ND | 1407,8 | #ND | #ND | 20 |
| GB | Hornsea Project Two - Breesea and Optimus Wind | 2022/06 | 165 | 1386000 | #ND | 38,6 | #ND | #ND | 4463,4 | #ND | 10,0 | 25 |
| DE | Kaskasi II | 2022/10 | 100 | 342000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Moray East | 2022/10 | 38 | 950000 | #ND | 40,0 | #ND | #ND | 3328,8 | #ND | #ND | #ND |
| NL | Hollandse Kust Zuid Holland I - II | 2022/12 | 70 | 700000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Thanet 2 | 2023/04 | 34 | 340000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| NL | Hollandse Kust Zuid Holland III - IV | 2023/06 | 70 | 700000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Forthwind Offshore Wind Demonstration Project | 2023/10 | 2 | 12000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| DK | Omo Syd | 2023/10 | #ND | 320000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Seagreen Alpha-Bravo | 2023/11 | #ND | 1075000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Seagreen Charlie-Delta-Echo | 2023/11 | 114 | 2300000 | #ND | 50,0 | #ND | #ND | 4993,2 | #ND | #ND | #ND |
| DE | Arcadis Ost 1 | 2023/12 | 100 | 257000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Dogger Bank | 2023/12 | 20 | 1200000 | #ND | 45,0 | #ND | #ND | 4730,4 | #ND | #ND | #ND |
| NL | Hollandse Kust Noord Holland I - II | 2023/12 | 21 | 700000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| DK | Vesterhavet Nord | 2023/12 | 70 | 160000 | #ND | 51,0 | #ND | #ND | 714,8 | #ND | #ND | #ND |
| DK | Vesterhavet Syd | 2023/12 | 27 | 168000 | #ND | 51,0 | #ND | #ND | 750,6 | #ND | #ND | #ND |
| DE | Gode Wind III | 2024/01 | 10 | 111000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | 25 |
| DE | Gode Wind III | 2024/01 | #ND | 131750 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| DK | Jammerland Bugt | 2024/01 | 2 | 240000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| DK | Mejlflak | 2024/01 | 60 | 120000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| DE | Wikinger Süd | 2024/01 | 12 | 10000 | #ND | #ND | #ND | #ND | #ND | #ND | 8,0 | #ND |
| DE | Gennaker | 2024/06 | 103 | 865200 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| DE | Baltic Eagle | 2024/08 | 6 | 476000 | #ND | 45,9 | #ND | #ND | 3170,4 | #ND | #ND | #ND |
| DK | Frederikshavn Offshore Demo | 2024/08 | 83 | 72000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| DK | Aflandshage | 2025/01 | 121 | 250000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Dogger Bank | 2025/01 | 63 | 1200000 | #ND | 45,0 | #ND | #ND | 4730,4 | #ND | #ND | #ND |
| GB | East Anglia Three | 2025/01 | 72 | 1400000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Hornsea Project Three | 2025/01 | 85 | 2400000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Inch Cape | 2025/01 | 100 | 784000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Moray West | 2025/01 | 80 | 850000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| DK | Nordre Flint | 2025/01 | 300 | 160000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| DE | EnBW He Dreiht | 2025/08 | 90 | 900000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| DK | Lillebælt-Syd (Lillegrund) | 2025/08 | 20 | 160000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| DE | Borkum Riffgrund III | 2025/12 | 45 | 240000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| DE | Borkum Riffgrund III | 2025/12 | 21 | 420000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| DE | Borkum Riffgrund III | 2025/12 | 21 | 240000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Dogger Bank | 2026/12 | 100 | 1200000 | #ND | 48,0 | #ND | #ND | 5045,8 | #ND | #ND | #ND |
| GB | Dudgeon Extension | 2026/12 | 67 | 402000 | #ND | 48,0 | #ND | #ND | 1690,3 | #ND | #ND | #ND |
| GB | East Anglia Two | 2026/12 | 90 | 900000 | #ND | 38,4 | #ND | #ND | 4238,4 | #ND | #ND | #ND |
| GB | Erebus (Demonstration) | 2026/12 | 10 | 96000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Hornsea Project Four | 2027/01 | 180 | 1000000 | #ND | 42,0 | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | East Anglia One North | 2027/04 | 225 | 800000 | #ND | 52,3 | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Norfolk Boreas | 2027/04 | 67 | 1800000 | #ND | 34,9 | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Norfolk Vanguard | 2027/04 | 225 | 1800000 | #ND | 34,9 | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Race Bank Extension | 2029/05 | 91 | 573000 | #ND | 38,6 | #ND | #ND | 1846,2 | #ND | #ND | #ND |
| GB | Awel y Môr | 2030/01 | 160 | 576000 | #ND | 47,5 | #ND | #ND | 2396,7 | #ND | #ND | #ND |
| GB | Blyth Offshore - 3A-4 | #ND | 172 | 58400 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Dounreay Tri Offshore WDC | #ND | #ND | 10000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Forthwind Offshore Wind Demonstration Project - 2 | #ND | 22 | 53000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Galloper Extension | #ND | 2 | 353000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Greater Gabbard Extension | #ND | 72 | 504000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Ideol-Atlantis Energy Project 2 | #ND | 62 | 1400000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| DK | KadetBanke | #ND | #ND | 864000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| DK | Paludan Flak | #ND | 10 | 228000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Rampion Extension | #ND | #ND | 400000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Seagreen Foxtrot-Golf | #ND | #ND | 1850000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| GB | Sheringham Shoal Extension | #ND | 56 | 317000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |
| DK | Trea Mollebugt | #ND | 80 | 720000 | #ND | #ND | #ND | #ND | #ND | #ND | #ND | #ND |

**Figure 45 Substantive variable dataset 3 visual 2/2 (Own figure,2021)**

## Appendix VI: Country specific geographical developments


**Figure 46 Visuals country specific WD & DtS development (Own figure,2021)**

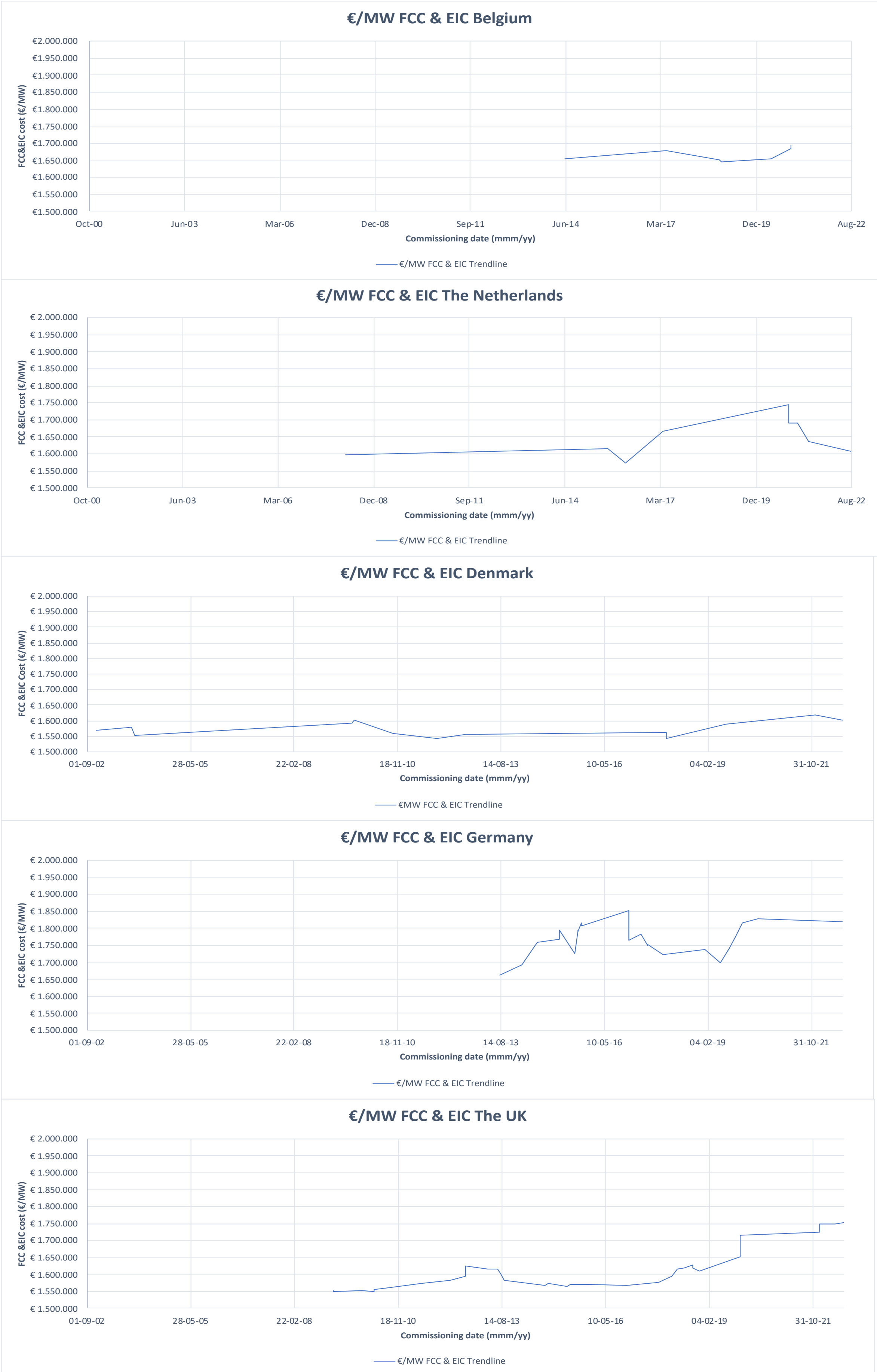



**Figure 47 Visuals country specific €/MW FCC & EIC cost (Own figure,2021)**

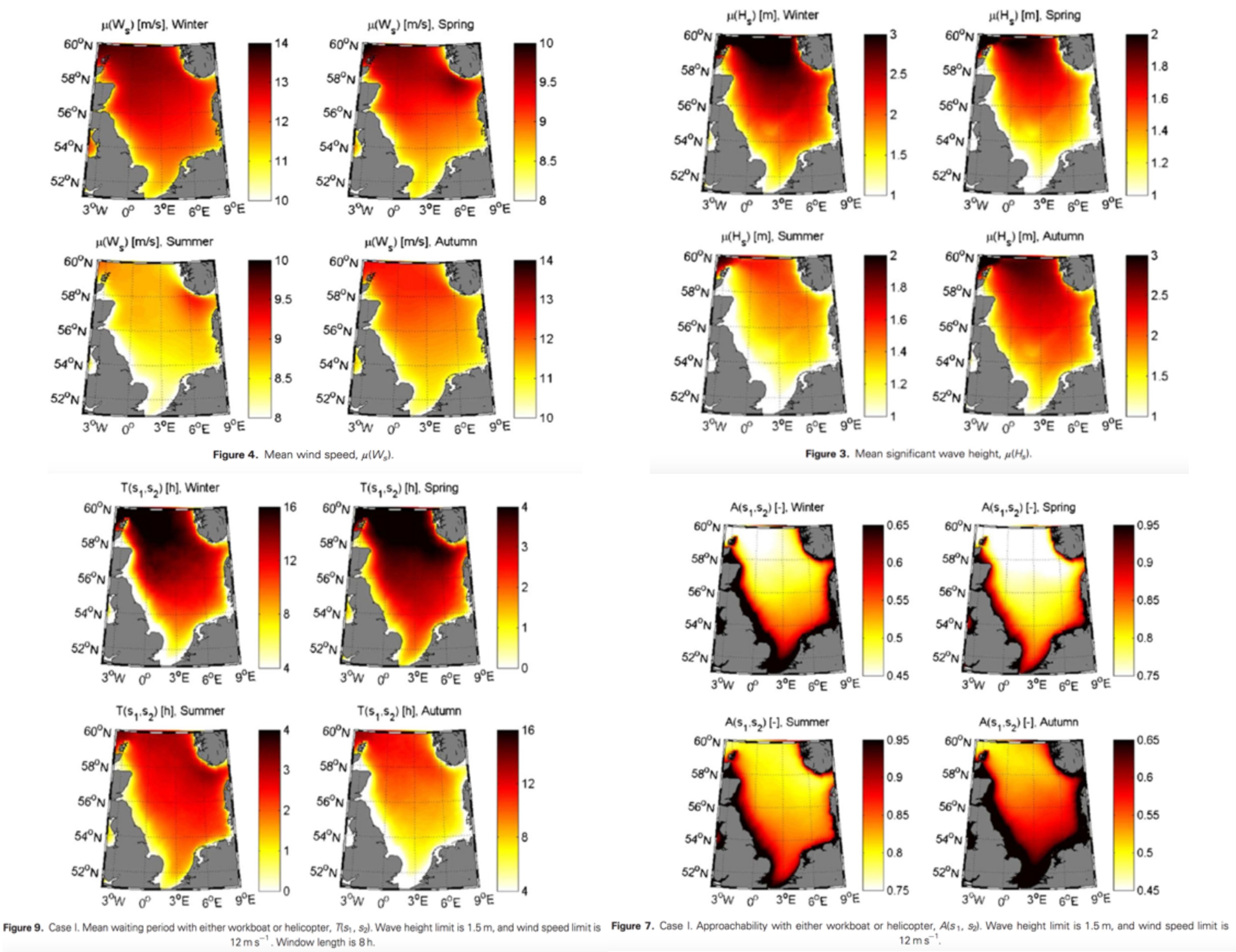



**Figure 48 Visuals Seasonal difference and impact DtS on Mean Wind speeds, Mean significant wave height, mean waiting hours and approachability percentages. (Enviromental Hydraulics Institute, 2016)**

## Appendix VIII: Working sheet Impact DtS on O&M

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | Total time of operations per turbine 2005 Average DfS of 4Km | | | |
| | No cost repair/reset | Minor Repair | Medium Repair | Major Repair | Major Replacement | Annual Serivice |
| Failure rate | 7,5 | 3 | 0,275 | 0,04 | 0,08 | 1 |
| Average repair time | 3 | 7,5 | 22 | 26 | 52 | 60 |
| Required Technicians | 2 | 2 | 3 | 4 | 5 | 3 |
| Vessel Type | CTV | CTV | CTV | FSV | HLV | CTV |
| Max speed vessel type (Km/h) | 46,3 | 46,3 | 46,3 | 33,4 | 12,9 | 46,3 |
| Average travel time (hr) | 0,172 | 0,172 | 0,172 | 0,238 | 0,62 | 0,172 |
| Average Accesibility over 4 season (%) | 80 | 80 | 80 | 70 | 65 | 80 |
| Average waiting time over 4 seasons (hr) | 2 | 2 | 2 | 3 | 4 | 2 |
| Total time of operation (hr) | 5 | 10 | 24 | 29 | 57 | 62 |
| Total time on year basis (hr) | 39 | 29 | 7 | 1 | 5 | 62 |
| Vessel cost (€) | € 6.503,92 | € 4.865,11 | € 1.114,55 | € 574,63 | € 14.961,28 | € 10.424,38 |
| Cost assosiacted with waiting (€) | € 2.007,38 | € 1.501,58 | € 344,00 | € 60,52 | € 234,41 | € 3.217,40 |
| Staff rate (€) | € 4.460,85 | € 3.336,84 | € 1.146,66 | € 268,99 | € 1.302,26 | € 10.724,67 |
| Repair cost (Average) (€) | € - | € 1.150,00 | € 21.275,00 | € 84.525,00 | € 384.675,00 | € 21.275,00 |
| Total operation cost (€) | € 12.972,15 | € 9.351,95 | € 23.536,21 | € 85.368,62 | € 400.938,54 | € 42.424,05 |
| Average turbine size 2005 (KW) | 2,5 | 2,5 | 2,5 | 2,5 | 2,5 | 2,5 |
| Operations cost €/Kw | € 5.188,86 | € 3.740,78 | € 9.414,48 | € 34.147,45 | € 160.375,42 | € 16.969,62 |
| | | | Excludes turbine size,project size,Maintenance strategy material cost. Just shows influence DfS | | | |
| | | | | | | |
| | | | Total time of operations per turbine 2020 Average DfS of 40,8Km | | | |
| | No cost repair/reset | Minor Repair | Medium Repair | Major Repair | Major Replacement | Annual Serivice |
| Failure rate | 7,5 | 3 | 0,275 | 0,04 | 0,08 | 1 |
| Average repair time | 3 | 7,5 | 22 | 26 | 52 | 60 |
| Required Technicians | 3 | 3 | 4 | 7 | 8 | 4 |
| Vessel Type | CTV | CTV | CTV | FSV | HLV | CTV |
| Max speed vessel type (Km/h) | 46,3 | 46,3 | 46,3 | 33,4 | 12,9 | 46,3 |
| Average travel time (hr) | 1,8 | 1,8 | 1,8 | 2,4 | 6,3 | 1,8 |
| Average Accesibility over 4 season (%) | 70 | 70 | 70 | 60 | 55 | 70 |
| Average waiting time over 4 seasons (hr) | 3 | 3 | 3 | 6 | 12 | 3 |
| Total time of operation (hr) | 8 | 12 | 27 | 34 | 70 | 65 |
| Total time on year basis (hr) | 58 | 37 | 7 | 1 | 6 | 65 |
| Vessel cost (€) | € 9.761,44 | € 6.168,12 | € 1.234,00 | € 676,93 | € 18.582,85 | € 10.858,71 |
| Cost assosiacted with waiting (€) | € 3.012,79 | € 1.903,74 | € 380,86 | € 71,30 | € 291,15 | € 3.351,46 |
| Staff rate (€) | € 10.042,63 | € 6.345,80 | € 1.692,72 | € 554,53 | € 2.587,98 | € 14.895,36 |
| Repair cost (Average) (€) | € - | € 1.150,00 | € 21.275,00 | € 84.525,00 | € 384.675,00 | € 21.275,00 |
| Total operation cost (€) | € 22.816,85 | € 13.663,92 | € 24.201,72 | € 85.756,46 | € 405.845,83 | € 47.029,07 |
| Average turbine size 2020 (KW) | 7,5 | 7,5 | 7,5 | 7,5 | 7,5 | 7,5 |
| Operations cost €/Kw | € 3.042,25 | € 1.821,86 | € 3.226,90 | € 11.434,19 | € 54.112,78 | € 6.270,54 |
| | | | Excludes turbine size,project size,Maintenance strategy material cost. Just shows influence DfS | | | |
| | | | | | | |
| | Total O&M cost Non cost repar/ reset | Total O&M cost Minor Repair | Total O&M cost Medium repair | Total O&M cost Major repair | Total O&M cost Major replacement | Annual serivice cost |
| 2004 | € 1.945.822,77 | € 561.117,16 | € 129.449,17 | € 68.294,90 | € 641.501,67 | € 848.480,98 |
| 2020 | € 7.529.561,96 | € 1.803.637,60 | € 292.840,79 | € 150.931,37 | € 1.428.577,32 | € 2.069.279,13 |
| % Diff. | 287% | 221% | 126% | 121% | 123% | 144% |
| Average % diff. | 170% | | | | | |
| Average turbines per site 2004 | 20 | | | | | |
| Average turbine per site 2020 | 44 | | | | | |
| | O&M €/KW Non cost repar/ reset | O&M €/KW cost Minor Repair | O&M €/KW cost Medium repair | O&M €/KW cost Major repair | O&M €/KW cost Major replacement | Annual serivice cost €/KW |
| 2004 | € 5.188,86 | € 3.740,78 | € 9.414,48 | € 34.147,45 | € 160.375,42 | € 16.969,62 |
| 2020 | € 3.042,25 | € 1.821,86 | € 3.226,90 | € 11.434,19 | € 54.112,78 | € 6.270,54 |
| % Diff. | -41% | -51% | -66% | -67% | -66% | -63% |
| Average % diff. | -59% | | | | | |
| No increase in turbine size | O&M €/KW Non cost repar/ reset | O&M €/KW cost Minor Repair | O&M €/KW cost Medium repair | O&M €/KW cost Major repair | O&M €/KW cost Major replacement | Annual serivice cost €/KW |
| 2004 | € 5.188,86 | € 3.740,78 | € 9.414,48 | € 34.147,45 | € 160.375,42 | € 16.969,62 |
| 2020 | € 9.126,74 | € 5.465,57 | € 9.680,69 | € 34.302,58 | € 162.338,33 | € 18.811,63 |
| % Diff. | 76% | 46% | 3% | 0% | 1% | 11% |
| Average % diff. | 22% | | | | | |

**Figure 49 Calculation overview impact DtS on O&M cost (Own figure,2021)**

## Appendix IX: Country specific availibility developments:

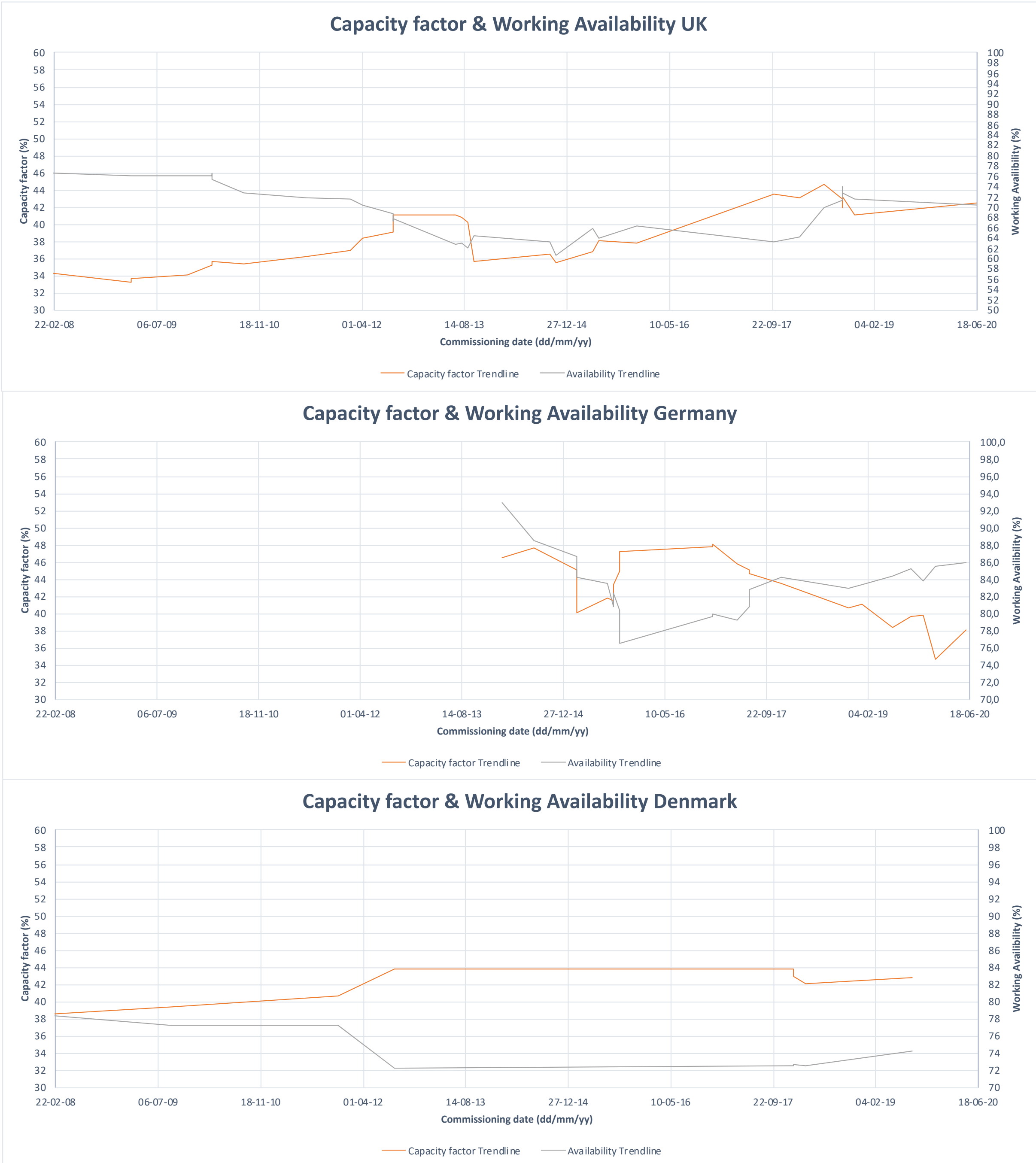



**Figure 50 Visuals country specific CF and Working availability development (Own figure,2021)**

- Baseline blade material cost
    - Fiberglass fabric (NAICS Code 3272123) = 60%
    - Vinyl type adhesives (NAICS Code 32552044) = 23%
    - Other externally threaded metal fasteners, including studs (NAICS Code 332722489) = 8%
    - Urethane and other foam products (NAICS Code 326150P) = 9%
- Advanced blade material
    - Fiberglass fabric (NAICS Code 3272123) = 61%
    - Vinyl type adhesives (NAICS Code 32552044) = 27%
    - Other externally threaded metal fasteners, including studs (NAICS Code 332722489) = 3%
    - Urethane and other foam products (NAICS Code 326150P) = 9%
- Blade assembly labor cost
    - General inflation index
- Hub
    - Ductile iron castings (NAICS Code 3315113)
- Pitch mechanisms and bearings
    - Bearings (NAICS Code 332991P) = 50%
    - Drive motors (NAICS Code 3353123) = 20%
    - Speed reducer, i.e., gearing (NAICS Code 333612P) = 20%
    - Controller and drive - industrial process control (NAICS Code 334513) = 10%
- Low-speed shaft
    - Cast carbon steel castings (NAICS Code 3315131)
- Bearings
    - Bearings (NAICS Code 332991P)
- Gearbox
    - Industrial high-speed drive and gear (NAICS Code 333612P)
- Mechanical brake, high-speed coupling, etc.
    - Motor vehicle brake parts and assemblies (NAICS Code 3363401)
- Generator (not permanent-magnet generator)
    - Motor and generator manufacturing (NAICS Code 335312P)
- Variable-speed electronics
    - Relay and industrial control manufacturing (NAICS Code 335314P)
- Yaw drive and bearing
    - Drive motors (NAICS Code 3353123) = 50%
    - Ball and roller bearings (NAICS Code 332991P) = 50%
- Main frame
    - Ductile iron castings (NAICS Code 3315113)

**Figure 51 Visual on used assumptions TCC and TTAIC cost (National Renewable Energy Laboratory, 2006)**

$$\boldsymbol{Individual\ turbine\ total\ rotor\ cost}\ [€] = \boldsymbol{B_c + H_c + PMB_c + SNC_c}$$

$With$:
$B_c = Blade\ cost\ [€] = ((0{,}4 * Rotor\ Radius^3 - 21.1) + 2{,}7 * Rotor\ Radius^{2{,}502}))/(1 - 0{,}28) * Number\ of\ blades$

$H_c = Hub\ cost\ [€] = \left((0{,}954 * (0{,}4948 * Rotor\ Radius^{2{,}53}) + 5.680{,}3)\right) * 4{,}25$

$PMB_c = Pitch\ mechanisms\ and\ bearing\ cost\ [€] = 2{,}28 * (0{,}2106 * Rotor\ diameter^{2{,}6578})$

$SNC_c = Spinner\ and\ nose\ cone\ cost\ [€] = (18{,}5 * Rotor\ diameter - 520{,}5) * 5{,}57$

$$\boldsymbol{Individual\ turbine\ drive\ train\ \&\ nacelle\ cost}\ [€] = \boldsymbol{LSS_c + BE_c + G_c + MHS_c + GEN_c + VAR_c + YDB_c + MF_c + EC_c + HCS_c + NC_c}$$

$With$:
$LSS_c = Low\ speed\ shaft\ cost\ [€] = 0{,}01 * Rotor\ diameter^{2{,}887}$

$BE_c = Bearings\ cost\ [€] = 2 * \left(\left(Rotor\ diameter * \left(\frac{8}{600}\right) - 0{,}033\right) * 0{,}0092 * Rotor\ diameter^{2{,}5}\right) * 17{,}6$

$G_c = Gearbox\ cost\ [€]$:
$Threestage\ planetry/helical = 16{,}45 * (Machine\ rating)$^$1{,}249$
$Single\ stage\ drive = 74{,}1 * (Machine\ rating)^1$
$Multi\ path\ drive = 15{,}26 *\ (Machine\ rating)^{1{,}249}$
$Direct\ drive = -$

$MHS_c = Mech\ brake\ \&\ HS\ coupling\ cost\ [€] = 1{,}9894 * (machine\ rating - 0{,}1141)$

$GEN_c = Generator\ cost\ [€]$:
$Three\ stage\ drive\ high\ speed = Machine\ rating * 65$
$Single\ stage\ PMG = Machine\ rating * 54{,}73$
$Multi\ path\ PMG = Machine\ rating * 48{,}03$
$Direct\ drive = Machine\ rating * 219{,}33$

$VAR_c = Variable\ speed\ electronics\ cost\ [€] = machine\ rating * 79$

$YDB_c = Yaw\ drive\ \&\ bearing\ cost\ [€] = 2 * (0{,}0339 * rotor\ diameter^{2{,}964})$

$MF_c = Main\ frame\ cost\ [€]$:
$Three\ stage\ drive\ high\ speed = 9{,}489 * rotor\ diameter^{1{,}953}$
$Single\ stage\ PMG = 303{,}96 * rotor\ diameter^{1{,}067}$
$Multi\ path\ PMG = 17{,}92 * rotor\ diameter^{1{,}672}$
$Direct\ drive = 627{,}28 * rotor\ diameter^{0{,}85}$

$EC_c = Electrical\ connections\ cost[€] = machine\ rating * 40$

$HCS_c = Hydraulics\ cooling\ system\ cost[€] = machine\ rating * 12$

$NC_c = Nacelle\ cover\ cost = 11{,}537 * machinerating + 3849{,}7$

$$\boldsymbol{CS_c = Control\ system\ cost}\ [€] = \boldsymbol{54.500\ per\ turbine}$$

$$\boldsymbol{T_c = Total\ tower\ cost}\ [€] = (\boldsymbol{0,2694} * \boldsymbol{Hub\ Height} * \boldsymbol{Swept\ area} + \boldsymbol{1779}) * \boldsymbol{1,5}$$

$$\boldsymbol{Individual\ TTAIC}\ [€] = \left(\left(\boldsymbol{1,581^{-5}} * \boldsymbol{Machine\ rating}^{\ \boldsymbol{2}} - \boldsymbol{0,0375} * \boldsymbol{machine\ rating} + \boldsymbol{54,7}\right) * \boldsymbol{machine\ rating}\right) + \left(\left(\boldsymbol{1,965} * \left(\boldsymbol{hub\ height} * \boldsymbol{rotor\ diameter}\right)^{\boldsymbol{1,1736}}\right)\right)$$

(National Renewable Energy Laboratory, 2006)

$PDS_c = Permits, development\ and\ site\ assesment\ cost\ [€] = 37 * machine\ rating$

$SP_c = Scour\ protetcion\ cost\ [€] = 55 * machine\ rating$

$SB_c = Surety\ bond\ [€] = \left((FCC + EIC + TCC) * N_t\right) * 0{,}03$

$OW_c = Offshore\ warranty\ cost\ [€] = ((R_c + DN_c + T_c) * N_t) * 0{,}15$

(National Renewable Energy Laboratory, 2006)

## Appendix XIII: Increase in failure rates as result of internal temperatures due to increasing wind speeds

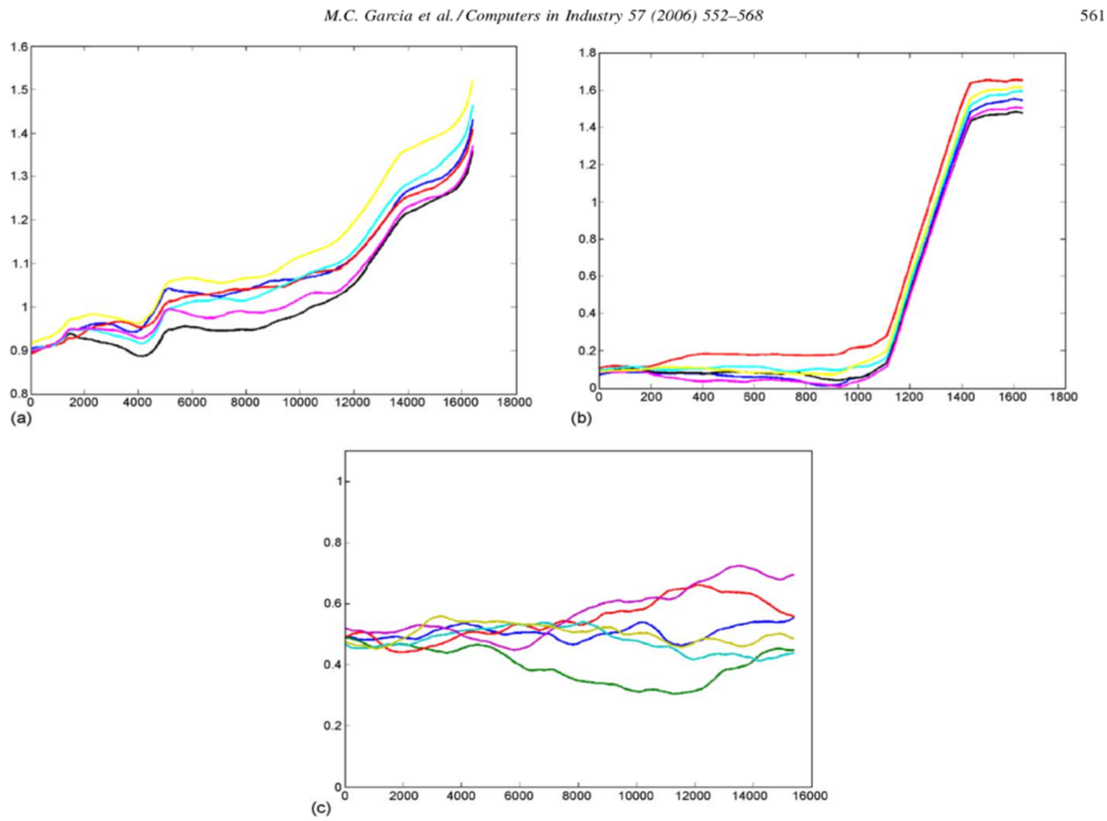



**Figure 52 Visual on evolution failure rates with corresponding gearbox bearing temperature (a), gearbox thermal difference (b), cooling oil temperature (c). (Universidad Pontificia Comillas, 2006)**

## Appendix XIV: Failure rate over years of operation

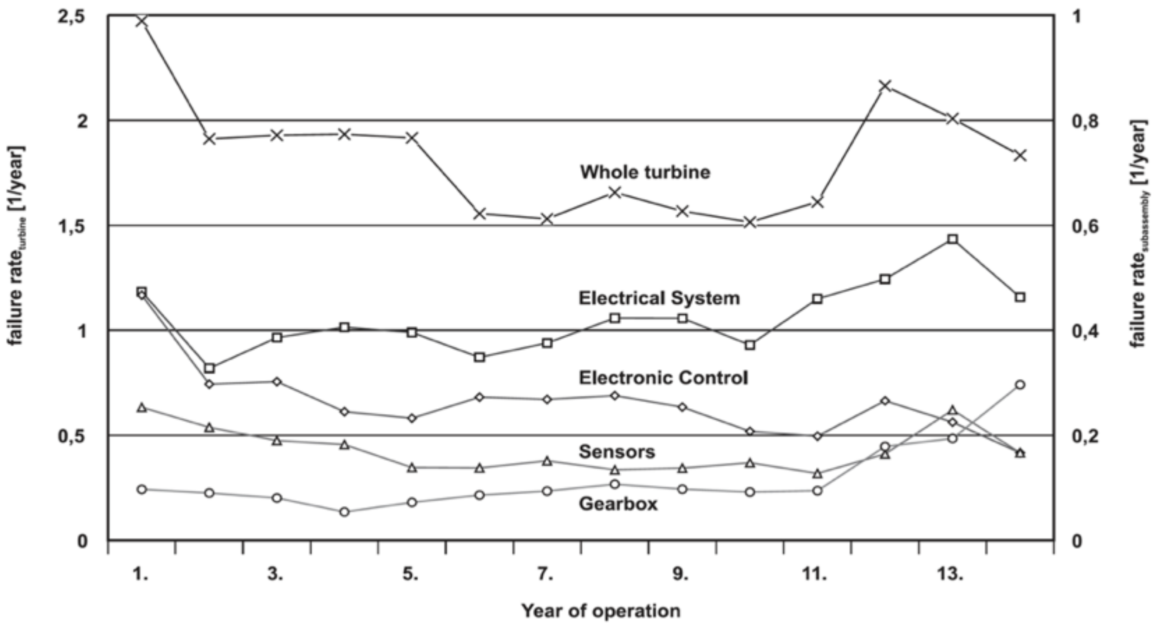



**Figure 53 Visuals on development failure rates during year of operations during lifetime. (Fraunhofer Institute for Energy Economics and Energy system Technology, 2011)**

## Appendix XV: Risk assessment categories discussed

**Risk classification of wind park investments - Literature study**

| Cat. | Wuester et al. (2016) | Turner et al. (2013) | Michelez et al. (2013) | Angelopoulos et al. (2016) | Liebreich & Young (2005) | Final |
|---|---|---|---|---|---|---|
| Commercial | Resource risk | Weather risk | Wind data availability | | Weather risk | Resource risk |
| Commercial | Technology Risk | Loss, damage or failure<br>Business interruption & downtime | Technology performance data | Technical risk | Technology risk | Technology risk |
| Commercial | Grid and Transmission Risk | Curtailment risk | Grid integration | Grid access | | Grid access risk |
| Commercial | | | Operational risks | Management risk | Maintenance cost risk | O&M risk |
| Commercial | Counterparty Risk | Counterparty risk | | | Counterparty risk | Counterparty risk |
| Macro- economic | | Power price | Supply and demand | | Electricity price/volume | Electricity price risk |
| Macro- economic | Liquidity Risk<br>Refinancing Risk | | | Renewable energy financing | | Financial risk |
| Political | Political Risk | | Public policy or implementation | Sudden policy change<br>Country risk | | Regulatory risk |
| Political | Policy or Regulatory Risk | Support cuts | | Policy design<br>Market design & regulatory | Renewable premiums/ incentives | Incentive scheme risk |

*Table 2 - Result from literature study on the risks of wind parks in the operational phase (Author's table)*

| 5. Main identified risks | 6. Final list of risks of this research set | | |
|---|---|---|---|
| Resource risk | A1 | Resource risk | Risk of wind input, leading to uncertainty in the production of electricity |
| Technology risk<br>Asset life risk | A2 | Technology risk | Risk in availability of the technical components of the wind parks for energy production due to damages, delays or failures |
| O&M risk<br>Maintenance cost risk<br>Management risk<br>Gearing risk | A3 | O&M risk | Risk in operation & maintenance of the wind park, depending on the capability of operators and their maintenance strategy, and the contract terms including gearing |
| Couterparty risk<br>Curtailment risk<br>Merchant risk<br>Electricity price risk | A4 | Merchant risk | Risk of the amount of energy that can be sold and against which price, which is partly determined contractually, and partly by the market |
| Inflation risk<br>Currency risk | B1 | Financial risk | Risk of a change in the value of the investment due to currency risk and inflation risk |
| Regulatory risk<br>Incentive scheme risk<br>Tax rate risk<br>Country risk | C1 | Regulatory risk | Risk of a change in public policy in the form of subsidies, taxes and energy supply regulations |

*Table 6 - Combining risks to limit interrelations, resulting in a final list risks for this research (Author's table)*

**Figure 54 Overview risk classification and risk categories. (Westhoff, 2018)**

## Appendix XVI: Country specific data related to WACC development

**Table 14 Country specific financial inputs for WACC determination (Own figure,2021 based upon (IEA Wind, 2018)**

| Financial Inputs | | Netherlands | UK | Belgium | Denmark | Germany |
|---|---|---|---|---|---|---|
| **Debt/equity ratio** | % | 70% | 70% | 75% | 70% | 75% |
| **Cost of equity** | % | 13% | 12,5% | 13% | 12,8% | 12% |
| **Cost of debt** | % | 4% | 4% | 5% | 4,8% | 4% |
| **WACC (Pre-tax nominal)** | % | 6,7% | 6,55% | 7% | 7,15% | 6% |
| **Annual Inflation** | % | 1,8% | 1,8% | 1,8% | 1,8% | 1,8% |
| **WACC (Pre-tax real)** | % | 4,67% | 4,67% | 5,11% | 7,23% | 4,13% |
| **Applicable Tax Rate** | % | 25% | 25% | 33% | 23,5% | 15% |

## Appendix XVII: Country specific subsidy & Fiscal policy

| Subsidy policy - Name of scheme | SDE + | Groenestroom-certificaten | Public Service Obligations (PSO) | Einspeisevergütung (§ 50 EEG) | Contracts for Difference |
|---|---|---|---|---|---|
| **Type** | Feed-in premium | Feed-in premium | Feed-in premium | Feed-in premium | Feed-in premium |
| **The cost of the subsidy scheme per kWh (public expenditure)** | Difference between required price (basic price) and the electricity market price which is corrected by an imbalance and profile factor and capped | Difference between the guaranteed price and the electricity market price which is reduced by ~10% | Difference between the guaranteed price and electricity market price | Difference between the base guaranteed price and the electricity market price | Difference between the guaranteed price (strike price) and the electricity market price |
| **Guaranteed price for investors** | Project-specific (determined in an auction) | Based on predetermined average (now €138/MWh) | Project-specific (determined in an auction) | Based on predetermined average | Highest bid granted in the auction sets the strike price (*pay as cleared*) |
| **Annual inflation correction guaranteed price** | No | No | No | No | Yes, CPI |
| **Method to assess income from electricity market** | Yearly average price | Yearly average price | Hourly average price | Monthly average price | Hourly average price |
| **Compensation for imbalance as part of the guaranteed price setting** | Yes, imbalance and profiling factor of ~10% of electricity price | No | No, but missed income is reimbursed for 25 years (last 5 years only the market price) | No, but missed income is reimbursed (at >6 consecutive hours of interrupted production) | No |
| **Subsidy cap: price per MWh** | Yes, limited by difference of the required price and the base electricity price (not corrected for inflation) | Yes, limited by the guaranteed price | Yes, limited by the guaranteed price | Yes, limited by the guaranteed price | Yes, limited by the strike price |
| **Subsidy cap: quantity** | Yes, project-based number of full load hours ('banking' is allowed), reached in 15 years | Yes, provided for 20 years | Yes, maximum 50,000 full load hours or 20 years | Yes, provided for 20 years. Front-loading in first 8 or 12 years | Yes, provided for 15 years |
| **Access to grid** | Provided (from 2015), not though the subsidy scheme | If developed by a farm, a higher tariff (€150/MWh) applies | Provided | Provided | Developed by a farm, sold to grid operator |

Source: PwC Analysis

TKI Wind op Zee

| Fiscal policy | | | | | |
|---|---|---|---|---|---|
| **Nominal corporate income tax rate** | 25% (20% for the first EUR 200,000 of taxable income) | 33% | 23.5% | 15% CIT plus solidarity surcharge of 5.5% on CIT Rate (together 15.38%) and 7% - 17% Trade Tax (varying by location) | 20% |
| **Depreciation terms** | Commercially, depreciation is taken into account over the period that the SDE subsidy is available (i.e. 15 years). For tax purposes, the economical and technical useful life of the asset (20 years for offshore windfarms), is taken into account | For offshore wind assets in principle there is no difference between the depreciation for commercial and tax purposes | Commercially, utility plants, including offshore windfarms, are depreciated on a straight line basis over the expected useful life of the asset (wind turbines for example 20-24 years by one leading player) while for tax purposes a declining balance method is applied | For tax purposes it is not allowed to depreciate each asset (e.g. tower, rotor blades) separately as it is required to depreciate the unit as a whole, which is also acceptable for commercial purposes | Commercially, depreciation is taken into account over the useful life of the assets. No tax depreciation is available but capital allowances may be deducted. The capital allowance amounts 18% calculated on a reducing-balance basis |
| **Recognition of (additions to) the decommissioning provision** | Commercially, additions to a decommissioning provision are recognized on an accrual basis | n/a | For tax purposes, there is no recognition of the decommissioning provision or any additions hereto | n/a | n/a |
| **Generic tax incentives available for offshore wind** | n/a* | n/a | n/a | n/a | n/a |
| **Specific tax incentives for offshore wind** | n/a | Farms may be eligible for a one-off investment deduction of 13.5% on the acquisition value | n/a | n/a | n/a |

**Figure 55 Visuals indicating country specific subsidy policy and fiscal policy (TKI Wind op Zee, 2015)**

## Appendix XVIII: CAPEX cost breakdown validation

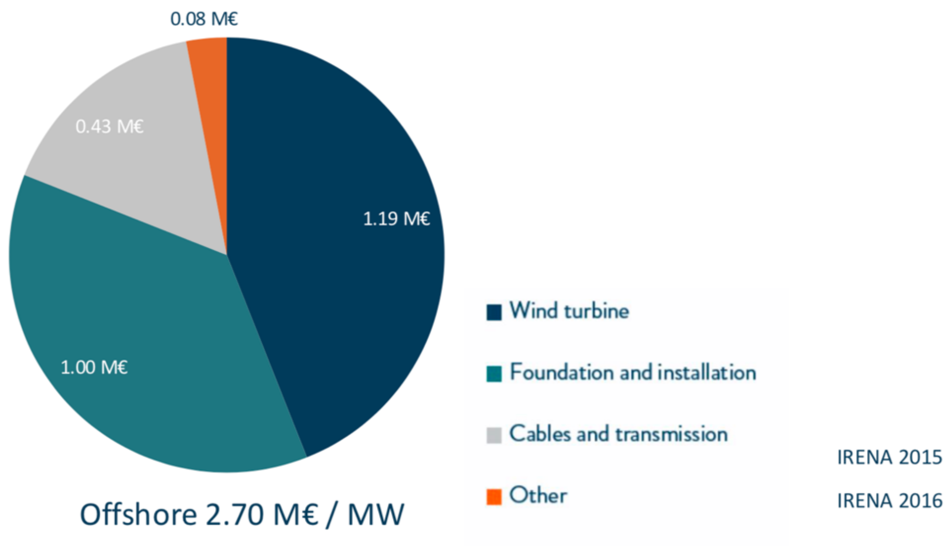



**Figure 56 €/MW CAPEX cost breakdown (De oude Bibliotheek Academy, 2018)**

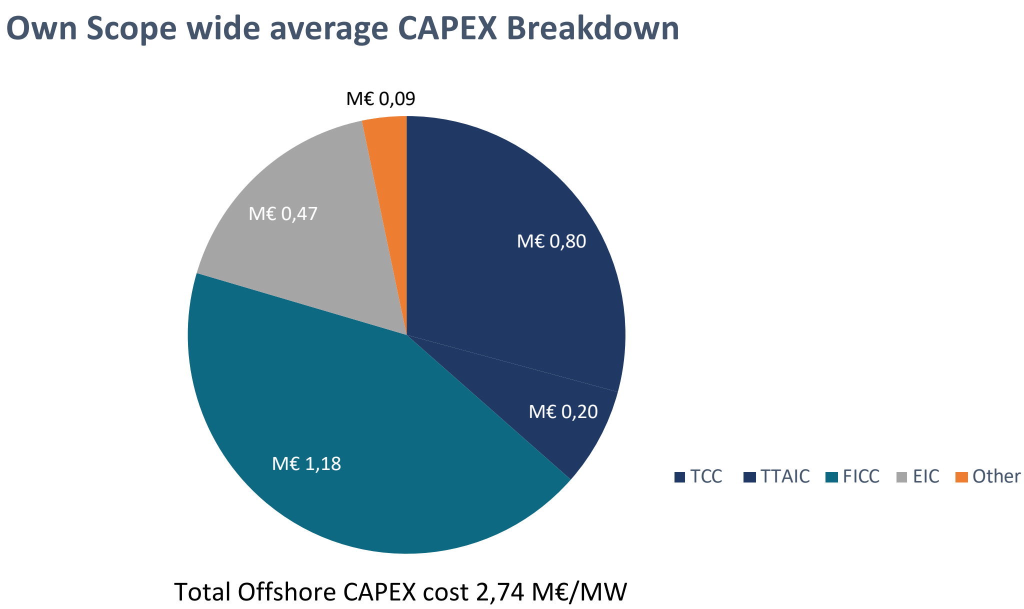



**Figure 57 €/MW CAPEX cost breakdown (Own figure,2021)**

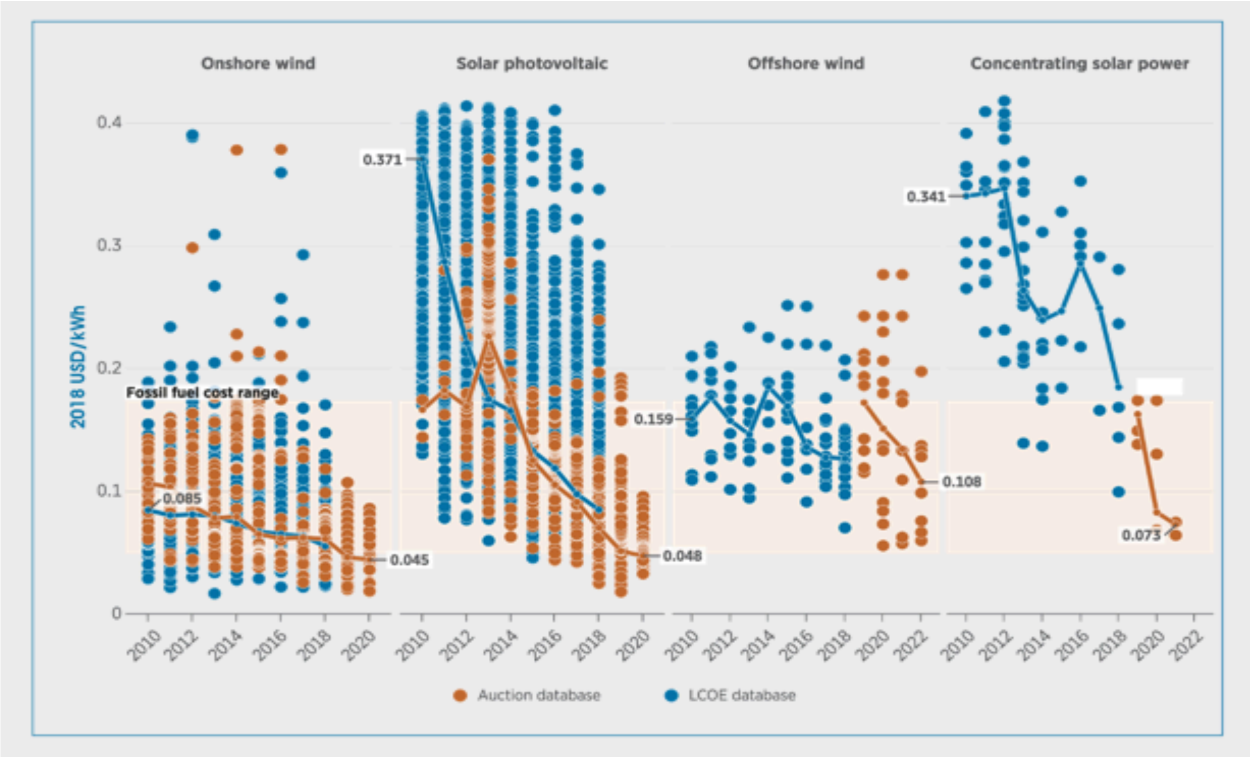



**Figure 58 Known LCOE trend (IRENA, 2019)**

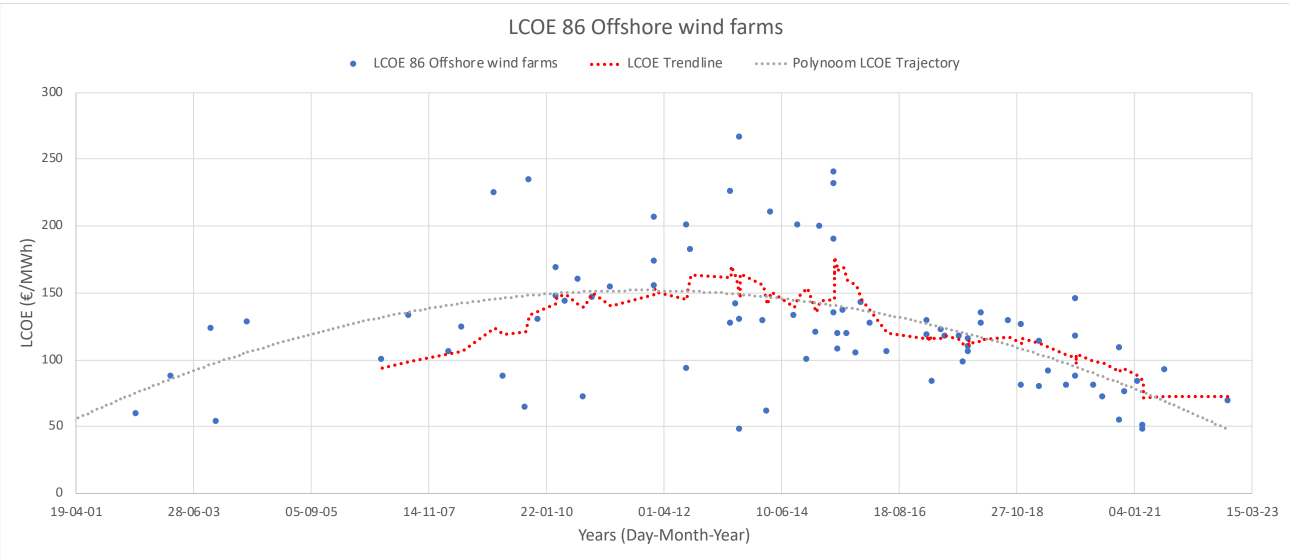



**Figure 59 Known LCOE trend based upon calculations (Gomez, 2020)**

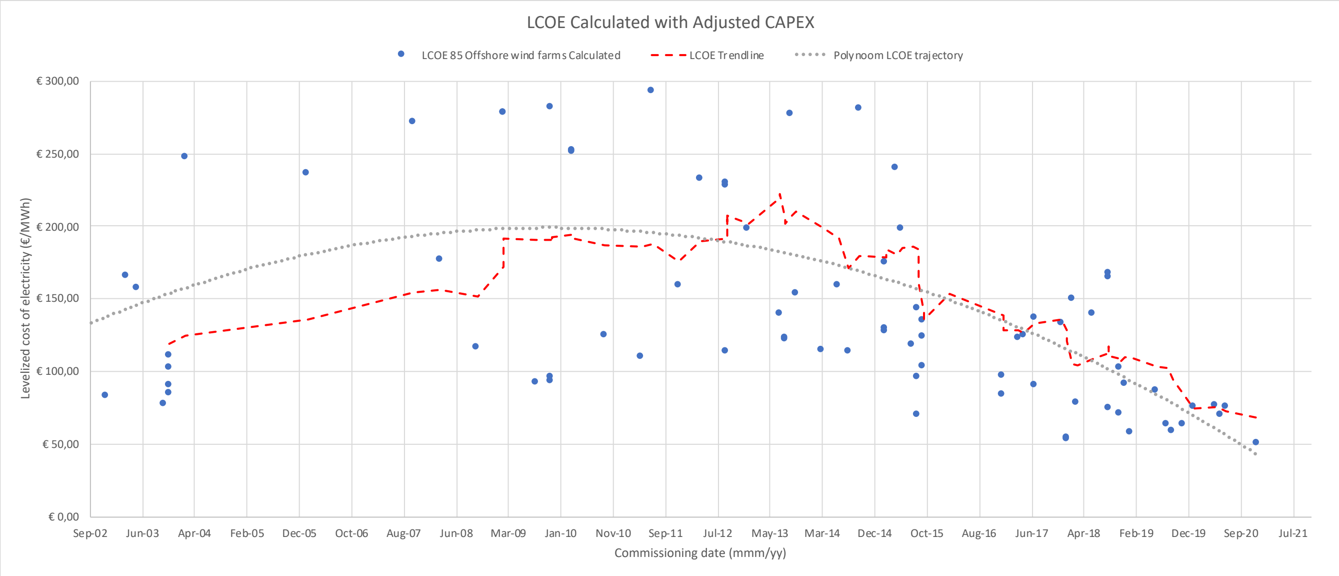



**Figure 60 LCOE trend with standard dependent variables (Own figure,2021)**

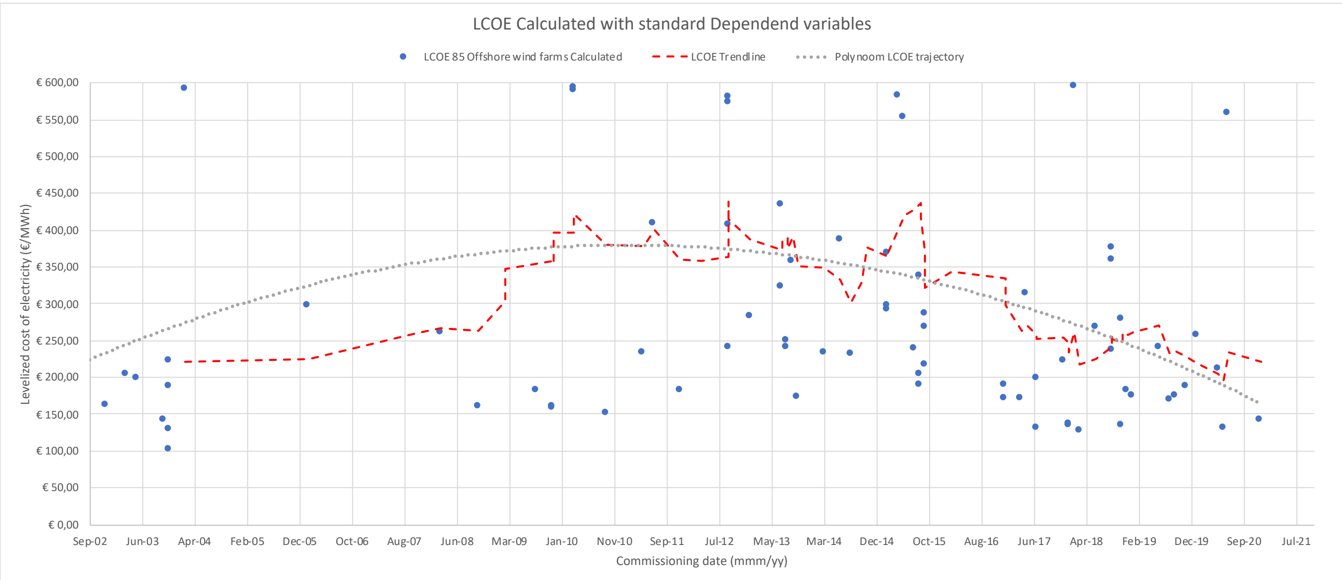



**Figure 61 LCOE trend with adjusted CAPEX (Own figure,2021)**

## Appendix XX: Conclusion statements validation

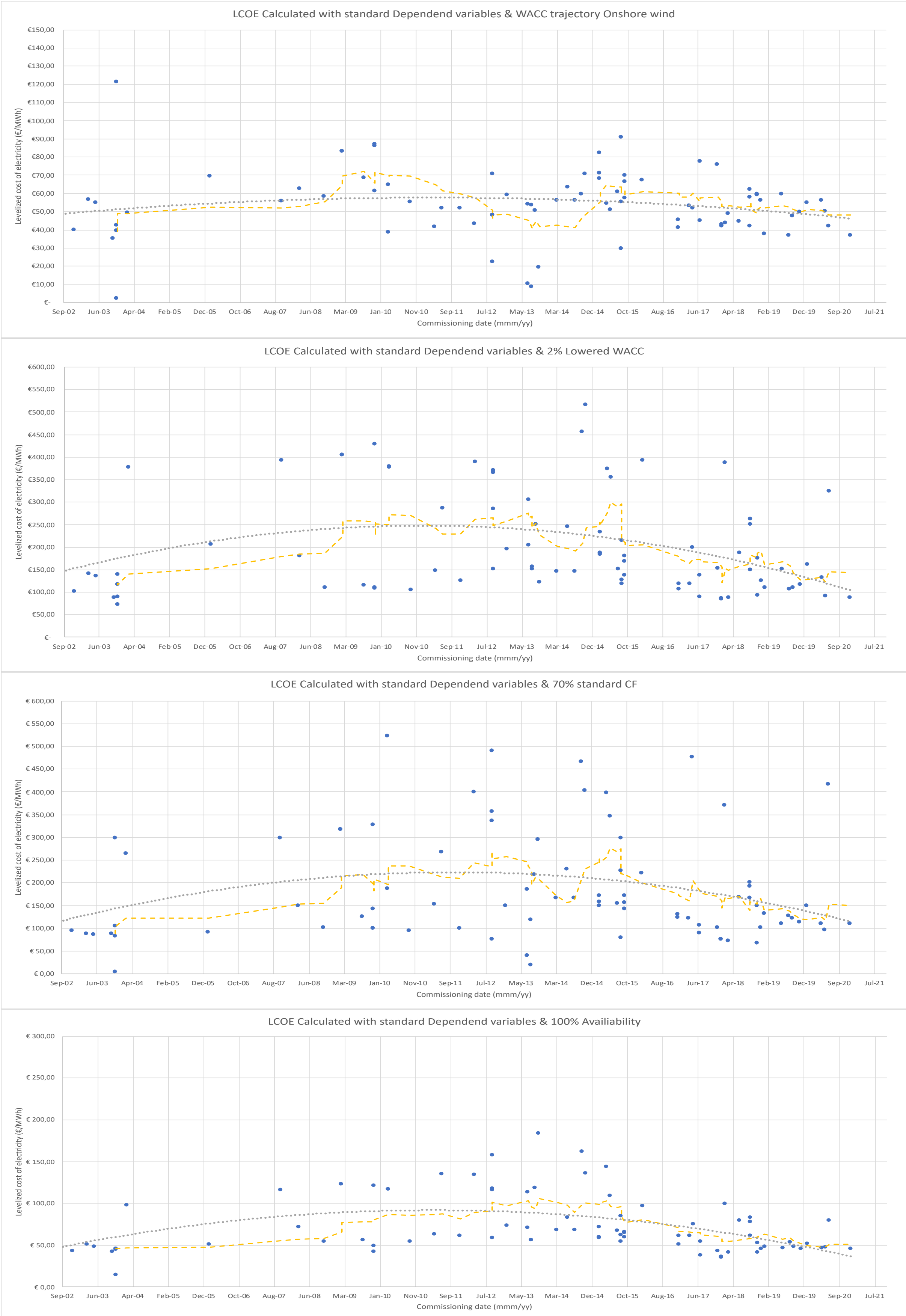
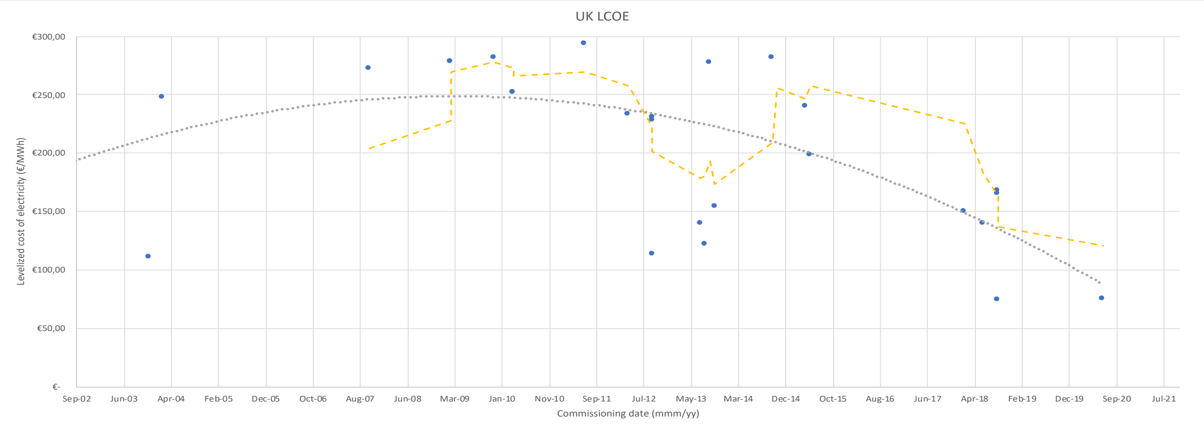
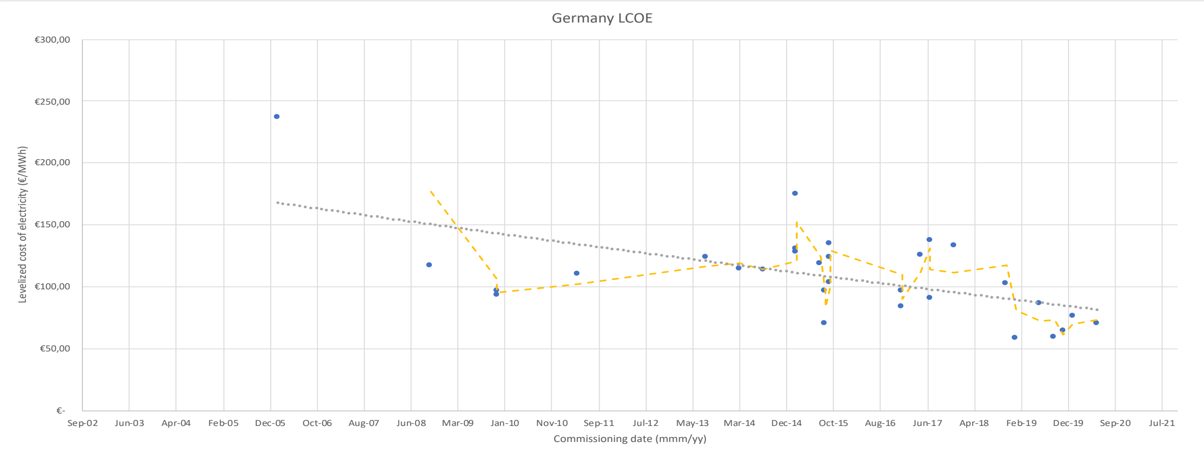
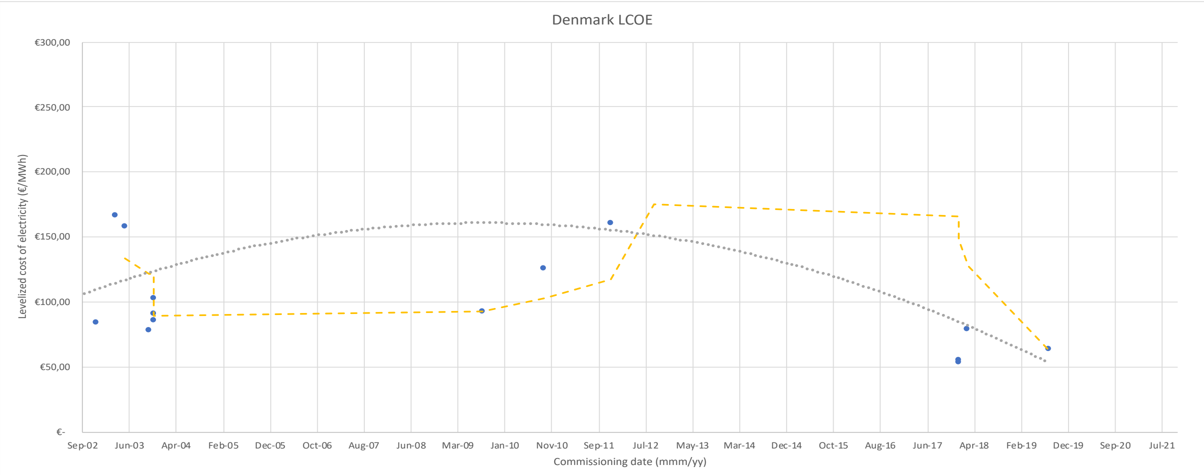


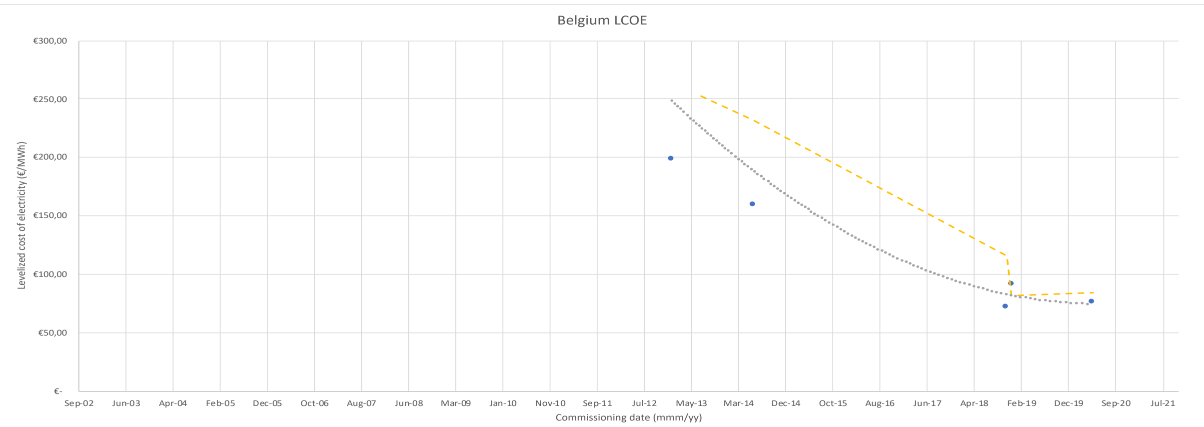

**Figure 62 Multiple visuals supporting made statements in conclusion (Own figure,2021)**

## Appendix XXI: Country specific LCOE trends



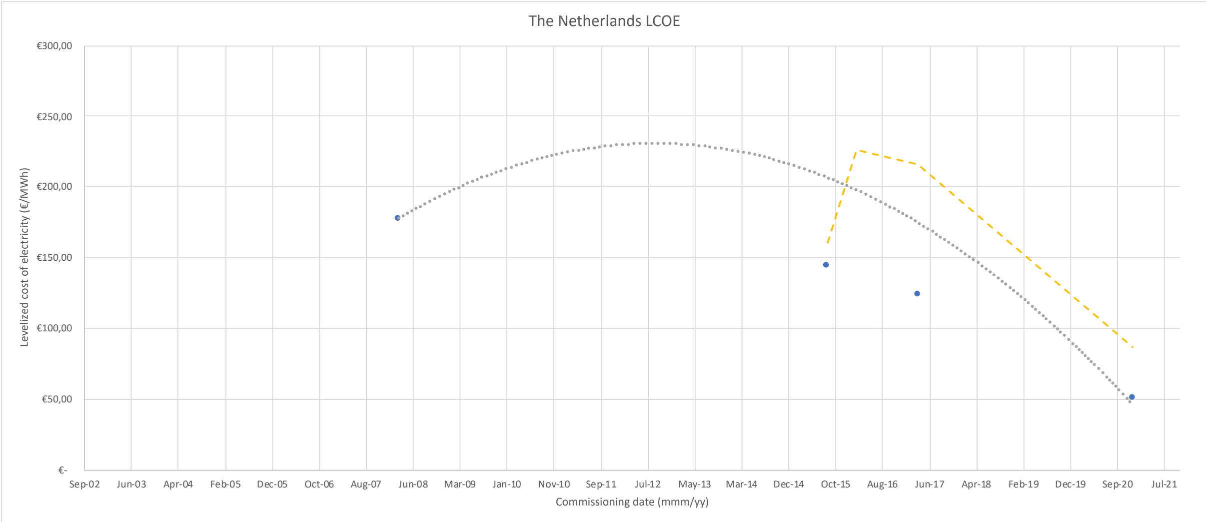



**Figure 63 Multiple visuals showing country specific LCOE trends (Own figure, 2021)**

## Appendix XXII Table overview of additional validations

**Table 15 Table overview of additional performed validations (Own figure,2021)**

| Subject | Estimated Value | Stated/known Value | Source |
|---|---|---|---|
| **Water Depth Development till 2019** | 350% | 400% | (windeurope, 2021) |
| **Distance to shore Development till 2019** | 420% | 500% | (windeurope, 2021) |
| **Average wind farm size development till 2010-2020** | 158% | 167% | (EWEA, 2019) |
| **Average Internal Wake losses in OWF's** | 11,9% | 11%-15% | (Prognos AG & The Fichter Group, 2013) |
| **Actual average CF in EU OWF's** | 40,4% | 40-45% | (Voormolen, 2015) |
| **Average full-load hours in EU OWF's** | 3537 | 3500-5000 | (P.E. Morthorst, 2016) |
| **Actual OWF availability including (un)scheduled downtime & wind conditions limitations** | 70,5% | <80% | (Enviromental Hydraulics Institute, 2016) |
| **OWF availability including scheduled downtime and wind conditions limitations** | 86% | 70-95% | (German offshore wind energy foundation, 2013) |
| **Turbine investment cost [M€/MW] in 2014** | 1,34 | 1,6 | (Center for Sustainable systems University of Michigan, 2014) |
| **CAPEX investment cost [M€/MW] 2000-2005** | 2,15 | 2,1 | (Voormolen, 2015) |
| **CAPEX investment cost [M€/MW] 2005-2010** | 2,52 | 2,8 | (Voormolen, 2015) |
| **CAPEX investment cost [M€/MW] 2010-2015** | 3,21 | 4,1 | (Voormolen, 2015) |
| **M€/MW investment "Westermeerwind" OWF** | 2,6 | 2,22 | (De oude Bibliotheek Academy, 2018) |
| **M€/MW investment Thortonbank OWF** | 3,97 | 4 | (De oude Bibliotheek Academy, 2018) |
| **M€/MW investment Gemini OWF** | 5,5 | 4,67 | (De oude Bibliotheek Academy, 2018) |