Report

Estimating energy system costs of sectoral RES and EE targets in the context of energy and climate targets for 2030

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Executive Summary

European policy makers currently shape the 2030 framework for climate and energy policies. This includes the question, whether dedicated targets for renewable energies (RES) and energy efficiency (EE) should be set besides a binding greenhouse gas (GHG) target and which ambition level should be fixed. In this context, the European Commission (EC) has suggested a GHG-target of 40%, a RES-target of at least 27% in final consumption by 2030 and an EE-target of 25% (European Commission, 2014b). Based on the impact assessment conducted by the EC (European Commission, 2014a) the 40% greenhouse gas emission reduction target alone would result into a RES-share of 26.4% by 2030. Therefore this ambition level was interpreted as the economic optimum and used as a basis for the determination of the RES target. However both, the impact assessment as well as further in-depth analysis (e.g. Employ-RES, 2014) have shown that a RES target of 30% would lead to higher macro-economic benefits as compared to a target of 27%. Thus, increasing the RES-target to 30% is still being discussed as an alternative option.

In the recent Communication on Energy Efficiency (European Commission, 2014c), the European Commission proposes an energy efficiency target of 30% for 2030 "given the increased relevance of bolstering EU energy security and reducing the Union's import dependency". Although a 25% EE-target was initially considered as cost-optimal option, the Commission concluded that the higher target "would still deliver tangible economic and energy security benefits". The decision on the concrete design of the 2030 climate change and energy policy package can be expected for European Council Meeting on 23/24 October 2014.

When discussing the target architecture as well as different ambition levels of EU RES and EE-targets, their impact on the competitiveness of the European economy is of key interest. However, many discussions tend to emphasize the current situation without considering the potential long-term developments of energy technologies. In view of the above, it is the objective of this briefing paper to show the future costs of the energy system by 2030 for different RES and EE-target levels.

We present the impact of energy efficiency and renewable energy targets on the overall energy sector. Our findings show that a triple target of greenhouse gas emissions, energy efficiency and renewable energy will lead to substantial cost savings for the overall energy sector as compared to a single CO_2 target. Furthermore, detailed modeling of the power sector shows that overall system costs of a 30% RES-target are even slightly lower than costs of a 27% RES-target, which is based in particular on the risk-mitigating effect of the target.

This briefing paper is based on the study "Estimating energy system costs of sectoral RES targets in the context of energy and climate targets for 2030" carried out by an international project consortium led by Fraunhofer Institute for System and Innovation Research ISI on behalf of the German Ministry for Economic Affairs and Energy (BMWi) and the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ). Project partners are Fraunhofer ISE, the Energy Economics Group from the University of Vienna, Prognos, Comillas University and ECN.

A model-based approach to estimate the future costs of the energy system has been chosen, by combining different energy sector models. We realise modelling analyses for the future renewables deployment pathways by 2030 with the Green-X model, a specialised model that allows assessing future RES deployment and related costs and benefits for European countries. We complement the analysis with the power sector model PowerACE, assessing impacts on and inter-linkages with conventional electricity supply as well as infrastructural prerequisites. A comprehensive optimisation of the European power sector until 2050 was carried out including the detailed modeling of renewable generation data with a high spatial and temporal resolution. Thus, capacity planning for conventional power plants, the operation of the power system and grid extension, reinforcement and management are taken into account[1]. For modelling the power sector we incorporate the investor's risk in terms of the used discount rates. Thereby, we assume a default discount rate of 6.5% for 2013, which is assumed to increase slightly to 7.5% by 2020. Additional risk elements for policy-induced, technology-induced and country-specific risks are introduced by multipliers modifying the default interest rate.

The modelling takes into account most recent assessments on the dynamic development of technology costs for conventional and RES-technologies as well as the available renewable resource potential. Location-specific characteristics of RES including the available resource potential (e.g. available amount of biomass) and conditions (e.g. wind speed, solar irradiation) have been considered for the modelling. This is required to adequately analyze costs of RES-technologies, since the resource availability and the associated conversion costs are heterogeneously distributed across Europe. Thus, electricity generation costs of wind onshore depend on the prevailing wind conditions, wind offshore costs on wind conditions, water depth and distance to shore, and solar PV on solar conditions and the plant size.

In addition, energy efficiency measures have been analysed based on detailed bottom-up analyses based on various modelling tools. These include the INVERT/EE-Lab model for buildings, the FORECAST platform for energy demand in industry as well as electricity uses in the residential and service sector and the ASTRA model providing potentials for energy demand in the transport sector. Based on the this detailed determination of bottom-up potentials, the associated financial impacts were estimated by identifying the share of the technical

1 Results from power generation have been fed into the grid model TEPES in order to assess grid-related issues of RES-E integration in more detail. However, this work is still ongoing and will be published at a later stage.

potential that is already cost-efficient and the remaining part that is still limited by financial barriers.

Based on the analysis realised in the context of this study, we came to the following conclusion when comparing the impacts of different target setting options:

1. A triple target of greenhouse gas emissions, energy efficiency and renewable energy will lead to substantial cost savings of up to € 21 billion for the overall energy sector as compared to a single CO_2 target. Additional costs resulting from the RES-targets remain moderate.

Based on our analysis, we estimated and compared the cost impact of the different target setting options presented above. Thereby, we calculate the additional costs or savings of GHG40 RES30 EE25 and GHG40 EE30 RES30 compared to the scenario without specific target for RES nor EE in place, i.e. the GHG40 scenario (see Figure 1).

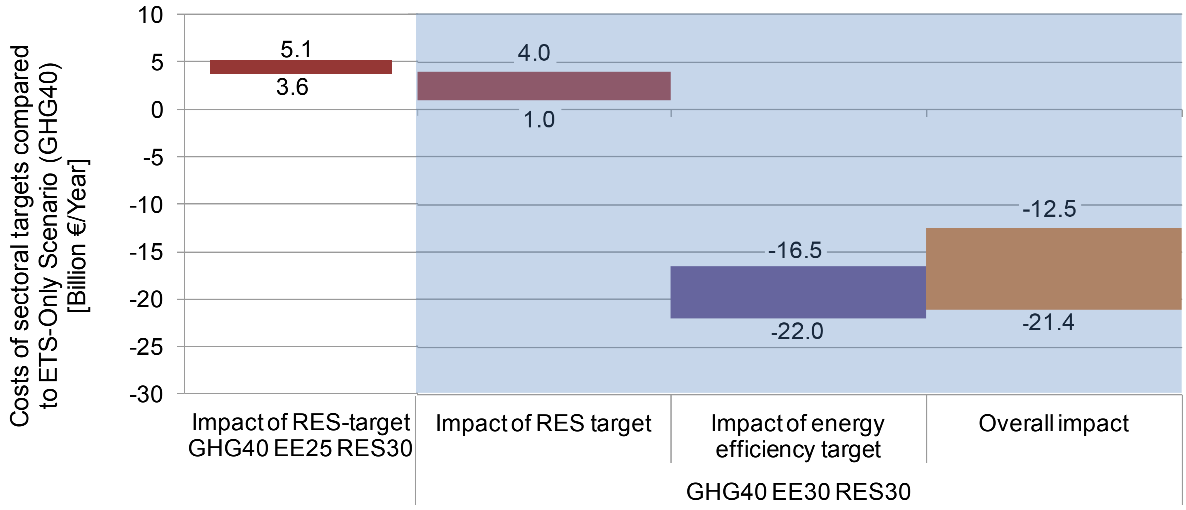

Figure 1: Costs of specific targets (renewable energy and energy efficiency) compared to a scenario with a pure GHG-reduction target

If we consider a GHG-target of 40% and a 30% RES-target in the absence of a target for energy efficiency (GHG40 EE25 RES30), the additional costs for the energy sector arising compared to the GHG40 scenario amount to € 3.6 to 5.1 billion per year (left side of Figure 1), which corresponds to less than 0.25% of the total system costs. Costs are shown as annual average over the period 2021-2030. The range of costs shown results from sensitivity analysis regarding the detailed approach used for the burden sharing regarding the RES target among MS. As the development of energy demand is the same in both scenarios there are no additional costs from energy efficiency measures.

If an energy efficiency target is added, the 30% RES-target requires a reduced amount of renewable-based final energy – instead of 331 Mtoe in the "GHG40 EE25 RES30" Scenario only 307 Mtoe are needed to achieve the 30% RES-target in the "GHG40 EE30 RES30" Scenario. As a consequence, additional costs arising from the increased use of RES that can be directly attributed to the RES-target are reduced to € 1 – 4 billion for a triple target of 40% GHG-reductions, 30% for RES and 30% for energy efficiency. Again these costs compare to the reference of the “GHG40” Scenario. The application of energy efficiency measures do not lead to an additional cost, but to economic savings ranging from € 16.5 to 22 billion per year. The **combined financial impact** of the 30% RES-target and the 30% energy efficiency target thus results in **overall economic savings of € 12.5 to 21.4 billion on average** (see Figure 1). Savings due to the energy efficiency target result in particular from the fact that lower discount rates have been applied in a proactive policy environment.

In the next step we present the results for the detailed analysis of a RES-target on the power sector.

2. <u>Overall system costs in the power sector of a 30% RES-target do not increase compared to a scenario with a pure GHG emission reduction target.</u>

Cost development in both analysed scenarios varies only slightly. The GHG40 EE30 RES30 Scenario leads to slightly lower total system costs than under the GHG40 scenario by 2030 due to the use of least cost resource allocation in both scenarios and lower discount rates for the GHG40 EE30 RES30 scenario. Whilst annual system costs in the GHG40 Scenario amount to € 221 billion by 2030, system costs in the GHG40 EE30 RES30 Scenario add up to € 219 bn. The difference in costs is more pronounced on the longer term by 2050, where annual system costs under the GHG40 are estimated to € 264 billion and under the GHG40 EE30 RES30 Scenario to € 259 bn.

One can observe a moderate increase of annual systems costs after 2030 by about 13-15% until 2050 (see Table 1). This development is mainly based on the fact that electricity demand increases by 22% between 2030 and 2050. Specific system costs decrease by about 4% between 2020 and 2050. The key reason is that technology learning reduces the specific generation costs of the individual generation technologies, in particular of RES technologies. By 2050 both scenarios are characterized by very similar specific system costs amounting to 60 €/MWh in the GHG40 EE30 RES30 Scenario and to 61 €/MWh in the GHG40 Scenario, respectively. This is in particular due to the **lower investment risk** for capital intensive RES-technologies under the RES-target option, leading to lower financing and therefore capital costs in case of a specific RES-target.

Table 1: Development of annual system costs and specific system costs[2]

Annual system costs		2020	2030	2050
GHG40	bill. $€_{2010}$	233	221	264
GHG40 EE30 RES30	bill. $€_{2010}$	231	219	259
Specific system costs				
GHG40	$€_{2010}$/MWh	65	63	61
GHG40 EE30 RES30	$€_{2010}$/MWh	64	62	60

Results of this analysis show that policies causing higher levels of RES-E in the scenarios do not lead to higher electricity generation costs as compared to other decarbonisation options. Considering this together with further additional benefits of RES such as reducing dependence on fossil fuel imports, the implementation of a specific RES-target in the order of 30% by 2030 appears to be beneficial.

Summary of main results

- The combined implementation of specific targets for energy efficiency and renewable energies in addition to a pure GHG emission reduction target will lead to **reduced total system costs of up to € 21 billion for the overall energy system**. This is mainly based on lower investment risks and financing costs for energy efficiency and renewable energy technologies if targets for EE and RES are in place.
- Additional costs resulting from the RES-targets without setting a specific target for energy efficiency remain moderate and are estimated to **€ 3.6 to 5.1 billion per year**, which corresponds to less than 0.25% of the total system costs. Considering the lower demand due to a 30% EE-target the additional costs of **RES will be reduced to € 1 to 4 billion** per year.
- In the power sector a **RES-target of 30%** leads to **slightly lower total system costs and lower costs per unit of electricity generated** than a scenario with a pure GHG emission reduction target due to lower risk premiums and financing costs.
- Estimating the impacts of target setting options for RES and EE requires the **application of modeling tools** with high level of detail regarding the costs and potentials of RES-use and energy efficiency measures. In this respect the modeling framework used in the present analysis provides significant added value by assessing impacts of targets for RES and EE with higher resolution as compared to the analysis used in the Impact Assessment by the EC.

[2] Annual system costs 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.

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1 Introduction

Provided that renewable energy sources (RES) contribute to mitigating climate change, increasing energy independence on fossil fuels from abroad and to creating employment, the European Union established binding targets to increase the share of RES in final energy consumption to 20 % by 2020 (The European Parliament and the Council of the European Union, 2009). Triggered by the stable policy framework on European level, RES have experienced considerable growth during the last decade. This dynamic development could be observed particularly in the electricity and biofuel sectors and has been enabled also because the policy framework included indicative RES targets in the electricity and transport sector until 2010[3], whilst no sector-specific targets have been defined for the heating sector.

As the 2020 horizon is approaching, the question of a post 2020 framework for climate and energy policies is currently under discussion. During the last year there have been active discussions on the target setting process for RES-targets as well as on targets for energy efficiency. With respect to the RES-target, discussions include the questions, whether a dedicated RES-target should be determined, which ambition level should be fixed and finally for which geographical region the target should be defined. Thus, a target can be set in an aggregated way on EU-level or may be allocated to smaller geographical regions, such as Member States.

In this context, the European Commission (EC) has suggested a GHG-target of 40%, a RES-target of at least 27% in final consumption by 2030 and an EE-target of 25% (European Commission, 2014b). In the recent Communication on Energy Efficiency (European Commission, 2014c), the European Commission proposes an energy efficiency target of 30% for 2030 “given the increased relevance of bolstering EU energy security and reducing the Union’s import dependency”. Although a 25% EE-target was initially considered as cost-optimal option, the Commission concluded that the higher target “would still deliver tangible economic and energy security benefits”.

In order to ensure Member States flexibility of how to transform their national energy systems, the European Commission proposed to have a binding target for RES and energy efficiency only at EU-level without breaking it down to national targets. It is now planned that the proposal for the 2030 climate change and energy policy package will be adopted at a European Council Meeting on October 23/24.

Taking into account the fact that the European Commission estimates the RES-share to amount to 26.4% triggered only by the 40% greenhouse gas emission reduction target

[3] Directive 2001/77/EC.

(European Commission, 2014), critics doubt the target will encourage considerable additional RES development.

Various pathways with a focus on different technology options of ensuring a transition to a low carbon economy exist. In this context, the associated cost aspects play a crucial role requiring a sound knowledge of total energy system costs of different pathways towards a future low carbon energy system. The increased use of RES plays a major role for the achievement of low carbon targets. According to the International Panel of Climate Change (IPCC) the achievement of low carbon concentrations may be difficult without the contribution of renewable and the use of RES may contribute to decreasing mitigation costs (Fischedick et al. 2011). Similarly, the Energy Roadmap 2050 confirms the need to increase the share of RES after 2020 (European Commission, 2011a). Although current conversion costs of RES-technologies mainly exceed conversion costs of conventional technologies, expected future cost reductions of renewable energy technologies can help reduce mitigation costs on the long-term (Philibert 2011).

With regard to the planned target architecture the impact of different target options on the competitiveness of the European economy is of key interest. Thereby, many discussions tend to emphasize the current situation without considering the potential long-term developments of energy technologies. In view of the above, it is the objective of this report to show the future costs of the energy system by 2030 for different RES and EE-target levels.

To do so, we present the impact of energy efficiency and renewable energy targets on the overall energy sector. Regarding the **energy efficiency target**, we analyse energy efficiency measures and their financial impact based on detailed bottom-up analyses based on various modelling tools. These include the INVERT/EE-Lab model for buildings, the FORECAST platform for energy demand in industry as well as electricity uses in the residential and service sector and the ASTRA model providing potentials for energy demand in the transport sector.

With regard to the **RES-target**, we present future costs of RES-technologies from a system perspective and compare them to present and future costs of competing technologies. It is the objective of this study to provide insights to total **future costs of the energy system** for different technology pathways by 2030, focusing on differing degrees of ambition or targets regarding the future RES-development. To do so, we realize new scenario runs in order to take into account the actual situation regarding targets, policies and technology costs. In a first step we investigate **past, present and future trends of technology costs**, considering conventional and renewable energy conversion technologies. Relevant factors such as increasing safety standards for nuclear power plants or the uncertain technology and cost development of CCS, with little or rather negative commercial experience available are included in the analysis. Due to the high relevance of development over time of technology cost and performance, this study will incorporate dynamic technology and cost development including effects such as technological learning or economies of scale. Then, we briefly show potential scenarios of **fuel and carbon price developments** and technologic and economic perspectives of competing technologies.

To adequately analyze costs of RES-technologies, **location-specific characteristics** have to be considered. This is required, as the resource availability and the associated conversion costs are characterised by a heterogeneous spatial distribution across Europe. Thus, electricity generation costs of wind onshore depend on the prevailing wind conditions, wind offshore costs on wind conditions, water depth and distance to shore, and solar PV on solar conditions and the plant size.

Subsequently, we realise **modelling analyses** for the future renewables deployment pathways by 2030 with the Green-X model, a specialised model that allows assessing future RES deployment and related costs and benefits for European countries in a detailed manner. For this purpose, we focus on the estimation of the **overall conversion costs of RES-technologies** in the electricity, heat and transport sector. In addition to the pure generation costs, we will estimate the support expenditures for consumers in case of explicit 2030 targets for RES compared to a baseline scenario without a specific RES-target.

Due to the fact that the ambition level of a RES-target and the involved costs strongly depend on the future development of energy demand, we include an additional analysis on **potential energy savings by 2030** into this report. Thus, we estimate the overall financial impact of combining different RES-targets ambition with different demand levels.

Depending on the type of the cost parameter analysed we use different **methodologies**. Thus, the technology cost comparison is based on literature review, potentially coupled with net present value models and small modules representing the effects of future cost development. Similarly, future trends of fuel and carbon prices are investigated by collecting information from existing studies and literature and processed in order to fit the requirements of this project. Regarding the impact of location–specific resource conditions, we base our work on own potential studies that include geographically explicit information e.g. on wind speed and solar irradiation. The development of overall conversion costs of RES in all sectors linked to concrete RES-development pathways by 2030 and for the integration of variable RES into the electricity system is analysed by using modelling tools.

Modelling tools uses for this work are the Green-X model (TU Vienna) for the expected development of RES-technology costs by 2030, the PowerACE (Fraunhofer ISI) model for system operation costs of fluctuating RES-E and the TEPES model from University of Comillas for the grid-related issues of RES-E integration.

This study is carried out by an international project consortium led by Fraunhofer Institute for System and Innovation Research ISI on behalf of the German Ministry for Economic Affairs and Energy (BMWI) and the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ). Project partners are Fraunhofer ISE, the Energy Economics Group from the University of Vienna, Prognos, Comillas University and ECN.

2 Framework conditions required to estimate the costs of climate and energy target options for 2030 in the energy sector

2.1 Comparing past, present and future levelized costs of energy

2.1.1 Renewable energy technologies

2.1.1.1 Wind power technologies

The use of wind power in the energy system has a long history. All concepts for wind turbines convert kinetic energy of wind into rotating energy, which is then converted to electric energy. Modern wind energy converters (WEC) dissipate 50% of the usable wind energy into electricity (Gasch, Twele, & Bade, 2007) (Hau, 2003). Wind turbines can be installed as single turbines, but often several turbines are combined to a wind farm. An individual site assessment is essential for each project as the WEC's position within the wind farm significantly affects the overall energy yield of the farm (Kaltschmitt, 2010).

Due to its competitiveness to conventional power generation wind power currently has the strongest market penetration of all renewable energy technologies. Starting from markets such as Denmark and Germany, there has been a change in the world market in recent years with the strongest growth in China, India and the USA. By the end of 2012, total capacity of all installed wind farms increased to a volume of 280 GW of which offshore wind power held a share of 5 GW. Annual installations have reached 45 GW in 2012 which contributes to a growth rate of about 22% during the past decade. Various studies predict a future market volume with a total capacity between 1,600 and 2,500 GW in 2030. Thereof, the share of offshore wind power is expected to be 40 GW by 2020 and 150 GW by 2030.

Specific investment of wind power plants experienced a substantial decrease during the 1990ies and the early years of the 21st century. Figure 7 shows the price development for a broader range of European countries. For all of the countries except Italy installation costs reached a minimum in 2004 with the lowest in Spain and the highest in Portugal and Germany. Nevertheless costs did not vary a lot between the different countries. Since this global minimum costs rose in all of the countries although the cost increase and the cost peak were different. The UK first reversed the trend of decreasing costs and reached a maximum of 1,494 €/kW in 2007. In most of the other countries costs started to fall again one year later with the highest cost peak of 2,022 €/kW in Italy. Greece and Portugal reached the cost peak in 2009 with 1,708 €/kW in the former and 1,495 €/kW in the latter. Additionally the spread between the installation costs of the different countries increased. In 2010 for instance, installation cost in Italy were around 50% higher than in Portugal. The bars on the right hand side of Figure 7 show the result of studies of the Fraunhofer ISE, stating that the variation in the investment costs is increasing whereas average costs will stay at a constant level. This is mainly caused by the increasing size of the facilities owing to a higher tower, a larger generator and a bigger rotor diameter. One important observation is that the trend in this industry is shifting towards larger and more powerful wind energy plants to increase the number of full load hours, the energy yield and the overall efficiency. However, the current costs of these wind power plants are not below 1,500 €/kW.

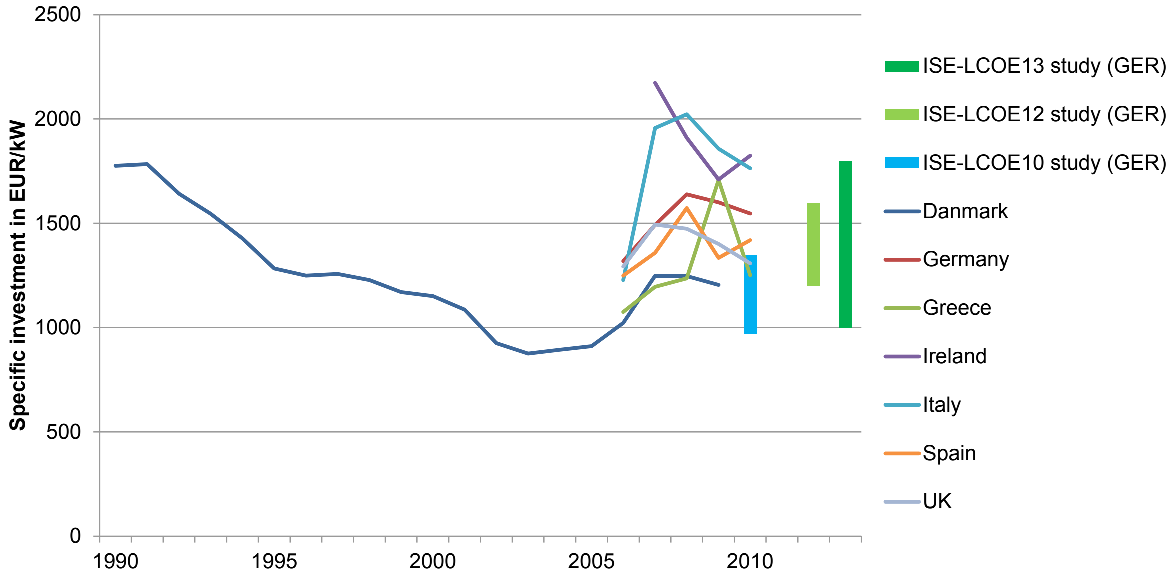

Figure 2: Development of specific investment for wind power technologies in European countries

Source: compiled by the authors based on (Statbank, 2014) (IRENA, 2012) (Kost, et al., 2013)

The future cost reduction potential is identified in different studies. Figure 8 shows the potential cost developments calculated by learning curves. Specific investment for installation of onshore wind power plants are expected to decrease from a 2010 minimum value of 1,350 €/kW and a 2010 maximum value of 1,685 €/kW to 1,060 €/kW for the former and 1,402 €/kW for the latter in 2030 (cost reduction of around 20%). The same situation is expected to appear for offshore wind power plants. The cost reduction is supposed to be around 20% (22% from 2,850 €/kW to 2,237 €/kW for min and 17% from 3,940 €/kW to 3,279 €/kW for max). Further assumptions on the costs of wind energy generation are depicted in Table 3 at the end of this section.

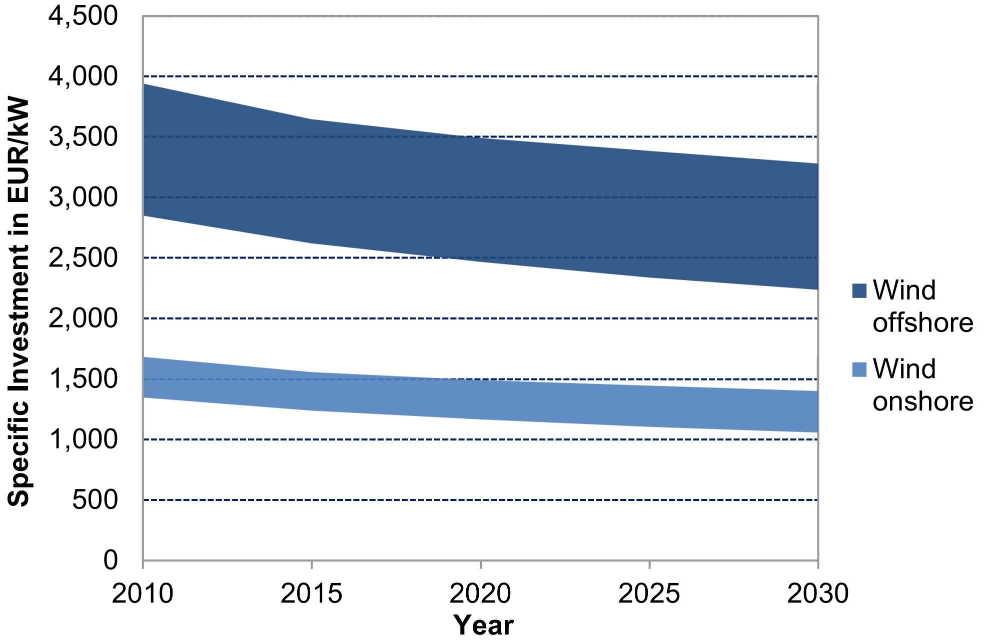

Figure 3: Forecast of specific investment for wind power

Source: Green-X model (TU Wien), Fraunhofer ISE, Prognos

2.1.1.2 Photovoltaics

Photovoltaic (PV) technologies can directly be transformed solar radiation into usable electricity. Photovoltaic systems with grid connection are fairly simple and consist of a few elements only. A single module, the smallest unit of the array, has a size of 1 to 2 square meters and generates an electric power of 100 to 300 W. Accordingly, multi MW systems need tens of thousands of modules. Major mechanical parts of a PV plant are the mounting systems; important electrical parts are the wiring, especially the DC wiring from the module arrays to the inverters.

Due to the historical development, PV technologies are classified according to their corresponding cell technology. Crystalline Silicon (c-Si) refers to mono, multi and ribbon c-Si, while Thin Film technologies include Cadmium Telluride (CdTe), amorphous-microcrystalline Silicon (a-Si, µc-Si), Copper Indium Gallium Selenide (CIGS) and Copper Indium Selenide (CIS). Concentrating photovoltaics (CPV) represent various technologies that concentrate the irradiation before directing it to the PV cell. Furthermore, there are technologies such as organic PV that have not yet been commercialized on a large scale.

Political support and decreasing prices caused a remarkable rise in global production capacity, resulting in a global installed PV capacity of more than 134 GWp at the end of 2013 and an expected further rise in installations in the forthcoming years. However, annual installations, which are at around 30 to 35 GWp in 2013, are only slightly above the level of 30 GWp from the previous years. This is specifically attributable to a reduction in the feed-in tariffs in key markets (i.e. in Germany). With 17 GWp of new installations, Europe was, as before, the most important market for photovoltaic in 2012. In 2013 and the coming years, however, higher growth rates are expected especially in China, Japan, India and North America.

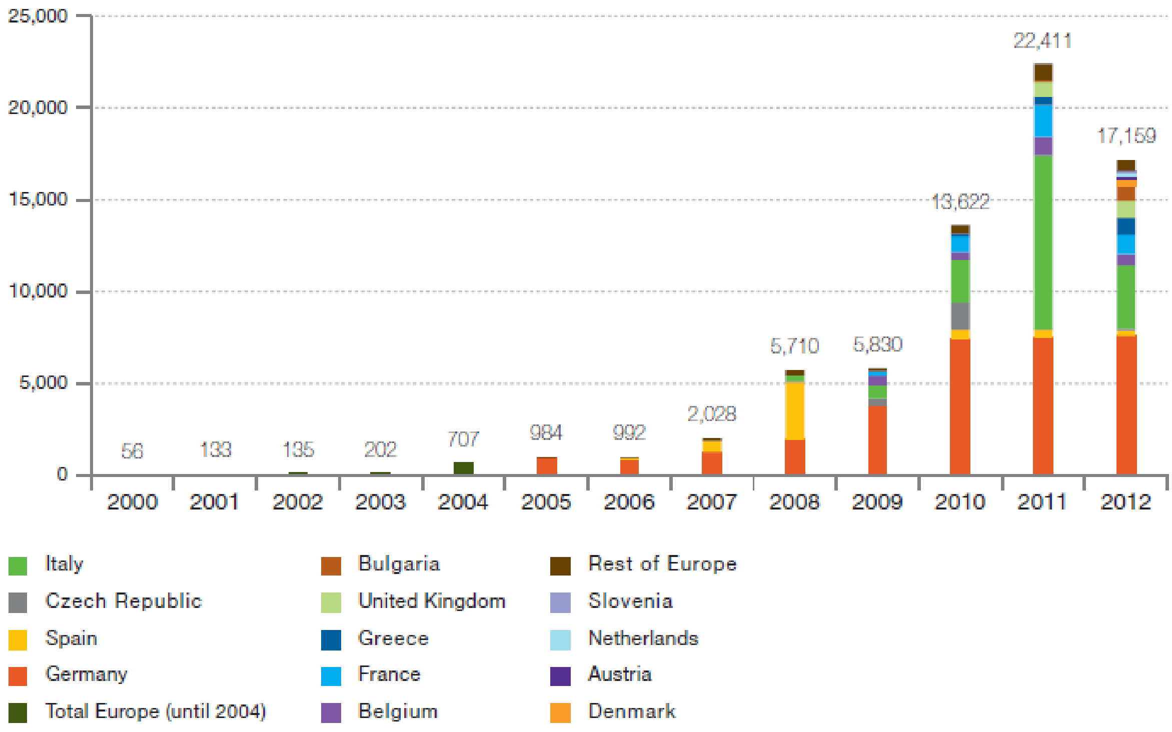

Figure 4: Evolution of European new grid-connected PV capacities 2000-2012 in MW

Source: (EPIA, 2013)

A more competitive PV market has led to strong cost cuts through the whole value chain. However, overall installation costs strongly differ between countries as e.g. costs in Germany are much lower than in other European countries. Figure 9 shows the market shares of PV installations in Europe. In many countries, the relation of annual installations is related to support mechanisms which often have led to a massive growth of installed capacity. Reduction of feed-in tariffs, however, influenced the market and led to a rapid slowdown of new installations in the years after the cut.

In 2013, installations are supposed to have reached some 35 GWp with China (8.6 GWp), Japan (6.3 GWp) and the US (5.5 GWp) being the biggest markets. Furthermore the European market share of total installations will decrease again. Thereby Germany is still the biggest single market by far. With installations of 3.8 GWp it is followed by Italy (1.7 GWp) and the UK (1.3 GWp) (Osborne, 2013).

Over the past 20 years, photovoltaic (PV) modules and systems have shown a tremendous cost reduction. With module prices decreasing by 20% every time the cumulative installed capacity doubled, PV systems reached a price level not considered possible before. The net price for PV cSi-modules from Germany reached a level of 0.69 €/Wp and 0.58 €/Wp for modules from China at the beginning of 2014 which is a decrease of around 80% compared to January 2008 (pvxchange) (EPIA, 2013).

Compared to the world market price for PV modules, the costs of installed PV systems vary substantially between the different countries. Figure 10 shows the variation in costs of installed PV systems (2011) for different European countries as well as for the US and the major Asian markets. Today, a similar difference between countries still exists. This difference can be explained by the fact that specific investment of a PV system does not only depend on the costs of PV modules and balance of system (BOS) components (such as wiring, switches, support racks and inverters) but also on installation costs, the project location, scale and funding conditions in individual countries (IRENA, 2012).

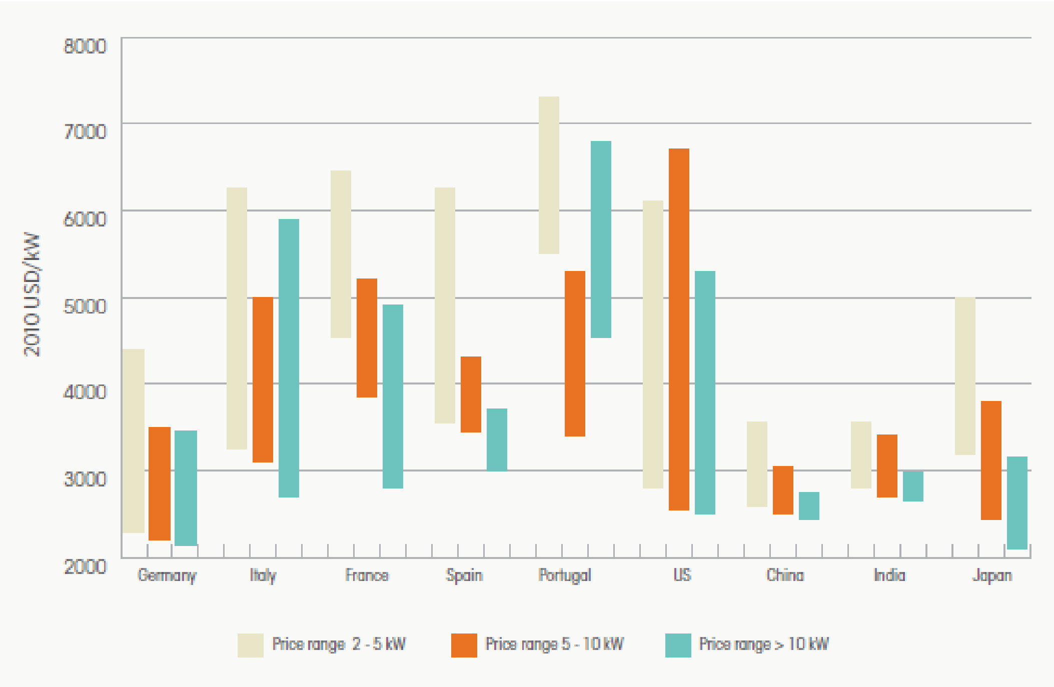

Figure 5: Installed PV system prices for residential applications in different countries, 2011

Source: (IRENA, 2012)

Figure 10 shows the cost reductions of small (<10 kWp) and medium (10-100 kWp) scaled roof-top systems in Germany (2006 – 2013). Specific investment dropped from 5,000 €/kWp in 2006 to 1,617 €/kWp at the end of 2013 for small sized systems and 1,395 €/kWp for medium sized systems. Price difference occurs due to larger systems split the balance of system (BOS) components costs by a larger number of PV electricity generation capacity while the price of the panels stay the same for both systems. Further assumptions on the costs of solar PV electricity generation are shown in Table 3.

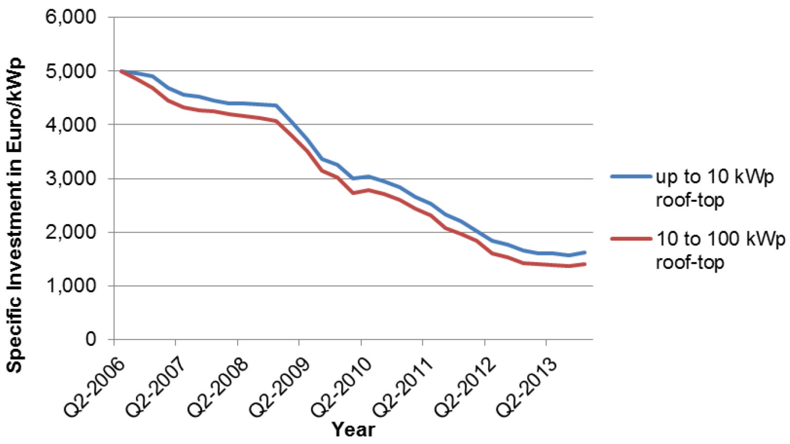

Figure 6: Development of PV specific investment of roof-top systems in Germany

Source: (EuPD, 2014)

Slowdown of price decline in 2013 is caused by a phase of consolidation in the PV industry in which a number of well-known manufacturers were forced to file for bankruptcy. Nevertheless, further price reductions will emerge after this phase of consolidation (Kost, et al., 2013). Costs for PV roof-top systems are expected to decrease by around 60% from 2010 to 2030 and reach a minimum value of 982 €/kWp and maximum value of 1,048 €/kWp (see Figure 12). Cost reduction potential is expected to be even higher for centralized large-scale PV power plants. A decrease of around 30% seems to be possible resulting in investment costs of 720 €/kWp to 1,480 €/kWp in 2030. Furthermore building integrated PV systems will stay more expensive.

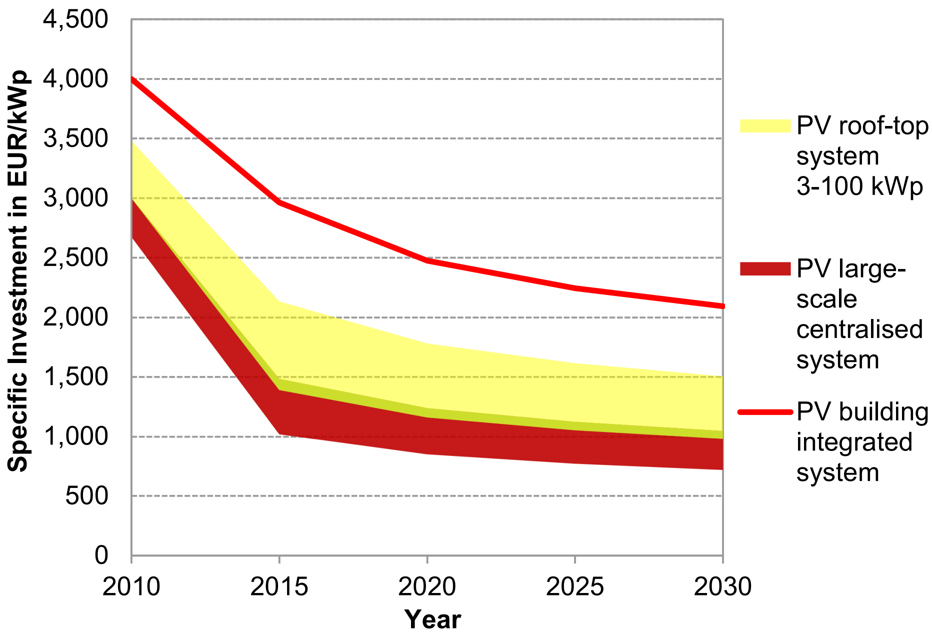

Figure 7: Forecast of total specific investment for PV systems

Source: Green-X model, Fraunhofer ISE

2.1.1.3 Concentrating Solar Power

Currently, the commercially most developed CSP technology is the Parabolic Trough technology. The rows follow the sun through a one-axis movement by a tracking device. When the fluid in the collector is heated up, it goes either through a steam turbine to generate steam or is directed to the heat storage to power the turbine later.

The Linear Fresnel reflector technology uses long horizontal segments of parallel mirrors to reflect and focus the sunlight onto the fixed absorber in a height of several meters (3 to 15 m). The different mirror rows are individually tracked according to the position of the sun. The Fresnel technology is regarded as a lower cost alternative for solar power generation due to inexpensive, nearly flat mirrors and fixed absorber tubes with no need for flexible high pressure joints. The lower efficiency of this technology makes storage up to now impossible.

In a Solar Tower plant a large number of flat mirrors, called heliostats, track the sun and focus the solar irradiation onto one single receiver which absorbs the incoming light transforming it to heat. For the heliostat field two configurations are possible: a more or less symmetric arrangement of heliostats around a 360° receiver or an asymmetric arrangement in which the mirrors are to the North (in the Northern hemisphere) or the South of the tower.

Mid-2013, there are CSP plants with a total capacity of 3.5 GW in operation worldwide. Additional power plants with a total capacity of 2.5 GW are currently under construction and about 7 GW are in the planning or development phase.

Today's specific investment is supposed to range between 3,500 and 5,000 €/kW for systems without storage between 5,500 and 6,000 €/kW for systems possessing storage tanks. Further assumptions on that issue are shown in Table 3 at the end of this section. Specific investment is supposed to decrease by around 45% for systems without storage and almost 60% for systems with storage (Figure 13). Resulting in investment costs of approximately 2,040 to 2,721 €/kW for the former and 3,624 to 3,980 €/kW for the latter.

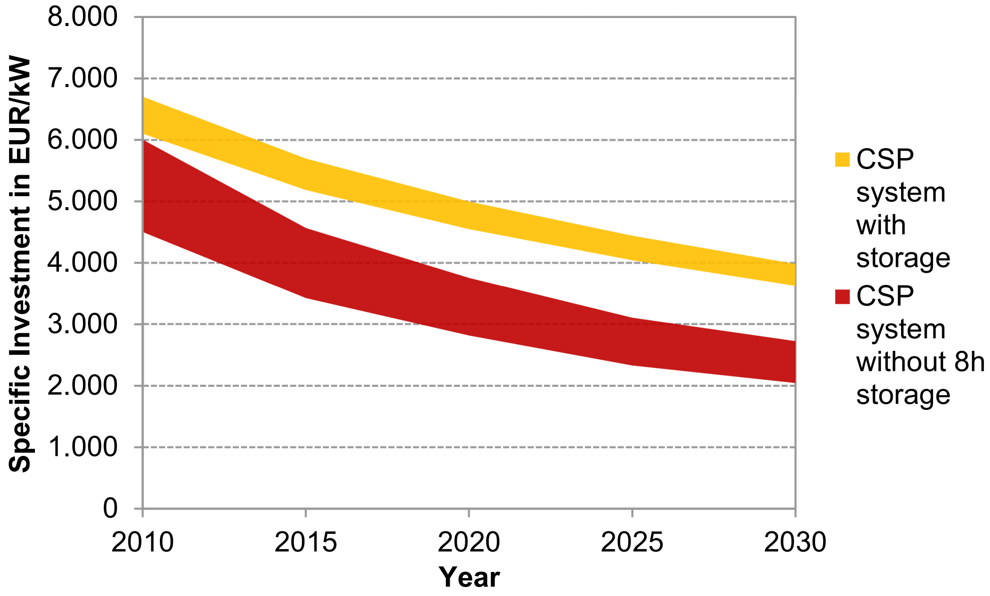

Figure 8: Forecast of specific investment for CSP plants

Source: Green-X model, Fraunhofer ISE

2.1.1.4 Hydroelectric power plants

Hydroelectricity uses the power out of nature's water cycle. Generally a distinction is made for hydroelectricity between run-of-the-river power stations, storage power stations (Impoundment dam) and pumped storage power stations (IEA, 2011).

Due to its high level of reliability, high efficiency and relatively low costs hydropower is and will be the major renewable electricity generation technology worldwide for a long time. It is contributing 16 percent (about 3,500 TWh in 2010) of the worldwide electricity generation and about 85 percent of global renewable electricity. The largest electricity generation takes place in China (694 TWh in 2010) and Brazil (403 TWh in 2010). In some countries the share of hydropower is nearly 100 percent, e.g. Albania and Paraguay (IEA, 2012). The world's largest power plant in terms of the installed power is the Three Gorges Dam in China. It has 26 turbines with a single unit capacity of 700 MW, the total installed capacity of 18,200 MW, and annual power production of 84.68 TWh (Chincold, 2011).

Electricity generation from hydropower is expected to have no further potential for technological progress and thus for cost reduction in investment costs. The World Energy Council sees hydropower potential already exploited to a high degree in Europe and North America and still significant potential in Latin America, Asia and particularly in Africa.

Specific investment of hydroelectricity can range between 1,610 and 6,590 €/kW for small-scale power plants and 1,600 and 6,265 €/kW for large-scale large-scale power plants depending on the site conditions. Further assumptions about the costs of hydro power plants are shown in Table 3 at the end of this chapter.

2.1.1.5 Energy from biomass

Biomass refers to all biological materials derived from living or recently living organism, which may become a source of energy by combustion, after methanization or other chemical transformations.

In 2005, biomass produced 1% of the global electricity supply. Production is mainly located in countries where production of organic waste is important e.g. North America and Western Europe. With more than 30.7% of the global production, the United States is the largest producer of electricity from biomass, followed by Germany and Brazil (Monde, 2009).

In industrialized countries, total contribution of modern biomass is on average only about 3% of total primary energy, and consists mostly of heat-only and heat and power applications. Many countries have targets to significantly increase biomass use, as it is seen as a key contributor to meeting energy and environmental policy objectives.

Specific investment and operation and maintenance costs vary across the different biomass technologies but they all show no further cost reduction potential due to the fact that this technology has been used for a long time and most of the technical progress is already made. Furthermore substrate costs are expected to stay at a constant level (0.03 €/kWh today, 0.025-0.04 $Euro_{2013}$/kWh in 2020 and 2030). Currently, biogas plants exhibit specific investment between 1,445 and 5,085 €/kW whereas biomass plants are between 350 (cofiring) and 4,375 €/kW. Further assumptions for the calculation of LCOEs are shown in Table 3 at the end of this section.

2.1.1.6 Geothermal power plants

Geothermal energy uses thermal resources from the earth`s interior. Potential energy is stored in either hot rock or reservoirs of steam and/or hot water. Depending on the characteristics of the well or other means that produce hot fluids of steam there are basically three different types of turbine design operating in geothermal power plants (Goldstein, 2011).

The International Geothermal Association reports an online geothermal production capacity of 11.25 GW_e in 2011 which results in an annual energy production of 69,370 GWh. About one fourth of this capacity as well as the energy production are originated in the United States, followed by the Philippines, Indonesia and Mexico. Nevertheless geothermal energy is only accounting for 0.3% of the worldwide electricity production. Whereas Iceland is to mention where geothermal energy provision accumulates to 66% of primary energy supply and 27.3% of power generation (IEA-GIA, 2013).

Actual growth is generated by exploiting wells not deeper than 3 km. Despite that the highest potential for geothermal energy is in the untapped thermal resource underlying most continental regions at depth varying from 3 to 10 km (Joseph N. Moore, 2013).

Currently, geothermal power plant exhibit specific investment between 2,335 and 7,350 €/kW and operation and maintenance costs of 101 – 170 €/kW and year. Further assumptions on the costs of geothermal electricity generation are shown in Table 3.

2.1.1.7 Wave energy

The wave power devices are based on ocean surface waves, which are generated by wind passing over the surface of the sea. The wave power is determined by the length, speed and density of the waves. This energy could be used for electricity generation, water desalination or pumping of water. The first wave energy converter was patented in 1799 (Lindroth & Leijon, 2011) and the first experimental wave farm opened in 2008 in Portugal (Lima, September 23, 2008). Many factors such as the method used to capture the energy of waves, the location and the power take-off system categorize wave power converter (WEC). About 200 different wave energy converters are currently in stage of development and testing (Hayward, McGarry, & Osman, 2012). Wave power resources are estimated around 2 TW in the world (Saket & Etemad-Shahidi, 2012). The USA, North & South America, Western Europe, Japan, South Africa, Australia and New Zealand have significant wave energy potential.

Wave energy has a certain potential to play role for sustainable development in the coming years. Compare to wind and solar technologies, power extraction from wave energy might be more predictable (Angelis-Dimakis, Biberacher, Dominguez, Fiorese, Gadocha, & Gnansounou, 2011) and continuous during the day (about 90% of the time compare to 20-30% for wind and solar) (Sahinkaya, Plummer, & Drew, 2009). Currently, specific investment is supposed to be around 4,750 – 7,450 €/kW even thou numbers are hard to predict since every device is custom-made. For further assumptions see Table 3.

2.1.1.8 Tidal power

Tidal power is a hydro power plant that uses the power of the ocean's tidal range (Baker, 1991). Tidal power can be classified into two main types of generating methods:

<u>Tidal current turbines</u> generate electricity by extracting the energy of moving water in a similar way to wind energy technologies. But since tidal current turbines operate in water they experience greater forces and moments than wind turbines. Furthermore current turbines must be able to generate in both directions to work during both flood and ebb (Fergal O Rourke, 2010).

<u>Tidal barrages</u> trap the incoming water behind a wall and release the water during low tide. Turbines generate electricity when the water is released during the second part of the ebb tide and the first part of the next flood. The electricity generation can be augmented by using the turbines as pumps at high tide in order to increase the level of water stored in the basin. This is because the energy available is proportional to the square of the tidal range. If a more

constant electricity generation over time is demanded or the local grid system is weak then operation in both directions may be preferable. This results in a lower water level in the basin and less energy per turbine (Baker, 1991).

The world's first large scale tidal power plant and until 2011 the world's largest is the Rance tidal power plant opened in 1966 at La Rance, France. This tidal barrage has an installed capacity of 240 MW (EnergyBC, 2014). Specific investment of this technology ranges from 5,000 to 8,000 €/kW. Further assumptions on the costs of this technology are shown in Table 3.

2.1.1.9 Summarising techno-economic assumptions of renewable energy technologies

Table 3 shows the detailed technological and economic specifications of the renewable energy technologies that were taken into consideration for calculating LCOE. Each technology consists of several sub-technologies which have specific technological design or have a specific use. For example biogas electricity generation involves agricultural biogas plants, landfill gas plants and sewage gas plants. In fact the possibility of producing heat additionally by combined heat and power (CHP) was added to cover a broader scope of generation technologies, but it not considered within LCOE calculations. The main input to the LCOE calculation is the specific investment (2010), annual operation costs, efficiency and lifetime.

Table 2 Cost summary (2010) of renewable energy technologies

RES-E subcategory	Plant specification	Investment costs 2010	O&M costs 2010	Efficiency (electricity)	Efficiency (heat)	Lifetime (average)	Typical plant size	Degradation
		[€/kW $_{el}$]	[€/(kW $_{el}$ year)]	[1]	[1]	[years]	[MW $_{el}$]	
Biogas	Agricultural biogas plant	2,890 – 4,860	137 - 175	0.3 - 0.36	-	25	0.1 - 0.5	
	Agricultural biogas plant - CHP	3,120 – 5,085	143 – 182	0.29 - 0.35	0.53 - 0.57	25	0.1 - 0.5	
	Landfill gas plant	1,445 - 2,080	51 – 82	0.33 - 0.37	-	25	0.75 - 8	
	Landfill gas plant - CHP	1,615 - 2,255	56 - 87	0.32 - 0.36	0.5 - 0.53	25	0.75 - 8	
	Sewage gas plant	2,600 - 3,875	118 – 168	0.29 - 0.33	-	25	0.1 - 0.6	
	Sewage gas plant - CHP	2,775 - 4,045	127 – 179	0.27 - 0.31	0.53 - 0.57	25	0.1 - 0.6	
Biomass	Biomass plant	2,540 - 3,550	97 – 175	0.26 - 0.3	-	30	1 – 25	
	Cofiring	350 - 580	112 – 208	0.35 – 0.45	-	30	-	
	Biomass plant - CHP	2,600 - 4,375	86 – 176	0.22 - 0.27	0.63 - 0.66	30	1 – 25	
	Cofiring – CHP	370 - 600	115 – 242	0.20 – 0.35	0.5 - 0.65	30	-	
Biowaste	Waste incineration plant	5,150 – 6,965	100 - 184	0.18 - 0.22	-	30	2 – 50	
	Waste incineration plant - CHP	5,770 - 7,695	123 – 203	0.16 - 0.19	0.62 - 0.64	30	2 – 50	
Geothermal electricity	Geothermal power plant	2,335 - 7,350	101 - 170	0.11 - 0.14	-	30	5 – 50	
Hydro large-scale	Large-scale unit	1,600 - 3,460	33 – 36	-	-	50	250	
	Medium-scale unit	2,125 – 4,900	34 – 37	-	-	50	75	
	Small-scale unit	2,995 – 6,265	35 – 38	-	-	50	20	
	Upgrading	870 – 3,925	33 – 38	-	-	50	-	
Hydro small-scale	Large-scale unit	1,610 - 3,540	36 – 39	-	-	50	9.5	
	Medium-scale unit	1,740 - 5,475	37 – 40	-	-	50	2	
	Small-scale unit	1,890- 6,590	38 – 41	-	-	50	0.25	
	Upgrading	980 - 3,700	36 – 41	-	-	50	-	
Photovoltaics	Small roof-top	1,500 - 2,300	33 - 38			25	0.001 - 0.015	0.002
	Large roof-top	1,200 - 2,100	33 - 38			25	0.015 - 0.5	0.002
	Building-integrated PV	2,000 - 3,500	33 - 38			25	0.001 - 0.05	
	Large ground mounted PV plant	1,100 - 1,600	33 - 38			25	0.5 - 200	0.002
Solar thermal electricity	Concentrating solar power plant (with 8h storage)	5,500 - 6,000	110 - 160	0.30 - 0.36 (net efficiency)	-	30	10 – 200	0.002
	Concentrating solar power plant (w/o storage)	3,500 - 5,000	110 - 160	0.30 - 0.36 (net efficiency)	-	30	10 – 200	0.002
Tidal stream energy	Tidal (stream) power plant - shoreline	5,000 – 7,100	95 – 145	-	-	25	0.5	
	Tidal (stream) power plant - nearshore	5,750 – 7,505	108 – 150	-	-	25	1	
	Tidal (stream) power plant - offshore	6,250 - 8,000	122 – 160	-	-	25	2	
Wave energy	Wave power plant - shoreline	4,750 – 5,750	83 – 140	-	-	25	0.5	
	Wave power plant - nearshore	5,150 – 6,050	90 – 145	-	-	25	1	
	Wave power plant - offshore	6,000 – 7,450	138 – 155	-	-	25	2	
Wind onshore	Wind power plant	1,350 – 1,685	30 – 50	-	-	20	2 - 4	0
Wind offshore	Wind power plant - nearshore	2,850 - 2,950	64 – 70	-	-	25	5	0
	Wind power plant - offshore: 5...30km	3,150 – 3,250	70 – 80	-	-	25	5	0
	Wind power plant - offshore: 30...50km	3,490 - 3,590	75 – 85	-	-	25	5	0
	Wind power plant - offshore: 50km...	3,840 - 3,940	80 – 90	-	-	25	5	0

Sources: Green-X model, Fraunhofer ISE, Prognos

Based on worldwide market developments, cost forecasts are derived by using learning rates for the technologies PV, wind power and CSP. Table 4 shows the calculated development of system costs in €/kW for different renewable energy technologies until 2030.

Table 3: Forecast for specific investment of renewable energy technology until 2030

Remark		Technology	Unit	2010	2014	2015	2020	2025	2030
system	upper range	PV	€/kW	4,000	3,085	2,963	2,473	2,244	2,091
BAU, roof-top system	upper range		€/kW	3,480	2,222	2,134	1,781	1,616	1,506
	lower range			3,000	1,449	1,391	1,162	1,054	982
ADV, large-scale centralised system	lower range		€/kW	2,675	1,063	1,020	852	773	720
	upper range		€/kW	3,000	1,546	1,484	1,239	1,124	1,048
BAU, system with 8h storage	upper range	CSP	€/kW	6,700	5,832	5,693	4,994	4,439	3,980
	lower range		€/kW	6,100	5,310	5,183	4,547	4,041	3,624
ADV, large-scale system without storage	upper range		€/kW	6,000	4,797	4,563	3,751	3,101	2,721
	lower range		€/kW	4,500	3,598	3,422	2,813	2,326	2,040
BAU, high grid connection cost, etc.	upper range	Wind onshore	€/kW	1,685	1,579	1,559	1,493	1,447	1,402
	lower range		€/kW	1,350	1,262	1,241	1,169	1,107	1,060
depth	upper range	Wind offshore	€/kW	3,940	3,693	3,645	3,490	3,384	3,279
ADV, nearshore & shallow water depth	lower range		€/kW	2,850	2,664	2,621	2,467	2,338	2,237
Biogas plant	lower range	Biogas	€/kW	1,445	konstant				
	upper range		€/kW	4,860					
Biogas plant - CHP	lower range		€/kW	1,615					
	upper range		€/kW	5,085					
Biomass plant	lower range	Biomass	€/kW	2,540					
	upper range		€/kW	3,550					
Biomass - CHP	lower range		€/kW	2,600					
	upper range		€/kW	4,375					
Waste incineration plant	lower range	Biowaste	€/kW	5,150					
	upper range		€/kW	6,965					
Waste incineration plant - CHP	upper range		€/kW	5,770					
	lower range		€/kW	7,695					
Geothermal power plant	upper range	Geothermal electricity	€/kW	2,335					
	lower range		€/kW	7,350					
Large-scale unit	upper range	Hydro power	€/kW	1,600					
Small-scale unit	lower range		€/kW	6,590					
Tidal (stream) power plant - shoreline	lower range	Tidal stream energy	€/kW	5,000	5,000	4,912	4,251	3,901	3,551
Tidal (stream) power plant - offshore	upper range		€/kW	8,000	8,000	7,852	6,801	6,242	5,682
Wave power plant - shoreline	lower range	Wave energy	€/kW	4,750	4,750	4,554	4,038	3,706	3,374
Wave power plant - offshore	upper range		€/kW	7,450	7,450	7,220	6,333	5,812	5,291

2.1.2 Conventional power plants

Technical and economic properties of conventional power plants from 2020 to 2050 are summarized in Table 5. Whereas specific investments, technical life time, carbon capture rate and operation and maintenance costs will stay constant, efficiency for conventional coal power plants and combined cycle gas turbine (CCGT) power plants will slightly improve due to technology improvements.

Table 4: Cost summary (2010) and forecast until 2050 for conventional power generation technologies

Technology	year	Effi-ciency	Technical life time [a]	Carbon capture rate	Specific Investment	O&M fix [€/ (kw*a)]	O&M var [€/ MWh]
CCS Coal Steam Turbine	2010						
	2020						
	2030	0.39	40	0.95	2600 - 3740	85	1.5
	2040	0.39	40	0.95	2600 - 3400	85	1.5
	2050	0.39	40	0.95	2600 - 3400	85	1.5
CCS Gas CCGT	2010						
	2020						
	2030	0.51	30	0.97	1500 - 2000	22.5	2.7
	2040	0.51	30	0.97	1500 - 2000	22.5	2.7
	2050	0.51	30	0.97	1500 - 2000	22.5	2.7
CCS Lignite	2010						
	2020						
	2030	0.38	40	0.95	3300 - 4180	114	1.5
	2040	0.38	40	0.95	3300 - 3800	114	1.5
	2050	0.38	40	0.95	3300 - 3800	114	1.5
Coal (no CCS)	2010	0.46	40	0	1300 - 1700	42.5	1.5
	2020	0.47	40	0	1300 - 1700	42.5	1.5
	2030	0.48	40	0	1300 - 1700	42.5	1.5
	2040	0.49	40	0	1300 - 1700	42.5	1.5
	2050	0.49	40	0	1300 - 1700	42.5	1.5
Gas CCGT (no CCS)	2010	0.57	30	0	800 - 1200	11.25	3
	2020	0.58	30	0	800 - 1200	11.25	3
	2030	0.59	30	0	800 - 1200	11.25	3
	2040	0.6	30	0	800 - 1200	11.25	3
	2050	0.61	30	0	800 - 1200	11.25	3
Gas turbines	2010	0.4	30	0	400 - 600	7.5	2.7
	2020	0.4	30	0	400 - 600	7.5	2.7
	2030	0.4	30	0	400 - 600	7.5	2.7
	2040	0.4	30	0	400 - 600	7.5	2.7
	2050	0.4	30	0	400 - 600	7.5	2.7
Lignite (no CCS)	2010	0.47	40	0	1900	57	1.5
	2020	0.47	40	0	1900	57	1.5
	2030	0.47	40	0	1900	57	1.5
	2040	0.47	40	0	1900	57	1.5
	2050	0.47	40	0	1900	57	1.5
Pumped storage	2010	0.91	40	0	1000	10	0
	2020	0.91	40	0	1000	10	0
	2030	0.91	40	0	1000	10	0
	2040	0.91	40	0	1000	10	0
	2050	0.91	40	0	1000	10	0
Nuclear	2010	-	40	-	3500	85	1.5
	2020	-	40	-	3500	85	1.5
	2030	-	40	-	3500	85	1.5
	2040	-	40	-	3500	85	1.5
	2050	-	40	-	3500	85	1.5

Sources: Green-X model, Fraunhofer ISE, Prognos

Coal

Until 2050, the investment and O&M costs for coal power stations will remain constant in real terms. Due to an expected increase in costs for commodities, improvements in production technologies do not lead to declining investment costs. The overnight investment costs for coal power stations can be assumed to equal 1,300 - 1,700 €/kW until 2050. The same applies to the O&M costs: With increasing commodity prices, spare parts will face increasing cost in the future. Given an assumed efficiency progress for O&M, however, the costs can remain at the same level as of today. The fixed O&M costs come to 42.5 €/kW per year and the variable O&M costs to 1.5 €/MWh. The technical lifetime of a conventional coal power station can be assumed to be 40 years – a value which represents a typical average lifetime for a power station. The improvement in the net efficiency of conventional power stations will slow down in the future and will rise from 47% in 2020 to 49% in 2050. Due to the increasing deployment of renewable energy technologies in the future, energy production from renewables will rise dramatically in the next 40 years. As a consequence, conventional power plants will need to operate fewer hours per year. This reduces the need for a stronger efficiency development since the use of increased operation pressure and temperatures will require high temperature materials that are very costly.

The investment costs for coal CCS power stations are significantly higher than those of conventional coal-based power stations. With 2,600 - 3,400 €/kW, they remain constant in real terms until 2050. The investment costs presented in this study reflect pre-combustion technologies as well as post-combustion approaches. Rising commodity costs compensate the production progress over time. The same applies to O&M costs. The fixed O&M costs amount to 85 €/kW per year, and the variable O&M costs to 1.5 €/MWh. The technical lifetime of a coal CCS power station is comparable with the lifetime of a conventional coal power station and equals up to 40 years. Due to the energy intensive CCS infrastructure the overall efficiency of a coal CCS power station is clearly lower than that of a conventional coal power station. Coal CCS efficiency will be around 39% up to 2050. The carbon capture rate of a coal CCS power station is expected to reach 95%.

Lignite

The investment and O&M costs for lignite power stations are similar to those of a conventional coal-based power station. They will remain constant in real terms for the same reasons as the ones stated above. The overnight investment costs for lignite power stations can be assumed to be 1,500 - 1,900 €/kW until 2050. The same applies to O&M costs. The fixed O&M costs amount to 57 €/kW per year, and the variable O&M costs to 1.5 €/MWh. The technical lifetime of a lignite power station can be assumed to equal 40 years. The total efficiency remains constant in the future and will equal 47% up to 2050. We expect that the current lignite-fired power plants with optimized technology are developed towards the use of dry brown coal technology.

The investment costs for lignite CCS power stations are significantly higher than those for conventional lignite-based power stations. With 3,000 - 3,800 €/kW they remain constant in real terms until 2050. The same applies to O&M costs. The fixed O&M costs come to 114 €/kW per year, and the variable O&M costs to 1.5 €/MWh. The technical lifetime of a lignite CCS power station equals 30 years. Lignite CCS efficiency will be 38% up to 2050. The carbon capture rate of a lignite CCS power station amounts to 95%.

Gas

We expect that the investment and O&M costs for gas CCGT power stations will remain constant in real terms as well. Here, too, the expected increase of costs for commodities will compensate improvements in production technologies. The overnight investment costs for gas CCGT power stations can be assumed to be 800 - 1,200 €/kW until 2050. The same applies to O&M costs. Due to increasing commodity prices, spare parts will cost more in the future. With an assumed efficiency progress for O&M, however, the costs can remain at the same level as of today. The fixed O&M costs come to 11.25 €/kW per year, and the variable O&M costs to 3 €/MWh. The technical lifetime of a gas power station can be assumed to be 30 years. Given the load variation of a gas power station (as a medium and peak load power station), the wear is greater than for base load coal or lignite power stations. The improvement in total efficiency will continue in the future and will rise from 58% in 2020 to 61% in 2050.

The investment costs for gas CCGT CCS power stations are higher than those for conventional gas CCGT power stations. With 1,500 - 2,000 €/kW they remain constant in real terms until 2050. The same applies to O&M costs. The fixed O&M costs amount to 22.5 €/kW per year, and the variable O&M costs to 2.7 €/MWh. The technical lifetime of a gas CCGT CCS power station equals 30 years as well. Due to the energy intensive CCS infrastructure, the overall efficiency of a gas CCGT CCS power station is clearly lower than that of a conventional gas power station. The CCGT CCS efficiency will be around 51% up to 2050. With 97%, the carbon capture rate is slightly higher than that of a coal CCS power station.

For single gas turbine power stations, the overnight investment costs are lower than for gas CCGT investment costs, as they reflect the smaller size and missing waste heat boiler. They amount to 400 - 600 €/kW and will remain constant until 2050. The fixed O&M costs equal 7.5 €/kW per year and the variable O&M costs are 2.7 €/MWh. The efficiency of a single gas turbine power station is lower than the efficiency of a gas CCGT power station. Given the lack of waste heat utilization, the overall net efficiency is about 40%. The technical lifetime of a gas turbine comes up to 100,000 operating hours. When being used as a peak load power station, a gas turbine can operate as well for 30 years.

Pumped storage

The investment costs for pumped storage power stations come up to 1,000 €/kW. Due to the fact that the number of suitable locations for such stations is limited, new sites for pumped storage power stations in the future will require a more complex implementation. Thus the overnight investment costs remain stable. The same applies to the O&M costs. The investment costs of 1,000 €/kW represent plant sites where either the lower or upper basin is given naturally. With an assumed efficiency progress for O&M, the costs can remain at the same level as of today. The fixed O&M costs amount to 10 €/kW per year, and there are hardly any variable O&M costs. The technical lifetime of a pumped storage power station can be assumed to be 40 years. The total efficiency equals 91% over the whole period of time.

Nuclear power

Due to the fact that there are just two nuclear power stations being built at the moment in Europe, the experience with new projects is limited. In addition the assumed construction costs of these two reactors increase constantly over the years. Thus the overnight investment costs come up to 3,500 - 6,000 €/kW and remain stable. The same applies to the O&M costs. The fixed O&M costs amount to 85 €/kW per year, and the variable O&M costs come up to 1.5 €/MWh. The technical lifetime of a pumped storage power station can be assumed to be 40 years.

2.1.3 Financing parameters

The standard default interest rate (based on WACC) used for the LCOE comparison is 7.5% in 2013 and until 2050.Taking into consideration that investment risk is different depending on where or in which technology the investment is made variable interest rates have to be taken into consideration. Therefore, we make technology specific risk assumption for each technology. This assumption includes also the expectations of a typical investor as well as the technology risk related to uncertain electricity generation and project risk. Technology specific risks as well as the methodology to calculate WACC are summarized in section 3.1.4. For the modelling described in the next chapter we introduce additional risk components including country and policy-related risks.

2.1.4 LCOE of energy technologies

The method to calculate Levelised Cost of Electricity (LCOE) is able to compare electricity generation and cost structures of different power generation technologies with each other. The basic idea behind LCOE is to divide the discounted sum of costs for construction and operation of a power plant by the discounted sum of produced electricity over the lifetime. The result is the so-called LCOE in € per kWh discounted to the same reference date to assure the comparability of the different LCOE values. Discounting the generation of electricity seems, at first glance, incomprehensible from a physical point of view but is a consequence of accounting transformations. But generated energy implicitly corresponds to the earnings from the sale of this energy. The farther these earnings are displaced in the future, the lower their cash value. For calculating the LCOE for new power plants, the following equation is applied:

$$LCOE = \frac{I_0 + \sum_{t=1}^{n} \frac{A_t}{(1+i)^t}}{\sum_{t=1}^{n} \frac{M_{t,el}}{(1+i)^t}}$$

$LCOE$	Levelised cost of electricity in €/kWh
I_0	Investment expenditures in €
A_t	Annual total costs in € in year t
$M_{t,el}$	Produced quantity of electricity in the respective year in kWh
i	Real interest rate (WACC) in %
n	Economic operational lifetime in years
t	Year of lifetime (1, 2,…, n)

Annual total costs are comprised of fixed and variable costs for power plant operation, maintenance, service, repairs and insurance payments. Also a residual value or disposal costs respectively can be added. The share of external financing and equity financing can be included in the analysis explicitly through the weighted average cost of capital (WACC) over the discounting factor (interest rate). It depends on the amount of equity capital, return on equity capital over lifetime, cost of debt and the share of debt used. Through discounting all expenditures and the quantity of electricity generated over the lifetime to the same reference date, the comparability of the LCOE is assured.

The LCOE is therefore a comparative calculation on a cost basis and not a calculation of the level of feed-in tariffs. They can only be calculated by using additional influence parameters. Rules governing private use, tax law and realized operator earnings make the calculation of a feed-in tariff based on the results for the LCOE more difficult. Furthermore, LCOE calculation does not take into account the significance or value of the electricity produced within the energy system in any given hour of the year.

The results of the LCOE calculation for wind and solar based electricity generation are illustrated in Table 7. The LCOE are sorted depending on the wind speed and on the solar radiation. For wind onshore and offshore they are separated into groups with low, medium and high wind speeds. PV based electricity generation is divided into groups with low, medium, high and very high solar radiation. The different groups present an average site in corresponding European countries with similar full load hours per technology and are listed in Table 6. Minimum (min) and maximum (max) LCOE show the current range of LCOE for each group and the development towards 2030. Min LCOE are calculated with higher full load hours and low investment costs and high LCOE present low lull load hours and high investment costs. The standard default interest rate WACC is 7.5% for all years with specific risk multipliers for each technology.

The resource analysis for wind and solar and their corresponding full-load hours (FLH) are based on the analysis in section 3.1.3. For the LCOE analysis they are grouped together at similar levels of full-load hours (see Table 6). Prices of CO_2 emission allowances and fuel prices from today to 2050 are taken from section 2.2.

Table 5 : Wind speeds and solar radiation related to European countries and their corresponding full load hours

Technology	Wind speed/ solar radiation	Corresponding countries (average site)	FLH lower range	FLH higher range
Wind Onshore	low	AT, BG, CY,CZ, DE, EE,FI, IT, LU, LV, PT, RO, SK, SL, ES	1,500	2,200
	medium	BE, HR, DK,FR, GR, HU, LT, MT, NL, PL, SE	2,200	2,600
	high	IR, UK	2,600	3,000
Wind Offshore	low	CY, GR, SE,	2,800	3,100
	medium	BE, FR, DE, MT, PL,	3,100	3,400
	high	DK, IR, NL, UK	3,400	4,000
PV	low	FI, SE	600	800
	medium	BE, CZ, DK, EE, IE, LV, LU, NL, PL, UK	800	1,000
	high	AT, BG, HR, FR, DE, HU, RO, SK, SL,	1,000	1,200
	very high	CY, GR, IT, MT, PT, ES,	1,200	1,500

LCOE of onshore wind power at locations with low wind speed and within a FLH range of 1500 to 2200 are in 2014 between 0.079 €/kWh and 0.137 €/kWh and are decreasing to a range of 0.070 €/kWh and 0.125 €/kWh in 2030. Countries with more-favorable wind conditions achieve LCOE from 0.067 to 0.093 €/kWh in 2014. LCOE for this group will fall to 0.059 to 0.085 €/kWh in the year 2030. At sites, where onshore wind turbines reach between 2600 and 3000 FLH, LCOE values are between 0.058 and 0.079 €/kWh in 2014 and 0.051 to 0.072 €/kWh in 2030.

Currently, offshore wind farms at very good locations achieve LCOE in the range from 0.080 to 0.121 €/kWh. LCOE for 2030 are calculated to be between 0.070 and 0.110 €/kWh. However, in European countries with low offshore wind conditions and low full-load hours LCOE ranges between 0.103 and 0.147 €/kWh in 2014 and in 2030 between 0.091 and 0.134 €/kWh.

LCOE of PV systems in countries with low irradiation and FLH between 600 and 800 lies in the range of 0.163 €/kWh to 0.391 €/kWh at present and will drop to a range between 0.125 and 0.284 €/kWh in 2030. In European countries with very high solar radiation as Cyprus, Italy or Greece low LCOE between 0.087 €/kWh and 0.195 €/kWh is reached at present. In 2030, LCOE at sites with FLH of over 1200 are calculated between 0.066 €/kWh and 0.142 €/kWh.

Table 6 : Development of LCOE for wind onshore, wind offshore and PV in Europe towards 2030

Technology	**Wind speed/ solar radiation**	2014		2020		2025		2030	
		min	max	min	max	min	max	min	max
Wind onshore	low	0.079	0.137	0.075	0.131	0.072	0.128	0.070	0.125
	medium	0.067	0.093	0.063	0.089	0.061	0.087	0.059	0.085
	high	0.058	0.079	0.055	0.076	0.053	0.074	0.051	0.072
Wind offshore	low	0.103	0.147	0.102	0.145	0.093	0.137	0.091	0.134
	medium	0.094	0.133	0.093	0.131	0.085	0.124	0.083	0.121
	high	0.080	0.121	0.079	0.120	0.072	0.113	0.070	0.110
PV	low	0.163	0.391	0.139	0.325	0.130	0.300	0.125	0.284
	Medium	0.130	0.293	0.111	0.243	0.104	0.225	0.100	0.213
	High	0.109	0.234	0.093	0.195	0.087	0.180	0.083	0.170
	very high	0.087	0.195	0.074	0.162	0.070	0.150	0.066	0.142

LCOE of the other analyzed power generation technologies are presented inTable 7. Here, LCOE are calculated for a range of FLH. To present the full range of potential projects and power plants, LCOE is evaluated by using again a min value (low costs and high FLH) and a max value (high costs and low FLH). Two different CO_2 price scenarios are calculated. The first scenario shows results with a CO_2 price of 60 €/t in 2050, the second scenario assumes 158 €/t in 2050.

Table 7 : Development of LCOE power generation technologies in Europe towards 2030 (CO_2 price in 2050 is 60 €/t)

Technology	2014		2020		2025		2030	
	min	max	min	max	min	max	min	max
CSP	0.203	0.260	0.181	0.232	0.167	0.213	0.155	0.198
Biomass	0.111	0.195	0.114	0.198	0.115	0.199	0.117	0.200
Biogas	0.084	0.198	0.082	0.196	0.080	0.194	0.080	0.194
Geothermal	0.052	0.196	0.052	0.196	0.052	0.196	0.052	0.196
Tidal	0.200	0.868	0.177	0.760	0.167	0.710	0.156	0.660
Wave	0.192	0.818	0.171	0.718	0.161	0.671	0.151	0.625
Coal	0.068	0.083	0.076	0.092	0.083	0.100	0.091	0.110
Coal-CCS							0.094	0.133
Lignite	0.051	0.068	0.058	0.076	0.065	0.084	0.072	0.093
Lignite-CCS							0.076	0.116
CCGT	0.090	0.114	0.098	0.124	0.102	0.131	0.107	0.143
CCGT-CCS							0.113	0.177
GT	0.117	0.148	0.128	0.161	0.135	0.172	0.142	0.187
Nuclear	0.056	0.098	0.056	0.098	0.056	0.098	0.056	0.098
Hydro large	0.026	0.270	0.026	0.270	0.026	0.270	0.026	0.270
Hydro small	0.026	0.282	0.026	0.282	0.026	0.282	0.026	0.282

Table 8 : Development of LCOE power generation technologies in Europe towards 2030 (CO_2 price in 2050 is based on the CO2 price development of the GHG40EE Scenario of the Impact Assessment (European Commission, 2014)

Technology	2014		2020		2025		2030	
	min	max	min	max	min	max	min	max
Coal	0.073	0.087	0.086	0.101	0.099	0.114	0.118	0.136
Coal-CCS							0.096	0.135
Lignite	0.056	0.073	0.068	0.085	0.082	0.100	0.101	0.121
Lignite-CCS							0.077	0.118
CCGT	0.091	0.115	0.101	0.126	0.108	0.136	0.120	0.154
CCGT-CCS							0.114	0.177
GT	0.119	0.149	0.133	0.164	0.145	0.179	0.161	0.202

LCOE for coal power stations and a CO_2 price of 60 €/t are between 0.068 €/kWh and 0.083 €/kWh at present and increase up to between 0.091 and 0.110 €/kWh in 2030. The LCOE of Coal-CCS power plants amount between 0.094 and 0.133 €/kWh in 2030.

The LCOE of lignite power stations are ranging between 0.051 and 0.068 €/kWh at present and increase to 0.072 and 0.093 €/kWh in 2030. The use of CCS-Technology would raise the LCOE in 2030 to 0.076 and 0.116 €/kWh.

LCOE for gas CCGT power stations are between 0.090 and 0.114 €/kWh at present and increase up to 0.107 and 0.143 €/kWh in 2030. For CCGT-CCS the LCOE achieve the range from 0.113 to 0.177 €/kWh in 2030.

Gas turbines have slightly higher LCOE with a range between 0.117 and 0.148 €/kWh at present and between 0.142 and 0.187 €/kWh in 2030.

LCOE for new nuclear power stations would come up to 0.056 and 0.098 €/kWh today and they increase until 2030 between 0.056 and 0.098 €/kWh.

The LCOE of biomass based power stations are between 0.111 and 0.195 €/kWh at present and they increase between 0.117 and 0.200 €/kWh in 2030.

Biogas driven power stations have wide spread LCOE with a range between 0.084 and 0.198 €/kWh at present and between 0.080 and 0.194 €/kWh in 2030.

For each technology, a range of potential full-load hours was assumed (Table 10). This assumption corresponds to typical use of the technology within the electricity system. Until 2050, the number of full-load hours of power plants with high CO_2 emissions strongly decrease due to an increase of prices for CO_2 emission allowances or the high RES share in the system.

In Table 9 the development of LCOE for coal, lignite and gas based power generation is presented with a CO_2 price in 2050 of 158 €/t. For all technologies and years the LCOE are higher than with a low CO_2 price of 60 €/t.

Table 9 : Full-load hours of power generation technology (assumption for LCOE calculation)

Technology	Corresponding countries (average site)	FLH lower range	FLH higher range
CSP	ES, GR, IT, PT	2,500	3,000
Biomass	All European countries	4,000	7,000
Geothermal		4,000	7,000
Tidal		1,000	3,000
Wave		1,000	3,000
Coal		3,000	7,000
Coal-CCS		3,000	7,000
Lignite		5,000	7,000
Lignite-CCS		5,000	7,000
CCGT		3,000	6,000
CCGT-CCS		3,000	6,000
GT		1,000	3,000
Nuclear		6,000	7,000
Hydro large		2,000	7,000
Hydro small		2,000	7,000
Biogas		4,000	7,000

A split of the LCOE into investment based cost and operation based cost shows differences for conventional power plants and renewable power plants as LCOE of renewable energy usually shows a higher share of LCOE based on investment cost whereas operation cost are relatively lower (Table 11).

Table 10 : Split of LCOE into investment based cost and operation based cost

LCOE (inv)	2014		2020		2030	
	Min	Max	Min	Max	Min	Max
Wind Onshore	0,041	0,103	0,038	0,098	0,035	0,092
Wind Offshore	0,060	0,118	0,059	0,117	0,050	0,105
Solar PV	0,064	0,189	0,051	0,136	0,043	0,119
Solar CSP	0,150	0,198	0,128	0,169	0,102	0,135
Biomass	0,019	0,114	0,019	0,114	0,019	0,114
Biogas	0,030	0,095	0,030	0,095	0,030	0,095
Geothermal	0,028	0,156	0,028	0,156	0,028	0,156
Tidal	0,150	0,718	0,127	0,610	0,106	0,510
Wave	0,142	0,668	0,121	0,568	0,101	0,475
Coal	0,015	0,028	0,016	0,029	0,017	0,033
Coal-CCS					0,034	0,067
Lignite	0,018	0,032	0,018	0,033	0,020	0,037
Lignite-CCS					0,043	0,075
CCGT	0,014	0,035	0,014	0,038	0,016	0,048
CCGT-CCS					0,025	0,080
GT	0,010	0,035	0,010	0,038	0,011	0,048
Nuclear	0,040	0,079	0,040	0,079	0,040	0,079
Hydropower	0,018	0,262	0,018	0,262	0,018	0,262

LCOE (op)	2014		2020		2030	
	Min	Max	Min	Max	Min	Max
Wind Onshore	0,017	0,033	0,017	0,033	0,017	0,033
Wind Offshore	0,020	0,029	0,020	0,029	0,020	0,029
Solar PV	0,024	0,028	0,023	0,028	0,023	0,024
Solar CSP	0,053	0,063	0,053	0,063	0,053	0,063
Biomass	0,081	0,092	0,084	0,096	0,086	0,098
Biogas	0,054	0,103	0,052	0,101	0,050	0,099
Geothermal	0,024	0,040	0,024	0,040	0,024	0,040
Tidal	0,050	0,150	0,050	0,150	0,050	0,150
Wave	0,050	0,150	0,050	0,150	0,050	0,150
Coal	0,053	0,055	0,061	0,063	0,074	0,076
Coal-CCS					0,060	0,067
Lignite	0,033	0,036	0,040	0,043	0,052	0,056
Lignite-CCS					0,032	0,041
CCGT	0,076	0,079	0,083	0,086	0,091	0,095
CCGT-CCS					0,088	0,096
GT	0,107	0,113	0,118	0,123	0,130	0,139
Nuclear	0,017	0,019	0,017	0,019	0,017	0,019
Hydropower	0,008	0,009	0,008	0,009	0,008	0,009

LCOE of each technology in each technology clearly depend on the technology cost and financing cost. Therefore, a sensitivity analysis for onshore wind should illustrate the influence of technology cost, full-load hours and WACC on the LCOE.

In Figure 14, combinations of full-load hours and specific investments are displayed. It can be noticed that LCOE are higher for sites with low FLH. Additionally, LCOE rises with the investment costs.

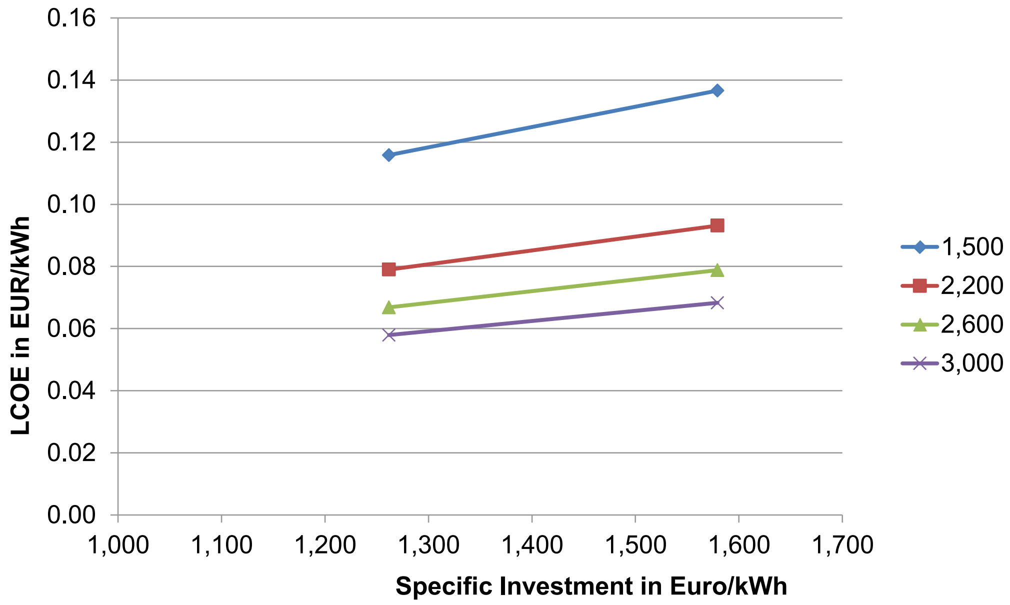

Figure 9: Variation of investment costs and full load hours for onshore wind turbines

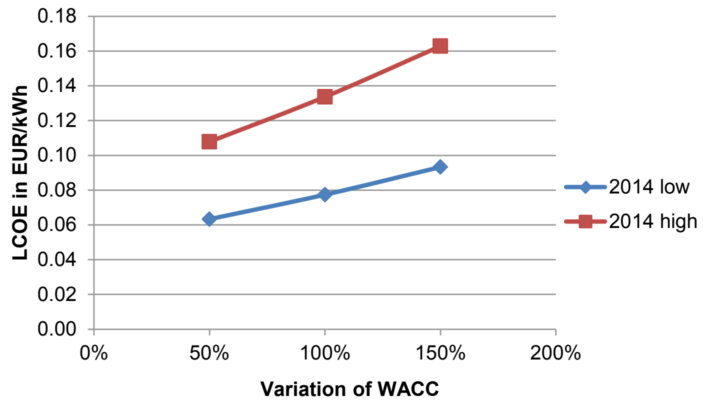

Figure 10: Variation of WACC for onshore wind turbines in 2014

In Figure 15 the influence for changing WACC in 2014 on LCOE of wind onshore turbines is presented. LCOE rise with a higher WACC and sink with a lower WACC. For the lower LCOE values, LCOE for 2014 decreases to 0.063 €/kWh with a WACC, which is only 50% of the standard WACC, and increases to 0.093 €/kWh with a WACC, which is 150% of the standard WACC. For system with high costs or lower energy generation the spread is still higher.

2.2 Analysing future trends of fuel costs and CO_2 prices

For the modelling calculations and LCOE calculations, the PRIMES 2013 (PRIMES) reference scenario has been used as a projection of the future energy prices. The carbon price scenarios are based upon a variety of studies. This chapter compares PRIMES energy prices with other scenario's, presents EU carbon prices scenario's, describes major trends and projects storylines of possible energy futures in Europe.

2.2.1 Future energy price trends

Energy price projections used in the PRIMES 2013 (PRIMES) reference scenario are included in this analysis, particularly as they are referred to in the recent Impact Assessment on energy and climate policy up to 2030, adopted in January 2014 (European Commission, 2014a). The fuel price assumptions of this scenario are based on a combination of the PROMETHEUS model (model runs completed in 2012), with added information from the IEA's World Energy Outlook of 2011 (WEO2011) and other studies. PROMETHEUS is a stochastic endogenous World energy model which projects energy supply, demand, energy prices and emissions. It assesses uncertainties and risks among which impact of policy actions (E3MLab, 2014a and E3MLab, 2014b).

To review the drivers and uncertainties of the future energy supply and demand, the World Energy Outlook 2013 (WEO2013) has been used. The WEO2013 introduces three scenarios; the **Current Policy Scenario (CPS)** which assumes no change in policy from now on towards the future; the **New Policies Scenario (NPS)** which also takes into account policies which have been announced by governments; and the **450PPM scenario (450S)**. 450 parts per million CO_2 molecules is considered to be the limit at which the world's temperature increase is expected to have a 50% chance to stay below 2°C. This scenario projects the required energy mix which would achieve this maximum temperature increase.

There are generally two key drivers shaping a projected fuel price trajectory for the next decades, notwithstanding the complex nature of global fuel price formation and the wide set of underlying factors.

- Market imbalances in supply and demand affecting the short to medium term price trajectory;
- Fundamental long term demand developments relate to the strength and effectiveness of worldwide and regional climate policies.

In Table 12 the price paths of the scenarios for fossil fuels are presented. The oil short to medium term price trajectory is mainly affected by imbalances in supply and demand, driven by among other demand from upcoming economies and upstream developments. The concentration of resources and limited availability create instability in the pice. Fundamental long term demand developments relate to the strength and effectiveness of worldwide and regional climate policies. The coal demand is characterised by a very uncertain future, especially caused by developments in non-OECD countries. The price is more stable compared to oil because of its abundant availability. The European gas price is expected to rise until about 2020 due to market tightness in the PRIMES scenario and in all three WEO2013 scenario's. Thereafter, an increasing supply of LNG and unconventional gas is expected to ease the market. In the longer term the increasing resource base due to the exploitation of unconventional resources is expected to give rise to only relatively modest price increases. An alternative storyline would see a much more modest future contribution of unconventional resources to the global gas market, giving rise to a substantially higher gas price, also in Europe. The coal and gas prices of PRIMES2013 are on the high side compared to IEA2013. The differences are explained among others, by the different approaches and different datasets.

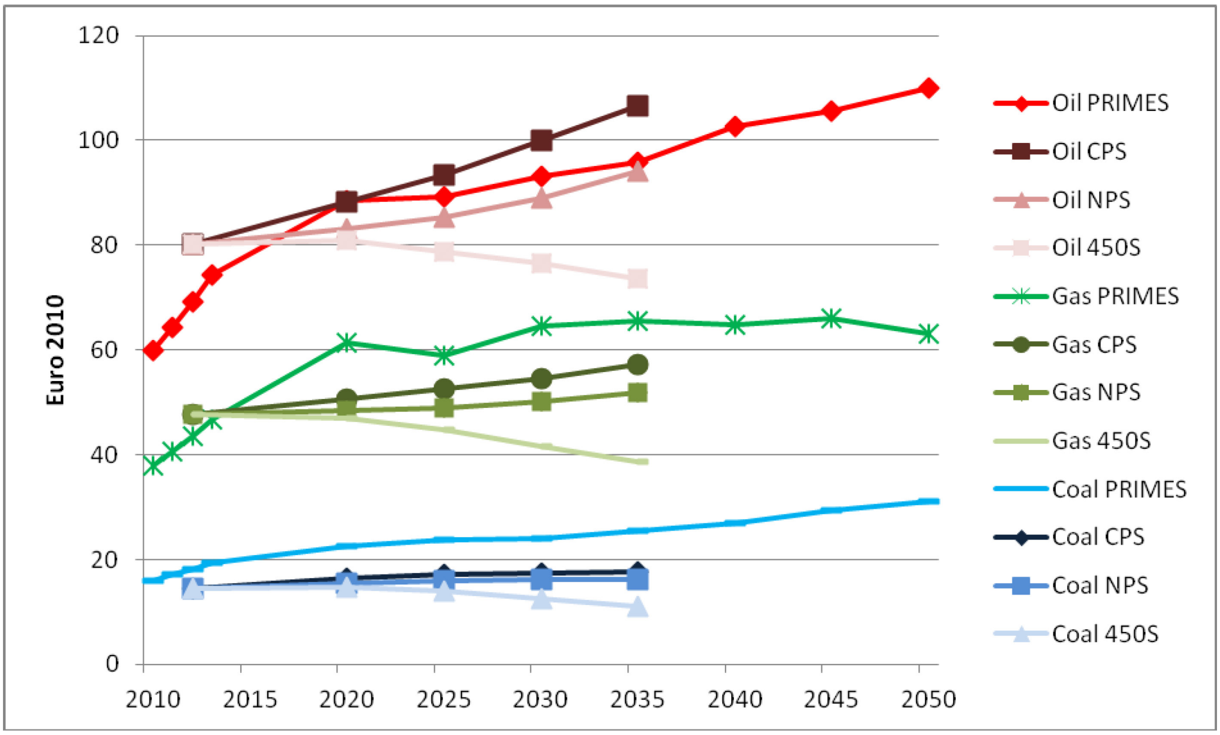

Figure 11: Projected fossil fuel prices per boe

2.2.2 Scenarios carbon prices

Future EU carbon prices are determined and affected by a large variety of factors. As these factors are (highly) uncertain, the resulting EU carbon prices are correspondingly uncertain as well. The best way to deal with this uncertainty is to conduct some price scenario analyses, including (the key assumptions on) the major relevant factors affecting EU carbon prices, as well as some sensitivity analyses in order to get some feeling for the relative importance of these factors and the implications of their uncertainty for the level and uncertainty of future EU carbon prices.

Table 12 presents an overview of the EU (ETS) carbon price projections for the scenarios included in the Impact Assessment of the EU 2030 policy package (European Commission, 2014a). Variations have been made in the combination of Emission target (Greenhouse gas target, GHG), Renewable Energy (RES) target and Energy Efficiency (EE) target.

In the Reference scenario the EU carbon price is expected to increase from 10 €/tCO_2 in 2020 to 35 €/tCO_2 in 2030 and 100 €/tCO_2 in 2050. In the other scenarios, projected carbon prices vary widely depending on the characteristics of these scenarios. More specifically, Table 12 shows among other: Carbon prices are generally substantially higher in 2050 (85-264 €/tCO_2) than in 2030 (11-53 €/tCO_2); Carbon prices are generally significantly lower in scenario based on more ambitious and explicit energy efficiency policies and higher ambition levels per renewables than those based on a single GHG target. This reflects the positive contribution of both renewables and energy efficiency to emission reductions in the ETS sectors, in particular in the power sector, thereby lowering the ETS carbon price.

Table 11: Price scenarios carbon prices in €2010/tCO_2

Scenario	2020	2030	2050
Reference scenario 2013	10	35	100
GHG35/EE	-	27	99
GHG37	-	35	100
GHG40	-	53	152

Scenario	2020	2030	2050
Enabling conditions			
GHG40	-	40	264
GHG40/EE	-	22	158
GHG40/EE/RES30	-	11	152
GHG45/EE/RES35	-	14	85

*i.e. GHG40 means 40% GHG reductions

Source: European Comission (2014a and 2014c).

2.2.3 Storylines

To get a grip on how energy sources are influenced, different storylines will be presented. Whilst reflecting the IEA/WEO scenarios, the storylines highlight differences in the global and European policies, in particular differences in the implementation and forcefulness of low carbon policies, as well as on the development/breakthrough and cost reductions of new low carbon technologies. The carbon price (ETS) depends too strongly on European policies to give a clear outcome.

The storylines are briefly described as follows and graphically shown in Table 13.

- The first storylines reflects the WEO2013 450PPM scenario, whereby the world achieves a huge emission reduction, resulting in a 50% chance of not surpassing a global temperature rise of 2°C by 2100. To achieve this, the largest energy consumers and emitters must abide to strict climate policies, which results in a steep decrease in the demand for oil and coal. Gas demand is not expected to decline since it is the cleanest fossil fuel, and gas centrals are a good back up for renewable sources.

- The second storyline reflects a situation where stringent climate policies are only implemented in the EU. In this storyline, the world demand for fossil fuels will keep increasing, and also its prices. Because of the rise in price of fossil fuels, the demand for renewable energy and energy efficiency also increase. In Europe the demand for coal and oil decrease. The evolution of gas demand is uncertain.
- The third storyline reflects the WEO2013 Current Policy Scenario. When this scenario plays out, the demand for coal can be expected to increase since it is a cheap and abundant energy source. Also the other fossil fuels are expected to have an increase in demand. The price of gas is expected to increase because the low availability in European gas supplies, and its import dependency. Because of the price rises, the renewable energy and energy efficiency is expected to be economically more and more viable, which causes an increase in investment and cheaper production.

Table 12: Summary of scenario storylines

450PPM scenario	Coal	Oil	Gas	EE/RES	ETS
Global demand	--	--	+/-	++	
European demand	--	--	+/-	++	
Price in Europe	--	--	-	--	depends
Europe green, rest of the world CPS					
Global demand	++	+	+	+	
European demand	-	+/-	+/-	++	
Price in Europe	+	+	+	-	depends
CPS, also in Europe					
Global demand	++	+	+	+	
European demand	++	+	+	+	
Price in Europe	+	+	++	-	depends

('--' means sharp decrease, '++' sharp increase; RES/EE means Renewable Energy Systems and Energy Efficiency; ETS means Emissions Trading System, which accounts for carbon emissions.)

3 Modelling the future development of renewable energies by 2030

The core objective is to provide a detailed depiction on future RES opportunities up to 2030 from a techno-economic viewpoint, considering deployment of RES technologies within the European Union. The target proposed by the EC of 27% might be perceived to be unambitious, provided that according to the EC's Impact Assessment (2014), a RES-share of 26.5% is achieved in a scenario without dedicated renewables policies beyond 2020. Therefore, we will compare costs of the proposed target with more ambitious targets amounting to 30%. Future perspectives of RES are elaborated by means of scenarios, including a reference case (in the absence of a dedicated 2030 RES target) as well as two distinct alternative RES policy tracks where 2030 RES targets of 30% are taken as explicit assumption and compared to a scenario leading to a RES-share of 27%. The model-based assessment of the energy sector described in this chapter focuses on the development of RES technologies only. Thus, the work presented here is the first part of an integrated analysis taking into account interactions with the power sector and grid issues assuming a system perspective.

It is planned to complement the analysis with currently ongoing detailed model assessment for the power sector, assessing thereby impacts on and inter-linkages with conventional electricity supply as well as infrastructural prerequisites. Thus, capacity planning for conventional power plants, the operation of the power system and grid extension, reinforcement and management are taken into account.

This quantitative assessment of Europe's renewable energy sector incorporate technology data described in chapter 1.

Modelling related to RES deployment is realised with the ***Green*-X model**, offering a detailed quantitative assessment of the future deployment of renewable energies on country-, sector- as well as technology level. ***Green*-X model**. This model performs a detailed quantitative assessment of the future deployment of renewable energies on country-, sector- as well as technology level. *Green*-X indicates the consequences of policy choices in a comprehensive manner, providing in addition to RES deployment targeted information on corresponding costs ((additional) generation costs) and expenditures (support expenditures, investment needs, O&M and fuel expenditures) as well as related environmental and economic costs and benefits (estimation of avoided fossil fuels and GHG emissions). The model has been broadly applied in order to support the European Commission with decisions regarding the political framework for renewable energies.

A short characterization of the model is given below, whilst for a detailed description we refer to www.green-x.at.

Short characterisation of the Green-X model

The model Green-X has been developed by the Energy Economics Group (EEG) at the Vienna University of Technology under the EU research project "Green-X–Deriving optimal promotion strategies for increasing the share of RES-E in a dynamic European electricity market" (Contract No. ENG2-CT-2002-00607). Initially focussed on the electricity sector, this modelling tool, and its database on renewable energy (RES) potentials and costs, has been extended to incorporate renewable energy technologies within all energy sectors.

Green-X covers the EU-27, and can be extended to other countries, such as Turkey, Croatia and Norway. It allows the investigation of the future deployment of RES as well as the accompanying cost (including capital expenditures, additional generation cost of RES compared to conventional options, consumer expenditures due to applied supporting policies) and benefits (for instance, avoidance of fossil fuels and corresponding carbon emission savings). Results are calculated at both a country- and technology-level on a yearly basis. The time-horizon allows for in-depth assessments up to 2030 and (brief) outlooks up to 2050. The Green-X model develops nationally specific dynamic cost-resource curves for all key RES technologies, including for renewable electricity, biogas, biomass, biowaste, wind on- and offshore, hydropower large- and small-scale, solar thermal electricity, photovoltaic, tidal stream and wave power, geothermal electricity; for renewable heat, biomass, sub-divided into log wood, wood chips, pellets, grid-connected heat, geothermal grid-connected heat, heat pumps and solar thermal heat; and, for renewable transport fuels, first generation biofuels (biodiesel and bioethanol), second generation biofuels (lignocellulosic bioethanol, biomass to liquid), as well as the impact of biofuel imports. Besides the formal description of RES potentials and costs, Green-X provides a detailed representation of dynamic aspects such as technological learning and technology diffusion.

Through its in-depth energy policy representation, the Green-X model allows an assessment of the impact of applying (combinations of) different energy policy instruments (for instance, quota obligations based on tradable green certificates / guarantees of origin, (premium) feed-in tariffs, tax incentives, investment incentives, impact of emission trading on reference energy prices) at both country or European level in a dynamic framework. Sensitivity investigations on key input parameters such as non-economic barriers (influencing the technology diffusion), conventional energy prices, energy demand developments or technological progress (technological learning) typically complement a policy assessment.

Within the Green-X model, the allocation of biomass feedstock to feasible technologies and sectors is fully internalised into the overall calculation procedure. For each feedstock category, technology options (and their corresponding demands) are ranked based on the feasible revenue streams as available to a possible investor under the conditioned, scenario-specific energy policy framework that may change on a yearly basis. Recently, a module for intra-European trade of biomass feedstock has been added to Green-X that operates on the same principle as outlined above but at a European rather than at a purely national level. Thus, associated transport costs and GHG emissions reflect the outcomes of a detailed logistic model. Consequently, competition on biomass supply and demand arising within a country from the conditioned support incentives for heat and electricity as well as between countries can be reflected. In other words, the supporting framework at MS level may have a significant impact on the resulting biomass allocation and use as well as associated trade.

Moreover, Green-X was recently extended to allow an endogenous modelling of sustainability regulations for the energetic use of biomass. This comprises specifically the application of GHG constraints that exclude technology/feedstock combinations not complying with conditioned thresholds. The model allows flexibility in applying such limitations, that is to say, the user can select which technology clusters and feedstock categories are affected by the regulation both at national and EU level, and, additionally, applied parameters may change over time.

3.1 Scenario definition and assumptions

The first main objective of this work is to compare the costs of the energy system in scenarios with different target ambition levels for the development of RES. Based on the scenarios modelled in the Impact Assessment accompanying the Communication: A policy framework for climate and energy in the period from 2020 up to 2030 (European Commission 2014a), we compare scenarios with a BAU development of RES assuming the European Trading Scheme to be the main support policy for RES leading to a share of about 26.5% by 2030 with a scenario including a target of RES for 30% (European Commission 2014a). Both scenarios imply a reduction of greenhouse gas emissions of 40% by 2030. Provided that additional scenarios modelled in the IA 2014 with the RES-share amounting to 35% by 2030 lead to an emission reduction level of 45% and hampers comparability between scenarios, we limit model calculations to a target level of 30%.

3.1.1 Ambition level of RES target and support policies

Costs of a certain RES development pathway do not only depend on the ambition level of the target, but may vary according to the RES technology mix. The technology mix can be influenced by the support scheme, used to improve the competitiveness of renewables technologies. Technology-specific feed-in tariffs or premiums often provide adequate support for less competitive technologies and thus stimulate their growth, whilst volume-based instruments such a quota obligations with technology-neutral support strongly favour low-cost options. This typically leads to higher generation costs in case of technology-specific support and lower generation costs in case of technology-neutral support. However, additional effects have to be considered. Thus, the application of technology-specific support for technologies with a high cost reduction potential may drive down costs and decrease generation costs on a longer term, while costs may remain constant – provided that the technology is not supported in any other world regions – under technology-uniform support. In addition, costs related to the required grid infrastructure tend to be higher for RES-scenarios with a stronger regional concentration. Consequently, we aim at comparing overall costs – including generation costs, system integration costs and infrastructure-related costs – in a scenario aiming at a low-cost development of RES by means of a technology-neutral quota obligation with a scenario aiming for a more balanced development of RES by means of technology-specific feed-in premiums. Thus, we compare the three distinct RES-development scenarios based on support with the ETS leading to a RES-share of 27%, a scenario using quota obligations to achieve 30% RES-share and a scenario using balanced feed-in premiums across countries with the target of 30% in final energy. Thereby, the policy assumptions are similar in all three scenarios until 2020 and diverge thereafter.

3.1.2 General assumptions and scenario overview

Scenario storylines for this modelling analysis are based on the PRIMES modelling realised for the Impact Assessment (European Commission 2014a) and on previous scenario work from the Energy Roadmap 2050 (European Commission 2011a). This data does in particular include the development of future CO_2 and fuel prices as well as the future development of electricity demand. We include the demand data, since we focus on the modelling of the supply side of the energy system. All scenarios respect the current ILUC proposal for biofuels and the sustainability criteria for biomass heat/electricity beyond 2020. An overview of the considered scenarios is shown in Figure 17.

The first scenario considered (ETS-Only EE) assumes the ETS to be the main driver to achieve emission reductions of 40% by 2030. Besides, energy efficiency measures are implemented, reducing thereby final energy demand. No dedicated support is provided for renewables after 2020 leading to a RES share of 27% by 2030.

In the scenario “QUO-30” policy settings regarding emission reductions and energy efficiency do not change, and we analyse the impact of a RES-target of 30%, achieved by using a technology-uniform quota obligation across all EU MS, incentivising a least-cost development of RES in terms of generation costs. Due to the strongly diverging resource conditions and the associated diverging generation costs, this type of policy support typically leads to stronger local concentration of RES capacity and, in turn, higher grid infrastructure costs. However, since non-economic barriers that generally limit an enhanced RES take-up are considered in the model-based assessment these concentration effects may still be moderate in the 2030 context.

The scenario “SNP-30” is similar to the “QUO-30” scenario with the difference that renewables support with a technology-specific feed-in premium incentivises a portfolio of RES technologies and, consequently, a rather even distribution of RES capacity across all EU MS can be expected.

The “ETS-Only” Scenario is based on the assumption that the ETS is the only driver to achieve the GHG emission reduction target of 40% by 2030. In contrast to the “ETS-Only-EE” no energy efficiency measures are applied. For this scenario no complete modelling run is realised, but it is included here since it serves as reference for calculating the additional costs of a 30% RES-target in case not explicit demand reductions are stimulated.

Figure 12: Scenario overview

Scenario Name	Description	Corresponding Scenario from IA
ETS-Only and energy efficiency "ETS-Only EE"	• 40% GHG emission reductions by 2030 • ETS main driver for low-carbon technology support • Energy efficiency measures in place • Achievement of 2020 RES targets • No dedicated support for RES beyond 2020 • 27% RES share by 2030	GHG40 EE
Cost-optimised RES development "QUO-30"	• 40% GHG emission reductions by 2030 • ETS one driver for low-carbon technology support • Energy efficiency measures in place • Achievement of 2020 RES targets • After 2020 continuation of RES support by means of an EU green certificate scheme. • 30% RES-Share by 2030	GHG40 EE RES30
Strengthened National Policies "SNP-30"	• 40% GHG emission reductions by 2030 • ETS one driver for low-carbon technology support • Energy efficiency measures in place • Achievement of 2020 RES targets • After 2020 continuation of RES support with balanced RES support across countries in terms of a feed-in premium. • 30% RES-Share by 2030	GHG40 EE RES30
ETS-Only „ETS-Only"	• ETS only driver for low-carbon technology support, no energy efficiency measures • Achievement of 2020 RES targets • No dedicated support for RES beyond 2020	GHG40

Regarding the modelling with Green-X, the main assumptions are summarised in the following box:

Summary on main assumptions for Green-X

- Geographical coverage: EU28 for Green-X, EU28 plus Norway and Switzerland for PowerACE
- Technology coverage: focus on all RES technologies for power, heating and cooling as well as biofuel production with a high level of detail. Information resulting from the conventional electricity system comes from the model PowerACE. Required inputs from the heating & cooling as well as for the transport sector are based on results from PRIMES-modelling.
- Energy demand: demand forecasts are taken from the Energy Roadmap 2050 (European Commission, 2011a) and correspond to the energy efficiency scenario.
- Fuel and CO_2 prices: Fuel and CO_2 prices are taken from the Impact Assessment 2014 (European Commission, 2014a)
- Different market values caused by the supply profile of weather-dependant RES are incorporated into the modelling.
- Imports of biomass to the EU: limited to biofuels and forestry biomass meeting sustainability criteria. All scenarios respect the implementation of the ILUC proposal for biofuels and sustainability criteria for using biomass beyond 2020
- Imports of electricity: electricity imports are only considered from Norway and Switzerland.

3.1.3 Resource potential of renewable energy sources

Based on technology costs and type described in section 2.1 aggregated cost-potential curves containing geographical information had been calculated. In order to achieve the optimized cost potential curve on a regional level the resolution of the data had been optimized due to restricted computing resources. The calculation sets a focus on wind and solar technologies (wind onshore/offshore, photovoltaic and concentrated solar power) due to the strong differences in generation costs caused by strongly location-dependent resource conditions. Figure 18 shows the structure of the analysis for potential calculations. To receive valid results high resolution of the input data had been used also considering the computing capacity. To achieve different aggregation levels, the input data had been implemented on its highest resolution on up 500 and 7500 meters and afterwards aggregated into cluster cells of 10 km.

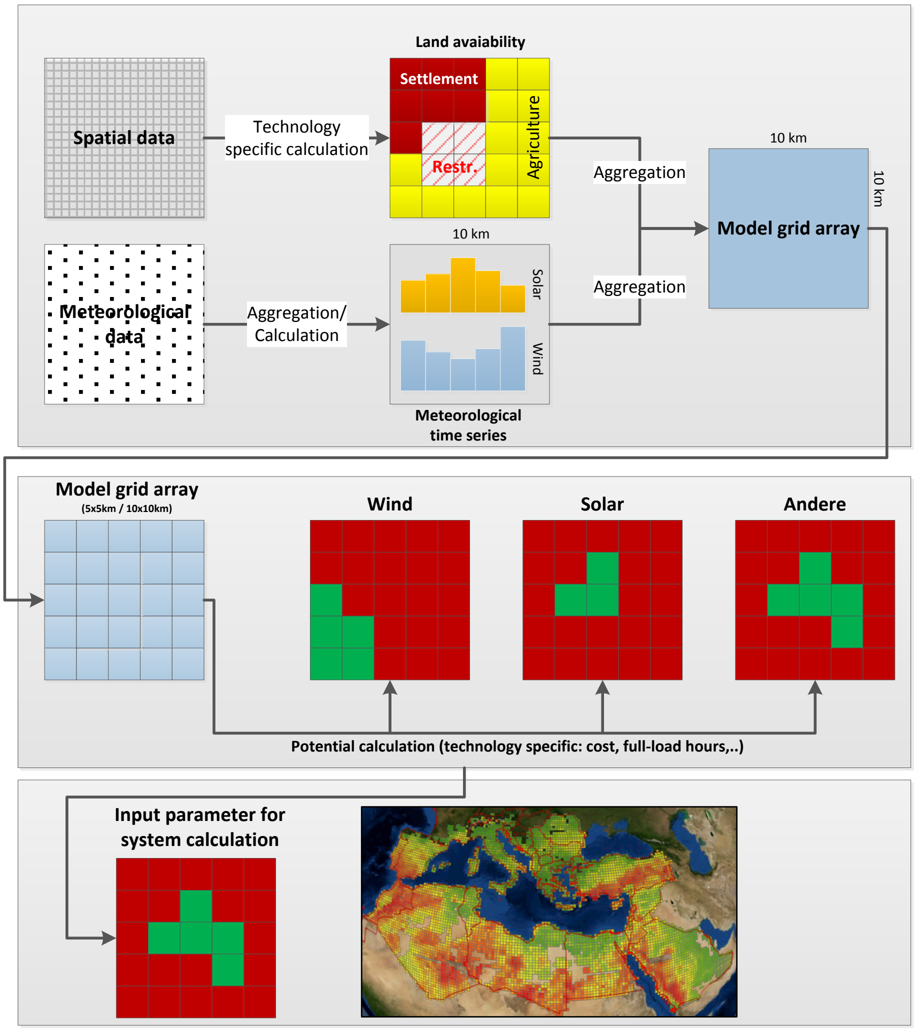

Figure 13: Workflow structure

The potential calculation for RES is a prerequisite for the modelling of the cost potential curves. To receive detailed results, at first, available areas have to be identified. Therefore, land-use, conservation and topographic data had been implemented[4]. Table 12 depicts the main data sources with predominantly high resolution data used to realise the potential calculations.

4 MODIS (Moderate-resolution Imaging Spectroradiometer) / CORINE Land Cover / SRTM (DEM/DTM)

Table 13: Data input

Name	Category	Resolution	Coverage
CORINE	land cover	250 m	EU
MODIS	land cover	500 m	EU+MENA
SRTM	Digital Elevation Model	90 m	EU+MENA
MERRA	meteorology (wind)	90 km	EU+MENA
National Wind Data	meteorology (wind)	1 km - 20 km	national
COSMO EU	meteorology (wind)	7.5 km	EU
Helioclim	meteorology (PV)	3 km	EU+MENA
WDPA	protected areas	~ 1 km	EU+MENA
CDDA	protected areas	~ 1 km	EU
NATURA 2k	protected areas	~ 1 km	EU
DSMW/FOA	protected areas / soil	~ 1 km	EU+MENA

The information from the data sources shown in Table 14 is stored in a model grid. The size of the grid is depending on the computing capacities used. In Figure 18 10 km resolution is chosen. However, input data is available in a resolution up to 90 meters for the digital elevation model and had been processed in original resolution within the model grids. To visualize the importance of high resolution, Figure 19 shows the difference between a 250 and 5000 meter resolution. This example demonstrates that in the lower resolution version many details are lost and might lead to deceptive results.

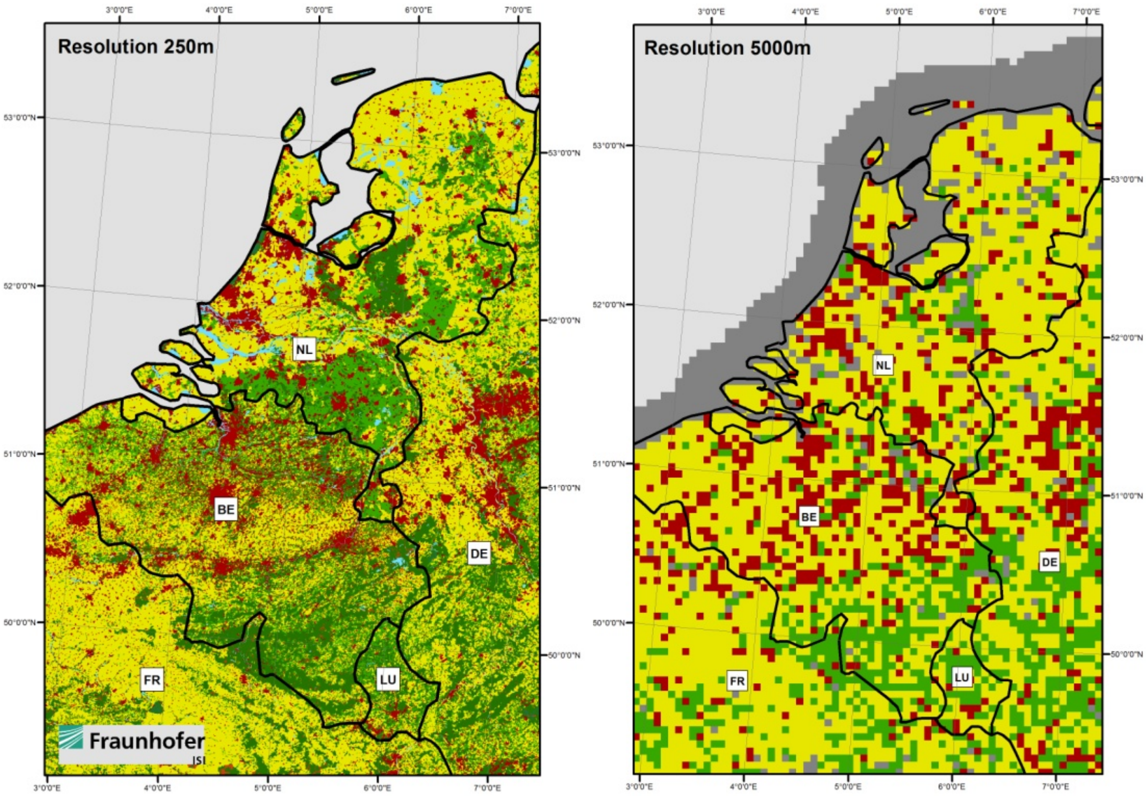

Figure 14: Comparison of different resolutions

Simultaneously to the calculation of the land availability meteorological data had been implemented into the model. This step is more complex as additionally to a high spatial resolution time resolution became more important. Wind and solar irradiance is highly variable and therefore hourly based time series had been used to calculate the diurnal variations appropriately. The meteorological data will be also aggregated to the cluster cells mentioned above.

The model grid with the spatial and meteorological data been used as input values to calculate full-load hours, specific costs and cost potential curves in the Green-X model.

3.1.4 Discount rates

The economic decision making leading to investment in energy technologies strongly depends on the assumed discount rate. For our modelling we assume the discount rate to correspond to the minimum return, an investor expects from an investment. This can be expressed by the weighted average cost of capital (WACC) describing shares and costs for equity and debt. Minimum return expectations of investors typically depend on the risk associated to an investment opportunity.

Thus, we incorporate existing risk expectations to determine the WACC used in the modelling. The risk types we consider include (see also Resch et al. 2014):

- Policy-induced risks
  Risks related to the policy framework, such as risk related to uncertain income streams from renewable support schemes such as feed-in systems or quota obligations or from more generic energy and climate policies such as the Emissions' Trading Scheme (ETS).
- Technology-related risks
  Risks may also be related to a specific renewables technology. Thus, risk can depend on the maturity of a technology, e.g. overall costs may not be known perfectly for a less mature technology since less experience exists, or on other technology-specific risk factors such as biomass fuel prices or technical problems such as risks of unexpected production cuts.
- Country-specific risks
  Due to the currently heterogeneous economic situation in the Member States, a certain risk component associated to the respective country typically influences minimum return requirements.

To incorporate the investors' risk in the RES policy assessment, we assume default risk settings and introduce multipliers reflecting the above mentioned risk categories. Multipliers are only applied to the risk premium of the WACC and not to the risk-free rate. In our default settings, we assume the WACC to amount to 6.5% in the time horizon until 2020 and to increase gradually to 7.5% by 2020.

For the **policy-related risk**, we differentiate between cross-sector instruments such as the ETS and renewables-specific support schemes including a quota obligation with tradable green certificates and a feed-in premium system.

Table 14: Risk multipliers for policy risk

	ETS	QUO	FIP
Default	**130%**	**120%**	**110%**
Low risk	118%	117.5%	105%
High risk	130%	130%	115%

The country-specific risk multipliers have been assumed as shown in Figure 20. These have been assumed to change over time. Thus, we include country-specific differences in risks into the analysis only until a certain time horizon in order to consider current differences but not to discriminate countries with stronger economic problems on a longer term. Therefore, we assume that these differences persist today and converge towards 2020, assuming that these differences will be levelled out on a medium term. The risk multipliers for country-related risk shown in Figure 20 illustrate the differentiated country-risk assumptions for the present and the convergence by 2020.

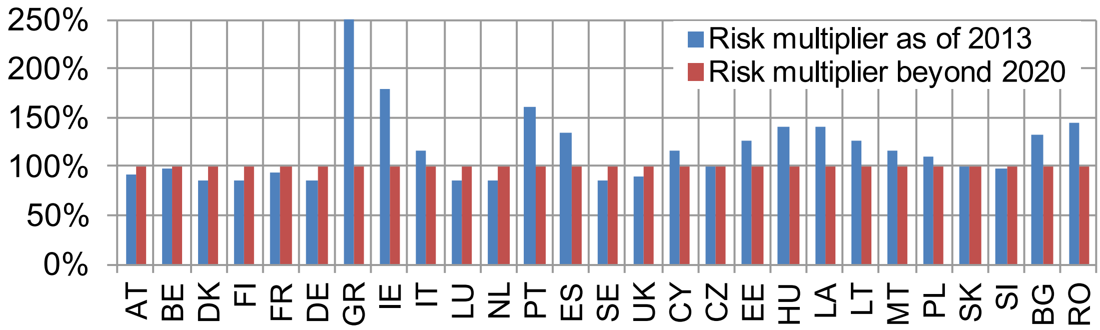

Figure 15: Risk multiplier for country-specific risk factors

Finally, we have applied risk multipliers for the different renewables technologies as presented in Figure 21. Thus, hydropower, PV and onshore wind are associated with lower risk than the default value (90-95%), whilst biomass, geothermal and CSP show values slightly above 100%. Wind offshore and wave & tide technologies until 2020 amount to 140%, but decrease due to the expected maturing process of these technologies to 120% after 2020.

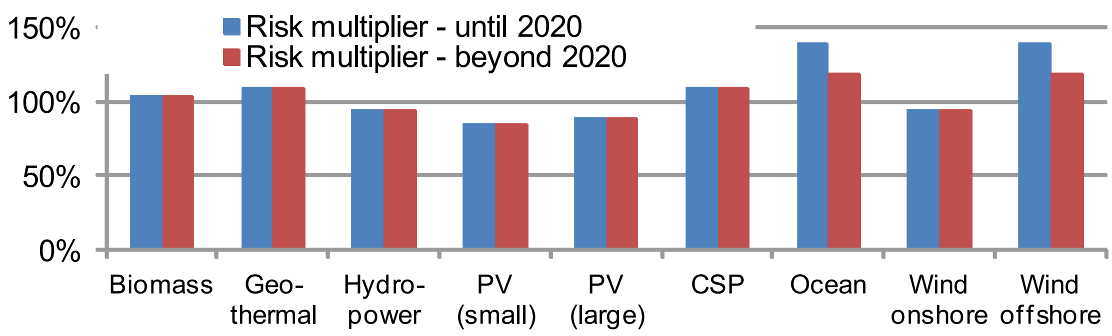

Figure 16: Risk multiplier for technology-specific risk factors

These values have been estimated in joint discussions of the project consortium reflecting work by Rathman et al. (2011), Resch et al. (2014) that has been validated in expert workshops.

3.1.5 CO_2 prices and fuel prices

CO2 prices and fuel prices are based on the Impact Assessment from the European Commission (2014a). Only in the ETS Only EE Scenario, we modified the CO2 price in order to reach the same RES-Share as in the corresponding GHG40EE Scenario. Assumptions are shown in Figure 22 and Figure 23. Background information on the fuel price development and the CO2 price development is provided in section 2.2.

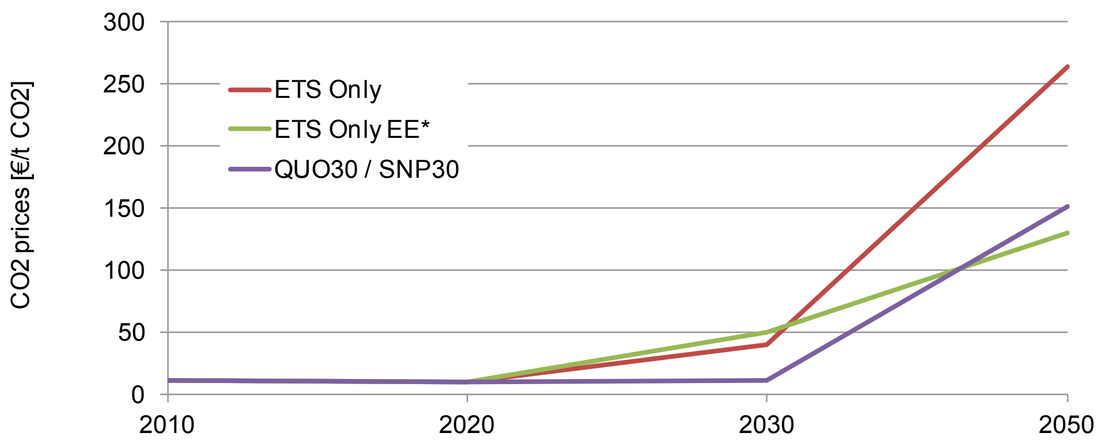

Figure 17: Assumptions for CO_2 prices in the modelling

* For the ETS Only EE Scenario the CO_2 price was modified compared to the scenarios from the Impact Assessment in order to align RES deployment, cf. section 2.2.

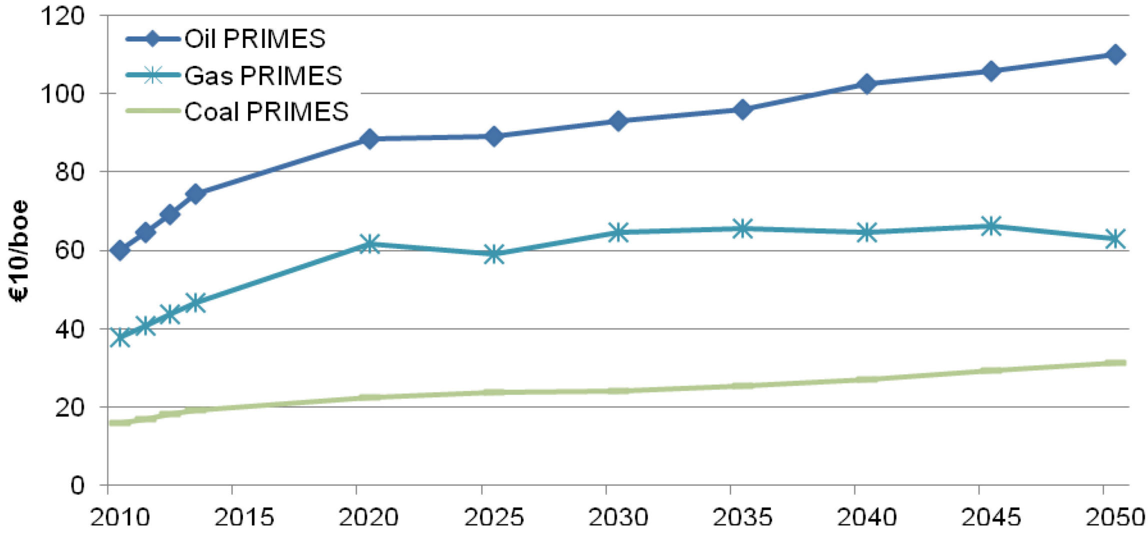

Figure 18: Assumptions for fuel price development. Source: European Commission (2014d).

3.2 Results

3.2.1 RES deployment

We initiate the presentation of results with a comparison of the RES deployment in the different scenarios. Observing the RES deployment in Figure 24, it becomes clear that according to the scenario definitions the development until 2020 is the same for each of the scenarios, reaching the 20% target set for 2020. Only after 2020, the development in the ETS-Only EE is below that of the scenarios assuming a target of 30%. This change becomes stronger when looking at the development of renewables in the electricity sector. The share of RES in electricity consumption by 2020 is expected to be roughly 35% in all three scenarios. Thereafter, the share of RES in electricity consumption continues the increasing trend in the scenarios assuming a 30% target by 2030, reaching 53% by 2030, while growth in RES-E share in the ETS-Only-EE Scenario slows down considerably and leads to a RES-E share of 43%. This indicates that the ETS alone does not provide sufficient stimulus for RES-E deployment. It also becomes clear that the RES-E share development is nearly the same in both 30% target scenarios. The additional final energy in 2030 provided from plants installed between 2021 and 2030 amounts to roughly 1,650 TWh in the SNP-30 and the QUO-30 Scenario and 1,200 TWh in ETS-ONLY (see Figure 24 – right). With regard to electricity generation, 750 TWh is generated in 2030 by renewable power plants in the 30% target scenarios, whilst 380 TWh of electricity are generated by the newly installed plants in the ETS-Only-EE Scenario.

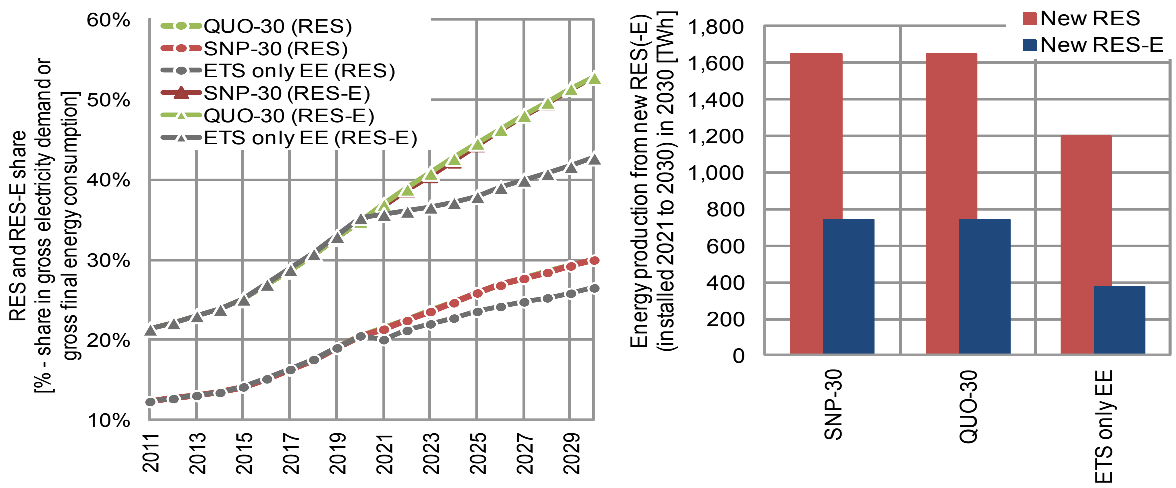

Figure 19: RES and RES-E share (left) and final energy from RES(-E) power plants installed between 2021 and 2030

Looking further into detail into the technology-breakdown of the electricity sector shown in Figure 25, it becomes obvious that new installations built between 2021 and 2030 are clearly dominated by wind onshore. The share of wind onshore is particularly strong in the QUO-30 scenario, caused by the low generation costs of wind onshore electricity compared to other renewables technologies. This shows that technology-neutral support schemes are not able to stimulate the development of less mature technologies and are therefore characterised by a low dynamic efficiency. More expensive and less mature technologies such as wind offshore, tidal stream or wave power and Solar PV develop strongest in the SNP-30 Scenario. This development is incentivised by technology- and country-specific support that is well adapted to the requirements and the cost situation of a technology in a certain country. Obviously, a RES target of 30% RES by 2030 requires a stronger total contribution of the various available RES-E options.

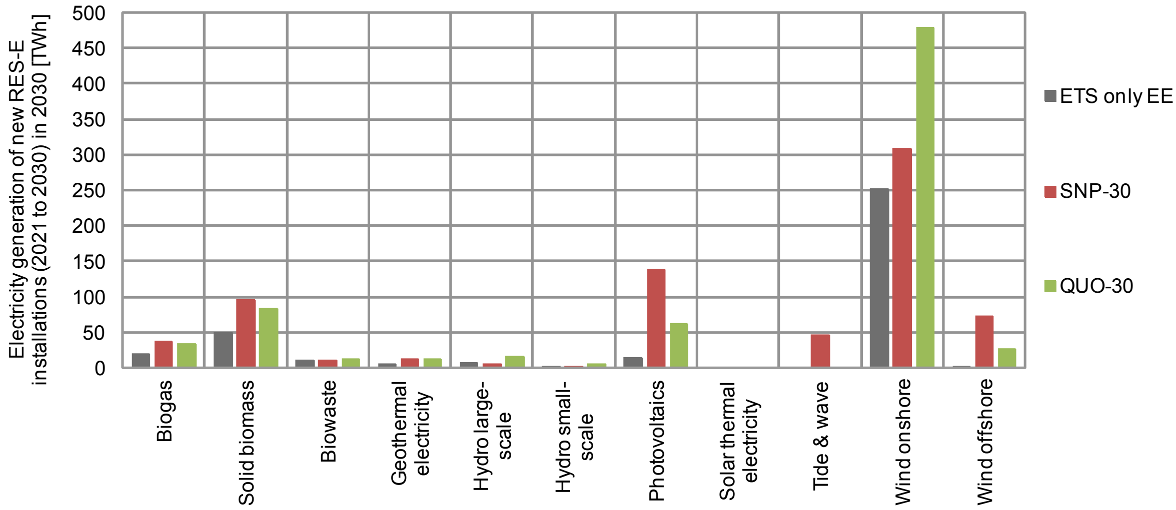

Figure 20: Technology-specific breakdown of RES-E generation from new installations by 2030 for new installations from 2021 to 2030 at EU 28 level

3.2.2 Costs and support expenditures

The modelled deployment pathways involve certain costs related to energy supply (additional generation costs), but also involve support payments. Thereby, we compare generation costs arising from the installation, operation and maintenance of a renewables installation in a first step. Figure 26 shows the total generation costs in the left and the specific generation costs in the right. Costs refer to the electricity output of plants that have been installed between 2021 and 2030 in the year 2030. Provided that more RES-E is generated in both 30%-target Scenarios, the overall generation costs in these scenarios are higher than in the ETS-Only EE Scenario. Costs for the SNP-30 Scenario are slightly higher than in the QUO-30 Scenario due to a stronger diversified exploitation of RES potentials. It should be noted, that cost components shown only include generation costs and additional costs arise from the integration of fluctuating RES in the electricity system and from a reinforcement or extension of the existing grid infrastructure. These analyses are currently being undertaken and will be presented in autumn this year. However, it can be expected that system integration and in particular grid costs are higher in a scenario where RES capacity is more locally concentrated. The consequence is a contrary effect on overall system costs, meaning that system integration and grid costs are higher in the QUO-30 Scenario than in the SNP-30 Scenario, whilst generation costs behave in the opposite way. When observing the specific generation costs in the right of Figure 26, lowest costs occur in the QUO-30 scenario. The costs of renewable electricity in a scenario supported only by means of the ETS are higher, due to higher financing costs associated to the higher uncertainty associated to the ETS compared to a dedicated renewables policy.

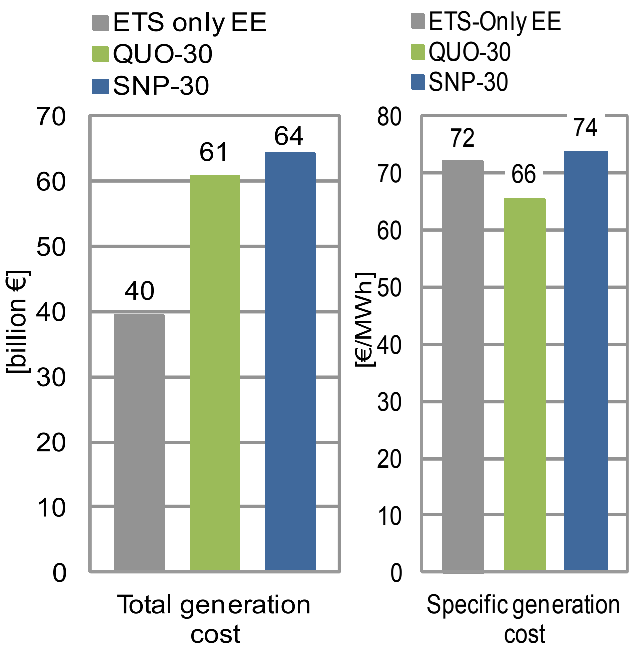

Figure 21: Total generation costs and generation cost per unit of electricity generated by 2030

In addition to the costs estimated assuming a system perspective, we analyse costs occurring only for selected economic agents. Thus, we assess to what extent different economic agents have to pay for the enhanced development of RES. These effects are not overall cost effects, but they reflect distributional effects and determine how the system-related additional costs are distributed among consumers and producers. We show annual support expenditures that have to be borne by electricity consumers and compare them with the different RES development pathways. Figure 27 shows that support expenditures for dedicated RES support (30% target Scenarios) range from € 20 – 22 billion, whilst the ETS-Only EE Scenario leads to considerably higher support payments of EU 41 billion on average. The high support expenditures in case of the ETS-Only EE Scenario can be explained with the mechanism of the ETS, where the marginal technology required to fulfil the emission reduction target sets the price. All other technologies with lower abatement costs are paid the uniform CO_2 price. As a consequence windfall profits arise, the amount of which depends on the steepness of the CO_2 abatement curve. In contrast, lower CO_2 prices due to the dedicated RES support applied in the QUO-30 and the SNP-30 Scenario reduce these windfall profits, whereby the technology-specific support in SNP-30 leads to slightly lower support expenditures than in the QUO-30 Scenario, where technology-uniform support is applied for the RES-E sector. It should be noted that support expenditures do not reveal any information on the overall generation cost of the system, but represent a price or distributional effect.

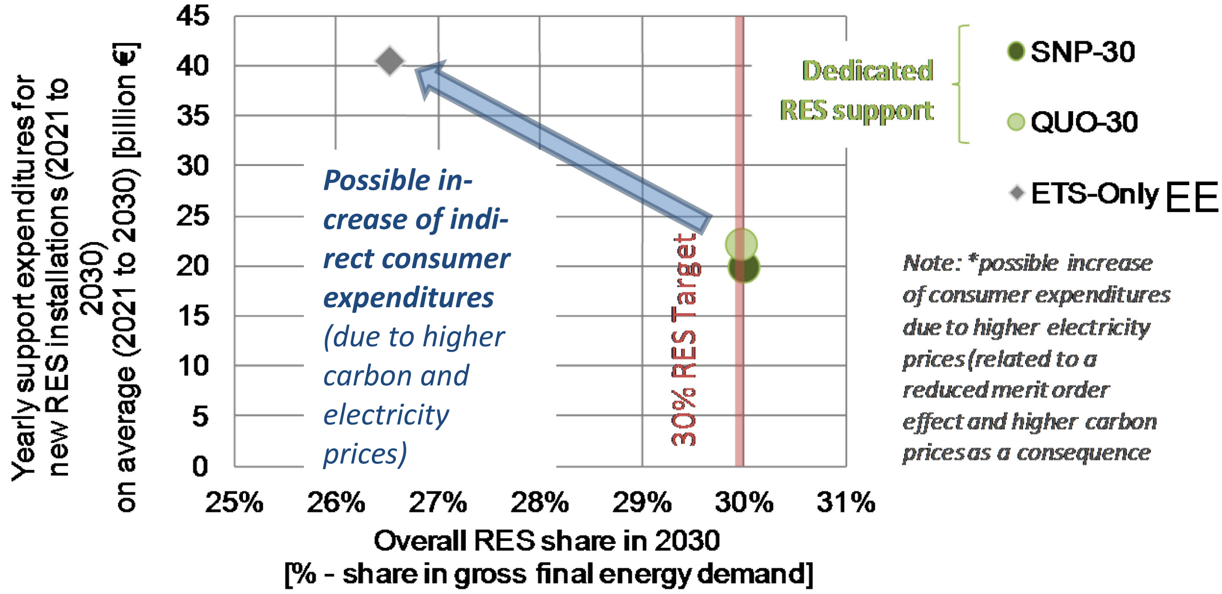

Figure 22: RES deployment by 2030 and the corresponding (annual average) support expenditures for new RES (installed 2021 to 2030) in the EU 28 for all assessed cases

3.2.3 Additional cost compared to different demand scenarios

The shown analysis focused on unchanged demand scenarios assuming the application of energy efficiency measures. Provided that the RES contribution in absolute terms related to a target in terms of RES-share depends on the level of energy demand, the ambition level of a RES target and costs of RES targets in turn depend on the final energy demand. Therefore, we realise a sensitivity analysis in order to estimate the financial impacts of different RES target ambitions in combination with different levels of energy demand. Figure 28 depicts the total amount of final energy provided by RES in the 30% target Scenario and compares it with the ETS-Only EE Scenario, as described in the previous section, and an additional scenario without a renewables target and without the application of energy efficiency measures (ETS-Only no EE). It can be seen that RES final energy contribution in the 30% scenario assuming reduced energy demand (RES30% no EE) remains at a similar level as in the ETS-Only no EE Scenario.

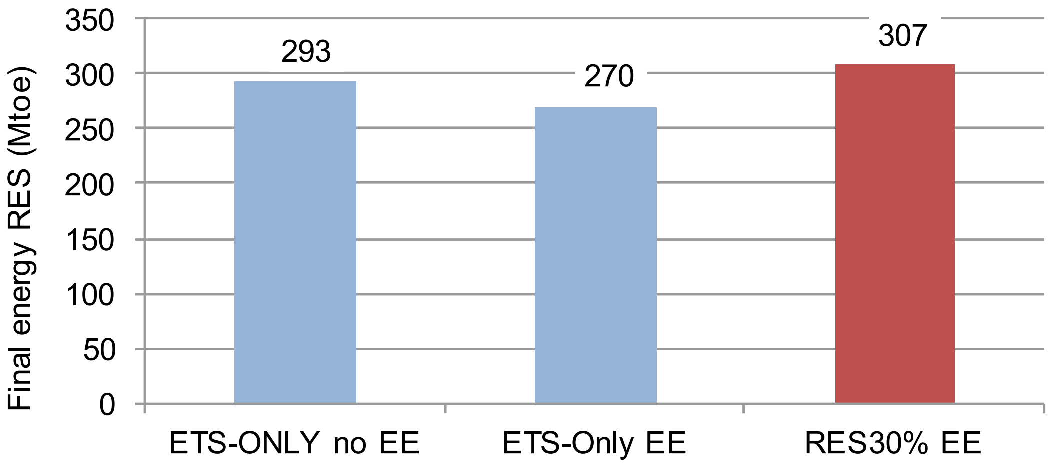

Figure 23: RES-based final energy in 2030 in the 30% target Scenario compared to no-RES-target scenarios with different demand levels

We compare the overall costs of the 30% target Scenarios (including the application of different support measures) with the corresponding reference scenario to assess the associated costs. This means that overall generation costs of the renewables development are calculated for the RES30% EE Scenario and compared to the two shown ETS-Only Scenarios.

The procedure to calculate the additional costs of a RES-target scenario with a reference is as follows:

1. First, we calculate the overall costs of the RES-deployment in the target scenario and in the reference scenario.
2. Second, we correct the overall cost by the value of the energy provided with RES to calculate "net costs", since we aim for estimating only the additional costs related to mainly higher technology costs of RES compared to those of conventional technologies. The implementation should take into account that RES-based energy replaces other generation technologies and therefore can be associated the inherent value of the energy provided. Therefore, we multiply the overall renewable final energy with a reference price reflecting the value of the energy and deduct this value from the overall costs calculated in the first step. We assume the reference price to amount to 60 €/MWh.
3. Third, we calculate the difference cost between the "net cost" estimated in the second step in the target scenario and the two reference scenarios.

Figure 29 provides an overview of the calculation procedure to estimate additional net costs of a target scenario compared to a reference.

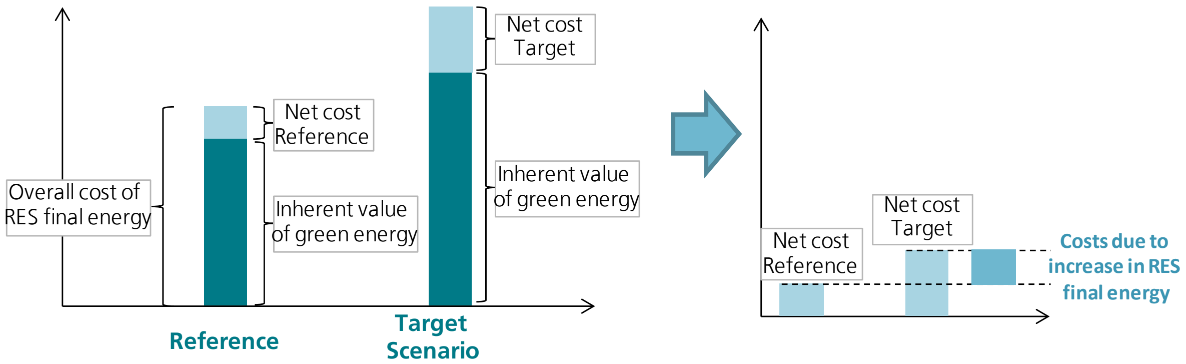

Figure 24: Scheme for calculating additional net costs resulting from a target scenario compared to a reference

Figure 30 shows the net costs of the Target Scenarios compared to the ETS-Only EE and the ETS-Only Scenario. The range shown reflects the application of different support measures including the QUO-30 and the SNP-30 Scenario. Whilst the left part of the figure depicts additional costs in the year 2030, the right part shows additional average costs per year occurring in the time horizon between 2021 and 2030. Observing Figure 30, it becomes clear that the highest net costs estimated for the year 2030 amount to € 9.3 billion/year. Comparing this to overall system costs, estimated in the Impact Assessment (European Commission, 2014a), this amount is less than 0.5% of total system costs of the EU. Average annual additional cost of 30% RES-target assuming the same energy demand over the period from 2021 to 2030 are even lower, ranging from € 2.5 to 5.3 billion. This is due to the fact that lower-cost options are exploited first and the closer the 2030 time horizon approaches the more higher-cost options have to be deployed. Comparing the 30% Target Scenarios to a Reference without energy efficiency measures, these additional net costs further decrease and lead to a range of € 1.5 – 7 billion in 2030, corresponding to an average net costs between € 1 – 4 billion from 2021 to 2030.

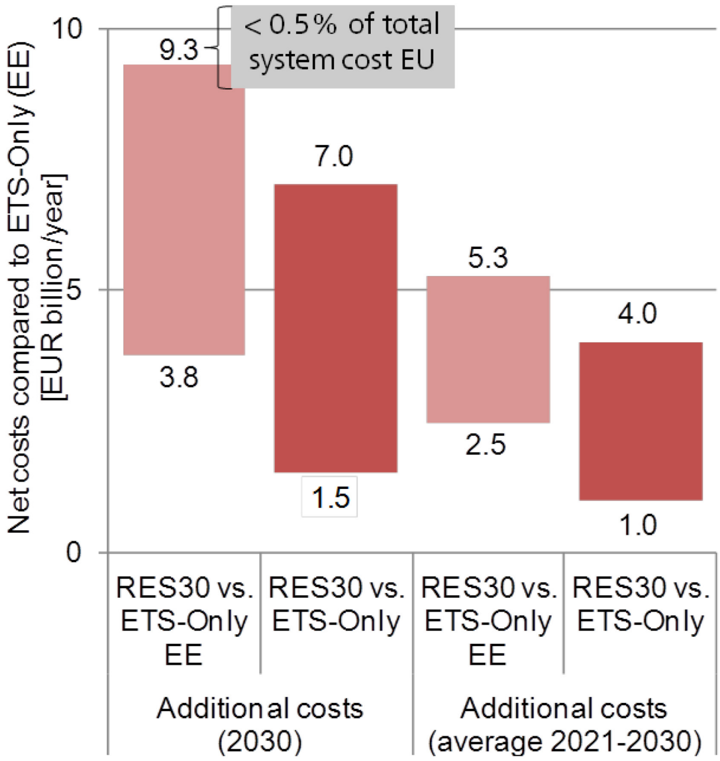

Figure 25: Additional net costs of 30%-Target Scenarios compared to a reference with stronger demand reductions (ETS-Only EE) and with an alternative reference assuming less demand reductions by 2030 (ETS-Only)

3.3 Conclusions

The modelling outcomes have shown that a sole target for emission reductions leads to a considerably higher financial burden (distributional effect) for consumers compared to scenarios with a 30% RES target. This effect is due to the „one-fits-all“ solution of the ETS, where the marginal technology sets the price for all abatement options and leads to windfall profits for lower cost options.

In addition the analysis has shown that a 30%-target may lead to lower specific generation costs than an ETS-Only EE setting, provided that risk premiums, financing costs and thereby support costs can be lowered if targets and policies focussing on renewable technologies are in place.

When looking at the additional net costs comparing a 30%-target Scenario with the ETS-Only Scenario, we estimate these costs to range from € 1 – 4 billion depending on the effort sharing approach.

The presented analysis focuses on the generation costs and support costs related directly to the renewable technologies. Thus, results presented here refer to generation costs only, but additional cost components arising from system integration of variable RES-E and grid-related costs may arise. This should be taken into account for the interpretation of the results of the analysis. Due to the strong interaction of RES with the remaining system, in particular in the electricity sector, an analysis of the overall energy system and the grid infrastructure is currently being analysed and will be published in autumn 2014. The ongoing work realises a joint optimisation of capacity planning and power plant dispatch using the model PowerACE. The model is characterised by a high level of detail regarding the representation of the power sector, including a detailed resource assessment (due to strong differences in generation costs for RES) and a high timely (hourly) resolution of renewables feed-in data. Finally, we use the grid model TEPES to consider and simulate the development of the grid infrastructure development to calculate the overall system costs for the power sector.

4 Modelling the future development of the EU power sector

4.1 Approach

Examining the EU electricity sector as a whole is a challenging task. Given that the balance between electricity supply and demand has to be maintained at all times during the year, a suitable modelling tool should fulfil the requirements of a high temporal resolution. Thus, we apply the electricity market model PowerACE with its high temporal resolution of variable RES generation profiles to analyze the future electricity system. PowerACE is applied to optimise system costs of the power sector by estimating the capacity mix or construction of power plants, their dispatch in selected years and the construction and use of storage technologies. The possible extension of the transmission grids between countries is also considered for the optimisation. Regarding the development of RES capacities we used the output of the Green-X simulations and based on that PowerACE estimates the requirement for conventional generation capacities.

The optimizing model PowerACE with its hourly resolution of RES generation profiles is well suited to analyze the impacts of variable RES on the electricity system. Thereby, we consider the relevant issues affecting the operation of the electricity system guaranteeing the security of electricity supply including:

- Match of supply and demand
- Providing balancing services
- Using storage options
- A simplified representation of the electricity grid in terms of connections from the centre of one country to another country)

Regarding the demand side typical load profiles of EU Member States are used to translate input data regarding electricity demand, which are usually available on an annual basis, into hourly electricity demand. The model allows investigating extreme weather situations, including situations with a high availability of wind and/or solar electricity in combinations with a low electricity demand. In these situations, the model considers different measures to cope with these circumstances such as applying storage options or curtailing surplus production of RES-E. Costs arising from these types of measures will be taken into account for calculating the overall system costs.

In addition, we examine requirements for grid infrastructures arising from the corresponding share of RES-E in the scenarios. These requirements will be analyzed in more detail with the model TEPES (see chapter 5). Restrictions in future grid extensions will be considered by assuming maximum interconnector capacities between countries.

Due to the high complexity and computation requirements, the PowerACE model currently covers an optimization over a time period focussing on the interim time steps 2020 and 2030 with an outlook to 2040 and 2050. The PowerACE model is based on the principle of perfect foresight for the 8760 hours per year. The latest server technology on the market is utilized in order to provide the necessary computing power.

In this context, we provide the following outcome:

- Development of CO_2 emissions in the electricity sector
- Investment and repowering needs for new electricity generation capacities on technology level
- Overall system costs and investment required in the different scenarios
- Market value of RES-technologies
- Technology mix of the electricity sector and utilisation rates of the most relevant types of power plants
- Installed capacities on technology level and electricity generation
- Imports and exports of electricity in the EU

A schematic overview of the PowerACE model is shown in Figure 31.

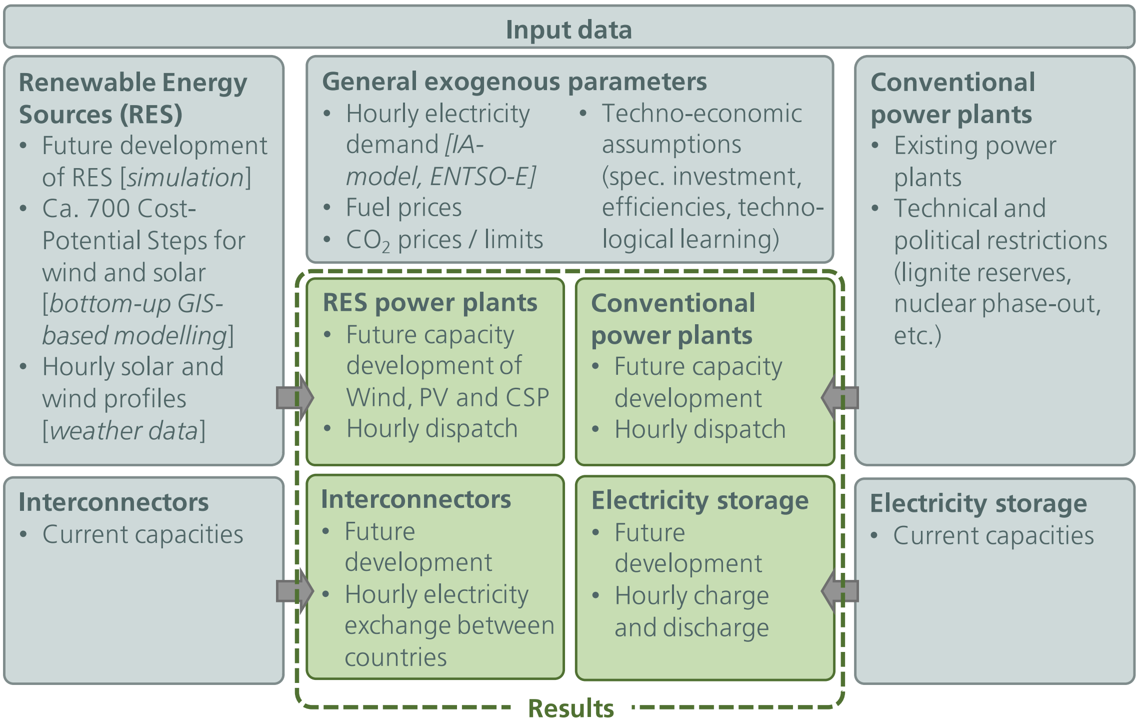

Figure 26: Basic principles of the PowerACE model

We apply the PowerACE model to evaluate system integration aspects for the three main scenarios proposed in WP5. It should be noted, that PowerACE optimizations solely focus on the electricity sector. Regarding the geographical focus we include the EU as a whole plus the neighbouring countries Switzerland and Norway. These countries are included, since electricity exchange with these countries occurs frequently and are relevant for the EU system perspective. In particular Norway is highly relevant for the EU power sector with high renewable shares, provided that Norway has high potentials for hydropower pump storage. Although we include Norway and Switzerland into the system calculation, we focus on representing the results of EU Member States.

The renewable electricity generation potential in PowerACE is modelled in a high level of detail (see also section 3.1.3) with the overall region being divided into more than 220,000 area cells. The actual generation potential and generation cost is calculated for each technology (wind onshore, wind offshore, PV and CSP) on every area cell based on detailed weather data. Aggregate potential steps representing area cells with comparable generation cost for each renewable electricity generation technology and country are calculated based on the detailed potential calculation in order to reduce demand on computational resources. These resulting ca 1000 potential steps are characterised 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 is integrated into the optimisation routine.

4.2 Assumptions

Modelling the future European electricity system requires the specification of a set of input parameters regarding the techno-economic characterisation of conventional and renewable power plants, storage facilities, grid extension options. In addition, the electricity demand is exogenous to the modelling.

4.2.1 Discount rates

The use of discount rates is based on the discount rates described in section 2.1.3 and 3.1.4. Thereby, discount rates for conventional power plants are assumed to amount to 7%, whilst discount rates for renewable power plants are differentiated according to the technology, country and policy risk. Electricity generation costs for renewable power plants are calculated with the Green-X model taken and then combined with the calculation for conventional power plants in order to estimate total system costs of the power sector.

4.2.2 CO_2 prices and fuel prices

Assumptions for CO_2 prices and fuel prices are described in section 3.1.5.

4.2.3 Electricity generation technologies

The modelling of future investment needs takes the existing power plant portfolio as of 2010 as determined in the Platts' World Electric Power Plant (WEPP) database[5]. Due to the high level of detail of this database and its influence on the calculation time of the model, the individual power plants have been aggregated to some extent. Regarding the future investment options, nuclear power plants are exogenous, provided that their use is based on political strategies rather than on commercial investment decisions. Thus, the future development of nuclear power plants in the EU in these scenarios is based on the current political plans of the Member States on the future use of nuclear power. Thereby, we assume that countries supporting nuclear power keep or renew their nuclear power plants, but still decrease their overall use on a longer term. As shown by Figure 32, installed nuclear capacity nearly halves from 117 GW in 2020 to 55GW in 2050.

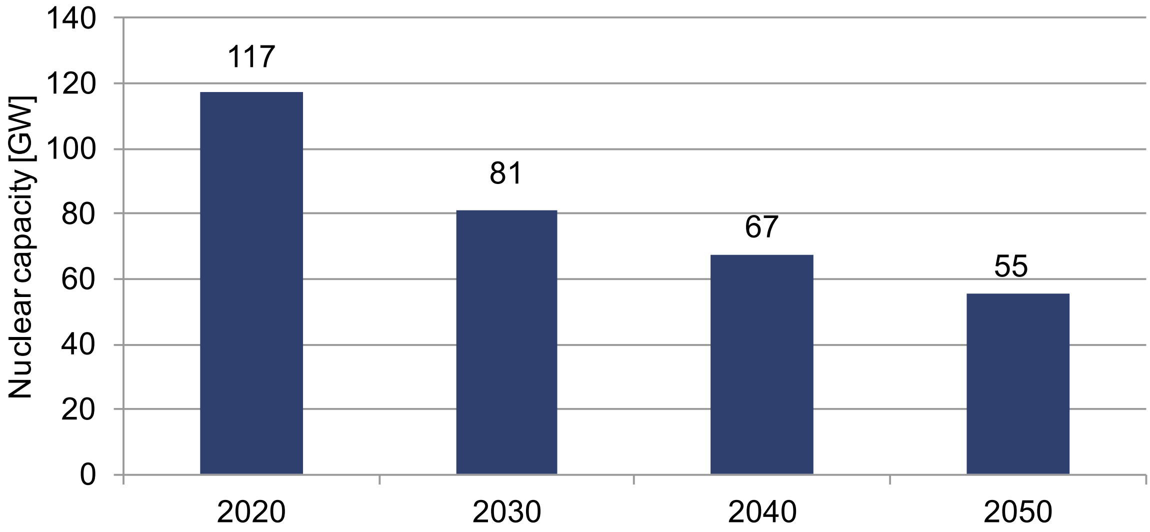

Figure 27: Development of installed nuclear capacity in the EU28

The use of lignite power plants is limited to Member States disposing of lignite resources, provided that transport of lignite with its low energy density is not cost-efficient.

Techno-economic assumptions for future investments in electricity generation technologies are based on the data described in chapter 2 (see Table 5 on page 17). Regarding the investment, where Table 5 provides a range for the calculation of the LCOE, the modelling is based on the investment shown in Figure 33.

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

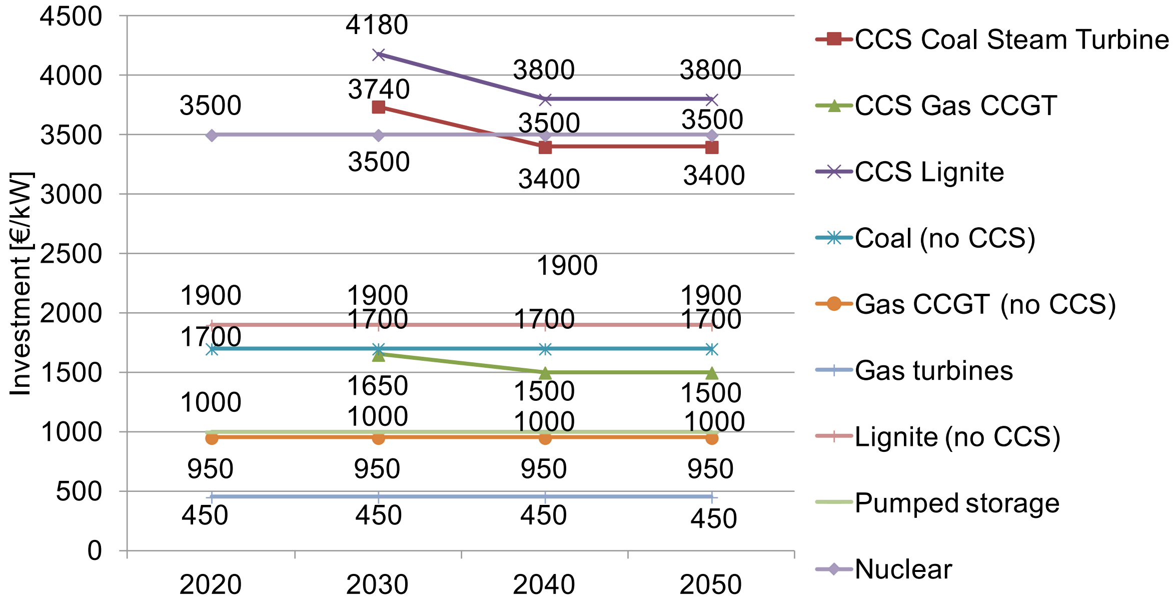

Figure 28: Techno-economic assumptions for the modelling in PowerACE

4.2.4 Storage technologies

PowerACE takes into account storage technologies to facilitate the integration of variable RES-E into the electricity system. Existing technologies can be differentiated according to the following categories:

- Hydro reservoir storage
- Hydropower pumped storage
- Other storage technologies

In contrast to run-of river hydropower plants, where electricity generation is not dispatchable, reservoirs provide the option of storing the incoming water from rivers in a reservoir. This allows for certain flexibility regarding its timely dispatch respecting always technical limits resulting from the installed capacity and the storage potential. The installed capacity and annual electricity generation of reservoir plants is exogenous in PowerACE, whilst their use and dispatch is optimised endogenously, respecting the capacity restrictions and the condition, that annual production has to be met. For their future development, known projects and the additionally available potential are considered.

Pumped storage power plants provide even more flexibility, provided that these reservoirs are additionally equipped with a pump that allows for pumping up the water and thereby consuming electricity in times of high electricity generation and low demand. As soon as demand increases, the stored water can be released and the kinetic and potential energy can be converted into electricity. All individual pumped storage power plants in PowerACE are aggregated to one cumulated pumped storage power plant per country with an efficiency of 80%.

Similar to the reservoir plants, existing plants, planned projects and the remaining available potential are considered for the modelling of future capacities..

Additional storage options such as adiabatic compressed air energy storage (CAES) and hydrogen storage still involve comparatively high costs. Provided that experiences with previous modelling studies have shown, that even the more cost-efficient pump storage option is not chosen by the model on a large scale, these additional storage options are not considered explicitly in the model. Instead, a simplified storage technology with the characteristics of a pump storage plant is considered as technology option for optimisation. Provided that pump storage power plants are among the most cost-efficient storage technologies, this represents a very optimistic assumption. Only because the model doesn't choose to make use of the cheap pump storage option, this simplification can be justified.

4.2.5 Electricity demand

In general the scenario design follows the structure of the GHG40 EE Scenario of the recent Impact Assessment of the European Commission (2014a). As no data on national level was available for electricity demand, we based the demand assumptions on the Energy Efficiency Scenario from the EU Energy Roadmap 2050 (European Commission, 2011a). Comparing the overall gross electricity generation in the Energy Efficiency Scenario from the Roadmap with the GHG40 EE Scenario (see Figure 34) it becomes clear that future trends in both scenarios are rather similar. Considering that the GHG40 EE Scenario includes data for Croatia, electricity generation in the GHG40 EE is slightly lower than in the Energy Efficiency Scenario from the Energy Roadmap 2050.

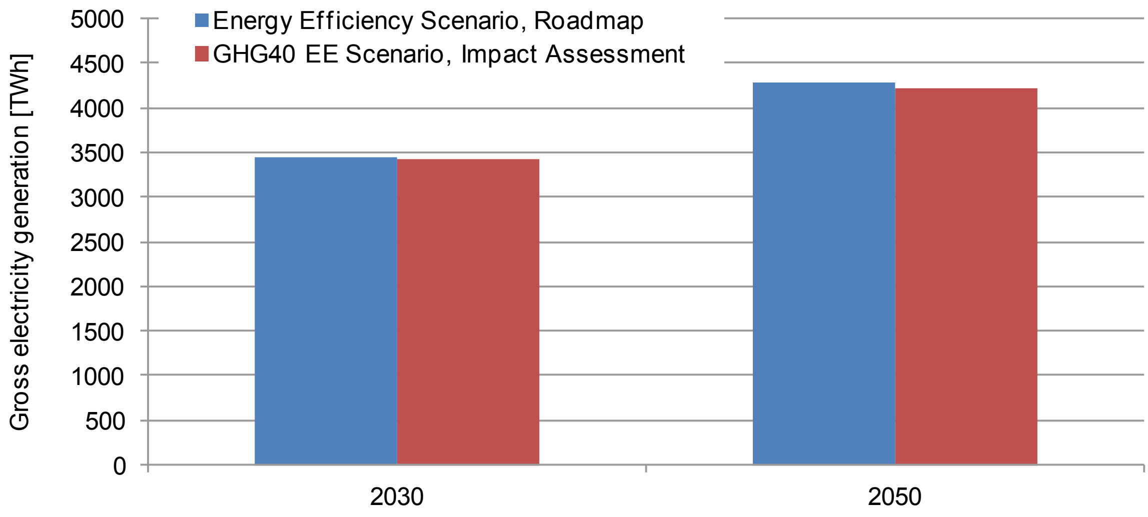

Figure 29: Gross electricity generation in the Energy Efficiency Scenario from the Energy Roadmap 2050 and in the GHG40 EE Scenario from the Impact Assessment[6]

Source: based on data from European Commission (2014 a, 2011a)

Thus, we integrate net electricity consumption plus losses from the transmission and distribution grid into our analysis. For all three scenarios we assume the same development for electricity demand as depicted in Figure 35. As data for Croatia was not available, electricity demand for Croatia has been estimated based on the development foreseen for Slovenia.

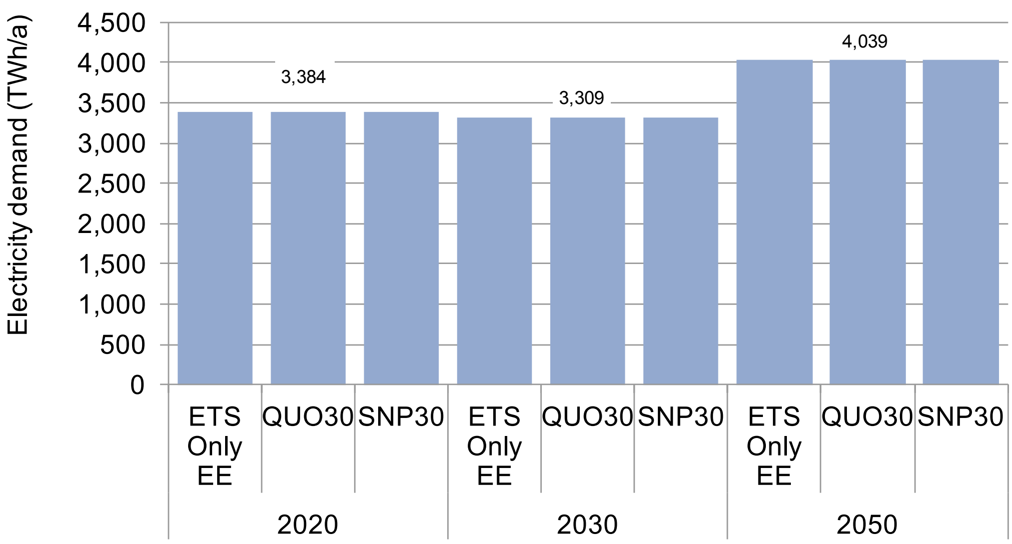

Figure 30: Electricity demand[7] in the EU28 based on the Energy Efficiency Scenario of the Energy Roadmap 2050 (European Commission 2011).

6 Whilst electricity generation in the Energy Efficiency Scenario of the EC-Roadmap refers to EU27, the figures shown for the Impact Assessment include electricity generation in Croatia and thus refer to EU28.

4.2.6 Electricity grid

PowerACE considers the possible extension and reinforcement of the electricity grid as one option to integrate high shares of fluctuating RES-E. Thus, infrastructure improvements compete with other technologies or measures such as storages, the use of flexible generation technologies such as gas turbines or curtailment. The integration of grid extension option in PowerACE is based on a simplified approach without representing the European electricity grid at a high geographical resolution. With the clear focus of PowerACE on the supply side of the energy sector, we integrate an aggregated transport model reflecting transport of electricity between but not inside countries based on net transfer capacities (NTC)[8]. The investment decision is based on cost for additional grid requirements, which are in turn mainly determined by technology types and the required investments, distances and by the terrain on which the new lines are built. Different technology types include whether direct current (DC) or alternating current (AC) technologies are chosen and whether the transmission line is built as an overhead line or as an underground cable.

We assume the distance between the countries to correspond to the distance between the centre of each country as shown in Figure 36.

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7 Electricity demand shown corresponds to the net electricity demand plus losses in the transmission and distribution grid.

8 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.

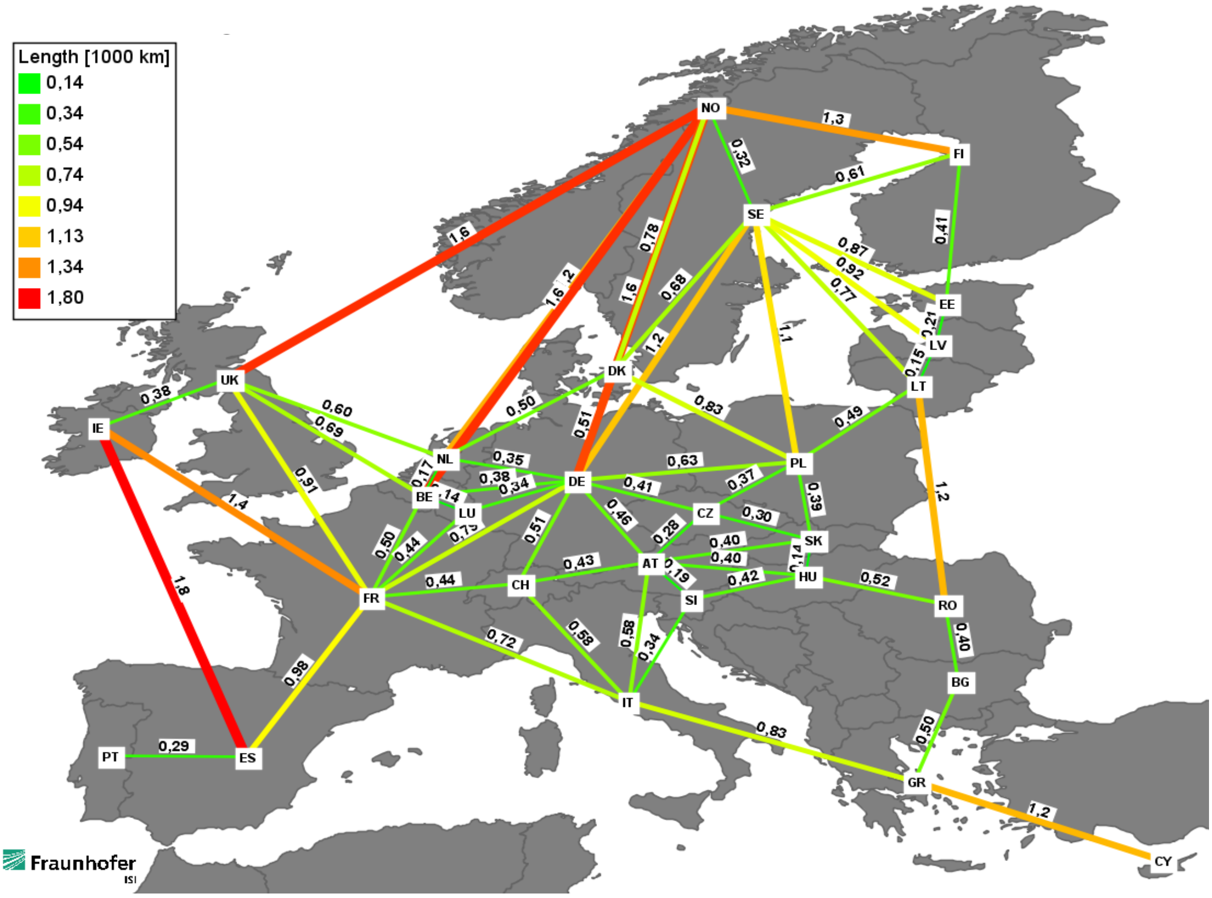


Figure 31: Distance between countries assumed for the extension of the electricity grid

Depending on the terrain where a power line is built, different technology options are feasible. Connections built on land can be either AC or DC, and be overhead or underground connections. Table 16 summarises the techno-economic assumptions made for the modelling.

Table 15: Assumptions for costs in grid investment

Technology	type	Terrain	Year	Investment (€ per MW NTC km)
DC	cable	ground	2020	1776
			2030	1776
			2040	1572
			2050	1368
DC	cable	sea	2020	1360
			2030	1360
			2040	1176
			2050	992
DC	overhead	ground	2020	288
			2030	288
			2040	288
			2050	288

For our modelling we assume half of the additionally constructed capacity to be DC lines whereof 50% are overhead lines and the other half is based on cables under the ground.

In general, it should be considered, that costs related to grid extension estimated with PowerACE are based on a simplified model and therefore subject to uncertainties. In particular the simplification regarding the distances between countries and the low geographical resolution is assumed to lead to inaccuracies. In reality, interconnections built between countries tend to cover much lower distances in particular for the early reinforcements and national reinforcements, whilst grid extensions in national grids are supposed to be covered by the distances between the centres of the countries to a certain extent. Comparisons with studies including more detailed grid modelling indicate that PowerACE tends to overestimate costs related to grid extension and reinforcement. The assumption that 50% of the additional connections use underground cables also tend to increase cost estimations, provided that underground cables are much more costly than the alternative overhead lines (see Table 16).

4.3 Results

This analysis assesses the impact of different RES-targets and associated RES support policy approaches by 2030. The focus of this study is on the evaluation of the costs of the EU power system in each of these scenarios. As the technology mix in 2030 strongly influences costs of the European power system in future years, we realise our modelling analysis up to the year 2050. This allows us to also compare the costs of our power system on a longer term.

The main findings of the scenario assessment are the following:

- The cost development over time is stable in all scenarios and the decarbonisation of the power sector does not lead to higher power system costs.
- In contrast, lowest overall costs are achieved in scenario with a RES-target of 30%, since lower discount rates provided by investment stability and stable returns lower capital costs of renewable energy technologies
- When comparing the estimated costs of the transmission grid with overall generation costs, it becomes clear that the contribution of transmission grid costs in overall system cost is comparatively low and amount to less than 4% of overall system costs in all scenarios by 2050 and also by 2030.
- The model does not choose to build storage capacity to facilitate grid integration of RES-E due to the comparatively high costs.

4.3.1 CO_2 emissions

For the modelling in PowerACE, it is possible to either provide the price for CO_2 as an input or to use a cap on CO_2 emissions for the power sector. In the scenario assessment carried out in this analysis, we used the price for one tonne of CO_2 as modelling input. With the assumption of a CO_2 price, development of CO_2 emissions in the EU power sector is a model output. CO_2 emissions in the EU, depicted in Figure 37, show a strong decarbonisation between 2030 and 2050, decreasing from over 900 Mt of CO_2 to less than 50 Mt of CO_2 by 2050. Total annual CO_2 emissions of the electricity sector are reduced to 3-4% of 1990 levels.

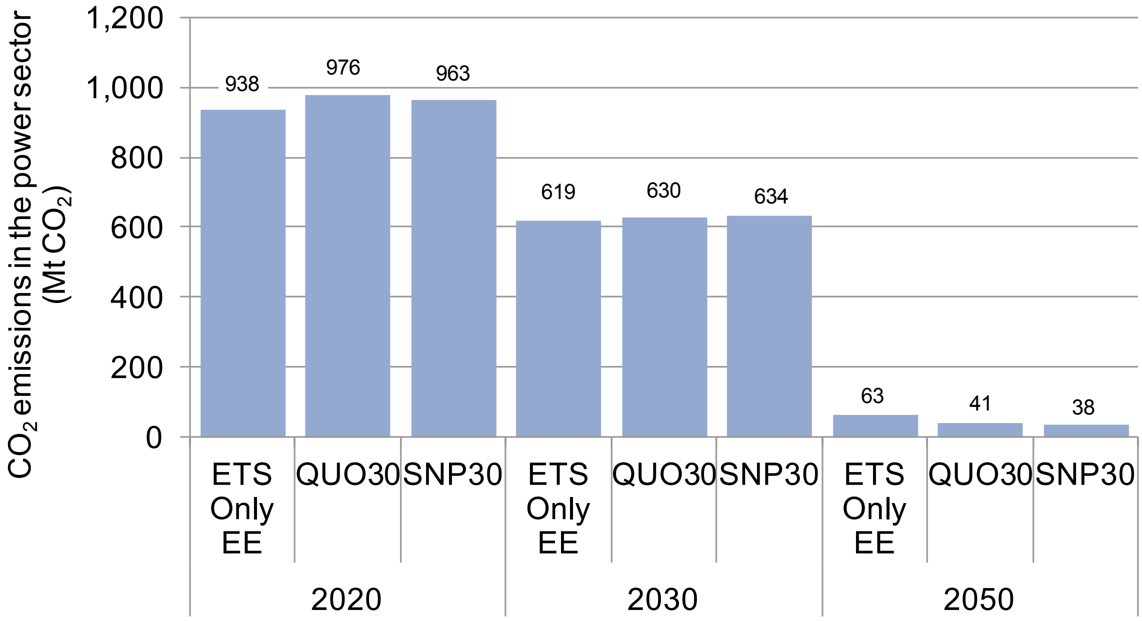


Figure 32: Development of CO_2 emissions in the EU power sector

When comparing the CO_2 emissions in power generation with the corresponding scenarios of PRIMES (see Figure 38), it becomes clear that CO_2 emission levels of PowerACE by 2050 are quite similar to the PRIMES modelling. Only in the GHG40EE or ETS Only EE Scenarios, PowerACE apparently achieves stronger emission reductions by 2030. This can also be explained by the fact that the CO2 price in this scenario assumed for 2030 had to be increased as compared to the original GHG40EE Scenario in order to achieve a RES-share of 27% (see section 3.1.5).

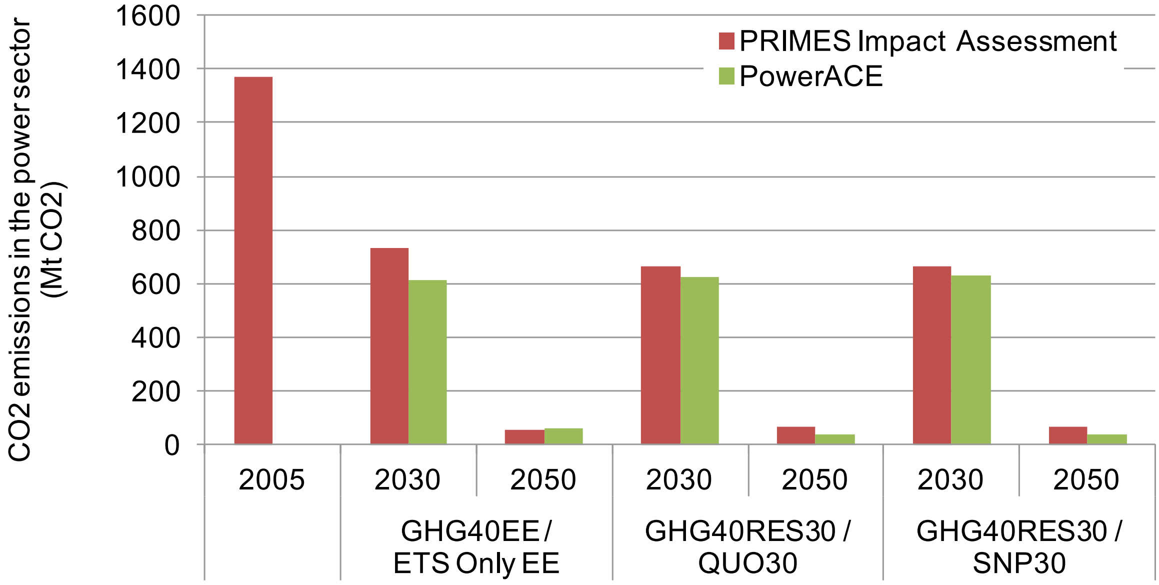


Figure 33: Comparison of CO_2 emissions in power generation in the EU27 in our modelling analyses with the corresponding scenarios of the Impact Assessment[9]

4.3.2 Technology mix

With regard to the resulting technology mix in the power sector, it is important to highlight that the development of the different technologies is partly predetermined, whilst other technologies evolve endogenously in the PowerACE modelling and are therefore modelling results. Nuclear generation capacity declines from levels of 118 GW in 2020 towards 55 GW in 2050 as a result of a political decision process (see Figure 39). The future development of renewable energy technologies is also an exogenous input determined using the Green-X model. All the other technology options including thermal power plants compete with each

9 For the PRIMES scenario, we estimated total emissions in the power sector by applying reduction factors against 2005-levels provided by European Commission (2014a) to total emissions for 2005 available at http://www.eea.europa.eu/data-and-maps/figures/structure-of-co2-emissions-from-2. CO2 emissions for the Impact Assessment may be slightly higher than disclosed by PowerACE, as emissions from district heating plants are considered, whereas PowerACE only shows emissions from thermal power plants.

other and are deployed following a least-cost approach. Provided that the path of RES technologies and nuclear power is already predetermined, this means, that practically the only option to decarbonise the power sector is to deploy CCS-equipped fossil-fuel power plants. Due to the current problems with the commercialisation of CCS projects, we assume that CCS is not available by 2020 and we allow CCS as of 2030.

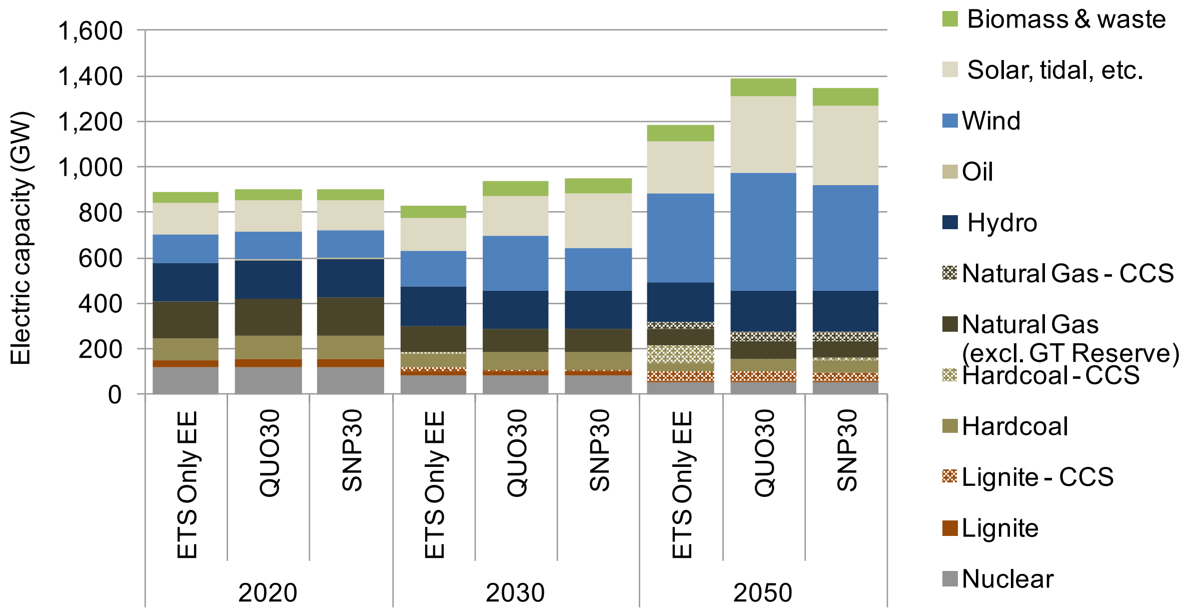


Figure 34: Installed capacity in the EU power sector in all considered scenarios

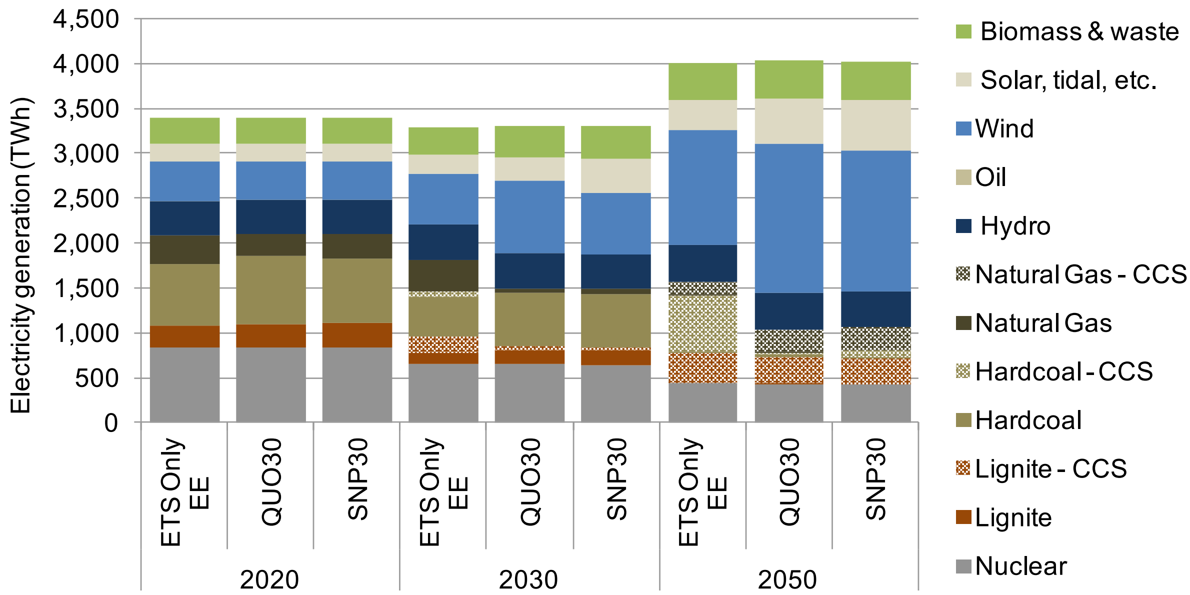


Figure 35: Electricity generation in the EU in all considered scenarios

Figure 39 and Figure 40 show the development of electric capacity and electricity generation, respectively. For the first modelling year 2020, all scenarios are still very similar. Regarding the differences, there is slightly more coal in the RES30 scenarios and less gas than in the ETS Only EE Scenario.

The use of low carbon technologies – CCS versus RES

As already mentioned above results show an increased use of CCS in particular in the ETS Only EE Scenario, whilst increasing use of RES are the main decarbonisation option deployed in the scenarios assuming a RES-target of 30%. With respect to the CCS development, lignite CCS develops in a first step until 2030 in the ETS Only EE Scenario achieving an installed capacity of 23 GW by 2030. In contrast lignite CCS in the RES-target Scenarios remains on a level between 4 and 5 GW by 2030 due to the lower CO_2 price in 2030. Hardcoal CCS in not developed at all neither in QUO30 nor in SNP30 by 2030, but increases to 10 GW in QUO 30 and 10 GW in SNP 30 on the longer term by 2050. Looking at the CCS capacity by 2050, ETS Only EE is clearly dominated by hardcoal with roughly 80 GW of installed capacity, while lignite CCS capacities range from 36 GW in SNP 30 to 43 GW in ETS Only EE. The main driver for the CCS-development is the CO_2 price, which increases only slightly up to 2030, but registers strong growth between 2030 and 2050. Thus, the use of lignite CCS starts to become competitive if the CO_2 price achieves roughly 50€ per ton of CO_2. Due to the lower costs of lignite CCS compared to hardcoal CCS, lignite CCS is developed earlier. However, the use of CCS lignite equipment is limited to a level similar to that of existing lignite power plants. As shown in Figure 41, the overall lignite capacity increases only slightly between 2020 and 2050 in the ETS Only Scenario. By 2050, nearly all lignite power plants are equipped with CCS. Figure 41 also illustrates that the more expensive hardcoal CCS options begins to develop strongly after 2030.

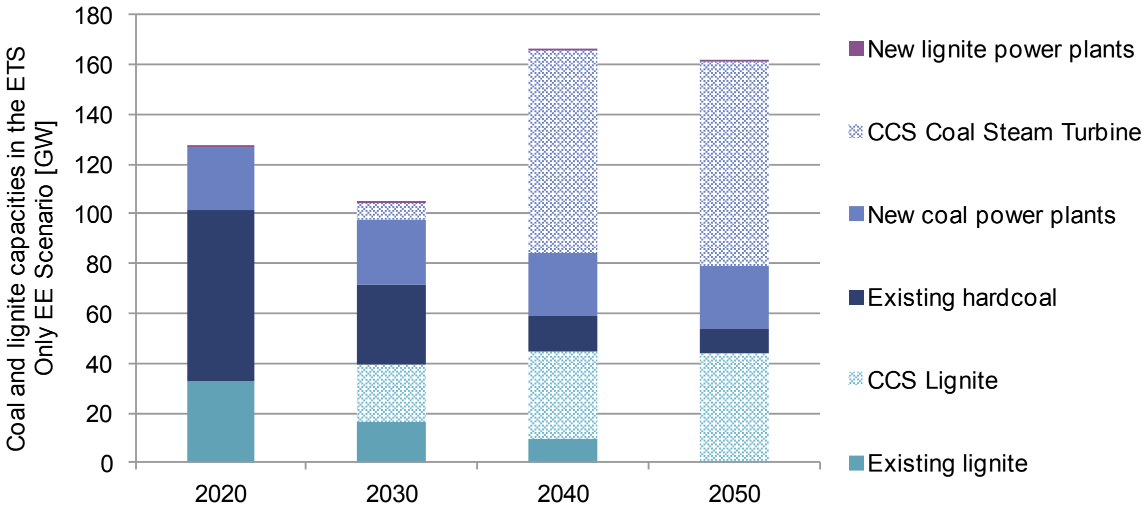


Figure 36: Electric capacity of coal and lignite power plants in the ETS Only EE Scenario

The role of gas

In terms of capacity the electric capacity of CCGT increases in particular in the ETS Only EE Scenario from 450 MW to 9.2 GW until 2040 and thereafter slightly decreases to 8.8 GW. In all three scenarios the installed capacity of gas turbines increases considerably in particular in the RES-target scenarios to roughly 72-73 GW by 2050. In combination with low electricity output, gas turbines serve as peak load power plants in order to cover situations with low electricity generation availability and high loads. The development of electricity generated based on gas power plants shows a slight increase from 325 TWh in 2020 to 359 TWh in 2030 in the ETS Only EE Scenario, whilst gas-based power generation decreases strongly to a range of 45 to 60 TWh per year in the RES-target Scenarios.

This development can be explained by the competitiveness of combined cycle gas turbines compared to other power plants in particular in the peak to medium load segment (covering annual full-load hours from 1000 h/a to 3000 h/a) in the ETS Only Scenario. This is due to the CO_2 price achieving 50 €/t of CO_2 by 2030. In contrast, the lower CO_2 price in the RES-target scenarios makes CCGT the most cost-efficient technology only for a very restricted range of utilisation between 1200 h/a and 1800 h/a. For higher utilisation rates conventional lignite power plants become more competitive and lead to a lower share of CCGT and a higher share of lignite power plants (without CCS) in the RES-target scenarios. Further increasing CO_2 price after 2050 make lignite power plants equipped with CCS the most competitive technology in the base load segment, whilst CCGT with CCS are more competitive in the medium load segment. Due to the lower CO_2 prices in the RES-target scenarios, there is more CCGT-CCS capacity by 2050 in the RES-target scenarios than in the ETS-Only scenario.

Development of RES(-E) share

With regard to the share of RES in gross electricity demand, Table 17 shows that the 2020 target of a 20% RES-share in gross final energy consumption translates into a slightly higher share of RES-E amounting to 35.3% in the ETS Only EE Scenario than in the RES target Scenarios (RES-E share of 34.9%). The picture changes by 2030, where the RES share of (nearly) 27% in the ETS Only EE Scenario translates into a RES-E share of 42.4%, whilst the 30% RES-target requires higher RES-E shares of 52.5%. Finally, the lower CO_2 price by 2050 in combination with no dedicated RES-support leads to an overall RES-share of 52.8% in the ETS Only EE Scenario and to 57.1% in electricity (see Table 17). The share of RES in final energy consumption by 2050 is clearly higher in both RES-target scenarios, increasing to about 60% in both cases (i.e. 60.8% in the QUO 30 Scenario and to 59.7% in the SNP 30 Scenario). Accordingly, the share of RES in gross electricity demand amounts to about 70% in both RES-target scenarios (i.e. 69.7% in the SNP 30 case, and 70.3% according to the QUO 30 case).

Table 16: Development the RES-E share in gross electricity demand in the EU28

Scenario	2020	2030	2040	2050
ETS-Only EE	35.3%	42.4%	44.4%	57.1%
QUO-30	34.9%	52.5%	56.2%	70.3%
SNP-30	34.9%	52.5%	57.4%	69.7%

The role of individual RES-E technologies

In general, the QUO 30 Scenario is characterised by the strongest development of wind power, in particular wind onshore, facilitated by renewable support following a least-cost deployment approach. Increasing shares of RES with lower utilisation rates lead to higher installed capacity in both RES-target scenarios. In particular in the QUO 30 Scenario a high share of wind energy in the generation mix by 2050 implies even higher total electric capacities than in the SNP 30 Scenario. In contrast, the SNP 30 Scenario leads to more diversified deployment of RES as a result of technology-specific policy support.

4.3.2.1 Curtailment of RES-E generation

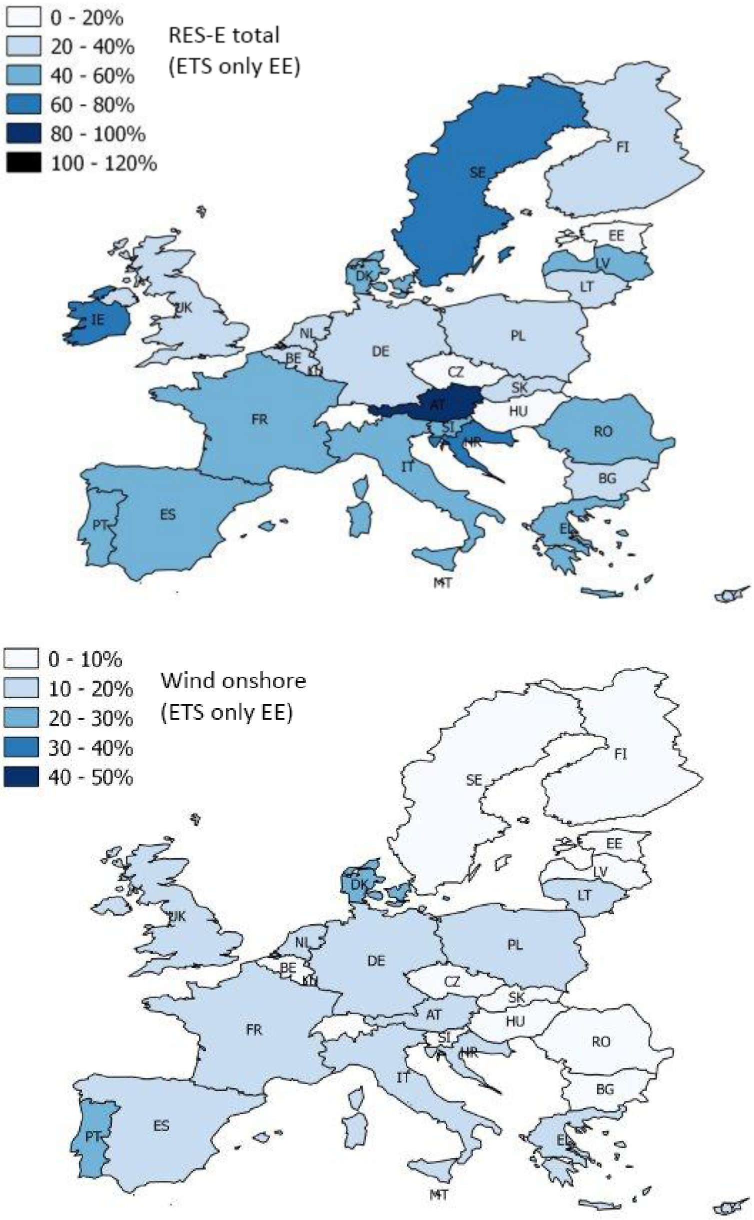
In a power system with high shares of RES the system has to deal with excess generation occurring in times of favourable weather conditions for wind and solar power combined with low electricity demand. Among other options such as extending the electricity grid or using storage options, the model considers the curtailment of electricity as one option to deal with excess generation. Typically, the model only selects this option if the alternative technologies such as building new transmission lines or the use of storage are more costly than discarding the use of the electricity generated. Modelling results show that curtailment in all scenarios analysed remains on a negligible level, even in the SNP 30 and QUO 30 Scenarios with a RES-E share of about 70% by 2050. In this case, only 0.01% of the renewable electricity generation has to be curtailed. Experiences with previous modelling analysis have shown that curtailment starts to become relevant only with a RES-E share exceeding 80%. The fact that RES-E capacities are fairly evenly distributed across Europe in the SNP 30 Scenario facilitates that curtailment is practically not required. Although the overall curtailment during a year is negligible, there curtailment in single hours may occur sporadically. Thus, the maximum curtailment in one hour in the SNP 30 Scenario in 2050 amounted to 99 GW (compared to a total load of 436 GW).

4.3.2.2 Regional distribution of renewable energy technologies (exemplified for wind onshore)

Caused by the dependence of electricity generation cost on regional resource conditions, the regional distribution of renewable energy technologies is determined by the respective resource conditions and the available policy support. In a cost-minimising approach across all EU MS, as pursued by the CO_2 price in the ETS Only EE Scenario and by the EU-wide quota system of the QUO 30 Scenario, the use of wind and solar technologies concentrates stronger on the regions disposing of abundant low-cost potentials. In addition, there is a trade-off between technology alternatives, meaning that in the scenario with balanced RES-support solar PV and wind offshore develop stronger at the expense of the lower cost technology wind onshore.

Figure 42 shows the electricity output for total RES-E and wind onshore by Member State in the ETS Only EE in 2030. A closer look at technology specific results indicates that total electricity generation based on wind onshore power plants by 2030 amounts to roughly 500 TWh in the EU, whilst wind onshore electricity generation in the SNP 30 achieves roughly 550 TWh and the cost-minimisation approach of the quota obligation even leads to an overall electricity output of 718 TWh. The distribution shows that most of wind electricity generated is located in the countries disposing of large area potentials including France, the UK, Spain, Germany and Italy. Without additional RES-support France shows the highest value for electricity generation based on onshore wind turbines in 2030 with 93 TWh per year as result favourable resource conditions and available potential.

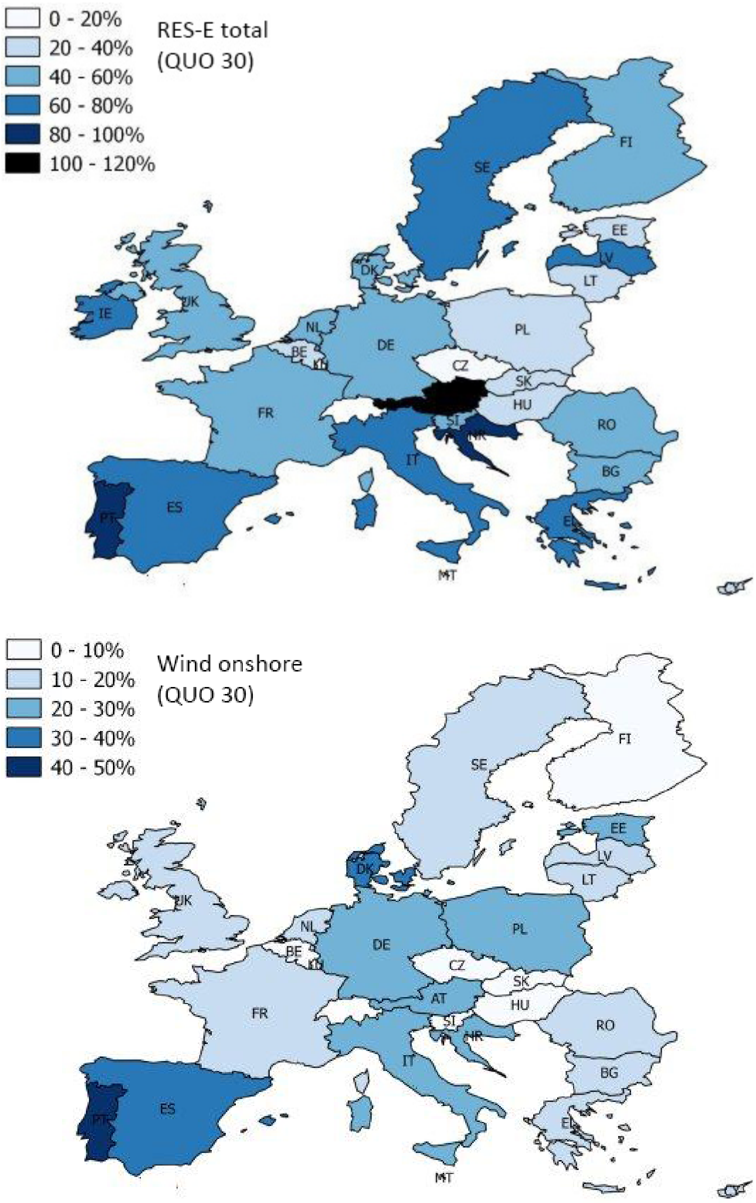
Corresponding figures for total RES-E are 1452 TWh in the case of ETS Only EE, and about 1800 TWh under both RES-target scenarios (QUO 30 and SNP 30). Concentration effects are becoming apparent to a certain extent if a least-cost policy approach is pursued as presumed for the QUO 30 scenario.



Country	Electricity generation by 2030			
	wind onshore		RES-E total	
	absolute terms	*relative terms*	*absolute terms*	*relative terms*
	TWh	demand share	TWh	demand share
AT	10.9	15.2%	66.6	92.9%
BE	8.6	8.8%	22.7	23.4%
BG	0.7	1.9%	12.2	33.9%
HR	2.8	14.2%	13.0	66.1%
CY	1.1	15.0%	1.6	20.9%
CZ	2.0	2.4%	15.6	18.2%
DK	10.7	29.2%	18.0	49.3%
EE	0.7	8.0%	1.5	17.2%
FI	0.5	0.6%	30.3	38.8%
FR	93.3	18.0%	221.4	42.8%
DE	62.7	10.9%	219.9	38.3%
GR	12.2	17.4%	34.4	48.9%
HU	2.5	5.0%	9.3	18.9%
IE	18.4	53.5%	23.7	68.7%
IT	56.5	15.6%	189.7	52.3%
LV	0.5	5.9%	5.0	55.1%
LT	1.5	11.6%	2.8	22.6%
LU	0.4	4.2%	0.9	10.1%
MT	0.1	6.2%	0.4	17.9%
NL	22.5	19.5%	45.3	39.2%
PL	27.0	14.2%	47.9	25.2%
PT	12.4	21.2%	33.0	56.6%
RO	2.2	3.3%	27.9	41.5%
SK	0.5	1.2%	10.9	28.3%
SI	0.2	1.3%	9.1	53.8%
ES	66.8	20.0%	154.2	46.3%
SE	10.7	7.8%	91.8	67.0%
UK	70.7	18.4%	143.0	37.2%
EU28	498.9	14.6%	1452.1	42.4%

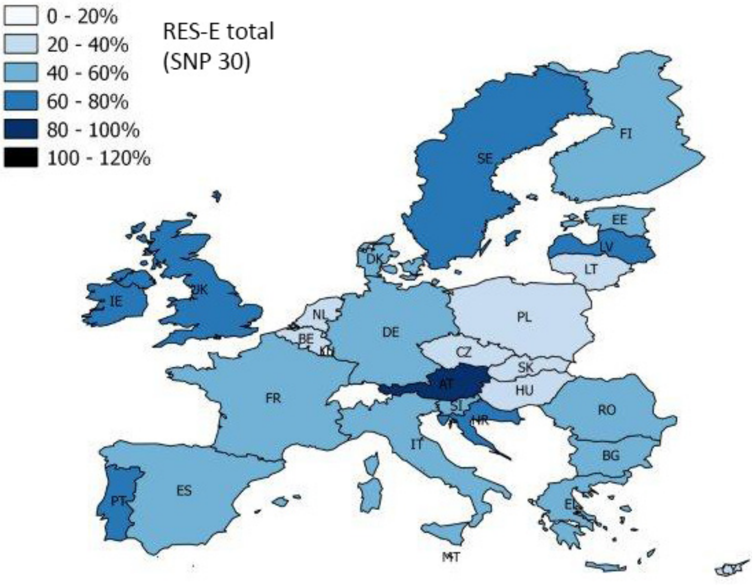
Figure 37: Electricity generation from RES-E (total) and Wind Onshore by Member State in the ETS Only EE Scenario in 2030

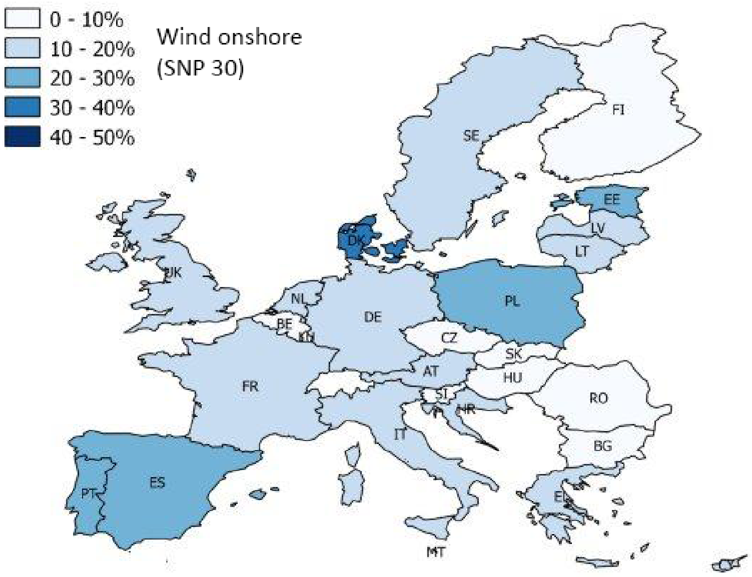
Compared to the ETS Only EE Scenario total electricity generation based on onshore wind in 2030 increases by nearly 220 TWh or 43% as a result of the support provided by the technology-neutral quota obligation (see Figure 43). In particular Germany and Spain are characterised by a strong increase in the use of onshore wind power compared to the ETS Only EE Scenario. With 120 TWh Germany is the largest producer of onshore wind electricity, followed closely by Spain with 118 TWh and France with 103 TWh. The regional distribution shown in Figure 43 also shows that the regional distribution of wind onshore generation is not characterised by a strong geographical concentration, also due to the fact that electricity generation from onshore wind power plants remains on a moderate level in some countries with favourable potential, but with important non-economic barriers in place setting a limit on the development of this technology by 2030, as happened in the UK by 2030.



Country	Electricity generation by 2030			
	wind onshore		RES-E total	
	absolute terms	*relative terms*	*absolute terms*	*relative terms*
	TWh	demand share	TWh	demand share
AT	18.9	26.3%	80.5	112.3%
BE	8.8	9.1%	23.7	24.4%
BG	6.1	17.1%	19.8	55.2%
HR	5.2	26.2%	16.2	82.0%
CY	1.4	18.5%	2.0	27.2%
CZ	2.7	3.1%	16.8	19.6%
DK	12.3	33.7%	20.8	56.9%
EE	2.2	25.9%	3.1	36.4%
FI	2.2	2.8%	33.7	43.2%
FR	102.5	19.8%	238.6	46.1%
DE	119.5	20.8%	285.9	49.8%
GR	12.3	17.5%	43.3	61.6%
HU	3.2	6.5%	11.6	23.4%
IE	18.4	53.5%	25.3	73.3%
IT	90.9	25.1%	235.8	65.0%
LV	0.9	10.2%	5.8	63.4%
LT	2.1	17.1%	3.6	28.9%
LU	0.5	5.4%	1.1	12.0%
MT	0.2	7.3%	0.5	24.6%
NL	22.5	19.5%	46.7	40.4%
PL	41.7	21.9%	66.5	35.0%
PT	27.1	46.4%	54.2	92.9%
RO	8.4	12.5%	39.0	58.1%
SK	0.9	2.5%	11.7	30.3%
SI	0.3	1.8%	9.6	56.6%
ES	117.9	35.4%	228.2	68.5%
SE	18.3	13.4%	100.5	73.4%
UK	70.7	18.4%	172.0	44.7%
EU28	717.9	21.0%	1796.5	52.5%

Figure 38: Electricity generation from RES-E (total) and Wind Onshore by Member State in the QUO30 Scenario in 2030





Country	Electricity generation by 2030			
	wind onshore		RES-E total	
	absolute terms	*relative terms*	*absolute terms*	*relative terms*
	TWh	demand share	TWh	demand share
AT	9.3	13.0%	69.7	97.3%
BE	8.6	8.8%	23.7	24.5%
BG	2.1	6.0%	16.6	46.3%
HR	3.1	15.9%	14.6	74.0%
CY	1.1	15.4%	1.8	23.8%
CZ	2.7	3.1%	19.0	22.2%
DK	12.3	33.7%	21.1	57.7%
EE	2.2	25.9%	3.6	42.6%
FI	2.2	2.8%	36.2	46.4%
FR	102.5	19.8%	284.5	55.0%
DE	61.4	10.7%	243.1	42.3%
GR	12.3	17.5%	41.8	59.5%
HU	2.5	5.0%	11.2	22.6%
IE	18.4	53.5%	27.6	79.9%
IT	54.6	15.1%	200.3	55.2%
LV	0.9	10.2%	6.0	65.7%
LT	2.1	17.1%	4.9	38.8%
LU	0.4	4.1%	0.9	10.0%
MT	0.1	5.9%	0.5	23.3%
NL	22.5	19.5%	46.1	39.9%
PL	41.7	21.9%	71.2	37.5%
PT	14.7	25.1%	41.7	71.5%
RO	3.3	4.9%	32.1	47.8%
SK	0.3	0.7%	11.7	30.2%
SI	0.2	1.2%	9.8	58.0%
ES	77.8	23.4%	195.2	58.6%
SE	18.3	13.4%	102.2	74.6%
UK	70.7	18.4%	258.5	67.1%
EU28	548.3	16.0%	1795.6	52.5%

Figure 39: Electricity generation from RES-E (total) and Wind Onshore by Member State in the SNP30 Scenario in 2030

In the Scenario SNP 30, overall wind onshore electricity generation by 2030 is only slightly above the levels achieved in the ETS Only EE Scenario where no additional support dedicated to RES-E is assumed after 2030 and considerably below the levels achieved in the QUO 30 Scenario. Provided that the RES-E share in SNP 30 and QUO 30 are similar by 2030, the remaining RES-E is mainly based on Solar PV and offshore wind. Similar to the ETS Only EE Scenario France produces most of the EU's wind onshore electricity by 2030, followed by Spain, the UK, Germany and Italy.

4.3.2.3 Monthly time resolution

Observing the monthly electricity generation in all scenarios by 2030 depicted in Figure 45, it becomes obvious that there are seasonal differences in demand and generation. In terms of seasonal availability, there is more wind power available in winter months and less in summer months. This profile is complemented with the availability of solar technologies, showing a better availability in summer than in winter. Compared to the ETS Only EE Scenario, the use of gas and oil power plants is reduced to a very low level in the RES-target scenarios. In the summer months which are characterised by a lower demand level the contribution of gas and oil is almost negligible on a monthly basis.

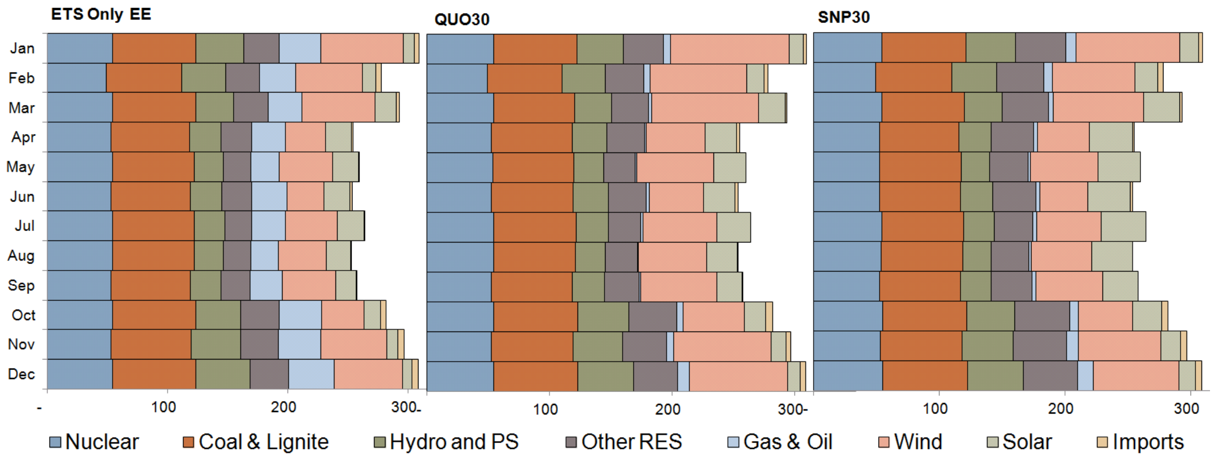


Figure 40: Monthly electricity generation by technology in 2030 (TWh)

4.3.3 The costs for a RES target of 30% by 2030 and 2050

In this section the outlook on the power system cost by 2050 is given by also presenting the interim period starting in 2020. Thereby, the annual total system costs are shown in absolute terms as well as the specific figures in terms of total electricity generation.

4.3.3.1 Annual system costs

The annual system costs shown in Table 18 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. Thereby existing infrastructure (plants, grid) are valued with the 2020 cost figures although they are considered as sunk costs and therefore not included in the optimisation procedure. It should be taken into account that this is a simplification, provided that costs of past installations may deviate considerably from the 2020 cost figures. This is in particular relevant for technologies showing a highly dynamic cost development such as solar PV (see section 2.1.1.2). However, this approximation becomes better, the further we look into the future, because the share of the currently existing power plants decreases over time. With regard to the costs of a potential grid extension, it is important to note, that grid costs in PowerACE are approximated and are subject to uncertainties. Potential extensions of the transmission grid are estimated by assuming connections between countries, but cost of extending the distribution grid and major parts of the national transmission grid are not covered by PowerACE.

One can observe a moderate increase of annual systems costs after 2030 by about 13-15% until 2050 (see Table 18 and Figure 46). This development is mainly based on the fact that electricity demand increases by 22% between 2030 and 2050. Furthermore the nearly entire decarbonisation of the energy system causes substantial additional investment needs in low carbon generation technologies and infrastructure particularly towards the end of the modelling period. We observe that the use of dedicated RES policies in the QUO 30 and the SNP 30 Scenario causes mainly a shift from coal plants based on CCS to wind and solar plants in particular. If no dedicated RES-policies are applied after 2020, the use of RES is somewhat lower and CCS technologies are used to lower carbon emissions. Thereby, it has to be taken into account, that generation costs of CCS technologies are not necessarily lower than those of RES power plants. There is no real competition between RES and CCS technologies, provided that the RES development pathway is predetermined in the Green-X model and fed into PowerACE as an exogenous input.

With regard to comparing costs in the three scenarios, it becomes evident that cost development varies only slightly. The least-cost resource allocation of RES as assumed under the QUO-30 Scenario leads to slightly lower total system costs than under the ETS Only EE scenario by 2030. Whilst annual system costs in the ETS Only EE Scenario amounts to € 221 billion by 2030, system costs in the QUO 30 Scenario add up to € 219 bn. The difference in costs is more pronounced on the longer term by 2050, where annual system costs under the ETS Only EE are estimated to € 264 billion and under the QUO 30 Scenario to € 259 bn. The SNP-30 scenario is characterised by similar total system costs as the ETS-Only EE case but leads to slightly lower grid expansion than the QUO-30 scenario.

Table 17: Development of annual system costs

Scenario		2020	2030	2050
ETS Only EE	bill. $€_{2010}$	233	221	264
QUO 30	bill. $€_{2010}$	231	219	259
SNP 30	bill. $€_{2010}$	231	231	268

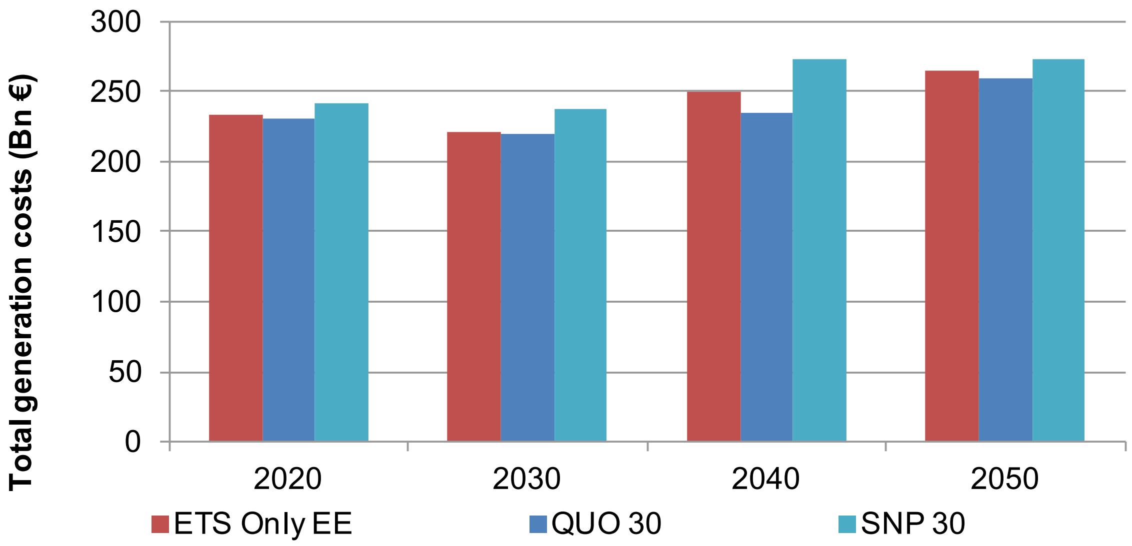


Figure 41: Annual system costs of the EU power system in billion $€_{2010}$

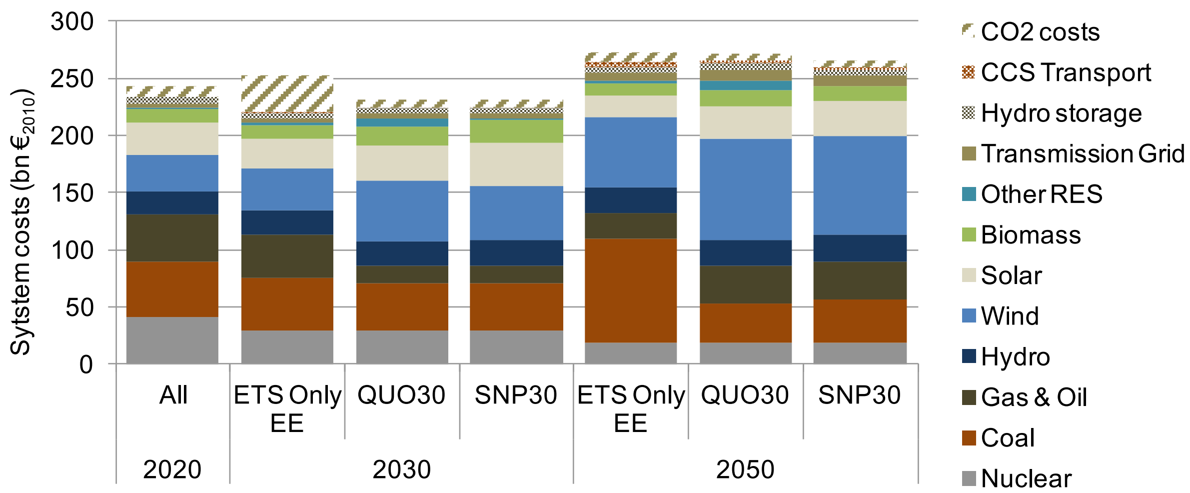


Figure 42: Cost components of annual overall system costs in the EU28[10]

Figure 47 shows the composition of the total system costs from the different generation technologies, costs for storage, transmission grid and CCS transport.

One can see that the share of transmission grid costs in total system costs is very limited amounting to roughly 2% of overall system costs by 2030 and from 2.8% to 3.7% by 2050. The same holds for storage costs of around 2% of overall system costs. Generally it has been found that besides the existing pump-storage hydropower plants only very limited need

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10 CO_2 costs are also shown, although theses should formally not be counted as part of the total system costs as they rather have the character of a tax, constituting costs for plant operator, but revenue for government. However, for completeness they are shown as cross-hatched area.

for additional innovative storage technologies such as CAES or batteries exists. The cost optimal solution to provide the flexibility needed by the system is mainly based on a balanced portfolio of transmission extension, hydro storage and peak power plants.

As stated above the shift from the ETS Only EE path to scenarios based on dedicated policies supporting RES development results in a shift of cost components for CCS based coal and lignite to wind and solar technologies, leaving the overall costs rather unchanged.

4.3.3.2 Average cost of the electricity system

Breaking down the annual system cost to a unit of electricity generated, we calculate the average cost of the electricity system. This helps to evaluate cost developments from a consumer perspective. It is important to note that specific system costs reflect average costs including fixed and variable cost elements and do not reflect electricity prices as determined in currently used market design based on marginal pricing. As the estimation of electricity prices strongly depends on the market design and requires precise assumptions on future market design, the estimation of electricity prices cannot be realized in the scope of this study. Moreover, electricity prices for consumers include additional price components including additional grid fees, taxes and producer margins and add up to considerably higher prices per unit of electricity generated than average generation costs shown in this section. In any case, the development of the specific generation costs can serves as an indicator for the possible future development trend of electricity prices.

In Table 19 the specific generation costs, i.e. total costs as fraction of electricity demand, excluding CO_2 costs are shown. These specific costs decrease by about 4% between 2020 and 2050. The key reason is that technology learning reduces the specific generation costs of the individual generation technologies. Looking at 2030, costs in the QUO 30 Scenario are slightly lower than in the ETS Only EE Scenario. In contrast, the development of more cost-intensive renewable technologies involve slightly higher average costs by 2030, but technology learning and scale effects bring costs back to a cost level similar to that of the ETS Only EE Scenario. By 2050 all three scenarios are characterized by very similar specific system costs amounting to 60 €/MWh in the QUO 30 Scenario, to 61 €/MWh in the ETS Only EE Scenario and to 62 €/MWh in the SNP 30 Scenario.

Results of this analysis show that costs associated to higher levels of RES-E share in the scenarios stay on a moderate level and do not lead to higher electricity generation costs. This means that increasing the share of RES in the electricity system can be achieved without strong impacts on specific electricity generation costs. Considering this together with further additional benefits of RES such as reducing dependence on fossil fuel imports, the implementation of a specific RES-target in the order of 30% by 2030 appears to be beneficial.

Table 18: Development of specific system costs

Scenario		2020	2030	2040	2050
ETS-Only EE	€$_{2010}$/MWh	65	63	62	61
QUO-30	€$_{2010}$/MWh	64	62	58	60
SNP-30	€$_{2010}$/MWh	64	65	62	62

4.3.4 Grid infrastructure

This section describes the resulting grid infrastructure extensions modelled as a simplified transport model between the centres of the MS. In this way, the cost-optimisation of the power sector considering the fixed development path of RES allows including measures of infrastructure as one option to deal with the integration of variable RES-E. Most relevant assumptions include the net transfer capacity, the distance between the country centres, transmission losses and the cost parameter for the different technology options.

With regard to the results we show the resulting net transfer capacity (NTC) on the one hand and the combined illustration of transport capacity and grid length – the grid capacity kilometres - in Figure 48. Provided that the electricity mix by 2020 is very similar in all scenarios, the NTCs and the grid capacity kilometres are practically the same. According to PowerACE results the NTC required in all scenarios by 2020 amounts to roughly 93 GW in terms of NTC or to 52,000 GW * km in terms of grid capacity kilometres. Up to 2030 only very limited extensions of the grid infrastructure in 2020 in terms of NTC are required to integrate the additional RES-E technologies into the electricity system. Whilst the ETS Only EE Scenario leads to grid capacities of 108 GW, grid capacities show a slightly stronger increase in both RES-30 target scenarios reaching a capacity of 120 GW in SNP 30 and 124 GW in QUO 30. Considering the length of the grid line extensions, the ETS Only EE Scenario shows 64,000 GW * km, and grid capacity kilometres in both RES-target scenarios are very similar amounting to 75,000 – 76,000 GW * km. These results show that the differences in RES-E share of roughly 27% in the EU ETS Only Scenario and the RES-target scenarios of 30% involve comparatively similar grid capacity (kilometre) needs. Results indicate that the difference in technology mix of the renewables does not lead to differences in grid capacity (kilometres) o a medium term by 2030. Increasing shares of RES-E lead to more pronounced differences in grid capacity needs by 2050. Thus, the lowest level of grid capacity kilometres – 116,000 GW * km) – is estimated for the ETS Only EE Scenario with a RES-E share of below 60% by 2050. Although the RES-E share is highest in the SNP 30 Scenario with 78.3%, the grid capacity kilometre requirements in the QUO 30 Scenario exceed those of the SNP 30 Scenario. Whilst for the QUO 30 Scenario, the model estimates 155,000 GW * km by 2050, grid capacity kilometres in the SNP 30 Scenario amount to 150,000 GW * km. This shows that a stronger utilisation of wind onshore resources occurring in the QUO 30 Scenario based on the least cost support of RES implies higher investments into the grid infrastructure.

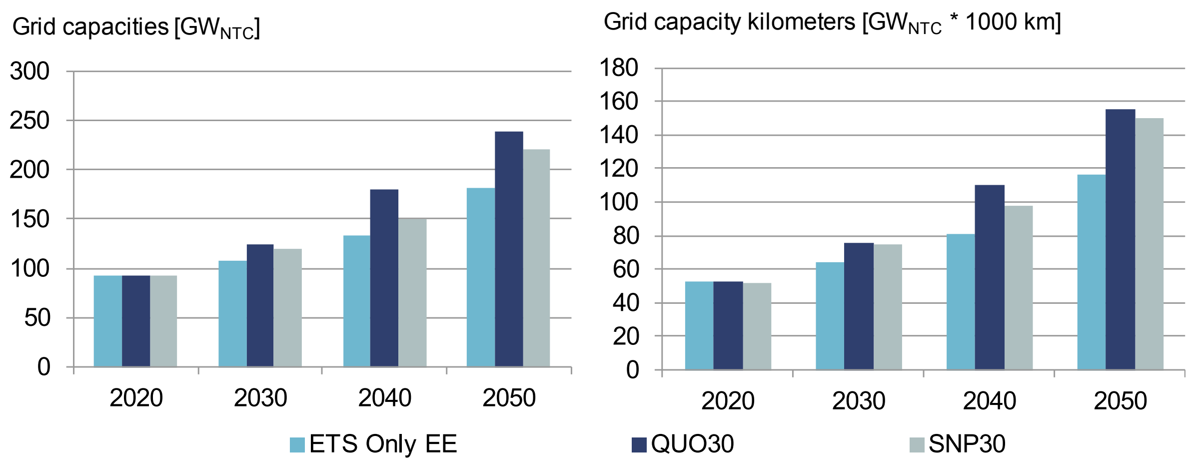


Figure 43: Grid capacities and grid capacity kilometres

4.3.4.1 Extension of the electricity grid

In the following we show the grid expansion needs for the year 2050 date, taking into consideration that grid extension and overall capacities are more critical than in 2030. Actually as we have found from our modelling grid expansion requirements until 2030 will be rather moderate as compared to the 2050 horizon.

In summary, all three scenarios result in considerable new interconnection capacities (see Figure 49, Figure 50 and Figure 51. Even in the ETS Only EE Scenario capacities for some interconnections have to be increased considerably. The greatest need for new power lines is caused by the necessity to connect the Iberian Peninsula, Italy and the United Kingdom to Central and Western European countries. In all three scenarios the abundant renewables potentials of southern Member States and Britain are exploited, leading to a high share of fluctuating generation. The lines are utilised to export the excess production that cannot be stored and conversely, to import power in times of calm winds, low solar generation and high demand. Especially Spain has to cope with a high share of fluctuating renewable generation from both wind and PV, but only has France as a direct neighbor in Europe. Therefore, the interconnectors between Spain and France have to be strengthened considerably. Due to its closeness to the critical regions, France becomes an important hub for renewable electricity. The strong need for grid investments in Western Europe, with power being transported over large distances, suggests that realising at least parts of the grid in the form of HVDC connectors could be most efficient. The concept and implications of a “Supergrid” approach will not be discussed here in detail, as it is beyond the scope of this study.

Another region requiring additional transmission lines is the connection between Norway with its abundant hydropower potential to the rest of Europe. This includes the connection to Denmark and to Central-Western Europe as well as a reinforcement of the connection to the United Kingdom. Required capacities are higher in the RES-target scenarios than in the ETS Only Scenario. The flexible hydro pump storage power plants located in Norway thus contributes of system integration of fluctuating RES.

In eastern and south-eastern Europe the grid expansions calculated by PowerACE-Europe are significantly lower than in Western Europe. This is mainly due to the lower share of fluctuating renewables: The higher share of generation technologies with adjustable generation such as hydropower, biomass and gas power plants in the eastern part of Europe reduces the necessity for power ex- or imports.

Finally, it is important to note, that less total additional transmission grid capacity is required in the SNP 30 Scenario, provided that RES-E generation is more balanced between Member States.

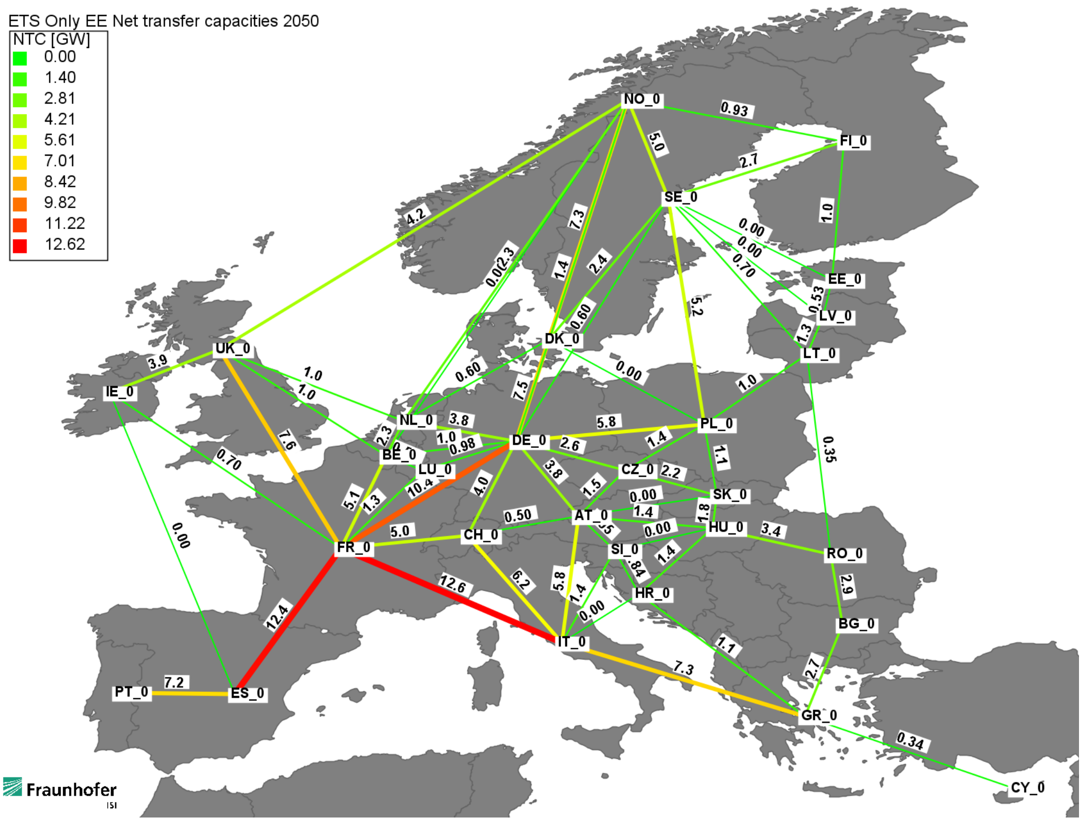


Figure 44: Net transfer capacities in the EU by 2050 in the ETS Only EE Scenario

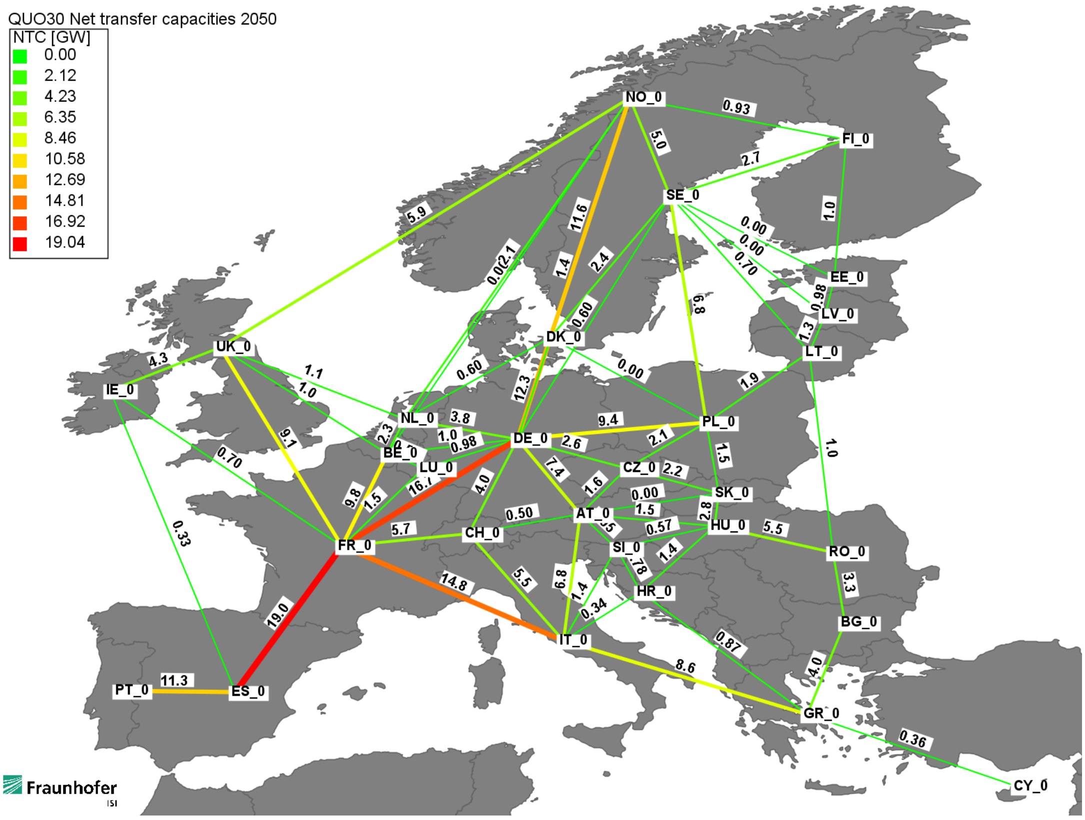


Figure 45: Net transfer capacities in the EU by 2050 in the QUO 30 Scenario

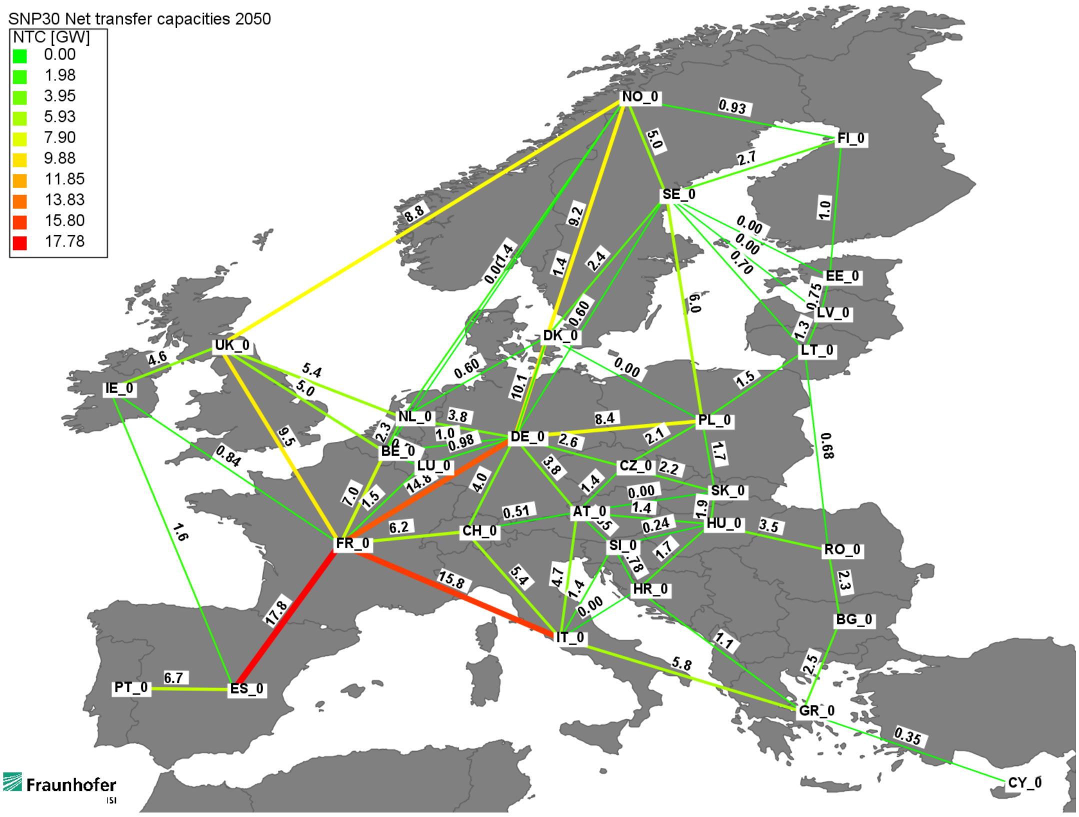


Figure 46: Net transfer capacities in the EU by 2050 in the SNP 30 Scenario

4.4 Conclusions

In this section, we analysed the financial impacts of different target setting options for RES in the power sector based on the optimisation model PowerACE. Thus, we optimised system costs of the power sector by estimating the capacity mix or construction of power plants, their dispatch in selected years and the construction and use of storage technologies. Thereby, the development of renewable technologies was not part of the optimisation procedure. Instead RES capacities estimated based on the Green-X simulations were used as exogenous input for PowerACE. The possible extension of the transmission grids between countries was also considered for the optimisation.

Results of this analysis show that costs associated to higher levels of RES-E share in the scenarios stay on a moderate level and do not lead to higher electricity generation costs as compared to other decarbonisation options. In the power sector a RES-target of 30% rather leads to slightly lower total system costs and lower costs per unit of electricity generated than a scenario with a pure GHG emission reduction target due to lower risk premiums and financing costs. This means that increasing the share of RES in the electricity system can be achieved without strong impacts on specific electricity generation costs.

Cost development in the three analysed scenarios varies only slightly. The QUO30 Scenario leads to slightly lower total system costs than under the ETS Only Scenario by 2030 due to the use of least cost resource allocation in both scenarios and lower discount rates for the QUO30 Scenario. Whilst annual system costs in the ETS Only Scenario amount to € 221 billion by 2030, system costs in the QUO30 Scenario add up to € 219 bn. The difference in costs is more pronounced on the longer term by 2050, where annual system costs under the ETS Only are estimated to € 264 billion and under the QUO 30 Scenario to € 259 bn.

Technology learning reduces the specific generation costs of the individual generation technologies, in particular of RES technologies on a longer term after 2030. By 2050 all scenarios are characterized by very similar specific system costs amounting to 60 €/MWh in the QUO30 Scenario, to 62 €/MWh in the SNP30 Scenario and to 61 €/MWh in the ETS Only Scenario, respectively.

In general the share of transmission grid costs in total system costs has been found to be very limited amounting to roughly 2% of overall system costs by 2030 and from 2.8% to 3.7% by 2050. The same holds for storage costs of around 2% of overall system costs. Generally it has been found that besides the existing pump-storage hydropower plants only very limited need for additional innovative storage technologies such as CAES or batteries exists. The cost optimal solution to provide the flexibility needed by the system is mainly based on a balanced portfolio of transmission extension, hydro storage and peak power plants.

5 Modelling energy efficiency options by 2030

Due to the strong dependence of the ambition level of a certain RES-target and the associated costs, this chapter provides a closer look into the options of further reducing energy demand by 2030. The work presented is based on detailed bottom-up analyses as described in the subsequent section[11].

5.1 Approach

The method underlying the assessment of energy efficiency potentials up to 2030 was **detailed bottom-up modelling of EU-wide and national potentials with the following models:**

- The **INVERT/EE-Lab model** (run by TU Wien) for residential and non-residential buildings
- The **FORECAST platform** (run by Fraunhofer ISI), including an industrial model as well as the electricity uses in the residential and service sector
- The **ASTRA model** (run by Fraunhofer ISI) providing potentials for the transport sector

In order to ensure comparability with the latest PRIMES projections, drivers such as the international fuel prices, the energy wholesale prices, the number of dwellings and the carbon prices were adapted from European Commission (2014a).

The international fuel prices assumed are displayed in Table 20.

Table 19: International Fuel prices (in €'10 per boe)

	2010	2015	2020	2025	2030
Oil	60,0	86,0	88,5	89,2	93,1
Gas	37,9	53,8	61,5	58,9	64,5
Coal	16,0	22,0	22,6	23,7	24,0

Source: European Commission (2014a). Primes-Modelling

Based on the international fuel prices and the country-specific electricity wholesale prices from the PRIMES 2013 projections, the end-use energy prices were projected based on the historical country- and sector-specific tax rates.

[11] The modelling work presented here has been realised in the context of an EU-supported project. More details are described in Braungardt et al. (2014).

Table 21 shows the scenarios which are developed for the projections. The first two are reference developments; the last three are relevant for the 2030 potentials.

Table 20: Overview of scenarios for future development of energy demand

Scenario name	Short name	Explanation
Baseline incl. Early Action	BASE_inclEA	Contains measures up to 2013 including. Can be compared with PRIMES 2013. Is useful in conjunction with EED (Art. 7) which admits "Early Action".
Baseline with measures	BASE_WM	Contains also measures which are already accepted or close to being accepted in 2014 and the near future. Sometimes this maybe very close to BASE_inclEA and can be the same.
Potential 2030 (low policy intensity)	Potential_2030_LPI	Potentials to 2030 with high discount rates and barriers persisting. The discount rates are sector and partially country specific. Details are provided in the report.
Potential 2030 (high policy intensity)	Potential_2030_HPI	Potentials to 2030 with low discount rates and barriers (partially or totally) removed. The discount rates are sector specific.
Potential 2030 (near economic)	Potential_2030_NE	Potentials which are not economic (that is the Net Present Value is negative given the discount rates used in the HPI scenario) but the scenario induces costs not much higher than present level energy consumption entails. This differentiates the NE potential from a pure "technical" potential which may include also higher cost.

The major difference of these bottom-up models as compared to a model like PRIMES is the **large degree of detail in the representation of technologies, actors and options which is necessary to reflect technology and actor-specific barriers**, or even measure-specific barriers. In the PRIMES descriptions it is stated that the model does integrate different types of barriers. However, PRIMES follows a more aggregate approach allowing only to a certain extent to directly integrate policies aiming at alleviating such barriers.

The high level of technological detail used in the approach applied in this study are illustrated below:

- The INVERT model distinguishes for each country a large number of different building types, building periods and specific decision makers with their actor-specific barrier structure. Individual technologies, e.g. for wall, roof or glazing, and their specific barriers are considered (see the examples of Figure 52 and Figure 53 for insulation packages in Bulgaria or Finland).

- FORECAST-Residential Appliances distinguishes a large number of individual appliances, with a separate model for IT-Appliances taking into account the specificity of each technology group, modeling therefore closely the impacts of eoc-design standards, labelling and top-runner programmes. For the residential sector for example the model distinguishes:
    - Large appliances: The model distinguishes refrigerators, freezers, washing machines, dryers and dishwashers
    - Information/Communication Technologies ICT: we distinguish televisions, laptop computers, desktop computers, computer screens, modems, set top boxes grouped in this category.
    - Lighting
    - Air conditioning
    - (electric and non-electric) Cooking
    - Others: The energy using devices not covered in the previous bullet points are grouped here

- FORECAST-Tertiary Appliances is a coherent bottom-up model, which allows simulating the electricity demand of the tertiary sector of the European countries by country up to 2035. FORECAST-Tertiary is based on the concept of energy-efficiency measures (EEMs), which represent individual options that improve energy efficiency after being diffused through the equipment stock. Examples are fluorescent lamps, reduction of stand-by losses or changed user behaviour. Consequently, policies are modelled by adjusting the dynamics and the level of diffusion of such EEMs, depending on general and technology specific economic parameters. The model distinguishes 8 sub-sectors, and 14 energy services including lighting, ventilation and cooling, refrigeration, cooking, data centres with servers, elevators, street lighting and others.

- FORECAST-Industry belongs to the family of bottom-up models considering the dynamics of technologies and socio-economic drivers and their impact on energy demand. Energy efficiency improvements take place via the diffusion of energy-efficiency measures. Their diffusion, in turn, depends on the cost-effectiveness (mostly payback time) including assumptions about barriers and heterogeneous expectations among companies. The model considers around 50 individual energy-intensive processes and products. For each process, it can be defined if it whether it is within the scope of the EU ETS or not. We distinguish about 14 individual energy carriers (electricity, light fuel oil, heavy fuel oil, natural gas, lignite, hard coal, district heating, biomass, etc.), calibrated to the Eurostat energy balances. The model further distinguishes electric cross-cutting technologies (CCT-E), like lighting, ventilation or pump systems or thermal cross-cutting technologies (CCT-T) like steam and hot water raising in the industrial sector from process-specific technologies as barriers to energy efficiency for those technologies are quite different from barriers for process-specific technologies (see Figure 54). In the model a number of 10-20 energy-efficiency measures are related to each CCT. Building standards as well as heating systems in the industrial sector are included via a stock model approach. The model draws on similar policy information on building standards as the INVERT model. In addition, the model follows an approach that differentiates different sizes of enterprises as they are subject to quite different barriers.

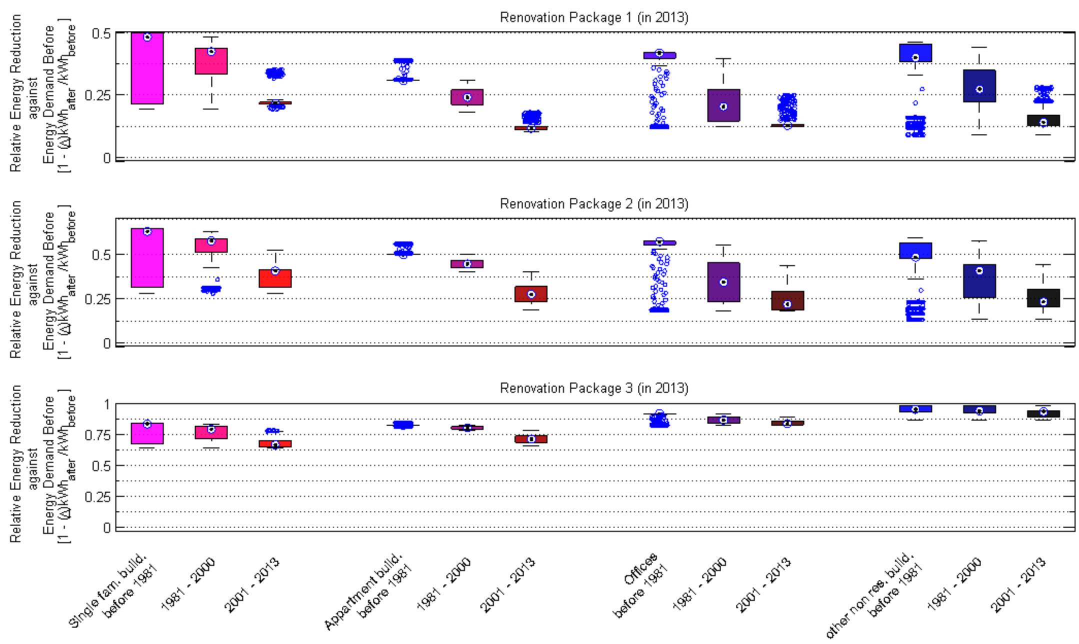


Figure 47: Relative energy reduction of different renovation packages in various building segments for the exemplary case of Bulgaria

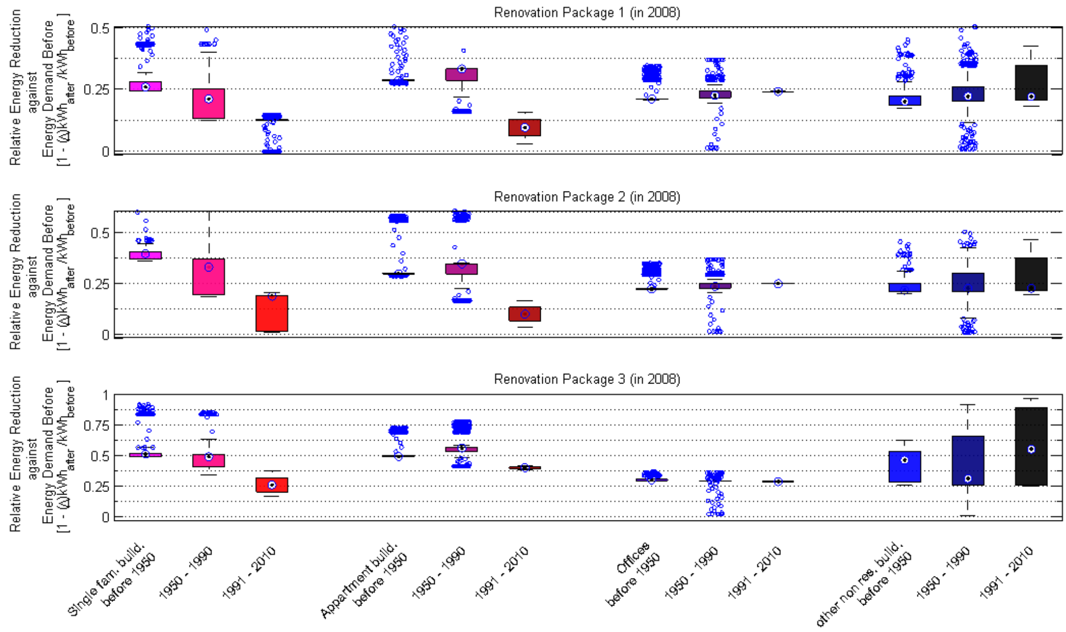
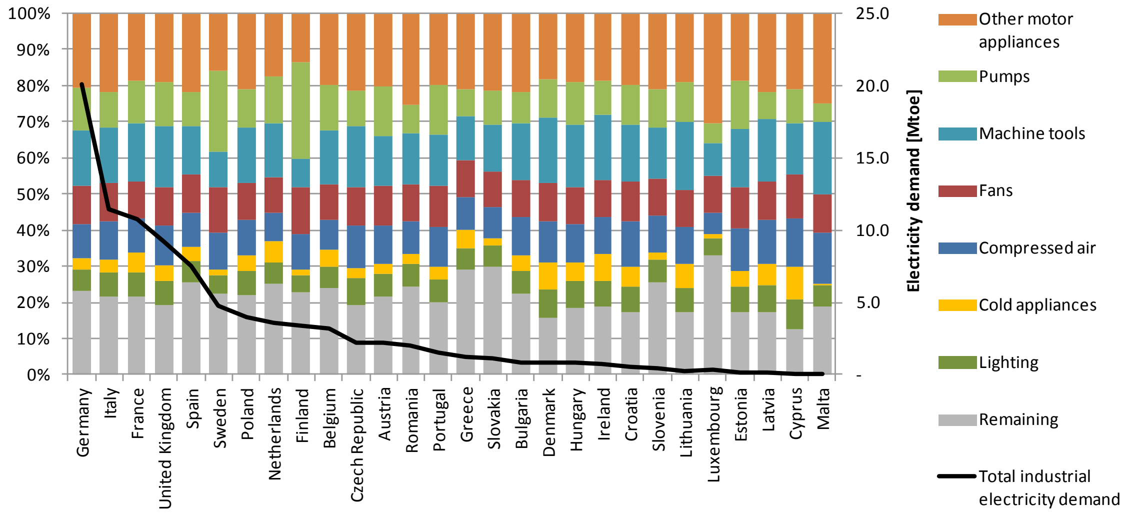


Figure 48: Relative energy reduction of different renovation packages in various building segments for the exemplary case of Finland



Source: FORECAST Industry model

Figure 49: Electricity demand by cross-cutting technology (CCT) and country in 2010 as share of total industrial electricity demand

Being able to represent this heterogeneity of technologies, actors and measure-specific barriers which are typical for energy efficiency is crucial in order to realise a realistic estimation of the financial impact associated to energy efficiency measures taking into account existing barriers and the respective policy measures to address the barriers.

In addition, presenting technologies in such a detailed manner allows to better draw on the growing empirical basis for **technological learning** (hence lowering of the additional cost), which is possible with energy efficiency similar to its relevance for the future costs of renewable energy technologies. Considering technological learning in a realistic manner provides further information on how policy instruments may contribute the cost of early market penetration of efficient technologies.

5.2 Discount rates: an important parameter in the impact evaluation

The modelling carried out by the EC with the PRIMES model uses comparatively high discount rates in order to reflect non-economic barriers – amounting up to 17.5% for the residential sector, which is lowered to 12% in the period after 2020 (European Commission 2014a). Due to the high upfront investment of energy efficiency measures, this assumptions leads to an overestimation of capital costs. In order to avoid this effect, we assume considerably lower discount rates than the discount rates used in the impact assessment and the reference projections (see Table 23).

Table 21: Overview of discount rates/payback assumptions used for the different sectors

Sector	Scenario	Discount rate
Household – space heating and hot water	All	3.1% to 3.7%
Tertiary – space heating and hot water	All	4.7% to 5.4%
Household - Appliances	Potential_2030_LPI	Typically 6% (discount rates vary between MS, appliances)
	Potential_2030_HPI Potential_2030_NE	2% (assuming removal of barriers as of 2020)
Tertiary - Appliances	Potential_2030_LPI Potential_2030_HPI Potential_2030_NE	15% 5% 5%
Industry	Potential_2030_LPI	Paypack up to 2 years accepted by 50% of companies; heating systems 15%
	Potential_2030_HPI	Paypack up to 5 years accepted by 60% of companies; heating systems 15%
	Potential_2030_NE	Companies accept longer payback periods [3)] heating systems 3%
Transport	N/A	N/A

Regarding the building sector (space heating and hot water in households and in the tertiary sector) the differences among the different scenarios is modelled through explicit policies that do remove existing barriers (in particular non-economic barriers) and the intensity of which varies across the scenarios. These policies are at first building codes (standards) with more or less compliance, varying degrees of economic incentives (e.g. for thermal building rehabilitation), different degrees of training and qualification (that act upon awareness and degree of information of the different actors and investors) as well as measures to enhance the rehabilitation rates or barriers, for example with respect to the user/investor dilemma. Hence, the discount rates in the building sector do not vary across the scenarios. Discount rates are distinguished between MS and between different investor types. In particular, different ownership constellations, income situation and age of building owners are taken into account. The country specific differences of the interest rates are based on Eurostat. The differentiation between different investor types is based on the stakeholder analysis and investigation of barriers in the project ENTRANZE (www.entranze.eu). In countries like France, Germany or Austria the interest rate is in the lower range from 3.1% to 3.7% for typical residential building owners, 4.7%-5.4% for non-residential buildings with higher values up to about 7.4% for low-income owners or elder people. In countries like Romania or Bulgaria the interest rates are in the higher range of 8-12% with higher values of up to 16% for low-income and aged building owners. In the near economic scenario companies also invest in measures with longer payback times and accept interest rates close to zero (assuming that these efficiency measures will be made attractive to companies, e.g. by subsidies). However, most of the measures are still very close to being cost-effective.

The differences in the assumptions for the discount rates in our approach compared the assumptions made in the Energy Roadmap is mainly based on the fact, that PRIMES does not take into account policies to lower investment risks into the cost calculation, whilst we consider the increased policy-induced stability in terms of lower discount rates. Thus, we assume that there are instruments to mitigate the risks and the risk perception. Also the perception of the energy user changes: with technologies developing they perceive less risk, awareness changes with respect to the threat of climate change, resource scarcity and high energy prices, a larger number consumers are willing to invest to mitigate those risks, policies are developed to accompany those awareness changes etc.

5.3 Cost-potentials for energy efficiency

The overview of the potentials derived from the detailed modeling analysis is shown in Table 24. The scenarios are those described in Table 21. Figure 55 shows in addition to the projections from PRIMES 2007, 2009 and 2013. It is seen that in the High Policy Intensity scenario final energy savings of 37% compared to the PRIMES 2007 reference projection are possible (i.e. in the “PRIMES 2007” metric which as the basis for the 2020 energy efficiency target and is also at present used in the discussion around 2030 targets).

Table 22: Potentials for energy efficiency by 2020 and 2030

EU28	Target for 2020 [Mtoe]	
	primary energy	final energy
EU28, Mtoe, Final Energy Demand	1483.00	1086.00

Main sectors	2008	Base_inclEA		Base_WM		LPI		HPI		NE	
		2020	2030	2020	2030	2020	2030	2020	2030	2020	2030
All sectors (primary energy)	**1691.34**	**1516.56**	**1429.96**	**1515.46**	**1425.72**	**1448.18**	**1292.51**	**1383.54**	**1170.61**	**1371.90**	**1135.31**
All sectors (final energy)	**1176.28**	**1118.27**	**1080.24**	**1117.46**	**1077.04**	**1067.85**	**976.40**	**1020.18**	**884.32**	**1011.60**	**857.65**
Residential sector	312.01	303.39	283.72	302.59	280.51	294.91	260.11	263.71	210.43	261.51	204.04
Tertiary sector	191.38	188.14	182.52	188.14	182.52	177.03	157.18	164.97	135.26	164.14	131.95
Transport	362.01	324.57	311.26	324.57	311.26	307.29	282.50	307.21	269.35	307.19	264.86
Industry	310.88	302.17	302.74	302.17	302.74	288.62	276.62	284.30	269.27	278.77	256.80

EU28, %, change compared to 2008

Main sectors	2008	Base_inclEA		Base_WM		LPI		HPI		NE	
		2020	2030	2020	2030	2020	2030	2020	2030	2020	2030
All sectors (primary energy)	100%	90%	85%	90%	84%	86%	76%	82%	69%	81%	67%
All sectors (final energy)	**100%**	**95%**	**92%**	**95%**	**92%**	**91%**	**83%**	**87%**	**75%**	**86%**	**73%**
Residential sector	100%	97%	91%	97%	90%	95%	83%	85%	67%	84%	65%
Tertiary sector	100%	98%	95%	98%	95%	92%	82%	86%	71%	86%	69%
Transport	100%	90%	86%	90%	86%	85%	78%	85%	74%	85%	73%
Industry	100%	97%	97%	97%	97%	93%	89%	91%	87%	90%	83%

EU28, %, change compared to Base_inclEA

Main sectors	2008	Base_inclEA		Base_WM		LPI		HPI		NE	
		2020	2030	2020	2030	2020	2030	2020	2030	2020	2030
All sectors (primary energy)											
All sectors (final energy)		100%	100%	100%	100%	95%	90%	91%	82%	90%	79%
Residential sector		100%	100%	100%	99%	97%	92%	87%	74%	86%	72%
Tertiary sector		100%	100%	100%	100%	94%	86%	88%	74%	87%	72%
Transport		100%	100%	100%	100%	95%	91%	95%	87%	95%	85%
Industry		100%	100%	100%	100%	96%	91%	94%	89%	92%	85%

Source: Braungardt et al. (2014)

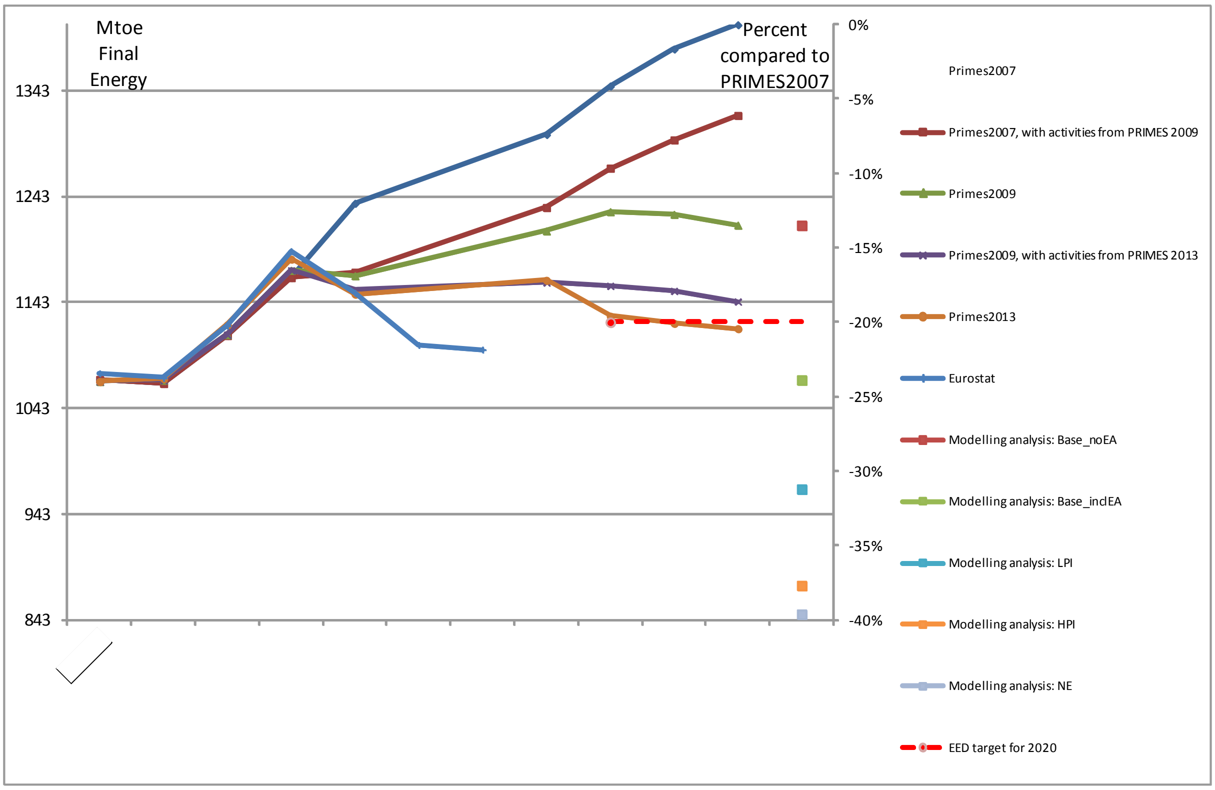


Figure 50: PRIMES projections 2007/2009/2013 and (final) energy efficiency potentials[12]

Source: Braungardt et al. (2014)

Based on the this detailed bottom-up potential determination, a cost-benefit-analysis was carried out, identifying the share of the technical potential that is already cost-efficient and the remaining part that is still limited by financial barriers. The result of the analysis is depicted in a cost curve (see Figure 56) that shows the specific potential as well as the financial benefits/costs involved for the years 2020, 2030, 2040, 2050. For the year 2020, the single measures are pointed out by means of coloured blocks. For the subsequent years, the order of the cost curve from the year 2020 is maintained and orientation lines help identifying the evolution of every single measure over time.

As indicated in Figure 56 the energy efficiency options for building envelopes are largely cost-effective, except some options for existing buildings in the household and tertiary sector that are uneconomic. When looking at the development of the options between 2020 and 2050 one can witness that in the long run they will become cost-effective as can be seen in 2040 and beyond. This illustrates that the specific costs for energy saving options in buildings change crucially on a long term basis due to increasing fuel prices and learning effects.

12 The figure is specified in the “PRIMES 2007” metric which as the basis for the 2020 energy efficiency target and is also at present used in the discussion around 2030 targets.

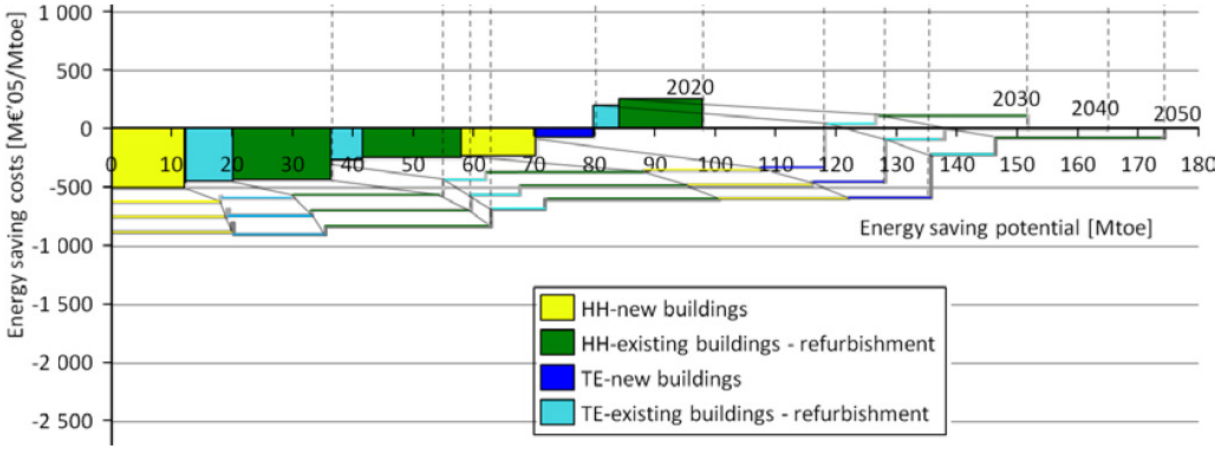


Figure 51: Exemplary illustration of the cost curve arrangement for residential and service sector buildings

5.4 Conclusions

In this section we have briefly represented the modelling of energy efficiency potentials existing at the level of the EU and of individual Member States. We have also discussed the associated financial impacts of the energy efficiency measures.

We argue that a methodologically sound modelling of energy efficiency options needs a detailed bottom-up modelling of potentials. In addition to the more aggregated modelling applied by PRIMES our bottom-up models count on a large degree of detail in the representation of technologies, actors and options which is necessary to reflect technology and actor-specific barriers, or even measure-specific barriers. Being able to represent this heterogeneity of technologies, actors and measure-specific barriers is an important ingredient in a realistic investigation of barriers and policy measures to overcome the barriers.

In addition, presenting technologies in such a detailed manner allows to better draw on the growing empirical basis for **technological learning**, which is possible with energy efficiency as it is with renewable energy sources. Considering technological learning in a realistic manner provides further information on how policy instruments may contribute the cost of early market penetration of efficient technologies.

Our scenario approach essentially uses usual capital costs, considering that there are instruments to mitigate the risks and the risk perception. In that we argue that policies of the future can learn from present experiences. Also the perception of the energy user changes: with technologies developing they perceive less risk, awareness changes with respect to the threat of climate change, resource scarcity and high energy prices, a larger number consumers are willing to invest to mitigate those risks, policies are developed to accompany those awareness changes etc.

6 Joint analysis of RES and energy efficiency potentials by 2030

After analysing costs of RES-target without changes in energy demand we assess the combination of RES-targets and energy efficiency targets. The estimation of combined costs are not realised by a hard link between both modelling approaches, but it represents rather an individual potential assessment of renewables (Green-X) and energy efficiency options.

6.1 Interaction between RES target and energy efficiency targets

As shown in Figure 57, the level of ambition of a certain RES-target depends on the level of energy demand. Thus, demand reductions reduce the ambition level of a constant target (expressed in share of final consumption). As one can observe from this figure, the target level of 30% related to the final demand after implementation of the energy efficiency target translates into a level of 21% in relation to the baseline demand with no efficiency target. Therefore the introduction of an energy efficiency target causes a substantially lower total RES deployment as compared to the baseline case. This causes lower average and marginal generation costs of the RES portfolio and therefore lower costs of the RES target as we will show in the following.

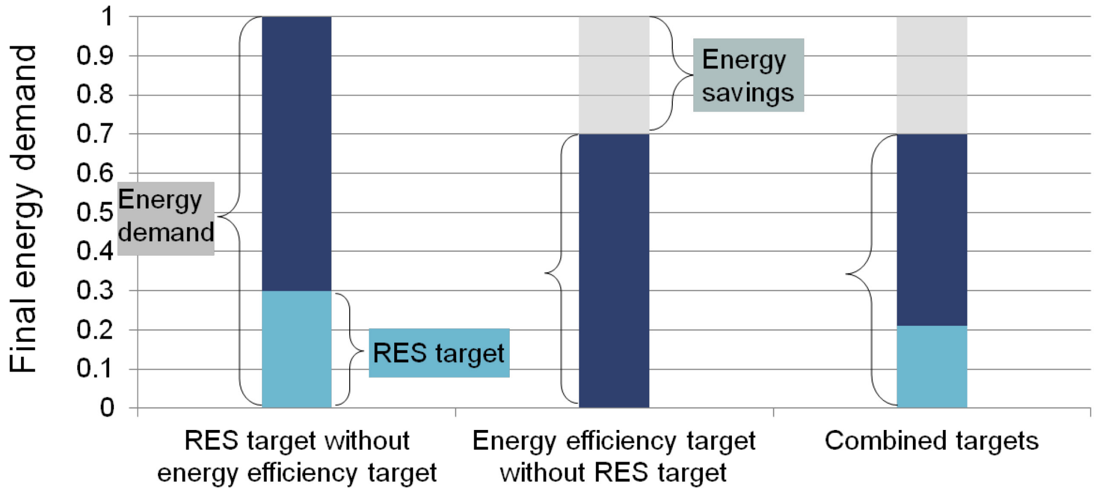


Figure 52: Interaction between RES target and energy efficiency target

6.2 Approach

The approach of combining RES and energy efficiency target is presented below in Figure 24. Generally both cost components of the RES target and the energy efficiency target are added. In the schematic example shown in the figure the cost reduction caused by the energy efficiency target is (partially) compensated by a RES target. In the following sections the implications of a combined target on final energy consumption, RES deployment and system costs will be presented.

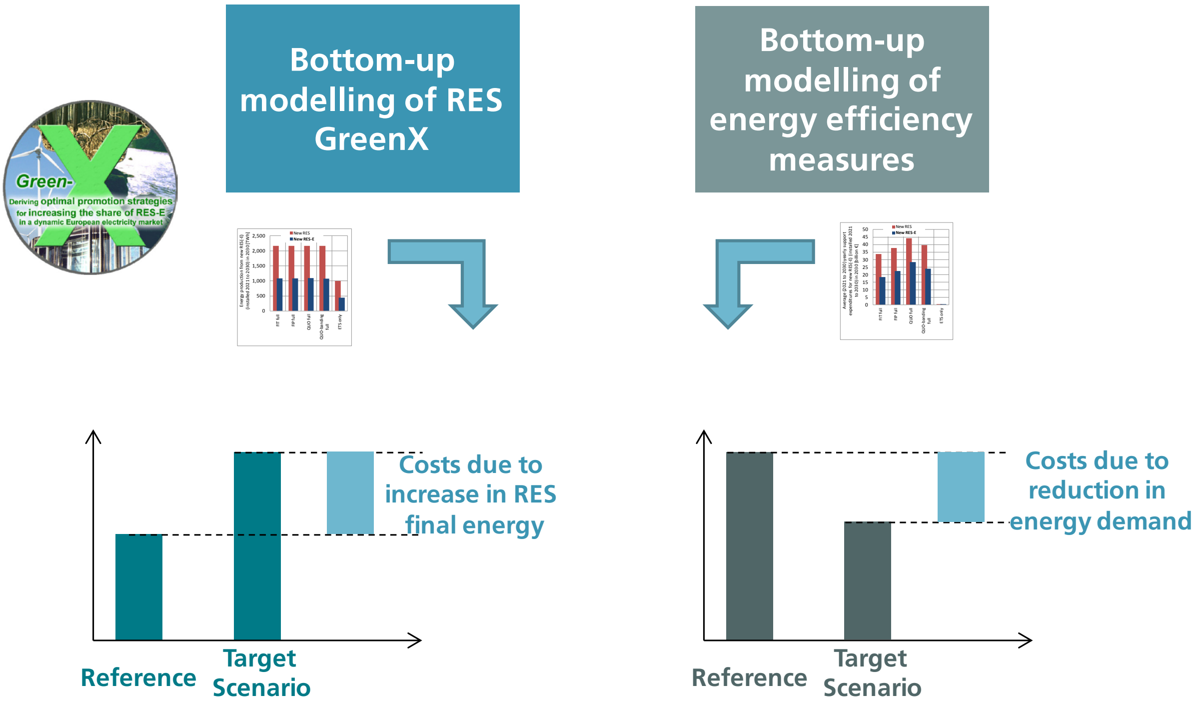


Figure 53: Approach of combining RES and energy efficiency – schematic presentation of the combination of the costs of each sub-target

6.3 Scenario definition

Scenarios analysed in this section are based on the scenario definitions already presented in chapter 3 on the modelling of the future development of RES by 2030 (see in detail section 3.1). However, the focus here is on the different ambition level of RES and energy efficiency target. Different policy measures such as feed-in systems or quota obligations in the area of renewable energy sources or different estimations for energy efficiency potentials depending on the policy intensity are not differentiated on scenario level, but they rather define range for the costs of a certain target ambition level. Thus, in addition to the ETS-Only EE Scenario we introduce a Scenario, where 40% GHG emission reductions by 2030 are achieved exclusively by the ETS, the ETS-Only Scenario and a Scenario where a 30% RES-target is achieved in the absence of energy efficiency measures. Table 25 provides an overview of the scenarios assessed.

Table 23: Scenario overview for joint analysis of RES and energy efficiency potentials by 2030

Scenario Name	Description	Corresponding Scenario from IA
ETS-Only	• ETS only driver for low-carbon technology support • No energy efficiency measures • Primary energy savings evaluated against the 2007 Baseline projections for 2030 of 25% • Achievement of 2020 RES targets • No dedicated support for RES beyond 2020 • 27% RES-Share by 2030	GHG40
30% RES no EE	• ETS main driver for low-carbon technology support, no energy efficiency measures • No energy efficiency measures • Primary energy savings evaluated against the 2007 Baseline projections for 2030 of 25% • Achievement of 2020 RES targets • After 2020 continuation of RES support by means of an EU green certificate scheme or a feed-in premium • 30% RES-Share by 2030	–
30% RES 30% EE	• ETS one driver for low-carbon technology support • Energy efficiency measures in place • Primary energy savings evaluated against the 2007 Baseline projections for 2030 of 30% • Achievement of 2020 RES targets • After 2020 continuation of RES support by means of an EU green certificate scheme or a feed-in premium. • 30% RES-Share by 2030	GHG40 EE RES30
35% RES 34% EE	• ETS one driver for low-carbon technology support • Energy efficiency measures in place • Primary energy savings evaluated against the 2007 Baseline projections for 2030 of 34% • Achievement of 2020 RES targets • After 2020 continuation of RES support by means of an EU green certificate scheme or a feed-in premium. • 35% RES-Share by 2030 • Energy Savings evaluated against the 2007 Baseline projections for 2030	GHG40 EE RES35

Figure 59 shows the final energy assumption and final energy contribution of renewable energy sources in Mtoe in 2030 for the four scenarios defined above.

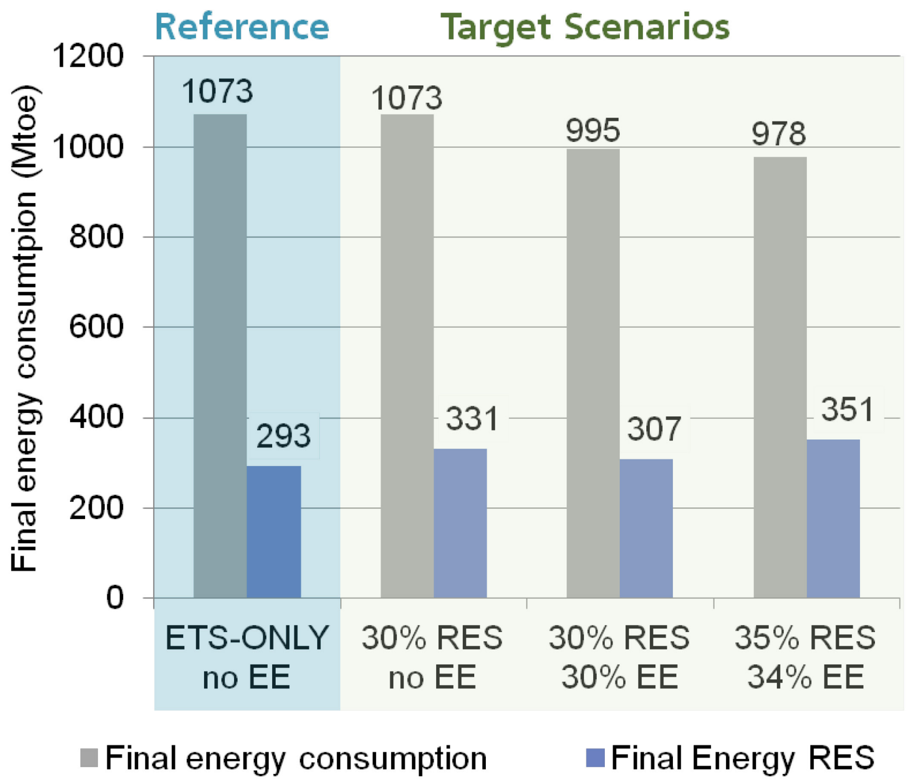


Figure 54: Final energy assumption and final energy contribution of renewable energy sources in Mtoe in 2030 for reference and target scenarios

6.4 Cost estimation of target options

The costs of the different combinations of RES and efficiency target estimated as described in section 7.2 are presented in Figure 60 below.

Thereby, we first show the estimated cost of a 30% RES target compared to a 27% RES-Share in the ETS-Only no EE Scenario. These figures are based on a comparatively high final energy demand of 1073 Mtoe by 2030 provided that no dedicated energy efficiency measures are in place (left side of Figure 60). Practically, costs shown reflect the difference of overall generation costs for RES in the “30% RES no EE” Scenario and the reference taken, in this case the “ETS-Only no EE” Scenario. Costs are shown as annual average over the period 2021-2030. The range of costs given for the same scenario with the same RES-targets and energy efficiency targets results from different policy measures, i.e. the approach that is used for the burden sharing regarding the RES target among MS. Without energy efficiency target, the additional average annual costs of a RES target of 30% amounts to € 3.6 to 5.1 billion. As the development of energy demand is the same in both scenarios there are no additional costs from energy efficiency measures.

If additional energy efficiency measures are applied, the 30% RES-target requires only a reduced amount of renewable-based final energy – instead of 331 Mtoe in the "30% RES no EE" Scenario only 307 Mtoe are needed to achieve the 30% RES-target in the "30% RES 30% EE" Scenario. As a consequence, additional costs arising from the increased use of RES that can be directly attributed to the RES- target are reduced to € 1 – 4 billion for a combined target of 30% for RES and 30% for energy efficiency. Again these costs compare to the reference of the "ETS-Only no EE" Scenario. The application of energy efficiency measures do not lead to an additional cost, but to economic savings ranging from € 16.5 to 22 billion. The combined financial impact of the 30% RES-target and the 30% energy efficiency target results in overall economic savings of € 12.5 to 21.4 billion on average.

After increasing the ambition level of the RES-target to 35% and the primary energy savings compared to the 2007 PRIMES baseline projections for 2030 to 34%, additional costs for the RES-target increase to a range of € 5-6.3 billion leading to a RES-contribution of 351 Mtoe by 2030. Economic savings from energy demand reduction increase slightly to € 20 to 26.8 billion and lead to a combined impact of 13.7 to 21.9 billion.

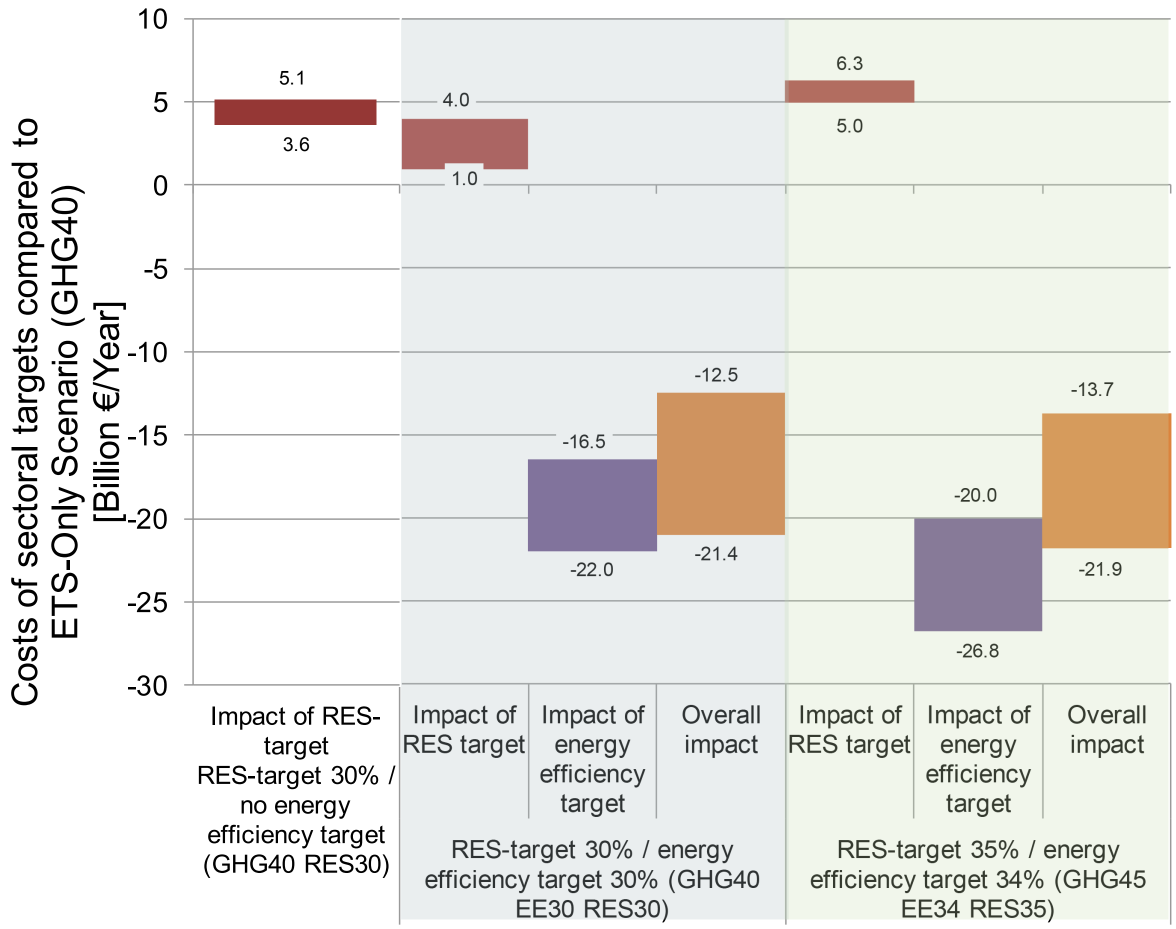


Figure 55: Costs of sectoral targets (RES and energy efficiency) compared to an ETS-Only Scenario

Summary of main results

The key results for the case **30% RES no EE** can be summarized as follows:

- Without energy efficiency target in place, the additional average annual costs of a RES target of 30% amounts to a moderate € 3.6 to 5.1 billion. As the development of energy demand is the same in both scenarios there are no additional costs from energy efficiency measures.

The key results for the case **30% RES 30% EE** can be summarized as follows:

- Without energy efficiency target, the additional average annual costs of a RES target amount to € 3.6 to 5.1 billion, corresponding to less than 0.25 % of energy system costs.
- These costs that can be directly attributed to the RES- target are reduced amounting from € 1 – 4 billion for a combined target of 30% for RES and 30% for energy efficiency.
- Energy efficiency targets reduce costs of RES-targets and lead to overall economic savings ranging from € 16.5 to 22 billion.

The key results for the case **35% RES 34% EE** can be summarized as follows:

- In this target combination the costs that can be directly attributed to the RES- target amount to € 5 – 6.3 billion.
- The savings that can be directly attributed to the EE- target amount to € 20.0 – 26.8 billion.
- In total the combination of RES- and EE-targets leads to overall economic savings ranging from € 13.7 to 21.9 billion.

6.5 Conclusions

The combined implementation of specific targets for energy efficiency and renewable energies in addition to a pure GHG emission reduction target will lead to **lower total system costs for the overall energy system**. This is mainly based on lower investment risks and financing costs for energy efficiency and renewable energy technologies if targets for EE and RES are in place.

Additional costs resulting from the **RES-target of 30%** without setting a specific target for energy efficiency remain moderate and are estimated to **€ 3.6 to 5.1 billion per year** in 2030, which corresponds to **less than 0.25% of the total system costs**. The savings resulting from energy efficiency targets over-compensated the additional costs resulting from the renewable energy target in all cases analysed here.

In quantitative terms the **combination of energy efficiency targets and RES targets** leads to overall average annual **savings in savings in terms of total system costs amounting to € 12-21 billion until 2030 with 30% RES and 30% energy efficiency**, whilst savings in a scenario with even higher RES and efficiency targets (**35% RES/34% efficiency) further increase to € 14-22 billion** per year on average.

With regard to the **power sector**, we have learned that a **renewable energy target of 30% does not lead to higher average electricity generation costs,** if suitable approaches for burden sharing and RES policies are implemented. According to our study a **RES-target of 30%** does not lead to a more expensive power sector in terms of generation costs, it even shows **slightly lower costs per unit of electricity generated** than a scenario with a pure GHG emission reduction target. Dedicated targets and policies for RES help reduce risk premiums, financing costs and support costs.

Estimating the impacts of different target setting options requires the application of detailed modelling tools with high level of detail regarding the potential of RES-use and energy efficiency measures. As to the power sector, the increasing share of RES requires a detailed modelling of generation data with a high temporal resolution.

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