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The consulting company of DIW Berlin

Market design for an efficient transmission of offshore wind energy

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Abbreviations

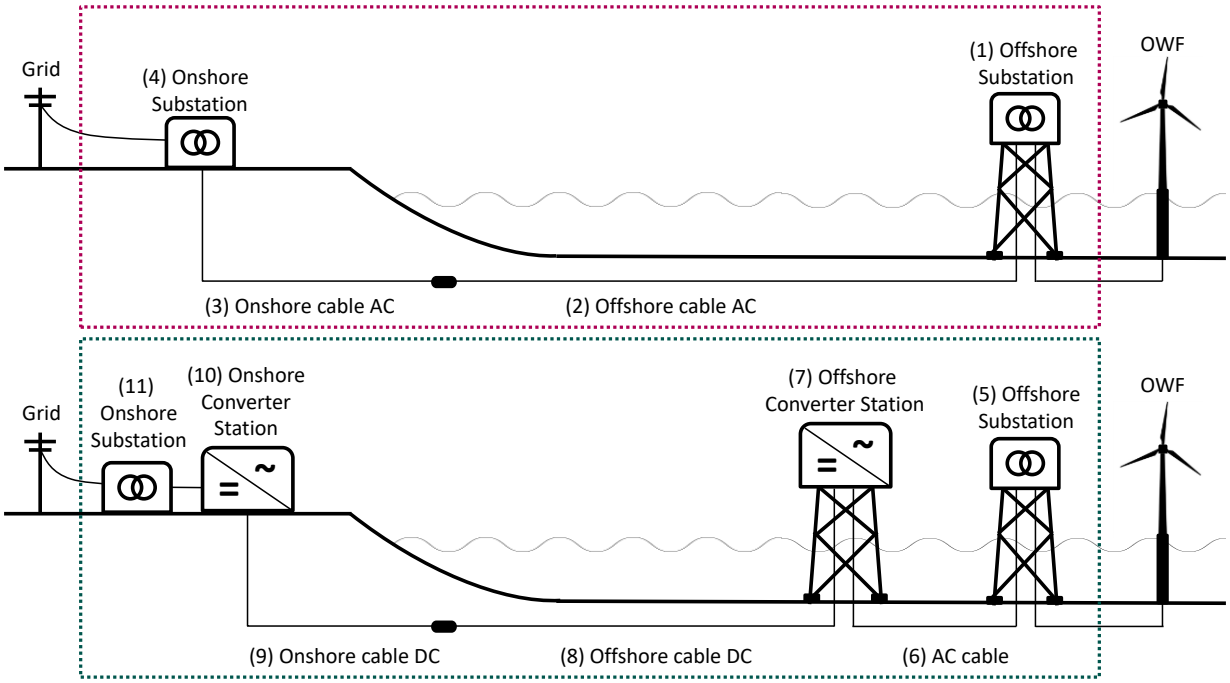
AC	Alternating current
BNetzA	Bundesnetzagentur (Federal Network Agency)
BSH	Bundesamt für Seeschifffahrt und Hydrographie (Federal Maritime and Hydrographic Agency)
CAPEX	Capital expenditure
DC	Direct current
FEP	Flächenentwicklungsplan (Maritime Spatial Development Plan)
LCoE	Levelized cost of electricity
m	Million
Ofgem	Office of Gas and Electricity Markets
OTA	Offshore transmission asset
OPEX	Operational expenditure
OWF	Offshore wind farm
OWFO	Offshore wind farm operators
TSO	Transmission system operator
WACC	Weighted average cost of capital

Executive Summary

Offshore wind energy represents a central component of Germany's energy policy. For offshore wind energy to be successful, cost-effective power generation at sea and an efficient transport of the produced electricity to the shore are necessary. An efficient market design is crucial for this.

Generally, the transmission system operator (TSO), the offshore wind farm operator (OWFO), or a third party can be considered for the development and operation of the offshore transmission asset (OTA, Figure I). Furthermore, it is also possible to separate development and operation and allocate the responsibility to two different parties.

Figure I
Simplified outline of an AC (alternating current) and DC (direct current) offshore transmission asset (OTA)



Source: DIW Econ.

The effect of the market design on the market outcome is twofold. First, the market design shapes the degree of integration between the OTA and the offshore wind farm (OWF). When the local TSO or a third party builds the OTA, development and operation of OTA and OWF take place separately, leading to increased coordination efforts for the respective parties. However, when development and operation of the OTA are bundled in the hands of the OWFO, the coordination effort is reduced (**separated vs. integrated**).

Second, the market design affects the level of competition. When regulation requires a competitive tender to determine the responsible actor for the development and operation of the OTA, all (potential) bidders are in direct competition.[1] Alternatively, in a monopolistic market environment, the local TSO is obliged to ensure both the development and the operation of the OTA (**monopoly vs. competition**).

A theoretical comparison of the different market designs with respect to cost efficiency indicates that the competitive and integrated model has an advantage (Figure II). In this scenario, the OWFO builds both the OWF and the OTA following a competitive tender.[2]

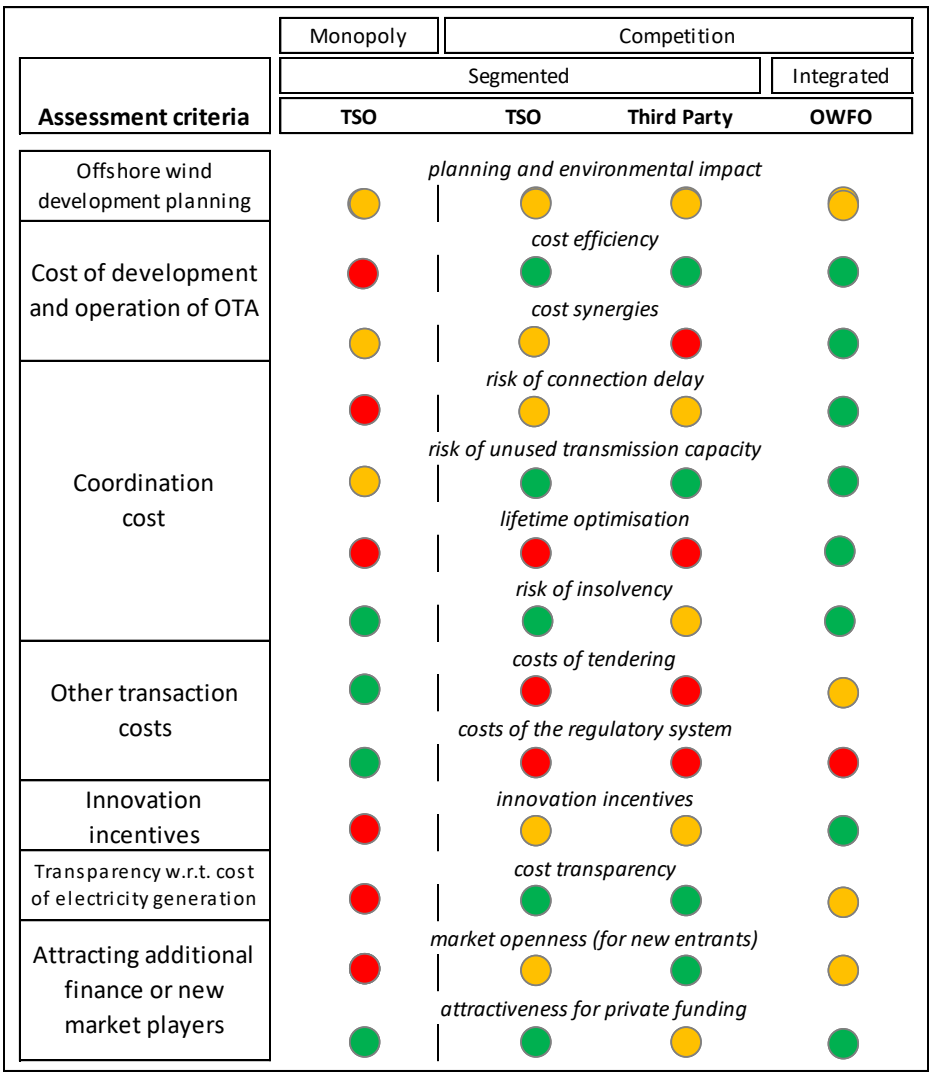
An international comparison of the market design of leading European countries for offshore wind energy shows that the monopolistic (separate) framework is the dominant model. This model is used in Germany, the Netherlands, and, until recently, Denmark (Danish Energy Agency, 2019). The United Kingdom (UK), on the other hand, pursues a competitive approach. An open tender determines the party responsible for the integrated development of both OWF and OTA. Later, a third party, which is also determined by a competitive tender, takes on responsibility for the operation of the OTA.

To test our theoretical conclusion empirically, we examine two comparable countries with contrary regulatory approaches. We calculate and compare the costs of OTAs in Germany and in the UK using the concept of Levelized Cost of Electricity (LCoE). LCoE represents the average discounted cost (EUR) per transferred energy unit over the entire lifetime of an OTA. Using published information on the investment costs of individual OTAs and unit cost information provided by national authorities, we calculate the LCoE of all OTAs for commercial OWF projects in the German North Sea and the UK.

[1] Depending on the design, the OWFOs, the (local) TSO and a third parties may participate in a competitive tender.

[2] The degree of competition may also vary in the case of an open tender. If the OTA is tendered jointly with the OWF, third parties and TSOs are implicitly excluded from the tender. In the analysis, we assume a maximally open competitive tender in which the decision (ex-ante) is open as to whether the OTA will be provided by the OWFO, TSO, or third parties. Only after the tender (ex-post) will it be clear whether the OTA will be developed in an integrated or separated way.

Figure II
Theoretical evaluation results of different market designs

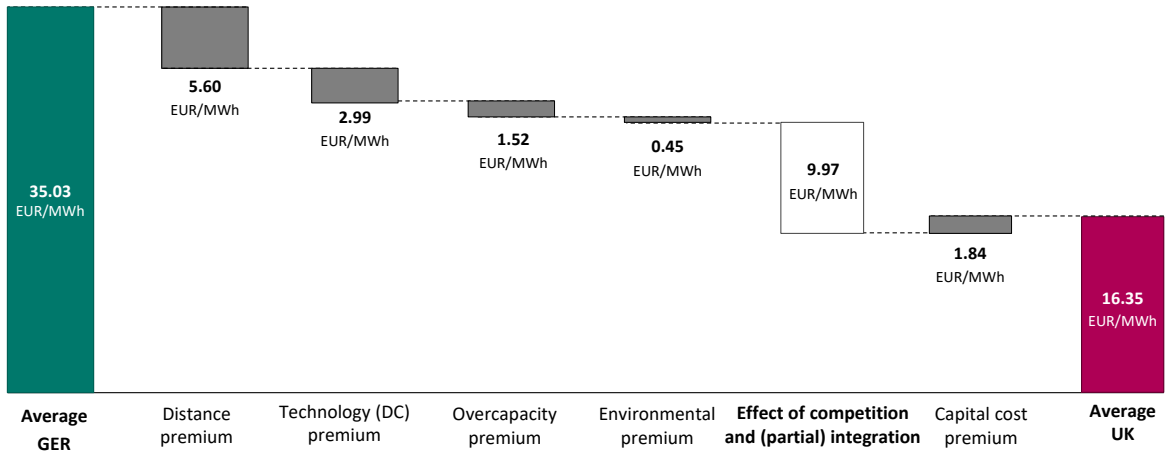


Note: The effects of the regulatory decision on the costs of the offshore transmission asset are displayed in direct comparison using the colour scale. Red stands for relatively high costs, green refers to lower costs. Yellow indicates that there is no clear advantage or disadvantage from a theoretical cost perspective. TSO stands for the transmission system operator, OWFO refers to the offshore wind farm operator.

Source: DIW Econ.

The average LCoE of German OTAs is 35 EUR/MWh, more than twice as much as the LCoE of British OTAs, which have an average LCoE of 16 EUR/MWh. After taking into account differences in the distance to shore, the choice of transmission technology as well as other relevant factors, the cost difference between OTAs in Germany and the UK is 10 EUR/MWh (Figure III).

Figure III:
Cost difference break-down of OTAs in Germany and in the UK in LCoE (EUR/MWh)



Source: DIW Econ.

The remaining cost difference can be ascribed to the different regulatory frameworks and thus consolidates the results of the theoretical analysis: A market design with a competitive tender (which leads to an integrated development of the OTA in the UK) reduces the costs of OTAs compared to a monopolistic (separate) regulatory approach. The offshore (liability) levy, a levy in Germany that allows the responsible TSO to pass on damages arising from connection delays or operational downtimes to the end consumers, is not yet included and increases the regulatory cost difference further.

The transmission quality of the OTA systems, measured in terms of the time of availability of the power transmission equipment, does not provide any indication of a disadvantage of competitive tenders. The offshore transmission availability of British OTAs is higher than the availability of monopolistically built OTAs (National Grid ESO, 2018; TenneT, 2017).

The economic costs of a monopolistic OTA market design in the German North Sea are estimated on the basis of the identified cost reduction potential and the already realised and forecasted costs of the offshore (liability) levy. We find that regulatory costs from 2013 to 2030 sum up to EUR 8.2 billion, of which EUR 6.7 billion are attributable to an inefficient market design (Figure IV).

Figure IV:
Development of annual economic costs due to inefficient market design of OTAs in the German North Sea between 2013-2030

Source: DIW Econ.

Low incentives to reduce costs and poor coordination constitute the largest cost share at EUR 3.4 billion. The lack of cost pressure for the TSO, which results from the possibility to directly pass on compensation costs to final costumers (offshore liability levy), leads to further costs of EUR 2.7 billion. Apart from the cost of connection delays already included in the offshore (liability) levy, costs of temporary and permanent overcapacity resulting from a lack of coordination explain additional costs of EUR 700 million. In addition to the costs of an inefficient market design, the preference for direct current (DC) systems and environmental requirements lead to additional costs of EUR 1.5 billion.

The present study shows that a competitive tender in conjunction with the possibility to integrate OWF and OTA can significantly improve the cost efficiency of transmitting offshore wind energy to shore.

1. Introduction

The expansion of offshore wind energy is a strategic component of Germany's energy and climate policy. Therefore, 15,000 MW of offshore wind power capacity are to be available in Germany by 2030 in accordance with the targets of the Federal Government. Apart from construction of the OWFs, efficient transport of the electricity produced on land is required in order for offshore wind energy to make a successful contribution to the success of the German energy transformation.

An international comparison of regulatory options with regards to responsibility for offshore electricity transmission in different countries reveals considerable differences. While the local TSO is exclusively responsible for the planning, construction, and operation of the OTA in the majority of countries, the developer is determined by a competitive tender only in a small number of countries.

In principle, three actors can be responsible for the OTA: the local TSO, the OWFO, or a third company. Planning, construction, and operation may be carried out by either the same or two different parties (as in the UK).

The question arises as to the costs and benefits of an open competitive tender of the OTA and the effect of the integration of OWFs and OTA. In the following, we examine how these different market designs affect the cost efficiency of OTAs.

The study is structured as follows: Section 2 evaluates the different regulatory approaches theoretically. Section 3 outlines current market designs in the UK, Germany, the Netherlands, Denmark, and Sweden. Section 4 compares and discusses the costs of different regulatory approaches in the UK and Germany empirically. Section 5 presents the aggregated economic costs in Germany. Section 6 concludes.

2. Regulation of offshore transmission assets

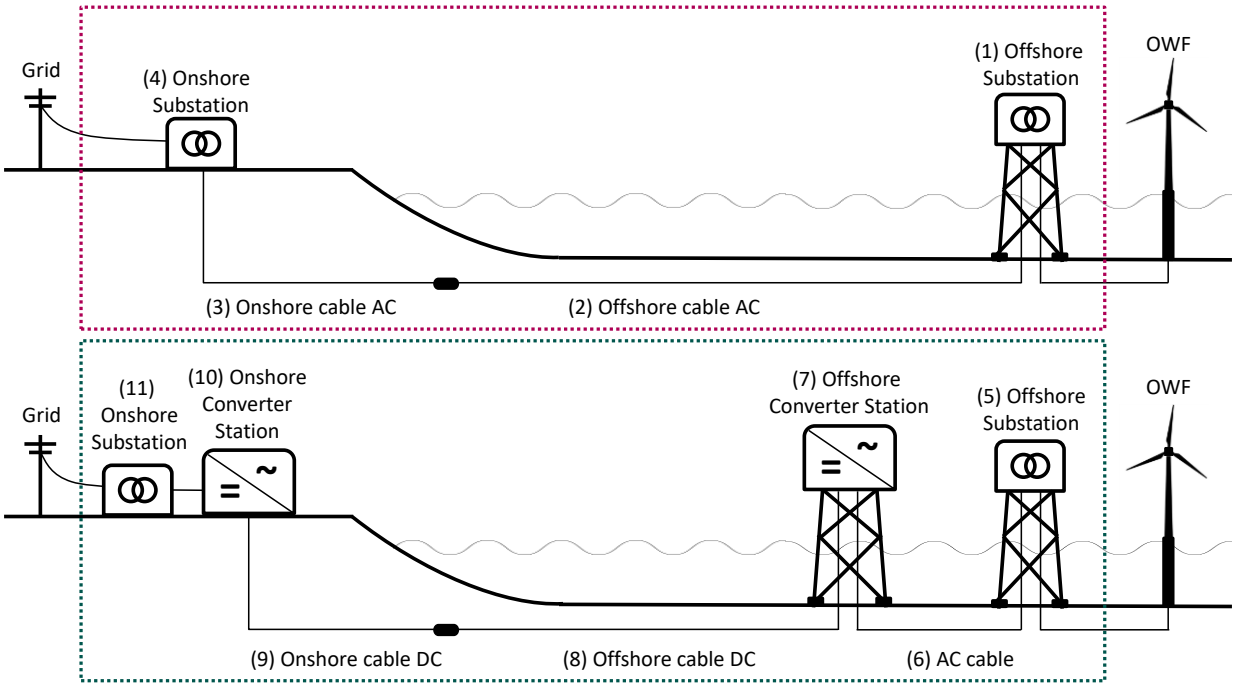
2.1 Market design in theory and practice

Offshore transmission asset and possible actors

All wind turbines of an OWF are connected to an offshore substation, which bundles the produced electricity in the form of alternating current (AC). There are two options for connecting the offshore

substation with an onshore substation, depending on the transmission technology selected: AC systems allow the transport of electricity directly from the offshore substation to the onshore substation via AC cables. With direct current (DC), the current must be converted from AC to DC prior to transmission and then converted back to AC ashore in order to be fed into the onshore AC grid. This is done in the respective offshore or onshore converter stations. In simplified terms, the so-called "offshore transmission asset" (OTA) refers to the area between OWF and onshore grid (Figure 1).

Figure 1:
Simplified outline of an AC (alternating current) and DC (direct current) offshore transmission asset (OTA)



Source: DIW Econ.

Multiple parties can be considered for the development and operation of the OTA. First, the (local) TSO may be in charge. In this case, the TSO expands its responsibility for the onshore grid to offshore areas. Generally, the TSO is subject to either national regulatory oversight or direct public control (as a state-owned company).

Second, the OWFO may be responsible for the OTA. In this case, the OWFO not only builds the OWF but is also in charge of the OTA.

Furthermore, a third party, a company that is neither OWFO nor (local) TSO, may be responsible for the OTA. In addition, development and operation can usually be separated. As an example, the OWFO can develop the OTA, with a third party operating it after commissioning.

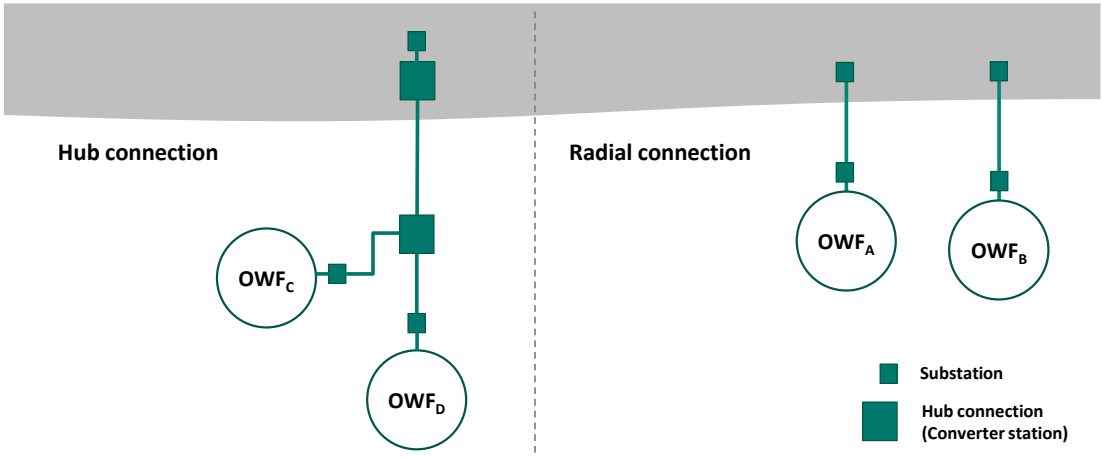
Economics of regulating offshore transmission assets

The traditional electricity supply chain can be divided into four stages: (i) the generation of electricity from different sources, (ii) the transmission of electricity over long distances using high-voltage power transmission, (iii) the distribution of electricity in regional and local areas using low-voltage power transmission, and (iv) the transmission of electricity to final consumers. In general, both distribution and transmission networks are regarded as natural monopolies and are therefore in need of regulation. A natural monopoly exists when the provision of a good, a service, or a bundle of goods by only one actor is more efficient than the provision by several market actors.[3] However, it is questionable whether the OTA can be characterised as a natural monopoly and should be regarded as a part of the power grid.

Traditionally, OWFs are connected to the mainland by radial (individual) connections, with one OTA connecting one OWF. In this case, the OTA may also be part of the OWF. Due to maritime conflicts of use, OWFs are sometimes planned in so-called wind farm clusters. In this case, a planning institution must determine whether it is more efficient to bundle different OWFs via a hub connection (common OTA) in order to reduce costs for development and operation, enhance land use, and minimise environmental impacts.

[3] The term natural monopoly used to refer to all activities in a utility company's value chain. However, with the trend of “unbundling” the network operation and the competitive distribution side, one often refers to the "core network", which has the characteristics of a natural monopoly: high fixed costs with particularly large economies of scale. In this case, the total cost of providing a good is significantly lower if only one party ensures supply (Decker, 2015). However, the OTA does not necessarily belong to the "core network".

Figure 2
Representation of a hub and radial connection



Source: DIW Econ.

Regarding competition, development and operation of a radial OTA can be carried out by the OWFO, the TSO, or a third party. In case of a hub connection, where different OWFs use a common transmission asset, a competitive tender for development and construction of the OTA is possible. However, in this specific case, an independent party (TSO or third party) is required for operation.[4]

Different market designs

The different market designs can be distinguished in two ways: the degree of integration and the degree of competition. If the OTA and the OWF are jointly developed and operated by the OWFO, this is referred to as a (vertically) integrated approach. Otherwise, we speak of a separate approach.

In a competitive market design, an open competitive tender is used to determine not only who is responsible for the development and operation of the OWF but also for the development and operation of the OTA.[5] In a monopolistic market design, the responsibility for the development and operation of the OTA is legally assigned to the TSO. There is no competitive tender.

[4] In this case, the operation by an independent party is important, as the OTA represents an essential facility. If one of the OWFOs were to operate the OTA, the OWFO would hold significant market power. The operator could use this strategic bottleneck to deny access for other OWFOs (competitors) or to charge disproportionately high prices for offshore electricity transmission.

[5] The OTA tender is based on the assumption that the greatest possible competitive pressure will arise if there is no restriction on potential bidders and TSOs, OWFOs as well as third parties can participate in the tender.

2.2 Theoretical evaluation of different regulatory approaches

The market design has considerable influence on the efficiency of the OTA and hence on the future development of offshore wind energy. An efficient OTA is characterised by low costs and high security of supply while environmental costs are also considered. In the following, we discuss and evaluate the incentives and effects created by the respective regulatory approaches relating to

- Planning
- Development and operating expenditures (short-term cost efficiency)
- Coordination and transaction costs
- Innovation incentives (long-term cost efficiency)
- Cost transparency
- Market openness and finance

Planning

The planning of offshore wind areas and the corridors for transmission assets may be subject to an appropriate regulatory authority in any market design. This way, a regulatory authority can define the projects with regards to time, space, and technology in a way that any party in each market design adheres to the same standards. In consultation with the respective parties, such an authority can further determine whether an OTA in the form of a hub or radial connection is of greater economic benefit. Additionally, an appropriate authority can optimise planning by assessing the environmental impact of all options and tender the best one.

A competitive tender is equally feasible for a hub or a radial connection. However, in both cases an adequate tender process must be designed. Depending on the type of connection, joint bids for the OWF and the OTA should be allowed. Likewise, bidders should be permitted to bid separately for the OWF and the OTA.

Development and operating expenditures (short-term cost efficiency)

Compared to monopolistic assignment, a competitive tender process increases cost efficiency. In order to secure a contract, participants must submit their lowest possible bid. This way, they have an incentive to develop and operate OTA at least cost. In addition, a competitive tender increases cost

pressure through greater transparency, as bidders can be asked to disclose the actual costs of an OTA to the respective authority and the public.

For cost synergies, it is possible for all parties to use economies of scale.[6] TSOs have cost advantages over third parties in terms of their natural size, onshore experience, and favourable financing possibilities. The exploitation of economies of scope[7] depends on the integration of OTA and OWF. Only within an integrated model, in which the OWFO plans and builds the OTA, economies of scope can be realised.

Coordination and transaction costs

Due to the complex nature of OWF and OTA, their coordination involves significant risks and costs. In an integrated approach, where the OWFO is also responsible for the development of the OTA, these coordination costs are internalised: The OWFO includes the additional coordination costs in its calculation. To minimise coordination costs, the OWFO has a high incentive to harmonise both projects in terms of time and technology.

If planning and construction of both projects is carried out by separate parties, coordination costs are not directly internalised. An appropriate framework can provide an incentive to improve coordination by rewarding timely connection and sanctioning delays. However, if these sanctions can be passed on to the final consumer, as it is the case with the German offshore (liability) levy, the incentive to minimise coordination costs decreases.

Equally, early completion can lead to vacancy and overcapacity costs. Within a competitive tender, as part of which the successful bidder is only paid for the capacity required, the risk of overcapacity or completion way ahead of schedule is low. However, if the TSO is responsible for the OTA and is under public pressure to provide sufficient and timely transmission capacity while being allowed to pass costs on to the final consumer, the likelihood of temporary or permanent overcapacity increases.

In addition, the separation of OTA and OWF makes it difficult to optimise the overall lifetime of both systems. A different lifetime causes additional coordination costs.

[6] They describe decreasing construction and operating costs with increasing quantities of built and operated OTAs are described.

[7] Refer to increasing cost advantages with increasing product variety. Through increased product diversity (OWF and OTA), a developer and operator can pool resources to use them more efficiently.

The coordination risk is also reflected in the insolvency risk. Due to their size and the possibility to pass on costs to the final consumer, TSOs usually carry a lower insolvency risk than third parties. By integrating both assets, however, the business risk can be reduced for third parties as well, reducing the risk of insolvency simultaneously.

Apart from costs directly associated with the development and operation of the OTA, regulatory costs need to be considered. Within the monopolistic TSO model, rules for onshore transmission assets can usually be adopted. By contrast, competitive tenders require the development of a new regulatory framework, which creates additional costs.

Innovation incentives (long-term cost efficiency)

The continuous development of transmission technologies and their use are decisive for long-term cost efficiency. Compared to the market design of a competitive tender, the incentives to further develop existing systems in the monopolistic model are lower, as costs arising from inefficient technology can be passed on to the final consumer. In case of a competitive tender, all bidders have an incentive to develop new, less costly solutions in order to increase the likelihood of winning a contract. Furthermore, a separated development of OWF and OTA restricts the incentive to develop innovations that require changes to both systems.

Cost transparency

In the monopolistic TSO model, there is little transparency due to information asymmetries. In addition, TSOs can mix the costs of the OTA with other network costs if the regulator's specifications are imprecise. This creates additional uncertainty about the true costs for the regulator and the public.

In a competition-based model, information asymmetries regarding individual costs are reduced by the tender process. The cost information obtained could also be made publicly available (retrospectively) and thereby achieve greater transparency. However, when OWF and OTA are integrated, this higher transparency may be reduced again by giving the OWFO the chance to intertwine the costs of the OTA and the OWF.

Market opening and financing

Only a competitive tender process can open the OTA market to new actors. In addition to OWFOs and TSOs, new national and international parties (third parties) may compete for the tendered

assets. A larger group of competitors would enhance the competitive effect of an open tender even further.

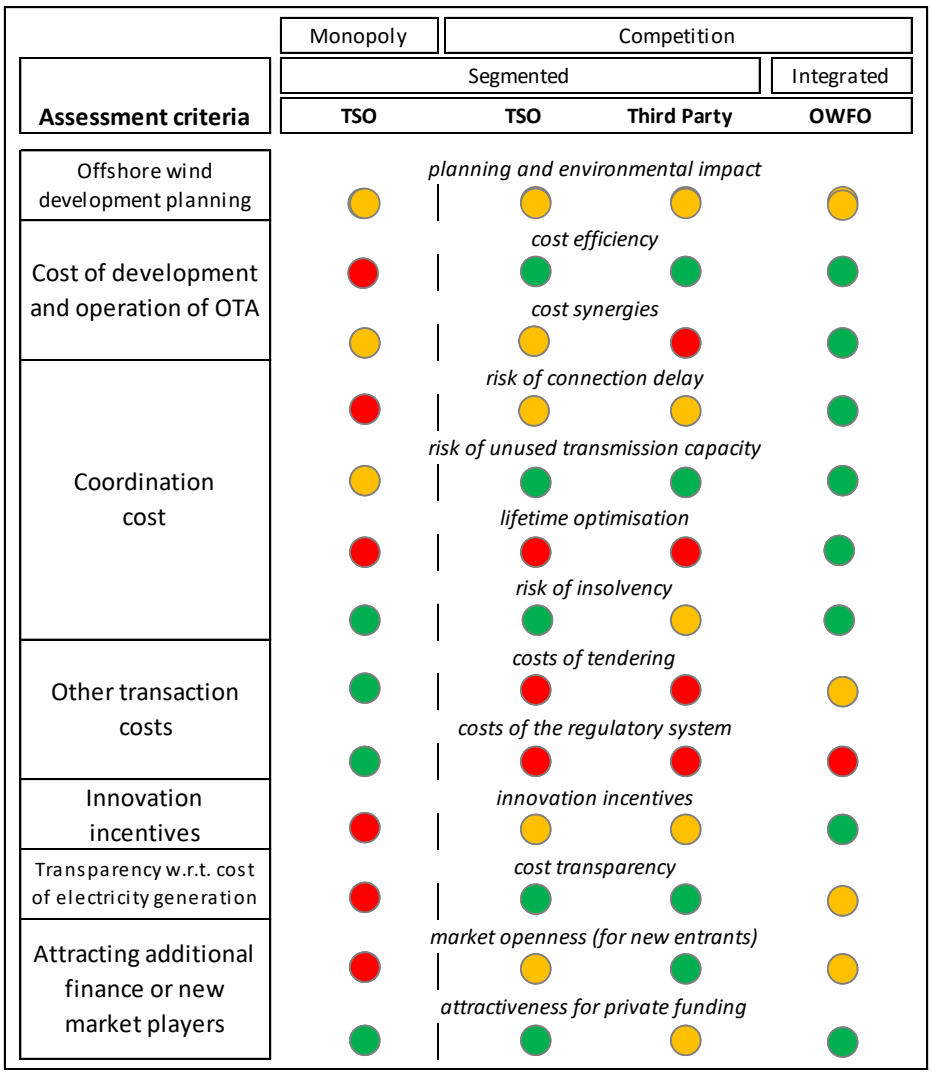
TSOs usually have a more favorable credit rating due to their size and mostly state-guaranteed returns, leading to lower capital costs than traditional companies have. In case of a competitive tender, investors have additional opportunities to invest in offshore wind energy projects via third parties. Due to the OWFO's opportunity to submit a joint bid for OWF and OTA, capital market conditions should improve due to lower coordination risks and higher (expected) returns.

Interim conclusion

As a consequence of economies of scale and economies of scope, an efficient OTA can be achieved primarily through integration and the greatest possible competition. A detailed planning process should analyse whether a hub or a radial connection is more desirable. This includes an economic and ecological assessment on a case-by-case basis. In this context, the regulatory authority must examine whether the operation of the OTA can be performed by the OWFO or whether it should be carried out by an independent party (TSO, third party). However, using appropriate regulation, construction can be carried out by any actor.

An open tender with the largest possible circle of candidates - which is eligible for the development and/or operation of the OTA - should identify the most cost-efficient company and induce the greatest cost pressure. However, the complexity of a tender and the increased transaction costs lead to additional regulatory costs. Compared to a monopolistic setting, competition leads to greater cost transparency and stronger incentives to improve coordination and pursue innovation. The results of the theoretical evaluation are summarised in Figure 3.

Figure 3:
Theoretical evaluation results of different market designs



Note: The effects of the regulatory decision on the costs of the OTA are displayed in direct comparison using the colour scale. Red stands for relatively high costs, green refers to lower costs. Yellow indicates that there is no clear advantage or disadvantage from a theoretical cost perspective. TSO stands for the transmission system operator, OWFO refers to the offshore wind farm operator.

Source: DIW Econ.

3. Offshore transmission assets: International comparison

The implementation of the discussed theoretical regulatory approaches for the transmission of offshore wind energy differs significantly by country. To compare regulatory characteristics not only hypothetically, we also examine the regulations of leading European countries in the field of offshore wind energy. We use the evaluation criteria already presented to highlight how each market design differs and how these differences affect the cost of developing OTAs.

3.1 United Kingdom

Planning

In the UK, the Crown Estate owns all offshore areas. It is responsible for identifying suitable locations and leasing them to OWFOs. The Crown Estate initiates the application process for new OWFs and their transmission systems. Other Crown Estate activities include providing information on proposed sites and supporting OWFOs' cooperation with planning and regulatory authorities.

Market design

The Office for Gas and Electricity Markets (Ofgem), together with the Ministry of Energy and Climate Change, developed a new law for the construction and operation of OTAs in 2009. According to this law, licenses for offshore transmission are granted through a competitive tendering process. Construction and operation can take place in two ways: The OWFO either builds the OTA and hands it over to the operator of the OTA, or the OTA operator builds and operates the OTA. So far, all OTAs in the UK have been built by the OWFO.

The lease, the permission to build and operate the OWF, and the development of the OTA are awarded to the bidder with the lowest total costs for OWF and OTA. The OWFO's investment costs (CAPEX) resulting from the construction of the OTA are covered by the price paid by the future operator of the OTA to the OWFO after its completion. In return, the operator of the OTA receives a regular revenue from the grid authority for the operation, maintenance, and subsequent decommissioning of the OTA. The transmission license is awarded to the bidder that asks for the lowest revenue. This tender revenue stream is fixed for 20 years, independently of the power produced by the OWF, and can be subsequently extended (Ofgem, 2010).

For the provision of OTAs, the UK thus follows a competitive approach where the construction contract integrated and awarded in a competitive way, while operation is also awarded competitively but separately from the operation of the OWF.

Cost impact

The competitive tender creates incentives to reduce the costs of building and operating OWFs and OTAs. Ofgem's review of the final transfer price of the OTA during handover to the operator ensures a high degree of cost transparency.

The integration of planning and construction of the OTA with the OWF enables synergies and minimises coordination costs through internalisation: OWFO's integrated construction of the OWF and the associated OTA provide a high incentive to complete the transmission on time. The operator of the OTA is also motivated to ensure a high level of security of supply, as transmission interruptions are penalised by reduced payments from the tender revenue stream. Likewise, high security of supply is rewarded with bonus payments.

Economies of scale during construction through the joint transmission systems of multiple OWFs using hub connections are not planned, as each OTA is tailored to the respective OWF. However, regarding operation and maintenance, it is possible for large providers specialising in OTA operation to achieve economies of scale.

However, the competitive approach results in additional costs for the regulator: Organising the bidding process that determines the operator licences generates transaction costs.

Overall, the UK's competitive tender for both the construction and operation of OTAs leads to high cost pressure. The tender not only selects the most cost-effective option but also provides an incentive for further innovation. The absence of technical specifications also allows the flexible use of cost-optimised technology.

3.2 Germany

Planning

In Germany, the Federal Maritime and Hydrographic Agency (BSH), together with the Federal Network Agency (BnetzA), identifies potential OWF areas. These as well as corridors for cable routes and transmission platforms are listed in the maritime spatial development plan (FEP).

Detail box 1:
The German experience with offshore transmission assets (OTAs)

Transmission system operators (TSOs)

TSOs receive network charges from final consumers in their region. The level of the network charges is determined by the costs incurred by the TSO as well as an additional profit margin to which the TSO is legally entitled. In addition, TSOs receive revenues for investments in network expansion that are approved by the BNetzA. This also includes the costs for OTAs. Until 2018, it was only possible to use the offshore liability levy to pass on the damages from interruptions to the final consumer. Starting in 2019, the new offshore levy will also cover the entire costs of newly built OTAs. The offshore levy further reduces the already low cost pressure on TSOs, as all costs incurred offshore are not included in the revenue cap of the (German) incentive regulation for TSOs and are carried entirely by final consumers. In addition, a lack of transparency makes it difficult to assess the actual costs incurred.

Coordination problems

The Offshore Network Development Plan (O-NEP) prepared by the TSOs and approved by the BNetzA has been replaced by the Maritime Spatial Development Plan (FEP) published by the BSH in 2019. In the FEP, the BSH defines not only the location and capacity but also the planning, routes, and schedules for the expansion of offshore wind energy. It remains to be seen whether this step will reduce the coordination difficulties between TSOs and OWFOs. In the past, OTAs were completed with an average delay of one year. Between 2013 and 2016 alone, the resulting damages amounted to more than EUR 1 billion, which final consumers had to pay for.

Table 1
Connection delays in the German North Sea

Commission year	Project	Tender and allocation	Development and construction	Thereof: Delays
2010	BorWin1	8	31	7
2015	BorWin2	9	54	14
2015	HelWin1	10	55	22
2015	SylWin1	8	47	2
2015	HelWin2	11	39	no delay
2015	DolWin1	9	53	24
2016	DolWin2	8	54	12
	Average	9	48	12

Note: All numbers represent the duration in months of each phase.

Source: Fichtner (2016).

Market design

In the current market design, the two TSOs, TenneT (North Sea) and 50Hertz (Baltic Sea) are responsible for the construction and operation of all OTAs.

To minimise the financial risk for OWFOs, German TSOs are obliged to pay compensation to the OWFO in the event of a late connection to the grid, grid interruptions, or maintenance work. The TSOs can pass on the resulting costs directly to the final consumer through the offshore liability levy. As of 2019, the offshore levy does not only include the additional costs from damages but also covers the total costs for the development of OTAs in Germany (Energy Industry Act, 2017).

Germany thus follows a monopolistic and separate approach for the construction and operation of OTAs.

Cost impact

First, in Germany, with its monopolistic market design, there is no competition for the construction and operation of OTAs. As a result, the TSOs have no incentive to save costs at any stage of the project. Second, restrictive planning by the BSH inhibits cost-saving opportunities. The planning principles of the current FEP include guidelines for noise reduction, the consideration of maritime cultural heritage, or specifications for decommissioning. However, there is no explicit principle to promote economically efficient transmission assets (BSH, 2018). Third, TSOs can pass on all OTA costs to the final consumer without suffering any loss in profit. This further reduces cost pressure, leaving the TSO without any incentive to strive for a (contractually) cost-efficient distribution of risk in the interests of the final consumer, e.g. in negotiations with suppliers.

In addition, the separation of OWF and OTA during planning and construction leads to increased coordination costs. These are reflected in connection delays resulting from a lack of coordination and increased maintenance work in the first years of operation due to compatibility problems (Fichtner, 2016). In addition to unplanned connection delays, further costs arise as a result of considerable overcapacity. Since not all OWFs are connected upon completion of the OTA, the OTA's capacity is often only used partially over several years.

However, cost savings might be generated from economies of scale. These can emerge from connecting several wind farms through a joint OTA. Due to the separate approach, there are no additional savings from economies of scope.

The BNetzA's previous requirements for onshore TSOs have been transferred uniformly to offshore transmission. Thus, no additional transaction costs arise from changes in the regulatory framework or the redesign of the tender process.

Overall, the monopolistic and separate regulatory framework in Germany provides few incentives for cost reductions or the use of innovative technologies. Due to the possibility to pass on costs to the final consumer through the offshore (liability) levy, TSOs have no incentive to develop innovations or reduce costs. The lack of transparency reduces cost pressure even further. Investment costs for OTAs only have to be disclosed to the BNetzA by TSOs every two years. Based on this, the BNetzA publishes rough cost estimates in the Offshore Network Development Plan (O-NEP).

3.3 Netherlands

Planning

In the Netherlands, the Ministry of Economics and Climate Policy is responsible for creating a development framework for the construction of OWFs, defining the areas, capacity, and routes for OTAs. The Ministry also specifies the technical conditions for transmission systems.

Market design

Similar to the market structure in Germany, the TSO (TenneT) is solely responsible for the design, construction, and operation of OTAs in the Netherlands. The TSO is state-owned and regulated by the Authority for Consumers and Markets (ACM).

The TSO receives state subsidies for the construction of OTAs. The OWFO may claim damages from the TSO in case of connection delays or longer interruptions. For the development and operation of OTAs, the Netherlands hence follow a separate and monopolistic market design as Germany.

Cost impact

Due to the lack of competition within the monopolistic structure in the Netherlands, there is no significant cost pressure. This circumstance is reinforced by a lack of cost transparency.

The separation of OWF and OTA during planning and construction prevents synergies and raises coordination costs. These are caused by connection delays, overcapacity costs, and difficulties in planning coordination.

On the other hand, TenneT, as a large supplier of OTAs, points to the positive effects of economies of scale and expects cost savings of 40% by 2023 through standardised equipment, an improved supply chain, and new working methods (Netherlands Enterprise Agency, 2017). In addition, no additional costs are incurred by the regulator as a result of a complex competitive tender.

3.4 Denmark

Planning and market design

The Danish Energy Agency is responsible for the planning of all OWFs and OTAs. In this planning process, the state-owned TSO (Energinet) is responsible for environmental impact assessments, and specifying the OWF's technical requirements. If these are fulfilled by the OWF, the TSO is obliged to provide the OTA. Denmark thus follows a separate and monopolistic approach with regards to the provision of the OTA. However, as of March 2019, Denmark has decided to switch to a competitive tender for the OTA (Danish Energy Agency, 2019). As of today, a detailed description of this mechanism is not yet available.

In addition to the planning activities of the Danish Energy Agency, there is an open-door procedure. OWFOs can take the initiative in proposing potential locations outside the areas designated by the state. This means that OWFO will also be responsible for planning the OTA and that the electricity generated will only be transferred to the TSO ashore. In this case, an integrated approach is adopted which, although not monopolistic, does not constitute full competition even in the absence of a planned tendering procedure. In practice, this approach has hardly been applied so far. In the past 10 years, only three OTA projects have been built in Denmark under the open-door procedure. As the respective OWFs connected provide a capacity of less than 30 MW, these are furthermore considered pilot projects.

Cost impact

In the first case of a separate and monopolistic approach, the cost effects are similar to those in Germany and the Netherlands. Lack of competition does not create additional cost pressure and ensures little transparency and incentives for innovation. Although the separation of OTA and OWF allows economies of scale for the TSO, it prevents economies of scope and creates additional coordination costs.

In the second case, the integrated open-door procedure, the OWFO responsible for the construction of the OTA is subject to higher cost pressure. In addition, synergies can be generated through joint construction and operation. In addition, coordination costs are reduced, as the interests of those responsible for the OTA and the OWF are aligned through integration. However, otherwise possible economies of scale of the TSO may be eliminated. Furthermore, higher transaction costs for the legislator are to be expected due to the higher administrative burden caused by two parallel proceedings.

With the new system of a competitive tender in place, it is likely that additional cost pressure will reduce the costs of offshore transmission assets. However, more details on the tender procedure are necessary to estimate the cost effects.

3.5 Sweden

Planning

In Sweden, only the OWFO is responsible for selecting a suitable site. If it receives approval from the regulatory authority, the OWFO is responsible for the planning, construction, and operation of the OTA in this decentralised model. This also includes the financing, which is why offshore wind energy could not compete with onshore wind energy in the past. There is currently no general grid development plan for offshore wind energy.

Market design

In the Swedish approach, the OWFO bears the entire responsibility and costs for the development and operation of an OTA. Due to the high availability of hydropower, the expansion of OWFs was considered uneconomical for a long time. The Swedish authorities are currently examining a new regime with the intention of setting more ambitious climate protection targets. The focus is on reducing the costs of the OTA. An extension of the transmission asset obligation of the state-owned TSO (Svenska kraftnät) to OWFs and a subsidisation of the development of the OTA by the OWFO are currently discussed (Swedish Energy Agency, 2018).

Cost impact

In Sweden, OWFs are not competitive in the existing system due to high costs, as OWFOs have to bear the full cost of the transmission asset. Although the OWFOs not only theoretically experience

low costs as a result of the integrated approach but are also able to exploit economies of scope, these benefits do not sufficiently compensate the burden of financing the entire OTA.

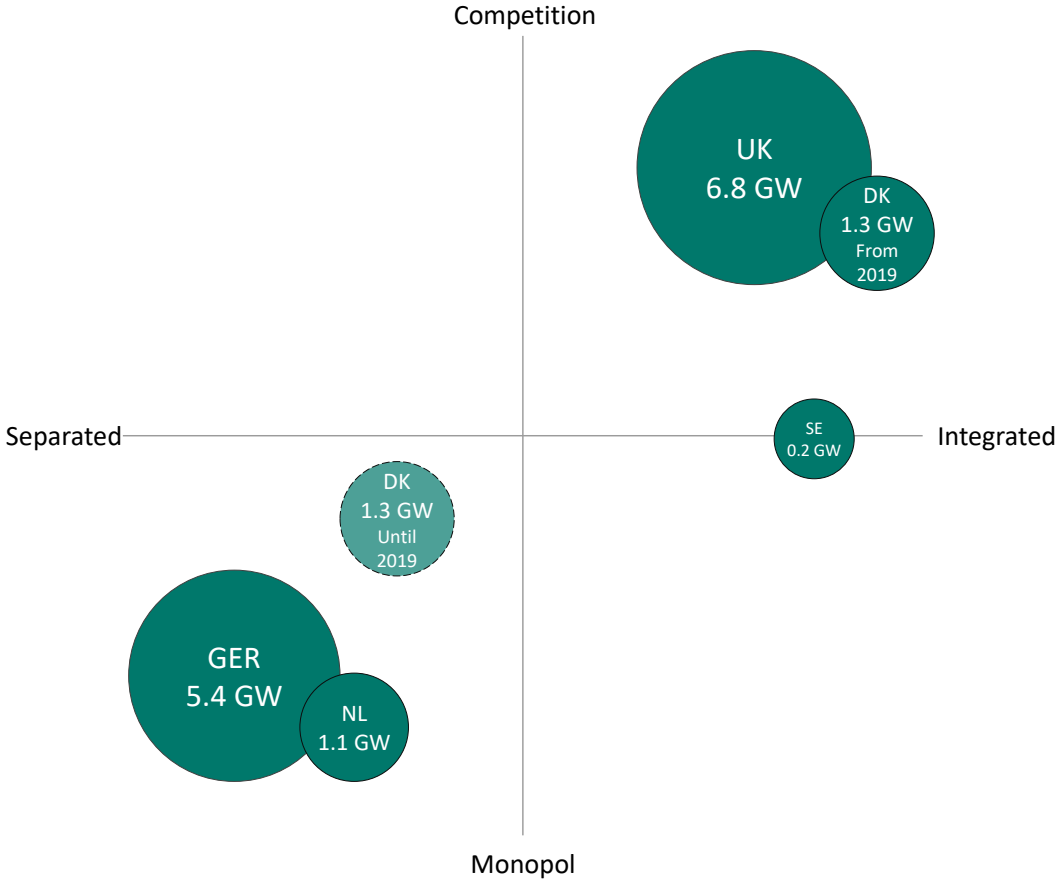
In case Sweden chooses to implement a TSO model, similar effects as in Germany and the Netherlands can be expected. These are characterised by high coordination costs and a low incentive for cost reductions.

Subsidising the OTAs is one way of increasing the competitiveness of OWFs compared to other power sources without sacrificing partial cost pressure in the construction of OTAs. However, given the limited development of Swedish offshore wind energy, a comprehensive evaluation is only possible to a limited extent.

Interim conclusion

In an international comparison, the monopolistic TSO model with separate construction and operation of OWFs and OTAs dominates. Although the possibility of an open-door procedure and the planned change towards a tender approach point towards more competition in Denmark in the future (Danish Energy Agency, 2019), the monopolistically separate TSO model is still practiced. Only the UK has implemented a competitive tender. Regarding integration, the British system is a hybrid one: OWF and OTA are integrated during planning and construction, however, they are operated separately.

Figure 4
Model of the regulatory approaches of the compared countries according to their relative degree of competition and integration between OWF and OTA



Note: The figure shows the relative capacity of offshore wind power in the respective countries (as of 2017).

Source: DIW Econ.

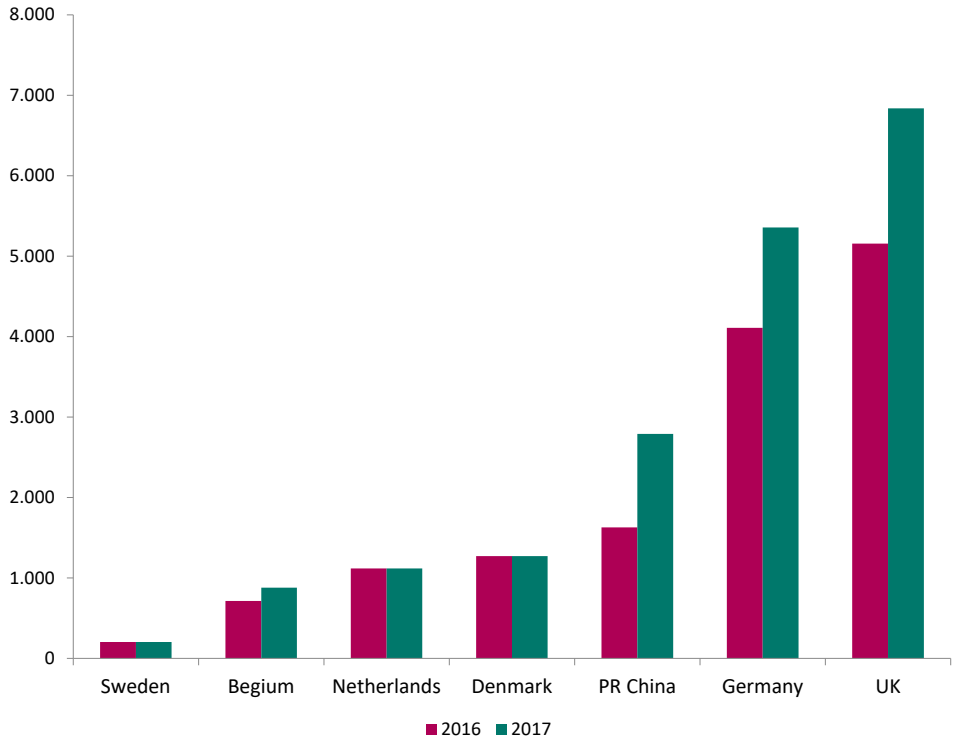
4. Empirical cost comparison of two different market designs

4.1 Data and method

Country selection: Germany and the United Kingdom

The results of the theoretical discussion on the incentives and cost effects of different market designs are empirically investigated in the following section. To measure the impact of different market designs, we compare the costs of OTAs in two structurally similar countries with different regulatory approaches. For this comparative analysis, Germany and the UK are suitable candidates.

Figure 5:
Global offshore wind energy capacity in MW by country

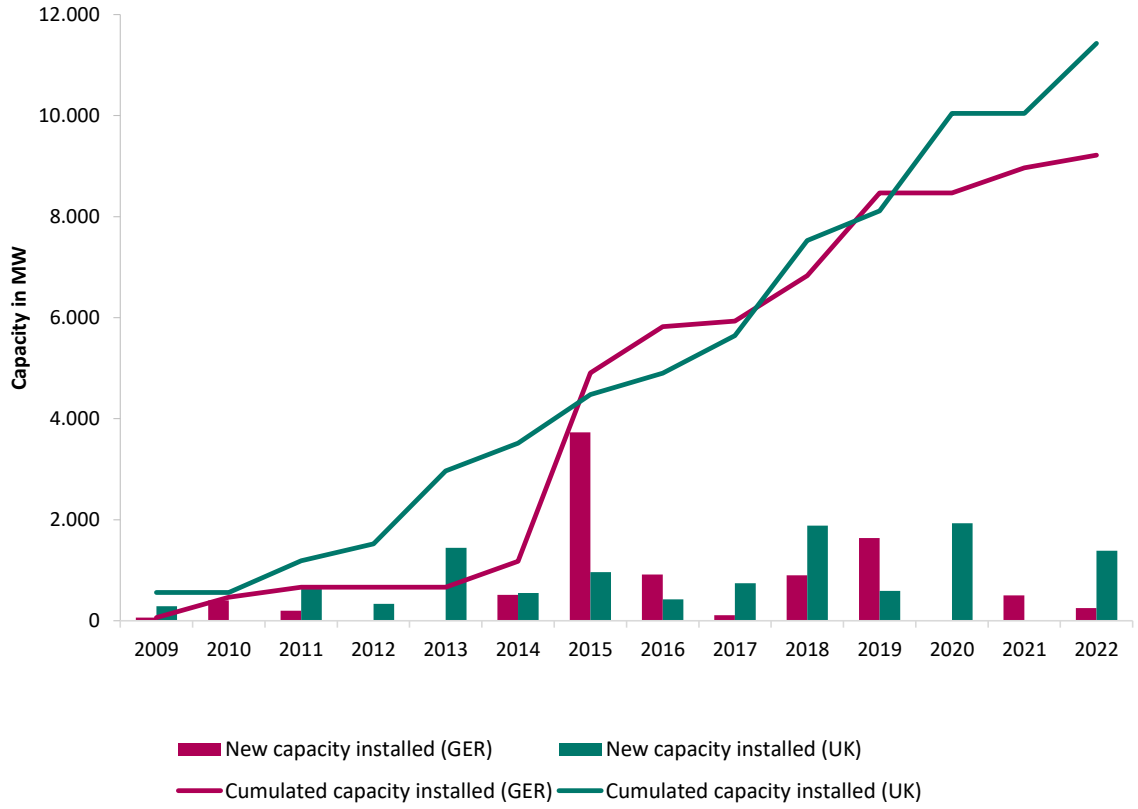


Source: Global Wind Energy Council (2017).

First, both countries provide the largest share of offshore wind energy in the world (Figure 5). Moreover, Germany and the UK are not only similar in size but also share a similar path of development: both countries have decided to place offshore wind energy at the centre of their energy policies (Figure 6). Second, this similar development is not limited to offshore wind energy.

Germany and the UK have so far been part of a single market and have made similar economic progress. They have comparable wage and price levels and are also similar in terms of technical knowledge, available infrastructure, and maritime conditions in the North Sea.

Figure 6:
Installed offshore wind energy in Germany and the United Kingdom



Source: Ofgem (2018) and BNetzA (2017).

Third, the two countries differ significantly in the market design chosen for the development of OTAs. Germany follows a monopolistic approach, in which planning, construction, and operation of the OWF and the OTA are separated. By contrast, the UK follows a competitive and integrated approach for the development of OTA combined with a competitive but separated model for the operation of OTAs. Due to the similar conditions but different regulatory approaches, these two countries provide a suitable case study to evaluate the influence of different market designs on the costs of OTAs. To measure and compare these costs in both countries, we use the concept of LCoE (see detail box 2).

Detail box 2:

Levelized Cost of Electricity (Transmission)

Levelized Cost of Electricity (LCoE) provides a comprehensive measure of the efficiency of an electricity producing or processing asset (Short, Packey & Holt, 1995). LCoE determine the present value per energy unit (e.g. MWh) at which an energy system amortizes its total investment and operating costs.

So far, this method has mostly been used to evaluate the economic efficiency of electricity generating assets. We transfer the concept of LCoE to measure the efficiency of electricity transmission. In our presentation, LCoE represent the discounted total costs (EUR) per transferred and discounted energy unit (MWh) over the entire lifetime of the asset.

$$\begin{aligned} &\textit{Levelized Cost of Electricity Transmission (LCoE)} \\ &= \frac{Total\ Lifetime\ Cost}{Total\ Lifetime\ Output} \\ &= \frac{PV\ CAPEX + PV\ OPEX}{PV\ Total\ MWh} \\ &= \frac{\sum_{t=1}^{n} \frac{I_t + M_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \end{aligned}$$

PV	Present value
CAPEX	Capital expenditures
OPEX	Operating expenditures
I_t	Investments in year t
M_t	Operating costs in year t
E_t	Energy transferred in year t
r	Real interest rate
n	Expected lifetime

An exemplary calculation of LCoE is given in Appendix A.

Source: Short et al. (1995).

Definition of the offshore transmission asset

Due to the different regulatory systems, there is no universal definition for the OTA system. To make the total costs of electricity transmission comparable, our study considers all necessary assets between the OWF and the onshore grid. For OTAs using AC, the OTA system starts with the substation at the OWF (No. 1 in Figure 1) and ends with the onshore substation (No. 4).

For OTAs that use DC, we define the OTA similarly to AC systems. As an OTA with DC technology often bundles several OWFs and their substations (No. 5) at its converter station (No. 7), all substations required for transmission (No. 5) are considered part of the OTA.

Data

CAPEX

The initial CAPEX represents the largest cost factor of the OTA. To calculate the LCoE, we use CAPEX data for 17 British and 9 German OTAs, which is available at Ofgem for the UK and at entso-e[8] and 50Hertz for Germany (ZfK, 2018; Ofgem, 2018; entso-e, 2018) respectively. For OTAs with missing external CAPEX data, we calculate the CAPEX using available unit cost information from BNetzA (2013; 2015; 2017) and Ofgem (2015). To calculate the subsequent cost effects from structural differences between German and British OTAs (Section 4.2), we further employ cost information from National Grid ESO (2015). These are based on enquiries from suppliers and serve as reference values.

Table 2:
(Real) Unit costs of individual OTA components in Germany and the United Kingdom

		Part of the transmission asset	Unit cost			Unit
			2013	2015	2017	
Germany	North Sea	DC cable	2.07	2.05	2.00	m EUR/km
		AC cable	1.55	1.54	1.50	m EUR/km
		DC station	1.03	1.03	1.00	m EUR/MW
	Baltic Sea	AC cable	2.07	3.33	4.35	m EUR/km
		AC station	0.21	0.31	0.40	m EUR/MW
	Onshore	AC cable	1.45	1.54	1.50	m EUR/km
		DC cable	4.14	4.10	4.00	m EUR/km
United Kingdom	North Sea & Irish Sea	AC cable	1.02	1.23	1.31	m EUR/km
		AC station	0.02	0.06	0.06	m EUR/MW
		AC cable	1.47	1.89	2.02	m EUR/km
	Onshore	AC cable	0.7	0.66	0.68	m EUR/km

Note: Unit cost converted from GBP/EUR at an average exchange rate of 1.20 EUR/GBP. All costs adjusted to 2017 prices. UK cost data for 2017 have been computed using inflation adjusted 2015 prices. Costs for OWF substations in the North Sea of Germany are calculated using costs from the Baltic Sea.

Sources: BNetzA (2013; 2015; 2017) and Ofgem (2015).

To validate our calculations, we have compared the costs calculated from our model with the available CAPEX information from both countries. Despite the high individuality of the projects, the overall difference between the external data and the investment costs calculated by us averages only

[8] European Network of Transmission System Operators for Electricity

1.3% in the UK and 2.0% in Germany (Appendix B). We therefore consider our model calculation to be fairly robust.[9]

OPEX

To calculate operating costs in both countries, we follow the assumptions of Brard (2018), who assumes annual OPEX being 1% of CAPEX. These assumptions correspond to a study on the actual OPEX in Germany, which suggests a range between 0.9% and 1.45% to be realistic (Ritzau, Macharey, Svoboda, & Wilms, 2017). Thus, we follow the opinion of a BNetzA report which considers the TSOs' own assessment of OPEX being 3.4% of the CAPEX as excessively high (Federal Network Agency, 2017).

Lifetime

In our basic model, we expect the lifetime of an OTA to be 25 years. This duration is primarily based on the expected technical lifetime and the legal approval of the connected OWFs. In Germany, the BSH grants OWF operation licences for 25 years (BMWi, 2015). In the UK, the tender revenue stream is fixed at 20 years. However, an extension or re-tender is possible if the OWF operates beyond this period (Ofgem, 2010).

This magnitude is also supported by empirical values and information from operators. The OWF "Vindeby" in Denmark, built in 1991, was dismantled in 2017 after the 25-year approval had expired. It produced electricity with all turbines to the end of its lifetime. For the OTAs, the TenneT TSO expects a lifetime of 30 years (TenneT, 2017).

Based on the horizon of statutory approvals and empirical values, we estimate that a lifetime of 25 years is most likely. However, to further consider longer or shorter lifetimes, we also consider lifetimes of 20 or 30 years in our sensitivity analysis (Appendix C).

Cost of capital (WACC)

For our model calculation, we assume nominal weighted average capital costs (WACC) of 5.67% for German transmission assets. These reflect the capital costs of TenneT in 2016 (Moody's, 2018). For the UK, we follow the findings of Ofgem's evaluation report, which found WACC of 6.83% for the respective period (Ofgem, 2018).

[9] Since we overestimate CAPEX by 1.3% in the UK and underestimate CAPEX by 2.0% in Germany, we are likely to underestimate the size of a cost premium caused by an inefficient market design.

Other factors

In our reference case, we expect a capacity utilisation of 3,500 full-load hours per year. This corresponds to a capacity factor of 40% and is derived from the average performance of the OWFs considered in our sample (Energy Numbers, 2018). To convert the British cost information from GBP to EUR, we use the average exchange rate from 2011 to 2017, which was 1.20 EUR per GBP. We further assume an inflation rate of 2% for our basic model. Thus, we follow the targets set by the European Central Bank (ECB) and the Bank of England (BoE).

Changes of these factors (such as a future increase in the efficiency of wind turbines, inflation, or exchange rate fluctuations) influence the absolute cost level. However, as our sensitivity analysis shows, this does not qualitatively affect our results (Appendix C).

Sample selection

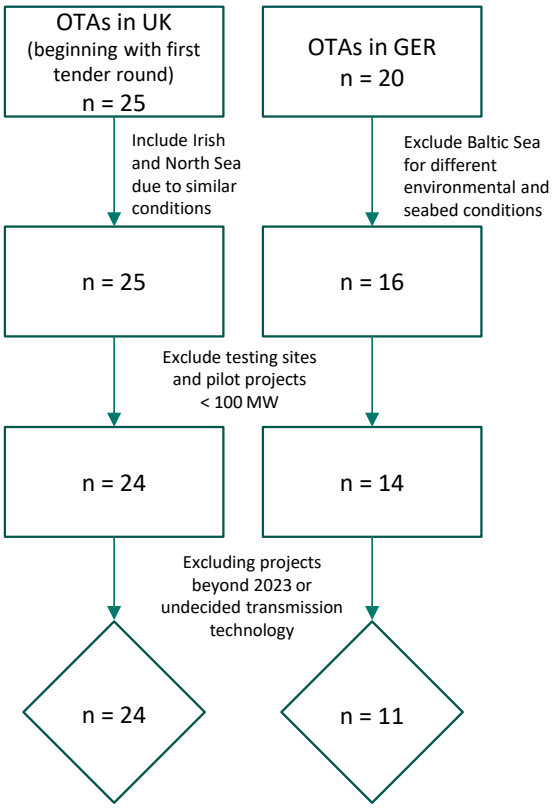
To evaluate different market designs, this study compares the costs of OTAs in the UK and Germany. In the UK, we consider all OTAs built from the first tender round in 2011 onwards. Since all OTAs in Germany are developed within the monopolistic and separate regulatory approach, we consider all German OTAs at first.

The descriptive statistics of the overall sample in the UK do not show any systematic differences between the Irish Sea and the North Sea. We therefore assume comparable geological and maritime conditions for construction and operation in both seas.

However, in Germany, conditions for construction in the North Sea and the Baltic Sea differ significantly. Although the transmission distance of OTAs in the Baltic Sea is significantly shorter than in the North Sea, costs are higher in the Baltic Sea.[10] These additional costs are often attributed to tougher seabed conditions, which are characterised by irregular soil profiles and undiscovered ammunition loads. As the accurate effect of environmental conditions on the costs of OTAs in the Baltic Sea cannot be isolated, we exclude the respective OTAs from our sample (Figure 7).

[10] The value of average OTAs in the Baltic Sea with LCoE of 45.04 EUR/MWh are clearly higher than the average values in the North Sea (35.32 EUR/MWh, original data with all OTAs). At the same time, OTAs in the Baltic Sea have an average connection length of only 93km compared to 135km in the North Sea.

Figure 7:
Selection criteria of underlying sample



Source: DIW Econ.

Furthermore, we do not consider OTAs with a capacity of less than 100 MW, since these usually represent non-commercial pilot projects. As a pilot project for DC technology, we also exclude BorWin1 from our empirical analysis. Our sample is further limited to projects until the year 2023. OTAs commissioned later do not offer sufficient planning security on a project level with regards to their implementation, transmission technology, or the scope of OWFs to be connected.[11] Despite these limitations, the remaining 18.5 GW of our sample still cover around 80% of total capacity in both countries,[12] providing a representative coverage of OTAs in the UK and Germany.

[11] Although SylWin2 (2025) was announced in the 2017 O-NEP, plans for further development were suspended towards the end of 2018. Whether SylWin2 will be built is currently unknown.

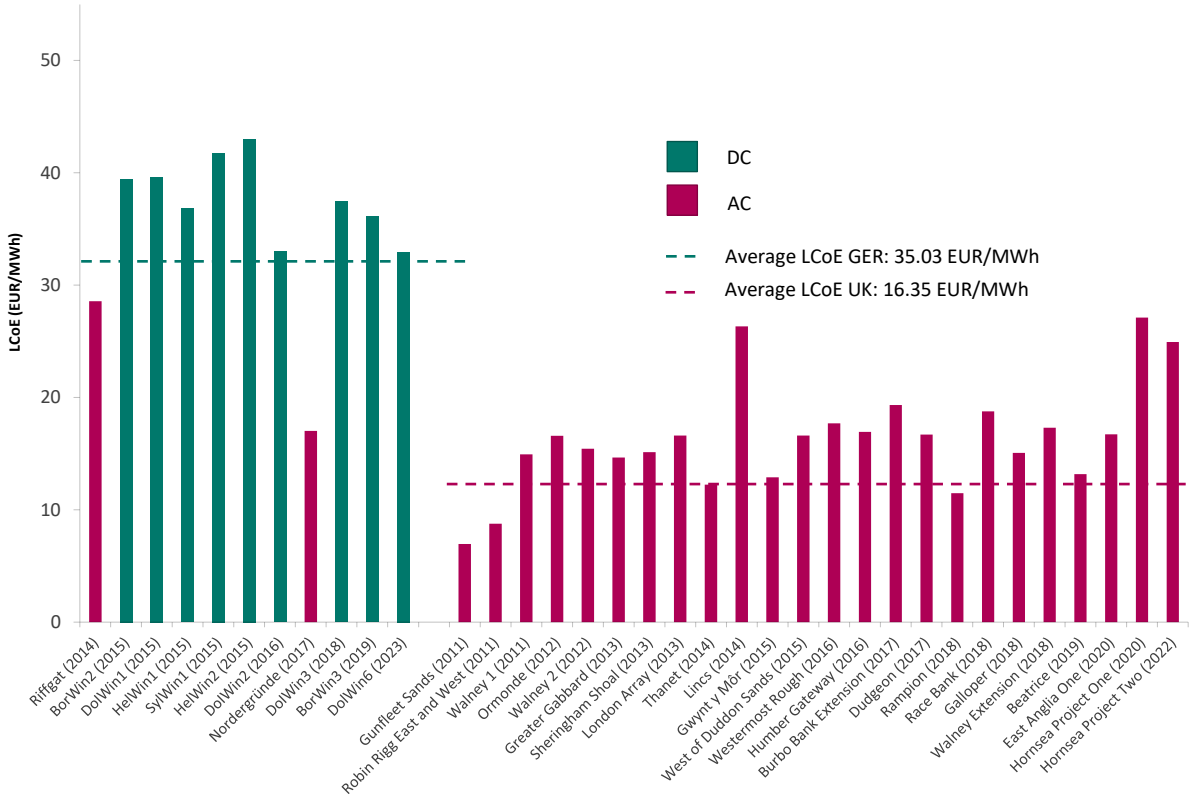
[12] In the UK, our sample covers 99% of foreseeable UK offshore capacity. In Germany, our sample covers 60% of the capacity of OTAs. This difference is mainly due to the fact that the Baltic Sea has been excluded and planning in Germany extends further into the future than planning in the UK. A significant proportion of the planned capacity in Germany is not scheduled until 2025. Information on planned OTAs is not yet available for this period in the UK.

4.2 Empirical results

4.2.1 Descriptive statistics

The average cost of offshore electricity transmission measured in LCoE is 35 EUR/MWh in Germany (North Sea) and 16 EUR/MWh in the UK. Thus, LCoE in Germany is more than twice as high as LCoE in the UK.[13]

Figure 8
LCoE in Germany (left) and the United Kingdom (right) at project level (final sample)



Source: DIW Econ.

Comparing the development of costs in Germany and the UK over time, the UK shows a slight increase in costs. However, this trend is mainly attributable to the sharp increase in transmission distance covered by British OTAs. In Germany, the OWFs were planned further at sea from the start.

[13] At 45 EUR/MWh, the average costs for OTAs in the Baltic Sea are significantly higher, although they have to bridge shorter distances.

This is mainly due to environmentally sensitive coastal areas, which is why transmission lengths have hardly changed.

Table 3
Mean values of the final sample over time

	United Kingdom			Germany (German)		
	until 2017	**from 2018**	**Δ**	**until 2017**	**from 2018**	**Δ**
Distance from shore (km)	16	44	+175%	69	72	+4%
Transmission capacity (MW)	308	734	+138%	609	900	+48%
LCoE (EUR/MWh)	15.18	17.74	+17%	34.91	35.50	+2%

Source: DIW Econ.

The LCoE difference of 19 EUR/MWh must be examined in the light of other differences between the OTAs in Germany and the UK. In addition to the higher LCoE, German OTAs have longer cable lengths (onshore and offshore) and rely largely on DC technology.

Table 4:
Mean values of the final sample by country and sea

	United Kingdom		Germany (German)	
	Irish Sea	**North Sea**	**North Sea**	
Technology	AC only	AC only	DC	AC
Distance from shore (km)	15	31	76	40
Onshore cable length (km)	10	21	61	17
Offshore cable length (km)	38	52	92	39
Transmission capacity (MW)	322	514	817	112
LCoE (EUR/MWh)	15.24	16.91	38.01	21.67
n	8	16	9	2

Source: DIW Econ.

To accurately estimate the impact of different market designs on overall costs, we first analyze the effect of other factors that may explain part of the cost difference between OTAs in the UK and Germany:

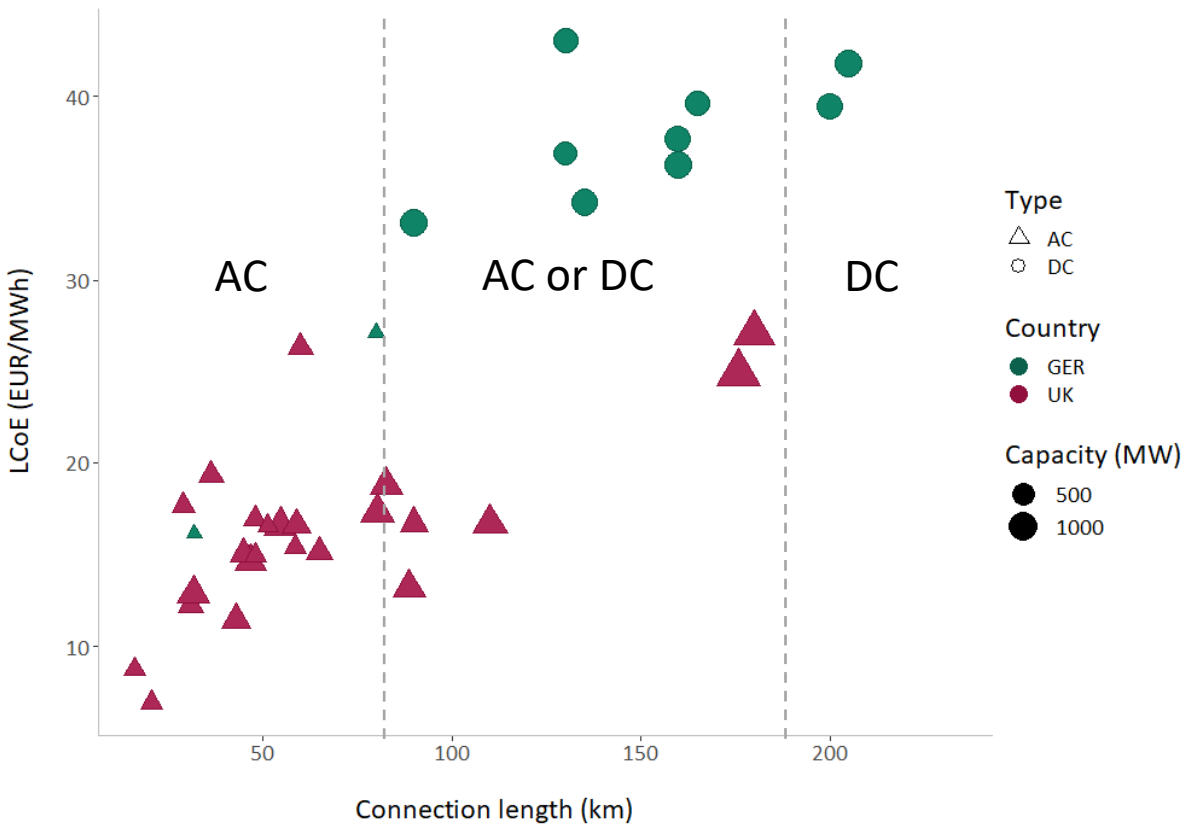
- Cable length: Onshore and Offshore
- Technology: AC vs. DC
- Overcapacity
- Environmental regulation

- Financing costs

4.2.2 Cable length

OTAs in the UK and Germany differ primarily by their transmission length. Since the costs of an OTA are largely determined by cable length, their differences are likely to explain part of the cost difference between the two countries.

Figure 9
LCoE as a function of the connection length (km), transmission capacity (MW), technology (AC or DC), and country in the context of the technical conditions of AC and DC systems



Note: The areas mark the corridor in which, according to the current research literature, the respective transmission technology has a cost advantage.

Source: DIW Econ.

Due to the higher purchase and installation costs, additional cable lengths increase CAPEX significantly. In Germany, we find on average an additional cable length of 44 km on land and 45 km at sea. Thus, the additional transmission length explains part of the higher LCoE in Germany.

To calculate the cost difference, we use published unit cost information for cables and installation based on requests from suppliers.[14] We estimate that the additional costs for the cable acquisition and installation of an average project in Germany add up to EUR 108 million. The additional distance thus explains 5.60 EUR/MWh of the higher LCoE in Germany compared to the UK.

4.2.3 Technology

Whether AC or DC systems are a more efficient transmission solution for a given project is a matter of controversy. Although capacity, location, and technical know-how play a crucial role, the length of the connection is usually described as the decisive factor. AC systems are preferred for shorter distances. Although they are characterised by higher cable costs, they have lower station costs as only one offshore substation is usually required (Figure 1). They are therefore regarded as a cost-effective transmission option for distances of up to 60-80 km (Xiang, Merlin, & Green, 2017). To cover longer distances with a frequency of 50 Hz, additional compensation stations are necessary along the route.[15] However, DC systems are traditionally used for longer distances. They usually feature higher station costs, resulting from two additional converter stations, but lower cable costs.

Due to the complex interplay of distance and transmission capacity, there is a wide corridor of connection lengths in which the application of both techniques can be economically viable. Our study supports this hypothesis. Within our sample, short distances are connected exclusively via AC systems. However, for medium and long distances both technologies are used.

The frequency of application of the respective technology differs by country. Germany focuses on DC systems whereas the UK relies only on AC systems. Another factor influencing the decision between AC and DC systems is the transmission performance of individual cables and the resulting effects on cable corridors. Currently, single AC cables are limited to a transmission capacity of 300 to 400 MW. An AC system with 900 MW in Germany would therefore require the installation of three AC cables instead of two DC cables for a comparable DC system. According to the BSH, DC systems are thus preferred due to their reduced impact on the marine environment. In addition, DC systems offer other advantages such as a quick start after a power failure and more options for stabilising the entire network (Korompili, Wu, & Zhao, 2016). Yet due to their high complexity, they also require greater control and coordination efforts (Saad, 2016). However, from a total cost perspective as

[14] These were collected by National Grid ESO for the year 2015 through requests from suppliers (National Grid ESO, 2015).

[15] These are used for the first time to connect British OWFs Hornsea Project One and Two.

given by the LCoE, these advantages do not create any substantial economic added value, even taking into account long-term developments such as a meshed grid in the North Sea.

In order to record the cost effects of the various transfer techniques, their different cost structures must be taken into account in the cost estimate. For the calculation of the cost effects, we use a typical German transmission asset with 900 MW, as it is defined by the authorities in the standardised technical specifications and most frequently built in practice. Based on the average cable distances in Germany, we calculate the cost of this typical transmission asset in Germany in the case of AC transmission and compare it to DC transmission.[16] We find additional costs of DC systems to be 2.99 EUR/MWh. This accounts for 16% of the LCoE cost difference between OTAs in Germany and the UK.[17]

4.2.4 Environmental regulation

In Germany, environmental regulations are already considered when choosing the transmission technology. Other environmental regulations that significantly influence the costs of OTAs in Germany include the 2K criterion as well as the additional measures that are required in sensitive coastal areas such as the Wadden Sea.

2K Criterion

As a precautionary measure, the 2K criterion sets a limit for the heating of sediment around offshore submarine cables in Germany. These are usually laid 1.5 m below the seabed. The 2K criterion means that the sediment between the cable and the seabed must not heat up more than 2 Kelvin 20 cm (or 30 cm in the Wadden Sea) below the seabed (BfS, 2005). The heating of a cable depends on the capacity of the cable in relation to its size. As a result, the cables laid in Germany are larger than necessary given the capacity of electricity actually transmitted. The additional capacity (diameter) of the cables is therefore only necessary to comply with the 2K criterion.[18] The resulting costs are directly attributable to the environmental requirements.

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[16] For this purpose, we also use the published unit cost information for cables and installation from suppliers, which were collected by National Grid ESO for the year 2015 through inquiries from suppliers (National Grid ESO, 2015).

[17] This cost difference was calculated on a project level for all DC projects and thus accounts for the fact that the German North Sea also features AC projects.

[18] This becomes clear when comparing the cable diameters laid in Germany with the respective capacities stated by cable manufacturers. The 320kV submarine cables from ABB used for e.g. DolWin2 with a copper

Wadden Sea

The German North Sea coast is largely surrounded by the national park of the German Wadden Sea. Being an environmentally sensitive area, this poses special challenges for cable laying. On the one hand, the stricter limit for the 2K criterion in these sections requires an even larger cable diameter to mitigate sediment heating. On the other hand, the laying process itself requires greater effort due to more complex laying methods (e.g. using a vibration sword), which are associated with higher costs.

The additional costs calculated on the basis of project-specific data for the corresponding areas of the cable sections lead to higher LCoE in Germany of 0.45 EUR/MWh.[19] However, it must be considered that further environmental economic costs are already included in the DC technology cost surcharge, since the technology decision in favour of DC systems for the German North Sea is driven by environmental concerns.

4.2.5 Overcapacity: Temporary and permanent

Traditionally, OWFs are connected to the mainland via individual OTAs. Alternatively, hub connections can be used whereby several OWFs are connected to one shared OTA.

So far, the UK has relied on individual (radial) OTAs, which are integrated with the OWF. However, in Germany, 82% of the OWFs in our sample are connected via hub connections built separately by the TSO. The individual offshore substations of those OWFs are then connected to the hub connection of the TSO, which transmits the electricity to shore. Due to the separate construction of the hub connection and the various OWFs, planning uncertainties arise. These lead to additional coordination costs and capacity overhangs (Offshore Management Resources, 2014; Fichtner, 2016).

Often, several years pass between completion of the first and the last OWF that share a hub connection. However, since the hub connection must be available from the commissioning date of the first OWF, temporary overcapacities arise. During this period, the hub connection transmits only part of its available capacity.[20] To calculate the resulting cost impact, we compare the LCoE

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conductor area of 1400mm² (TenneT, 2012) are rated for higher capacities according to official manufacturer data (ABB, 2012).

[19] Calculation based on supplier costs for cables and installation methods (National Grid ESO, 2015).

[20] The effect is repeated towards the end of the lifetime of OWFs. Since OWFs are often connected at intervals of several years (e.g. there are 7 years between the connection of Amrumbank West and KASKASI II to HelWin2), it can be technically assumed that previously connected OWFs also have to be dismantled several years earlier. The OTA then works again with overcapacity. However, since no empirical values are available for this, the resulting costs cannot be reliably calculated within the framework of our empirical analysis.

calculated with actual transmission capacity in the affected years with the LCoE for full capacity utilisation.

In addition, hub OTAs in Germany are often planned and built before the final arrangement of the connected OWFs is known. In addition to the challenge of timing, this can result in the available capacity of the hub OTA exceeding the cumulative capacity of the connected OWFs, even after all planned OWFs have been commissioned. This circumstance creates permanent overcapacity for several OTAs.

Both types of overcapacity can be calculated by comparing the amount of actual electricity produced by the OWFs with the transmission capacity available by the OTAs. This comparison shows that the consequences of temporary and permanent overcapacity explain 1.72 EUR/MWh of higher LCoE in Germany.

4.2.6 Capital costs

Another difference between OTAs in Germany and in the UK that affects costs are financing possibilities for the developers of an OTA. German TSOs have better conditions, as they can access favourable financing possibilities through state-guaranteed returns on sales and capital-supporting measures such as the offshore (liability) levy. The developers and operators of OTAs in the UK, on the other hand, are exposed to a higher risk and thus face tougher financial conditions. In order to determine the resulting cost differences more closely, we consider the WACC (nominal pre-tax) for the average period examined in our sample. Data by Ofgem suggests WACC of 6.83% (Ofgem, 2018) in the UK. The rating agency Moody's calculates the corresponding cost of capital for the TenneT Holding at 5.67% (Moody's, 2018).

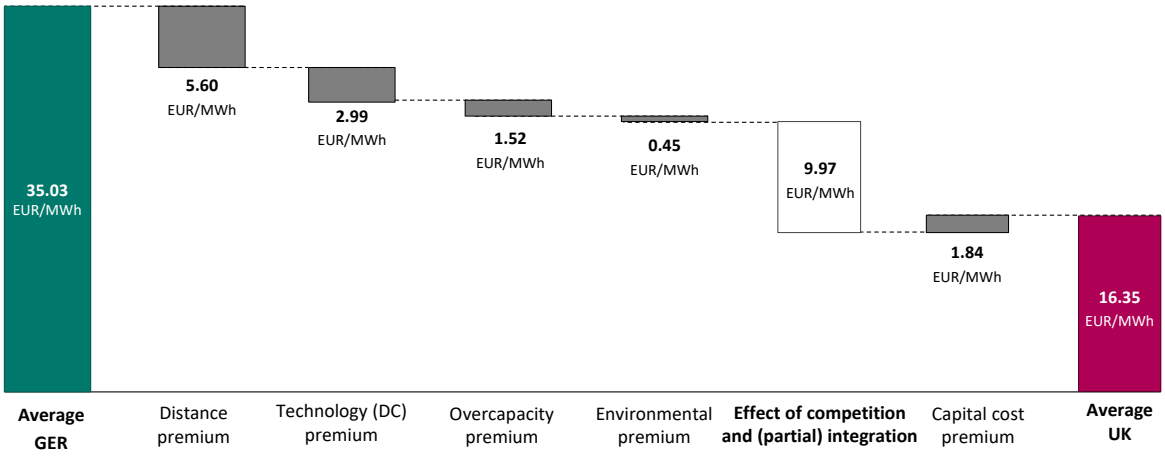
In order to analyse the cost effects, we harmonise the basic conditions of both countries by calculating the LCoE for British OTAs with the capital costs of a German TSO. The result shows that LCoE in the UK would decrease by 1.52 EUR/MWh if the same financing conditions were available as in Germany.

4.2.7 Cost differences due to different market designs

After considering the spatial, technical, environmental, and financial differences, a significant LCoE difference of 10 EUR/MWh remains between both countries. It can be assumed that the remaining cost difference is mainly due to the different market design for OTAs, which allows an integrated construction and a competitive tendering process in the UK but relies on a separate and monopolistic

market design in Germany. The costs from missing competition and lack of integration represent the largest share of the additional regulatory costs in Germany, next to technology choice (DC), overcapacity and environmental requirements.

Figure 10
Schematic breakdown of the average LCoE (EUR/MWh) difference between OTAs in Germany and Germany



Source: DIW Econ.

4.3 Further discussion

4.3.1 Supply security

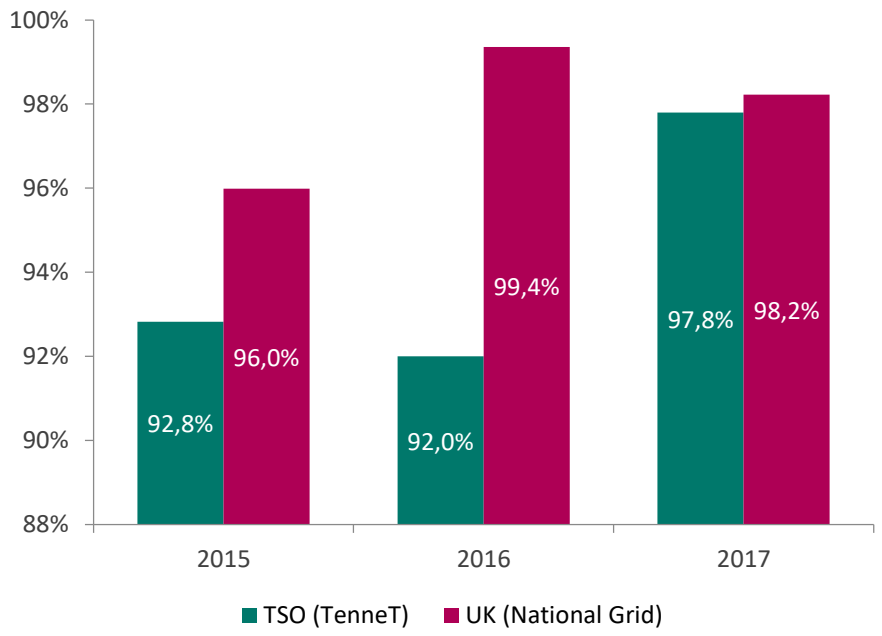
A comprehensive evaluation of the regulatory framework should not be limited to costs. Therefore, we also consider the quality of transmission. As OTAs are critical infrastructure components of energy supply, their average availability is crucial. Regulation in the UK offers a mechanism to incentivise network availability: If network availability falls below 98%, the OTA operator's revenues are reduced. Reversely, if the OTA operator exceeds the target, it receives bonus payments.

In Germany, OWFOs may claim damages from the TSO for interruptions, maintenance works and connection delays.[21] However, the TSOs are free to pass on these claims directly to the final consumer via the offshore (liability) levy without suffering any revenue losses.

[21] In the event of interruptions, the OWFO can claim damages after the eleventh day of the interruption, after the first day of the interruption if the interruption occurred due to an intentional act, and after the 19th day of the calendar year if disturbances occurred on more than 18 days of the calendar year. However, in the case of maintenance, a claim arises after the eleventh day of the interruption. For a valid claim, a maintenance induced interruption does not need to take place on consecutive days as in the case of interruptions from disturbances (BMWi, 2017).

A look at the freely accessible data on network availability shows that the availability of British OTAs is higher on average than that of German OTAs. Even taking into account the greater distance the OTAs in Germany have to bridge, the available figures point to a similarly high reliability of British OTAs. Thus, the higher LCoE in Germany cannot be attributed to a higher quality of supply.

Figure 11
Offshore network availability of a TSO (TenneT) and average OTAs in the United Kingdom



Source: National Grid ESO (2018) and TenneT (2017).

4.3.2 Offshore (liability) levy

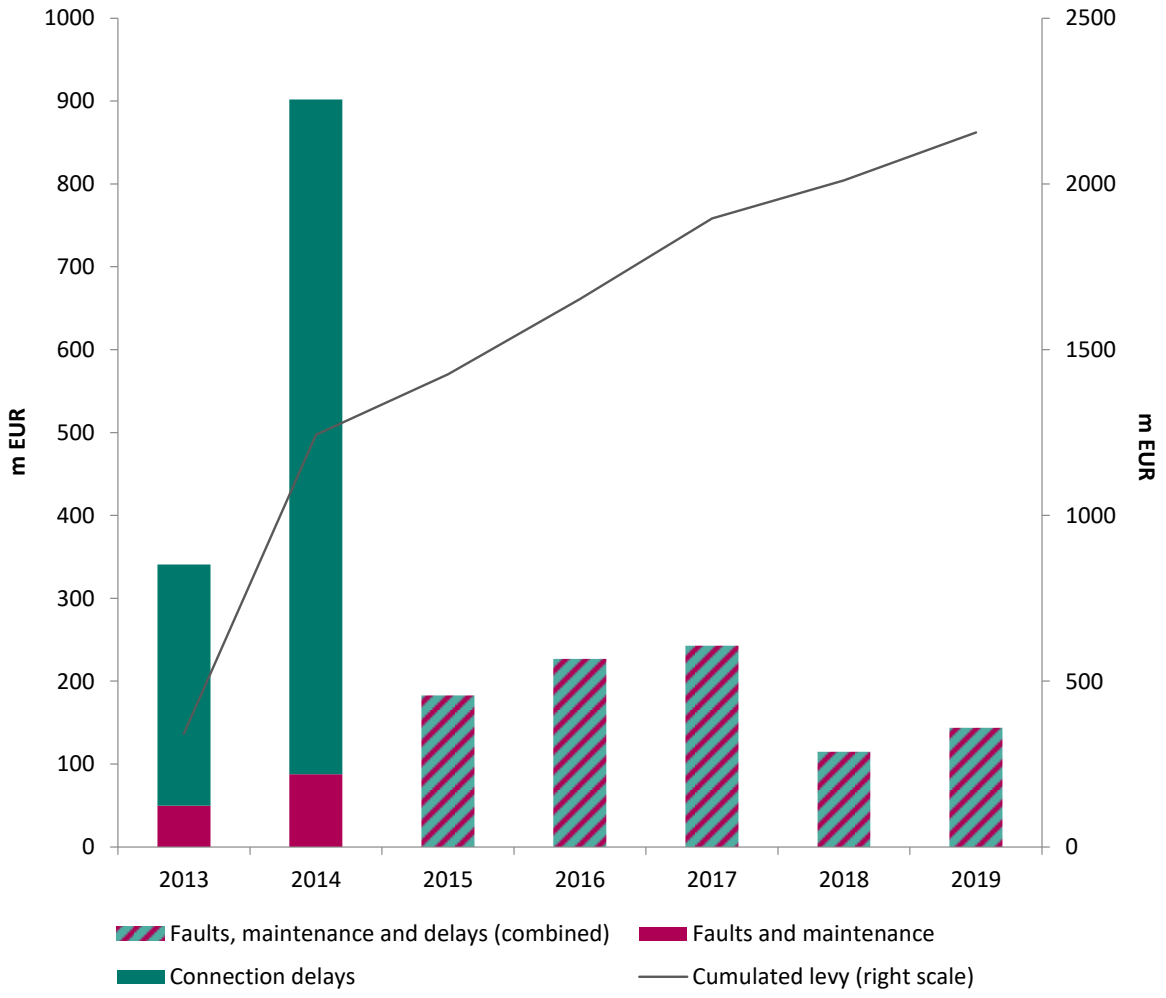
In addition to the direct expansion costs and transmission quality, Germany also incurs additional coordination costs: If an OWF is connected late, the electricity produced cannot be fed into the grid and thus cannot be sold. The operator's lost electricity revenues are to be compensated by the TSO responsible. These compensation payments are reflected in the offshore (liability) allocation.

Detail box 3:
Offshore (liability) levy

In order to accelerate the expansion of the offshore network in Germany, the offshore liability levy was added in the 2012 amendment to the German Energy Industry Act (EnWG). This allows TSOs to pass on all compensation costs, which had to be paid to the OWFO as a result of delayed connection or long interruptions, to the final consumer. From 2019 on, the offshore liability levy will be integrated into the extended offshore levy. The latter not only includes the passing on of damage claims to the final consumer, but also covers the total investment costs of the offshore transmission asset in accordance with §17 EnWG.

Due to their aggregated nature, the published data on the amount of the offshore (liability) levy in recent years does not allow conclusions on the additional costs incurred on a project level. Moreover, there is no transparency about the exact causes of the levy costs. Therefore, they are not yet part of the present analysis. However, the damages from the levy must be added to the already higher regulatory costs in Germany, since their amount contributes significantly to the OTA costs in Germany. Currently, the cumulative claims for damages from the offshore (liability) levy amount to almost EUR 2 billion.

Figure 12
Absolute amount of the offshore (liability) levy in Germany between 2013 and 2019

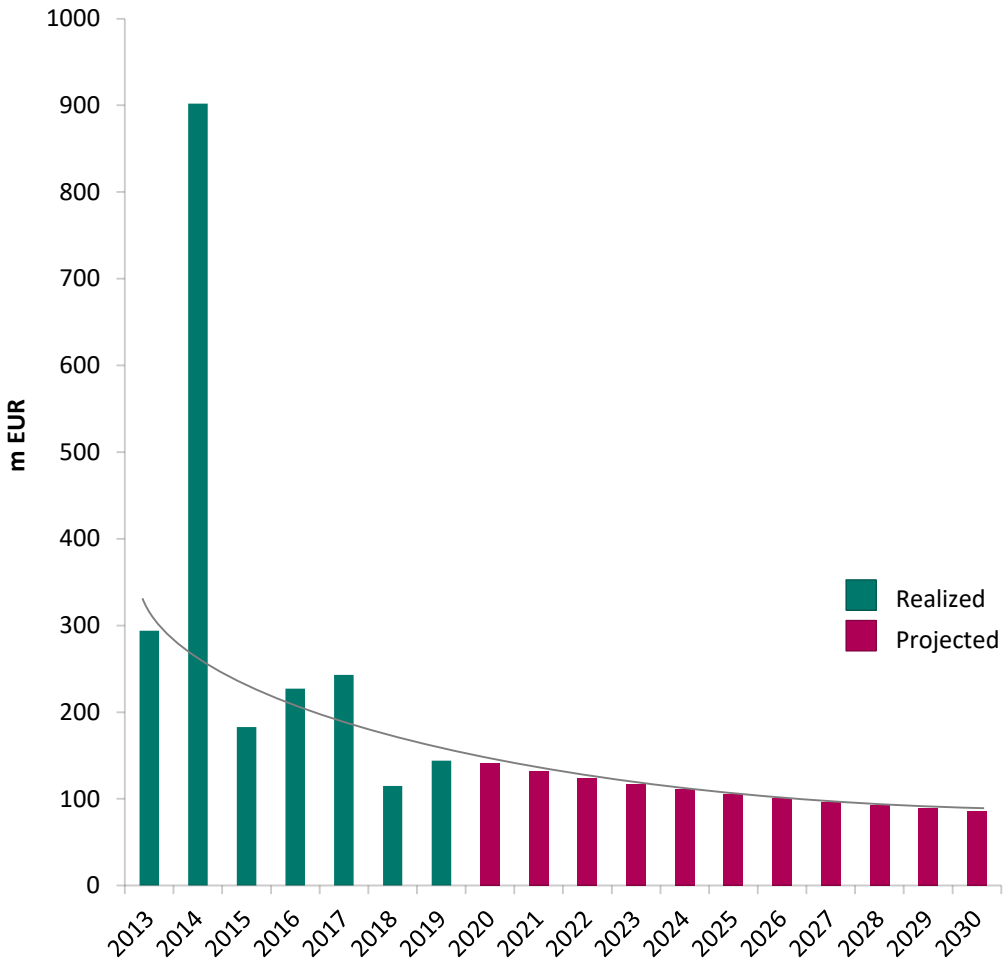


Note: As of 2015, the amount of the offshore (liability) levy is no longer disclosed separately.

Source: DIW Econ.

At the beginning of the OTA expansion in Germany, costs resulting from connection delays made up the main part of the offshore (liability) levy. Having moved the timeline of OTA projects forward (temporary overcapacity), TSOs now indicate that damage claims resulting from connection delays are no longer relevant (BMWi, 2017). We therefore assume that the allocation costs incurred since 2015 are primarily attributable to malfunctions and maintenance.

Figure 13:
Absolute amount of actual and forecasted offshore (liability) levy between 2013 and 2030 in million EUR



Note: Based on the information reported by TSOs on disruptions and maintenance work on OTAs, including downtime and affected capacity, we find no significant reduction in interruptions between 2016-2018 (TenneT, 2019). This already considers the increased risks in the initial operation of an OTA. Therefore, all first years are excluded for the OTAs. At the same time, we expect that the generally higher number of OTAs to be built from 2019 onwards will not lead to a complete reduction of interruptions. Therefore, we assume in our forecast (quadratic function, R^2=0.39) that network interruptions with relevance for the offshore levy will only decrease slightly in the future.

Source: DIW Econ.

To include the resulting costs in our analysis even without project-specific attribution, we consider the proportionate costs induced by the offshore levy in the subsequent calculation of the aggregated economic costs (Section 5).

4.3.3 Limitations

When interpreting the results, one needs to bear in mind that the present study is subject to certain limitations.

First, the calculation of the LCoE depends on various assumptions. In addition to technical assumptions such as lifetime and full load hours, financial factors such as WACC, inflation, and the exchange rate influence the underlying calculations. To evaluate the effect of these factors in our calculation, we provide a sensitivity analysis (Appendix C). We find that even major changes in our assumptions do not qualitatively affect our results.

A further limitation results from the available cost information. Although the level of actual construction costs incurred in the UK is available for the majority of all projects examined, the same information is only available to a limited extent in Germany. The CAPEX values derived from O-NEP and Ofgem may therefore differ from the actual costs for individual projects. However, the robustness check shows that our calculations provide a robust estimation of the actual costs. When compared to the actual costs, the difference is less than 2% (Appendix B).

In addition, the lack of actual operating costs makes it difficult to accurately model the total costs incurred. The legal guidelines of 3.4% (until 2018) and 0.8% (as of 2019) in Germany as well as the 1% found in research literature for OTAs in the UK (Brard, 2017), only approximate actual operating costs. However, the value of 1% of CAPEX chosen for our analysis does not differentiate between the two countries and is therefore considered neutral. The assumption is supported by an expert opinion on the determination of an appropriate share of OPEX in Germany (Ritzau, Macharey, Svoboda, & Wilms, 2017), with the estimated true OPEX for OTAs in Germany lying between 0.9% and 1.45% of CAPEX.

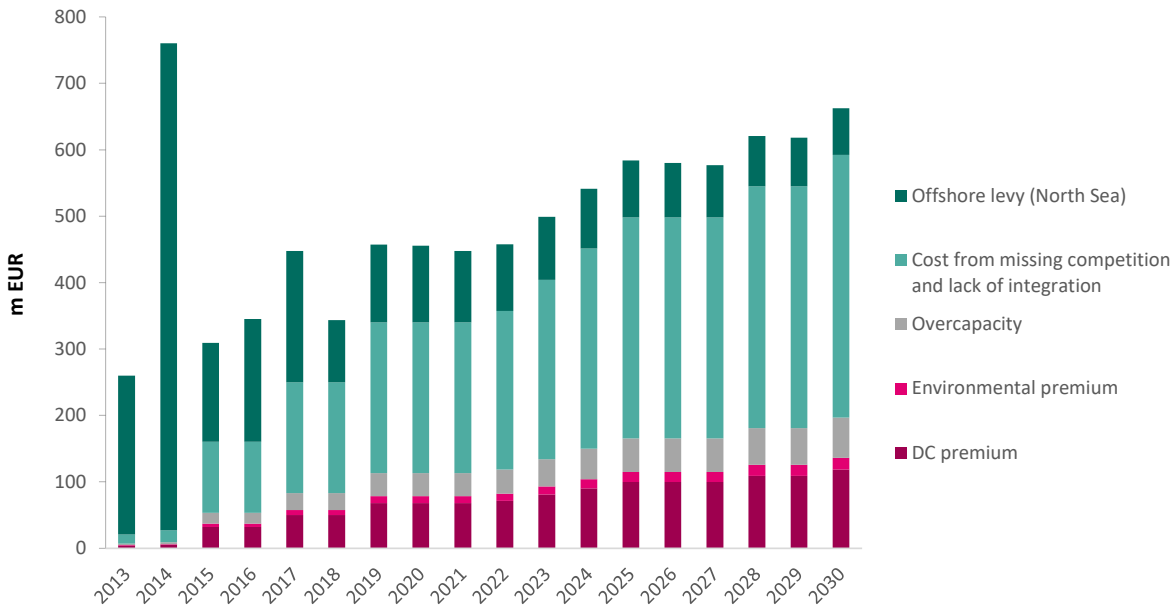
Despite the limitations outlined above, the robustness checks and the external empirical evidence suggest that the assumptions are sufficiently accurate for our model. However, the limited cost information available renews the demand for greater cost transparency, especially in Germany.

5. Aggregated economic costs

To evaluate the aggregated economic consequences of the additional regulatory costs in Germany, we use the LCoE components identified in Section 4. These are complemented by the already realised costs of the offshore (liability) levy and their projection up to the year 2030 (Figure 13).

As the available levy costs are not sea-specific and our LCoE analysis only applies to the North Sea in Germany, we weight the costs of the offshore (liability) allocation according to the capacities installed in the respective seas. For data on the expected development of offshore wind energy, we base our calculation on the BNetzA's latest grid development plan (O-NEP).

Figure 14:
Annual economic costs due to an inefficient market design of OTAs in the German North Sea between 2013-2030



Source: DIW Econ.

The additional costs due to regulatory effects relate exclusively to OTAs in the German North Sea, as we have excluded OTAs in the Baltic Sea in our empirical analysis due to their significantly higher LCoE. The regulatory costs from 2013 to 2030 amount to a total of almost EUR 9 billion. The inefficient market design marked by low incentives for cost reduction and a lack of coordination represents the largest cost block with EUR 3.4 billion. These already take into account the different capital costs that can be observed in Great Britain. The second largest item with a total amount of EUR 2.7 billion is the lack of cost pressure resulting from the possibility to pass on additional costs directly to the final consumer via the offshore (liability) levy. Apart from the connection delay costs that are already included in the offshore levy, temporary and permanent overcapacity caused by a lack of coordination generate costs of EUR 700 million. Furthermore, the preference for DC systems as well as other environmental requirements lead to additional costs of EUR 1.5 billion.

6. Conclusion

The present study compares the different market designs for the development and operation of OTAs. To compare their effectiveness, we investigate the LCoE of OTAs in two comparable countries with different market designs. The UK uses a competitive tender process for the development and operation of OTAs. In Germany, the local TSO is obliged to build and operate the OTA as a monopolist. Additionally, the planning and construction of British OTAs are integrated within the OWFO. By contrast, German OTAs are planned and built separately from OWFs within the current regulatory framework.

In order to quantitatively compare the effect of these regulations, we use cost information from national authorities, TSOs, and other sources to calculate the LCoE of all relevant OTAs built between 2011 and 2023. The comparison shows that German OTAs are significantly more expensive. This result is robust even after considering the differences in distance, technology choice, capacity utilization, environmental regulation, and financing conditions. The cost difference is not explained by a higher security of supply in Germany and even is amplified by the offshore (liability) levy.

This remaining cost difference between the average LCoE of OTAs in the UK and Germany primarily measures the cost impact of the different regulatory approaches. These unfold in the additional cost pressure from the competitive tender and the integrated construction of OWF and OTA in the UK compared to the monopolistic and separated TSO model in Germany.

The economic costs of an inefficient market design for OTAs in the German North Sea can be estimated on the basis of the identified cost reduction potentials and the already realised and forecasted costs of the offshore (liability) levy. The total regulatory costs from 2013 to 2030 amount to EUR 8.2 billion, of which EUR 6.7 billion are attributable to inefficient market design and EUR 1.5 billion to environmental requirements. Low incentives to reduce costs and the lack of integration between OWF and OTA make up the largest cost block with EUR 3.4 billion. The lack of cost pressure, resulting from the possibility of passing on additional costs directly to the final customer via offshore (liability) allocation, leads to a further EUR 2.7 billion in additional costs. In addition to the connection delays already included in the offshore levy, temporary and permanent overcapacity due to a lack of coordination produces additional costs of EUR 700 million. The preference for DC systems and environmental requirements lead to further costs of EUR 1.5 billion.

The available cost information (at project level) limits the empirical scope of the present analysis and renews the demand for greater cost transparency in Germany. However, the empirical nature of the

underlying assumptions, the robustness check of the calculated CAPEX, and the results of the sensitivity analysis suggest that our results provide an accurate picture of the costs of OTAs in Germany and the UK.

This study shows that due to the monopolistic market design of OTAs in the North Sea, final consumers in Germany will have to pay additional costs of EUR 6.7 billion until 2030. The results show that a competitive tender and the possibility of integrating OWF and OTA can make a significant contribution to improving the cost efficiency of offshore wind energy transmission.

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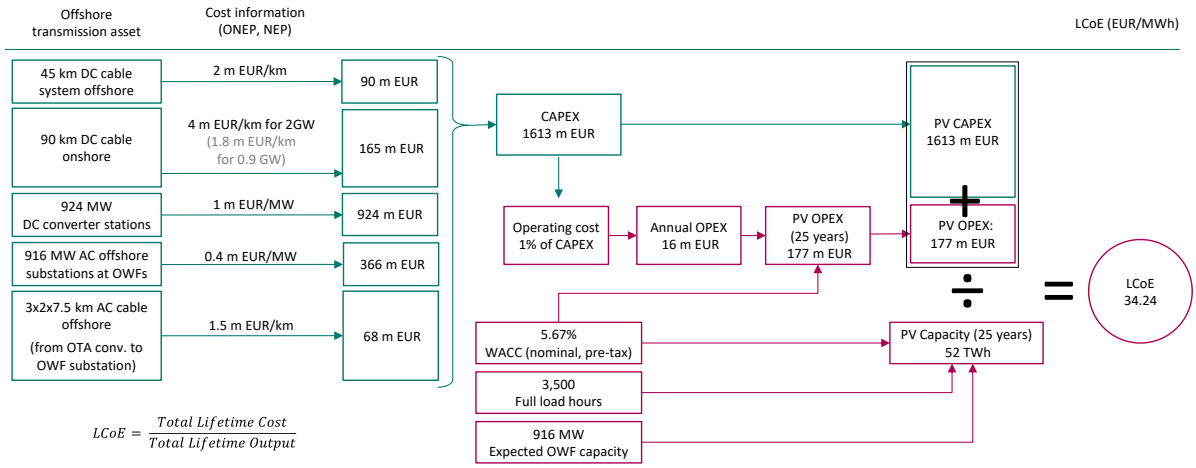
Appendix

Appendix A: LCoE calculation

Figure 15:
Exemplary calculation of LCoE for DolWin2 (924MW)

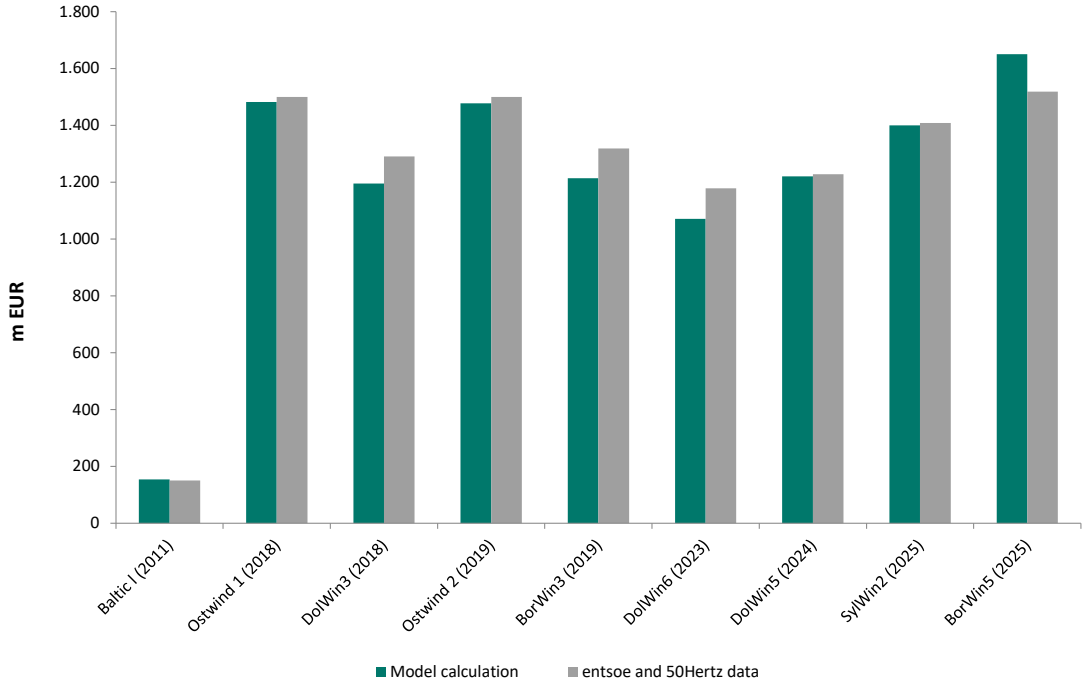


Source: DIW Econ.

Appendix B: CAPEX Calculation

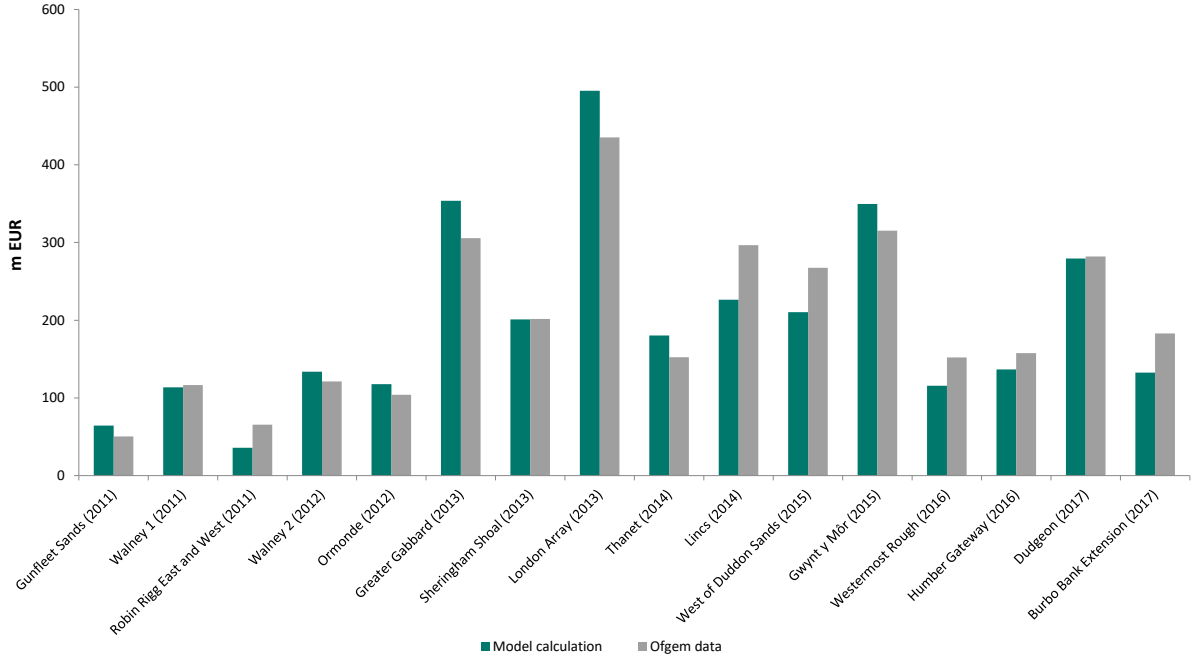
To check the robustness of our model calculation, we compare the calculated CAPEX with externally published cost information for OTAs in Germany and the UK. Although our model underestimates or overestimates the results in individual cases, the comparison with external costs show only a small overall deviation. Despite the high degree of individuality of the single projects, the overall average deviation between the external data and the total costs calculated by us only amounts to 1.3% in the UK and 2.0% in Germany. Therefore, the results of this comparison suggest that our model produces sufficiently accurate CAPEX values.

Figure 16:
Comparison of calculated CAPEX in million EUR with external data of entso-e and 50Hertz for available projects in Germany



Source: DIW Econ with data from entso-e (2018) and 50Hertz (ZfK, 2018).

Figure 17:
Comparison of calculated CAPEX in million EUR with external data from Ofgem for available projects in the United Kingdom



Source: DIW Econ with data from Ofgem.

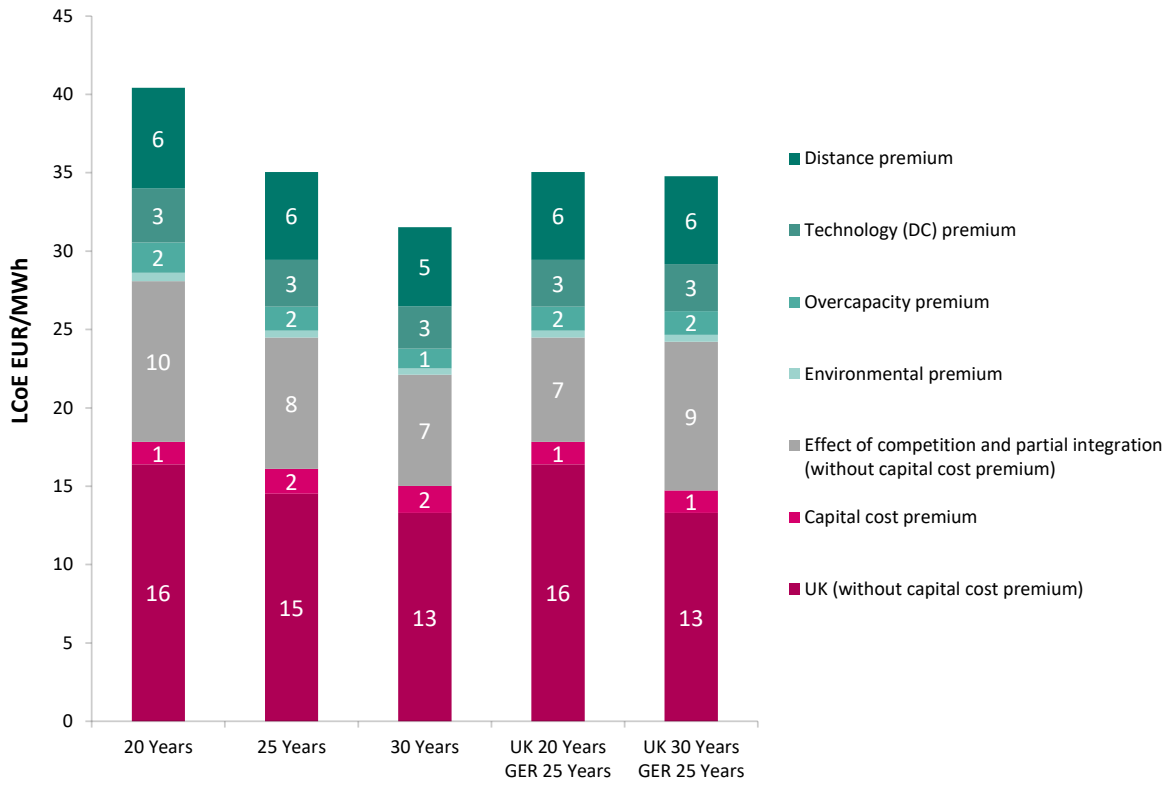
Appendix C: Sensitivity analysis

The LCoE calculation depends on multiple assumptions that have been based on empirical findings (Section 4.1). To check their robustness further, we investigate the mechanism of the individual parameters. For this purpose, we test how changed assumptions affect the results of our LCoE calculation.

Lifetime

In our basic model, we assume an OTA lifetime of 25 years. This represents the current assessment of the technical lifetime of OWFs. In addition, we use the UK's originally projected revenue stream of 20 years as the lower bound UK (Ofgem, 2010). The upper bound reflects the expectations of TenneT as well as plant manufacturers, which estimate a lifetime of 30 years (TenneT, 2017; ABB, 2015).

Figure 18:
Sensitivity analysis of the average LCoE components (EUR/MWH) using different lifetimes

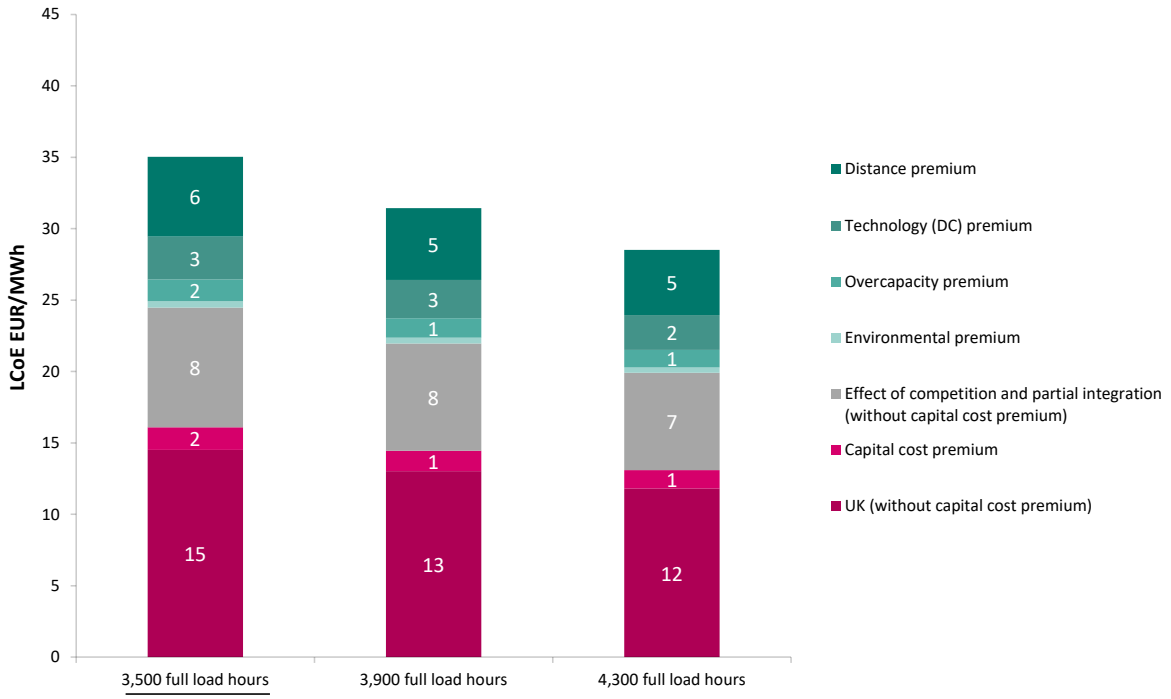


Source: DIW Econ.

Full load hours

In our basic model, we refer to an annual capacity utilization of 3,500 full-load hours. This corresponds to an average capacity factor of 40%, which represents the average capacity utilization of the OWFs covered by our sample (Energy Numbers, 2018). In the future, full load hours are likely to increase as turbines are built further offshore (with higher wind speeds). In addition, technical developments will further increase the efficiency of the wind farms.

Figure 19:
Sensitivity analysis of the average LCoE components (EUR/MWH) based on different full load hours

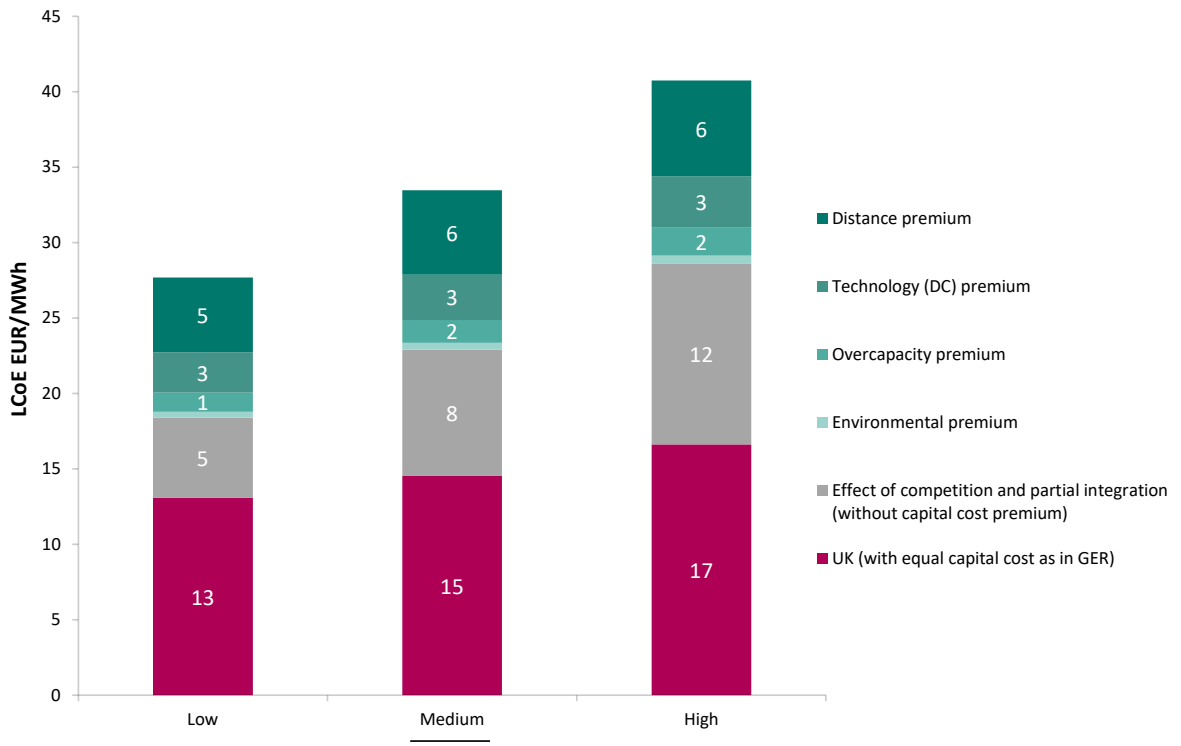


Source: DIW Econ.

Capital costs (WACC)

Our calculations are based on the WACC (nominal pre-tax) of 5.67% for TSOs (Moody's, 2018) and 6.83% for OTA developers in the UK (Ofgem, 2018). To better compare the impact of different WACC levels on our results, we drop the assumption of different cost of capital in Germany and the UK. Hence, the TSO's WACC (5.67%, TenneT) is used as the reference value for capital costs. The present analysis includes a low (4.5%) and high (7%) capital costs scenario.

Figure 20:
Sensitivity analysis of the average LCoE components (EUR/MWH) using different capital costs

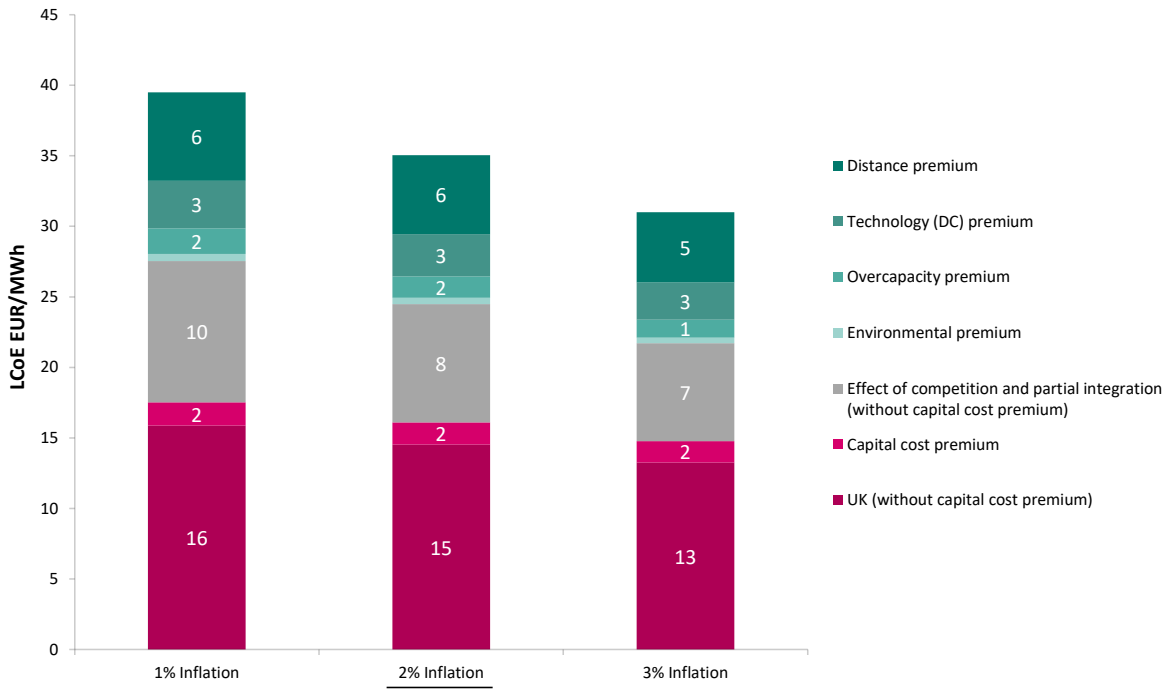


Source: DIW Econ.

Inflation

Our basic model assumes an inflation rate of 2%, which is based on the average inflation rate between 2011 and 2017. Further, this value reflects the targets set by both the ECB and the BoE. To also include periods with lower and higher inflation, we calculate the impact of lower (1%) and higher (3%) inflation rates in the following.

Figure 21:
Sensitivity analysis of the average LCoE components (EUR/MWH) using different inflation rates

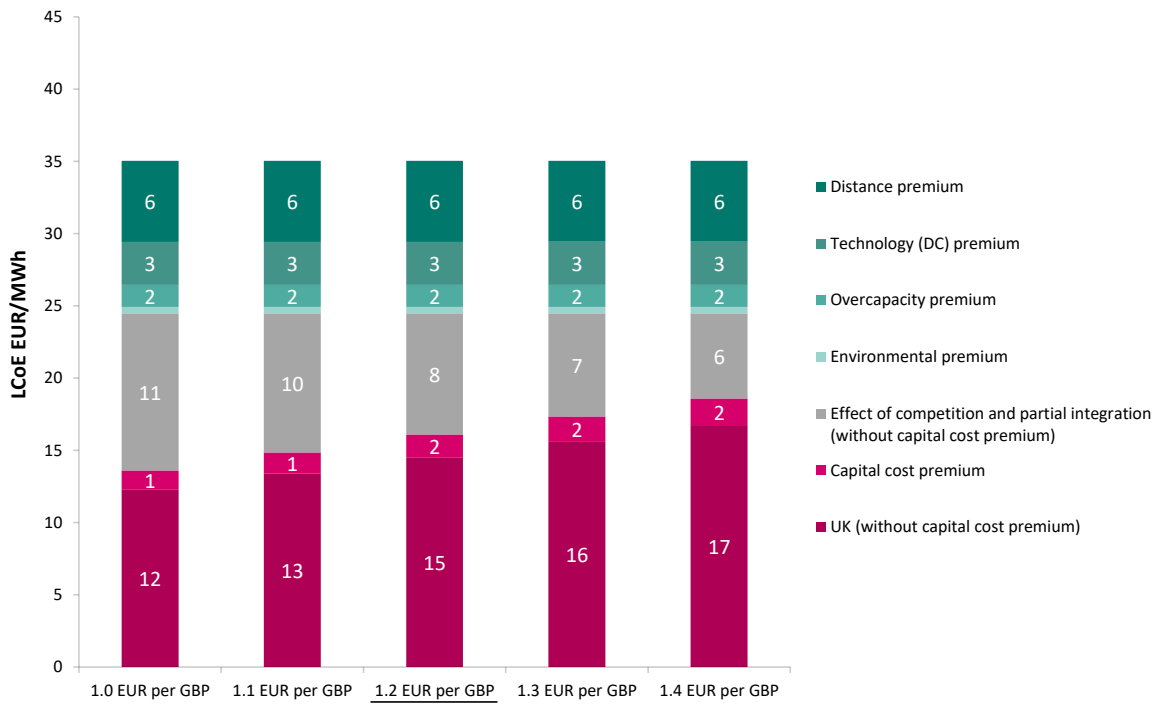


Source: DIW Econ.

Exchange rate

As all cost information from the UK is provided in GBP, we use the average 2011-2017 exchange rate (1.2 EUR/GBP) in our base model. To set a range for exchange rate changes, we follow the volatility of the exchange rate between 2011 and 2017, which fluctuated between 1.07 EUR/GBP and 1.43 EUR/GBP (ECB, 2019).

Figure 22:
Sensitivity analysis of the average LCoE components (EUR/MWH) using different exchange rates



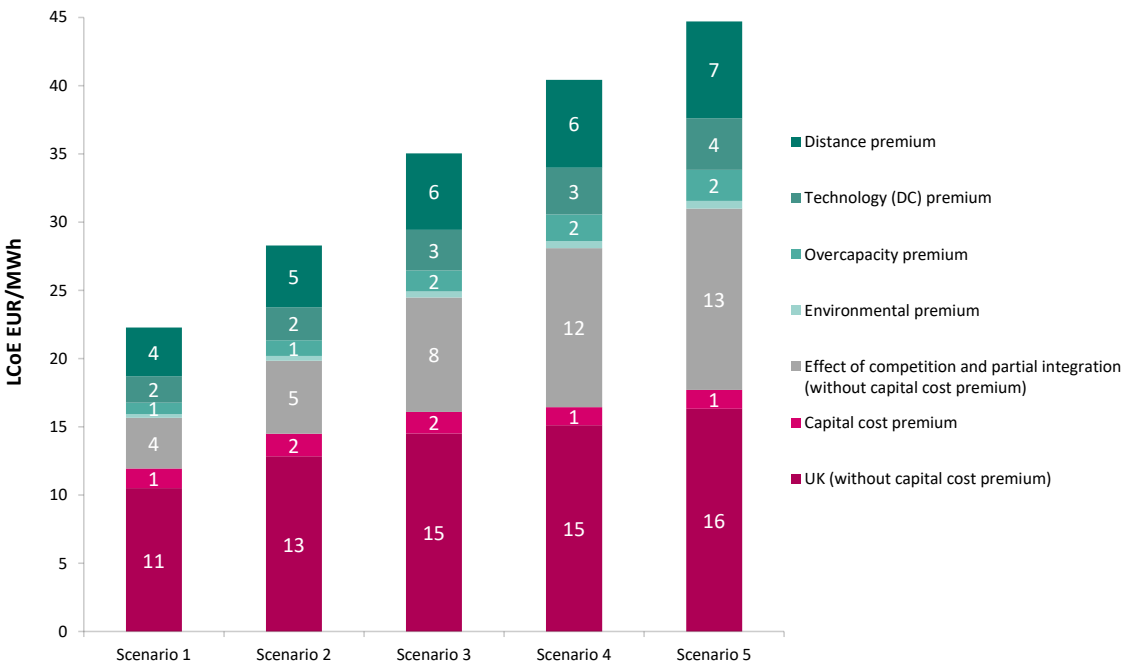
Source: DIW Econ.

Combined scenarios

To consider the joint effect of a change in multiple assumptions, we create four hypothetical scenarios with assumptions that either minimize or maximize the calculated effect of missing competition and a lack of integration in Germany.

- Scenario 1: Technical progress and further quantitative easing coupled with higher inflation and a weak Euro
- Scenario 2: Technical progress and a weak Euro
- Scenario 3: Reference scenario with empirical assumptions
- Scenario 4: Technical progress is offset by exceptional wear; simultaneously the pound depreciates
- Scenario 5: Technical progress is offset by exceptional wear; simultaneously the pound depreciates and inflation is low

Figure 23:
Sensitivity analysis of the average LCoE components (EUR/MWH) using various scenarios



Source: DIW Econ.

Table 5:
Summary of different scenarios

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Lifetime (Years)	30	30	25	20	20
Full load hours	4,300	3,900	3,500	3,500	3,500
Inflation	3%	2%	2%	2%	1%
Exchange rate	1.3 EUR/GBP	1.3 EUR/GBP	1.2 EUR/GBP	1.1 EUR/GBP	1.1 EUR/GBP