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Offshore wind power grid connection costs - Analysis of social transfer costs for different allocation mechanisms

Lukas Weißensteiner,
Energy Economics Group, Vienna University of Technology,
Gusshausstrasse 25-29/373-2; 1040 Vienna, Austria
Phone +4315880137368, E-mail: weissensteiner@eeg.tuwien.ac.at

Hans Auer,
Energy Economics Group, Vienna University of Technology,
Phone +4315880137357, E-mail: auer@eeg.tuwien.ac.at

Abstract

Until liberalisation of the electricity sector and unbundling of electricity grids, costs for the connection of power plants to the grid were added to overall costs of an integrated utility in providing energy services.

Since then particularly the deployment of renewable energy sources for electricity generation (RES-E) has raised the question where exactly to define the boundary of responsibilities between operators of power plants and operators of grids and whom to attribute corresponding connection costs.
Grid connection costs comprise a major cost component of renewable generation investments: Specific grid connection costs are especially high for (comparatively small scale) power plants taking advantage of favourable but remote resources as wind energy and especially offshore wind energy.

In the presence of public support for electricity generation from renewable energy sources the question of primary cost allocation arises: While eventually electricity consumers will be passed over these costs, this paper analyses cost efficiency from consumers' perspective for different cost allocation mechanisms.

Results of this analysis give evidence that – depending on the characteristics of the supply curve of deployed potentials – a primary allocation of grid connection costs to grid operators leads to a smaller producer surplus and hence to lower transfer costs of electricity consumers.

Keywords: wind power, grid connection cost allocation, social transfers

1. Introduction

1.1. *Motivation*

Connection of power plants to electricity grids has not led to disputes concerning the allocation of corresponding costs as long as the value chain of energy service provision had not been unbundled. From the viewpoint of an integrated firm these costs simply added to long run marginal costs.

Unbundling of the electricity industry, which, in the member states of the European Union, was triggered by the directive of the European Commission on the internal market for electricity (DIRECTIVE 2003/54/EC), was intended to separate potentially competitive segments of this value chain (generation and supply) from the natural monopoly of electricity grid operation. Implementation of this directive into national regulation has led to a variety of interpretations of the attribution of responsibilities between grid operators and generators concerning the allocation of system integration costs – comprising of grid connection costs, grid reinforcement costs and system operation costs/balancing:

- Super shallow system integration approaches limit generation investments to the actual plant, attributing already the (financial) responsibility for the connection to the grid to the grid operator.
- Shallow charging attributes grid connection cost to the generators, while grid operators bear the costs of necessary grid reinforcements.
- Finally, deep integration specifies a practice of charging plant operators for grid reinforcement and system operation in addition to the costs for the direct connection line.

Hybrid charging methodologies – subsuming elements of more than one mentioned practices – add to the variety of regulations currently implemented in different European electricity markets[1]. Table 0.1 in the appendix gives an overview of current policies for the allocation of RES-E integration costs in selected European countries.

In this context, it has to be stressed that reduced expenditures on the side of one party due to less responsibilities lead to – not necessarily proportional – additional costs on the side of the other party. In the end consumers pay: Hence, in terms of welfare economics, efficient configurations in the allocation of duties have to be found, which keep the need for public transfers to a minimum.

Disaggregated components of grid and system integration costs of large scale renewable generation have been quantified in various studies: For wind energy, specific costs for balancing as well as grid extensions derived from various national case studies are presented in publications of IEA task 25 (Holttinen et al., 2008). The evolution of grid integration cost components in relation to the deployment ratio of wind energy is being assessed for single European countries as well as on EU-27 level with the help of the GreenNet-Europe simulation model (Auer et al., 2007). While costs of balancing and grid reinforcement vary over a broad range due to different power system and infrastructure configurations and due to different calculation approaches, costs for direct grid connection can be assessed accurately on the basis of information on the rated capacity of respective wind farms, distance to the point of connection and the corresponding voltage level of feed-in.

Critical discussions on the topic of primary cost allocation mechanisms for DG/RES-E generation units focus mainly on efficient investment signals for the location of power plants in the presence of grid scarcities. Barth et al. (2008) find evidence from an economic analysis that system integration costs shall be borne by plant operators in the presence of functioning markets reflecting scarcity concerning grid usage and capacity.
Modelling interactions of applied policies for system integration cost allocation and RES-E deployment in European countries leads Auer et al. (2006) to the conclusion, that adding grid connection to capacity investment will significantly delay or even cut down RES-E installations.

[1] A recent cross-country analysis of implemented regulations concerning RES-E grid and system integration has been conducted within the Intelligent Energy Europe project GreenNet-Incentives and can be found on the project website www.greennet-europe.org.

1.2. Research question

Grid connection costs comprise a significant cost component of renewable generation investments: Specific grid connection costs are especially high for wind power plants in relation to conventional generation facilities for the reason that rated power is comparatively small and favourable but remote resources are being deployed.[2]
In the presence of public support for electricity generation from renewable energy sources the question of primary cost allocation arises: While eventually electricity consumers will be passed over these costs, this paper analyses cost efficiency from consumers' perspective for different cost allocation mechanisms.

Core questions addressed in this paper comprise:

- What effects do different approaches of allocation of grid connection costs have on the supply curve for (offshore) wind power?

and

- What effects do these changes impose on respective (social) transfer costs and producer surplus?

1.3. Approach

After a discussion of the composition of long run marginal costs for electricity production form wind power, the characteristics of the supply and demand curves for wind power are explored taking into account both the impact of different mechanisms of cost allocation and the effect of renewable energy policies.

Setting up a formal relation for the total cost for renewable energy policies from a national economic point of view for different allocation approaches of grid connection costs, resulting transfer costs (subsidies) imposed on electricity consumers are assessed qualitatively.

Eventually, potential transfer cost savings are being quantified in a comparative analysis of different cost allocation scenarios for the deployment of UK round II&III offshore wind projects.

2. Long run marginal cost of electricity generation from wind power

Long run marginal cost (LRMC) of electricity production and the expected market value of generated power are the key determinants for generation investment from a purely economic point of view (disregarding institutional, social, environmental factors).

It shall be stated at this point that the term *marginal cost* as used in LRMC appears spurious from a microeconomic point of view, which defines marginal costs as production costs of an incremental unit of output or even as savings resulting from not producing an incremental unit of output compared to production. From this perspective,

[2] While for offshore wind energy the second reason is clearly fulfilled, installed capacities may reach the scale of conventional power plants in near future. As of January 2009 the maximum rated power of an offshore wind farm has been reported 165.5 MW (Nysted, Denmark) (Source: www.offshore-wind.de).

what is denominated as LRMC of electricity production rather should be referred as long run average costs (LRAC). The reason, still, for using the term marginal is, that additional capacity and additional generation, for which investment decision is subject to expectations on future positive returns, are marginal to the respective electricity market and its existing generation capacity.
In this sense, LRMC of wind power – from a static perspective – include specific capital costs[3] and operating costs. Specific capital costs are determined by specific investment costs, the expected life time or investment horizon, the capacity factor of the installation and the applied interest rate. Specific operating costs include planned maintenance, repair, rental of land, insurance, administration (incl. metering) and electricity consumption[4] (compare Formula 2-1 and Formula 2-2) below.

$$LRMC = \frac{\alpha \cdot c_{INV}}{T} + c_{VAR\ O\&M}$$ Formula 2-1

and $$\alpha = \frac{z \cdot (1+z)^{LT}}{(1+z)^{LT} - 1}$$ Formula 2-2

where

LRMC	Long run marginal costs of electricity production from wind power [€/MWh]
α	Capital Recovery Factor [1/y]
T	Full Load Hours [h/y]
c_{INV}	Investment costs [€/MW]
$c_{VAR\ O\&M}$	variable costs for operation and maintenance [€/MWh]

and

z	Interest rate [1]
LT	Lifetime / depreciation time [y]

It is highly disputable to what extent *system integration costs* comprising grid connection costs, grid reinforcement costs and system operation costs (balancing/capacity) shall be accounted as part of generation costs (investment costs and operating costs) as well.

Auer et al. (2007a) argue that grid reinforcements shall be in the responsibility of grid operators in order not to violate the principle of unbundling. If cost savings can be realized in grid connection due to a subadditive cost function – which seems evident in the case of offshore wind connection – corresponding costs should also be initially attributed to grid operators. In contrast, Barth et al. (2008) find, that shallow grid connection costs as well as deep reinforcement costs have to be charged to RES-E producers in order to maintain an economically efficient solution, in which evolving grid scarcities are being reflected. Obviously, the valuation of economic effects of different costs allocations has been assessed on the basis of different criteria in these studies.

In the following economic analysis only the differentiation of grid connection costs being or not being part of LRMC of wind power plant operators will be discussed. In principle,

[3] Total investment costs (overnight investment costs plus interest rates during construction) are often denominated as capital costs. In the context of this paper, capital costs specify (total) investment costs plus opportunity costs of this investment, which is an interest over the respective lifetime or the investment horizon.
[4] According to a strict microeconomic definition, not even these cost positions of operating cost can be counted as marginal production costs, but rather as part of fixed costs, since one unit of additional or lesser production does not influence this cost category. Short run, in this context, refers to a planning horizon of plant commitment up to one year rather.

this analysis is applicable to grid reinforcement costs as well but may be less demonstrative. Balancing costs can be passed on to market participants through transparent market mechanisms. In practice, corresponding costs to a significant extent depend on the actual design of imbalance markets (secondary and tertiary reserves) along with actual balancing demand caused by deviations from submitted production schedules. For instance, introduction of short term production-schedule submission will decrease imbalances and imbalance costs especially for wind power plant operators in comparison to 3-days-ahead schedule submission before weekends, which has been and still is common practice in many European power markets. A second example for institutional reasons increasing costs in this category is the allowed aggregation level of wind feed-in: In most cases wind feed-in can be aggregated to balancing groups taking advantage of smoothing effects. These effects are positively correlated with the number and capacity of aggregated units and, most important, their geographical dispersion (Obersteiner et al. 2007). Despite these advantages, it can be observed, that the market design does not allow for aggregation of wind and, therefore, artificially raises imbalance costs, which eventually have to be borne by electricity consumers[5]. Currently, in Europe, an inhomogeneous picture of organising balancing responsibility (for RES-E) can be observed: while in countries with a longer track record of RES-E promotion the formation of balancing groups is foreseen (e.g. Germany), balancing of single metering points is obligatory in countries with a younger according history (e.g. Hungary, Romania, Poland).

In operational terms there also exists a trade-off between efforts for forecasting wind feed-in and imbalance-costs.

In the presence of RES-E support schemes balancing responsibility can be imposed on wind power producers, independently from the mechanism applied:
Under so-called market based mechanisms and feed-in premium systems generators are participating in wholesale markets as balancing responsible parties. Also in countries applying a "classical" feed-in tariff scheme, financial incentives for meeting generation schedules can be put into force.

3. Welfare-economic considerations of disaggregating the supply function of wind power

In an environment of energy policy driven strategies for increasing the share of renewable energy sources for electricity generation, the quantification of welfare economic effects in a traditional way of depicting the consumers' willingness to pay for different quantities of a good and producers' willingness to supply this good at different prices and summing up consumer and producer surplus is virtually impossible:

For the reason, that the demand for electricity from wind power is exogenously triggered by promotion instruments and can not be related to an actual willingness to pay, the consumer surplus can not be directly measured. Taking this into consideration a viable approach for estimating consumer surplus can be undertaken only in performing an analysis of external costs of RES-E and wind deployment to society (compare EWEA, 2009).

[5] It can be argued, that aggregation of geographically dispersed units according to the principle of balancing groups neglects potential grid bottlenecks between different connection points.

Economic welfare resulting form the surplus of producers also has to be treated with caution in an economic environment of subsidisation: As the profits of generators are resulting from pursuing a certain energy policy, their adequacy is subject to political discussions and excessive rents of the industry will not be accepted by electricity consumers.

For above reasons mentioned, the economic efficiency of a RES-E support scheme is often evaluated on the basis of transfer costs for electricity consumers instead. These costs are defined as extra costs for RES-E generation within a certain support scheme in comparison to its market value on wholesale markets not taking into account external costs for society (Ragwitz, 2006). The objective of these analyses determining social costs is to identify successful implementations of support schemes, which are characterised by the result, that a certain deployment of existing potentials has been effectuated at minimum costs to consumers.

3.1. Demand curve for wind energy

External distortions of the market for RES-E in form of national support policies are leading to a situation, where demand in this market is either totally inelastic in the presence of fixed (technology specific) quotas (Q) or totally elastic in the presence of a feed-in tariff (FIT1,2) as long as the success of the respective support scheme meets the expectations of responsible authorities (compare Figure 3.1). A practical implementation of RES-E support schemes often foresees caps preventing unintended states of the system: whereas in quota systems with tradable green certificates this capped demand refers to a lower and upper limit of the certificate price (as implemented in e.g. the UK, Poland, Romania[6]) it refers to an overall limit of available funds for a certain period in time in several FIT systems.

Consumer surplus is defined as the benefit resulting from consumers' payments in the range of market prices only in comparison to a higher willingness to pay for a certain product. In the presence of politically induced RES-E-promotion instruments, the consumer surplus of deploying renewable sources can hardly be estimated or even measured. Applying a formalistic approach of comparing the demand curve and the actual level of RES-E support, the resulting consumer surplus may be either infinite in case of a totally inelastic demand or zero in case of totally elastic demand.

In the following analysis the question of applying different support mechanisms is not considered. It is assumed, that for a certain electricity market either a quota system with tradable green certificates or a feed-in tariff system is in place. Both systems effectuate the deployment of the same wind energy potential. This implies, that the market clearing price of certificates at the time, when the quota is reached, equals exactly the feed-in tariff, which is sufficient for the same deployment[7].

[6] As a matter of fact, never in the history of implemented quota systems in Poland and Romania the certificate price had been a product of demand intersecting supply according to market principles but sticks to a regulated maximum cap.

[7] Higher rates of return, which may be demanded by investors in a quota system due to increased risks of a volatile certificate market, are not being considered.

3.2. Supply curve for wind energy

LRMC of electricity generation from wind power differ widely due to unevenly distributed wind potentials within different regions in single electricity markets. For the reason, that in almost all cases grid connection comprises a significant cost component for wind power installations, these differences might be even greater if grid connection costs are regarded as part of LRMC.

To obtain the supply curve for electricity production from wind power, the capacities of available potentials are ranked according to their specific long run marginal costs of deployment from most cost-efficient to most costly potentials. Discounted, site specific grid connection costs are added to this stepped long run cost curve. Long run marginal costs of electricity production from wind power are denoted as C1 and C2, depending on the methodology of grid connection cost allocation.

The order of deployment of different wind potentials to meet a certain demand may be different depending on the cost allocation scheme applied. Still, in the following analysis of support costs an identical generation portfolio is assumed to be deployed.

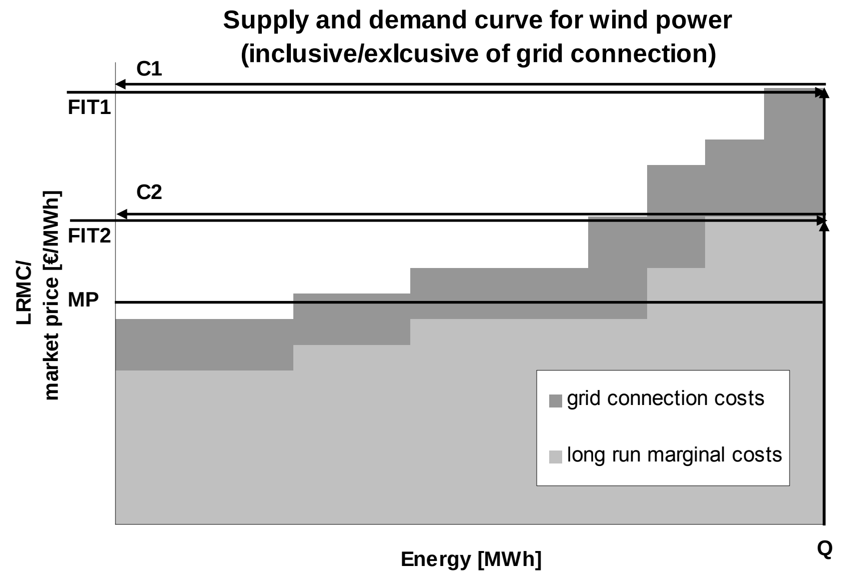

Figure 3.1: Supply and demand curve for wind power, LRMC and grid connection costs[8]

Figure 3.1 qualitatively depicts the supply functions of wind power for the two different cases of primary grid connection cost allocation[9]. The demand (quota) is equal in both cases, whereas, in case a feed-in tariff system is in place, different tariffs are resulting.

C_1, C_2	long run electricity production costs of the marginally deployed wind farm, inclusive (1) or (2) exclusive of the costs for the grid connection) [€/MWh]
FIT_1, FIT_2	feed-in tariffs, sufficient to achieve demanded deployment [€/MWh]
Q	Quota, equalling the deployment reached through FIT_1 / FIT_2 [MW]
MP	Market price of wind energy[10] [€/MWh]

[8] Only for better visibility the lines indicating the level of feed-in tariffs and costs do not overlap in the graph.
[9] According to the depiction, some potentials are regarded to be distinguished by different grid connection costs only, while the long run production costs are equal.

3.3. Producer surplus of plant operators

Producer surplus in addition to consumer surplus determines economic surplus. Still, in the case of producer surplus being generated in a subsidised market, it is not regarded as equivalently valuable to society in comparison to consumer surplus. Eventually, producer surplus to a large extent constitutes transfer costs, which for political reasons are demanded to be low.

The producer surplus of wind farm operators determines revenues above individual production costs. Its magnitude depends on the deployed volume and the slope of the supply curve and in this respect also on the regulation in place for the allocation of grid connection costs.

In the case of primary attribution to generators (scenario 1), according to Formula 3-1, the producer surplus can be derived from summing up the spreads between long run marginal costs C1 and the respective individual long run production costs. Producer surplus is marked in hatched pattern in Figure 3.2.

$$PS_1 = \sum_{i=1}^{n} \left(C_1 - LRMC_i\right) * q_i \qquad\qquad Q = \sum_{i=1}^{n} q_i \qquad \text{Formula 3-1}$$

PS_1	producer surplus of wind farm operators in allocation scenario 1 [€]
$LRMC_1$	long run production costs of individual wind farms [€/MWh]
q_i	energy yield of individual wind farms [MWh]
n	number of wind farms installed

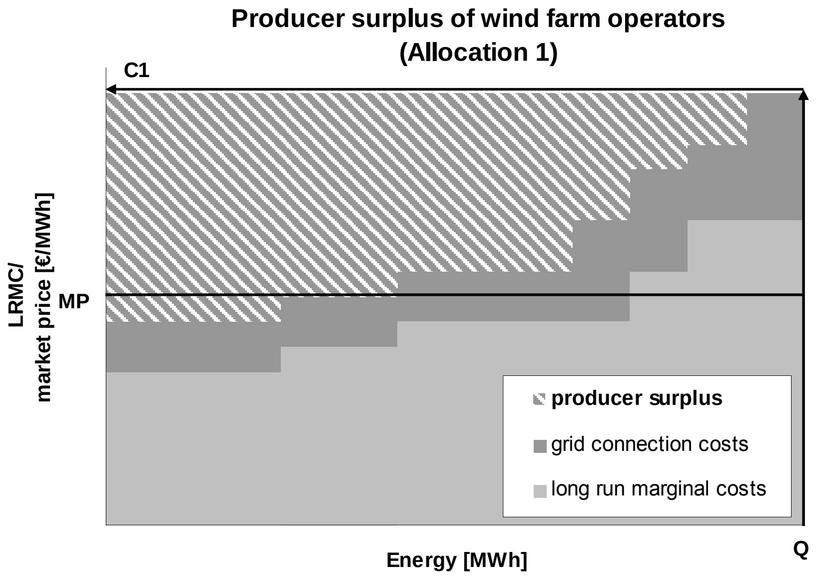

Figure 3.2: Producer surplus of wind farm operators (grid connection costs allocated to producers)

[10] The market value for wind energy is analysed for the Central European power market by Obersteiner et al. (2009). The market price, at which the feed-in of wind farm operators can be settled on wholesale markets, is typically lower than the average price level in these markets, given that wind power has reached a significant share.

Primary allocation of grid connection costs to grid operators (scenario 2), results in lower long run production costs of the marginal unit and a lesser producer surplus according to Formula 3-2 and as depicted in Figure 3.3.

$$PS_2 = \sum_{i=1}^{n} \left(C_2 - LRMC_i\right) * q_i \qquad\qquad Q = \sum_{i=1}^{n} q_i$$

Formula 3-2

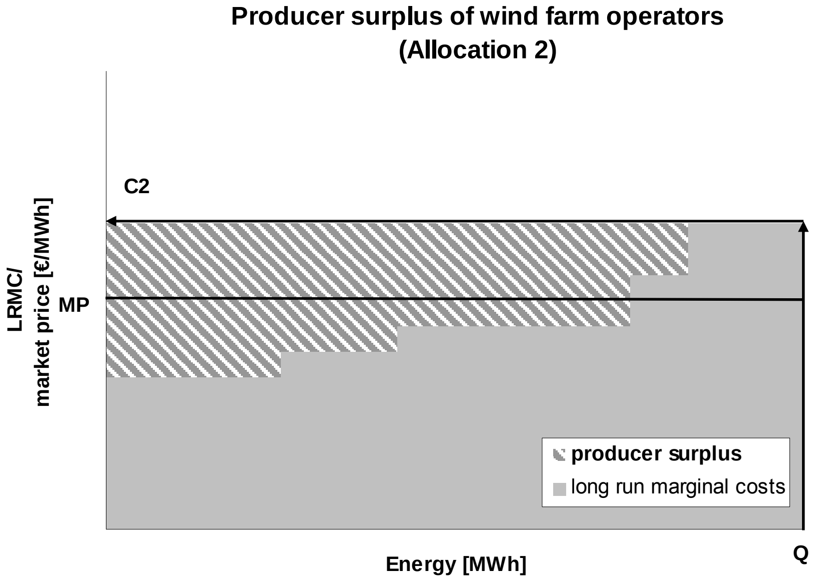

Figure 3.3: Producer surplus of wind farm operators (grid connection costs allocated to grid operators)

3.4. Transfer costs to electricity consumers

The resulting producer surplus in scenario 2 is lower compared to scenario 1. But as connection costs, which are primarily attributed to grid operators, will be passed on to final energy consumers, this reduction does not equal the savings of consumers: The corresponding effect on transfer costs will be analysed in the following.

Specific transfer costs are assumed to be independent from the applied promotion instrument and shall be defined in this context as the additional costs to consumers resulting from the deployment of a certain wind potential, comprising higher production costs as well as higher grid and system related costs in comparison to conventional generation. Simplifying, the market value of wind is assumed to equal the wholesale electricity market price and other grid related costs than for connections are not considered[11].

Transfer costs in scenario 1 can be calculated as the difference between the long run production costs of the marginally deployed wind farm including its specific capital costs for grid connection and the market price, related to the volume Q, as reflected in Formula 3-3 and depicted in Figure 3.4.

In order to limit the magnitude of transfer costs, different promotion schemes are designed in a way to simulate a stepped demand curve, where different remuneration

[11] If transfer costs shall be quantified in absolute terms, these simplifications are not applicable. But they do not affect the conclusions of this comparative analysis.

levels are reserved for different technologies or different power scales or even different ranges of resource availability.

$$TC_1 = (C_1 - MP) \times Q$$ Formula 3-3

TC_1 transfer costs to consumers in allocation 1 [€]

MP Market price of wind energy [€/MWh]

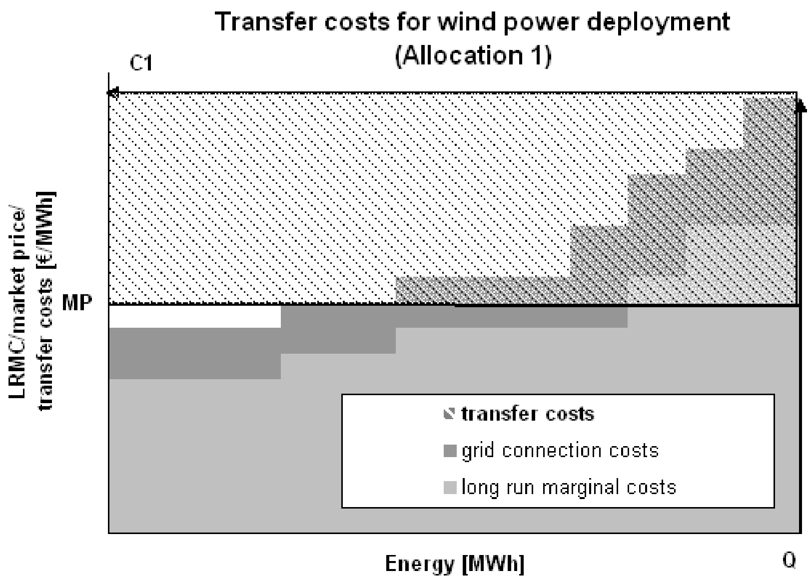

Figure 3.4: Transfer costs for consumers for wind power deployment (grid connection costs allocated to producers)

In the second scenario, the pass through of grid connection costs by grid operators into grid tariffs needs to be considered in the calculation of transfer costs. These include the difference between marginal (pure) production costs and the market price, related to the volume Q, and the sum of individual specific capital costs of grid connection, applying a monopolistic grid operator's rent. See Formula 3-4 and Figure 3.5. For the reason of better visibility, the specific long run costs of grid connection have been shifted towards the upper margin of the graph.

$$TC_2 = (C_2 - MP) * Q + \sum_{i=1}^{n} \left(q_i * GC_{i,reg} \right)$$ Formula 3-4

TC_2 transfer costs to consumers in allocation 2 [€]

$GC_{i,\,reg}$ specific capital costs of individual connections (to be borne by grid operators) [€/MWh]

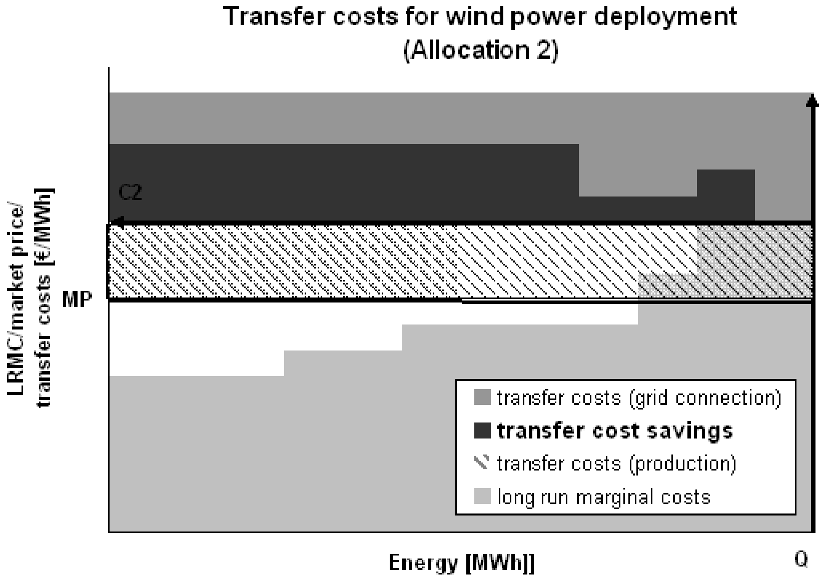

Figure 3.5: Transfer costs for consumers for wind power deployment (grid connection costs allocated to grid operators)

3.5. Transfer cost savings

As indicated in Figure 3.5, the second allocation scenario results in lower total transfer costs for the support of a certain volume of wind power to consumers. These savings are expressed in Formula 3-5.

$$TCS = (C_1 - C_2) * Q - \sum_{i=1}^{n} \left(q_i * GC_{i,reg} \right)$$ Formula 3-5

These savings are positive, if marginal grid connection costs are increasing with the deployed volume and pure production costs are not disproportionally declining. In the case of (offshore) wind energy differences in pure production costs seem to be mainly caused by different full load hours, whereas grid connection costs are mainly dependent on the spatial distance to a suitable connection point in the existing electricity grid. Latter effect is regarded to be dominant; therefore cost savings according to allocation scenario 2 are expected to be realisable.

In qualitative terms, potential transfer cost savings as depicted in Figure 3.5 are underestimated compared to Formula 3-5 for the reason that total costs of grid connection are expected to be lower when all offshore transmission infrastructure investments are carried out by a regulated TSO: Savings can be realised through joint connection designs[12] and through lower capital costs in comparison to renewable energy project developers.

[12] In a study by Econnect (2005) potential savings achieved by cost efficient joint offshore wind farm connections against single solutions are explored for UK Round II projects.

4. Evidence of potential transfer cost savings in the deployment of Round II and Round III offshore wind farms in the UK

4.1. LRMC of electricity generation from offshore wind

While overnight investment costs for offshore wind turbines are approximately 20% higher than for onshore turbines in specific terms, costs for foundations, installation and grid connection can escalate to a multiple in comparison – showing a broad distribution depending on factors as distance to shore, depth of water, weather conditions and according possible delays of installations (dti, 2007).

4.2. Supply curve for UK Round II offshore wind farms

In order to quantify the possible effect of different allocation mechanisms of grid connection (offshore transmission) costs on overall transfer costs for a distinct case, a supply curve of offshore wind projects to be realized in the course of the UK Round II and Round III Crown Estate license is being developed.

Long run marginal costs are separated into

1) costs for connecting the offshore substation to the onshore electricity grid (transmission cable),
2) costs for the offshore substation,
3) all remaining cost components (wind turbine, tower, foundation, intra-wind farm connection, project management, environmental studies etc.)

Information of capital costs of single offshore wind farm projects can be hardly obtained on a comparable basis for various reasons: Firstly, non-disclosure policies of affected parties make respective information unavailable on disaggregated level. Additionally, capital costs have been reported to have doubled in real terms within the four-year period 2005 – 2008 (BWEA, 2009)[13]: early installations have been brought online in a premature market characterised by tight competition between developers as well as suppliers and underestimation of risks and efforts[14] resulting in overall project losses, while current investment conditions are characterized by supply chain constraints, increased input prices and higher demanded returns for suppliers as well as developers.

For these reasons, uniform average specific capital costs of 2009 excluding offshore grid connection have been assumed for the following analyses for all wind farms[15].

Non-distance dependent specific costs for transmission infrastructure, operating expenditures, discount rates, project lifetimes and load factors are assumed to be

[13] Ernst&Young (2009) report a cost increase by 100% in the five-year period from 2004 to 2008.
[14] BWEA (2009) refers to several insolvencies and buy outs of early projects in this context.
[15] Costs for foundation as well as equipment installation are site-specific; still, they are assumed to differ negligibly compared to transmission. When quantifying transfer cost savings, this assumption contributes to an underestimation of potential savings for the reason that more remotely located wind farms tend to account for higher costs with this respect.

uniform as well. Project specific connection costs are taken from a *Study on the Development of the Offshore Grid for Connection of the Round Two Wind Farms*, commissioned by the Department of Trade and Industry (Dti), UK (Econnect, 2005), and a respective study for Round III projects (Senergy Econnect and National Grid (2009)). Project specific distance dependant infrastructure costs have been inflated at a rate of 10% per year until 2009 taking into account observed cost escalations (Ernst&Young, 2009).

Current capital costs are stated to amount to approximately 3 mGBP (BWEA, 2009)[16], inclusive of foundation and electrical infrastructure. Up to 20 % of this amount are attributed to the connection to the grid including non distance dependent infrastructure costs (inter-array cabling, offshore substation[17]).

Recent studies on the economics of offshore wind power estimate a broad range of operating expenditures: While dTI (2009) states costs of 46 kGBP/MW/a, Ernst&Young state costs of 79 kGBP/MW/a plus 18 kGBP/MW/a decommissioning costs.

Table 4.2 gives an overview over economic parameters used in this case study for the preparation of a disaggregated supply curve for wind offshore projects in the UK. All cost figures are given for the year 2009 and are based on data from Ernst&Young (2009), BWEA (2009), EWEA (2009), Econnect (2005), Senergy Econnect & National Grid (2009) and DTI (2005) as well as own adaptations.

Table 4.1: Overview over economic parameters of UK offshore wind projects

Capital expenditures		
Capital costs (excl. offshore substation and transmission)	2.394.000	£/MW
Capital costs of offshore connection	90.000 – 440.000	£/MW
Capital costs of offshore substation	114.000	£/MW
Operating expenditures		
Operating expenditures (incl. decommissioning, excl. transmission, substation)	87.500	£ /MW /yr
Operating expenditures transmission	7.500	£ /MW /yr
Operating expenditures substation	2.500	£ /MW /yr
Economic parameters		
Discount rate (pre-tax real)	12	%
Load Factor (net)	38	%
Project lifetime	20	years
Availability	94	%

[16] 3.2 mGBP/MW according to Ernst&Young (2009), 2.0-2.2 m€/MW according to EWEA (2009b)
[17] 19% according to Ernst&Young (2009).

The time-frame for depreciation of the transmission infrastructure is set equal to the lifetime of the project. The same applies for the required rate of return. These assumptions appear consistent for the operation of the transmission infrastructure by the project developer or a licensed independent offshore transmission operator[18]. Only in case incumbent TSOs are being obliged to connect offshore wind farms and finance according costs via mark-ups to common transmission charges, as is the case in Germany, longer depreciation horizons and lower interest rates can be presumed. Table 4.2 summarises different components of Long Run Marginal Costs of Round II & III Offshore windfarms in the UK indexed for the year 2009.

Table 4.2: LRMC$_{2009}$ for UK Round II and Round III offshore wind projects

Long Run Marginal Costs		
capital LRMC (excl. transmission, substation)	92	£/MWh
operational LRMC (excl. transmission, substation)	26	£/MWh
capital LRMC transmission	3,2 – 15,7	£/MWh
operational LRMC transmission	2	£/MWh
capital LRMC substation	5	£/MWh
operational LRMC substation	1	£/MWh
LRMC total	133 – 146	£/MWh

A graphical representation of this data in the form of a supply curve is given in Figure 4.1.

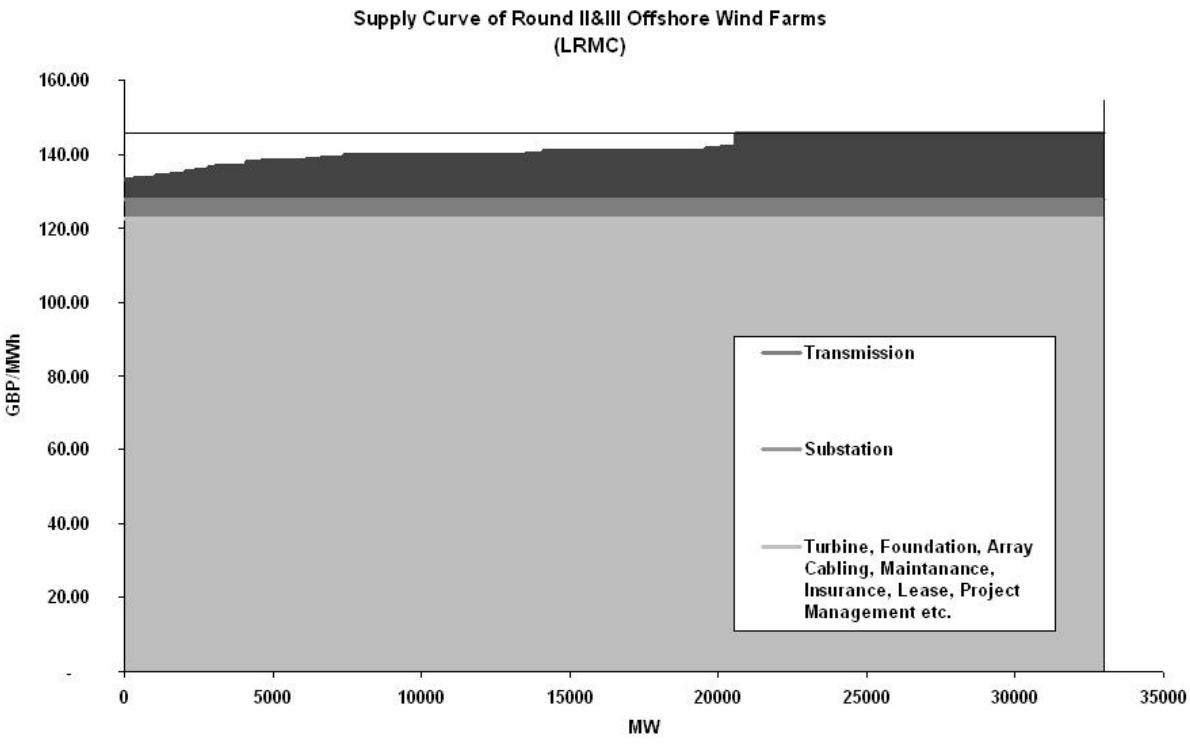

Figure 4.1: Long run marginal costs of electricity production from UK Round II&III offshore wind farms

[18] DTI (2005) refers to the risk of premature termination of connectees and asset stranding with respect to comparatively high capital costs as well as a potential change of wind technology concerning the depreciation time.

While approximately 118 GBP/MWh of total LRMC stem from CAPEX and OPEX of the wind turbine inclusive of the foundation and inter-array cabling as well as costs for insurance, lease of the seabed, onshore transmission network use of system charges and project management including environmental studies, around 5 GBP/MWh can be attributed to the substation. LRMC resulting from the installation and operation of the transmission infrastructure are in a range between 5 and 18 GBP/MWh, depending primarily on the distance to shore and the availability of suitable onshore infrastructure.
The resulting producer surplus in a scenario, where the full capacity is being deployed and revenues equalling long run average costs of the marginal wind farm can be obtained is marked in grey colour.

4.3. Potential transfer cost savings

Potential transfer cost savings resulting from a rearrangement of the cost allocation mechanism in place for the integration of offshore wind power will be analysed based on the methodology developed in section 3 according to Formula 3-5.
Two allocation scenarios will be differentiated:

1) Base case: a deep integration policy is assumed, project developers need to incur upfront and operational costs of the transmission infrastructure.
   Effectively, this policy is assumed to be identical in outcome with the recently implemented UK offshore transmission regulation, which foresees an independent operator charging tariffs, which are a result of a public tendering process[19].
2) Super-shallow approach: Substation and offshore connection including onshore integration are being provided by incumbent transmission grid operators. Additional costs are being recovered via conventional TSUoS-charges[20]. Capital costs are altered to a level of 6,25 % real pre tax (DTI (2005)). The depreciation horizon is kept constant at 20 years, even if a longer utilisation could be expected in comparison with project specific licencees.

Implementation of a super-shallow charging approach leads to potential transfer cost savings of 884 mGBP per year for the outlined case of deploying approximately 33 GW offshore wind capacity in UK Round II&III projects in comparison to the base case allocation. This amount would be sufficient to support the installation of additional 2.631 MW offshore wind capacity, underlying highest projected costs in a Round III project[21] and a reference market value of 40 GBP/MWh, equalling an 8% increase in installed capacity.

[19] Apart from lower financing efforts, this regulation is not expected to deliver an economic advantage to wind farm operators: offshore transmission charges are expected to equal LRMC costs of installing and operating respective infrastructure within the projects. Ernst & Young (2009) cite that *many industry participants assume that the new regime will be value neutral to the project until this is proven otherwise*.
[20] This approach corresponds to the German offhore integration policy.
[21] According to a super-shallow cost allocation scenario total costs of the most distant Round III project would amount to 141 GBP/MWh in comparison to 146 GBP/MWh in the base case allocation.

5. Results

5.1. Results of the qualitative analysis

The qualitative analysis of the supply curve of power generation technologies with comparatively high specific grid connection costs – as is the case for wind energy – shows, that different regulatory provisions concerning the allocation of disaggregated grid integration costs influence the overall transfer costs (subsidies) from consumers' perspective independently from the support mechanism applied, e.g. a quota-system with tradeable green certificates or feed-in-tariffs.

Imposing the primary responsibility for bearing the costs of grid connection of offshore wind power on the grid operator may be favorable from consumers' perspective due to following reasons – depending on the composition of cost components and the applied methodology of monopoly regulation:

1) If grid connection costs significantly influence the slope of the supply curve and if the volume of available subsidies allows for the deployment of potentials characterized by comparatively high connection costs, high shares of these subsidies are being spent on the coverage of producer surplus in case that plant operators have to bear these costs.

2) In case of cost allocation to the grid operator, efficiency criteria are being imposed on the pass through into tariffs by a regulatory body.

3) Demanded rate of return on investment is higher for wind power producers in comparison to regulated monopolists. Therefore, allocation of connection costs to grid operators leads to less costs to be passed over to consumers.

4) Coordination in the connection of adjacent wind farms leads to cost savings (due to a subadditive cost structure in this case) in comparison to competitive separate project developments.

5.2. Results of the quantitative analysis of UK Round II&II offshore wind

In this paper, a case study has been prepared, which compares the status quo as well as the future regulation of offshore electricity transmission in the UK to the German connection regime. For wind energy projects of rounds II&III of the Crown Estate's licensing procedure an arbitrary cost curve has been developed. Two scenarios of primary cost allocation are being compared: In the base case, the deep allocation scenario, all generators need to be remunerated with the long run generation costs of the marginal project inclusive of connection costs. In the second case, wind farm operators need to receive a compensation in the range of marginal production costs exclusive of transmission infrastructure costs, while incumbent TSOs are demanded to extend their field of operation offshore and recover additional costs via common TNUoS charges. This practice bears the potential to limit producer surplus and reduce transfer costs to electricity consumers.

The application of a super shallow integration cost allocation methodology to wind farms with a total capacity of around 33 GW may lead to transfer cost savings in the range of 884 mGBP per year. This amount is sufficient to support the installation of additional capacity in the range of 8% (2.631 MW), even if comparatively high specific generation costs (141 GBP/MWh) and a moderate electricity whole sale price of 40 GBP are assumed.

Producer rents, which result from comparatively low connection costs are not being offset by competitive bids for the seabed license in the course of an auctioning process: Payments to the Crown Estate comprising of an upfront "option fee" and a yearly "rent" in Rounds II&III are not dependent on costs related to the distance from shore or the nearest appropriate connection point (Crown Estate (2003)).

6. Conclusions

In an environment of public support for renewable electricity generation technologies, the efficiency of financial transfers of consumers is a topic of highest priority.

In this paper, it has been investigated, to what extent the allocation of responsibilities for providing and operating the electricity transmission infrastructure for offshore wind farms between generators and TSOs influences the resulting transfer costs to society.

In the case of offshore transmission being within the responsibility of grid operators, corresponding cost are passed on to electricity consumers in the form of network tariffs. In this case, consumers need to finance aggregated costs of these infrastructure elements.

In contrary, if wind farm operators are attributed this responsibility, consumers need to finance in addition the contribution of the marginal transmission infrastructure to the producer surplus of submarginal projects, when it is assumed, that the difference in specific production costs is mainly determined by distance dependent costs of offshore connections.

Additionally, wind farm operators are expected to demand higher rates of return for employed capital than TSOs.

From this perspective, it is suggested to mandate incumbent TSOs to provide and operate offshore transmission infrastructure on the basis of common regulated cost recovery mechanisms.

Super shallow charging does not provide intrinsic incentives for cost efficient location of wind farms. For this reason, to be able to gain cost advantages from the perspective of consumers arising from the reallocation of responsibilities concerning grid connection, coordinated planning procedures are necessary to be put in place. It seems, that according strategies for the determination of exclusive deployment areas through national authorities are effective already today.

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Appendix

Table 0.1: Overview of current policies for the allocation of RES-E integration costs in selected European countries.

	Grid connection	Grid reinforcement	Balancing
Austria	Producer	Producer	End user
Belgium	Producer	End user	Producer
Denmark	Producer[x)]	End user	Producer
France	Producer	Producer	End user
Germany	Producer[x)]	End user	End user
Greece	Producer	End user	End user
Ireland	Producer	Producer	End user
Italy	Producer	Producer	Producer
Portugal	Producer	Producer	End user
Spain	Producer	Producer	Producer
United Kingdom	Producer	Producer	Producer
Cyprus	Producer	End user	End user
Czech Republic	Producer	Producer	Producer
Estonia	Producer	End user	Producer
Hungary	End user	End user	Producer
Lithuania	Producer	Producer	End user
Malta	Producer	End user	End user
Poland	Producer	Producer	Producer
Bulgaria	Producer	End user	End user

Source: http://res-legal.eu/en.html (visited March 2009), own investigations

[x)] Costs for connecting offshore wind are borne by the TSO and passed on to the end user.