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Modelling Least-Cost RES-E Grid Integration under different Regulatory Conditions based on the Simulation Software Green*Net*

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1 INTRODUCTION

The core objective of the project **GreenNet-EU27** is to derive least cost strategies for RES-E grid integration into the European electricity grids. Further important objectives are the dissemination of the project results and practical guidelines to a broad audience, especially to key stakeholders as there are decision makers, regulators, grid companies and RES-E generators. Besides a variety of other dissemination channels the project website www.greennet-europe.org is a core dissemination tool of the project **GreenNet-EU27**.

This report mainly summarizes and compares results of least cost RES-E grid integration scenarios based on the software tool **GreenNet**.

Special emphasis is given to the effect of different cost allocation practices on RES-E deployment in general and wind power deployment in special. Further, interactions among RES-E technologies are investigated and discussed against the background of currently implemented support schemes for RES-E in Europe. Sensitivity analyses reflect the bandwidth of grid and system related cost in EU-25 Member States.

Results on Energy Efficiency (EE) scenarios conclude this report. Therefore special attention is paid to the interaction between demand and supply side.

The report is organized as follows:

In **chapter 2** the implementation of grid and system related cost of RES-E integration within the formal framework of the software tool is described in detail. Further relevant cost elements are identified and definitions are provided in other to avoid misinterpretations. Approaches for modeling different cost elements are described in detail and underlying empirical data is summarized.

Chapter 3 summarizes results of RES-E grid integration scenarios and selected EE cases. A scenario definition gives an overview on investigated cases. Further general assumptions with respect to main input data are provided. Results mainly focus on effects of different cost allocation strategies on RES-E deployment and interactions among RES-E technologies investigated. For EE scenarios energy savings on EU-25 and country level are investigated and interactions with the supply side are shown.

In **chapter 4** conclusions are drawn and an outlook for the future development of the simulation software **GreenNet** is given.

The **appendix** contains selected results for Switzerland and Norway as well as the Candidate Countries Bulgaria, Croatia and Romania.

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2 METHODOLOGY FOR THE MODEL IMPLEMENTATION OF RES-E INTEGRATION COST IN GREENNET

The analytical framework used for the simulation software **Green*Net*** has been modified within the project **Green*Net*-EU27** with respect to the implementation of grid and system related cost due to RES-E integration. This chapter gives an overview on the methodologies applied and includes a definition of terms and system bounds. Further, the major sources of empirical data used are listed in the corresponding sub-chapters.

When taking into account grid- and system-related aspects of RES-E integration the following two major categories have to be discussed and analyzed in detail:

- Grid Infrastructure (connection of RES-E generation technologies to the existing grid, reinforcement of the existing grid due to RES-E integration)
- Power system operation (contribution of intermittent RES-E generation to system capacity, effects of intermittent RES-E generation on the operation of the power system)

Within the analytical framework of the software tool **Green*Net*** the cost elements are – in case of selection and allocation to the RES-E generator – added as follows:

- Cost for grid connection, grid reinforcement and system capacity are added to the long-run marginal cost of RES-E generation only and therefore influence the investment decision for new capacity.
- Balancing costs of intermittent RES-E generation are added to the long-run as well as short-run marginal cost. This cost component thereby influences the investment decision and – theoretically – the decision whether or not to run the generation unit (as short-run marginal cost of wind power are comparable low this might not effect the operation in practice).

The basic principle of the allocation of grid and system related cost due to RES-E generation in the supply curve is shown in Figure 2.1 below.

RES-E generation having no intermittent nature as well as conventional generation is modeled without any additional system operation requirements and cost.

In the existing version of the software tool **Green*Net*** cost for grid connection and grid reinforcement are taken into account for wind power only. For several other RES-E technologies the cost for grid connection are implemented as a part of the investment cost (and are therefore always allocated to the RES-E generator according to the current practice) and cost for reinforcement are neglected.

As the results of the case studies on RES-E grid integration carried out in WP 5 show, cost for grid connection are in the range of up to 3 % for technologies for which sites are not constraint by the primary energy source (e.g. biomass) and therefore the allocation practice has only minor effect the investment decision.

However there are RES-E technologies besides wind power (e.g. small hydro, tidal and wave energy) that have considerable cost for grid connection and that may necessitate reinforcements of the existing grid in the future. The implementation of a separate cost allocation for grid-related cost for these technologies is planned within future research projects.

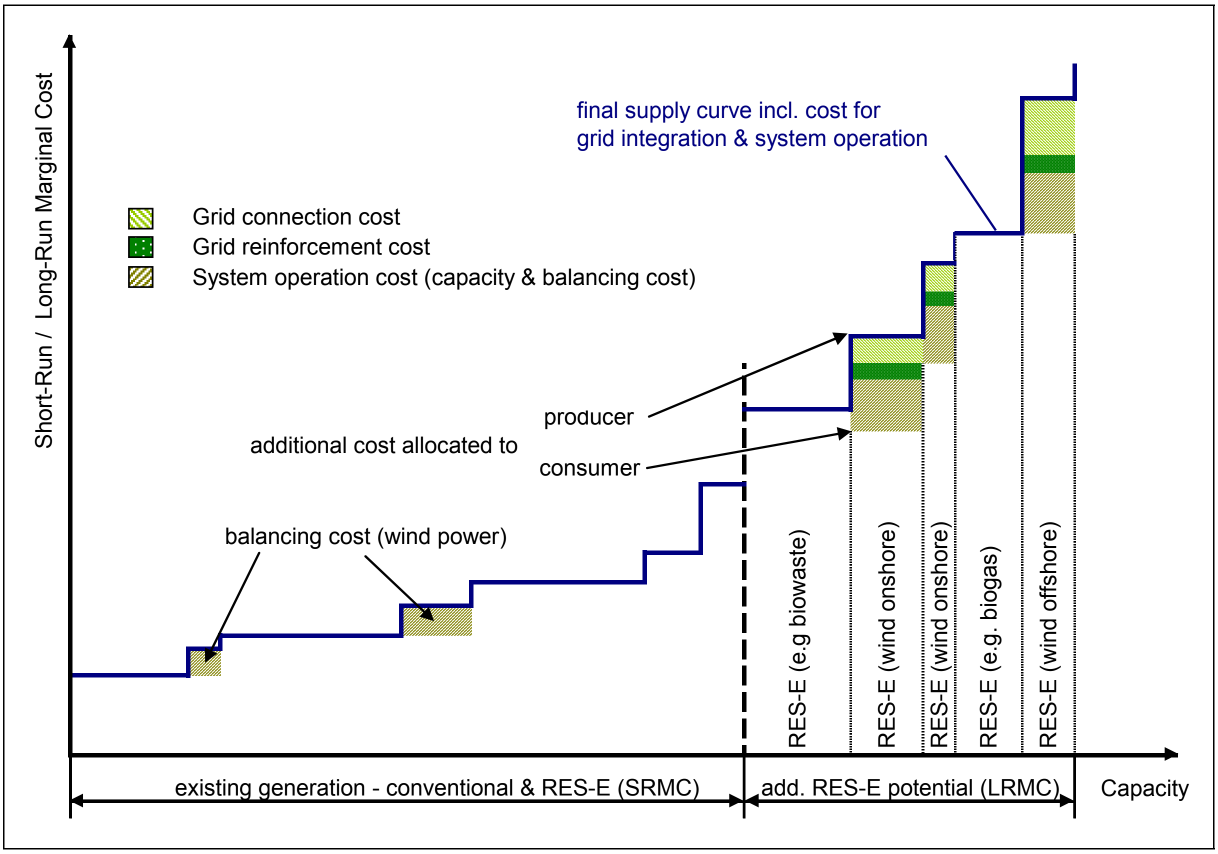

Figure 2.1. Implementation of the additional system operation costs (due to intermittent RES-E generation) as well as corresponding grid connection and reinforcement costs in the formal framework of the simulation software **Green*Net***

2.1 Grid infrastructure costs

In general the integration of any power generation technology into the existing power grid is connected with investments in grid infrastructure. This is also the case for the grid integration of RES-E power plants. In this context two different aspects have to be considered:

i) The connection of RES-E power plants to the existing power grid – the corresponding investments are indicated as **grid connection costs (GC)**.

ii) Reinforcements of the existing power grid due to RES-E grid integration – the corresponding investments are indicated as **grid reinforcement costs (GR)**.

As already mentioned in the current version of the software tool **Green*Net*** these investments are considered separately for wind power only, for several other conventional as well as RES-E power generation technologies grid connection cost are treated as a part of the overall investments and grid reinforcement cost are neglected.

In order to avoid any misinterpretation of the results presented in this report a detailed definition of terms and system bounds used within the project **Green*Net*-EU27** is given in the following chapter.

2.1.1 Grid connection costs

The term *grid connection* indicates the physical connection of a RES-E power plant or a number of RES-E power plants (e.g. a wind farm) to the nearest connection point of the existing grid being technically and economically feasible i.e. the so called external grid. **It does not comprise the so called internal grid** connecting e.g. the turbines of a wind farm with the common connection point of the site.

The grid connection usually comprises the power line/cable connecting the common connection point of the site with the connection point of the existing grid (in general the substation) as well as modifications and extensions of the corresponding substation.

For offshore wind farms the connection point of the existing grid in any case is located onshore independent of the underlying connection concept. I.e. even if the high voltage power grid is extended to the sea in the sense of a coordinated (and least cost) grid connection of offshore wind farms, the grid connection comprises even this high voltage power line. Figure 2.2 illustrates the system bounds used in **Green*Net*-EU27** for both connection concepts – the individual connection of single wind farms to the existing onshore power grid and the coordinated connection of a number of wind farms located in a certain area.

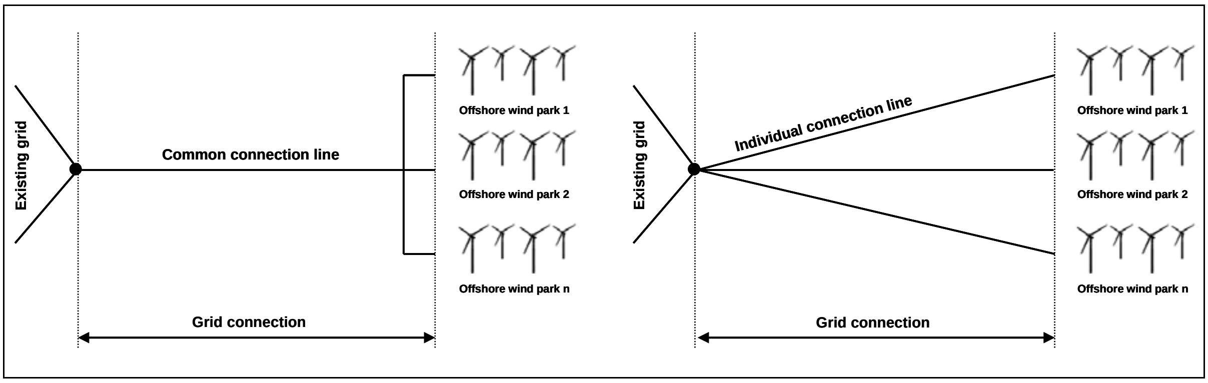

Figure 2.2. Illustration of the term grid connection as used in **Green*Net*-EU27** for the case of an individual connection of offshore wind farms to the existing onshore power grid (right) and coordinated connection of offshore wind farms via a common link (left)

The term *grid connection costs* indicates several costs for connecting a RES-E power plant or a number of RES-E power plants (e.g. a wind farm) to the existing grid (i.e. the cost of the external grid).

In general, grid connection costs of RES-E generation technologies are determined by a variety of factors. Most important once are:

- the distance of the RES-E plant to the point of common coupling to the grid;
- the possibility to apply standardized equipment (for substations, cables, etc.)
- the necessity to extend the local grid and/or to switch to a higher voltage level.

In the past, grid connection costs have been comprehensively discussed for wind energy. But, also for traditional RES-E technologies – such as small hydropower – grid connection often appears to be a significant barrier. In general, grid connection is an important economic constraint for those RES-E generation technologies being mainly determined by the local availability of resources. Therefore, often a compromise between best sites and proper grid conditions appears. On contrary, for biomass grid connection – in general – is no crucial barrier as the particular location of the plant is even more independent from resource conditions.

The costs for connection to the electrical grid range from almost 0% for a small wind farm connected to an adjacent medium voltage line and upwards. For a 150 MW offshore wind farm figures up to 25% of overall investment costs of the wind farm have been published for these items. Especially for offshore wind grid connection costs to a large extent depend on the (offshore) distance to the connection point to the existing grid. A recent comparison between onshore and offshore wind farms undertaken by Junginger (2003) indicates for both internal and external grid connection a cost range (share of total investment costs) from 15 to 30% for offshore wind and 10 to 15% for onshore wind.

Model implementation

In practice grid connection costs are – independent of the power generation technology – considered as part of the total investments and are therefore paid by the RES-E generator. An alternative way might be the allocation of grid connection cost to the grid operator in order to minimize barriers for the grid access of (new) generators. Therefore **the software tool Green*Net* simulates both cases – the allocation of grid connection cost to the RES-E generator and to the grid operator**. In the latter case the grid operator socializes cost, i.e. the end user finally pays for grid connection in form of a higher grid tariff.

So far in **Green*Net*** a separate allocation of grid connection cost is implemented for wind power only. However it is planned to extend this approach to other RES-E technologies for which the grid connection issue is of relevance like for small hydro, wave and tidal energy within future research projects.

Costs for connecting wind power are implemented in the **Green*Net*** model based on empirical data collected and compared within WP5 of this project:

- for wind onshore grid connection cost are assumed to be 8 % of specific investment cost for all bands
- for wind offshore bands with similar distances to shore are clustered and allocated to four different cost levels ranging from 10 to 25 % of the corresponding total specific investment cost

For both wind on- and offshore a depreciation period of 15 years and an interest rate of 6.5 % are applied.

2.1.2 Modeling grid reinforcement cost

The term *grid reinforcement* indicates several reinforcements of the existing transmission grids necessary to integrate RES-E power plants into the power grid. Reinforcements of the distribution grid are for now not taken into account in **Green*Net*** as empirical data is very rare. Whilst reinforcements of the distribution grids usually can be clearly allocated to the originator, reinforcements of the transmission grid may on the one hand become necessary for a number reasons (increased power trade, modification of spatial distribution of power demand and/or supply) and on the other hand imply advantages for a number of players in the power market (traders, consumers, utilities, RES-E generators, etc.). This makes it difficult to allocate reinforcement measures in the transmission grid to a certain power generation technology (e.g. wind power or even nuclear power).

Grid reinforcement measures include the upgrade of existing power lines and/or the installation of additional power lines both resulting in an increased resulting capacity.

The term *grid reinforcement cost* indicates several costs for reinforcements of the existing transmission power grids that can be allocated to RES-E grid integration, i.e. **only part of investments for reinforcements of the transmission grid are allocated to the specific RES-E generation technology** for reasons mentioned above. The methodology used for modeling these cost is described in detail in the following sections.

Empirical data

Within the last years several studies were carried out addressing needs for grid reinforcements due to the grid integration of wind power. To derive comparable numbers for reinforcement cost based the empirical data available cost were derived according to a common methodology described in the following:

- On the one hand specific cost data, determined in country specific studies as seen in Table 2.1 are used to assess grid related reinforcement expenditures,
- on the other hand reinforcement cost are calculated resting upon common prices for transmission or distribution lines (€/km) and furthermore
- different scenarios of wind deployment are taken into account resulting in several shares of wind generation (related to the total generation).

To achieve a uniform calculation methodology an interest rate of 7.5% and a depreciation time of 40 years were taken for granted for all specific studies. In case that there is no data on average full-load hours for wind power generation given in literature 2000 and 4000 h/yr are assumed for wind onshore and offshore respectively. Currency conversions, if necessary, were carried out using the average exchange rate in the specific year of study release.

As already indicated above only part of the reinforcement cost for the transmission grid are taken into account as the fed in wind power generation on average only requires part of the additional power line capacity. Hence there are other market players profiting from additional transmission capacity too. The additional capacity remaining for other market actors is depending on the wind power production as well as on the distribution of generation and loads for each moment and therefore changing over time which makes it difficult to define a share of “non-utilized” capacity that may be allocated to other market players.

Finally the capacity factor of wind power was found to be a suitable measure indicating the utilization of the grid[1]. This simplification allows to define the reinforcement cost of wind power as

$$C_{GR,\,Wind} = CF_{Wind} * C_{GR,\,total}$$

[1] Please note that this approach tends to overestimate grid reinforcement cost of a certain technology as it implies the assumption that the fed-in power utilizes the reinforced line(s) only, which is usually not the case for an intermeshed transmission grid.

where

$C_{GR,\ Wind}$ ……......... Cost of grid reinforcement allocated due to wind power

CF_{Wind} …………… Capacity factor of wind power

$C_{GR,\ total}$ …………... Total cost of grid reinforcement

The application of the method described above on the empirical data available leads to the resulting numbers given in the table below. The corresponding graph shows that there is a correlation between reinforcement costs for the transmission grid and the wind power penetration. Further it can be seen, that numbers are varying in a relatively wide range due to varying structural conditions in the different countries investigated.

Table 2.1. Overview on empirical data on costs for reinforcements of the transmission grid due to integration of wind power.

Grid Extension Cost - Empirical Data based on Country Studies		
Wind generation (Share in % of total)	**Reinforcement Cost €/MWh**	**References**
1,5% 2,6%	0,27 0,29	*van Roy et al. (2003)*
4,5%	0,52	*Verseille (2003)*
6,2% 9,4% 12,1%	0,11 0,24 0,29	*DENA (2005)*
4,8% 7,2%	0,18 0,36	*Janiczek et al. (2003)*
19,1%	0,56	*t´Hooft (2003)*
14,9% 23,6%	1,42 1,63	*ILEX / UMIST (2002)*
6,4% 7,0%	0,68 0,68	*DETI / NIE (2003)*

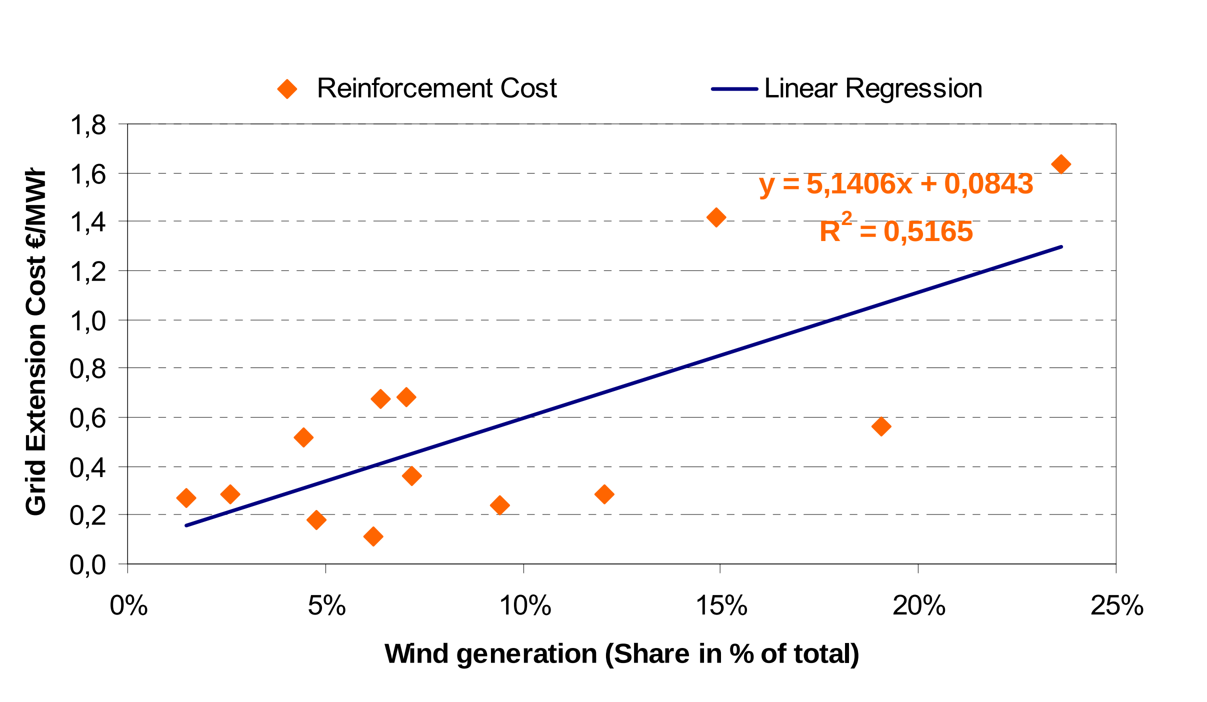

Figure 2.3. Cost for reinforcements of the transmission grid due to integration of wind power as a function of wind power penetration. Sources are given in Table 2.1.

In order to represent the overall bandwidth of grid reinforcement cost, three scenarios are implemented in the software tool **Green*Net***. It is assumed that reinforcement costs of the transmission grid are increasing linearly with wind power penetration.

As already mentioned above costs for grid reinforcements due to wind power are allocated (if selected) to the long run marginal cost of new plants only. In order to be able to reflect country-specific conditions within model runs the scenario selection is implemented on country-level.

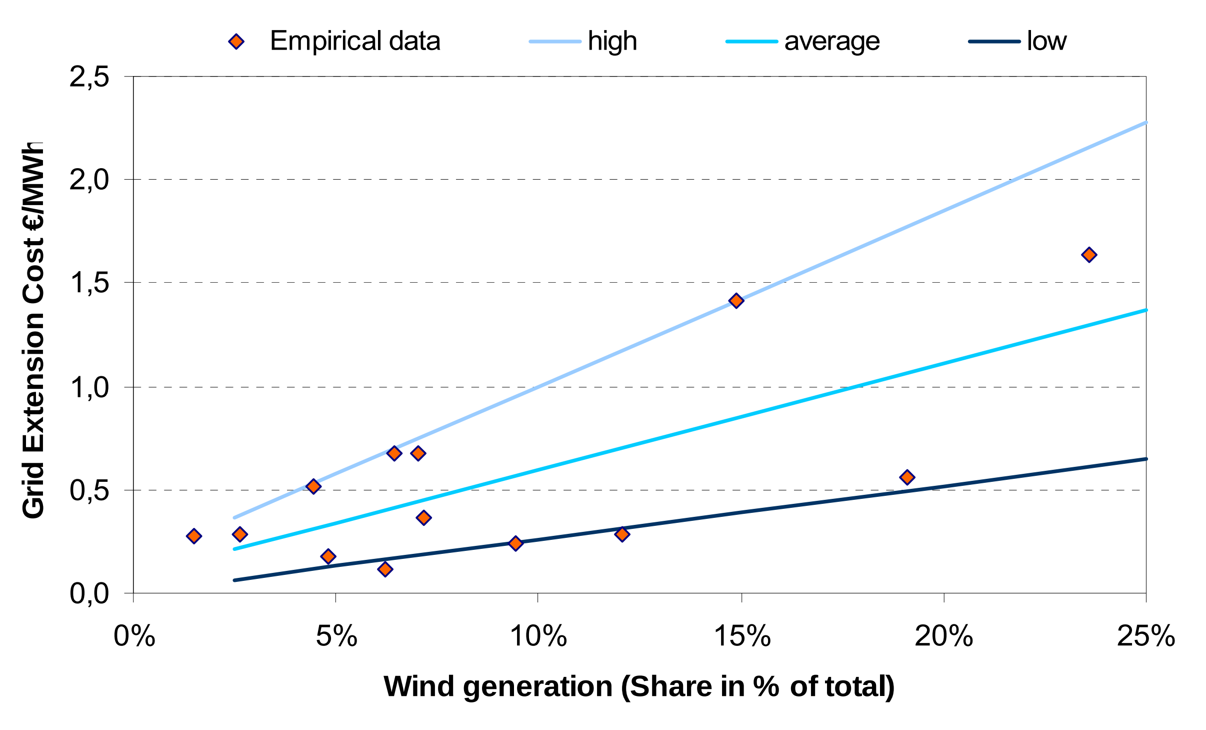

Figure 2.4. Model implementation of grid reinforcement costs of wind power in GreenNet based on empirical data available.

2.2 Modeling system operation cost

System analyses addressing the impact of intermittent wind power generation on the operation of power systems carried out so far[2] show that wind power is affecting system balancing on different time scales:

- In the **time scale from minutes to several days** wind power is, as a result of its intermittent nature, affecting the operation of conventional power plants and due the limited accuracy of wind power forecasts requiring additional balancing power, both effects causing additional cost for the power system.

- When considering impacts on power system operation **in the medium to long-term** (i.e. several years ahead) it becomes clear that wind power due to its limited contribution to system capacity requires a sort of back-up in order to be comparable with conventional power generation. Again additional cost can be allocated to these system capacity requirements.

The first item in **Green*Net*** is indicated as the **issue of balancing wind power** and corresponding cost are indicated as **balancing cost of wind power**. It is important to mention that these costs are occurring as soon as wind power is integrated into power systems.

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[2] Even within the project GreenNet-EU27 various modelling approaches were used to analyse impacts of wind power on system operation for different power systems (UK, Nordel, Germany). A comprehensive overview on the modelling approaches applied and the corresponding results is given in the WP2 report, available on the project website www.greennet-europe.org. Comprehensive analyses further can be found in Dena (2005), ILEX/UMIST(2002) and UKERC (2006).

The second effect in **GreenNet** is referred to as the **issue of system capacity** and corresponding cost are indicated as **system capacity cost of wind power**. System capacity cost – other than balancing cost – are not incurred until excess capacity in the power system becomes scarce and corresponding incentives for installing it come from the power market in form of increasing market prices. However these costs can be allocated to wind power as well and in the software tool **GreenNet** it is assumed that costs are incurred without time delay.

For now only cost due to intermittent generation from wind power are implemented in the simulation model **GreenNet** even if there are other RES-E technologies relying on primary energy sources with intermittent nature too like PV, tidal and wave energy. This is on one hand because wind power is the only intermittent energy source that is likely to reach a noticeable share on total generation until 2020 in Europe and on the other hand there is even a lack of empirical data on impacts of the other power technologies mentioned on power system operation.

Due to the geographical coverage of the model **GreenNet** – at the current stage several EU-25 Member States are implemented plus the Candidate Countries Bulgaria, Romania and Croatia as well as Norway and Switzerland – only a simplified top-down approach is suitable for modeling system operation cost. Feedback on the results of the predecessor project **GreenNet** give evidence that the method of the thermal equivalent provides an approach appropriate for the objectives of this project.

In the following chapter the modeling approach is described in detail addressing the role and the quantitative bandwidth of the capacity credit of wind power comprehensively.

2.2.1 Modeling system capacity cost of wind power

The core objective of the analyses of system capacity requirements is to determine the contribution of intermittent RES-E generation to system security. In other words, to determine the amount of conventional capacity that can be displaced by intermittent RES-E capacity, whilst maintaining the same degree of system security.

The ability of wind power to replace conventional capacity has been discussed since the renaissance of this energy conversion technology in the end of the 1970s. The parameter used to quantify this ability is the so called capacity credit which is usually defined as follows (see e.g. Giebel (2005)):

*"**The Capacity Credit** (CC) assigned to a regenerative conversion plant is the fraction of installed (regenerative) capacity by which the conventional power generation capacity can be reduced without affecting the loss of load probability(LOLP)[3]"*

[3] **Loss Of Load Probability** (LOLP) is the probability that a loss of load event occurs, i.e. that the electricity demand of a power system cannot be met by its own power generation. As this definition doesn't take into account the possibility of power imports from neighbouring systems one has to be aware that the loss of load event doesn't indicate a black out of the power system. Typically, system operators aim for 1 event in 10 years (or better, of course). For the LOLP, the match between resource and demand is decisive, as well as the response times of the existing power plants. Power supply systems with a high percentage of storage (e.g. pump storage) can accommodate higher penetrations of wind energy than supply systems consisting solely of nuclear and coal fired plants (Giebel (2005)).

Within the last decades a number of studies have been carried out aiming at quantifying the CC for different power systems. When comparing results from different studies one has to be aware that the modeling approach applied as well as major assumptions may vary and affect the result to a considerable extent. In Ensslin et al. (2006) exactly this issue is addressed by a structured description of different approaches used so far and by analyzing the impact of parameter variations on the CC of wind power. The results show that variations of the major input parameters like LOLP, spatial distribution of wind sites and the wind year considered influence the resulting CC in a range of x to y % each.

The lesson learnt from this analysis for the model implementation of the CC in **Green*Net*** is that given the geographical coverage of the model the realistic bandwidth has to be covered in form of different scenarios.

For the definition of CC scenarios in **Green*Net*** mainly recent analyses are taken into account, as the quality of wind generation data has increased considerably within the last years, given the fast deployment of wind power in the investigated countries[4] (see Figure 2.5).

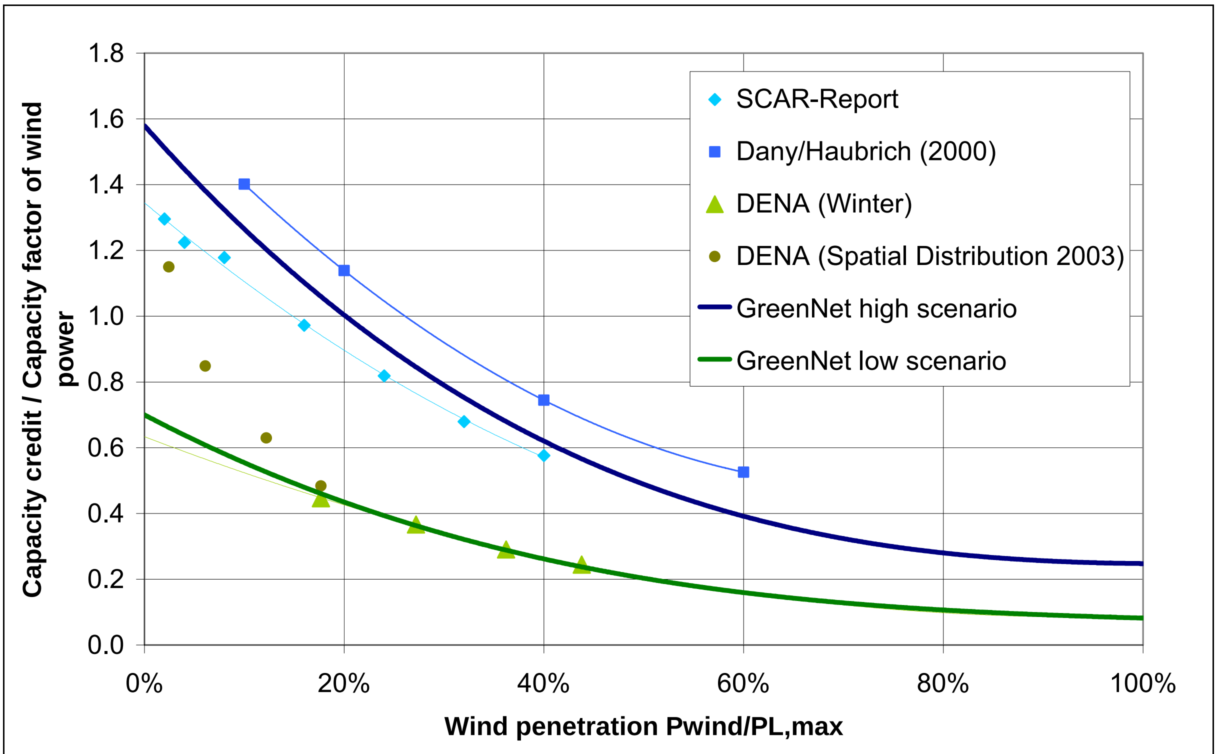

Figure 2.5. Definition of Capacity Credit scenarios implemented in the GreenNet model. Sources: ILEX/UMIST (2002), Dany/Haubrich (2000), DENA (2005).

Finally in the **Green*Net*** model the CC scenarios are implemented as illustrated in Figure 2.6 below.

[4] Whilst the “high scenario” is oriented at the results from (ILEX/UMIST 2002) and Dany/Haubrich (2000), the “low scenario” is derived from the numbers published in DENA (2005) for the winter period. As these scenarios mark the upper and the lower limit of the capacity credit of wind power respectively the simulation software **Green*Net*** covers the realistic bandwidth of this parameter.

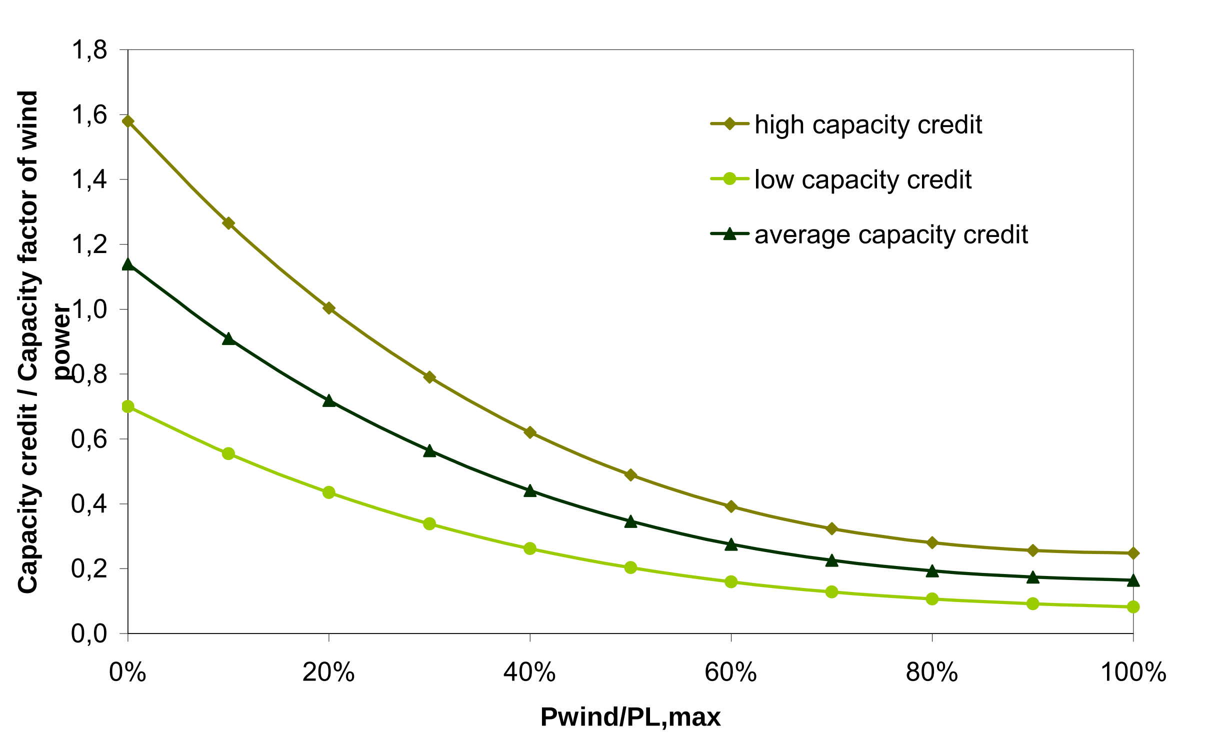

Figure 2.6. Implementation of CC scenarios in the simulation software GreenNet

The modeling approach

The methodology applied to calculate the system operation cost in **GreenNet** is described in the following.

First, the annual wind generation is calculated from installed capacity in MW and the full load hours.

$q_{el} = MW_{wind} * H_{el\_wind}$

where
q_{el}.............................Quantity of annual wind generation [MWh/yr]
MW_{wind}......................Installed capacity of wind [MW]
H_{el_wind}........................Full load hours of wind generation [h/yr]

Then the amount of conventional capacity replaced by wind power – i.e. the capacity of the so called thermal equivalent – is determined based on the capacity factor of the generation technology replaced (e.g. generation from CCGT (Combined Cycle Gas Turbine) power plants).

$MW_{thermal\ equivalent\ gross} = q_{el} / (CF * 8760)$

where
$MW_{thermal\ equivalent\ gross}$...Gross capacity of thermal equivalent [MW]
CF................................Capacity factor [%]

When taking into account the CC of wind power (according to the scenarios illustrated in Figure 2.6 above), only part of the capacity of the thermal equivalent has to be provided in form of system capacity:

$$MW_{thermal\ equivalent\ net} = MW_{thermal\ equivalent\ gross} * (1 - CC_{wind} / CF_{wind} * H_{el\_wind} / 8760)$$

where
$MW_{thermal\ equivalent\ net}$.....Net capacity of thermal equivalent having to be installed [MW]
CC_{wind} / CF_{wind} ....Ratio of Capacity credit to Capacity Factor of wind power according to Figure 2.6
H_{el_wind}.....................Full load hours of wind generation [h/yr]

Finally, the specific capital cost of the capacity needed to system wind power (typically OCGT (Open Cycle Gas Turbines) units are used for system purposes) are determined as follows:

$$C_{system\ capacity} = (\alpha * I * MW_{thermal\ equivalent\ net}) / q_{el}$$

where
$C_{system\ capacity}$...........Specific capital cost of system capacity [€/MWh(wind)]
α............................Annuity factor
I.............................Investment cost of system generation technology [€/kW]

These costs can be interpreted as the corresponding capacity cost due to integration of wind power.

Below an illustrative example is shown:

E.g., 10 GW of wind capacity generates 30 TWh per annum (assuming 3000 full load hours. 4 GW of CCGT at 85% load factor produces the same annual generation as 10 GW of wind power. However, conventional capacity delivers two services, electricity production and capacity.

Without capacity credit

If one assumes that wind power doesn't contribute to the capacity margin at all, then to be equivalent to conventional generation, system capacity would be required in the range of the capacity of the thermal equivalent (i.e. in this case 4 GW). This capacity should come from a power generation technology being suitable for peaking operation and showing low capital cost. The corresponding annualized specific cost of an OCGT unit (fulfilling these criteria) are assumed to be 55 €/kW-yr[5]. Thus, capital cost of 4 GW of OCGT peaking capacity is €222m per annum and 7.39 €/MWh_{wind} respectively.

With capacity credit

If it is considered that wind power does contribute to system security, albeit at a smaller rate than conventional capacity, then the capacity requirement is reduced by the level of that contribution. If it is assumed that 25% of wind capacity (i.e. 2.5 GW out of 10 GW) contributes to the system the additional OCGT capacity requirement is reduced to 4 GW – 2.5 GW = 1.5 GW. At 55 €/kW-yr the OCGT capacity cost is now €84m per annum and 2.80 €/$MWh_{wind\ generation}$ respectively.

The table below summarizes the two different approaches (with versus without capacity credit) of the example given above.

[5] Assumptions: Investment cost 420 €/kW, Interest rate 10%, Depreciation time 15 years.

Calculation of the specific capacity cost of wind power with vs. without capacity credit.

Example: Calculation of capacity cost		
Wind power capacity	**10**	**GW**
Full load hours	**3000**	**h/yr**
Wind power generation	**30000**	**GWh**
Without capacity credit		
CCGT capacity factor	85	%
CCGT full load hours	7446	h/yr
Thermal capacity equivalent	4	GW
Capacity credit wind	0	%
Capacity contribution wind	0	GW
Required back-up capacity	4	GW
Specific cost of back-up capacity	65	€/kW/yr
Annual back-up capacity cost	262	Mio.€/yr
Levelised back-up capacity cost	**8.73**	**€/MWh**
With capacity credit		
CCGT capacity factor	85	%
CCGT full load hours	7446	h/yr
Thermal capacity equivalent	4	GW
Capacity credit wind	25	%
Capacity contribution wind	2.5	GW
Required back-up capacity	1.5	GW
Specific cost of back-up capacity	65	€/kW/yr
Annual back-up capacity cost	99	Mio.€/yr
Levelised back-up capacity cost	**3.31**	**€/MWh**

In order to illustrate the bandwidth of system capacity cost of wind power the method of the thermal equivalent is in the following applied to the German power system. Depending on the capacity credit scenario taken into account, up to a wind power penetration of 10 % (as a share of installed capacity on system peak demand) system capacity cost are in the range of 0 - 4 €/MWh(wind) while for high penetrations up to 30 % a bandwidth of 2.5 - 5.5 €/MWh(wind) can be observed. For the theoretical case that wind power doesn't contribute to system capacity at all cost of 7.4 €/MWh(wind) are calculated independent of the wind power capacity installed (see Figure 2.7).

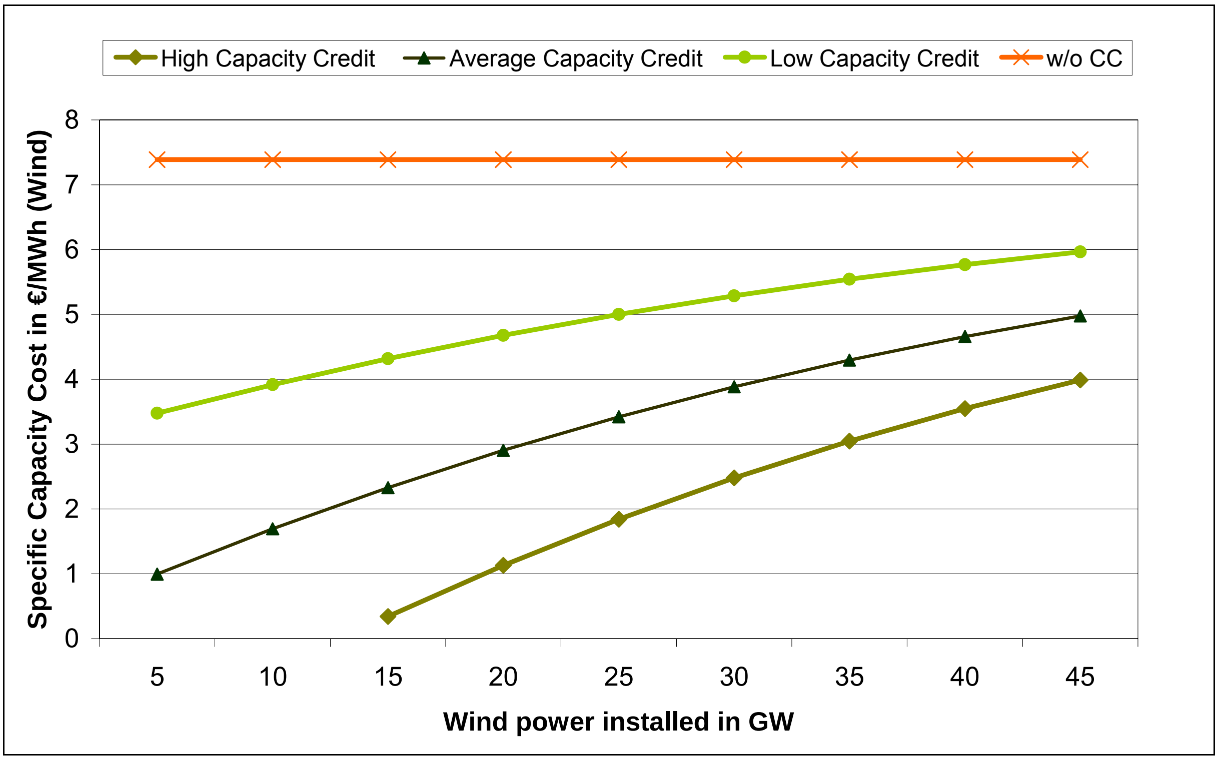

Figure 2.7. Germany – additional system capacity cost of wind power depending on the installed wind power capacity for capacity credit scenarios implemented in **Green*Net***. *Assumptions: Peak demand (2020) 100 GW, load factor of thermal equivalent 85 %, specific annual capital cost of thermal equivalent 55 €/kW-yr, capacity credit according to Figure 2.6*

System capacity in form of responsive loads

When access capacity in power systems becomes scarce, in principle there are two options available to assure system security

i) the installation of additional generation capacity
ii) the reduction of demand in hours where the system is at risk

Historically power demand was considered as given and in order to assure a certain level of security of supply within the process of system capacity planning the capacity needs for the medium to long term were defined. In the liberalized power market centralized system capacity planning is no more an issue as incentives for new power capacity are provided by the power market. Increasing power prices thereby provide incentives for investors to install new power capacity but also imply incentives for consumers to reduce their demand if power prices exceed their individual willingness to pay.

This alternative option to provide system capacity in form of responsive demand is implemented in the software tool **Green*Net*** as well.

In case of consideration of responsive loads instead of assessing additional system capacity requirements with specific annual capital cost (e.g. 55 €/kW-yr for an OCGT unit) an option fee for the remuneration of demand reductions has to be considered.

According to the option fees paid for responsive demand in Norway in 2005 in the range of 3 to 15 €/kW-yr the default level in the software tool **Green*Net*** is set at 10 €/kW-yr (see Figure 2.8 below).

This empirical example shows, that besides the advantage that responsive loads can be activated without delay compared to the installation of new generation capacity, this alternative option may be even more cost efficient.

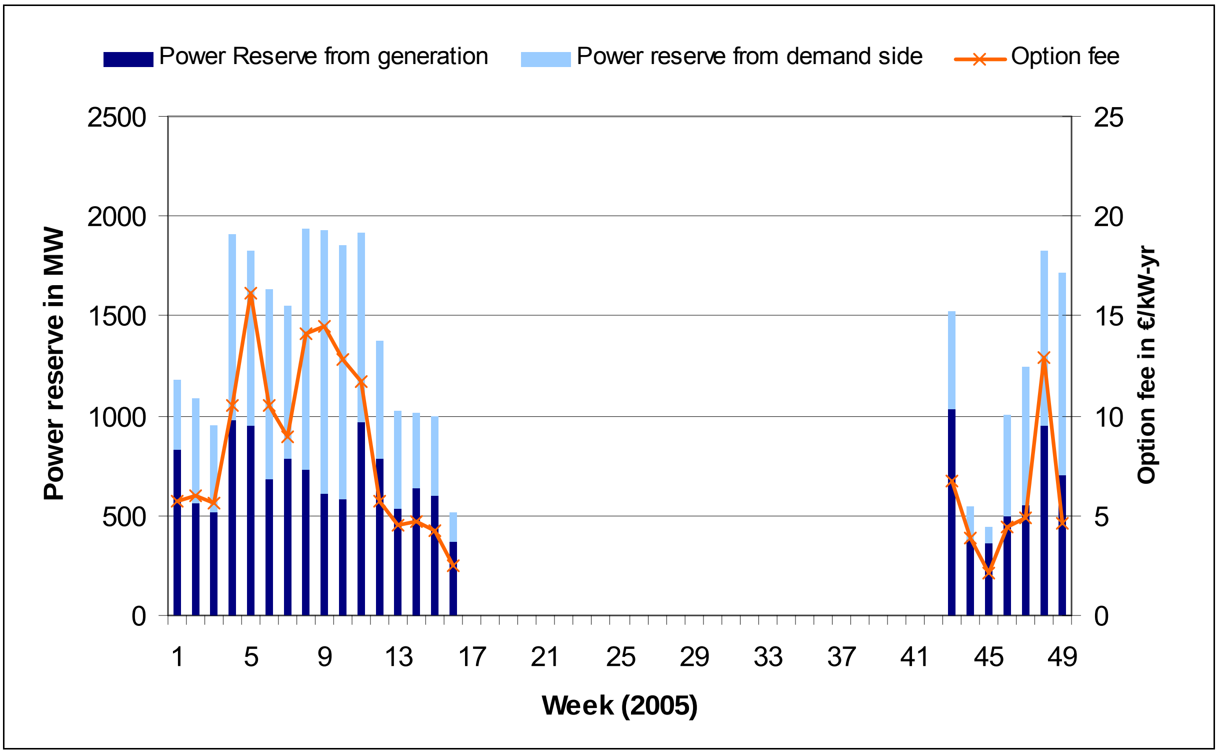

Figure 2.8. Quantities and prices for power reserves from generation and demand on the Norwegian Regulating Power Option Market (RCOM) in 2005.
Source: Statnett (2006).

2.2.2 Modeling balancing cost of wind power

The model implementation of (short-term) balancing cost of wind power has not been modified within this project. In **Green*Net*** balancing cost are assumed to be 50 % of system capacity cost of wind power[6]. This approach guarantees that the bandwidth of balancing cost shown in empirical data is covered with the simulation tool.

Finally system operation costs for the German power system are determined according to the modeling approach used in **Green*Net*** (see Table 2.2 below).

[6] The empirical basis for this assumption is given in WP2-report of the project GreenNet available on the project website www.greennet.at

Table 2.2. Germany – System operation cost of wind power for wind penetrations up to 35 GW w/o consideration of the capacity credit of wind power

Wind capacity	GW	5	5	10	15	20	25	30	35
Full load hours	h	3500	3500	3500	3500	3500	3500	3500	3500
Wind generation	GWh	17500	17500	35000	52500	70000	87500	105000	122500
CCGT load factor	%	85	85	85	85	85	85	85	85
CCGT full load hours	h	7446	7446	7446	7446	7446	7446	7446	7446
Thermal capacity equivalent	GW	2.350	2.350	4.701	7.051	9.401	11.751	14.102	16.452
Capacity Credit Wind	%	0.0	24.9	22.1	19.5	17.2	15.2	13.4	11.7
Wind capacity contribution	GW	0.000	1.244	2.208	2.931	3.449	3.798	4.007	4.106
Required additional capacity	GW	2.350	1.106	2.493	4.120	5.952	7.954	10.094	12.345
Specific cost of additional capacity	€/kW/yr	55	55	55	55	55	55	55	55
System capacity cost	Mio.€	129.26	60.84	137.10	226.61	327.35	437.45	555.19	679.00
System capacity cost per MWh Wind	**€/MWh**	**7.39**	**3.48**	**3.92**	**4.32**	**4.68**	**5.00**	**5.29**	**5.54**
Balancing cost per MWh Wind	**€/MWh**	**3.69**	**1.74**	**1.96**	**2.16**	**2.34**	**2.50**	**2.64**	**2.77**
Capacity & Balancing cost per MWh Wind	**€/MWh**	**11.08**	**5.21**	**5.88**	**6.47**	**7.01**	**7.50**	**7.93**	**8.31**

Assumptions: System peak demand (2020) 100 GW, load factor of thermal equivalent 85 %, specific annual capital cost of thermal equivalent 55 €/kW-yr, full load hours 2500 h/yr (50 % offshore); capacity credit according to low scenario in Figure 2.6

3 LEAST COST RES-E GRID INTEGRATION – RESULTS OF GREENNET SIMULATION RUNS

3.1 Definition of scenarios

In order to accelerate integration of currently not fully competitive RES-E generation technologies into competitive electricity markets financial support is necessary to reach particular RES-E energy policy goals. However, the deployment of RES-E is not only depending on type and design of support mechanisms implemented, but also on the practice of allocation of cost related to the grid integration of RES-E, representing a financial as well as non-financial barrier. As described in the previous section of this report, the main cost elements thereby are cost for

- grid Infrastructure (cost for connecting RES-E generation technologies to the existing grid (GC), cost for reinforcement of the existing grid due to RES-E integration (GR)) and
- power system operation (SO) (cost due to limited contribution of intermittent RES-E generation to system capacity, cost for power balancing)

In the Member States of the European Union still no common and transparent cost allocation policy for cost elements mentioned exists. In order to derive recommendations for a harmonized approach the objective of the model runs is to investigate the **impact of different cost allocation policies** for the EU 25 Member States with respect to RES-E deployment and investment needs.

The **reference scenario** refers to the current practice of allocation of cost for RES-E integration in the EU-25 Member States. Different cost elements are allocated as follows:

- **Grid connection costs** are interpreted as part of the total investments and therefore allocated to the RES-E developer.
- For the allocation of **grid reinforcement costs** currently there is no unique practice in the EU-25 Member States. In most countries deep charging is applied, which means that this cost element is allocated to the RES-E developer as well. Shallow grid connection charging for now is applied in Belgium, Denmark, Germany and The Netherlands only.
- **Costs for balancing wind power** are treated diversely within EU-Member States. In countries using a quota obligation to support RES-E like e.g. Belgium, Sweden and UK balancing cost are allocated to the RES-E developer, while in countries where feed-in tariffs are applied usually RES-E developers are not charged for imbalances. Exemptions are Spain and The Netherlands, both supporting RES-E via feed-in tariffs and charging RES-E developers for imbalances.
- Given the present excess capacity in European power systems, even if wind power penetrations are already considerable in selected countries there are no **cost for system capacity** occurring[7]. However future projections of power capacities give evidence, that the limited contribution of wind power to system capacity will have to be compensated with “additional” system capacity in future. These cost are not likely to be allocated to the RES-E developer, they are rather subject to power markets and therefore will be allocated to end-users.

[7] However, the model implementation in ***GreenNet*** foresees a continuous development of system capacity cost independent of future trends on excess capacity.

Besides the reference scenario both extreme scenarios i.e. either the RES-E developer (**"deep charging"**) or the end-user pays several additional cost of RES-E grid integration (**"super-shallow charging"**) are conducted.

In order to reflect the bandwidth of cost for grid reinforcement and system operation illustrated in the previous chapter further sensitivity analyses are carried out for these cost elements (**"high", "average" and "low" cost scenarios**).

A special focus is given to wind energy, both wind on- and off-shore, as this RES-E technology will be, firstly, the most relevant RES-E generation option in the future mainly located in areas with weak grid conditions (i.e. causing additional grid extension costs) and, secondly, is a technology with a volatile supply structure (i.e. creating system operation costs).

All considered scenarios related to the issue of RES-E grid integration are summarized in Figure 3.1.

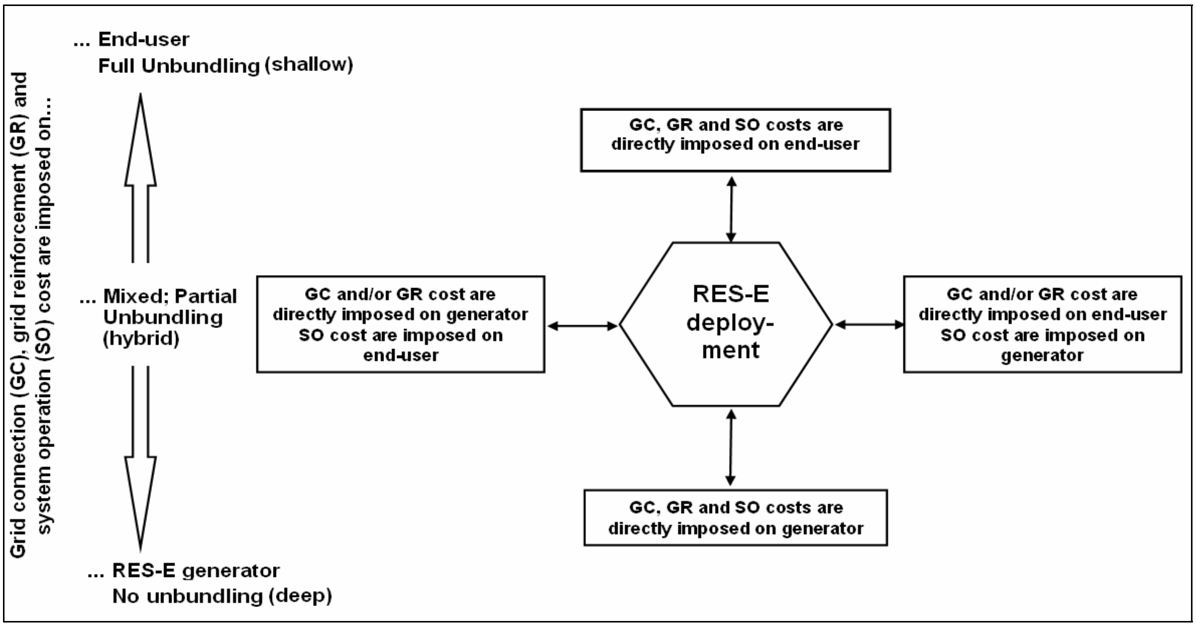

Figure 3.1 Overview of the investigated scenario

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).

Energy Efficiency scenarios

Besides scenarios addressing the supply side, the software tool **Green*Net*** simulates Energy Efficiency measures (EE) on the demand side as well. Special attention is paid to the interactions between demand side measures (DSM) and the deployment of RES-E. Furthermore, energy savings and corresponding cost are simulated for several relevant appliances in the industrial, tertiary and residential sector. Promotion instruments for EE investigated thereby are

- tax incentives (TI) and
- granted tariffs (GT)

3.2 Scenario assumptions

Gross electricity consumption

The electricity demand forecast up to 2020 is based on the PRIMES baseline scenario. In this projection electricity demand within EU-25 Member States will rise – on average – by 2.1% p. a. up to 2010 and by 1.7 % p. a. thereafter. Of course, on country level different demand projections are used. For example while the demand forecast for Greece is 2.5% p.a. up to 2010, a projection of only 1.0% p.a. is assumed for Germany.

Electricity prices

Default electricity prices are based on energy price assumptions in the PRIMES baseline scenario described above (see Figure 3.2).

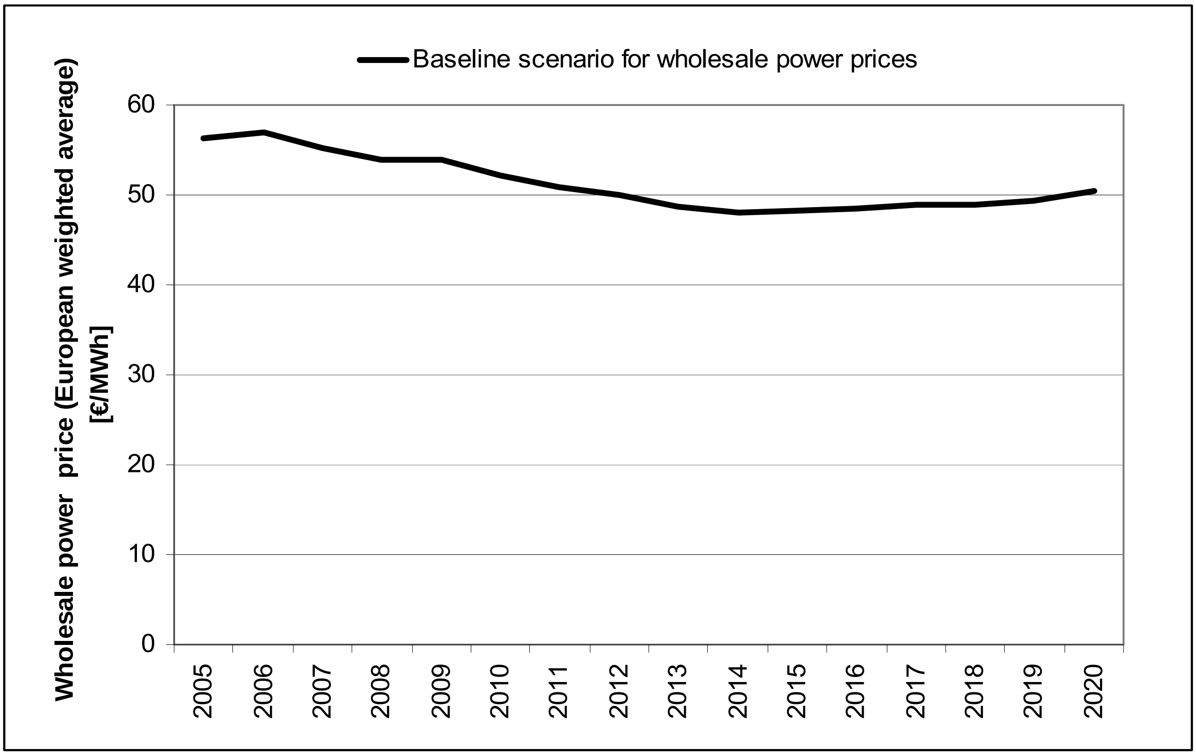

Figure 3.2 Development of wholesale power prices up to 2020 based on PRIMES baseline scenario

Primary energy prices for biomass products

As RES-E technologies are considered endogenously in the **Green*Net*** model assumptions with respect to their primary energy prices are necessary. Figure 3.3 gives an overview about the variations of biomass prices in EU-25 countries. The price level differs among the countries and biomass fractions, respectively. Prices are lowest for biowaste, followed by forestry and agricultural residues, and they are high for both forestry and agricultural products. With respect to the price forecast, for agricultural products diverse sub fractions are considered separately. For the remaining fractions a slight price increase in the range of 0.2-0.5 % p.a. is assumed.

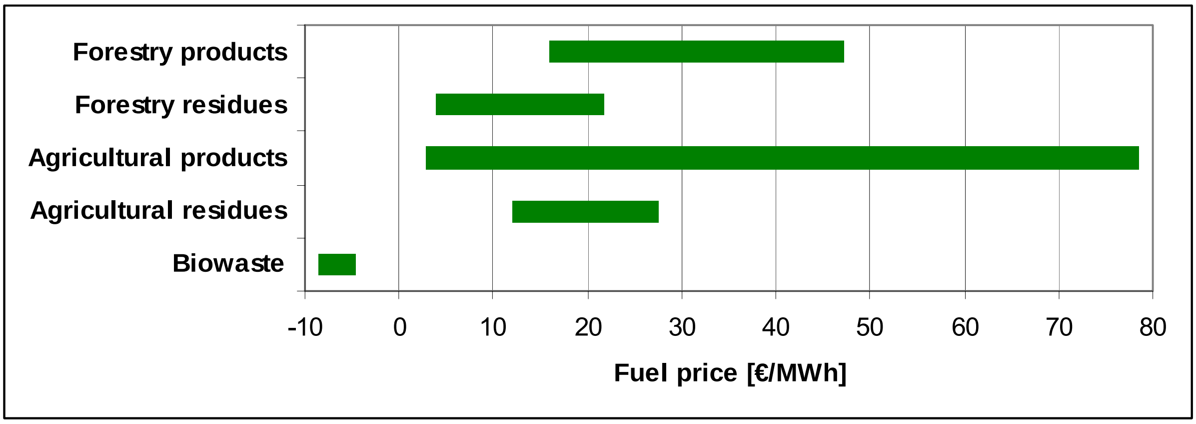

Figure 3.3 Variation of the prices for different biomass products in EU-25 Member States expressed in $€_{2004}$ prices

Source: Own investigation

Assumptions with respect to grid connection costs

According to empirical data analyzed within case studies in work package 5 of this project grid connection cost are assumed to be 8 % of total investments for wind onshore and in the range of 10-25 % for wind offshore depending on the distance to shore of the considered band. The implementation of grid connection cost allows to apply separate learning rates. However in the following scenarios the same learning rates as for the corresponding generations units are applied.

Assumptions with respect to grid extension costs

As explained in section 2.1.2, based on country-specific studies, long-run marginal costs for grid reinforcements due to the integration of wind power have been identified. This set of data determining grid reinforcement cost as a premium per MWh wind generation for certain amounts of wind penetration, is described within the model **Green*Net*** by a continuous mathematical function – representing the average cost-scenario as illustrated in Figure 3.4. In order to get aware of uncertainties, two additional scenarios have been implemented – i.e. a high as well as a low cost-scenario.

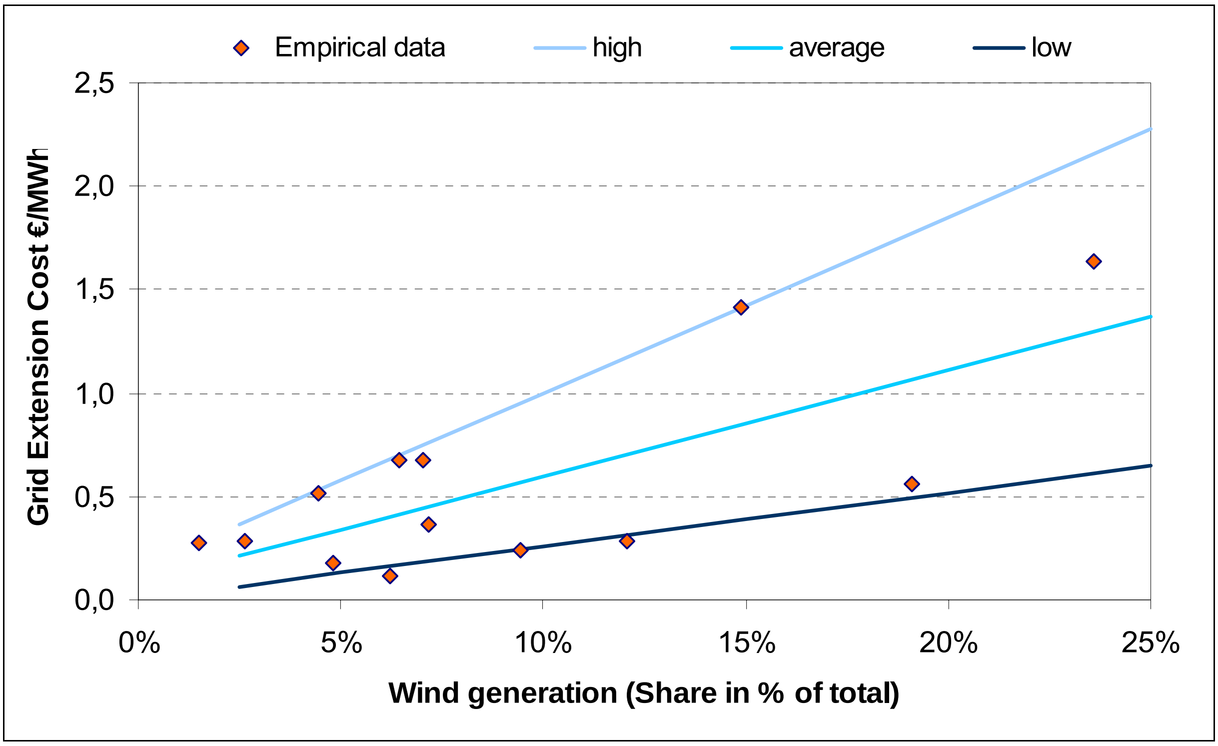

Figure 3.4 Model implementation with respect to the calculation of grid extension costs for wind energy (expressed as premium in €/MWh wind generation)

Assumptions with respect to system operation costs

The overall calculation of system operation costs is described in section 2.2 in detail. With respect to the calculation of a likely capacity credit continuous mathematical functions have been applied in the software tool **Green*Net***, see Figure 3.5.

Similar to the model implementation of grid reinforcement cost, three capacity credit scenarios (i.e. high – medium – low) are implemented in the model **Green*Net*** in order to reflect the bandwidth shown in the comparison of empirical data.

As system capacity in general can be provided by either additional capacity (e.g. in form of OCGT units) or in form of demand response both options are implemented. The corresponding default setting for annual specific cost is 55 €/kW,yr for OCGT and 10 €/kW,yr for demand response.

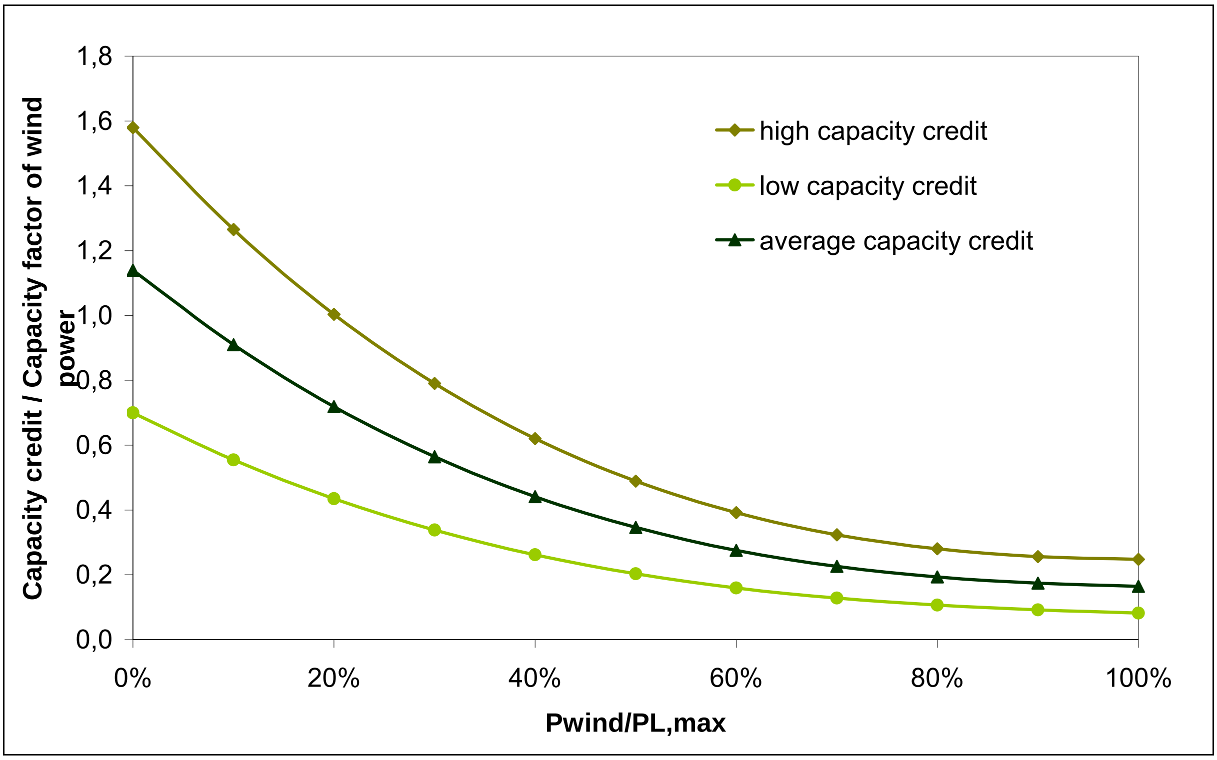

Figure 3.5 Model implementation with respect to the calculation of the capacity credit for wind energy

Future cost development of RES-E technologies

Dynamic cost developments of electricity generation technologies are considered within the simulation tool **Green*Net*** in the following way:

Investment costs (experience curves or expert forecast)

Operation & Maintenance costs (expert forecast)

Improvement of the energy efficiency (expert forecast)

For most technologies the investment cost forecast is based on technological learning, see Table 3.1. As learning is taking place on international level, the deployment of technologies on the global level has been taken into account. More precisely, for the simulation runs global RES-E deployment consists of the components as described below:

- Deployment within the EU-25 Member States is endogenously determined, i.e. is derived within the model
- Expected developments in the “Rest of the world” are based on forecasts as presented in the IEA World Energy Outlook 2005 (IEA, 2005).

Table 3.1 Dynamic assessment of investment costs for different RES-E technologies within **Green*Net***

RES-E category	Applied approach	Assumptions
Biogas	Experience curve (global)	LR (learning rate) = 5%
Biomass	Experience curve (global)	LR = 12.5% up to 2010; 10% after 2010
Geothermal electricity	Experience curve (global)	LR = 8%
Hydropower	Expert forecast	No cost decrease in considered period
Photovoltaics	Experience curve (global)	LR = 20% up to 2010, 12% after 2010
Solar thermal electricity	Experience curve (global)	LR = 18% up to 2010, 12% after 2010
Tidal & Wave	Expert forecast	Decrease 5%/year up to 2010, 1%/year after 2010
Wind on- & offshore	Experience curve (global)	LR = 9.5%

Assumed payback time / interest rate

The economic assessment of new investments is highly influenced by the investor's necessary rate of return and the payback time. In the **Green*Net*** model the rate of return is based on the weighted average cost of capital (WACC) method. For all scenarios a unique WACC value of 6.5% is assumed, independently from the RES-E technology and the kind of support scheme.[8] The payback time of the investments is set equal to 15 years for all plants.

Simulated RES-E support schemes

Within this project it is assumed that the RES-E policies currently implemented within the Member States retains available up to 2020, i.e. no harmonization of the support schemes among the Member States takes place in the near future. The general framework conditions in which the different RES-E policies are embedded highly influences the effectiveness of the support scheme. In the simulated cases the "free" design options of the instruments are chosen in a way such that good investment conditions exist. Concrete the following (optimistic) conditions are set:

- Investor confidence, characterized by
  - Continuous RES-E policy / long term RES-E targets;
  - Clear and well defined tariff structure / yearly quota for RES-E technologies;
- Reduced investment and O&M costs, increased energy efficiency over time;
- Existing social, market and technical barriers can be overcome in time.

[8] This means there are no additional risk premiums for less mature technologies or specific support schemes. Of course, differences in the guaranteed duration of the support scheme (e.g. if a feed-in tariff is guaranteed for 5 or 15 years) are considered in the model.

Simulated EE support schemes

In the current version of the software tool ***GreenNet*** three different support schemes for EE measures are implemented. The way of their implementation is described briefly in the following.

Investment subsidies

The ***GreenNet*** toolbox simulates the effects of investment subsidies in percent of the total investment costs for electricity saving systems. In reality, investment subsidies are restricted to a specific budget allocation. This fact is also considered in the toolbox.

Tax incentives

For simplification, it is assumed that tax benefits are granted on the investments spent on electricity saving systems. In contrast to investment subsides, however, it is assumed that the budget for the tax incentives scheme is not restricted.

Granted tariffs

A simple approach, but not frequently used, is the so called "granted tariff". With this support scheme, the investor receives a grant if certain energy saving systems are installed or if a "standard" technology is replaced, i.e. every kWh saved will be granted by a payment. To avoid high transaction costs, it is assumed that the electricity saved refers to average savings expected in relation to using a standard technology (i.e. savings against a baseline). In addition, to simulate realistic cases, a budget restriction is considered in the ***GreenNet*** toolbox.

3.3 Simulation results

3.3.1 Reference scenario

According to the reference scenario total RES-E generation within the EU-25 Member States increases from 492 TWh/yr in 2005 to 1028 GWh/yr in 2020. While generation from original RES-E technologies like hydro power and biowaste remains almost stable, especially for wind power, biomass and biogas a considerable increase up to 2020 can be observed (see Figure 3.6).

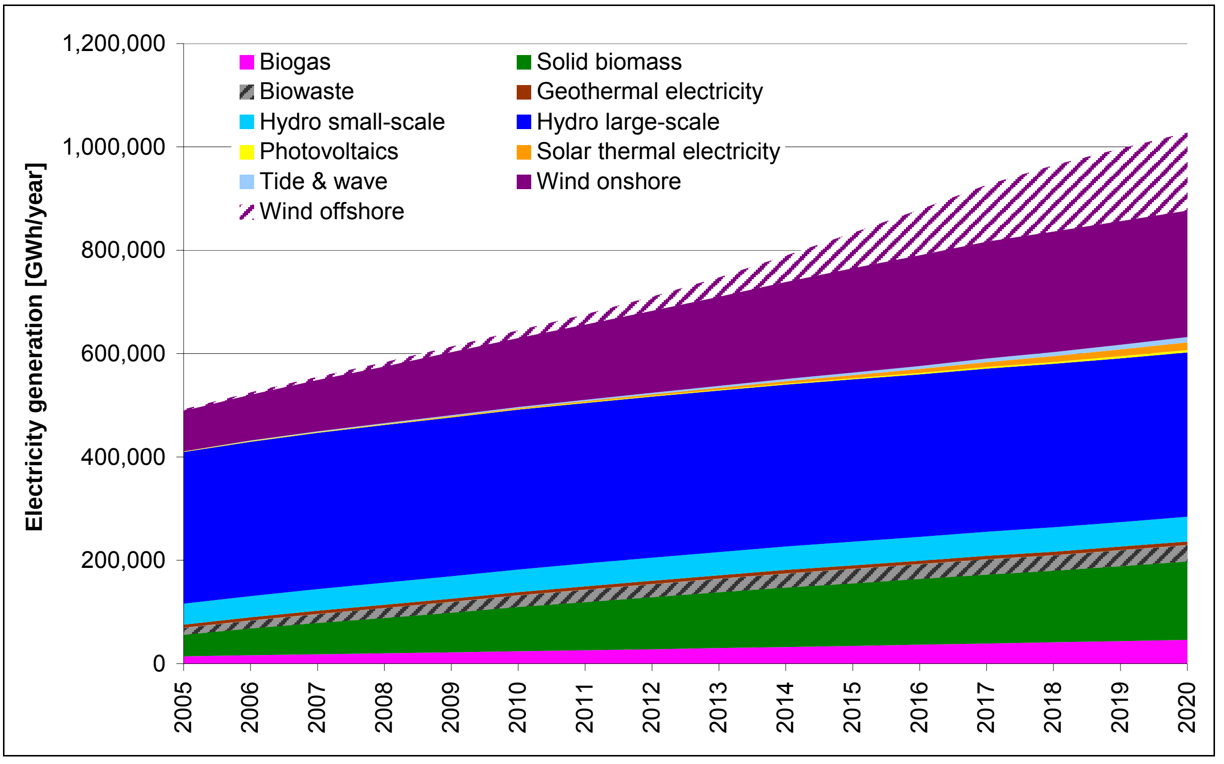

Figure 3.6 Reference scenario - deployment of RES-E generation in EU-25 Member States up to 2020

This development is even reflected in the shares of technologies on total RES-E generation depicted in Figure 3.7. While the share of hydro power decreases from 78 % in 2005 to 36 % in 2020, the share of RES-E generation from wind power increases from 17 % in 2005 to 39 % in 2020. Therefore according to the reference scenario wind power is likely to be the dominant RES-E technology in the mid-term. This result also underlines the special attention paid to wind power within the project GreenNet-EU27 with respect to its grid integration.

When looking at new RES-E installations again the dominance of wind power is obvious in absolute terms. Within this technology offshore installations are becoming increasingly important as from 2010. While installations of biomass and biogas power units remain almost stable for the period considered, future promising technologies like PV and solar thermal electricity show increasing installations as from 2013 (see Figure 3.8).

Yearly investment needs for RES-E installations shown in Figure 3.9 reflect the deployment of RES-E as well as their specific investment cost. The latter varies considerably between the technologies investigated. Therefore e.g. for the year 2020 even if installed capacities for wind onshore are more than five times higher, expenditures for PV plus solar thermal electricity are in the same range.

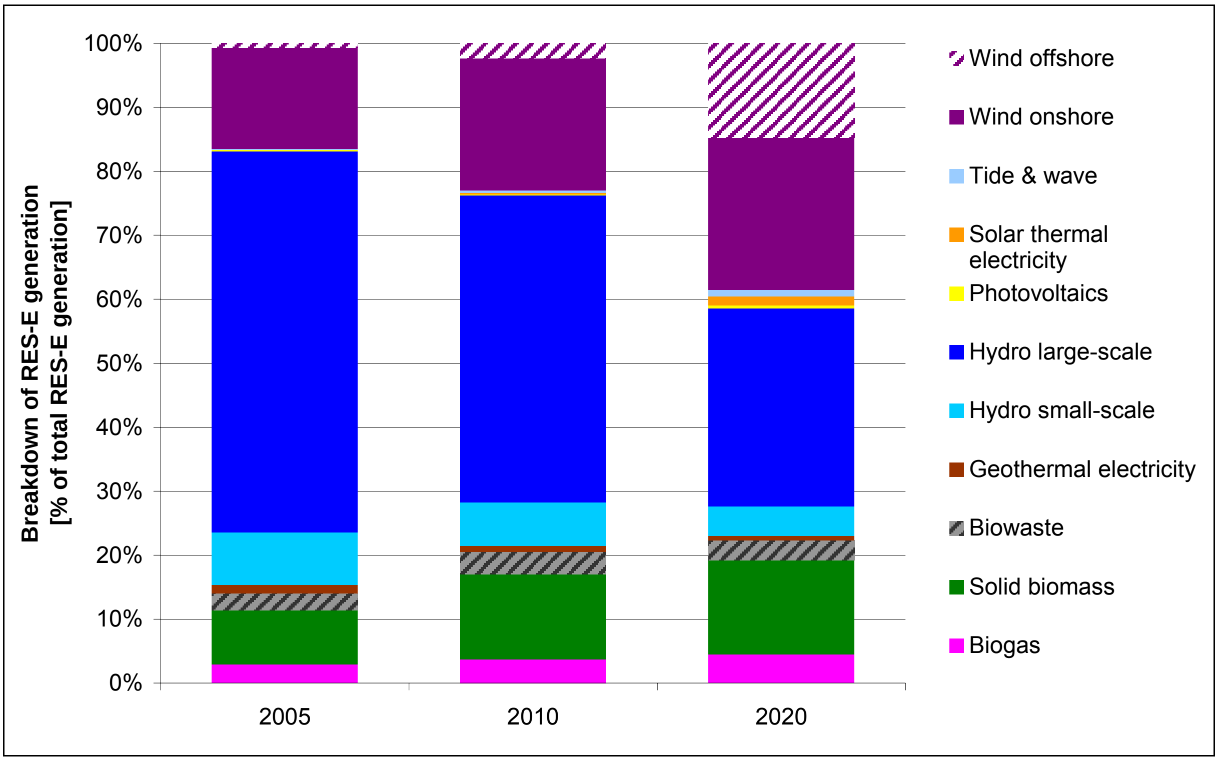

Figure 3.7 Reference scenario – Breakdown of RES-E generation in EU-25 Member States

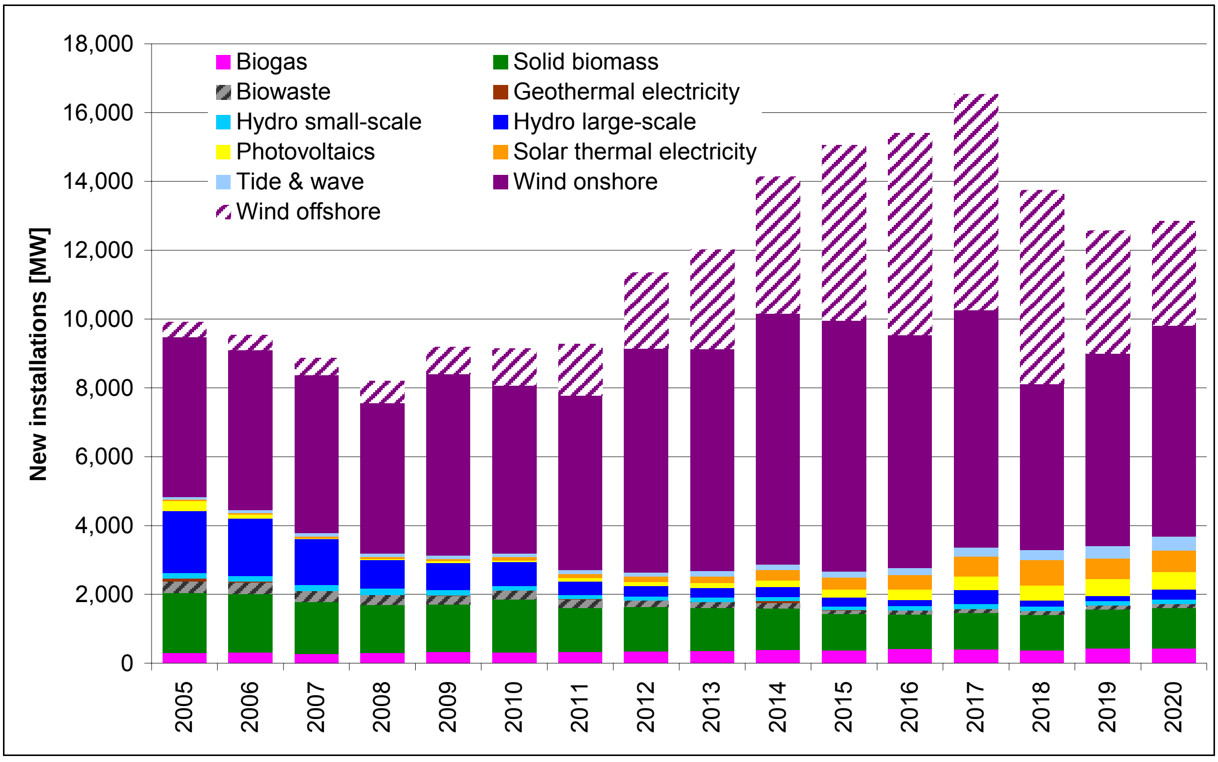

Figure 3.8 Reference scenario – yearly RES-E installations in EU-25 Member States up to 2020

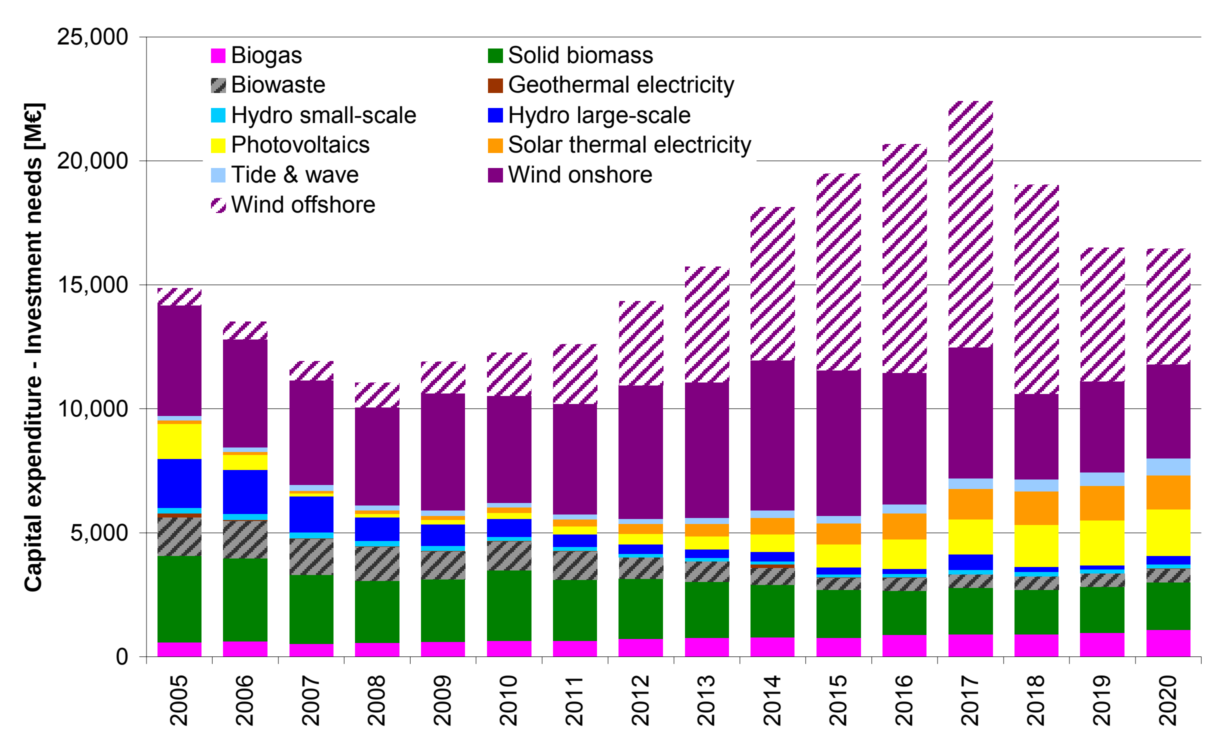

Figure 3.9 Reference scenario – Yearly investment needs due to RES-E installations in EU-25 Member States up to 2020 (including cost for grid connection)

Moreover RES-E market and grid integration is related to additional cost shown in the following for the reference scenario.

System capacity cost due to integration of wind power are increasing from 209 M€/yr in 2005 to about 1,500 M€/yr in 2020. This cost element is related to the need of "additional" system capacity as a result of the limited capacity contribution of wind power. Signals for the installation of power capacity are provided in form of increasing prices on the power market. Given current market designs in Europe system capacity cost will be reflected in power prices and will therefore be borne by the end user as indicated in Figure 3.10.

In practice – given the level of excess capacity in European power markets – system capacity costs are not seen jet. However, mid-term projections of power capacity give evidence, that this effect may be observed in the medium to long term.

If power markets will not provide adequate system capacity in future, markets for power capacity might evolve. Prices for power capacity would then reflect the capacity contribution as well, which might be interpreted as an allocation of system capacity cost to the RES-E developer.

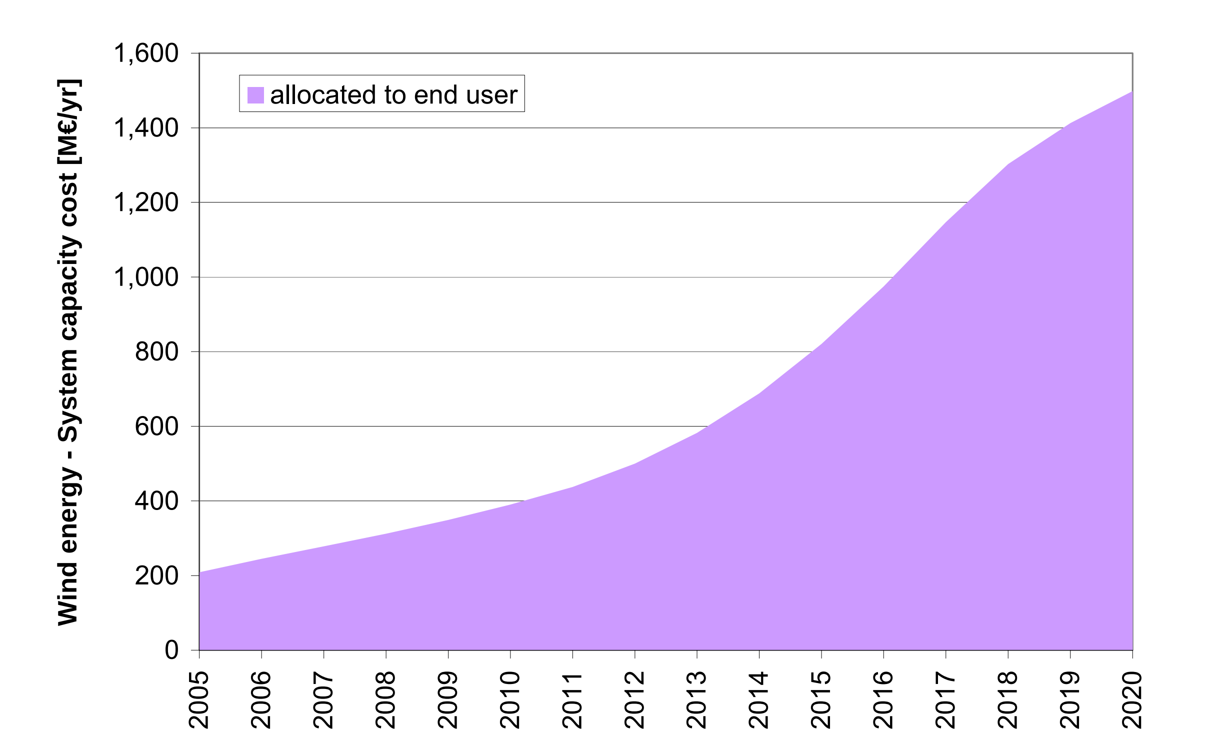

Figure 3.10 Reference scenario – development of system capacity cost due to wind energy in EU-25 Member States up to 2020.

Annual cost for balancing wind power increases from about 100 M€ in 2005 to 750 M€ in 2020. As shown in Figure 3.11 according to the current practice of market integration of wind energy about half of these costs are allocated to wind power developers.

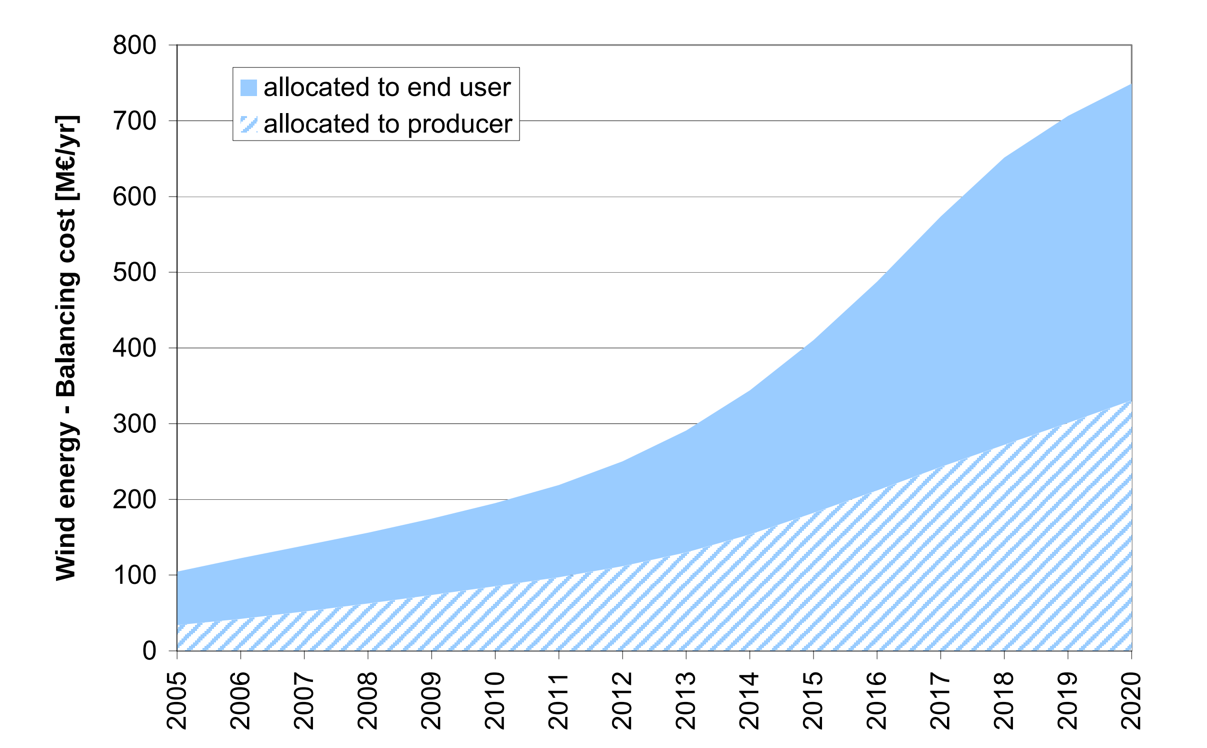

Figure 3.11 Reference scenario – development of cost for balancing wind power in EU-25 Member States up to 2020

The connection of power plants to the existing grid is currently interpreted as a part of the development. Therefore corresponding cost are borne by the power plant developer as part of total investments. Figure 3.12 shows how annualized grid connection costs for wind energy installed after 2004 develop up to 2020. Annual cost increase up to 1707 M€ and are therefore almost double the expenditures for balancing wind power.

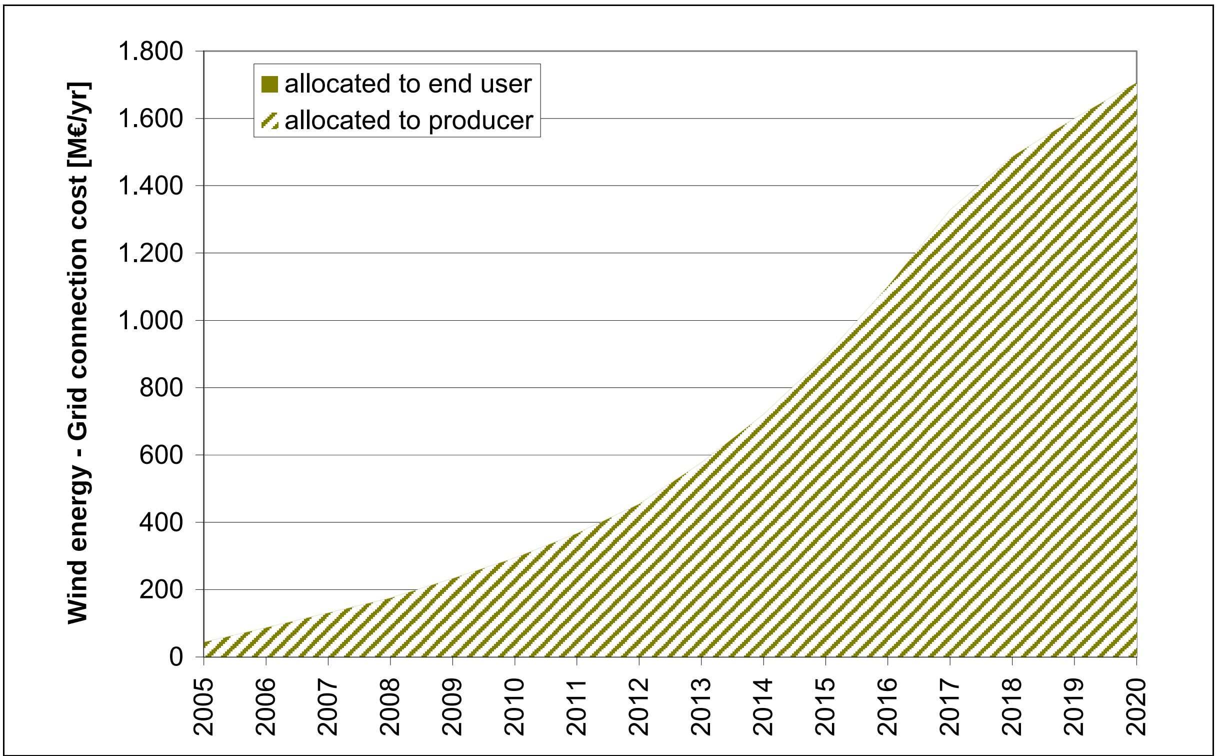

Figure 3.12 Reference scenario – development of annual grid connection cost due to grid integration of wind power (only plants installed after 2004) in EU-25 Member States up to 2020

Currently within the majority of EU-25 Member States even cost for reinforcements of the existing grid related to RES-E grid integration are allocated at least partly to RES-E developers. This fact is expressed in Figure 3.13 showing the development of grid reinforcement cost caused by grid integration of wind power in EU-25 Member States. Corresponding annualized costs increase up to more than 300 M€ in 2020.

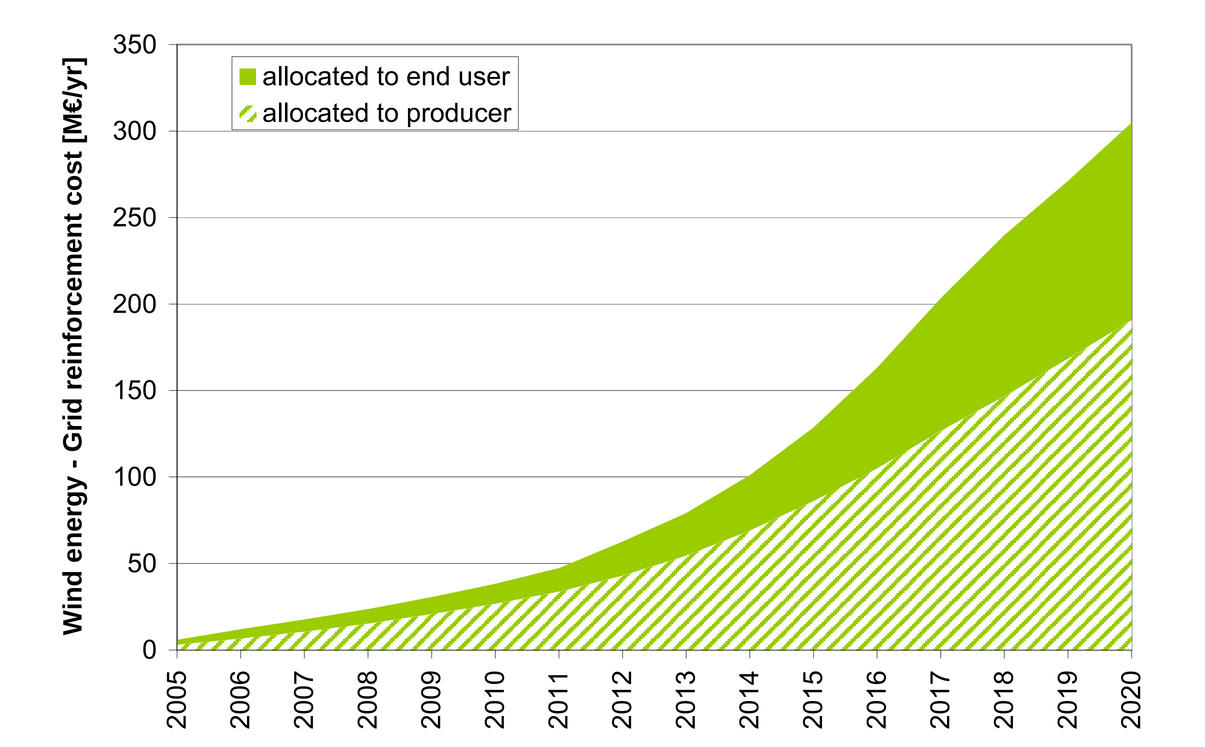

Figure 3.13 Reference scenario – development of grid reinforcement cost due to grid integration of wind power in EU-25 Member States up to 2020 (only installations after 2004 considered)

3.3.2 Deep charging vs. super-shallow charging scenario

In the following results are shown for the two extreme cases – the deep charging and the super-shallow charging scenario – and compared with the reference case. While for the deep charging scenario several cost elements are allocated to the RES-E developer, the super-shallow charging scenario indicates a practice where several cost elements (including cost for grid connection) are allocated to the end user.

The practice of allocation of cost for RES-E grid and market integration apparently affects the RES-E deployment. This effect is shown in Figure 3.14 depicting the development of total RES-E generation for the two extreme cases and the reference scenario.

In relative terms total RES-E generation in 2020 is 4 % higher for the super-shallow charging scenario compared to the reference. Deep charging instead leads to a decrease of total RES-E generation in the height of about 4 % of the reference value in 2020 (see Figure 3.15).

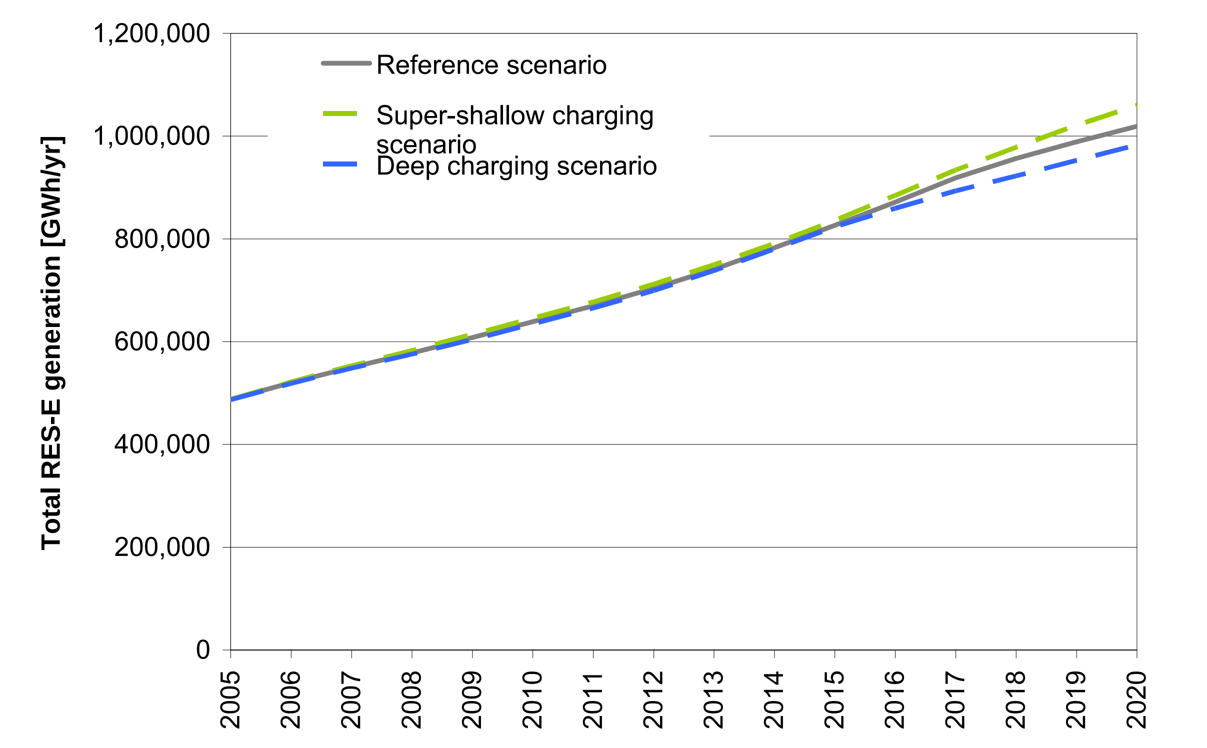

Figure 3.14 Comparison of development of total RES-E generation in EU-25 Member States for different cost allocation policies up to 2020.

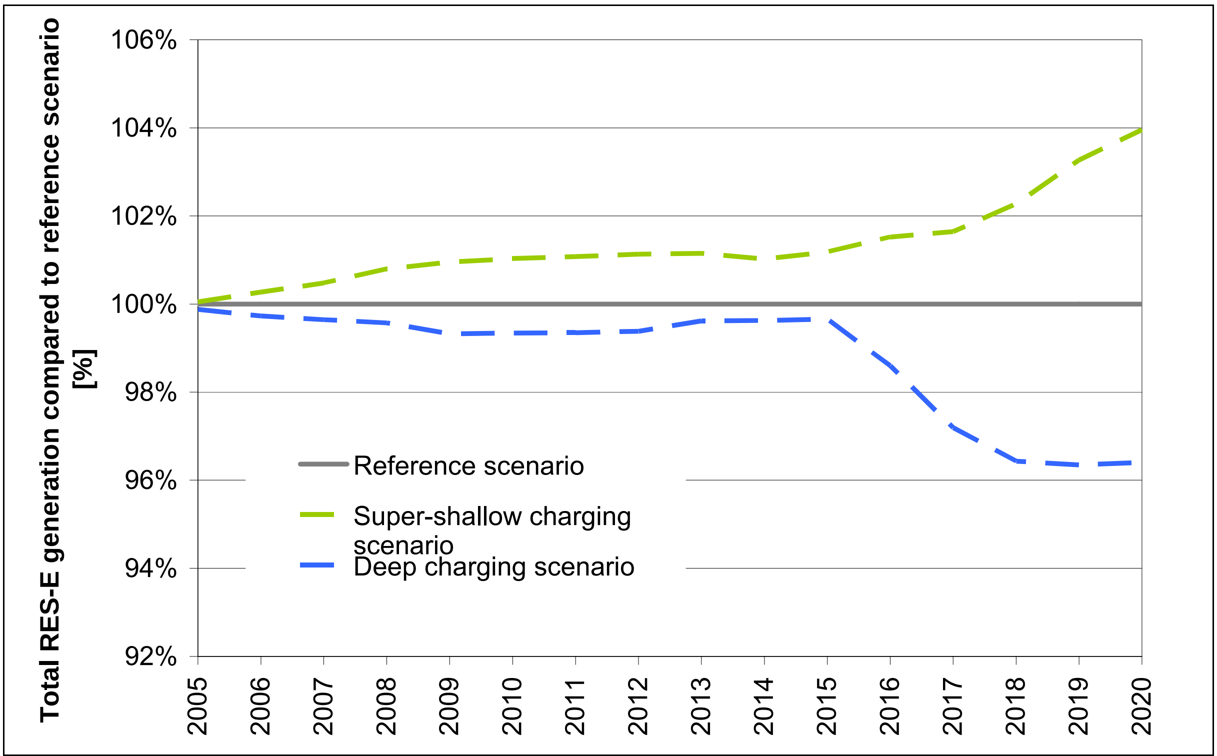

Figure 3.15 Development of total RES-E generation in EU-25 Member States up to 2020 for different cost allocation policies compared to the reference scenario.

The effects on RES-E deployment described are mainly driven by changes in wind power installations. Therefore this technology is analyzed in detail in the following.

For the reference scenario wind power generation from plants installed after 2004 reaches 353 TWh in 2020. For the super-shallow charging scenario the corresponding number is 395 TWh which means an increase of 12 % whereas generation in 2020 for the deep charging scenario amounts to 317 TWh or minus 10 % (see Figure 3.16 and Figure 3.17).

Deviations between the scenarios investigated related to new installations of wind power are increasing as from 2015 (see Figure 3.18).

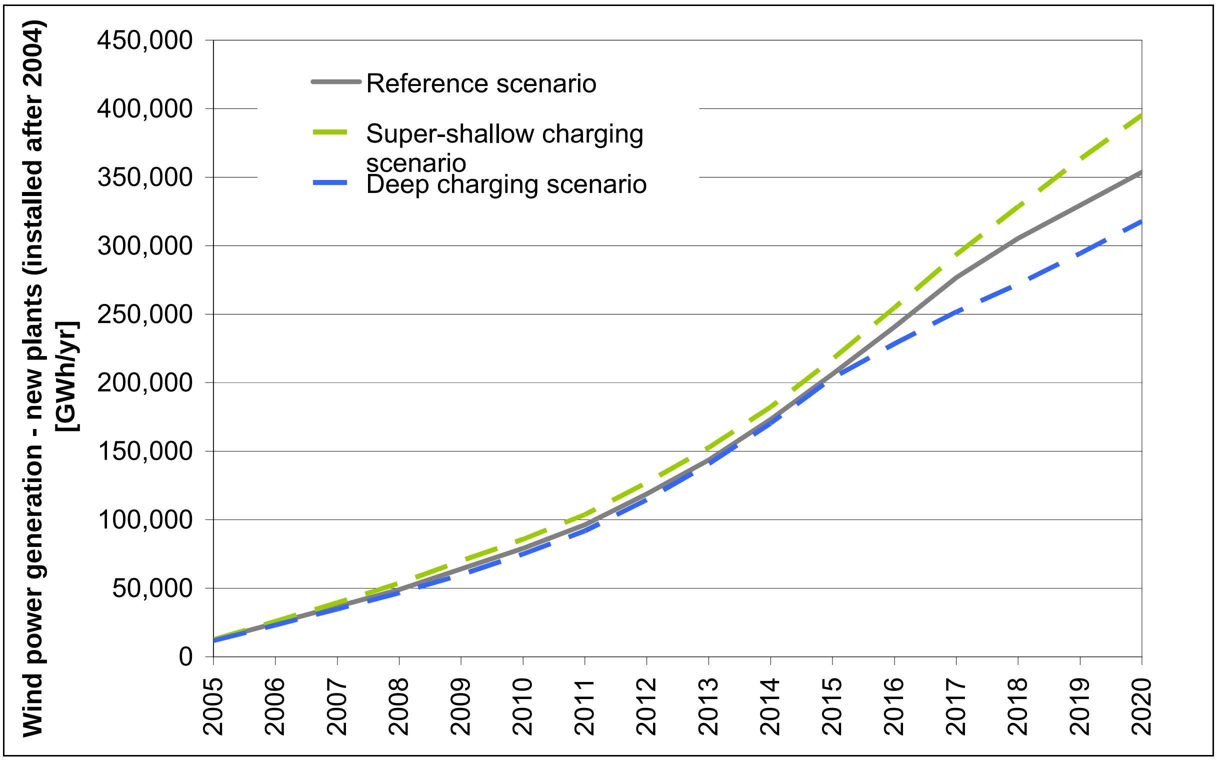

Figure 3.16 Comparison of development of wind generation from so called “new plants” (installed after 2004) in EU-25 Member States for different cost allocation policies up to 2020.

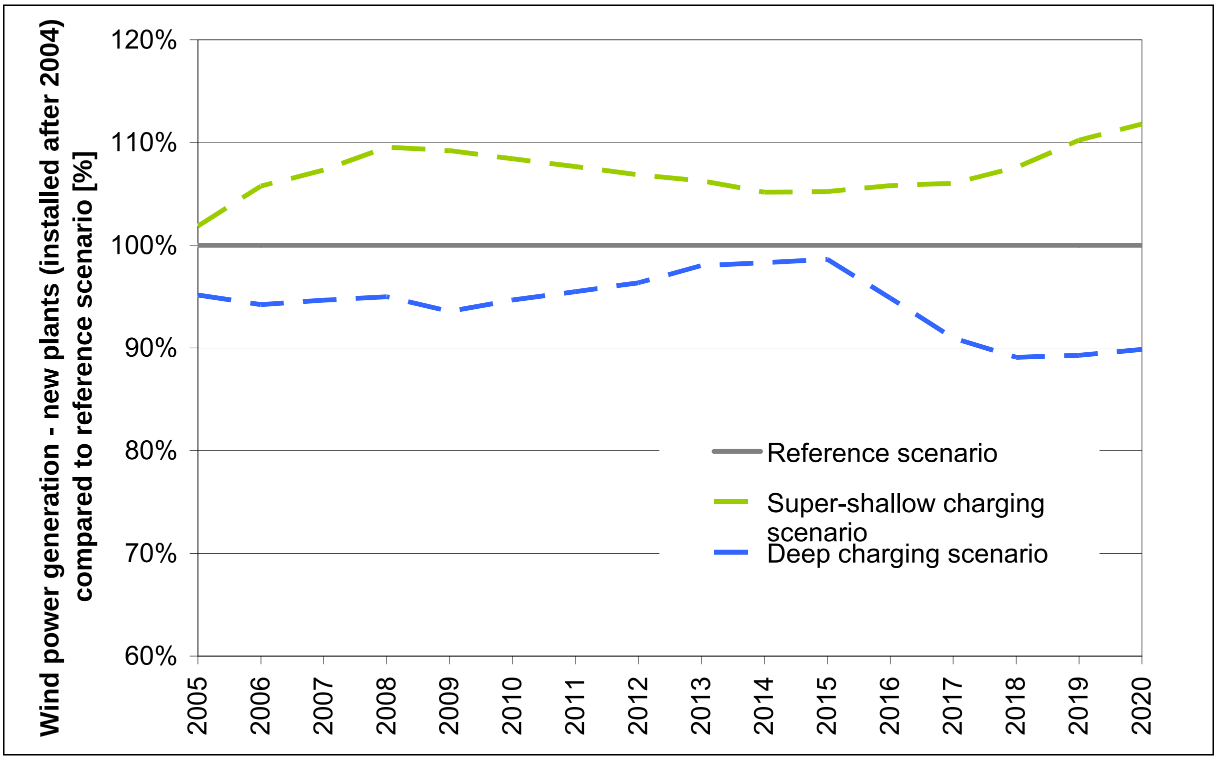

Figure 3.17 Development wind generation from so called “new plants” (installed after 2004) in EU-25 Member States up to 2020 for different cost allocation policies compared to the reference scenario.

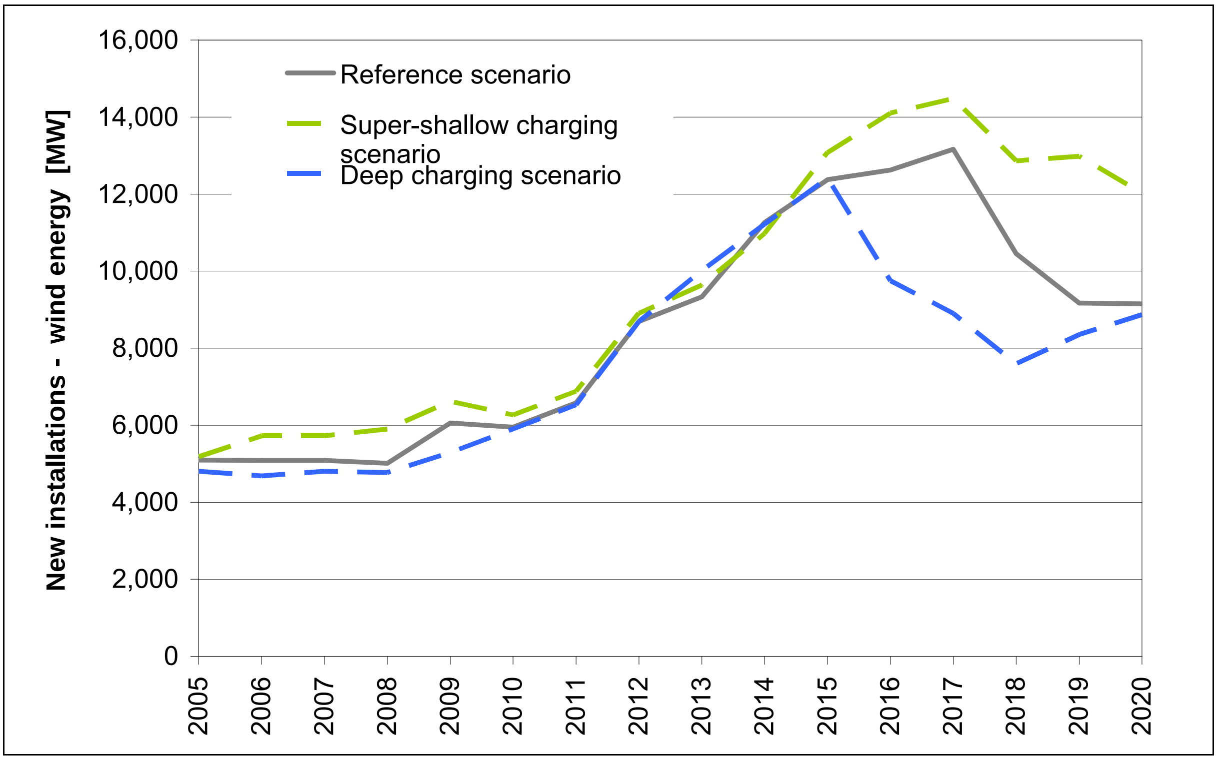

Figure 3.18 Comparison of new installations of wind power in EU-25 Member States for different cost allocation policies up to 2020.

The practice of allocation of additional cost related to wind power integration obviously affects the development of this technology. However due to quota obligations implemented in selected countries like United Kingdom, Belgium, Italy, Sweden and Poland changes in wind power development have an impact on other technologies as well. This effect is exemplarily illustrated in Figure 3.19. Given RES-E quotas in the mentioned countries additional installations of wind on- and offshore are compensated for by lower installations for biogas, biomass and large hydro power.

Further, this graph indicates, that deviations from the reference case are higher for wind offshore which might be explained by higher cost for grid connection for this technology.

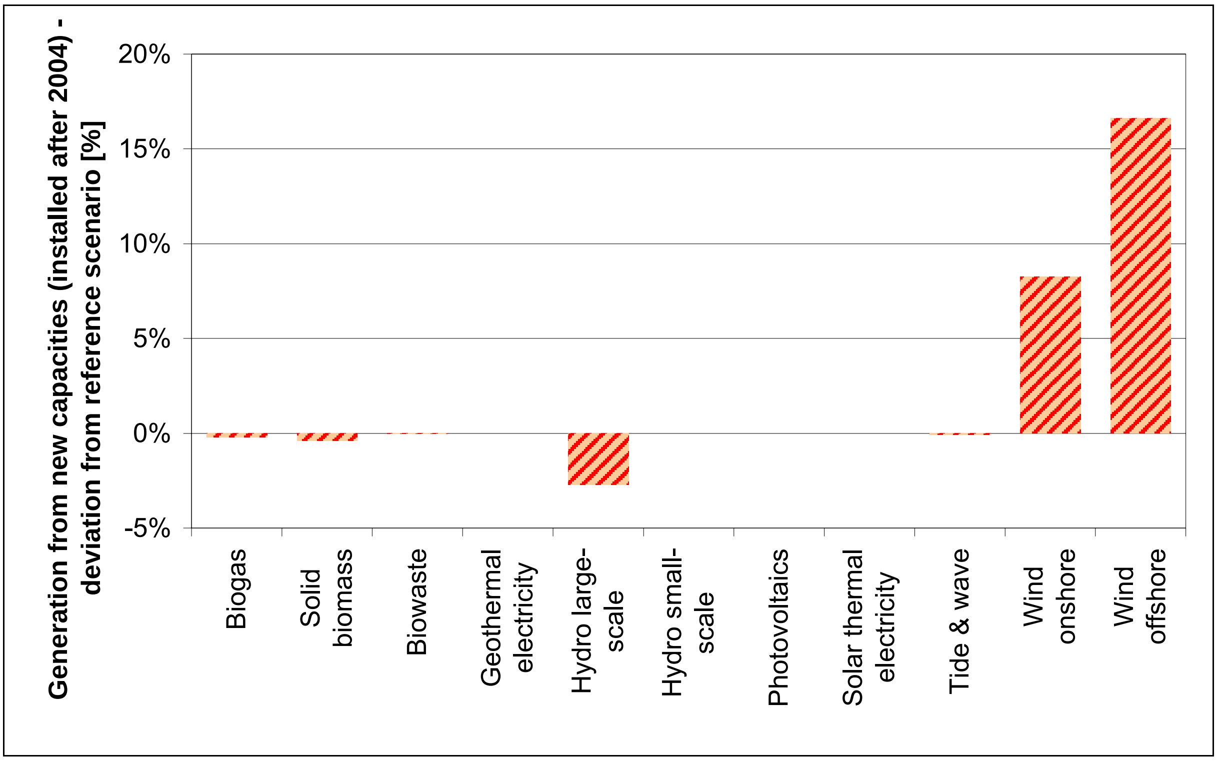

Figure 3.19 Super-shallow charging scenario – Changes in generation from new plants (installed after 2004) for different RES-E technologies in EU-25 Member States in 2020 compared to the reference scenario.

3.3.3 Sensitivity analyses – cost for grid and market integration of wind power

The following analysis show the bandwidth of cost for grid and market integration of wind power according to scenarios implemented in the software tool ***GreenNet*** and are based on the reference case with respect to the cost allocation practice.

In order to reflect the bandwidth of grid reinforcement cost shown in empirical data, three cost scenarios are implemented in ***GreenNet***. According to these scenarios annual cost for grid reinforcement in the EU-25 Member States are in the range of 139 to 510 M€ in 2020. Additionally for the *Average Scenario* annualized reinforcement cost due to historic installations of 100 M€ are calculated.

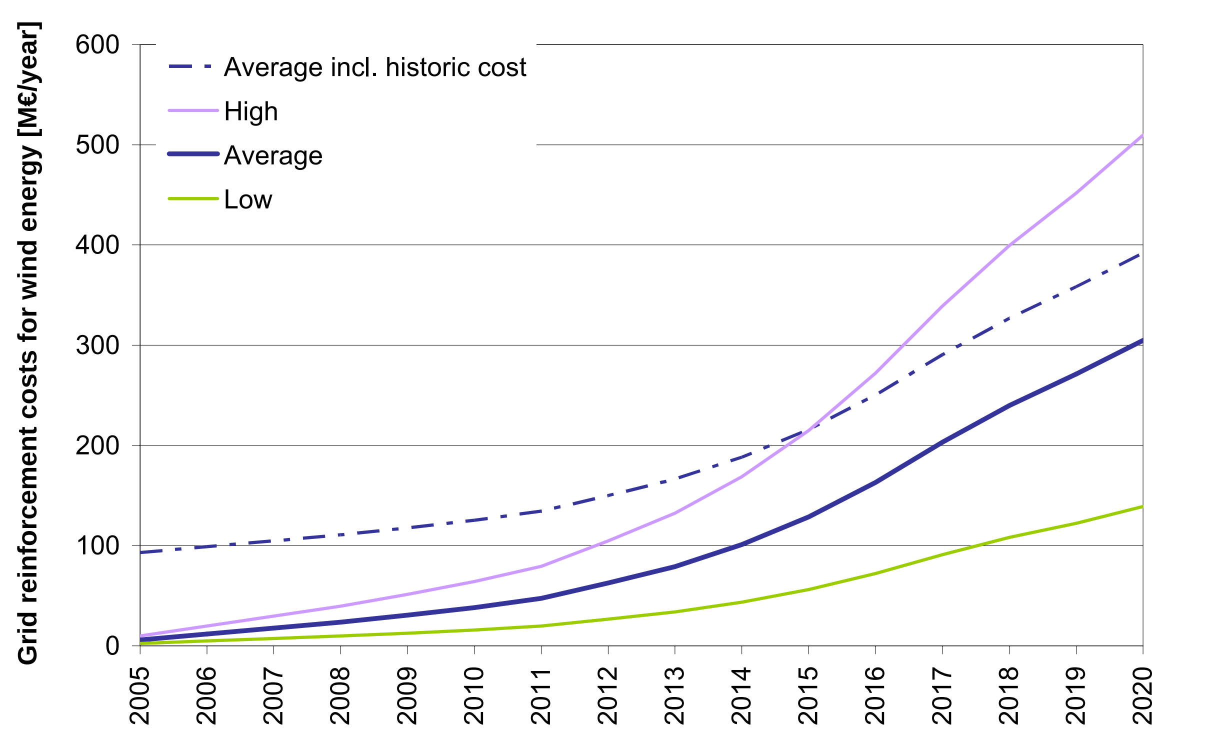

Figure 3.20 Development of grid reinforcement cost due to grid integration of wind power in EU-25 Member States up to 2020 for different cost scenarios implemented in the software tool ***GreenNet***.

For system operation cost of wind power country specific conditions are reflected in form of scenarios for the capacity credit of wind power. Furthermore the simulation tool allows to simulate the theoretical case without any capacity credit.

A new feature developed within the project ***GreenNet*-EU27** is the consideration of demand response for providing system capacity as an alternative to the installation of additional power capacity.

In Figure 3.21 results for the scenarios mentioned are compared again based on the cost allocation practice according to the reference case. System operation costs thereby include costs for balancing wind power and costs for system capacity.

System operation cost for the EU-25 Member States range from 1422 M€/yr to 3100 M€/yr in 2020 depending on the capacity credit scenario applied. When neglecting the capacity credit of wind power system operation costs are doubling compared to the *Average Scenario*.

Providing system capacity in form of demand response leads to system operation costs that are in the range of 20 % of corresponding numbers for the *Average Capacity Credit Scenario*. This is due to the fact, that assumed annual specific cost (10 €/kW, yr) are considerably lower than assumed annualized specific investments for OCGT units (55 €/kW, yr)[9].

[9] Please note, that the overall potential for demand response in a power system is limited by the difference between base and peak load. This restriction is not implemented in the current version of ***GreenNet***.

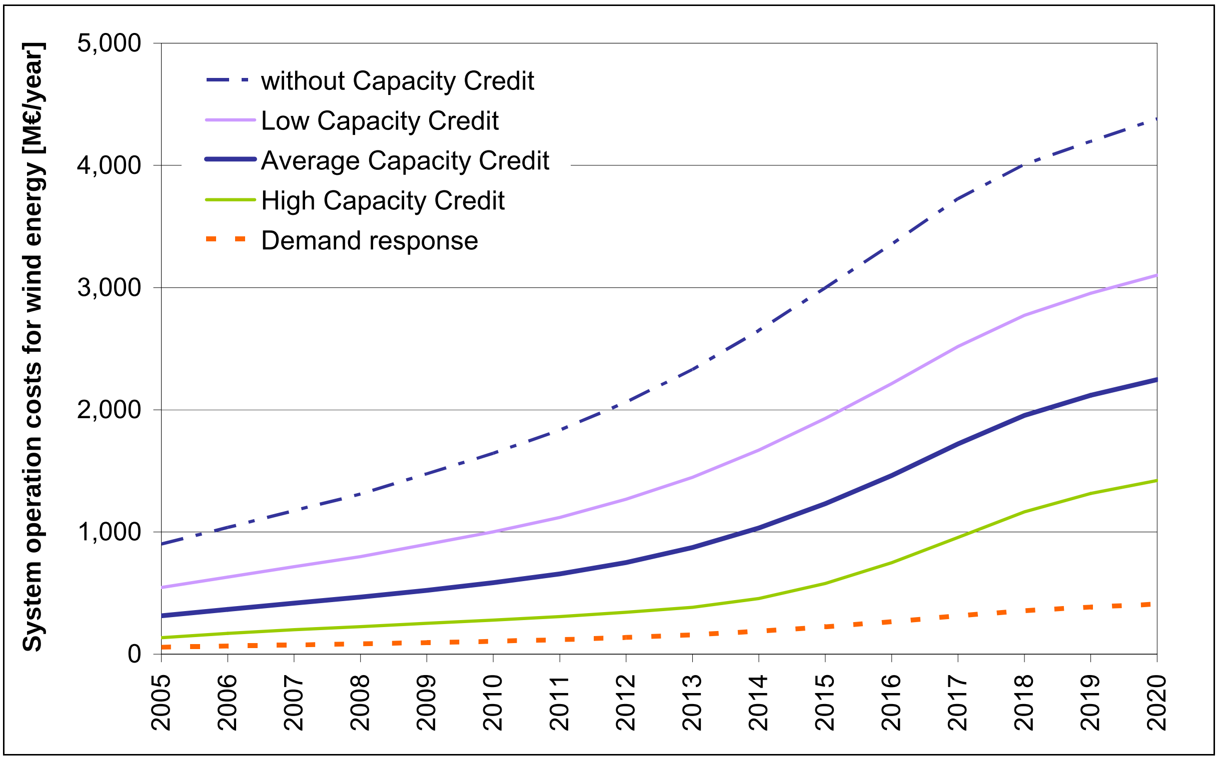

Figure 3.21 Development of system operation cost due to integration of wind power in EU-25 Member States up to 2020 for different capacity credit scenarios implemented in the software tool ***GreenNet***.

Assumptions: Capacity factor of thermal equivalent 0.85; Specific investment cost of OCGT unit 55 €/kW, yr; Option fee for demand response 10 €/kW, yr

3.3.4 Results of Energy Efficiency scenarios

Exemplarily results for two promotion strategies for Energy Efficiency (EE) applied commonly in the EU-25 Member States are shown in this chapter. Promotion schemes investigated are tax incentives (30%) and granted tariffs (20 €/MWh(saved), guaranteed for 10 years).

Tax incentives in ***GreenNet*** are modeled as grants on investments without any budget restriction i.e. a tax incentive of x % corresponds to an investment subsidy of the same size. Granted tariffs are applied per unit of saved energy – e.g. 20 €/MWh(saved) – and guaranteed for a certain period. Within the investigated scenario no budget restriction is considered.

Figure 3.22 compares the development of gross electricity demand according to PRIMES baseline with those of investigated EE-scenarios. While the PRIMES baseline forecast shows an average increase of gross demand in the range of 1.5 % annually, demand remains almost constant for the investigated EE-scenarios up to 2020.

Compared to the PRIMES baseline consumption in 2020, cumulative energy savings amount to 19 % for the tax incentive scenario and 18 % for the granted tariff scenario (see Figure 3.23).

On country level cumulative energy savings in 2020 are varying in a wide range between 8 and 40 %. Countries showing cumulative savings lower than 10 % are Poland, Spain, the Netherlands and Luxembourg. Highest savings are achieved in Malta, France, Sweden, Czech Republic and Slovakia and Denmark.

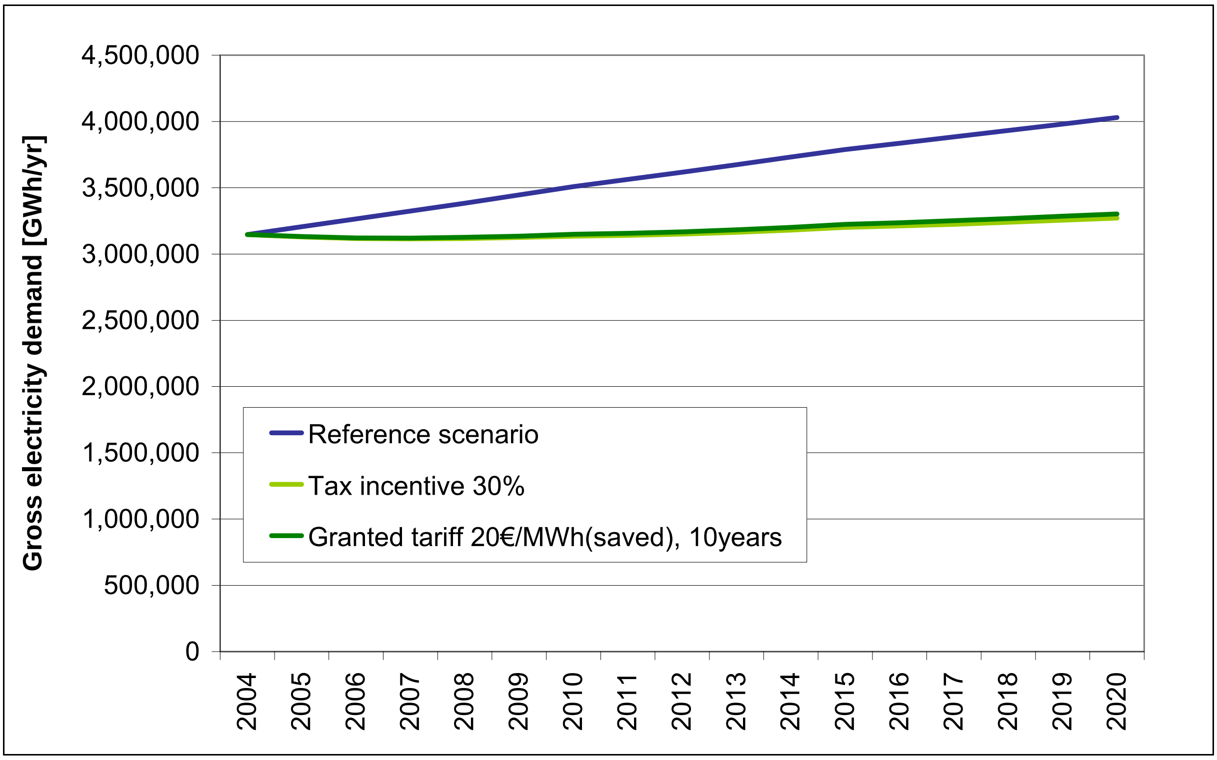

Figure 3.22 Development of gross electricity consumption in EU-25 Member States up to 2020

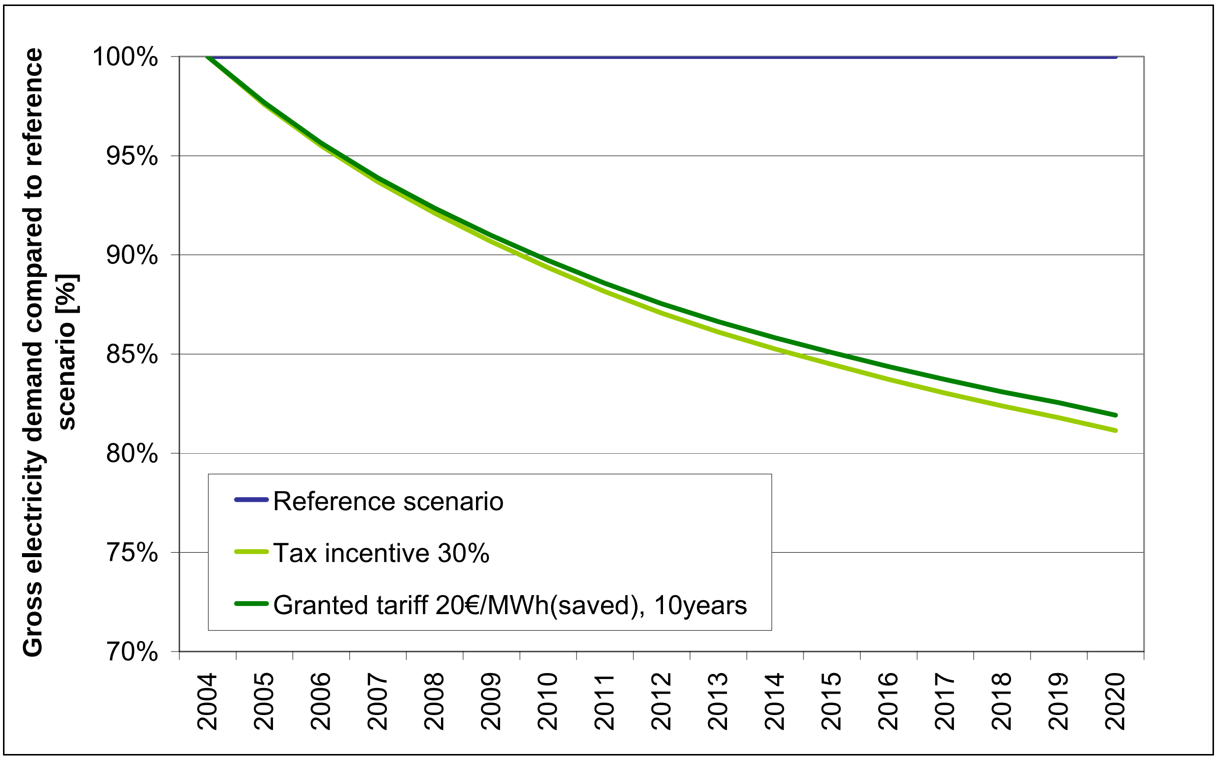

Figure 3.23 Development of gross electricity consumption in EU-25 Member States up to 2020 compared to the PRIMES baseline scenario.

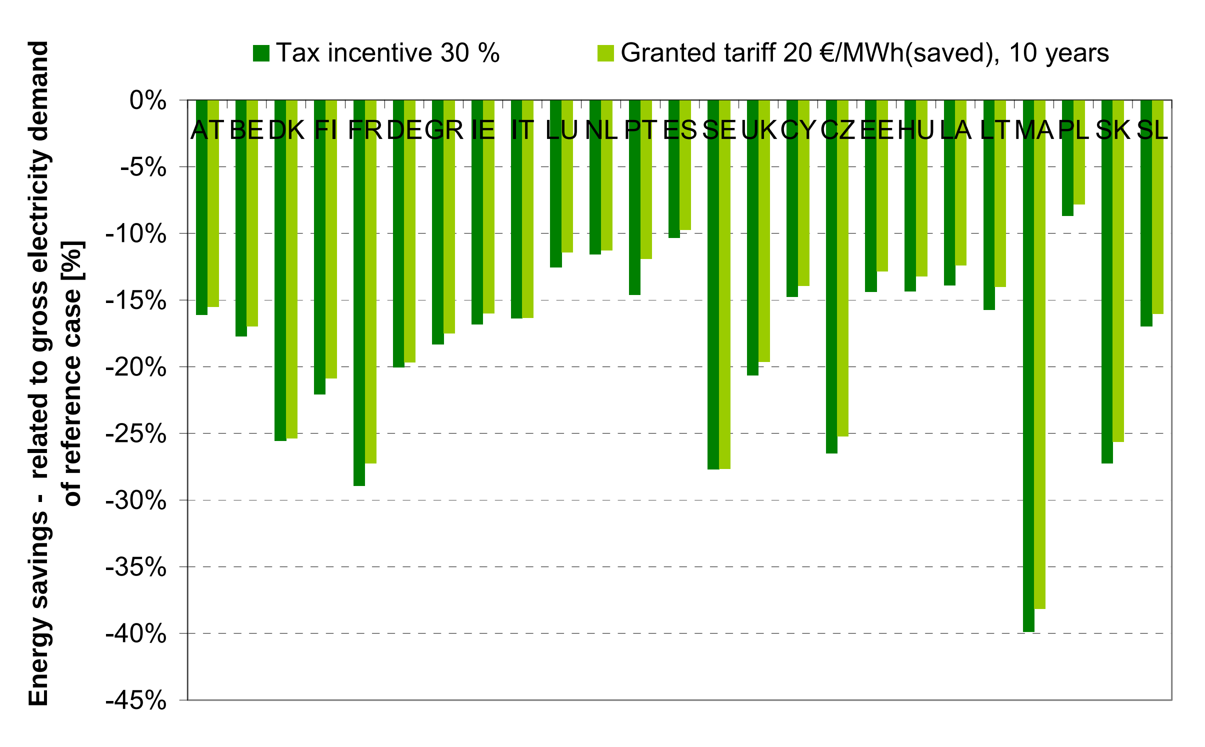

Figure 3.24 Cumulative energy savings in 2020 as a share of gross electricity demand according to PRIMES baseline on country level.

While a reduction in electricity demand doesn't affect RES-E deployment in countries with price driven promotion instruments, there is a linkage between both developments for quantity-driven instruments given that RES-E quotas are defined as a share of electricity consumption.

This effect is illustrated in the following graph on EU-25 level. For the investigated EE-scenarios RES-E generation from plants installed after 2004 is around 1 % less compared to the reference scenario in 2020. As price-driven instruments for RES-E support in the EU-25 region are dominant, the linkage between demand and RES-E deployment is minor.

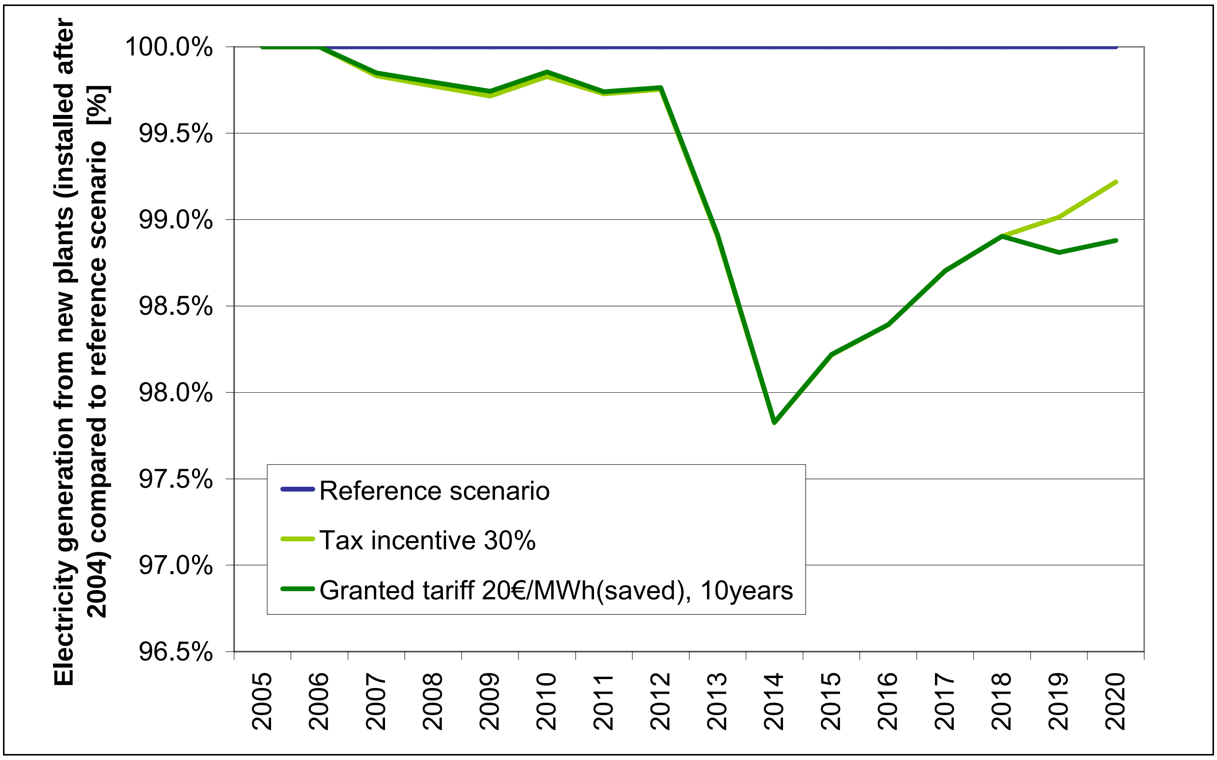

Figure 3.25 Development of RES-E generation from new plants (installed after 2004) in EU-25 Member States compared to the reference scenario.

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4 CONCLUSIONS

Effects of the cost allocation practice on RES-E deployment shown have to be interpreted against the background of underlying support policies for RES-E in Europe. Of course a change of the cost allocation policy is likely to go in hand with an adoption of RES-E support policy.

However the reader should be aware of the fact, that effects shown reflect the financial aspect of cost allocation only. As the issue of grid integration represents a considerable non-financial barrier to the deployment of RES-E technologies relying on locally primary energy sources effects are likely to be underestimated.

Carried out sensitivity analyses indicate a broad range of cost for system and grid integration depending on the selected scenario. Therefore for in depth analyses on country level, settings have to be proven carefully against country specific conditions.

As shown in the results, the linkage between EE-measures and RES-E deployment is minor. Again this result has to be interpreted against currently implemented RES-E promotion schemes, dominated by price driven instruments.

According to the results shown in this report wind power is likely to represent the dominant RES-E technology in terms of generation in the EU-25 Member States in 2020. This trend supports the special emphasis given to the issues of grid and market integration of this technology within this project.

Further developments of the software tool ***GreenNet*** might include an extension of the geographical coverage and the extension of the modeling approach presented in this report to further RES-E technologies.

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APPENDIX

This appendix contains selected results related to RES-E deployment for countries not being covered within chapter 3 of this report.

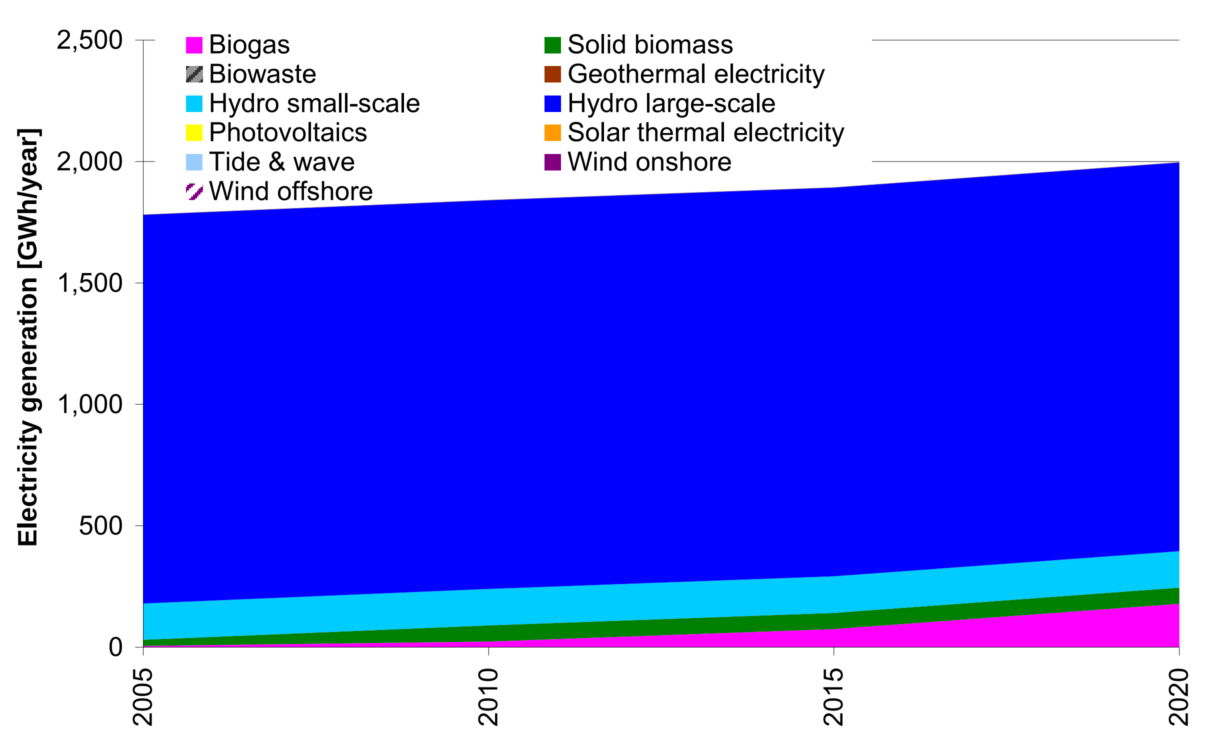

Figure A-1 Bulgaria – development of RES-E generation up to 2020 according to the reference scenario

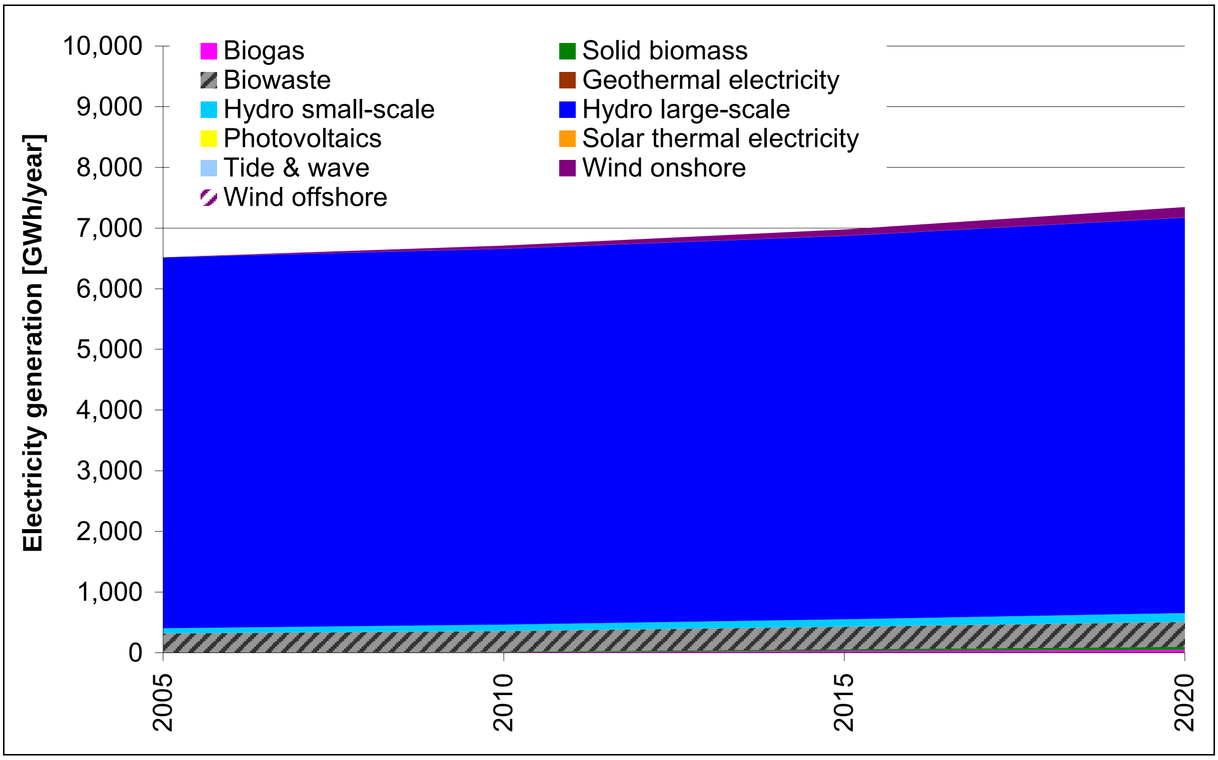

Figure A-3 Croatia – development of RES-E generation up to 2020 according to the reference scenario

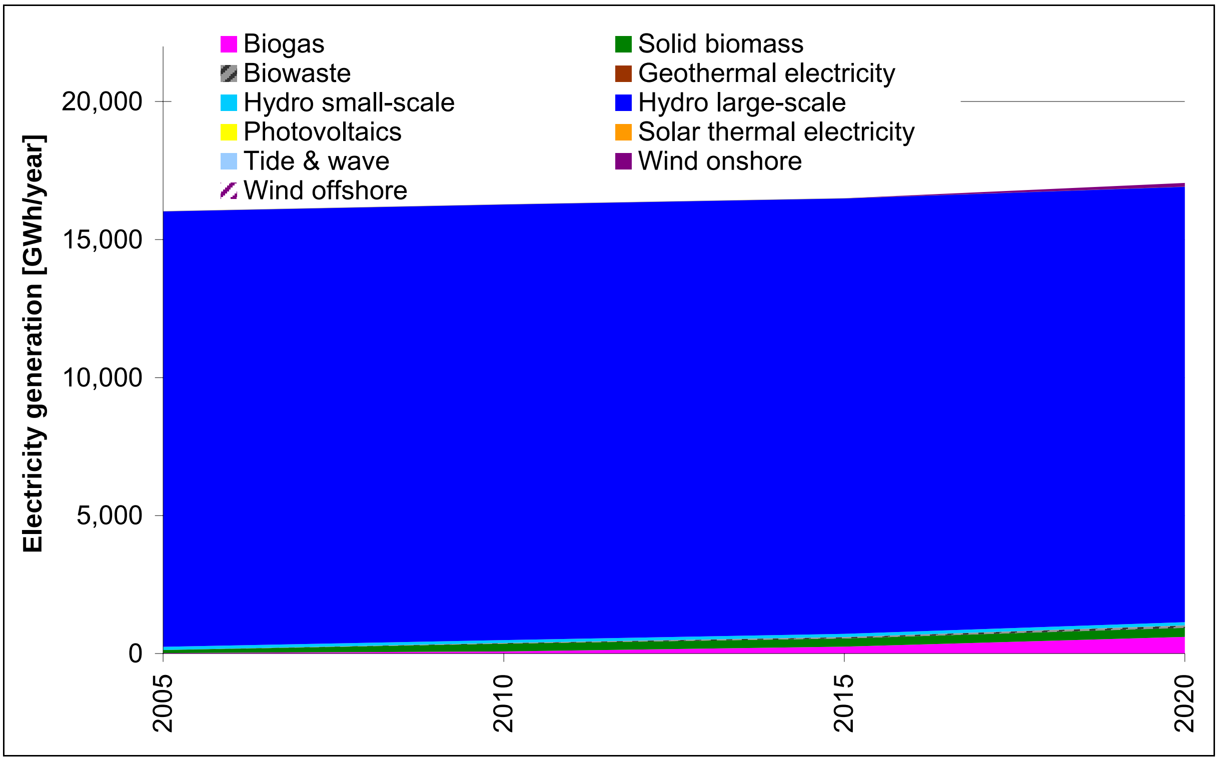

Figure A-2 Romania – development of RES-E generation up to 2020 according to the reference scenario

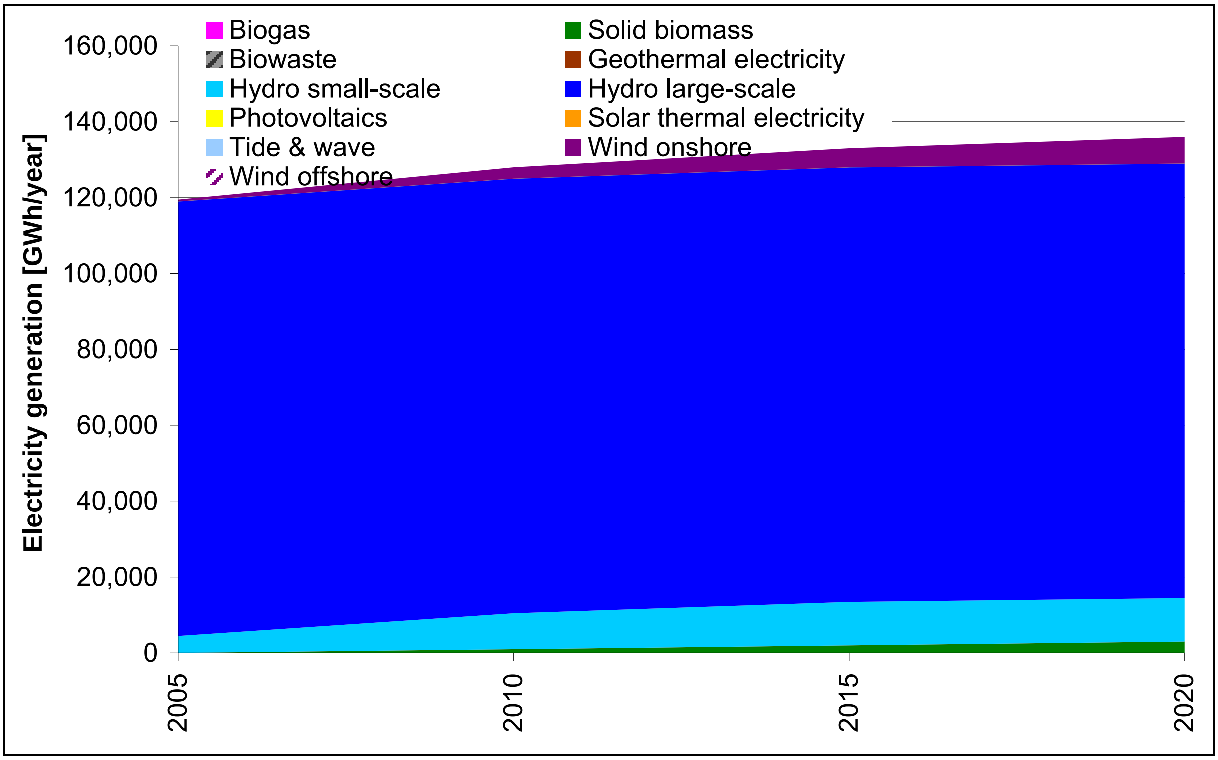

Figure A-4 Norway – development of RES-E generation up to 2020 according to the reference scenario

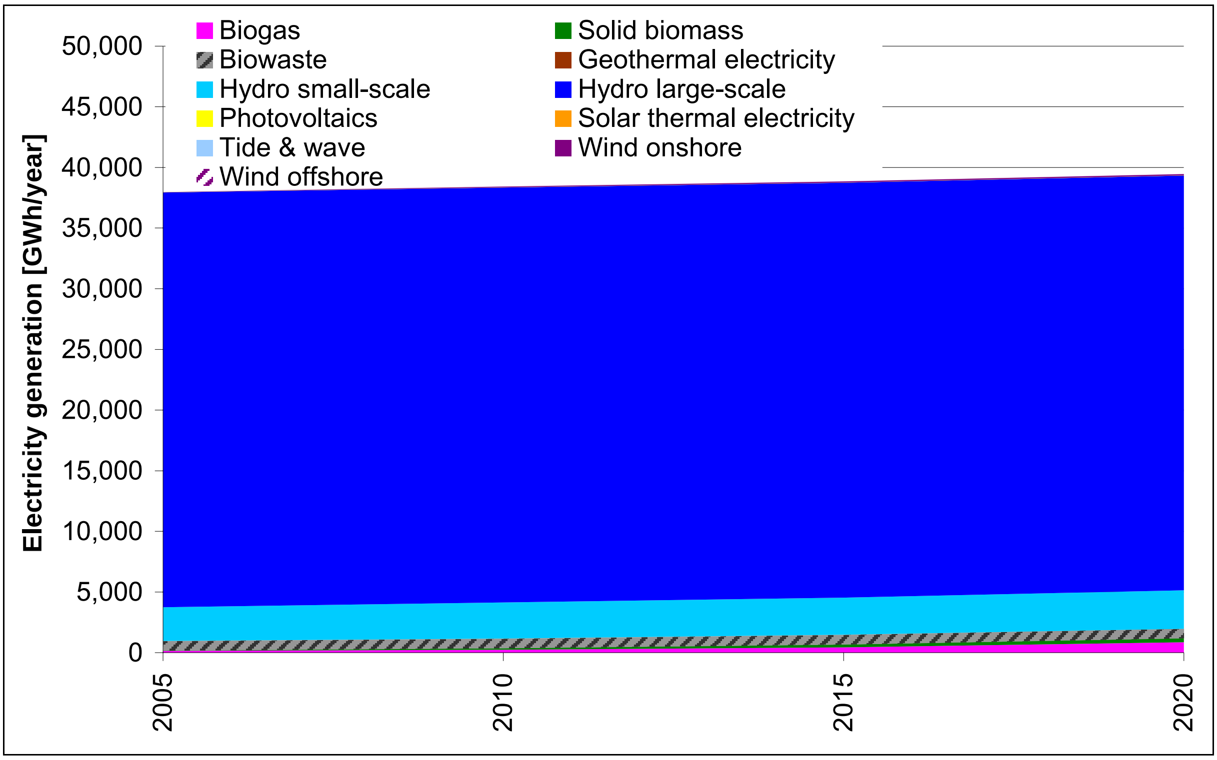

Figure A-5 Switzerland – development of RES-E generation up to 2020 according to the reference scenario