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Final report

Optimized pathways towards ambitious climate protection in the European electricity system

(EU Long-term scenarios 2050 II)

Financed by the Federal Ministry for the Environment, Nature Conservation, Building and Nuclear Safety

Part of the RWTH Aachen study "Required investments into the European energy infrastructure in the light of climate aspects"

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Institute

Fraunhofer Institute for Systems and Innovation Research ISI

Breslauer Str. 48, 76139 Karlsruhe, Germany

www.isi.fraunhofer.de

Contacts

Dr. rer. pol. Frank Sensfuß

Telephone: 49 (0)721 6809 133, Fax 0721/809-272

e-mail: Frank.Sensfuss@isi.fraunhofer.de

Dr. rer. pol. Benjamin Pfluger

Telephone: +49 (0)721 6809 163, Fax 0721/809-272

e-mail: Benjamin.Pfluger@isi.fraunhofer.de

Executive Summary

Scope of the study: This study investigates concrete and realizable pathways towards a European electricity sector in line with the goal of keeping global warming below 2°C. It uses scenario analysis to examine the development of the electricity sector in the EU 27, Norway and Switzerland up to the year 2050. The study is carried out by the Fraunhofer Institute for Systems and Innovation Research ISI for the German Federal Ministry for the Environment, Nature Conservation, Building and Nuclear Safety. It provides additional scenarios to the previous study "Tangible ways towards climate protection in the European Union", published in 2011. The results of the scenarios function as input data for a comprehensive grid study "Required investments into the European energy infrastructure in the light of climate aspects" conducted by the RWTH Aachen and funded by the German Federal Ministry for the Environment, Nature Conservation, Building and Nuclear Safety.

Focus: The scenario analysis focuses on three major aspects:

First of all, it provides a detailed picture of possible technology pathways in the electricity sector characterized by low carbon emissions and different levels of electricity demand. Therefore a cap of 75 Mt is applied to the average annual CO_2 emissions in 2050, equivalent to a 95% reduction compared to 1990 levels in all three scenarios. In contrast to the previous study published in 2011, the technology mix includes CCS and nuclear as additional decarbonisation options. The analysis is carried out using a least cost approach and modelling the entire time frame 2020-2050 in steps of 10 years.

Secondly, the study analyzes the impacts of increased efficiency when consuming electricity on the required infrastructure, the electricity supply structure and the cost of the system. Scenario D "Moderate Demand" is based on the electricity demand of the TRANS-CSP study (DLR 2006) and projects a moderate demand development in Europe. In addition, a scenario with higher electricity demand is calculated, which is based on the demand level in Scenario 3 ("Diversified supply technologies scenario") of the Energy Roadmap 2050 published by the European Commission in 2011 (European Commission 2011).

In a third step, the impact of changed public acceptance of land use for renewable energy is analyzed based on the example of onshore wind. Increased land use for onshore wind is applied in Scenario E and a 15 GW restriction on German offshore wind capacity is enforced in the model.

Main findings:

The study shows that ambitious CO_2 reduction in the European electricity sector can be achieved at moderate costs.

Increased efforts targeting higher efficiency in electricity consumption are important, because lower demand reduces the cost of electricity supply to a considerable extent. This also implies a reduced need for sometimes contested infrastructures such as power lines and electricity generation facilities.

Another central finding is that greater acceptance of onshore wind can help to reduce the total cost of power supply.

As CO_2 targets become more ambitious over time and trigger a strong growth in renewable electricity generation, grid infrastructure will need to be extended.

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Glossary

AC	Alternating current
(AA)-CAES	(Advanced adiabatic) compressed air energy storage
BMUB	Federal Ministry for the Environment, Nature Conservation, Building and Nuclear Safety
CAPEX	Capital expenditures
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CO_2	Carbon dioxide
CSP	Concentrating solar power
DC	Direct current
ENTSOE	European Network of Transmission System Operators for Electricity
ETS	European Emissions Trading Scheme
EU	European Union
FLH	Full-load hours
GIS	Geographic information system
GT	Gas turbine
GW	Gigawatt
HVDC	High voltage direct current
NREAP	National Renewable Energy Action Plan
MENA.	Middle East and North Africa
Mt	Megaton
MWh	Megawatthours
NTC	Net transfer capacity
O&M	Operation and maintenance
PHES	Pumped hydro electric storages
PV	Photovoltaic
RES-E	Renewable electricity generation
TSO	Transmission system operator
TWh	Terawatthours
TYNDP	Ten-Year Network Development Plan 2012 (ENTSOE)

1 Scope and context of this study

The central motivation for this study is to provide a broadened range of decarbonisation scenarios for a detailed study of the development of the European electricity grid. Therefore this study investigates concrete least-cost pathways towards a European electricity sector in line with the goal of keeping global warming below 2°C. It analyzes the development of the electricity sector in the EU 27, Norway and Switzerland up to the year 2050. The study is carried out by the Fraunhofer Institute for Systems and Innovation Research ISI for the German Federal Ministry for the Environment, Nature Conservation, Building and Nuclear Safety. It provides additional scenarios to the previous study "Tangible ways towards climate protection in the European Union" published in 2011 (Pfluger et al.). The scenario results function as input data to a comprehensive grid study "Required investments into the European energy infrastructure in the light of climate aspects" conducted by the RWTH Aachen.

1.1 Scenario definition

The previous study "Tangible ways towards climate protection in the European Union" used two scenarios (A and B) to show that a very ambitious decarbonisation of the European electricity sector to ca 5% of 1990 emission levels is possible without nuclear and carbon capture and storage technologies (CCS). In this study, three additional scenarios are calculated with alternative scenario settings but the same target of reducing CO_2 emissions to 5% of 1990 levels. The applied CO_2 targets are given in the following table. Taking into account that overall emissions in the analysed region amounted to approximately 1500 Mt in 1990, the CO_2 emission cap in 2020 requires a reduction of more than 50% compared to 1990 levels. This level of CO_2 reduction in the power sector is discussed in the "Roadmap for moving to a low-carbon economy in 2050" (European Commission 2011a) as a possible target for the year 2030. All three scenarios include CCS technologies as part of the optimisation. Because the issue of nuclear energy is currently mainly based on political preferences in the respective countries and actual plant costs are highly uncertain, the development of nuclear generation capacity is included in the analysis by an exogenous development path which reflects the authors' current assessment of possible developments within the EU. Total nuclear generation capacity is assumed to decline to ca 55 GW in 2050 (ca 41% of the capacity in 2010).

Table 1 Applied CO_2 limits

Scenario	2020	2030	2040	2050	Unit
Scenario C ("Efficiency")	700	400	150	75	Mt
Scenario D ("High demand")	700	400	150	75	Mt
Scenario E ("Modified wind")	700	400	150	75	Mt

Scenario C is based on Scenario B's electricity demand[1] development in the previous study. Scenario D uses the same assumptions in general, but broadens the range of the scenarios by a considerably higher electricity demand which increases to approximately 4200 TWh in 2050. This is comparable to the Scenario "Diversified supply technologies scenario" of the EU Energy Roadmap 2050 (2011) (European Commission 2011) for the EU countries. Scenario E is calculated to reflect possible changes in land use and preferences regarding renewable development. It is based on the demand assumptions of Scenario C. The land available for wind onshore turbines in Europe increases and the

[1] Demand is defined as the net electricity consumption + all grid losses

wind offshore development in Germany follows a fixed path to reflect the current political debate. The demand developments of all scenarios are shown in Figure 1.

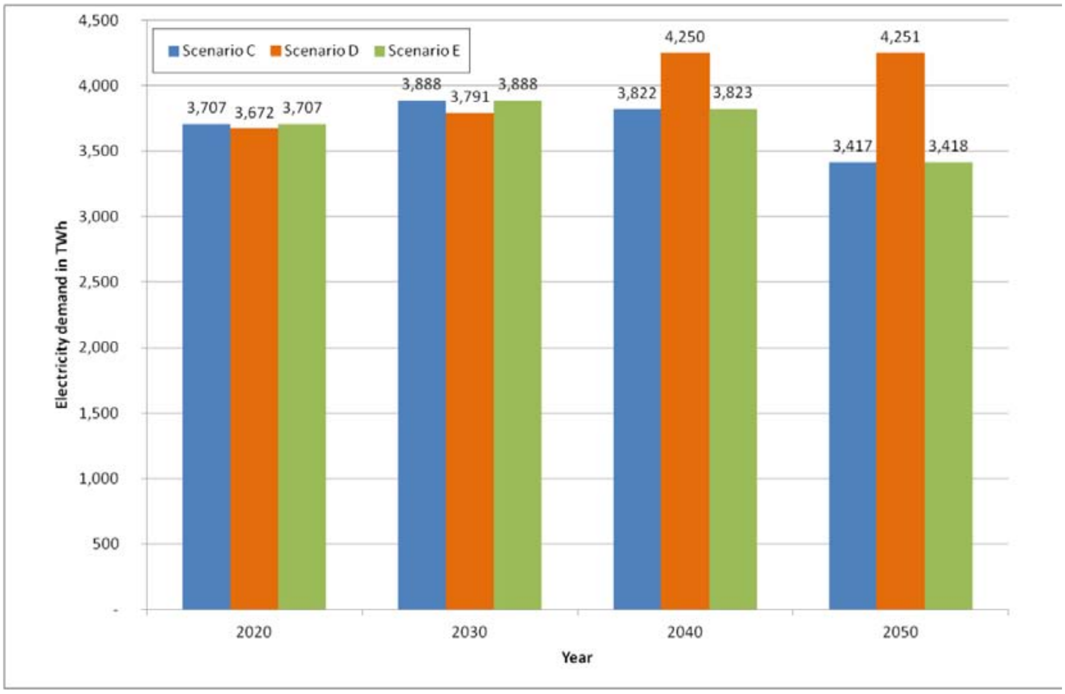


Figure 1 Assumed electricity demand of the EU-27 plus Norway and Switzerland in the selected scenarios

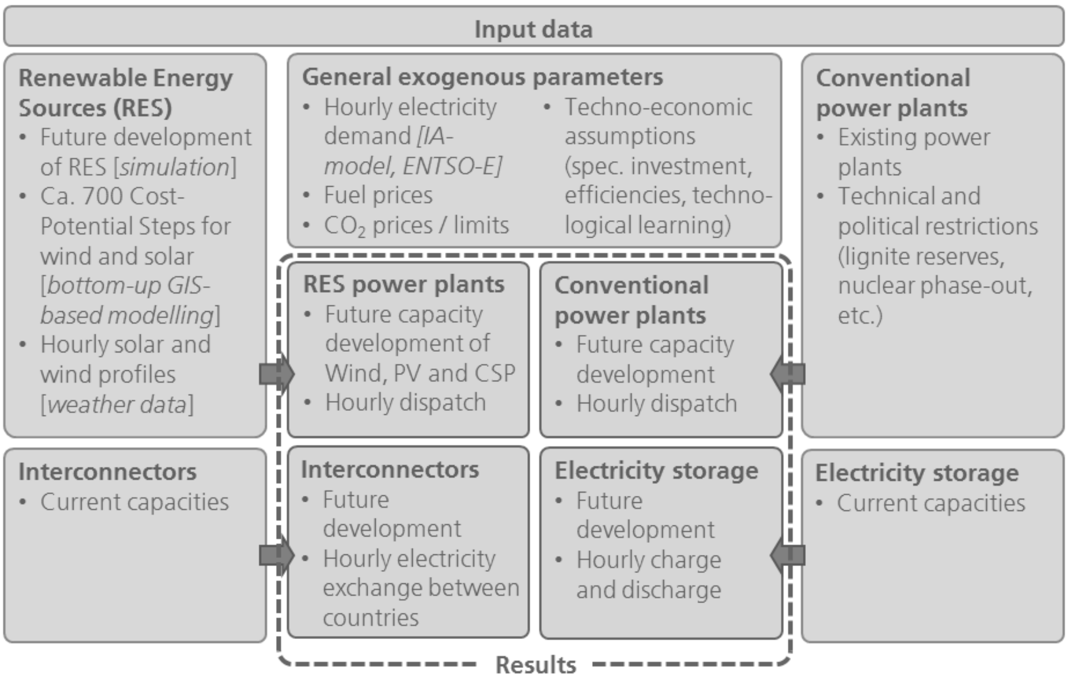
Generally it is assumed that all countries meet their RES-E obligations described by the technical portfolio in the National Renewable Energy Action Plans. In terms of grid development, it is assumed that the Ten Year Network Development Plan 2012 of the European Network of Transmission System Operators for Electricity (ENTSOE) is realised as a minimum condition. The resulting international electricity transfer capacities are applied as a minimum for the international electricity transfer capacities. In order to reflect possible political constraints on import dependency, it is assumed that each country has to meet at least 85% of its annual electricity demand by domestic production (minimum annual national self-supply rate). An overview of the central assumptions of the scenarios is given in Table 2.

Table 2 Overview scenarios

	Scenario C "Efficiency"	Scenario D "High demand"	Scenario E "Modified Wind"
CO_2 cap 2050	-95% 1990		
Electricity demand 2050 (TWh)	ca 3420	ca 4250	ca 3420
Minimum annual national self-supply rate	85%		
CCS	Free optimisation		
Nuclear	Fixed development path		
Renewable development assumption	National NREAP 2020		National NREAP 2020 + fixed development for wind offshore DE
Land use for RES-E	Standard	Greater land use for onshore wind	
Grid assumptions	TYNDP as minimum condition		

2 Overview PowerACE Optimisation model

PowerACE is a detailed model for the analysis of the electricity sector. It can be configured as agent-based simulation tool or as tool for the optimisation of electricity systems in Europe and MENA. In this study the model is used as a least cost optimisation tool to calculate pathways of renewable electricity generation, storage, conventional power plants and the required international transmission capacity. Figure 2 shows the structure of the PowerACE model with the core components.



(Graphic: Benjamin Pfluger)

Figure 2 Structure of the PowerACE Model

This study analyses the period to 2050 in steps of 10 years. The model seeks to minimize summed system cost[2] over the entire time period with perfect foresight. Perfect foresight is a technical term for the fact that the model optimizes the system with full information on all data required at any time step and on all the consequences of the decisions on any time step. Capital costs of all investment options are included as annuities. Investment options available to the model include renewable and conventional power plants, interconnectors for electricity transport and storage facilities. The objective function which determines the central target to develop an electricity system with the lowest cost possible within the given framework conditions, also includes the cost of hourly dispatch such as fuel cost or variable operation and maintenance cost.

Besides the central function to find a least cost system additional constraints can be integrated in the analysis. The most important constraint is that demand and supply have to be matched in any region of the model for every single hour of the target years which are modelled by 8760 hours. Other important constraints are CO_2 limits, annual national self supply rates and minimum or maximum conditions for single parameters such as net transfer capacity[3] for a transmission connection.

Renewable electricity generation potential is modelled in a high level of detail. The entire region is divided into more than 220000 areas. The actual generation potential and generation cost is calculated for each technology (wind onshore, wind offshore, PV and CSP) on every area based on detailed weather data. Based on the detailed potential calculation, aggregate potential steps representing areas with comparable generation cost for each renewable electricity generation technology and country are calculated in order to reduce demand on computational resources These resulting ca 1000 potential steps are characterized by technology, country, full load hours, potential capacity, specific cost and an hourly load profile for the meteorological year applied. Based on this format renewable electricity generation can be integrated into the optimisation routine.

3 Financial and technological assumptions

The model uses conventional power plants, storage facilities, grid expansions and renewable generation technologies to match demand and supply. The central technological and financial assumptions used in the three scenarios will be explained in the following.

3.1 Discounting

This study seeks to analyse optimal pathways for a low carbon electricity systems. In order to provide a level playing field for all technology options a uniform discount rate of 7% is applied to all technologies for the calculation of cost annuities. The calculation of annuities is common method to translate capital cost of an investment into a constant annual value. The annuities of investment are an important part of the cost function to be minimized by the modelling system.[4]

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2 System cost is defined as the sum of cost included in the analysis. These are fuel cost, operation and maintenance cost and the capital cost of the infrastructures such as power plants, renewable generation units, storages and cost for interconnectors between countries.

3 Net transfer capacity reflects the capacity that can actually be traded on a single line. Physical transmission capacity of lines is generally higher. For more information see: http://www.elia.be/en/products-and-services/cross-border-mechanisms/transmission-capacity-at-borders/calculation-methods

4 Another aspect which is heavily debated in the economic literature (e.g. Chichilnisky 1997) is intertemporal discounting of the cost function i.e. discounting future cost to the net present value of

3.2 Fuel prices

Another central input parameter for the analysis of the electricity sector is the development of fuel prices. In case of natural gas and hardcoal prices are based on the World Energy Outlook 2012. The prices of other fuels are based on (Zickfeld et al. 2013). In comparison to many published studies the underlying fuel prices of conventional fuels can be considered as lower end estimations. It has to be kept in mind that the fuel price scenarios used in this study represent a world with strong efforts towards climate protection thus reducing the pressure on resources and prices of conventional fuels. In general this increases the competitiveness of conventional power plants in the competition with renewable generation technologies.

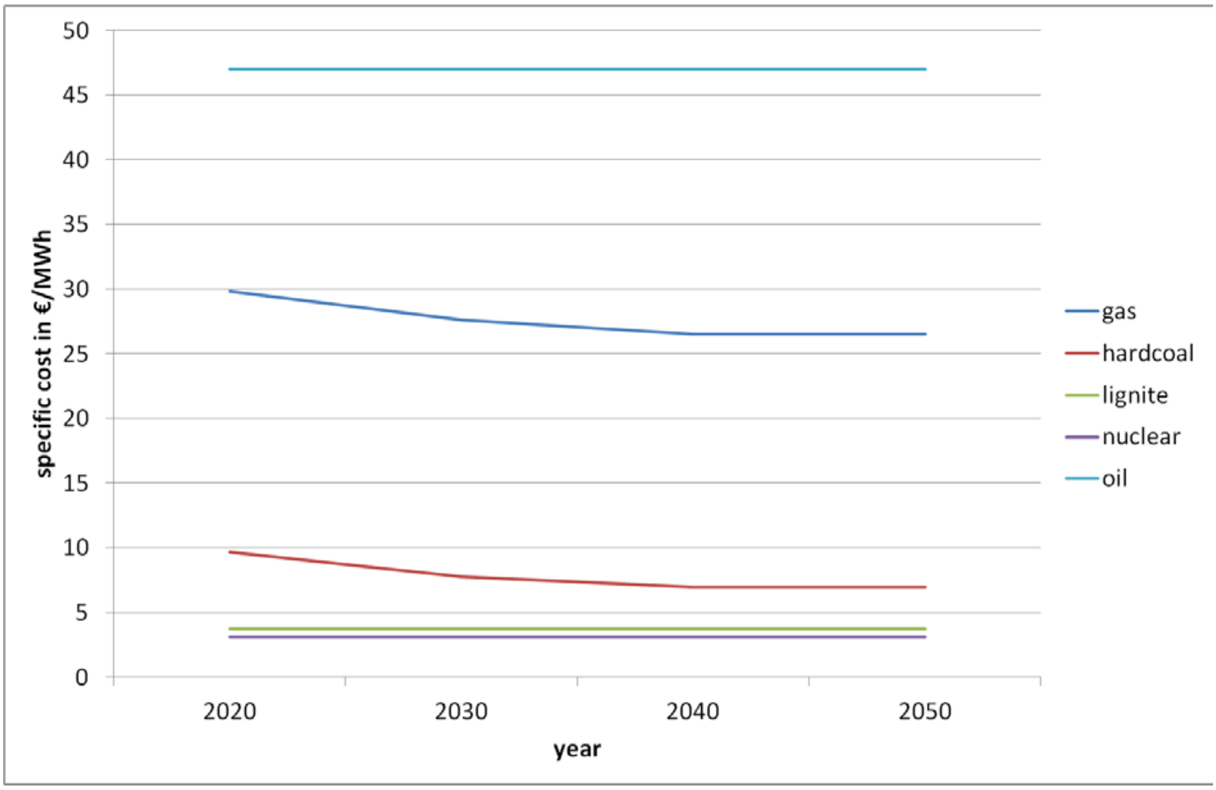

Figure 3 Fuel price assumptions in the scenario calculation

3.3 CO_2 Price

The analysis is based on a CO_2 cap for the electricity sector. As a consequence no exogenous CO_2 price is applied as input factor to the modelling system. However, as the optimization model seeks to ensure the CO_2 cap the marginal CO_2 (shadow) price can be calculated as a model output which is presented in the result chapter 5.7.4

3.4 Cost of renewable generation technologies

Renewable generation technologies are important options in a low carbon electricity sector. In this study the following cost of renewable generation technologies is assumed. All investment assumptions in this study represent overnight project cost including construction cost. The cost assumption for photovoltaic, wind onshore and wind offshore are based on (Zickfeld et al. 2013).

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today. In this study no intertemporal discount rate is applied to the cost function which means that cost have the same weight in the overall cost function at any time step regardless from the period they occur. Applying a positive intertemporal discount rate would reduce the weight necessary efforts in the future thus increasing the tendency of the modeling system to late investments in low carbon infrastructure.

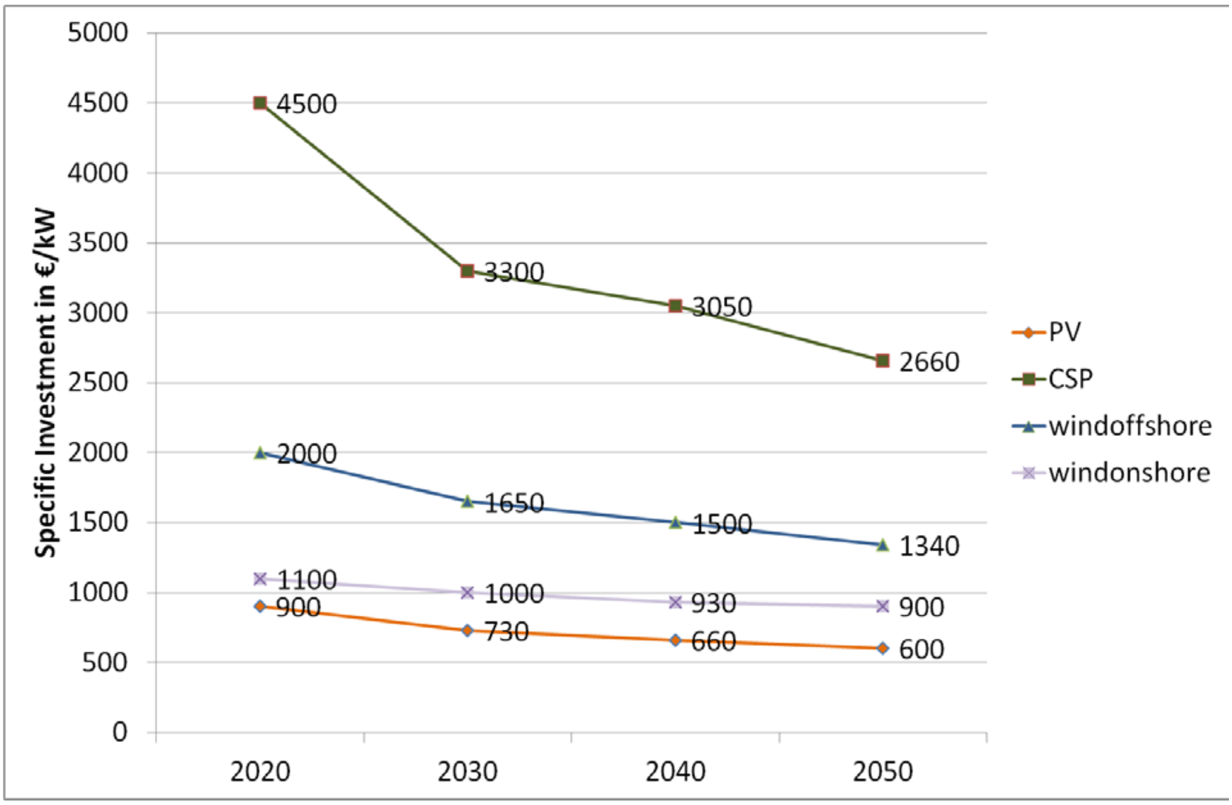


Figure 4 Assumptions on specific investment on renewable generation technologies

In case of Concentrated Solar Power (CSP) the cost represent an average value of CSP plants with storage of eight full load hours peak production capacity. The cost of CSP plants in the model differs slightly as the ratio between field and generator is calculated for each area based on the solar radiation data. The assumed cost of wind onshore represents the cost of a wind project with 120 m hub height. Due to the maturity of the technology the assumed cost reduction to 2050 is limited. The cost for photovoltaic is an approximation of plants with different sizes, but a high share of utility scale power plants with lower cost. As photovoltaic has proven to be and still remains a fast learning technology considerable cost reductions are assumed. The cost for wind offshore represent a wind power plant at 10 m sea depth and a distance to coast of 10 km. Higher sea depths and longer distances to coast are penalized in the renewable potential calculation with additional cost. As an example the additional cost for wind offshore plants with 200 km distance to coast and 50 km sea depth amount to ca 60% of the cost presented above. The applied learning assumptions on wind offshore are rather optimistic. Considering the limited importance of wind offshore in the scenarios this lower end cost assumption seems to be acceptable. The results show that even with these optimistic assumptions for wind offshore, wind onshore will in most cases continue to be the superior solution in cost terms. A comparison with the recent EU Reference Scenario 2013 (EU 2013) shows that the ranking of the renewable technologies is comparable. However the overall assumptions on specific investments in this study are lower. In case of wind and PV the cost assumptions tend to be ca 30% higher in 2050 in the EU study. Cost for large scale PV end up with 788 €/kW in 2050 in the EU study. Considering that another cost study by DIW estimates cost of large PV in 2050 to 425 €/kW (DIW 2013) the assumption of 600 €/kW can be considered a mid range assumption. In case of wind onshore a survey on typical cost assumptions shows a range between ca 600 and 1100 €/kW in 2050 (Pahle et al. 2012). Again the chosen assumption of 900 €/kW is in the mid range of this corridor. In case of CSP and wind offshore a comparison is difficult as the cost depend on various factors such as storage size or sea depth.

3.5 Conventional power plants

The existing power plant portfolio as of 2010 is included in the model in high detail, using Platts' World Electric Power Plant (WEPP) as data source[5]. The individual plants have to be aggregated into groups to some extent to keep calculation time low. Lignite power plants are restricted to countries with lignite resources like Germany as bulk transport of lignite is not cost efficient.

The development of nuclear power plants heavily depends on political decisions. Therefore the development of nuclear technologies is provided as a fixed input to the model. It is assumed that those countries which currently support nuclear energy production will keep or replace their nuclear power plants, but with a considerable decline in overall capacity in Europe. Taking into account the high uncertainty that is associated to the future development of nuclear generation technology this assumption has to be considered as one possible guess of the future outcome of political processes which has to be made within this study. The guiding idea was to provide reasonable results within the scope of this analysis based on a robust, informed guess on one possible future of nuclear in Europe. As a comparison the EU Energy Roadmap 2050 (2011) (European Commission 2011) shows different scenarios which end up with a nuclear capacity in 2050 between 15.5 and 126.6 GW. The Energy Roadmap 2050 Scenario "High RES" ends up with 40.6 GW nuclear capacity in 2050. Based on this range the projection used in this study can be considered as a moderate projection in the midfield of the broad range of possible developments.

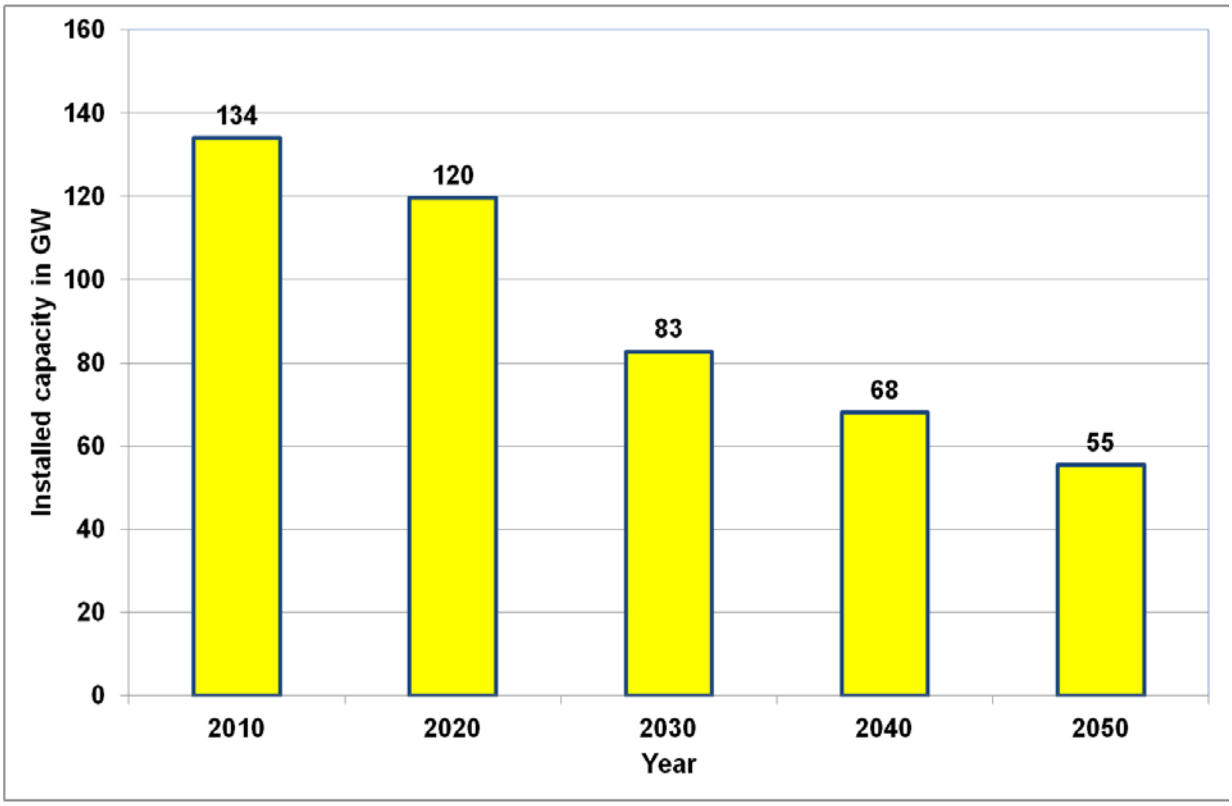


Figure 5 Assumed development of nuclear generation capacity in EU27, CH, NO

[5] For details on the database, please refer to: http://www.platts.com/Products/worldelectricpowerplantsdatabase

The hourly dispatch of existing and new plants and the construction of new plants apart from nuclear capacity is a part of the optimization problem. The least cost mix of the additional generation capacities needed to meet demand is calculated by the model. Therefore the conventional power plant options are an important part of the calculation. Table 3 provides an overview of the central parameters for power plants in this analysis. Different types of gas-fired, hardcoal and lignite power plants are available within the optimisation. Apart from nuclear and one specific gas power plant type (gas turbines), all technologies are also available as power plant with carbon capture and storage (CCS).

Table 3 Parameters of conventional power plants

Technology	Year	Efficiency	Life time	Capture rate	Invest €/kW	Fix. O&M cost in €/kW	Var. O&M cost€/MWh
CCS_Hardcoal	2020	0.39	40	0.95	3400	85	1.5
CCS_ Hardcoal	2030	0.39	40	0.95	3400	85	1.5
CCS_ Hardcoal	2040	0.39	40	0.95	3400	85	1.5
CCS_ Hardcoal	2050	0.39	40	0.95	3400	85	1.5
CCS_Gas_CCGT	2020	0.51	30	0.97	1500	22.5	2.7
CCS_Gas_CCGT	2030	0.51	30	0.97	1500	22.5	2.7
CCS_Gas_CCGT	2040	0.51	30	0.97	1500	22.5	2.7
CCS_Gas_CCGT	2050	0.51	30	0.97	1500	22.5	2.7
CCS_Lignite	2020	0.38	40	0.95	3800	114	1.5
CCS_Lignite	2030	0.38	40	0.95	3800	114	1.5
CCS_Lignite	2040	0.38	40	0.95	3800	114	1.5
CCS_Lignite	2050	0.38	40	0.95	3800	114	1.5
Hardcoal	2020	0.48	40	0	1700	42.5	1.5
Hardcoal	2030	0.48	40	0	1700	42.5	1.5
Hardcoal	2040	0.48	40	0	1700	42.5	1.5
Hardcoal	2050	0.48	40	0	1700	42.5	1.5
Gas_CCGT	2020	0.6	30	0	750	11.25	2.7
Gas_CCGT	2030	0.6	30	0	750	11.25	2.7
Gas_CCGT	2040	0.6	30	0	750	11.25	2.7
Gas_CCGT	2050	0.6	30	0	750	11.25	2.7
Gas_GT	2020	0.4	30	0	300	7.5	2.7
Gas_GT	2030	0.4	30	0	300	7.5	2.7
Gas_GT	2040	0.4	30	0	300	7.5	2.7
Gas_GT	2050	0.4	30	0	300	7.5	2.7
Lignite	2020	0.47	40	0	1900	57	1.5
Lignite	2030	0.47	40	0	1900	57	1.5
Lignite	2040	0.47	40	0	1900	57	1.5
Lignite	2050	0.47	40	0	1900	57	1.5

Source: own database constructed from various input sources.

3.6 Electricity grid

The extension of the electricity grid is one of the central technology options for the future development of the electricity sector. It competes with other technologies such as storages and generation technologies. However, a detailed modelling of the entire European electricity grid is not within the scope of this project. Therefore a simplified approach is chosen. The electricity transport between countries is represented by a transport model based on net transfer capacity (NTC)[6]. The

[6] Net transfer capacity reflects the capacity that can actually be traded on a single line. Physical transmission capacity of lines is generally higher. For more information see: http://www.elia.be/en/products-and-services/cross-border-mechanisms/transmission-capacity-at-borders/calculation-methods

cost of the extension of the transport capacity is modelled by a formula which takes into account distances, technology types such as AC or DC transmission and terrain such as ground and sea.

The required transport distance between countries is determined as the distance between the centres of each country. An overview about the total distances is given in the following figure.

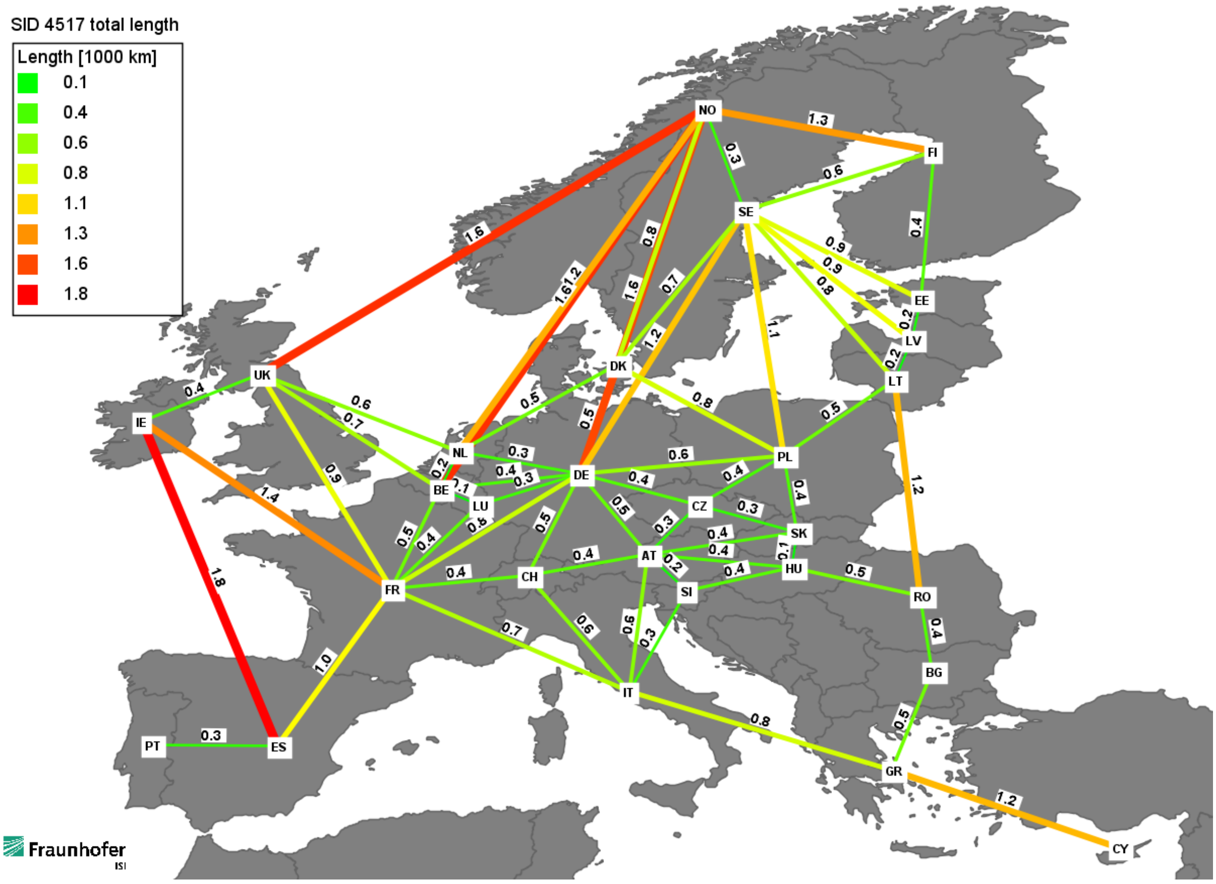


Figure 6 Transport distances in the underlying grid model

Thereby sea distances and onshore distances are differentiated. Onshore connections can be realized as AC or DC connection, of which both options can be calculated with a certain share of overhead or underground connections. In this study it is assumed the new lines in Europe are realized as DC connections with an underground cable share of 50%. Due to the higher cost of underground cables and the long distances between the centres of each country it can be argued that the assumed cost of the grid extension for international transport are rather high. The resulting costs for the connections between countries are displayed in the following figure. Any interconnector capacity that is built in the model is included in the system cost calculation with the corresponding cost. It is important to note that the cost of the connections between countries are higher than the cost of the short cost cross border connections in order to account for reinforcements in the national grids that may be caused by increasing cross border flows

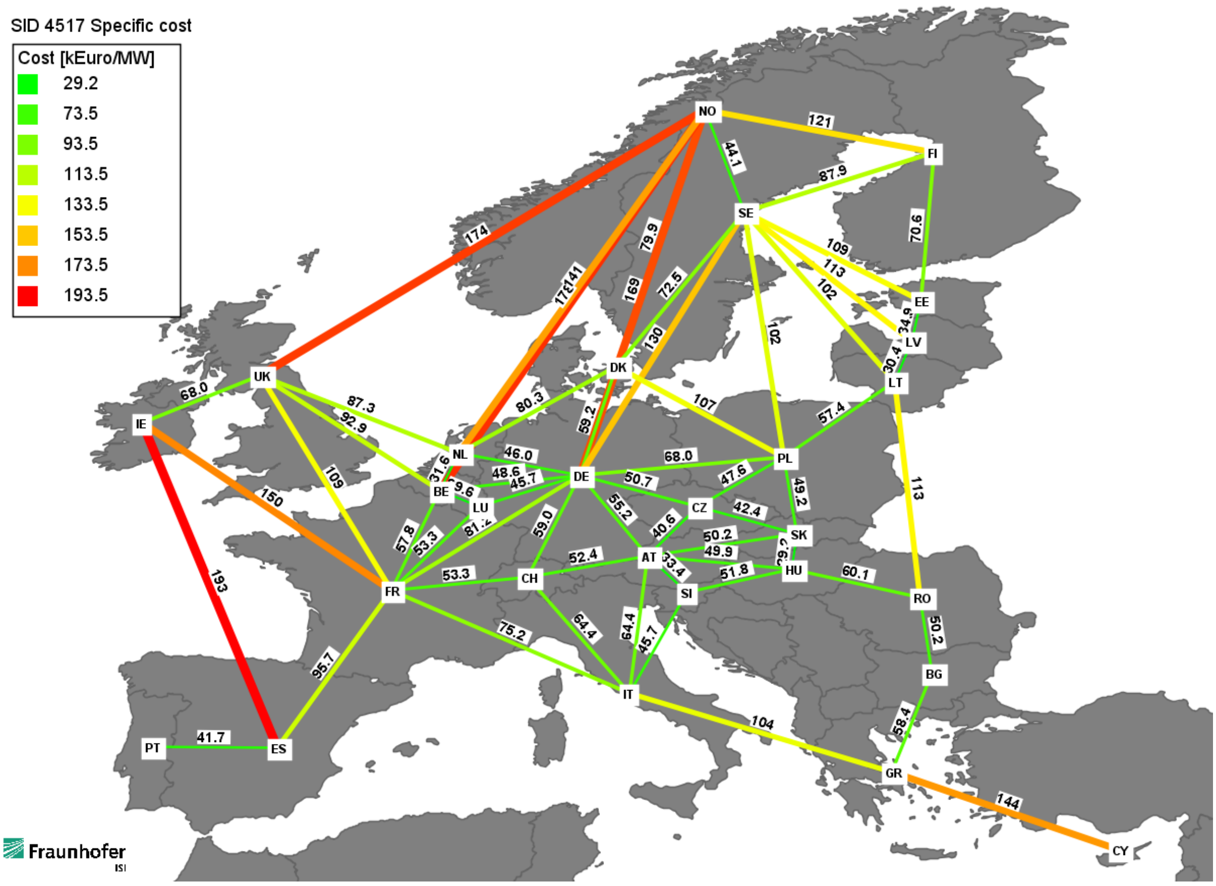


Figure 7 Specific investments for the extension of connections between countries in the scenarios

The existing interconnector capacity is included in the optimization as a minimum condition. In addition to the existing interconnector capacity it is assumed that the ENTSOE Ten-Year Network Development Plan 2012[7] grid connections are built. Further extensions of the interconnections between countries are part of the optimization procedure.

3.7 Storage technologies

Storage technologies are an important part of the electricity sector. In our modelling approaches storages are divided in three categories: hydro reservoir storages, pumped storages and new storage technologies.

3.7.1 Hydro Storage

Hydro reservoir storages are modelled separately from hydro run of river plants and pumped storage plants by the following approach: The national electricity annual generation and installed capacity of hydro storages are given as input parameters to the model. The actual hourly production of electricity can be dispatched freely by the model within the limits of the installed capacity and by the condition that it has to meet annual production. The actual capacity and possible annual production is given as a fixed input according the best knowledge of the authors. Known projects and potentials for the extension of hydro reservoir storages are taken into account. An overview of the hydro storage capacities is given in Figure 8.

[7] https://www.entsoe.eu/major-projects/ten-year-network-development-plan/tyndp-2012/

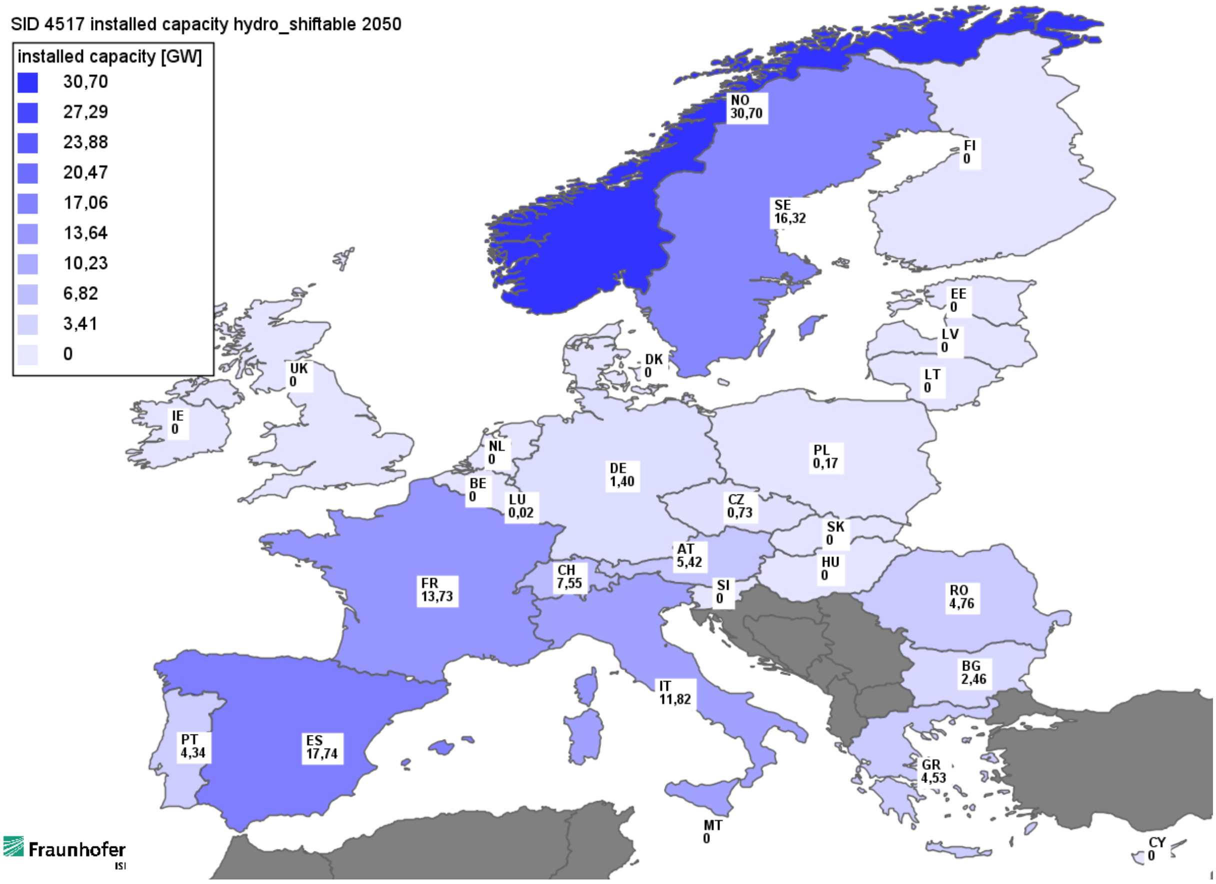


Figure 8 Installed capacity of hydro storage in 2050

3.7.2 Pumped Hydro Storage

Another important source of flexibility in the electricity system is pumped hydro storages. In order to keep computation times at a reasonable level all pumped hydro storages of a given country are aggregated into one cumulated pumped hydro storage plant with a system efficiency of 80% and a storage volume of eight full load hours. The actual capacity is given as a fixed input according the best knowledge of the authors. Known projects and potentials for the extension of hydro pumped storages are taken into account.

3.7.3 New storage technologies

In addition to hydro technologies various other storage technologies are discussed for the electricity sector. An overview of the cost ranges of the major technologies is given in the following figure. It has to be stated that storage technologies are very demanding in computational resources. Therefore a simplified approach is necessary.

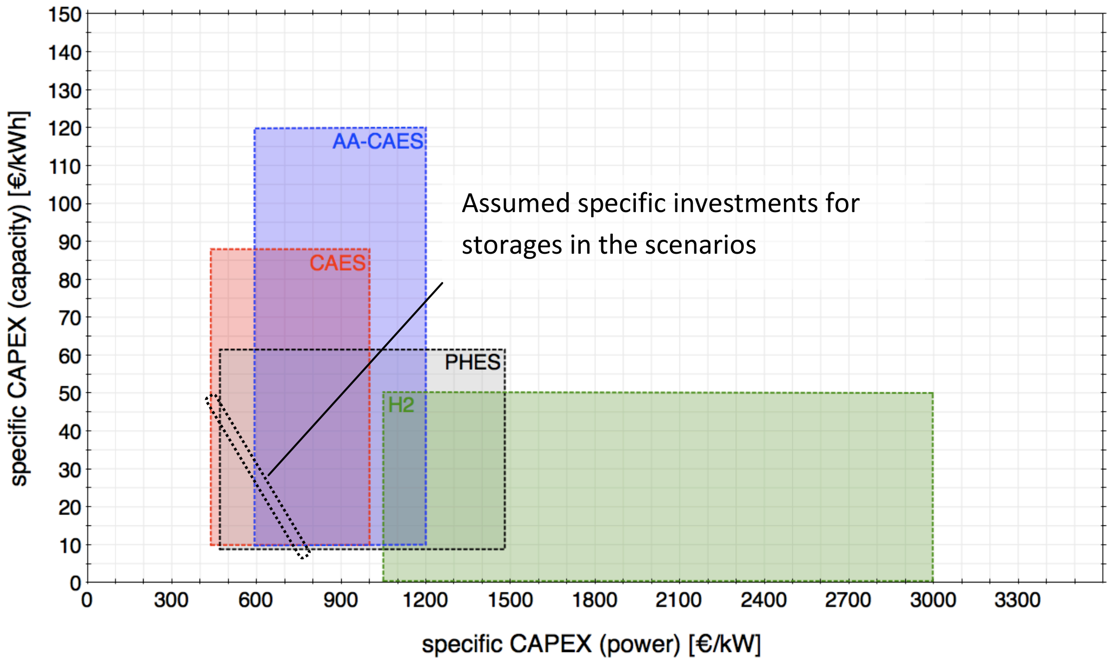


Figure 9 Possible specific investment ranges for 8 hours of storage for pumped hydro electric storage (PHES), (advanced adiabatic compressed air energy storage [(AA-) CAES] and hydrogen storages (H2)[8]

Due to the long modelling experience with the Power ACE model it is known that the construction of new storages is rarely chosen within the optimization of the electricity sector. This is a result is largely based on the fact that the technologies are too costly for the limited hours of utilization. Therefore a simplified storage with the characteristics of a new pump storage plant is provided to the technology choice algorithm. Since pump storage power plants are the most efficient and cheapest large scale electricity storage technology on the market, this is a very optimistic assumption for the characteristics of storage technologies. Given the fact that the model does not choose to utilize even these cheap options in a larger scale this simplified low cost assumption can be justified. The resulting input parameters on storage facilities are shown in Table 4.

Table 4 Assumptions on the characteristics of electricity storage facilities in PowerACE

Technology	Year	Investment	O&M	Lifetime	Efficiency
-	-	[€/kW]	[€/(kW*a)]	[years]	[%]
Storage	2020	1000	10	40	80%
	2030	1000	10	40	80%
	2040	1000	10	40	80%
	2050	1000	10	40	80%

Source: own calculations.

[8] Source: Fraunhofer ISI based on specific projects for each technology. CAPEX is an abbreviation for capital expenditures.

4 Modelling renewable electricity generation

One challenge - among others - within the model is dealing with fluctuating generation from renewable energy sources as they play an important part in a decarbonised electricity sector. To receive reliable results, a detailed renewable energy potential analysis is necessary. This objective is achieved in two complementary work steps. The first step is the calculation of the land available for the deployment of renewable energy plants (chapter 4.1).The second step is the calculation of the renewable energy potential at the available sites determined by the prior work step. The potential calculation is carried for the years 2020, 2030, 2040 and 2050 – (chapter 4.6). For both steps data with comparable standard have been used to receive an overall picture.

4.1 Analysis of the land use

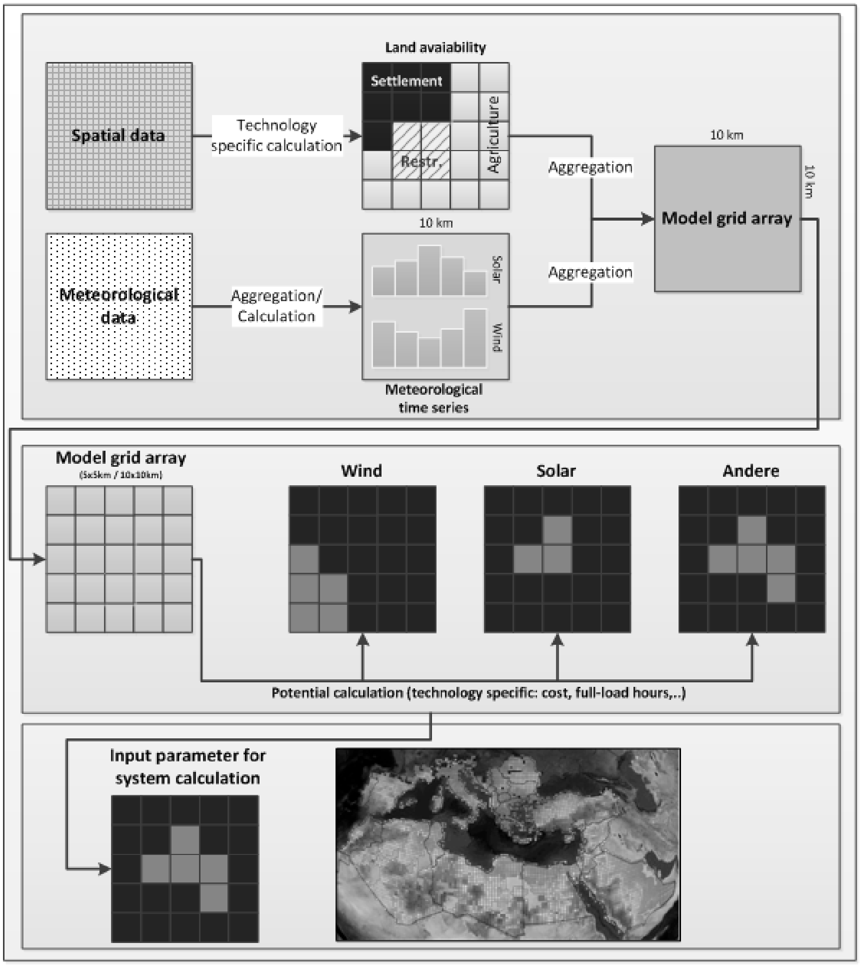


Figure 10 Model overview of the RE potential calculation

The meteorological and land use information is stored into a model grid. The model grid consists of tiles with an edge length of 10 km at the equator. Due to the shape of the earth the edge length decreases towards the northern hemisphere. Once the edge length is determined, the information within the tile borders is aggregated. The basic data used is calculated in the highest available resolution. Furthermore, the technical restrictions for the different technologies are applied.

For the calculation of the land availability several data sources have been used. As the range of the model spreads from northern Europe to the MENA countries in the south it has been decided to use a combination of CORINE (CLC) (European Environment Agency 2006) and MODIS land cover (Huld et al. 2010). While CORINE is used for the European area, MODIS is used for the MENA countries. The reference year is 2006 for both datasets.

The central result of the spatial analysis is the available area on each single grid element by land use category. The available area differs for every technology based on specific restrictions such as maximum slope and distance to urban area. The following figure shows the relative size of the different land use categories in Europe. It obvious that croplands and forrest are the most important land use categories. The next step in the scenario design is to provide assumptions regarding the utilisation of the different land use categories.

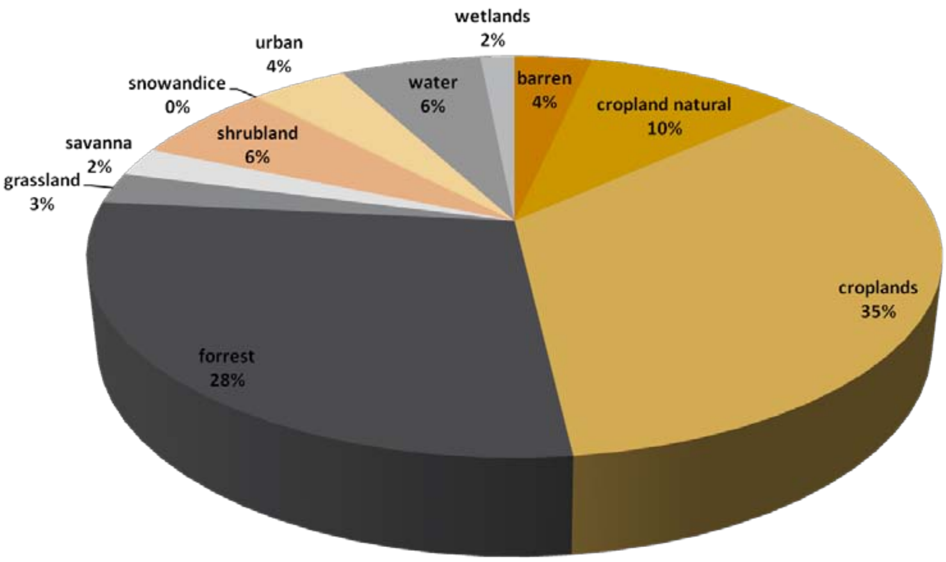


Figure 11 Land use in Europe

An overview of the utilisation of the different land use categories is given in Table 5 It has to be stated that this assumption has an important impact on the available renewable generation potential of the electricity system.

One goal of the additional Scenario E is provide an assessment of the impact of higher acceptance for wind onshore reflected in higher utilisation factors. The land utilisation factors of Scenario E are given in Table 5.

Table 5 Assumptions on Land use for Scenario C and D. Assumptions for Scenario E in brackets

Land use	Wind (Scenario E)	PV	CSP
barren	25% (30%)	15%	15%
cropland natural	15% (20%)	2%	2%
croplands	15% (20%)	2%	2%
forest	15% (20%)	0%	0%
grassland	15% (20%)	2%	2%
savannah	25% (30%)	15%	15%
scrubland	25% (30%)	15%	15%
snow and ice	15% (30%)	5%	0%
urban	0% (0%)	8%	0%
water	0% (0%)	0%	0%
wetlands	0% (0%)	0%	0%

4.2 Electricity generation potential

After determining the area available for the construction of renewable power plants on the area tiles with the renewable potential model the next step is to analyse the actual generation potential in terms of full load hours for each technology. It is obvious that in the case of wind and solar technologies very detailed meteorological data is required.

In the following the underlying meteorological data is described. Different requirements regarding the weather dataset apply to the potential calculation and time series calculation. To assess the potential for renewable energy sources, medium to long term averages of the central--- weather parameters (wind speed and its temporal distribution characteristics, solar radiation, ambient temperature) are needed. Time series on a yearly basis for five to ten years can be a resilient data source. To model hourly time series for renewable energy electricity generation, temporal resolution in weather data should meet the temporal resolution required for modelling the electricity generation. To analyze cost efficient electricity systems with a significant share of fluctuating electricity generation from wind and solar radiation, hourly production time series for these technologies are a crucial input.

4.3 Solar potential calculation

For calculating PV and CSP time series irradiance data for several data points (stations) is considered (SoDa Web Service 2010). The stations are distributed with a distance of 0.25 times 0.25 degrees of longitude and latitude. This implies that one station represents an area of less than 2,500 km². Overall more than 6250 stations (data points) with hourly time series are included in the analysis for the EUMENA region.

The resulting time series of electricity generation is used to calculate the fullload hours of reach station which are than assigned to the closest area tiles used in the modelling of renewable electricity generation potential. For more details see section A.4 in the Appendix.

4.4 Wind potential calculation

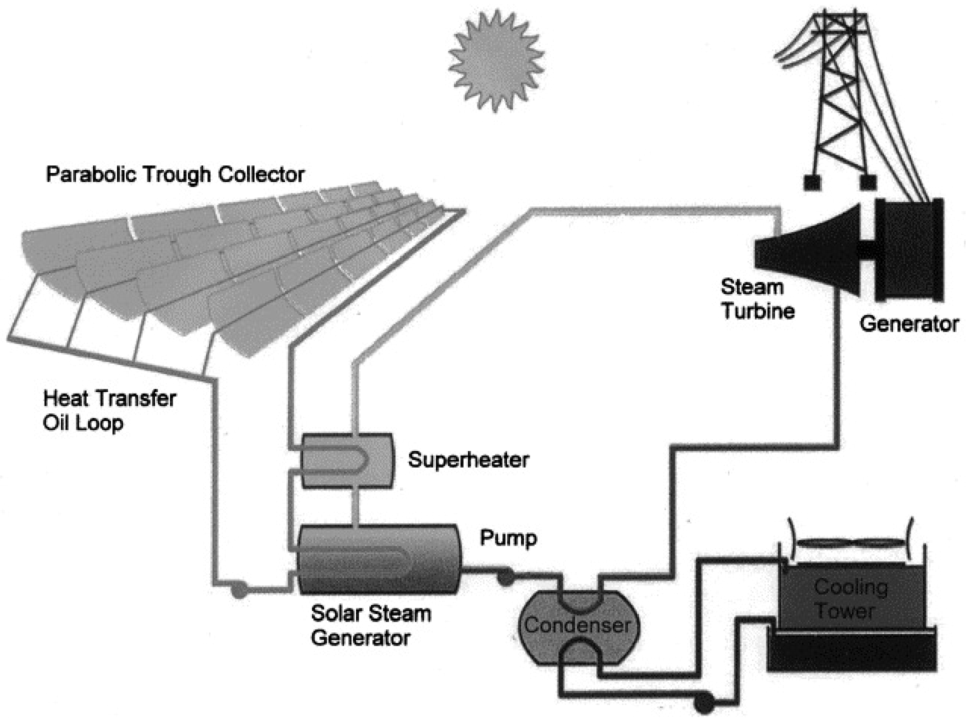
In order to calculate the power output of these turbines data on wind speed, temperature and air pressure is necessary. This study relies on several national wind speed atlantes including Merra, Anemos and Cosmo-EU. Reanalysis data[9] provide spatially evenly distributed data with less or even without data gaps. Reanalysis data providing hourly time series are e.g. Merra[10] and COSMO-EU.

In the potential calculation of wind speeds at hub height the logarithmic height correction is applied. The required roughness length is calculated based on the land use of the surrounding area. The actual output calculated based on selected turbine types with a hub height of 120 m. For more details see section A.5 in the Appendix.

4.5 CSP potential calculation

In a CSP-plant heat is collected in a solar collector field and used in a turbine to generate electricity. The heat can also be stored to operate the CSP-plant more flexibly. A possible plant layout is shown in Figure 12. Time series calculation described in this section deals with the heat output of the solar collector field. The actual heat storage and electricity generation is than optimized within the electricity market model PowerACE.

Time series for the solar collector field output where calculated using solar irradiance data described above and a calculation procedure described in (Broesamle et al. 2001). The plant is described as a one-axis tracked parabolic through collector with typical geometric, optical and thermal losses. Factors influencing the hourly heat output of the heat absorber of a CSP-plant are direct solar radiation, collector area, concentration factor, and further plant specific characteristics as geometric, optical, and heat losses.



(Broesamle et al. 2001)

Figure 12 Components of a CSP-plant

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[9] Data from meteorological data assimilation projects as a gridded data set incorporating observations and numerical weather prediction models

[10] MERRA (Modern Era Retrospective-analysis for Research and Applications) (NASA 2013) Merra Data has a spatial resolution of 1/2 degrees latitude × 2/3 degrees longitude

4.6 Renewable generation potential

In the following section the results based on the methodology described above is presented. The overall potential for wind and solar technologies in the region EU27 +2 amounts to more than 8000 TWh generation potential with costs below 80 €/MWh in 2050 for Scenario C (“Efficiency ”) and Scenario D (“High demand”). The lowest generation cost start with ca 3 TWh below 20 €/MWh and more than 3000 TWh area available at cost below 40 €/MWh in 2050.

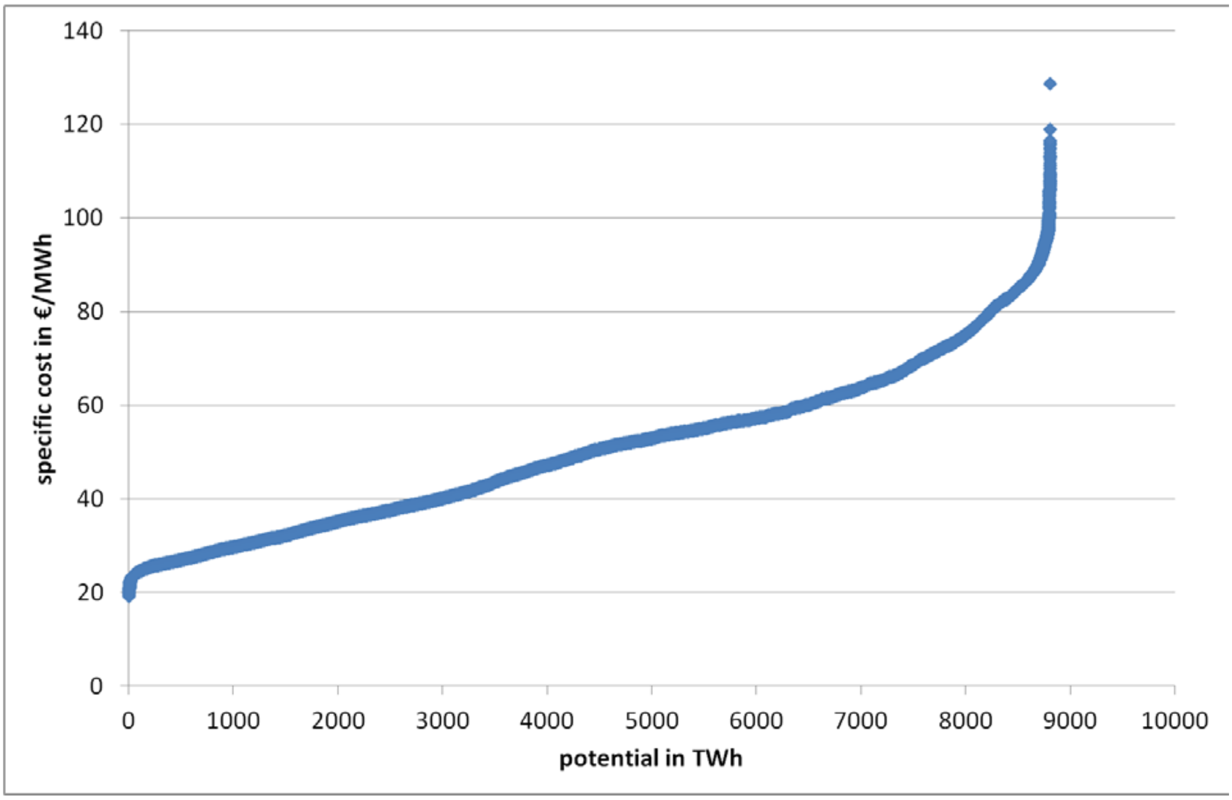

Figure 13 Generation potential for wind and solar technologies 2050 (here illustrated for Scenario C “Efficiency” and Scenario D (“High Demand”)

The most important technology in terms of low cost generation potential under the given assumptions is wind onshore. The resulting potential for wind onshore in Scenario C is presented in Figure 14. A comparison to the total generation potential in Figure 13 shows that most of the low cost generation potential is wind onshore generation potential. The importance of land use assumptions is shown by comparing the wind onshore generation potential of Scenario E (“Modified Wind”) in Figure 15. Overall generation potential with generation cost below 100 €/MWh is more than 1400 TWh higher in Scenario E (“Modified Wind”) than in Scenario C (“Efficiency”) and Scenario D (“High Demand”). The important low cost potential with generation costs below 40 €/MWh is more than 800 TWh higher than in Scenario C.

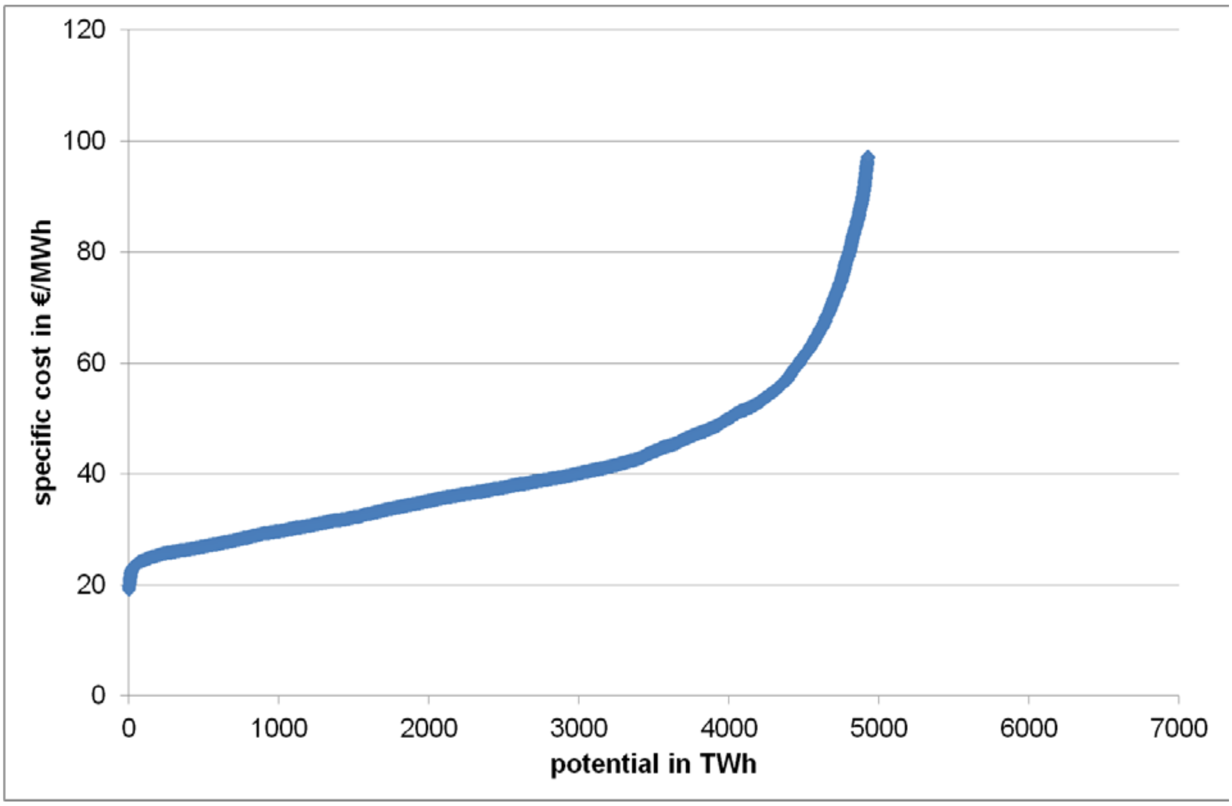

Figure 14 Generation potential for wind onshore in Scenario C ("Efficiency") and Scenario D ("High Demand")

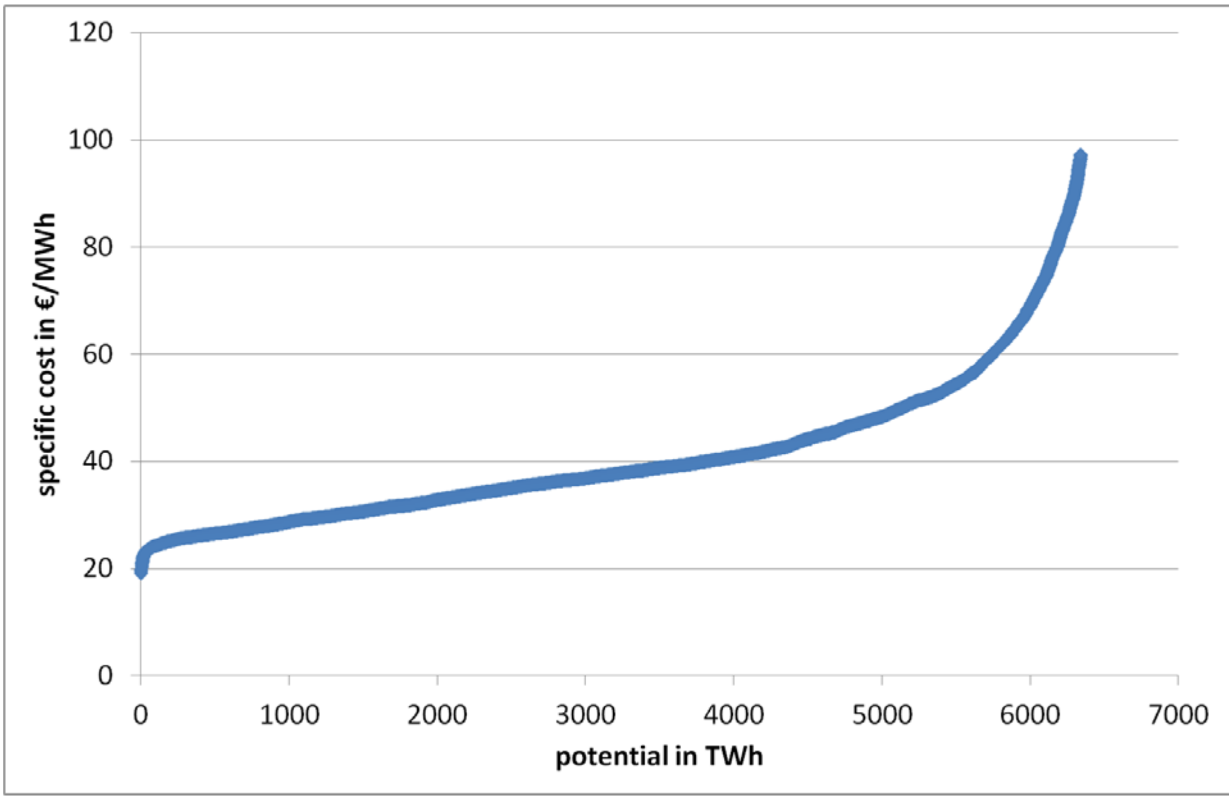

Figure 15 Generation potential for wind onshore in Scenario E ("Modified Wind")

5 Results

This study investigates concrete cost pathways towards a European electricity sector in line with the goal of keeping global warming below 2°C. It analyzes the development of the electricity sector in the EU 27, Norway and Switzerland up to the year 2050. Due to the fact that a long run projection is connected with high uncertainty several scenarios are calculated which cover a broad range of possible developments. In a previous study two scenarios have been calculated which reach the ambitious climate targets despite a phase out of nuclear generation and no use of carbon capture and storage technologies (CCS) in the electricity sector. This study complements the scenarios by three scenarios which include CCS as technology option and a moderate reduction in total nuclear capacity. Scenario C ("Efficiency") analyses an electricity sector with an ambitious development of electricity demand. Scenario D ("High demand") is calculated in order to assess the impact of higher electricity demand on the results. Scenario E ("Modified Wind") is based on the electricity demand of Scenario C but with higher availability of land for the construction of wind onshore plants and modified assumptions on the use of wind offshore in Germany.

Detailed results of the scenario analysis are presented in the next sections. Main findings of the analysis are:

Cost of strong decarbonisation: The analysis shows that under the given framework conditions advanced efforts in climate protection do not necessarily lead to increasing cost of electricity after 2020**.** In all three scenarios specific cost[11] of electricity stay at a comparable or decreasing level throughout the time period 2020-2050.

Role of renewables in cost efficient decarbonisation: All three scenarios seeking for the most cost efficient pathway towards decarbonisation end up with high shares of renewable electricity generation of more than 80 % in total generation of the year 2050 although CCS is an option available to the optimisation. Among all generation technologies wind onshore grows strongly over time to be the dominant generation technology in 2050.

Benefits of energy efficiency: The comparison of the scenarios shows that lower demand can decrease the demand for infrastructure and the total cost of the electricity system considerably. However specific cost stay at comparable level.

Main findings on the electricity grid: As renewable electricity generation grows the grid infrastructure needs to be extended. However, the strongest growth of the grid infrastructure takes place after 2030 when the share of renewable electricity generation exceeds 70%.

The role of storages: The flexibility of the hydro power plants and additional conventional power plants is used to balance the system via the electricity grid. The model does not identify demand for new storages.

The importance of a debate on land use: The results show that renewable electricity generation technologies such as wind onshore can be an important part of a decarbonised electricity sector. However the scenario comparison also shows that the contribution e.g. of wind onshore depends strongly on the land that is available for the construction of plants. In this case the most important

[11] Specific cost are defined as the total annual system cost included in the analysis divided by net electricity consumption by consumers (grid losses are subtracted)

aspect is acceptance for the impact on landscape and the local population which has to be balanced with the economic benefits.

5.1 Overview of scenario results

5.1.1 Scenario C ("Efficiency")

Scenario C ("Efficiency") is characterized by a low development of electricity demand which is based on increased efforts towards energy efficiency. Electricity demand in 2050 is less than 5% higher than in 2010. In a low carbon scenario this development requires that additional demand by economic growth and new demand e.g. for electricity in the transport sector is compensated by energy efficiency measures. Total annual CO_2 emissions of the electricity sector are reduced to ca. 5% of 1990 levels. Nuclear generation capacity follows of politically driven path towards ca. 55 GW generation capacity in 2050. Other technology options such as conventional power plants and renewable electricity generation are built by a least cost optimization approach. National renewable targets of the National Renewable Energy Action Plan (NREAPs) and grid capacities according to the TYNDP 2012 are enforced as minimum conditions.

In Scenario C the ambitious CO_2 reduction target is reached predominantly with a high share of renewable electricity generation. The share of renewable in total generation starts with 49% in 2020 and grows to 82% in 2050. Electricity generation by wind energy is the most important generation technology. CCS plays a minor role, with the diffusion starting in 2030 and generation growing to 90 TWh in 2040 representing less than 3% in total generation. Nuclear generation follows the fixed path of capacity enabling a generation of 397 TWh in 2050.

Total annual system cost[12] stays at a level of 225-230 billion € between 2020 and 2040. The decline of demand in 2050 also leads to a decline in total system cost. Specific cost of net electricity demand start with 66 €/MWh in 2020. Despite the ambitious path in CO_2 reduction, the development of specific cost[13] shows a slight decline to 63.9 €/MWh in 2050 due to the decreasing cost of renewable generation technologies. The marginal cost of CO_2 abatement start with 15€/t in 2020 and reaches its peak with 78€/t in 2040. Thereafter decreasing demand leads to a decline to 54 €/t in 2050.

12 Total annual cost include fuel cost, operation cost and annual capital cost calculated by the method for annuities for all generation technologies, storages and grid connection between countries.

13 Specific cost are defined as the total annual system cost included in the analysis divided by net electricity consumption by consumers (grid losses are subtracted)

Table 6 Central Parameters and results for Scenario C ("Efficiency"), Region: EU 27 +2,

	Data type	2020	2030	2040	2050	Unit
CO_2 Cap 2050	Input	700	400	150	75	Mt
Demand incl. Grid losses	Input	3,707	3,888	3,822	3,417	TWh
Storage Losses	Result	7	10	14	15	TWh
Net Renewable Generation[14]	Result	1809	2534	2948	2810	TWh
Curtailment	Result	6	30	67	59	TWh
CCS Generation	Result	0.0	25	89	88	TWh
Nuclear Generation	Input	975	654	495	397	TWh
Fossil Gen. w.o. CCS	Result	931	686	305	138	TWh
Total RES-E Share[15]	Result	49%	65%	77%	82%	none
Marginal CO2 price	Result	15	44	78	54	Euro /t
Total Annual cost[16]	Result	225.7	229.2	226.6	199.4	Bill. €
Specific cost	Result	66.2	64.2	64.7	63.9	€/MWh

(SID 4517)

5.1.2 Scenario D ("High demand")

Scenario D ("High demand") is based on the scenario setting of Scenario C ("Efficiency") but is characterized by a development of electricity demand which is based on continued growth in electricity demand. The resulting demand 2050 is ca. 20% higher than in 2020 and more than 25 higher than demand in 2010. The central goal of this scenario is to analyse and identify the additional infrastructure required to meet the additional demand. Total annual CO_2 emissions of the electricity sector are reduced to ca. 5% of 1990 levels. Nuclear generation capacity follows a politically driven path towards ca. 55 GW generation capacity in 2050. Other technology options such as conventional power plants and renewable electricity generation are built by a least cost optimization approach. National renewable targets of the NREAPs and grid capacities according to the TYNDP 2012 are enforced as minimum conditions.

In Scenario D the ambitious CO_2 reduction target is reached with a high share of renewable electricity generation despite the increased demand. The share of renewable in total generation starts with 49% in 2020 and grows to 81% in 2050. Electricity generation by wind energy is the most important generation technology. CCS again plays only a minor role starting in 2030 with generation growing to 356 TWh in 2040, representing less than 10% in total generation. However, compared to Scenario C

[14] Net renewable generation is defined as the sum of all electricity generation by renewable technologies minus total curtailment of electricity

[15] The Total RESE-E Share is defined as the net renewable generation divided by the total generation (demand incl. Grid losses plus storage losses)

[16] Total annual cost include fuel cost, operation cost and annual capital cost calculated by the method for annuities for all generation technologies, storages and grid connection between countries.

CCS generation grows by 268 TWh to 2050 to meet the higher demand for low carbon electricity driven by the given CO_2 cap. However the main technology covering the increased demand is wind onshore which grows by ca. 500 TWh in 2050. Nuclear generation as in scenario C follows the fixed path towards 392 TWh in 2050.

Total annual system cost start at a level of 223 billion € in 2020. Afterwards total system cost grow to ca. 250 billion € p.a. because of the increasing demand. Specific cost of supplying net electricity demand start with 66 €/MWh in 2020. Despite the ambitious path in CO_2 reduction, specific cost show a slight decline to 64.1 €/MWh in 2050. This slight decline is mainly caused by the fact that technology learning of renewable in terms of cost reduction outweighs the additional cost caused by the use of less suitable generation sites since the best spots are already utilized. Another minor technical aspect is that the degree of freedom for the model is higher in 2050 since most of the existing infrastructure is no longer in use. Therefore the optimisation procedure has more options to calculate the optimal power system. The marginal cost of CO_2 abatement start with 15€/t in 2020 and shows a steady increase to 83/t in 2050.

Table 7 Central Parameters and results for Scenario D ("High demand"), Region: EU 27 +2

	Data type	2020	2030	2040	2050	Unit
CO_2 Cap 2050	Input	700	400	150	75	Mt
Demand incl. Grid losses	Input	3,672	3,791	4,250	4,251	TWh
Storage Losses	Result	6.5	10.3	15.9	19.3	TWh
Net Renewable Gen.	Result	1791	2464	3137	3394	TWh
Curtailment	Result	7	25	77	100	TWh
CCS	Result	0	3	356	356	TWh
Nuclear	Input	984	653	492	392	TWh
Fossil w.o. CCS	Result	904	681	282	149	TWh
Total RES-E Share	Result	49%	66%	74%	81%	none
Marginal CO_2 price	Result	16	41	73	83	Euro /t
Total Annual cost	Result	223	223	253	249	Bill. €
Specific cost	Result	66.0	64.1	65.0	64.1	€/MWh

(SID 4515)

5.1.3 Scenario E ("Modified Wind")

Scenario E ("Modified Wind") is characterized by a low development of electricity demand which is based on increased efforts towards energy efficiency. Electricity demand 2050 is ca. 10% lower than in 2020 and less than 5% higher than in 2010. Total annual CO_2 emissions of the electricity sector are reduced to ca. 5% of 1990 levels. Nuclear generation capacity follows a politically driven path towards ca. 55 GW generation capacity in 2050. Other technology options such as conventional power plants and renewable electricity generation are built by a least cost optimization approach. National renewable targets of the NREAPs and grid capacities according to the TYNDP 2012 are enforced as minimum conditions. In contrast to the otherwise identical Scenario C ("Efficiency") land use assumptions for wind onshore have been changed towards an increase of land available for wind onshore and the wind offshore development in Germany follows a fixed path to reflect the current political discussions

Similar to Scenario C and D the ambitious CO_2 reduction target is reached with a high share of renewable electricity generation. The share of renewable generation in total generation starts with 49% in 2020 and grows to 85% in 2050. The higher land use for wind energy increases the RES-E share compared to Scenario E showing the sensibility of land availability for renewable electricity generation. This result highlights two important aspects. The first aspect is the fact that land use assumptions are an important part for electricity system studies which is rarely discussed and should gain more attendance by scientists and the decision makers. The second aspect is practical one. Since land availability for renewable seems to be an important factor for the development of the electricity system the political debate on economical, ecological and public acceptance aspects is likely to gain more and more importance as we move to an electricity system with higher share of renewable generation.

Wind energy is again the most important generation technology. Due to the increased importance of renewable generation CCS generation reaches only a level of ca. 31 TWh in 2040, representing less than 1% in total generation. Nuclear generation capacity follows the fixed path leading to 389 TWh generation in 2050. Actual use (so called dispatch) of nuclear is slightly lower than in the previous scenarios due to the growing renewable generation. Total annual system cost covered by the analysis start at a level of 225 billion € in 2020. Similar to scenario C cost drop to ca. 197 billion € in 2050 due to the lower demand. Specific cost of net electricity demand start with 66.6 €/MWh in 2020. Despite the ambitious path in CO_2 reduction, specific cost show a slight decline to 63.2 €/MWh in 2050. Another minor technical aspect is that the degree of freedom for the model is higher in 2050 since most of the existing infrastructure is no longer in use. Therefore the optimisation procedure has more options to calculate the optimal power system. The marginal cost of CO_2 abatement start with 14€/t in 2020 reaching a peak of 78 €/t in 2040.

Table 8 Central Parameters and results for Scenario E ("Modified"), Region: EU 27 +2

	Data type	2020	2030	2040	2050	Unit
CO_2 Cap 2050	Input	700	400	150	75	Mt
Demand incl. Grid losses	Input	3,707	3,888	3,823	3,418	TWh
Storage Losses	Result	7.4	10.7	14.5	14.8	TWh
Renewables	Result	1817	2580	3015	2871	TWh
CCS	Result	0	0	31	31	TWh
Nuclear	Result	976	646	481	389	TWh
Fossil w.o. CCS	Result	921	674	311	142	TWh
Total RES-E Share	Result	49%	67%	80%	85%	none
Marginal CO_2 price	Result	14	39	78	55	Euro /t
Total Annual cost	Result	225	227	224	197	Bill. €
Specific cost	Result	66.6	63.7	64.9	63.2	€/MWh

(SID 4955)

5.2 Generation Mix

After the presentation of the overview of the scenarios results the next sections 5.2 5.7 show more detailed scenario comparisons with regard to the generation mix and its regional distribution, grid infrastructure and an analysis of the cost of the system.

One central category for the analysis of the results is the generation mix of the electricity sector in the modelled region. The following section describes the results for the net electricity generation[17] mix. Current discussions on climate policy in the EU include the debate on renewable targets for 2030 in the EU as discussed in a press release in January 2014 (European Commission 2014). Table 9 and Table 10 show the development of the RES-E Share, that is the fraction of total net electricity generation generated from renewable sources in the modelled region EU27+2 and the EU. Generally the share of renewable generation in 2020 is higher in EU 27+2, as Norway and CH are already utilizing their hydro resources. In all scenarios the RES-E share in the EU is roughly above 45% in 2020 and continues to increase to ca. 80% in 2050. It is remarkable that this development is mainly driven by cost optimization under the given CO_2 cap in the scenarios. This shows that renewable electricity generation can be very cost-efficient for CO_2 abatement in the electricity sector.[18] It has to be noted that the fixed capacities of nuclear power plants do not limit the significance of the results. If the diffusion of new nuclear power plants is optimized endogenously in the model the resulting development of nuclear is likely to be even lower for a broad range of cost assumptions.

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17 Here net electricity generation is defined as the actual output of the plant minus own consumption. In case of renewable curtailment is already subtracted. Total net electricity generation is the entire generation that is fed into to grid to cover demand, grid losses and storage losses.

18 However, concluding from this outcome that a sole CO_2 target could trigger such a development is overly simple as actual policy and market design strongly affects the required interest rate for real life project investments. For more details on this aspect see Ragwitz and Steinhilber 2012.

Table 9 Development the RES-E share in total generation EU 27 +2

	2020	2030	2040	2050
Scenario C (“Efficiency“)	49%	65%	77%	82%
Scenario D (“High demand“)	49%	66%	74%	81%
Scenario E (“Modified wind“)	49%	67%	80%	85%

In 2020 overall renewable generation amounts to ca. 1800 TWh in EU27+2. Thereof only ca. 1440 TWh are enforced by minimum conditions on existing and planned hydro plants and the NREAP pledges of each country. This result shows that in an ambitious path towards decarbonisation of the electricity sector renewable electricity generation can be the most cost efficient option even in the short run up to 2020. In such a scenario it is even cost efficient to go beyond NREAP targets. In the scenario setting and assumptions renewable electricity generation is the dominant cost efficient source for a decarbonisation of the electricity sector throughout the entire time period.

Table 10 Development of RES-E share in total generation EU 27

	2020	2030	2040	2050
Scenario C (“Efficiency“)	47%	63%	75%	80%
Scenario D (“High demand“)	46%	62%	72%	78%
Scenario E (“Modified wind“)	49%	64%	77%	82%

5.2.1 Generation Mix of Scenario C (“Efficiency”)

The results for the generation mix of Scenario C („Efficiency“) are shown in Figure 16. After 2020 wind onshore is the most important generation technology, overall wind onshore generation grows to more than 1500 TWh in 2050. Electricity generation by hydro power plants stays at a level of ca. 500 TWh. PV and CSP account for ca. 400 TWh. Other renewables like biomass account for ca. 400 TWh in 2050. Nuclear generation decreases from ca. 1000 TWh in 2020 based on the exogenous scenario settings to ca. 400 TWh in 2050. While solid conventional fuels still play a major role in 2020 their overall share decreases heavily up to 2050. The main reason for the decline in electricity generation by coal and lignite is the CO_2 constraint and the lack of competitiveness of CCS to the renewable generation technologies.

The development of installed capacity is given in Figure 17. The installed capacity grows from ca. 1100 GW in 2020 to ca. 1380 GW in 2040. Thereafter capacity declines to ca. 1280 GW. Due to the switch towards renewable the installed capacity grows stronger than demand. In terms of capacity wind onshore grows strongest to 567 GW in 2040. One aspect of the capacity calculation in addition to the capacity that is calculated by the model to meet demand in every hour is that reserve capacity is added to the system and cost calculation. Every country is required to add 10% of its peak demand as reserve based on gas turbines. The assumption is made to increase the reliability of the modelled system to cover adverse weather conditions that are not covered by the model. The total peak load of the system reaches its maximum in 2020 with 622 GW thus being 34 GW lower than the sum of the national peak loads. This is another aspect which shows the benefits of international cooperation in the electricity sector.

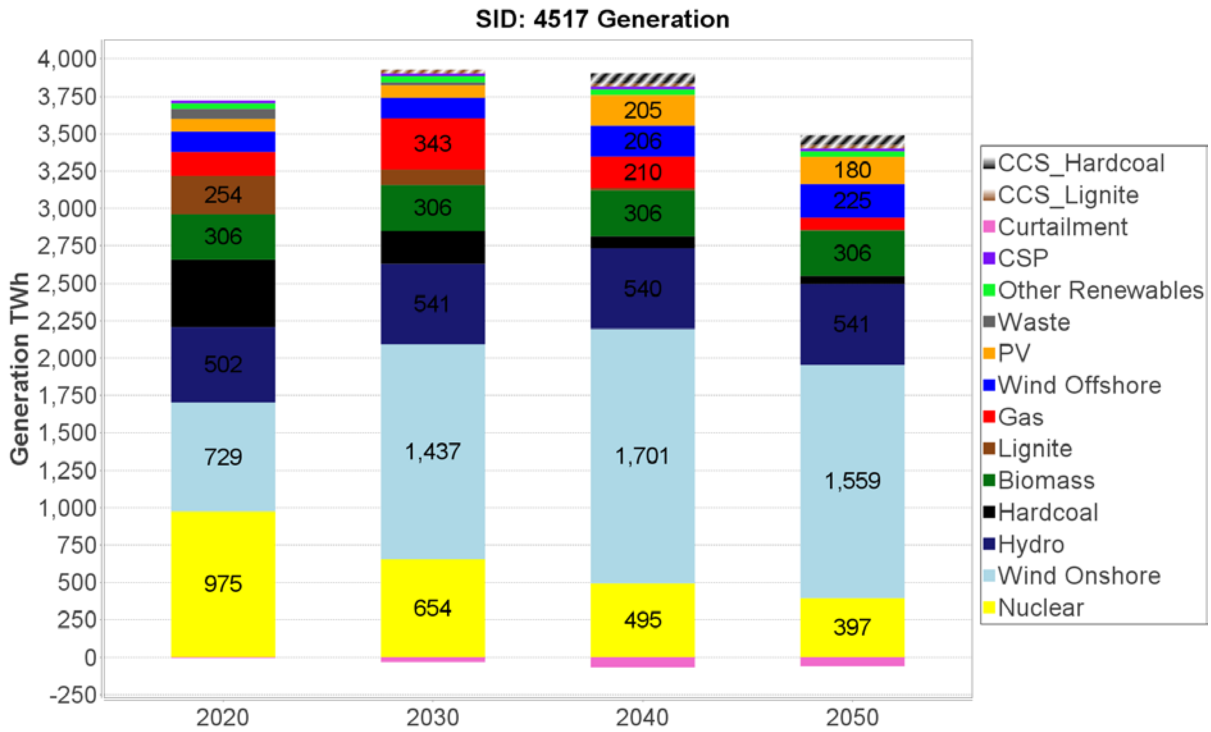

Figure 16 Generation Mix Scenario C ("Efficiency")

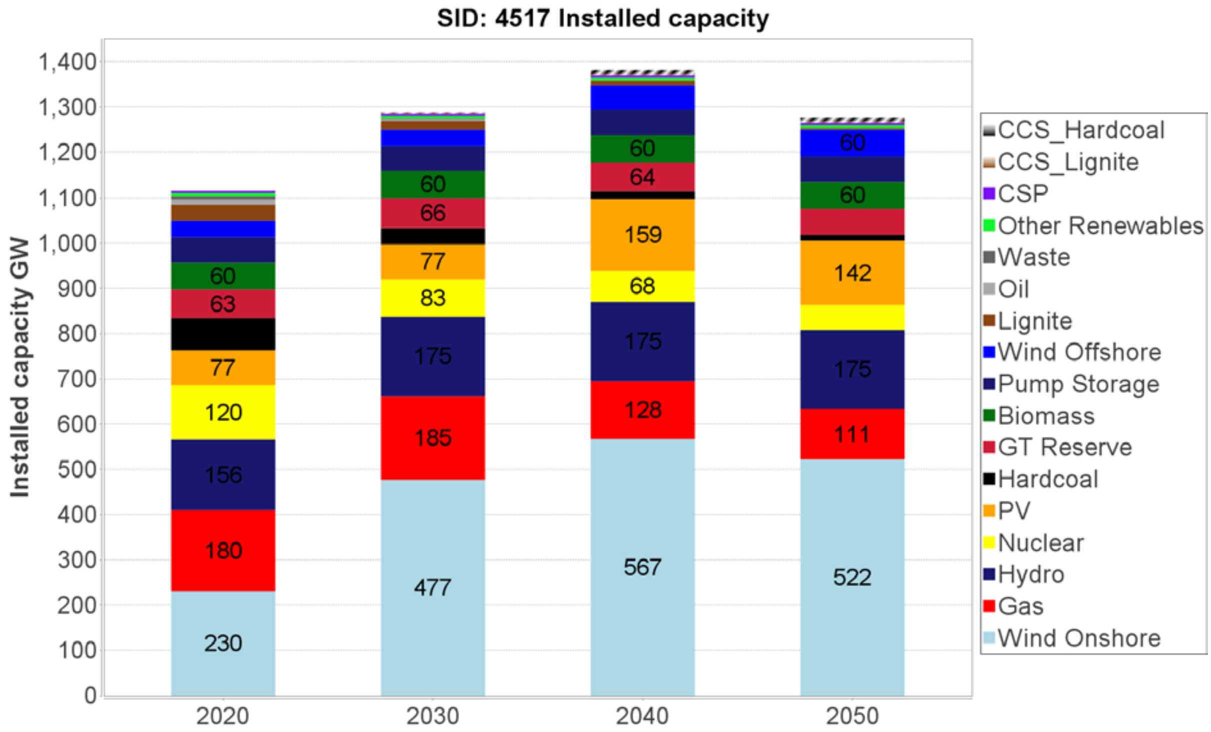

Figure 17 Installed capacity in Scenario C ("Efficiency")

5.2.2 Impact of higher demand on the generation mix– comparison of Scenario C and D

The comparison of Scenario C ("Efficiency") and Scenario D ("High demand") shows the impact of higher demand on the generation mix. In Figure 18 the changes of the overall generation mix caused by higher electricity demand are displayed. For a complete picture of the generation mix in Scenario D ("High Demand") see Appendix A.2.The major differences between both scenario start in 2040 when overall electricity demand reaches substantially different levels. The higher electricity demand of Scenario D is mainly covered by wind onshore generation, CCS coal power plants and a minor share of gas CCS plants. Further growth of electricity demand after 2040 is covered by ca. 300 TWh additional wind generation and ca. 150 TWh of PV generation. In addition ca. 40 TWh of additional gas generation are used to cover peak demand.

The differences in installed capacity of both scenarios are given in Figure 19. The development of capacity follows the trends in generation. One remarkable aspect is the comparison of full load hours of wind energy. Additional 193 GW wind onshore generation capacity is needed in 2050 to cover the higher demand in Scenario D ("High Demand"). This additional capacity reaches only ca. 2600 full load hours in average while the basic 522 GW installed in Scenario C ("High Efficiency") reaches 2990 full load hours 2990 in average. This comparison shows that the model has to utilize less favourable sites to generate the electricity required to cover demand. Due to the higher demand the additional reserves (GT Reserve) are also higher in Scenario D.

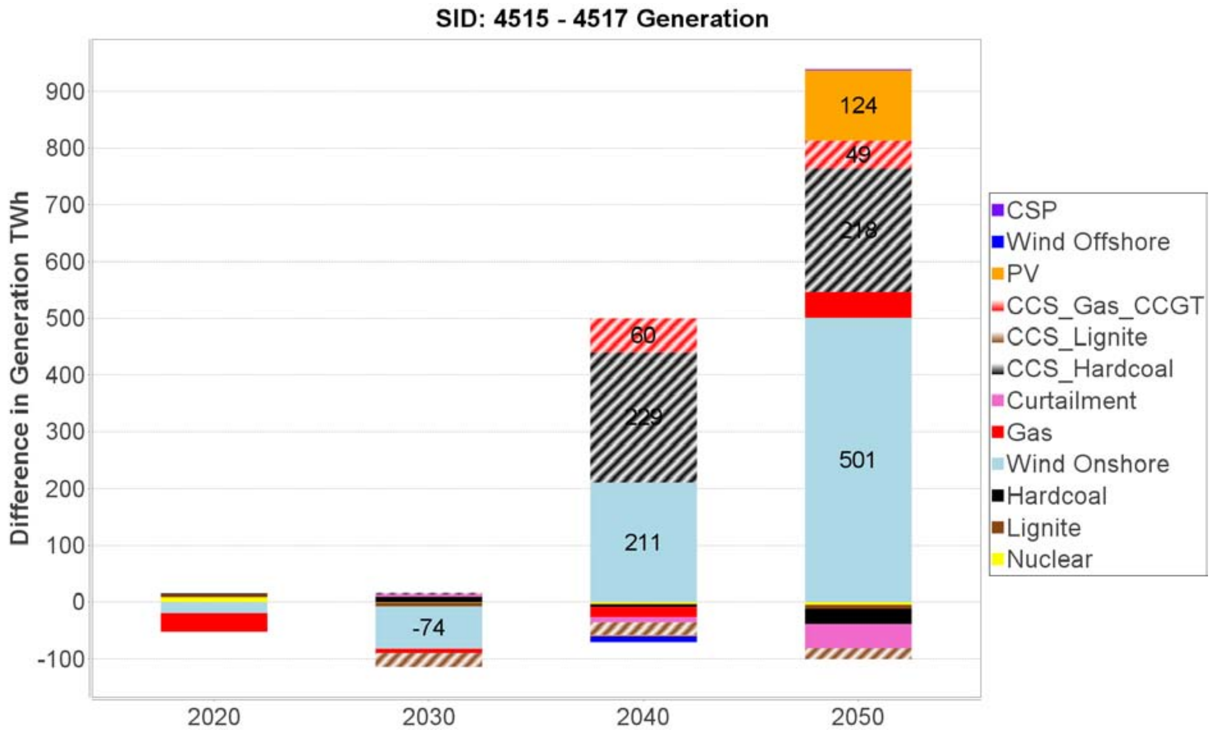

Figure 18 Impact of higher demand on the generation mix (Scenario D- Scenario C)

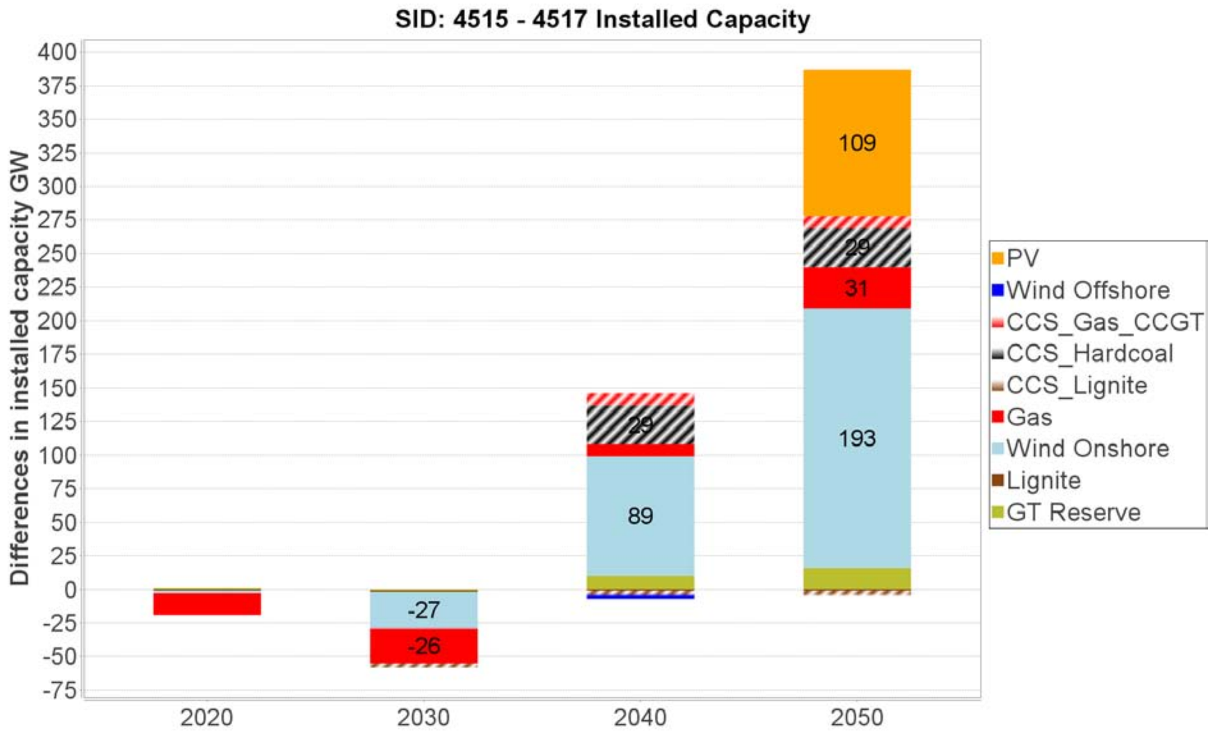

Figure 19 Impact of higher demand on installed capacity (Scenario D- Scenario C)

5.2.3 Impact of modified wind assumptions on the generation mix

The comparison of Scenario C ("Efficiency") and Scenario E ("Modified Wind") shows the impact of additional wind onshore resources and a constraint on German offshore utilisation. For a complete picture of the generation mix in Scenario E ("Modified Wind") see Appendix A.2. All other parameters of the scenario are identical. Total demand incl. grid losses reaches ca. 3420 TWh in 2050. The share land available for wind onshore generation has been increased by 5% (see Table 5) in all relevant land use categories. Since the impact of wind energy on other land uses like agriculture is limited stronger land use for wind onshore is not a matter of scarcity but of public acceptance. Therefore an increase in land use by 5% is still a moderate increase in an alternative scenario. This change in land use translates into an increase of the available potential of ca. 30%. The increased potential leads to economic advantages as more plants can be built at sites with high energy yields and low generation cost. As a consequence of the additional cheap potential of one technology the competition between technologies is also affected, as other technologies have to compete against an increased low cost potential of wind energy. The stronger utilization of the available area for wind onshore production leads to an overall growth of ca. 143 TWh for wind onshore until 2050. The additional wind onshore generation replaces CCS generation fired with hardcoal and lignite, wind offshore, and to a minor extend PV power plants. A central result of this comparison is that due to its low generation cost wind onshore resources are utilized by the optimization model if available. This has an important impact on the evaluation of the scenario calculations. From a modelling perspective it shows that the assumptions on the availability of land for wind onshore usage are crucial for the calculated results. It has to be kept in mind that utilisation of the most important land use categories is still only 20% in the scenario with increased wind potential. From a political perspective the results show that wind onshore and its public acceptance is a critical factor for a least cost low carbon electricity sector in the future.

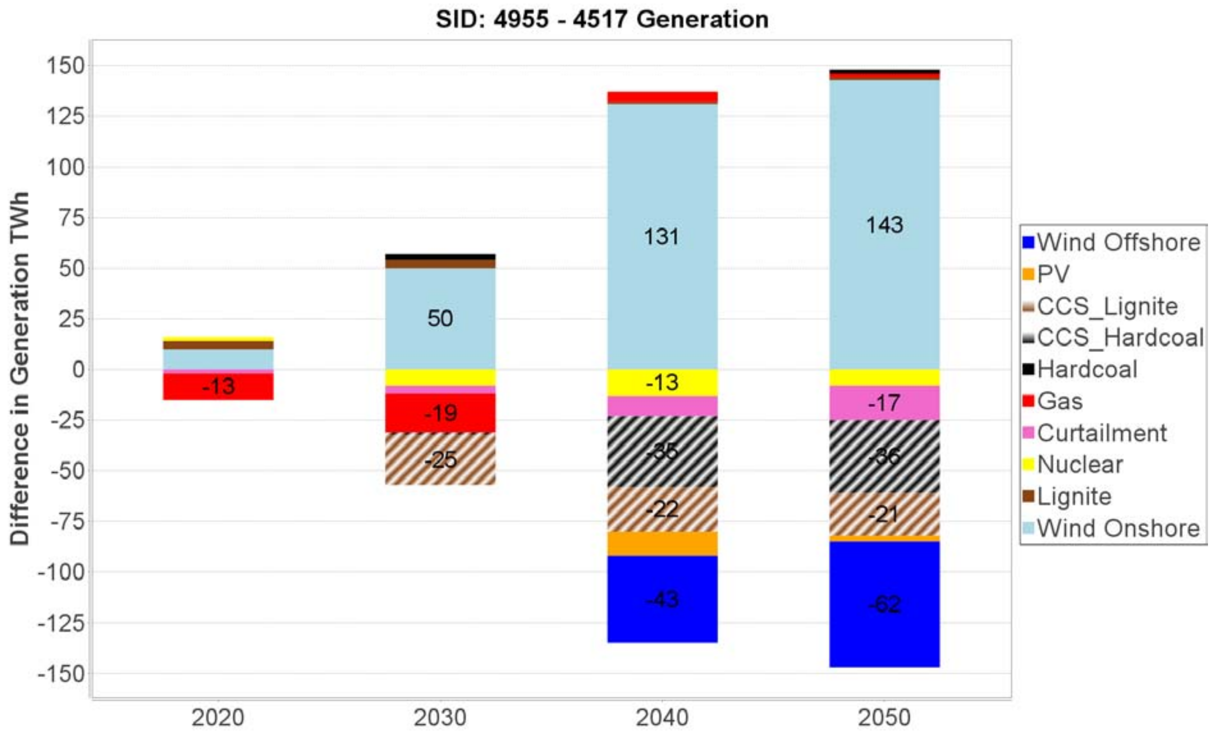

Figure 20 Impact of changed wind assumptions on generation mix (Scenario E- Scenario C)

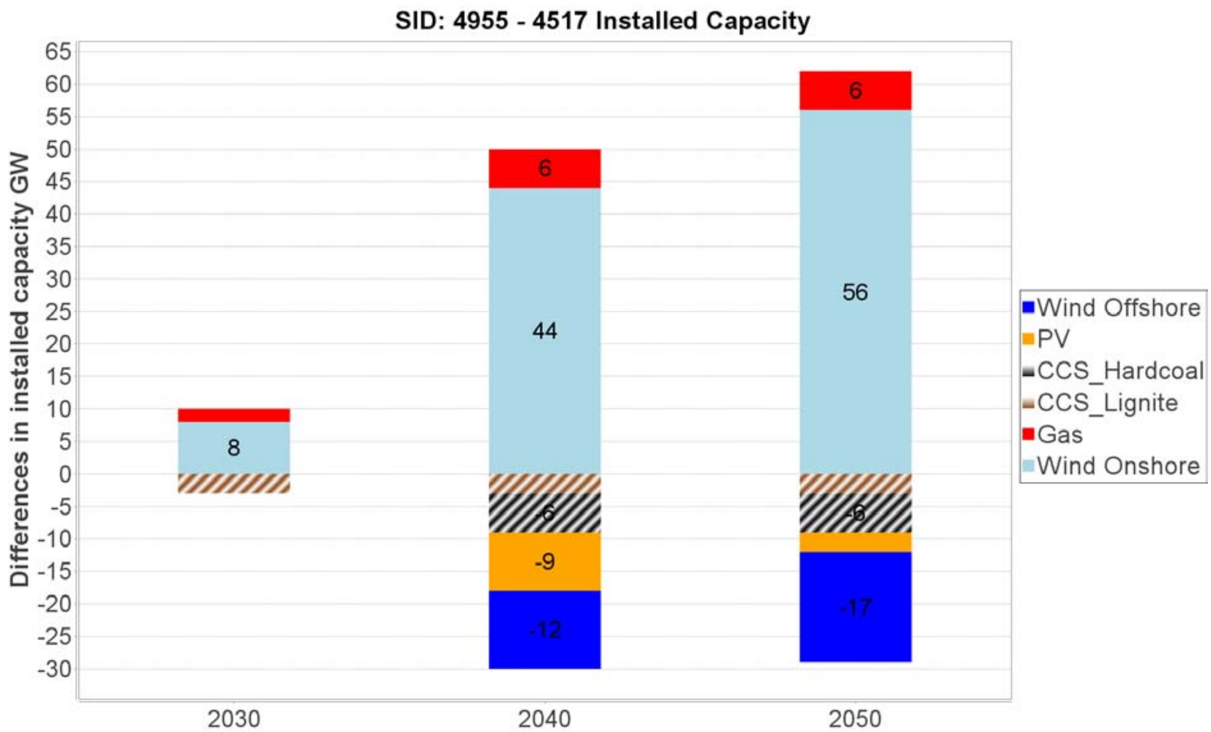

Figure 21 Impact of changed wind assumptions on installed capacity (Scenario E- Scenario C)

5.3 Curtailment of RES-E generation

Electricity systems with high share of renewable electricity generation have to deal with excess generation in cases of good weather conditions and/or times of lower demand. Curtailment of renewable electricity generation is an option available to the model. It is utilized only if other options like building new transmission lines or storages facilities are not cost-efficient. An overview of the development of the share curtailed power in overall renewable generation is given in Table 11. In

2020 curtailment is in the order of magnitude of 0.5% of renewable generation and grows with increasing share of renewable generation. In 2050, the overall share of curtailment reaches 2-3% of the renewable electricity generation. Although curtailment stays at a moderate level in energetic terms the curtailment in single hours can be substantial in terms of curtailed capacity. As example the maximum curtailment in a single hour reaches 231 GW in 2050 for Scenario D ("High demand")

	2020	2030	2040	2050
Scenario C ("Efficiency")	0.4%	1.2%	2.3%	2.1%
Scenario D ("High demand")	0.4%	1.0%	2.4%	3.0%
Scenario E ("Modified wind")	0.5%	1.3%	2.6%	2.6%

Table 11 Development of RES-E curtailment

5.4 New storage facilities

Storage facilities are an option that is heavily discussed in the public debate on the balancing of renewable. However, it hast to be stated that storage facilities are a costly option in terms of investment and energetic losses connected with the storage process. In the current analysis a synthetic storage with the low cost and high efficiency of a pump storage plant is available in all countries as an option for the optimisation procedure. This is a very optimistic assumption as most new storage technologies like CAES or batteries are characterized by higher cost and / or higher losses. Despite this optimistic assumption overall construction of new storages in the entire region is below 50 MW in all scenarios which is negligible considering the size of the system. The model tends to prefer, using the transmission as well as existing hydro storages or peak power plants over the construction of new storages for the balancing of the system.

5.5 Distribution of renewables across Europe

The next step of the analysis is the regional distribution of renewable generation technologies, which is important for understanding the technological choices and the need for transmission infrastructure.

5.5.1 The development of Wind onshore

Again the starting point for the comparison of the scenarios is the analysis of the results in Scenario C ("Efficiency"). Figure 22 shows the regional distribution of electricity generation by wind onshore. It shows that wind onshore plays a major role in all countries. However, UK, France, Germany, Norway and Italy are characterized by a remarkable generation of more than 150 TWh in year 2050. With 288 TWh wind onshore generation UK has the highest national wind onshore generation in 2050 in Scenario C ("Efficiency"). Due to the superb wind conditions of UK, wind onshore generation in UK is high in all scenarios that have been calculated by our modelling system in a least cost approach. If political acceptance for such a strong utilization of wind onshore resources in UK is not that high, the UK could alternatively utilize its strong wind offshore sites instead to replace wind onshore generation. However, in such a case path with significantly lower wind onshore generation in UK comes with an additional cost.

In the case of Germany it has to be stated that high generation of wind onshore is to some extend caused by the minimum self supply conditions applied in this scenario. The minimum self supply condition is imposed as political constraint in order to reflect the fact that a strong imbalance in electricity trade may not be acceptable in political terms. On hourly scale national production share can be lower since no restriction is placed on hourly dispatch. In order to meet the national minimum self supply constraint the models seeks the cheapest low carbon technologies in every country. Since wind onshore is the cheapest low carbon technology available throughout the whole time horizon the available land resources are heavily utilized. This is especially the case in Germany

5.5.1.1 Scenario C („Efficiency“)

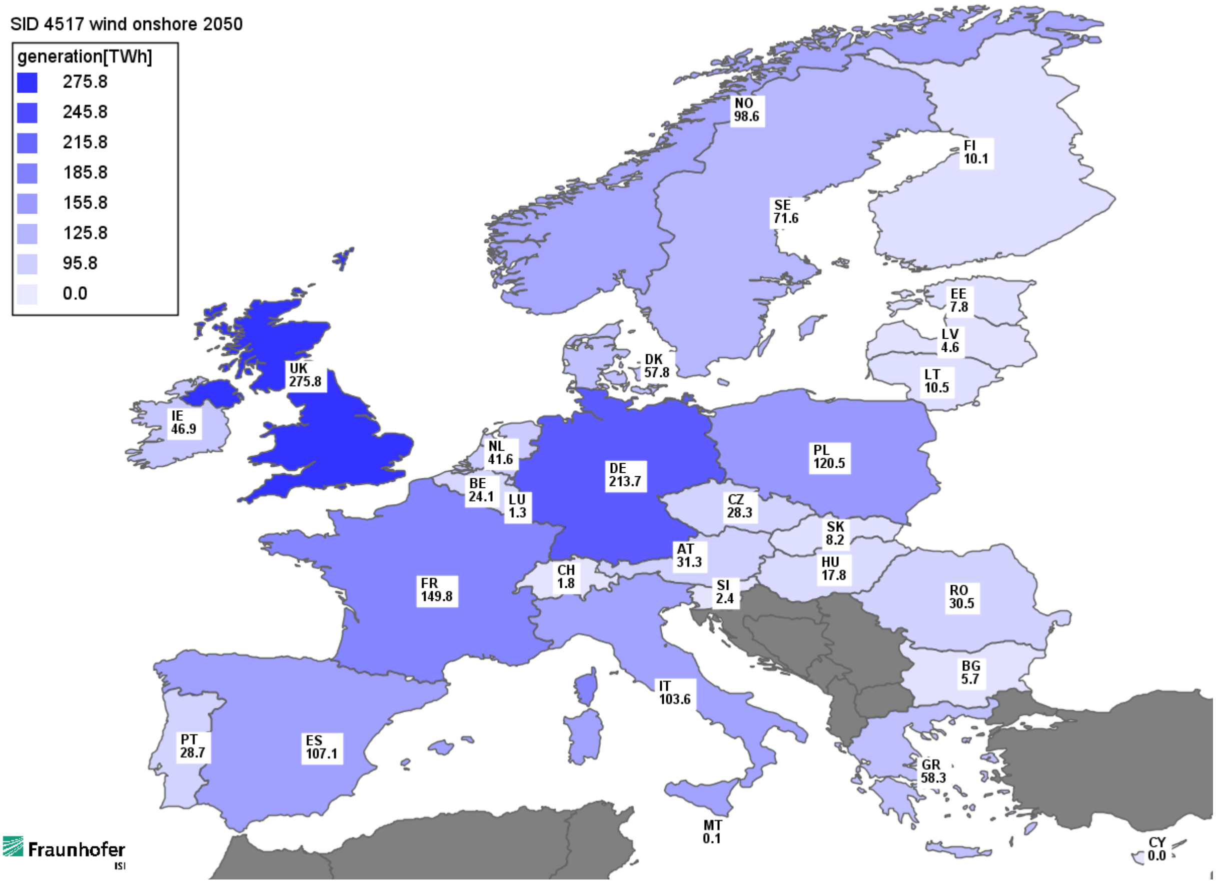

Figure 22 Generation of wind onshore in Scenario C in 2050

5.5.1.2 Impact of higher demand on wind onshore (Comparison C and D)

The next step of the analysis is the comparison of Scenario D and Scenario C to show the impact of higher demand on the regional distribution of wind onshore generation. Figure 23 shows the additional wind onshore generation in the Scenario D. In Scenario D electricity demand in 2050 is ca. 830 TWh higher. The graph shows that ca. 500 TWh of the additional demand are covered by wind energy. The strongest growth takes place in France due to the availability of good additional resources. The maximum annual growth in France takes place in the period 2030-2040 with an average of 5.9 GW new wind onshore capacity per year which translates in to 9.5% annual growth in installed capacity. A remarkable development which is triggered by several aspects: In the high demand scenario demand in France increases by ca. 70 TWh between 2030 and 2040 while nuclear generation is decreasing by 115 TWh. As consequence a high demand for electricity generation with low carbon intensity arises which can be covered by the national wind potential in France. However it has to be stated that such a development requires an enormous effort in terms of public acceptance, planning & construction and administrative abilities. Further increase in generation takes place in Norway, Italy and Germany. While the strong wind development in Germany and Italy is again caused by the self supply restriction leading to the utilization of the cheapest technologies available on national level, the additional growth in Norway takes place because of the high quality of the wind resources.

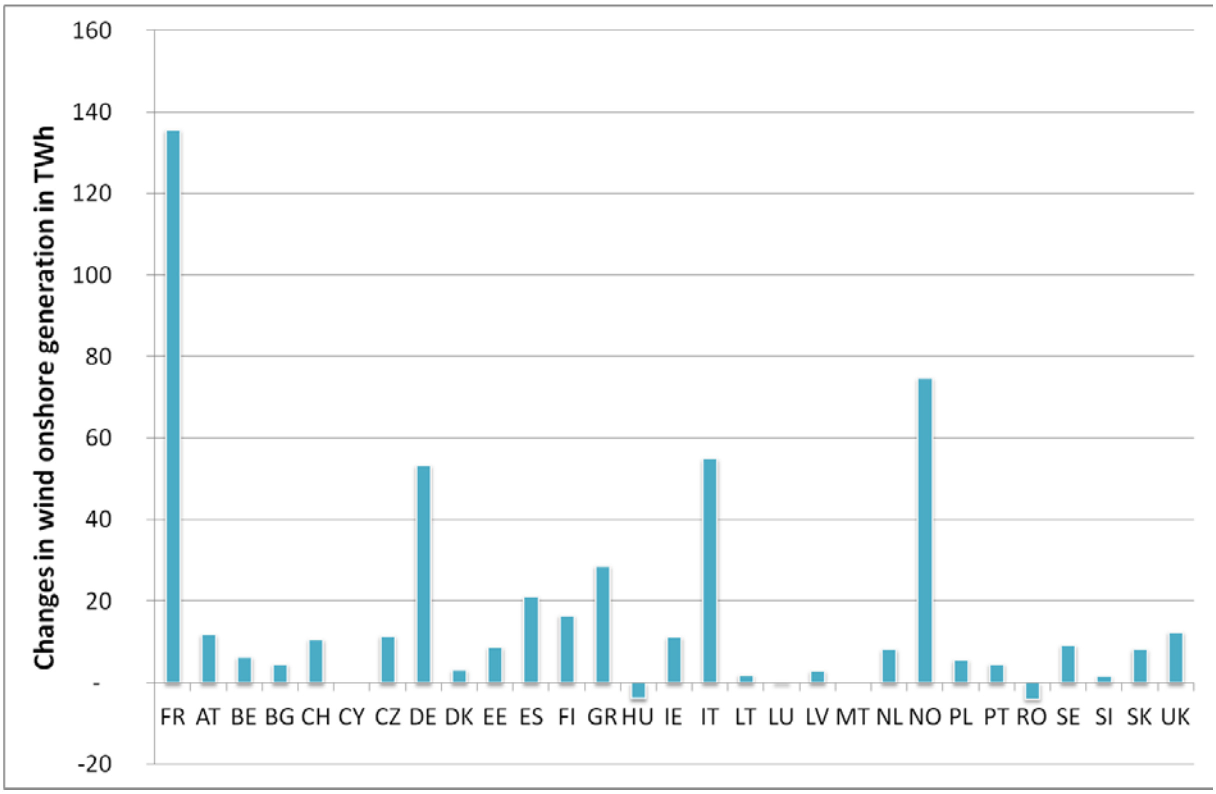

Figure 23 Comparison of additional wind onshore generation due to higher demand (Scenario D – Scenario C) in 2050

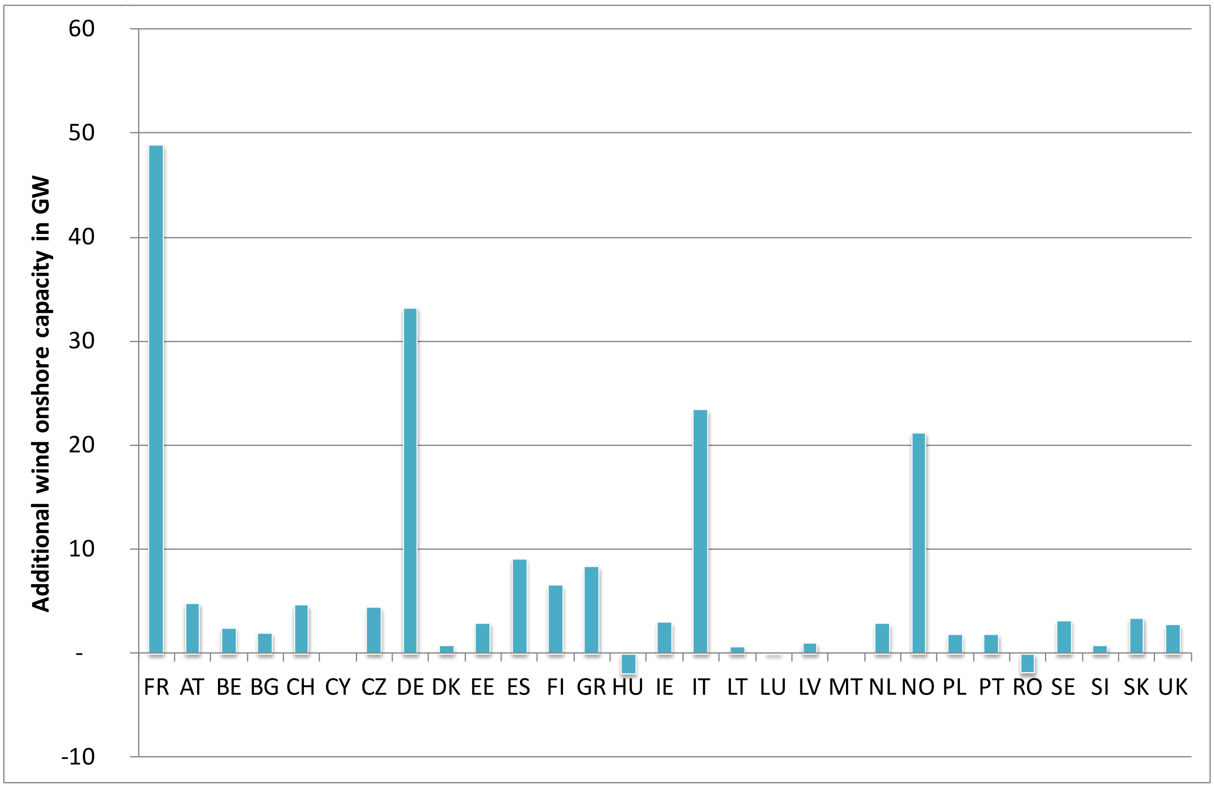

Figure 24 Comparison of additional wind onshore capacity due to higher demand in 2050 (Scenario D – Scenario C)

5.5.1.3 Impact of higher land use on wind onshore (Comparison C and E)

The comparison of Scenario C and E shows the impact of higher availability of wind onshore resources on the distribution of wind onshore. A comparison of both scenarios is given in Figure 25. The higher land use for wind onshore generation leads to the strongest growth in Germany where the additional potential is utilized to replace the constrained wind offshore generation[19]. Additional growth takes place in Italy and Spain where wind onshore generation replaces CCS and PV. In Norway wind onshore generation decreases slightly by ca. 15 TWh in 2050 as more wind onshore generation takes place in Central Europe.

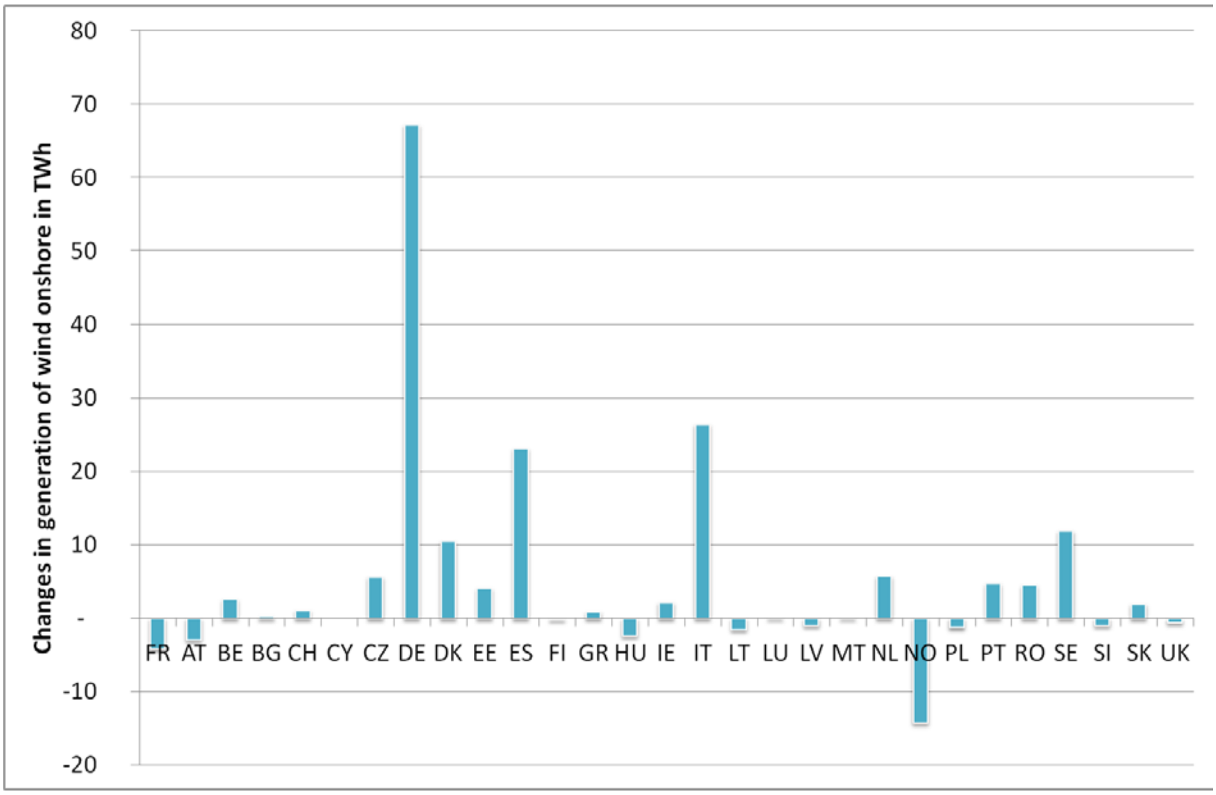

Figure 25 Comparison of wind onshore generation in (Scenario E - Scenario C) in 2050

5.5.2 The development of Wind offshore

5.5.2.1 Wind offshore in Scenario C („Efficiency")

The results for the development of wind offshore in Scenario C are shown in Figure 26. Due to the availability of large low cost wind onshore resources the growth of wind offshore generation in the region is limited. In all countries with the exception of Germany the development of wind offshore is solely enforced by the requirement to meet the national technology target of each country for 2020 documented in the NREAP. After 2020 no further growth in wind offshore generation takes replace. Only in Germany production grows to 118 TWh in 2050 which is beyond the target documented by the NREAP. The main reason for the stronger growth in wind offshore generation is the fact that wind onshore resources are heavily utilized and additional generation is necessary to meet the

19 The German wind offshore generation is limited to 15 GW in 2050 to reflect the offshore target of the German coalition agreement, which states 15 GW as target value for 2030. http://www.bundesregierung.de/Content/DE/_Anlagen/2013/2013-12-17-koalitionsvertrag.pdf;jsessionid=52CA264DCF29D15E55BD35EFDDE70541.s3t1?__blob=publicationFile&v=2

national annual self supply rate (85% in energetic terms in 2050). In this situation wind offshore generation is the cheapest carbon free generation technology available to the model.

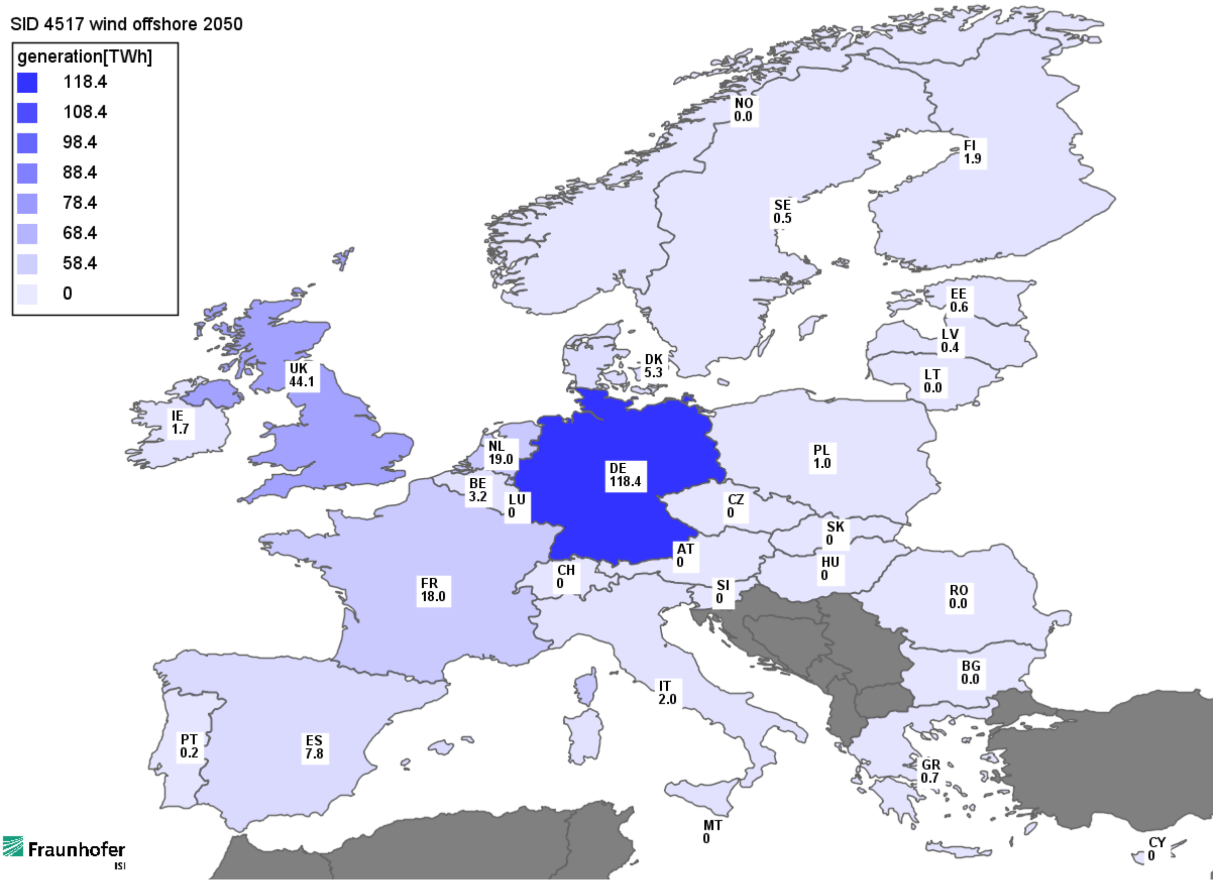

Figure 26 Development of wind offshore generation Scenario C in 2050

5.5.2.2 Impact of demand on wind offshore (Comparison C and D)

The comparison of Scenario C and D shows no significant impact of electricity demand on wind offshore generation. This finding seems be valid as long as the demand does not exhaust the potentials of cheaper resources like wind onshore or photovoltaic in southern Europe.

5.5.2.3 Impact of modified wind assumptions on wind offshore (Comparison D and E).

The only difference between Scenario D ("High Demand") and E ("Modified Wind") in terms of wind offshore generation is a drop in electricity generation in Germany by ca. 62 TWh which is enforced by the scenario assumption that Germany builds only 15 GW offshore, which reflects the current policy targets. In other countries no limit is imposed. In all three scenarios the NREAP targets for 2020 are enforced for every country as minimum condition. The model does not build any capacity beyond the NREAP offshore target in all countries with the exception of Germany. Therefore the additional cheap wind onshore potential cannot affect the results on these countries as the offshore generation capacity is determined by the minimum condition of the NREAP.

5.5.3 The development of Photovoltaic (PV)

5.5.3.1 Photovoltaic development in Scenario C („Efficiency")

The following picture shows the regional results for the electricity generation by PV in 2050. The highest PV generation is located in Spain, Italy, Portugal, Romania and Germany. While the good solar conditions in Spain and Italy are not surprising, the strong PV generation in Germany needs additional explanation. The high electricity generation of PV in Germany is caused by the national renewable targets for 2020 as documented in the NREAP. It is assumed that the national targets for 2020 also apply to the following years. As an example the PV capacity of Germany in 2020 cannot be reduced to a value below the 2020 NREAP target. In Romania the good sites for wind power are limited which leads to stronger growth in PV to fulfil the national self supply rate.

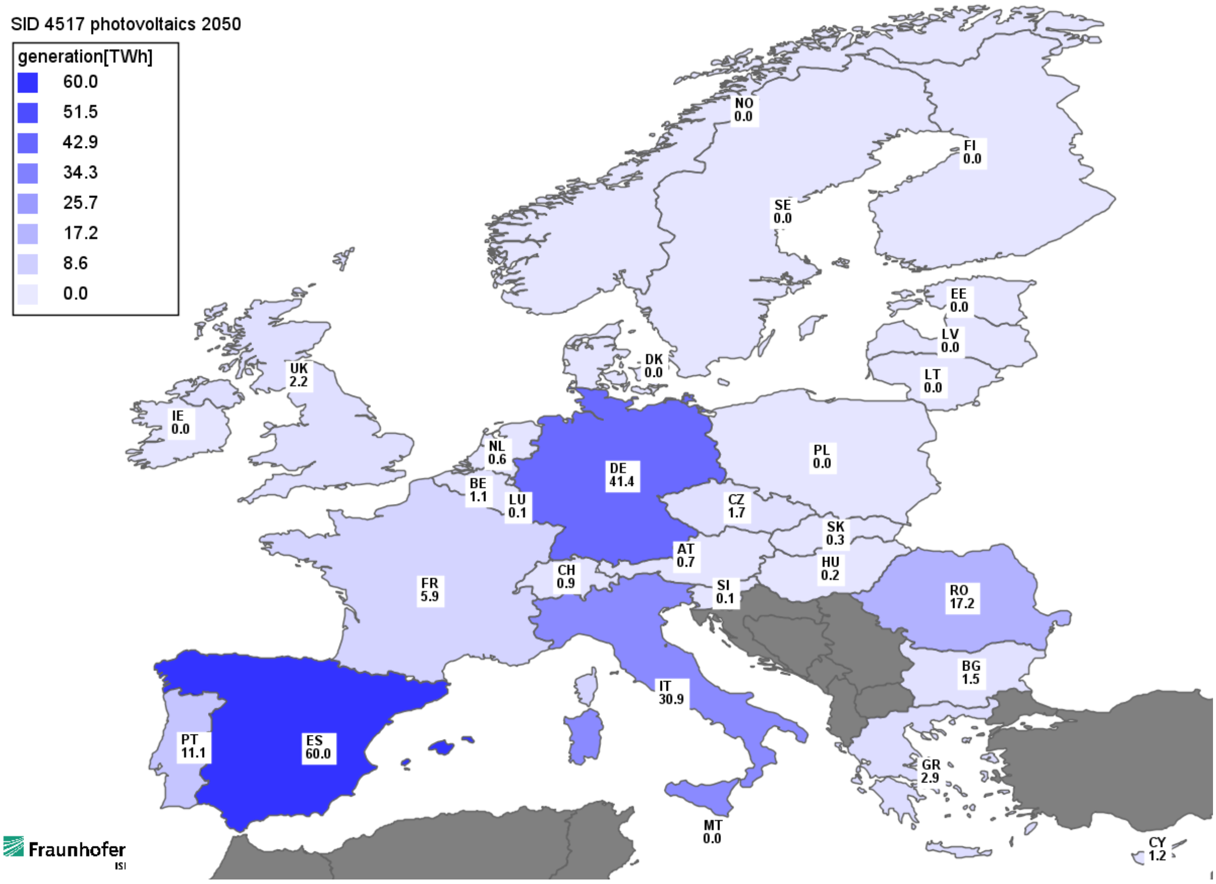

Figure 27 Generation of PV in Scenario C ("Efficiency") in 2050

5.5.3.2 Impact of higher demand on PV (Comparison C and D)

A comparison between Scenario D and C provides insights into the impact of higher demand on the resulting development of photovoltaic. At a first glance the strong growth of photovoltaic in Germany by more than 40 TWh is remarkable. The underlying mechanism is that Germany needs to fulfil its self supply rate. As additional PV generation is cheaper than the remaining wind resources the optimization model builds PV whenever it is the cheapest low carbon resource. Additional growth of more than 30 TWh photovoltaic generation takes place in Italy and Spain which can be explained by the good solar conditions and low generation cost in southern Europe.

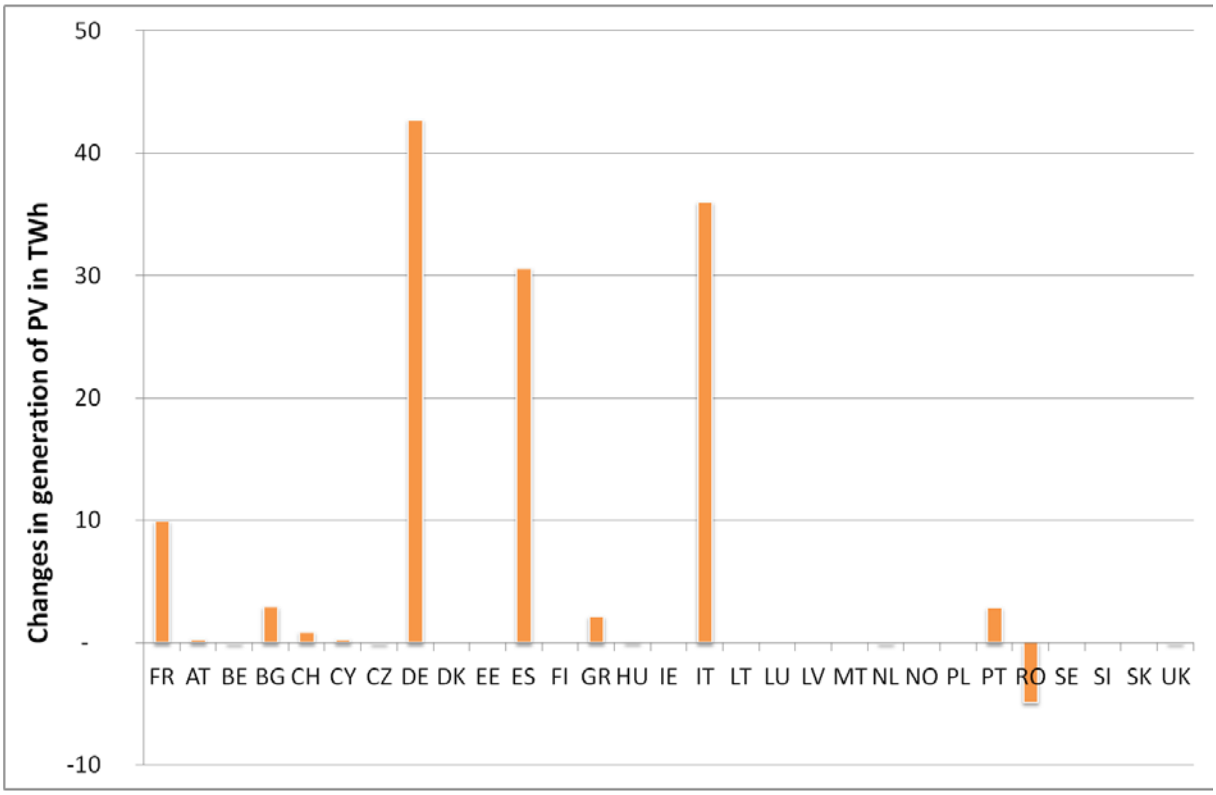

Figure 28 Impact of higher demand on PV generation in 2050 (Scenario D –Scenario C)

5.5.3.3 Impact of modified wind assumptions on PV (Comparison D and E)

Changes of the wind assumption do not have a major impact on the development of PV. A comparison of scenario D and E is given in Figure 29. In Northern Europe this finding is not very surprising, as PV does not play a major role in these countries. Again the situation in Germany has a special context. Additional wind onshore potential is available by the changed land used assumptions on scenario E. But the additional wind onshore potential is already utilized to compensate for the loss of wind offshore generation caused by the limit on the wind offshore capacity. Therefore no competition to PV takes place.

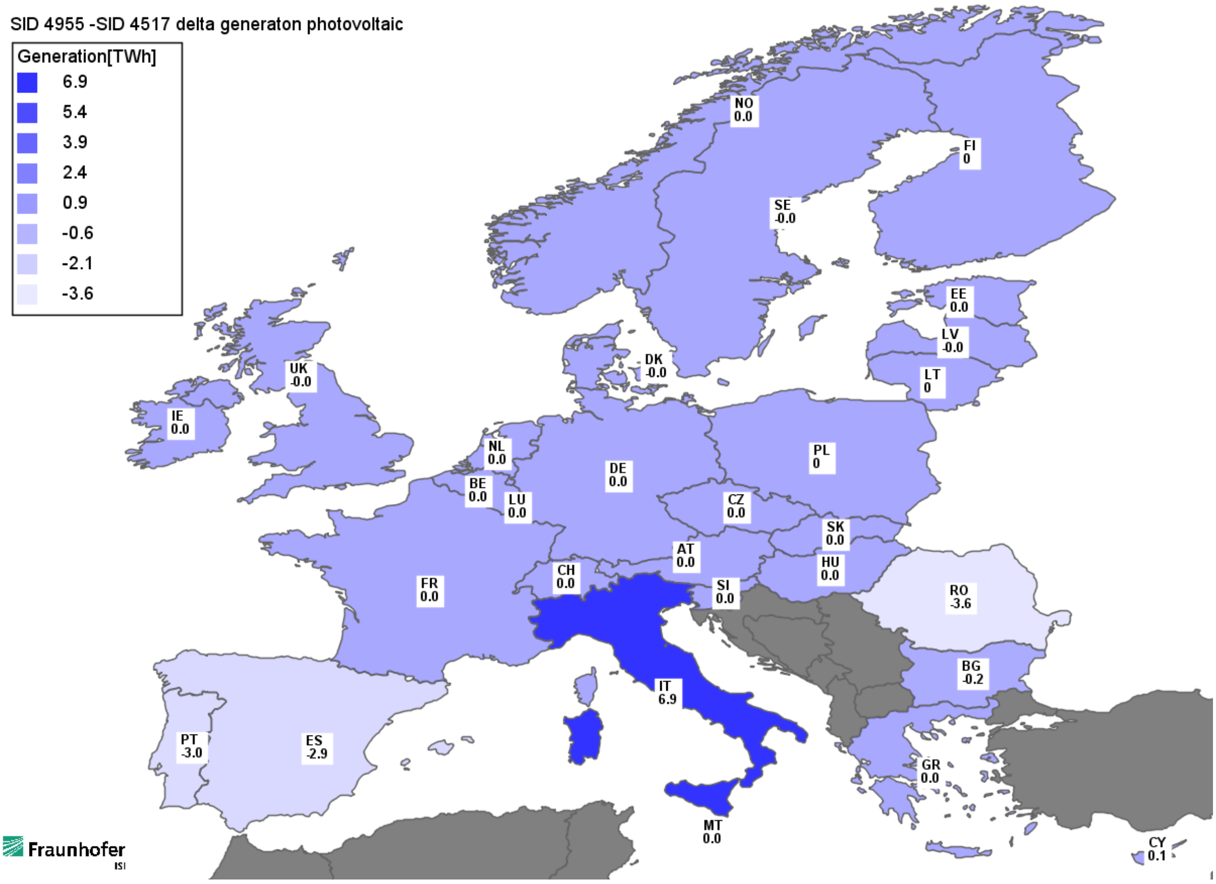

Figure 29 Impact of changed wind assumptions on photovoltaic in 2050 (Scenario E- Scenario C)

5.5.4 The development of Concentrating Solar Power (CSP)

5.5.4.1 Development of CSP in Scenario C („Efficiency“)

Concentrating Solar Power is the only “new” renewable technology that can provide flexibility to the electricity system by the utilisation of thermal heat storage. Figure 30 shows the regional results for CSP generation. CSP plays only a minor role in the calculated scenario. Due to the higher cost it is rarely competitive to the other low carbon technologies. Since hydro, nuclear and to a limited extend CCS can supply the capacity and flexibility for the balancing of the system the additional value of the CSP storage capacities is not high enough in this scenario to trigger stronger CSP construction in the model.

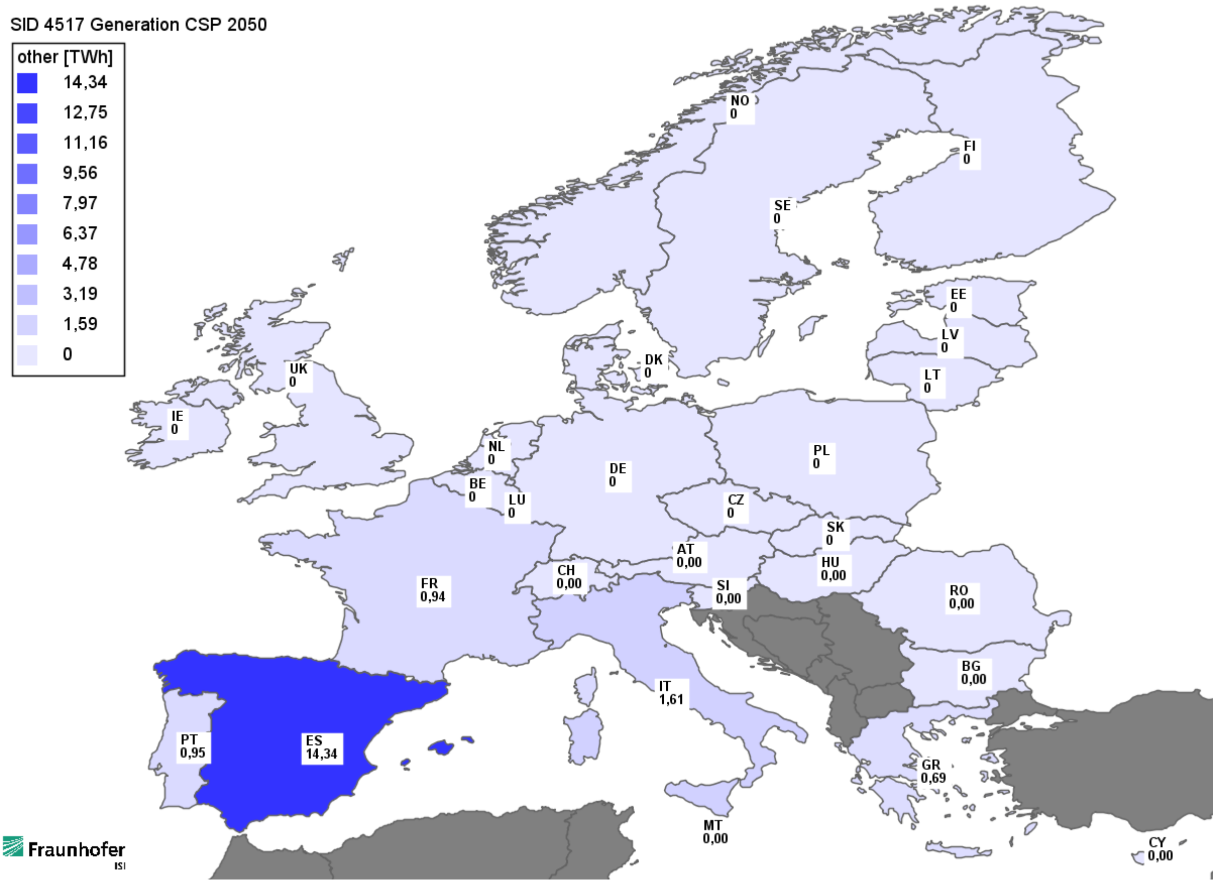

Figure 30 Generation of CSP in Scenario C in 2050

5.5.4.2 Impact of higher demand on CSP (Comparison C and D)

The higher demand leads to no major changes in the installed capacity of CSP plants. Italy is the only country with a growth in CSP capacity of 400 MW in 2050.

5.5.4.3 Impact of modified wind assumptions on CSP (Comparison C and E)

The changed assumptions on wind do not change the installed capacity of CSP plants in the comparison of scenario D and E. This is due to the fact that CSP generation does not exceed the minimum generation required to meet the NREAP target of the relevant countries. As the CSP capacity is enforced by a minimum condition in the model it is not affected by growing wind onshore potential.

5.6 Results on the electricity grid

The next part of the analysis of the scenarios deals with the grid infrastructure modelled in the system. The electricity infrastructure is modelled by a simplified approach as transport model between country centres. Each line is characterized by a net transfer capacity, a given length, line losses and the cost of additional transport capacity.

5.6.1 General development of the grid infrastructure

One central result of the analysis is the assessment of the demand for new grid infrastructure. In order to get an impression on the overall demand for infrastructure an indicator combining transport capacity and the length of the actual line seems to be a better indicator than a sole analysis of the development of the overall transport capacity. Therefore a grid infrastructure indicator is derived by multiplying the capacity of each line with the length of the line and summing up the results for each line.

The following picture provides a comparison of the development of the indicator in all three scenarios. Up to 2030 the grid indicator has the same value in all three scenarios as grid extension is enforced by the minimum condition for the TYNDP 2012. Despite the strong growth of renewable generation the model does not extend the grid infrastructure beyond the TYNDP 2012 until 2030. In the period 2040 to 2050 the grid infrastructure grows in all scenarios. The highest value is reached in Scenario D with the highest demand. Higher demand leads to higher transport requirements for the growing renewable electricity generation. Although Scenario C and Scenario E have the same level of electricity demand the need for new grid infrastructure in Scenario E is ca. 5 % higher. In the least cost approach the stronger utilization of wind onshore resources leads to higher demand for grid infrastructure.

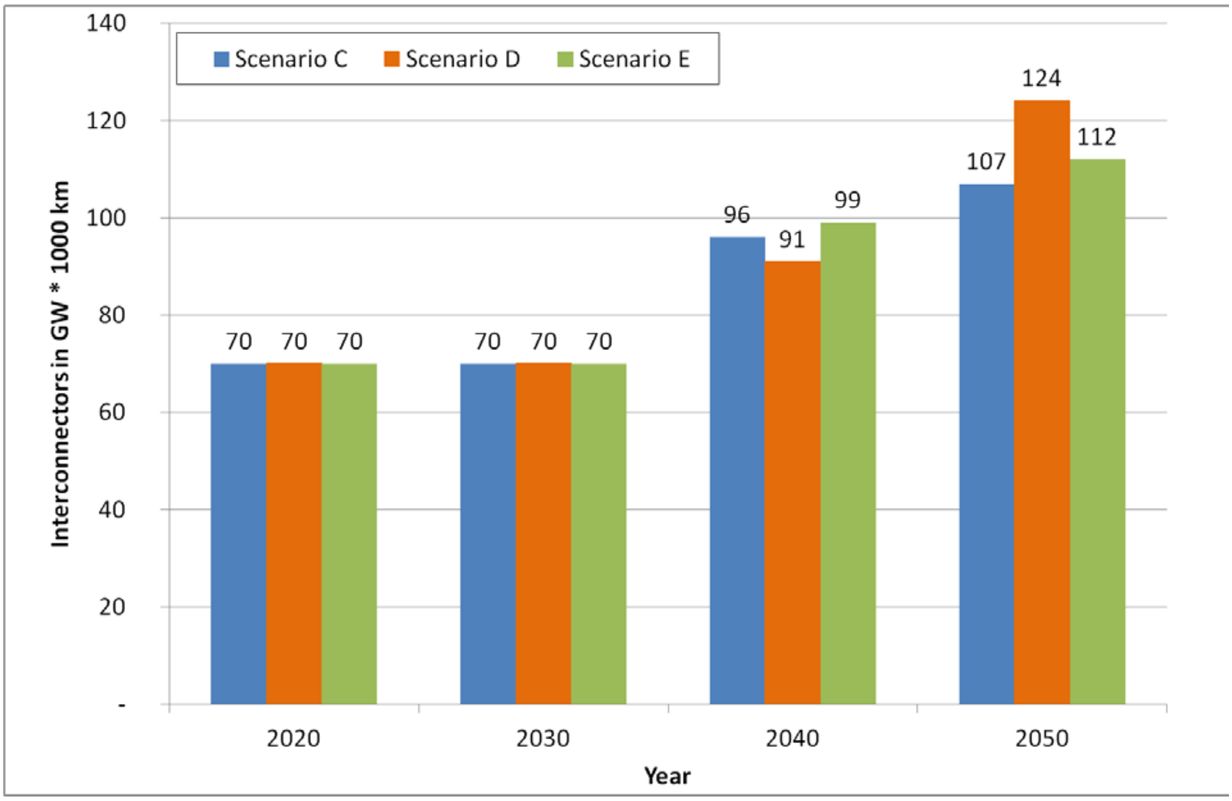

Figure 31 Development of the grid infrastructure in the analysed scenarios

5.6.2 The electricity grid in scenario C ("Efficiency")

The next step of the analysis of the grid infrastructure is the analysis of the regional development of the electricity grid. In Figure 32 net transfer capacities in 2050 in Scenario C are displayed. The strongest interconnector is between Spain and France. It has to be stated that in almost all scenarios, regardless the input assumptions the interconnector between France and Iberian Peninsula turns out to be one of the most important connections in the least cost model. The connection provides the capability for the Iberian Peninsula and Central Europe to balance each other. This effect is strengthened by the different weather regimes in terms solar radiation and wind speeds for the renewable generation units. Other important connections are the connections between France and Italy and connections to Norway. The connection between France and Italy is mainly utilized for imports.

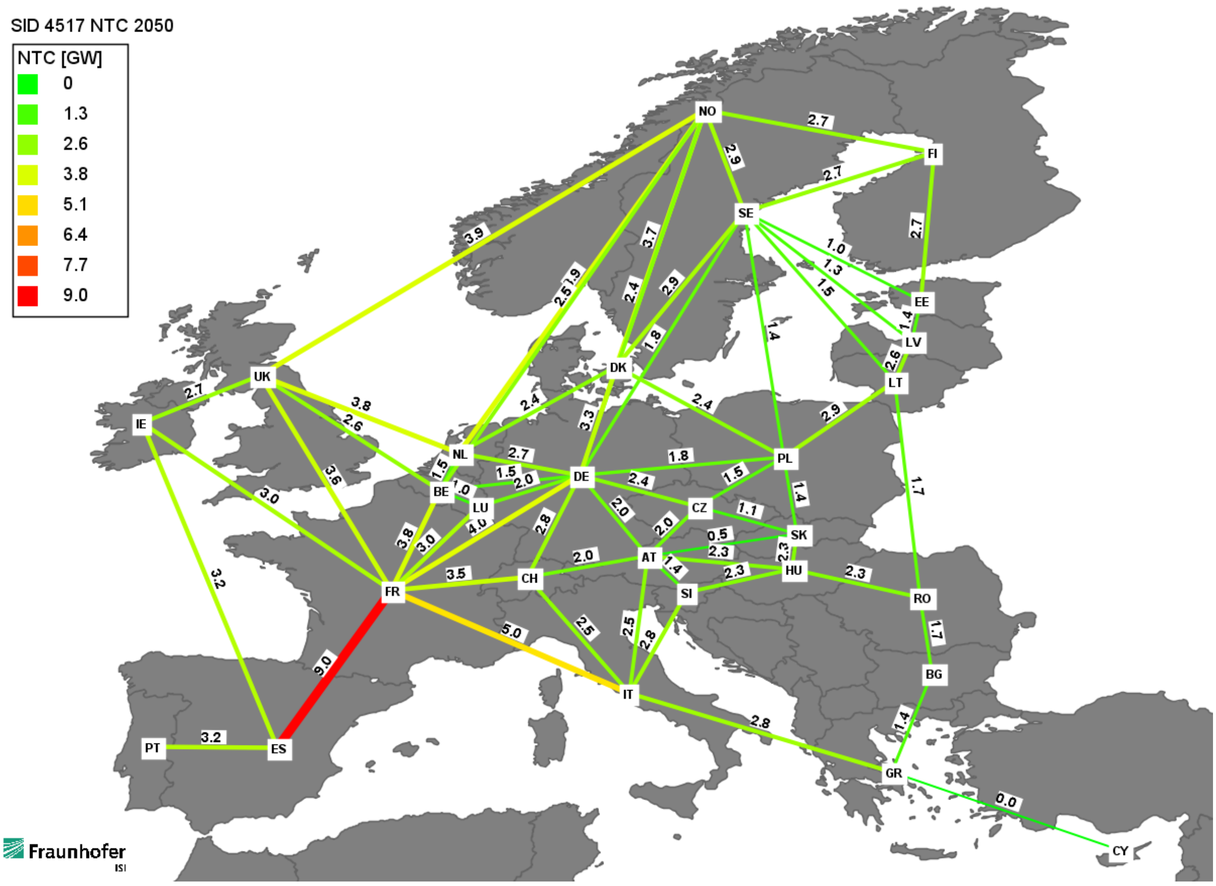

Figure 32 Net transfer capacity in Scenario C ("Efficiency") in 2050

5.6.3 Impact of higher demand on the electricity grid (Comparison C and D)

The following figure provides a comparison between Scenario D and Scenario C which shows the impact of higher demand on the grid infrastructure. One remarkable result of the comparison is the growth of interconnections between Germany and its neighbouring countries. Overall growth of the net transfer capacities to Germany is more than 9 GW. This is mainly caused by the higher share of volatile generation requiring more balancing throughout the region and stronger imports of electricity. The second observation is that connections to Norway grow by more than 4 GW. This effect is mainly caused by the additional wind onshore generation for export purposes in Norway and the valuable balancing capability of the hydro resources. Additional growth of grid lines also takes place on the axis France/Switzerland-Italy for balancing purposes.

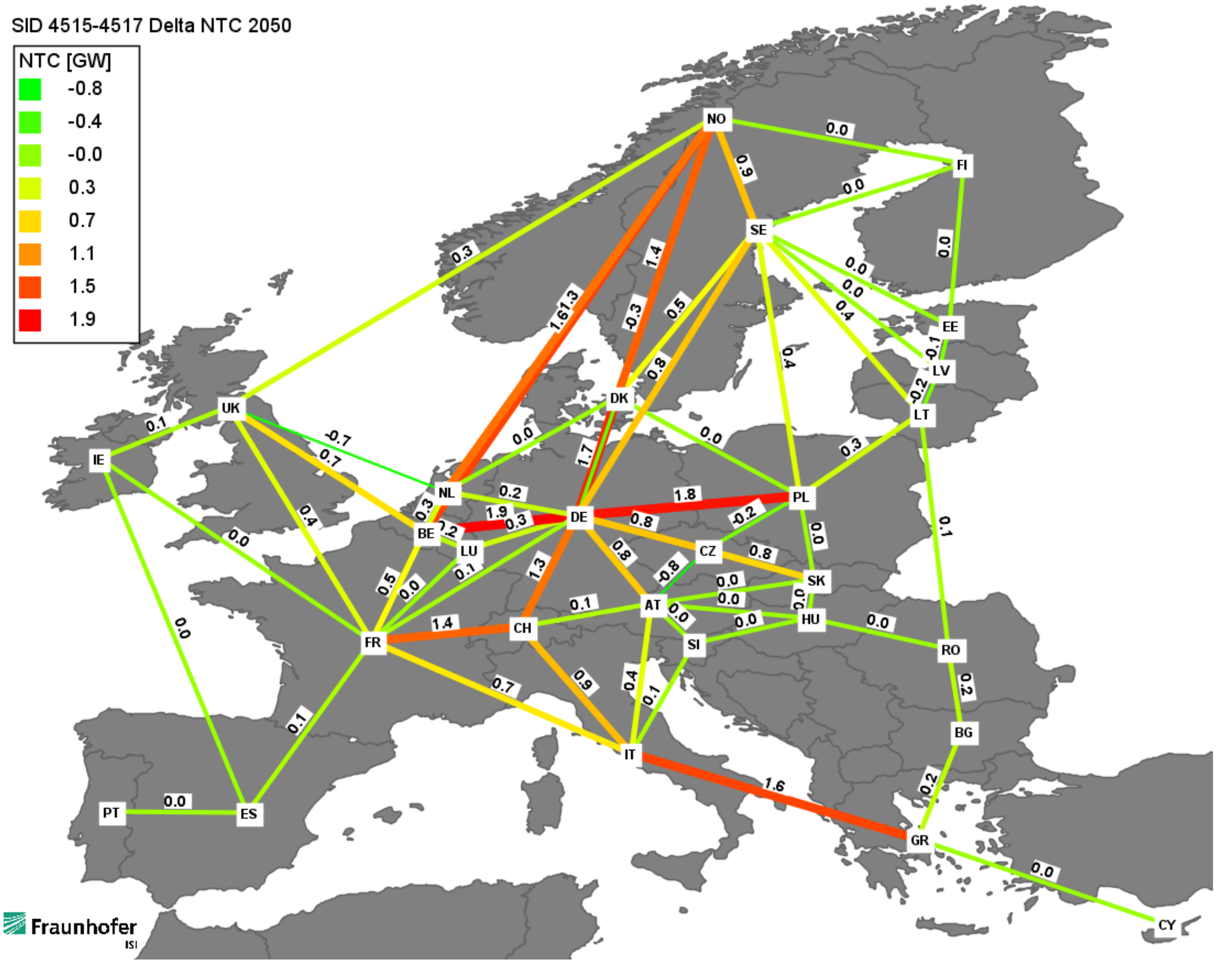

Figure 33 Impact of higher demand on total interconnector capacity (Scenario D- Scenario C) in 2050

5.6.4 Impact of modified wind assumptions on the electricity grid (Comparison C and E)

The impact of changes in the assumptions on wind energy on the overall grid infrastructure is limited. The following figure shows the comparison of Scenario D and Scenario E. In most cases the changes in the capacity of the interconnectors is below 1 GW.

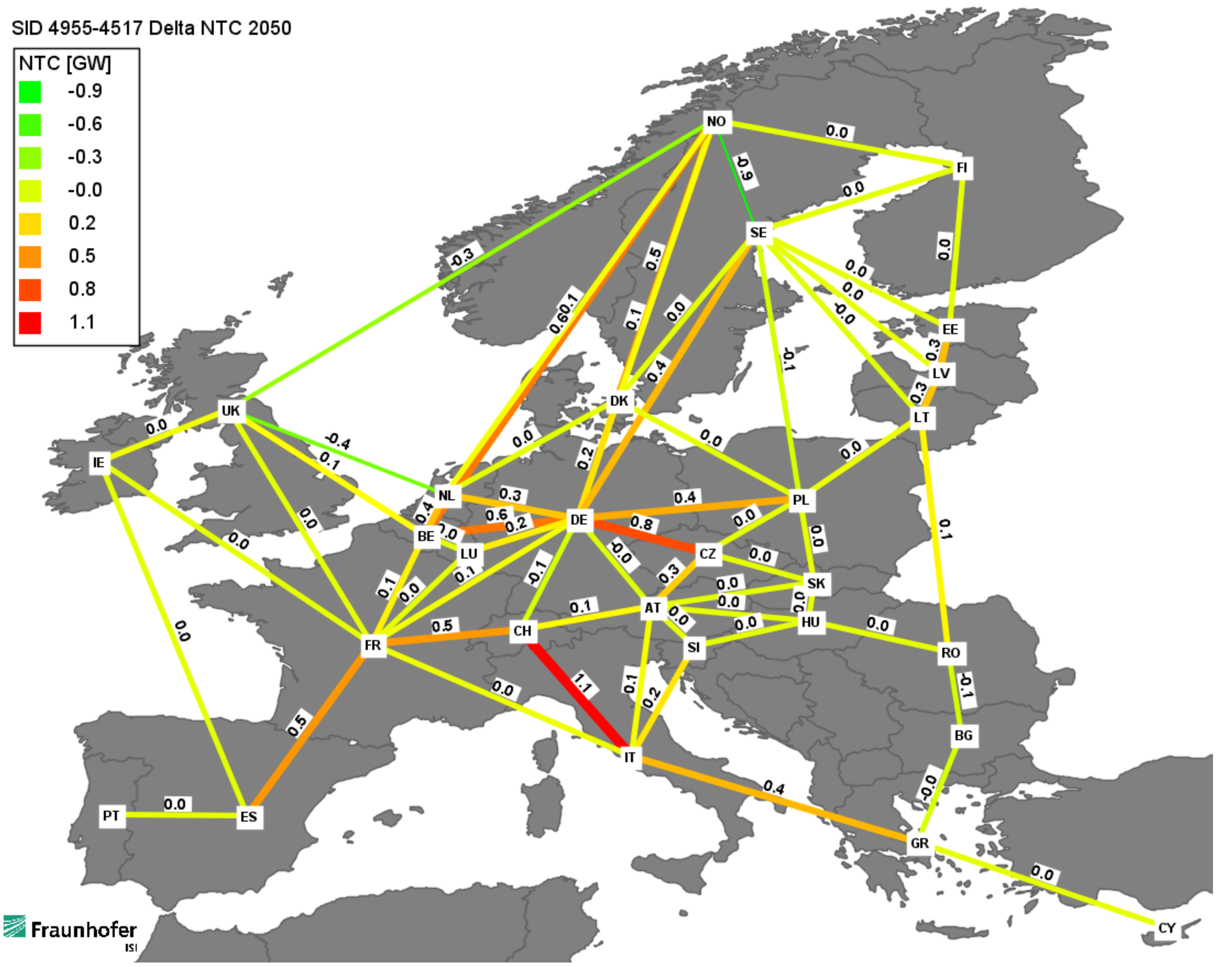

Figure 34 Impact on changed wind assumptions on interconnector capacity (Scenario E- Scenario C) in 2050

5.7 The costs for ambitious climate protection in the European electricity system

5.7.1 Annual system cost

After the analysis of the infrastructure for electricity generation and transport the next step is the analysis of the system cost. Overall system cost is the target indicator for the least cost approach of the model. It includes fuel cost of all plants, capital and O&M cost of all generation units and the cost of the electricity transport as depicted in a simplified transport model of the electricity grid infrastructure between countries.

A crucial aspect of all comparisons of system cost over time is the treatment of the existing infrastructure. The least cost approach treats the existing infrastructure as sunk cost. In other words the existing infrastructure is already paid for and therefore not relevant for the cost optimization approach of the future development. This common approach leads to the fact that cost comparisons over time are complicated. A sole analysis of the cost of the new infrastructure and the fuel cost or O&M cost of existing plants leads to a steady increase of system cost over time as the existing infrastructure without capital cost diminishes and new plants need to be constructed. On the other hand the actual investment needed to build the existing infrastructure is unknown as it consists of very diverse elements built at different times in very different technological, economical and political framework conditions. Despite this dilemma it seems to be valuable to provide a rough assessment on the relation between the cost of the electricity system in the near future (2020) and the end of the period (2050). The solution to deal with the high uncertainty concerning the capital cost of the existing infrastructure is to account for all existing infrastructure with the specific cost of new technology options in the year 2020. As an example all existing hardcoal plants are accounted for by the capital cost of a new plant built in 2020. This has to be considered as a very rough approximation since some technologies such as photovoltaic plants have been characterized by considerably higher cost in the past, while other technologies such as some conventional plants have been constructed at lower specific investments in the past e.g. due to lower demands plant characteristics such as efficiency. Despite this obvious source of error in the cost figure provides a basis for the cost comparison in the time period 2020 to 2050. The resulting development of the system cost is shown in the following table. It is important to note that this cost analysis does not include the cost of the distribution grid and major parts of the national transmission grid.

Table 12 Development of annual system cost[20]

Scenario	2020	2030	2040	2050	unit
Scenario C ("Efficiency")	225.7	229.2	226.6	199.4	bill. $€_{2010}$
Scenario D ("High demand")	223.0	223.1	253.1	249.2	bill. $€_{2010}$
Scenario E ("Modified wind")	225.0	227.5	224.2	197.3	bill. $€_{2010}$

In Scenario C with low electricity demand annual cost stay at a stable level until 2040 and drop to ca. 200 billion € 2050, mainly due to decreasing demand and cost improvements of renewable generation technologies. Scenario C with higher demand starts on a comparable stable level of 223 billion € in the period 2020 to 2030. The slightly lower cost in 2020 and 2030 compared to Scenario C reflects the electricity demand which is 1% lower in 2020 and 2.5% lower in 2030 compared to Scenario C. Thereafter rising demand and the CO_2 restriction lead to a cost increase to a total of ca. 250 billion € in the period 2040-2050. In total the annual cost of the electricity system with higher demand are ca. 50 billion € or 25% higher. This result shows the considerable amount of capital that is not required for the electricity supply in an energy efficiency scenario. The comparison between scenario D and E shows the impact of better acceptance for wind onshore. The cost saving induced by the higher land use for wind onshore starts with 0.7 billion € in 2020 and reaches its maximum with ca. 2.4 billion € in 2040. However in terms of total annual cost the impact of the demand level on annual cost is considerably stronger.

5.7.2 Specific cost

The analysis of total system cost provides an overview of the financial resources that have to be allocated to the electricity sector. However, from a consumer perspective specific cost of electricity is a more relevant criterion since it can provide an indicator of the general tendency in the development of electricity prices. But it is not identical to electricity prices. It is calculated by dividing the total cost of the electricity system by the net electricity demand. It should be noted that in a real world consumer perspective cost for the remaining part of the grid infrastructure, taxes and player margins are added to the bill which leads to a higher overall cost level. A comparison of the analysed

[20] Total annual cost include fuel cost, operation cost and annual capital cost calculated by the method for annuities for all generation technologies, storages and grid connection between countries.

scenarios is given in the following table. All scenarios start with specific cost of ca. 65 €/MWh in 2020 and costs decline afterwards to 2050. Differences between the scenarios are rather limited and in the order of magnitude of 1 to 2%. The cheapest scenario is Scenario E due to the moderate demand with modified assumptions and the more favourable assumptions regarding the land use for wind energy.

Table 13 Development of specific cost

Scenario	2020	2030	2040	2050	unit
Scenario C („Efficiency“)	66.2	64.2	64.7	63.9	€/MWh
Scenario D („High demand“)	66.0	64.1	65.0	64.1	€/MWh
Scenario E („Modified wind“)	66.6	63.7	64.9	63.2	€/MWh

Generally all scenarios show a decline in specific cost and even overall cost stay at a moderate level. Taking into account the ambitious CO_2 reduction applied in these scenarios this is an important result. Ambitious CO_2 reductions in the European electricity sector can be reached without strong impact on specific electricity cost.

5.7.3 Components of the system cost

Another interesting aspect of the analysis of system cost is the contribution of the different cost types to the total system cost.

5.7.3.1 Scenario C („Efficiency“)

This section analyses the development of the different cost types in scenario D. In 2020 the biggest cost factor are the fixed cost of existing and new conventional power plants. It decreases by more than 50% to 2050. The fuel cost decrease in line with the declining conventional production. As the assumed development of fuel price is rather stable changes in fuel prices have only a minor impact on the development of fuel cost. Another remarkable outcome is the development of the grid cost which increases by 53% from 2020 to 2050. However, considering the strong growth in grid infrastructure modelled in the scenarios the share of the modelled part of the electricity grid in total cost is still limited (roughly 6%).

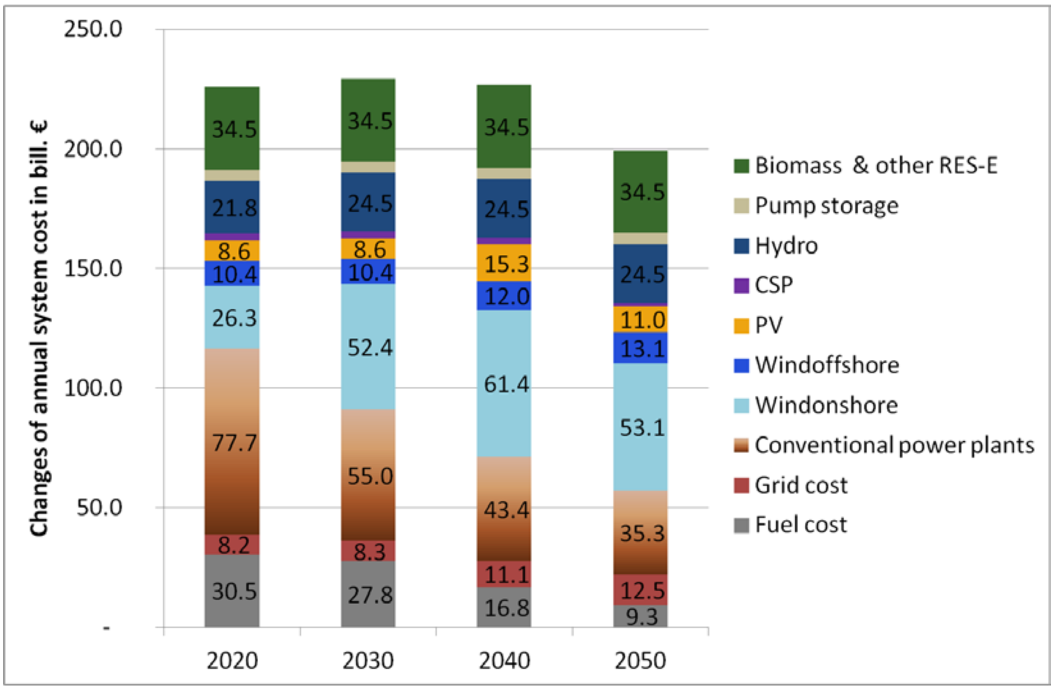

Figure 35 Overview of components of the annual system cost

5.7.3.2 Impact of higher demand on system cost (Comparison C and D)

The next step is to analyse the impact of higher demand on the structure of the cost. The higher generation of renewable and CCS plants described in chapter 5.2.2 is also visible in the comparison of the cost structure. Major differences between scenario C and D start in 2040 with a strong increase in cost of conventional CCS plants and growth of wind onshore. In 2050 the total increase in the cost of ca. 50 billion Euro is split between renewables and conventional including growth in grid cost.

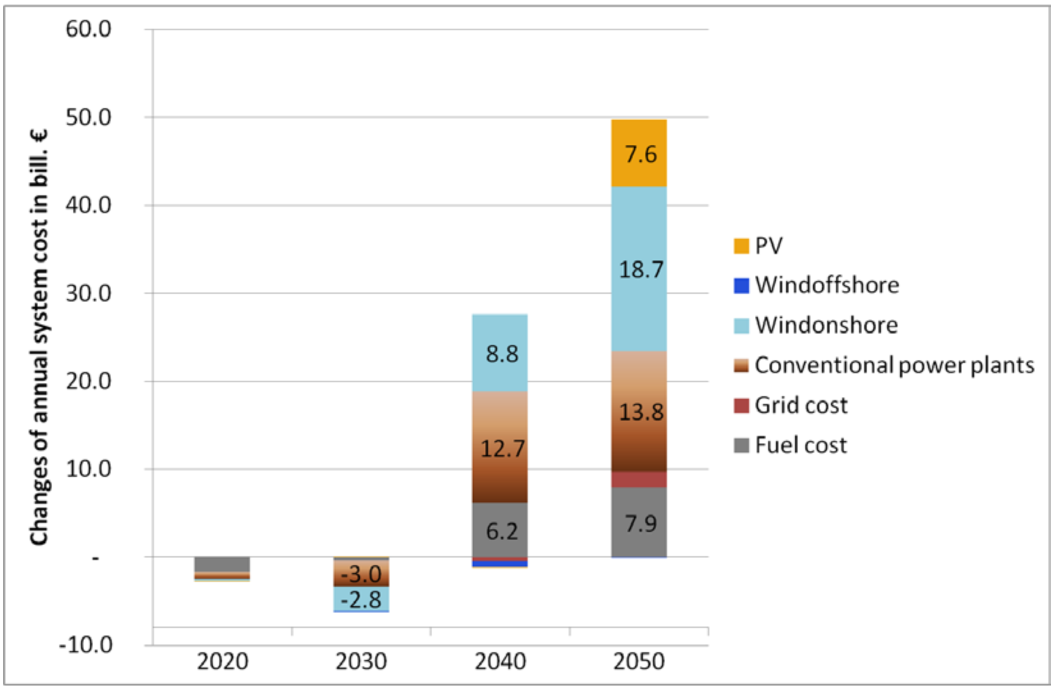

Figure 36 Impact of higher demand on system cost

5.7.3.3 Impact of modified wind assumptions on system cost (Comparison D and E)

In general the impact of the changed wind assumptions on the cost structure is lower than the impact of demand. The additional wind production contributes to additional cost for wind energy and electricity grid. This increase in cost is compensated by lower cost for conventional plants, wind offshore, photovoltaic and conventional fuels. A graphical comparison of the cost structure in scenario D and E is given in Figure 37.

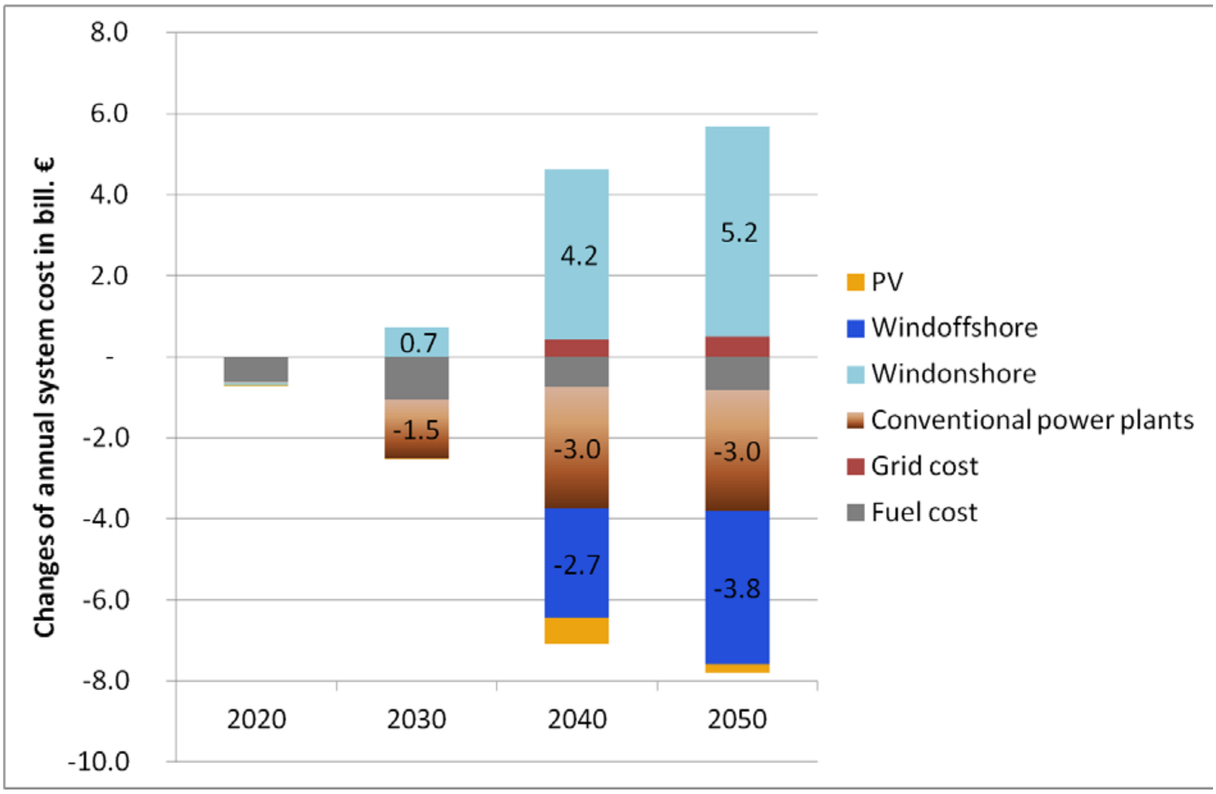

Figure 37 Impact of changed wind assumptions on system cost

5.7.4 Marginal CO_2 price

An important indicator for the effort necessary to reach the required CO_2 target is the marginal CO_2 price. In the model it is calculated through the shadow cost variable of the CO_2 constraint of the optimization problem. Generally it can be stated that the internal marginal CO_2 price cannot directly be compared to the prices of the European Emissions Trading Scheme (ETS) which covers additional industrial sectors and includes mechanisms for international trade. Furthermore the shadow price can be distorted to some extend by boundaries of the model such as the requirement to meet national NREAP targets. The ambitious CO_2 target of 700 Mt in 2020 (less than 50% of 1990 levels) can be reached at a marginal CO_2 price of ca. 15 €/t. In 2030 the ca. 40 €/t are required. In case of the moderate demand scenarios the marginal CO_2 price reaches its peak with 78 €/t in 2040 and declines to ca. 55€/t in 2020. The lower marginal CO_2 price in 2050 is caused by the reduction in electricity demand which has a twofold impact. Lower demand itself leads to lower electricity production thus reducing the pressure on the CO_2 limit. The second effect is that renewable potentials can be utilized at a lower level where the cost curve has a lower slope. In case of higher demand the marginal CO_2 prices continues to increase to 84 €/t in 2050.

Table 14 Marginal CO_2 Price

Scenario	2020	2030	2040	2050	Unit
Scenario C („Efficiency“)	15	44	78	54	€/t
Scenario D („High demand“)	16	41	73	84	€/t
Scenario E („Modified wind“)	14	39	78	55	€/t

6 Conclusions

This study investigated concrete pathways towards a European electricity sector in line with the goal of keeping global warming below 2°C. It analysed the development of the electricity sector in the EU 27, Norway and Switzerland up to the year 2050. Due to the fact that such long-term projections are always connected with high uncertainty, several scenarios were calculated to cover a broad range of possible developments. In a previous study (Pfluger et al.), two scenarios were calculated which reach the ambitious climate targets despite a phase-out of nuclear generation and no use of carbon capture and storage technologies (CCS) in the electricity sector. This study complements these scenarios using an improved modelling technique and includes three additional scenarios featuring CCS as a technology option and incorporating a moderate reduction in total nuclear capacity. Scenario C ("Efficiency") analyses an electricity sector with an ambitious electricity demand reduction. Scenario D ("High demand") assesses the impact of higher electricity demand on the results. Scenario E ("Modified Wind") is based on the electricity demand of Scenario C but with more land available for the construction of wind onshore plants and modified assumptions about the use of offshore wind in Germany.

This study applied a least-cost optimisation model to obtain insights into technologically and economically feasible developments in the electricity sector. Due to its structure including a uniform cost of capital and uniform technology costs, it assumes perfect competition between infrastructures and their location. However, real-world investments in local sites deviate from this perfect competition by two major aspects. The first aspect is the cost of capital, which is heavily influenced by political and regulatory framework conditions that can lead to different risk premiums. One example of this are thehigher risk premiums in southern Europe for investments which are not backed by additional financial security mechanisms. The second aspect concerns the costs of projects. Administrative barriers at local or national level or the local market situation of the required resources in terms of technology and workforce can also have a significant impact on the actual cost of a project. As these aspects can be influenced by political decisions, the modelling approach used provides valuable indications of where political efforts could overcome barriers hindering the progression towards low-cost solutions in a decarbonised electricity sector.

The analysis was carried out using the PowerACE Europe optimisation model. This study uses the model as a least cost optimisation tool to calculate pathways of the electricity infrastructure such as renewable electricity generation, storage, conventional power plants and the required international transmission capacity. The model seeks to minimize summed system cost[21] over the entire time period. Available investment options include renewable and conventional power plants,

[21] System cost is defined as the sum of the costs included in the analysis. These are fuel costs, operation and maintenance costs and the capital cost of the infrastructures such as power plants, renewable generation units, storage and the cost for interconnectors between countries.

interconnectors for electricity transmission and storage facilities. Two main features of the model are its high temporal resolution in hourly dispatch which covers every hour of a given year and its very high resolution of renewable generation potential based on analysing the weather conditions of more than 220,000 regions within Europe.

Cost of strong decarbonisation: Despite the very ambitious target to reduce CO_2 emissions to 5% of 1990 levels in 2050, the specific cost[22] of electricity remains at a comparable or even decreasing level throughout the time period 2020-2050. This shows that, under the given framework conditions, advanced efforts for climate protection do not necessarily lead to rising electricity costs after 2020[23]**.**

Role of renewables in cost-efficient decarbonisation: All three scenarios targeting the most cost-efficient pathway towards decarbonisation of the electricity sector with different assumptions about demand and land use for renewables culminate in high shares of more than 80 % renewable electricity generation in total generation. This robust result underlines that renewable electricity generation is the most cost-efficient solution for decarbonising the electricity sector under given cost assumptions. This development is already apparent in 2020 when the model builds more renewable electricity generation than is required by the Nation Renewable Energy Action Plans (NREAP). Among all the generation technologies, onshore wind continues to grow strongly over time to become the dominant generation technology in 2050. It is also remarkable that renewables are the most cost efficient technologies although a curtailment of up to 3 % of annual renewable generation in 2050 is calculated by the least-cost model.

Benefits of energy efficiency: Comparing the scenarios reveals two main benefits of greater efforts to increase energy efficiency in terms of lowering electricity demand. Lower demand can decrease the total cost of the electricity system considerably. In our scenario, the results for 2050 show a reduction of 25% in total annual cost in 2050 when demand decreases by the same factor. Another consequence of increased energy efficiency is lower demand for infrastructures such as power lines and new electricity storage facilities or plants which are often contested and face public resistance in many cases. Another important aspect is that less capital is locked into the electricity system. But the comparison also shows that the specific cost as an indicator for the probable development of electricity prices is not affected by higher demand. This indicates that decarbonisation can be achieved cost effectively even at higher demand levels.

Main findings on the electricity grid: As the amount of renewable electricity generation grows, the grid infrastructure will need to be extended. However, the strongest grid infrastructure growth takes place after 2030, when the share of renewable electricity generation exceeds 70%. In all scenarios, there are enhanced grid connections between Germany and its neighbours. Other important developments include strong connections between France and Spain and between central Europe and Norway. Changed assumptions about wind energy have a limited impact on the overall grid infrastructure which highlights the robustness of the defined transmission corridors.

The role of storage: Although all scenarios move in the direction of more than 80% renewables in total generation, no additional storages are built by the optimisation tool. The flexibility of the hydropower plants and additional conventional power plants are used to balance the system via the

[22] Specific costs are defined as the total annual system cost included in the analysis divided by net electricity consumption by consumers (grid losses are subtracted)

[23] This study incorporates no comparison to a scenario with lower levels of CO_2 reduction

electricity grid. This result has been shown in many comparable scenario calculations using this model and can therefore be considered robust. This is in strong contrast to the widespread public belief that strong growth in renewables requires equally strong growth in additional storage technologies.

The importance of a debate on land use: The results showed that renewable electricity generation technologies such as onshore wind are an important part of a decarbonised electricity sector. However, comparing the scenarios also reveals that the contribution of e.g. onshore wind is heavily dependent on the land that is available for development. In the case of large scale PV and CSP, parallel land use options on the same land are limited, e.g. for agriculture and there is direct competition with alternative land uses. The situation for wind energy is different. The impact on alternative land uses is very limited. In this case, the most important aspect is public acceptance for its effect on the landscape and the local population. Since onshore wind turns out to be one of the cheapest options for decarbonisation, these economic benefits have to be weighed up against other social preferences. In the end, the outcome of this debate will be the central factor determining the importance of onshore wind with its huge low-cost generation potential in techno-economic terms. In a broader perspective, there is a similar picture for other infrastructures of the electricity sector such as electricity grids. From a scientific perspective, these issues require broad interdisciplinary cooperation as they involve aspects of social sciences, psychology, politics, engineering and economics.

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Appendix:

A.1 Appendix National demand

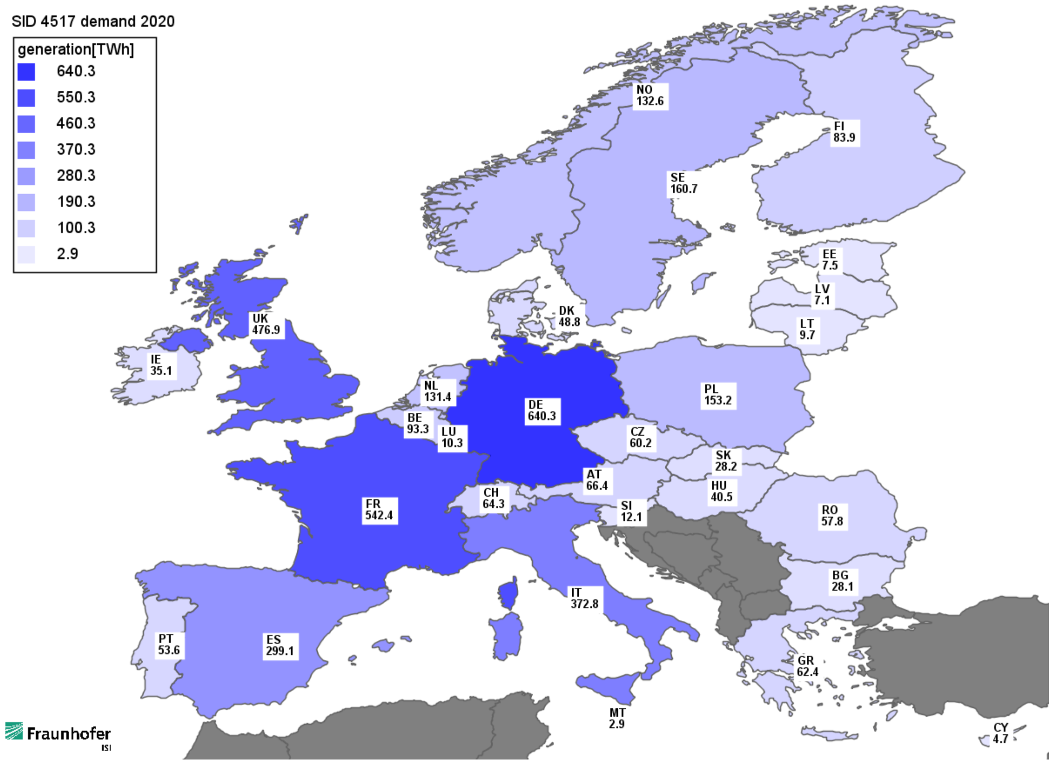

Figure 38 Demand incl. national grid losses in 2020 as assumed in Scenario C and Scenario E

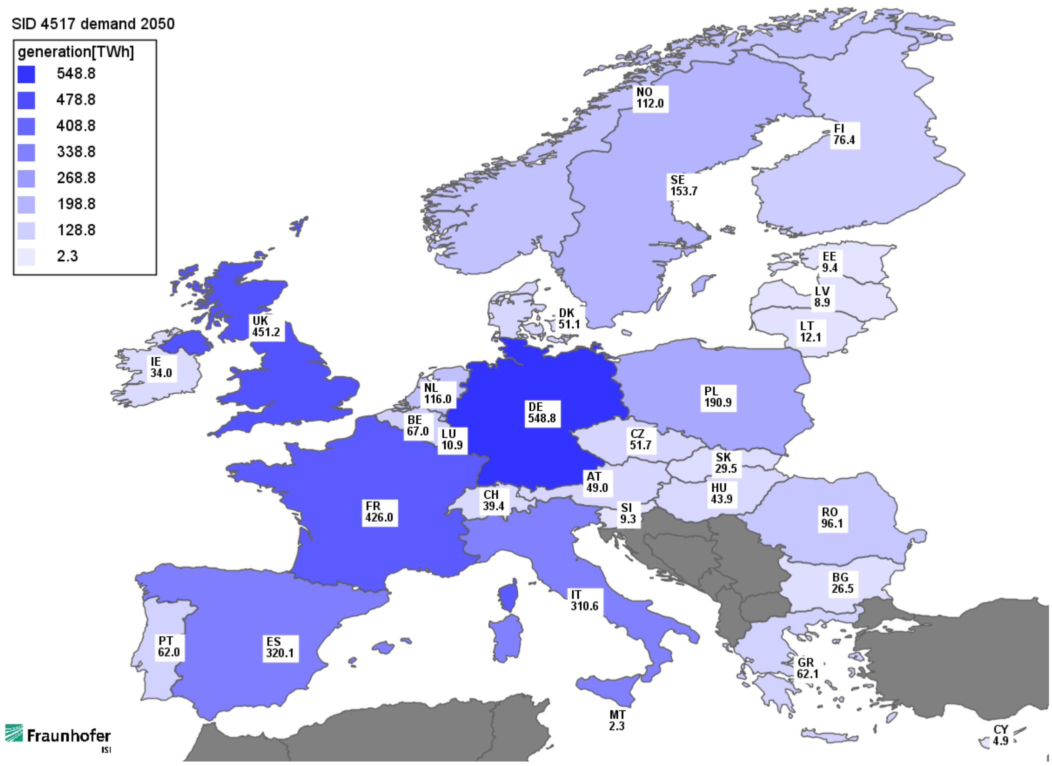

Figure 39 Demand incl. national grid losses in 2050 as assumed in Scenario C and Scenario E

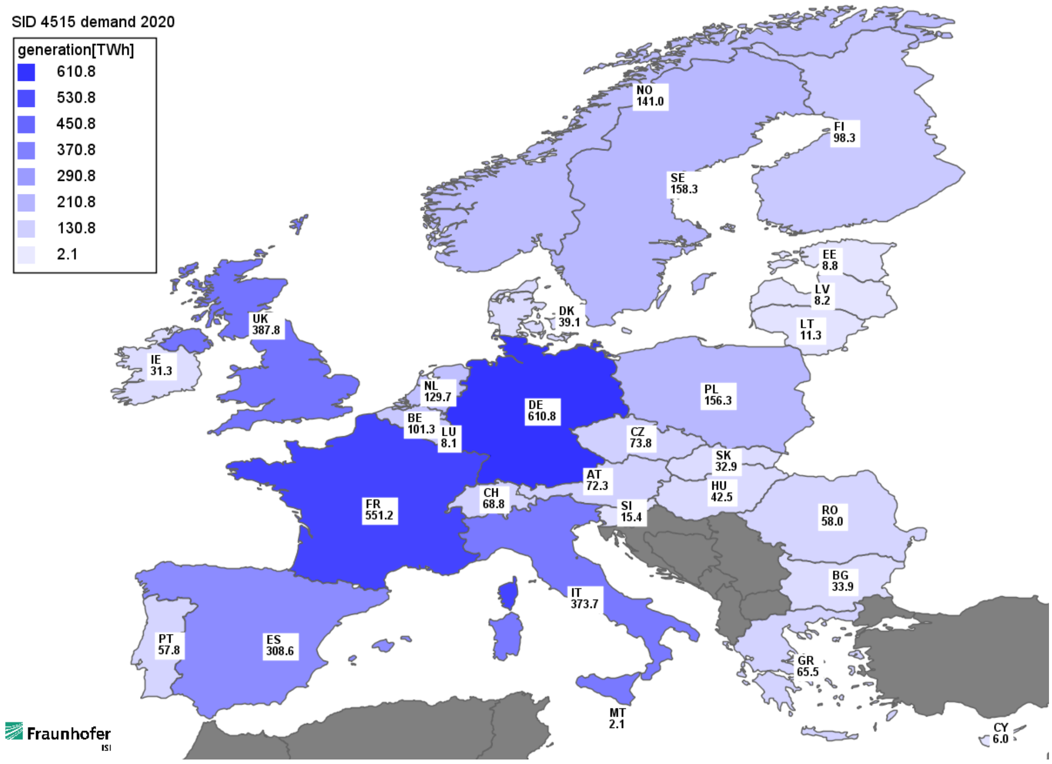

Figure 40 Demand incl. national grid losses in 2020 as assumed for Scenario D

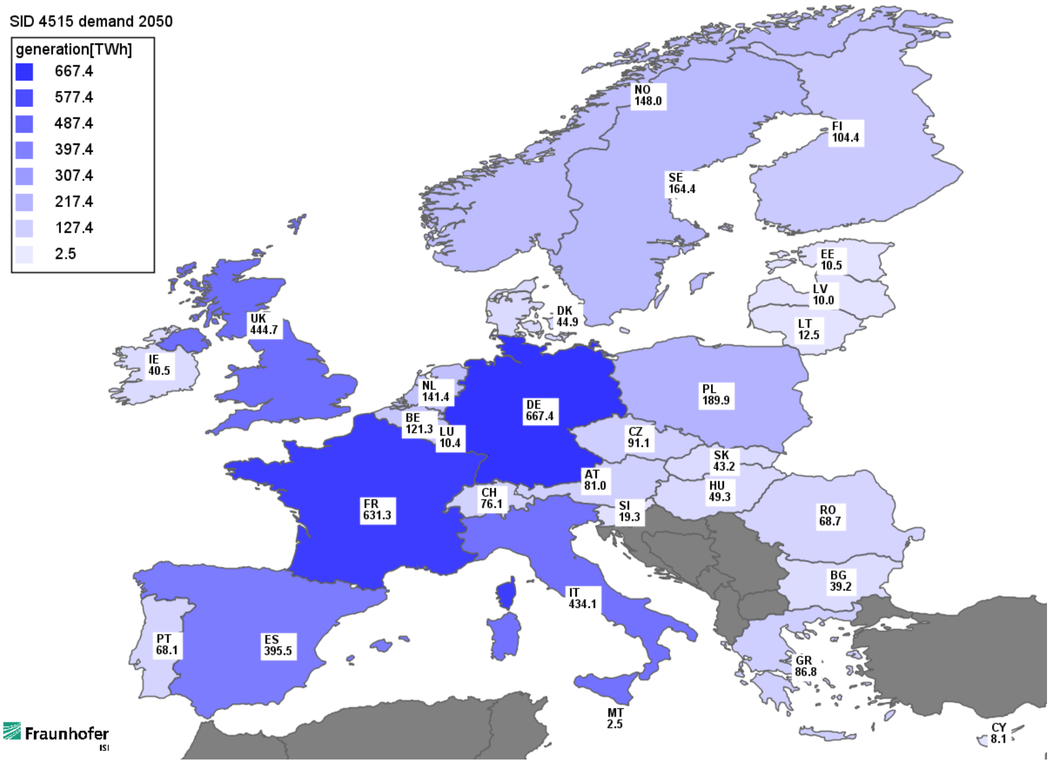

Figure 41 Demand incl. national grid losses in 2050 as assumed for Scenario D

A.2 Additional results: generation mix

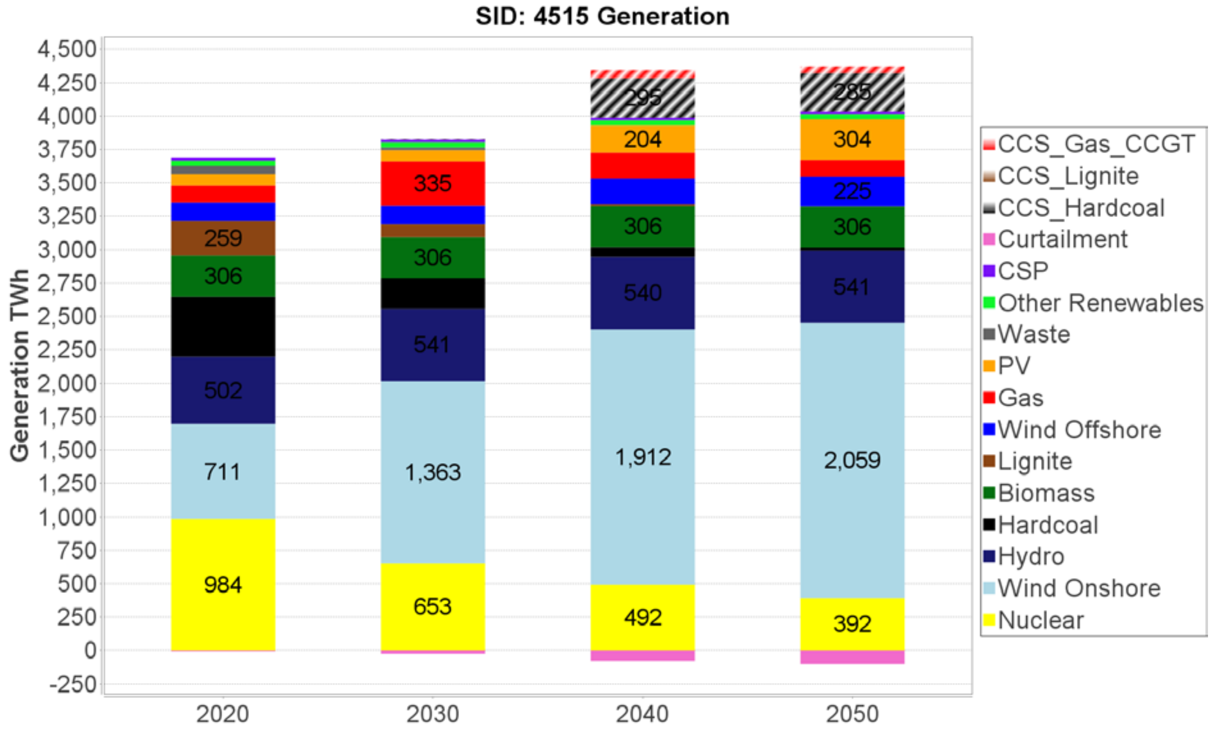

Figure 42 Generation mix Scenario D ("High Demand")

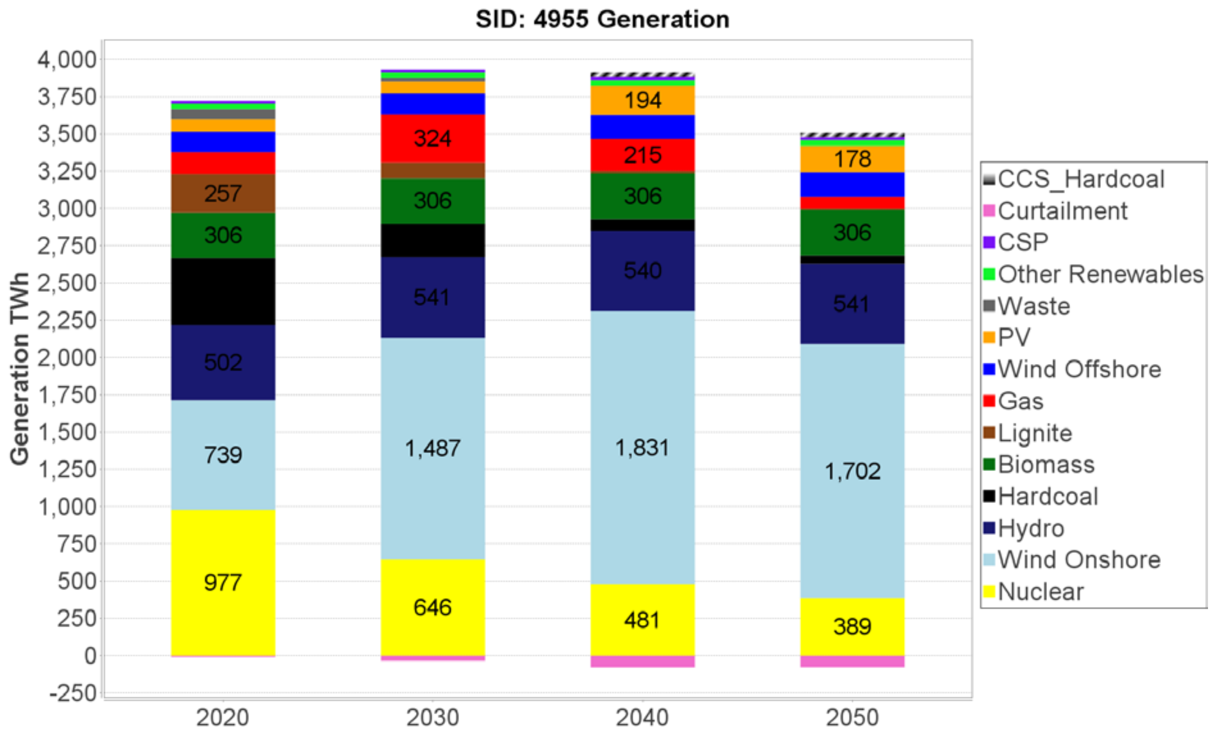

Figure 43 Generation mix Scenario E (“Modified Wind“)

A.3 Additional results: capacity

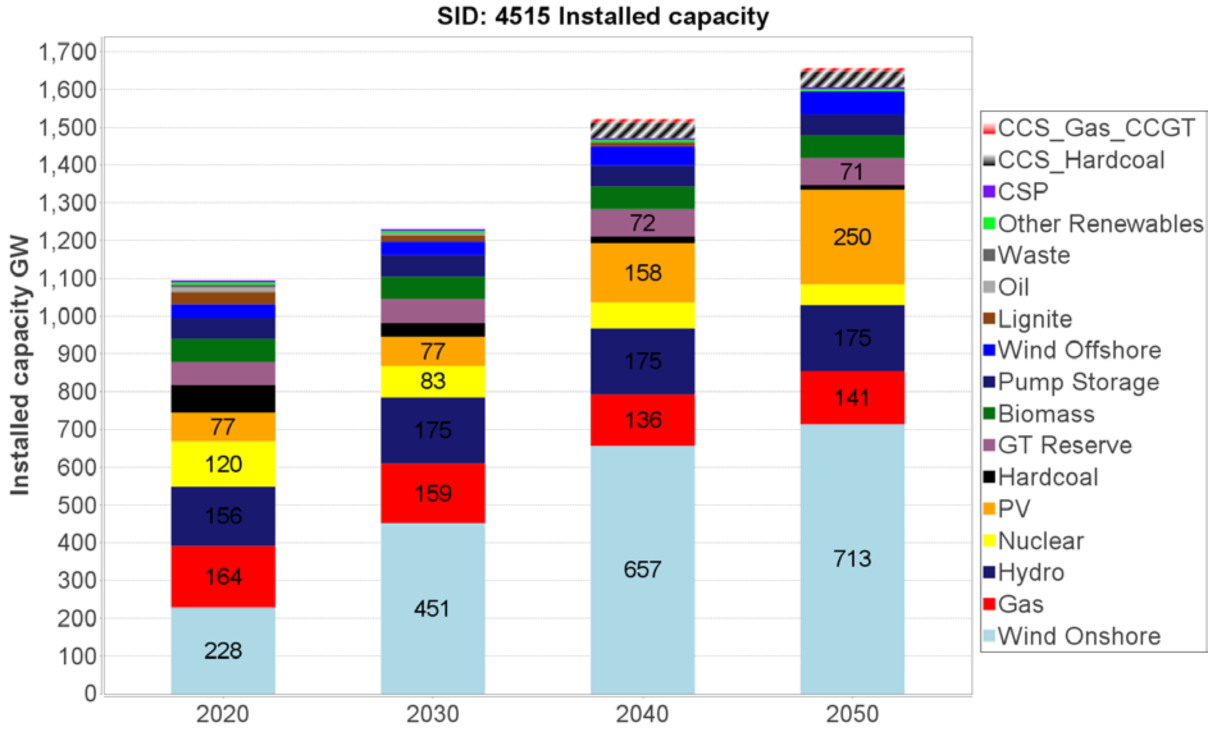

Figure 44 Installed capacity in Scenario D ("High Demand")

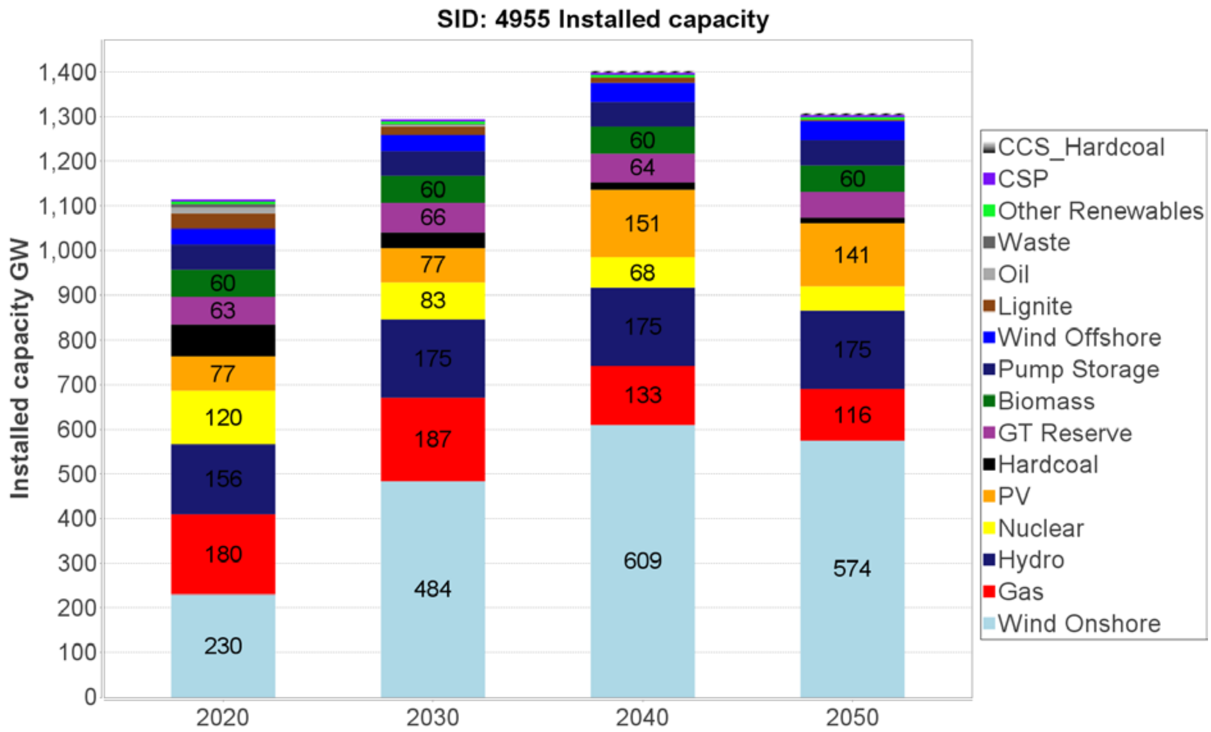

Figure 45 Installed capacity in Scenario E ("Modified Wind")

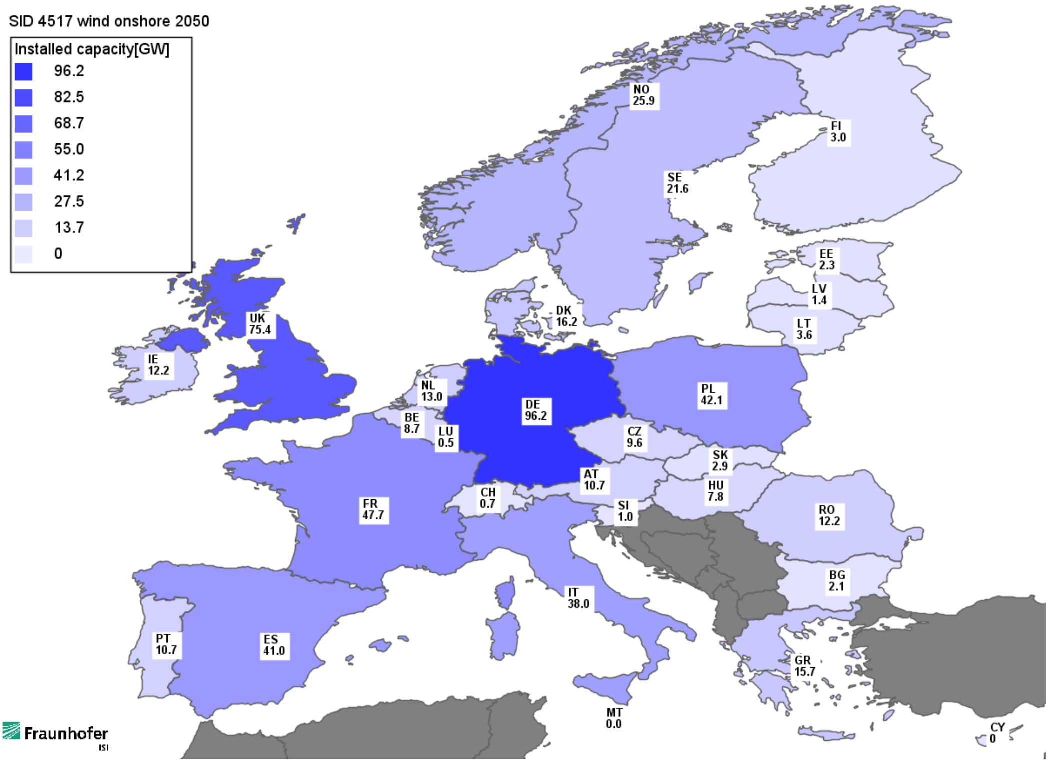

Figure 46 Installed capacity wind onshore Scenario C in 2050

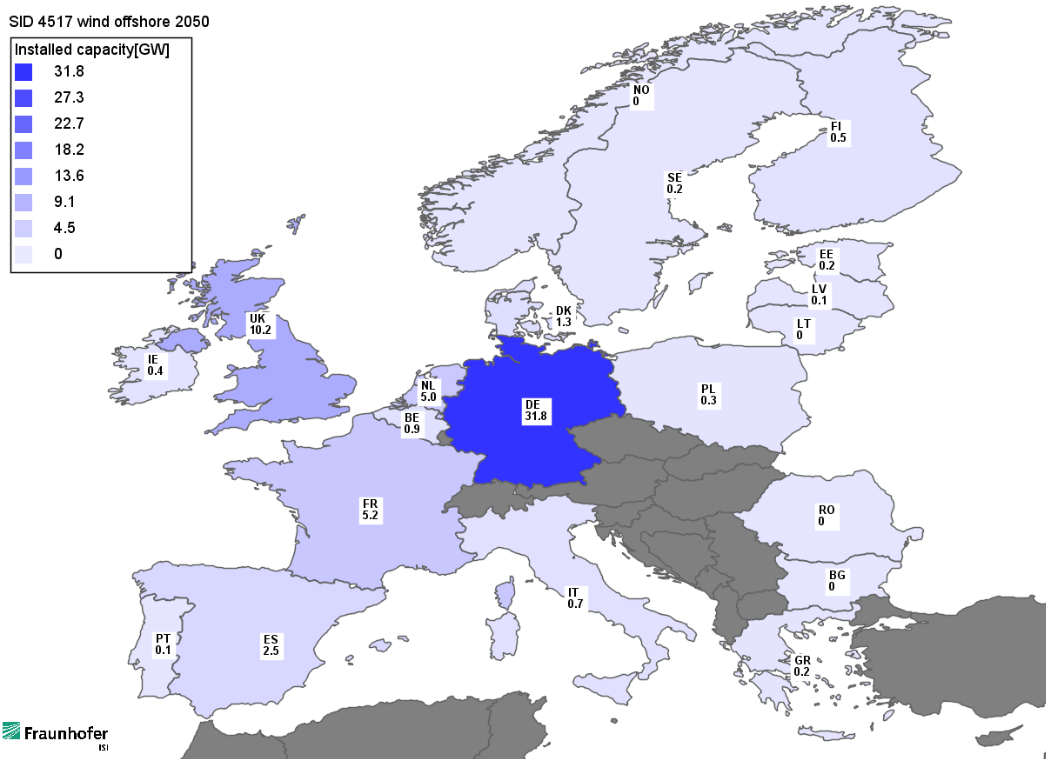

Figure 47 Installed capacity wind offshore Scenario C in 2050

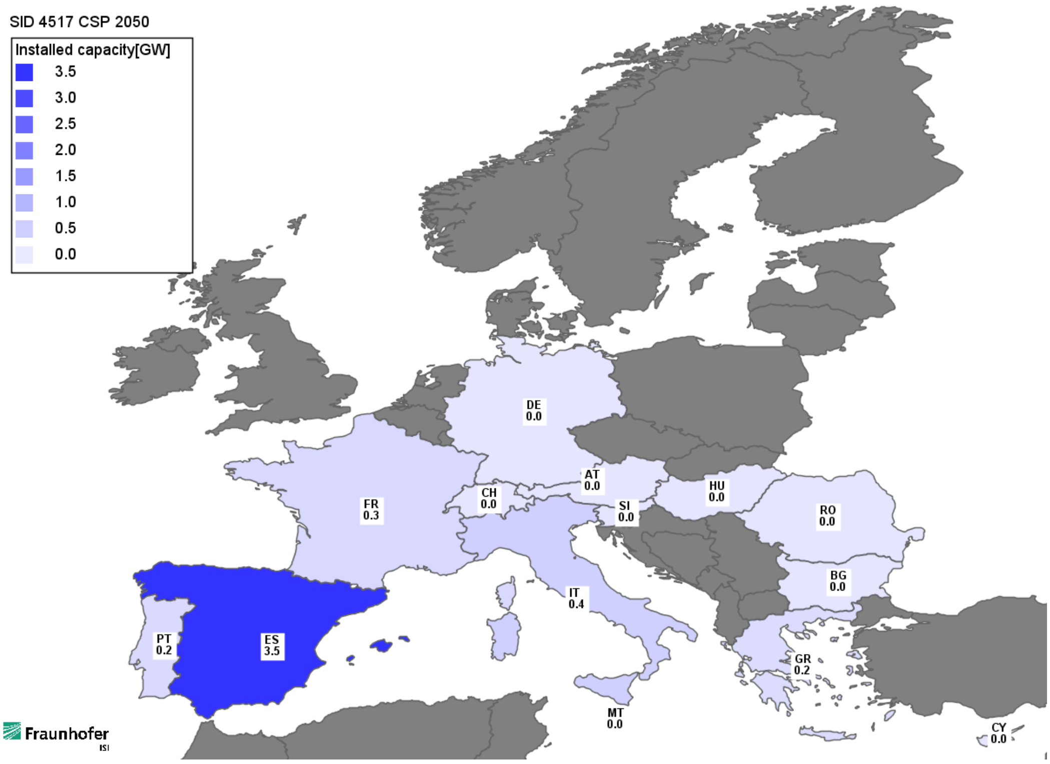

Figure 48 Installed capacity CSP Scenario C in 2050

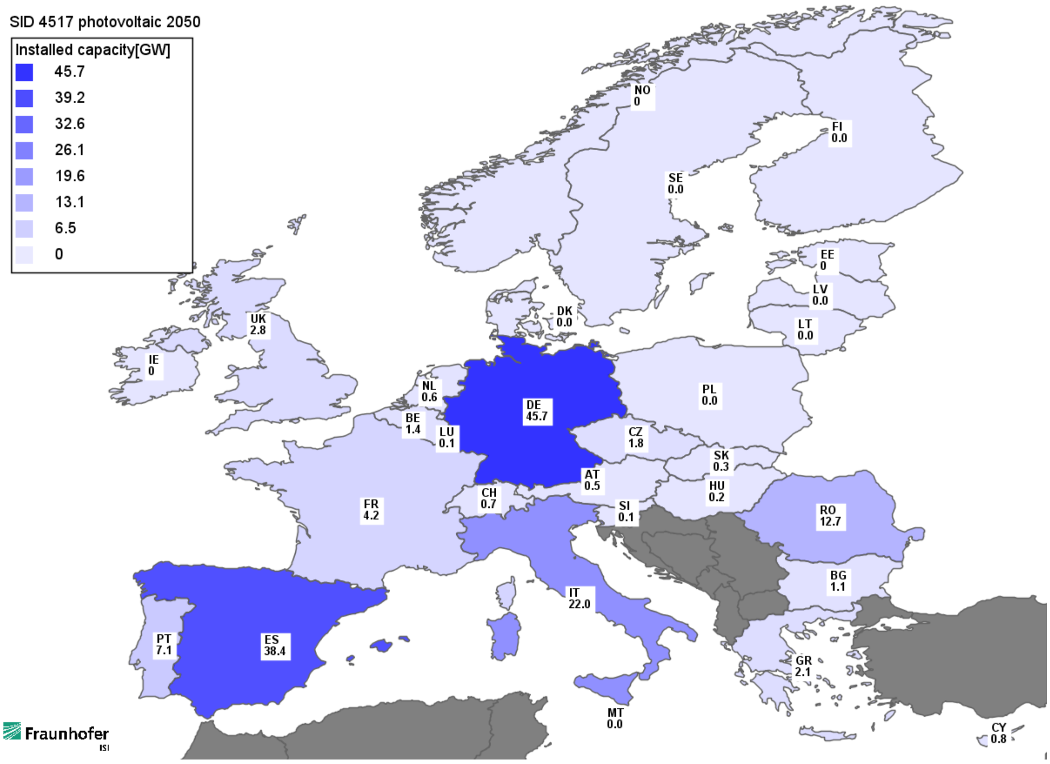

Figure 49 Installed capacity photovoltaic Scenario C in 2050

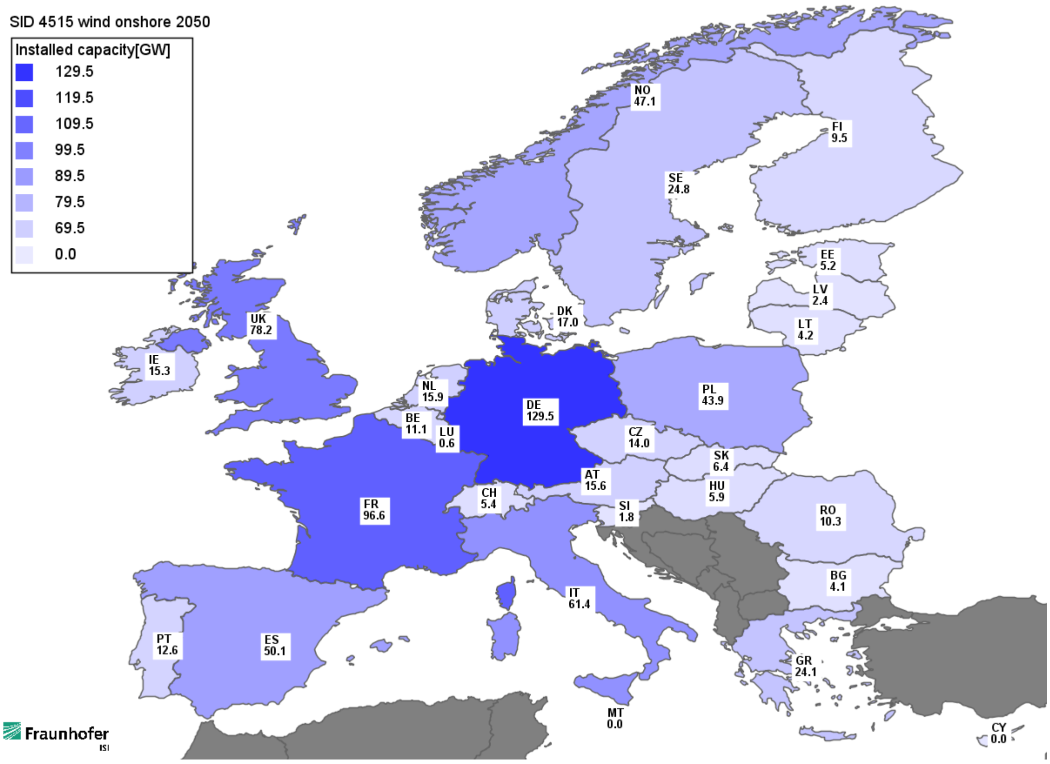

Figure 50 Installed capacity wind onshore Scenario D in 2050

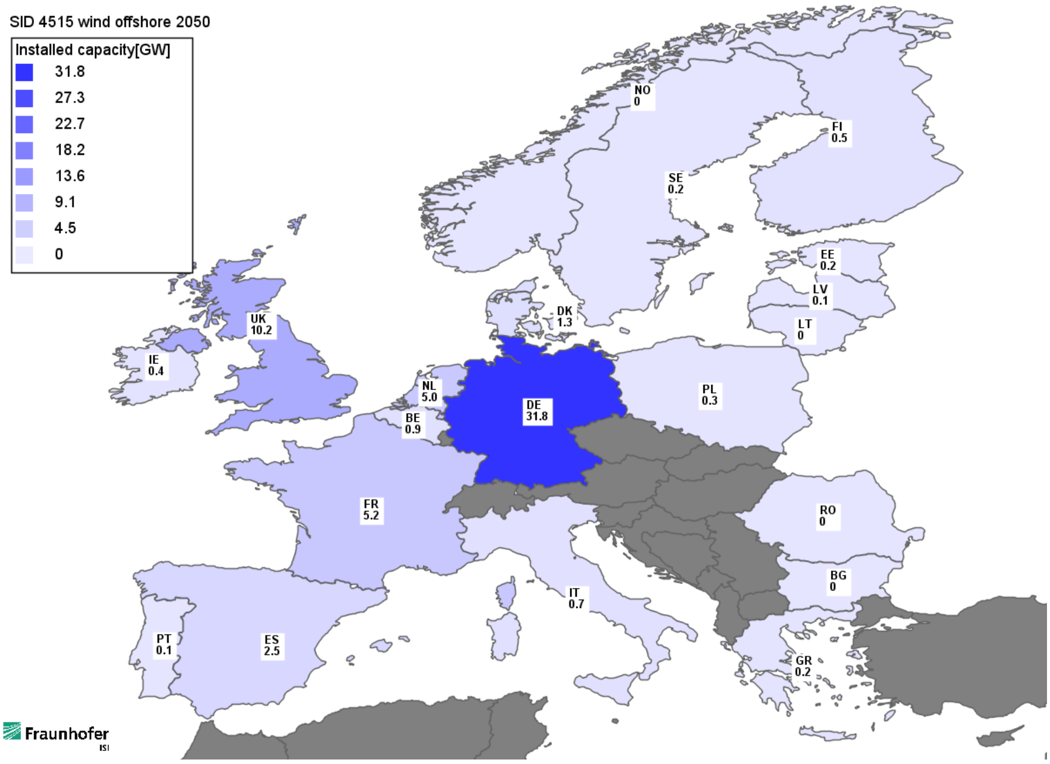

Figure 51 Installed capacity wind offshore Scenario D in 2050

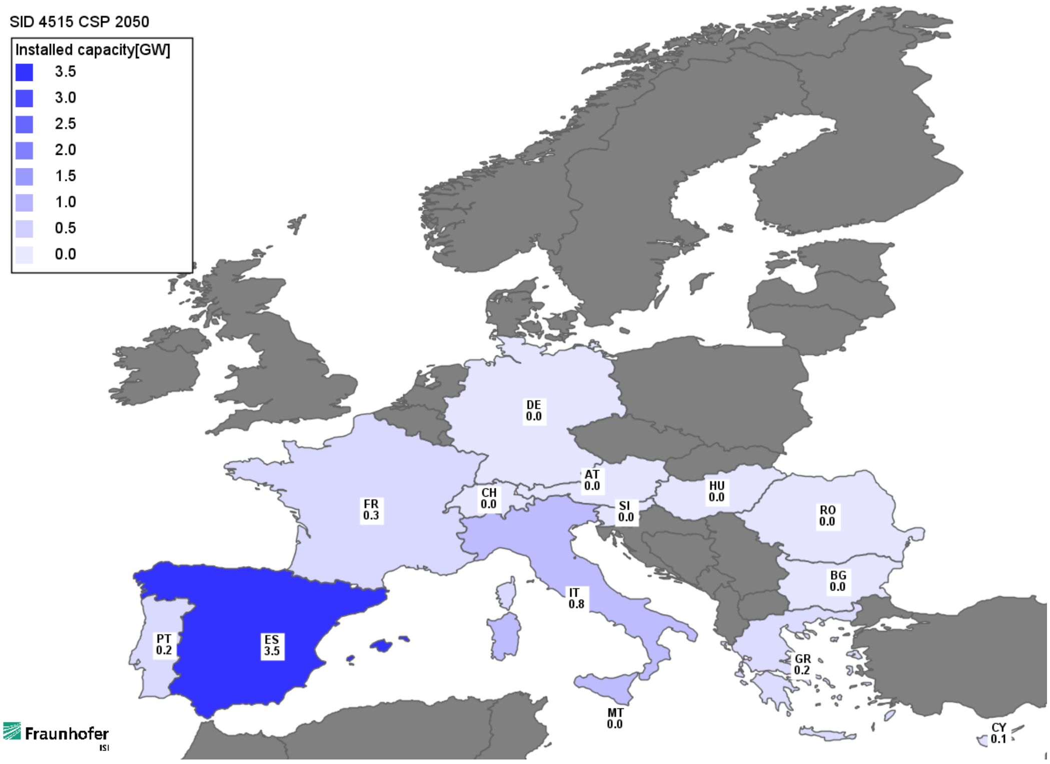

Figure 52 Installed capacity CSP Scenario D in 2050

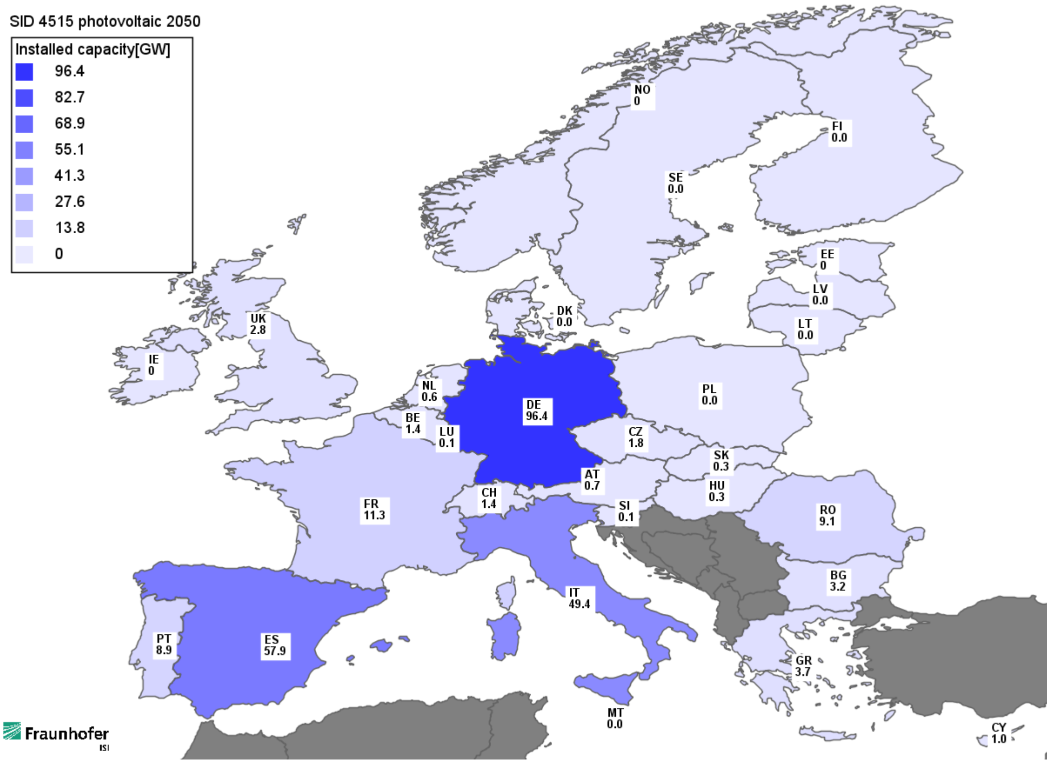

Figure 53 Installed capacity photovoltaic Scenario D in 2050

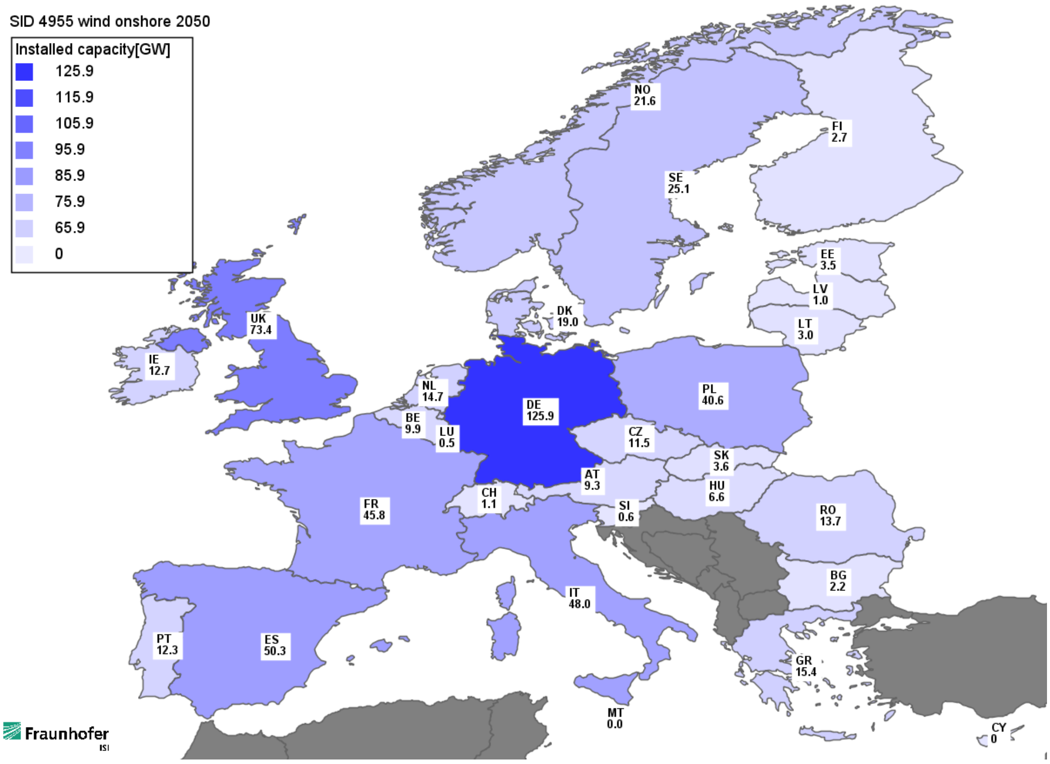

Figure 54 Installed capacity wind onshore Scenario E in 2050

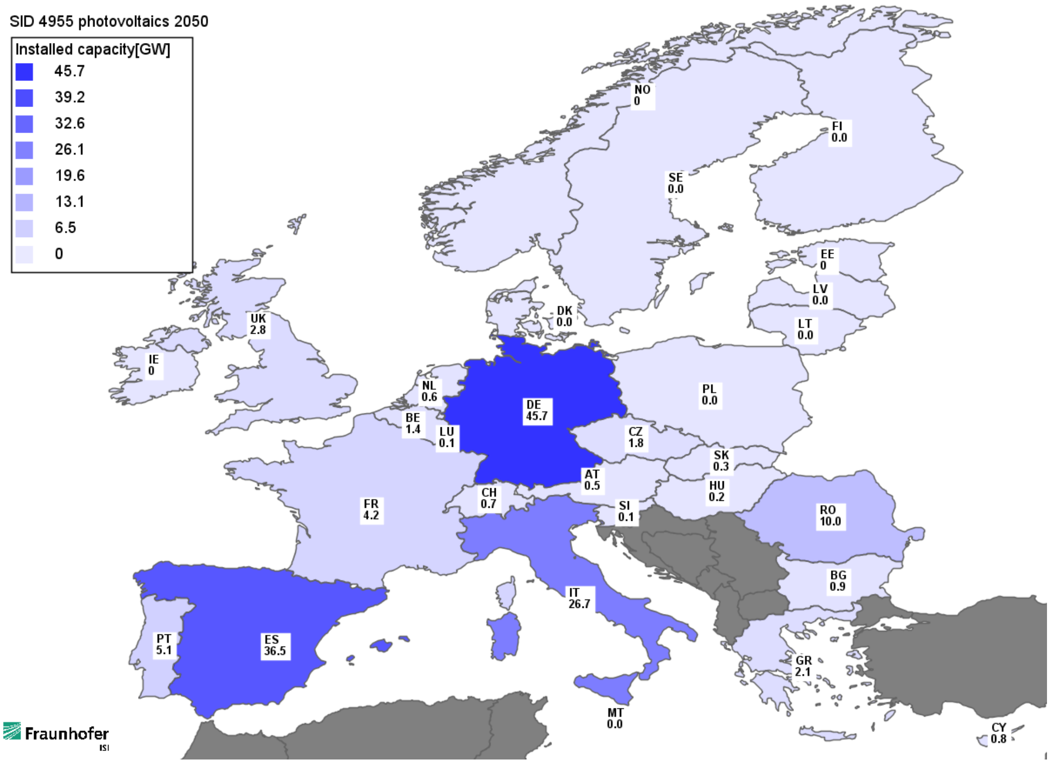

Figure 55 Installed capacity photovoltaic Scenario E in 2050

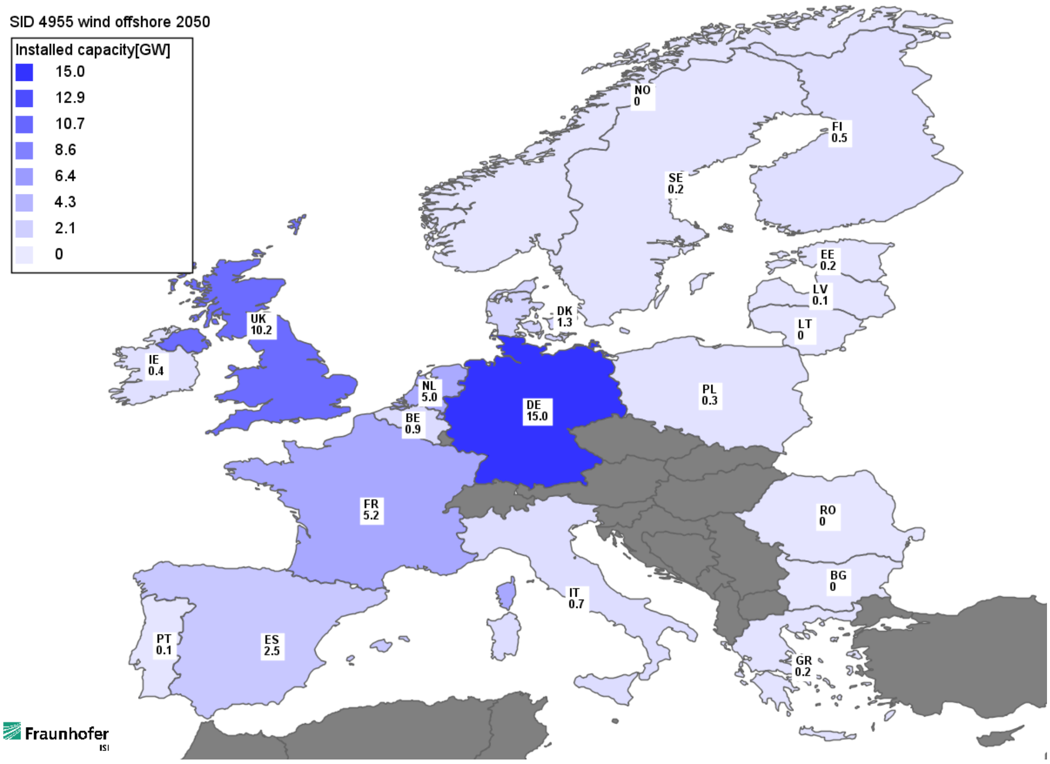

Figure 56 Installed capacity wind offshore Scenario E in 2050

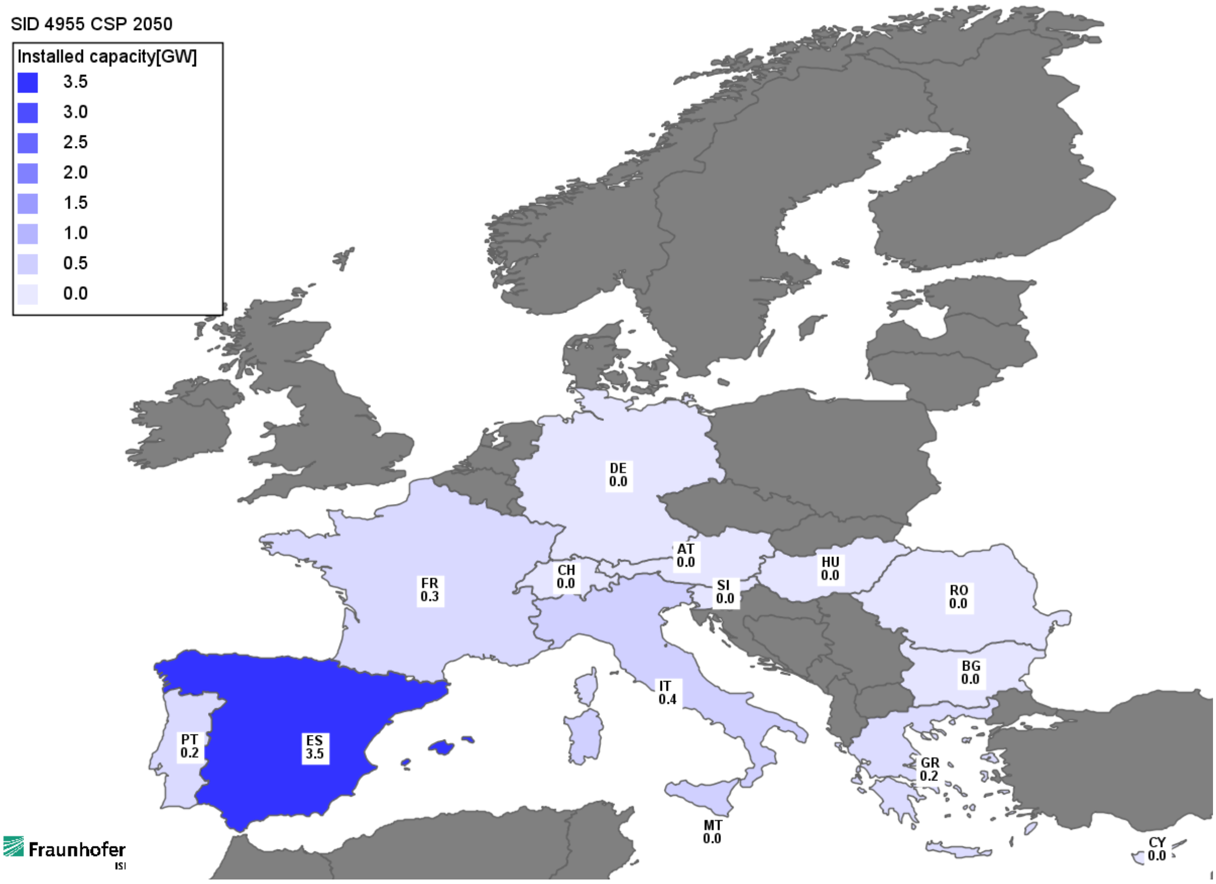

Figure 57 Installed capacity CSP Scenario E in 2050

A.4 Additional information on PV potential and time series calculation

The main factors influencing plant efficiency are irradiance and module temperature compared to Standard Test Conditions (STC), shading, and inverter load.

Irradiance is the primary factor defining the generation of the module. The irradiance reaching the solar panel depends on the position of sun, clouds and the orientation of the module, albedo and shading of the module by surrounding objects. Soil reflectance is considered with an albedo of 0.2. To account for shading, irradiance on module plane is reduced to 70% directly after sunrise and before sunset. This reduction declines proportionally to the rising solar altitude angle and irradiance reaches 100% at a solar altitude angle of 17° (Schubert 2012).

Different solar photovoltaic cell technologies have different spectral response rates depending on the wavelength. Figure 5 shows spectral response rates for amorphous single and triple junction (a-Si SJ and a-Si TJ), crystalline silicon (mc-Si and c-Si), and copper indium selenide (CIS). In times of low solar altitude and high air mass, relative efficiency of amorphous silicon is lower than for crystalline silicon (Kenny et al. 2006).

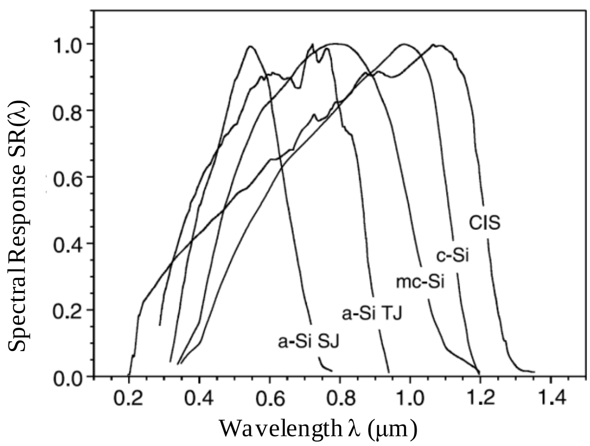

Figure 1 Spectral Response (SR) for different cell types (Kenny et al. 2006).

Besides the cell material, the module temperature has a strong influence on module efficiency as well. Rising module temperatures result in lower efficiency (Haselhuhn et al. 2008). To account for module efficiency depending on module temperature and actual irradiance an approach based on (Huld et al. 2010) was used.

Inverters are necessary to convert direct current to alternating current. Inverter efficiency depends on the load factor. To calculate inverter efficiency an approach based on (Macêdo and Zilles 2007) is used.

In a first step solar irradiance on the module plane is calculated. Based on this information module temperature is calculated considering solar irradiance, ambient temperature and mounting. The calculation is based on a method and parameters taken from (Šúri et al. 2007). Plant generation for each configuration *Psys* is calculated, in the third step.

For each station the hourly generation for all configurations is weighted according to the preset flexible parameters and aggregated to get the generation for each station:

$P_{station} = \sum_{m=0}^{m=3}\sum_{c=0}^{c=2}\sum_{o=0}^{o=3}\sum_{i=0}^{i=7} x_m \cdot x_c \cdot x_o \cdot x_i \cdot P_{plant}$ where *h* is the hour of the year, t is the cell technology index, s in the mounting type index, γ is the tilt angle, α is the module orientation, G_{mod} is the irradiation and T_a is the ambient temperature.

A.5 Additional information on wind potential calculation

The first step of the potential calculation is to define reference turbines used for the calculation of wind potentials. In this study two reference turbines are used depending on the wind conditions. In case regions with high wind speeds (IEC Class 1) and offshore areas the turbine power curve of the Repower 3.4M 104 with a hub height of 120 m is used. In case of regions with lower wind speeds (IEC Class 2-4) the turbine power curve of the Repower Repower 3.2 M114 is used for the potential calculation.

In order to calculate the power output of these turbines data on wind speed, temperature and air pressure is necessary. This study relies on several national wind speed atlants e.g. Merra, Anemos and Cosmo EU. Reanalysis data[24] provide spatially evenly distributed data with less or even without data gaps. Reanalysis data providing hourly time series are e.g. Merra[25] and COSMO-EU.

As discussed above for potential calculations a high spatial resolution is necessary and differences in spatial resolution have a high impact on the results. In Figure 58 a comparison for different spatial resolutions of different wind speed data sources for Germany is provided. The left map shows Merra Data, the middle map shows Anemos data with a resolution of 5 km times 5 km for Germany, the left map shows wind atlas data of the DWD. As different requirements are imposed on data for potential and time series calculations wind atlas data was used where available[26] and Anemos data for other areas.

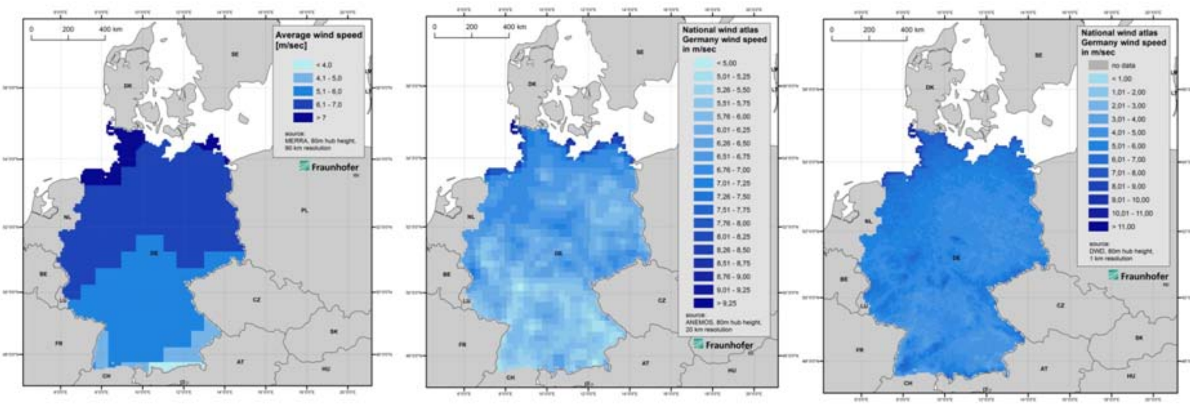

Figure 58 Differences in the wind data resolution

The next step is to calculate the actual power output of wind turbine at the selected site. Factors influencing the hourly electricity production of wind power plants are the plant hub height, the

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[24] Data from meteorological data assimilation projects as a gridded data set incorporating observations and numerical weather prediction models

[25] MERRA (Modern Era Retrospective-analysis for Research and Applications) (NASA 2013) Mere Data has a spatial resolution of 1/2 degrees latitude × 2/3 degrees longitude

[26] EG, TN, MOR, GER, UK, ESP

turbine power curve, the present wind speed, and air density. The wind speed in hub height is again influenced by present atmospheric conditions and land use.

Wind power P flowing through a wind turbines rotor area is $P = \frac{\rho v^3}{2}$ where ρ is the air density and v is the wind speed in hub height.

Wind speed and air density depend on height above ground, but as the available energy of the moving air molecules is proportional to the cube of their velocity, the vertical profile of wind speed is a main driver for the power output.

Flow near the surface encounters obstacles and hence friction losses reduce the wind speed. Friction losses depend on surface roughness and atmospheric layering (Stull 1988).

A.6 Additional information on land use calculation

The resolution for the land use calculation is 250 meters for CORINE and 500 meters for the MODIS dataset. The spatial resolution is important for the calculation of the land availability as a poorer resolution might average out sites with good land availability and renewable energy potential.

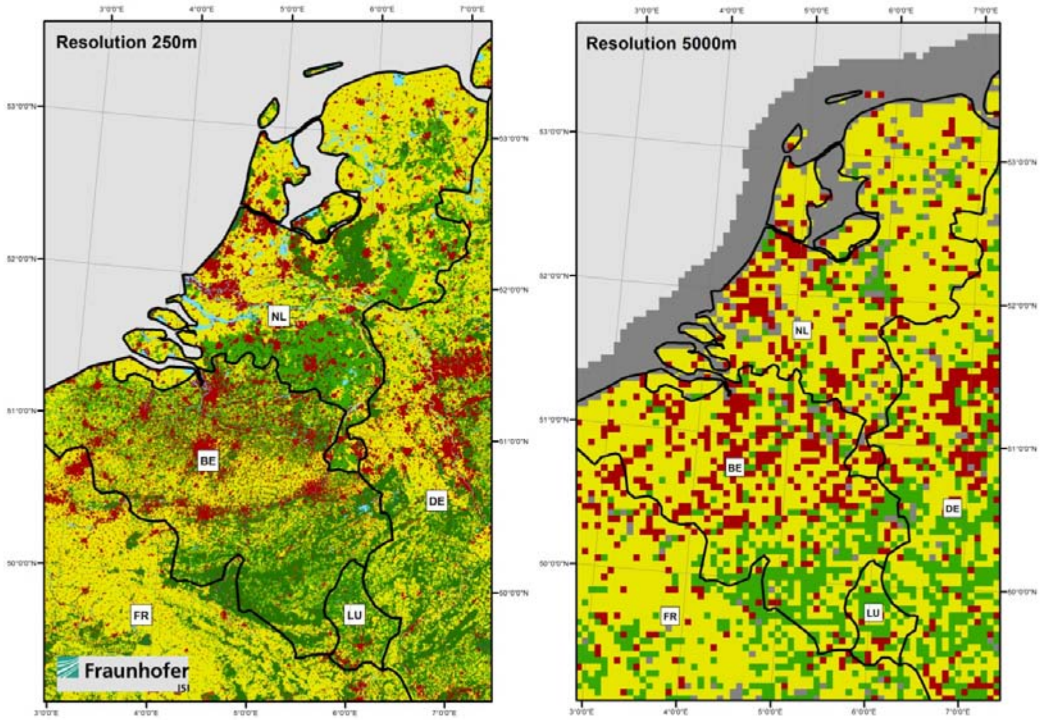

Figure 59 Example of different land use resolutions based on the CORINE land cover

Figure 59 shows the difference between two chosen resolutions in the Benelux states. Especially in the dense populated areas and in areas with strong fragmentation in land use the possible error rises with a lower resolution.

In the next step restrictions on land availability for renewable generation are implemented. Restrictions considered are: conservative areas such as Natura 2000 areas, minimum clearance, slope and height. Fort the digital elevation model SRTM data with a 90m resolution is used (Broesamle et al. 2001). In the case of wind, a minimum distance of 1500m and a slope of up to 30° have been applied in this example. The restrictions for open space photovoltaic are similar.

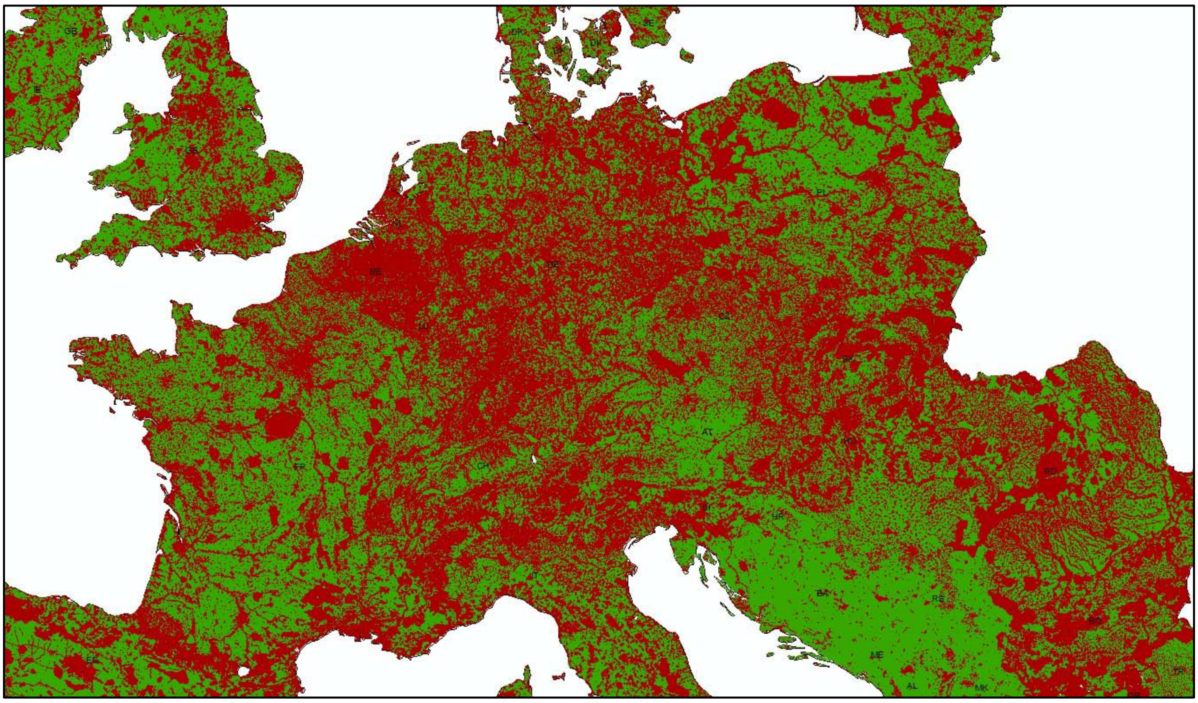

Figure 60 Not restricted areas (in green) for wind onshore in western and central Europe

Figure 60 shows an example for the calculation of possible lands use sites that are not restricted. It is obvious, that in the case of wind a lot of surface area is not available for wind onshore installations. Based on the data used it appears that there is few space available in Germany, Belgium and Switzerland and a lot of Space available, i.e. former Yugoslavia. This has different reasons. One reason is, that this area is not as dense populated then Germany. The other reason is simpler, only few conservation areas are already registered in the NATURA 2000 cadastre (Macêdo and Zilles 2007) or the IUCN (Haselhuhn et al. 2008). This shows also one challenge and potential source of errors, when dealing with international research areas with different detail data levels. In this case the calculation is done with this data, as the data mentioned is one of the few sources that deliver conservation areas on an international level with a spatial reference.

A.7 Important Changes to the precious study (Scenario A and B)

This section provides a short description of the central changes in the methodology of this study compared to Scenario A and Scenario B of the study "Tangible ways towards climate protection in the European Union" carried out in 2011 on behalf of the German Federal Ministry for the Environment, Nature Conservation, Building and Nuclear Safety (Pfluger et al. 2011).

1) Modelling renenewable electricity generation

In Scenario A and B the development of renewables was calculated with a simulation tool taking into account electricity prices and CO_2 prices based on a database on potentials. The resulting development of renewables was used as an input for the optimisation model. In Scenario C, D and E of this study the development of renewables is part of the system optimisation. CO_2 prices are calculated endogenously as a shadow price of the CO_2 cap. Furthermore the calculation of renewable potentials is now an explicit part of the model where all necessary parameters like weather datasets, land use and plant parameters can be directly assigned. Generally data quality on the available weather datasets is improved considerably. As a consequence the model used for this study is more likely to calculate a system with lower overall cost.

2) Electricity demand

One central aspect for the comparison of the different scenarios is the development of electricity demand. Scenario A of the previous study is based on extremely ambitious reduction of electricity demand. Scenario B of the previous study, Scenario C and E of the current study are based on a more moderate efficiency scenario. Scenario D represents a possible future with high electricity demand.

3) Cost assumptions for renewable power plants

The general assumptions on cost development of renewable have been adjusted to reflect technological progress which has been very fast for photovoltaic in recent years.

4) Fuel prices

Fuel prices have been adapted to include more recent projections. Generally prices for important conventional fuels such as coal and gas are lower than in the previous study.

5) Conventional power plants

In Scenario A and Scenario B CCS technologies were excluded by the Scenario definition and a complete decline of nuclear technologies was assumed. In Scenario C, D and E CCS is included as an option and nuclear development follows a fixed path.

6) Electricity grid

The technology choice is more differentiated in this study, as the previous study assumed static cost of 1000€/kW*km onshore and 1667 €/kW*km for offshore connections. In all three scenarios of this study the cost are calculated individually for based on different technology options.

7) Impact of modelling changes on the cost results of this study

The full integration of renewables into the optimisation and the updates on the weather datasets and cost assumptions lead to the situation that cost results between Scenario A and B of the preceding study and the current study (Scenario C, D, E) are not comparable. Generally, the modified approach and data quality of this study should lead to lower cost solutions for the electricity system.