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Offshore Wind Potential in the North Sea

Long-run supply curves and cross-country competitiveness

Preface

In September 2021, the Danish Energy Agency conducted a public consultation on the proposed methodology for assessing the overall profitability of Denmark's planned energy islands. This report presents the results of one the three analyses announced in the public consultation, namely the construction of a long-term supply curve for offshore wind energy from the North Sea.

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Executive summary

This report describes the construction of long-run supply curves for offshore wind power from the North Sea. These supply curves can be used to assess the relative long-run competitiveness of the individual North Sea countries on the market for offshore wind power generation. Moreover, the supply curves can provide a long-run proxy for capture prices of electricity from the North Sea.

The analysis focuses on the North Sea area, as it expected to be the main arena for EU's planned massive offshore wind build-out towards 2050. This reflects the areas excellent wind resources, relatively shallow waters and considerable size. In the present analysis, it is assumed that the offshore wind build-out will be fully market based without the need for any state subsidies – an assumption supported by recent offshore wind tenders in e.g. Denmark and the United States.

The results suggest that Denmark has the potential to become a significant net exporter of offshore wind energy by 2050. More specifically, the analysis finds that it would be cost effective to locate around 10-15% of the total North Sea build-out by 2050 in the Danish part of the North Sea, that is already designated as development zones for renewable energy, corresponding to 25-35 GW of installed capacity (incl. already existing offshore wind farms). The analysis also indicates a level of long-run capture prices for offshore wind in the range 265-310 DKK/MWh (or approx. 35-42 EUR/MWh) across the region.

The analysis is based on the technical potentials and expected construction and operating costs for offshore wind farms – taking into account differences in water depths, distances to landfall sites and wind conditions. The supply curves are constructed assuming radially connected offshore wind farms (either HVAC or HVDC, depending on distance). The costs and configuration of more complex transmission concepts (i.e. energy hubs and meshed-grid networks) is rather uncertain, whereas the costs of radial offshore wind farms can be estimated based on many already commissioned projects. The cost of radially-connected offshore wind farms can be regarded as a non-discriminating, upper bound on the cost of evacuating offshore wind from the North Sea, as other transmission concepts would be realised if they prove more cost-effective.

Methodology

The starting point for the analysis is the estimation of long-term LCoE (Levelised Cost of Electricity) for offshore wind farms based on expected CAPEX, OPEX and production potential at all possible sites across the North Sea. LCoE can be interpreted as the lifetime average electricity price, which would equate the present value of costs (both CAPEX and OPEX) and income (sale of electricity) (**see Box 1**).

Only LCoE-differences due to variations in *distance to landfall, water depth and wind conditions* are modelled. All other costs are assumed to be identical across all possible sites. This evidently represents a significant simplification of the cost of establishing actual offshore wind farms. However, these variables are key drivers of LCoE-differences across sites, and arguably – for the purposes of this highly aggregated study – capture most of the relevant variation in costs and feasibility. It is assumed that the cost of establishing and operating offshore wind farms exhibit the same dependencies on depth, distance, etc. across countries.

Cost estimation

For each cost component, its dependency on *distance to landfall, water depth and wind conditions* (if any) is quantified.[1] Next, these cost functions are used to compute LCoE-levels for each 1 km^2 area of the North Sea that are deemed available for the development of offshore wind. This results in a quantification of Denmark's and other North Sea countries' long-run offshore wind energy potentials and associated costs.

In the first part of the analysis, the *distance to landfall* is measured as the nearest distance to the country to which the area belong. Here the focus is on the gross potentials (not taking into account environment protection areas, maritime traffic density, etc.) and the derived aggregated and individual country supply curves.

In the second part of the analysis, it is assumed – somewhat more realistically – that the energy generated offshore must be supplied to countries according to their long-term (2050) projected energy demands – instead of being evacuated to the nearest domestic shores. For this purpose, the most cost-effective distribution of generating capacity (including radial transmission) across countries is found by solving a cross-border cost minimisation problem. For simplicity, it is assumed that each country must receive all imported electricity at a specific landfall point on its North Sea coast. Electricity for domestic consumption can still be connected directly to the nearest shore.

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[1] The calculations are performed using unit cost levels corresponding to an offshore wind farm of approx. 1 GW capacity.

The analysis seeks to reflect potentials and costs in the long run – defined here as the year 2050. This horizon also matches the horizon of the EU's offshore wind strategy and its net-zero emissions target.

The supply curves and their interpretation are based on the theoretical expectation of free entry and exit in the offshore wind sector and that private actors will continue to develop offshore wind farms as long as the capture price of offshore wind power exceeds LCoE (**see Box 1)**.

Box 1: Long-run capture prices and average costs of offshore wind power

Classical economic theory states that the equilibrium price of a given service in a market with perfect competition, in the long run, will equal the average cost of production. If the market price of the service is higher than the average cost of production (including the required market return on the invested capital), the market will attract new businesses. The competition for market share will push down the price of the service itself, while the demand for the factors of production (capital and labour) will increase. Both mechanisms will lead to declining profits. If production becomes unprofitable, companies will leave the market, re-establishing an equilibrium where the price of the service corresponds to its average cost of production.

In practice, the energy market (in Europe and elsewhere) does not entirely fit the stylized description above. Instead, the energy market consists of several interconnected markets (e.g. electricity, gas and district heating) with numerous market players. The suppliers in the electricity market also operate with various technologies (thermal power plants, wind farms, solar PV plants, biomass, storage, etc.), some of which have strongly weather-dependent output. In addition, the market participants are subject to extensive regulation and the state authorities are often involved in setting up new capacity, for example, in the form of tenders or conditions for grid connection.

In the long run, where renewable energy plants can be expected to be developed on market conditions, a reasonable assumption is that net additions of offshore wind capacity will be established to the point where the capture price for offshore wind power covers production costs (calculated as LCoE, cf. below).

The low marginal cost of producing electricity from wind farms also means that production almost solely depends on the wind speed. This mechanical link between wind conditions and production means that total output over the wind farm's life can be determined quite accurately, which allows a long-term supply curve for offshore wind to be calculated without modelling capacities and pricing for other technologies. This contrasts with a thermal power plant, for example, whose much higher marginal costs (depending on fuel and CO_2 quota prices) causes power generation to strongly depend on market conditions. This dependency makes it difficult to estimate long-term LCoE for such plants without a detailed model of the entire electricity market including patterns of dispatch of different technologies.

Cost data

LCoE levels are calculated for all North Sea areas. The levels reflect the cost of establishing radially connected wind farms at the given sites. In the baseline, a power density of 4.5 MW/km^2 is used across all locations in the North Sea, even though, in reality, the countries included have used different densities in the past due to different trade-offs between attainable LCoE levels (typically increasing with density due to wake losses) and space use.

Table 1
Baseline assumptions

Countries included in the analysis	Norway, Denmark, Germany, The Netherlands, Belgium & UK
Reference offshore wind farm size	1 GW radially connected (for cost calculations)
Offshore wind farm density	4.5 MW/km^2
Minimum distance to shore	20 km
Onshore cable length	50 km
Wake and transmission losses	5 percent / 3 percent (for both AC and DC)

The expected long-run LCoE is calculated based on the Danish Energy Agency's technology catalogue and various reports by engineering firms. The technology catalogue includes development, investment and operating costs for offshore wind farms. **Table 2** lists the different cost- and production components in the LCoE-calculation and their modelled dependency on the key geographical factors mentioned above.

Table 2
LCoE components and their variation with water depth, distance to shore and wind speed

Category	Cost element	Assumed dependence
CAPEX	Base investment (wind turbine, array cables etc.) per MW capacity	Fixed for reference wind turbine
CAPEX	Foundation costs per MW capacity	Water depth
CAPEX	Grid connection cost (offshore platforms incl. substations and cables) per MW	Distance to shore (platform cost depends on the choice of AC vs. DC, which depends on distance)
OPEX	Fixed costs per MW capacity	Fixed (in practice, some dependency is likely, but not quantified in this analysis)
OPEX	Variable costs per MWh	Fixed
DEVEX	Development costs as a percentage of Capex	Fixed
Production	Full-load hours	Site-specific wind-speed distributions
WACC	Real discount rate of 5%	Fixed

Sources: Ea Energianalyse: Offshore wind and infrastructure (April, 2020), slide 25; DEA technology catalogue (March, 2022), Chapter on offshore wind.

Geographical data

The geographical dataset for the North sea has a resolution of 1 km^2. For each individual point there is information on water depth, distance to nearest shore of the associated country (EEZ) and wind speed distribution. The underlying dataset also contains information on whether the individual points are part of a Natura 2000-area as well as the intensity of ship traffic in the area.[2][3]

The North Sea consists of relatively shallow waters. More specifically, almost half of the entire North Sea area has a water depth below 60 meter. In Denmark, Germany, Belgium and the Netherlands this is the case for more than 90% of the area. It is assumed that fixed bottom foundations (either monopiles or e.g. jacket structures) are viable until around 60 meters. The greatest depths are found along the coast of Norway (**see Chart 1,** left). Even these areas are included in the gross potential, however, as it is assumed that the cost of floating wind turbines by 2050

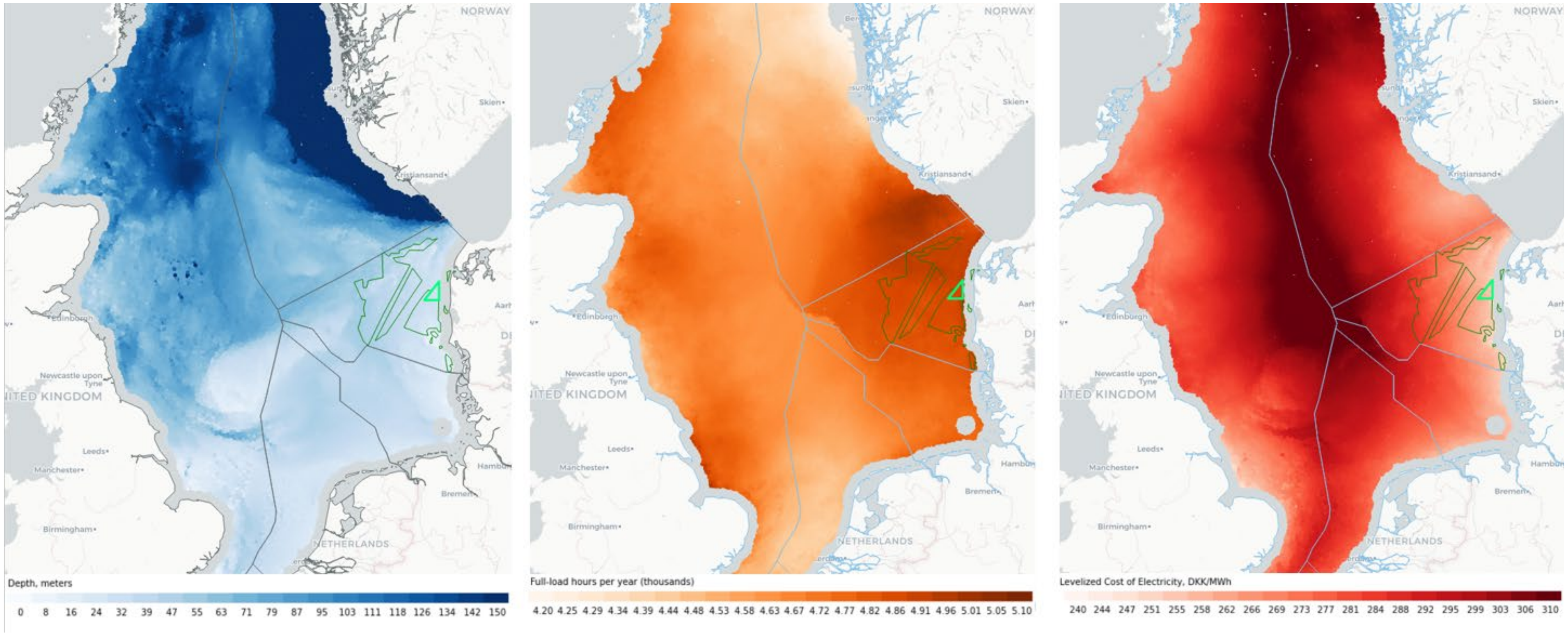
[2] The geographical dataset is constructed on the basis of data from European Marine Observation and Data Network (EMODnet) and Global Wind Atlas
[3] Natura 2000 is a network of core breeding and resting sites for rare and threatened species, and some rare natural habitat types which are protected in their own right. It stretches across all 27 EU countries, both on land and at sea.

will be at par with fixed-bottom foundations at 60 meters of depth. The center heat map shows the variation in attainable full load hours.

The LCoE-heatmap (right) shows that near-shore areas with low water depth and high average wind speed are characterized by low LCoE levels making it economically more attractive to develop offshore wind at such locations. Furthermore, as expected, LCoE-levels are gradually increasing as the distance to the shore increases.

The Chart also illustrates the notable effect of shallow depth on LCoE, where especially Dogger Bank (mainly within the British EEZ) is a light red spot in an otherwise deep red area far offshore. Finally, the effect of wind resources is also visible, where e.g. the Danish near-shore locations offer lower LCoE-levels than the Dutch due to stronger winds at the Danish locations.

Chart 1: Heatmaps of water depths, full load hours and LCoE-levels



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Demand for offshore wind from the North Sea

In its 2020 offshore wind energy strategy, the European Commission targets 300 GW of offshore wind in the EU by 2050.[4] Although the strategy does not specify in which European waters this capacity is envisaged, it is likely that the North Sea will play a major role, given its favorable geographical characteristics.

Estimating the demand

To quantify the demand for offshore wind power from the North Sea, this analysis takes as its baseline the EU commission's 2050 net-zero carbon emission scenario (Fit-for-55 MIX scenario). The scenario is run through the Balmorel energy system model to determine optimal generation capacities across European countries/bidding zones and technologies. Based on this analysis, the total demand for offshore wind energy among the North Sea countries is estimated to be around 1200 TWh in 2050, cf. **Table 3**, corresponding to an installed offshore wind capacity of approx. 250 GW.

Table 3
Scenario for electricity demand in the North Sea countries by 2050

Countries	DK	DE	NL	BE	UK	NO	Total
Total demand, TWh	125	1028	354	179	781	181	**2648**
Generation excl. offshore wind, TWh	59	646	74	56	442	181	**1458**
Residual to be covered by offshore wind, TWh	66	382	280	123	339	0	**1190**

Source: Danish Energy Agency calculations based on input from Ea Energy Analyses.

From this estimate of the total demand for electricity (which includes demand related to both direct and indirect electrification), the estimated generation from sources other than offshore wind[5] are subtracted to arrive at a residual demand to be covered by offshore wind.

[4] European Commission, November 2020: *An EU strategy to harness the potential of offshore renewable energy for a climate neutral future.*
[5] By 2050, this is expected to be predominantly onshore wind and solar power plants.

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The underlying assumption is that the build-out of onshore technologies is preferable to offshore wind power due to lower LCoE, however, onshore technologies are to a significant extent limited by public acceptance. On the other hand, offshore wind power capacity can be installed in practically limitless quantities compared to the size of the relevant demand. Furthermore, it is assumed that the power generated in the North Sea is also consumed among the North Sea countries, i.e. there is zero net power export out of the region. Additionally, it is assumed that the North Sea countries do not install offshore wind capacity in other nearby seas such as the Irish, Baltic or the Norwegian Sea.

In practice, of course, the consumption of electricity produced in the North Sea will not be entirely restricted to the North Sea countries given the dynamics of the physical electricity transmission grid and economic market flows (**see box 1**). However, these simplifying assumptions will suffice for the present purposes of this analysis.

Results

The analysis finds an overall long-term capture price for electricity generated from offshore wind of approx. 270 DKK/MWh (35 EUR/MWh) (**Part 1**). A more comprehensive and nuanced analysis (**Part 2**) suggests that Denmark has the potential to become a significant net exporter of offshore wind energy by 2050 – with Germany likely to be the main importer of this energy. It is found that it may be cost-effective to install 25-35 GW of capacity in the Danish part of the North Sea. This may be higher if offshore electrolysis become a viable option, as the cost of transmission is markedly lower for hydrogen than for electricity, increasing the competitiveness of Danish energy exports.

Part 1

In this first part of the analysis, the variable *distance to landfall* is being measured as the distance to closest shore of the country to which a given 1 km^2 area belong. Furthermore, no limitations on area use (due to e.g. environmental protection, maritime traffic corridors, military zones, etc.) are imposed. Hence, the potential found should be seen as a hypothetical gross potential. These – admittedly unrealistic – assumptions are relaxed below.

The gross supply curve and marginal price

As the geographical data show (**see Chart 1**), the North Sea area exhibits relatively low water depths and favorable wind conditions, making the area economically attractive for developing offshore wind at scale.

A gross supply curve can be constructed by sorting the 1 km^2 areas by their LCoE levels and plotting these against the cumulative capacity. Such a curve describes the estimated relation between the North Sea's overall capacity (incl. existing offshore wind farms) and associated costs (**see Chart 2**) of establishing the marginal capacity. The curve shows that the most cost-effective sites with very low LCoE are somewhat limited. The costs increase rather steeply until around 100 GW of capacity. After that level, the curve flattens and a very large area with comparatively little variation in costs is available – extending all the way beyond 1000 GW, i.e. far beyond expected demand.

If the estimated total demanded capacity of 250 GW (corresponding to 1,200 TWh offshore wind energy) is applied to the gross supply curve, the capture price per MWh (LCoE) required by the market to ensure the installation of the marginal wind farm is around 270 DKK/MWh (35 EUR/MWh) (**see Chart 3**). In other words, to ensure that the estimated future demand can be satisfied on a market basis (i.e. without subsidies), the 2050 capture price for electricity from offshore wind price must be around 270 DKK/MWh (35 EUR/MWh). Even allowing for +/- 20% variation in the assumed demand (e.g. in the range 200-300 GW), the estimated capture price remains in a narrow interval reflecting the flatness of the long-term supply curve.

The capture prices derived from the LCoE levels in **Chart 1** can be interpreted as "system prices" in the sense that any bottlenecks in international transmission is implicitly ignored. This stems from the assumption that all wind farms are connected to the closest national shore. This very restrictive assumption is relaxed in the second part of the analysis below – leading to higher prices in high-demand countries due to higher average transmission costs.

Chart 2: Gross long-term supply curve for North Sea offshore wind capacity

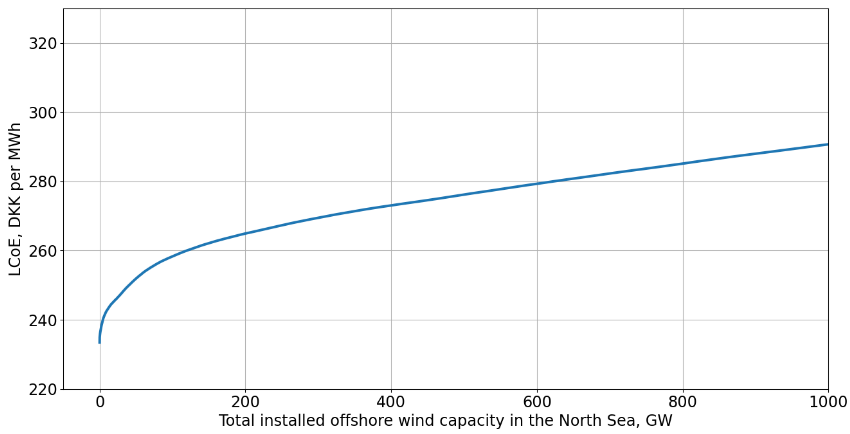
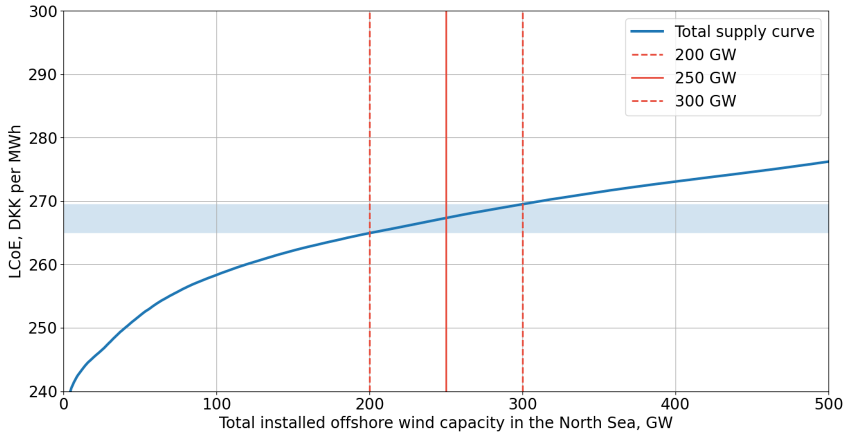


Chart 3: Estimated capture price for offshore wind in 2050



Part 2

This second part of the analysis focuses on the cost-effective distribution of generation capacity across the North Sea area, and – more narrowly – the Danish potential for exporting offshore wind energy to other North Sea nations. Therefore, the assumptions regarding transmission are modified. Specifically, the variable *distance to landfall* is no longer defined as the distance to the closest national shore. Instead, it is assumed that countries importing power must receive the power at a specific point on their shore. The cost calculation still allows wind farms generating power for national consumption to be connected to the nearest shore, though.

Moreover, additional geographical filters are applied to data. In the case of Denmark, the 2021 maritime spatial plan is used, in which areas designated to e.g. offshore wind development and renewable energy are laid out.[6] For the other countries, a residual method is used, where – somewhat conservatively – 25% of the total area is randomly removed to account for possible conflicting uses of the areas (e.g. fishing, defense, natural resource extraction, etc.). At a later stage, the analysis may be expanded to use actual maritime spatial plans for the other countries to the extent that such plans are accessible and provide a reasonably accurate picture of the likely space use in 2050.

Furthermore areas with intensive ship traffic and nature conservation areas (Natura 2000) are filtered out. However, with respect to Natura 2000, an exception is made for the UK: the large Dogger Bank area is assumed to be available for wind farm

[6] See https://havplan.dk

development – consistent with the fact that the UK is already using this area for that purpose.[7]

The Danish export potential

In order to estimate future distributions of power exports and imports, it is analysed how the estimated offshore wind demand in 2050 (**see table 3**) can be covered as cost-effectively as possible among the North Sea countries. In practical terms, this is done by solving a cross-border cost-minimisation problem, taking into account the site-specific variation in the transmission costs to specific landfall points in each country. **Chart 4** shows the cost-effective distribution of offshore wind areas to meet the countries' demand in 2050 using baseline assumptions. The colors represents the different countries[8], whereas the light hue represents HVAC-connected wind farms and the dark hue the HVDC-connected wind farms. The Charts in the **Appendix** show how the distribution change when assumptions about total power demand is varied, and will be touched upon in the sensitivity analysis below.

The map in **Chart 4** shows a clear picture of neighboring countries having an export advantage, as the cost of transmission increases with the distance to the importing country. Taking the Danish EEZ as an example: blue dots denote areas that are connected to Denmark, whereas red dots denote areas used for power exports to Germany. Note also that a large part of the areas already designated to offshore wind in the Danish maritime spatial plan (shown as green polygons[9]), should be used for exports to Germany according to the cost-minimising solution.

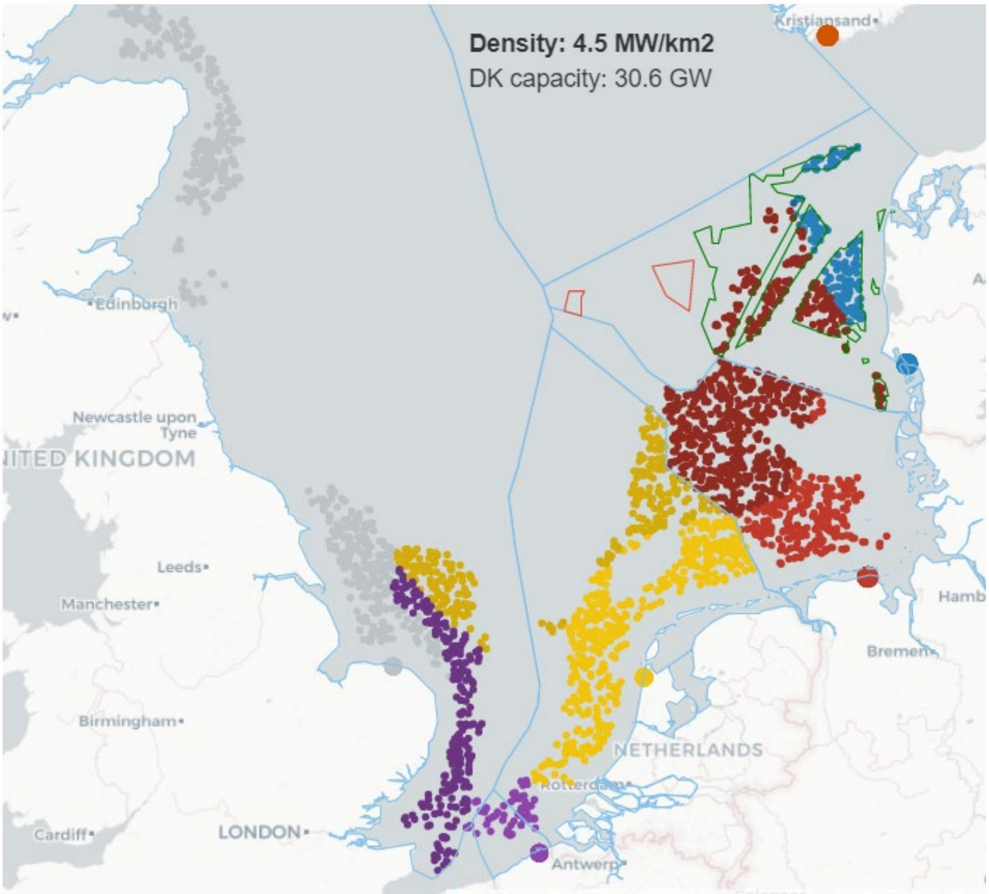
Please note that the analysis excludes a larger part of the total EEZ area for Denmark than for the other countries, and thus may somewhat understate the Danish export potential.

[7] See e.g. https://doggerbank.com/

[8] DK=Blue, DE=Red, NL=Yellow, BE=Magenta, UK=Grey

[9] The red polygons are additional areas which might in future also be designated offshore wind areas.

Chart 4: Scenario for cost-effective distribution of approx. 250 GW capacity



Note: Part of the simulated UK production along the northernmost parts of the UK shore is not visible on this map.

Chart 5 shows which countries can be expected to become net importers and net exporters of offshore wind energy from the North Sea by 2050, respectively. It can be seen that Germany and Belgium will be the main importers, reflecting these countries' limited sea areas compared to their electricity demand. Conversely, Denmark and the United Kingdom have the potential for becoming significant exporters of offshore wind energy. This calculation indicates that it is economically viable for Denmark to expand well beyond the capacity that is needed to cover Denmark's estimated domestic demand. However, it is essential to highlight uncertainties associated with these results, especially the overall level of electricity demand in 2050. Changes in the overall electricity demand is likely to strongly affect the demand of offshore wind energy. This reflects the assumption that countries will first exhaust their cheaper onshore production potentials, and offshore wind will cover the residual needed to meet total demand. A moderate shortfall in the total level of electricity demand could thus be reflected almost one-to-one in the demand for offshore wind energy.

The differing needs for transmission to cover the individual countries electricity demands leads to variation in marginal LCoE-levels, cf. **Chart 6**, which may again be regarded as a proxy for the equilibrium capture price for power delivered at the landfall point. The prices vary from around 265 DKK/MWh (35 EUR/MWh) in Denmark and the United Kingdom to around 310 DKK/MWh (42 EUR/MWh) in Germany and Belgium.

Chart 5: Annual net electricity export from offshore wind

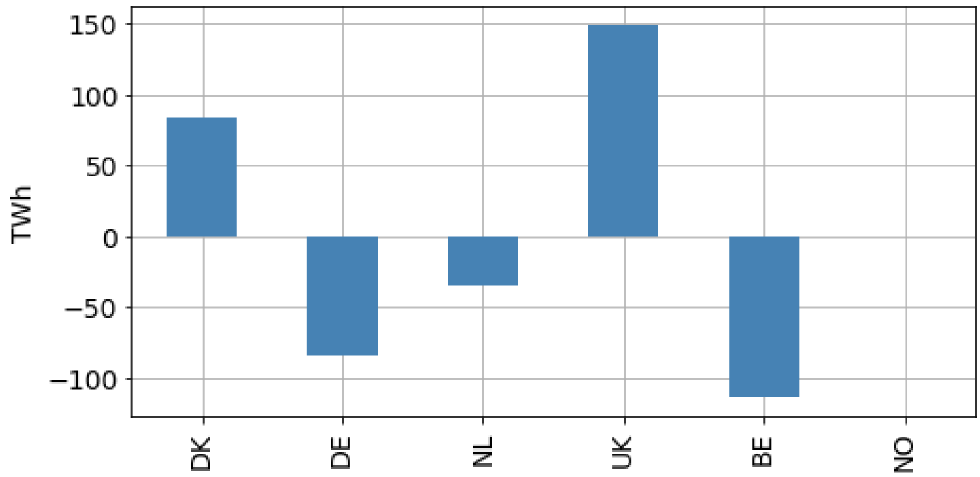
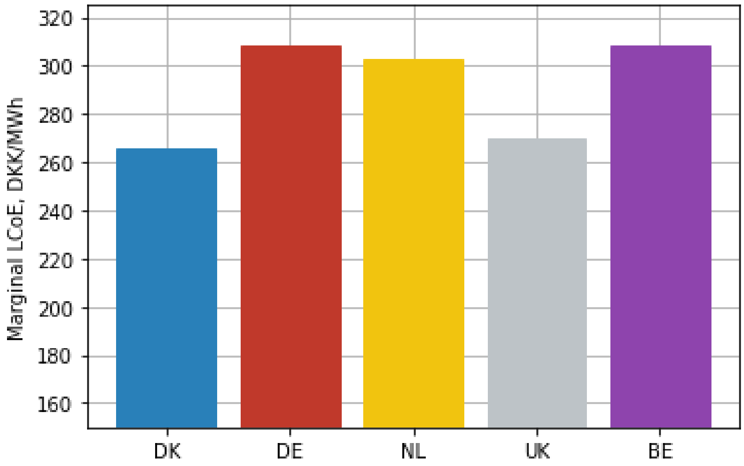


Chart 6: Marginal LCoE-levels for supplying wind farms



Sensitivity analysis

The results reported above are based on estimated values, which are subject to significant uncertainties. This is particularly the case for long-term projections of total electricity demand and technology costs. Hence, sensitivity analysis is needed to assess the robustness of the results.

Sensitivity analyses are performed by both changing one variable at a time, and by changing multiple variables simultaneously. The single-variable analysis seeks to quantify how a change in a single factor (e.g. the future level of electricity demand) will impact the results. Chart 7 shows how the baseline result for the estimated cost-effective Danish potential of around 31 GW capacity responds to changes in (one variable at a time) *total power demand*, *turbine densities*, *geographical filtering* and *cable costs*.

Changes in total power demand have the most significant effects on the result. This reflects that demand for offshore wind power in the Danish EEZ is residually determined in two senses. First, due to the assumption of offshore wind being the technology that must cover whatever residual demand remains after cheaper renewables have been exhausted, offshore wind power as such is arguably residually determined. In addition, the Danish areas are only becoming interesting for the power importing countries (such as Germany) once these countries own offshore wind potentials (with lower transmission costs due to closer proximity) have been exhausted. Hence, lower power demand overall leads to significantly lower demand for offshore wind power in general, and – since importing countries can better serve a lower demand from own areas – to a lower demand for the Danish areas specifically. The maps displayed in **Charts A.1 and A.2** of the

Appendix illustrate how Denmark's potential changes when assumptions about total power demand are varied.

Changes in wind turbine density has two opposite effects for the Danish offshore wind potential. On the one hand, higher density means that more capacity can fit in the designated wind areas – increasing the physical potential. On the other hand, higher possible density means that importing countries are better able to cover their own needs – limiting the cost-effective supply from the Danish areas. The net effect for Denmark is that higher density reduces the Danish potential for export. The same arguments apply to the case where the restrictions on developing offshore wind in the Natura2000 areas are removed, which will also alleviate some space constraints in the importing countries.

Converse, an increase in the cost of HVDC-cables and AC/DC-converters does not strongly affect the result, as the price increase is the same for all countries in the region. Given the partial nature of the analysis, higher HVDC costs will not affect the quantity demanded, but will lead to some increase in the marginal price for power delivered to e.g. Germany, cf. Chart 9.

Chart 7: Sensitivity analysis regarding cost-effective level of Danish offshore wind capacity in the North Sea (single-variable sensitivities)

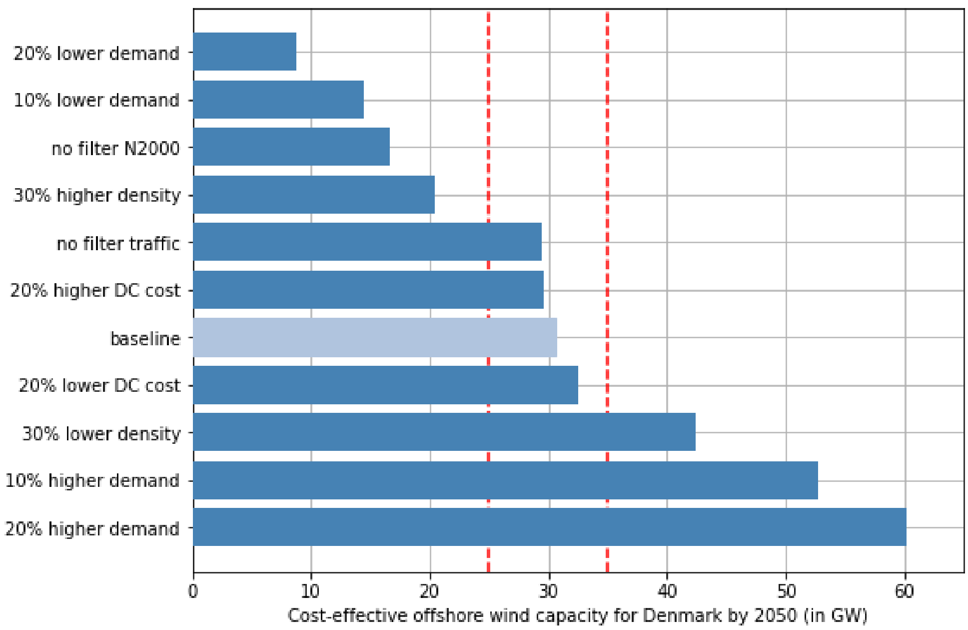
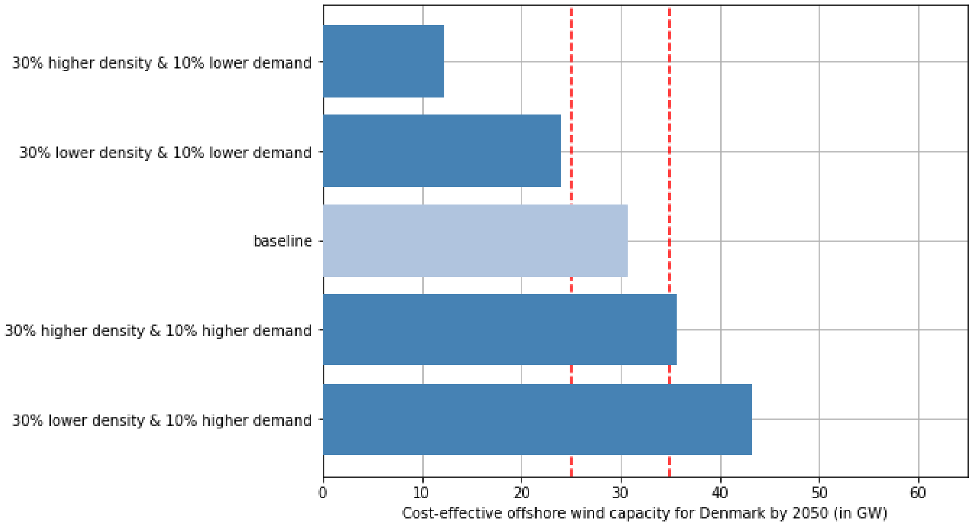
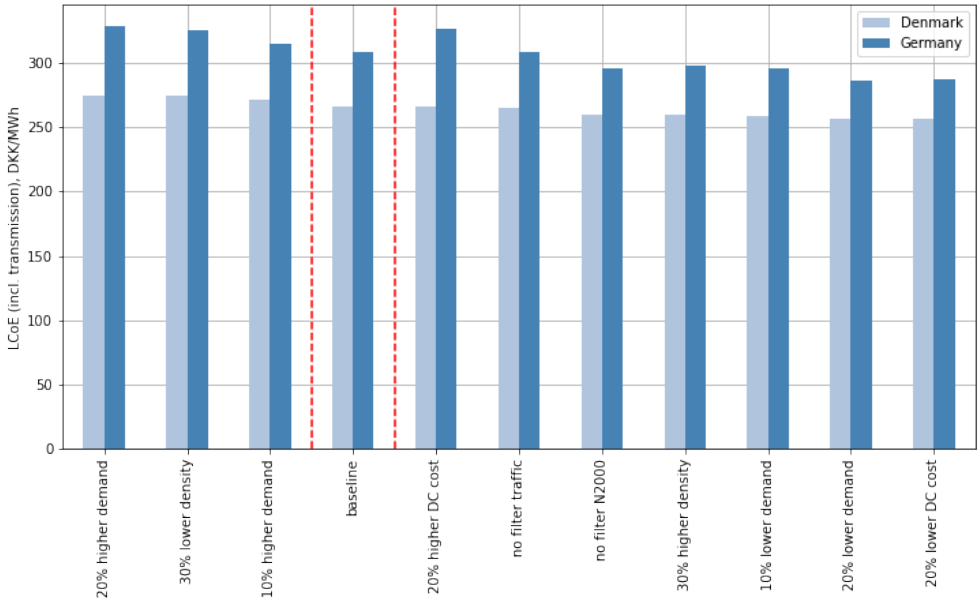


Chart 8: Sensitivity analysis regarding cost-effective level of Danish offshore wind capacity in the North Sea (multi-variable sensitivities)



Charts 8 shows how simultaneous changes to total power demand and density affect the cost-effective potential for Denmark. In the "worst case", where demand is lower and density is higher, the potential drops to a level close to the envisaged 10 GW energy island. In that case, Denmark's North Seas areas will mainly serve domestic demand for direct and indirect electrification. The Danish areas will always tend to be the most competitive to serve that demand, and the potential is unlikely to fall much further in any case – except in a scenario where the envisaged large increase in domestic electricity consumption does not materialise.

Chart 9: Sensitivity analysis for marginal LCoE-levels



Conclusion

This study estimates long-run supply curves for offshore wind in the North Sea. Based on a simple long-run marginal cost perspective, the analysis establishes a proxy for the long-term capture price for offshore wind and quantifies Denmark's long-term competitiveness in establishing offshore wind farms in the North Sea.

The approach is founded on economic theory, which states that in the long run, the equilibrium price in a market will move towards the average costs associated with producing the product or service. The analysis, therefore, uses offshore wind farms' LCoE as a proxy for the capture price of offshore wind power.

The analysis finds a long-run capture price for offshore wind power in the range 265-310 DKK/MWh (approx. 35-42 EUR/MWh) across the region. Furthermore, a more detailed analysis is carried out, estimating import/export distributions across the North Sea countries. The result is that in a simulated cost-effective build out of the North Sea, Denmark has the potential to establish a total capacity of 25-35 GW of offshore wind by 2050 – and thus become a significant net exporter of offshore wind energy.

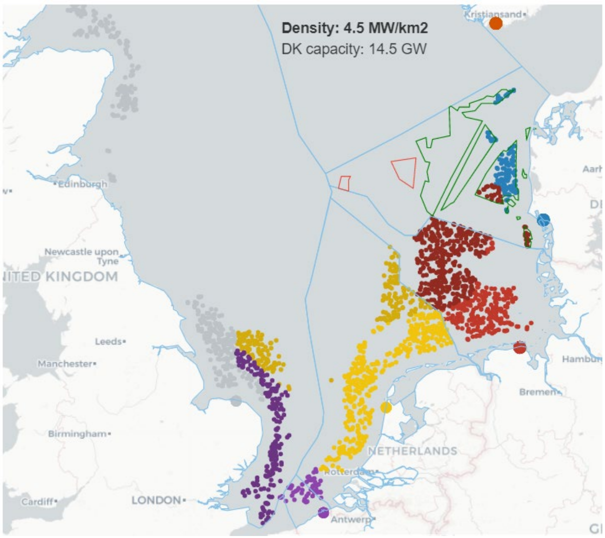
The approach provides only a simplified picture of long-run electricity price formation and variation in LCoE across the North Sea. The results rely on the assumptions of perfect competition, absence of government subsidies, free entry and exit in the offshore wind sector, and uniform cost structures across countries.

The current analysis takes into account a significant electricity demand from hydrogen production, but implicitly assumes that all such production takes place onshore. Relaxing this assumption to allow for offshore hydrogen production and transmission via pipelines would likely increase Denmark's energy export potential, as the cost of transporting energy over long distances – and in the relevant quantities – is significantly lower for hydrogen than for electricity.

Notwithstanding the simplifying assumptions made in this analysis, the results suggests that the construction of the envisaged Danish energy island in the North Sea with a capacity of up to 10 GW would likely be economically viable in the long run. The energy island's 10 GW capacity is well within the estimated total cost-effective offshore wind potential for Denmark.

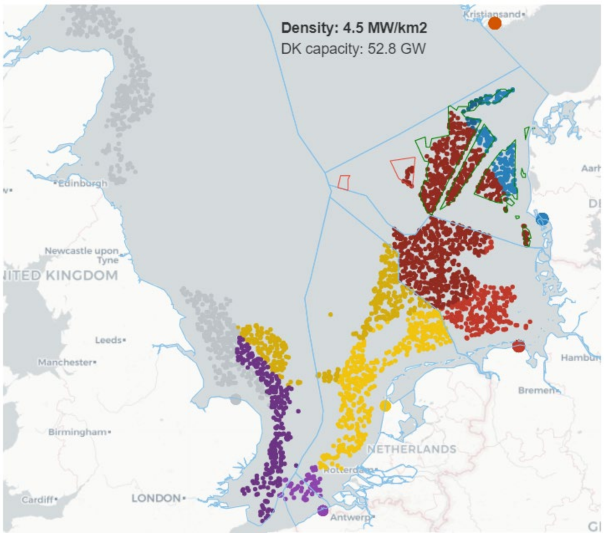
Appendix

Chart A.1: Scenario for cost-effective distribution of approx. 250 GW capacity with 10% lower total power demand compared to baseline



Note: Part of the simulated UK production along the northernmost parts of the UK shore is not visible on this map.

Chart A.2: Scenario for cost-effective distribution of approx. 250 GW capacity with 10% higher total power demand compared to baseline



Note: Part of the simulated UK production along the northernmost parts of the UK shore is not visible on this map.