Master´s Thesis- master in Energy Sciences- Offshore wind energy cost trends and learning curves.

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Abstract

This thesis aims to give an insight in the historic cost trends and developments of offshore wind energy in the main five countries deploying this technology Europe. It has been done by analysing 86 operational offshore wind farms commissioned after 2000 till the ones under development that will be ready before the end of 2022. A first increase of the Capital Expenditures (CAPEX) is found that is linked to various factors like the distance to shore and depth, commodity prices and supply chain development till around 2015 when the cost starts decreasing. Analysis' results indicate that this late cost improvement may continue in the coming years and it is caused by an amalgam of factors. Using CAPEX, Annual Energy Production, Weighed Average Cost of Capital and Operational Expenditures, the development of average Levelized Cost of Electricity (LCoE) is shown to increase also in the first period from 120 €/MWh in 2000 towards 190 €/MWh in 2015 and then decreasing till 100 in the end of 2018, which is a direct result of the CAPEX decrease and the effort into improve the efficiency. The results indicate a learning in the last years that is expected to keep going in the near future, reaching values of 2.5-2 €/MW for the CAPEX and around 50€/MWh for the LCoE.

Acknowledgement

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Introduction

In the eighteenth century, with the beginning of the industrial revolution, the anthropogenic greenhouse gas emissions to the atmosphere have grown exponentially due to industrial processes, causing what we now know as climate change. This change in atmospheric conditions will result in a more unstable climate with the rise of extreme phenomena such as droughts, hurricanes, storms, polar ice melting and a higher global average temperature.

With the growing awareness of this many agreements have been created to reduce, or at least control, the amount of emissions released into the atmosphere. The latest international agreement has as long-term goal to keep the rise in global average temperature below 2 °C and to limit the increase to 1.5 °C, since this would substantially reduce the risks and effects of climate change. This is the Agreement of Paris.

Many states signed the Paris Agreement in 2016 to combat climate change by addressing greenhouse emissions through adaptation of the power systems, creating new policies and founding sustainable projects, starting in 2020. By 2018, the agreement was signed by 195 states and 184 are parties to it.

The implementation of new forms of renewable energy generation are needed to satisfy the increasing demand of energy while reducing the amount of greenhouse gases (GHG) emitted to the atmosphere. The energy sector accounts for around 29% of total emissions, so renewable energy technologies are rapidly developing in order to reduce them on time. Some of the adopted strategies to support renewables are feed-in tariffs, quotas with tradable green energy certificates, and competitive auctions initiated by the government making renewable energy sources of major interest to investors (Del Río & Linares, 2014). Most of the renewable energy technologies are relatively new, with commercial applications running for less than 20 years. One of these new technologies is offshore wind, which was identified in 2013 as one of the key technologies for achieving the 2020 targets (DECC & POST, 2013).

Offshore wind energy (OWE) is a relatively new technology that has grown exponentially since the beginning of 1991, with the first such wind farm in Vindeby, Denmark, having 11 turbines with a power of 450 kW, giving a total capacity of 4,95 MW.(Henderson, 2015). In 2018 Europe connected 409 new offshore wind turbines to the grid across 18 projects. This brought 2,649 MW of net additional capacity. Europe now has a total installed offshore wind capacity of 18,499 MW (Figure 1) (Windeurope, 2019).

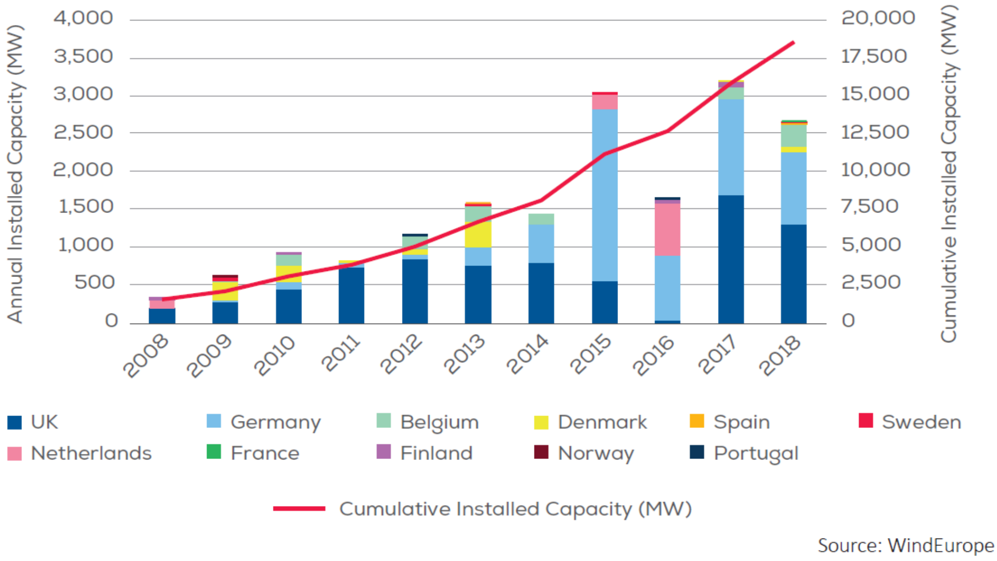


Figure 1: Offshore wind energy power installed in Europe in the period 2008-2018 (Windeurope, 2019).

However, even if the energy cost for offshore wind energy (OWE) has been historically higher than the average of conventional technologies, fossil or renewable, the evolution of OWE in the last years shows a trend where this cost is decreasing (Figure 2**¡Error! No se encuentra el origen de la referencia.**). This gives us the fact that OWE is expanding and, due to its advantages, the trend may continue in the coming years. Some of the benefits are these by (NESGlobalTalent, 2016):

- Turbines can be built sizeable, allowing for more energy collection from larger windmills, increasing the efficiency and the Power output.

- The fact that the wind turbines are far out at sea makes them much less intrusive on the countryside, allowing for larger farms to be created per square mile.

- There are typically higher wind speeds at sea and higher availability, as offshore conditions use to be windy. Also, there are no physical restrictions such as hills or buildings that could block the wind flow. These characteristics allows more energy to be generated at a time and with fewer interruptions than conventional onshore, due to the availability of wind.

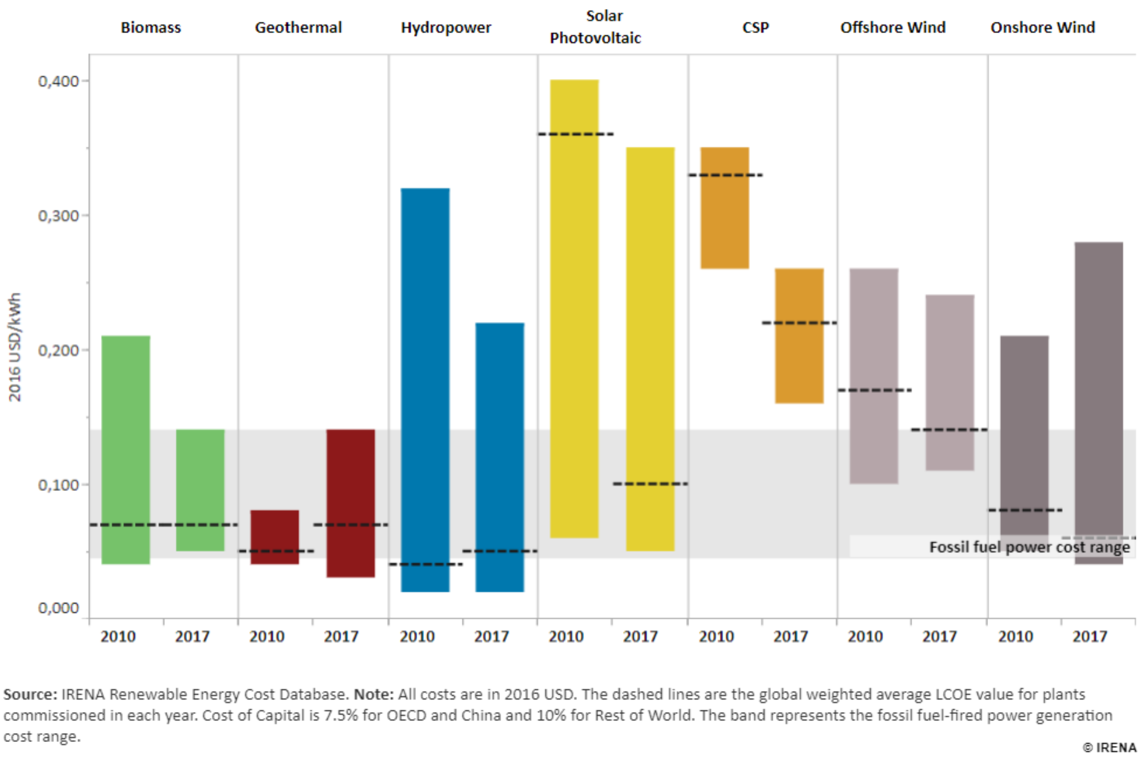


Figure 2:Global Levelized Cost of Electricity from utility-scale renewable power generation technologies 2010-2017 (IRENA, 2018).

However, some issues remain, such as that these cost-reduction effects have coincided over the past few years and have alternated with cost increases, (Van der Zwaan, Rivera-Tinoco, Lensink, & van den Oosterkamp, 2012) leading into a price development in the last years that, gives not only decreasing market price for OWE, but also cost increment. This rise have been studied by various researchers arguing that this could be caused by multiple factors, like the changing price in commodities (Van der Zwaan et al., 2012), the increasing depth and distance from shore for the projects (Voormolen, Junginger, & van Sark, 2016), the research investments (Grafström & Lindman, 2017) beside others.

Latest years cost developments for offshore wind farms (OWF) give an insight into the sector's evolution. In 2013 in Germany the Levelized cost of electricity (LCoE) ranged between 114-190 €/MWh and it is expected to reach the 90 €/MWh in 2030 (Windeurope, 2019) while in December 2017, the Netherlands approved a bid for its cheapest offshore project yet with €54.50 per megawatt-hour, for a site about 24 km off the coast. Just five months before, the winning bid for the same site was €72.70 (McKinsey & Co). This means that the LCOE for new OWF is still decreasing and it is expected to keep this way as shown in Figure 3**¡Error! No se encuentra el origen de la referencia.** (Henderson, 2015). This will allow OWE to be competitive against conventional fossil fuel energy.

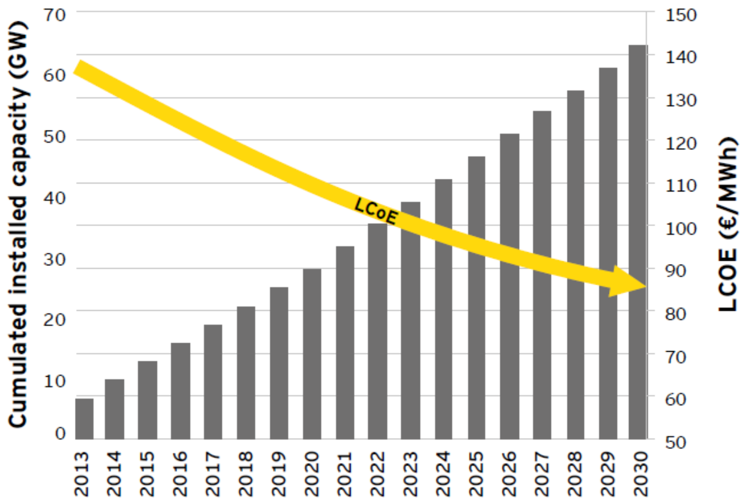


Figure 3:Evolution of the LCoE according to the cumulated installed capacity (Henderson, 2015)

This cost reduction has been evolving with the growth of OWE in the recent years. However, this trend has not being like this always. Once OWE was starting its commercialization the cost started growing for the first years with a growing installed capacity. Some studies were done to unravel how cost trends would be for the first years, in terms of LCoE and initial investment, but with no success (M. Junginger, Faaij, & Turkenburg, 2005). The problems with OWE cost are that it has changed in a different way than researchers expected, so the analysis of past cost trends for the future presents irregular historical trends. However, as stated earlier, trends in cost reduction are stabilizing, allowing some tools to be used to analyse future trends. Experience curves are one of these tools.

Experience curves are used to measure technological change by empirically quantifying the impact of increased learning on the cost of production, and where learning is measured through cumulative production or capacity (Lindman & Söderholm, 2012).

Experience curves have been widely used in the energy market for multiple technologies, including onshore wind energy, and can be used to analyse OWE's historical costs and develop an analysis with future costs. However, when it comes to cost, performance and technology used, offshore wind is different from onshore.

While it has been proven that one-factor learning curve works with onshore wind energy, in the past it has been shown that it does not work with offshore (Voormolen et al., 2016). This could be caused by the fact that in onshore the turbine, even if this one also depends on other factors, is around the 71% of the total cost of the project while in offshore this represents around the 40% (Wüstemeyer, Madlener, & Bunn, 2015). This means that offshore do not depended mainly on the upscaling of turbine production, but also on the technology development, research, installation experience, project location and financial factors.

So, besides the similarities between off-shore and on-shore wind energy technologies, these have insurmountable differences that makes OWE different from on-shore, so the experiences curves made for these will be different and adapted to the special mentioned conditions for offshore. Factors like the newest installed power, R&D and the addition of new data from OWF recently commissioned, and planned to be commissioned in the near future, may give a good insight of the future LCoE (Voormolen et al., 2016).

Also, some expert's elicitation surveys have been done before to predict the future development of wind costs. This method is widely use and offers a close estimation of the future expectations as shown in (Wiser et al., 2016a). With the experience curve method, it is possible to build models for the future and make a differentiation between the possible values and factors used. However, an expert elicitation would add reliability to the experience curves as in Figure 4**¡Error! No se encuentra el origen de la referencia.**.

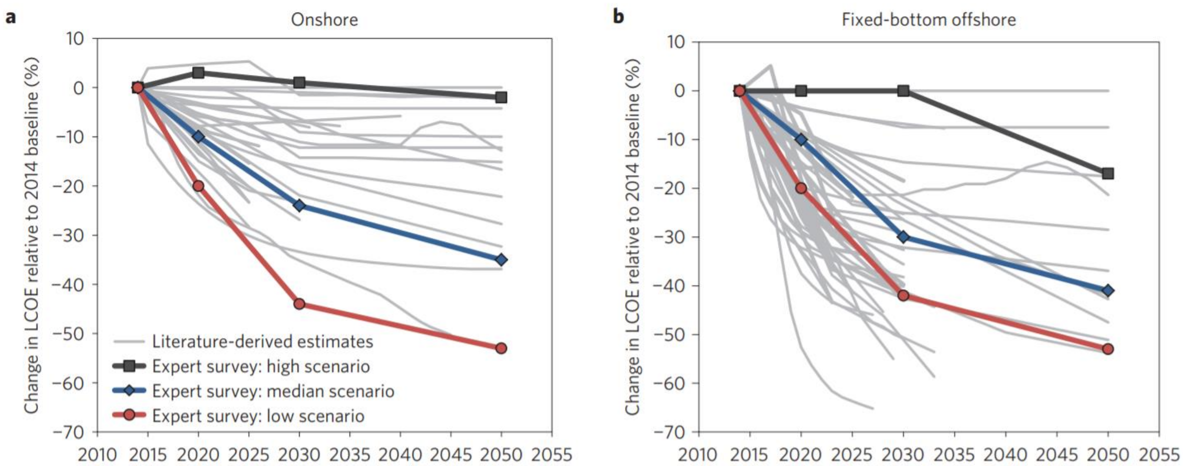


Figure 4: Estimated change in LCOE comparing expert survey results with other forecasts (Wiser et al., 2016a)

In Figure 4 the baseline of 2014 and the middle point in 2030 were built by asking to the experts the expected average cost for the LCoE and by requesting details on five core input components of LCoE: total upfront capital costs to build the project (CAPEX, €/kW); levelized total annual operating expenditures over the project design life (OPEX, €kW/year); average annual energy output (capacity factor, %); project design life considered by investors (years); and costs of financing, in terms of the after-tax, nominal weighted-average cost of capital (WACC, %) (Wiser et al., 2016a).

As a result, numerous studies have been created to forecast the future trend for OWE, but as it has not been until recently that the costs have begun to decline, previous studies have not been able to evaluate future costs with this trend as an input. In this study the main objectives are to unravel the costs historic trend from 2001 till the beginning of 2019 with the data available nowadays, analyse it and elaborate some future expectation on how the costs will develop considering the obtained learning rates for the LCoE and the CAPEX.

Currently the majority of the offshore wind farms are installed in Europe. The UK has the largest amount of installed offshore wind capacity in Europe, representing 43% of all installations followed by Germany with 34%. Denmark remains the third largest market with 8%, despite no additional capacity in 2017. The Netherlands (7%) and Belgium (6%) remain at the third and fourth largest share respectively in Europe (Windeurope, 2019). Combined, the top five countries englobe 98% of all grid-connected turbines in Europe. Therefore, these countries will be the focus of the study to see the development of OWE.

Research questions

How has the LCoE developed historically and how will it develop in a medium-term (2030) for off-shore wind energy projects in Europe?

- **Which factors affect the cost of OWE projects?**
- **How variables, like CAPEX, CF, OPEX etc. have evolved?**
- **How will the costs develop in the near future?**

Theoretical background

In this section the theoretical background that forms the basis of this research is provided describing the processes developed, the main theory needed and the factors calculations.

Offshore Wind Energy

Offshore wind power or offshore wind energy (OWE) is the use of wind farms constructed usually in the ocean on the continental shelf, to harvest wind energy to generate electricity. Higher wind speeds are available offshore compared to on land, so offshore wind power's electricity generation efficiency is higher than onshore.

An offshore wind farm has the typical layout of Figure 5 comparing it with onshore wind farms. In offshore the turbine, that generates the electricity through the wind on the sea, needs an extra part to fix it to the seabed, this is the foundation. The foundation represents an important part of OWE and exist different kinds of them like monopile, the most used, jacked, tripod etc. depending on the depth where the farm is installed and the seabed conditions.

The farm is inter-connected with array power cables that takes the power to an offshore substation that converts the electricity into a high tension current to minimize the losses in the export cable. This export cable, as its name says, exports the electricity from offshore to onshore, where this is converted again and connected to the conventional transmission system for the grid.

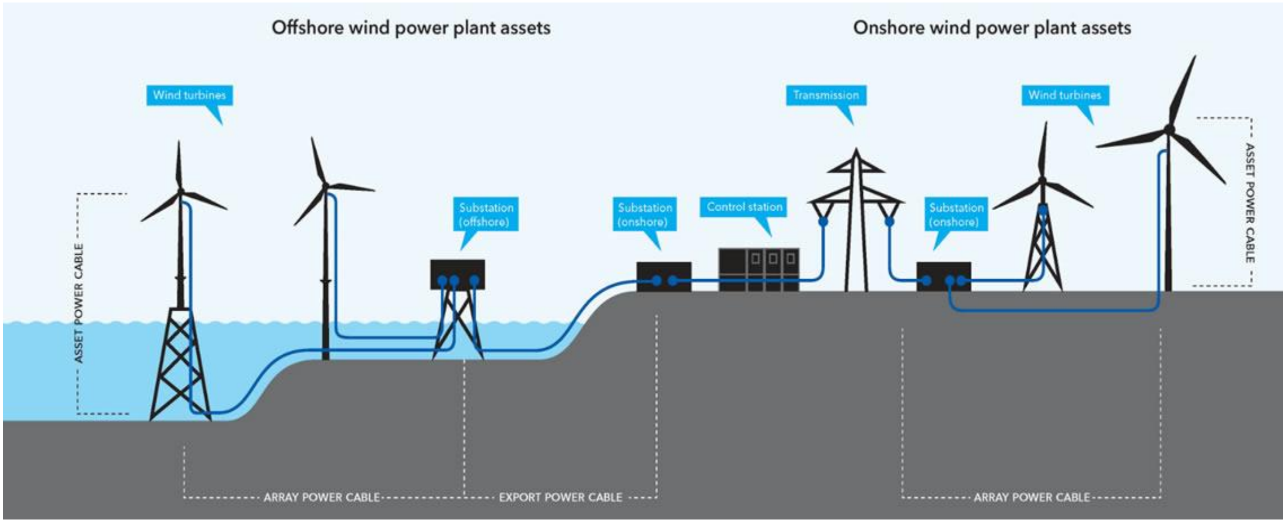


Figure 5:Typical layout of an offshore and onshore wind farm ("DNV GL Blog," n.d.).

This OWFs have a cost that vary along time and from farm to farm. We can compose the factors that affect the cost in four big groups that are:

- Capital expenditures (CAPEX)
- Operational expenditures (OPEX)
- Annual energy production (AEP)
- Financial Expenditures (FinEx, where the main factor is the WACC)

CAPEX

The Capital expenditures (CAPEX) are the funds invested in the projects that include the acquisition of all the components, the development phase, and the installation of the wind farm until it has been fully commissioned. It does not include the financial expenditures and it is used to check the initial investment done in a project and the cost per MW installed.

The value chain that affect the CAPEX for an OWF could be classifies in the different parts and processes involved in the fully commissioning of it, from the installation works, vessels rental and engineering work and surveys to the manufactured goods needed in the farm (cables, turbines, transformer etc.).

These drivers that influence the final CAPEX may be categorised as either (i) 'intrinsic' or (ii) 'external', reflecting the extent to which offshore wind developers and energy policymakers are able to influence them (Greenacre, Gross, & Heptonstall, 2010).

Intrinsic drivers include:

- Depth, since the foundation type used, and the size, change with it and therefore the cost.
- Distance, since the cables length is directly proportional to the distance from shore and the installing, operation and maintenance also increase with it.
- Lack of competition in production of key components. Some products that influence greatly the cost are only produce by a few companies, like the turbines and the cabling (Windeurope, 2019). This lack of competition may lead into higher prices since there is no need into improving them like in a competitive market.
- Supply chain/infrastructure bottlenecks. Some components do not have a specific market for themselves and they had to be "taken" from others. The best example are the installing vessels because, till recently, these were not specific for this task and were "taken" from oil and gas industry. This means that when the demand of oil and gas was high the vessels price increased.
- Planning and consent.

External drivers of cost escalation include:

- Cost of finance .
- Exchange rates because some components must be purchased in different currencies.
- Commodity prices, since a big fluctuation in these may influence the components manufacturing cost to some degree.

OPEX

The Operational Expenditures (OPEX) in its definitions is "*an ongoing cost for running a product, business, or system*". It is usually confused with the Operation and Maintenance (O&M) but these terms are not the same. Indeed, the O&M is part of the OPEX, representing the last one also any other annual operating expenses. It is estimated that O&M is about 50% of the total OPEX for offshore wind (IRENA, 2012). Other possible expenditures are the replacement of parts, subsidies, depreciation and annual taxes (Gonzalez-Rodriguez, 2017).

The Operating expenses include:

- License fees inherent of the energy generation offshore.
- Maintenance and repairs since the wind turbines require of continuous supervision and regular operations to guarantee their correct functioning.
- Supplies to replace broken parts, if necessary, and to replace those with normal wastage.
- Utilities for the crew that must remain offshore to work on the wind farm.
- Insurance coverage that helps mitigate risks during transportation, construction or operation of the asset.
- Salary and wages of the employees.
- Others.

AEP

The Annual Energy Production (AEP) of a wind turbine is the total amount of electrical energy that is produced over a year measured , in our case, in megawatt hours or terawatt hours (MWh or TWh) ("Annual Energy Production. Windspire," n.d.).

The AEP depends on other important concept that is the Capacity Factor (CF). The capacity factor is the average power generated on annual basis, divided by the rated peak power. Let's take a five-megawatt wind turbine. If it produces power at an annual average of two megawatts, then its capacity factor is 40% (2÷5 = 0.40, i.e. 40%) ("Energy Numbers" n.d.).

These values have to be addressed for a few years to do an average since, if only one year is taken, this value may be over, or below, estimated by one year with unusual atmospheric conditions.

WACC

OWF requires big investments, and the acquisition of these by the developers comes with some financial expenditures that are summed to the final cost. To quantify these expenditures the Weighted Average Cost of Capital (WACC) is the most common factor for this kind of studies and found in plenty literature. A project's WACC represents its blended cost of capital across all sources, including common shares, preferred shares, and debt. The cost of each type of capital is weighted by its percentage of total capital and they are added together (Corporate Finance Institute, 2019).

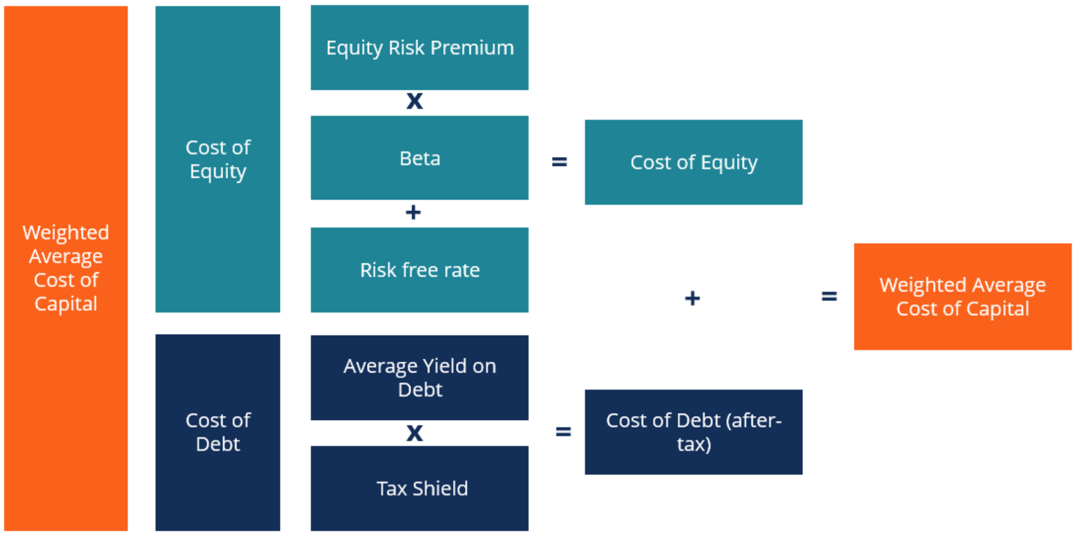


Figure 6: WACC composition by (Corporate Finance Institute, 2019).

Simplistically, WACC is the weighted average cost of finance, where the weighting is based on the share of funds provided from different sources. For example, an equity provider supplying half of the investment for a project expecting to release 15% and a lender provides the other half as debt with a 5% interest rate, leading to a calculated 'WACC' of 10%. This calculation works fine when you get your capital back at the end of the period (BVG Associates, 2016). But in offshore wind the value of the asset reduces to effectively zero over its life. So, the finance payments must cover the repayment of the capital as well as the interest. This means the true WACC is higher than previous calculation. Lenders providing funds for less than the wind farm's lifetime complicates the situation and increases the final true WACC.

In the case of offshore wind projects it is required a large amount of capital with budgets sometimes over 2 billion euros giving a typically debt-equity ratio around 70:30. The cost of debt and equity is the result of several factors: general economic welfare, technology related risks and in the case of offshore wind also policy risks (3E, 2013). This affects the WACC following Equation 1 and in different way for each country since this is specifically calculated for each one.

Equation 1: WACC calculation

$$WACC\% = share\ of\ equity * cost\ of\ equity(\%) + share\ of\ debt * cost\ of\ debt(\%)$$

However, due to unstable and/or unpredictable policy frameworks with a change in risk perception the WACC can change largely from year to year, which will have a significant effect on the LCoE (Voormolen et al., 2016). To quantify the importance of WACC we can check Figure 7 where we can see that the change in the WACC for a project may change the LCoE largely. For example a rise of 1% in the WACC would cause an increment in the cost pf energy of 5€/MWh (Poudineh, Brown, & Foley, 2017).

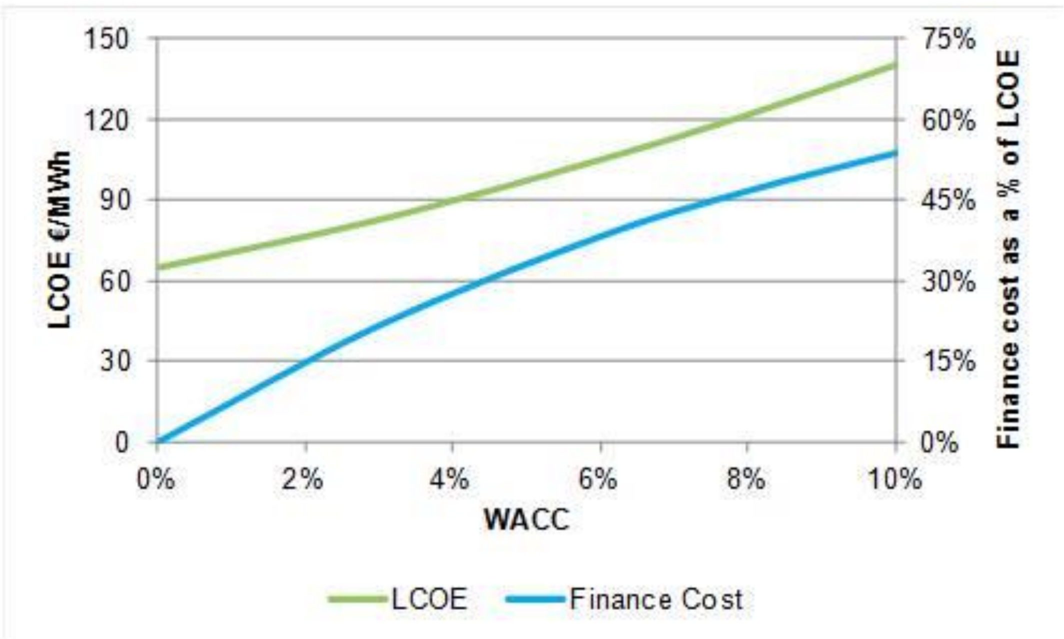


Figure 7: WACC fluctuations by (Poudineh et al., 2017).

Levelized cost of Electricity

Levelized cost of electricity (LCoE) is often cited as a convenient summary measure of the overall competitiveness of different generating technologies. It represents the per-MWh cost (in discounted capital) of building and operating a generating plant over an assumed financial life and duty cycle. Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed utilization rate for each plant type (EIA, 2018).

Following the formula used by Junginger (Voormolen et al., 2016) we got:

Equation 2: Levelized cost of electricity.

$$LCoE = \frac{CAPEX + \sum_{t=1}^{L} \frac{OPEX}{(1+i)^t}}{\sum_{t=1}^{L} \frac{AEP}{(1+i)^t}}$$

Where:

i = the discount factor, similar to the Weighed Average Cost of Capital (WACC).

t = the year of operation.

L = lifetime of the OWF.

AEP = Annual energy production, based on the Capacity Factor (CP).

OPEX = Operational expenditures.

CAPEX = Capital expenditures.

Other calculations for the LCoE have been launched to provide new nuances to the total lifetime cost introducing development expenditures (DEVEX) and abandonment expenditures (ABEX) (Megavind, 2015). The model developed by MEGAVIND has been proved to be an accurate tool to calculate the LCoE for OWE but it also needs more specific data, sometimes unavailable for the general public, to develop this LCoE (" Megavind," n.d.).

Experience and learning curves

Experience curves have been largely used to develop economic models to see how the production cost on a certain technology may change during time depending on one or various factors. This approximation was previously used for onshore wind but very little for offshore wind (Martin Junginger et al., 2004) and most of them failed to predict the trend for offshore costs as there was no cost decrease until recently.

One thing to mention is that it is common to use interchangeably the terms experience curve and learning curve. They have different meanings, though. The Experience Curve is an analytical tool designed to quantify the rate at which accumulated output experience, to date, has an impact on total unit cost of a technology's functional output. The learning curve is an analytical tool designed to quantify the rate at which a cumulative work-hour or cost experience allows an organization to reduce the amount of resources it needs to spend on performing a task. The experience curve is broader than the curve of learning in terms of the costs covered, the range of output during which cost reductions occur, and the causes of reduction ("Experience and Learning Curve" n.d.).

It is possible to talk about learning effects when a cumulative past output is negatively related to the cost of creating the following unit. Looking at it from a mathematical way learning curves can be described as:

Equation 3: Presence of learning efects.

$$E_{CQ} = \frac{\Delta C/C}{\Delta Q/Q} < 0$$

Where:

E_{CQ} = the "cost-cumulative output elasticity".

C = Cost.

Q = cumulative quantity produced.

Here, C is the cost associated with the initial investment of an OWF (CAPEX) and Q is the cumulative capacity of all the previous OWF (Dismukes & Upton, 2015).

The one factor learning curves (OFLC) describe the cost of a given technology by the fact that upscaling the production of this leads to a reduction in the cost, which is represented by cumulative capacity or production of a certain technology (Kahouli-Brahmi, 2008). The usual way to express the OFLC is by:

Equation 4: One factor learning curve equation (Yu, Van Sark, & Alsema, 2011).

$$C = C_i Q^{-b}$$

Where:

C = Cost per unit of production.

C_i = Cost of the first unit installed or produced.

Q = cumulative capacity output.

b = Learning index or experience index

This OFLC depends on the economies of scale, where the cost of a certain good is reduced in conjunction with the increase in production. Economies of scale exist when the percent increase in output is greater than the percent increase in costs needed to achieve the increase in output (Dismukes & Upton, 2015) . Or mathematically:

Equation 5: Economies of scale.

$$E_{Cq} = \frac{\Delta C/C}{\Delta q/q} \; < \; 1$$

Where:

E_{CQ} = the "cost-cumulative output elasticity".

C = Cost associated with the initial investment to build the windfarm (CAPEX).

q = Quantity produced.

In this case, q is the installed capacity of an OWF in MW. If E_{CQ} is equal to 1 then doubling of C, will lead to doubling of q. If economies of scale are present, though, then the cost-output elasticity will be less than one, and therefore doubling the cost will more than double the output (Dismukes & Upton, 2015).

However, the one factor learning curve only relates the cost change with the cumulative capacity, ignoring other possible factors and effects like the ones of cumulative R&D expenditures (Yu et al., 2011).

Other option that incorporate the learning factor, or knowledge stock (*KS)* have been introduce into the OFCL as a new variable (Klaassen, Miketa, Larsen, & Sundqvist, 2005):

Equation 6: Two factors learning curve equation.

$$C = C_i Q^{-b} KS^{-\alpha}$$

Where KS is equal to $(1 - ή)KSt - 1 + RDt$, where ή is the annual depreciation rate and RDt the R&D expenditures at time t and α is the elasticity of learning by researching. This is known as the Two factors learning curve (TFLC) (Yu et al., 2011).

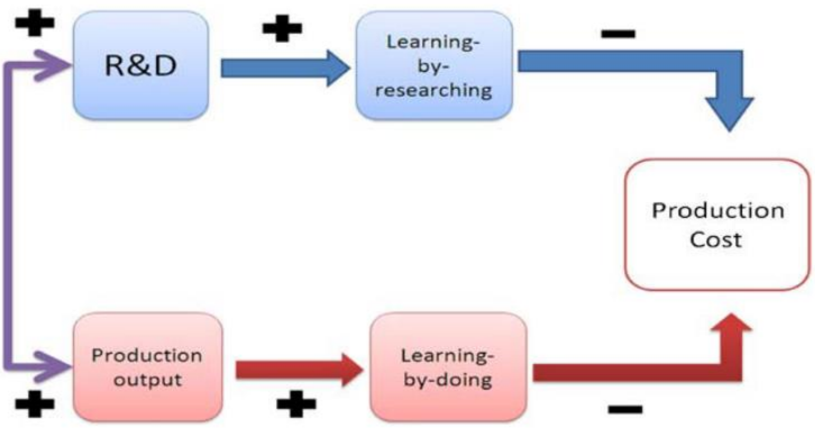


Figure 8: Relationships and feedbacks between R&D, production growth and production cost (Yu et al., 2011)

The main issue is that the learning curve is for one product, while OWE farms consist of a combination of several specific products such as turbines, tower, foundations, cabling, etc. Experience curves therefore fits better, as the learning curve is really about a descent in labour costs in a company, whereas the experience curve is to describe the total costs of a technology in a whole industry while being based on the same concepts as learning curves. Second is that this method only accounts the production but neglects other possible characteristics, like depth and the distance to the shore in our case, that also influence the cost. Although, it can still be expected that the cost go down by the development of several factors like the following ones (Voormolen et al., 2016):

- Learning-by-doing.
- Learning-by-using.
- Learning-by-search.
- Standardization of the product.
- Redesigning and upsizing of the product.

These factors may reduce the cost of the products during a certain period. However, these are not the only factors to consider. Other factors may cause also a cost change that in some cases may even overcome the reduction gained by the experience like, the financial risk, political framework, Capacity factor, etc.

Because of the difficulty to obtain cost data for each factor the energy price is the main data used and then this related to the cost for this new technology as described by Boston Consulting Group (1968). However, with offshore energy this may be an issue since this new technology is also associated with risks and uncertainties so, to be save, the profit margins are a bit higher than the usual and may not represent perfectly the cost of production (Wüstemeyer et al., 2015).

Definitions and scope

Current situation

The first of this kind of installations can hardly being called offshore since the distance from shore and depth are less and almost no comparable to the new farms. These first wind farms were installed close to shore (>10km) and with water depth ranging 5-10m.

Figure 9: Vindeby offshore wind farm

While the main difference between the current situation and the past is that when offshore technology began its commercial phase, it seemed to be a reasonable idea to use the same technology for offshore wind farm as the one used in onshore with slight adjustments. However, the needs for further offshore R&D and expertise was underestimated. Keeping in mind that competition for onshore products is much stronger, and that marginal improvements per fixed R&D expenditures are small, insufficient onshore investment can lead to distinct losses in onshore market share (Wüstemeyer et al., 2015).

One example of this problem is the 160MW wind farm Horns Rev in Denmark with 80 Vestas V80 turbines that were adapted for offshore usage (Richardson, 2010). Two years after the commissioning, all wind turbines had to be removed for refurbishment, maintenance and replacement works due to eminent transformer and generator problems (Sweet, 2008). Companies tried to adapt onshore technology saving additional R&D investment. These soon realised that OWF needed a new division and that it is not just an onshore extension. However, optimizing products for offshore usage means at the same time making them inefficient for onshore wind power, since additional features, such as an extended corrosion resistance, are unnecessary cost drivers (Wüstemeyer et al., 2015).

Since the firsts OWF the followed trend has been increasing the size and rated power of the turbines, the depth and the distance from shore. This leaded in the period 2000-2015 in an increase of the Capital Expenditures (CAPEX) from 1.5 M€/MW in 2000 to 4.0 M€/MW in 2010 and a decrease in the recent years 2015-2018 that is explained further in this paper.

Size and rated power

The first turbines installed had a diameter around 65m and a capacity of 2MW while in 2018 the average rated capacity of new installed turbines was 6.8 MW (Figure 10**¡Error! No se encuentra el origen de la referencia.**), 15% larger than in 2017 and rotors size of 160m. Since 2014 the average rated capacity of newly installed wind turbines has grown at an annual rate of 16% (Windeurope, 2019).

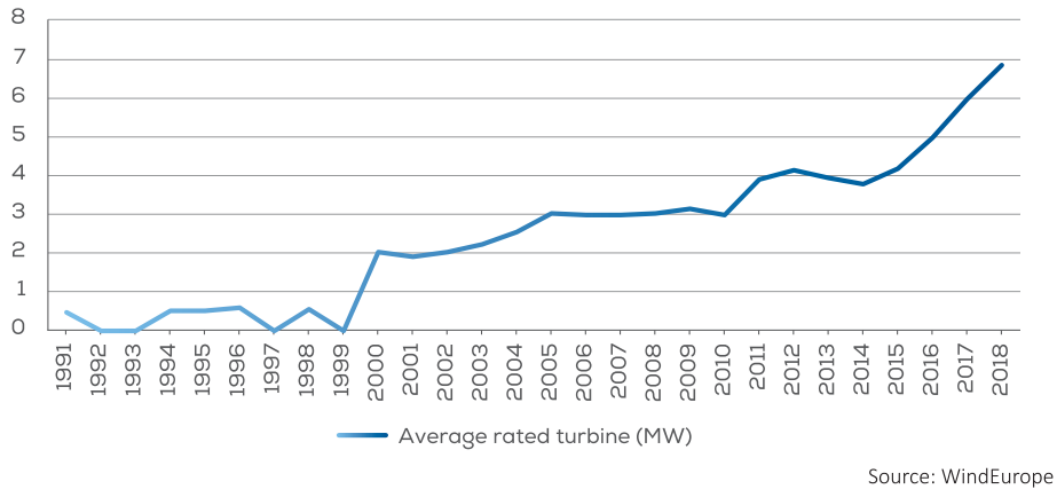


Figure 10: Yearly average of newly installed offshore wind turbine rated capacity (MW)

This trend in the size rise looks like will keep on track next years since it is already confirmed the commercialization of a 10 MW and 164m rotor turbine by Vestas in the beginning of 2021 and a 12 MW turbine by Haliade-X is under development for 2022 (International Energy Agency, 2018).

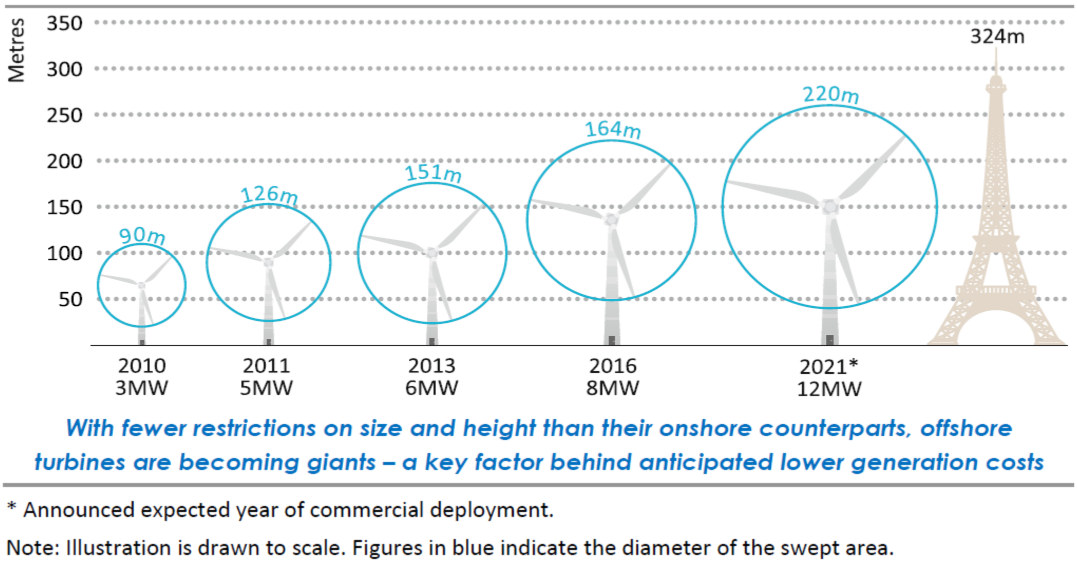


Figure 11: Evolution of the largest commercially available wind turbines

The main reason to explain this size trend is that the new turbines develop a higher capacity factor to maximize CF and by hence the annual energy production (AEP) (Figure 12) **¡Error! No se encuentra el origen de la referencia.¡Error! No se encuentra el origen de la referencia.**. But the question is then, what is the CF we have been talking and, why the efforts to increase it?

So, the ratio between a turbine capacity and rotor area is the power density (W/m2). A bigger rotor diameter leads to a lower power density so less energy (lower wind speeds) is required to reach the rated capacity of a turbine. This leads into a higher CF as seen in Figure 12.

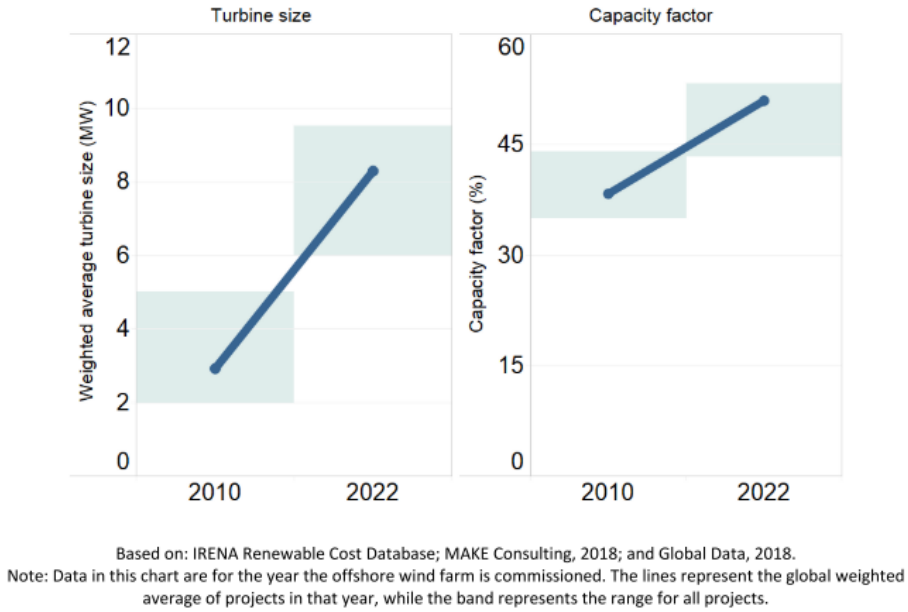


Figure 12: Average offshore wind farm turbine size and capacity factors, 2010-2022 (IRENA)

However, the turbine size has also positive effects in the Operation and Maintenance (O&M) part since a powerful turbine requires less care and cost than multiple turbines with a lower rated power (Ioannou, Angus, & Brennan, 2018). Due to this size changes each new wind farm used different foundations, with a different pile diameter. If at a certain point an ideal turbine size is reached, standardization may bring some advantages (Martin Junginger et al., 2004). However, while there seems to be some room for cost reductions, this is unlikely to occur since each OWF has different properties depending on the location like the average wind speed, seabed conditions and distance from shore.

Depth and distance from shore

Together with the size increase comes the depth and distance from shore. These two depends on the project`s location and may influence the final cost of the project since the distance increase the oil used by the vessels, the construction times, the cables length and the O&M costs. The depth influence directly in the cost of the turbines foundations as shown in the FLOW model by (Voormolen et al., 2016) in **¡Error! No se encuentra el origen de la referencia.**. Although the foundations cost may represent, excluding transportation and installations, around 19% of the CAPEX (Wüstemeyer et al., 2015) this could be more if the foundations

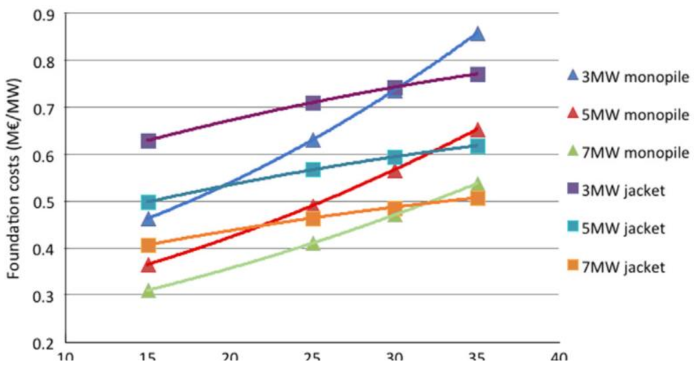


Figure 13: Cost of fountation depending on the depth by Voormolen.

instead of being monopile is jacked, for example, or even more if these are floating since these are still under development.

Since the depth is a factor that influence the overall CAPEX, it is a major concern to solve some of the issues involved. The actual trend goes for OWF further from shore to search for new spots with high quality winds. However, together with the distance comes a depth increase (Figure 14) till a point where actual technologies like jacked and monopile structures wont suit the requirements. New technologies, like floating foundations, are just starting to appear in the market as commercial projects, like the 30 MW demonstration project that is currently in operation in the UK since 2017. The Hywind Scotland Wind Farm has a nominal power capacity of 30 MW, consists of five turbines of 6 MW each and uses a spar buoys design (Equinor, n.d.) (International Renewable Energy Agency, 2018). After three months of operation, the Hywind farm claimed to have achieved a remarkable average capacity factor of 65% (Equinor, 2018). The advantages and expected development of this technology is developed futher in this research.

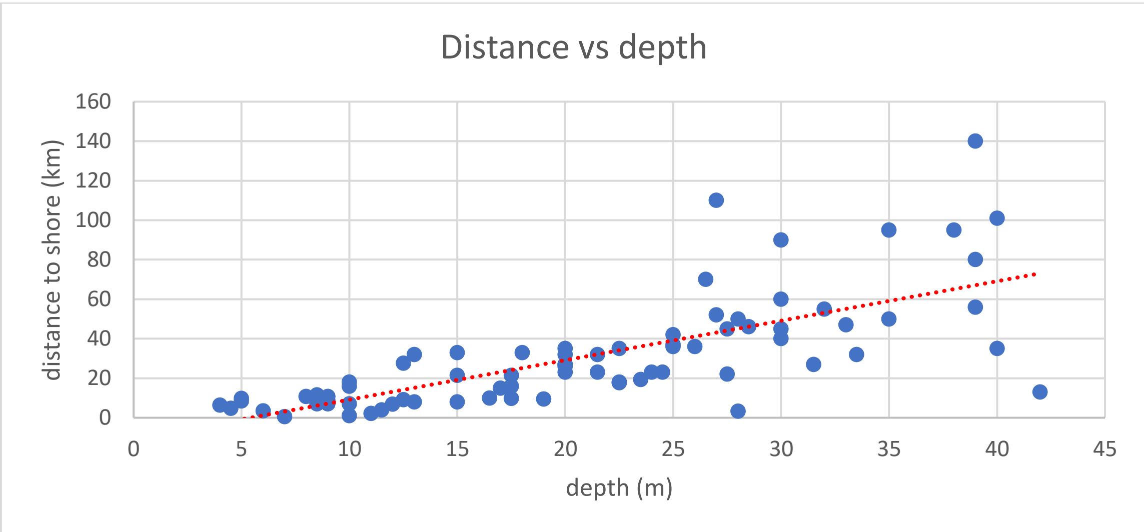


Figure 14: Depth change with the distance from shore

Methods

In order to comprehend the cost trends and the future developments of offshore wind energy the historic and current data from European OWFs has been analysed. The collected data, in the majority of the cases, are: the commission date, the power of the OWF, the turbines model, specifications and power, water depth, average distance of the farm from shore (in some cases when the data was not available this was calculated by geographical approximation with Google Earth), foundation type and OWF location. After that the parameters like the CAPEX and the LCoE were calculated. In order to analyse the historic and actual price developments for OWE all the possible and useful data has been collected and presented as in Table 1 with the main OWFs in Germany, the Netherlands, Belgium, the UK and Denmark since these accumulate 97.6% of the total installed capacity in Europe (Windeurope, 2019). The original goal of the analysis is to indicate how costs change during time due to these factors and analyse the effect of scale and learning effects but also how any other financial and technical factors affect the LCoE. In order to assess the reliability of the analysis, 86 existing OWFs have been included in the database to calculate these trends from the selected European countries

The data for the wind farms has been extracted mainly from (4C Offshore, n.d.) and some gaps have been filled with literature review and online search. This database contains all useful information about 86 European OWFs in Belgium, the UK, Germany, The Netherlands and Denmark.

Table 1: Included characteristics of the selected wind farms for the database elaborated.

Characteristics	**Unit/classification**
CAPEX	M€/MW
Commissioning date	Month and year
Capacity of the OWF	MW
Turbine capacity	MW
Turbine model	Manufacturer and name
Country	BE, DE, DK, NL, UK
Water depth	m
Foundation type	Monopile, jacked, tripod, gravity based, floating.
Distance to shore	km
Average capacity factor	
Status	FC, UC, PG/UC, PC
Rotor diameter	m
Expected lifetime	years
LCoE	€/MWh
WACC	
Cumulative installed capacity	MW
Cumulative generated energy	TWh

The water depth and distance from shore were specified for some projects while looking for the information, but this was not possible for every windfarm. In those cases where the information was not available it has been calculated through geographical approximation. This means that for the distance from shore the location of the OWF, available for every farm in

4Coffshore, was taken and with Google earth measure the km from the coast. For the depth it was necessary to use a map of the bottom of the North and Baltic sea like in Figure 15. However, these were just approximations since the depth varies even inside the same OWF, so the exact depth was very hard to get.

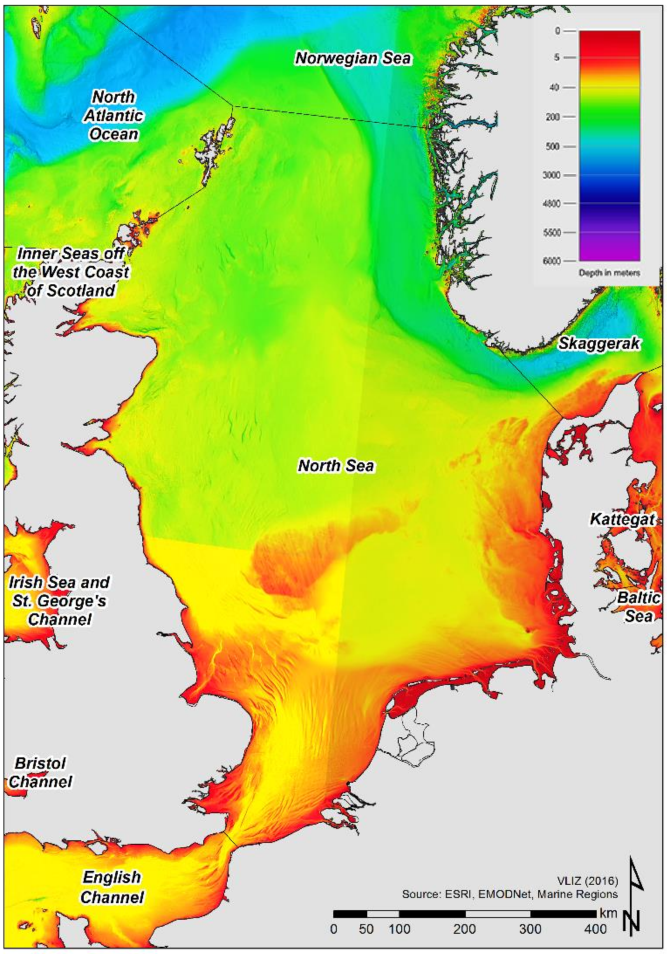


Figure 15: North sea depth map (De Hauwere, 2012).

The performance and Annual Energy Production of OWFs is based on the CF (capacity factor). This has been obtained for OWFs in Germany, Denmark, the United Kingdom and Belgium through ("Energy Numbers - Thinking about energy," n.d.)(2018). However, the Netherlands and some other windfarms from the mentioned countries were not available here so the missing gaps were filled taking data from different websites like, OWE websites and project developer´s websites where the expected annual production for the windfarms was given so the CF could be easily calculated.

The prices have been normalized into the same currency (€) and with the corrected inflation, so all data is expressed in real 2019 Euros from its value in January. This has been done by using the European inflation rates (Binder & Wieland, 2008). Also, it was necessary to convert the different currencies into euros, so the historic conversion rates have been applied for British pounds and Danish crowns (Fxtop, 2016).

Cumulative installed capacity and energy generation

By adding the power of each OWF in order of commissioning date, the cumulative installed capacity was calculated. This way, with the increasing availability of installed power, it is possible to see the technology development.

Equation 7: Cumulative installed capacity.

$$Cumulative\ installed\ capacity = \sum_{t=1}^{L} Power\ of\ the\ OWF$$

The cumulative energy generation follows a similar way than the cumulative installed capacity. The average AEP for each windfarm is added following the order of commissioning date. Although, it is important to consider that the OWF do not produce the same amount of energy every always, since this may change largely depending on the meteorological conditions of each year. However, the average numbers for the production are enough to have rough amounts for the production.

Equation 8: Cumulative energy generation.

$$Cumulative\ energy\ generation = \sum_{t=1}^{L} CF * Power\ of\ the\ OWF * 8760h$$

Calculating the LCoE

The Levelized Cost of Electricity was calculated through the Equation 2 explained before. However, there are some issues regarding this term that must be explained to understand the results and the meaning of these.

Our result for the LCoE is in €/MWh, this means that it will give the cost of the produced energy considering the whole lifetime of the OWF or, in other words, it represents the per-MWh cost of building and operating a generating plant over an assumed financial life and duty cycle. The lifetime may change from one farm to another and this must be considered since the information about the expected life of many farms was not available. Most of the farms have values of 20 or 25 years, being 25 the most abundant. So, if the value was missing, 25 years have been taken as default.

OPEX approximation

The OPEX is certainly a factor subject to change from year to year and, as the CAPEX, depends to a certain point on the distance from shore and the windfarm size. Figure 16 shows the comparison of the breakdown of CAPEX and OPEX for a typical offshore wind farm (Crabtree, Zappalá, & Hogg, 2015).

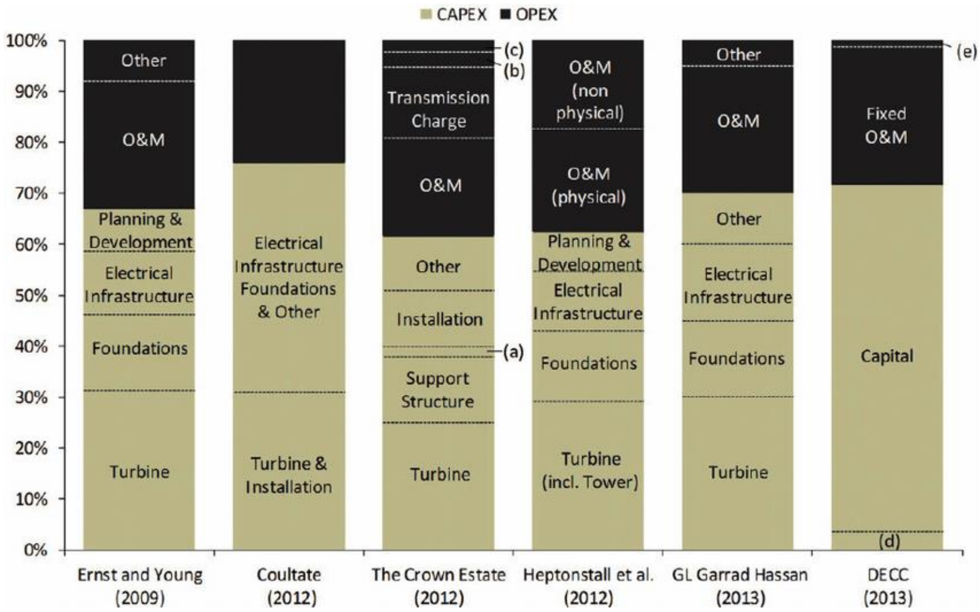


Figure 16: OPEX values in literature.

Although the CAPEX and OPEX contribution to the final cost changes depending on the reference source taken. Thus, wind farms are capital-intensive compared to conventional sources of fossil fuel fired technologies such as a natural gas power plant, for which fuel charges increase OPEX costs to typically between 40% and 70% of the LCOE.

The real OPEX values for the studied windfarms are unavailable since companies are not willing to share this because of the confidentiality of their accounts. However, some estimations have been done in literature representing always values around the 27% of the total cost.

Other way to estimate the OPEX is depending on the qualities of the OWFs through the formula used in (Ioannou et al., 2018) when the characteristics of the farms matches the ones used in this paper. These characteristics are:

- Distance from shore between 15 and 65 km.
- OWF capacity between 250 and 1000 MW.
- Wind turbine rating between 2 and 7 MW.

If the OWF specifications matches the required by this paper the Equation 9 is used to get an approximation of the OPEX.

Equation 9 :OPEX approximation with 3 variables

$$dOPEX = -6.349 * 10^8 * P_{wt}^{0.187} + 2.595 * 10^{-19} * \exp(0.830 * D) + 8.413 * 10^5 * P_{wf} + 9.506 * 10^8$$

There has been also reported a formula by IRENA to get an approximation of the OPEX based in the Annual Energy Production (AEP) for an OWF.

$$OPEX\left(\frac{M€}{year}\right) = 17 * \frac{AEP}{1000000}$$

It is appreciated that there are some ways to determine the OPEX and it was not possible to decide which one is better so, in order to get the more realistic and accurate value, these three methods have been used to calculate the OPEX. In the case that an OWF do not meet the requirements to apply Ioannou's formula only two estimations where made. Then the averages from these were calculated and used as the OPEX value for further estimations. To explain better the applied method, we have the next example:

Table 2: OPEX approximation example

Method	OPEX obtained
Equation 6	53
IRENA formula	45
27% from CAPEX	47
Final OPEX	(45+47+53)/3 = 48.33

CAPEX calculation

The CAPEX has been obtained through the initial investment cost. This means, that the found total cost till the commissioning for each windfarm has been divided by the installed power in MW, getting a result in million euros per Megawatt installed.

WACC approximation

The WACC results from 2000 till 2014 have been extracted from the literature by (Voormolen et al., 2016). For projects from 2015 the WACC it has been calculated using the Equation 1 and getting online the values for the equity and debt. It has been possible also to get some specific WACC for some projects, so this was taken when possible to get more accurate results.

AEP calculation

The annual energy production was available for some of the OWF in the developer's webpages. This production estimations works fine for those OWF that are too new to get reliable enough information about the energy production.

However, the best option was to get the real average production for the OWF but this AEP was not available for every project and has been derived from the Capacity factor (Equation 10) that was found for certain projects ("Energy Numbers - Thinking about energy," n.d.).

Equation 10: Annual energy production from the capacity factor

$$AEP = CF * P_{WF} * 8760h/year$$

For the other missing data, the annual production has been estimated through the commissioning year, the turbine model and the average winds on the location.

Data harmonization

The database has been realized with all the OWF currently working in the already mentioned countries in Europe. However, these countries use different currencies like Euros, British pounds and Danish crowns.

The database has been realized with all the OWF currently working in the already mentioned countries in Europe. However, these countries use different currencies like Euros, British pounds and Danish crowns.

The currencies can be transformed into the same one by converting them into the desired monetary unit using the historical currency values. Also, these OWFs were commissioned in different years, so the units could not be fairly compared if inflation is not considered. To standardize all the cost data into the same unit it must be converted into the same currency for the same year, like Euros in January of 2019. All the inflation and historical currency values were taken from (Fxtop, 2016) and the final value was calculated as in the following example:

Equation 11: cost harmonization with currency and inflation conversion.

$$Cost * Currency\ conversion * \frac{inflation\ correction\ in\ year\ t}{100} = Final\ cost$$

Table 3: Example table for the currency conversion and inflation correction.

Cost (€, £, Dkk)	Year	Currency conversion	Inflation correction	Final cost (€ 2019)
725 £	2013	0.8492	104.64	893
200 €	2018	1	100.74	201.48

Experience curves

To elaborate the experience curves the data base has been determined with python in order to calculate the learning rates for the one and two factors curves. The input parameters used vary depending on the result we want to obtain if it is for the CAPEX or for the LCoE.

For the CAPEX the yearly average cost per MW installed and the cumulative installed capacity have been used as input to determine the learning while for the LCoE the yearly average cost per MWh and the cumulative generated electricity was used, both cumulative values in a logarithmic scale. Also, for the TFLC the knowledge must be another input parameter in order to quantify the effect of the R&D expenditures. In the case of the Knowledge stock (KS) there was no possibility to obtain the real expenditures in R&D but other way to quantify the expenditures used for research were found in (Grafström & Lindman, 2017). The patents for wind technology were available in the IRENA site with the year per year patents and the cumulative values, so this can be used as an indicator of the R&D expenditures. However, for the experience curves a depreciation rate that is close to 10% in wind turbines but, since offshore do not depends like onshore on these and has much more elements,, the standard of 15% (Grubler, 2012), was taken for this study and applied to the KS.

Once the input parameters are represented in the graphs the curves fit the data, giving the equations showed in the Theoretical background (Equation 4 and Equation 6) with the completed values. Also, the R-squared has been calculated to measure of how close the data are to the fitted regression line and the closer it is to 1 may improve also the accuracy.

Results

In this section, the results of the analysed database are presented to provide a response to which factors and how they evolved in OWE, from geographical along with depth and distance to physical as the CF and financial as the WACC. The possible relationship between these factors and costs is also presented. All the data set with the information and results from the OWF can be found in the annex I.

Size, rated power and Capacity factor developments

As explained before these three terms are highly related. The bigger the rotor diameter use to come with a higher rated power and CF because the ratio between a turbine capacity and rotor area is the power density (W/m2). A bigger rotor diameter leads to a lower power density so less energy (lower wind speeds) is required to reach the rated capacity of a turbine.

As seen in Figure 17 the CF grows in the wind turbines lineally with the rotor diameter and the rated power.

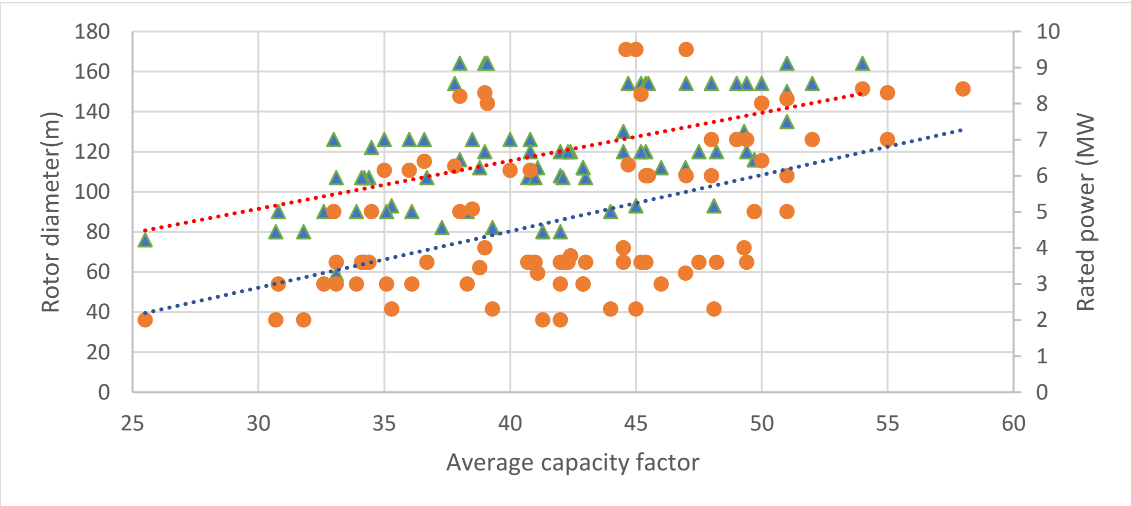


Figure 17: Relation between rotor diameter, rated power and CF. (The CF depends on other factors too that are more location dependent)

The trend has been analysed historically and the developers keep pushing for higher CF trough upsizing the turbines as explained in the current development section. However, it has been found that this size trends may find a limit in a couple years with some experts predicting that fixed-bottom offshore wind turbines could top 18 MW in capacity by 2030 (Deign, 2016).

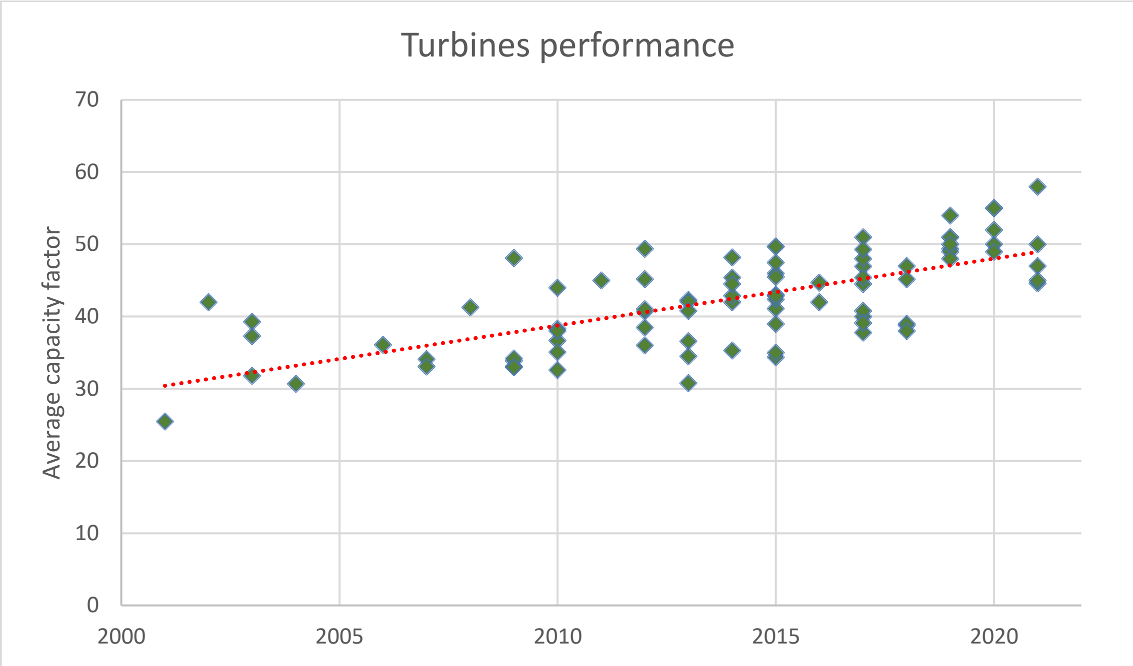


Figure 18: Turbines performance trend in CF values from 2001 till 2021.

Distance and depth developments

The trend analysed for the OWF shows an increase in both depth and shore distance. This trend is caused by two main facts, the search for new places to install the OWF with higher-quality winds, but also higher depth and distance, and the lack of high-quality winds that are closer to shore as they have already been taken (Greenacre et al., 2010). The analysed OWFs confirm this previous statement in Figure 19.

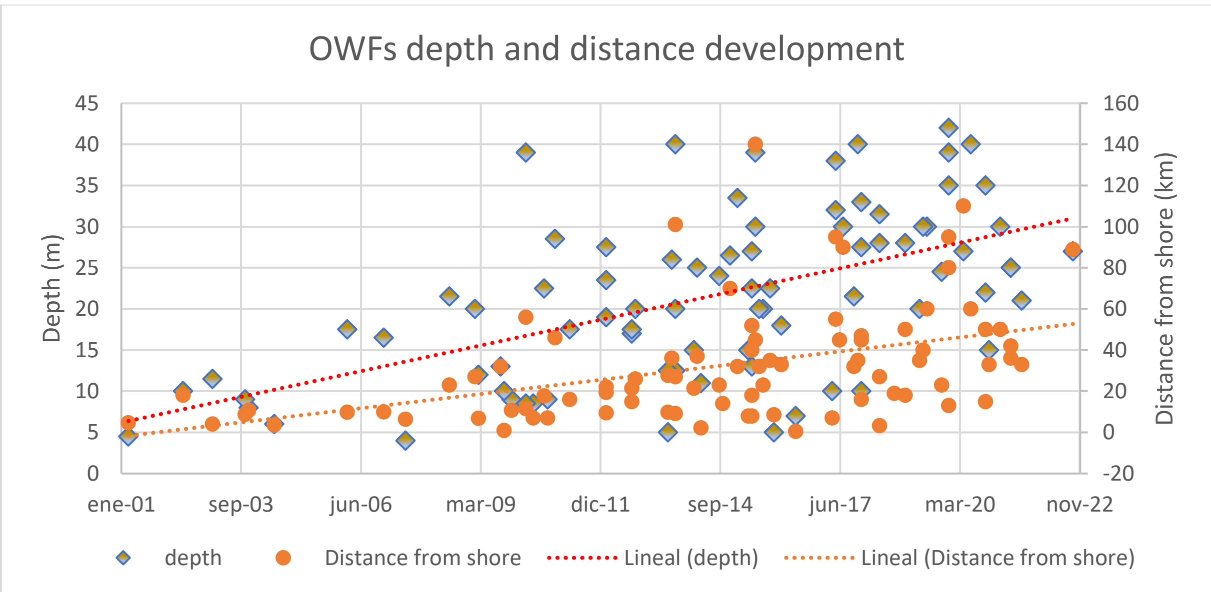


Figure 19: Offshore wind farms depth and distance development 2001-2022.

CAPEX developments

In this section, the CAPEX is analysed to know how it has evolved from 2001 to the actual days and which factors affect this, such as depth, turbine size, distance from shore, etc.

The value chain for the OWF could, as stated earlier, is classified in the various parts and processes involved in the full commissioning of it (Gonzalez-Rodriguez, 2017). These ones contribution to the final cost of the project may change from one project to another, but, as average in the literature review, the values in Figure 20 are a good representation of the OWF elements.

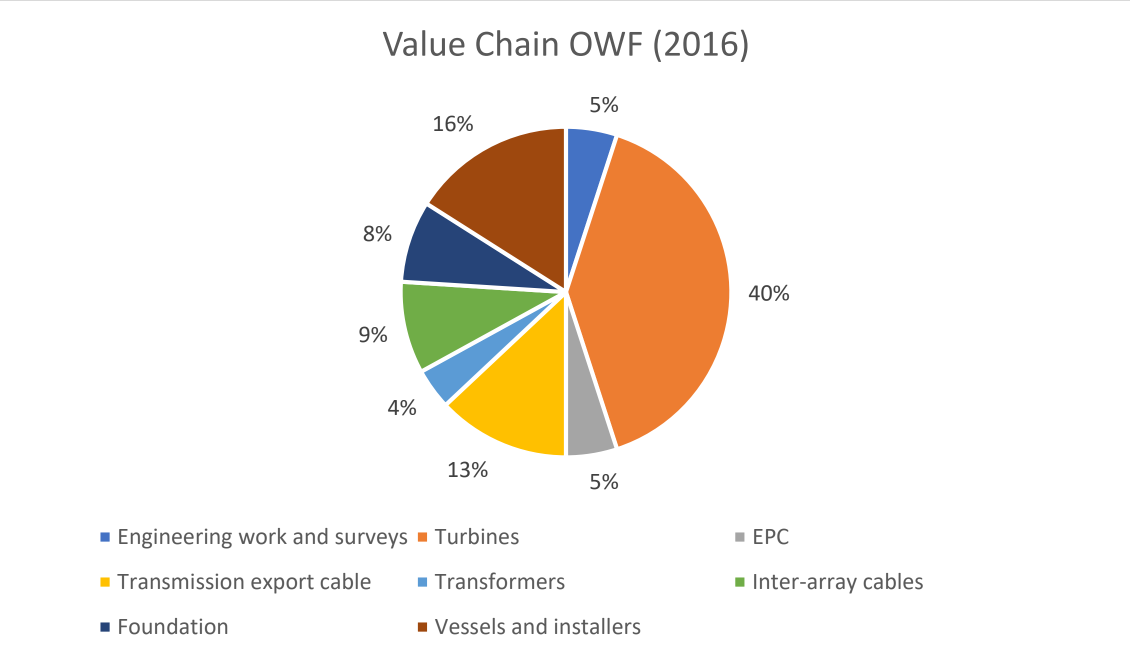


Figure 20: Value chain of Offshore Wind Farms component and planning.

This insight into the cost of the components provides a better understanding of the factors that are more influent on the CAPEX. An increase in turbine prices can result in a higher change in the overall investment than an increase in transformer costs. Also, not every factor is susceptible of learning and scaling effects on the same way. Because OWF is an amalgam of different technologies, those that are specific to offshore energy may in the future have a lower cost, while those that are not sector - specific may already be mature and may not present a remarkable improvement that could change the final investment.

Following the research by (Voormolen et al., 2016) the CAPEX development during the period 2001-2008, where the average cost went from 2M€/MW to 3.2M€/MW, may have been caused by the sector tendency to build further from shore and in deeper waters together with the increase in the commodities prices. Even during the post-boom credit crisis of 2007/2008 till 2015 the cost kept increasing till 4.1M€/MW but, even if these factors previously mentioned still influence in the cost, these could not explain by themselves the total change in the CAPEX, so other factors drove the increase.

This observed ascending price trend of Figure 21 from 2001 till 2015 has gone against the convention of decreasing costs usually achieved through economies of scale, learning curves and supply chain improvements (Gonzalez-Rodriguez, 2017).

It is not until 2015-2016 that the CAPEX began to decline, going below the 4M€/MW average and is expected to continue to decline (International Renewable Energy Agency, 2018). The latest projects commissioned during 2017 and 2018 got the CAPEX reduced influenced by the the already mentioned scaling of the wind turbines, besides other factors, allowing these to reduce the final cost per MW of the newer projects. This trend is expected to continue as it has already been confirmed that the final average CAPEX will be lower than previous years for future projects under construction, or at least in the final phase of the planning. These future projects are those at the right side of the red line, that marks the beginning of 2019, in Figure 21. However, as long as an OWF is not commissioned, actual cost is not exact, but the difference between actual and expected cost can be substantial (Schwanitz & Wierling, 2016) so this data must be analysed carefully.

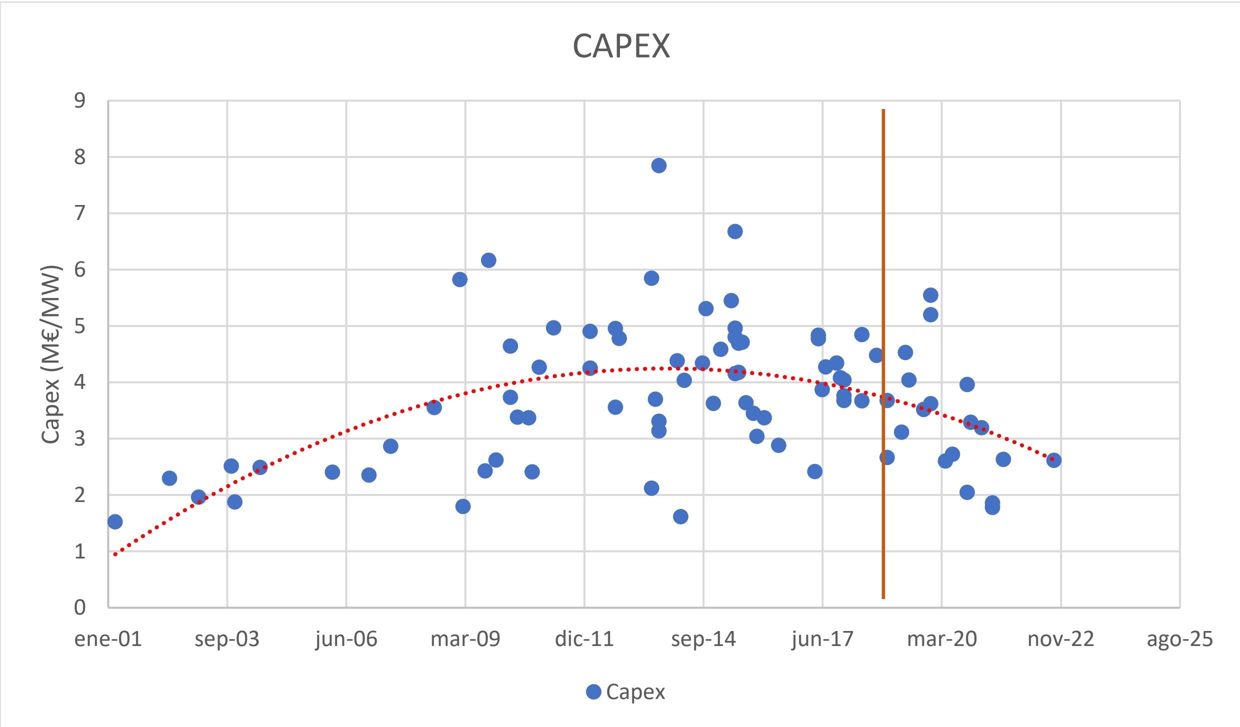


Figure 21: CAPEX development 2000-2021

Although some of the analysed OWF should be called near-shore, as the distance in the sea is relatively low, as well as the depth. This could make the comparison between farms unfair, since in the first instance, the cost of these near-shore farms would be lower than those far offshore. Some previous studies where done unifying these two parameters in order to exclude their influence in the cost. However, once the nearshore farms are eliminated from the analysis, those with a distance from shore inferior to 15km and a depth smaller than 15m, the results barely change, as in (Voormolen et al., 2016) in the period after 2008 . This leads to the conclusion that, as expressed by other authors, distance and depth are not sufficient parameters to explain the latest historic costs evolution of the CAPEX by themselves.

To look for an explanation for these results it was necessary to consult some experts in the field of OWE. It was known by consulting experts from Mtorres and Vestas, two OWE products developers, that this recent reduction in CAPEX was primarily caused by the sector's development and adaptation. In the beginning of OWE the turbines were just adaptations of the already matured onshore models, so the prices were lower since the market did not need a big specialization. However, with the increase of distance and depth, beside other inherit factors from offshore constructions, onshore technology was not adequate in terms of efficiency, and adaptation. This means that offshore needed a specific and differentiated niche of the market. While this was developing OWE did not have a supply chain specifically created for it, so it had to compete with onshore and oil supply chains, increasing the final investment and the installing times.

It is nowadays when the experts assure that the demand is growing enough so the supply chain and market is adapting for OWE and allowing the technology to develop as expected by economies of scale. Some of the factors that helps OWE to develop better now are:

- Vessels created specifically for OWE installations and less competition with oil vessels, decreasing also the installation times.
- Supply chain improvement with sector-specific products and advances in manufacturing.
- Wind turbines size increase reduce the time and cost for the manufacturing of the components and in the installation per MW installed.

The commodities influence, as explained before, has been dismissed too as the main factor in the CAPEX fluctuations. Figure 22 has been adjusted to see the influence of commodity prices in the CAPEX by considering the steel and copper index, since these are the most important in our case. To compare the CAPEX of each OWF with the indexes and adjustment was done. Since the OWF takes an average of two years to build, the CAPEX was compared with the index of two year before the date of commissioning, so it would be compared when the commodity was acquired. Also, in Figure 22 is possible to see that there is no clear correlation between the changes in the steel and copper prices and the CAPEX after 2008.

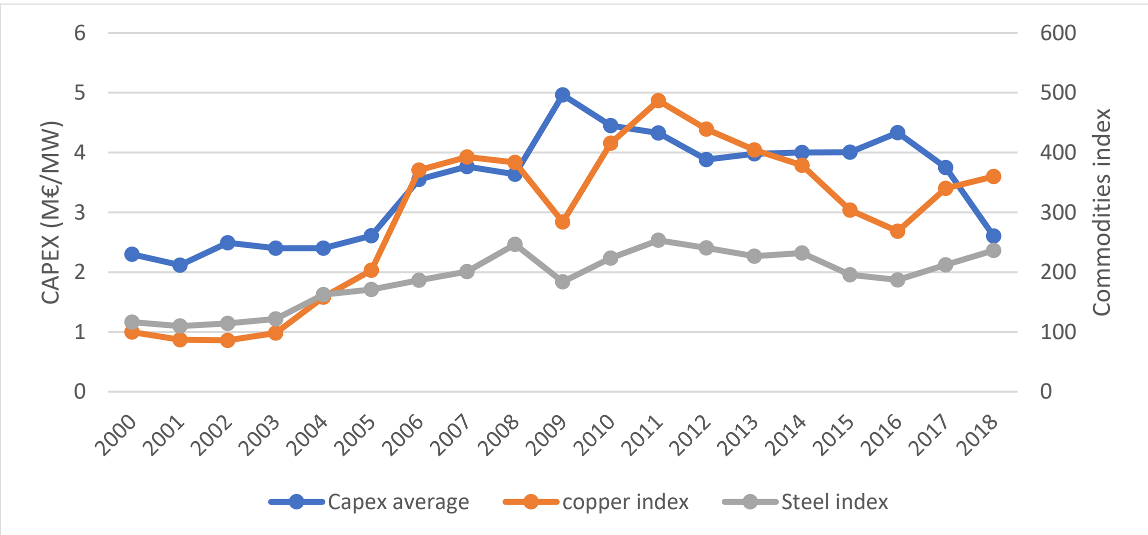


Figure 22: Commodities and CAPEX tendencies.

This does not mean that there is absolutely no influence by the commodities, but this is not enough to explain by itself the development of the CAPEX and it would not change in the same way as commodities do in the future projects since other factors, like the explained above, are more influent.

Another factor that could affect the CAPEX is the wind farm size. Looking at the sizes of the last OWF its visible that the sector is upscaling the installations, so more MW are installed per farm (Windeurope, 2019).

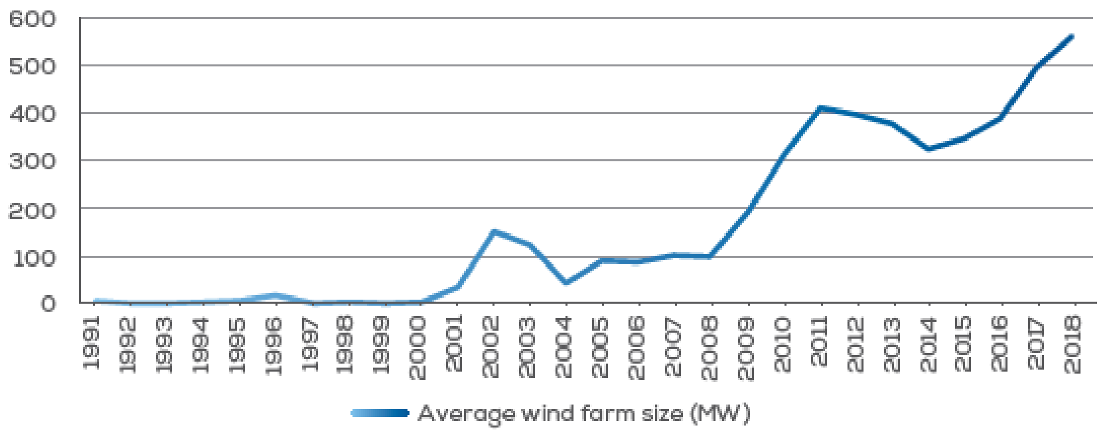


Figure 23: Average size of commercial offshore wind farms in construction and grid-connected in the given year (Windeurope, 2019).

However, this trend does not show a clear advantage in the CAPEX reduction. Checking the historical data in Figure 24 it is shown that the OWF size has a very small influence in the final CAPEX, this relation present an almost straight line around 4M€/MW, but it could have a clearer effect in the OPEX and the LCoE.

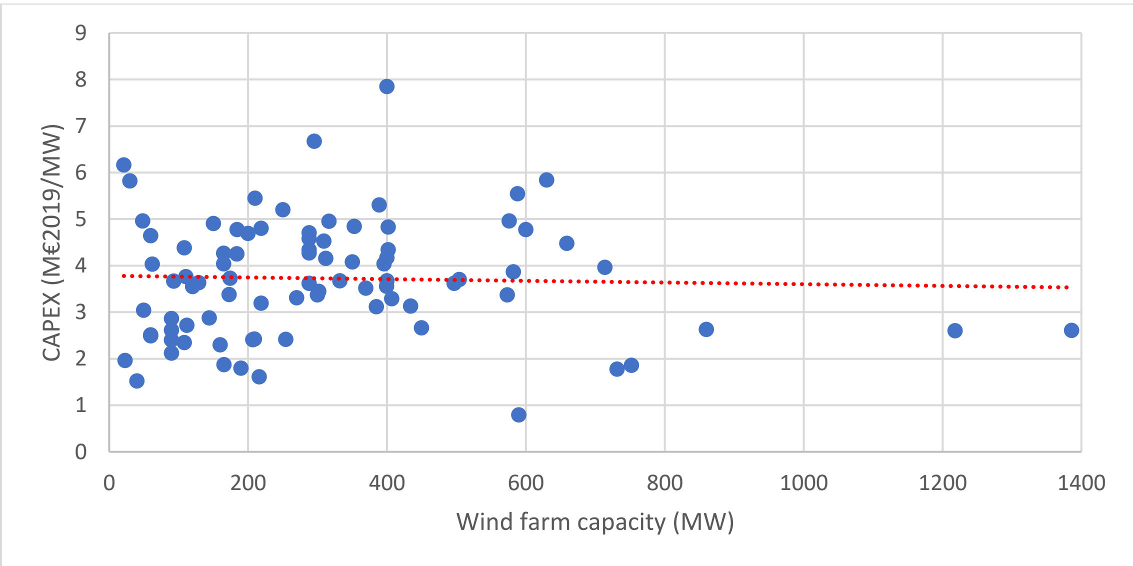


Figure 24: Impact of the size of the OWF in the CAPEX

Looking at the relationship between the CAPEX and the cumulative installed power, the trend is clearer. While, as explained earlier, the beginning of OWF increased the CAPEX in the first years, the exponential growth in the installed capacity shows a cost reduction per MW installed while the cumulative capacity increased, accelerating the cost reduction Figure 25.

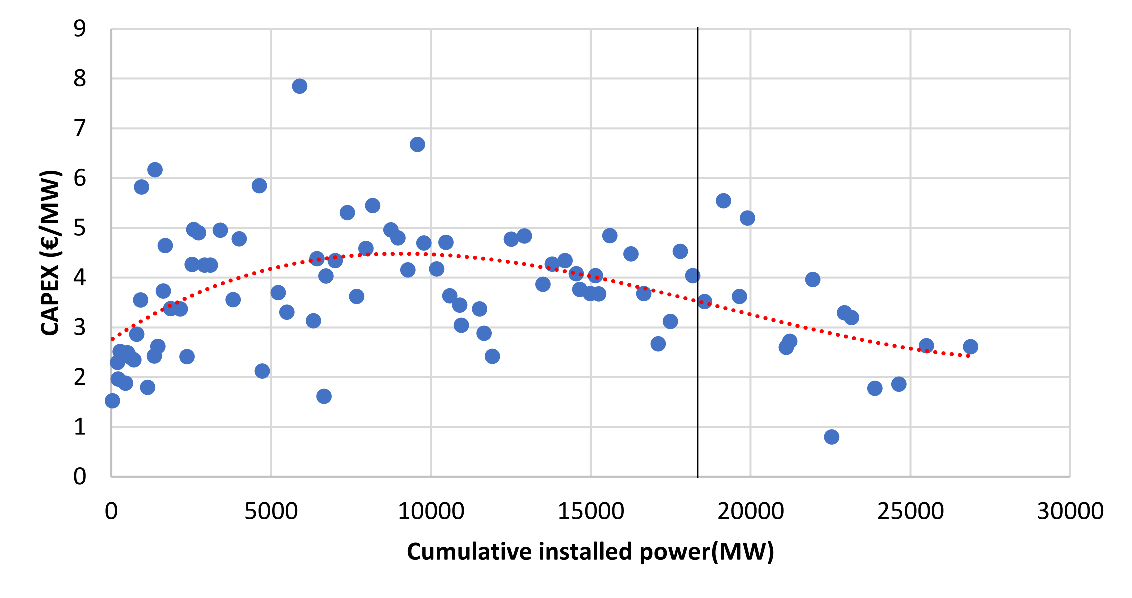


Figure 25: CAPEX development with cumulative capacity installed.

As before a polynomial line has been added to the graph with visual purposes, but it cannot be to extrapolate a future development.

However, the investment cost cannot decrease indefinitely, this is expected to keep the reduction till it reaches levels close to 2.8-2.6 €/MW in the next 6 years (Poudineh et al., 2017). The reason for such a specific development is that with that CAPEX, the expected production and OPEX the LCoE will drop to the conventional energy levels so further developments is seen as unnecessary once the market levels are reached.

LCoE development

The LCoE has been calculated with the formula explained before in the theory part. This Equation 2 has been filled with the obtained CAPEX but the other elements needed for the formula, like the WACC, the AEP and the OPEX, were found or calculated in order to obtain the LCoE.

WACC results

The Weighed Average Cost of Capital was found in literature for the period 2001-2014, but after this it was calculated with the Equation 1 when the values for the debt and equity were found. For those that could not be found the specific WACC gotten for some projects were used as the WACC for the country in the commissioning year.

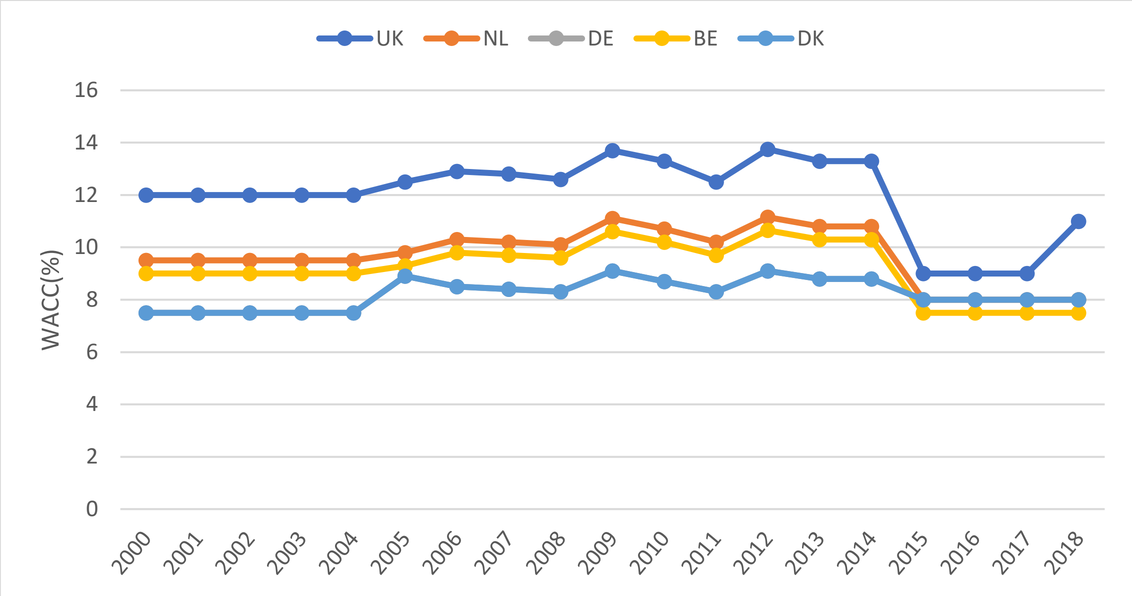


Figure 26: WACC historical development by literature and research.

The WACC has evolved favorously in the last years since it reduced its value, in some cases like in the UK greatly. This may have been caused by the risk reduction for the investors fot these capital intensive industry since it has been largely proven and keeps growing.

In the next years it is expected that returns to developers in Europe will reach 6% at the lower end of the 6-7.5% post-tax nominal range (Poudineh et al., 2017). In the case of offshore wind, then we can see that(BVG Associates, 2016):

- Reducing WACC has already had a significant impact on LCoE.

- There is still plenty of scope left to reduce LCoE further by even lower WACC (assuming interest rates remain low and reasonably stable).

- There is evidence that further WACC reductions will be seen in the coming years.

The Levelized electricity costs is calculated for each of the 86 offshore wind farms in the North Sea since the first ones commissioned in 2001, according to the previous explanations in Equation 2.

LCoE development

The Levelized cost of electricity is calculated for each of the 86 offshore wind farms in the North Sea since the first ones commissioned in 2001, according to the previous explanations in Equation 2. The brown line in 2019 (Figure 27) indicates nowadays and those point located on the right side of it are the projects that have reached, at least, the confirmation phase, so they will start the construction phase soon or they are already under construction and maybe even with partial energy generation.

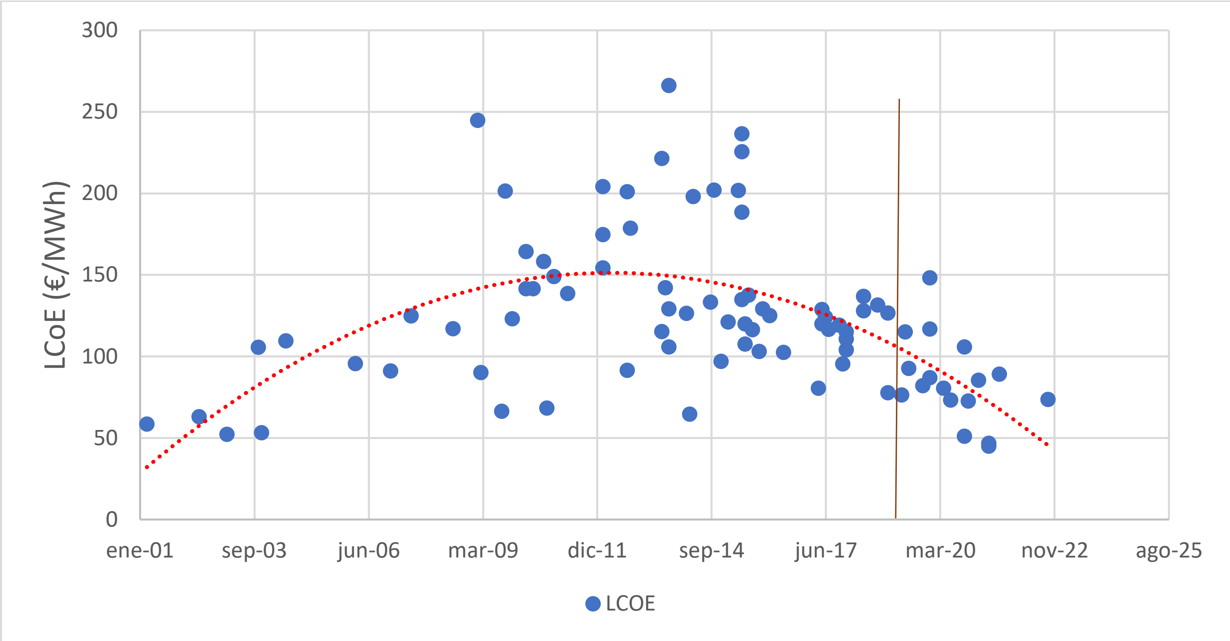


Figure 27: LCoE historic development

As we can see in Figure 27 the LCoE of OWE have had an increase trend from 2001 with costs below 100€/MWh, till around 2015 with a price next to 180€/MW, both far from the market price. The reasons for this increment are highly related with the CAPEX rise those years since the LCoE depends largely on it. Around a 70%-65% of the energy cost was determined by the initial investment (Chaviaropoulos, Natarajan, & Jensen, 2014).

These results appear a bit unfair for the energy cost of the OWF built after 2006 since the majority of the first ones were built near shore (less that 15km from shore) and in shallow waters (less than 15m depth) where, as stated in the CAPEX part, onshore technology could be implemented easier. Is after 2006 where the technology implemented is more offshore-specific and could be compared better with the following years (Breton & Moe, 2009).

After 2014 the LCoE starts decreasing back to 100€/MWh again at the end of 2018, but this time with the majority of the OWF further from shore offshore and with higher depths than in 2001. The reduction is caused by the favourable changes in the Financial expenditures, with a lower WACC in recent years, together with the previously stated CAPEX improvements. Although, not only these are the changes in OWE that allows lowering the energy cost, but also the AEP is improving with each new generation of wind turbines thanks to higher capacity factors.

If we present the data in LCoE against the cumulative installed power, it is possible to appreciate better the trend changes (Figure 28). The first OWF installed has no large capacity installed compared to the actual ones with an average capacity of 79.6 MW in 2007 to 561 MW in 2018 (Windeurope, 2019). Also, the number of commissioned OWF per year is also growing. This means that the trend year by year shows the trend worse as it gives every OWF the same value without taking their power into consideration.

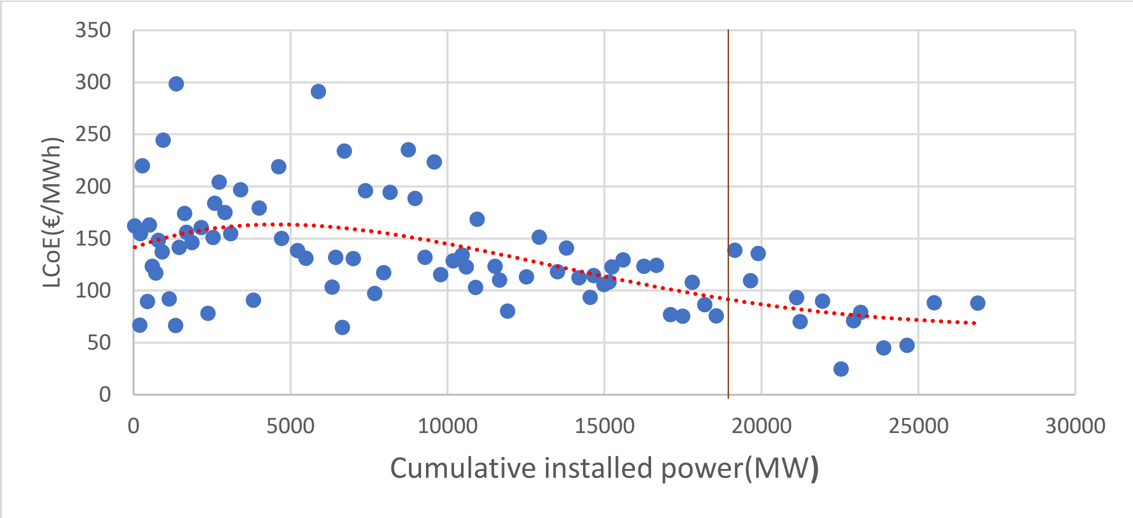


Figure 28: LCoE values against the cumulative capacity installed.

As before, a polynomial line has been added to the graph with visual purposes, but it cannot be to extrapolate a future development.

However, in Figure 28 it is also visible, as happens in the CAPEX graph (Figure 25), that there is an increase in the first years with the oldest installations closer to shore, in shallow waters and in a sector changing from adapter technology onshore to sector specific systems for offshore.

In the last part of the curve in Figure 28 the LCoE, as it happens with the CAPEX, starts stabilizing and it is predicted to keep that way in the near future with the planed projects. The current cost is around 85€/MWh for the projects commissioned in 2019 in the studied countries, with projections that reach 63 €/MWh for projects that will be commissioned in 2022 being the current market price for electricity around 55€/MWh ("Energy market reports", EU Commission).

In Figure 29 it is presented the same trends than before for the LCoE, but this time differentiated per country for Germany, Belgium, The Netherlands, United Kingdom and Denmark (DE, BE, NL, UK, DK).

The lines for Germany and Belgium show the highest cost reduction of all, from around 180-190 €/MWh in the beginning to below 100€/MWh nowadays next to the other countries' prices, except the UK. Also, these two countries present the latest implementation of OWE from the studied ones, starting commissioning projects in 2010 and 2011 but without being this a disadvantage for the actual development since it caught up in prices those countries that started earlier. However wind technology is better analysed globally than reducing it to national level (M. Junginger et al., 2005) so the improvements in the price may not be caused by improvements in the technology in certain country but in the financial and political factors in that country. However, the installation time and the development phase may be influenced by these factors intrinsic to the country, affecting that the final technology implemented would not be the state o the art at the moment like it happens with UK and Denmark with the CF (Voormolen et al., 2016).

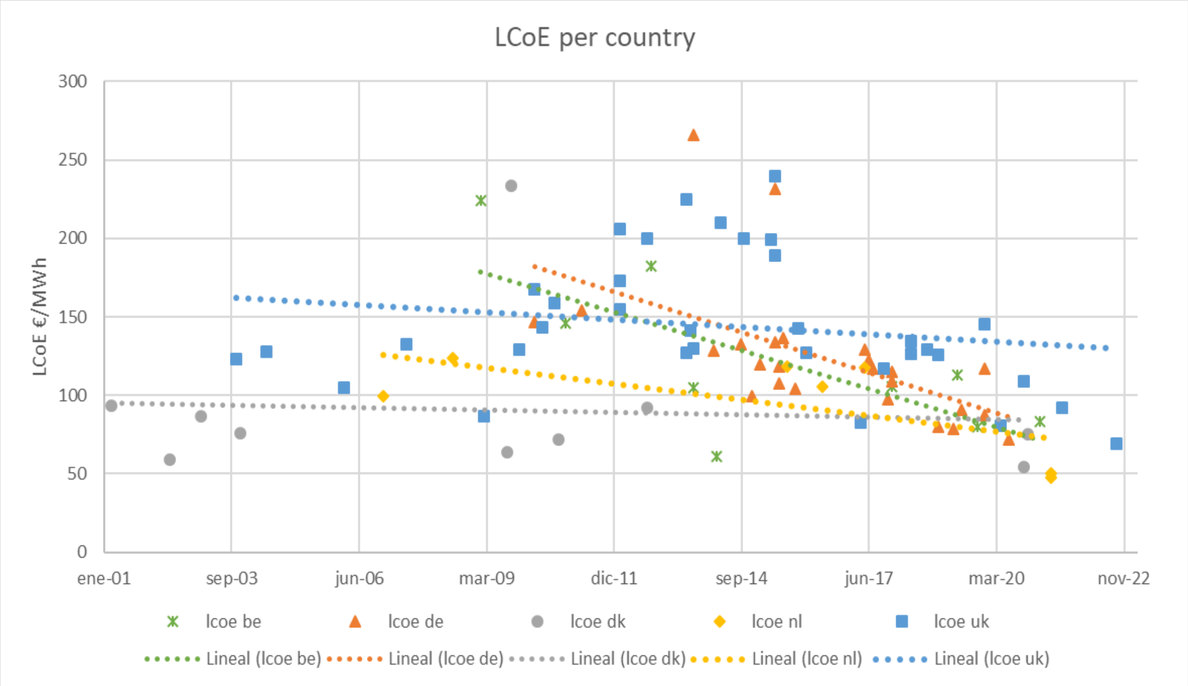


Figure 29: LCoE development per country

The line for Denmark shows a decrease in the price, but this is the slightest of the studied ones since it started also with quite contained costs with an average below 150€/MWh till reaching prices around 65€/MWh nowadays. Something similar happens with The Netherlands, with the difference that this gets into the offshore wind market later, in 2007, with costs that start a bit below €/MWh and reaching around 70€/MWh in 2019.

The case for the UK is a bit different since this one also started in 2003 with the highest prices above 200€/MWh and being close to 140€/MWh in the beginning of 2019, way above the other countries. The higher WACC in the UK than in the other countries as showed in, increase the final Financial Expenditures is the main factor causing the higher LCoE. If the UK had the same WACC than Denmark the cost for the energy would be around 20% lower than the historic ones (BVG Associates, 2016).

Table 4: First and last year parameters comparison per country.

	UK		*DK*		*DE*	
Year	*2004*	*2018*	*2001*	*2012*	*2011*	*2018*
LCoE (€2018/MWh)	*163,289*	*125,080*	*114,561*	*90,860*	*170,098*	*77,023*
CAPEX(M€2018/MW)	*2,514*	*4,167*	*1,522*	*3,555*	*4,644*	*3,116*
WACC(%)	*12*	*9*	*7,5*	*9,1*	*10,2*	*8*
Capacity Factor (%)	*31,8*	*45,2*	*25,5*	*49,4*	*38*	*46,8*

	NL		BE	
Year	2007	2018	2009	2017
LCoE (€2018/MWh)	127,135	113,433	197,852	108,329
CAPEX(M€2018/MW)	3,55232	2,85	4,265	3,85
WACC(%)	10,2	8	10,6	7,5
Capacity Factor (%)	33,1	49,3	33	46,97

Experience curves

The learning for OWF will be analysed with an OFLC and a TFLC. The OFLC will help to understand to which extent the scale effect influences the CAPEX and the LCoE and how these have changed historically because of the learning and what to expect in the future. If it is only considered the CAPEX (€/MW) it leads to leaving out the increased CF, and the financing costs which greatly benefit from risk reduction for investors for this capital-intensive industry.

It was analysed in two ways. With the traditional Power Capacity analysis where the cost is presented with the Cumulative installed capacity for the CAPEX, and the Energy model, where the cost is presented against the cumulative energy production. In the first one, as presented before, the capacity of the OWF is summed and in the Energy analysis the average CF is taken to calculate an approximated production year per year as for the AEP used in the LCoE.

When talking about learning curves for OWE there is a problem. In other technologies the cost starts decreasing with the rise in production but, as stated before, this did not happen in offshore wind since there was a period when the cost increased with the production. This increase may have been caused by the fact that the farms have been built further from shore and in deeper waters in search for new places with high quality winds while having public acceptance. Also, the first OWFs had a smaller size since these were closer to “prototype plants” than to the current farms. This may cause an unreal learning rates with lower values than the actual ones. To compensate these differences and elaborate a more accurate analysis those parameters that influence the cost in a certain way have been filtered. These parameters are the depth, distance from shore and power of the OWF.

The chosen parameters had values of 15m of depth, 15 km of distance from shore and 150MW of installed power. These parameters where chosen to exclude those farms that are more near-shore than OWF and the smaller ones. The reason to choose these values is that from 2015 most of the windfarms have these characteristics and almost all the planned and under construction ones. This helps to create a trend more reliable towards create a learning curve useful for the future OWF.

In numbers the OWF from 2015 are like this:

- 84.8% of them are further than 15km from shore.
- 80.4% have average depths higher than 15m.
- 86.9% have a power capacity higher than 150MW.

The KS has been constructed with the database of IRENA using the cumulative patents for wind technology. The results in Figure 30 shows a growing trend the first years with higher R&D expenditures.

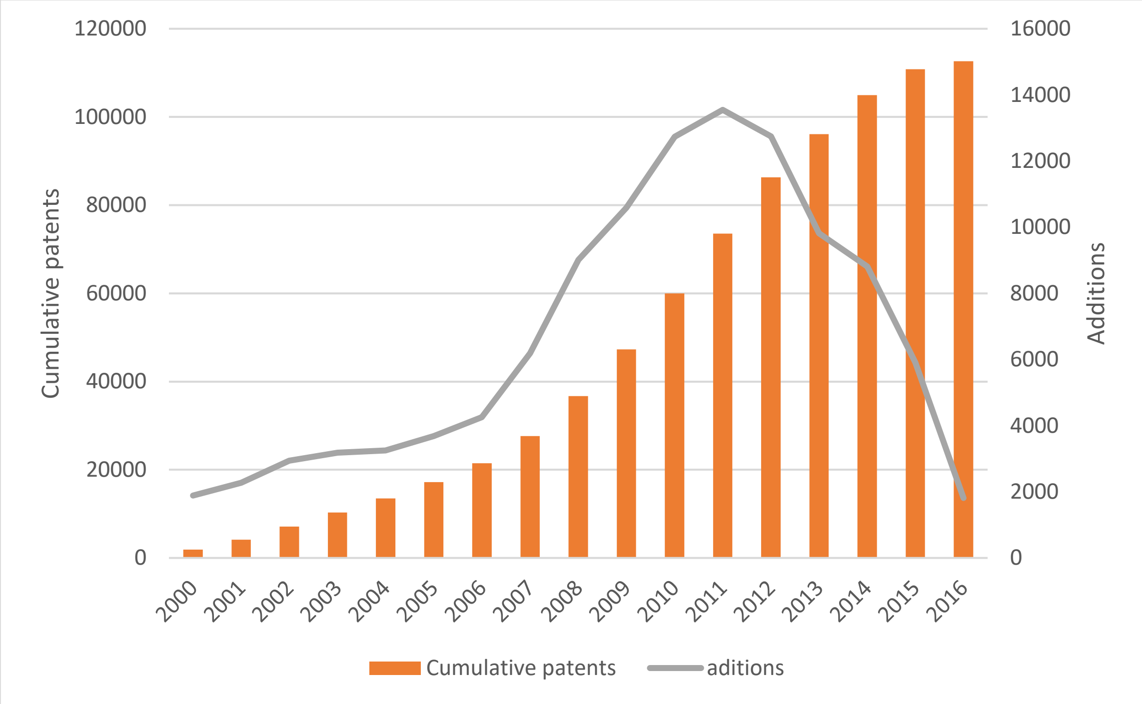


Figure 30: Wind technology patents development (IRENA).

However, after the year 2011, the additions start decreasing drastically. This with a depreciation rate of 15% (Grubler, 2012) will make that the knowledge stock, with the cumulative patents, starts descending too in the next years if the trend does not change.

One and Two factors experience curves

The one and two factor experience curves have been elaborated for the CAPEX and the LCoE in two different, but similar, ways. The CAPEX presents the cost in million Euros per MW installed against the cumulative capacity installed in the studied countries. This is called the Power Capacity analysis.

The results for the Power Capacity analysis are divided, as explained before, in filtered and unfiltered. The results of the unfiltered analysis show all the OWF and give a negative learning rate of -8.02 percent, which means that the price increases with the cumulative installed capacity, while the learning rate for the filtered is 8.29 percent, so in this case there is positive learning and the cost decreases with the installed capacity. This represents perfectly our case as explained before with the first OWFs and their higher and increasing costs and the latest ones with a decreasing cost per MW installed. While the unfiltered shows a diseconomy of scale this does not happened with the filtered one, where it shows an economy of scale and the cost improvement with the installed capacity.

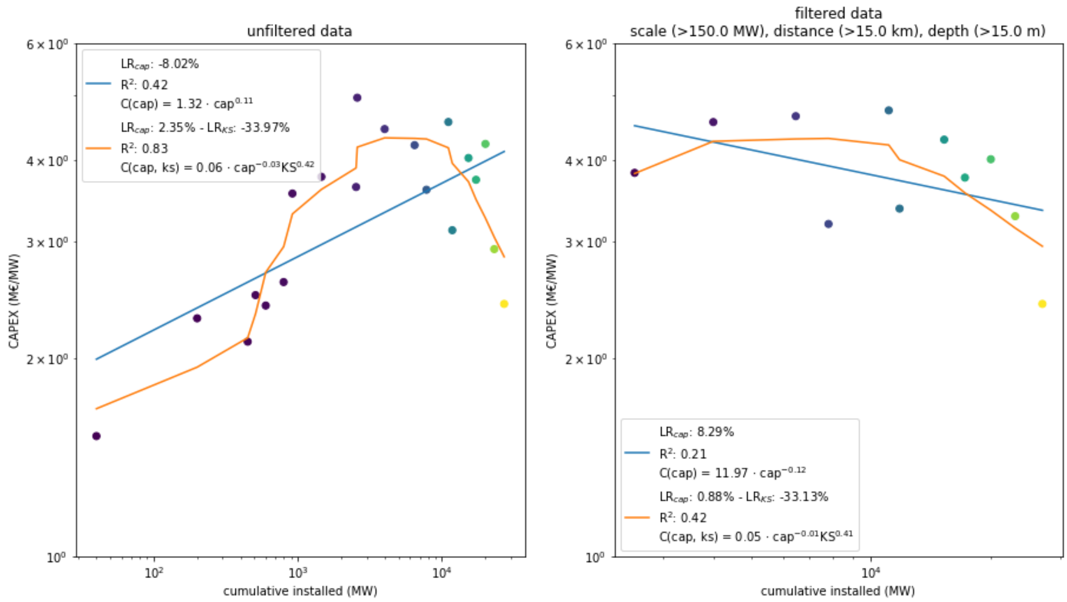


Figure 31: Power Capacity analysis for the CAPEX.

The filtered one fits better the expected trend for the CAPEX in the future than the unfiltered, even if this has a higher r-squared, that means a better correlation between the curve and the data. However, the values for the filtered Power Capacity analysis presents values from 2010 and on, except 2011, since any of the previous commissioned OWF meet the requirement to pass the filter, so the analysis is done with less years as input.

In the two factors curve we have something different. The learning rates for the filtered and the unfiltered are negative for the learning by search, or KS, and positive, but low, for the learning by doing (increasing production). So, this curve fits better the data with higher R-squared but gives a negative learning rate for the R&D that might means that the investment in research increase the prices and a lack of this reduce them. This may be true, but the increase in R&D is more likely to have coincided with other factors that have driven up costs more related to the wind farms ' intrinsic conditions explained in the section on CAPEX development than by the R&D expenditures itself. Also, comparing the TFLCs of the filtered and unfiltered analysis shows that for the two factors curve at the end of the period in the unfiltered one gives a descent in the CAPEX which leads to an equation similar to that of the filtered analysis. This means that the future costs using the two factors equation will be closer values that those calculates with the one factor, since the CAPEX will grow with one while the other will decrease.

The R-squared is quite low in both curves because there is a substantial difference between the CAPEX of different projects. Also, some years only have a few commissioned farms while others may have more than 8, so the cost may be greatly influenced in a year with a few OWF by one farm with a cost far from the expected average.

The one and two factor experience curves for the LCoE is presented in €/MWh produced against the cumulative energy generation. This is called the Energy analysis. The Energy analysis results show a similar trend to the Power Capacity analysis as the LCoE and the CAPEX are highly correlated, as explained earlier. The improvement in the OWF's efficiency and the reduction of the WACC, however, makes the Energy analysis a little different from the Power Capacity as seen in Figure 32.

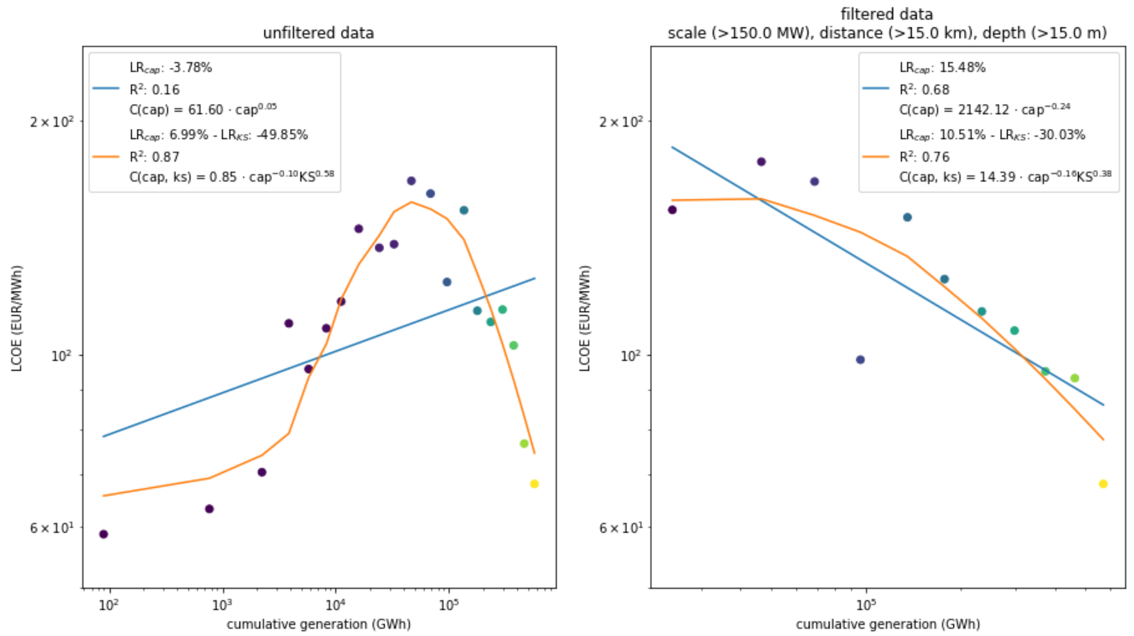


Figure 32: Energy analysis for the LCoE.

Here the learning rates for the one factor curves are -3.78% for the unfiltered and 15.48% for the filtered one. In the first the different LR compared with the one from the Power Capacity analysis means that the increase in the CAPEX may have been caused in part to maximize the energy production and efficiency, improving the LCoE. This means that the increase in the CAPEX was useful to maximize the cumulative generation of energy by improving the efficiencies. The main purpose in the development of OWE is to minimize the LCoE. this result is not surprising since the CAPEX reduction is an effect of looking for the LCoE reduction. Although, it still shows a diseconomy of scale.

The filtered analysis presents a more constant trend with a regular economy of scale and a high learning. This refutes what was said before about being the minimization of the LCoE the main goal of the developer. Also, this fits better the expected trend for the LCoE in the future than the unfiltered, even with higher correlation between the data and the curve as showed in the r-square value.

In the two-factor analysis this changes since the curve in the unfiltered one at the end of the period gives a descend in the LCoE as it happens with the CAPEX. In addition, the filtered has a smaller learning for the installed capacity, comparing it with the one factor curve, and negative LR for the KS as in the Power capacity analysis. The explanation for the negative value in the learning by research could be the same than before, or the R&D expenditures increased the cost, or it coincided with an increment of the costs caused by other factors. Also, the two factors curve gives an accelerated learning in the end of it that leads into a higher LCoE reduction.

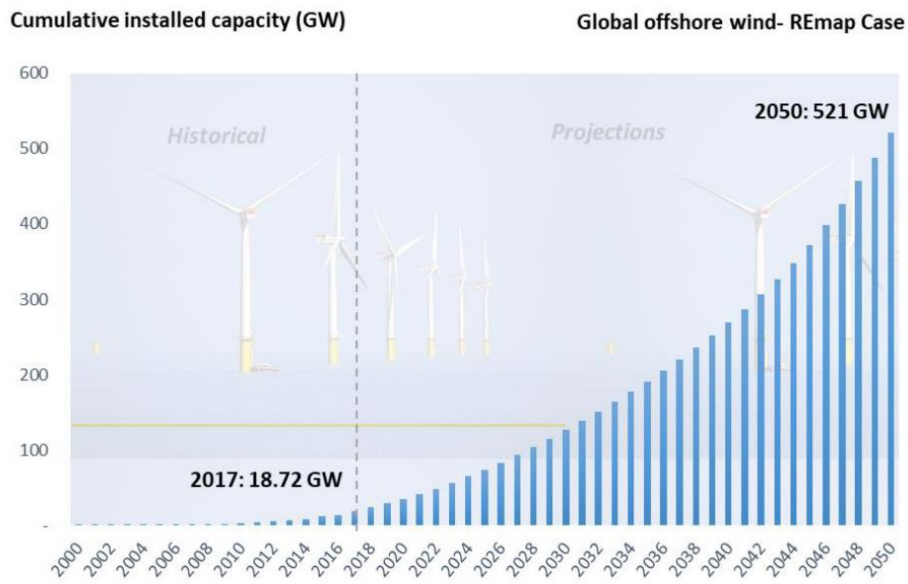
Although, even with the growth, the learning is expected to decrease almost completely once the market price is reached by offshore wind energy since there would not be an incentive for the companies to improve their systems (Poudineh et al., 2017).

Comparing both analyses, it is noteworthy in the timeline that the AEP improvement made it possible for the LCoE to start the learning phase earlier than the CAPEX. Improvements in energy efficiency and manufacturing came at the expense of higher initial investment per MW, but energy generation costs were reduced.

Expected development for 2030

OWE is expected to keep growing globally and in an exponential way. Nowadays around 85% of the installed capacity comes from the studied countries in this research but other countries, like China, is also increasing their investments in this kind of technology having nowadays 2.64 GW installed.

For the near future of 2030 the expectations in the globally market for OWE is to grow till reaching around 130-140 GW of installed capacity (IEA, 2018). This growth may help cost reductions since, as already mentioned, wind technology is better analysed globally than reducing it to national level (M. Junginger et al., 2005).



Source: IRENA, 2018b, 2018c.

Figure 33: Historical and projected total installed capacity of offshore wind, 2000-2050.

From this expected growth 80% of the installed capacity will be in the studied countries, so 108GW are expected to be ready for 2030 in this European countries (IRENA, 2018). While for a technological learning analysis it would be better to use global cumulative capacity installed instead only five countries, the calculated experience curves are focused in the studied countries and may not be useful for others. Some reasons are that other countries, like China, may have different manufacturing costs that makes the CAPEX smaller and cheaper than un the EU. Also, a different risk perception may change the WACC so other experience curves should be elaborated with global parameters in order to have useful equations for global data.

The obtained learning equations with filtered data were:

Table 5: Filtered analysis learning equations.

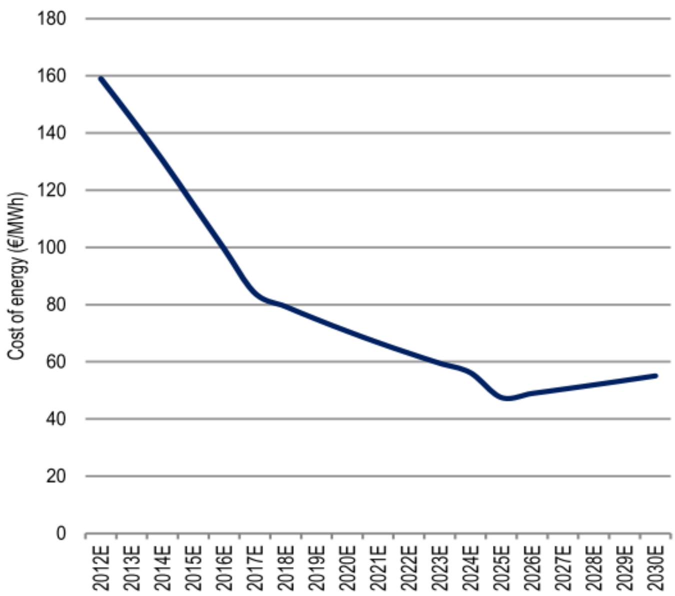
	OFLC	TFLC
CAPEX	$C(cap) = 11.97 * cap^{-0.12}$	$C(cap, ks) = 0.05 * cap^{-0.01} KS^{0.41}$
LCOE	$C(cap) = 2142.12 * cap^{-0.24}$	$C(cap, ks) = 14.39 * cap^{-0.16} KS^{0.38}$

When applying this formulas to the expected growth in capacity the installed capacity of 108GW, with its corresponding energy generation with an average CF of 55% (Colmenar-Santos et. al. , 2016) and the expected knowledge stock development we got as result the following table:

Table 6: Filtered analysis results for 2030 expected installed and generated power.

	OFLC	TFLC
CAPEX	*2.979 €/MW*	*1.536€/MW*
LCOE	$88.48€/MWh$	*42.10€/MWh*

As we can see the reached values for the TFLC are lower than those from the OFLC. However, the values reached are far from each other so it is convenient to see some other studies to compare results and give more reliability.The expectations of the LCoE for 2030 done by Credit Suisse are those presented in Figure 34 where the cost descent to 58€/MWh.



Source: Credit Suisse estimates

Figure 34: Credit Suisse estimations for the LCoE, by year of project commissioning.

This estimation for the energy cost assumes that from 2024/25 onwards, it is negligible additional savings in the LCOE that would lower the curve more for the following reasons (Poudineh et al., 2017):

- Limited incentive to push the costs of wind down further: Auctions have cleared at 'market prices' (the Netherlands at the market price for 2022 onwards, Germany 2024/25). Unless commodity prices fall, we see less incentive for developers or OEMs to push costs down further, as wind would be more competitive than all other types of generation.

- Many of the costs appear as low as they can be: Incremental drops in costs become harder and harder to achieve. There is a large amount of steel, labour, vessels and fuel that goes into an offshore wind installation, and savings can only go so far.

Comparing the values by Credit Suisse and the calculated with the experience curves it is appreciated the similitude between both. While the one factor results are higher and the two factors a bit lower than the founded results on literature but similar and fitting better the expectations for 2030. However, there is a good reason given by this paper (Poudineh et al., 2017) that implies that the LCoE may not go as low as the expected in the two factors curve, but a bit higher. This one says that the energy price may not go lower than the market price since the incentives to reduce the cost once this point is reached are not enough to keep going with the technology development as before. So, once reached around 55 € per MWh both, the CAPEX and the LCoE may suffer a deacceleration on its cost reduction trends.

Discussion

Multiple ways of analysing cost trends for OWE were found in previous papers researched for this thesis. Some of these implied things like applying uniform definitions for CAPEX in order to exclude the effect of changing locations (Voormolen et al., 2016) but this method did not explain the past increase in the CAPEX completely but only part of it. However, the mentioned supply chain improvements, that allowed part of the cost's reductions, are harder to quantify since these needs' extra information from the manufacturers that is not easily accessible. Therefore, those available parameters, that also influence the price and defines some of the characteristics of the OWF, were taken as a filter for the experience curves. These are the already mentioned depth, distance from shore and installed power. If a way to quantify the supply chain is found, together with the needed data, then a multi-factor experience curve could be done with more input and, maybe, with better results and reliability.

In the unravelling of the costs all the original parameters were taken to be analysed. That's why the depth, as well as the distance from the shore, was not placed under a uniform definition for this research. The influence of these may not be as relevant as in the past for the early projects of OWE. However, the best way to analyse the trend was to keep the original parameters from the OWF as the trend continues to move towards deeper waters and further from the shore. It was therefore found to be more accurate to see cost development as a complete OWE analysis and not merely to see cost reduction in component production and installation without the influence of these factors.

Not only the physical parameters were kept unchanged but also the financial ones. Some other researches like (Poudineh et al., 2017) have used a constant WACC to analyse the trend of the LCoE. This is helpful when the goal is to see only technological development, but in this case the influence of Financial Expenditures and historical development has been of study interest. In the experience curves, the financial improvements for OWE were also considered in this way. However, the WACC for each project was hard to find and some projects value for specific years was taken as the WACC for the whole country that year. This might bee improved if the real data for the debt and equity was found or the real WACC values for the countries studied and not base these ones in estimations and one-project financial results.

Also, the added data covers only till the most recent projects that have been confirmed to be commissioned in the next years. More data could have been added to the analysis from other projects that will be built in later years, but this was found to be too inaccurate as the data for these projects are still a draft of the real ones, sometimes even too optimistic, implying a possible major change in the final costs. These projects, in other words, did not offer enough confidence to be analysed as certain future costs. Not all the projects analysed were commissioned, however, and the final cost is subject to change, sometimes even to a large extent (Schwanitz & Wierling, 2016). However, these are in a sufficiently advanced state to be considered in the analysis, as they provide valuable information about the development of near-future costs. Also, the database has some uncertainty related to the acquisition of all the information. While for most of the projects the values founded are accurate enough when talking about costs, for some there is only an approximation of the real values, in some cases because the OWF has not been commissioned yet, like those from 2019 and on, and for others the values are an approximation since the real ones have not been released to the general public, like some of the first OWF.

Also, the CF for some OWFs was not available because could not be found or the OWFs were not commissioned yet or not for enough time to get a reliable average CF. In these cases, also some estimations were done based on the turbine models, the year and the rotor diameter. Although, these estimations may present a certain degree of uncertainty and are always less reliable than the actual real values. For other technical parameters, like the rotor diameter, or the installed power, the values are contrasted so no uncertainty is present there.

To elaborate the KS the patents were taken as an input value. However, this may not represent perfectly the R&D expenditures since there might not be a direct relation between this and the patents. The elaboration of the TFLC could improve with more accurate values for the R&D. Also, as discussed before, the negative LR for these are not convincing since the investment for research is not expected to enough to cause the cost increment. However, without the real values, this could not be probed but only speculation based on other researches. Furthermore, the depreciation rate for the KS of 15% was estimated based on the founded values for the wind turbines of 10% in (Grubler, 2012) and the technology value of 30%,. Since, as explained, the OWE depends on the turbines less than the onshore it was sensitive to get the general value of 15% because this is between the turbines and the technology value, being our value closer to the wind technology one because of its closer relation.

One important point to consider is that all the OWF in this study are ground-based, like jacket, monopile, gravity based… since the floating ones are not commercially available yet. Floating wind turbines allow access to deep-water sites with stronger and more consistent wind speeds, where traditional fixed-bottom wind turbines become prohibitively expensive and difficult to install (International Energy Agency, 2018). However, this new technology may suppose a big step for OWE since it means the introduction in big markets like Japan and the USA, increasing the cumulative installed capacity greatly and improving the development of OWE (Wiser et al., 2016b). Although, the introduction of this new technology may increase the global cost of OWE in its first stages. But in this study only the actual used and extensively implemented technologies have been considered, and not pilot projects or research centres.

Because OPEX data were unavailable in this research, it was kept constant mainly depending on the installed capacity and the type of turbines used. The problem is that this way does not consider the effects of a changing OPEX in the LCoE that in reality is not constant and expected to decline by 2030 between 4 and 9 percent.

Comparing this study with others of the same kind there are some differences in the procedure and the results. The base for this thesis was the paper by (Voormolen et al., 2016) but adding experience curves and current updated data. This is the reason why the results differ since in Voormolen's paper the data gives different trends with an increasing cost while in this it happens the other way thanks to the latest developments in OWE. Another important issue of model specification is the assumed geographic learning domain. Previous studies on this point differ since some assume that learning is a global public good and therefore the cumulative capacity installed must be viewed worldwide and not analysed by country. This therefore implies that the learning - by - doing effects resulting from the expansion of national capacity will affect not only the analysed, but all other countries as well, and the calculated learning rates will apply where global capacity doubles (Lindman, 2015).

Conclusion

This study was motivated to complete the previous studies in OWE with the most recent information available for the already built and close to be commissioned OWFs in five European countries. Furthermore, previous experience curves in this field consider only one factor, leaving out the improvements that the investment in research and innovation has achieved. This is also one of the few studies that includes unravelling OWE and experience curves together using the most up-to-date data so the defined trend for the future follows the current trend.

The hardest challenge was to obtain all the data and information needed from the selected projects in the countries of study. Nearly all contracts are confidential, and the data is classified, making it hard to compare some of the OWF's characteristics that had to be estimated. Due to different contract schemes and other agreements, not only cost data are not easily available, but also complex. Nonetheless, the data for the latest projects was easier to obtain and more accurate in the case these were already commissioned. This might be caused because the LCoE has been reduce for the newest projects and a higher transparency in the characteristics of these OWFs leads into a better risk perception and a better financial support from governments.

Offshore Wind Energy has been struggling with cost fluctuations since its beginning, developing a rise in the cost on its first years that have led into a high-risk perception in the past. However, the results indicate that latest improvements in the offshore wind technology, with higher efficiencies, and the cost reductions in the manufacturing and installation have achieved a reduction in the final costs. Even with the trends of constructing further from shore and in deeper waters, together with the fluctuations in the commodities prices, that may influence the cost in higher expenditures, the CAPEX and the LCoE have developed favourably for OWE. Also, the financial factors are showing a more optimistic scenery for OWE helping also the final cost reduction.

The exponential growth of installed cumulative capacity installed reaching almost 18 GW in the beginning of 2019 has led to cost improvements. Looking at CAPEX, it has decreased its average from 4.5 M€ in 2015 to 3 M€/MW installed in the beginning of 2019 with expectations of reaching around 2.5-2 M€/MW installed in 2030. The CF has been growing every year with the newest wind turbines and this trend is expected to keep going from 30% in 2001 with the first turbines till reaching around 60% in 2030 for new OWF. Other factors like the OPEX have been reported in other papers to have a descending trend but it could not be analysed in this one for the lack of data.

The LCoE has evolved negatively in the first year of OWE due to the challenges that the sector has had to upfront, like the depth and distance, the supply chain adaptation and the optimization of the components' manufacturing. However, after this increment the efforts into maximize the efficiency and reduce the CAPEX made the LCoE to change from 170€ per MWh in 2015 to 90€ per MWh in four years with expectations of reaching the market price, around 60-50 €/MWh, in the next ten years.

For further research to improve the content of this one some more parameters could be added and with better quality data from the developers in order to develop a more accurate analysis and classify the cost fluctuations by factor.

Last but not least, it is necessary to emphasize that, in order to achieve a competitive energy technology that can replace part of the conventional fossil-based power plants and key in the renewable energies deployment, it is necessary to continue with the improvements in the sector, even with the promising trend that OWE is following.

Glossary

Abreviations:

- AEP Annual energy production
- CAPEX Investment costs (Capital Expenditure)
- CF Capacity Factor. Net Energy Production as percentage of maximum
- GW Gigawatt (1.000 megawatt)
- HVDC High-voltage direct-current transmission
- IEA International Energy Agency
- IRENA International Renewable Energy Agency
- Jacket Type of foundation with four piles
- KS Knowledge stock
- LCoE Leverage Cost of Energy
- LR Learning rate
- kWh Kilowatt per hour
- Monopile Type of foundation with one pile
- MW Megawatt (1.000 kilowatt)
- MWh Megawatt hour
- OWF Offshore Wind Farm
- WE Offshore Wind Energy
- O&M Operation & Maintenance
- OPEX Operating costs (Operating expenditure)
- OFLC One factor learning curve
- R&D Research and development
- TFLC Two factor learning curve
- Tripod Type of foundation with three piles
- TSO Transmission System Operator.
- TWh Terra Watt hours (1 TWh = 1,000 GWh = 1,000,000 MWh)
- WACC Weighted Average Cost of Capital

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Annex

Project	Ctry.	State	Date	MW	Turbines (MW)	Foundation	CF	CAPEX	OPEX	Distance (km)	Depth (m)	Rotor	life (years)	WACC	LCOE
Middelgrunden	DK	FC	mar-01	40	2	Gravity-Base	25,5	1,52	4,29	4,7	4,5	76	25	7,5	93,12
Horns Rev 1	DK	FC	jun-02	160	2	Monopile	42	2,30	9,98	18	10	80	25	7,5	59,32
Samsø	DK	FC	feb-03	23	2,3	Monopile	39,3	1,96	3,71	4	11,5	82	25	7,5	86,53
North Hoyle	UK	FC	nov-03	60	2	Monopile	31,8	2,51	5,40	8,7	9	80	25	12	122,80
Nysted	DK	FC	dic-03	165,6			37,3	1,88	6,89	10,8	8	82	25	7,5	53,35
Scroby Sands	UK	FC	jul-04	60	2	Monopile	30,7	2,49	5,36	3,5	6	80	25	12	127,53
Barrow	UK	FC	mar-06	90	3	Monopile	36,1	2,40	7,06	9,8	17,5	90	20	12	105,00
Egmond aan Zee	NL	FC	ene-07	108	3	Monopile	33,1	2,35	7,70	10	16,5	59	20	9,8	99,77
Burbo Bank	UK	FC	jul-07	90	3,6	Monopile	34,1	2,86	6,77	6,4	4	107	20	12,5	132,76
Prinses Amaliawindpark	NL	FC	jul-08	120	2	Monopile	41,3	3,55	10,57	23	21,5	80	20	10,3	123,78
Thornton Bank phase I	BE	FC	feb-09	30	5	Gravity-Base	33	5,82	2,93	27	20	126	25	9,7	223,78
Lynn & Inner Dowsing	UK	FC	mar-09	190	3,6	Monopile	34,2	1,80	8,96	6,9	12	107	25	12,8	86,69
Horns Rev 2	DK	FC	sep-09	209,3	2,3	Monopile	48,1	2,43	12,63	32	13	93	25	8,4	63,55
Sprogø	DK	FC	oct-09	21	3	Gravity-Base	33,9	6,17	3,51	1	10	90	25	8,4	233,82

Rhyl Flats	UK	FC	dic-09	90	3,6	Monopile	33,1	2,62	5,57	10,7	9	107	25	12,8	129,39
Alpha Ventus	DE	FC	abr-10	60	5	Jacket	38	4,64	5,24	56	39	116	20	8,3	146,50
Robin Rigg	UK	FC	abr-10	174	3	Monopile	35,1	3,73	12,32	11,5	8,5	90	20	12,6	167,76
Gunfleet Sands	UK	FC	jun-10	172,8	3,6	Monopile	36,7	3,38	9,89	7	8,5	107	25	12,6	143,21
Thanet	UK	FC	sep-10	300	3	Monopile	32,6	3,37	15,49	17,7	22,5	90	25	12,6	159,06
Rødsland 2	DK	FC	oct-10	207	2,3	Gravity-Base	44	2,41	13,98	7	9	90	20	8,3	71,72
Belwind	BE	FC	dic-10	165	3	Monopile	38,3	4,27	12,64	46	28,5	90	20	9,6	146,10
EnBW Baltic 1	DE	FC	abr-11	48,3	2,3	Monopile	45	4,96	6,71	16	17,5	93	20	9,1	153,84
Ormonde	UK	FC	feb-12	150	5,075	Jacket	38,5	4,90	9,38	9,5	19	126	25	13,3	205,77
Walney Phase 1	UK	FC	feb-12	183,6	3,6	Monopile	41	4,25	13,52	19,4	23,5	107	20	13,3	172,98
Walney Phase 2	UK	FC	feb-12	183,6	3,6	Monopile	45,2	4,25	11,95	22,1	27,5	120	25	13,3	154,74
Anholt	DK	FC	sep-12	399,6	3,6	Monopile	49,4	3,56	26,56	15	17	120	20	8,7	92,34
Sheringham Shoal	UK	FC	sep-12	316,8	3,6	Monopile	40,7	4,95	19,61	21,4	17,5	107	25	13,3	199,66
Thornton Bank phase II	BE	FC	oct-12	184,5	6,15	Jacket	36	4,78	12,30	26	20	126	20	10,2	182,16
Kentish Flats	UK	FC	jul-13	90	3	Monopile	30,8	2,12	6,66	9,8	5	90	20	12,5	126,92

London Array	UK	FC	jul-13	630	3,6	Monopile	40,8	5,85	39,91	27,6	12,5	120	25	12,5	224,72
Greater Gabbard	UK	FC	ago-13	504	3,6	Monopile	42,1	3,70	27,30	36	26	107	25	12,5	141,07
Thornton Bank	BE	FC	sep-13	1244	6,4	Jacket	36,6	1,09	49,30	27	20	126	20	9,7	47,44
BARD Offshore 1	DE	FC	sep-13	400	5	Tripile	34,5	7,85	33,50	101	40	122	25	8,3	266,17
Lincs	UK	FC	sep-13	270	3,6	Monopile	42,3	3,31	17,36	9,1	12,5	120	20	12,5	129,94
Riffgat	DE	FC	feb-14	108	3,6	Monopile	44,5	4,38	7,85	21,5	15	120	25	9,1	128,34
Northwind	BE	FC	mar-14	216	3	Monopile	42,9	1,62	11,02	37	25	112	25	10,65	61,05
Teesside	UK	FC	abr-14	62,1	2,3	Monopile	35,3	4,04	5,80	2,2	11	93	25	13,75	210,17
Meerwind Süd/Ost	DE	FC	sep-14	288	3,6	Monopile	42	4,34	17,32	23	24	120	25	9,1	132,58
West of Duddon Sands	UK	FC	oct-14	389	3,6	Monopile	45,4	5,31	25,23	14		120	25	13,75	200,05
DanTysk	DE	FC	dic-14	288	3,6	Monopile	48,2	3,62	18,06	70	26,5	120	25	9,1	99,25
EnBW Baltic 2	DE	FC	feb-15	288	3,6	Monopile and jacked	47,5	4,59	18,45	32	33,5	120	25	8,8	119,87
Westermost Rough	UK	FC	may-15	210	6	Monopile	45,5	5,45	13,58	8	15	154	25	13,3	199,43
Borkum Riffgrund 1	DE	FC	jun-15	312	4	Monopile	39	4,15	17,64	40		120	25	8,8	134,00
Nordsee Ost	DE	FC	jun-15	295,2	6,15	Jacket	35	6,67	18,94	52	27	126	25	8,8	231,19

Humber Gateway	UK	FC	jun-15	219	3	Monopile	42,9	4,80	14,58	8	13	112	25	13,3	189,14
Gwynt y Môr	UK	FC	jun-15	576	3,6	Monopile	34,4	4,96	32,30	18	22,5	107	25	13,3	239,48
Trianel windpark Borkum I	DE	FC	jul-15	200	5	Tripod	49,7	4,70	13,05	45	30	116	25	8,8	118,51
Global Tech I	DE	FC	jul-15	400	5	Tripod	49,7	4,17	27,15	140	39	116	25	8,8	107,62
Butendiek	DE	FC	ago-15	288	3,6	Monopile	43	4,71	17,99	32	20	107	25	8,8	136,61
Eneco Luchterduinen	NL	FC	sep-15	129	3	Monopile	46	3,64	8,98	23	20	112	25	10,8	118,58
Amrumbank West	DE	FC	nov-15	302	3,775	Monopile	42,4	3,45	16,70	35	22,5	120	25	8,8	104,18
Kentish Flats Extension	UK	FC	dic-15	49,5	3,3	Monopile	41,1	3,04	5,25	8,5	5	112	20	13,3	142,37
Race Bank	UK	FC	feb-16	573,3	6,3	Monopile	44,7	3,37	30,11	33	18	154	24	13,3	126,86
Westermeerwind	NL	FC	jun-16	144	3	Monopile	42	2,88	8,94	0,5	7	108	25	10,8	105,22
Burbo Bank Extension	UK	FC	abr-17	254,2	8	Monopile	39,1	2,42	11,00	7	10	164	25	9	82,79
Veja Mate	DE	FC	may-17	402	6	Monopile	45,4	4,83	27,96	95	38	154	25	8	128,82
Gemini	NL	FC	may-17	600	4	Monopile	49,3	4,77	42,88	55	32	130	20	8	117,78
Gode Wind 1 and 2	DE	FC	jun-17	582	6,264	Monopile	37,8	3,87	29,29	45		154	25	8	122,14
Sandbank	DE	FC	jul-17	288	4	Monopile	44,5	4,27	18,65	90	30	130	25	8	116,74

Dudgeon	UK	FC	oct-17	402	6	Monopile	48	4,34	23,54	32	21,5	154	25	9	116,98
Wikinger	DE	FC	nov-17	350	5	Jacket	51	4,08	21,06	35	40	135	25	8	97,34
Nobelwind	BE	FC	dic-17	165	3,3	Monopile	46,97	4,04	12,88	47	33	112	20	7,5	105,53
Nordergründe	DE	FC	dic-17	110,7	6,15	Monopile	40	3,76	6,28	16	10	126	25	8	115,20
Nordsee One	DE	FC	dic-17	332,1	6,15	Monopile	40,8	3,68	17,26	45	27,5	126	25	8	109,25
Aberdeen Offshore Wind Farm	UK	FC	may-18	93,2	8,2	Jacket	38	3,67	4,62	3,3	28	164	25	9	126,30
Galloper	UK	FC	may-18	353	6	Monopile	47	4,84	22,62	27	31,5	154	23	9	134,48
Walney Extension	UK	FC	sep-18	659	8,25	Monopile	45,2	4,48	36,85	19		154	25	9	128,93
Borkum Riffgrund 2	DE	FC	dic-18	450	8,3	Various	39	2,67	19,78	50	28	164	25	7	79,84
Rampion	UK	FC	dic-18	400,2	3,45	Monopile	38,8	3,68	21,46	18		112	25	9	125,89
Arkona	DE	PG/UC	abr-19	385	6,417	Monopile	50	3,12	20,48	35	20	154	25	8	78,81
Rentel	BE	PG/UC	may-19	309	7	Monopile	48	4,53	20,94	40	30	154	20	7,5	112,78
Merkur	DE	PG/UC	jun-19	396	6	Monopile	51	4,04	23,20	60	30	150	25	7	90,72
Norther	BE	UC	oct-19	369,6	8,4	Monopile	54	3,52	23,19	23	24,5	164	20	7,5	79,97
Deutsche Bucht	DE	UC	dic-19	250	8,13	Monopile	51	5,20	19,11	80	39	164	25	7	116,99

Hohe See	DE	UC	dic-19	497	7	Monopile	49	3,62	31,45	95	35	154	25	7	87,14
Beatrice	UK	PG/UC	dic-19	588	7	Jacket	49,4	5,54	37,58	13	42	154	25	9	145,18
Hornsea Project One	UK	UC	abr-20	1218	7	Monopile	52	2,60	70,60	110	27	154	25	11	80,54
OWP Albatros	DE	UC	jun-20	112	7	Monopile	49	2,72	5,98	60	40	154	25	8	71,87
Kriegers Flak	DK	UC	oct-20	590	8	Various	50	2,05	27,40	15	22	167	25	8	54,39
East Anglia ONE	UK	UC	oct-20	714	7	Jacket	55	3,96	38,21	50	35	154	30	11	108,77
Horns Rev 3	DK	UC	nov-20	406,7	8,3	Monopile	55	3,29	22,37	33	15	164	25	8	75,45
Northwester 2	BE	PC	feb-21	219	9,5	Monopile	45	3,20	12,00	50	30	164	20	7	83,48
Borssele 1 and 2	NL	PC	may-21	752	8	Monopile	50	1,86	34,19	36	25	167	25	8	50,20
Borssele 3 and 4	NL	PC	may-21	731,5	9,5	Monopile	47	1,78	31,46	42	25	164	25	7	47,49
Triton Knoll	UK	PC	ago-21	860	9,5	Monopile	44,6	2,63	39,63	33	21	164	25	11	91,79
Hornsea Project Two	UK	PC	oct-22	1386	8,4	Monopile	58	2,61	86,65	89	27	167	25	10	68,96