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Technological progress observed for fixed-bottom offshore wind in the EU and UK

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ABSTRACT

Offshore wind is a rapidly maturing low-carbon energy technology, for which the technology cost has increased before starting to decline. In literature, the cost development trends of offshore wind and factors responsible were poorly studied. Understanding the factors contributing to the cost developments and their individual impacts are vital for long-term energy policy actions and investment decisions. Therefore, this study combined three different but highly complementary quantitative methodologies to analyze the technological progress observed for fixed-bottom offshore wind in the EU and UK. The technology diffusion curve was first applied to identify the individual development phases of offshore wind technology. Then, the cost developments observed across the identified phases were quantified using experience curve and bottom-up cost modeling methodologies. In the formative phase of the development process, the offshore wind farm's specific capital expenditure had increased from 2 M€/MW in 2000 to 5 M€/MW in 2010, thereby resulting in negative LR. The increase in specific capital expenditure increased the Levelized Cost of Energy (LCoE) from ~110 €/MWh to above 150 €/MWh. After that, during the upscaling and growth phase, the specific capital expenditure declined from 5.4 M€/MW in 2011 to 3.3 M€/MW in 2020. LR of 8–11 % was observed for specific capital expenditure in this phase. In the same phase, the LCoE declined more rapidly than the specific capital expenditure, i.e., from roughly 150 €/MWh in 2011 to 69 €/MWh in 2020, a 54 % decline. This rapid decline observed in recent years was due to the favorable financing conditions, increased capacity factor, and decreased technology costs, including investment and operational costs. Based on the technological progress assessed for offshore wind and its contributing factors in this study, we also estimated the near-term offshore wind LCoE, 55 €/MWh in 2021–2023 and 48 €/MWh in 2024–2026, which aligns well with recent auction outcomes.

Abbreviations

AEP	Annual Energy Production
BOP	Balance-of-plant
BoP	Balance of Plant
CAPEX	Capital Expenditure
CF	Capacity Factor
CTV	Crew Transfer Vessel
DCF	Discounted Cash Flow
DECOM	Decommissioning expenditure
DEVEX	Development Expenditure
EC	Experience Curve
EU	European Union
FID	Financial Investment Decision
FBOW	Fixed-Bottom Offshore Wind

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HICP	Harmonized Index of Consumer Prices
HVAC	High Voltage Alternative Current
HVDC	High Voltage Direct Current
kV	kilovolt
kWh	Kilowatt-hour
LBD	Learning-by-doing
LBS	Learning-by-searching
LCoE	Levelized Cost of Energy
LR	Learning Rate
MFEC	Multi-Factor Experience Curve
MW	Megawatt
NREL	National Renewable Energy Laboratory
O&G	Oil and Gas
OECD	Organization of Economic Co-operation and Development

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OEM	Original Equipment Manufacturer
OPEX	Operational Expenditure
OWF	Offshore Wind Farm
R&D	Research and Development
SFEC	Single-Factor Experience Curve
SGRE	Siemens Gamesa Renewable Energy
SOV	Service Operation Vessel
TP	Transition Piece
WACC	Weighted Average Cost of Capital
Symbols	
Symbols	*Parameters*
C	Specific investment cost in M€ per MW
CE	Levelized Cost of Energy in €/MWh
CQ	Cumulative electricity generated in GWh
CC	Cumulative installed capacity in MW
wd	Water depth in meters
ds	Distance to shore in km
fs	Wind farm size in MW
tp	Turbine rated power in MW
α	Intercept of the regression equation
β	Regression model coefficients
ε	Error term of the regression equation
δ	Share of debt (%)
τ	Tax rate (%)
€	Euro
M€	Million Euro
£	British Pound Sterling

1. Introduction

Offshore wind is a rapidly maturing large-scale low-carbon energy technology and becoming a pivotal component in the future energy mix of countries around the North Sea and Baltic Sea region, i.e., in decarbonizing the energy systems. Targeted subsidies, progress in marine spatial planning (European MSP Platform, 2020), incentives in the form of grid connections & site development has increased the deployments of fixed-bottom offshore wind (FBOW[1]) in the EU and UK (Fig. 1) and unlocked cost reductions (Jansen et al., 2020). FBOW refers to the variant of offshore wind where substructures are embedded in to the seabed and are rigid in its motion. Due to its rapid cost decline observed in recent years, FBOW is currently gaining traction in China and several other markets, which include the US, Korea, Taiwan, Vietnam, Australia,

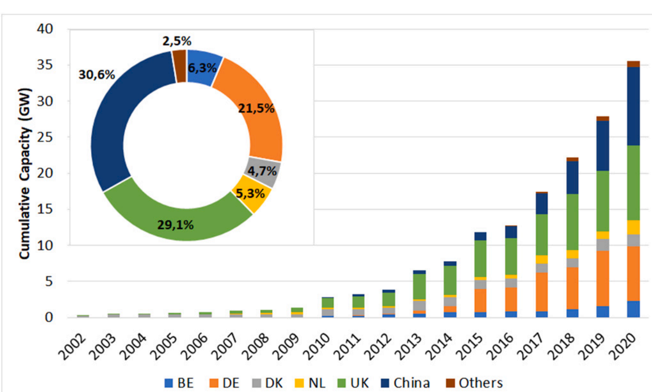


Fig. 1. Global cumulative installed capacity of fixed-bottom offshore wind. The doughnut chart shows the distribution of the total market share by 2020. Data source: (4Coffshore, 2020a, 2020b; GWEC, 2020).

New Zealand, India, and Japan (NREL, 2017; Rodrigues et al., 2015). This momentum is expected to increase technology's market growth and facilitate further cost reduction opportunities.

Next to the EU and UK, China is the second-largest offshore wind market in terms of deployment (Fig. 1). However, the offshore wind turbine supply and technology development in China is different from the EU and UK. The EU and UK share project developers, OEMs and supply chain for wind farm components to a larger extent. Turbine supply in China is primarily made through regional Original Equipment Manufacturers (OEMs), and the upscaling of turbines is limited compared to developments observed in the EU and UK. Besides, learning in installation and sourcing of Balance of Plant (BoP) are location-specific due to geographic differences and availability of technology, e.g., installation vessels (GWEC, 2020). These differences suggest that both innovation systems are not comparable. Hence, the technological learning observed for FBOW in the EU and UK alone was analyzed in this study, i.e., market scope.

Offshore wind technology costs, Capital Expenditure (CAPEX) and Levelized Cost of Energy (LCoE), had steadily increased in the EU and UK until early 2010. After that, a sharp decline was observed (Voormolen et al., 2016). Subsidies awarded and strike prices/tariffs[2] achieved in offshore wind auctions showed a similar development trend, with recent auction outcomes indicating offshore wind technology as soon-to-be fully subsidy-free (Jansen et al., 2020); refer to Appendix A. Below, we review the past literature that has forecasted the cost developments of offshore wind and their drivers to identify the research gaps. Then, we present the objective of this study.

Earlier studies that had analyzed offshore wind's technological progress presented optimistic forecasts from the beginning of its development (from 1990) and had not foreseen cost increases during the early development periods. Chapman and Gross (Gross and Chapman, 2001) assumed 15–20 % LR to derive offshore wind CAPEX based on high-cost onshore wind sites. Junginger et al. (2004) stated that offshore wind farms (OWFs) investment costs might decline by about 25–39 % by 2020, from 1.6 M€$_{2001}$/MW (M€ refers to Million Euros and the subscript refers to the base year of the cost). Santhakumar et al. (2021) provided a detailed review of offshore wind cost developments from literature and concluded that studies have commonly followed aggregated applications of experience curve approach by assuming LRs from analogous technologies. Such applications have failed to consider the risks and factors that were specific to offshore wind technology, resulting in over-optimistic cost outlooks. The study also suggested that multi-factor experience curve models or similar quantitative methodologies that can explicitly consider the raw material costs, site characteristics, scale effects and soft costs, should be applied to better understand offshore wind's technological progress. Schwanitz and Wierling (2016) performed a similar analysis and concluded that over-optimistic assumptions systematically flaw scenario projections for investment costs of offshore wind in the literature. In recent years, few empirical analyses provided evidence on the increasing trend observed for the offshore wind technology cost (Isles, 2006; Vieira et al., 2019; Voormolen et al., 2016). Dismukes and Upton (Dismukes and Upton, 2015), for example, analyzed the presence of economies of scale and learning effects for offshore wind projects installed in the EU and UK until 2012 and concluded that the technology does not exhibit economies of scale, nor any industry-wide and country-specific learning effects.

To reason the increasing technology costs until early 2010, studies had commonly attributed factors including changes in raw material costs, supply-chain constraints (Murphy, 2017), projects being installed in deeper waters and farther from the shore over time (see Fig. 2) (Prässler and Schaechtele, 2012), installation delays (Kostka and

[1] In this article, the terms "FBOW" and "Offshore Wind" are used interchangeably and always refers to fixed-bottom offshore wind technology unless otherwise the variant is specifically stated.

[2] Strike price (or tariff) is the €/MWh amount paid to an offshore wind generator for a fixed length of time (e.g., 15 years in UK) or fixed amount of energy generation (or load hours , e.g., Denmark).

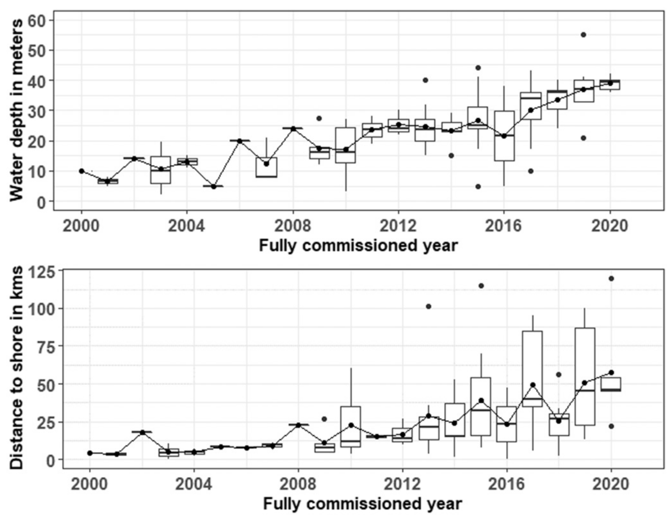


Fig. 2. The water depth and distance to shore of offshore wind projects in the EU and UK as a function of their commissioning year. The solid line in the figure shows the average water depth and distance to shore of offshore wind projects. Data source: (4Coffshore, 2020a, 2020b; Think RCG, 2020).

Anzinger, 2015), and high cost of capital (3E, 2013; Voormolen et al., 2016). Similarly, the rapid cost decline after early 2010 had been attributed to increased economies-of-scale effect[3] (see Table 1), improvements in capacity factor (International Renewable Energy Agency, 2020), and low cost of capital (Credit Suisse, 2018). However, these factors' impacts have not been quantified separately from the overall cost developments. A clear understanding of the historical development of offshore wind technology costs, including periods of cost increases, contributing factors, and their impacts on final costs, is vital in assisting further cost reductions for the technology. It can also help avoid early cost increases in emerging markets. For example, revenue risks are higher for technologies in their early development stage, resulting in a higher cost of capital. Implementing subsidies that provide certainty in project revenue or quicker return on investment could drastically reduce the financing cost of early deployments, thereby reducing the LCoE, e.g., the accelerated FiT model in Germany under EEG 2014 benefit the developer in paying back debt earlier (IEA-RETD, 2017). In addition, China's early decision to implement competitive auctions without a fully-developed supply chain and market players made it economically unviable for developers to progress the projects. The projects only progressed after the government introduced higher tariffs (IEA-RETD, 2017). Hence, understanding these developments and quantifying their impacts on cost developments are vital for effectively stimulating technological learning.

Moreover, the technological change of energy technologies is a complex evolutionary process, which involves multiple stages and diverse characteristics contributing to the cost developments (Grübler et al., 1999). Dedecca et al. (2016), for example, described the development process of offshore wind and explored market strategies available for private players by segmenting the overall progress into three phases, innovation, market adoption, and market stabilization. Such theoretical understanding can inform quantitative studies about technology diffusion, contributing learning mechanisms, and market barriers. Possibly, such knowledge could also have foreseen the early cost increases for offshore wind – a large-scale technology (Rubin et al., 2007). Despite these benefits, theoretical understanding of the technological change process was often overlooked in quantitative studies (Junginger and Louwen, 2020; Meng et al., 2021). The implications of not considering theoretical understanding of technological change process in quantitative assessments are evident, i.e., over-optimistic offshore wind forecasts discussed above. A methodological improvement, differing from past applications, is necessary to disaggregate offshore wind's developments in a manner where the design factors of the technology, both technical and economic, can be considered. Resolving these critical shortcomings in the literature, i.e., detailing the offshore wind's cost developments and contributing factors through the application of an improved methodological framework, forms the main objective of this study.

In summary, this article aims to:

- Distinguish the development phases of offshore wind's technological change process and discuss the development pattern and learning mechanisms involved
- Estimate the learning effects observed for offshore wind CAPEX and LCOE, and also quantify the impact of individual cost drivers separately

2. Theory: offshore wind technological change process

Research, Development, Demonstration, and Deployment (RDD&D) paradigm is commonly used to explain the energy technology development process (Gallagher et al., 2012; Kerr et al., 2021). In literature, few studies have applied such models to describe the development and diffusion of offshore wind. Dedecca et al. (2016) described the offshore wind development in three stages and explored market strategies available for private wind farm developers. van der Loos et al. (2020) described the technological trajectory of offshore wind and argued that institutional constructs had led offshore wind to rapidly adopt a dominant design that emerged early in the technology development. The study also stated that radical experimentations in the market, which are generally expected at the beginning of technology development, only began to emerge after 20 years of technology diffusion. While these studies described the technological trajectory of offshore wind and interaction between different innovation system stakeholders well, the discussion and quantification on factors involved in cost increase or reduction were limited. Besides, offshore wind is also a compound energy system where several components make up the technology. Each component, influenced by multitude of design factors, hold a significant share in the total cost (Smart et al., 2016). To detail the development process and understand the learning mechanisms involved, we have followed a five-stage energy technology development process described by (Santhakumar et al., 2021); see Fig. 3. The five phases are prototype & demonstration, initial build-up, upscaling, growth, and maturity, which are further detailed below.

An innovative technology emerges in the market as a product of fundamental and applied research involving laboratory testing, prototype projects. In most cases, the new technology is also a product of existing technology components combined in innovative ways, referred to as combinatorial evolution (Gallagher et al., 2012). As a first step towards commercialization (prototype and demonstration phase), technology undergoes an initial experimentation phase, where radical designs and solutions are tested to prove technology viability; resulting in a dominant design (Geels et al., 2017). Second (initial build-up phase), commercial deployments are initiated once a series of successful demonstrations is completed. These early-stage deployments provide learning opportunities for technology cost reduction, supply chain development, and initiate market creation. At this stage, the new technology starts competing with market-established solutions, although incentives are often necessary to compensate for the price gap. Third (upscaling phase), the upscaling of the technology design begins, either unit- or industry-scaling, or both, depending on the technology-specific

[3] Economies-of-scale can be categorized into unit-scale and manufacturing scale economies. The unit scale economies refer to cost reduction through upscaling of a product size or capacity. Manufacturing scale economies refer to cost reduction through mass production of standardized products, allowing for distribution of fixed and overhead costs over increased number of outputs.

Table 1
Upscaling observed for offshore wind turbine rated power and wind farm size. The summary includes the fixed-bottom offshore wind projects installed in DE, DK, UK, NL, BE. Data source: (4Coffshore, 2020a, 2020b; Tuya and Nilo, 2019).

	Year (refers to fully commissioned year)				
	Before 2000	2000–2005	2006–2010	2011–2015	2016–2020
Number of windfarms	4	8	16	30	32
Average farm size (MW)	7.18	76.97	126.96	266.69	408.84
Max farm size (MW)	16.8	165.6	300.0	630.0	1218.0
Average turbine rated power (MW)	0.51	2.23	3.29	3.98	6.51
Max turbine rated power (MW)	0.60	3.00	5.075	6.15	9.50

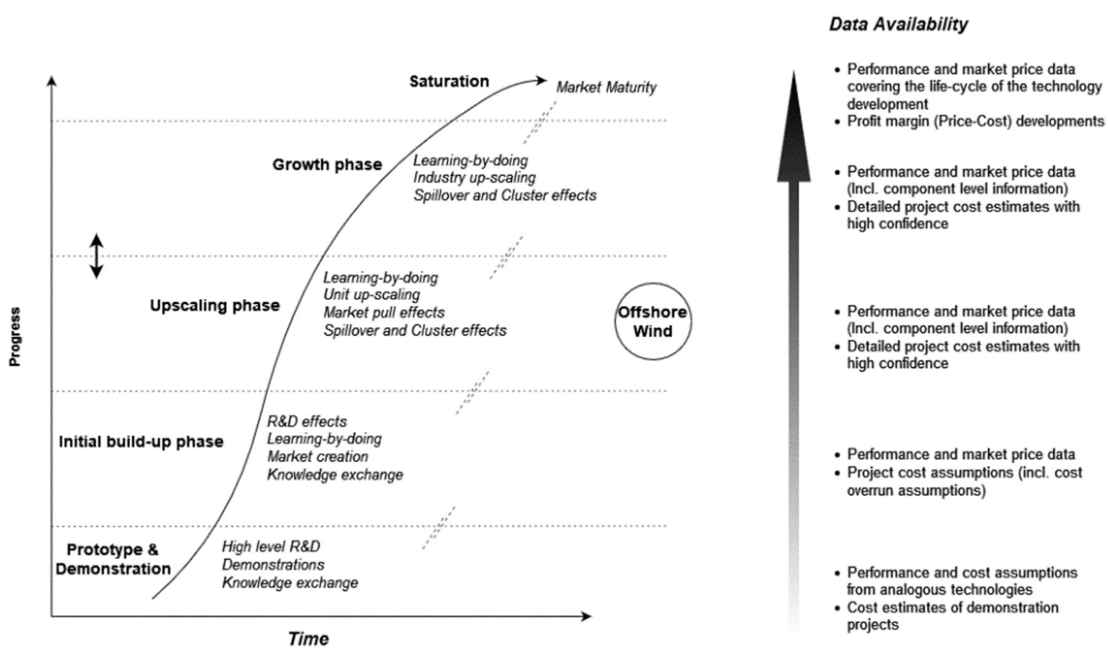


Fig. 3. Illustration of energy technology development process involving five stages and diverse characteristics. Source: Modified from (Santhakumar et al., 2021).

characteristics (Wilson, 2012, 2009). Later (growth phase), widespread deployments in the market continue to yield incremental improvements as the new technology becomes competitive. Finally (maturity phase), the development potential of technology saturates or is commonly replaced by new, improved technology (Grübler et al., 1999). In this sequential process, the role of distinct learning mechanisms like learning-by-doing, learning-by-searching, and unit-scale economies, and their impacts change as technology develops from emerging to well-established status. For simplification, the prototype and demonstration and initial build-up phases are referred to as the formative phase of the technology, as considered by (Wilson, 2012).

3. Methodology

This study combined three methodologies to identify the development phases discussed above and quantify the technological progress observed for offshore wind. They are,

1) *Technology diffusion curve* is used to identify the development phases of offshore wind
2) *Experience curve approach* is used to quantify the impact of different learning mechanisms on cost development
3) *Bottom-up engineering cost modeling* is used to identify cost reduction factors at component level of the technology

First, technology diffusion curves (logistic growth curves) were used to identify the extent and uptake of different development phases of offshore wind (MacGillivray et al., 2015). The logistic growth curve describes the changes in the growth of a particular variable over time, i.e., the growth process follows an *s-shaped* profile where the initial growth rate is exponential from its lower bound, but after reaching a point of inflection, the growth rate decelerates as the maximum upper bound is approached (Höök et al., 2011). By fitting the logistic growth curve on unit-upscaling and cumulative capacity parameters of offshore wind, the duration of the formative phase, the uptake of the upscaling and growth phase were identified. The following steps involves quantifying the cost developments across these phases and identifying the factors responsible for them.

Second, the experience curve approach, one of the widely adopted methodologies to anticipate technology cost developments (Nagy et al., 2013), was applied to quantify the learning effects observed for offshore wind CAPEX and LCoE. Compared to CAPEX, LCoE provides a holistic picture of technology developments in the market by considering the CAPEX, Operational Expenditures (OPEX), cost of capital, project lifetime, Decommissioning Expenditures (DECOM), and all other expenditures essential for generating energy. It is also a critical metric that significantly impacts investment and policy actions and compares different technologies' competitiveness in the market; however, it neglects system-level values (IEA, 2020). The experience curve models used to quantify their Learning Rates (LR) are discussed here. The conventional Single-Factor Experience Curve (SFEC) model quantifies the overall cost development in a single aggregated parameter, LR (Junginger and Louwen, 2020). Multi-Factor Experience Curve (MFEC) models were also used to separate the impacts of site characteristics and economies-of-scale from the overall cost developments; refer to Appendix B. The experience curve models are shown in Table 2 (Model 1 to

Table 2
Experience curve models for analyzing specific CAPEX and LCoE developments.

Model no	Model description (refer to symbols section for details)
For Specific CAPEX	
1	$\ln(C_t) = \ln \alpha + \beta_0 \ln (CC_t) + \varepsilon$
2	$\ln(C_t) = \ln \alpha + \beta_0 \ln (CC_t) + \beta_1 \ln (wd) + \varepsilon$
3	$\ln(C_t) = \ln \alpha + \beta_0 \ln (CC_t) + \beta_1 \ln (wd) + \beta_2 \ln (ds) + \varepsilon$
4	$\ln(C_t) = \ln \alpha + \beta_0 \ln (CC_t) + \beta_1 \ln (wd) + \beta_2 \ln (ds) + \beta_3 \ln (fs) + \varepsilon$
5	$\ln(C_t) = \ln \alpha + \beta_0 \ln (CC_t) + \beta_1 \ln (wd) + \beta_2 \ln (ds) + \beta_3 \ln (fs) + \beta_4 \ln (tp) + \varepsilon$
For Levelized Cost of Energy (LCOE)	
6	$\ln(CE_t) = \ln \alpha + \beta_0 \ln (CQ_t) + \varepsilon$

5). Model 1 represents the conventional SFEC model with cumulative installed capacity alone as an explanatory variable, i.e., an aggregate proxy for overall experience gain. Then, subsequently, water depth (model 2) and distance to shore (model 3) were added to separate site-characteristic effects from specific CAPEX developments. Later, wind farm size (model 4) and turbine rated power (Model 5) factors were added to the experience curve model equations to separate the scale effects from the specific CAPEX developments. The addition of these factors in the experience curve equation was expected to address the omitted variable bias problem in SFEC (Söderholm and Sundqvist, 2007) and quantify their influences separately.

The LCoE of offshore wind projects was estimated as shown in Eq. (1). The cumulative electricity generated until 2020 from offshore wind was used as an experience variable to estimate the LR observed for LCoE, as shown in Model 6 of Table 2.

$$LCoE = \frac{CAPEX + \left(\sum_{t=1}^{n} \frac{OPEX}{(1+i)^t}\right) + \frac{DECOM}{(1+i)^{t+1}}}{\sum_{t=1}^{n} \frac{AEP}{(1+i)^t}} \tag{1}$$

The LR from the experience curve equations was estimated as shown in Eq. (2).

$$LR = 1 - 2^{-\beta_0} \tag{2}$$

The experience curve model outcomes describe the influence of individual learning mechanisms on overall technology cost developments. However, the insights on technology cost breakdown or developments implemented at the component level of the technology and their impact on technology cost are absent; for example, how much do water depth variations influence the CAPEX and which wind farm component designs are majorly influenced by these variations?. Such insights are essential in analyzing the bottlenecks for technology deployments and foreseeing technology prospects with confidence. Hence, as the third step, a detailed cost breakdown of offshore wind technology was derived over periodic intervals by applying a bottom-up cost modeling approach. The cost model is described in Fig. 4, which comprehensively illustrates the cost components of the technology investment cost and the factors impacting the LCoE. Moreover, the cost modeling approach in this study did not consider market effects in its component-level cost assumptions, i.e., excludes profit assumptions resulting from market concentration and demand-supply constraints. The benefit is that the model outcomes helped identify the cost impact of technological developments and site characteristics alone, which was the objective.

4. Data and assumptions

Empirical information relevant to OWF's installed between 1990 and 2020 in the core markets (DK, NL, BE, DE, UK), comprising 88 fully commissioned (in operation) and 2 decommissioned OWFs, were used in this study. This information includes CAPEX of wind farms and elements necessary to estimate their LCoE. The data collection criteria, methods, sources, and limitations are discussed below.

4.1. Offshore wind CAPEX data

Within the core markets of offshore wind, different countries have followed different site development and grid connection approaches (Flin, 2019; IEA-RETD, 2017), i.e., whether the project developer or the government bears the responsibilities of those activities. These differences among the countries eventually have implications on the final CAPEX incurred by the developer. Therefore, the CAPEX's scope was defined first, and then the unaccounted costs were corrected accordingly to create a like-by-like comparison between projects. In this study, the CAPEX refers to all the expenditure incurred until the onshore grid connection point. CAPEX = site development cost + OWF development and construction cost + grid connection cost (from OWF to onshore grid connection point).

4.1.1. For UK projects

To realize an investment project (OWF), two types of financial structures exist, corporate finance and project finance (Wind Europe, 2019). In project finance, the investment is made off the balance sheet of project owners, and the project is also turned into a separate business entity called *Special Purpose Vehicle* (SPV). With wind farm projects getting bigger in terms of scale and capital, SPV type of financing is prevalent for offshore wind in recent years (Aldersey-Williams et al., 2019). SPV's are also legally registered companies, and their annual audited accounts are submitted to the appropriate authorities in their countries. For the UK, this is *Companies House* (GOV.UK, 2020), where UK companies' annual accounts are made available to the public free of cost. The CAPEX figures of such wind farms were derived by analyzing their yearly financial statements, i.e., extracting the additions (costs) made for tangible assets each year during the construction period and totaling them. A similar methodology has been discussed in (Aldersey-Williams et al., 2019; Ederer, 2015).

Furthermore, under the Offshore Transmission Operator Regulations (Ofgem, 2018), UK windfarm developers had transferred their transmission assets to Offshore Transmission Owner (OFTO) or were in the process of transferring them. These transactions were also reflected in their audited accounts. However, those costs were not deducted in this study while estimating total CAPEX, per the scope defined above.

4.1.2. For DK, NL, BE, and DE projects

For DK, NL, BE, and DE, the offshore wind investment costs were taken from a past study (Tuya and Nilo, 2019). The CAPEX estimates of these wind farms were also cross-referenced with estimates mentioned in publicly available peer-reviewed articles and reports, including (Dismukes and Upton, 2015; Kaiser and Snyder, 2010). The basic wind farm characteristics were taken from publicly available online resources, e.g., databases, reports, and articles (4Coffshore, 2020a, 2020b; Think RCG, 2020).

4.1.3. Inflation and currency exchange

The reported CAPEX from the indicated sources were assumed to be in nominal terms in the year when the Financial Investment Decision (FID) was made. Also, several projects were denominated in different currencies other than the €. First, the inflation effects were adjusted by converting the CAPEX into 2015 real terms using the respective countries' Harmonized Index of Consumer Prices (HICP) index (Eurostat, 2020). The yearly average exchange rates (2015) between currency pairs were then used to convert the cost into € terms. The same procedure was followed throughout the analysis to normalize cost. Hence, all the cost information presented in this article is expressed in 2015 € real terms unless otherwise stated.

The exchange rate between € and GBP (£) is highly volatile since 2008 due to several factors, including the European sovereign debt crisis and UK's decision to leave the EU after the Brexit vote in 2016 (Bloomberg, 2016). In this study, 1 € = 0.83 £ was assumed as an average conversion rate for the chosen base year (2015) to normalize the

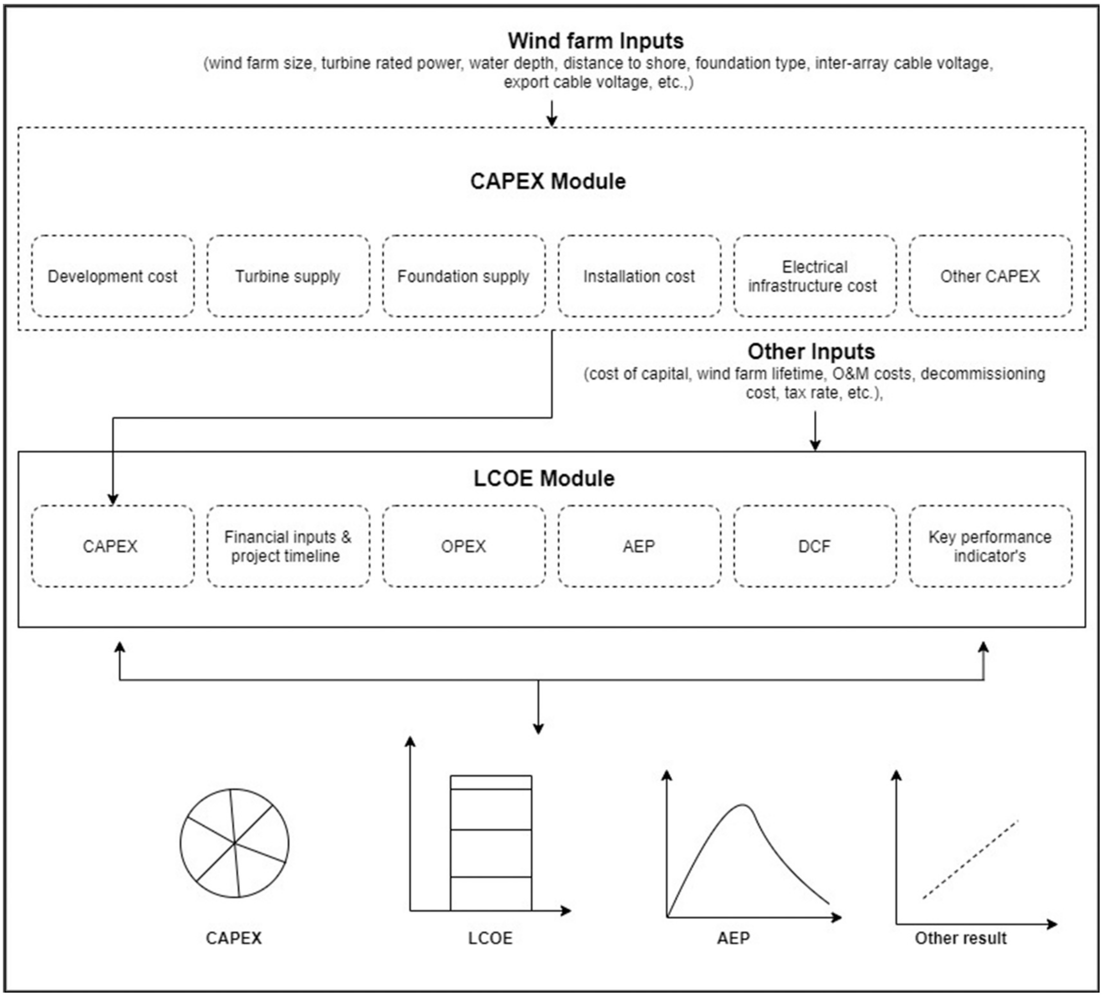


Fig. 4. Bottom-up cost modeling framework to estimate CAPEX and LCOE of offshore wind technology. The model specifications and assumptions are detailed further in Appendix C and D.

OWF cost. To accurately quantify the impact of exchange rate fluctuation on OWF investment cost, detailed tracking of material flow between these regions is necessary,[4] which is outside of the scope of this study; refer to an example in (Bolinger and Wiser, 2013).

4.1.4. Corrections for wind farm site development and grid connection

A comparison of regulatory differences in site development and grid connection between countries and corrections made in this study to harmonize the CAPEX data are summarized in Table 3. The resulting harmonized CAPEX for OWF's are shown in Fig. 5 (left).

Large scale energy technologies have commonly observed cost overruns in their formative phase of the development process, which results in increasing cost for technology before it starts to decline (Rubin et al., 2007); refer to Section 5.2.1 for more details. Between 1990 and early 2010, the offshore wind deployments were made through the existing experience and practices of the onshore wind and Oil & Gas (O&G) industry. During this period, cost increases were observed, and also the sector applied its previously gained experience from the O&G sector and started developing technology-specific components and solutions for offshore wind. After 2010, these technology-specific components and solutions were deployed in the wind farms. Besides, after 2010, rapid cost decline was also observed. The CAPEX data was separated into two sets, before and after 2010 (or before and after 2.5 GW of cumulative capacity across the EU and UK deployments), to observed the technological developments and capture the drivers behind cost increase and cost reduction separately, see Fig. 5 (right). However, to understand the impact of changing this assumption, we have also performed a sensitivity analysis (refer to Section 5.3.1).

Moreover, in literature, studies had also referred to this development as "learning threshold[5]", where the unit technology cost starts to decline after early cost overruns, commonly resulting from construction delays and market concentration (Colpier and Cornland, 2002; Rubin et al., 2007).

The dataset utilized in this study, including the CAPEX described above, is available in (Santhakumar, 2020a).

[4] Noonan and Smart (Noonan and Smart, 2017) estimated the UK content of OWF projects deployed in UK in 2016 as 32 %. The share is expected to be smaller in previous years, which signals the exposure of UK offshore wind project prices towards the exchange rate fluctuations.

[5] IEA defines similar milestone as *"materiality"*, a threshold beyond which the technology is considered to have a sufficient market share for its impact on supply chains to be material (1 % of national stock in a given sector). Beyond this threshold, the technologies are considered to be sufficiently mature in their design, production and deployments.

Table 3
Comparing national regulations on wind farm site developments and offshore transmission connections, and necessary data corrections are outlined.

Country	Regulation on offshore transmission	Regulation on wind farm site development	CAPEX data corrections[a]
UK	In the UK, the offshore wind project developer builds transmission assets and grid connections. Subsequently, the transmission assets are tendered by a regulatory body (Ofgem) to an Offshore Transmission Owner (OFTO), i.e., granting licenses to operate the offshore transmission asset (Ofgem, 2018). This model ensures that generation and transmission assets have separate ownership once the projects are operational. OFTO could also undertake the responsibility for developing and constructing transmission assets, but wind farm developers have not favored this option to date. *Exception:* Wind farms with transmission connections ≤132 kV do not come under the OFTO regime (KPMG, 2014) and must pay an additional tariff for distribution networks (OWPB, 2016). In this case, wind farm developers will have the responsibility of building and operating the transmission assets.	The Crown Estate identifies zones for OWF development and lease sites to the developers (The Crown Estate, 2020). The developer then undertakes site investigation, consenting and permits, acquiring grid permits, and designing and constructing wind farms.	For transmission: *No changes* For site development: *No changes*
NL	TenneT, a state-designated Transmission System Operator (TSO), is responsible for connecting all OWF to the onshore grid (Tennet, 2020). OWFs, for which the developer has built the transmission links (totaling 957 MW), include Egmond aan Zee, Princes Amalia, Eneco Luchterduinen, Gemini (Flin, 2019).	The government undertakes site identification, surveys, consents, and grid permitting before the auction. The developer (winning bidder) is awarded all necessary permits to progress with wind farm construction and a subsidy contract (SDE+).	For transmission: *Include transmission costs* For site development: *Include site development costs*
DK	Energinet (Danish TSO) is responsible for connecting offshore wind parks into the onshore grid. For nearshore wind parks (from energy agreement 2012 or in the open-door model), the developer is responsible for developing and constructing transmission assets (Danish Energy Agency, 2017). In the recent tender, Denmark has passed on constructing transmission assets to the project developer (Energistyrelsen, 2019); for example, Thor wind farm tender.	Government/ designated stakeholders undertake site identification, preliminary surveys, consents, and grid permitting before the auction. The developer (winning bidder) is awarded all necessary permits to progress with wind farm construction and a subsidy contract. However, the winning bidder refunds preliminary site investigation costs (Danish Energy Agency, 2017).	For transmission: *Include transmission costs* For site development: *No changes*
BE	Till 2018, the developer was responsible for building the transmission link to the onshore grid. This model was the case for the current 1.5 GW of operational capacity. One-third of the transmission cable costs will be financed by TSO (Elia) as an additional support measure (CMS, 2017). Currently, the regulation is changing, where the TSO will be responsible for connecting OWFs to the onshore grid (GWEC, 2020).	The Marine Areas Development plan identifies the zone for the development and operation of wind farms. Developers need to acquire domain concession, marine protection permits, and cable permits to construct and operate wind farms (CMS, 2017). The subsidies are discussed with the ministry after acquiring domain concession. The process is currently moving towards a more centralized approach (Schoors and Bourgeois, 2019), similar to NL and DK.	For transmission: *No changes* For site development: *No changes*
DE	The TSO's, Tennet, Amprion in the North Sea, and 50 Hertz in the Baltic Sea are responsible for constructing and operating transmission assets connecting OWFs. Nearshore wind farms are provided with High Voltage Alternative Current (HVAC) connections, and far offshore farms are provided with High Voltage Direct Current (HVDC) connections. Before 2013, the “Reactive TSO” model was followed, where the connection was legally guaranteed. However, after 2013, “proactive TSO” is being followed, where the offshore grid development plan (O-NEP) is drawn up by TSO and updated yearly. The current process is considered objective, transparent,	In EEG 2014, the Federal Maritime and Hydrographic Agency of Germany (BSH) identifies zones for prospective developers. Then, the developer undertakes site selection, investigation, and steps to acquire consents & permits. In EEG 2017, the government undertakes site selection according to a nationally coordinated marine spatial plan and offshore grid plan and performs site investigations. The developer (winning bidder) will get a subsidy contract, grid permits, and grid connection guarantee. After that, the developer can apply to gain consent (via BSH).	For transmission: *Include transmission costs* (In the HVDC connection, the OWF developer has to increase the farm output voltage using an HVAC substation, i.e., to match the HVDC converter station's input voltage. Therefore, the wind farm developer bears the HVAC substation cost) For site development: *No changes*

(*continued on next page*)

Table 3 (*continued*)

Country	Regulation on offshore transmission	Regulation on wind farm site development	CAPEX data corrections[a]
	and a non-discriminatory allocation procedure that allows transmission assets to be shared across OWFs (IEA-RETD, 2017).		

[a] The cost assumptions used for the correction of wind farm site development and grid connections are discussed in Appendix E.

energy generation, see Fig. 6 (right).

4.2.2. Operational expenditures (OPEX)

OPEX[6] estimates of OWF varies depending on farm characteristics, Operation & Maintenance (O&M) strategy employed by developers (CTV setup for nearshore or SOV for far-offshore) (Ashish and Asgarpour, 2016; Ørsted A/S, 2018), and whether the O&M infrastructure base is grouped for a set of projects operated by the same developer. As a common practice, turbine contracts for OWFs are supplied with an initial warranty period of several years (typically 5 years). After that, developers decide whether they should extend the O&M contract with the turbine OEM, outsource to a specialized company like marine contractors, or take the O&M activities in-house. OWF developers with deep engineering expertise have commonly chosen to take O&M in-house to minimize costs, although this does lead to higher contingency.

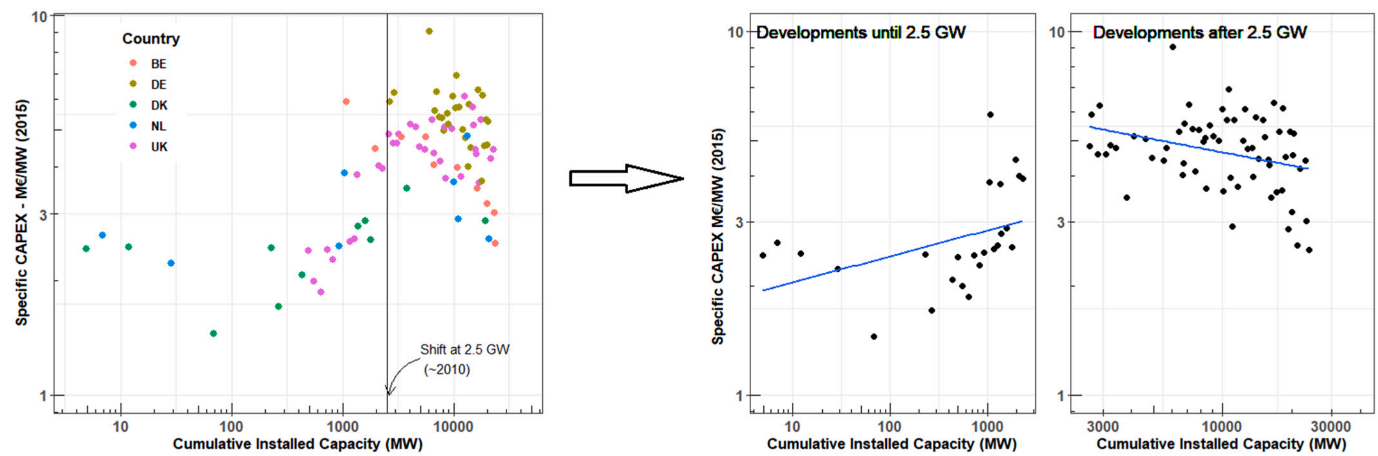


Fig. 5. Developments observed for offshore wind specific CAPEX (left) and the specific CAPEX observed until 2020 are split into two sets to illustrate the shift in technology deployments (right).

4.2. Inputs for LCoE estimation

4.2.1. Annual Energy Production (AEP)

The capacity factor (CF) of OWFs has increased from 25 % in 2001 to roughly 50 % in 2020, Fig. 6 (left). Besides the wind resources available at the site, several technical factors, including developments in hub height, rotor diameter, wind farm operations, and rated power of the turbine, contributed to this development, see Table 4. The effects of increased hub height and rotor diameter on AEP developments were similar to the onshore wind (Wiser et al., 2020). After 2011, the rated power of onshore wind turbines roughly remained unchanged, but larger blades were attached to increase the energy capture (Wiser et al., 2016). In offshore wind, on the other hand, turbine OEMs initially develop a turbine platform with a determined swept area and generator size, and then, the platform's generator capacity was increased. The high Research and Development (R&D) cost involved in developing an offshore wind turbine platform is considered a potential reason for such a trend (Murphy, 2017). Despite this difference between the onshore wind and offshore wind sectors, unit-upscaling effects are expected to be the same (Elia et al., 2020), e.g., reducing the specific material consumption and increasing the AEP.

Moreover, the CF of the wind farm can vary over its lifetime due to year-to-year wind variations (Williams et al., 2017) and developments on the operational side (DNV GL, 2017). Nevertheless, it was assumed in this study that the wind farm's CF values are equal to their lifetime average. This assumption was made to estimate technology's cumulative

Ørsted stated that their OPEX guidance has decreased from 0.100 M€ per MW per year for 3–4 MW turbines to 0.067 M€ per MW per year for 6–8 MW turbines[7] (International Renewable Energy Agency, 2020; Ørsted A/S, 2018). While the specific cost of logistic setup and insurance cost remained the same, the upscaling of turbines in recent years has resulted in cost reductions of about 50 % at the operational level (Ørsted A/S, 2018). Vattenfall also indicated their OPEX guidance of about 0.06 M€ per MW per year for projects beginning operation in 2019, deployed with 6–8 MW turbines (Danish Energy Agency, 2016). By regressing these recent developments observed for OPEX with a proxy index representing the unit-scale economies achieved for O&M operations (Fig. 7), the OPEX estimates were derived for the individual projects installed between 2010 and 2020. The maximum value from the trendline, 0.112 M€ per MW per year, was assumed for projects with turbine capacity <3 MW, i.e., projects installed before 2010.

The proxy index, the number of turbines per MW, describes the impact of installing higher-rated turbines on OWF's life cycle operational costs. In contrast to the O&G, offshore wind technology requires installing and operating many similar structures. Reducing the number of structures in an OWF through unit-upscaling reduces the required

[6] In literature, the terms *OPEX* and *O&M costs* are used interchangeably. In this study, OPEX includes operation and maintenance cost (predictive and corrective), insurance and management costs (i.e., all-in expenditure relevant to operating and maintaining wind farm assets).

[7] 1 EUR = 7.45 DKK is used as a conversion factor. The total lifetime of OWF is assumed to be 25 years, with initial 5 years of O&M undertaken by turbine OEM.

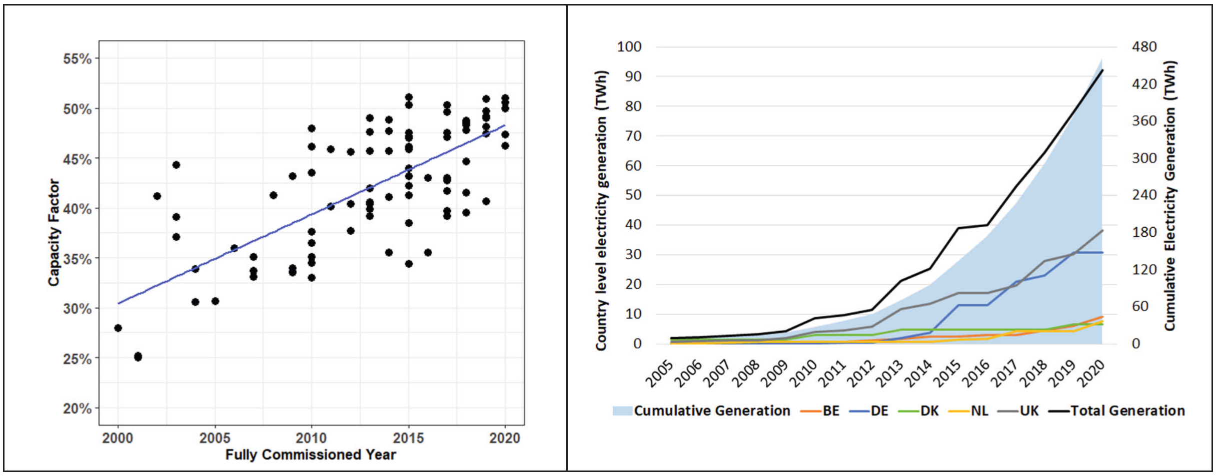


Fig. 6. Developments observed for OWF capacity factor over time (left), and cumulative energy generated by offshore wind technology in the European region (right), Data source: (Santhakumar, 2020a; ZP Smith, 2020).

Table 4
Summary of factors that have contributed to the increase in OWF's AEP.

	Units	2001	2010 (average)	2020 (average)
Hub height	(m)	64	75.07 (+17 %)	110.50 (+73 %)
Rotor diameter	(m)	76	98.50 (+30 %)	161.67 (+113 %)
Turbine rated power	(MW)	2	3.18 (+59 %)	8.05 (+302 %)
Capacity factor	(%)	25	39.98 (+60 %)	49.01 (+96 %)

number of installations, operational and decommissioning activities. This effect decreases the specific investment and operational costs. However, upscaled turbines also require larger jack-up vessels and wider spacing in the wind farm to minimize wake effects, potentially increasing LCoE. The optimal rated power of wind turbines and farm size is currently unknown, and the higher rated power of the turbine does not necessarily result in lower LCoE (Shields et al., 2021).

4.2.3. Weighted Average Cost of Capital (WACC)

The cost of capital is the *"expected rate of return that the market requires to attract funds to a particular investment"* (Pratt, 1999). The cost of capital plays a significant role in the final cost of energy for technologies like offshore wind (Hundleby, 2017). In this study, the cost of capital was estimated as Weighted Average Cost of Capital (WACC), where both debt and equity of the investment are weighted proportionally. The WACC estimate was then used as the discount rate for LCoE calculations.

Before estimating offshore wind WACC, the availability of OWF project-level data and factors influencing the cost of capital were reviewed. Steffen (Steffen, 2019) described three dimensions that can introduce differences in the cost of capital between renewable energy technology (RET) projects. They are,

- the *country* in which the project will be undertaken (macroeconomic factors and policy mechanisms)

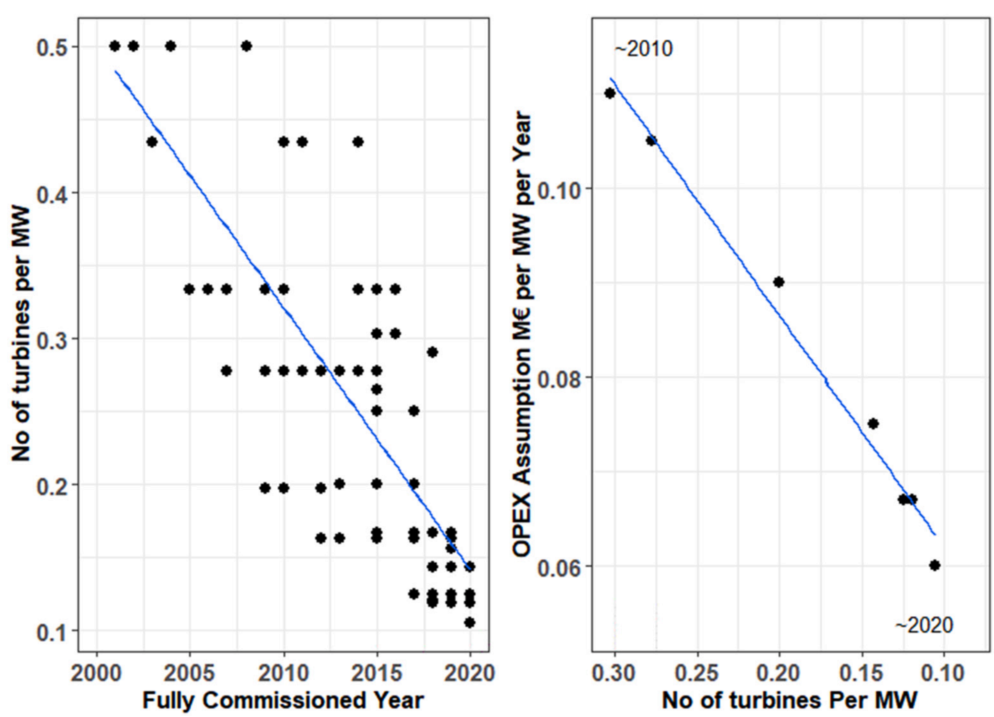


Fig. 7. Proxy index describing the scale economies achieved for O&M operations (left), and OPEX assumptions derived from recent literature (right).

- the *investment risk* that is pertinent to the technology
- the development of risks from both country and technology over *time* (and *with experience)*

Country effects for offshore wind*:* On a macroeconomic level, the expansive monetary policies employed in the EU and UK after the 2008–2009 financial crisis has resulted in low interest rates for banks, see Fig. 8. The decrease in debt premiums for offshore wind technology through experience, combined with a fall in interest rates in the economies, has rapidly reduced the final debt rate for project-financed OWFs in recent years (Green Giraffe, 2019). Other indicators, like political uncertainties, also influence the investment risks perceived for OWF projects. However, those effects were excluded from consideration because all the countries of interest in this study were assumed to be stable economies with long-term commitments made towards decarbonizing their energy systems.

Investment risk for offshore wind*:* Emerging technologies initially pose higher risks for investors due to their nascent status. However, when technology becomes more mature and reliable with experience, investment risks decrease, and competition in the market increases. These dynamics result in lower expected returns.

The following assumptions were used in estimating the WACC for offshore wind over time, Eq. (3). The Euro Area and the UK's central bank policy rates were assumed as a risk-free rate (IMF, 2020)) for debt rate estimation. The debt and equity pricing assumptions were referred from estimates noted in past literature (Green Giraffe, 2019; Murphy, 2017; Steffen, 2019; Wind Europe, 2019)). These assumptions were applied in Eq. (3) to estimate generic pre-tax WACC rates for offshore wind in the EU and UK markets.

$$WACC = \delta^{*}cost\ of\ debt + (1-\delta)^{*}cost\ of\ equity \tag{3}$$

Eq. (3) does not consider any tax implications. The debt portion of the investment generally comes with tax benefits, as interest payments are tax deductibles. Hence, the post-tax WACC was estimated using Eq. (4),

$$WACC_{post-tax} = \delta^{*}cost\ of\ debt^{*}(1-\tau) + (1-\delta)^{*}cost\ of\ equity \tag{4}$$

Besides the macroeconomic factors and technology-specific investment risks, the government's policy and regulatory settings also impact the returns expected by the OWF developers; for example, the nature and duration of the subsidies determine the final risks/benefits of the investment. For offshore wind, such differences between countries were summarized, and their influence on the final WACC was ranked in three levels (High, Medium, and Low), see Table 5. For example, Transmission System Operator (TSO) building offshore grid connections for wind farms have better access to cheaper capital due to their regulated revenue model and their ability to recover the incurred losses by passing charges to its consumers (e.g., Germany). This setting can lower development risk for OWF developers, resulting in reduced WACC for OWF development.

The resulting WACC estimates are shown in Fig. 9 (left) and used as discount rates in estimating the LCoE of OWFs. Moreover, it is essential to remember that the WACC presented in Fig. 9 only represents the high-level country-wise developments. The WACC for individual projects can vary depending on its capital structure and innovations implemented in the wind farm; for example, deployment of innovation in the OWF like new turbine technology, export cable, or new installation strategy can be perceived as added risks by the investors.

Lastly, notable studies like IRENA renewable cost reports and IEA technology outlook assume a fixed discount rate of about 8 % and 7.5 % for OECD countries and acknowledges the bias discussed below. Fixed WACC assumption does not reflect the exogenous developments of monetary policies, endogenous learning on renewable investments (Egli et al., 2018), and the impact of policy settings (IEA, 2018; International Renewable Energy Agency, 2020). The bias in utilizing such an assumption is shown by comparing the LCOE estimates of offshore wind calculated using the WACC estimates derived in this study and IEA's assumption, see Fig. 9 (right). If the bias were insignificant, all the LCoE estimates would be aligned closer to the diagonal line. However, this is not the case, the project's LCoE below the diagonal line was underestimated (in early development years), and data points above the solid line were overestimated (in recent years) (International Renewable Energy Agency, 2020). This observation emphasizes the need to understand renewable energy technology's financing conditions, especially capital-intensive ones.

4.3. *Techno-economic inputs for bottom-up cost modeling*

As mentioned in Section 3, the cost breakdown for OWF CAPEX and LCOE was estimated over periodic intervals to discuss component level cost drivers. The inputs for bottom-up calculations were chosen to represent the average characteristics of the North Sea OWF projects deployed during the same periods (see Table 6). This way, a meaningful comparison with the outcomes of MFEC models can be derived.

5. Results and discussion

5.1. *Identifying the development phases of offshore wind*

This section details the identification of the development phases of offshore wind technology using logistic growth curves. Two growth parameters, turbine rated power and cumulative installed capacity, were analyzed, as shown in Fig. 10.

The formative phase of offshore wind, which occurred between 1990

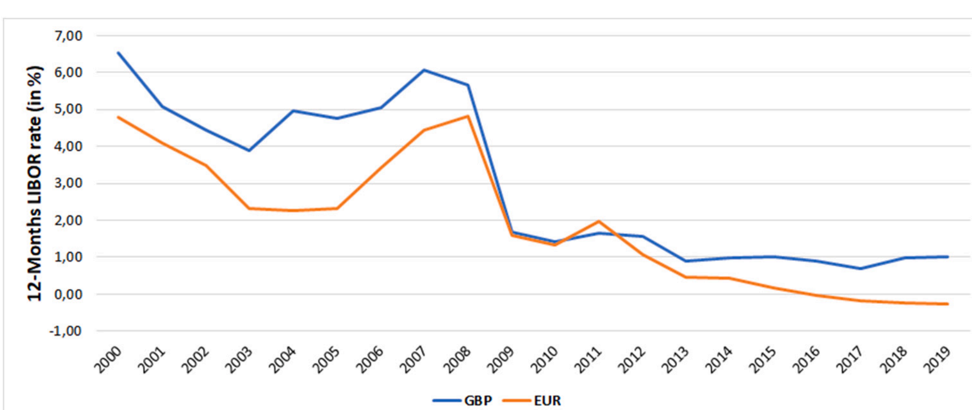


Fig. 8. 12-Month London Interbank Offered Rate (LIBOR) developments. It is seen as an indicator of the health of the financial system and provides an idea of the trajectory of impending policy rates of central banks. Data source: (Federal Reserve Bank of ST. Louis, 2020).

Table 5
Summary of offshore wind support schemes available in different countries. The investment risks experienced by the offshore wind farm developers were ranked in three levels, High, Medium, and Low. The WACC estimated in Eq. (3) was considered for the 'Medium' case, and then the premiums were added or subtracted for the 'High' and 'Low' cases (3E, 2013). 2000 was used as a reference year for deriving investment risks over time.

Country	Subsidy type	Does the government undertake site development?	Transmission incentive	Final benefits/risks to developer	Corporate tax rate (Noonan et al., 2018)	Investment risks for project developer (WACC pre-tax basis) – Ranking
DK	Feed-in tariff (premium over electricity market price)	Yes (refer to Table 3)	Yes	- Predictable revenue for developers - Avoided sunk costs in site development (in the tender scheme) - Reduced construction risks (TSO will connect the windfarms)	22 %	Low
NL	SDE +	Yes	Yes	- Predictable revenue for developers - Avoided sunk costs in site development - Reduced construction risks (TSO will connect the windfarms)	25 %	Low
BE	Green Certificate (Groenestroomcertificaten)	No	Partial (refer to Table 3)	- Exposed to wholesale market price volatility - Fixed minimum purchase price of green certificates (upside for developers) - Limited allocation risk for developers (IEA-RETD, 2017)	34 % (13.5 % deduction on acquisition value)	Medium
DE	*Past:* EEG 2014: Feed-in tariff (premium over electricity market price)	No	Yes	- Predictable revenue for developers - Reduced construction risks from the transmission - Limited allocation risk for developers	29.8 %	Medium
	Present: EEG 2017 Feed-in tariff (premium over electricity market price)	Yes	Yes	- Predictable revenue for developers - Avoided sunk costs in site development - Reduced construction risks (from transmission)	29.8 %	Low
UK	*Past:* • Capital grants scheme • Renewable Obligation Certificates (ROC)	No	No (refer to Table 3)	- Exposed to wholesale market price volatility and ROC price volatility - Limited allocation risks for developers	19 %	High
	Current: Contract for Difference (CfD)	No	No (refer to Table 3)	- Predictable revenue for developers - Budget cap in a tender round increases the allocation risk for developers	19 %	Medium

and early 2010, was distinctive for offshore wind as the industry was built on the onshore wind and O&G industry's existing experience. The onshore wind per se has already experienced a prolonged formative phase between the late 1970s and early 1990s, going through its upscaling phase in the late 1990s (Wilson, 2012). In early commercial deployments, the onshore wind turbine models (<3 MW turbines) adapted to the sea conditions were commonly deployed to test the technology and gain experience. However, the harsh marine conditions have led to faults in the electrical component's operation (Sweet, 2008). These events and interests in further exploiting unit-scale economies prompted the sector to develop turbines suited for sea conditions, i.e., 3+ MW turbine models developed for OWF's, which began in late 2000. This shift in development marked the beginning of the rapid unit-upscaling of offshore wind turbines. The exponential growth trajectory for unit-upscaling is continuing today as there has been no definitive inflection point in the logistic fit. The introduction of 12+ MW turbines in 2020, with planned deployments in 2023–2025 (GE Renewable Energy, 2020; SGRE, 2020), and expectations beyond 15 + MW turbine platforms, confirms the expected growth. Furthermore, considering the recent auction outcomes where fixed-bottom OWF's are seeing near zero-subsidy levels, the pressure to reduce the higher cost of floating foundation variant will be an added determinant for upscaling offshore wind turbines further, next to the technical limits (Maness et al., 2017; Sieros et al., 2012).

The growth in cumulative installed capacity during the formative phase was slow, as the technology's experience in the market was limited and the unit-level capacity of installed turbines and farm capacity was smaller (see Table 1). However, after the beginning of the upscaling phase, the installations of many turbine units with higher rated capacities had yielded rapid growth of the technology in the market. It is also crucial to note that offshore wind technology's upscaling and growth phase is still underway when writing this article.

5.2. Offshore wind CAPEX developments

This section discusses the CAPEX developments observed for

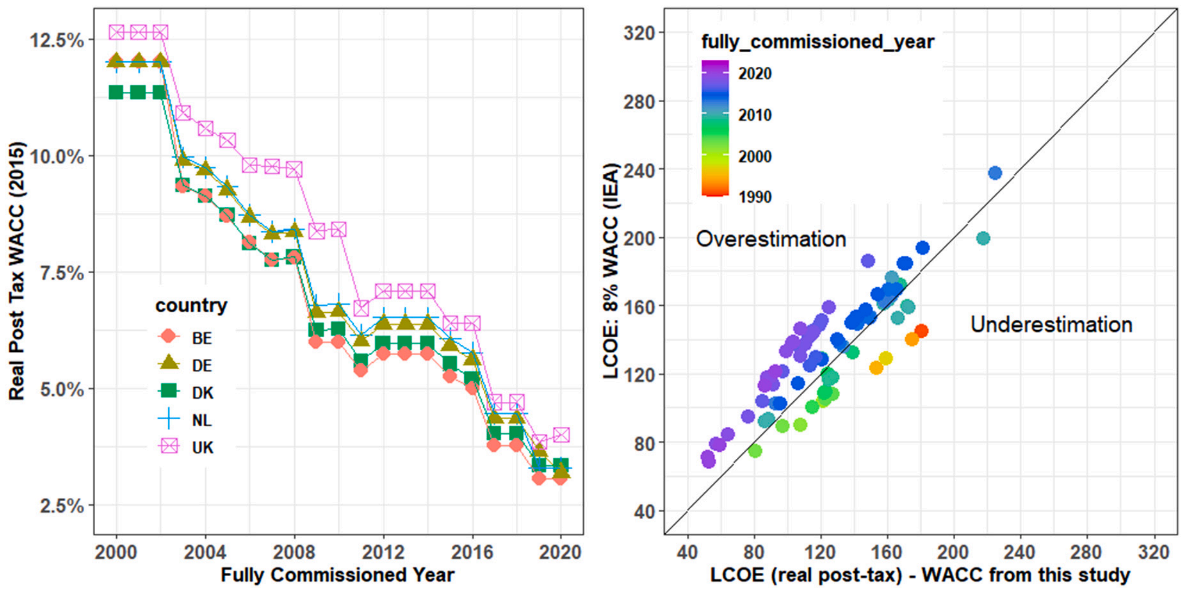


Fig. 9. Real post-tax WACC developments for offshore wind (left), and an illustration of the bias in utilizing fixed WACC assumption (right).

Table 6
Technical and economic inputs for the bottom-up estimations.

Wind farm parameters	Units	Period 1 2000–2005	Period 2 2006–2010	Period 3 2011–2015	Period 4 2016–2020	Period 5[a] 2021–2023	Period 6[a] 2024–2026
Farm size	MW	75.9	126	280.8	455	750	1008
Turbine rated power	MW	2.3	3.6	3.6	7	10	12
No of turbines		33	35	78	64	75,2	84
Water depth	m	10	15	25	35	35	30
Distance to shore	km	10	15	35	50	70	90
Foundation type		Monopile	Monopile	Monopile	Monopile	Monopile	Monopile
Rotor diameter	m	93	107	120	154	193	220
Hub height	m	80	85	90	110	115	120
inter-array cable voltage	kV	33	33	33	66	66	66
Export cable voltage (AC)	kV	33	33	132	220	220	220
Project lifetime[b]	years	25	25	25	25	25	25
OPEX of the wind farm	k. € per MW per year	90	112	112	75	60	58
WACC (real pre-tax)	%	10.85	8.52	7.05	4.80	3.88	3.62
Capacity factor	%	34.65	37.18	42.14	46.69	50.30	53.01

[a] Periods 1 to 4 represent the projects already fully commissioned. Periods 5 and 6 represent the projects expected to be installed.
[b] OWF projects deployed between 1990 and 2010 were expected to have 20 years of the project lifetime. Nevertheless, it is expected that project developers extend the project lifetime to extract value from the deployed project. Hence, 25 years of project life was assumed in all cases.

offshore wind by detailing the outcomes of experience curve analyses and bottom-up cost modeling.

5.2.1. Early cost overruns/increase

Large scale power plant technologies and process systems have commonly observed cost overruns in their formative phase of the development process due to factors including delay in construction, performance shortfalls, market concentration (monopoly/oligopolistic behavior), and other unforeseen complications (Koch, 2012; Kostka and Anzinger, 2015; Rubin et al., 2007; Sovacool et al., 2014). This early cost increase is less pronounced in modular technologies like solar PV module and battery due to its ability in achieving product standardization sooner, involvement of repetitive manufacturing processes resulting manufacturing scale economies and low-market entry barrier (Malhotra and Schmidt, 2020).

As a large-scale energy technology, offshore wind observed increased specific CAPEX in its early development stage; see Fig. 5 (left). The cost increased till 2.5 GW cumulative capacity (or by 2010), and after that, started to decline. Hence, the CAPEX data was separated into two sets, before and after 2.5 GW cumulative capacity across the EU and UK deployments, to illustrate the shift in technology and cost development. It is to be noted that it is possible that certain factors such as market concentration or raw material cost could increase the price of the technology again at a later stage of the technology development process, emphasizing the need to understand the drivers.

The first subset of the CAPEX data (i.e., before 2.5 GW) could have been split again at the 100 MW cumulative capacity to improve the approximation of learning effects in the experience curve models. The projects before 100 MW cumulative capacity were small-scale multi-device prototype and demonstration projects, indicating the influence of onshore wind and O&G industry experience. For example, these projects were installed closer to the shore (<5 km) and in shallow water depths (<5–10 m). These projects also used kW scale onshore wind turbines without major modifications. Nevertheless, these deployments are part of the learning process of the technology, i.e., formative phase of the technology development. Hence, these prototype and demonstration projects were not separated, and all the projects before 2.5 GW cumulative installed capacity were considered projects of the formative phase of offshore wind. In other words, the fit of the experience curve model alone was not the main criteria for the data split. This study acknowledges the limitation and suggests that the learning effects estimated before 2.5 GW cumulative capacity should be regarded as conservative.

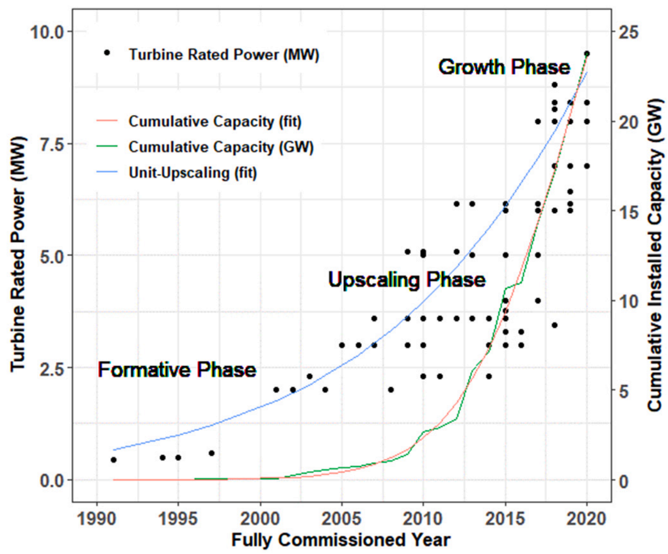


Fig. 10. Offshore wind technology unit and capacity growth fitted using logistic growth curves.

5.2.2. CAPEX developments observed during the formative phase of offshore wind: Experience curve models 1 to 5 (before 2.5 GW capacity or before 2010) in Table 7

Model 1 (SFEC), which utilizes cumulative installed capacity as a proxy factor for overall experience gain, results in −5.0 % LR for offshore wind in its formative phase. The negative LR implies that no learning has occurred. However, when the water depth factor was included (model 2), the LR increased to −0.8 %. This change emphasizes omitted variable bias in SFEC[8] and shows how the omission of critical factors in the experience curve model can undermine the technology's learning. Then, the inclusion of distance to shore (in model 3) increased the LR to −0.56 %. However, the distance to shore parameter was not statistically significant at the chosen levels. Furthermore, in models 4 and 5, the addition of farm size and turbine rated power factors brings multicollinearity issues. Hence, the coefficients should be interpreted with caution.

5.2.3. CAPEX developments observed during the upscaling and growth phase of offshore wind: Experience curve models 1–5 (after 2.5 GW capacity or after 2010) in Table 7

Besides LBD, the wind turbine's unit-upscaling reduces the specific cost of the technology. Simultaneously, this cost reduction effect increases the technology adoption in the market, thereby increasing market growth. Both cost reduction through innovation and the diffusion process should be treated as concurrent effects. Just as technology diffusion is necessary for achieving cost reduction (experience curve theory assumption), cost reduction through innovation is necessary to increase technology diffusion.

The LR observed for offshore wind beyond the 2.5 GW cumulative capacity is of interest here as it excludes the overrepresentation of initial project price increases. Model 1 (SFEC) estimated 8.0 % LR. Similar to the previous case, when water depth (model 2) and distance to shore (model 3) factors were included, the LR increased to 10.6 % and 10.9 %. Model 3, which includes cumulative capacity and the site characteristic factors, was found to show the highest Adjusted R^2 value. The addition of farm size and rated power of wind turbines in models 4 and 5 alter the LR estimates, and their negative coefficients indicate the role of scale effects. However, both factors are not statistically significant at the chosen levels (<10 %) in the models. Hence, the estimates should be interpreted with caution.

Lastly, the technology diffusion curves and the MFEC model outcomes described the development phases and learning effects observed for offshore wind technology. However, it does not provide many details at the technology's component level, nor the available evidence in some cases confirms the effects of underlying cost drivers; for example, the scale effects factors were found to be statistically insignificant in the experience curve models. Hence, in the following section, bottom-up cost modeling outcomes are discussed to break down the cost drivers across individual components of the OWF, primarily complementing the MFEC model outcomes discussed above.

5.2.4. CAPEX developments estimated using bottom-up cost modeling

Fig. 11 shows the specific CAPEX estimated using the bottom-up cost modeling. The technological developments and their cost impacts observed for the turbine and electrical infrastructure supply are discussed below. Refer to Table 8 for a detailed summary of component cost developments.

The turbine supply price of OWF projects is not publicly disclosed due to contract terms between supplier and project developer. Past studies have commonly applied parametric relations to estimate wind turbine costs as a function of its rated power (MW), mainly referred from the onshore wind industry (Ioannou et al., 2018a, 2018b; ODE Limited, 2007; Shafiee et al., 2016). In this study, limited publicly available information was utilized to describe offshore wind turbine price developments, and those estimates are then compared with onshore wind turbine price developments, see Fig. 12. Two key observations should be noted here. First, the price peak observed for the onshore wind turbines between 2007 and 2010 was attributed to three factors, namely, commodity prices (see steel price index in the figure and its influence on turbine price with a minor time lag), labor & civil engineering costs before the 2009 financial crisis, and demand-supply constraints (IRENA, 2018). For example, Vestas turbine's average selling price was 36 % more in 2008 than the 2005 price level. As OWF's had deployed onshore wind turbines during the formative phase, the impacts on the offshore wind industry during 2007–2010 were expected to be the same. Second, after 2010, there was a clear distinction between the offshore wind turbine and onshore wind turbine market prices. Several factors, including cost premium for offshore wind technology, market factors (Section 5.3.2.2), the scale of purchase, and supply contract terms, are expected to influence this difference; refer to Appendix C.

The electrical infrastructure supply cost had increased from 0.23 M€/MW in 2000–2005 to 0.33 M€/MW in 2006–2010. Early OWF's installed closer to shore were directly connected to the onshore grid at the same voltage level as the inter-array grid (33 kV or lower in some cases). When the wind farm size increased in 2006–2010, the number of export cables required for the power transfer also increased, increasing the electrical infrastructure costs. After 2010, as the distance to shore and farm capacity increased further, an offshore substation was constructed to increase the transfer voltage and export the energy generated. Utilizing high voltage export cables with increased current carrying capacity has reduced the export cable requirements and transmission losses, limiting the cost increases for grid connection. However, the installations of wind farms farther from the shore (>60 km) in recent years increased the length of export cable and installation costs (see Table 8).

In summary, bottom-up cost modeling outcomes provided a detailed breakdown into component-level cost drivers of offshore wind. This discussion also emphasized the role the turbine unit-upscaling had played in cost reduction, albeit, the wind turbine rated power was not statistically significant in the MFEC models presented in Table 7. Hence, the number of turbines was included as an additional factor in model 5 of Table 7 to test unit-scale economies on overall cost development. The

[8] The inclusion of water depth as a factor in the experience curve model has also increased the adjusted R^2 value of the model, compared to the SFEC model. The adjusted R^2 indicates the goodness of the statistical model and the value only increases if the new explanatory variable improves the model more than would be expected by chance.

Table 7
Experience curve results for offshore wind specific CAPEX developments.

Dependent variable										
ln (Specific CAPEX - M€/MW (2015 real))										
	Until 2.5 GW of cumulative installed capacity					After 2.5 GW of cumulative installed capacity				
	(1)	(2)	(3)	(4)	(5)	(1)	(2)	(3)	(4)	(5)
ln (cumulative installed capacity MW)	0.071*	0.011	0.008	0.091	0.201+	−0.120*	−0.162**	−0.167***	−0.158**	−0.144*
	(0.033)	(0.046)	(0.048)	(0.080)	(0.114)	(0.047)	(0.047)	(0.046)	(0.048)	(0.060)
ln (water depth in meter)		0.257+	0.234	0.156	0.131		0.175*	0.050	0.067	0.074
		(0.142)	(0.165)	(0.174)	(0.171)		(0.068)	(0.084)	(0.089)	(0.091)
ln (distance to shore in km)			0.017	0.035	0.052			0.083*	0.085*	0.086*
			(0.061)	(0.061)	(0.062)			(0.035)	(0.036)	(0.036)
ln (farm size in MW)				−0.123	−0.144				−0.032	−0.032
				(0.096)	(0.095)				(0.049)	(0.049)
ln (turbine rated power in MW)					−0.295					−0.041
					(0.222)					(0.101)
Constant	0.549*	0.278	0.321	0.482	0.151	2.644***	2.445***	2.637***	2.663***	2.576***
	(0.208)	(0.248)	(0.295)	(0.316)	(0.398)	(0.429)	(0.417)	(0.410)	(0.414)	(0.470)
Observations	25	25	25	25	25	64	64	64	64	64
R^2	0.168	0.276	0.279	0.334	0.390	0.097	0.187	0.256	0.261	0.263
Adjusted R^2	0.132	0.210	0.176	0.201	0.230	0.083	0.160	0.219	0.211	0.200
Residual std. error	0.298 (df = 23)	0.284 (df = 22)	0.290 (df = 21)	0.285 (df = 20)	0.280 (df = 19)	0.231 (df = 62)	0.221 (df = 61)	0.213 (df = 60)	0.214 (df = 59)	0.216 (df = 58)
F statistic	4.640* (df = 1; 23)	4.192* (df = 2; 22)	2.705+ (df = 3; 21)	2.507+ (df = 4; 20)	2.433+ (df = 5; 19)	6.686* (df = 1; 62)	6.999** (df = 2; 61)	6.886*** (df = 3; 60)	5.219** (df = 4; 59)	4.149** (df = 5; 58)
Note:	*+ $p < 0.1$; * $p < 0.05$; ** $p < 0.01$; *** $p < 0.001$*									
LR in SFEC or LBD in MFEC	***−5.0 %***	***−0.8 %***	***−0.6 %***	*−6.5 %*	*−14.9 %*	***8.0 %***	***10.6 %***	***10.9 %***	***10.4 %***	***9.5 %***
Comments				*	*					

Model 4 and 5 in Table 7 were found with multicollinearity issues, which refers to a situation where two or more explanatory variables in a multiple regression model are highly correlated. The variance inflation factor (VIF), which quantifies the severity of multicollinearity in the regression model, is used to gauge this issue (VIF < 5 is assumed as a threshold to identify multicollinearity).

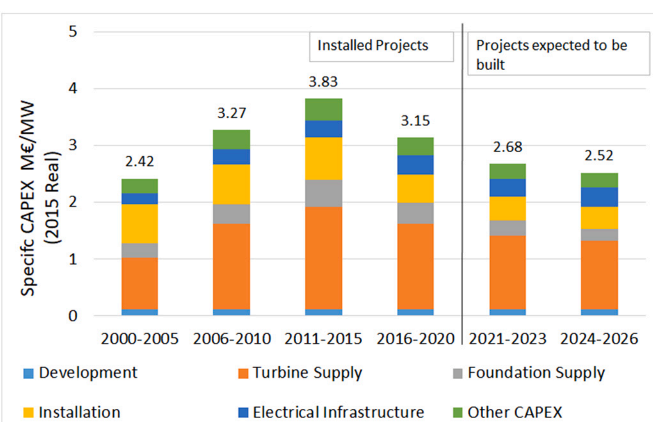


Fig. 11. Offshore wind specific investment cost developments derived using bottom-up cost modeling.

LR outcomes became biased due to the multicollinearity issues.[9] Replacing the rated power of wind turbines with the number of turbines as a factor also did not significantly change the LR outcomes. This observation signals that a trade-off between omitted variable bias and multicollinearity issues is necessary to assess the relative importance of explanatory variables included in the experience curve models and maintain the LR estimate's accuracy (de La Tour et al., 2013).

5.3. *Uncertainty analysis – specific CAPEX*

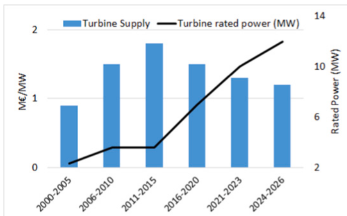
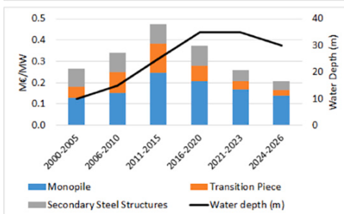
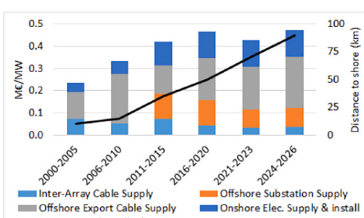
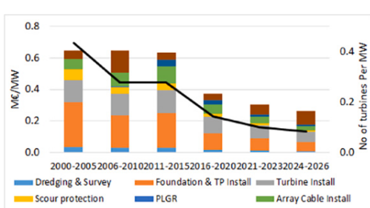
5.3.1. *Uncertainties of the LR outcomes in experience curve analysis*

5.3.1.1. The impact of CAPEX data split choices. Initially, the LRs of CAPEX were estimated before and after 2.5 GW of cumulative capacity (Table 7). The impact of varying this assumption was tested by choosing different cumulative capacity where the data separation could be made, provided the resulting dataset beyond the chosen capacity represents at least three cumulative doublings of the installed capacity (Nemet, 2009; Santhakumar et al., 2021). Model 3 and 5 from Table 2 were then used to estimate the LR at the chosen cumulative capacities for the following reasons. Model 3 was found to show the highest Adjusted R^2 compared to all MFEC considered in this study (Table 7). Model 5 was also considered in this analysis due to its detailed form, which considers both site-characteristic and scale effects factors. When the dataset was not split (i.e., at 0 GW), the early project price increases of OWFs over-represent its effect in the resulting dataset by yielding negative LR; refer to Appendix G. Nevertheless, the LR was found to be highly sensitive to the assumptions made on cumulative capacity where the data separation could be made (Fig. 13).

Furthermore, models 5 LR outcomes at different cumulative capacity

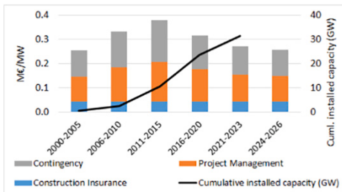
[9] Including turbine rated power, farm size and number of turbines in the same experience curve model has increased the VIF values for each factor >10 (turbine rated capacity =15.49, no of turbines = 36.33, farm size = 39.43), indicating clear case of multicollinearity issue.

Table 8
Summary on component-level technological advancements observed for offshore wind (from bottom-up cost analysis).

<table>
<tr><th>OWF cost components</th><th>Cost development trend</th><th>Summary on cost drivers and technological advancements</th></tr>
<tr><td>Development expenditure (DEVEX)</td><td>The development cost assumption in the bottom-up cost model is fixed at 0.12 M€/MW.</td><td>In specific terms, the development cost can vary widely depending on the project scale (in MW) because fixed costs like the met mast and other legal service costs remain relatively at the same amount for a wind farm project (Valpy et al., 2014). Detailed cost information on individual activities of the development process is limited. Hence, a fixed value is assumed in this study.</td></tr>
<tr><td>Turbine supply</td><td>
</td><td>As early offshore wind projects commonly deployed onshore wind models adapted to sea conditions, their supply costs are expected to correlate with onshore wind turbine cost developments (Fig. 12). Later, turbines specific to the offshore wind industry were introduced to achieve unit-scale economies and improve reliability in its operations. The cost premium for offshore wind turbine technology and market concentration was expected to have played a role in the cost increases observed for OWF projects between late 2000 and 2015. In recent years, the turbine supply cost has fallen due to the upscaling of turbine power and market dilution.
Cost Drivers: unit-scale economies, market concentration</td></tr>
<tr><td>Foundation supply</td><td>
</td><td>*1) Monopile Foundation:* Both water depth (including seabed conditions) and rated power of turbine influences the foundation mass. However, installing offshore wind turbines with higher rated power reduces the specific supply cost of the foundation through unit-scale economies.
2) Transition Piece (TP): In 2010, a design fault in grouting[a] was discovered across many European OWF's. The grout connection was breaking up, and the turbine placement on the monopile foundation was found to have shifted (Golightly, 2016). Before this event, TP[b] mass was increasing, similar to foundation mass. Several solutions, including introducing a taper, shear keys, and bolted connections, were recommended for grouting issues. In recent deployments, bolted connections are the norm, as it provides an effective connection between monopile and TP and reduces the required wall thickness of the TP material at the overlap area. Ørsted stated that the introduction of bolted connections between monopile and TP and further design optimization has resulted in a cost reduction of 15–20 % on foundation supply from ~2015 level (Ørsted A/S, 2018).
3) Secondary Steel Structures: Secondary steel structures include J-tubes and their support, boat landing, ladders, internal and intermediate resting platforms. Similar to foundations and TP, installing upscaled turbines has reduced the specific cost of secondary steel structures.
Cost Drivers: design optimization, unit-scale economies, LBD</td></tr>
<tr><td>Electrical infrastructure</td><td>
</td><td>*1) inter-array cable supply:* The standard voltage for the inter-array grid of OWF's used to be 33 kV. However, when the wind turbine rated power and farm capacity were increased, the limited current carrying capacity of 33 kV cable increased the cabling requirements. To counter these increased cable requirements, 66 kV inter-array voltage has been adopted in recent years. For example, ten 7 MW turbines can be connected in a 66 kV string, compared to 33 kV string, where only five 7 MW turbines can be connected. This advancement introduces cost savings in terms of both cable purchase and installation (Wester, 2015). In the future, a 132 kV inter-array grid is foreseen as the rated power of the wind turbine passes the 10+ MW milestone.
2) Offshore electrical connection (substation + export cable): Refer to Section 5.2.4 for details on cost developments observed for offshore electrical connection.
Cost Drivers: Distance to shore, electrical infrastructure configuration, technological advancements (e.g., high rated cables, substation)</td></tr>
<tr><td>Installation</td><td>
</td><td>Besides LBD, the reduced number of installation operations in a wind farm due to the unit-upscaling of wind turbines is a major cost driver. For example, if 3.6 MW turbines are used, the developer needs to install 125 turbines for a 450 MW wind farm. If 10 MW turbines are used, the developer only needs to install 45 turbines for the same 450 MW wind farm.
LR for foundation and turbine installation was estimated; refer to Appendix C. LR for installation refers to a percentage reduction in installation duration (not costs) for every doubling of foundation units installed.
1) Foundation Installation: This study estimated the LR for foundation installation as 7.92 %. The LR increased to 11.97 % if only monopile foundations were considered.
2) Turbine Installation: This study estimates the LR for turbine installation as −3.24 %. Negative LR implies that the installation duration for turbines increases, thereby increasing the costs. However, when a turbine rated capacity is included as an explanatory factor in the experience curve model, the LR is increased to 10.37 %. Upscaled turbines with bigger rotors and taller towers have introduced complications in the installation process. The complications include increased offshore lifts, limited crane lift span from installation vessels, smaller weather windows. Despite overall negative learning observed for turbine installation, the reduction in the number of turbine positions due to unit-upscaling has resulted in cost reduction, i.e., the net effect.
3) Export Cable Installation: The distance to shore and the number of export cables installed are two primary factors influencing export cable installation costs. In this study, 15 % of the total reference installation duration was assumed as weather downtime for the export cable installation process due to the lack of data availability. Furthermore, the export cables of the North Sea OWF's has suffered a higher failure rate due to incorrect installation procedures (Strang-Moran, 2020), trawling, or anchors being dropped on cables (Warnock et al., 2019), and the presence of a fiber</td></tr>
</table>

(continued on next page)

Table 8 (*continued*)

OWF cost components	Cost development trend	Summary on cost drivers and technological advancements
		optic core in the export cable (Offshore Wind Programme Board, 2017). Such events increased OWF downtime, revenue decline, and premiums of construction insurance (Offshore Wind Programme Board, 2017). *Cost Drivers: LBD, reduction in the number of turbine positions in OWF, technological advancements reducing cable requirements*
Other CAPEX		Refer to Appendix C for assumptions made for "Other CAPEX". Cost reduction is expected for construction insurance and contingencies as the technology gain experience through increased deployments. However, unforeseen incidents like export cable failure could alter this. In recent years, many institutional investors and financial services are willing to invest in the OWFs at the construction phase, indicating the maturity of offshore wind technology (Murphy, 2017; Wind Europe, 2019). *Cost Drivers: Experience gain through LBD, technology track record*

[a] DNV-GL defines grouting in the present context as a "*structural connection between two overlapping steel components, one being larger than the other where the grout is cast in the void between the two to form a load transferring snug fit body between said steel components*" (DNV GL AS, 2016).

[b] The primary purpose of the TP is to facilitate a connection between the foundation and turbine tower. Besides, if the monopile is misaligned during the installation, TP can correct those alignments for turbine installation. Eneco Luchterduinen, a Dutch wind farm, eliminated the transition piece and directly connected all the secondary steel structures to the monopile, yielding cost reductions in foundation supply and installation cost.

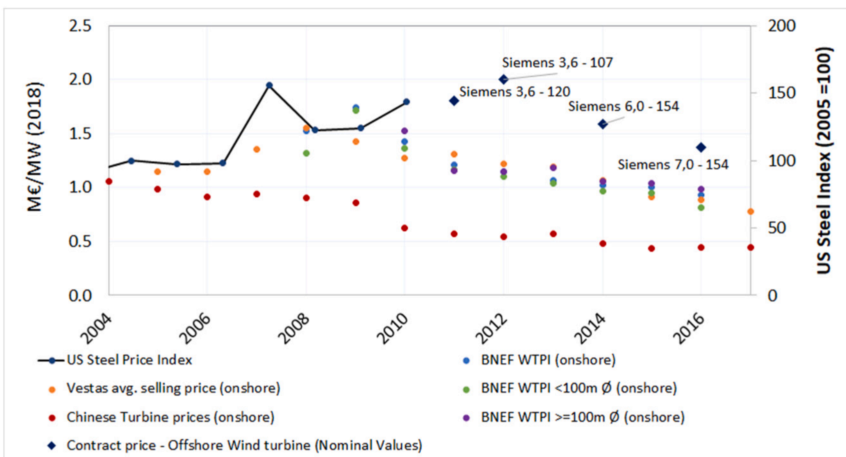


Fig. 12. Comparing the developments of onshore wind turbine and offshore wind turbine market prices. Chinese wind turbine prices do not include tower or transportation costs, as they are included in their engineering procurement and construction contracts. Data source: (IRENA, 2018), and refer to Appendix C.

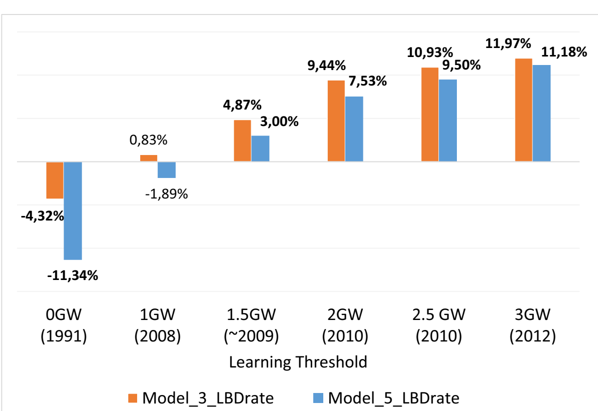


Fig. 13. Impact of CAPEX data split choices on LR outcomes.

were used to derive specific CAPEX.[10] The OWF characteristics described in Table 6 were assumed as inputs for specific CAPEX estimation. This step was made to assess the fit of the experience curve models and to identify at which cumulative capacity the separation of the CAPEX data provides sensible results, see Fig. 14. Comparing to the specific investment costs derived using the MFEC model at 1,4 and 5 GW, the specific investment costs derived at 2 and 3 GW align well with the trend observed in North Sea projects. However, specific CAPEX was underestimated in 2000–2005 and 2006–2010 periods.

5.3.1.2. Limitations on using distance to shore as a site characteristic factor in the MFEC model. Distance to shore was used in the MFEC models as a proxy factor to approximate the influence of grid connection cost and potential cost increase on building the wind farms farther from the shore. The two possible underestimations of effects in using this factor are acknowledged here. First, the distance to shore factor only describes the distance from OWF to the shore (i.e., approx. landfall) and does not account for onshore grid connection length. The lack of data available for this factor in different countries limits accounting for this effect.

[10] The issue of multicollinearity in Model 5 was discussed in Section 5.2.2. For the case of prediction, the multicollinearity is not an issue. Even when the multicollinearity is high, the least-squares regression equation can be highly predictive.

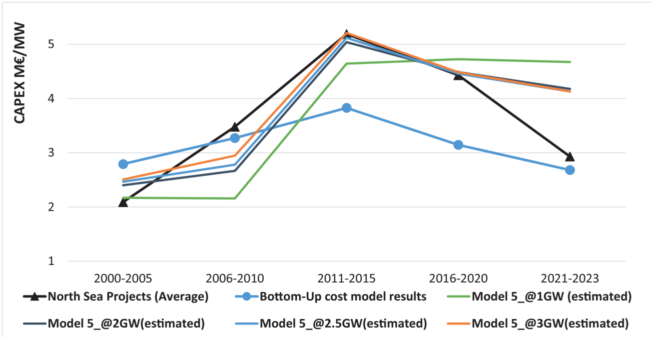


Fig. 14. Describing the goodness of fit of experience curve outcomes and comparing with bottom-up cost model outcomes.

Onshore grid connection length was observed to be significant for OWFs in Germany (TenneT, 2020). Second, there is no distinction made between HVDC and HVAC technology. The combined onshore and offshore connection distance makes HVDC technology suitable for German OWF's (Xiang et al., 2016). The converter station of HVDC technology is expensive compared to HVAC technology. On the other hand, HVDC cables are lighter and cheaper than HVAC cables (Beiter et al., 2016; Johannesson et al., 2009). These variations between grid connection technology choices introduce differences in OWF investment costs between Germany and other countries.

5.3.2. Uncertainties of the bottom-up cost modeling

The bottom-up cost modeling methodology's primary objective in this study was to identify the offshore wind's component-level cost drivers. When compared with North Sea OWF project prices, a considerable difference exists, indicating significant influence of market effects, see Fig. 14. The potential factors driving such differences are discussed here.

5.3.2.1. Foundation design variations. Monopile, jacket, tripile, tripod, and gravity-based foundations fall under the fixed foundation category. However, monopile remains a prevalent choice due to its simple structure, industrialized manufacturing, low cost, and ease in the installation process (Lacal-Arántegui et al., 2018; Voormolen et al., 2016). This study only considered the monopile variant for the bottom-up cost modeling step. Hence, the component cost variations arising due to the design choices should be considered (Fig. 15).

5.3.2.2. Market price vs. technology cost. Wind turbines are the primary component of the OWF. Compared to the onshore wind sector, the offshore wind turbine's supply-side in the European region is concentrated among a small group of companies (IEA, 2019), Fig. 16. During 2005–2015, about ~65 % of installed capacity was supplied by Siemens Gamesa Renewable Energy (SGRE). Their share was even higher during 2011–2014 when the supply of turbines specific to OWFs began. In recent years, new entrants in the market are expected to have stimulated competition, thereby bringing down profit margins and relaxing market supply constraints.

Likewise, the market concentration on other wind farm components, including foundations, electrical infrastructure supply, vessel availability, could have factored in the price increases observed during the early development stages of offshore wind. Due to the lack of project-specific information, those factors had not been analyzed in this study. In recent years, introducing an auction system to determine the subsidy levels for OWF projects across the EU region has stimulated more competition between suppliers or put more pressure on the supply chain (i.e., limited demand through allocation of capacity via auction). Therefore, the profit margin expectation across the offshore wind value chain is assumed to decrease.

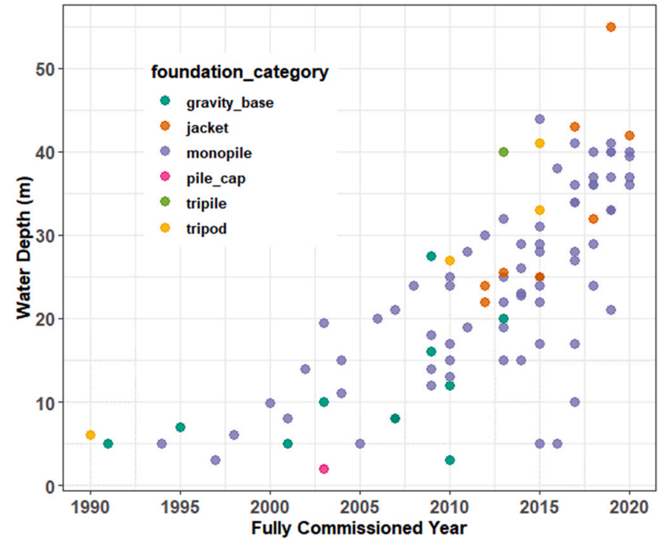


Fig. 15. Different foundation designs deployed for fixed-bottom offshore wind projects at different water depths. Data source: (Dismukes and Upton, 2015; Tuya and Nilo, 2019).

5.4. Levelized Cost of Energy (LCoE) developments

LCoE is the €/MWh amount the OWF developer must earn for each MWh energy generated over the project lifetime to cover the DEVEX, CAPEX, OPEX, DECOM, and financing expenditures. In Section 3, post-tax WACC values, which account for country-specific tax rates, were derived to estimate LCoE. However, it should be noted that the headline corporate tax regime changes over time and is highly location-specific (KPMG, 2020), which complicates the comparison and analyzing the technology performance alone. Therefore, the developments and LR for the LCoE are discussed here on a pre-tax basis. The LCoE estimated for OWFs installed in the European region is shown in Fig. 17. Offshore wind LCoE has increased from roughly 110 €/MWh in early 2000 to above 150 €/MWh in 2010–2015 due to the increase in specific CAPEX. Between 2009 and 2013, the debt and equity margins also increased. The rise in margins post-financial crisis years indicates the high cost of funding rather than the high risk of OWF projects. Despite the rise in funding margins during those years, the overall cost of capital was stable due to the low interest rates (Green Giraffe, 2019).

The capacity factor (CF) improvements observed for OWFs limited the LCoE increases to ~150 €/MWh level. The CF increased from 35 % in 2000–2005 to 43 % in 2011–2015. The offshore wind LCoE in 2011–2015 would be 21 % more if the capacity factor were similar to the levels observed between 2000 and 2005. This comparison is only made here to showcase the influence of the capacity factor on LCoE estimates, because a portion of the CAPEX increases observed during 2005–2015 were attributed to developing upscaled turbines, improving the reliability of wind farm, implementing improvements in electrical infrastructure, and similar advancements that had resulted in better AEP for OWF's, refer to Table 8. Hence, the net effect in LCoE developments should be taken into account when interpreting the overall progress. After 2013–2015, the LCoE of offshore wind has declined rapidly. OWF's in 2020, on average, saw a 54 % decline in LCoE from 2010 to 2015 levels.

The cumulative energy generated from OWF's was used as an explanatory variable to derive an LR for LCoE developments (see Table 9). Despite the increase in LCoE observed between 2005 and 2010, the overall LR for offshore wind LCoE was positive (3.6 % LR). However, it should be noted that this LR should be considered underestimated, as the external effects like market concentration in turbine supply that occurred during 2000 to early 2010 couldn't be corrected to estimate the

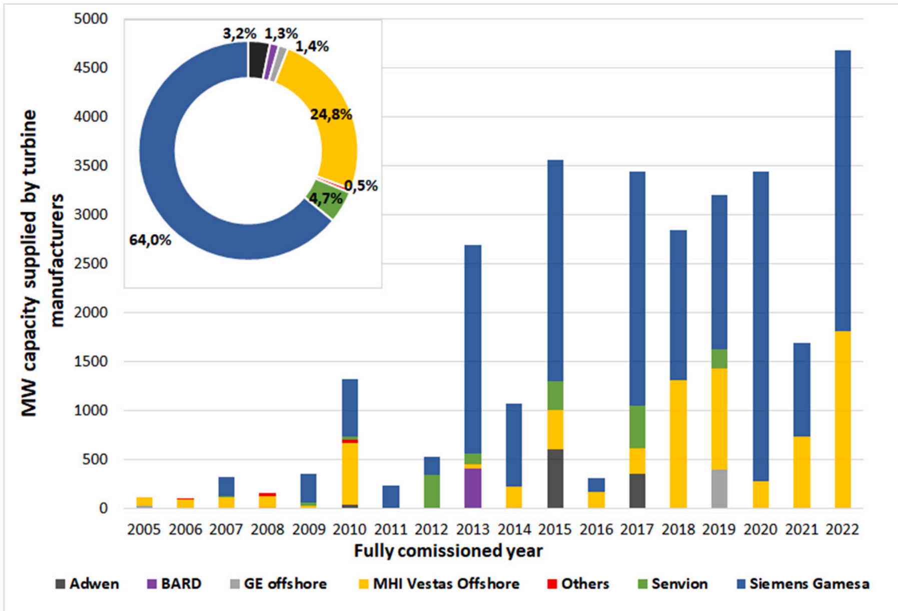


Fig. 16. Offshore wind turbine supply by different companies for EU OWF projects installed until 2022 (doughnut chart describes the total share).

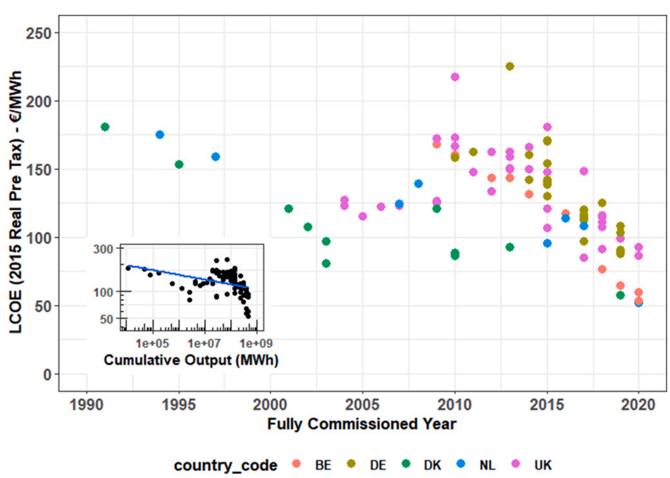


Fig. 17. Offshore wind LCOE developments (Pre-Tax Real 2015 EUR/MWh).

true LR. When only the projects installed after 2010 or 2.5 GW cumulative capacity were considered, the LR increased to 19.5 %. This LR, on the other hand, should be considered overestimated, as it excludes the data points from all the early projects and only covered the projects from the upscaling and growth phase, where unit-upscaling effects and reduction in profit margins due to competition were more pronounced. The true LR is expected to be between 3.6 % and 19.5 %. In the experience curve analysis, the component level contributions on the observed LCoE were absent. Hence, similar to the CAPEX analysis, a detailed breakdown of LCoE was made using the bottom-up cost modeling approach.

Fig. 18 describes the contribution of individual cost components in the LCoE developments. The CAPEX contribution increased from 30.32 €/MWh in 2000–2005 to 38.71 €/MWh in 2006–2010 and 40.18 €/MWh in 2011–2015 and then decreased to 29.60 €/MWh in 2016–2020. The developments of OPEX, DECOM and DEVEX can be seen in the figure. Overall, the LCoE decreased roughly from 128 €/MWh in 2000–2005 to 75 €/MWh in 2016–2020. 72 % of this reduction is from financing expenditures, and the remaining 28 % from the DEVEX, CAPEX, OPEX, and DECOM components. The reduced financial expenditures resulted from

Table 9
LR estimates for LCOE developments (Eq. (6) from Table 2 shows the experience curve model for LCOE developments).

	Dependent variable	
	ln (LCOE – 2015 Real Pre-Tax (EUR/MWh))	
	From initial experience level (0 GW) (1)	After 2.5 GW capacity (upscaling and growth phase) (2)
ln (cumulative output (MWh))	−0.053***	−0.313***
	(0.014)	(0.034)
Constant	5.751***	10.680***
	(0.249)	(0.650)
Observations	89	64
R^2	0.144	0.571
Adjusted R^2	0.135	0.565
Residual std. error	0.276 (df = 87)	0.208 (df = 62)
F statistic	14.687*** (df = 1; 87)	82.686*** (df = 1; 62)
Note:	*+p < 0.1; *p < 0.05; **p < 0.01; ***p < 0.001*	
LR	***3.6 %***	***19.5 %***

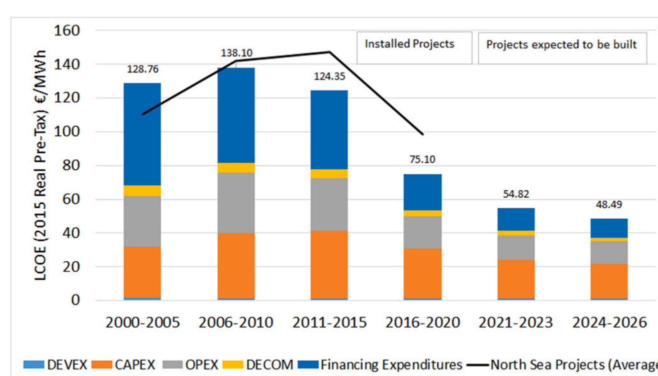


Fig. 18. LCOE outcomes from bottom-up cost modeling. Refer to Table 6 for inputs assumed in LCoE estimation. The LCOE model, following a discounted cash flow approach utilized in this step, can be found in (Santhakumar, 2020b). Financing expenditures were estimated using the approach described by (Egli et al., 2018).

the favorable financing conditions (low interest rates in the economies and increased confidence in technology) and improved capacity factors[11], and to some extent, from decreased CAPEX and OPEX. If the cost developments until 2024–2026 were considered, the reduction observed from financial expenditures was expected to reduce to 62 %, and the reduction from other expenditures increases to 38 %. The impact of the decreasing cost of capital on LCoE developments was still notable during these periods. However, the recent developments in CAPEX, OPEX, and CF are expected to sustain the observed LCoE reduction trend.

Finally, comparing the bottom-up LCOE outcomes with LCOE estimates of North Sea projects, an absolute difference of about 17 €/MWh was observed, see Fig. 18. The variations were primarily due to the uncertainties of bottom-up CAPEX estimation, discussed in Section 5.3. Despite the differences, the LCoE breakdown informs much detail on the individual component's contribution to the LCoE developments and complements the experience curve analysis.

6. Summary of technological progress observed for offshore wind

Vindeby, the world's first OWF located 2 km off the south Danish coast, was constructed in Denmark in 1991 with about 4.95 MW (11 × 0.45 MW turbines). Roughly three decades later, Hornsea Project One, one of the largest OWF projects located 120 km off the Yorkshire Coast, began its full operation in 2020 with about 1218 MW capacity (174 × 7 MW turbines). These events show how fast offshore wind technology has scaled and developed over these years. The technological progress achieved by the offshore wind results from an intricate evolutionary process involving multiple stages and diverse characteristics contributing to its development, as summarized in Fig. 19.

The specific CAPEX increased during the formative phase from roughly 2 M€/MW in 2000 to 5 M€/MW in 2010, resulting in negative LR. The combination of site characteristics effect, installation delays, market concentration, and offshore wind technology-specific market switch (i.e., moving away from adapting existing practices to developing technology solutions and components for offshore wind) resulted in increased specific CAPEX. However, during this period, upscaled turbines and improve electrical infrastructure were deployed, and also operational reliability of wind farms improved, which has increased the CF from approx. 35 % to 43 % during those periods. The LCoE increased from ~110 €/MWh in early 2000 to above 150 €/MWh in 2010 due to increase in specific CAPEX, but the increase in CF limited the LCoE increases further and improved prospects of the technology. Hence, the negative LR observed during these years should not interpreted as no learning has happened and the net effect on LCoE developments should be recognized, i.e., LCoE holistically covers the life cycle expenditures and performance of the technology. Hence, a more significant metric than CAPEX.

From early 2010, rapid unit-upscaling of wind turbines and increased market growth occurred. The maximum rated capacity of wind turbines increased from 3.6 MW in 2011 to 9.5 MW in 2020. The cumulative installed capacity of offshore wind in the EU and UK increased from 3 GW in 2011 to 24 GW in 2020. During this phase, the specific CAPEX declined from 5.4 M€/MW in 2011 to 3.3 M€/MW in 2020 due to unit-scale economies, LBD, component-level technological advancements. In the same phase, LCoE declined more rapidly than specific CAPEX. The LCoE in 2020 is 69 €/MWh, which is a 54 % decline from 2010 to 2015 LCoE levels (150 €/MWh). LR of 19.50 % was observed for LCoE during this period. This rapid decline observed for LCoE is primarily due to the favorable financing conditions, improved capacity factor, and reduced technology investment and operational costs. Availability of low interest rates in the economy and lower expected return on investments decreased the WACC from roughly 7 % in 2010 to 3–4 % in 2020. The capacity factor of OWFs increased from 40 % in 2010 to 50 % in 2020, resulting from upscaled turbines, installations in sites with stronger wind resources, and improved availability of wind farms.

Moreover, the near-term technology cost expectations estimated in this study, i.e., 55 €/MWh in 2021–2023 and 48 €/MWh in 2024–2026 (from Fig. 18), align well with recent auction outcomes, indicating the benefits of understanding the technology cost drivers in deriving reliable cost outlooks. The world's biggest offshore wind park planned off the coast of England, Dogger Bank, won contracts to sell power at a guaranteed price of roughly 48 €/MWh (Mathis, 2019).

Lastly, the technological progress and developments realized in the offshore wind sector provide spillover opportunities for floating wind and other emerging offshore energy technologies like wave and tidal. For example, upscaled offshore wind turbines decrease the specific cost of foundation supply, thereby increasing its market attractiveness. Also, experience gained across subsea electrical solutions and marine installations from offshore wind can be used in wave and tidal technology deployments. Besides, offshore wind technology development also benefits onshore wind, i.e., re-spillover effects. For example, SGRE transferred its extensive offshore wind experience and unveiled a new 5.X onshore wind platform, including high-capacity offshore yaw drives, automated lubrication of drivetrain, and movement of the transformer to the tower center to reduce vibration and cable transport loss in the nacelle. These improvements are expected to increase the AEP and reduce the LCOE of onshore wind further (De Vries, 2020). A similar transfer of experience is also seen for Vestas onshore wind turbines (Windpower Monthly, 2019).

7. Conclusion

Offshore wind technology costs, CAPEX and LCoE, has steadily increased in the EU and UK before starting to decline. In literature, however, studies had provided optimistic projections for the technology, resulting from application of aggregated methodologies like the SFEC model and overlooking the qualitative context of the technological change. Recent studies attributed several factors to reason the cost development trend of offshore wind, but their impacts have not been quantified separately. Therefore, this study has combined three different but highly complementary quantitative methodologies to overcome the shortcomings mentioned above and quantified the technological progress observed for offshore wind in a detailed manner.

The technology diffusion curves were first used to identify the pace and uptake of formative, upscaling & growth phases of offshore wind technology. The characteristics observed for the offshore wind across these phases were also aligned with the theoretical understanding of the energy technology innovation process to test the evolution of the progress (Fig. 19). Then, the experience curve models were applied to quantify the learning effects observed for offshore wind technology. Site characteristics and scale economies factors were used as explanatory variables in the MFEC models, in addition to cumulative installed capacity. The identification of the development phases using the technology diffusion curves in the first step was critical in hypothesizing the primary cost drivers for technology, e.g., reasoning cost overruns in the formative phase, and then, cost reduction in upscaling & growth phase through unit-scale economies and LBD. However, the details on technological advancements at the component level and their impact on costs were absent. Therefore, as a final step, bottom-up cost modeling was utilized to overcome this limitation (Section 5).

During the formative phase, the specific CAPEX increased from roughly 2 M€/MW in 2000 to 5 M€/MW in 2010. This increase in specific CAPEX also increased the LCoE from ~110 €/MWh in early 2000 to above 150 €/MWh in 2010. Among several other factors, the switch

[11] The annual energy production (a function of capacity factor) is a denominator in the LCOE formula and discounts the total expenditures incurred by the project over the project lifetime. Hence, its influence should not be neglected when the component-level contributions are interpreted.

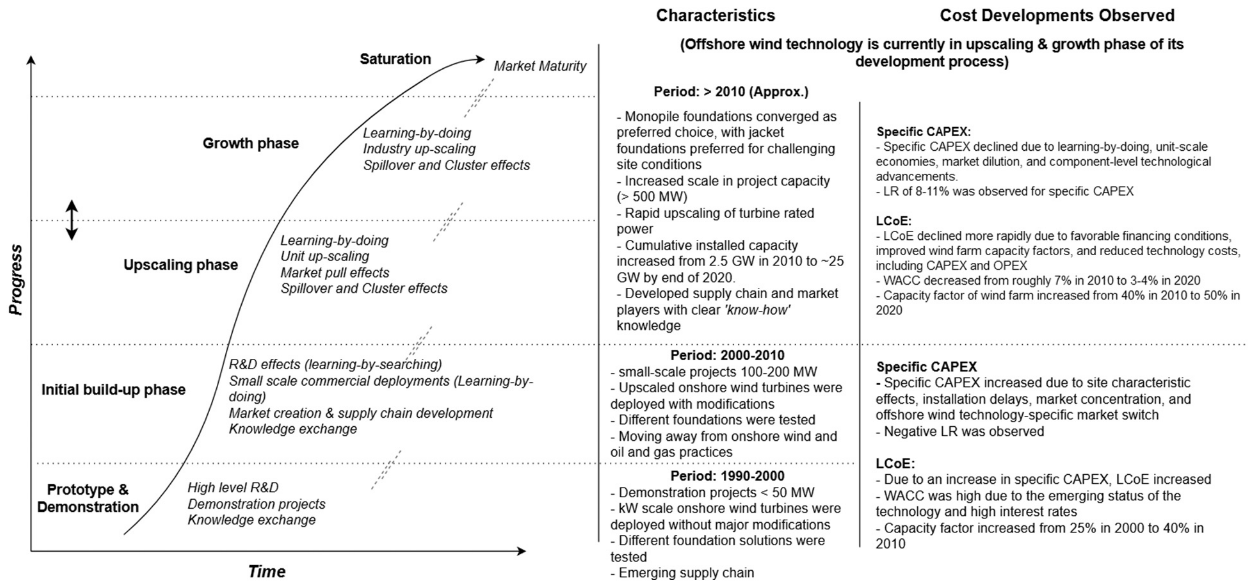


Fig. 19. Summary of the technological progress observed for fixed-bottom offshore wind technology in the EU market.

from adapting existing practices of onshore wind and O&G industry to developing technology components and solutions for offshore wind increased the technology costs during the formative phase. However, it provided learning opportunities to deploy optimized electrical infrastructures, develop turbine technology and wind farm components that yield better technology performance. Then, in the upscaling and growth phase of the technology, the specific CAPEX declined from 5.4 M€/MW in 2011 to 3.3 M€/MW in 2020. LR of 8–11 % was observed for specific CAPEX developments. LCoE declined more rapidly, i.e., from 150 €/MWh in 2010 to 69 €/MWh in 2020. This rapid decline resulted from the availability of favorable financing conditions, improved capacity factors, and reduced technology costs, including CAPEX and OPEX.

Future studies extrapolating technology costs in other markets should be cautious about the long-term role of financial expenditures (exogenous developments of interest rates and technology risks of offshore wind) and the impact of capacity factor (mean wind speed, wake effects). This observation also underscores the importance of opening up the black box of experience curve methodology to understand individual cost drivers' impact on overall progress. By doing so, the potential for over−/under-estimation of cost developments can be avoided. Throughout this analysis, the MFEC model results and bottom-up cost breakdown were considered complementary. This arrangement has considerably benefitted the study in recognizing the sequential stages of technology development, quantifying learning effects, and identifying component-level cost drivers of offshore wind technology.

Finally, the results suggest that it is crucial to recognize individual methodologies' advantages and disadvantages while analyzing technological progress. This study has shown how an improved framework with three different but highly complementary methodologies can effectively analyze technological progress and illustrate the underlying cost drivers. This current application has focused on quantifying the fixed-bottom offshore wind technology's past achievements in the EU market. Future research should apply the lessons learned here to derive the future outlook of offshore wind, especially for emerging variants like floating offshore wind.

Research data for this article

The dataset utilized in this study is available in (Santhakumar, 2020a). The LCOE model, following a discounted cash flow approach utilized in this study, is available in (Santhakumar, 2020b).

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data

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