Comparing Regulatory Designs for the Transmission of Offshore Wind Energy

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ABSTRACT

Offshore wind plays an ever-increasing role for the global transition to renewable energy. For offshore wind energy to be successful, cost-effective transport of the produced electricity to shore is necessary. The development and operation of the offshore transmission asset is costly and regulated differently across the globe. In most countries, the TSO is responsible for the transmission and develops and operates the asset separately from the offshore wind farm. Other countries have established a competitive tender with integrated development of the offshore wind farm and the transmission asset. However, there is so far no empirical analysis of the economic benefits of different regulatory designs regarding the offshore transmission assets. In this paper, we collect a unique data set on offshore transmission assets that compares empirical cost and quality of offshore transmission assets in two countries with different regulatory regimes for the first time. With project level data we can control for geographical as well as technical difference to assess which regulatory design might lead to lower economic costs for the offshore transmission asset. Comparing the cost in the two leading countries for offshore wind energy, we find that a competitive regime leads to lower transmission cost and similar transmission availability.

Keywords: Offshore wind, Transmission, Regulation, Cost efficiency

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1. INTRODUCTION

Offshore wind energy is growing steadily worldwide (Rodrigues et al. 2015). With an average growth rate of 30 percent per year between 2008 and 2018, offshore wind energy represents a key element of the global transition to renewable energy sources (International Energy Agency 2019). This success is driven by a cost decline in conjunction with larger public acceptance compared to onshore wind power (Fraunhofer ISE 2018).

Some papers have dealt with questions of how markets and regulations should be designed to promote the renewable energy sector. Primarily, these addressed electricity markets. Botterund & Auer (forthcoming) have compared electricity markets in the EU and US to identify improvements for increasing the competitiveness of wind energy. In a different context in Australia, the impact of the exercise of market power and public subsidies on the investment attractiveness of wind energy has been investigated (Mountain 2013). However, not only the design of electricity markets has been found to affect the success of wind energy. As an exam-

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ple, Newbery (2012) studies the effect of various contractual forms between the wind farm operators and the energy system operator to increase cost efficiency.

One market design aspect which has not been addressed by the literature empirically relates to the construction of offshore wind farms and the electricity transmission infrastructure. Usually accounting for 13 to 25 percent of total construction costs of the wind farm (Noonan et al. 2018), the offshore transmission asset remains a critical cost component of any offshore wind project. The national regulatory frameworks determine how offshore transmission assets are developed (planned and built) and operated. Hereby, they are likely to affect the efficiency and the cost of offshore transmission assets.

Theoretically, three actors can be responsible for the offshore transmission asset: the local TSO (Transmission System Operator), the developer of the offshore wind farm, or a third company. Development and operation may be carried out by either the same or two different parties. Depending on the regulatory framework, this leads to different outcomes.

First, the regulatory framework shapes the degree of integration between the offshore transmission asset and the offshore wind farm. We speak of an integrated approach if the developer of the offshore wind farm is also responsible for the transmission asset. If the local TSO or a third party develops or operates the transmission asset, we define this as a separated approach.

Second, the regulatory setting affects the degree of competition. When ex-ante the responsibility for the offshore transmission asset is exclusively assigned to one party, a monopoly occurs. When the development (and operation) is determined via a tender process, this creates a competitive environment.

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 planning, construction, and operation of the offshore transmission asset in most countries, the developer or operator of the offshore transmission asset is seldom determined by a competitive tender.

So far, there is no empirical assessment of the costs and benefits of an open competitive tender of the offshore transmission asset and the effect of integration with the offshore wind farm. Although previous articles have dealt with regulatory options for offshore transmission (Meeus 2015; Delhaute et al. 2016), this paper is the first to empirically investigate the cost differences attributed to different regulatory frameworks for offshore transmission assets in the form of Levelized Cost of Electricity (LCoE). Therefore, we compare the LCoE between two countries with opposite regulatory frameworks. Germany and the United Kingdom offer the largest sample for offshore transmission assets while employing different regulatory frameworks to build and operate them. Germany uses a monopolistic approach where the TSO is solely responsible for development and operation of the transmission. Thus, development and operation are separated from the offshore wind farm. The United Kingdom relies on a competitive and partially integrated approach where the operator of the offshore wind farm bids on developing the wind farm and the transmission asset together. After commissioning, the offshore transmission asset is re-tendered for operation to a third party.

Cost information about transmission assets built by TSOs are highly restricted. However, by investigating and merging a variety of sources, we were able to build a unique data set collecting cost data on a project level for all offshore transmission asset in the German North Sea and in the UK.

Naturally, both countries differ not only in terms of their regulatory framework. To overcome this problem, we have developed a method to control for technical, geographical and environmental differences between offshore transmission assets. Yet despite this, we cannot rule out that the unexplained cost residual may partially reflect other differences between the two countries.

Still, our findings suggest that a regulatory framework that uses a competitive approach and allows in principle for an integrated development leads to lower transmission costs.

The paper is structured as follows: Section 2 presents a theoretical discussion and reviews the existing literature. Section 3 outlines the method and the data used. In Section 4, we provide our empirical results. Section 5 discusses the findings, limitations, and policy implications. Section 6 concludes.

2. THE OFFSHORE TRANSMISSION ASSET

2.1 Technology & Layout

Although all offshore transmission assets serve the same purpose, they differ in technology and layout. These differences need to be considered when evaluating regulatory options.

All wind turbines of an offshore wind farm are connected to an offshore substation, which bundles the produced electricity in the form of alternating current in two ways. AC systems allow the transport of electricity directly from the offshore substation to the onshore substation via AC cables. Alternatively, DC systems convert the electricity from AC to DC prior to transmission and then convert the electricity back to AC on land in order to be fed into the onshore AC transmission grid.

Furthermore, offshore transmission assets may connect one or multiple offshore wind farms. Traditionally, offshore wind farms are connected to the mainland by radial (individual) connections, with one offshore transmission asset connecting one offshore wind farm (Figure 1). Due to maritime conflicts of use, offshore wind warms are in some cases planned in so-called wind farm clusters. In this case, a planning institution must determine whether it is more efficient to bundle different offshore wind farms via a hub connection (common transmission asset) to reduce costs for development and operation, enhance land use and minimize environmental impacts (Dedecca and Hakvoort 2016).

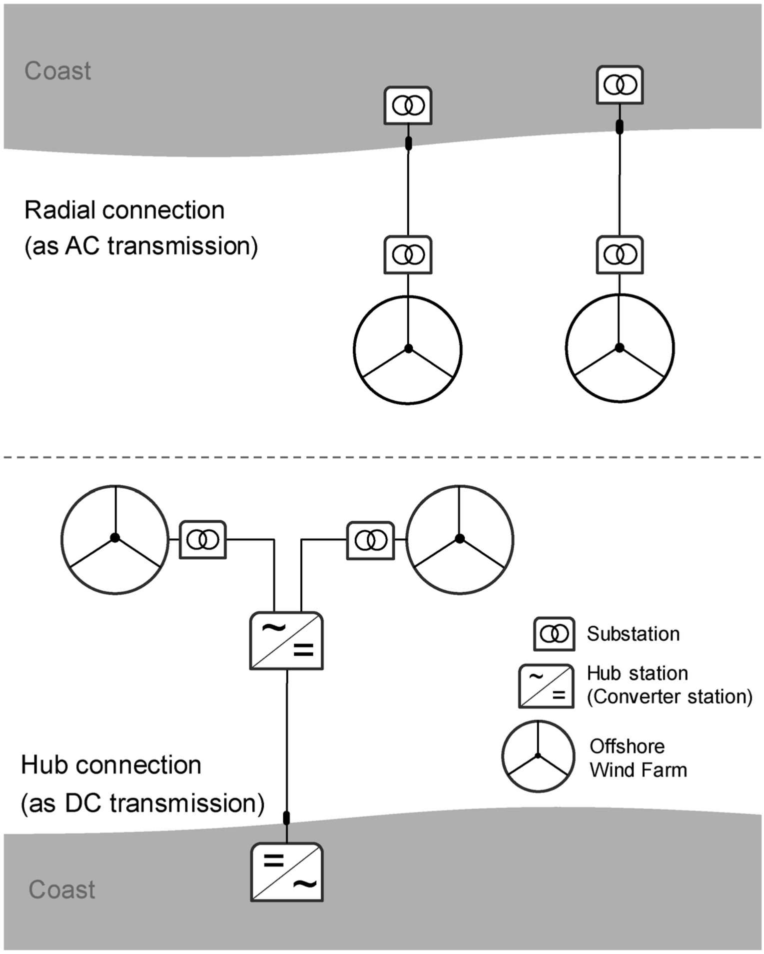
2.2 Actors & Regulatory Options

Depending on the layout of the transmission asset, multiple parties can be responsible for the offshore transmission asset (Green and Vasilakos 2011). Furthermore, development and operation can in principal be separated between parties.

First, the (local) TSO may be in charge for development and operation of the offshore transmission asset. Generally, the TSO is subject to either national regulatory oversight or under direct public control (as a state-owned company). In this case, the TSO expands its responsibility from the onshore grid to offshore transmission assets, creating a (ex-ante) monopoly for the development and operation of the transmission asset.

Second, the offshore wind farm operator can be responsible for the offshore transmission asset. In this case, the wind farm operator not only builds the offshore wind farm but also manages the offshore transmission asset. However, in the case of hub connections, the operation of an offshore transmission asset linking multiple wind farms from different parties creates a strategic bottleneck. As a result, the operation of a hub connection requires an independent party. However, planning and construction of a hub connection can still be carried out by any actor.

FIGURE 1
Exemplary illustration of different layout and technology options for offshore transmission assets.



Furthermore, a third party, a company that is neither the offshore wind farm operator nor the (local) TSO, may be completely or partially responsible for the offshore transmission asset. As an example for being partially responsible, the offshore wind farm operator might develop the offshore transmission asset while a third party operates it after commissioning.

2.3 The Economics of Offshore Transmission

The regulatory framework influences the efficiency of the offshore transmission asset and hence the future development of offshore wind energy (Meeus 2015). We characterize an efficient transmission by low costs and high security of supply while considering external effects such as environmental costs.

The different regulatory regimes can be distinguished in two ways: the degree of integration and the degree of competition. If the offshore transmission asset and the offshore wind farm are jointly developed and operated by the offshore wind farm operator, this is referred to as a (vertically) integrated approach. Otherwise, we speak of a separated approach.

In a competitive framework, an open competitive tender is used to determine not only who is responsible for the development and operation of the offshore wind farm but also who oversees the development and operation of the corresponding offshore transmission asset. In a monopolistic regulatory framework, the responsibility for the development and operation of the offshore transmission asset is (ex-ante) legally assigned to the TSO. In the following, we will discuss the economic impact of the different regulatory outcomes.

TABLE 1
Regulatory options for the offshore transmission asset and potential outcomes

	Separated Approach	Integrated Approach
Monopolistic Regime	(1) TSO	
Competitive Tender Regime	(2) Third Party/TSO	(3) Offshore Wind Farm Developer

Economies of Scale

Offshore transmission assets are subject to economies of scale during development. These are evident in the design, project management and operation phases. Empirically, they have been documented regarding purchases of e.g. substations and export cables (Gonzalez-Rodriguez 2017). It is likely that these scale effects also apply for operation, but empirical evidence is not yet available. As a result, this suggests that TSOs have a cost advantage over third parties in terms of their natural size. Depending on the extent of offshore activities, the offshore wind farm developer is assumed to be able to similarly exploit scale effects through its integrated size. However, evidence for constant returns of scale from offshore wind farms may suggest that scale effects in the development of offshore wind energy are smaller than previously thought (Dismukes and Upton 2015). Concerning regulation, the limited extend of scale effects would restrain the viewpoint of an offshore transmission asset as a natural monopoly (Gómez 2013).

Coordination

Large-scale infrastructure ventures are hard to manage efficiently. Both, offshore wind farm and transmission asset represent two complex projects on their own. Furthermore, they need to be coordinated. We regard coordination to be efficient when both assets are completed simultaneously, are characterized by a similar life span, and have a congruent capacity. Under a separated regulatory framework, where both projects are carried out by separate parties, higher coordination cost are likely to occur. National evidence supports this assumption. Kostka & Anzinger (2016) find that transmission assets built under a separate regulatory framework in Germany are on average delayed by 13 months. Other problems in a separated model can arise from compatibility problems leading to increased maintenance works within the first years of operation.[1] Although coordination failure can emerge under any regulation, an integrated development might internalize the risk of coordination failure by the offshore wind farm developer.

1. Fichtner (2016). Beschleunigungs- und Kostensenkungspotenziale bei HGÜ-Offshore-Netzanbindungsprojekten. Available at <https://www.offshore-stiftung.de/sites/offshorelink.de/files/documents/Optimierungspotenziale%20Offshore-HG%C3%9C-Projekte_final.pdf >.

Incentives

Depending on the regulatory option, incentives to reduce costs differ significantly. Foremost, a developer under a monopolistic framework will be under less cost pressure than developers under a competitive framework. Usually being a state-owned company, a TSO can pass on additional costs to consumers. In Germany, these additional surcharges passed on to consumers from connection delays and interruptions alone have summed up to EUR 2 bn until 2019.[2] By contrast, a framework of competitive tendering will lead to higher cost pressure (Pollitt 2008). This will result in all participating actors to experience greater incentives to reduce costs.

Other Factors

Furthermore, the regulatory setting will determine learning curves, as industry experience plays a crucial role for the efficient commissioning of the transmission asset. Under a monopolistic regime, TSOs are able to build on the experience gained onshore and can consolidate structures and supply chains by guaranteed assignments for offshore transmission assets. Under a competitive tendering process, offshore wind farm developers can capitalize on their offshore experience compared to third parties.

Additionally, the regulatory decision also affects financing cost. As state owned companies, TSOs have more favourable credit ratings due to their size and guaranteed returns, leading to lower average costs of capital than the offshore wind farm developer or third parties. Ultimately, an integrated regulatory model may foster innovations that require technical changes to both projects.

However, it is unclear which of these factors predominantly affects the cost of the offshore transmission. We are interested in answering the question under which regulatory framework offshore transmission assets are build most efficiently by comparing offshore transmission costs in two countries with opposite regulatory frameworks.

2.4. International Experience

The regulatory approach for the offshore transmission differs significantly by country. In an international comparison, the monopolistic TSO model with separate construction and operation of offshore wind farms and offshore transmission assets dominates (e.g. in Germany, Netherlands or Sweden). 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 currently predominant. However, the UK has implemented a competitive tender as of 2010. Regarding integration, the British system is a hybrid one: the planning and construction of the offshore transmission asset is awarded to the bidder with the lowest total costs for the offshore wind farm and the offshore transmission asset, leading to an integrated development. The operation is afterwards separately re-tendered to a third company (Ofgem 2010).

2. 50Hertz, Amprion, TransnetBW & TenneT (2019). Offshore Netzumlage 2013-2019. Available at <https://www.netztransparenz.de/>.

3. METHOD

3.1 Definition of the offshore transmission asset

There is no universal definition of the offshore transmission asset. To make the total costs of electricity transmission comparable, our paper considers all necessary assets between the offshore wind farm and the onshore grid. This includes all transmission equipment and necessary infrastructure, such as the platforms. Therefore, the system begins with the substation of the offshore wind farm and ends with the onshore substation. This substation is then connected with the grid of the respective local TSO.

3.2 Sample

To evaluate the efficiency of different market designs, we compare two countries with similar conditions but different regulatory regimes. For this comparative analysis, we chose Germany and the UK for several reasons. First, both countries provide the largest share of offshore wind energy in the world and have seen a similar development as both countries placed offshore wind energy at the centre of their energy policies (Figure 2).

Second, Germany and the UK have a similarly developed economy, comparable knowledge and infrastructure, and have been part of a single market. Third, both countries have opposite regulatory frameworks for offshore transmission assets.

Germany follows a monopolistic approach for the offshore transmission asset, in which planning, construction, and operation are executed by the TSO and separated from the offshore wind farm. By contrast, the UK applies a competitive and integrated model for developing the offshore transmission asset combined with a competitive but separate model for operation.

To compare the different regulatory frameworks, we consider all offshore transmission assets built from the first tender round in the UK and all offshore transmission assets in Germany since they all have been developed within the monopolistic and separate regulatory approach. We assume comparable geological and maritime conditions for construction and operation in the North Sea and the Irish Sea. We exclude offshore transmission assets from the Baltic Sea due to more difficult geographical conditions.[3] We discard projects with a capacity of less than 100 MW. Ultimately, we exclude BorWin 1 in Germany as a testing project for HVDC transmission.

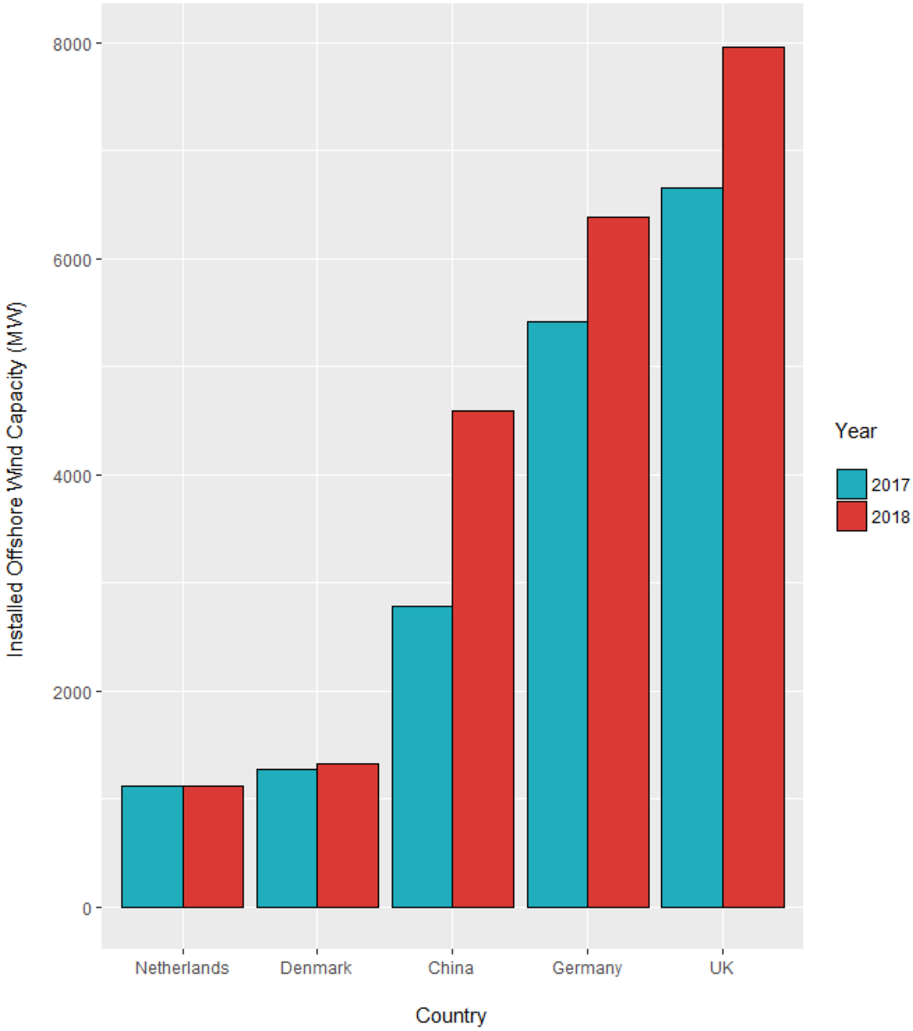
The final sample consists of 21 offshore transmission assets in the United Kingdom and 10 assets in Germany. Together, the data represent 14.2 GW transmission capacity and cover 85 percent of current capacity in both countries (Figure 3).

3.3 Levelized Cost of Electricity

To measure the costs for offshore transmission assets in both countries, we use the concept of Levelized Cost of Electricity (LCoE). LCoE provide a comprehensive measure for the efficiency of an electricity producing (or transmitting) asset (Short et al. 1995). LCoE determine the cost per energy produced (E_t) over its expected lifetime (n), at which an energy system

3. The LCoE of average offshore transmission assets in the Baltic Sea of 45.04 EUR/MWh are much higher than the average values in the North Sea (35.32 EUR/MWh, original sample with all assets). At the same time, transmission assets in the Baltic Sea have an average connection length of only 93km compared to 135km in the North Sea. The Baltic Sea is characterized by irregular seabed profiles and undiscovered ammunition loads. The resulting cost impact cannot be reliably determined.

FIGURE 2
Global offshore wind capacity in leading countries for 2017 and 2018
(Global Wind Energy Council 2018).



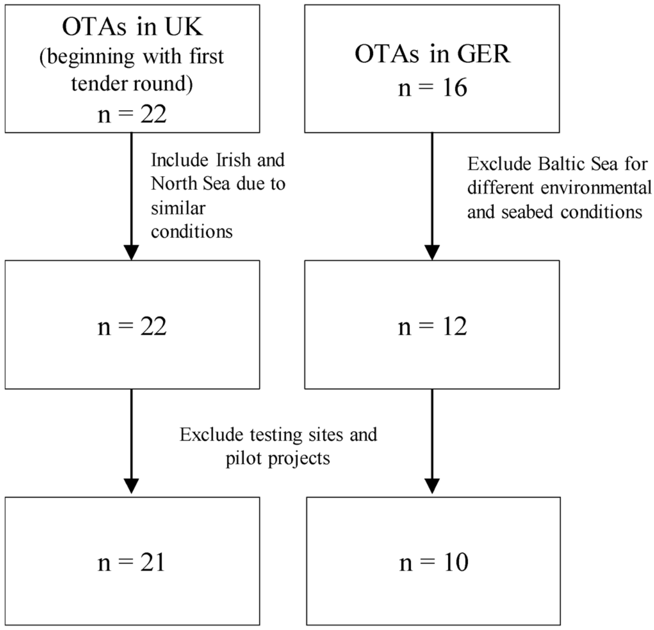
amortizes its total investment (I_t) and operating (M_t) cost, discounted by the real interest rate (r).

$$LCoE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

3.4 Data

CAPEX represents the largest cost component of the offshore transmission asset. We use publicly available CAPEX data for most offshore transmission assets in our final sample (Table 4, Appendix). For projects with missing CAPEX information, we calculate the CAPEX

FIGURE 3
Sample selection.



based on empirical unit cost information from the BNetzA (2013, 2015, 2017b) and Ofgem (2015, Table 2). To calculate the cost from structural differences between German and British offshore transmission assets other than the regulatory framework, we employ cost information from National Grid ESO (2018). These are based on enquiries from suppliers and serve as reference values.

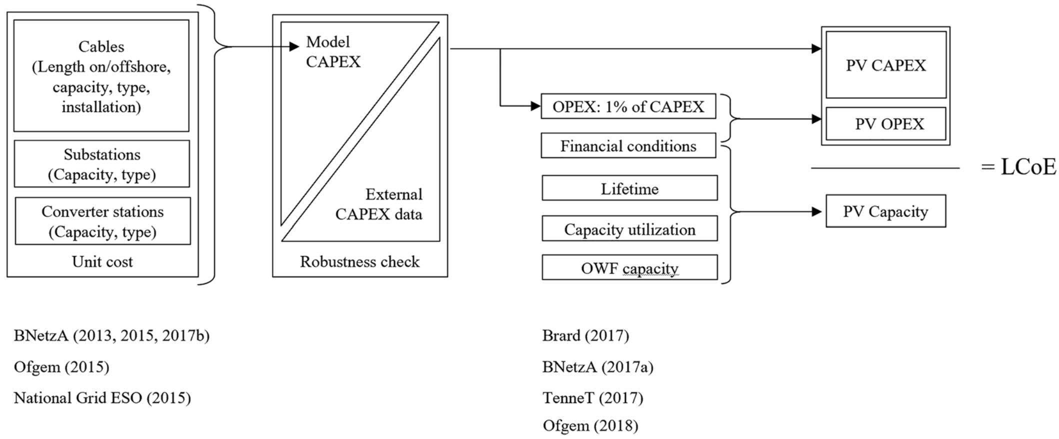
TABLE 2
Unit cost information for components of offshore transmission assets.

			Unit cost			
Part	Country	Location	2013	2015	2017	Unit
DC cable	GER	North Sea	5,171	2,805	2,203	EUR/MWkm
DC station	GER	North Sea	1.03	1.03	1.00	m EUR/MW
DC cable	GER	Onshore	2,068	1,944	1,950	EUR/MWkm
AC cable	GER	North Sea/Onshore	13,606	13,560	13,513	EUR/MWkm
AC cable	UK	North/Irish Sea	5,455	4,493	3,135	EUR/MWkm
AC station	UK	North/Irish Sea	0.02	0.06	0.06	m EUR/MW
AC cable	UK	Onshore (<15km)	7,702	9,838	6,875	EUR/MWkm
AC cable	UK	Onshore (>15km)	2,445	2,019	1,361	EUR/MWkm

Note: We adjusted the empirical cost of cables provided by the national authorities for transmission capacity. 2015 AC cable prices in Germany are extrapolated. Unit cost are converted from GBP to 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.

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 difference between the average external cost and our investment cost is minimal (Appendix). We therefore consider our model calculation to be sufficiently robust. For operating cost, we follow the assumptions of Brard (2017), who estimates annual OPEX being 1 percent of CAPEX. These assumptions correspond to a paper on the actual OPEX in Germany, which suggests a range between 0.9 percent and 1.45 percent (Ritzau et al. 2017). Thus, we follow the opinion of a report of the Federal Network Agency in Germany which considers the TSOs' own assessment of OPEX being 3.4 percent of the CAPEX as excessively high (BNetzA 2017a).

FIGURE 4
Method and references used for the underlying cost model.



We gathered technical data on a project level to calculate CAPEX using unit cost for assets with missing external data. Following a robustness check (Table 4, Appendix), we complement the CAPEX data with empirical information on operational details to calculate LCoE.

We further expect the lifetime of a transmission asset to be 25 years. This duration is based on the expected technical lifetime and the legal approval of the connected offshore wind farms. 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 empirically supported. The offshore wind farm Vindeby in Denmark has been built in 1991 and was dismantled in 2017 after the 25-year approval had expired. Although this value might change in the future, we estimate that a lifetime of 25 years is most likely.

For our model, we assume nominal weighted average cost of capital (WACC) of 5.67 percent for German transmission assets. These reflect the cost of capital for TenneT in 2016.[4] We further follow the findings of Ofgem (2018) with WACC of 6.83 percent for developers in the United Kingdom.

We employ a capacity utilization of 3,500 full-load hours per year representing the average performance of the offshore wind farms connected in our sample in both countries.[5] Additionally, we use an exchange rate of 1.20 EUR per GBP and an inflation rate of 2 percent. Both values provide a close approximation of the average values during the investigated period (Figure 4).

4. Moody's (2018). TenneT Holding B.V. Annual update to credit analysis. Available at <https://www.tennet.eu/fileadmin/user_upload/2018_05_18_-_Published_TenneT_Holdings_credit_opinion.pdf >.

5. Energy Numbers (2018). UK and Germany's offshore wind capacity factors. Available at <http://energynumbers.info/germanys-offshore-wind-capacity-factors >; <http://energynumbers.info/uk-offshore-wind-capacity-factors >.

4. RESULTS

Table 3 shows the initial descriptive results. We find that the average cost of offshore electricity transmission measured in LCoE is 35 EUR/MWh in the German North Sea and 15 EUR/MWh in the British sample. Thus, LCoE in Germany are more than twice as high as LCoE in the UK. However, the LCoE difference of 20 EUR/MWh must be examined in the light of other differences. German transmission assets have longer cable lengths (onshore and offshore) and rely largely on DC technology. Furthermore, they often use hub connections and are subject to additional environmental regulations. Before estimating the impact of the different regulatory frameworks on overall costs, we first analyse the cost effects of these other factors.

4.1 Distance

Offshore transmission assets in the United Kingdom and in Germany differ by their transmission length. As cable lengths determine cost and therefore explain part of the cost difference between the two countries. 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 39 km on land and 49 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 (National Grid ESO 2015). We find that the additional costs for cable procurement and installation of an average project in Germany add up to 5.91 EUR/MWh of the higher LCoE in Germany compared to the UK.

4.2 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. They are characterized by higher cable cost but have lower station cost 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 80 km (Xiang et al. 2017). DC systems are used for longer distances. They feature higher station cost, resulting from two additional converter stations but lower cable cost.

For offshore transmission assets in Germany and the United Kingdom, short distances are connected exclusively via AC systems. For medium and long distances, both technologies are used.

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. Due to their higher per cable transmission capacity, DC systems are preferred for their reduced impact on the maritime environment in Germany. Yet due to their high complexity, they also require greater control and coordination (Saad 2016).

To calculate their cost effect, we use a typical German transmission asset with 900 MW, as defined in the German standardized technical specifications. Based on the average cable distances in Germany, we calculate the cost of this asset in Germany in the case of AC transmis-

TABLE 3
Offshore transmission assets

Offshore Transmission Asset	Country	Technology	Transmission Capacity (MW)	Windfarm Capacity (MW)	Onshore Connection Length (km)	Offshore Connection Length (km)	LCoE (EUR/MWh)
Riffgat (2014)	GER	AC	113	113	30	50	27.1
BorWin2 (2015)	GER	DC	800	770.8	75	125	39.4
DoIWin1 (2015)	GER	DC	800	712	90	75	39.6
HelWin1 (2015)	GER	DC	576	576	45	85	36.9
SylWin1 (2015)	GER	DC	864	864	45	160	41.8
HelWin2 (2015)	GER	DC	690	613	45	85	42.4
DoIWin2 (2016)	GER	DC	924	916	90	45	34.2
Nordergründe (2017)	GER	AC	111	111	4	28	16.2
DoIWin3 (2018)	GER	DC	900	844	80	80	37.7
BorWin3 (2019)	GER	DC	900	897	30	130	36.3
Mean	GER		667.8	641.7	53.4	86.3	35.2
Min	GER		111	111	4	28	16.2
Max	GER		924	916	90	160	42.4
Std. Dev.	GER		295.6	286.1	27.6	39.3	7.6
Gunfleet Sands (2011)	UK	AC	173	173	11.4	9.3	7.0
Walney 1 (2011)	UK	AC	184	184	2.7	45.3	14.9
Robin Rigg East and West (2011)	UK	AC	180	180	3.6	12.5	8.8
Walney 2 (2012)	UK	AC	184	184	15	43.7	15.4
Ormonde (2012)	UK	AC	150	150	8.4	43	16.6
Greater Gabbard (2013)	UK	AC	500	500	1.8	45	14.6
Sheringham Shoal (2013)	UK	AC	315	315	43	22	15.1
London Array (2013)	UK	AC	630	630	0.7	54	16.6
Thanet (2014)	UK	AC	300	300	4.8	26.2	12.2
Lincs (2014)	UK	AC	270	270	12	48	26.3
West of Duddon Sands (2015)	UK	AC	389	389	18	41	16.6
Gwynt y Môr (2015)	UK	AC	574	574	11	20.7	12.9
Westermost Rough (2016)	UK	AC	205	205	15	14	17.7
Humber Gateway (2016)	UK	AC	220	220	30	18	16.9
Dudgeon (2017)	UK	AC	402	402	48	42	16.7
Burbo Bank Extension (2017)	UK	AC	258	258	10.4	26	19.3
Walney Extension (2018)	UK	AC	659	659	12	68.3	17.3
Rampion (2018)	UK	AC	400	400	27	16	11.5
Race Bank (2018)	UK	AC	573	573	11.6	71	18.8
Galloper (2018)	UK	AC	340	340	1.7	45	15.1
Beatrice (2019)	UK	AC	588	588	18.6	70	13.2
Mean	UK		356.9	356.9	14.6	37.2	15.4
Min	UK		150	150	0.7	9.3	7.0
Max	UK		659	659	48	71	26.3
Std. Dev.	UK		171.3	171.3	13.9	19.7	4.6

Note: The years displayed represent the commissioning years when the asset is completed and transmission begins. Onshore and Offshore Connection Length refer to the length of an individual cable. This is different to the overall cable length, as often multiple cables are laid to connect offshore wind farms. However, the individual cabling length (not depicted) has been considered on a project level to calculate costs.

sion and DC transmission (National Grid ESO 2015). After comparing the DC costs with the estimated AC scenario, we find additional costs of DC systems to explain 2.96 EUR/MWh.[6]

4.3 Environmental regulation

In addition to the selection of transmission technology, further environmental regulations influence the cost in Germany such as the 2K criterion and additional regulation for sensitive coastal areas such as the Wadden Sea.

2K Criterion

The 2K criterion limits the heating of the sediment between the cable and the seabed to 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 (diameter). 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.[7]

Wadden Sea

The German North Sea coast is surrounded by the German Wadden Sea. Being an environmentally sensitive area, this poses challenges for cable installation. First, the stricter limit for the 2K criterion in these sections requires an even larger cable diameter to mitigate sediment heating. Second, the laying process requires more complex laying methods (e.g. using a vibration sword), which are associated with higher cost.

Using cost information from National Grid ESO (2015), the additional costs calculated based on project-specific data for the respective cable sections lead to higher LCoE in Germany of 0.47 EUR/MWh.

4.4 Overcapacity: Temporary and permanent

So far, the UK has relied on individual (radial) offshore transmission assets which are integrated with the offshore wind farm. However, in Germany, most offshore wind farms are connected via hub connections built separately by the TSO. Often, several years pass between completion of the first and the last offshore wind farm that share a hub connection. However, since the hub connection must be available from the commissioning date of the first offshore wind farm, temporary overcapacities arise. During this period, the hub connection's utilization is below its available capacity.[8] To calculate the resulting cost impact, we compare the LCoE calculated with actual transmission capacity in the affected years with the LCoE for full capacity utilisation.

6. 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.

7. 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 conductor area of 1400mm^2 are rated for higher capacities according to official manufacturer data (ABB 2012. HVDC Light. It's time to connect. Available at <https://new.abb.com/docs/default-source/ewea-doc/hvdc-light.pdf >.)

8. The effect is repeated towards the end of the lifetime of wind farms. Since offshore wind farms are often connected at intervals of several years (e.g. 7 years for Amrumbank West and KASKASI II to HelWin2), it can be assumed that previously connected wind farms are also dismantled several years earlier. The transmission asset then has excess capacity again. However, since no empirical values are available for this phenomenon, the resulting costs cannot be reliably calculated.

In addition, hub connections in Germany are often planned and built before the final arrangement of the connected offshore wind farms is known. In addition to the challenge of timing, this can result in the available capacity of the hub offshore transmission asset exceeding the cumulative capacity of the connected offshore wind farms, even after all planned offshore wind farms have been commissioned. This circumstance creates permanent overcapacity for several offshore transmission assets. Both types of overcapacity can be modelled by comparing the amount of actual electricity produced by the wind farms with the transmission capacity available by the offshore transmission assets. This comparison shows that the consequences of temporary and permanent overcapacity explain 1.68 EUR/MWh of higher LCoE in Germany.

4.5 Cost of capital

Another difference between offshore transmission assets in Germany and in the UK is the cost of capital. German TSOs have better financing conditions, as they have state-guaranteed returns on sales. Developers in the UK, on the other hand, are exposed to higher risk and thus face tougher financial conditions. To calculate cost differences, we consider the WACC (nominal pre-tax) for the average period examined in our sample. Data by Ofgem (2018) suggests WACC of 6.83 percent while Moody's[9] calculates the corresponding cost of capital for the TenneT Holding at 5.67 percent.

To analyse the cost effects, we harmonise the basic conditions of both countries by calculating the LCoE for British offshore transmission assets with the capital costs of a German TSO. The result shows that LCoE in the UK would further decrease by 1.73 EUR/MWh if the same financing conditions were available as in Germany.

4.6 Cost differences due to different market designs

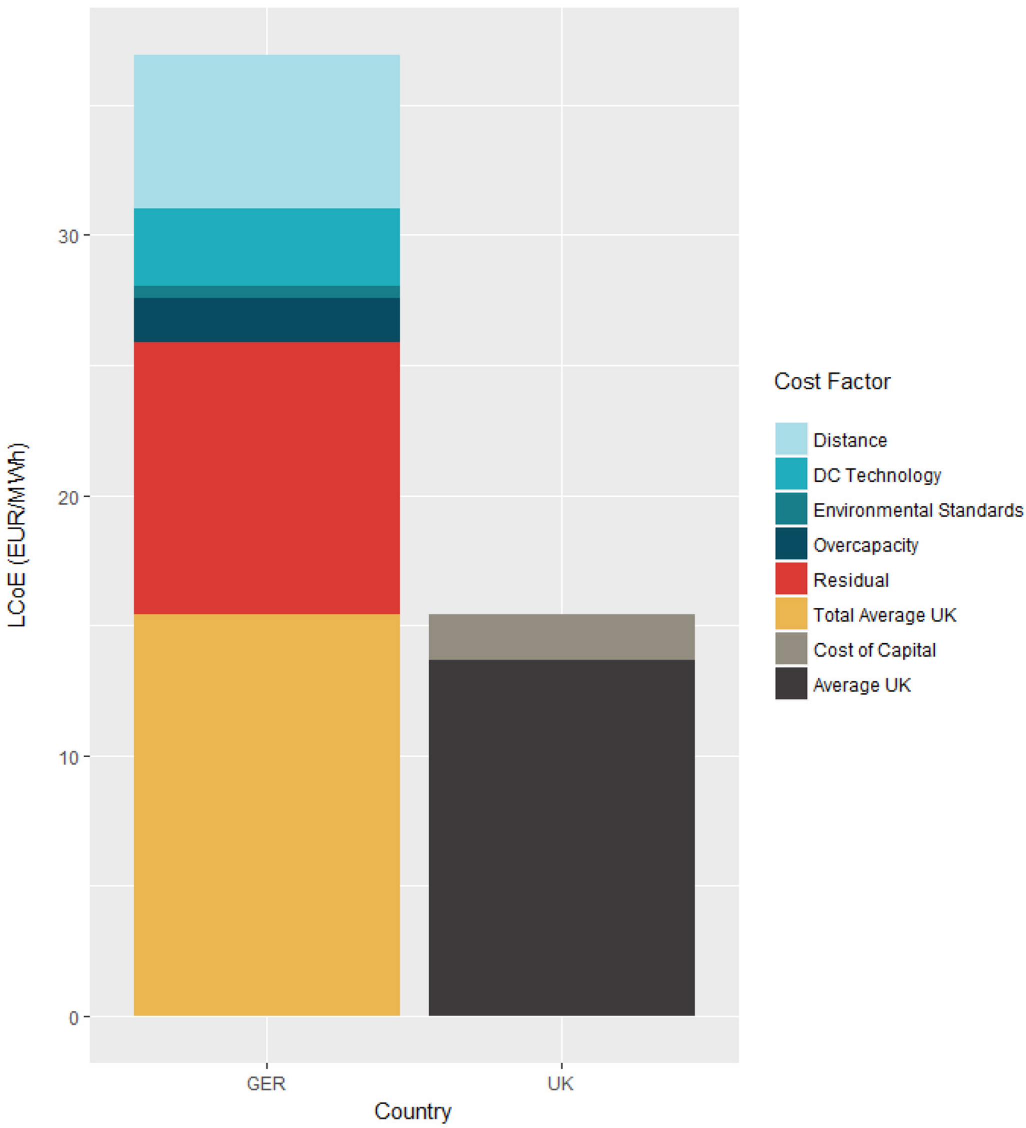
After considering the geographical, technical, environmental, and financial differences, a LCoE difference of 10.47 EUR/MWh remains between both countries. Therefore, we hypothesize that the remaining cost difference is primarily due to the different regulatory framework for offshore transmission assets in both countries. As a direct consequence of the regulatory framework, additional coordination costs need to be considered. These result from oversized transmission assets and time gaps between the commissioning of wind farms and transmission assets in Germany as well as the higher cost of capital in the United Kingdom. Accounting for this suggests an LCoE difference between Germany and the United Kingdom due to different regulatory frameworks of 10.42 EUR/MWh. Although we controlled for other regulatory differences, such as environmental restrictions, one needs to bear in mind that this residual may be partially explained by other unobserved differences (e.g. in workforce cost). Nevertheless, this paper argues that the most prevalent difference between both countries is the regulatory design: In the UK, the regulation allows an integrated construction and a competitive tendering process, whereas in Germany, a separate and monopolistic regulatory framework determines the development of offshore transmission assets. Hereby, the result suggests that improved coordination and competitive incentives outweigh the benefits of economies of scale captured by a TSO.

The LCoE difference does not yet include the additional coordination cost incurred by the German offshore (liability) levy. If an offshore wind farm is connected late or the transmission

9. Moody's (2018). TenneT Holding B.V. Annual update to credit analysis. Available at <https://www.tennet.eu/fileadmin/user_upload/2018_05_18_-_Published_TenneT_Holdings_credit_opinion.pdf >.

suffers interruptions, the electricity produced cannot be fed into the grid. The lost electricity revenues of the wind farm operator are to be compensated by the responsible TSO. These compensation payments are reflected in the offshore (liability) levy. TSOs can pass on all compensation payments, which had to be paid to the offshore wind farm operator as a result of delayed connection or long interruptions, to the final consumer. Due to their aggregated nature, the published data on the amount of the offshore (liability) levy does not provide information on the costs incurred on a project level and are not broken down between North and Baltic Sea. Therefore, they are not yet part of the analysis. However, the damages from the levy must be

FIGURE 5
Breakdown of the average LCoE (EUR/MWh) difference between offshore transmission assets in Germany (left) and the United Kingdom (right).



The residual (red) displays the unexplained cost difference attributed to different regulatory frameworks.

added to the already higher LCoE, since their amount contributes significantly to the cost of offshore transmission in Germany.

Assuming a similar effect of the regulation in the Baltic Sea and considering the costs created by the offshore (liability) levy, our results suggest that the monopolistic and separated regulatory framework in Germany produced additional costs for consumers of around EUR 3 billion until 2019 alone.[10]

5. DISCUSSION

5.1 Supply security

As offshore transmission assets are critical infrastructure components of energy supply, a comprehensive evaluation of the regulatory framework should also consider transmission quality. Regulation in the UK incentivises network availability: If network availability falls below 98 percent, the offshore transmission asset's operator's revenues are reduced. Reversely, if the offshore transmission asset operator exceeds the target, it receives bonus payments.

In Germany, offshore wind farm operators may claim damages from the TSO for interruptions, maintenance works and connection delays (BMWi 2017). 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.

A look at the accessible data on network availability shows that the availability of competitively built offshore transmission assets is on average higher than TSO operated assets. Thus, the higher cost in Germany cannot be attributed to a higher quality of supply (Figure 6).

5.2 Limitations

The present paper is subject to certain limitations. First, the calculation of the LCoE depends on multiple assumptions such as lifetime, full load hours, WACC, inflation, and the exchange rate. By validating all input variables for the LCoE calculation empirically, we reckon that our results provide a realistic account of actual cost incurred.

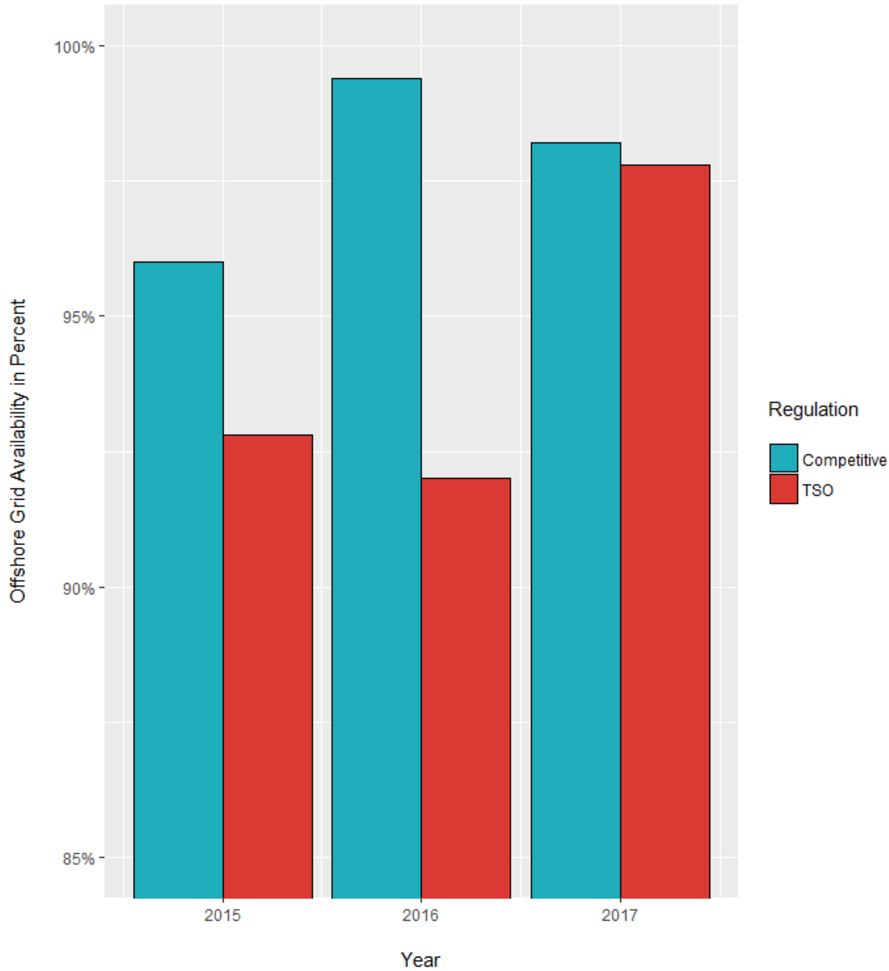
A further limitation results from the available cost information. Although the level of actual construction costs incurred in the UK is available for most of all projects examined, the same information is only available to a limited amount of offshore transmission assets in Germany. The CAPEX values derived from unit cost information may therefore differ from the actual costs for individual projects. However, comparing our estimates with actual costs shows that the mean difference is only 1.5 percent in the UK and 2.2 percent in Germany and thus sufficiently accurate (Appendix). However, the limited cost information available renews the demand for greater cost transparency, especially in Germany.

6. CONCLUSION

The present paper compares different regulatory frameworks for the development and operation of offshore transmission assets. To compare their effectiveness, we investigate the

10. Calculated using the amount of electricity produced offshore of 85 TWh (BMWi 2019) and the cumulated offshore (liability) levy until 2019 of EUR 2.16 billion (50Hertz, Amprion, TransnetBW and TenneT 2019. Offshore Netzumlage 2013-2019. Available at <https://www.netztransparenz.de/>).

FIGURE 6
Average availability of offshore transmission assets built under a competitive (integrated) and a TSO regulatory framework.



Notes: Data from National Grid ESO (2018) for UK and TenneT (2017). TSO data from TenneT includes Dutch offshore transmission assets that represent 16 percent of TenneT's total offshore transmission capacity. However, other data from Germany alone suggests similar results. TenneT (2019). Marktrelevante Informationen - Offshore. Available at <https://www.tennet.eu/de/strommarkt/transparenz/transparenz-deutschland/ >.

LCoE of offshore transmission assets in two countries with different regulation. The United Kingdom uses a competitive tender process for the development and operation of offshore transmission assets. In Germany, the local TSO is obliged to build and operate the offshore transmission assets as a monopolist. Additionally, the planning and construction of British offshore transmission assets are integrated within the offshore wind farm. By contrast, German transmission assets are planned and built separately from the offshore windfarm within the current regulatory framework.

In order to compare the effect of these regulations empirically, we created a new data set collecting cost information on a project level from national authorities, TSOs, and other sources to calculate the LCoE of offshore transmission assets built so far. The comparison shows that German offshore transmission assets are significantly more expensive. This result is robust even after modelling 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 is further amplified by the offshore (liability) levy. Including the latter, additional costs due to the regulatory framework in Germany sum up to EUR 3 billion until 2019 alone.

We argue that the remaining cost difference between the average LCoE of offshore transmission assets in the UK and Germany primarily measures the cost impact of the different regulatory approaches. These unfold in the higher incentives to lower costs from the competitive tender and the integrated construction of offshore wind farm and transmission asset in the UK compared to the monopolistic and separated TSO model in Germany.

The limited sample size restrains the use of a more advanced econometric techniques. Furthermore, in comparison with the UK, Germany has a highly restricted cost information policy. An improvement in cost transparency in Germany would be beneficial for future research. However, the empirical nature of the underlying assumptions, the robustness checks, and the sensitivity analysis suggest that our results provide an accurate picture of the offshore transmission costs in Germany and in the UK. Thus, the present paper offers direct policy implications for the current and future development of offshore wind energy. The results suggest that a competitive and integrated regulatory framework can improve the cost efficiency of transmitting offshore wind energy.

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APPENDIX

TABLE 4
Comparison of calculated CAPEX in million EUR with external data for available projects in Germany and the United Kingdom

Offshore Transmission Asset	Model CAPEX (m EUR)	External CAPEX (m EUR)
Baltic l (2011)	154	150
Baltic ll (2015)	530	600
DoIWin3 (2018)	1195	1290
BorWin3 (2019)	1214	1318
Ostwind 1 (2018)	1482	1500
Ostwind 2 (2019)	1477	1500
Mean	1009	1060
Min	154	150
Max	1482	1500
Std. Dev.	497	508
Gunfleet Sands (2011)	64	50
Walney 1 (2011)	114	116
Robin Rigg East and West (2011)	36	66
Walney 2 (2012)	134	121
Ormonde (2012)	118	104
Greater Gabbard (2013)	354	306
Sheringham Shoal (2013)	201	202
London Array (2013)	495	435
Thanet (2014)	180	152
Lincs (2014)	226	297
West of Duddon Sands (2015)	210	267
Gwynt y Môr (2015)	350	315
Westermost Rough (2016)	116	152
Humber Gateway (2016)	137	158
Dudgeon (2017)	279	282
Burbo Bank Extension (2017)	133	183
Mean	197	200
Min	36	50
Max	495	435
Std. Dev.	117	103

Note: External CAPEX data comes from the European Network of Transmission System Operators for Electricity, the British Office of Gas and Electricity Markets and press releases[a,b,c,d]. As the offshore wind farm substation is not accounted for in the external cost data of the transmission assets in Germany, we exclude them in the modelled CAPEX for comparison, too.

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[b] entso-e (2019). Project 191 - OWP TenneT Northsea Part 2. Available at <https://tyndp.entsoe.eu/tyndp2018/projects/projects/191>.

[c] Ofgem (2019). Offshore transmission tenders. Available at <https://www.ofgem.gov.uk/electricity/transmission-networks/off-shore-transmission/offshore-transmission-tenders >.

[d] ZfK (2018). Offshore: Arbeiten für zweite Stromtrasse in der Ostsee haben begonnen. Available at <https://www.zfk.de/energie/strom/artikel/offshore-arbeiten-fuer-zweite-stromtrasse-in-der-ostsee-haben-begonnen-2018-09-03/ >.

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