The economics of floating offshore wind – A comparison of different methods

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ABSTRACT: Different technologies for Floating Offshore Wind (FOW) systems have been developed and multiple studies exist that aim at comparing the techno-economic advantages and disadvantages of each technology. However, the assumptions and calculations used in these different studies vary largely resulting in high variation of the final cost estimates. This points to the need of developing a consistent method that allows for technology comparison at whole system but also sub-system level. In this paper, the sensitivity of the final results to the different assumptions and calculation set-ups is investigated. This study provides a discussion of the suitability of the applied methods, and as a result suggests the standardisation of the procedure, while defining a set of recommendations for good practices in techno-economic assessment of FOW technologies. The suggested common framework will facilitate the comparison of different FOW technologies based on costs and increase investor confidence.

1 INTRODUCTION

Offshore wind represents a large renewable energy resource, that has been increasingly exploited in the last 10 years. Deployment of offshore wind capacity has increased by around 30% per year since 2010. Furthermore, turbines of increasing size have been deployed with the largest available wind turbines growing from 3 MW in 2010 to 8 MW in 2016, and with expected ratings of up 15-20 MW by 2030 (IEA 2019). Capacity factors have also increased from 38 to 43% from 2010 to 2018 (IRENA 2019). Most of the deployed technologies are bottom-fixed through monopiles or jackets. Floating offshore wind technologies are being developed, that have the potential to unlock resource areas at water depths larger than 50-60 m at which bottom-fixed foundations are not economical. This also offers the opportunity for deployments further offshore where higher and more constant wind speeds can be found. Pre-commercial and small commercial deployments already exist. Ongoing research projects aim to reduce the costs and environmental impacts of these technologies. An example of such projects is the FLOTANT project, an EU H2020 funded research project, where innovations in the cables, moorings and platform of a floating offshore wind turbine are introduced. To understand how the new system compares to other technologies, a consistent techno-economic assessment technique is required.

1.1 *Background*

Studies aiming at quantifying the costs and cost differences for a number of Bottom-Fixed Offshore Wind (BFOW) technologies, such as (Ioannou et al. 2017) and Floating Offshore Wind (FOW) technologies, such as (Rhodri & Costa Ros 2015) and (Ebenhoch et al. 2015) have been performed, where comparisons between these two types of offshore wind projects have also been pursued (Myhr et al. 2014). More recently, a techno-economic model suitable for both BFOW and FOW projects was developed within the LEANWIND project (Judge et al. 2019). Due to the lack of available data, it is challenging to quantify the costs of these types of projects. For this reason, various studies have focused on the development of parametric functions that describe the cost changes depending on certain design, deployment and cost variables, such as turbine capacity, distance to shore or cost of material. Widely used parametric functions were developed in (Dicorato et al. 2011) to quantify capital expenditures for BFOW technologies, which have been partly updated in (Gonzalez-Rodriguez 2017). In a similar way, these type of relationships have been developed for the quantification of all costs occurring during the life-cycle of a BFOW project in (Shafiee et al. 2016) and (Ioannou et al. 2018b). Data for the generation of these relationships have been collected, for example, in (Gonzalez-Rodriguez 2017) and (The Crown Estate & Offshore

Renewable Energy Catapult 2019). In this context, the SPARTA project sets an example as an industry-led operational data collection and sharing exercise of offshore wind projects (OREC 2018). In FOW, similar parametric models have been developed for the quantification of the Levelised Cost of Energy (LCoE) in (Castro-Santos et al. 2016) and of installation costs in particular in (Castro-Santos et al. 2018). Latest implementations consider the uncertainty of LCOE model inputs through their stochastic representation. This is the case for BFOW in (Kolios & Brennan 2018), where, as part of the ROMEO project, advanced O&M models are being developed, or in (Ioannou et al. 2020) where uncertainty is considered in all phases of the project life-cycle. For FOW, Gomez *et al.* (Gómez et al. 2015) developed an LCoE assessment tool within the LIFE50+ project, for which more detailed financial metrics and model structure, and a thorough sensitivity analysis are discussed in (Lerch et al. 2018). Castro-Santos *et al.* introduced the consideration of uncertainty in the inputs of LCoE calculations with the help of stochastic modelling in (Castro-Santos & Diaz-Casas 2015) by quantifying the impact of these inputs on life-cycle costs and economic indexes. In this study not only LCoE was considered but also other financial metrics such as the Internal Rate of Return (IRR) or the Discounted Pay-Back-Period (DPBP). Cost modelling from the investor perspective was discussed in the BFOW study (Ioannou et al. 2018a), where the cash flows over the project life-cycle were represented and different types of investor, and thus project entry and exit timings were studied.

1.2 *Objectives*

A range of methods based on a variety of assumptions have been used in the past to evaluate the techno-economic impact of offshore wind projects. In this paper, we will review existing literature on techno-economic assessment of offshore wind technologies and analyse the suitability of the used approaches to evaluate upcoming floating offshore wind projects employing larger turbines, at larger water depths and distances from shore. Additionally, we will discuss the suitability of past approaches for technology comparison, as well as the requirements to allow for cost comparison across different studies. The goal is to identify newly arising requirements to previously developed techno-economic assessment methodologies, as well as to define recommendations for future applications of this type of analysis.

For this purpose, both BFOW and FOW projects and studies are compared in section 2. Cost models used for the assessment of offshore wind projects and technologies are reviewed and discussed in detail in section 3. Based on the discussion on the suitability of the used methods in section 4, final conclusions are drawn in section 5.

2 CHARACTERISTICS OF OFFSHORE WIND PROJECTS - REALITY VS. MODELS

Offshore wind projects have been developed at diverse locations and different numbers and types of turbines have been employed. Based on existing projects and the reviewed literature the characteristics of both Bottom-Fixed (BFOW) and Floating Offshore Wind (FOW) projects are compared with the cases studied in literature.

In Figure 1 turbine capacity and farm size considered in BFOW and FOW cost studies is shown in comparison to values from real projects. Information from real projects was extracted from (WindEurope 2018), (WindEurope 2019), (4C Offshore), and (RenewableUK). The considered costs studies are discussed in more detail in section 3. For these references, the deployment year used here, refers to the currency reference year employed in the studies. Where this was not provided, the publication year is assumed to have been used as the reference year for the discussed costs.

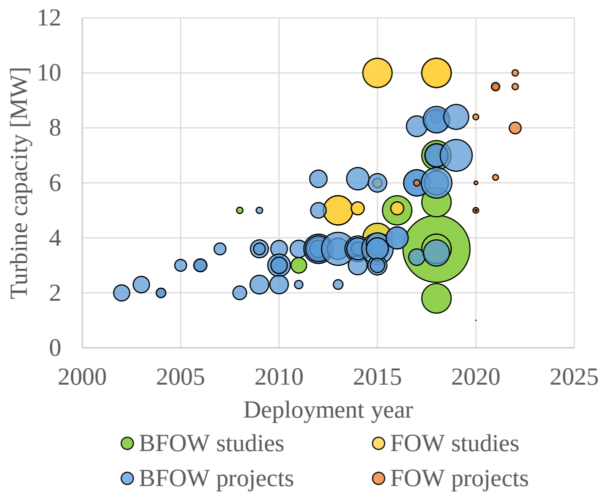

Figure 1: Turbine capacity of offshore wind projects over different deployment years. The size of the bubbles indicates the farm capacity, which ranges from 1 to 2520 MW. Both, real projects and previous LCoE studies are represented (Garcia-Teruel & Jeffrey 2020).

As it can be observed from this figure, turbine capacity rating has been increasing steadily over the last 20 years, where FOW deployments continue the trend of BFOW ones. Current research projects already consider turbine capacities of 12 MW (Quancard et al. 2020), but ratings are expected to reach 15 to 20 MW by 2030 (IEA 2019). It becomes clear from the increasing turbine capacity trend that less turbines of higher rating are being installed in offshore wind farms. The largest farm capacity found in real projects collated here is 1,218 MW for the planned Hornsea One wind farm expansion by 2021. The deployed capacities analysed in previous cost studies mostly agree with reality, where a slight tendency for considering larger farm capacities than deployed in reality can be observed. Reasons for this are 1) that in

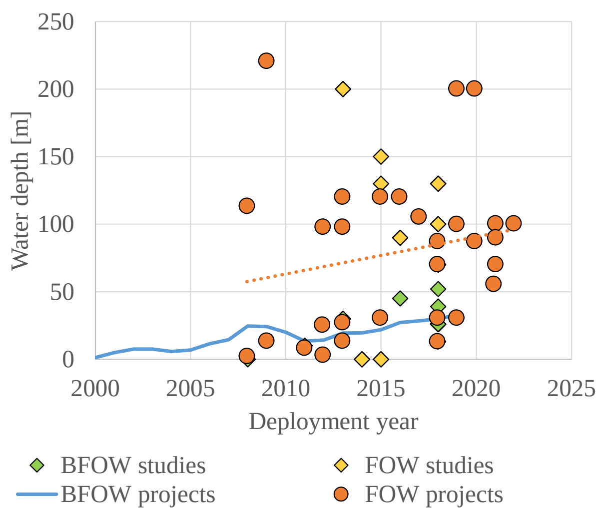

Figure 2: Water depth of offshore wind projects over different deployment years. Both, real projects and previous LCoE studies are represented (Garcia-Teruel & Jeffrey 2020).

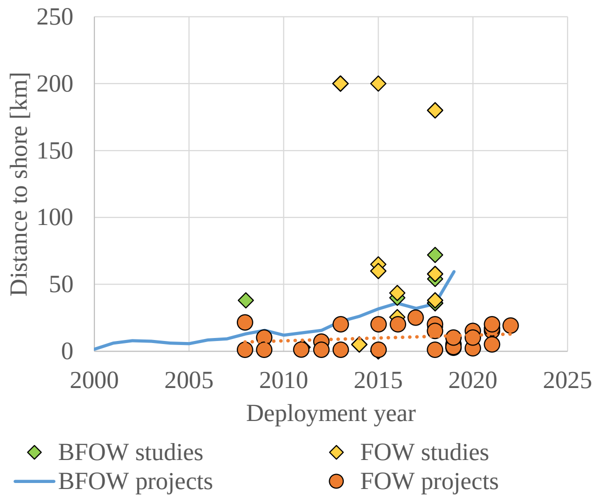

Figure 3: Distance to shore of offshore wind projects over different deployment years. Both, real projects and previous LCoE studies are represented (Garcia-Teruel & Jeffrey 2020).

these kind of studies future scenarios are discussed to demonstrate the ability of offshore wind to generate electricity at grid scale and 2) to demonstrate the potential for cost reduction through economies of volume.

The water depth and distance to shore of existing projects, as well as, considered in literature are shown in Figures 2 and 3, respectively . The rolling average water depth and distance to shore for BFOW projects was extracted from (WindEurope 2019). For FOW projects this information was recorded in (Hannon et al. 2019) for single deployments.

As expected, water depths of FOW projects are mostly in the range from 50 to 100 m, with single deployments at water depths of 200 m or greater. Water depths considered in, both, BFOW and FOW studies agree with those found in deployments to date and expected in the next two years.

In terms of distance to shore, a good agreement between studies and real projects is also seen for BFOW. However in FOW, deployments to date have taken place in near-shore locations, whereas costs studies have mostly considered locations further from shore, with most case studies considering distances around 50 km or around 200 km. This can be related to the fact that FOW offers the opportunity to unlock areas with larger water depths, where near shore areas are being exploited first, due to the lower costs associated to them. However, FOW technologies offer also the opportunity to employ the greater and more steady wind resource available at deeper waters further offshore. This opportunity has been investigated to evaluate the economic feasibility of such deployments.

3 COST MODELS FOR OFFSHORE WIND

A range of cost models to evaluate the economic feasibility of offshore wind projects have been developed in the past decade. They commonly reflect the costs associated to the whole life-cycle of an offshore wind project. This is divided into five phases represented in Figure 4: Development and Consenting (P&C), Production and Acquisition (P&A), Installation and Commissioning (I&C), Operation and Maintenance (O&M) and Decommissioning and Disposal (D&D). Specific costs that have been considered in literature within each of these phases are provided as examples in the figure. This structure has been used for, both, BFOW and FOW project analysis. In the production and acquisition phase, costs of single components are considered, which will be different for BFOW and FOW. The main difference will lie in the costs associated with the foundation in BFOW which are often split into the platform, mooring and anchoring systems for FOW projects.

3.1 *Cost metrics*

Different cost measures have been used to compare offshore wind technologies and projects.

Investment Costs or Capital Expenditures (CapEx) have been used to compare different offshore wind technologies. These are defined as all the costs incurred in phases 1, 2, 3 and 5.

The *Levelised Cost of Energy* (LCOE) is a measure commonly used to compare energy generating technologies, which represents the ratio of the costs incurred over the lifetime n of a project in relation to the annual energy produced over the operational life.

$$\begin{aligned}\mathrm{LCoE} &= \frac{\mathrm{NPV}(\mathrm{CapEx}+\mathrm{OpEx})}{\mathrm{NPV}(\mathrm{AEP})}\\ &= \frac{\sum_{t=0}^{n}\frac{\mathrm{CapEx}_t+\mathrm{OpEx}_t}{(1+r)^t}}{\sum_{t=0}^{n}\frac{\mathrm{AEP}}{(1+r)^t}}\end{aligned} \tag{1}$$

As mentioned before, Capital Expenditures (CapEx) are all expenses incurred in phases 1-3 and 5, whereas Operational Expenditures (OpEx) will encompass all

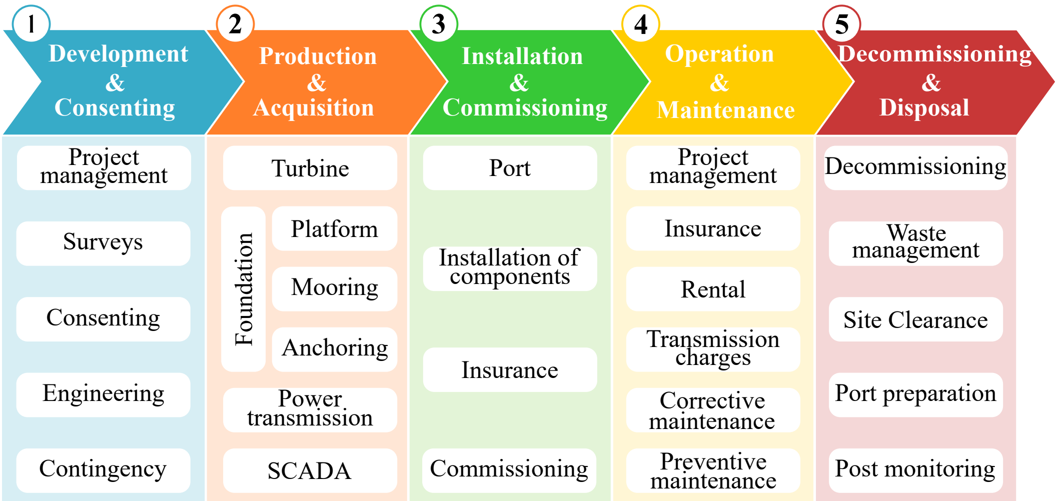

Figure 4: Project phases considered in a Life Cycle Cost Assessment (LCCA) of offshore wind projects (Garcia-Teruel & Jeffrey 2020).

expenses associated to phase 4. Annual Energy Production (AEP) is calculated based on the turbines power curve and a wind speed occurrence distribution, as specified in the standard (CENELEC 2017), or from a given Capacity Factor (CF) that indicates the percentage of power absorbed from the total rated power. To obtain the net AEP in both cases, turbine availability and losses need to be additionally considered. The net present value of each of these components is calculated by applying a discount rate r on the year t the costs were incurred.

The *Net Present Value* (NPV) has also been used in isolation, to represent the total discounted costs of a project.

The *Pay-Back-Period* (PBP) shows the time required to recover the original investment. The *Discounted Pay-Back-Period* is an extension of this measure that accounts for the time value of money by applying discounting to the cash flows.

The *Internal Rate of Return* (IRR) represents the discount rate that would result in an NPV of zero. This measure is used to assess the profitability of a project.

3.2 *Assumptions*

Analysing the costs of future technologies and projects requires a range of assumptions. Common parameters that need to be defined and their impact on LCoE results are discussed in detail in (Lerch et al. 2018). Assumptions not represented by a single parameter and not discussed in detail in literature are introduced in the following.

System boundaries need to be defined, which limit the types of costs that will be considered. Some examples of system boundaries found in literature are shown in Figure 5.

The choice of *economic parameters* such as the discount rate or the lifetime, have been extensively studied through sensitivity analysis, where the discount rate has been consistently found to have one of the largest impacts on the resulting LCoE (e.g. in (Ebenhoch et al. 2015), (Shafiee et al. 2016), (Ioannou et al. 2018a), and (Lerch et al. 2018)). However, the sensitivity of the results to the years in which each of the costs occur has not been considered. Different strategies representing concepts used in the reviewed literature are shown in Figure 6. The most common approach is represented with Timeline 1 in blue, where most CapEx are assumed to occur in year 0, constant yearly OpEx over the operational life are considered and D&D is assumed to take place in one year after the end of the operational life. Timeline 2 in orange considers longer initial phases, and no operational costs in the first years of operation, whereas Timeline 3 in green not only considers longer initial phases, but also that phases 2 and 3 start once phase 1 has finished, and accounts for a longer D&D phase after the end of the operational life. This is, for an operational life of 20 years, a variation of 10 years in the whole project timeline can be observed between these different approaches. Ebenhoch *et al.* also considered the possibility of a turbine replacement in their timeline, with a total project duration of 47-62 years in (Ebenhoch et al. 2015).

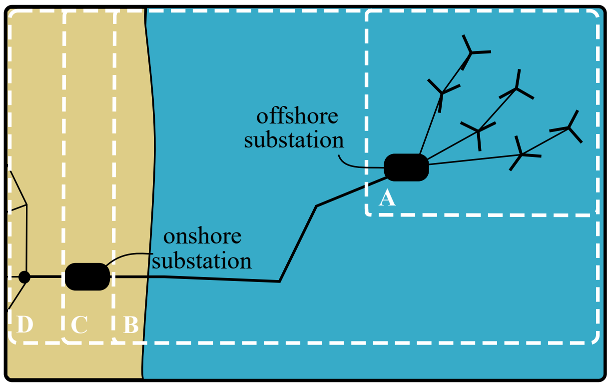

Figure 5: System boundaries used for the calculation of the costs associated with an offshore wind farm (Garcia-Teruel & Jeffrey 2020).

Given that the discount rate has a large impact on the discounted cost results, the distribution of the costs over the project timeline is expected to have an equivalently significant impact. As means of example,

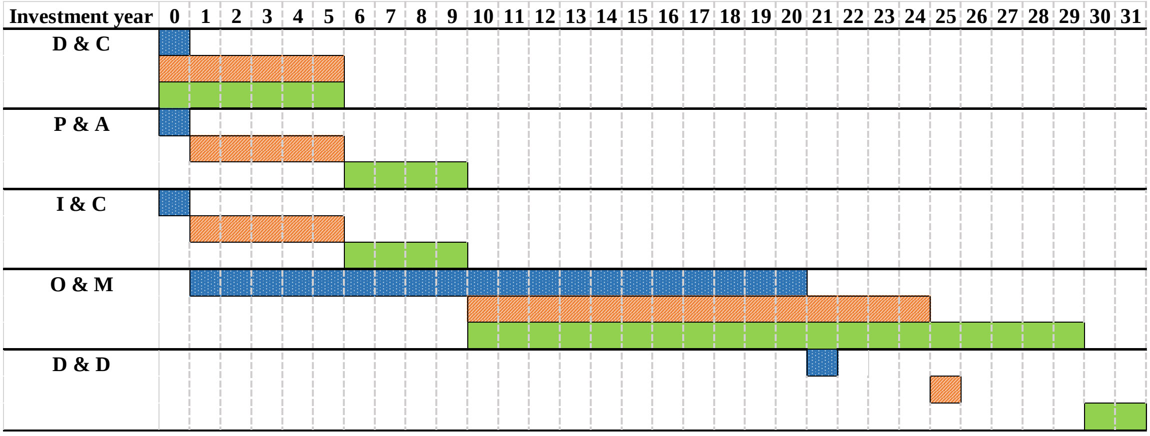

Figure 6: Assumed investment years for different types of spending in reviewed cost studies. The three options in blue, orange and green, are referred to as Timeline 1, 2 and 3, respectively (Garcia-Teruel and Jeffrey 2020).

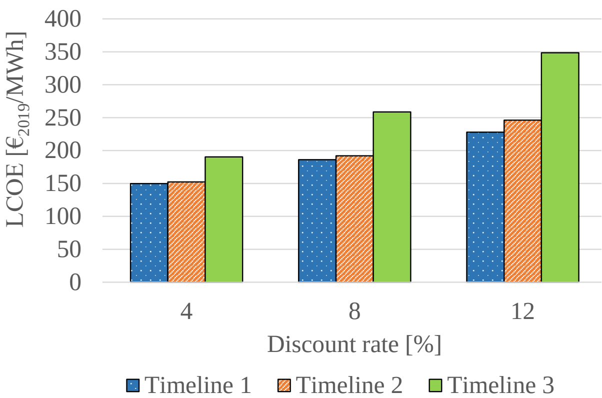

Figure 7: Assumed investment years for different types of spending in reviewed cost studies. The three options in blue, orange and green, are referred to as Timeline 1, 2 and 3, respectively (Garcia-Teruel & Jeffrey 2020).

the LCoE was calculated following timelines 1, 2, and 3, and discount rates of 4, 8, and 12% were used, to compare the impact of the chosen investment years, versus the discount rate value itself on the LCoE results. This was done based on the cost numbers provided in (Ioannou et al. 2018a). The results are shown in Figure 7. It can be seen that for percentage changes in discount rate of 50%, up to a 34% change in the LCoE value can be achieved. However, from considering different investment timelines, as shown in Figure 6, while keeping the discount rate the same, percentage changes of up to 53% in the LCoE value can be observed. This demonstrates the importance of the cost model implementation itself. Despite the large impact that this assumption has on the LCoE results, the investment timeline is often not specified in cost studies, as shown in Table 1.

3.3 *Model implementations*

Due to the lack of available data and the uncertainty associated to certain parameters used for cost modelling, such as the available weather windows for installation or maintenance procedures, cost model implementations are differentiated here by the strategy used to represent uncertainty. Deterministic implementations have been used, where the costs for different technologies have been calculated. These implementations have been extended by considering different case studies, such as three different water depths or distances to shore. In a further step, sensitivity studies have been performed, where one input parameter is varied at a time, to analyse its effect on the final cost results. More recently, stochastic implementations have been developed, that represent uncertainty around components prices, failure rates, weather windows and economic parameters by using probability distributions for these model inputs.

Based on the previously described cost model characteristics, the reviewed literature is summarised in Table 1 to provide an overview of the used methods and assumptions.

The resulting LCoE values for these studies are shown in Figure 8, depending on (a) turbine capacity, (b) farm capacity, (c) water depth and (d) distance to shore. The values are converted into €$_{2019}$ by accounting for 1.5% yearly inflation, based on the average inflation in Europe from 2010 until 2019, and using an exchange rate from GBP to EUR of 1.136 based on the 2019 average. The values provided in the references are assumed to be based on the currency value at the year of publication if not otherwise stated.

From these figures it can be seen, as expected, that LCoE generally decreases with turbine and farm capacity and increases with water depth and distance to shore. Although no clear LCoE reduction can be inferred for increasing turbine capacity in BFOW, FOW projections using 10 MW turbines show lower LCoE values than previous BFOW cases. In terms of farm capacity, it becomes apparent that around 500 MW farm capacity has been commonly considered for FOW deployments. From the collated LCoE results, little dependency on LCoE with farm capacity can be seen, with a wide range of LCoE values calculated for the same farm capacity. A clear increase in LCoE with water depth can be observed, where a steeper increase can be observed for BFOW. This agrees with the initial motivation for the use of float-

Table 1: Overview of cost models used in literature for offshore wind technologies.

Reference	Technology	Metric	Uncertainty	System Boundaries	Investment timeline
(Dicorato et al. 2011)	BFOW	CapEx	Case studies	D	NA
(Shafiee et al. 2016)	BFOW	LCoE	Sensitivity	D	2
(Gonzalez-Rodriguez 2017)	BFOW	CapEx, OpEx	Report of uncertain factors	D	NA
(Kolios & Brennan 2018)	BFOW	OpEx	Stochastic	D	?
(Ioannou et al. 2018a)	BFOW	NPV(CapEx, OpEx), Cash flow	Sensitivity	D	?
(Ioannou et al. 2018b)	BFOW	LCOE, CapEx, OpEx	Case Studies	C	?
(Ioannou et al. 2020)	BFOW	NPV, IRR, LCoE	Stochastic	D	?
(Myhr et al. 2014)	Both	LCoE	Sensitivity	C	2
(Ebenhoch et al. 2015)	Both	LCOE	Sensitivity	C	3
(Gómez et al. 2015)	Both	LCoE	Stochastic	B	?
(Judge et al. 2019)	Both	LCoE, NPV, IRR, PBP	Stochastic	B	?
(Castro-Santos & Diaz Casas 2014)	FOW	LCoE	Deterministic	C	?
(Castro-Santos & Diaz-Casas 2015)	FOW	NPV, LCoE, IRR, DPBP	Stochastic	C	?
(Castro-Santos et al. 2016)	FOW	LCoE	Case Studies	B	1
(Castro-Santos et al. 2018)	FOW	Installation	Case studies	B	NA
(Lerch et al. 2018)	FOW	LCoE	Sensitivity	C	?

ing technologies at larger water depths. However, if the approximated trends are extrapolated, this figure would indicate that FOW would also be more economical than BFOW at lower water depths. A reason for this could be that FOW studies aim to reflect future deployments, where learning effects are assumed. Finally, an increase in costs with distance to shore can be observed, although the data show a large spread. No significant difference can be observed here between BFOW and FOW projects.

4 DISCUSSION

Based on the discussed characteristics of real offshore wind deployments versus technology cost studies, and the properties and sensitivity of the discussed model results, the suitability of the used models to assess economical feasibility of offshore wind projects and technologies is discussed.

4.1 *Are the used models suitable to compare economic feasibility of different technologies?*

Bottom-fixed offshore wind projects, have been assessed in the past, where specific technology and deployment characteristics are known. In floating offshore wind, however, few commercial deployments exist to date and research on new technologies is still ongoing. For this reason, a differentiation should be made in the assessment of mature versus emerging technologies, where commonly in the former real projects are evaluated, whereas in the latter the aim is to compare different concepts to understand their economic potential.

Projects will take place in a given country, under a certain legal and political framework. The system boundary to calculate the costs for a project developer will then be different. For this reason, a system boundary according to the country specific regulations should be used. When comparing technologies, this should be done independently of the country of deployment, since for a given resource, water depth and distance to shore, a technology might be more cost efficient than another. To account for innovations in all possible components directly associated with an offshore wind project, the authors suggest that system boundary C should be used for floating offshore wind cost studies. For this purpose, standard values for components, where no innovations might be introduced in certain projects such as the onshore substation or the export cable, should be provided.

Additionally, standard farm locations, with associated distance to shore, water depth and resource should be defined, for a fair comparison of different technologies and their advantages and disadvantages. Analogously, standard conditions for O&M strategies at those locations should be defined. The definition of standard study cases would also facilitate comparison

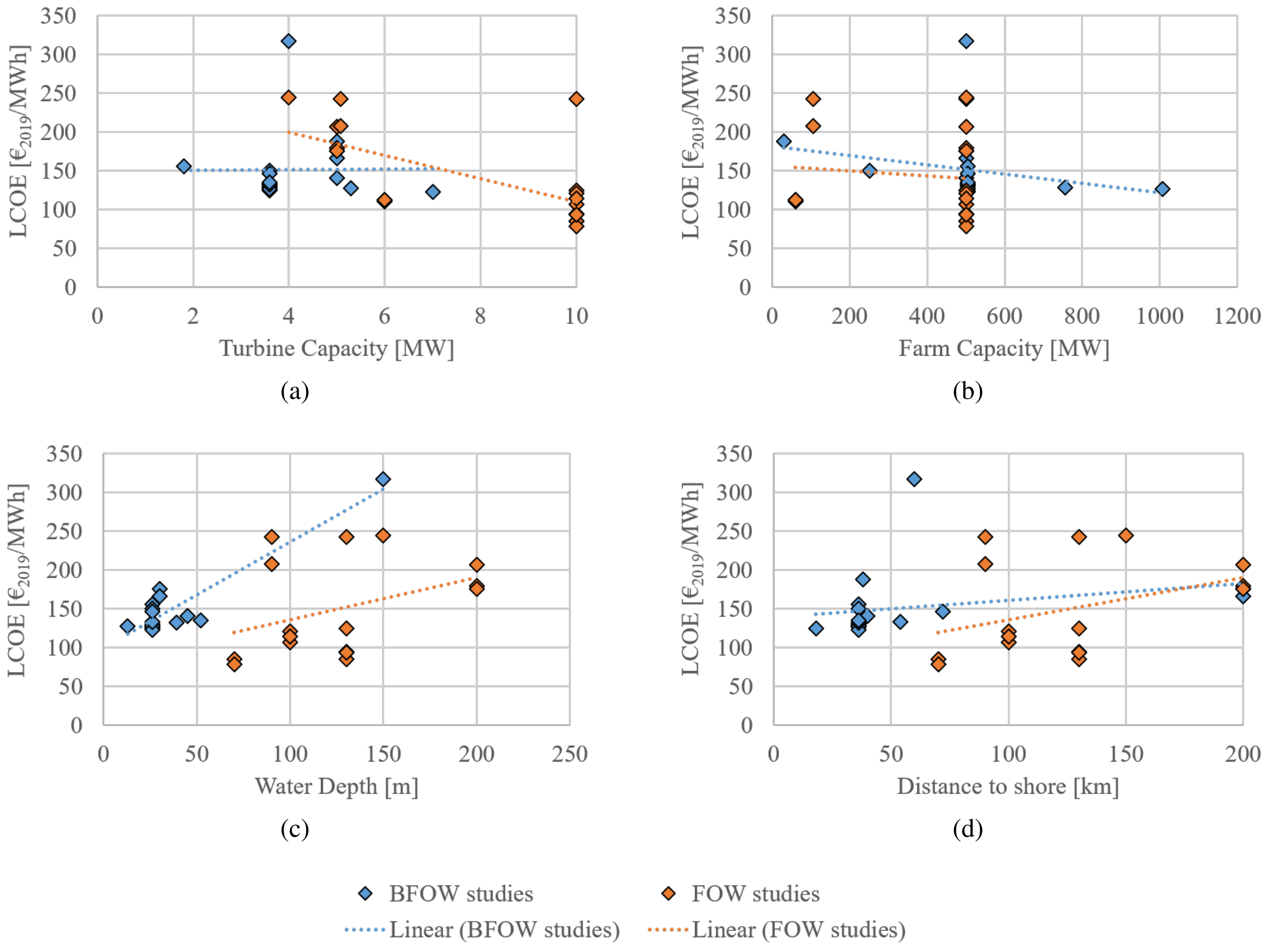

Figure 8: LCOE over parameters (a) Turbine Capacity, (b) Farm Capacity, (c) Water Depth, and (d) Distance to shore. Results from previous LCOE studies for both bottom-fixed (BFOW) and floating offshore wind projects are shown here (Garcia-Teruel & Jeffrey 2020).

of independent cost studies.

To avoid introducing unnecessary uncertainty in technology comparison, the Cost of Energy (CoE) rather than the LCoE should be considered at the current stage of the FOW sector. This is, costs per MWh for the project lifetime should be analysed without applying discounting, since the discount rate has a large impact on LCoE values, but will also vary depending on the project framework. In this way, costs would also be independent of the chosen investment strategy. For the analysis of projects at more advanced stages of technology development, if any type of discounting is applied the investment timeline should be specified. This will be project specific, however, a standard investment timeline should be defined that can be considered at early stages.

In terms of the model implementations, in general stochastic models allow for a more comprehensive representation of the costs associated with an offshore wind project. At project level, lower uncertainty is expected, so that in specific cases a deterministic model can support an initial evaluation. For comparison of different concepts, which will be inherently linked to higher system uncertainties, stochastic models seem particularly suitable to represent the possible costs associated with a technology.

A summary of the recommended approaches for costs studies aiming at project and technology comparison, and therefore at different development stages, is given in Table 2.

Table 2: Approach for project and technology comparison.

Assessment characteristics	Project	Technology
Cost metric	LCOE, IRR, DPBP	COE
Uncertainty	Deterministic/ Stochastic	Stochastic
System boundary	Project specific	C
Deployment & O&M	Project specific	Standard conditions

4.2 *Are there new requirements for these models to be suitable to assess upcoming FOW technologies and projects?*

Parametric relationships were developed for the estimation of components costs. However, given the expected increase in turbine capacity, but also in cable ratings, new parametric relations will be required to estimate the costs of the new components being developed. In the same way, reliability information of these new components will need to be studied and shared, so that the analysis of O&M strategies is suitable for the new systems. Additionally, O&M models need to be expanded to be able to consider new strategies, such as disconnecting and tugging turbines to port for repair.

5 CONCLUSIONS

The offshore wind sector has been rapidly growing in the past years and technologies are changing to allow for electricity production at larger depths further offshore with floating concepts. Deployed and planned bottom-fixed and floating offshore wind projects and costs studies for these technologies were reviewed here. Based on these, the suitability of the existing models was discussed, to analyse the economic feasibility of floating offshore wind technologies.

It is suggested that to allow for technology comparison, rather than project comparison, standard deployment conditions (i.e. farm size, water depths, etc.) should be introduced. A standard choice of system boundaries for this type of analysis should be defined, where we suggest costing up to the onshore substation. Additionally, standard values should be assigned for common components, which might not be included in some innovation studies, such as the turbines, substations or the export cable. To reduce the uncertainty of the calculations, the Cost of Energy rather than other cost metrics should be employed at the current stage of the floating offshore wind sector, given the high sensitivity of discounted costs to the chosen discount rate and investment assumptions, which have no added value in the comparison of emerging technologies.

Setting up standards for the techno-economic assessment of emerging technologies such as floating offshore wind, would facilitate technology comparison, and therefore increase investor confidence. This would support the selection of the more promising technologies to support their development up to commercialisation.

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