Disaggregating cost components of the supply function of wind power and welfare effects for different allocation mechanisms

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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 analyses 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 lead 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/capacity:

- Super shallow system integration approaches limit generation investment 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 additional capacity 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 markets¹.

It has to be stressed in this context 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 subsumed 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 respective 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.

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, 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 $cost^3$ and operating cost. Specific capital costs are determined by specific investment

² While for offshore wind energy the second reason is clearly fulfilled, installed capacities may in near future reach the scale of conventional power plants. As of December 2008 the maximum rated power of a offshore wind farm has been reported 165.5 MW (Nysted, Denmark) (Source: www.offshorewind.de).

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)

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 consumption⁴ (compare Formula 2-1 and Formula 2-2) below.

$$LRMC = \frac{\alpha \cdot c_{INV}}{T} + c_{VAR \ ORM}$$
Formula 2-1
Formula 2-2
and

where LRMC Long run marginal costs of electricity production from wind power [€/MWh] Capital Recovery Factor [1/y] α Т Full Load Hours [h/y] Investment costs [€/MW] CINV variable costs for operation and maintenance [€/MWh] C_{VAR O&M} and Interest rate [1] Ζ 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 an 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 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, this analysis is applicable to grid reinforcement costs as well but may be less demonstrative. Balancing costs can be passed on market participants through transparent market mechanisms. In practice, corresponding costs to a significant extent depend on the actual design of imbalance markets (tertiary and secondary 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 various European power markets. A second example for institutional reasons increasing costs in this category is the allowed aggregation level of

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.

wind feed-in: In most cases wind feed-in can be aggregated to balancing groups taking advantage of smoothening 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 consumers⁵. 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).

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 of political discussions and excessive rents of the industry will not be accepted.

For the 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.

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.

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, Romania⁶) it refers to an overall limit of available funds for a certain period in time in several FIT systems.

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.

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. Due to the fact, that 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 cost 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 deployment of wind potentials meeting a certain demand will be different according to the cost allocation scheme applied. Still, in the following analysis of support cost an identical generation portfolio is assumed to be deployed.

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.



Figure 3.1: Supply and demand curve for wind power, LRMC and grid connection costs⁷

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

C1, C2	long run electricity production costs of the marginally deployed wind farm,
	inclusive (1) or (2) exclusive of the costs for the grid connection)

FIT1, FIT2 feed-in tariffs, sufficient to achieve demanded deployment

Q Quota, equalling the deployment reached through FIT₁ / FIT₂

MP Market price of wind energy⁸

3.3. Producer surplus of plant operators

The producer surplus of wind farm operators determines the transfer costs to society in addition to average production costs. Its magnitude depends 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 C1and the respective individual long run production costs. Producer surplus is marked in squared pattern in Figure 3.2.

$$PS_1 = \sum_{i=1}^n (C_1 - MC_i)^* q_i$$
 $Q = \sum_{i=1}^n q_i$ Formula 3-1

PS1producer surplus of wind farm operators in allocation scenario 1MC1long run production costs of individual producers

⁷ Only for better visibility the lines indicating the level of feed-in tariffs and costs do not overlap in the graph.

⁸ The market value for wind energy is analysed for the Central European power market in Obersteiner et al. (2009). The market price, at which the feed-in of find farm operators can be settled on wholesale markets, is typically lower than average price levels in markets with significant wind shares.

qi energy yield of individual wind farms

n number of wind farms installed



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

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





(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 considered⁹.

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.

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

Formula 3-3

TC1transfer costs to consumers in allocation 1MPMarket price of wind energy



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

⁹ 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.

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.

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

TC₂ transfer costs to consumers in allocation 2

GC_{i, reg} specific capital costs of individual connections on the side of the grid operator



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

3.5. Transfer cost savings

As can also be read from 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.

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

These savings are positive, if marginal grid connection costs are increasing with the deployed volume.

4. Results

The 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 consumer's 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 cost of grid connection of offshore wind power on the grid operator may be favourable 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, when 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.

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

5. Conclusions

In the case of grid connection being within the responsibility of grid operators, corresponding cost are being passed on to electricity consumers in the form of network tariffs. In contrast to an aggregated approach, not costs of the marginal unit are determining the contribution of grid connection to overall support costs but average costs. This is due to the fact, that regulated grid operators are being granted to recover only actual costs approved by a regulatory body at an agreed rate of return, which is expected to be lower in comparison to a wind farm developer exposed to higher sources of risk.

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 in order to determine (exclusive) cost efficient deployment areas for additional wind generation.

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