Reaching the era of subsidy-free offshore wind

Malte Jansen[1], Iain Staffell[1], Lena Kitzing[2], Sylvain Quoilin[3],
Edwin Wiggelinkhuizen[4], Bernard Bulder[4], Iegor Riepin[5], Felix Müsgens[5]

[1] Centre for Environmental Policy, Imperial College London, United Kingdom
[2] Energy Economics and Regulation Group, DTU Technical University of Denmark, Denmark
[3] Smart Energy Systems Research Unit, KU Leuven, Belgium
[4] TNO, Netherlands
[5] Chair of Energy Economics, BTU Cottbus-Senftenberg, Germany

Abstract

Offshore wind energy has become a mainstream technology for decarbonising electricity. Its development thus far has been driven by support schemes, but recent cost reductions raise the prospect of offshore wind becoming cheaper than conventional generation. Many countries use auctions to financially support offshore wind power, but differences in auction design make their results difficult to compare.

Here we harmonise the auction results from five countries based on their design features, showing that offshore wind can be considered commercially competitive across northern Europe. Between 2015 and 2019, the price paid for offshore wind has fallen by 11.9±1.6% per year. The bids received in 2019 translate to an average price of €51±3/MWh, and substantially different auction designs have received comparably low bids. The level of subsidy implied by auction results depends on future power prices, but Germany and Netherlands have subsidy-free offshore wind farms, and it appears likely that in 2019 the UK has auctioned the world's first negative-subsidy offshore wind farm.

Main Text

Decarbonising energy systems is a global necessity. Electricity from renewable energy sources (RES) will be crucial for the transformation. Together with photovoltaics and onshore wind, offshore wind energy has become a major contributor of renewable electricity in Europe. With growth rates exceeding 35% p.a. for the last five years[1], global installed capacity reached 18.5 GW by the end of 2018. Over 127 GW is forecasted by 2040 under the IEA's most conservative scenario[2] and the European Commission has announced its ambition between 250 GW and 450 GW of offshore wind in 2050 for Europe alone[3]. Global technical potentials exceed 10,000 GW of capacity and 5,000 TWh annual production in each of Europe, America and Asia[4,5].

This historic increase came at a cost. Offshore wind energy was significantly more expensive than conventional generation and even among options for decarbonisation[6,7]. Recently, the technology has experienced rapid cost reductions, which have been widely discussed in the media and consultancy reports[8–10], with some speculating that subsidy-free offshore wind was already achieved. As with the rapid cost reductions in solar photovoltaics[11] and energy storage[12], the pace of offshore wind cost reductions has proceeded more rapidly than was widely anticipated, in contrast to increasing capital costs during earlier stages of development[13–16]. For example, Wiser et al.[17] used an expert survey in 2016 to forecast cost reductions for wind power, and the prices received in recent auctions have already fallen below the expectations for 2050.

Controversy remains around how close offshore wind power is to economic competitiveness against other decarbonisation options[18,19]. NREL compared auction results from the Netherlands, United Kingdom and Denmark by adjusting values to account for grid connection, development costs and contract lengths[20]. A transparent methodology was not provided though, which limits the replicability of results and the ability to update data in this fast-paced industry. The IEA Wind TCP Task 26 has compared country-specific impacts on the levelised cost of electricity (LCOE)[21], comprehensively covering the costs of offshore wind. Whilst the publications provide valuable background, they do not explain the bids and the pace of the underlying cost reduction. Both issues are addressed in this paper.

Competitiveness can be measured by comparing costs (usually LCOE) to other technologies or to wholesale market prices, as an aggregated measure of competition in the system[21,22].

However, actual LCOE data are only available in selected countries because of their commercial value and sensitivity[23,24] and these can be misrepresentative[25], and so costs must be estimated. For offshore wind, estimates of investors' expected LCOE can be derived from auction results, and data on successful bids are often published openly. Although bids should correlate with costs, they cannot be directly translated, as information on expected revenues from wind power projects is unavailable.

Several important differences exist between auction designs, including the length of support, whether it rises with inflation, optionality in building the project, and whether development costs are included. Most critically, the contracts for differences (CfDs) used for remuneration can be categorised as 1-sided (providing a lower-bound price below which revenues from the wind farm cannot fall) or 2-sided (providing a fixed price with both lower and upper bound). For this reason, a bid of €20 /MWh in Germany may provide more financial revenue to a wind farm developer than a bid of £50 /MWh in the UK.

We harmonise the winning bids from 41 wind farms across auctions in five European countries from 2005 to 2019, accounting for the main features of each auction. Wind farms were selected based solely on their payment allocation scheme, i.e. only wind farms that were auctioned. All offshore wind technologies were considered, as were all countries that had held at least two auction rounds at the time of writing (the minimum required to detect a trend). These five countries represented 78% of global offshore wind capacity, and the only other country to hold more than 1% of global capacity was China, which was not included as it had only auctioned a single offshore wind farm at the time of writing[1].

This analysis provides two measures: the expected revenues (in $€_{2019}$ per MWh) for each wind farm, which we then compare with potential future wholesale market prices to estimate the effective subsidy, and thus the financial competitiveness of each wind farm. This paper aggregates data on auction settings and results and explains the outcome in European auctions for offshore wind, allowing conclusions on whether offshore wind has already reached cost-parity in Europe.

Offshore wind auctions in Europe

Five countries in Europe have held auctions for offshore wind capacity. In total, 17 auctions have been held, bringing forth over 20 GW of capacity. The evolution of winning bids across these auctions is summarised in Figure 1. This does not reveal a clear trend and is confounded by several bids of €0 (made into 1-sided CfD auctions) beginning in 2017. While a declining trend can be observed, this reveals as much about the heterogeneity amongst auction designs as it does about the reduction in wind farm costs.

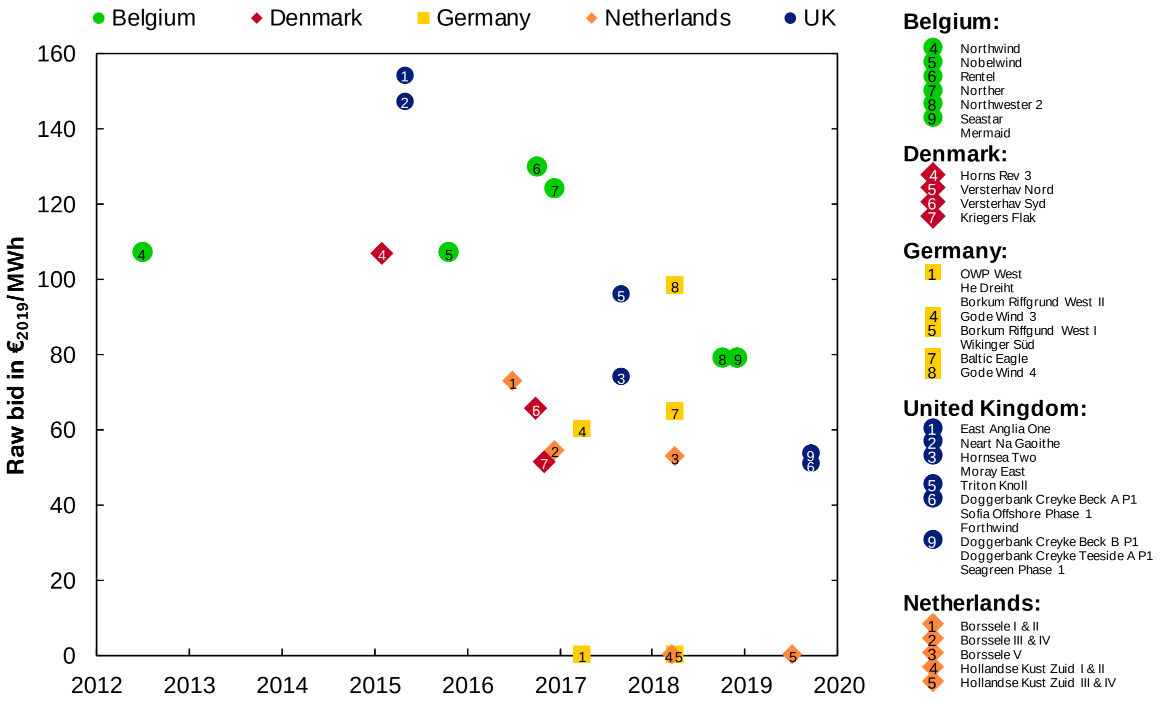

Figure 1: Raw bids received by auctions for new offshore wind capacity in five European countries over the past eight years. Points show the date that auctions were announced, and are converted from local currency to €$_{2019}$.

General principles

All auctions for offshore wind in Europe are designed so that the wind farm operator receives a guaranteed price for a certain predefined period. This so-called strike price or bid price closes the gap between the market reference price (i.e. wholesale electricity prices) and a guaranteed price. However, the exact arrangements of the payments differ between countries, and the specific design of the support scheme gives rise to significant differences in the bids received, and so must be accounted for when comparing bids across different schemes. Clarification on auction design features and their influence can be found in [26–29]. Examples of the differences in implementation are:

- Remuneration mechanism: specifically the allocation of market upside. One-sided CfDs usually pay when wholesale prices are below bid prices but do not demand money if wholesale prices are above bid prices. With two-sided CfDs, investors must compensate for wholesale price revenues above bid prices. Further explanation can be found in Supplementary Note 1.
- Support duration: as the fixed time period (years) or determined as a total support volume (TWh).
- Indexation: whether the guaranteed price is adjusted for inflation, choice of inflation index and base year for indexation.
- Market reference price: what is the basis for comparison to the guaranteed price (e.g. hourly, daily, monthly average).
- Floors of market price below which no support is being paid out (e.g. at negative market prices for several consecutive hours).
- Grid connection costs allocation.
- Land lease cost.
- Site development costs allocation.
- Possibility of capturing alternative revenue streams (e.g. ancillary services).
- Penalty for non-fulfilment of the contract: are the bids conceived as options to build, not necessarily reflecting cost estimates in all cases.

National auction designs

The auction schemes vary considerably across the five countries we consider, as summarised in Table 1. All auctions provide renumeration based on produced energy (i.e. per kWh), but other design aspects are not comparable between auction schemes. The most noteworthy differences are introduced below. Further details are given in Supplementary Table 1.

Table 1: Main characteristics of the auction systems for offshore wind capacity in five European countries. Full details about each wind farm in these auctions are provided in Supplementary Table 1.

Country	Wind capacity [GW] (total / offshore)[30]	Date of auctions	Capacity awarded (all rounds) [GW]	Wind farms awarded	Average bid[a]	Minimum bid	Sided	Duration (years)	Grid costs in bid	Site costs in bid	Inflation adjustment
Denmark[b]	5.7 / 1.3	2005–16	2.2	7	€84[c]	€50[c]	2	12[d]	×	✓	×
UK	21.0 / 8.2	2015–19	9.8	11	€65[e]	€46[e]	2	15	✓	✓	✓
Netherlands	4.5 / 1.1	2016–19	3.0	5	€32	€0	1	15	×	×[f]	×
Germany	59.3 / 6.4	2017–18	2.7	10[g]	€19	€0	1	20	×	✓	×
Belgium	3.4 / 1.2	n/a[h]	2.3	10	€104	€79	1	16[i]	×[j]	×	×

[a] Capacity weighted average across all auction rounds

[b] New design in each auction

[c] DKK 625 and 372 in original currency

[d] Support length based in energy production, typically designed to last 10-12 years

[e] £57 and £40 in original currency

[f] Land lease paid for by the wind farm in the latest tender round

[g] Two wind farms with undisclosed bids and thus not further evaluated in this paper [31]

[h] Renewable obligation certificate scheme mirroring NL auction results

[i] 16-20 years, with 16 years for latest wind farms

[j] Financial cap on total investment

Denmark was the first country to introduce offshore wind auctions in 2005, with the most recent one held in 2016. Each auction is negotiated as part of the parliamentary energy agreements and specifically designed for each auction round. It is the only country that limits the support length based on the cumulative energy production of the project.

The UK held auctions for CfDs in 2015, 2017 and 2019. The UK and Denmark are the only countries in the group to employ a two-sided CfD, and the UK is the only country to include transmission costs in bids, rather than these costs being socialised. Bids from UK auctions are also the only ones that are adjusted for inflation throughout the lifetime.

The Netherlands has had five offshore wind energy auctions since 2015[32]. Initial assessments of site conditions and environmental impacts are conducted by the government prior to the auction, the results are available free of charge. The Netherlands is providing RES support for 15 years including a cap on the maximum support, within this period by limiting the number of subsidised full load hours. Zero bids have won in the last two auction rounds, with the latest project being obliged to pay in excess of €1m per year in land lease for the used area within the 12-mile zone (implying the wind farm receives below the average market price).

Germany's first auction took place in April 2017. Projects needed to showcase an advanced stage of development to be eligible to participate in the 2017/2018 auctions. Germany has attracted notable competition, with 29 projects bidding in total and only ten winners (so far). The support length of 20 years is the longest of all countries. Three out of four winning projects commissioned in the North Sea bid €0 /MWh in 2017. The second auction in 2018 on average had higher prices, despite further bids at €0 /MWh.

Belgium is running a certificate allowance system with an auction system due to be introduced in 2019. The conditions of Belgium's RES support scheme are comparable to those in the Netherlands, and subsidy levels are directly derived from their results[33]. It can therefore be seen as an extension of the Dutch auction scheme.

Despite these different designs, auctions across several countries have attracted competition between developers and yielded bids that are approaching the wholesale cost of electricity. Only one case (the 2010 Anholt tender in Denmark) had just a single bidder, partly due to tight restrictions in the auction design and the early development stages of the European offshore wind energy industry. Likewise, up to now only the Danish Rødsand 2 project failed to materialise as auctioned in 2006, because the reduced availability of wind turbines at that time had challenged the business case post-auction. The project was successfully built in a second attempt, albeit at a higher price.

Harmonisation of expected revenues

Overview of the methodology

Significant differences in both auction and product design across countries have been identified. Many of these differences directly influence the costs and/or revenues of projects, and thus influence the bids received.

The winning bids in European auctions for offshore wind were harmonised using a monthly cash-flow analysis, accounting for the most significant factors identified in the previous chapter (see Methods). We define the 'harmonised expected revenue' as the discounted average revenue per MWh of electricity generated over the lifetime of the project. This gives the equivalent bid that would be offered into a support scheme with a 2-sided CfD with 25-year support duration, indexation to inflation, and site development costs paid by investors.

The harmonised expected revenue incorporates all the money a wind farm can expect to earn over its lifetime, including revenues for later in the project's lifetime when support has run out. It is therefore complementary to the widely-used LCOE metric, referring to revenue rather than cost. It could therefore be a proxy to LCOE in perfectly competitive markets. The details for each wind farm that were used to harmonise expected revenue, including key dates and technical specification, are given in Supplementary Table 1.

Comparable bids across auctions

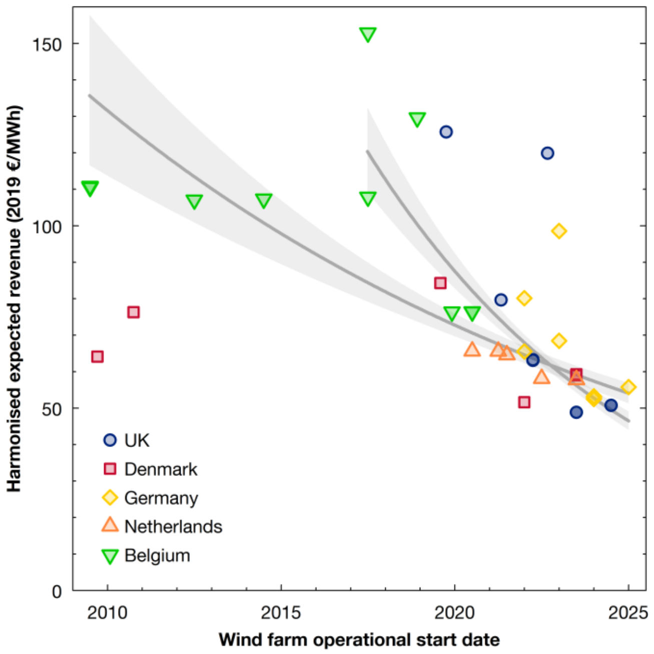

Figure 2: Harmonised expected revenues for each offshore wind farm auctioned in Europe. Each symbol shows the planned start date of operation against the harmonised expected revenue. Lines show the regression of bids across all countries, covering all bids and the most recent bids (since 2015). Shaded areas depict ±1 standard deviation on each regression. Wholesale electricity prices are assumed to remain constant in real terms when deriving revenue beyond the end of the support duration. Other price scenarios are shown in Supplementary Figures 1 & 2.

Comparing the harmonised expected revenues in Figure 2 with the raw bids reveals substantial differences: The raw bids range €0-150 /MWh, whereas expected revenues are €50-150 /MWh, with a cluster at €60-80 /MWh. Wind farms that are due to be built after 2020 are converging towards a range of €50-70 /MWh. From this analysis we cannot identify one country that consistently creates lower bids than others, despite varying site conditions, auction criteria and level of competition. A capacity-weighted logarithmic regression through all auction results yields a reduction in the harmonised revenue requirement of 5.8% per year, with a standard error of the regression of ±1.1%. When considering the more recent auctions, with a start date from 2015 onwards, this rate increases to 11.9±1.6% per year. Results for individual countries are presented in Supplementary Table 2 and Supplementary Figure 2. A logarithmic fit was chosen to ensure that regression results cannot fall below zero. The increased rate of cost reduction indicates that auctions may have helped to improve efficiency in the offshore wind industry.

Large differences in the time frame between auction date, final investment decision (FID) and planned commencement of operation can be noted. For some zero bids in Germany, more than five years lie between the auction result and commencement of operation, whereas several wind farms in the UK made FID on the day of winning the auction or shortly after. This gives German wind farm developers more time for turbine costs to decrease and lets the bids appear more in line with each other.

Figure 2 shows that harmonised expected revenues for several projects have fallen below €50 /MWh. This locates offshore wind towards the lower end of estimated LCOE for fossil generators[22]. Such comparison must be caveated though, as these revenues will only reflect costs in perfectly competitive markets, and cost comparisons between variable renewables and dispatchable fossil-fuelled generators are subject to ongoing debate around integration costs[34–36].

The harmonised expected revenue of most projects depends on the future development of wholesale prices. First, wholesale prices are directly received by projects under 1-sided CfDs provided they are above the bid. Second, with an assumed technical lifetime of 25 years, all projects are expected to sell their output on the wholesale market after their auction remuneration expires. Medium- to long-term wholesale prices are therefore of particular importance to these results, but at the same time, they are highly uncertain. This is not only an academic exercise but an issue that the bidding companies must deal with, and one that the energy industry is, in general, familiar with. Estimates can be made using electricity market models to quantify the future energy system, but these depend on numerous uncertain assumptions, such as the future CO_2 allowance price. The fact that we find similar revenues for wind farms across several countries in the future would, however, indicate that several bidders have arrived at comparable outlooks on the future power prices.

The results in Supplementary Figure 2 consider the sensitivity of these results to the future trajectory of wholesale power prices. We explore this uncertainty by presenting a range of prices derived from independent sources. First, we consider the European Commission's 2016 Reference Scenario, and scale projected prices from 50-150%. This accounts for structural changes in the electricity market (e.g. increased penetration of renewables and higher carbon prices), but is fundamentally a theoretical modelling exercise. To complement it, we take the average historic power prices from 2004-2018 in each country and apply a constant real-term annual growth rate from –2% to +2%, which more than spans the range of historic price growth seen in these countries.

We argue that the long-term prices are probably the better indicator. The EU 2016 Reference Scenario prices are set to double electricity prices in many countries between 2010 and 2020 and therefore we exercise caution using this price forecast alone. We provide the results of all described price scenarios in Supplementary Figure 2 as well as the means to test other price trajectories using Supplementary Software 1. From this assessment, we observe the large influence that the power price has on the harmonised revenues, an investigation that each bidder will have to face individually.

Moving towards subsidy-free offshore wind

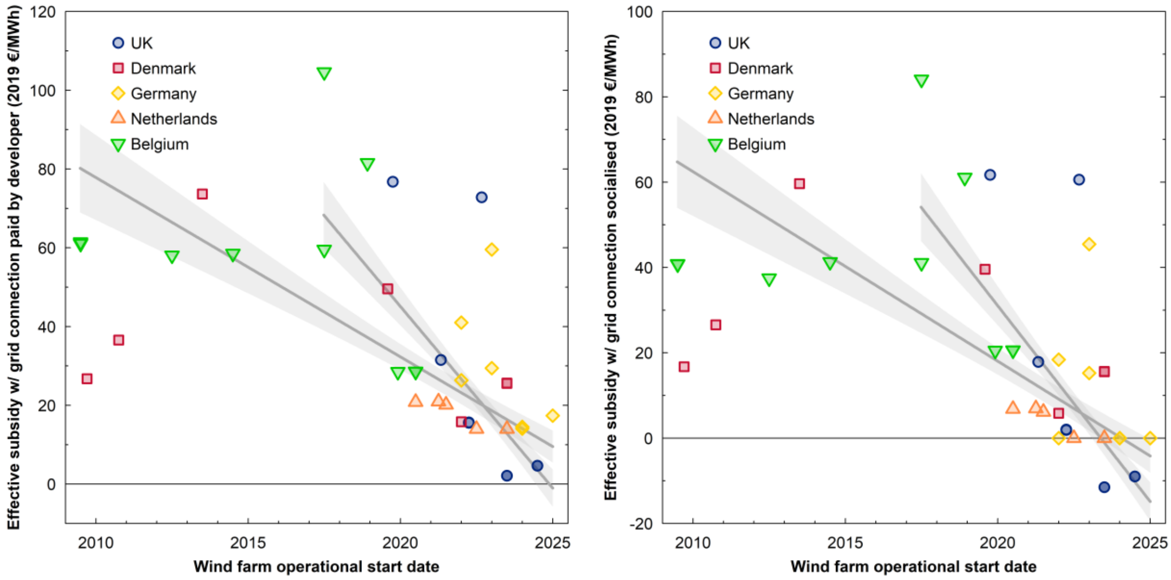

Figure 3: Effective subsidy for each offshore wind farm auctioned in Europe, assuming (left) that grid connection cost should be paid for by the developer and thus considered as part of the wind farm, and (right) that it should be socialised and considered as part of the overall grid infrastructure. Each marker shows the effective subsidy for each wind farm at the planned date of operation. Lines show the regression through bids across all countries, covering all bids, and recent bids from 2015 onwards. Shaded areas depict ±1 standard deviation on each regression. Wholesale electricity prices are assumed to remain constant in real terms when calculating support level from each CfD. Other price scenarios are shown in Supplementary Figure 3.

The harmonised expected revenues (including the support payments expected under each wind farm's CfD contract) can be compared to the expected revenues that would be generated on the wholesale market alone (as if each wind farm were a purely merchant project). The difference between these allows us to derive the effective subsidy that is being paid to each farm, as shown in Figure 3. This is the difference between the discounted income stream due to the RES support payments. If the expected harmonised bid is equal to the expected wholesale market price, the effective subsidy is zero and the project is subsidy-free. These subsidies are the amount of money that will have to be refinanced through the RES support scheme.

This study does not deal with the question of whether grid construction costs should be paid by developers (the allocation-by-cause principle) or be paid by society (socialised as part of a country's infrastructure investment). Figure 3 therefore presents both versions, keeping in mind that grid costs account for €13 /MWh on average. It must be noted that most countries have chosen the latter option, and their funding models for grid infrastructure differ greatly. In the UK, socialised grid costs are borne jointly by generators and demand through transmission charges for the transmission grid whereas offshore connection are paid by the wind farm only. Germany recovers grid charges (including for new offshore wind farms) through final consumer bills only. Offshore grid connection costs remain a key uncertainty despite efforts to gather data[23,37,38] and model[31] these costs for each wind farm (given in Supplementary Table 1).

With socialised grid connection costs, subsidies have reached –€12 /MWh for the latest UK auction, with a large cluster between –€10 /MWh and €20 /MWh. This implies that several wind farms could expect to earn less money under the RES support scheme than under wholesale market terms alone (even with expected revenue cannibalisation effects). With the grid costs being paid for by the developer, the lowest effective subsidy is at €2 /MWh when assuming wholesale power prices grow at 0% p.a. in real terms. Even slight growth in market prices (above 0.28% p.a.) means that the cheapest wind farms are therefore subsidy-free.

It can make sense for companies to forgo revenues in exchange for their predictability. The funding from the RES support scheme minimises risk in several ways. Most notably, exposure to future market prices is reduced, which in turn can reduce the cost of financing these multi-billion Euro projects, allowing for a lower LCOE in the first place[39]. Secondly, using the RES support scheme in all cases comes with monetary (e.g. socialised grid connection) and non-monetary privileges (e.g. site allocation, consenting and planning) thus limiting the pre-development costs for each project.

Across all auctions and with grid support paid for by the developer, the expected support is falling by €5.30 ±1.00 /MWh per year. Considering only auction results from the last 5 years, the support has been falling even more dramatically, by €10.20 ±1.60 /MWh per year, implying that offshore wind farms built from 2025 onwards will on average be subsidy-free if these cost reduction rates continue. The rates of reduction are virtually identical if grid costs are socialised, with €5.20 ±0.90 /MWh (all auctions) and €10.20 ±1.50 /MWh (2015-2019) per year.

This suggests that the era of subsidy-free wind farms will begin in 2023 based on recent auctions, or in 2024 when all data are considered.

Sensitivity to future power prices

To analyse the significance of future price developments for subsidy-free offshore wind, we vary future wholesale price assumptions and calculate resulting effective subsidies. Figure 4 summarises how the effective subsidies are affected by wholesale electricity prices changing by between –2.5% and +2.5% per annum in real terms.

Countries which offer 2-sided CfDs (UK, Belgium and Denmark) show a greater sensitivity to future wholesale prices, as higher reference prices can see farm developers paying money back to society. The minimum bids received in Germany and the Netherlands show no sensitivity to power prices (horizontal lines in Figure 4 right panels). These 1-sided €0 /MWh bids will only see support paid if wholesale prices turn negative, which is only expected in a minority of hours per year (see Methods). If these wind farms ought to pay for grid connections, this would be added onto the zero bid (Figure 4, top-right). It is noteworthy that the UK with its latest auction appears to offer the lowest support payment for any wind farm, with an effective subsidy of less than –€12 /MWh, which in part is due to the implementation of a two-sided CfD whilst power prices are predicted to increase by the government[40].

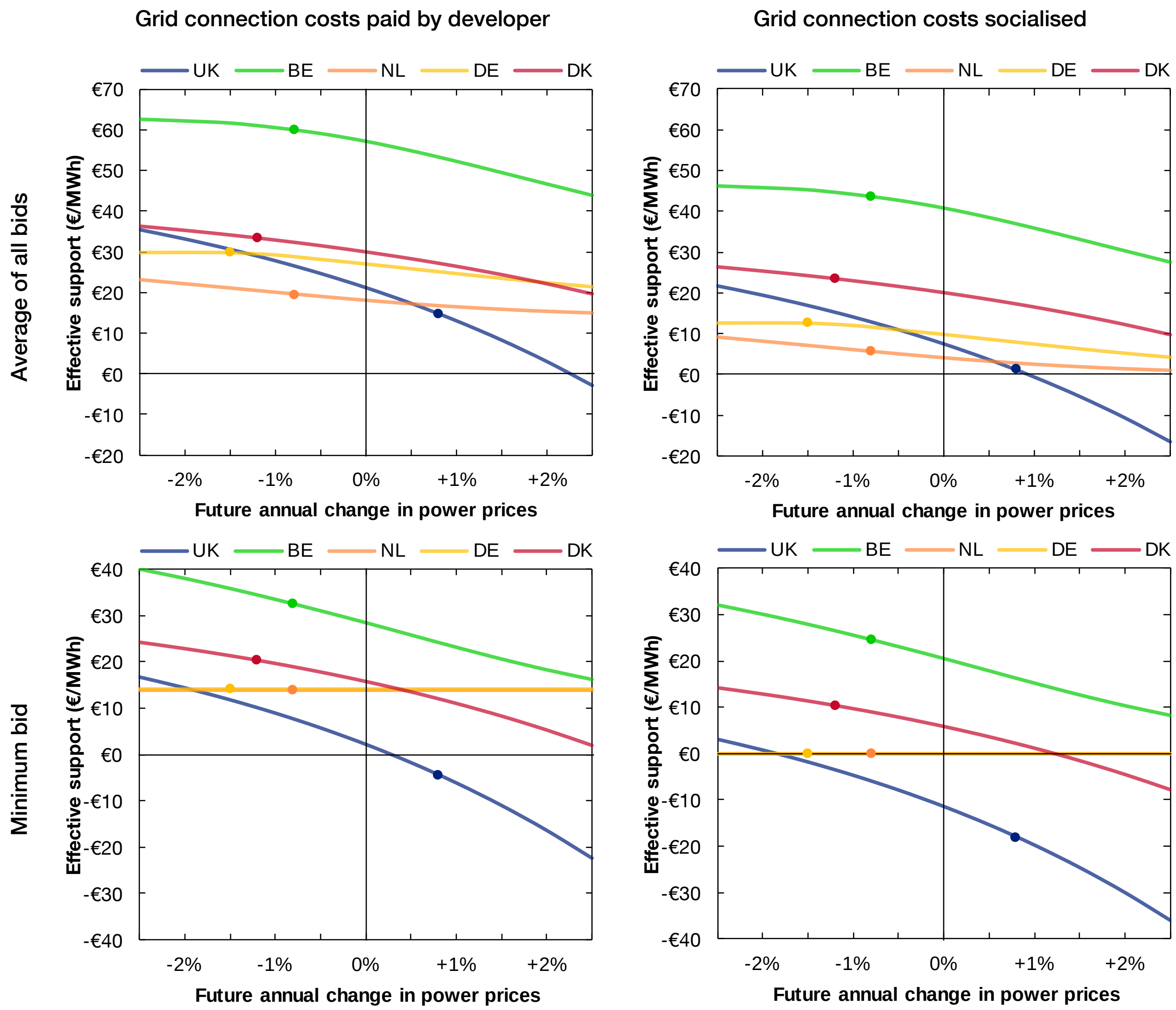

Figure 4: Effective subsidy given to offshore wind farms as a function of future real-terms growth in wholesale power prices. The four panels show four variants, considering the average bid (left) and minimum bid (right) received in each country, assuming grid connection costs should be paid by the developer (top) and should be socialised (bottom). Circles on each line indicate the average real-terms growth in wholesale power prices experienced over the period of 2004–18.

The results of the latest UK auctions indicate that if wholesale prices continue to see moderate growth of above 0.3% p.a. (which is below the historic rates) then these farms will receive negative subsidy: and will be the first to pay money back to society. If grid construction costs are assumed to be socialised, UK offshore wind farms would be subsidy-free even if power prices fell by more than 1.5% p.a. in real terms. Wind farms in Germany and the Netherlands are subsidy-free under any price scenario, whereas Belgian are trailing the in terms of effective subsidy. The last auction in Denmark took place in November 2016, almost 3 years before the latest auction in the UK. This results in a comparatively high effective subsidy and at the same time is showing comparable cost progression to the industry as a whole.

Discussion & Conclusions

The era of 'subsidy-free' offshore wind turbines has begun. This conclusion is founded on zero bids in the Netherlands and Germany which effectively track wholesale power prices, and bids around £40 /MWh in the UK which will be below future wholesale prices if historic growth rates are maintained. Recent projects in the Netherlands have bid €0 /MWh and will pay land lease, indicating that offshore wind is at the point where it will likely to pay money back to the system.

Despite significant variations in auction design, we find that once bids are harmonised the expected lifetime revenues of wind farms are homogenous across countries, without specific outliers that would be attributable to the auction design. This implies that policy makers have managed to create auction designs which fairly reflect the actual costs of developing offshore wind farms, and that the specific auction design is not particularly influential on the outcome. This finding could aid in designing the upcoming auction schemes for offshore wind globally. It also opens the door to further questions, such as whether auctions are suitable policy instrument for driving down costs in less mature technologies such as wave, tidal, and floating offshore wind energy. The study does not unveil whether policymakers should discontinue support for renewables once price-parity is achieved, as the revenue stabilisation offered by CfDs has been instrumental in making this possible for offshore wind[2].

Harmonising bids into expected revenues creates a proxy for the actual costs of offshore wind which closely relates to the levelised cost of electricity (LCOE) plus profit for the company. We show that wind farm costs are decreasing across Europe in a uniform fashion, having undercut the €50 /MWh threshold recently. This makes offshore wind a competitive way to produce electricity and is an extraordinary story of success for a relatively young industry. It is possible that future wind farm developers will aim to build 'merchant' offshore wind farms without financial support, completely free of government support. Development costs may however rise as wind farms move to less favourable locations or to less mature technologies.

There are several reasons why the harmonised expected revenues we report may diverge from underlying costs. Auction results can be seen as an 'option to build' which need not be realised if costs do not fall sufficiently[31]. However, the final investment decision (FID) has already been taken for some recent bids (including the cheapest ones), including one on the day of the auction result (see Supplementary Table 1). We interpret these tangible financial commitments as a sign of developers' intent to go forward with the awarded bids. The breadth and heterogeneity of our sample (41 projects in different countries and auction rules) also suggests that such 'option bidding' effects are unlikely.

The presence of market power could also distort revenues away from underlying costs in either direction. If the industry is going through a shakeout period, investors may bid below cost to deter new entrants from providing competition, accepting short-term losses in return for gaining market share and higher long-term profits. This would mean true costs were above the harmonised expected revenues we report. Alternatively, an oligopoly of large developers could exploit the lack of competition to artificially inflate auction prices. This would mean true costs lie below our harmonised expected revenue, and that offshore wind was more competitive than our analysis suggests.

Electricity generated from offshore wind is often sold through power purchase agreements (PPAs), especially in the UK. PPAs provide long-term revenue stability and offtaker risks are assumed by a counterparty. It is possible these would yield agreed prices below the wind-weighted average wholesale price used here, for example if limited competition between providers facilitated excess profits. This would lead to lower harmonised expected revenues, suggesting that offshore wind is cheaper than our results suggest. Evidence on the discounts offered in PPAs is not publicly available, so we cannot establish whether they are reflective of the underlying revenue cannibalisation found across the investigated countries.

Regardless of the exact level of prices and costs, policymakers can take the rapid decreases shown here as evidence that offshore wind will deliver in the future as a low-cost and low-carbon technology. Hence, the initial spending made on support schemes has been successful in helping to create an industry that is now able to survive without subsidies. This opens up questions around the next steps to support the further rollout of offshore wind turbines. This will likely entail designing RES support schemes which move away from payment support and instead focus on planning issues, market integration, grid connection and ease of access to financing.

Building on the story of success, policymakers may want to extend their attention to support less mature technologies such as floating offshore wind, which would allow access to deeper waters with higher wind speeds. These technologies are currently at a less mature stage but may prove vital in harnessing the world's best wind resources[2].

Our findings are derived from wind farms in Europe, but hold relevance for other parts of the world. Europe has been at the forefront of offshore wind due to its favourable conditions of relatively shallow waters and high wind speeds. This enabled cost-efficient monopile foundations to be used in most, but not all offshore wind projects. One-fifth of the capacity we consider uses jacket or gravity-based foundations. Regions of Asia and North America also benefit from shallow waters[2], and could expect some of the learning of Europe (e.g. turbine size increase, construction techniques, financing) to play a key role in achieving similar results. The rates of price reduction found here may prove equally applicable to other world regions, and to other foundation types if they achieve comparable scale up, albeit from a higher starting price level.

As decarbonisation of the world's electricity systems gains traction, attention must be given to the issues of balancing and flexibility, and to the decarbonisation of heat, transport and industrial applications. With offshore wind at competitive prices, numerous sector-coupling applications are coming into reach that could not have been imagined as cost-competitive just a decade ago.

Methods

General principle

Both auction- and product design vary significantly between different countries. We identified major differences from a review of government literature and present them in Supplementary Table 1. Many of these differences directly influence the costs and/or revenues of projects, and thus influence the bids. This is obvious for the support duration but also e.g. for one-sided vs. two-sided support schemes where the former has an implied option to profit in the event of future wholesale price increases. Consequently, one-sided CfDs require lower bids to make projects profitable.

The differences between auction designs were accounted for by developing a methodology to harmonise the winning bids in European auctions for offshore wind. Our harmonization accounts for the most significant factors identified in Table 1. The bids are harmonised using a monthly cash-flow analysis, which addresses seasonal variation in wind capacity factors and allows volume-based support schemes to expire part-way through a year. Hence, we define the 'harmonised expected revenue' as the (discounted) average revenue per MWh of electricity generated over the lifetime of the project. This can be interpreted as the bid that would give an equivalent NPV over the project life if it were offered into a hypothetical auction that offered a 2-sided CFD with 25-year duration, indexed with inflation. On this basis, we can compare the bids (and the implied expected revenues) over each wind farm's entire lifetime, and e.g. include revenues for later in the project's lifetime when support has run out. Details on each wind farm were sourced from developer and manufacturer websites and professional databases (e.g. 4COffshore) as well as renewables and offshore wind news outlets, primarily [41–45].

The following sections detail how we adjust each bid's strike prices to obtain harmonised expected revenue. Each adjustment changes the monthly cash-flow, which results in monthly payments to the wind farm from the market and the 'effective' payments from the RES support scheme. The payment over the lifetime of the project is then aggregated. This yields the average payment per MWh received for the total (supported) payments. We also calculate the payments which would have resulted if the electricity would have been sold exclusively on the wholesale market. Finally, we calculate the difference between both, representing the actual average subsidy paid.

Harmonising length of payments

Support duration

Support durations vary between projects. For most projects, legislation specifies an explicit time duration d_s. For the Danish projects with an energy-based limit, we calculated the resulting support duration $d_{s,DK}$ as follows:

$$d_{s,DK} = \frac{E_s}{P_{inst} * h_y * CF} \quad (1)$$

With

With	$d_{s.DK}$	Support duration for Denmark
	E_s:	Supported Energy
	P_{inst}:	Installed Capacity
	h_y:	Hour in one year
	CF	Capacity factor

The capacity factor CF is estimated using the Renewables.Ninja model with the appropriate wind turbine model for each project[46,47]. The numbers are validated against external data points where possible[48,49] , and are found to be highly correlated. For projects using next-generation turbines we developed parametric power curves[50] if these were not publicly available. While we attempt to use representative capacity factors, these have no influence on the main results presented as both harmonised revenue and expected support are normalised per MWh. They can have second-order effects due to output-dependent support duration, but this yields minimal changes.

External factors that could influence capacity factors over the farm's lifetime (such as degradation[51,52], wake effects[53], stilling[54] or climate change[55]) are not considered as they are currently subject to much uncertainty. These could be incorporated once better understood using the cashflow models that we make available open source.

Total lifetime

We model each wind farm's revenue over its whole lifetime, both from their strike price and the wholesale market alone. While the total lifetime of offshore wind projects is still debated, most publications estimate them between 20 and 30 years (e.g.[56–60]). Therefore, we assume that the lifetime d_l for all projects is 25 years. This is needed to calculate the income after RES support from the auction has run out. Variations to this assumption have limited impact on results due to the effect of discounting.

Strike prices and market revenues

As explained above, projects' annual revenues are determined either based on the strike price or based on the market price. Before we can identify which applies in any given year for any given project, we first must derive a consistent time series for both. Among other things, we normalise currencies to Euros and all values to real monetary values for the year 2019.

Market revenue time series

We assume that wind farms sell their output on the wholesale market (or at least receive payments based on the sold electricity's wholesale market value). Historic wholesale power prices are obtained from ENTSO-E and Open Power Systems Data[61,62]. Large uncertainties exist regarding the future of power prices, in particular as we need them more than 25 years in the future. The influence of power prices is paramount for our considerations as it affects the bids in a significant way. Obtaining consistent price forecast scenarios is challenging as the national price forecast would show inconsistencies on the input assumptions (fuel prices, CO_2-emission prices, etc.).

To address the uncertainty around future power prices we choose a diversified approach. (1) The EU 2016 Reference Scenario PRIMES model provides a consistent output covering all of Europe[63], which forecasts annual average power prices for every fifth year until 2050. It is to note that the prices are significantly higher than today's prices. Therefore, we multiply the prices provided with factors of 0.5, 1.0, and 1.5 to create an understanding of the impact of price variations. (2) Whilst best efforts have been made to model future power prices, we aim to mitigate the influence of modelling altogether, by using the average annual power prices to establish the long-term price variations. We use long-term prices (2004-2018) averages and assume an annual growth between -2% and 2% in 1% steps based on this.

We can establish that the time-weighted average wholesale price for the time period t is dependent on the assumed price growth pr. Latter can either be given in % growth p.a., or predetermined by external inputs, such as the time series from the EU 2016 Reference Scenario.

$$twp_t = twp_0 * pr^{\frac{t}{12}} \tag{2}$$

With: twp_0 time-weighted average wholesale price at project start

pr rate of price growth

t time in months since project start

However, it is well known that electricity generation from wind does not receive the average price[64]. The price that offshore wind turbines will be able to realise on the market on average shall be called 'capture value' (also referred to as market value factor, see[65]). We derive a capture value is a multiplier typically below one which subtracts from the average power prices based on the linear interpolation between today's empirically determined data and the price scenarios for 2030[66]. The capture value cr is a multiplier which determines the percentage that wind can capture of the time-weighted wholesale price. It is a large source of uncertainty for wind farm developers, as it is expected to decrease over time. The results from our modelling for the country-specific average values are shown in Supplementary Table 3:

$$cr = \frac{\sum_h output_h * price_h}{\sum_h output_h * \overline{price}} \tag{3}$$

With: $output_h$ output in hour h

$price_h$ price in hour h

$\overline{price}$ time-weighted average price across all hours

h hours

This further allows us to calculate the wind-weighted average wholesale price wwp_t:

$$wwp_t = twp_t * cr_t \tag{4}$$

Linear interpolation of the market value cr between today and 2030 is assumed and can be justified using the different scenarios in the UK National Grid Future Energy Scenarios annual publications[67] shown in Supplementary Figure 5. The modelling shows a roughly linear relation between installed wind power and the merit-order effect. We therefore can assume a linear relationship in our assessment as well, both for the merit-order effect as well as the capture value derived from hourly time series analysis between today's data and 2030's estimation.

Strike price time series

Determination of strike price time series is relatively straightforward: In a first step, we convert strike prices to € (if applicable) using market exchange rates[68]. In a second step, we convert nominal values to real monetary values of 2019 using country-specific averages for the years 1998 to 2017[69]. The long-term inflation for all five countries was 1.65% p.a.. For the UK auctions, the strike price is adjusted by the inflation rate, which derived from the data[69] and amounts to 1.89% p.a.. All available inflation data is shown in Supplementary Table 4. Note that the indexation measure used is based on the GDP deflation index rather than consumer price indexation, as often used by central banks. This is believed to get a more accurate representation of indexation[70]. The strike price SP_t at time t is by auction design either to be discounted or kept constant in real terms:

$$SP_t = \frac{SP_0}{ir^{\frac{t}{12}}} \tag{5}$$

With:	SP_0	Strike price at project start
	ir	Inflation rate (GDP deflation)
	t	Time in months since project start

Determining revenues during support duration

At this point, we have two normalised time series for the years of the support duration (the strike price time series and the market revenue time series, both calculated above). Which one is applicable is determined as follows:

Two-sided CfDs

For projects under two-sided CfDs, the strike price essentially determines a fixed payment. Hence, the relevant time series during the support duration is the strike price.

One-sided CfDs

For projects under one-sided CfDs, the situation is more attractive: These projects have the right (but not the obligation) to choose the market revenues even during support duration in case they exceed the strike price. We address this optionality in two ways: first, we select the maximum of monthly strike price and market revenue as the resulting revenue during those months. This is in analogy to the option's intrinsic value. Second, the option has an additional 'time value' – reflecting the fact that the wholesale revenue described above is uncertain. It could increase – and the projects under one-sided CfDs would profit. It could also decrease, but the projects under one-sided CfDs would lose less (as they can choose not to exercise the option and sell at the strike price). Note again that in contrast to option terminology, we use "strike price" equivalent to "bid price" in this paper.

We further establish the uplift premia up as a function of the strike price sp. The uplift premia term describes the additional income for the generator over the market prices that is caused by capturing the upside under a 1-sided CfD. The uplift premium is a function of the ratio between strike price and wholesale market price and differs for every wind farm. Supplementary Figure 4 allows deriving the value for each wind farm. It is not applicable for 2-sided CfDs:

$$up(sp) = \frac{\sum_h output_h * max\{price_h, sp\}}{\sum_h output_h * price_h} \tag{6}$$

With:	$output_h$	output in hour h
	$price_h$	price in hour h
	sp	strike price
	h	hours

Harmonising bids

Weighted Average Cost of Capital (WACC)

Having calculated one specific revenue time series for each project, we then adjust these time series to reflect the (country-specific) weighted average cost of capital (WACC). This discount rate is also called the real cost of capital (over and above the inflation rate). Financing costs of wind power projects are dependent on the local funding conditions and ease of access to capital. Supplementary Table 5 presents WACC from different sources for onshore and offshore wind, with offshore wind being more expensive. The average from across these sources was used, with country-specific values ranging from 6.2–7.9%, and the average across all countries being 7.3%.

Revenues from market

As all input parameters are defined now, the revenue for three different cases can be calculated. (1) Revenues without any RES support scheme payments $r0_t$, (2) revenues under a 1-sided CfD $r1_t$ and (3) under a 2-sided CfD $r2_t$.

$$revenue = \begin{cases} r0_t = output_t * wwp_t & no\ support \\ r1_t = r0_t * up_t & 1 - sided\ CfD \\ r2_t = SP_t & 2 - sided\ CfD \end{cases} \tag{7}$$

With: $r0_t$ Revenue at market prices

The 'harmonised expected revenues' HER for each case then results in:

$$HER = \begin{cases} \sum_t \frac{r0_t}{(1+dr)^t} & no\ support \\ \sum_{t \in ST} \frac{r1_t}{(1+dr)^t} + \sum_{t \notin ST} \frac{r0_t}{(1+dr)^t} & 1 - sided\ CfD \\ \sum_{t \in ST} \frac{r2_t}{(1+dr)^t} + \sum_{t \notin ST} \frac{r0_t}{(1+dr)^t} & 2 - sided\ CfD \end{cases} \tag{8}$$

With:	dr	Discount rate
	ST	Support time from 1 to sd
	sd	Support duration in years

This allows us to calculate the effective subsidy ES as follows:

$$ES = HER - \sum_t \frac{r0_t}{(1+dr)^t} \tag{9}$$

Grid connection costs

In a final step, we account for the fact that some auction designs pay for grid connection and others put the costs onto the developer. Harmonising the effective subsidy ES by subtracting the grid costs CG accounts for the difference in the auction conditions and happens after the cash-flow analysis. The implied cost differences can be regarded as a significant subsidy (see[31]). We have collected wind farm-specific connection costs were available in the overall data table in Supplementary Table 1, averaging country-specific data where primary data was missing. In some cases (e.g. Germany) connection costs are given in €/kW following the methodology in[31], which then can be converted into $€_{2019}$/MWh using capacity factors. The UK is the only country where wind farms pay in full for the grid connection. The effective subsidy with grid connection $ES_{GridConn}$ therefore only applies to the UK auction results, as $ES_{GridConn} = ES_{UK}$. For all other countries $ES_{NoGridConn} = ES_{DK,NL,BE,DE}$. The relationship between $ES_{GridConn}$ and $ES_{NoGridConn}$ are:

$$ES_{NoGridConn} = ES_{GridConn} - CG$$

In the results section of the paper, we opt to show results with and without grid connection costs as equally valid options. The discussion on cost recovery of grid infrastructure is to be held at a different occasion.

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Author contributions

FM and MJ conceived the study. IS, FM, MJ and IR developed the analysis. All authors contributed to data gathering. All authors wrote and edited the paper.

Additional information

Data availability: The data that support the findings of this study are available from the corresponding author upon request.

Code availability: The cashflow model used in this study is available with the manuscript as supplementary material.

Competing interests

The authors declare no competing financial interests.