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Abstract

Nearshore wind development has been seen as the cost reducing option that could shrink the cost gap between onshore and offshore development. The cost advantage is linked to more shallow water and shorter connection to shore even avoiding an offshore substation. Public tendering for offshore wind in Denmark has opened up for near-shore wind turbine farms as an alternative for lowering the cost of new offshore wind development. Whether these proposed near-shore locations will manage to significantly lower costs is not clear. The tenders have resulted in bids that are at comparable levels for the nearshore and the further offshore wind farms. We compare the cost drivers and possible cost differentials with preferences for locating wind farms further away from the coast. The main cost driver is water depth and in the Danish case water depth is increasing slowly or is not even correlated with the distance from shore. Therefore the willingness to pay for moving turbines away from the coast may be sufficiently high to balance the increased cost. The actual comparison of costs and willingness to pay must be carried out for the specific case with cost characteristics and willingness to pay by the affected population.

Keywords: offshore wind; cost curve; cost drivers; preferences; nearshore

1 Introduction

Wind energy is one of the most cost-efficient renewable technologies when ambitious targets for renewable energy have to be met. In many countries, the cheapest wind resources on-shore are now competitive with conventional generation. Currently there exist high expectations for the development of wind energy, particularly in Europe, out of which offshore wind turbine developments will be central as tools to achieve current energy targets. Offshore wind development is still more costly but because land for onshore development is scarce in many countries, offshore wind sites have also been developed especially in Europe. In 2017 Denmark had 4228 MW onshore and 1292 MW offshore capacity of wind (Danish Energy Agency, 2017). Costs for offshore wind varies a lot depending on specific location, water depth and distance as well as actual technology applied. Even though recent years have shown a significant decrease in costs for offshore wind, and as a consequence a narrower differential between onshore and offshore wind costs, offshore wind remains more expensive than onshore wind. As a consequence of the shift from onshore to offshore projects and the higher costs associated to these, the expansion of wind contribution to electricity generation has become more expensive resulting in slower growth. Financing of the necessary support has become more of a public issue with electricity consumers, especially industry, increasingly pressuring to be exempted from contributing to financing via public service obligations. However, further cost reductions are expected (Wiser et al., 2016a), (Wiser et al., 2016b) and especially the option of using more shallow waters closer to shore is considered as a way to reduce costs of offshore wind. The choice between nearshore and (far)-offshore is particularly relevant, both because of increased public resistance due to visual disamenities produced by nearshore projects, and because of the potential cost reduction benefits attained by building wind farms closer to the shore.

In Denmark this option has also been considered and some nearshore sites were already included in tenders in 2017. This paper investigates the cost characteristics of nearshore wind and the specific cost drivers that are expected to make it cheaper than further offshore wind. We define nearshore wind as turbines that are up to 15 km off the coast. Based on this need, an analysis of the differences between costs and cost drivers for both offshore and nearshore is needed, as well as an exploration towards other possible factors that might affect the relative advantage of nearshore compared to offshore projects. We compare Danish nearshore sites with further ashore wind potentials in Denmark and elsewhere. Costs for nearshore are expected to be lower due to lower connection costs, foundation, and to some extent, operation and maintenance. These lower costs must be balanced by the less favourable wind conditions and the costs associated with public resistance. Carefully selecting the nearshore sites with low resistance and low cost characteristics can hopefully reduce the cost of expanding the offshore wind capacity in Denmark where there is a considerable amount of coast line compared to the area of the country. Here, the focus is on trying to determine the cost differential for wind farms located at different distance from the coast in comparison to the typical cost curve for further off wind farms in DK. The most important cost driver is probably water depth and in this respect Denmark is probably not representative of offshore conditions in other regions. There may still be available shallow sites in Denmark that are further from the coast, and these may be substantially preferred to the nearshore sites.

The paper is organised with a first section describing the cost characteristics of offshore wind and the main variables and assumptions included in the calculation of Levelised Cost of Energy (LCOE). The next section examines the offshore potentials in Denmark and associate potentials with cost drivers. Following section evaluate the cost advantage of nearshore wind with Danish characteristics. The last section discusses and compares the cost advantage with public preferences for shifting wind development further offshore. A final section concludes on the findings and implications for Danish wind expansion.

2 Levelised Cost of Energy

When comparing costs of energy, the levelised cost of energy (LCOE) is a commonly used measure, which focuses on the cost of supplying energy (electricity) and do not include properties as the varying quality of supply and the fluctuating value of supply at different hours of the day and year. We are focusing on comparing nearshore and offshore wind development in Denmark including different sites that may imply some variation in wind conditions and specific short term generation profile, but the difference in profile and thereby value per generated unit is not expected to be significant, such as can be the case when comparing across more fundamentally different technologies and power markets/countries.

There may be minor differences in the lifetime of turbines and the variability of the generation, but they are generally small within the wind technology, and therefore the LCOE is a reasonable measure for the comparison here.

2.1 LCOE assessment for power generators

Calculating the LCOE is a tool not only used for assessing the economic performance of offshore wind energy but is utilised throughout the industry to evaluate the cost-effectiveness of different forms of power generation technologies and to compare them with each other. In that way, a comparison also between conventional and renewable power generators can be made even though these technologies can differ significantly in their cost structure. While conventional generators usually face a high share of their total lifetime costs with variable costs such as expenses for fuel, for most renewable energy sources a significant part constitute the investment costs occurring at the beginning of the investment projects, particularly for those technologies where no cost for fuel accrues. The LCOE thus is, on the surface, a straightforward measure for the investigation scope of an energy market as a whole to examine the competitiveness of different energy technologies. The LCOE expresses the cost over the lifetime of an asset related to the expected energy production, which is usually based on average annual production, and it furthermore accounts for the time value of money by discounting the cost and energy over the lifetime. While it can be challenging to identify the correct discount factor to be used for calculating LCOE when comparing different technologies, in the case of comparing offshore with nearshore wind, this is not a difficulty, and therefore LCOE is an excellent tool to use.

While comparing the LCOE for different power generation systems within a specific market is a simple indicator to identify which technology produces electricity at the lowest cost, it is not so simple to compare LCOE analyses across studies for different markets or countries even for the same power generation technology without considering cost allocation principles and regulation. Countries use various regulations and guidelines of how to assign cost elements to generation or grid and sometimes costs are indirectly affected by national support variations. A Danish partnership of different commercial and state entities has tried to propagate a standard approach to calculate the LCOE specifically for offshore wind energy (Forcherio, 2014) in order to facilitate a cost comparison of electricity production in a growing joined European energy system, but national regulations still suggest various methods for the LCOE assessment.

2.2 LCOE comparison of wind using national characteristics/differences

Great care has to be taken when utilising LCOE measures for comparing different projects, mainly when the projects compared are sited in different countries. While the units for LCOE are the same, there is no standard definition regarding which costs are included in the calculation of this measure.

(Visser & Held, 2014) studies different assessments of LCOE in the Netherlands, United Kingdom, Germany and Spain and finds out that besides from CAPEX and OPEX, which are considered in every analysis, residual costs such as decommissioning, grid balancing, and cost of market integration are not integrated into the LCOE analyses of every country. Furthermore, grid connection costs are frequently ignored, since very few countries (such as the UK) include these costs in the scope of the project and the LCOE assessment. These kinds of differences will, therefore, affect the LCOE estimates for different projects, and make comparison difficult.

In order to illustrate the difference in approach of the United Kingdom and Denmark, the standard guideline for LCOE calculations in Denmark, a report of the Danish Energy Agency is used, which describes the financial and technical assumptions behind LCOE analyses in this country (Danish Energy Agency, 2015b). The comparison of the United Kingdom and Denmark regarding the relevant factors as presented by (Visser & Held, 2014) is shown in Table 2.1. The factors are indicated with yes or no depending on their inclusion in the respective LCOE analysis method.

Country	United Kingdom	Denmark
Equipment cost[1]	Yes	Yes
Other investment[2] & fixed planning cost	Yes	Yes
Capital cost (debt, equity)	No	No
O&M cost	Yes	Yes
Decommissioning cost	Yes	No
Cost assessment for grid connection	Yes	No
Network related cost/Balancing cost	Yes	Yes
Cost of market integration/Grid expansion cost	No	Yes

Table 2.1: Comparison of LCOE evaluation methods in the UK and Denmark

As seen in Table 2.1, whereas the general CAPEX and OPEX are included in the LCOE calculation in both countries, the inclusion of grid connection cost into the capital cost, in fact, differs due to different regulations in both countries. Also, the decommissioning costs are included in the British method and are taken into account as a "provisioning fund" as part of the total operational cost. By accumulating these payments over the lifetime, a fund is created that serves to pay the decommissioning expenditures at the end of the lifetime. The Danish approach, however, assumes that the decommissioning costs are offset by the residual asset value and thus are excluded from the assessment (Danish Energy Agency & Energinet.dk, 2014). The difference in both approaches may impact differently onshore and offshore projects, depending on the need to decommission foundations. The electrical balancing costs are included in both regimes, but a broader impact on investments concerning the electricity system is not considered in the British methodology. In Denmark, on the other hand, the costs for adjusting or expanding the electrical infrastructure, which is of particular importance for renewable energy sources, is included in the calculation.

[1] Technology cost, e.g. turbines, control systems

[2] Construction/installation cost, foundation cost

The height of balancing costs differs in the countries due to the respective production portfolio and the flexibility of and the transmission with the surrounding electricity system. Despite a high share of energy production stemming from wind power, the average balancing costs for wind power producers in Denmark is estimated at 2 EUR/MWh, which is in the lower range of the wind energy balancing costs in Europe, due to the interconnection with other electricity markets and most notably the flexible hydropower plants in the Norwegian power system (Danish Energy Agency, 2015b). The balancing costs for wind power producers in the United Kingdom in contrast are estimated at 3 EUR/MWh at the upper range of average wind energy balancing costs in Europe, likely due to the poorer interconnection to the electricity grid of continental Europe (EWEA, 2015), or differences in the design of the balancing market, in regard to regulating power and frequency restoration reserves.

As a consequence of the different approaches and values regarding the above-mentioned factors included in the LCOE analyses, a comparison of the LCOE of specific technologies assessments between different countries can be somewhat biased. A general trend of cost development of specific technologies over different countries can therefore preferably be evaluated by relative cost reduction projections over time than by absolute values of specific years.

Another highly sensitive parameter for the LCOE calculation is the choice of the discount rate as stated in (Visser & Held, 2014), which usually varies throughout different countries. This procedure is due to a different perception of risk and various estimations of alternatives for public investments in specific national markets. If the risk for an investment is assumed to be high, an increased discount rate will reflect a higher needed return on the investment in order for the project to be regarded as profitable. The risk depends on the general market conditions such as the supply chain market or the dependency of imports and is estimated differently in different countries. Having many alternatives to the investment in a particular market furthermore generates opportunity costs for an investor that could be spent on other projects. The volume of alternative investment opportunities obviously also varies from country to country, thus also being reflected in different discount rates. The more alternative project possibilities there are investable, the more expected return is needed for the specific investment to be attractive enough.

The characteristic values of discount rates that are suggested by governmental bodies can differ significantly between countries and in particular between the United Kingdom and Denmark. While the British government suggests a discount rate of 10% (nominal) for all projects to be able to have a neutral national comparison of projects in terms of financing and risk assessment(DECC (Department of Energy & Climate Change), 2013), the Danish regulation suggests a discount rate of 4% (real)(Danish Energy Agency, 2013). Even though differing in nominal and real terms, inflation is not likely to compensate this gap if other factors such as market risks are not assessed in the difference between real and nominal discount rate. As a consequence, Danish LCOE assessments of offshore wind energy usually are characterised by a tendency of having lower levelised costs than British evaluations, due to the lower financing costs in Denmark. Therefore, the limited comparability between the absolute values of LCOE has to be kept in mind when comparing the economic performance of offshore wind energy between different countries. For the investment calculation and decision the NPV is the usual measure to compare and LCOE is related but less important (González et al., 2011).

From an investor's point of view, the LCOE assessment within a national market is also subject to other limitations. Since the projection of energy generation, especially for fluctuating renewable energy sources, is prone to uncertainty, an LCOE analysis does not always express the full profitability of a project for the investor, or it contrarily underestimates the LCOE by overestimating energy production. Moreover, monetary profits over the lifetime of the asset are not considered when looking exclusively at the LCOE, so that support schemes and electricity market prices are not integrated into the analysis. An attractive support scheme policy can, for instance, outweigh the accruing cost so as to promote a specific technology. Similarly, a particular market price structure can compensate for the occurring costs with the result that particular technologies can be more profitable although they are constituted by a higher LCOE. As (Joskow, 2011) argues, a comparison of LCOE for different technologies implies to treat the produced electricity as a uniform product which is always or in average priced equally. Yet due to market price fluctuations or different capacity factors and thus operating times the revenue stream can affect the actual profitability of the asset considerably.

Looking at some of the factors driving differences in LCOE for wind energy (Millborrow, 2016) illustrates the effect of wind condition combined with different investment costs. Figure 1 reproduce this comparison that illustrates higher cost level for offshore and also larger variation in costs depending on actual wind speed compared to onshore. This may suggest that nearshore should have a relatively large cost advantage to outweigh the likely less favourable wind conditions.

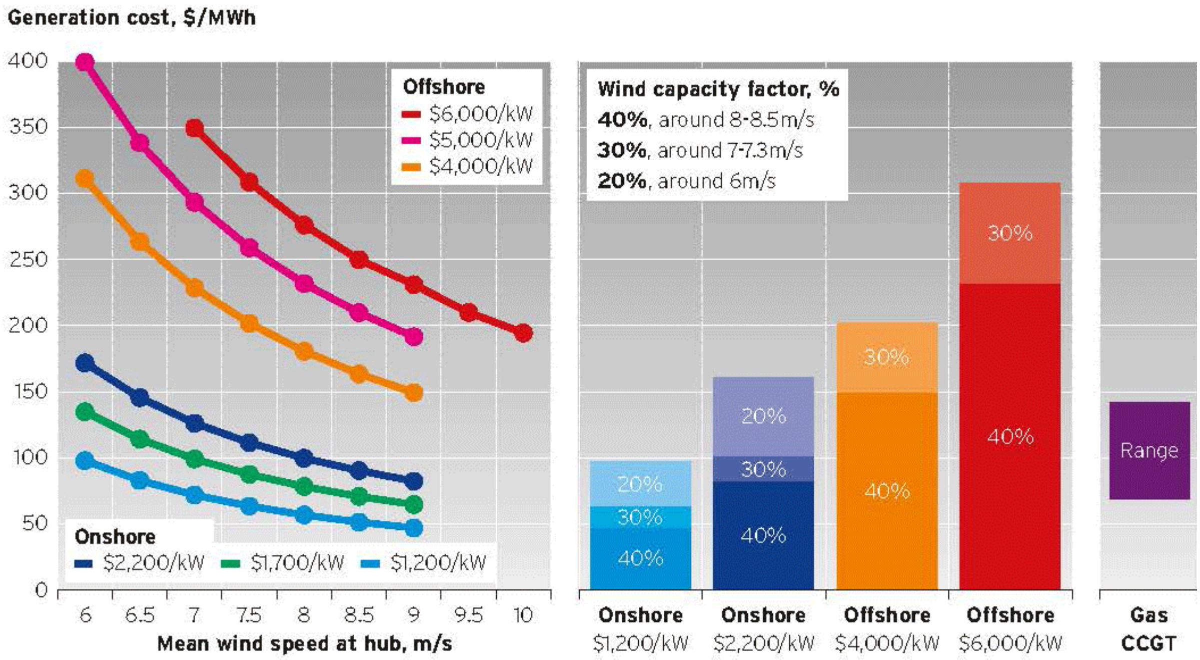

Figure 1: International comparison of LCOE for onshore and offshore wind depending on capacity factor and investment costs. Source: (Millborrow, 2016)

In Figure 1 the sensitivity of LCOE to investment cost and wind speed is given for both onshore and offshore wind.

Looking at estimates provided by (Wiser et al., 2011, fig. 7.23)) a LCOE of 5 USD cents/kWh with low investment cost at a 35% capacity factor is given . The right panel in their figure indicates a reduction of LCOE by 1.5-2 USD cents/kWh by reducing the discount rate from 7% to 3%.

2.2.1 Investment costs for offshore

Commonly the total investment costs are broken down into various cost components. By presenting different shares for the cost components, different projects can be compared with each other in more detail, since for instance the effects of the geographical characteristics of the offshore wind farms on the investment can be revealed. The comparison of different wind farms, however, in general, is more accurate for projects with similar commissioning time, similar geographical characteristics or comparable technical characteristics as for instance the type of turbines or the installed capacity.

Table 2.2 presents estimates of cost shares for onshore and offshore wind farms found in the literature for different publication years. The inclusion of components differs when looking at the different cost breakdowns, making it challenging to allocate different costs where they actually arise. Mainly, the installation cost is sometimes not reflected independently in presented cost breakdowns, leading to a distortion of the remaining cost component shares. Also, the cost for electrical components is sometimes not addressed in cost breakdowns, due to the fact that these components are not always included in the project scope of the wind farm investor, but are constructed and invested by other entities. The problem of different investment cost splits throughout the literature has been mentioned by (Voormolen et al., 2015). The cost shares for nearshore wind farms will probably be most similar to the offshore wind farms, with a marginally higher turbine share and slightly lower shares for electrical/connection costs and foundation.

	IRENA (2012) Onshore	IRENA (2012) Offshore	EWEA (2009) Offshore	Kitzing & Morthorst (2015) Offshore
Turbine	65-84%	44%	49%	40%–60%
Foundation		16%	21%	20%
Electrical/connection	9-14%	17%	21%	
Installation/ Construction	4-16%	13%		25%
Other	4-10%	10%	9%	

Table 2.2: Onshore and offshore wind farm cost shares from the literature

2.2.2 Operation and maintenance costs for offshore

Operation and Maintenance costs (O&M) or OPEX are expressed within the annual costs after commissioning of the farm and tend to increase over the farm's lifetime. The O&M costs are either expressed as variable cost per MWh generated or as a fixed cost per MW installed capacity, also lacking a standard approach for their definition. This is due to the fact that different parts of OPEX are variable cost, such as repair costs and to a certain extent spare parts and maintenance (which are likely to be related to the production level) and other parts are fixed costs, such as insurance costs, administration and regular maintenance (which are likely to be related to the fixed installed capacity. According to (Energinet.dk & Danish Energy Agency, 2017), for 2015 fixed O&M costs are 57,300 EUR/MW/year, while the variable costs are 4.3 EUR/MWh.

One can combine the variable cost depending on the energy produced and the residual fixed cost to obtain the total OPEX cost. For offshore wind, the variable part of the OPEX is estimated to be half of the total OPEX (Voormolen et al., 2015). In general, information regarding OPEX is hard to obtain. In the literature it is estimated to be in a range of 15–49 EUR/MWh (Kitzing & Morthorst, 2015),(Morthorst & Kitzing, 2016) in variable terms and 2.2%–4% in fixed terms as share of CAPEX (DECC (Department of Energy & Climate Change), 2013; Heptonstall et al., 2012; Prässler & Schaechtele, 2012). Over the total lifetime of the farm, the OPEX can encompass 25–30% of the total project cost (Kitzing & Morthorst, 2015).

Considering the aforementioned geographical cost drivers, mostly the distance to the nearest maintenance port directly affects the OPEX, due to the cost connected to the travel time of the maintenance vessel and potentially rougher weather conditions at sites further offshore, which constrain the operation time on site. After assessing the total cost of a wind farm project, the LCOE can be estimated when predicting the energy generation of the farm over the total lifetime.

3 Offshore and nearshore cost curve for Denmark

3.1 Current status of offshore wind energy in Denmark.

Offshore wind energy has been growing in Denmark in a sustained manner, since the first offshore wind turbine park, *Vindeby*, was erected in 1991. As of 2017, there are 12 offshore wind turbine farms in Denmark, since the decommissioning of the *Vindeby* park, with a total installed capacity of 1271 MW (Danish Energy Agency, 2015a). A list of existing offshore wind energy farms and some necessary information is found in Table 3.1.

Wind Farm	Lifetime Capacity Factor	Age [Years]	Installed Capacity [MW]
Anholt 1	48.6%	4	399.6
Avedøre Holme	38.0%	7	10.8
Frederikshavn	30.5%	14	7.6
Horns Rev I	41.8%	15	160

Horns Rev II	47.7%	8	209.3
Middelgrunden	25.4%	17	40
Nysted (Rødsand) I	37.0%	14	165.6
Nysted (Rødsand) II	43.4%	7	207
Rønland I	44.5%	15	17.2
Samsø	39.1%	15	23
Sprogø	34.2%	8	21
Tunø Knob	30.2%	22	5
Vindeby (closed)	21.6%	26	4.95
Total	**41.4% (avg.)**	**13.2 (avg.)**	**1271**

Table 3.1: Existing offshore wind farms in Denmark

It is expected for offshore wind to keep expanding in future years, as part of the strategy regarding renewable energy goals. Currently, there are eight projects under development or assigned for environmental impact assessment with a total nameplate capacity of up to 2.2 GW: *Horns Rev 3, Kriegers Flak, Vesterhav Nord og Syd, Nissum Bredning, Omø Syd, Jammerland Bugt, Mejl Flak,* and *Lillebælt Syd*. Horn Rev3 will be completed in 2019, the next two after 2020. Only Vesterhav Nord and Syd are nearshore wind farms at a total capacity of 350MW. Furthermore, a number of areas for future tenders are being considered for the development of new offshore wind energy farms. Some of the areas are offshore locations close to the shore, which aim to lower the costs for installing and operating the wind turbines, as for example *Sejerøbugten, Smålandsfarvandet* and *Sæby* (Danish Energy Agency & Energinet.dk, 2013).

3.2 Costs for Offshore wind in Denmark

The major factor resulting in higher offshore cost in Denmark in comparison with onshore wind is the significantly higher capital cost. Costs will vary depending on the location, due to water depth, distance to coast, sea conditions, and more (Kitzing & Morthorst, 2015). However, the variation in Denmark is expected to be lees due to less variation in water depth, distance to shore and less variation in offshore wind conditions.

Denmark is probably positioned in the low end of the international average cost for off-shore wind development. This is evident from a comparison of levelised cost of offshore wind energy (LCOE) including projections from major agencies and associations in the wind sector. In Figure 2 we compare cost levels across the projections of several reports. The wideness of the cost range for each source reflects both the uncertainty in technology development and the underlying difference in cost driving characteristics within the area examined (country/region). The Danish Energy Agency numbers and forecasts are at the lowest level compared to the levels provided by other sources. Therefore, we must expect that the cost benefits from moving wind farms from average off-shore to nearshore locations in Denmark is less than for most other countries (in line with the generally shallow seabed conditions in Denmark).

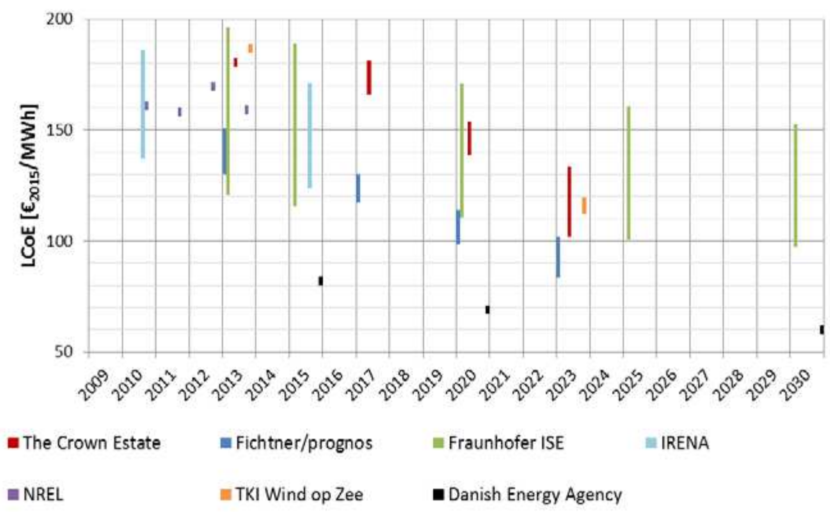

Figure 2 Comparison of levelised cost estimates and ranges for offshore wind in the literature

The estimates in **Figure 2** are based on the following sources: (Fichtner/prognos, 2013; Fraunhofer ISE, 2013; International Renewable Energy Agency, 2012; The Crown Estate, 2012; TKI Wind op Zee, 2015).

The cost projections in **Figure 2** assume a considerable cost reduction over time, but it is not clear whether this is expected to cover mainly the far off-shore projects in deeper waters. The cost reductions in offshore have been studied internationally examining learning, time and scaling effects as in (Van der Zwaan et al., 2012). If cost decreases are expected to be dominated by foundation technology improvement and installation cost reductions, then the nearshore projects may benefit less and thus the relative cost advantage of nearshore wind will decline over time.

3.3 The Danish offshore LCOE cost curve

We are interested in creating a cost curve that combines the potential exploited with the associated cost of doing so, for nearshore and far offshore wind energy. Among the factors that affect the costs for different potentials, we could consider three general categories: technical costs that will vary with water depth and distance to shore, costs associated to availability and profiles of wind in the area, and costs associated with the social impact produced by the wind farm. In (Pablo; Hevia-Koch & Klinge Jacobsen, 2018) onshore basic costs were combined with costs to secure local acceptance for onshore development relative to offshore.

From a technical perspective, as different wind sites are exploited, two main variables will affect these previous costs: distance to shore, and water depth. Technical costs will be affected by both variables: as water depth increases it becomes more expensive to install the wind turbines, and at specific water depths, more expensive foundation technologies have to be used. Similarly, as the distance to shore increases, O&M becomes more expensive and the costs for cabling during installation, as well as the costs related to port availability and installation time increase as well.

When looking at the prospect of future offshore wind energy expansion, we must account not only for the total existing potential in terms of areas with wind but also for the associated evolution of cost as this potential is exploited. As offshore wind energy grows, the first areas to be utilised will be those with lower costs, and therefore leaving for later exploitation high-cost areas. Even if we ignored the time dimension and associated technological changes, sites that are exploited earlier will still present lower costs, either due to being sites with better wind potential conditions, or with conditions that make investment costs lower (such as water depth).

Based on data obtained by the RESOLVE model, and presented in (Beurskens & Hekkenberg, 2011), we construct a cost curve for offshore wind potential in Denmark that considers a total offshore wind expansion potential of 10.7 GW. Based on the data and cost levels available at the time the LCOE levels range between 9 c€/kWh for small amounts of exploited potential, climbing steadily up to approximately 17 c€/kWh before spiking up to a final level of 19.9 c€/kWh for the full potential. This upwards sloping curve represents the increased costs of further exploiting wind sites, as discussed above. These estimates are consistent with several other studies finding prognosis of offshore wind LCOE (Fichtner/prognos, 2013; Fraunhofer ISE, 2013; IRENA, 2012; Mone et al., 2015; The Crown Estate, 2012; TKI Wind op Zee, 2015), a selection of which is shown in Figure 2. It is interesting to note the extensive range of uncertainty regarding the levels of LCOE prognosticated.

Recently, offshore cost estimates have dropped significantly for Denmark and neighbouring areas, as evidenced by the recent Kriegers Flak project with a winning bid of 4.9 c€/kWh. Interestingly, this development presents a level below any of the existing LCOE estimates. For this reason, we adjust the cost curve such that the cost level but not the relation with water depth and other drivers remain the same. We assume that for example the increased cost of exploiting areas with deeper waters, further from the shore, or with lower wind potential still increase costs. The adjusted cost curve potentials following (Beurskens & Hekkenberg, 2011) data are presented in Figure 3.

The adjusted cost curve includes all offshore potentials in Denmark, but only a limited amount of the include potential is actually nearshore potentials. We want to compare this mainly further offshore potential with cost curves for nearshore. Around 1000 MW of the potential in the figure corresponds to nearshore locations and the cost level is close to the just above 6c€/kWh expected for the Vesterhav Syd site that will be developed 2019-2021.

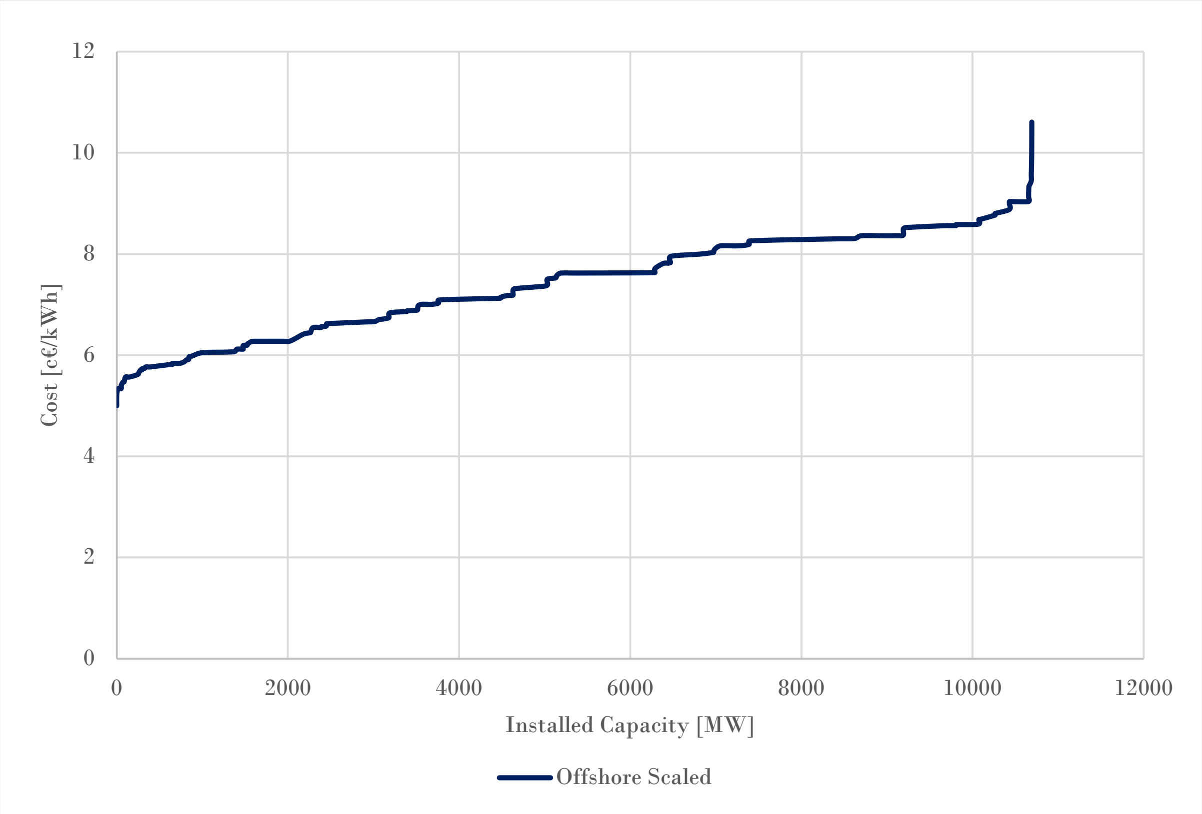

Figure 3: Offshore wind cost curve for Denmark adjusted from 2011 figures used in (Beurskens & Hekkenberg, 2011) *to level of Kriegers Flak (LCOE)*

4 Results for comparing nearshore and further offshore development in Denmark

4.1 Cost differences in Denmark

We define nearshore wind as turbines that are up to 15 km off the coast, which provide a lot of potential in Denmark that have a very long coastline. The distance is not the only important cost driver, but it is this parameter that is significant and related to both cost advantages for nearshore development and disadvantages arising from public preferences against close to shore wind turbines.

To quantify the potential cost advantages of nearshore, we use an international source (EEA, 2009) that provides scaling factors based on only distance to shore and water depth. We then recalculate and calibrate based on investment data from one specific Danish wind farm Rødsand II.

Table 2 provides scaling factors for investment costs based on only depth and distance from shore. The origin is 4 km from shore and a water depth of 15m. Nearshore costs are then represented by the first 5 columns up to 15 km from shore giving also factors for two additional distances in the last two columns. For the water depth the table exceeds what is basically realistic for Denmark. If keeping the distance down to max 15 km the depth will rarely be more than 25m. That means the least favourable cost characteristics in Denmark will probably be characterised by only 9% higher investment cost than in the origin. With max 15 km from shore as the definition for nearshore we will not have to consider if an offshore substation will have to be build, which would probably be nearly as large a cost difference as the 9% in the table.

Water depth\ Distance from shore	4 km	8 km	10 km	12 km	15 km	20 km	25 km
5m							
10m	0.967	0.974	0.978	0.982	0.988	0.998	1.008
15m	**1.000**	1.008	1.012	1.016	1.022	1.033	1.043
20m	1.034	1.042	1.046	1.050	1.056	1.067	1.078
25m	1.067	1.075	1.080	1.084	1.090	1.102	1.113
30m	1.124	1.133	1.137	1.141	1.148	1.160	1.172
35m	1.237	1.247	1.252	1.257	1.264	1.277	1.290

Source: Calculated based on EEA, 2009 (Table 6.4)

Table 2 Investment cost scaling factors used for DK comparison

To compare the (EEA, 2009) scaling factors with data for Denmark a simple regression for total levelised costs of 14 offshore wind farms based on depth and distance from shore is reported. We utilise information for distance to shore, water depth, and LCOE for Danish offshore wind farms from 1991 up to 2018, which is a long period of time considering the tremendous technology development. We don't account for that, but acknowledge that these factors may be just as important for explaining different cost levels. The water depth here ranges from a few m up to around 25 m. To see the influence of distance to shore and water depth, we create three linear regression models that express LCOE as a function of distance to shore, water depth, and both. The results of two of the models are presented in Table 3. As we can see, the models indicate that the LCOE is not explained by the distance to shore, which has a very non-significant coefficient, but by the depth of the water. We can see that distance to shore fails to be significant even at the 10% level. While there is definitively correlation between the two variables in general this effect seems less critical in the Danish data.

This result might be explained by the particularities of the Danish continental shelf, where it extends for a significant distance after the shoreline with a very limited slope, and the inner Danish waters also includes a lot of shallow waters grounds and flaks. Compared to other countries in the EU, such as The Netherlands, Belgium, or Germany, there are numerous locations in Denmark where the water depth is limited, despite increased distances to the shore. This means that a reduction in distance to shore does not necessarily imply a reduction in water depth; and therefore the impact on LCOE will be less.

The regression results must be used carefully and we just see it as an indication of an upper limit for the cost effect of water depth. Simply using the depth parameter estimate would increase costs with around 33% from 15m to 25m depth compared to the maximum 9% with scaling factors. Clearly this illustrates that the Danish story of offshore wind is very much influenced by other factors than the "pure" cost drivers represented by depth and distance. We go forward *using the EEA very low values* for investment cost dependence on water depth that will be more favourable to locating wind further away from the cost if there is any substantial preference for pushing wind further away.

Regression on LCOE with **depth and distance**	Estimate	Std. Error	t value	Pr(>|t|)
Intercept	46.5945	9.8109	4.749	0.0008
Depth	2.9624	0.7152	4.142	0.0020
Distance	0.0766	0.4617	0.166	0.8715
Regression on LCOE with **depth only**	Estimate	Std. Error	t value	Pr(>|t|)
Intercept	47.1235	8.8592	5.319	0.0002
Depth	2.9889	0.6656	4.491	0.0009

Table 3 Results for regression with depth and distance from shore for Danish offshore wind farms

The ability to generalise the cost curves from a Danish sample of nearshore wind farm sites, was investigated but it is very difficult to characterise other potential sites in DK depending on the few cost drivers that can be extracted from existing developments/projects. The historical data are covering many years and a tremendous development in turbine size and technology. The amount of local conditions affecting the optimal farm layout, seabed characteristic differences and connection costs seems to dominate the generalizable cost drivers. The connection costs for example vary more among nearshore Danish sites than between average nearshore and average offshore DK sites.

The shares of cost components are different for near-shore and far offshore wind farms, but the cost drivers are basically the same. Connection cabling, as well as installation (and mostly foundations) represent a smaller cost share for nearshore wind, but due to the more varying local conditions for connection, the distance from shore is less important as cost driver compared to the depth. The sea depth and wind conditions are the main drivers, similar to far offshore, and the turbines/steel costs are providing similar cost impacts for the two categories. We therefore chose to illustrate a potential cost advantage based on the two cost drivers only as given in the scaling factors from Table 2.

In **Figure 4** the investment cost curves for different distances and depth are illustrated with the Rødsand II wind farm as the reference sited at an approximate 10km distance from shore and an average depth of 10m. Two other recent investment cost figures are also provided in the graph as points.

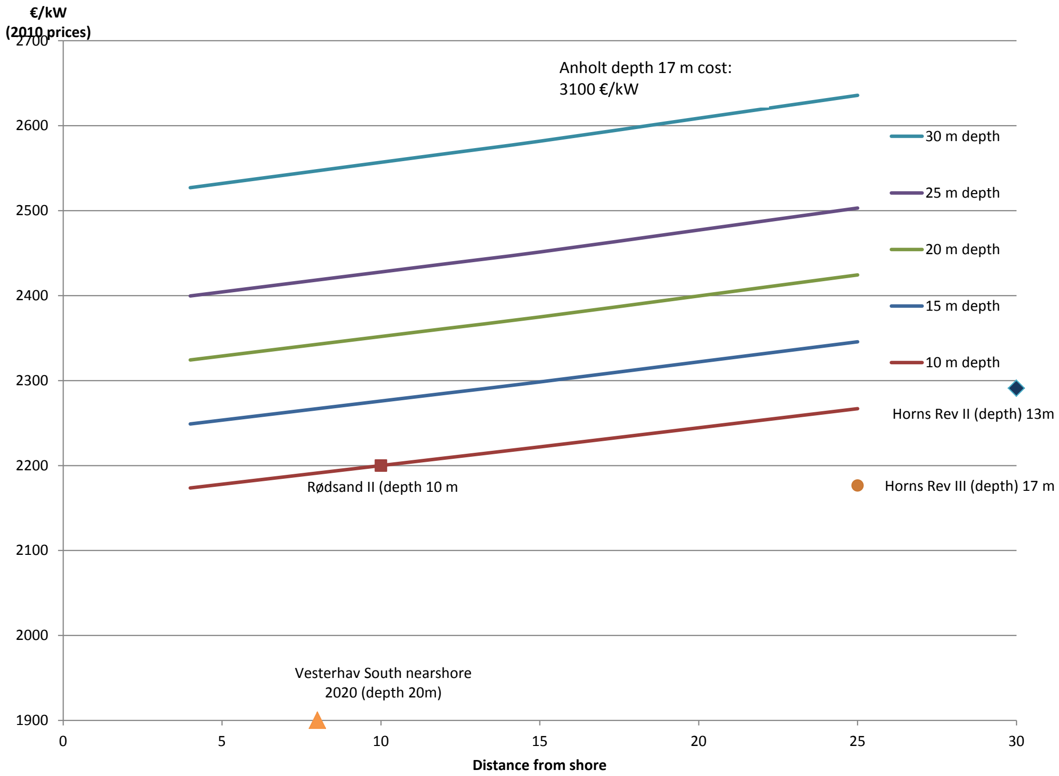

Figure 4 Investment cost illustration for DK in 2010 with indicative benefit (Based on investment cost for Rødsand II and EEA scaling factors in Table 2)

The illustration for potential benefits in DK clearly shows that the main cost benefit will be achieved if it is possible to reduce the water depth by locating the wind farms closer to shore (moving left **and down** in the figure). If water depth is not reduced, then the cost reduction of moving from a location similar to Horns Rev III to a location just 4-5km from shore will be only 4% (just moving left). If conditions regarding water depth like Horns Rev III (approx. 17m) are very scarce, the relevant comparison might be between average water depths of 25m versus water depths similar to some DK nearshore sites, of around 15m. The benefit in this case will be around **10%** reduction of CAPEX. The nearshore tender in Denmark resulted in quite low bids for nearshore at Vesterhav Syd and Nord that are equivalent to cost reductions of around 20% in a time span of about 10 years from Rødsand to Vesterhav development.

4.2 Perspectives on willingness to pay for moving turbines further offshore

To compare the cost advantage of locating wind farms closer to shore in Denmark a hypothetical willingness to pay is combined with the cost advantage of moving turbines further offshore. The marginal costs of only increasing the distance is the lower limit of costs and the case where increasing distance from one level to the next (for example 4 km to 8 km) leads to increasing depth also from 10 to 25m represent the upper limit on marginal costs. Any marginal cost level within the top curve and the bottom one (increasing distance with 10m depth constant) is possible, but the lower part of the range is most likely in Denmark where increasing distance by eg. 4 km increase depth with 5-10m.

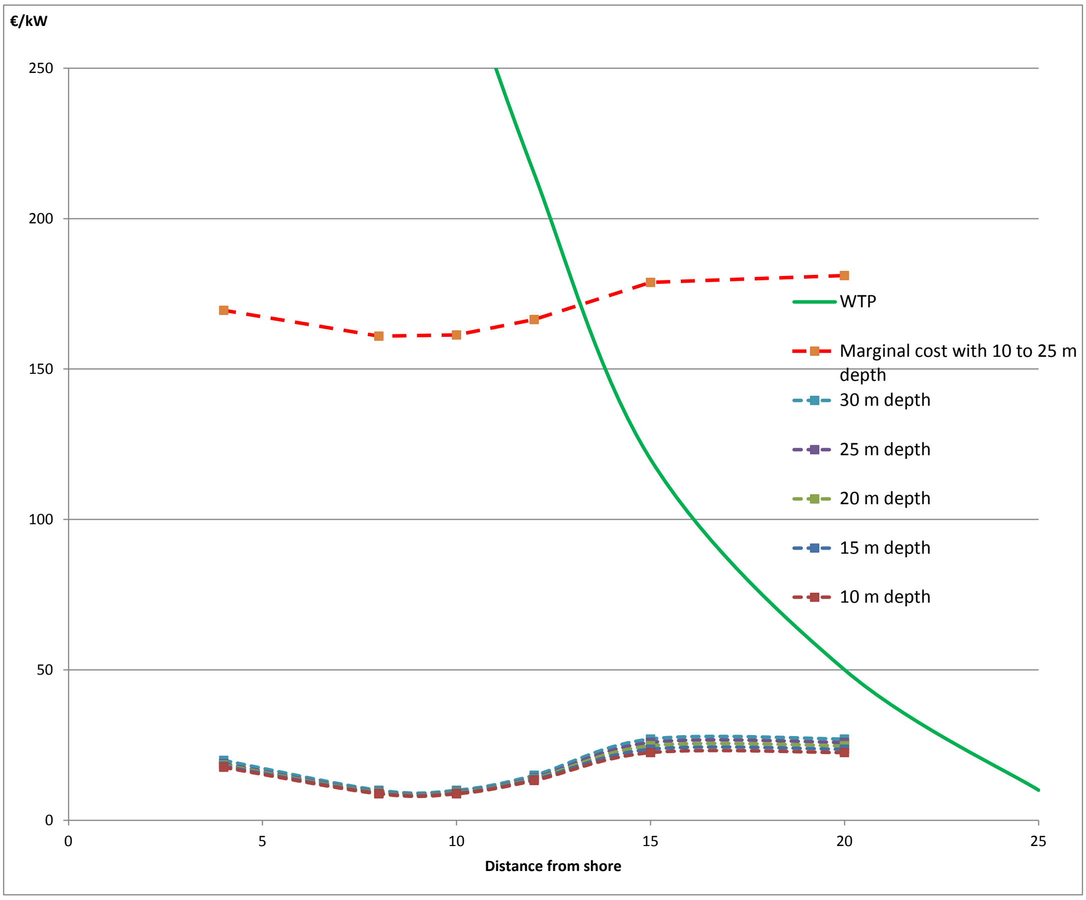

Figure 5 Examples of nearshore marginal costs and willingness to pay for moving turbines further off shore

The range of marginal cost for increasing distance and depth at the same time most representative for Danish conditions is probably 50-100 €/kW for 4 km distance and 5m depth addition. With the diminishing marginal willingness to pay for distance example assumed there would be a benefit of moving turbines to somewhere between 15 and 20 km from shore. This exemplifies that the marginal willingness to pay for distance is relevant to consider for the specific sites in consideration for development, but that the actual cost additions (especially depth) implications should be balanced with that. As the marginal willingness to pay for wind is probably extremely site and context specific (Pablo Hevia-Koch & Ladenburg, 2016), (Pablo Hevia-Koch et al., 2018) this is just an illustrative example, but others have examined the willingness to pay for the distance and (Krueger et al., 2011) find that there is willingness to pay for moving turbines 20 km off the cost corresponding with the additional costs of doing so.

5 Conclusion and policy implications

The main conclusion is that nearshore potentials in Denmark may not be sufficiently cost attractive to balance the willingness to pay to locate wind farms slightly further away from the coast. This is due to the relatively shallow waters in Denmark allowing wind farms to be developed a bit further from shore without considerably increasing the water depth.

Nearshore wind potentials exist in Denmark, and they have potentially lower costs than further offshore, but the cost advantage is probably lower than in other countries, because offshore costs are comparatively lower in Denmark. The nearshore potentials are smaller, and possible wind farm sizing is also limited for some sites in Denmark. However, there are still potentials with lower costs than further ashore sites. It is difficult to identify one main contribution as e.g. more shallow water as the source of expected lower costs based on a small sample of data examined for Denmark. Significant cost advantages are however only expected if water depth is considerably lower than at more offshore sites.

An illustrative calculation of benefits indicates that cost could be only 4% lower nearshore if no reduction in water depth is achieved. Compared to this, moving from 25 km distance at the same time as reducing water depth from 25m to 15m may provide cost reductions of around 10%.

The smaller possible size of the nearshore projects may facilitate more competition, especially from domestic developers as has been an argument in Denmark, but it may also lead to less participation from the global offshore developers that exploit economies of scale in wind farms. If dominated by the first, this produces a more competitive environment for the bidding process of the smaller nearshore projects that may allow new entrants into the offshore development and eventually pushes for lower prices.

Finally we illustrate that there is a possible trade-off between the additional cost of moving turbines further offshore and the willingness of people to pay for that. As long as further offshore do not imply increased depth the additional cost may be smaller than the willingness to pay, but for other cases increased depth will mean higher costs that can only be matched by willingness to pay for moving from extreme nearshore sites to 8-15 km off the coast. The local site specific cost characteristics and local willingness to pay must be considered in any case and no generalisation can be made even for the relatively small Danish case.

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