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Conditions and costs for renewables electricity grid connection: Examples in Europe

Derk J. Swider[a,*], Luuk Beurskens[b], Sarah Davidson[c], John Twidell[c,d], Jurek Pyrko[e], Wolfgang Prüggler[f], Hans Auer[f], Katarina Vertin[g], Romualdas Skema[h]

[a] *University of Stuttgart, Germany*
[b] *Energy Research Centre of the Netherlands, The Netherlands*
[c] *IT Power, UK*
[d] *AMSET Centre, UK*
[e] *Lund University, Sweden*
[f] *Vienna University of Technology, Austria*
[g] *Energy Restructuring Agency, Slovenia*
[h] *Lithuanian Energy Institute, Lithuania*

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Abstract

This paper compares conditions and costs for RES-E grid connection in selected European countries. These are Germany, the Netherlands, the United Kingdom, Sweden, Austria, Lithuania and Slovenia. Country specific case studies are presented for wind onshore and offshore, biomass and photovoltaic power systems, as based on literature reviews and stakeholder interviews. It is shown that, especially for wind offshore, the allocation of grid connection costs can form a significant barrier for the installation of new RES-E generation if the developer has to bear all such costs. If energy policy makers want to reduce the barriers for new large-scale RES-E deployment, then it is concluded that the grid connection costs should be covered by the respective grid operator. These costs may then be recouped by increasing consumer tariffs for the use of the grid.

Keywords: Grid connection; Case studies; Embedded generation; Costs; Renewable electricity; Europe

1. Introduction

Grid connection and extension costs are significant factors for integrating RES-E generation technologies into an existing electricity network. The costs of grid connection are especially relevant if, for example, offshore wind is considered, for which the next suitable grid[1] connection point may be several tens of kilometres away. Hence, additional grid connection costs occur that are generally not required for integrating conventional generation technologies (this is mainly due to the fact that those networks already exist and have been paid for in the past). The costs of grid extension are important if changes in generation and demand at one point in the network cause power congestion in another (deeper) point in the network. Usually, it is not possible to identify a single cause for the change. Thus, the allocation of the resulting costs to a single RES-E generator is at least ambiguous, if not impossible.

Consequently, two questions arise: (i) what conditions apply for RES-E grid connection and extension, and, (ii) who has to pay for additional costs? If a new developer has to pay all these costs up-front, then a compromise between the best generation sites and acceptable grid conditions has to be made. This means that RES-E developers may have a first-mover disadvantage by having to include these costs within their long-run marginal

*Corresponding author. Tel.: +49 711 685 87851;
fax: +49 711 685 87873.
E-mail address: djswider@ier.uni-stuttgart.de (D.J. Swider).

[1] This may be a high-voltage transmission grid because of the relatively large capacity of the offshore wind farm.

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generation costs. If, on the other hand, the grid connection costs are covered by the respective distribution or transmission system operator (as the grid forms a natural monopoly, these costs are then 'socialized' to all customers via grid tariffs), consequently, the initial burden does not fall only on the first RES-E developer.

These aspects are relatively new to the literature. One line of research regards the design and operation of power systems with large amounts of RES-E with special focus on wind. MacDonald [1], Auer et al. [2], Gül and Stenzel [3], Holttinen et al. [4] and others provide such reviews for different system configurations. Experiences from large-scale wind integration of areas in Europe and elsewhere are discussed by Söder et al. [5]. The situation of large-scale wind integration in Germany is, for example, analysed in greater detail by Bartels et al. [6] and Swider and Weber [7]. Several other studies add to this general line of research. Grubb [8] assesses the operation costs of a system with wind power generation by analysing the effects of wind's variability on the load-duration curve. Dale et al. [9] estimate the extra cost to the electricity consumer for large-scale wind scenarios in the United Kingdom. DeCarolis and Keith [10] simulate a small exemplary system and assess the costs of increased wind input in a carbon-constrained world with the system assumed to be static. Dondi et al. [11] focus more on technical aspects and review the position of distributed generation with respect to the installation and interconnection of such units with the existing grid. Tande and Uhlen [12] assess the connection of a large wind farm to a regional power system with a weak link to the main transmission grid. Andersson et al. [13] report on a feasibility study of connecting a large offshore wind farm in the German Baltic Sea to the existing transmission grid. Barriers of RES-E grid integration are studied by Alderfer et al. [14], focussing on technical barriers on distributed projects in the United States, and Agterbosch et al. [15], focussing on social barriers on wind projects in the Netherlands. Auer et al. [16] estimate the impact of individual cost allocation schemes on future installed RES-E generation.

In order to answer the questions asked above, the major objective of this paper is to present the results of selected country-specific case studies on conditions and costs for RES-E grid connection under different regulatory regimes, namely: Germany, the Netherlands, the United Kingdom, Sweden, Austria, Lithuania and Slovenia. For these European countries, prominent RES-E technologies were selected. The information came from literature reviews and stakeholder interviews. The results are analysed for best-practice.

The remainder of this paper is structured as follows. A short description of the respective electricity systems is given in Section 2. The conditions of RES-E grid connection are discussed in Section 3. The costs of RES-E grid connection are analysed in Section 4. Finally, conclusions are drawn in Section 5.

2. Description of electricity systems

Following the EU Directives 96/92/EC and 2003/54/EC the electricity markets in Europe must be fully liberalized by 1st July 2007. By then (i) all electricity users should be able to choose their own suppliers, and (ii) electricity network service providers must be separated (unbundled) from generating and/or supply companies. Of the considered countries, only Lithuania and Slovenia, which acceded the European Union in 2004, have not yet achieved this target.

Another requirement of the EU Directives for each country is for the establishment of an effective regulatory body (i.e. the Regulator), that ex ante regulates the electricity network. The major reason is that the electricity network forms a natural monopoly and is thus not subject to normal market mechanisms. In most of the countries considered, the access to the transmission and distribution network at liberalisation was based on a regulated third party access. In Germany, however, the access to the network was based on a negotiated third party access, and only after the EU directive 2003/54/EC became effective, the national energy law was revised and a Regulator established.

Following the liberalization in many of the considered countries, mergers in the generation sector have resulted in a more concentrated market structure. In both Germany and the Netherlands, for example, the centralized power plants are owned by just four companies. This results in an oligopoly and raises questions regarding the success of the liberalization, since lack of competition may allow electricity prices on the wholesale markets to increase, so leading to increasing retail electricity prices, especially for small customers.

The installed capacities for electricity generation and the electricity production in the considered European countries are quite different. Germany has the largest electricity system in Europe (in 2004 consumption of 597 TWh and installed capacity 124 GW) and Slovenia, one of the smallest electricity systems in Europe (in 2004 consumption of 15 TWh and installed capacity 3 GW) [17]. For this study, however, not only the size of a system is relevant, but also the respective share of RES-E.

Table 1
Installed total capacities and share of RES-E (including large-scale hydropower) [2,17]

Country	Capacity (GW)		Share of RES-E (%)	
	2000	2004	2000	2004
Germany	118	124	13	22
The Netherlands	21	22	4	8
The United Kingdom	79	80	7	7
Sweden	34	34	58	55
Austria	18	21	65	70
Lithuania	7	6	14	15
Slovenia	3	3	33	33

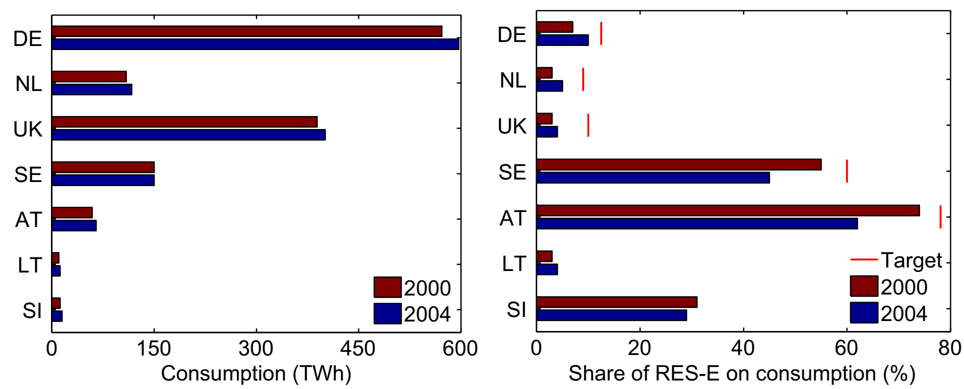

Fig. 1. Consumption, RES-E production share and 2010 target of the EU Directive 2001/77/EC (including large-scale hydro-power, which production is noticeably rainfall dependent by year) [2,17].

The large share of RES-E production in Sweden and Austria, compared with the other countries in Table 1 and Fig. 1, is because their electricity supplies are dominated by large-scale hydro-power generation and not, as for the others, by thermal generation. Note that annual rainfall variation causes fluctuation in RES-E production. The thermal generation is based on nuclear and coal in Germany and on gas, coal and nuclear in the United Kingdom.

Table 1 shows the change of total capacities and share of RES-E. The growth in Germany, the Netherlands and the United Kingdom is especially noticeable, mainly due to significant growth rates of onshore wind energy installations. For instance, Germany has the largest installed wind capacity of any country worldwide, with more than 16 GW cumulative by 2004 [17] (and steadily increasing since then). However, due to the large electricity system, this corresponds to an electricity production share of only 4%. Nevertheless, the installations in Germany significantly contributed to the impressive worldwide yearly growth rates of installed wind capacities of up to 35%/y in recent years [18]. However, the rate of deployment is beginning to decrease in Germany, mainly because the available sites for wind farm building onshore are becoming scarce. Hence, investors tend to re-power older onshore wind turbines and to think about offshore installations as a new promising option.

The new installed capacities of other RES-E technologies are not usually as large as for wind power. This is due to either the large long-run marginal generation costs, e.g. for photovoltaic power (nevertheless, the annual growth rates of photovoltaic installed capacity are impressive), or to the limited number of technically and economically prospective sites. The latter is especially so for Germany and the Netherlands regarding the development of hydro-power. However, there are still huge potentials for biomass installations. The proportions of RES-E technologies, based on the respective electricity production of the considered countries in 2004, are given in Table 2.

Table 2
Share of RES-E in 2004 (% of RES-E production, including large-scale hydro-power) [2]

Country	Hydro	Wind	Biomass	PV	Other
Germany	38	44	17	1	0
The Netherlands	2	38	60	<1	0
The United Kingdom	11	5	84	<1	<1
Sweden	87	<2	10	<1	<2
Austria	90	3	6	0	1
Lithuania	98	<1	2	0	0
Slovenia	99	0	<1	<1	<1

The contribution from photovoltaics remains very small due to the large costs. Also small, obviously, are emerging new renewable energy technologies, such as wave and tidal stream energy. Although the United Kingdom has the greatest potential wind resource in Europe, the relative contribution from wind energy is smaller than in Germany and the Netherlands,[2] mainly due to the differences in the support mechanisms (as will be discussed below).

In the considered new member states, i.e. Lithuania and Slovenia, in the past development of RES-E did not receive much attention. This may be due to the relatively young economies where environmental issues are usually not the biggest concern. Nevertheless, both countries already have a high share of electricity production by RES-E technologies, namely hydro-power. The potentials for new hydro-power installations are however limited, therefore attention is now given to biomass and wind energy.

Following the preceding discussion of the seven countries, it can be concluded that the development of RES-E has substantially increased over the past years. It is expected that the achieved growth rates of established technologies will eventually decrease, but new options, like offshore wind, will result in even higher shares of RES-E in the future. However the extent of such cumulative

[2]However, the wind power installations in the United Kingdom start to increase in recent years.

development is, next to other aspects, highly dependent on the conditions and costs for RES-E grid connection.

3. Conditions for RES-E grid connection

The purpose of liberalized electricity markets in Europe is to increase efficiency by competition, so decreasing electricity prices for the end consumers. However, the EU directive 2001/77/EC partly contradicts this aim. The directive deals with the promotion of RES-E in the European electricity market. Each European country has to set a national indicative target of the share of RES-E on the gross electricity consumption. These national indicative targets should be consistent with the European Community indicative target of 12% of gross national energy consumption by 2010 and in particular with the 22.1% indicative share of RES-E in total Community electricity consumption by 2010. From Table 1 and Fig. 1 it can be seen that most of the considered countries progressing steadily towards these targets.[3]

The introduction of RES-E, especially wind and photovoltaic power, can increase generation costs as compared with conventional generation. This is due to their higher long-run marginal generation costs as compared to conventional generation. Hence, the requirement of a defined share of RES-E partly contradicts the aim of liberalization for reduced costs and requires governmental action to achieve the respective national target.[4]

3.1. Supporting schemes

Consequently, in Europe RES-E technologies are supported by various institutional policy tools, e.g. feed-in tariffs, quota obligations, green-certificate trading, fiscal measures like tax benefits, investment grants (for a discussion covering the European Union countries cf. [19]).

Feed-in tariffs at preferential rates are characterized by a defined unit price that the system operators are obligated to pay to the RES-E generators. The consequent additional costs are passed through to all consumers as a premium on the unit price of purchased electricity. A variant of the feed-in tariff is to pay a fixed premium above the electricity spot market price to RES-E generators.

Quota obligations are government regulations requiring electricity companies to market specified fractions of their total supply from RES-E and failure to supply leads to fines. The mechanism for such trading may be built upon green-certificates (e.g. Renewable Obligation Certificates). For instance, the Regulator may award RES-E generators with unit-production green-certificates, and the obligated suppliers can then purchase these certificates to fulfill their obligation. This leads to the development of a secondary market where certificates are traded, in addition to the actual electricity. Pure tendering exists along-side such obligated quotas, and is characterized by a series of tenders for the supply of RES-E, which is then supplied on a contract basis at the price resulting from the tender.

Most of the considered countries use the feed-in tariff as their support scheme for the development of RES-E technologies and give additional tax and/or investment incentives. Of the considered countries only the United Kingdom and Sweden use quota obligations. The implementation of the schemes is however slightly different from country to country. For example, in Germany the system operators are mandated to pass the additional costs of the fixed feed-in tariff on in a cost equalization procedure. Thereby a clearing takes place between the transmission system operators, so that each gets an adequate share of the extra costs based on the electricity demand in the respective grid area. The resulting costs are then transferred to the end consumers.

In the Netherlands the government sets ex ante premiums that are based on the projected cost gap of RES-E compared to the market price of conventional electricity. The resulting expenses from the payment of feed-in premium costs are financed through the national budget, so there is no direct link between electricity consumers and RES-E generators. The system of RES-E incentives has experienced several adjustments in the past years, of which the most radical is the unannounced stop of the feed-in premium grants in August 2006 for newly submitted projects (the premium for projects that were already granted are not touched). The reason for this stop was a projection by the Ministry of Economy according to which the electricity target of 9% in the year 2010 was expected to be met based on known projects. The stop was announced as being temporary and is dependent on political priorities. At the time of writing, the continuation of the Ministry of Economy policy is still unsure.

One additional difference concerns the participation of the RES-E generation in the conventional power market. In Germany a RES-E generator does not participate in the latter and hence additional costs, e.g. for regulating power, have to be born by the grid operator and finally by the society. This can be seen as an additional benefit for RES-E generators and is especially important for highly variable and less predictable wind generation. Thus participation of RES-E in the liberalised electricity markets of the Netherlands and of the United Kingdom is more stringent than in Germany.

Other differences are the guaranteed period of paying fixed feed-in tariffs, the bandwidth of the feed-in tariffs and the reduction of the payment for new developments in future years (e.g. due to learning effects). The latter are given for the considered countries with a feed-in tariff in operation and for the year 2006 in Table 3. Thereby the

[3]As discussed above, note that the achievement of national targets for Sweden and Austria depends on the annual rainfall variations due to the high share of large-scale hydro-power generation.

[4]The introduction of wind in a market may lead to reduced market prices, however, other integration costs (e.g. grid extension and reinforcement costs, additional balancing costs) need to be covered that, depending on the respective power system, may result in a net increase of end consumer tariffs, cf. Dale et al. [9].

Table 3
Bandwidth of feed-in tariffs in the year 2006 (in EUR/MWh)

Country	Wind power				Biomass		Photovoltaics	
	Onshore		Offshore					
	Min	Max	Min	Max	Min	Max	Min	Max
Germany[a]	55	87	62	91	39	175	457	624
The Netherlands[b]	65		97		0	97	97	
Austria[a]	78		–		30	165	470	600
Lithuania	64		–		58		–	
Slovenia	58	60	–		91	94	374	

[a]The feed-in tariffs are currently under revision.
[b]Premium on the electricity market price.

bandwidth of minimal and maximal tariffs is primarily based on the installed capacity, the respective availability of the energy carrier (especially relevant if wind and photovoltaic are considered) and the year of installation. Grid connection costs, depending on the respective cost allocation approach (as will be discussed later), have usually been considered by policy makers for defining the feed-in tariffs.

It can be seen that the feed-in tariffs are quite similar for the different countries considered. Slight deviations are mainly due to differences in the supply of the respective energy carrier. For wind and photovoltaics, this corresponds to differences in the expected full-load hours (for example in 2004, the national average full-load hours were[5] (i) for photovoltaic plant in Germany, 613 h/y, about 660 h/y in the Netherlands and 750 h/y in Austria; (ii) for wind onshore, 1534 h/y in Germany, about 1810 h/y in Austria and 1739 h/y in the Netherlands). For biomass generation plant, the full-load hours relate mostly to local differences in costs e.g. regarding harvest, transport and quality, of the respective local biomass.

3.2. Grid connection

Next to the conditions of the respective RES-E supporting schemes, the conditions of RES-E grid connection and system service requirements are of importance. For example in the United Kingdom, obtaining a grid connection can cause significant problems to the progress of RES-E regarding both increasing the costs and delaying the project, mainly due to the time necessary for negotiations with the connecting entity. Relevant negotiation issues are way-leaves for the necessary connection assets, the lack of coordination between grid and planning consents and the overall lack of clarity in the system of grid connection. This, however, is not only specific to the situation in the United Kingdom. Similar concerns are expressed in other countries, however not with the same intensity.

In general, the national governments require RES-E technologies to be connected with priority compared to conventional generation. They are usually connected to the nearest available connection point of the existing grid. This procedure is defined in national grid codes that are often different for the distribution and the transmission network. One major difference is that the power plants connected to the transmission network may be obliged to provide system services, while the power plants connected to the distribution network may not. Such system services are requirements, for example, on the active and reactive power and restoration of supply. The specifics of these requirements are, however, not fully harmonized within Europe. Exemptions are allowed to the rules defined by the Union for the Co-ordination of Transmission of Electricity (UCTE), which has the primary aim of assuring overall system security.

The procedure for grid connection is basically as follows. In a feasibility study the network operator examines whether the system conditions prevalent at the planned point of connection are technically sufficient for operation of the generating unit. Should the system conditions suffice for operation, the network operator submits a verifiable offer as to the network connection scheme. Should the system conditions at the system point of connection not be adequate, the network operator furnishes evidence of this inadequacy. Then, the network operator, together with the connection holder, examines appropriate modifications, such as network reinforcements. Following this feasibility study, a formal connection offer is made, and, if accepted, leads to detailed design work to determine the final connection charge and additional requirements. Eventually the project is commissioned. Matevosyan et al. [20] and Kroposki et al. [21] provide discussions on the technical regulations for the connection of RES-E to the grid.

[5]'Full load hours' per year (h/y) equal annual production (kWh/y) divided by capacity factor (kW). Note that in 2004 the market development has been very dynamic with many RES-E plants installed at the end of the year. This leads to somewhat lower full-load hours than could be expected for an average year.

For RES-E, there are usually deviations from the requirements defined for conventional generation. The major reason is because fluctuating power injections from RES-E into the grid may jeopardize system operation. For example in Germany, the RES-E generator has to ensure that, upon request, it must be possible to reduce the RES-E power supply. This is especially relevant for wind power generation. For instance, in exceptional cases, the network operator is permitted to instruct a temporary restriction of the power output or the disconnection of a wind farm. Such a restriction of power transfer will only be performed during extreme grid disturbance. This can affect RES-E developers as they are not able to produce and usually receive no compensation for the lost remuneration.

3.3. *Cost allocation*

One final aspect to discuss is the method of allocating the respective grid connection (and extension) costs. In general, the grid integration of any electricity producing technology is not for free, whether conventional or RES-E power plant. However, the allocation of such costs will affect the RES-E producers much more than the conventional producers, since the RES-E producer's costs are more sensitive to any increase in the costs. Therefore, most importantly, shallow and deep grid integration costs should be distinguished.[6] Both are characterized by the different parts that need to be paid for by the RES-E generator.

Shallow costs are charged if the RES-E developer pays for only the costs of connecting the plant to the grid, and not for grid reinforcement. The major advantage of this approach is that it induces relatively cheap grid integration costs, since any grid reinforcements are paid by the network operator (and ultimately by the consumers of electricity). The major disadvantage for the consumers of the RES-E developer paying only shallow costs is that the network operator may overestimate the total costs of grid reinforcement, knowing the costs will be socialized. Hence effective regulation and, hopefully, competitive tendering is necessary.

Deep costs are charged if the RES-E developer pays for all costs associated with the connection, including all network reinforcement costs. The main benefit of this approach is that it includes the actual costs of integrating a new generator into the existing network within the generation costs of the RES-E developer. Thereby the RES-E producer is expected to optimize the costs by deciding on the location of the investment so that the efficiency of the network may increase. The main disadvantage of this approach is the increased investment cost of the RES-E developer. The improved network conditions, following any grid extension or reinforcement, serve all present and future network users, not just the new

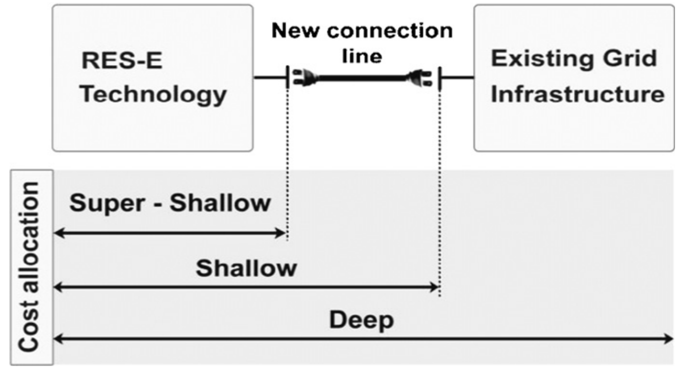

Fig. 2. Approaches of RES-E grid integration cost allocation.

RES-E generator. Therefore, it is usually unfair to allocate all arising costs to a particular RES-E generator. This may also cause a first-mover disadvantage, since RES-E producers may want to wait for others to implement their projects first.

There are two other cost allocation methods. With the first, the RES-E generator bears no costs at all. Such a *super-shallow* approach would definitely favour RES-E generators, since all costs related to the grid integration are covered by the end consumers and do not affect the generation costs. The second is a *hybrid* approach, whereby the RES-E generator has to pay only a fraction of any additional grid extension and reinforcement costs. Obviously, the latter constitutes a compromise for the RES-E generator between paying none or all of shallow and deep grid integration costs. This is illustrated in Fig. 2.

To highlight some distorting effects of the different methods, consider the situation where a RES-E developer has to cover the shallow grid integration costs, i.e. the cost for the grid connection. With such an approach, the new built grid connections to the existing grid will probably belong to the RES-E generators, since they pay for them. In general, this method is acceptable to all parties. But what happens if an offshore wind park is considered? Then the situation gets more complicated, especially if later another RES-E generator decides to initiate a project near to an existing wind park. Obviously, the intention of a newcomer will be to connect the RES-E power plant to the nearest point. So a newcomer may want to use the connection line of the existing RES-E generator (this may include extending the existing line). Do the newcomers then need to pay any remuneration to the existing RES-E generator? Or will they need to pay for their own connection so having two connections near each other rather than one shared connection? Keeping these questions in mind, it may be more efficient for overall system operation if the utility network operator pays for, and owns, the whole grid connection, thereby anticipating possible future grid extensions.

It is obvious that the choice of the allocation of grid connection and integration costs is of major importance and can adversely affect the economic viability of new

[6]A more detailed discussion of these methods can be found in Knight et al. [22].

RES-E developers. Thus, the objective is how to allocate the costs fairly between the stakeholders. Of the considered countries Germany, the Netherlands and Slovenia apply a shallow approach, the United Kingdom and Lithuania apply a hybrid approach and Sweden and Austria apply a deep approach. This overview is an indication of the real situation only, as, in reality, it is not as easy to distinguish the diverse approaches as in theory. There is no consensus, mainly because there are many stakeholders involved, each with their own interests and expectations.

Following such a discussion, at the time of writing, the German government decided to give developers for offshore wind power an additional incentive to invest (in addition to the feed-in tariff). Thereby a super-shallow approach was adopted that commits the German network operators to pay for the grid connection costs. Thus a new offshore grid will be built and owned by the network operators. The costs will be socialized to the consumers and will not be covered by the RES-E developers. Furthermore, the feed-in tariff for wind offshore is about to be increased, implying that it was formerly much too low. These decisions can be seen to form major incentives towards the future deployment of offshore wind power in Germany.

It is concluded that the conditions for RES-E grid integration may have substantial influence on the RES-E development in Europe. The difficulties are seldom technical, but predominantly concern the allocation of costs, especially if grid connection costs constitute a significant share of the total investment.

4. Costs for RES-E grid connection

The costs of RES-E grid connection are highly dependent on the point of connection, the characteristics of the network at the connection point and, more generally, on the definitions used and the system boundaries considered.

4.1. System boundaries

In principle, shallow and deep costs of RES-E grid connection can be distinguished. Both can have costs related to (i) recurrent costs (e.g. operations and maintenance) and (ii) capital investment costs (costs that occur only once in a project, mostly at the start). In case of wind power investment costs include the turbines, foundations and cable connection up to the site substation. This substation is generally the connection point to the grid. Usually, most aspects of electric power control and quality are dealt with by components housed in each turbine, and otherwise in the site substation. Substations are generally divided between the part accessible by the wind farm operator, and the separately locked part accessible only by the grid operator.

Here the substation is treated as a component of the grid connection. All costs related to this substation are considered as shallow grid connection costs, including the power line from the substation to the connection point in the existing grid (thus including any transformers and road or river crossings). These costs are influenced strongly by the distance to the nearest grid connection point, so giving a wide cost range of specific case studies.

After the grid connection point, all expenses in the existing grid related to the connection of the new wind power plant are considered to be deep grid connection costs. Especially in case of wind power, being variable, grid extensions and reinforcements can have an important financial impact. Nevertheless, these costs are seldom reported and thus not part of this study.

The first requirement for compiling case studies on the costs of RES-E grid connection is the access to relevant data. This can be difficult, since information regarding investments is often considered to be confidential. In addition, relevant stakeholders often do not see any benefit in providing such data. Basically, two survey methods have been used: (i) literature research and (ii) interviews with relevant stakeholders.

4.2. Connection costs

The analysis of specific case studies lends to the problem that the grid connection costs are site-specific: they depend on the distance to the existing grid, on the terrain and on the voltage level, to name a few influencing factors. Another difficulty is the difference between projected and realized costs. This is of special importance for offshore wind power, since few projects have yet been realized in the considered countries. The case study results on the connection costs for the considered technologies and countries are given in Table 4. If possible a bandwidth of usual connection costs is given. Note that for some countries and technologies the conducted case study results showed to be incomparable. Thus, they have been excluded from the discussion in this paper. For these costs is referred to the country specific case study reports in [23].

Wind onshore is by far the most developed RES-E technology in the considered countries and the results can be seen to be fairly robust. The case study results for wind onshore highlight that the connection costs are very similar in the considered countries. Peculiar results may be the case study costs for Austria and Lithuania. For Austria, the large costs are due to the specific case study with a very long cable length of about 21 km connecting the Alpine wind park to the connection point of the existing grid. For Lithuania, the small costs are due to the specific case study near the grid.

Wind offshore just starts to grow and thus the case study results predominately rely on projected and not on realized costs. The case study results for wind offshore highlight the high dependence of the distance to the existing grid. While in the Netherlands prospective offshore sites are comparatively near shore, there are only a few such sites in Germany. Thus, the bandwidth of grid connection costs of wind offshore in Germany is much higher. This is one of

Table 4
Bandwidth of RES-E grid connection costs (in EUR/kW for 2004; cost figures have been rounded)

Country	Wind power				Biomass		Photovoltaics	
	Onshore		Offshore					
	Min	Max	Min	Max	Min	Max	Min	Max
Germany	45	170	185	600	–		–	
The Netherlands	40	150	180	205	–		0	100
The United Kingdom	95	130	–		–		50	
Sweden	85		–		–		–	
Austria	210		–		30		–	
Lithuania	35		–		–		–	
Slovenia	–		–		15		–	

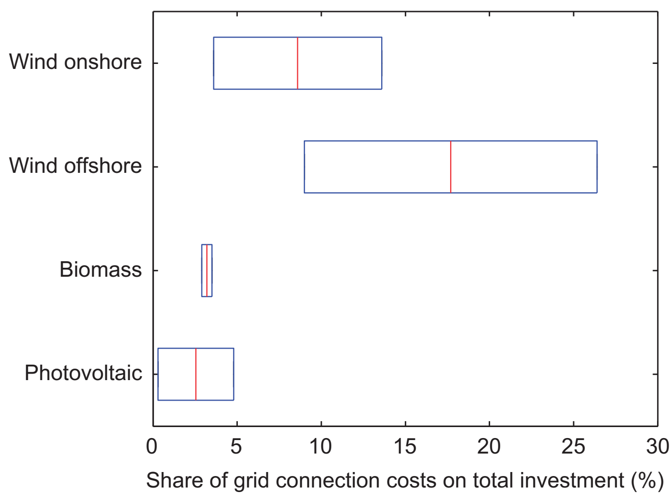

Fig. 3. Bandwidth of the share of RES-E grid connection costs on total investment.

the major reasons why investors do not tend to favour wind offshore in Germany and the development is delayed compared to expectations.

Biomass usually has requirements and costs regarding grid connection that are most similar to conventional generation if compared with other RES-E technologies. The costs are comparatively low and deviations between the considered countries are simply due to the case studies being site specific.

Photovoltaics can have connection costs that are either nearly negligible or they are in a comparable range as the connection costs for wind onshore. The former is due to many photovoltaic installations being on the roofs of buildings and can thus easily connected to the existing grid. The latter is the case if a photovoltaic farm is installed that usually needs free terrain and is not necessarily near to the existing grid.

As indicated above, the grid connection costs may affect the development of the RES-E deployment. This aspect can be analysed in more detail by calculating the share of RES-E grid connection costs on total investment. In Fig. 3 the bandwidth of the share of RES-E grid connection costs on total investment is depicted regardless of any country specifics and thus presents generalised ranges.

It can be seen that the share of the grid connection costs on the total investment is relatively small for biomass and for photovoltaics, generally because of close connection distance. This is completely different for wind power. For wind onshore, the mean share of grid connection costs on total investment of the considered countries and case studies is about 9% on average and in case of wind offshore as high as 18% on average. The share of grid connection on total investment costs can, however, be higher than 25% for the German wind offshore case. Hence, it can be concluded that the grid connection constitutes a major factor on the overall costs.

4.3. Generation costs and feed-in tariffs

One question to be answered is, if the current feed-in tariffs sufficiently include grid connection costs. Thus, the generation costs need to be determined. The generation costs are considered to be the long-run marginal cost of the generated electricity or, in other words, the unit generation costs over the lifetime of the plant. These costs are equivalent to the average price that would have to be paid by consumers to repay the investor for the capital, operation and maintenance and fuel expenses, with a rate of return equal to the discount rate. In principle the methodology allows the comparison of single units, but may not reflect the full economic impact of a new power plant connected to an existing system. This approach closely follows [24] but includes grid connection costs. The calculation is as follows:

$$C_g = \frac{\alpha \cdot C_{inv} + C_{run}}{T_{el}} + \frac{C_{fuel}}{\eta_{el}} - p_{heat} \cdot \frac{\eta_{th}}{\eta_{el}} \cdot H_{share}, \quad (1)$$

with C_g the unit generation cost (EUR_{2004}/MWh), C_{inv} investment costs (EUR_{2004}/MW), C_{run} running costs (EUR_{2004}/MW/y) , C_{fuel} fuel costs (EUR_{2004}/MWh), p_{heat} heat price (EUR_{2004}/MWh), H_{share} share of heat production scheduled for sale during the year (%), η_{el} electrical

Table 5
Bandwidth of RES-E unit generation costs (in EUR/MWh for 2004; cost figures have been rounded; lifetime assumed 20 years; interest rate 10%; country specific full-load hours following Table 6)

<table>
<tr><th rowspan="3">Country</th><th colspan="4">Wind power</th><th colspan="2" rowspan="2">Biomass</th><th colspan="2" rowspan="2">Photovoltaics</th></tr>
<tr><th colspan="2">Onshore</th><th colspan="2">Offshore</th></tr>
<tr><th>Min</th><th>Max</th><th>Min</th><th>Max</th><th>Min</th><th>Max</th><th>Min</th><th>Max</th></tr>
<tr><td>Germany</td><td colspan="2">90</td><td>105</td><td>125</td><td colspan="2">–</td><td colspan="2">–</td></tr>
<tr><td>The Netherlands</td><td>80</td><td>85</td><td>100</td><td>120</td><td colspan="2">–</td><td colspan="2">885</td></tr>
<tr><td>The United Kingdom</td><td colspan="2">80</td><td colspan="2">–</td><td colspan="2">–</td><td colspan="2">810</td></tr>
<tr><td>Austria</td><td colspan="2">105</td><td colspan="2">–</td><td colspan="2">110</td><td colspan="2">–</td></tr>
</table>

Table 6
Full-load hours for calculation of bandwidth of RES-E unit generation costs (in h following [2])

Country	Wind power		Biomass	Photovoltaics
	Onshore	Offshore		
Germany	1650	3100	–	–
The Netherlands	2200	3100	–	750
The United Kingdom	2450	–	–	700
Austria	1850	–	6500	–

efficiency (%), η_{th} thermal efficiency (%), T_{el} electrical full-load hours (h/y) and α annuity factor $(1/y)$.

With this definition, the unit generation costs of all considered RES-E technologies can be calculated. For anything other than biomass, only the first term of the equation applies. For wind and photovoltaic power, the unit generation costs are dominated by the investment costs because the energy carrier (wind and sunshine) is free of charge. Hence, there are no significant differences between the share of RES-E grid connection costs on the total investment and the generation costs. Any additional costs for adequate standby generation possibly needed in case of variable sources of electricity generation like hydro, wind and solar, have not been considered. In order to determine the generation costs of biomass plants, costs with regard to the production of heat are treated as heat credits and are deducted accordingly. Heat credits are determined by evaluating the heat generation of a reference system with a biomass-fired boiler.

The bandwidth of the calculated RES-E unit generation costs is given in Table 5. To compare results, parameters influencing the unit generation costs have been harmonized; namely the discount rate defining the annuity factor and the life-time. The discount rate has been fixed to be 10% and the lifetime to be 20 y for all the considered RES-E technologies. The full-load hours are chosen to represent a usual year and are given in Table 6 [2]. The minimum and the maximum value of the unit generation costs in the table are due to specified ranges for investment and grid connection costs in the considered case studies. For details is again referred to the country specific case study reports in [23].

It may be interesting to compare the unit generation costs with the feed-in tariffs given in Table 3 to highlight if the latter sufficiently consider the actual costs including grid connection.

Wind onshore shows similar results regarding the unit generation costs for the considered countries. The deviation of the Austrian case is due to the long grid connection and resulting costs as discussed above. With this exception the feed-in tariffs seem to be reasonable and give incentives to invest. Note that for the Netherlands, the feed-in tariff is a premium on the electricity market price and is thus comparatively larger than for the other countries considered; in the Netherlands it thus forms an attractive incentive for investment.

Wind offshore shows similar results regarding the unit generation costs for the considered countries. One notable aspect is that even though the analysis of the grid connection costs highlighted that those can be comparatively high in Germany, due to the far offshore location of the wind farms, the reported unit generation costs are relatively low. This is due to the considered country specific case studies, where very favourable assumptions of the investment costs have been considered. Regarding the feed-in tariffs the situation is totally different from onshore wind, as currently little 'real world' experiences are available. Here the comparison indicates that the feed-in tariffs are on the lower end of the estimated unit generation costs, especially for Germany. This is due to more favourable assumptions regarding the achievable full-load hours as assumed for the case studies, but also to an underestimation of the investment and especially the grid connection costs.

Biomass has not been studied in that detail as the grid connection costs usually do not play such a significant role. The only case considered here has unit generation costs that are well covered by the respective feed-in tariff.

Photovoltaics shows similar results regarding the unit generation costs for the considered countries. The remaining deviations are due to lower assumptions on the investment costs and full-load hours in the case for the United Kingdom. A comparison with the feed-in tariff for the Netherlands shows that the support is by far not sufficient to increase the share of photovoltaics on the electricity generation.

The comparison for the considered countries and RES-E technologies highlights that especially the development of wind offshore may be hampered due to comparatively low financial support regarding the coverage of high investment and usually underestimated grid connection costs.

4.4. Stakeholder interests

In order to derive conclusions or best-practice cases for RES-E grid connection, it is finally important that stakeholder interests and expectations are clearly defined. The following stakeholders (actors) can be distinguished:

- energy policy makers;
- regulators;
- RES-E generators;
- conventional generators;
- network operators;
- supply companies;
- end consumers.

Generally, for RES-E, the most important and influencing actors are energy policy makers and the associated Regulators. With the high reliability of the system in mind, they follow two aims, (i) establishing efficient and cost minimized electricity markets and (ii) introducing a defined share of RES-E generation. The former is based on the need to fulfill the primary aim of the majority of end consumers for paying minimal costs for electricity consumption. The latter is based on several reasons, but most important are climate and environmental issues. These aims require a rational trade-off. Hence, the goal is to achieve a reasonable share of RES-E generation in the system but with least-costs.

The introduction of relatively capital-cost intensive RES-E generation may be criticized for having the negative effect of a less efficient electricity system, but there are positive effects. The latter include higher employment rates in the supported sectors, possibilities to export the supported technologies and thus considerable positive effects on the overall economy (this aspect is however controversially discussed in the literature, cf. [25]). Additionally, the integration of RES-E generation in an existing thermally dominated system leads to a higher diversification of the generation portfolio and may thus result in a reduction of fossil fuel price risks (such an analysis can be based on the portfolio theory known from financial mathematics, cf. [26]).

The RES-E generators obviously aim to receive as much support as possible, ultimately resulting in at least break-even operation and hopefully increased profit. They prefer a situation in which any additional costs, like the grid connection (and other integration) costs, are covered by other actors in the market. This would increase the incentives to invest in RES-E technologies and hence leads to a higher share of RES-E on the electricity production. Another important aspect is the RES-E generators' exposure to risks. Any investment depends on the investors expectations on the future development. For example, if a new RES-E investment receives a fixed feed-in tariff for a defined period of time, the exposure to market risks is reduced. If, on the other hand, the new RES-E investment has to compete on the conventional electricity market, then the exposure to market risks is not limited at all and the payback of investment and other costs is not guaranteed, as for conventional generation technologies.

Established conventional generators do not want to be exposed to the risks of reducing full-load hours for the sake of the system accepting financially supported RES-E. This is of special importance if RES-E generation is not subject of the conventional market and is scheduled with priority. In an electricity market wind power will nearly always be scheduled with priority due to the comparatively low variable generation costs. However, wind power is usually not treated the same way as conventional generation regarding the guaranteed availability of generation. In contrast to conventional generators, they are usually not obliged to submit a production schedule day-ahead and do thus not cover any costs with respect to deviations from such a schedule. The variability of RES-E generation may cause additional difficulties and costs, because the generation is not as firm and predictable as conventional generation. It may thus require fast reserves and overall a higher flexibility of the system (i.e. power plants with fast start-up capabilities, cf. [7]). A new conventional generator will want to be treated fairly regarding all these grid connection and other integration costs.

The network operators have the primary responsibility of securing supply. One desire is to have equal conditions for all network operators. This is of special importance if there is a regulation of the end user tariffs and if the network operators are not equally exposed to new partly variable RES-E generation (as for example in Germany). The network operators may also request clear incentives to guarantee that fast reserves are available at all times. For instance, RES-E from (stored) hydro-power is very controllable and invaluable for network control. The network operators also need clear definitions regarding the connection of new generators. It is important that they have the rights to access the entire network at all times, including grid connections possibly paid for by a new RES-E generator. This requirement is due to the electricity network being very sensitive to failures, which may not only cause problems at the particular site, but also at other points in the network. Such failures may jeopardize the operation of the whole network if not taken care of.

5. Conclusions

Following the preceding discussions, the main factors affecting RES-E deployment (apart from the site conditions) are (i) the costs for grid connection, (ii) the unit generation costs, (iii) the respective feed-in tariff or another supporting scheme and (iv) the allocation of the costs. Within this paper has been shown that especially the latter can form a significant barrier for investing in new RES-E installations if the developer has to bear all those costs and, for example, is not remunerated by a sufficient feed-in tariff. Hence, if the major objective is to have accelerated RES-E grid integration with fewer barriers than the status quo, then the strategy should be to socialize all RES-E grid connection (and other integration) costs.

Regarding the share of RES-E, the situation in Germany seems to be the most favourable of all the considered countries. Especially the recent introduction of a super-shallow approach for wind offshore, significantly reduces the barrier for their further deployment. Even if the German case seem to favour RES-E investments, improvements are still possible. An interesting aspect is to think about changing the RES-E supporting scheme by defining a premium on the market price based on several characteristics, e.g. historic full-load hours or general characteristics of the site. These characteristics could then be subject to revision if the conditions change. The RES-E generator can then participate in the conventional electricity market and would have to compete in a competitive market environment. Any additional costs, e.g. for regulatory power (that is due to the forecasting errors of wind power production), can then adequately be assigned to the respective originator. The current RES-E supporting scheme in the Netherlands already leads in this possibly more efficient direction.

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