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COMPARING DIFFERENT COST ALLOCATION POLICIES FOR LARGE-SCALE RES-E GRID INTEGRATION IN EUROPE

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ABSTRACT

The EC-Directive 2003/54/EC (repealing EC-Directive 96/92/EC) on liberalization of electricity markets in Europe requires the electricity industry to be competitive, yet realises that many elements of the electricity supply chain are still natural monopolies. Consequently, separation of the competitive segments of electricity generation and customer supply from the grid infrastructure is seen as a precondition for non-discriminatory grid access for third parties (e.g. RES-E generators) as well as for transparent procedures for disaggregated cost allocation and grid regulation / grid tariff determination. However, legislation and definition of RES-E policy goals on national as well as EU level still face a variety of lacks (e.g. ignoring fundamental unbundling principles) in almost all European countries. In the ongoing EC-Project Green*Net*-EU27 these inadequacies are addressed comprehensively. Moreover, dynamic time paths of RES-E deployment are modelled in selected EU Member States up to the year 2020 for different degrees of unbundling and cost allocation policies in the context of RES-E grid integration. The modelling results clearly demonstrate that the degree of unbundling and the implemented allocation principles of different disaggregated cost elements significantly influence RES-E deployment both on national as well as EU level up to the year 2020. The major conclusion is that serious unbundling and correct allocation of RES-E related grid integration costs only guarantee fulfilment of the ambitious EC goals with minimal costs for society.

1 INTRODUCTION

The EC-Directive 2003/54/EC (repealing EC-Directive 96/92/EC) on liberalization of electricity markets requires the electricity supply industry to be competitive, yet realises that many elements of the electricity supply chain are still natural monopolies [8]. Consequently, it is considered best for different segments of the electricity system to be separated into clearly defined and separately accounted entities, as there are electricity generation, high-voltage transmission, low-voltage distribution and customer supply. This is called unbundling, which is one of the cornerstones of the liberalised electricity market. Separation of the competitive segments electricity generation and customer supply from the grid infrastructure is seen as a precondition for non-discriminatory grid access of third parties (e.g. RES-E generators) as well as for transparent grid regulation procedures and grid tariff determination.

But legislation and definition of RES-E policy goals on national as well as EU level still face a variety of lacks and inconsistencies [7], e.g.

- mixing up demarcation lines between the RES-E power plants and the grid infrastructure (new grid connection lines, reinforcement/extension of the existing grid) as well as overall system operation,
- neglecting disaggregated cost allocation of RES-E grid integration and, subsequently
- mixing up different instruments for recovering the different disaggregated cost elements (RES-E promotion instruments versus wholesale/balancing markets versus grid tariffs).

In the ongoing EC-Project Green*Net*-EU27 (www.greennet-europe.org) these inadequacies are addressed comprehensively. Moreover, dynamic time paths of RES-E deployment are modelled in selected EU Member States up to the year 2020 for different degrees of unbundling and cost allocation policies in the context of RES-E grid integration.

Depending on the interface between the RES-E power plant and the grid infrastructure in recent years increasingly the terms “deep”, “shallow” and “hybrid” integration costs have been established [13]. The “deep” integration cost approach expects the RES-E developer to cover at least several grid-infrastructure related costs (connection, reinforcement/extension). On contrary, in the strict “shallow” integration cost approach several grid-infrastructure elements are allocated to the grid operator and socialised in the grid tariff.

Literature on critical reviews of unbundling in the context of RES-E grid integration is scarce. The most comprehensive empirical overview study on RES-E grid connection charging in the “old” EU15 Member States is conducted in [13]. A few conceptual papers on strategic approaches on grid infrastructure planning (and operation) in the context of large-scale RES-E grid integration exist (see [2], [5], [17]). On country level corresponding publications exists e.g. for The Netherlands [10], Denmark [3], UK ([9], [12]), Ireland [16], Germany [4], but only a few of them explicitly address separation of RES-E (wind) grid connection.

The major objective of this paper is to conduct a comprehensive comparison of RES-E (wind) deployment in two EU Member States with fundamental different RES-E promotion instruments (Germany (feed-in tariff) versus UK (tradable green certificates)) for different RES-E grid integration cost allocation approaches ("deep", "shallow", "hybrid") up to the year 2020 based on the software tool Green*Net*. Moreover, parameter variations are carried out to demonstrate the effects of different grid integration cost allocation policies on RES-E (wind) deployment.

The paper is organised as follows: section 2 addresses the basic principles of unbundling in restructured electricity markets and the core role of the grid infrastructure in this context. In section 3 the simulation software Green*Net* is described briefly. In section 4 two country specific applications of Green*Net* for two fundamental different RES-E promotion instruments (feed-in tariff (Germany) versus tradable green certificates (UK)) are conducted and the corresponding results are discussed comprehensively. Finally, in section 5 conclusions on least cost RES-E grid integration are derived against the background of correct unbundling.

2 UNBUNDLING AND THE ROLE OF THE GRID INFRASTRUCTURE

2.1 Grid connection

Grid connection often is a significant economic barrier for RES-E generation technologies in dispersed locations. If the new RES-E developer has to pay all the costs of grid connection up-front ("deep" integration cost approach), then a compromise between the best generation sites and acceptable grid conditions has to be made, as is often the case for wind and small-hydro power [15]. On contrary, grid connection for biomass or biogas – in general – is no crucial barrier as the particular location of the plant is even more independent from resource conditions. To pay for the connection, the RES-E developer includes the costs into the long-run marginal generation costs. However, if the grid connection costs are covered by the grid operator ("shallow" integration cost approach) and the costs are socialized in the grid tariffs, then the initial burden does not fall on the RES-E developer.

2.2 Grid reinforcement/extension

Besides new grid connection lines (regardless of the distance and/or voltage level of connection) also grid reinforcement/extension measures may be necessary elsewhere in the existing network due to large-scale RES-E (wind) integration. In the "deep" integration cost approach the corresponding reinforcement/extension costs are also allocated to the RES-E generators.

The core problem now is that any changes in an intermeshed grid infrastructure will change the load flows in the system. The status quo as well as changes of load flows, however, have a variety of dimensions, as there are e.g. changes in generation and load centres, bottlenecks, or power trading activities. Therefore, the allocation of load flow changes to one single event (e.g. grid reinforcement/extension caused by new RES-E (wind) integration) is ambiguous.

Moreover, considering the currently ongoing benchmarking and grid tariff regulation procedures on the transmission and distribution grids in many European countries[1] correct cost allocation of grid infrastructure elements in the context of RES-E integration is crucial. Then only, correct grid tariff determination is practicable.

2.3 Natural monopoly character of electricity grids

From the economic point-of-view a necessary and sufficient condition for a natural monopoly – like capital intensive electricity grids are – is the *subadditivity* of costs [19]. In the following, the natural monopoly character is illustrated based on the example to offshore wind connection to the existing grid infrastructure. Usually, the following economic situation occurs (see also equation (1)):

If $C_{Transmission,i}$ are the offshore transmission grid connection costs of an individual wind farm i in case of separate grid connection (Figure 1a) and $C_{Transmission,common}$ the common offshore transmission grid connection costs of all wind farms (c_i is the individual short distribution grid component of wind farm i) (Figure 1b) the following cost relation exists:

$$C_{Transmission,common} + \sum_{i=1}^{n} c_i < \sum_{i=1}^{n} C_{Transmission,i} \tag{1}$$

i.e., the cumulated transmission grid connection costs of the individual offshore wind farms (Figure 1a) are higher than the common transmission grid connection costs (plus individual short distribution grid components) of a collective of several wind farms (Figure 1b).

[1] I.e., the determination of eligible costs for investments into grid infrastructure assets and grid operation and, subsequently, socialisation of corresponding costs in the grid tariffs.

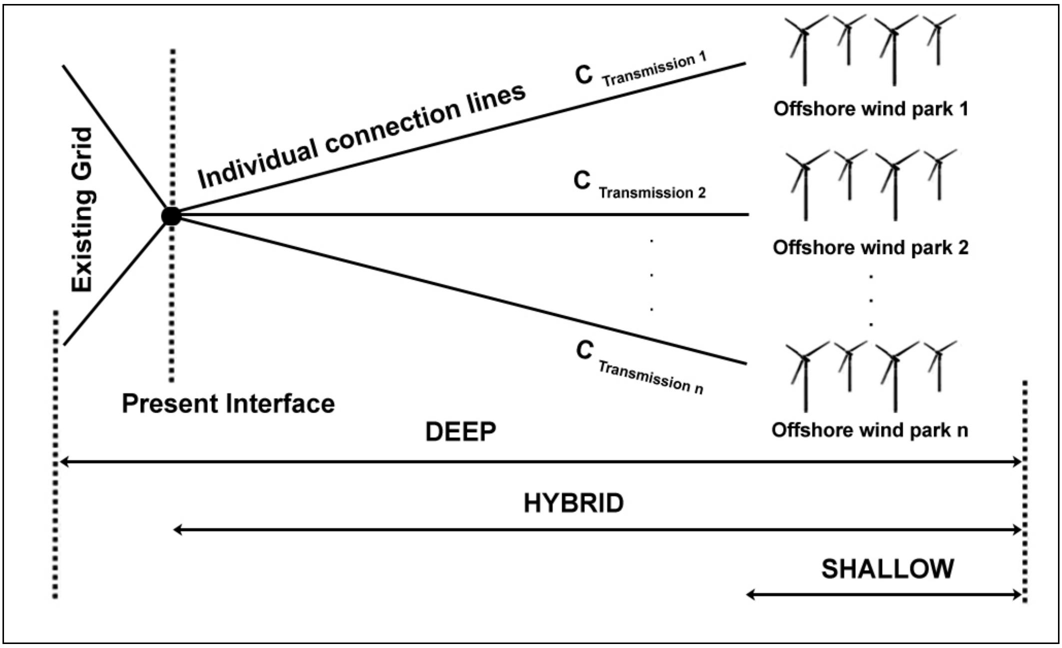

Figure 1a: Separate offshore grid connection of each individual wind farm and indication of different interfaces ("deep" versus "shallow" versus "hybrid") of integration cost allocation schemes

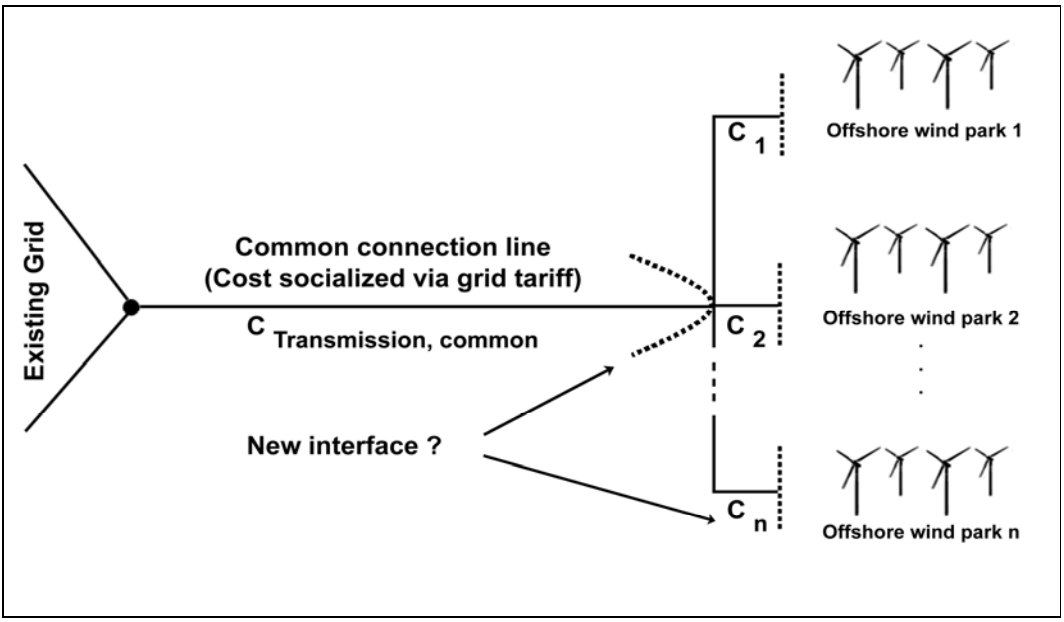

Figure 1b: Common offshore grid connection of several wind farms and definition of possible new interfaces to demarcate wind generation from the grid infrastructure

2.4 Status quo of RES-E grid integration policies in Europe

The previous section demonstrates that the textbooks in economic theory expect to allocate both grid connection costs and grid reinforcement/extension costs to the grid infrastructure and to spread (socialize) these costs through the transmission and distribution tariffs (and not to include either of these two cost components to the RES-E project costs and recover them in the corresponding promotion instruments).[2]

In practice, however, several grid-related cost components (or at least the grid connection costs) are still allocated to the long-run marginal generation costs of the RES-E power plant in almost all European countries (see Table 1). In a few countries (e.g. Denmark) a rather strict separation of the grid infrastructure and the RES-E power plant is already implemented (i.e. most transparent case ("shallow" integration cost approach)).

In some of the remaining European countries the existing pattern may change in the next years, not least due to the currently ongoing benchmarking and grid regulation procedures being conducted by national regulators. Although these procedures are driven to meet the unbundling principles of the EC-Directives 2003/54/EC&96/92/EC (and to implement cost transparency into grid infrastructure charging in general) rather than by RES-E grid integration finally the existing interface between the RES-E power plant and the grid infrastructure may be shifted increasingly towards the RES-E power plant ("shallow" integration cost approach). On contrary to the "deep" integration cost approach this guarantees perfect cost transparency and fulfills the basic unbundling principles.

Table 1: Status quo of different RES-E grid integration cost allocation schemes in the 'old' EU15 Member States ("deep", "shallow", "hybrid"). Source: [13]

	RES-E grid integration cost allocation scheme	**Max. grid connection cost**	**Cost transparency**
Austria	Deep	10% of investment	Low
Belgium	Hybrid	5-10% of investment	High
Denmark	Shallow	5-10% of investment	High
Finland	No standardised approach	-	Medium
France	Hybrid	10-20% of investment	Medium
Germany	Hybrid	-	Low
Greece	Hybrid	-	Low
Ireland	Deep	3-8% of investment	High
Italy	Deep	-	Low
Luxembourg	Deep	-	Low
Netherlands	Hybrid	-	High
Portugal	Deep	15% of investment	Medium
Spain	Deep	-	Low
Sweden	Deep	10% of investment	Low
UK	Hybrid	8-12% of investment	High

[2] In principle, there exist both options: (i) socialisation within a supply area of a grid operator or (ii) socialisation across the whole country (i.e. covering also several other grid operators).

3 LEAST-COST RES-E INTEGRATION MODELING BASED ON GREEN*NET*

The evaluation of strategies for least cost RES-E grid integration (with and without consideration of additional costs for grid connection, grid reinforcement/extension and/or system operation) for different cost allocation policies is conducted based on the simulation software Green*Net*. Section 3.1 below briefly describes this software tool.

3.1 The Green*Net* computer model

The Green*Net* model conducts a comparative and quantitative analysis of least-cost RES-E grid integration strategies in the liberalised European electricity market (i.e. the existing version covers several 'old' EU15 Member States and the four new Member States Czech Republic, Hungary, Poland and Slovakia).[3] The analysis can be conducted on aggregated (EU Member States') level or for individual Member States on an annual basis for the period 2005 to 2020 (2004 is the initial year). The major purpose of this software tool is to investigate RES-E deployment under different cost allocation policies on RES-E grid integration ("deep" versus "shallow" versus "hybrid") based on the currently implemented RES-E promotion instruments in the different EU Member States (see Figure 2).

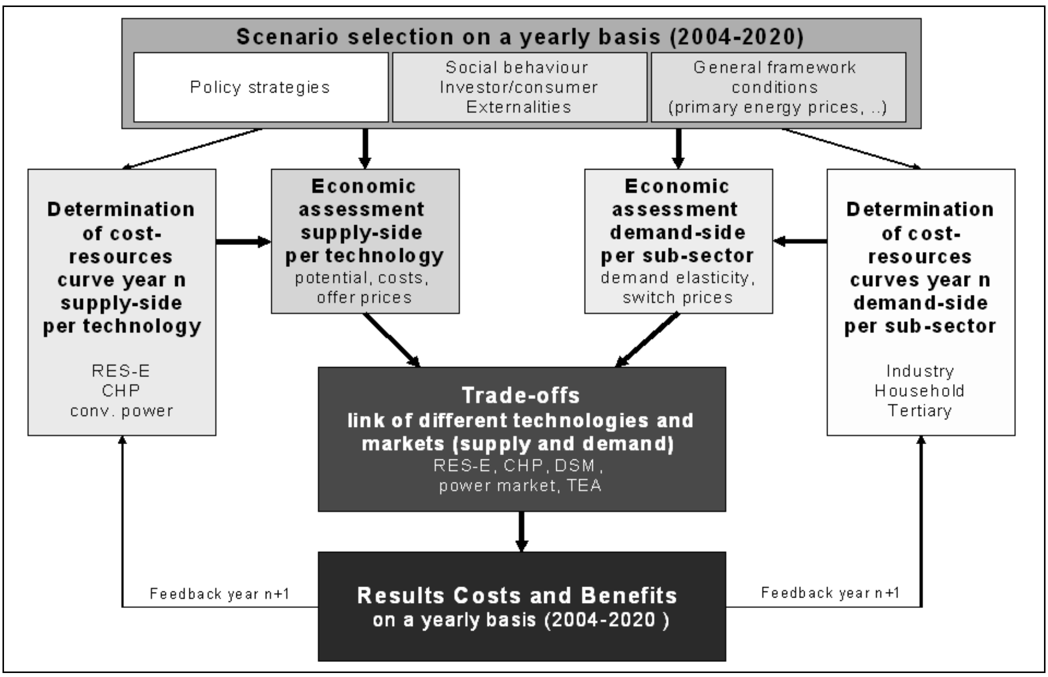

Figure 2: Overview on the least-cost modelling approach in Green*Net*

[3] The full version of Green*Net* covering the EU25+ region is available by the end of year 2006.

The general modelling approach in Green*Net* is to describe both RES-Electricity generation technologies (supply curve) and energy efficiency measures (demand curve) by deriving corresponding dynamic cost-resource curves. The costs as well as the potentials of these dynamic cost-resource curves can change year by year. These changes are given endogenously in the model depending on the outcome of the previous year (n-1) and the policy framework conditions set for the simulation year (n).

Figure 3 below describes the derivation of the dynamic cost-resource curve (supply-side) of a particular RES-E generation technology in detail. The static additional mid-term potential for the year 2020 of a particular RES-E generation technology (e.g. wind-onshore) is described by different bands being characterised by different potentials and long-run marginal generation costs for the integration into the existing electricity system (left-hand side in Figure 3). The different bands describe the economic conditions of different generation sites (e.g. in case of wind-onshore the annual full load hours, etc.). However, due to a variety of barriers and constraints (industrial, technical, market, administrative, societal) not the entire potential within a particular band can be utilized in one year. Therefore, the achievable potential of each year has to be determined (left-hand side in Figure 3).

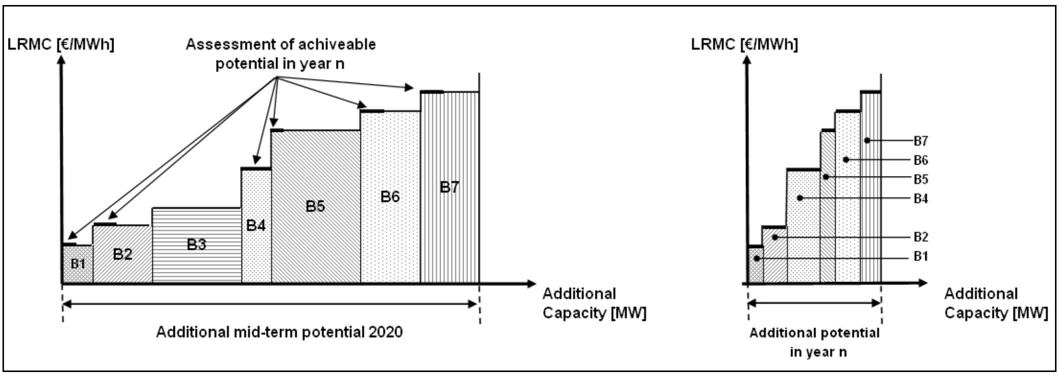

Figure 3: Cost-resource curve assessment of a particular RES-E generation technology: Additional mid-term potential in year 2020 (left hand side) and derivation of achievable potential in year n (right hand side)

The absolute level of the long-run marginal generation costs per band, furthermore, is given also endogenously in the Green*Net* model. This means in particular, that in case of technological learning the generation cost level per band decreases in year (n) depending on the already implemented potential per band in the previous year (n-1).

Based on the derivation of the dynamic cost-resource curves an economic assessment takes place in the Green*Net* model considering scenario specific settings like RES-E policy selection, socio-economic parameters (consumer/investor behaviour) as well as wholesale electricity price and demand forecasts. Wholesale electricity price projections on the conventional power market are implemented exogenously in Green*Net*. Different wholesale price scenarios (e.g. for different fuel prices, CO_2 certificate prices, etc.) are calculated based on the optimisation tool E2M2^s (having been developed together with Green*Net* in the same EC-project). A comprehensive model description of E2M2^s can be found in [18].[4]

Then, in the economic assessment additional costs for system operation (system capacity and system balancing),[5] grid connection and grid reinforcement are modelled and – in case of selection – allocated to the marginal generation costs of the corresponding RES-E technology. Figure 4 below shows the consideration of these additional cost elements in the supply curve of the Green*Net* model.

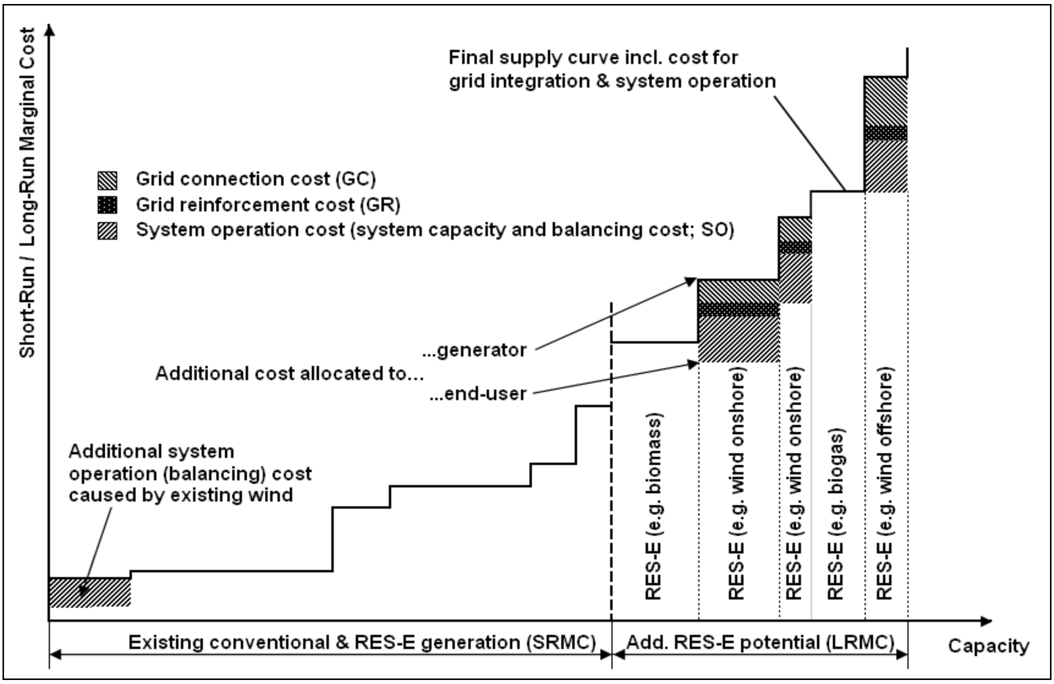

Figure 4: Implementation of the additional system operation costs (due to intermittent wind generation), grid connection costs and grid reinforcement costs in the supply curve of the Green*Net* model

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[4] The format of result presentation in E2M2^s is compatible with the Green*Net* model. An iterative approach is used in modelling the interactions between the conventional power market (E2M2^s) and RES-E generation (Green*Net*). In a first step, RES-E deployment up to 2020 is modelled based on Green*Net* assuming a wholesale electricity price forecast derived from an E2M2^s model run (using estimates on RES-E deployment from literature). In a second step, RES-E projections and the residual request for conventional power generation determined in Green*Net* are used as input parameters for a new E2M2^s model run. In a third step, an updated wholesale electricity price forecast again is used as an input for a new Green*Net* model run. This procedure is repeated iteratively until predefined deviations are acceptable (for details see [11]).

[5] The assessment of the system operation cost in the Green*Net* model is briefly described in the appendix. For a comprehensive description of the methodological approach and empirical data in this context, however, it is referred to [1], [2] and [12].

The overall economic assessment, finally, includes a transformation from generation and saving costs to bids, offers and switch prices.

Promotion instruments for RES-E technologies include the most important price-driven strategies (feed-in tariffs, tax incentives, investment subsidies, subsidies on fuel input) and demand-driven strategies (quota obligations based on tradable green certificates (including international trade), tendering schemes). In addition, electricity taxes and other direct promotion instruments supporting energy efficiency measures on the demand side can also be chosen and investigated. As Green*Net* is a dynamic simulation tool, the user can change RES-E policies and parameter settings within a simulation run on a yearly basis. Furthermore, several instruments can be set for each country individually.

The results are derived on a yearly basis by determining the equilibrium level of supply and demand within each market segment considered. For a comprehensive description of the Green*Net* modelling approach it is referred to [11]. Moreover, an even more detailed description of the derivation of the dynamic cost-resource curves as well as the comprehensive Green*Net* data base is conducted in [15].

3.2 Scenarios selection in Green*Net*

Several simulation runs in Green*Net* are based on the assumption that currently implemented RES-E policy instruments remain unchanged up to 2020 (Business as Usual (BAU) RES-E policy). Sensitivity analyses are conducted for different allocation policies on grid-related and system-related costs for RES-E grid integration.

In case of grid-related costs this means that – in the extreme scenarios – either the RES-E developer (“deep”) or the end-user (“shallow”) pay several additional costs of RES-E grid integration or both of them (“hybrid”) cover different cost elements. In the “hybrid” scenario – the default settings in Green*Net* – the RES-E developer e.g. covers grid connection costs and the end-user covers grid reinforcements/extension costs in the grid tariff, see also Figure 5.

Additional system operation costs – caused by intermittent wind generation – are usually allocated to balancing markets (in mature/advanced electricity markets) or to transmission system operators (in electricity markets being still in transition). Finally, the end-user has to cover these cost elements either in the energy price (the balancing market price is linked to the wholesale electricity market price and there exist interdependences between these two markets) or in the latter case in the grid tariff. Alternatively, the additional system operation costs can also be allocated to the RES-E developer.

An overview on the bandwidth of possible scenario settings in the simulation model Green*Net* is given in Figure 5.

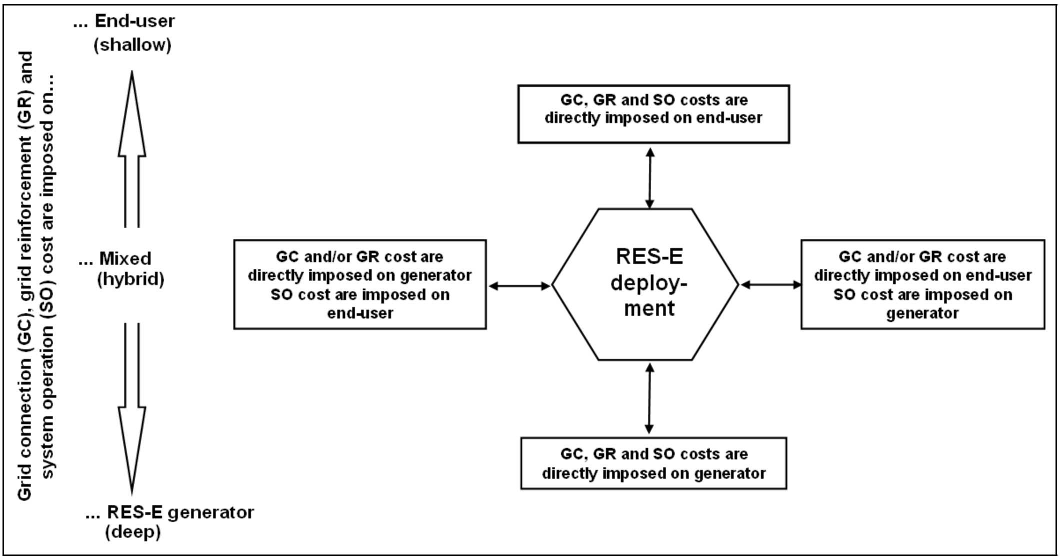

Figure 5: Overview on the bandwidth of possible scenario settings in the model Green*Net*

In the simulation software Green*Net* empirical data for grid-related and system-related costs are derived from a variety of country-specific case studies on RES-E grid integration. As far as grid infrastructure costs are concerned (grid connection, grid reinforcement/extension) corresponding specific costs are determined depending on the share of RES-E penetration in the system (high/average/low scenarios). For quantifying the additional system operation costs in the different European system configurations the so-called capacity credit of intermittent wind generation has to be estimated. Subsequently, the net effects and costs of increasing wind-related intermittency in the system on the residual power plant mix is determined. For a comprehensive description of the methodological approach and empirical data in this context, besides the appendix, it is referred to [1], [2] and [12].

3.3 Bandwidth of RES-E deployment for different grid integration cost allocation policies according to Green*Net*

Figure 6 below summarizes the bandwidth on RES-E deployment on aggregated EU15 Member States' level up to the year 2020 for different RES-E grid integration cost allocation policies (incl. variations of the capacity credit of wind generation and, subsequently, varying system operation costs) based on the simulation software Green*Net*. The Green*Net* modelling results clearly demonstrate that the "deep" RES-E grid integration cost approach significantly reduces deployment of installed RES-E capacities up to the year 2020 compared to the "shallow" or "hybrid" scenario.

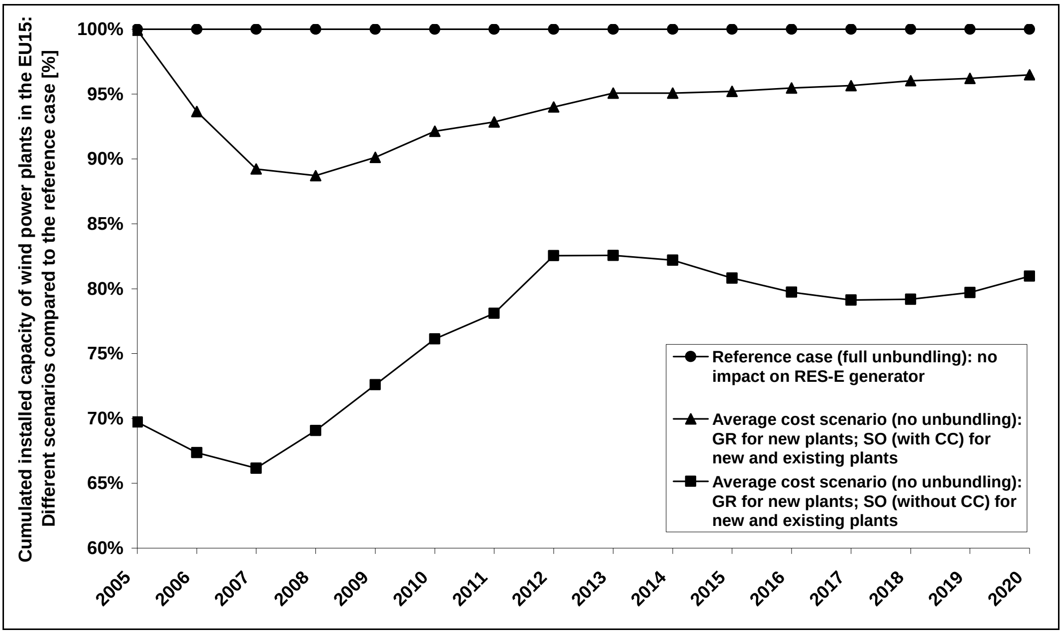

Figure 6: Impact of grid reinforcement/extension costs and system operation costs on cumulated installed RES-E capacities (no unbundling; "deep") compared to the fully unbundled case ("shallow") on EU15 Member States' level based on Green*Net*. Legend: GR=Grid reinforcement/extension, SO=System Operation, CC=Capacity Credit.

4 COUNTRY-SPECIFIC CASE STUDIES: GERMANY AND UK

In this section the impact of different cost allocation policies on future RES-E deployment is analysed in detail for the two EU Member States Germany and UK. These two countries are chosen against the background of the implementation of two fundamental different RES-E promotion schemes. While in Germany RES-E generation technologies are supported by feed-in tariffs (price-driven instrument) in UK a tradable green certificate system is implemented (quota/demand-driven instrument). In the following, the particular design of these two RES-E promotion instruments is briefly summarized.

4.1 Design of RES-E promotion schemes in Germany and UK

4.1.1 Germany

In Germany grid integration of RES-E generation technologies is supported by “Feed-in Tariffs (FITs)”. FITs are defined in the Renewable Energy Sources Act, REA (“Erneuerbaren-Energie-Gesetz”; [6]). For wind-onshore as well as wind-offshore a stepped FIT is foreseen; i.e. the absolute level of the tariff depends – among other parameters like distance to shore and water depth – on the quality of the particular site. Furthermore, starting in year 1 with the fixed absolute FIT level according to REA the FITs are reduced by 2% annually for wind-onshore and wind-offshore, see Table 1. For remaining RES-E generation technologies similar stepped FITs are defined in Germany.

Table 1: Feed-in-tariffs for wind-onshore and wind-offshore in Germany according to the actual version of the Renewable Energy Act (REA)

Feed-in Tariff	Guaranteed duration	Remarks
Wind-Onshore	20 years	<u>Stepped FIT:</u> 87 €/MWh for the first 5 years; then between 55 and 87 €/MWh depending on the quality of site. FITs are reduced by 2% annually; no adjustment for inflation.
Wind-Offshore	20 years	<u>Stepped FIT:</u> 91 €/MWh for the first 12 years; then between 61.9 and 91 €/MWh depending on the distance to the shoreline and water depth. FITs are reduced by 2% annually starting in 2008; no adjustment for inflation.

4.1.2 United Kingdom (UK)

In the UK, electricity suppliers have to meet the commitments of “The Renewables Obligation Order” (RO; [14]) by tradable green certificates, the so-called “Renewables Obligation Certificates (ROCs)”. Thereby, each ROC represents 1 MWh of electricity generated by an eligible RES-E generation technology. For the period 2005/2006 the quota for the ROCs was set at 5.5% of each supplier’s total delivered electricity. The quota obligation is adjusted on a yearly basis. It will increase up to 10.4% in 2010/2011.

The electricity supplier in UK finally has the following three options to meet the RO commitments:

(i) to physically purchase electricity from eligible RES-E generators and to pay the corresponding price for ROCs;

(ii) to buy ROCs from other electricity suppliers or from the Non-Fossil Purchasing Agency (NFPA) putting periodically ROCs on auction;

(iii) to pay the penalty (so-called “Buy-Out Price”) set by the regulator (OFGEM) for non-compliance of the quota.[6]

If a tradable green certificate market works effectively, the price of a certificate reflects the difference between the wholesale electricity market price and the generation costs of new RES-E generation capacities. The “value” of a certificate, thus, represents the additional costs of generating RES-E electricity compared to conventional generation technologies.

4.2 Results on RES-E deployment in Germany and UK based on Green*Net*

In the following sections the results on RES-E deployment (i.e. annual installed capacities; annual electricity generation) in Germany and UK are discussed up to the year 2020 for different cost allocation policies of disaggregated RES-E grid integration costs. The following default settings are used in the simulation software tool Green*Net*:

- Exogenous wholesale electricity market prices according to the E2M2^s-BAU-scenario (details see footnote 4).
- RES-E promotion instruments in Germany and UK according to currently implemented national legislation (detailed description see in the previous section).
- For grid reinforcement/extension costs (GR) as well as system operation costs (SO) an average cost scenario is selected.
- Furthermore, system operation costs (SO) are determined considering average values for the capacity credit of wind generation.
- Finally, grid connection costs (GC) are assumed to be 5% of the total investment costs of wind-onshore and 10-25% of wind-offshore (depending on the distance to shore and water depth). For remaining RES-E generation technologies – mainly connected on distribution grid level – grid connection costs are neglected.

4.2.1 Germany

In Germany the allocation policy of additional grid-related and system-related costs has a considerable impact on the future deployment of both wind-onshore and wind-offshore (see Figure 7).

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[6] Several penalty payments – representing the shortfall between the obliged and actual presented ROCs of the electricity supplier – are collected in a central fund. This fund is re-distributed to electricity suppliers having met the obligation (in relation to the number of ROCs each electricity supplier has presented).

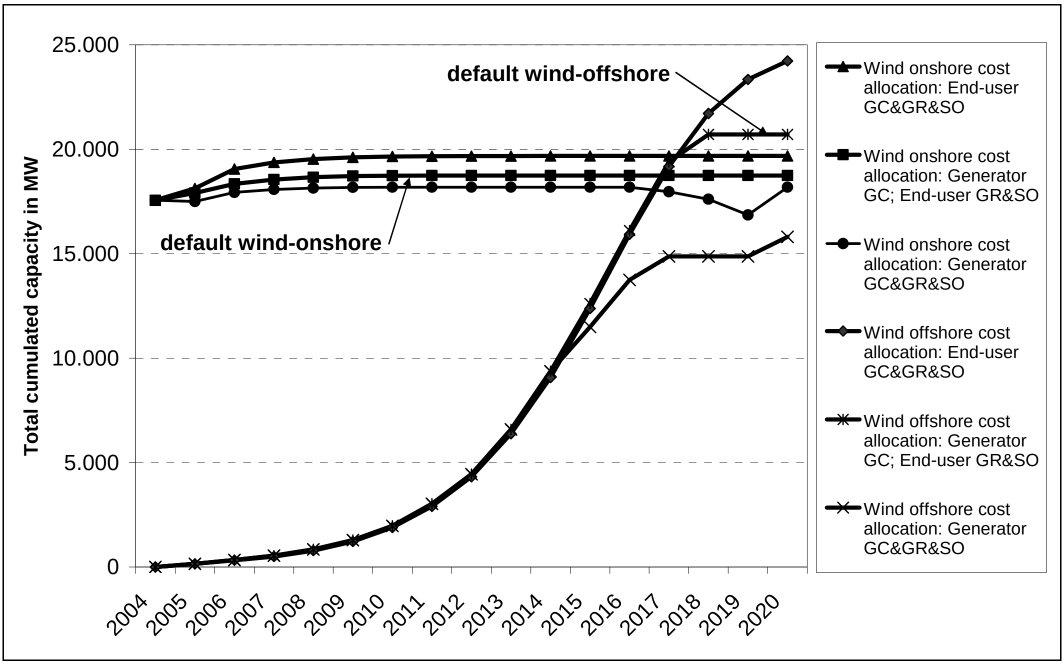

Figure 7: Germany: Development of total cumulated capacity of wind-onshore and wind-offshore for different grid integration cost allocation scenarios up to 2020. Source: Green*Net* model runs. Legend: GC…grid connection, GR…grid reinforcement/extension, SO…system operation.

While for wind-onshore deviations from the default integration cost allocation scenario ("hybrid") can be observed already in the first years of the simulation period, for wind-offshore different integration cost allocation policies don't influence offshore-wind deployment before 2015. In detail, the following results are derived for wind-onshore and wind-offshore in Figure 7:

- For wind-onshore the cumulated installed capacity increases from 17,560 MW in 2004 to 18,750 MW in 2020 in the "hybrid" integration cost allocation scenario (being currently implemented in Germany according to REA). The "shallow" integration cost allocation scenario (i.e. full unbundling; grid connection costs are socialised in the grid tariffs) results in an additional installed wind-onshore capacity of 1,000 MW in 2020. In the "deep" integration cost allocation scenario finally 550 MW less installed wind-onshore capacity occurs in 2020 compared to the "hybrid" settings. The major reason for saturation of total cumulated wind-onshore capacities beyond 2010 is upcoming re-powering of already existing onshore-wind farms. In Figure 8 below re-powering of onshore-wind in Germany is analysed in detail.
- On contrary to wind-onshore, wind-offshore still is a pre-mature RES-E generation technology and, therefore, mainly non-financial barriers (beyond the design of the particular feed-in tariff) have a significant impact on its development. A

few selected examples of non-financial obstacles are e.g. administrative and legislative uncertainties (i.e. unclear responsibilities for offshore grid connection), market barriers (i.e. supply shortfalls in wind turbine manufacturing due to repowering of onshore-wind), social acceptance problems, etc.). These non-financial barriers are implemented in the Green*Net* model using the S-curve approach of market integration of new technologies (corresponding parameters can be set between 0-100%). Therefore, wind-offshore deployment mainly follows the S-Curve approach in several integration cost allocation settings of Green*Net* up to 2015. Starting with 2015, however, the different settings begin to tail-off. In 2020 finally the cumulated wind-offshore capacity in Germany varies considerable for the three different integration cost allocation scenarios: 20,700 MW ("hybrid"), 24,200 MW ("shallow"), 15,800 MW ("deep").

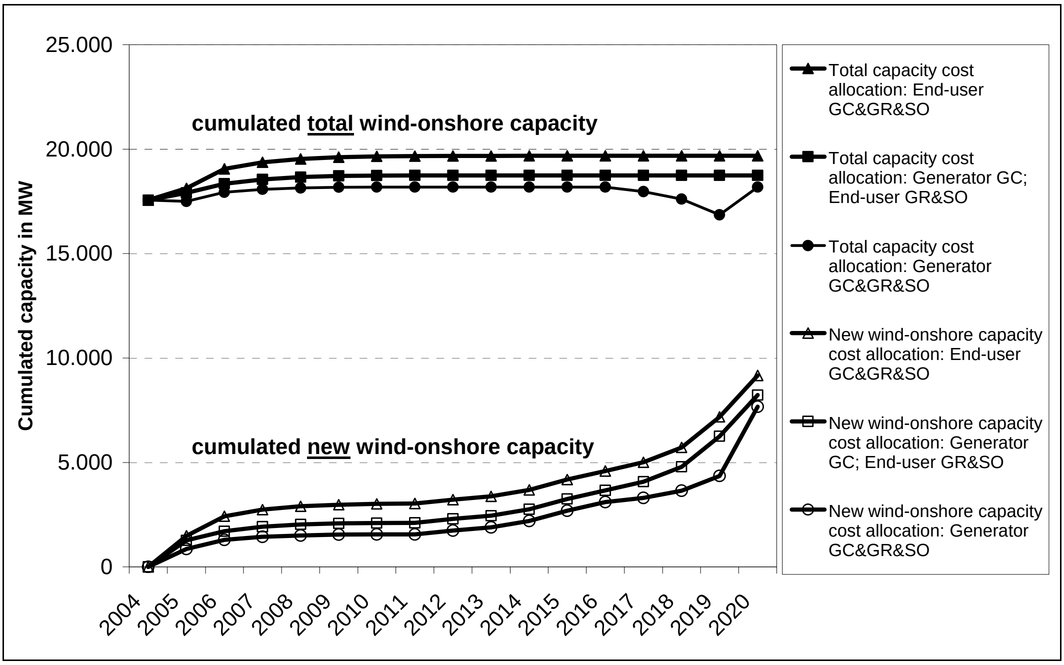

Figure 8: Germany: Development of cumulated total capacity of wind-onshore versus cumulated new capacity of wind-onshore for different grid integration cost allocation scenarios up to 2020. Source: Green*Net* model runs. Legend: GC…grid connection, GR…grid reinforcement/extension, SO…system operation.

For RES-E policy makers the major question is how to adjust the existing FITs for wind-onshore and wind-offshore in the "shallow" cost allocation scenario (full unbundling; corresponding grid connection costs are socialised in the grid tariffs) to reach the same wind penetration up to the year 2020 like in the default case ("hybrid"). The necessary adjustment is determined based on iterative Green*Net* simulation runs. In Germany, for wind-onshore the FIT has to be reduced by 3%, for wind-offshore around 16% are expected.

In Figure 9 finally the deviation of entire German RES-E generation portfolio from new RES-E power plants (installed between 2004 and 2020) in the extreme grid integration cost allocation scenarios ("shallow", "deep") is compared with the reference case ("hybrid") in the year 2020. Whereas there is a considerable impact on generation of wind-onshore and wind-offshore, remaining RES-E generation technologies are not affected. This is due to the fact that a FIT like in Germany is a technology-driven supporting mechanism addressing each RES-E generation technology separately. According to Figure 9 in the "shallow" grid integration cost approach annual generation rises by 10% and 17% for wind-onshore and wind-offshore respectively. In the "deep" grid integration cost approach corresponding annual generation declines with 7% and 24% compared to the reference case ("hybrid").

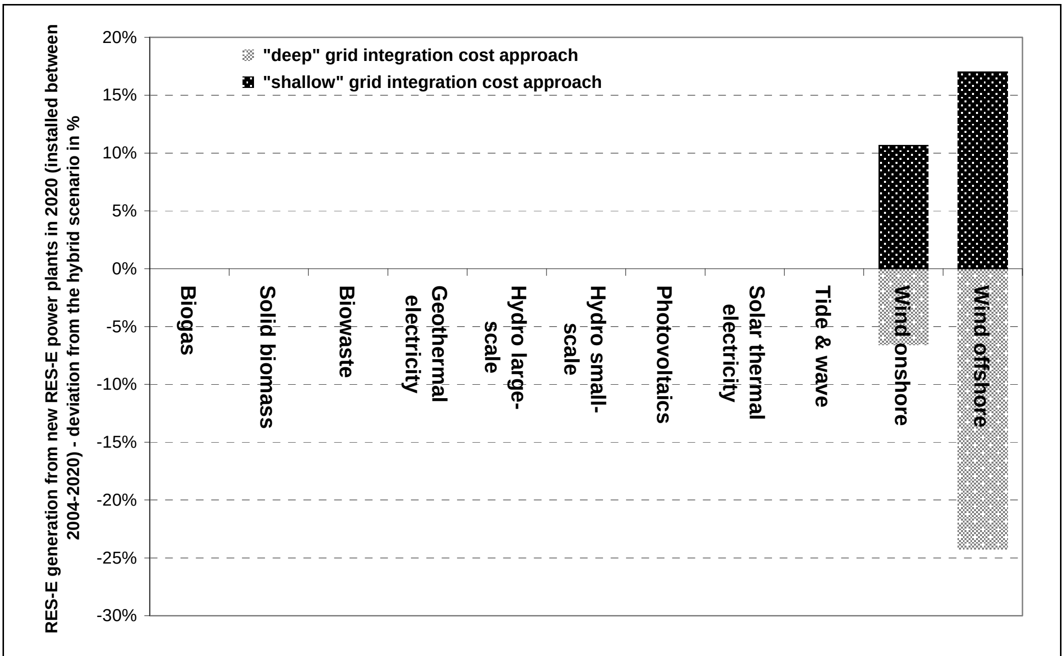

Figure 9: Germany: Deviation of RES-E generation from new RES-E power plants in 2020 (installed between 2004 and 2020) in the extreme grid integration cost allocation schemes ("shallow": full unbundling; "deep": no unbundling) compared to the reference case ("hybrid": partial unbundling). Source: Green*Net* model runs.

4.2.2 United Kingdom

On contrary to the German FIT system, in the UK's ROCs scheme a single RES-E generation technology can't be influenced ex-ante. This is due to the fact that the entire RES-

E generation technology portfolio is addressed simultaneously to meet a particular quota. Moreover, changes in the grid integration cost allocation scheme result in an endogenous redistribution of the entire RES-E generation technology portfolio within the quota. Figure 10 indicates the deviation of the entire RES-E generation technology portfolio from new RES-E power plants (installed between 2004 and 2020) in the extreme grid integration cost allocation scenarios ("shallow", "deep") compared to the reference case ("hybrid") for the UK case in the year 2020:

- The "shallow" integration scenario doesn't show any changes in the RES-E generation technology portfolio in 2020 compared to the default settings ("hybrid"). This indicates that the gap between the long-run marginal generation costs of the different RES-E technologies is higher than the corresponding grid connection components. Therefore, a particular RES-E generation technology is not displaced by a competing one in this scenario.
- In the "deep" integration scenario wind-offshore generation is 17% less in 2020 compared to the default settings ("hybrid") while generation from biogas, tide/wave as well as wind-onshore is significantly higher in relative terms. In this scenario wind-offshore becomes the RES-E generation technology determining the certificate price of the ROCs.

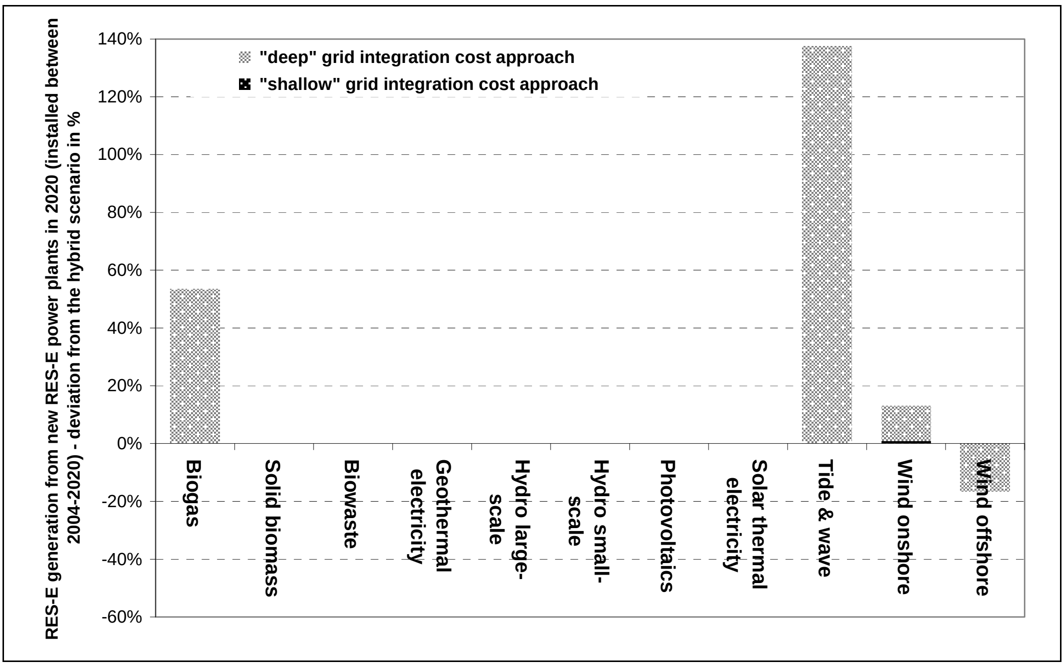

Figure 10: United Kingdom: Deviation of RES-E generation from new RES-E power plants in 2020 (installed between 2004 and 2020) in the extreme grid integration cost allocation schemes ("shallow": full unbundling; "deep": no unbundling) compared to the reference case ("hybrid": partial unbundling). Source: Green*Net* model runs.

Finally, an interesting parameter to be studied is the corresponding certificate price of the ROCs for the different grid integration cost allocation policies in UK, see Figure 11. Until 2012 the certificate price equals the penalty (setting in Green*Net*: 43.6 €/MWh)[7] in several cases. This indicates that the RES-E quota is not fulfilled in the corresponding period. In the following period up to 2020 the ROCs price decreases towards zero in the “shallow” (full unbundling) and “hybrid” (partial unbundling) integration scenarios indicating that the RES-E quota easily can be met. In the “deep” (no unbundling) integration scenario – where the RES-E generator has to cover several grid integration cost – the ROCs price naturally remains at a higher price level.

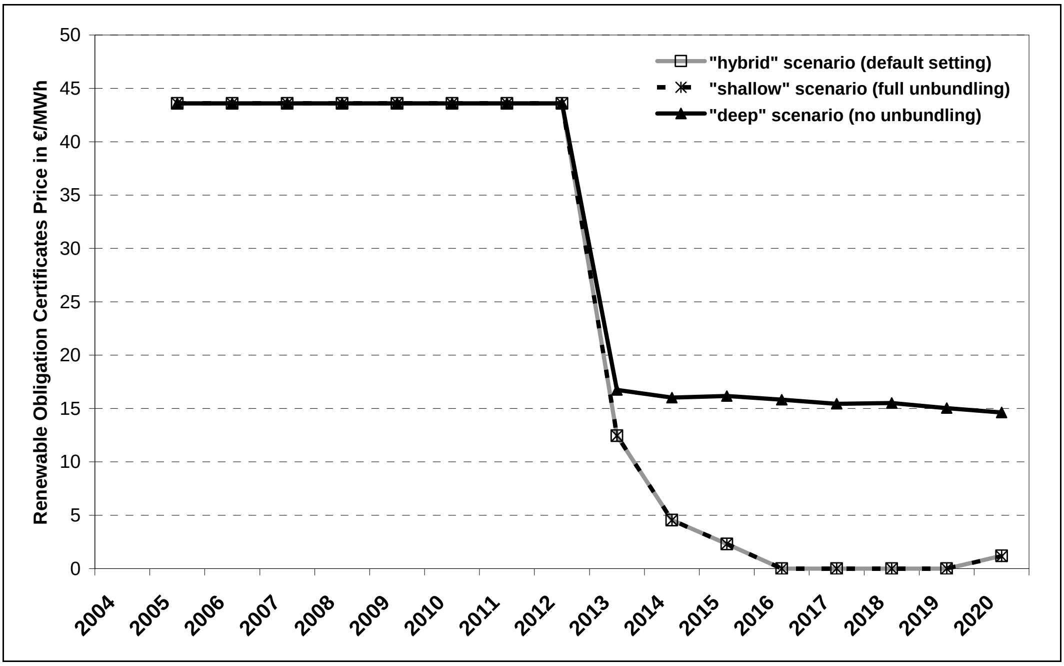

Figure 11: United Kingdom: Development of the certificate price of the ROCs up to 2020 for different RES-E grid integration cost allocation scenarios (“deep”, “shallow”, “hybrid”). Source: Green*Net* model runs.

5 CONCLUSIONS

The modelling results derived from the simulation software Green*Net* clearly demonstrate that the degree of unbundling and the cost allocation policies of different disaggregated RES-E grid integration costs significantly influence RES-E deployment both on national as well as European level.

[7] In recent years the penalty in UK (“Buy-Out Price”) has been £30 per MWh.

Moreover, for large-scale RES-E grid integration a clear definition of the demarcation lines between the RES-E power plant itself, the grid infrastructure and overall system operation is supposed to be indispensable. In the past, not least due to small amounts of RES-E generation the share of additional grid-related and system-related costs has been small compared to the long-run marginal generation costs of the different RES-E power plants. Therefore, these additional costs have not been clarified in detail, but often treated as part of the long-run marginal RES-E generation costs and, subsequently, were allocated to the corresponding RES-E promotion instruments.

But this practise will increasingly cause problems with increasing shares of (intermittent) RES-E generation in the different European electricity systems:

- On the one hand, it is obvious that in almost all EU Member States the legal status quo still violates the basic unbundling principles of the corresponding EC Directives as well as economic theory of capital-intensive network industries in general.
- On the other hand, best-practise cases on RES-E grid connection (e.g. wind-offshore connection) in countries like Denmark increasingly define the future benchmarks on least-cost RES-E grid integration.

As a consequence of still existing lacks on allocation and reimbursement of grid-related and system-related costs of RES-E grid integration in the EU Member States (RES-E promotion instruments versus grid tariffs versus balancing/wholesale electricity markets) it is recommended to establish a strategic EU-wide policy discussion on unbundling in this context. Moreover, the analyses throughout the paper clearly prove evidence that serious unbundling and correct cost allocation of RES-E related grid integration costs only guarantee fulfilment of the ambitious EC goals with minimal costs for society.

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APPENDIX

A.1 Quantifying additional system balancing cost caused by intermittent wind generation in the Green*Net* model

In the short term, when determining the extra system balancing requirements – and corresponding cost – caused by intermittent wind generation in a system the additional deviation compared to a system without wind has to be identified. Recent publications mainly quantify the corresponding additional balancing cost allocated to intermittent wind generation in the UK, Denmark, Germany and also parts of the U.S. In the Green*Net* model the synthesis of these country-specific results is implemented based on a concave function, determining the additional wind-related net balancing cost depending on wind penetration in the system. The concave function indicates saturation between 3-4 €/MWh_{Wind} for high wind penetrations in a system). For further details in this context it is referred to [1], [2] and [12].

A.2 Quantifying additional system capacity cost caused by intermittent wind generation in the Green*Net* model

Long-term system capacity analyses estimate the capacity contribution of intermittent wind generation on system level. Although wind generation throughout a national network makes some contribution to assured capacity, this contribution is significantly less than that for equivalent conventional generation or non-intermittent RES-E generation. The relevant parameter in estimating the system capacity requirement caused by intermittent wind generation is the capacity credit (a comprehensive survey on country-studies in this context can be found in [2]). This capacity credit is equal to the average capacity factor at low wind penetrations but decreases with increasing wind penetration in a system. Therefore, the amount of capacity of conventional generation has to be determined that can be displaced by intermittent wind generation while maintaining the same degree of system security. After the determination of the capacity credit, subsequently, in the Green*Net* model the calculation of the additional system capacity cost caused by intermittent wind generation is based on the so-called 'thermal equivalent approach' (published in [12]). The 'thermal equivalent approach' works as follows: The annual wind generation is calculated from the installed capacity in megawatts and the annual full load hours. Then the equivalent amount of conventional capacity required to produce the same annual amount of electricity is determined, assuming a CCGT (combined cycle gas turbine) at an average load factor. However, conventional capacity can be viewed as delivering two services, energy and capacity. Assuming, first, that wind provides no contribution to capacity margin, then to be equivalent to conventional generation wind would require back-up from equivalent conventional capacity. This capacity could come from a number of sources, including old conventional and pumped-hydro generation, new CCGTs or new open cycle gas turbines (OCGTs). For the cost calculation the capacity requirements are allocated to new but not leading-edge OCGTs, suitable for peaking operation, based on the consideration that at the margin only OCGTs will be used as any economically feasible existing generation would already be utilised on the system. The annualised capital costs are finally determined depending on annual wind generation. In the second case, if it is considered that wind does contribute to system security, albeit at a smaller rate than conventional capacity, the above capacity requirement is reduced by the level of that contribution. Again, the annualised capacity costs are then derived depending on annual wind generation. For further details in this context it is referred to [12].