Essays on the Economics of Decarbonization and Renewable Energy Support

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Nomenclature

a .... Annum

avail .... availability

BMU .... Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit (German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety)

BMWi .... Bundesministerium für Wirtschaft und Technologie (German Federal Ministry of Economics and Technology)

bn .... Billion

BSW .... Bundesverband Solarwirtschaft (German Solar Industry Association)

CAES .... Compressed air energy storage

CCGT .... Combined cycle gas turbine

CCS .... Carbon capture and storage

CHP .... Combined heat and power

CO_2 .... Carbon dioxide

CSP .... Concentrating solar power

ct .... Cent

Dena .... Deutsche Energie-Agentur (German Energy Agency)

Dii .... Desertec Industrial Initiative

DNI .... Direct Normal Irradiance

EC .... European Commission

EEA .... European Environment Agency

EEX .... European Energy Exchange

EIA .... Energy Information Administration

ENTSO-E ... European Network of Transmission System Operators for Electricity
EREC .... European Renewable Energy Council
ES .... Spain
EU .... European Union
EU ETS ..... European Union Emissions Trading System
EUR .... Euro
EWI .... Energiewirtschaftliches Institut an der Universität zu Köln
(Institute of Energy Economics at the University of Cologne)
FIT .... Feed-in tariff
FOM .... Fixed operation and maintenance costs
GER .... Germany
GHG .... Greenhouse gas
GJ .... Gigajoule
GW .... Gigawatt
GWh .... Gigawatt hour
GWS .... Gesellschaft für Wirtschaftliche Strukturforschung mbH
h .... Hour
HH .... Household
HVDC .... High voltage direct current
IEA .... International Energy Agency
innov .... innovative
kW .... Kilowatt
kWh .... Kilowatt hour
kWp .... Kilowatt peak
LCOE .... Levelized costs of electricity
m .... Meter
m^2 .... Square meter
MC .... Marginal costs
MENA .... Middle East and North Africa
Mio .... Million
MV^{el} .... Marginal value of power supply
MV^{ren} .... Marginal value of renewable energy supply
MW .... Megawatt
MW_{el} .... Megawatt electric

MW_{th} .... Megawatt thermal

MWh .... Megawatt hour

MWh_{el} .... Megawatt hour electric

MWh_{th} ...... Megawatt hour thermal

NA .... North Africa

NMC .... Net marginal costs

NREAP ...... National Renewable Energy Action Plan

NTC .... Net transfer capacities

O&M .... Operations and maintenance

OCGT .... Open cycle gas turbine

PT .... Portugal

PV .... Photovoltaics

reg .... region

RES .... Renewable energy sources

RES-E .... Renewable energy sources for electricity generation

s .... Second

t .... (Metric) tonne

TEP .... Tradable emission permits

TES .... Thermal energy storage

TGC .... Tradable green certificates

TSC .... Total system costs

TWh .... Terawatt hour

TWh_{el} .... Terawatt hour electric

TWh_{th} .... Terawatt hour thermal

TYNDP ..... Ten-Year Network Development Plan

W .... Watt

Chapter 1

Introduction

1.1 Background and motivation

The European Union (EU) aims to reduce greenhouse gas (GHG) emissions by 80 - 95 % in 2050 compared to 1990 levels (EU Council (2009)). Given the power sector's dominant share of GHG emissions in Europe and comparatively high technological potential for abating GHG emissions, the transition towards a low-carbon economy implies an almost complete decarbonization of Europe's power sector. Compared to today, massive GHG emission savings could be achieved along various pathways and through various technology mixes.

To achieve commitment with the GHG emission reduction targets, the EU has implemented a cap-and-trade system for GHG emissions (EU-ETS) that includes electricity generation and energy-intensive industries (EU (2009b)). Aside from GHG emission reduction targets and the EU ETS, the EU has also adopted mandatory renewable energy targets. In 2020, renewable energy technologies are set to supply 20 % of the EU's energy consumption (EU (2009a)) and at least 34 % of the EU's electricity consumption (EC (2010b)).

Although supplementary renewable energy targets can hardly be justified from a climate protection perspective – given the implementation of the EU ETS which limits the overall GHG emissions in Europe – there is a political will to expand renewable energy generation across Europe. However, to date, most renewable energy technologies (except for small-scale hydro power and low-cost biomass power plants) are not yet competitive in Europe, even when accounting for external costs of GHG emissions. To nevertheless encourage renewable energy generation, most EU member states have implemented renewable energy support schemes.

Renewable energy support schemes can commonly be classified into price- and quantity-based regulations, fiscal incentives and public finance (e.g., IRENA (2012) and IPCC (2011)). While price-based regulations such as feed-in tariffs or feed-in premiums fix the price paid for renewable electricity, quantity-based regulations such as quota obligations (in combination with tradable green certificates) and tenders set the quantity of renewable electricity to be generated.

Feed-in tariffs (FIT) are the most commonly referenced support scheme used by EU member states, followed by quota obligations and feed-in premiums (CEER (2013)). In contrast to under quota obligations and feed-in premiums, renewable energy generators under a FIT system are sealed off from the market price signal. While this limits the financial risk for renewable energy investors, it also prevents an efficient allocation of financial resources from the total system perspective.

Aside from these traditional support schemes, the deployment of renewable energy capacities and particularly photovoltaic (PV) systems is also driven by the emergence of grid parity in many European countries. Grid parity marks the point in time at which the electricity generation costs of PV systems have dropped below the level of end-consumer electricity prices, such that the consumption of self-produced PV electricity becomes cheaper than the consumption of grid-supplied electricity.[2] Since the consumption of self-produced electricity is exempt from paying taxes, levies and other surcharges, the concept of grid parity reflects a financial incentive for the deployment of PV systems. Moreover, network operators traditionally charge energy-related instead of capacity-related network tariffs. The exemption from additional charges and the current network tariff structure incentivize the consumption of self-produced rather than grid-supplied electricity once the electricity generation costs of PV systems have fallen below the end-consumer electricity price.

1.2 Structure and scope of the thesis

The thesis consists of five essays investigating various aspects associated with the decarbonization of Europe's power sector and the politically incentivized expansion of renewable energy generation. All essays can be read independently. In the following, the content of each essay is briefly outlined.

[2]Such markets are currently emerging in Germany, Denmark, Spain and Italy, within both the residential and the commercial sectors (IEA (2013)).

1.2.1 Decarbonizing Europe's power sector by 2050: Analyzing the economic implications of alternative decarbonization pathways

The analysis presented in Chapter 2 discusses the economic implications of alternative decarbonization pathways for Europe's power sector up to 2050. It has been published in the Journal *Energy Economics* (Jägemann et al. (2013a)).[3] The paper was written in co-authorship with Michaela Unteutsch (née Fürsch), Simeon Hagspiel and Stephan Nagl and I am the leading author of this paper.

The decarbonization of Europe's power sector can be achieved along various pathways up to 2050. By applying a linear electricity system optimization model for Europe, we find that the costs of decarbonization vary between 139 and 633 bn €$_{2010}$ up to 2050. In line with economic theory, the decarbonization of Europe's power sector is achieved at minimal costs under a stand-alone CO_2 reduction target, which ensures competition between all low-carbon technologies. If, however, renewable energies are exempt from competition via supplementary renewable energy targets or if investments in new nuclear power and fossil-fuel based power generation with CO_2 capture and storage (CCS) are politically restricted, the costs of decarbonization significantly rise. Moreover, we find that the excess costs of supplementary renewable energy targets depend on the acceptance of alternative low-carbon technologies. For example, given a complete nuclear phase-out in Europe by 2050 and politically implemented restrictions on the application of carbon capture and storage technologies, supplementary renewable energy targets are redundant. While in such a scenario the overall costs of decarbonization are comparatively high, the excess costs of supplementary renewable energy targets are close to zero.

1.2.2 The economic inefficiency of grid parity: The case of German photovoltaics

The essay presented in Chapter 3 analyzes the economic inefficiency associated with the concept of grid parity for the case of photovoltaic (PV). It has been published in the Working Paper Series of the Institute of Energy Economics at the University of Cologne (Jägemann et al. (2013b)).[4] The paper was written in co-authorship with Simeon Hagspiel and Dietmar Lindenberger and I am the leading author of this paper.

PV grid parity has recently been achieved in Germany on the household level, which incentivizes electricity consumers to invest in PV and battery storage capacities for

[3]This article is copyrighted and reprinted by permission. The presented article first appeared in Energy Economics, Vol. 40 .

[4]A preliminary version of this paper was presented at the second International Workshop on Integration of Solar Power into Power Systems in Lisbon (2012).

in-house PV electricity consumption. This paper analyzes the optimization behavior of households and the economic consequences of the indirect financial incentive for in-house PV electricity consumption by combining a household optimization model with an electricity system optimization model. Up to 2050, we find that households save 10 % - 18 % of their accumulated electricity costs by covering 38 - 57 % of their annual electricity demand with self-produced PV electricity. Overall, cost savings on the household level amount to more than 47 bn €$_{2011}$ up to 2050. However, while the consumption of self-produced electricity is beneficial from the single household's perspective, it is inefficient from the total system perspective. Accumulated to 2050, the single household's optimization behavior is found to cause excess costs of 116 bn €$_{2011}$. Moreover, it leads to significant redistributional effects by raising the financial burden for (residual) electricity consumers by more than 35 bn €$_{2011}$ up to 2050. In addition, it yields massive revenue losses on the side of the public sector and network operators of more than 77 and 69 bn €$_{2011}$, respectively, by 2050.

1.2.3 An illustrative note on the system price effect of wind and solar power - The German case

The essay presented in Chapter 4 analyzes the system price effect of wind and solar power generation. The paper has not yet been published and I am the sole contributor.

Exposing wind and solar power to the market price signal allows for cost-efficient investment decisions, as it incentivizes investors to account for the marginal value (MV^{el}) of renewable energy technologies. As shown by Lamont (2008), the MV^{el} of wind and solar power units depends on their penetration level. More specifically, the MV^{el} of wind and solar power units is a function of the respective unit's capacity factor and the covariance between its generation profile and the system marginal costs. The latter component of the MV^{el} (i.e., the covariance) is found to decline as the wind and solar power penetration increases, displacing dispatchable power plants with higher short-run marginal costs of power production and thus reducing the system marginal costs in all generation hours. This so called 'system price effect' is analyzed in more detail in this paper. The analysis complements the work Lamont (2008) in two regards. First of all, an alternative expression for the MV^{el} of wind and solar power units is derived, which shows that the MV^{el} of fluctuating renewable energy technologies depends not only on their own penetration level but also on a variety of other parameters that are specific to the electricity system. Second, based on historical wholesale prices and wind and solar power generation data for Germany, a numerical 'ceteris paribus' example for Germany is presented which illustrates that the system price effect is already highly relevant for both wind and solar power generation in Germany.

1.2.4 A note on the inefficiency of technology- and region-specific renewable energy support - The German case

The essay presented in Chapter 5 adds to the ongoing debate surrounding the cost-efficient achievement of politically implemented renewable energy targets. The paper has not yet been published and I am the sole contributor.

Renewable energy (RES-E) support schemes have to meet two requirements in order to lead to a cost-efficient renewable energy mix. First, RES-E support schemes need to expose RES-E producers to the price signal of the wholesale market, which incentivizes investors to account not only for the marginal costs per kWh ($\overline{MC}$) but also for the marginal value per kWh ($\overline{MV^{el}}$) of renewable energy technologies. Second, RES-E support schemes need to be technology- and region-neutral in their design (rather than technology- and region-specific). That is, the financial support may not be bound to a specific technology or a specific region. In Germany, however, wind and solar power generation is currently incentivized via technology- and region-specific feed-in tariffs (FIT), which are coupled with capacity support limits. As such, the current RES-E support scheme in Germany fails to expose wind and solar power producers to the price signal of the wholesale market. Moreover, it is technology- and region-specific in its design, i.e., the support level for each kWh differs between wind and solar power technologies and the location of their deployment (at least for onshore wind power). As a consequence, excess costs occur which are burdened by society. This paper illustrates the economic consequences associated with Germany's technology- and region-specific renewable energy support by applying a linear electricity system optimization model. Overall, excess costs are found to amount to more than 6.6 Bn €$_{2010}$. These are driven by comparatively high net marginal costs of offshore wind and solar power in comparison to onshore wind power in Germany up to 2020.

1.2.5 The economic value of storage in renewable power systems: The case of thermal energy storage in concentrating solar power plants

The last part of this thesis (Chapter 6) analyzes the economic value of storage as a function of the overall generation mix and illustrates the economic inefficiency arising from feed-in tariff (FIT) systems for the special case of thermal energy storage units in concentrating solar power (CSP) plants. The paper was written in co-authorship with Stephan Nagl and Michaela Unteutsch (née Fürsch). It has been published in the Working Paper Series of the Institute of Energy Economics at the University of Cologne (Nagl et al. (2011a)) as well as in Nagl (2013).[5]

[5]The essey published in this thesis is a revised version.

Thermal energy storages (TES) can reduce the production costs (per kWh) of CSP plants due to a higher usage of the capital intensive power plant block. As a consequence, investors have an incentive to build thermal energy storages without considering the wholesale price signal under a FIT scheme. Our simulation with a linear electricity system optimization model shows that TES units are not cost-efficient from a system perspective in today's electricity systems as CSP plants can directly feed into the grid when wholesale prices are comparatively high. Hence, FIT systems set an inefficient incentive to invest in TES units by neglecting wholesale price signals. However, the value of storage increases in electricity systems with higher shares of fluctuating renewable generation. Therefore, CSP plants with integrated thermal storages may play a significant role in mostly renewable-based electricity systems in the future.

Chapter 2

Decarbonizing Europe's power sector by 2050 - Analyzing the economic implications of alternative decarbonization pathways[6]

2.1 Introduction

In October 2009, the European Council endorsed the objective of the European Union (EU) to reduce greenhouse gas (GHG) emissions by 80-95 % in 2050 compared to 1990 levels (EU Council (2009)). Given the power sector's dominant share of CO_2 emissions in Europe and its comparatively high technological potential for abating CO_2 emissions, the transition towards a low-carbon economy implies an almost complete decarbonization of Europe's power sector.[7] The decarbonization could be achieved through various

[6]This article is copyrighted and reprinted by permission. The presented article first appeared in Energy Economics, Vol. 40

[7]The electricity and heat production accounted for 36.5 % of total CO_2 emissions in the EU in 2009 (IEA (2011)).

technology mixes that all allow for massive CO_2 savings in comparison to today's electricity systems, as shown by a number of recent studies (e.g., EC (2011), ECF (2010), Eurelectric (2010), EWI (2011), Greenpeace (2010) and Greenpeace (2012)).

Aside from the European Emissions Trading System (EU ETS) – which acts as the cornerstone of EU climate policy for electricity generation and energy-intensive industries (EU (2009b)) – the EU has implemented mandatory renewable energy targets. In 2020, renewable energy technologies are supposed to supply 20 % of the EU's energy consumption (EU (2009a)) and at least 34 % of the EU's electricity consumption (EC (2010b)).[8]

If supplementary renewable energy targets are implemented to reduce GHG emissions, the issue of counterproductive overlapping regulation arises. First-best economic principles – based on the seminal work of Crocker (1966), Dales (1968) and Montgomery (1972) – suggest that GHG reduction targets could be achieved at least-cost by the implementation of a stand-alone cap-and-trade system covering all sources of GHG emissions. A market for tradable emission certificates is cost-efficient as it establishes a uniform GHG emission price, which serves as a common benchmark for the marginal costs of each potential GHG abatement option. Boeters and Koorneef (2011) argue that supplementary instruments, such as mandatory renewable energy targets, interfere with this least-cost principle by exempting renewables as a particular GHG abatement option from the common benchmark price. Thus, given the assumption of perfect markets, supplementary renewable energy targets are either redundant or associated with excess costs. This argumentation is in line with Tinbergen (1952), who showed that a number of policy targets is best addressed by an equal number of policy instruments.[9]

In this paper, we analyze the costs of decarbonization and the excess costs of supplementary renewable energy (RES-E) targets for Europe's power sector in over 36 scenarios up to 2050. Our analysis contributes to the literature in several ways. First, we explicitly account for the fact that the costs of decarbonization and the excess costs of supplementary RES-E targets depend on two key conditions: the acceptance of alternative low-carbon technologies (such as new nuclear power plants and CCS technologies) and the development of the economic conditions (mostly defined by the EU's electricity demand, renewable energy investment costs and fossil fuel prices). Second, we apply a linear electricity system optimization model for Europe, which is characterized by a

[8]According to the National Renewable Energy Action Plans of the EU member states (EC (2010b)), the share of renewable energy sources in electricity consumption is targeted to increase to 34.3 % in 2020.

[9]The theoretical implications of overlapping regulation for the costs of decarbonization (in the first- and second-best world) have widely been analyzed. Lehmann (2012), Fischer and Preonas (2010) and Del Río González, P. (2007) provide a survey of recent literature on the theoretical interaction of GHG emission reduction and renewable energy targets.

comparatively high technological and regional resolution, to analyze the implications of alternative decarbonization pathways for Europe's power sector. Hence, we are able to accurately capture the technological and economic consequences of political interference up to 2050.[10]

Our work complements a number of recent articles published in peer-reviewed journals (Fürsch et al. (2013a), Haller et al. (2012), Capros et al. (2012a) and Capros et al. (2012b)) and studies (Dii (2013), Dii (2012), RES2020 (2009), Realisegrid (2010), EC (2011) and Eurelectric (2010)) analyzing the decarbonization of Europe's power sector. All of these articles and studies show that the achievement of ambitious emission reduction targets for Europe's power (energy) sector in 2050 is technically feasible. However, none of these articles or studies quantify the costs of decarbonizing Europe's power sector together with the excess costs of supplementary RES-E targets up to 2050, accounting for the availability of alternative low-carbon technologies such as nuclear power and CCS.[11]

In the base-case economic scenarios, we find that the decarbonization of Europe's power sector in 2050 could be achieved at minimal costs of 171 bn €$_{2010}$ if competition between all low-carbon technologies is ensured and no restrictions on the use of nuclear power and CCS are implemented. However, if renewables are exempt from competition with alternative low-carbon technologies by prescribing supplementary RES-E targets the costs of decarbonization significantly rise to at least 408 bn €$_{2010}$ – corresponding to an increase of 140 % compared to the minimal costs of decarbonization. The excess costs of supplementary RES-E targets, on the other hand, can be as high as 237 bn €$_{2010}$ or as little as 15 bn €$_{2010}$ – depending on the acceptance of new nuclear power plants and CCS technologies. For example, given a complete nuclear phase-out in Europe by 2050 and politically implemented restrictions on the application of CCS to conventional power plants, supplementary RES-E targets are redundant. While in such a scenario the overall costs of decarbonization are comparatively high, the excess costs of supplementary RES-E targets are close to zero (in comparison to a stand-alone CO_2 reduction target).

The structure of the paper is as follows: Section 2.2 relates the paper to existing literature. Section 2.3 provides a short description of the linear electricity system optimization model for Europe's power sector used in the analysis. Section 2.4 defines the scenarios and Section 2.5 presents the results of our analysis. Conclusions are drawn in Section 2.6.

[10]However, the model does not account for endogenous learning curve-effects and assumes a price-inelastic electricity demand (see Section 2.3.7).

[11]We define the costs of decarbonization as the difference in total system costs between scenarios with ambitious CO_2 reduction targets for Europe's power sector and scenarios with no CO_2 reduction targets.

2.2 Related literature

A wide range of models can be applied to analyze the consequences of policy interference for the energy system or sub-systems (such as the power system).[12] In general, two classes of energy system models can be distingushed, as done in Figure 2.1. Following the explanation of Götz et al. (2012), 'top-down' models describe the energy system from a macroeconomic perspective. By using a full equilibrium framework, they account for repercussions of the energy system on the rest of the economy. As a consequence, 'top-down' models are generally characterized by high aggregation levels that accompany low sectoral and technological details of energy conversion (e.g., electricity production). Important examples of 'top-down' energy models are computable general equilibrium, input-output and macroeconometric models.

'Bottom-up' models, in contrast, look at the energy system from a technological perspective. They are typically characterized by an explicit techno-economic parameterization and a high degree of technological detail, which allows for a comprehensive analysis of technological adjustment processes induced by policy interference. As explained by Götz et al. (2012), Herbst et al. (2012) and Möst and Fichtner (2008), two main approaches can be distinguished: Simulation models, such as agent-based simulation models or system dynamics, describe the development of the energy system as a result of individual decision-making processes (based on observations and expectations), accounting for aspects such as incomplete information or strategic behavior. Optimization models, in contrast, calculate the optimal development of the energy system given an objective function and a set of constraints that reflect technological limitations and political targets. The objective function of optimization models mostly comprises the maximization of welfare, i.e. the maximization of net total surplus of suppliers and consumers (with price-elastic energy demands) or the minimization of total energy system costs (with price-inelastic energy demands). Note that the cost-minimization problem corresponds to a welfare-maximization approach given the assumption of price-inelastic energy demands. Since repercussions of the energy system on other sectors of the economy are generally not considered, 'bottom-up' models are often termed 'partial equilibrium models'.

In this paper we apply a linear optimization model for Europe's power sector (i.e., a system costs minimization model with price-inelastic electricity demands) to analyze the implications of alternative decarbonization pathways for Europe up to 2050.

[12]The following paragraph is based on Götz et al. (2012), Herbst et al. (2012) and Möst and Fichtner (2008). The interested reader is referred to these studies for a further discussion of energy system models.

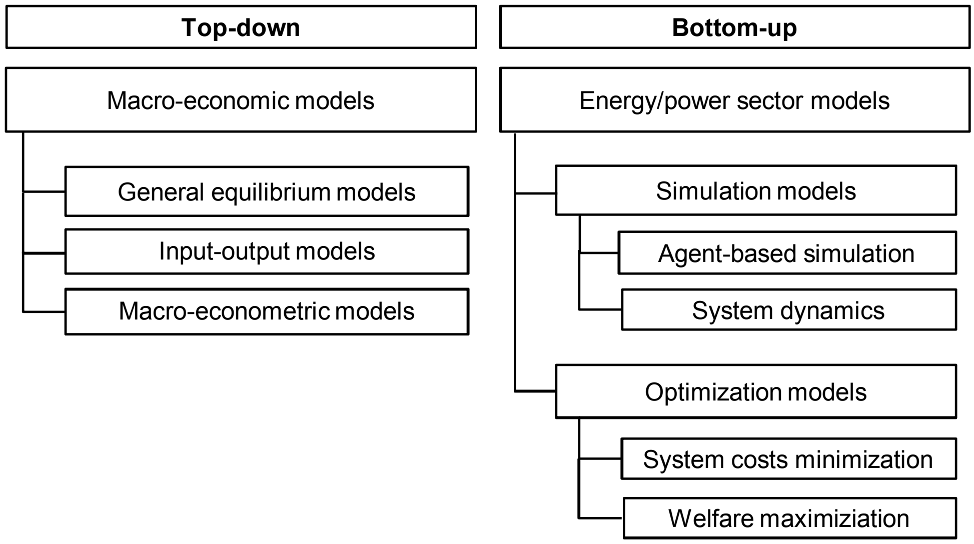


FIGURE 2.1: Classification of energy system models
Source: Own illustration based on Herbst et al. (2012), Götz et al. (2012) and Möst and Fichtner (2008).

Our paper is related to three strands of literature: the first focuses on the interaction between systems of tradable GHG emission permits (TEP) and tradable green certificates (TGC); the second quantifies the costs related to the EU's renewable energy targets for 2020; the third analyzes long-term decarbonization strategies for Europe's power sector up to 2050.

The interaction between TEP and TGC at the European level has, for example, been analyzed by De Jonghe et al. (2009) and Unger and Ahlgren (2005). De Jonghe et al. (2009) apply a welfare maximization model to three interconnected regions (France, Germany and the Benelux) and show that different support measures influence each other. In particular, they find that the price of both TGC and TEP can become zero given non-binding restrictions. Unger and Ahlgren (2005) analyze the impact of a TGC market on both the electricity market and a TEP market by using a welfare maximization model for four Nordic countries (Sweden, Norway, Denmark and Finland). They show that the introduction of a system of TGC reduces the wholesale electricity price and the price of TEP.[13] Moreover, Böhringer and Rosendahl (2010) examine the consequences of overlapping regulations based on a theoretical analysis. They conclude that a tradable renewable energy quota imposed on top of a tradable CO_2 quota promotes power production by the dirtiest fossil fuel technologies, as it will reduce the price of CO_2 permits and therefore benefit emission-intensive technologies.

[13] Interactions between TEP and TGC within single countries have been analyzed by Amundsen and Mortensen (2001) and Abrell and Weigt (2008).

Quantitative evidence of the cost implications of supplementary renewable energy targets – as an integral part of the EU's climate policy for 2020 – has recently been provided by Aune et al. (2012), Böhringer et al. (2009), Böhringer et al. (2009), Boeters and Koorneef (2011) and Capros et al. (2011).[14] Their quantiative results for 2020 confirm the theoretical argumentation concerning counterproductive overlapping regulation. As compared to a stand-alone GHG emissions regulation, the EU's 20 % renewable energy target (in total energy consumption) by 2020 is found to lead to excess costs.[15] Fischer and Newell (2008) and Palmer and Burtraw (2005) confirm the results for the U.S. electricity sector. They find that renewable portfolio standards are not as cost-effective as a cap-and-trade system in achieving GHG emission reductions.

In contrast to the existing quantitative evidence considering the EU's 20 % renewable energy target for 2020, our work complements a number of recent articles published in peer-reviewed journals and studies analyzing longer-term decarbonization strategies for Europe's power sector up to 2050, already referred to in Section 1. As shown in Table 2.1, the articles and studies vary with regard to both the modeling approach and the assumptions made about the availability of alternative low-carbon technologies such as nuclear power and CCS.

Capros et al. (2012b) and Capros et al. (2012a) analyze the decarbonization of Europe's economy up to 2050 by applying a partial equilibrium hybrid model for the EU energy markets. Their decarbonization scenarios highlight the strong role of the power sector for decarbonizing Europe's economy by 2050. Moreover, they confirm that strategies excluding some decarbonization options are more costly than strategies combining all decarbonization options.

In contrast, Fürsch et al. (2013a) and Haller et al. (2012) both use an optimization model for Europe's power sector (plus North Africa (NA) and Middle East and North Africa (MENA), respectively) and focus on the role of grid expansions in a cost-efficient transformation of the European electricity system towards having significant shares of renewable energies by 2050. Given their assumption that ambitious CO_2 reduction targets are achieved via the large-scale deployment of renewables across Europe, they do not account for the fact that a mixture of nuclear power, CCS and renewables may

[14] Aune et al. (2012) use LIBEMOD, a 'multi-market energy equilibrium model'. Böhringer et al. (2009) and Böhringer et al. (2009) apply three 'multi-regional, multi-sectoral general equilibrium models' (DART, PACE and Gemini-E39). Boeters and Koorneef (2011) use the computable general equilibrium model 'WorldScan', and Capros et al. (2011) apply the 'PRIMES' model, a 'partial equilibrium hybrid model which combines bottom-up engineering detail with a micro-economic foundation of economic decisions by agents' (Capros et al. (2012b)).

[15] However, Boeters and Koorneef (2011) also identify specific cases in which the EU's 20 % renewable energy target for 2020 acts as a correction of pre-existing inefficiencies – resulting from second-best effects caused by initial taxes on fossil fuels – and hence enhances total welfare.

be cost-efficient from a system point of view.[16] Moreover, the geographical scope of the electricity system optimization model applied in Haller et al. (2012) ('LIMES-EU$^+$') differs from the one applied in this paper.[17] The 'LIMES-EU$^+$' model covers the power system of the EU-27 member countries, Norway, Switzerland, and the MENA region. In total, 20 geographical regions are modeled (i.e., several countries are aggregated to larger geographical regions), which are connected by 32 transmission corridors. The electricity system optimization model used in this paper also covers the EU-27 member countries (except for Cyprus and Malta), Norway and Switzerland. In addition, North Africa is modeled as a satellite import region. In contrast to Haller et al. (2012), grids are modeled with one node per country. Hence, our model covers 28 countries connected by 65 transmission corridors. Moreover, the single countries are further subdivided into wind and solar power regions in order to better account for regional wind speed and solar radiation conditions (see Section 2.3.2). Besides the regional resolution, the electricity system optimization models applied in Haller et al. (2012) and this paper also differ with regard to their technological scope. While the 'LIMES-EU$^+$' model covers nine generation technologies, we model 34 technologies (see Section 2.3.1).

When analyzing the implications of decarbonizing Europe's electricity system via the large-scale deployment of renewables, it is imperative to account for regional differences in renewable energy technologies and the wide range of electricity generation and storage technologies. It needs to be ensured that the electricity system is flexible enough to cope with fluctuating renewable energy generation and that it is provided with sufficient back-up capacities during times with low-infeed from wind and solar capacities. As our model accounts for these geographical and technological details, we argue that our model is an appropriate tool to quantify the costs of alternative decarbonization pathways for Europe's power sector by 2050 and is able to capture the implications of renewable energy targets and restrictions on alternative low-carbon technologies.

[16]While Fürsch et al. (2013a) model an RES-E quota of 80 % by 2050, Haller et al. (2012) explicitly exclude nuclear power and CCS as investment options in their economic analysis up to 2050.

[17]Note that Fürsch et al. (2013a) apply the same electricity system optimization model as used in this paper. However, in contrast to Fürsch et al. (2013a), we do not account for endogenous grid extensions (see Section 2.3.2).

Table 2.1: Recent articles and studies addressing the longer-term decarbonization of Europe's power/energy sector up to 2050

	Model	Sector	Region	Time horizon	Investment option	
					CCS	Nuclear
Articles						
Fürsch et al. (2013a)	Optimization (System cost minimization)	Power	Europe +NA	2050	Yes	Yes
Haller et al. (2012)	Optimization (System cost minimization) *'LIMES-EU+'*	Power	Europe +MENA	2050	No	No
Capros et al. (2012a), Capros et al. (2012b)	Hybrid* *'PRIMES'*	Energy	Europe	2050	Yes	Yes
Studies						
Dii (2013), Dii (2012)	Optimization (System cost minimization) *'PowerACE'*	Power	Europe +MENA	2050	Yes	Yes
RES2020 (2009)	Optimization (Welfare maximization) *'Pan Europen TIMES'*	Energy	Europe	2030	Yes	Yes
Realisegrid (2010)	Optimization (Welfare maximization) *'Pan Europen TIMES'*	Energy	Europe	2030	Yes	Yes
EC (2011)	Hybrid* *'PRIMES'*	Energy	Europe	2050	Yes	Yes
Eurelectric (2010)	Hybrid* *'PRIMES'*	Energy	Europe	2050	Yes	Yes

*The 'PRIMES' model is a 'partial equilibrium hybrid model which combines bottom-up engineering detail with a micro-economic foundation of economic decisions by agents' (Capros et al. (2012b)).

2.3 Model description

In order to quantify the cost implications of alternative decarbonization pathways, we use a linear electricity system optimization model for Europe. The model is an extended version of the linear electricity system optimization model of the Institute of Energy Economics (University of Cologne) as presented in Richter (2011). Earlier versions of the model have been applied e.g. by Paulus and Borggrefe (2011) and Nagl et al. (2011b). The possibility of endogenous investments in renewable energy technologies has recently been added to the model (Fürsch et al. (2013a), Nagl et al. (2011a)).[18] In the following, a basic overview of the applied model is given. For a detailed mathematical description of the model, the interested reader is referred to Fürsch et al. (2013a).

2.3.1 Technological resolution

The model incorporates investment and generation decisions for all types of power plants: conventional (potentially equipped with CCS technology), combined heat and power (CHP), nuclear, renewable energy technologies and storage technologies (pump, hydro and compressed air energy (CAES)). In contrast to investments in generation and storage capacities, the extension of interconnector capacities, which limit the inter-regional power exchange, is exogenously defined.

Today's power plant mix is represented by several vintage classes for hard coal, lignite and natural gas-fired power plants. With regard to renewable energy technologies, the model encompasses onshore and offshore wind turbines, roof and ground photovoltaic (PV) systems, biomass (CHP-) power plants (solid and gas), hydro power plants, geothermal power plants and concentrating solar power (CSP) plants (including thermal energy storage devices).[19]

To account for technological progress, several future plant developments of both conventional and renewable energy sources are modeled. Regarding conventional technologies, technological progress is assumed to increase the net efficiency. Moreover, CCS can be applied to conventional power plants from 2030 onwards. For renewable energies the technological process is modeled by the availability of new technologies in later years. For example, existing onshore wind turbines are assumed to have a turbine capacity of 3 MW on average. In the event of investments in new wind turbines, the model has

[18]In earlier model versions, investments in renewable energy technologies took place along a predefined expansion path.

[19]Biogas is assumed to be produced by silage (silo maize and grass), liquid manure, dung or biogenic settlement waste. Solid biomass is assumed to include energy crops such as wood from short rotation plantation, corn, agricultural residues (like straw), logging residues, used wood and dry sewage sludge.

the option to install 6 MW turbines with higher full load hours (due to higher turbine heights and increased efficiency) from 2015 onwards.

2.3.2 Regional resolution

The model covers all 27 countries of the European Union, except for Cyprus and Malta, but includes Norway and Switzerland. In addition, North Africa is modeled as a satellite import region.[20] Grids are modeled with one node per country. Hence, the model covers 28 countries connected by 65 transmission corridors. Moreover, to account for regional wind speed and solar radiation conditions, the model considers several subregions within the countries, which differ with regard to the hourly electricity feed-in profiles and the achievable full load hours of wind turbines (onshore and offshore) and solar power plants (PV and CSP) per year. Overall, the model distinguishes between 47 onshore wind, 42 offshore wind and 38 solar subregions across Europe.

2.3.3 Temporal resolution

The model determines the cost-efficient investment and dispatch strategy for meeting the electricity demand of each country in 5-year time steps from 2010 until 2050.[21] The dispatch of generation and storage capacities is calculated for 4 typical days per year that are scaled to 8760 hours in the model. Each typical day defines the electricity demand per country (in MW) based on historical hourly load data by ENSTO-E (2012). Moreover, the typical days determine the hourly water inflow of hydro storages and the hourly electricity feed-in of wind and solar power plants per subregion (in MW/MW$_{installed}$) – including hours with both very high and very low wind and solar-based electricity generation – based on historical hourly wind speed and solar radiation data by EuroWind (2011). The use of typical days allows for a reduction of the calculation time of the model while maintaining the characteristic daily and seasonal features of the demand, water inflow (of hydro storages) and electricity feed-in profiles (of wind and solar power plants).

2.3.4 Objective function

The objective of the model is to minimize accumulated discounted total system costs (5 % discount rate) – which include investment costs, fixed operation and maintenance

[20]By assumption, only solar-based renewable energy technologies can be deployed in North Africa. North African wind conditions are also relatively favorable, but not modeled within this analysis. By 2050, an additional 14 GW of net transfer capacities are installed between North Africa and Spain.

[21]In addition, the model years 2060 and 2070 are included in order to account for long lifetimes of capital-intensive generation capacities.

costs, variable production costs and costs due to ramping thermal power plants.[22] The total system costs do not include investment costs for the necessary infrastructure and operational costs for grid management. Investment costs occur for new investments in generation and storage units and are annualized with a 5 % interest rate for the depreciation time. The fixed operation and maintenance costs represent staff costs, insurance charges, interest rates and maintenance costs. For CCS power plants, fixed operation and maintenance (FOM) costs include fixed costs for CO_2 storage and transportation.[23] Variable costs are determined by the fuel price, net efficiency and total generation of each technology. Depending on the ramping profile additional costs for attrition occur. Combined heat and power (CHP) plants can generate income from the heat market, thus reducing the objective value.[24] All assumptions regarding fuel prices (Table A.1), investment costs (Table A.2 and Table A.5), electricity demand (Table A.3), maximum potential for heat generated in CHP plants (Table A.4), FOM costs (Table A.6 and Table A.7) and net efficiencies (Table A.6 and Table A.7) are listed in the Appendix.

2.3.5 Techno-economic constraints

The accumulated discounted total system costs are minimized, subject to several techno-economic constraints. The match of electricity demand and supply needs to be ensured in each hour and country, taking storage options and inter-regional power exchange into account. The maximum electricity generation of dispatchable power plants (conventional, nuclear, storage, biomass and geothermal plants) per hour is restricted by their seasonal availability which is limited due to unplanned or planned shutdowns (e.g., because of repairs).[25] Unlike dispatchable power plants, the maximum power exchange per hour between two neighboring countries is limited by the net transfer capacities. The minimum electricity generation per hour of dispatchable power plants and storage options is given by their minimum part-load level. The maximum ramp-up speed of dispatchable power plants is limited by their specific start-up time. The deployment of

[22]The model's optimization premise (minimization of accumulated discounted total system costs) implies a cost-based competition of electricity generation and perfect foresight.

[23]The assumption of fixed rather than variable costs for CO_2 storage and transportation is based on the fact that the construction of the pipeline and the storage system accounts for the largest part of the costs for transporting and storing CO_2 (McKinsey & Company (2008)). The costs do not to increase with the cumulative amount of CO_2 already stored (due to limited potentials for storing CO_2), given the assumption that the storage potential is sufficient to cover all CO_2 emissions captured in CCS plants in the scenarios.

[24]However, we account for a maximum potential for heat in cogeneration within each country that is compensated by the heating market.

[25]The availability of dispatchable power plants is the same for each country, year and hour, but differs for each season. The maximum electricity generation of storage technologies is additionally restricted by the storage level of a particular hour.

wind and solar power technologies is restricted by a space potential in km^2 per subregion, while the use of lignite and biomass sources (solid and gaseous) is restricted by a yearly potential in MWh_{th} per country.[26]

Moreover, the peak demand of each country needs to be ensured by securely available capacities and net imports in the peak-demand hour. While the securely available capacity of dispatchable power plants within the peak-demand hour is assumed to correspond to the seasonal availability, the securely available capacity of wind power plants (onshore and offshore) within the peak-demand hour (capacity credit) is assumed to amount to 5 % based on TradeWind (2009) and the German Energy Agency (2005).[27] In contrast, PV systems are assumed to have a capacity credit of 0 % due to the assumption that peak demand occurs during evening hours in the winter.[28] This peak-demand constraint accounts for back-up capacity needs to meet security of supply requirements within a system with high shares of fluctuating renewable energy technologies.

2.3.6 Political constraints

In addition to techno-economic constraints, the model also accounts for the possibility to consider politically implemented restrictions and requirements. For example, the accumulated CO_2 emissions within Europe's power sector can be restricted to a predefined CO_2 cap per year. The approach of modeling a quantity-based regulation (CO_2 cap) instead of a price-based regulation (CO_2 price) ensures that the same level of CO_2 emission reductions is achieved in all simulated scenarios – which facilitates the comparability of results. Moreover, given the formulation of an EU-wide CO_2 cap, the CO_2 abatement target is achieved at minimal costs, i.e., at equalized marginal costs per ton of CO_2 additionally abated within Europe's power sector.

In addition to restrictions on CO_2 emissions, EU-wide technology-neutral or national technology-specific renewable energy (RES-E) quotas can be implemented in the model.

[26] The Institute of Energy Economics bought data of onshore wind potentials from EuroWind (EuroWind (2009)) and data of biomass fuel potentials from the Leipzig Institute for Energy (IE (2008)). The space potentials for offshore wind are taken from a study by the European Environment Agency (EEA (2009)), which is publicly available. The potential for PV systems has been determined as part of the study EWI (2010), which is also publicly available. All sources used account for alternative land uses. EEA (2009) and EWI (2010) offer a description of how the potentials have been derived.

[27] Hence, 5 % of the total installed wind power capacities within a country are assumed be securely available within the peak demand hour.

[28] This assumption is based on a detailed analysis of historical electrical load data (based on ENSTO-E (2012) and historical solar radiation data based on EuroWind (2011)) for all EU member states for the years 2007-2010 (Ackermann et al. (2013)). The analysis has shown that in southern European countries, such as Greece, electricity demand may not only peak during the evening hours in the winter, but also during midday in the summer, for example due to the increased use of air conditioners. However, due to the fact that peak demand hours still occur during the evening in the winter (when the sun is not shining), we chose the conservative approach of assuming PV to have a securely available capacity of 0 % at times of peak demand.

In the case of EU-wide technology-neutral RES-E quotas, defined as a percentage of Europe's electricity demand, RES-E technologies are used where they are cheapest, i.e., when the marginal costs per additional unit power generation from RES-E technologies are equalized. Moreover, political restrictions regarding the construction of new nuclear power plants or conventional power plants equipped with CCS can be implemented by limiting the option to invest in those technologies.

2.3.7 Limitations and scope

The chosen modeling approach is a profound tool to derive a comprehensive set of technically feasible and economically efficient development pathways for Europe's power sector by 2050. Specifically, the implications of alternative decarbonization pathways can be analyzed by varying political regulations for given economic framework conditions. The model is characterized by a high technological and regional resolution, allowing the impact of supplementary RES-E targets and restrictions on alternative low-carbon technologies to be accurately captured.

However, there are also limitations of the modeling approach. An important assumption is the exogeneity of the electricity demand. As a consequence of assuming a price inelastic electricity demand, we do not capture the possible long-term effect, i.e., that an increase in end consumer electricity prices triggered by supplementary renewable support mechanisms may in turn reduce electricity demand.[29]

Moreover, instead of modeling endogenous learning curve effects, we assume exogenous cost degressions of non-mature technologies (i.e., RES-E and CCS technologies). The learning curve concept states that every time the cumulative (i.e., worldwide) volume of installed capacities doubles, costs fall by a constant percentage (learning rate). However, predictions of future costs based on the learning curve concept must be approached with caution, as there is no guarantee that the past trend, on which the learning rate is determined, will apply in the future (Parsons Brinckerhoff (2012), Nemet (2006) and UKERC (2010)). Moreover, learning-by-doing is not the only factor influencing future cost degressions. Specifically, cost reductions due to technology breakthroughs (induced by research and development activities) are not captured by the learning curve concept (Parsons Brinckerhoff (2012)).[30] Despite the caveats stated above, the learning curve concept can provide valuable insights into possible future cost degressions of non-mature technologies. However, given the fact that we model the European (and not the global)

[29]Lijesen (2007) provides an overview of empirical data on the real-time, short-term (i.e. one year or less) and long-term elasticity of electricity demand.

[30]UKERC (2010) provides a further discussion of uncertainties and caveats associated with the learning curve concept.

electricity system up to 2050, we do not account for endogenous learning curve effects for non-mature technologies in the model, but assume exogenous cost degressions.[31] As such, we abstract from possible cost degression effects induced by different investment levels in key technologies within the different scenarios. However, we argue that the potential effects are rather low, especially in the long run, due to two reasons: First, cost degressions of non-mature technologies are driven by capacity expansions across the entire world (and not only across Europe). Second, learning curves are typically double logarithmic, such that the necessary additional investments to achieve additional cost degressions increase exponentially with the installed capacity. Hence, the larger the worldwide installed capacity of non-mature technologies becomes, the lower the actual impact of further capacity expansions in Europe on the investment costs will be.

In addition, we disregard potential benefits of renewables in our analysis (other than no CO_2 emissions), which are often brought forward to motivate supplementary RES-E targets and support mechanisms. One argument, for example, is that learning-by-doing can create a source of positive externality (technology spillover), which would in principle provide a justification for some short-term support to aid the adoption of new technologies (Sorrell and Sijm (2003); Goulder and Parry (2008)).[32] However, in order to efficiently internalize the positive externality via the implementation of a renewable energy support mechanism, the subsidy would need to equal the value of the technology spillover, which is in fact very difficult to measure (Mankiw (2011)). Another line of argumentation is that the deployment of renewables may serve other policy objectives besides GHG abatement (Sijm (2005)), namely job creation and enhanced energy security (EU (2009a)). However, Frondel et al. (2010) argue that the net employment effect of renewable energy support mechanims may not be positive, as rising end consumer electricity prices (as a consequence of renewables support schemes) result in a loss of purchasing power and investment capital, thereby causing negative employment effects in other sectors. On the other hand, the argument of improved security of supply may have merit via the promotion of diversity in generation sources and a lower import dependency on fossil fuels. However, we do not account for potential benefits of renewables in our analysis, other than the fact that they are low-carbon technologies, because the potential benefits often brought forward to justify renewable energy suppourt mechanisms are either likely to be non-existent or difficult to quantify and thus to include in the model.

[31] Moreover, accounting for endogenous learning in the model significantly increases the complexity (and solvability) of the model, as learning curves render the optimization problem non-linear.

[32] When a positive externality (technology spillover) exists, the social costs of adopting a new technology are less than the private costs of the investor. As a consequence, less investments are made than the socially optimal level.

2.4 Scenario definitions

The decarbonization of Europe's power sector can be achieved through various technology mixes, each allowing for massive CO_2 savings in comparison to today's electricity system. To systematically analyze the implications of alternative decarbonization pathways for Europe's power sector under different economic conditions to 2050, a matrix of 36 scenarios is defined (Table 2.2).

TABLE 2.2: Scenario matrix

Political regulations			Economic conditions		
CO_2 and RES-E	Nuclear investment	CCS investment	Low-cost	Base	High-cost
No target	Option	Option	1-I-L	1-I-B	1-I-H
	Option	No option	1-II-L	1-II-B	1-II-H
	No option	Option	1-III-L	1-III-B	1-III-H
	No option	No option	1-IV-L	1-IV-B	1-IV-H
CO_2 target	Option	Option	2-I-L	2-I-B	2-I-H
	Option	No option	2-II-L	2-II-B	2-II-H
	No option	Option	2-III-L	2-III-B	2-III-H
	No option	No option	2-IV-L	2-IV-B	2-IV-H
CO_2 & RES-E target	Option	Option	3-I-L	3-I-B	3-I-H
	Option	No option	3-II-L	3-II-B	3-II-H
	No option	Option	3-III-L	3-III-B	3-III-H
	No option	No option	3-IV-L	3-IV-B	3-IV-H

The scenarios differ with regard to political regulations ('CO_2 ', 'RES-E', 'Nuclear' and 'CCS') and economic conditions ('Low-cost', 'Base' and 'High-cost'). Below, the exact specifications of both the alternative political regulations and the economic conditions assumed in the different scenarios are presented. These include:

- No target: Neither CO_2 nor RES-E quotas are implemented.
- CO_2 target: EU-wide CO_2 quotas are implemented until 2050 (see Table 2.3).
- CO_2 & RES-E target: In addition to EU-wide CO_2 quotas, EU-wide technology-neutral RES-E quotas are implemented until 2050 (see Table 2.3).[33]

[33] RES-E imports from North Africa can be used to fulfill the EU-wide RES-E quota from 2025 onwards.

- Nuclear investment option: Investments in new nuclear power plants are possible across Europe from 2025 onwards.

- No nulcear investment option: While the usage of existing nuclear power plants is not restricted, investments in new nuclear reactors are. This leads to a complete nuclear phase-out in Europe until 2050.[34]

- CCS investment option: CCS becomes a commercially available investment option after 2030.

- No CCS investment option: Investments in CCS are restricted.

Table 2.3: EU-wide CO_2 and EU-wide (technology-neutral) RES-E quotas

	2020	2030	2040	2050
CO_2 reduction in comparison to 1990 levels	20 %	42 %	65 %	90 %
RES-E generation in % of Europe's electricity demand	36 %	50 %	66 %	85 %

Due to the fact that the costs of decarbonization under alternative political targets (CO_2 and RES-E quotas) and restrictions (investments in nuclear power and CCS) critically depend on the economic conditions in place, we control for three economic scenarios ('Low-cost', 'Base' and 'High-cost'). As shown in Table 2.4, the difference between the economic scenarios refers to the level of RES-E investment costs, fossil fuel prices, the gas-to-coal spread and total electricity demand. The scenario specifications serve the purpose of deriving high and low costs of decarbonization.[35]

Table 2.4: Specification of economic conditions

	'Low-cost' scenario	'Base' scenario	'High-cost' scenario
RES-E investment costs	low	medium	high
Fossil fuel prices	low	medium	high
Gas-to-coal spread	low	medium	high
Europe's electricity demand	decrease	constant	increase

Regarding future RES-E investment costs, the scenario assumptions cover very pessimistic ('High-cost') and optimistic projections ('Low-cost'), as shown in Table A.2

[34]While Germany is assumed to phase-out its existing nuclear power plants before 2022, as current legislation stipulates (Deutscher Bundestag (2011)), all other existing nuclear power plants throughout Europe are assumed to remain in operation until the end of their technical lifetimes.

[35]In other words, the assumptions of the 'Low-cost' scenario imply lower costs of decarbonization (in comparison to the assumptions of the 'Base' scenario), while the assumptions of the 'High-cost' scenario imply higher costs of decarbonization.

of the Appendix. In all three economic scenarios ('High-cost', 'Base' and 'Low-cost'), RES-E investment costs are assumed to decrease over time, with the less mature RES-E technologies (such as offshore wind, CSP and PV) realizing higher cost degression rates towards 2050 than technically mature RES-E technologies (such as biomass power plants and onshore wind). However, the actual level of future RES-E investment costs significantly differs between the scenarios. In particular, the difference in future RES-E investment costs between the pessimistic ('High-cost') and the optimistic scenario ('Low-cost') is larger for less mature technologies (than for more mature technologies), since the future cost development of less mature technologies is associated with greater uncertainty.

Besides the future level of RES-E investment costs, the costs of decarbonization depend on the development of fossil fuel prices and, in particular, on the development of the gas-to-coal spread. The higher the fossil fuel prices are, the lower the costs of switching from fossil to renewable technologies, and thus the costs of decarbonization, become. Besides the switch from fossil to renewable technologies, the switch from coal- to gas-fired power plants is another option to reduce CO_2 emissions. The costs of this mitigation option depend on the gas-to-coal spread, and not on the absolute level of the gas and coal prices. The higher the gas-to-coal spread becomes (i.e., the more expensive gas becomes relative to coal), the higher the costs of switching from coal to gas (in order to reduce CO_2 emissions), and hence the costs of decarbonization, become. In all three economic scenarios, the fossil fuel prices and the gas-to-coal spread are assumed to increase over time.[36] However, the specific rate of increase differs across the scenarios (see Table A.1 of the Appendix). In order to achieve a wide range of decarbonization costs, we assume a large increase in fossil fuel prices and the gas-to-coal spread in the 'High-cost' scenario and a low increase of fossil fuel prices and the gas-to-coal spread in the 'Low-cost' scenario.

Moreover, the costs of decarbonization also depend on the level of the electricity demand. In particular, the higher the electricity demand becomes, the more costly the achievement of ambitious CO_2 emission reduction targets (in comparison to historically observed emission levels) will be. In the three economic scenarios, Europe's electricity demand is assumed to either decrease by 15 % ('Low-cost'), to stay constant at 2010 levels ('Base') or to increase by 15 % ('High-cost') up to 2050 (compared to 2010 levels). The scenario specifications aim at deriving a wide range of decarbonization costs, including very high and very low costs of decarbonization. A detailed listing of the scenario-specific electricity demand per country in TWh can be found in Table A.3 of the Appendix.

[36]In the scenarios, the gas-to-coal spread increases due to the fact that the gas price increases at a higher rate than the coal price.

Except for RES-E investment costs, fossil fuel prices and electricity demand, all other parameters are kept constant throughout the scenarios.[37] In particular, the development of Europe's electricity grid up to 2050 is assumed to be the same in all scenarios. While power transfers within the single market regions are assumed to face no transmission constraints (as market regions are modeled as copper plates), power exchange between the market regions is limited by exogenously defined interconnection capacities, which are assumed to increase overall by a factor of 2.5 by 2050 (compared to 2010 levels). Specifically, interconnection capacity extensions are limited to projects that have already entered the planning or permission phase today, based on the ENTSO-E's 10-Year Network Development Plan (ENTSO-E (2010)), but whose commissioning is assumed to be delayed. As such, the assumed interconnection capacity expansions correspond to the values assumed in Fürsch et al. (2013a) (Scenario B: Moderate transmission grid). This increase allows for the deployment of renewable energy technologies at favorable regions across Europe (such as wind power in northern Europe and solar power in southern Europe), as well as the corresponding power flows from market regions with favorable renewable energy potentials to market regions with less favorable renewable energy potentials. However, the assumed expansion of interconnection capacities cannot be seen as optimal from a total system perspective.[38] Nevertheless, the assumption of limited (instead of optimal) interconnection capacity expansions seems appropriate for several reasons: First, many grid extension projects are currently facing significant delays, often due to long planning and authorization procedures and local opposition based on health and environmental concerns (Fürsch et al. (2013a) and Buijs et al. (2011)). Thus, the assumed interconnector capacity increase (factor of 2.5 by 2050) seems rather ambitious, especially when taking into consideration that intra-regional transmission lines will need to be massively expanded in order to integrate renewable energies. Second, it is questionable to what extent a country with favorable RES-E potentials would go to exploit their own resources, possibly jeopardizing their landscapes, in order to provide neighboring countries with cheaper RES-E electricity – even though it may minimize overall power generation costs. Third, the cost savings from an optimal interconnection capacity expansion, in comparison to the assumed expansion factor of 2.5 by 2050, are found to be moderate (Fürsch et al. (2013a)).[39]

[37]The most important parameters with regard to the total system costs (and hence the costs of decarbonization) are listed in the Appendix, including investment costs and fixed operation and maintenance costs of renewable, conventional, nuclear and storage technologies, as well as fuel prices, electricity demand per country and year, efficiency factors (generation), CO_2 emission factors and technical lifetimes of all technologies.

[38]Within the single market regions, which are subdivided into several subregions for wind and solar power generation, renewable energy technologies are cost optimally deployed, given the implicit assumption of no transmission constraints within the market regions (copper plate).

[39]Fürsch et al. (2013a), who analyze the role of grid expansions in a cost-efficient transformation of the European electricity system (to an 80 % RES-E share) by 2050, find that large grid extensions (both within and between countries) allow for the full exploitation of the most favorable RES-E sites throughout Europe and are thus beneficial from a least-cost perspective. However, the cost savings due to an optimal

In addition, overnight investment costs of nuclear power plants are assumed to amount to 3,160 $€_{2010}/kW_{el}$ in all scenarios. This is in line with the assumption made in the IEA's World Energy Outlook 2011, which estimates the overnight costs of new nuclear power plants to lie between 2,700 - 3,600 $€/kW_{el}$ (i.e. 3,500 - 4,600 USD/kW_{el}) in OECD countries (IEA (2011)). Note that these figures exclude financing costs, which commonly account for a significant share of the total cost of building a nuclear plant (IEA (2011)). However, if plants are built by publicly-owned (instead of privately-owned) utilities, the costs of financing are significantly lower due to access to cheap government-backed financing (IEA (2011)).[40]

2.5 Scenario results

The subsequent analysis is structured as follows: Section 2.5.1 provides a general overview of the total system costs associated with the alternative decarbonization pathways for different economic framework conditions. Section 2.5.2 analyzes the minimal costs of decarbonization given a stand-alone CO_2 reduction target of 90 % in 2050 (compared to 1990 levels) and discusses the cost implications of both the economic framework conditions and politically implemented restrictions on the use of nuclear power and CCS. Thereupon, Section 2.5.3 analyzes the excess costs of supplementary RES-E targets depending on the economic framework conditions and the availability of alternative low-carbon technologies. Moreover, the cost implications of national technology-specific instead of EU-wide technology-neutral targets in 2020 are discussed.[41]

2.5.1 Overview of total system costs and costs of decarbonization

Table 2.5 lists the discounted scenario-specific total system costs and the costs of decarbonization, accumulated to 2050 in billion (bn) $€_{2010}$. Total system costs are defined as the sum of discounted investment, fixed operation and maintenance and variable generation costs of the electricity generation system accumulated from 2010 until 2050.[42]

dimensioning of interconnection capacities are rather small. Fürsch et al. (2013a) compare the overall cost-efficient system transformation (scenario A) to a scenario in which interconnector capacities are only moderately extended (scenario B). The difference in accumulated investment costs between scenario A and scenario B up to 2050 amounts to only 1.7 %.

[40] Note that construction delays, which are commonly observed in new nuclear programs or when building non-standard designs, can greatly increase costs, as shown by the two evolutionary power reactors (EPRs) currently being built in Finland and France (IEA (2011)).

[41] The general focus of the analysis is on the cost implications of politically implemented targets and restrictions, rather than the cost-efficient development of regional capacities or generation throughout Europe. Nevertheless, an overview of the cost-efficient capacity and generation mix in 2050 for the different scenarios can be found in Table A.9 of the Appendix.

[42] Total system costs also include the annualized investment costs of all existing conventional, renewable and storage capacities in 2010, which are assumed not to be completely depreciated by the year 2010.

Total system costs do not include investment costs for the necessary infrastructure and operational costs for grid management. The costs of decarbonization correspond to the difference in total system costs between the scenarios with a CO_2 target and the scenarios with 'no target'. For example, the costs of decarbonization of Scenario 2-III-B (431 bn €$_{2010}$) are derived by substracting the total system costs of Scenario 1-III-B (1,345 bn €$_{2010}$) from the total system costs of Scenario 2-III-B (1,776 bn €$_{2010}$).[43]

Table 2.5: Total system costs (and costs of decarbonization) accumulated (up to 2050) and discounted (5 %) [bn €$_{2010}$]

Political scenario				Economic scenario		
CO_2 and RES-E	Nuclear investment	CCS investment		Low-cost [L]	Base [B]	High-cost [H]
No target	Option	Option	[1-I]	1,248	1,331	1,415
	Option	No option	[1-II]	1,248	1,331	1,415
	No option	Option	[1-III]	1,261	1,345	1,430
	No option	No option	[1-IV]	1,261	1,345	1,430
CO_2 target	Option	Option	[2-I]	1387 (139)	1502 (171)	1588 (173)
	Option	No option	[2-II]	1394 (146)	1518 (187)	1616 (201)
	No option	Option	[2-III]	1506 (258)	1776 (431)	1948 (516)
	No option	No option	[2-IV]	1541 (280)	1858 (513)	2051 (621)
CO_2 & RES-E target	Option	Option	[3-I]	1466 (218)	1739 (408)	1879 (464)
	Option	No option	[3-II]	1469 (221)	1741 (410)	1882 (467)
	No option	Option	[3-III]	1512 (264)	1811 (466)	1984 (554)
	No option	No option	[3-IV]	1546 (285)	1873 (528)	2063 (633)

The scenario matrix provides several important insights on the effects of alternative energy policies on both the total system costs and the costs of decarbonization under different economic framework conditions ('Low-cost', 'Base' and 'High-cost'). First, total system costs are the lowest in scenarios with no politically implemented targets or restrictions (Scenario 1-I-L to 1-IV-H). In this case, however, CO_2 emissions increase by 25-68 % by 2050 (compared to 1990 levels) due to a massive increase in electricity generation from low-cost coal-fired power plants across Europe.[44] Second, if a stand-alone CO_2 reduction target is implemented and both low-carbon technologies – nuclear power and CCS – are available for power generation (2-I-L to 2-I-H) the decarbonization of Europe's power sector can be achieved at moderate costs. Third, the costs of decarbonization significantly rise with the number of political targets and restrictions in place.

[43]Equally, the costs of decarbonization of Scenario 3-I-H (464 bn €$_{2010}$) are derived by substracting the total system costs of Scenario 1-I-H (1,415 bn €$_{2010}$) from the total system costs of Scenario 3-I-H (1,879 bn €$_{2010}$).

[44]This is in line with Haller et al. (2012), who estimate that in the absence of emission caps, investments in coal-fired power plants take place, causing emissions in 2050 to be 20-40 % higher than in 2010.

Specifically, costs of decarbonization are the highest given both supplementary RES-E targets and politically implemented restrictions on the use of nuclear power and CCS (3-IV-L to 3-IV-H). Fourth, the impact of the economic scenario on the costs of decarbonization increases with the number of political targets and restrictions in place. For example, the rise in the costs of decarbonization due to supplementary RES-E targets (in comparison to a stand-alone CO_2 reduction target) is the largest in the 'High-cost' economic scenarios (compare Scenario 3-I-H with Scenario 2-I-H).

Overall, the costs of decarbonization vary between 139 and 633 bn €$_{2010}$ depending on the political and economic framework conditions in place. This corresponds to an increase of between 11 % and 44 % compared to the total system costs when no CO_2 reduction targets are implemented. In the following sections, the cost implications of different political targets and restrictions are analyzed in more detail.

2.5.2 Minimal costs of decarbonization given a stand-alone EU-wide CO_2 target

The decarbonization of Europe's power sector is achieved at minimal costs given a stand-alone EU-wide CO_2 reduction target and no restrictions on the usage of nuclear power and CCS. Total system costs increase from 1,331 bn €$_{2010}$ in Scenario 1-I-B – where no CO_2 reduction targets are implemented – to 1,502 bn €$_{2010}$ in Scenario 2-I-B – where Europe achieves a 90 % CO_2 reduction target by 2050 (compared to 1990 levels). As such, the decarbonization of Europe's power sector up until 2050 is achieved at moderate costs of 171 bn €$_{2010}$, or plus 13 %.

As shown in Figure 2.2, the 90 % CO_2 reduction target in 2050 is accomplished through the expansion of nuclear power, renewable energies and CCS technologies in Scenario 2-I-B. Specifically, the expansion of nuclear power accounts for 770 Mt CO_2 in 2050, the expansion of renewables for 207 Mt CO_2 and the application of CCS for 149 Mt CO_2 .[45] These scenario results point out the cost advantage of nuclear power in low-carbon power systems. However, our cost assumptions for nuclear power do not account for the risk costs of nuclear accidents (but do account for the costs of nuclear waste disposal).

As shown in Figure 2.3, installed nuclear power capacities increase from 135 GW in 2010 to 221 GW in 2050 in Scenario 2-I-B – with the largest expansions occuring in Italy, Great Britain, Germany and Spain. In 2050, 48 % of Europe's electricity demand is supplied by nuclear power. Aside from nuclear power, renewables play a crucial role in achieving the 90 % CO_2 reduction target. In 2050, total onshore wind capacities amount to 130 GW,

[45]The CO_2 savings are derived by comparing the CO_2 emissions of Europe's electricity generation mix in 2050 with the emissions in 2010.

supplying 377 TWh or 11 % of Europe's electricity demand. Moreover, biomass CHP-power plants (plus 18 GW) and geothermal capacities (plus 15 GW) are expanded across Europe up until 2050. Conversely, no investments take place in offshore wind and solar power technologies (PV and CSP). In total, renewables account for 36 % of Europe's electricity demand in 2050. CCS applied to thermal power plants plays an important part in countries with traditionally high shares of lignite-fired power generation, such as Germany, Poland and the Czech Republic. In 2050, installed capacities of lignite-CCS power plants amount to over 23 GW in Germany, 9 GW in Poland and 7 GW in the Czech Republic.[46] In total, lignite-fired power plants equipped with CCS technology supply 11 % of Europe's electricity demand in 2050 in Scenario 2-I-B.

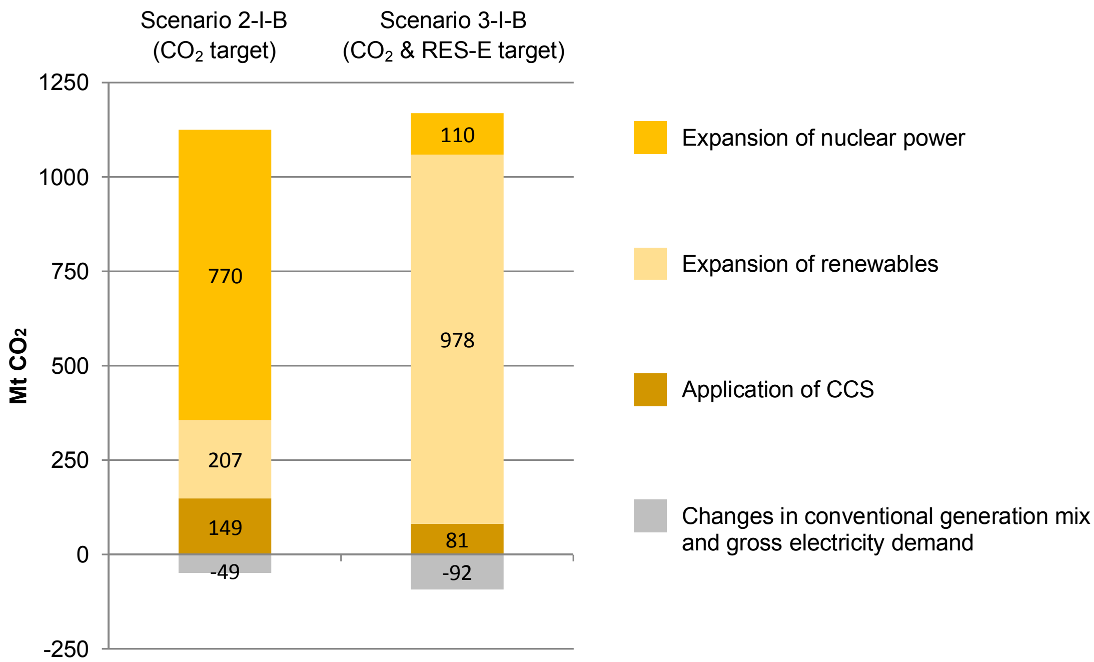


FIGURE 2.2: Total CO_2 savings in 2050 compared to 2010 levels [Mt CO_2]

2.5.2.1 Implications of the economic framework

The costs of decarbonization in the 'Low-cost' (2-I-L) and 'High-cost' scenarios (2-I-H) hardly differ from the costs of decarbonization in the 'Base' scenario (2-I-B). While the costs of decarbonization amount to 139 bn €$_{2010}$ in the 'Low-cost' scenario (2-I-L), the costs of decarbonization amount to 173 bn €$_{2010}$ in the 'High-cost' scenario (2-I-H), which corresponds to a plus of 11 % and 12 %, respectively, compared to the total

[46] CCS applied to coal- and gas-fired power plants is not a cost-efficient investment option. This is due to the fact that renewables depict a lower cost CO_2 abatement option to achieve commitment with the EU-wide CO_2 reduction targets in the long run compared to coal- and gas-fired power plants equipped with the CCS technology.

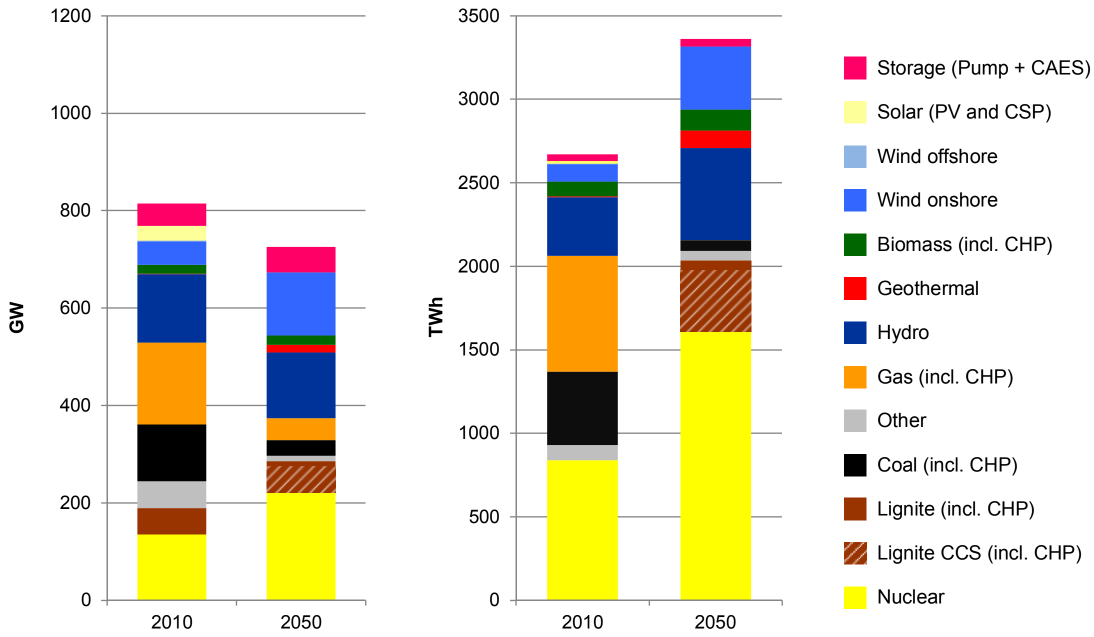


FIGURE 2.3: Capacity and generation mix in 2050 in Scenario 2-I-B
(The historical 2010 values are based on EURELECTRIC (2012).)

system costs if no CO_2 reduction targets are implemented (Scenarios 1-I-L and 1-I-H). These results highlight the fact that the decarbonization of Europe's power sector does not need to be associated with a drastic increase of total system costs up until the year 2050. Even in the 'High-cost' scenario (2-I-H), the costs of decarbonization are manageable as long as competition between all low-carbon technologies – including nuclear power and CCS – is ensured.

So far, it has been shown that the decarbonization of Europe's power sector is achieved at minimal costs under a stand-alone CO_2 reduction target and no restrictions on the use of nuclear power and CCS. However, nuclear power and CCS are currently facing strong headwinds in several EU member states, primarily due to public concerns about the associated risks. For reasons of policy relevance, we quantify the implications of politically implemented restrictions on the use of nuclear power and CCS for both the costs of decarbonization and the marginal costs of compliance with the CO_2 reduction targets.

2.5.2.2 Implications of restrictions on the use of nuclear power and CCS

After the Fukushima disaster in March 2011, several EU member states decided to either phase out their existing nuclear power plants, postpone plans to construct new nuclear power plants or reinforced the decision to stay a nuclear-free country. Given the current policy situation, we analyze the cost implications of politically implemented restrictions on the use of nuclear power in Europe.

If the construction of new nuclear power plants is restricted across Europe, the costs of decarbonization increase by 152 % to 431 bn €$_{2010}$ in Scenario 2-III-B compared to the minimal costs of decarbonization in Scenario 2-I-B (171 bn €$_{2010}$).[47] The corresponding excess costs of 260 bn €$_{2010}$ primarily occur due to the large-scale replacement of nuclear power plants by more expensive RES-E technologies.

In comparison to Scenario 2-I-B, total installed capacities across Europe significantly increase in Scenario 2-III-B due to the massive expansion of fluctuating wind (on- and offshore) and solar power (PV) plants, which exhibit significant lower full load hours than nuclear power plants. While total installed capacities amount to 726 GW in the case of no political restrictions on the use of nuclear power across Europe (Scenario 2-I-B), total installed capacities amount to 1,185 GW (plus 63 %) given a complete nuclear phase-out in Europe by 2050 (Scenario 2-III-B).[48]

Besides the availability of nuclear power, the availability of CCS also significantly affects the costs of decarbonization up to 2050. From a technical viewpoint, CCS technology could play an important role in the transition towards a decarbonized power sector in Europe. However, it remains uncertain whether CCS will be commercially available for application in conventional power plants after 2030, primarily due to public concerns regarding the transportation and storage of CO_2 .

If CCS does not become commercially available for application in conventional power plants in Europe after 2030, the costs of decarbonization increase by 9 % to 187 bn €$_{2010}$ in Scenario 2-II-B compared to the minimal costs of decarbonization in Scenario 2-I-B (171 bn €$_{2010}$). Overall, Germany, Poland and the Czech Republic replace 39 GW of lignite-CCS power plants (in Scenario 2-I-B) with 27 GW of additional nuclear capacities, 6 GW of additional gas capacities and 10 GW of additional lignite power plants (in Scenario 2-II-B).[49] However, if nuclear power is also not an investment option, the cost increase due to a restriction of CCS is more pronounced. Specifically, the costs of decarbonization increase by over 13 %, which can be explained by the fact that lignite-CCS power plants need to be replaced with more expensive RES-E technologies instead of nuclear power plants.

[47]The restriction on the construction of new nuclear power plants leads to a complete phase-out of nuclear power in Europe by the year 2050 due to the assumption that all existing nuclear power plants are shutdown at the end of their technical lifetimes.

[48]Specifically, 221 GW of nuclear capacities are replaced by 144 GW of additional onshore wind capacities, 172 GW of additional offshore wind capacities and 136 GW of additional PV capacities in 2050. Moreover, 189 GW of gas-fired power plants and 45 GW of storage capacities (CAES) are additionally deployed by 2050 to ensure the countinuous balance of demand and supply.

[49]This is in line with Capros et al. (2012a), who find that if nuclear is an investment option, the absence of CCS only causes moderate changes in the cumulative energy system costs.

If the construction of both new nuclear power plants and conventional power plants equipped with CCS technology is restricted across Europe, the costs of decarbonization rise by 200 % to 513 bn €$_{2010}$ in Scenario 2-IV-B compared to the minimal costs of decarbonization in Scenario 2-I-B (171 bn €$_{2010}$). For comparison, the costs of decarbonization increase by 100 % to 280 bn €$_{2010}$ in the 'Low-cost' scenario (2-IV-L), and by 260 % to 621 bn €$_{2010}$ in the 'High-cost' scenario (2-IV-H) as a consequence of politically implemented restrictions on the use of nuclear power and CCS.

In addition to the rise in the costs of decarbonization, the impact of politically implemented restrictions on the use of nuclear power and CCS can also be identified by an increase in the marginal costs of compliance with the annual CO_2 reduction targets, as shown in Table 2.6.

Table 2.6: Marginal costs of compliance with the annual CO_2 reduction targets [€$_{2010}$/t CO_2] (not discounted)

Nuclear investment	CCS investment	Scenario	2020	2030	2040	2050
			'Low-cost'			
Option	Option	[2-I-L]	36	16	29	62
Option	No option	[2-II-L]	36	29	41	68
No option	Option	[2-III-L]	36	27	65	65
No option	No option	[2-IV-L]	36	50	79	73
			'Base'			
Option	Option	[2-I-B]	41	19	28	78
Option	No option	[2-II-B]	41	34	32	76
No option	Option	[2-III-B]	41	27	103	91
No option	No option	[2-IV-B]	42	58	128	99
			'High-cost'			
Option	Option	[2-I-C]	39	17	36	82
Option	No option	[2-II-C]	35	35	72	83
Nooption	Option	[2-III-C]	41	26	101	177
No option	No option	[2-IV-C]	38	61	129	197

The marginal costs of compliance reflect the change in the total system costs associated with the abatement of the last ton of CO_2 needed to achieve the CO_2 reduction target for a specific year. As such, the marginal costs of compliance present the additional costs of the last CO_2 abatement option chosen compared to that of the replaced technology.

As per assumption, the politically implied CO_2 reduction targets become more restrictive over time (CO_2 target increases from 20 % in 2020 to 90 % in 2050), whereas the costs of existing low-carbon technologies decrease over the years and new technologies become available. Hence, the marginal costs of compliance do not need to increase steadily over time. An example for the impact of new technologies on the marginal costs of compliance is the introduction of CCS from 2030 onwards, which causes the marginal costs of compliance in Scenario 2-I-B to drop from 41 $€_{2010}$/t CO_2 to 19 $€_{2010}$/t CO_2 between 2020 and 2030. Conversely, in Scenario 2-II-B, where CCS does not depict an investment option, marginal costs of compliance decrease only from 41 $€_{2010}$/t CO_2 to 34 $€_{2010}$/t CO_2 between 2020 and 2030.[50]

Likewise, the availability of nuclear power – as a comparatively low-cost CO_2 abatement option – has a significant impact on the marginal costs of compliance with the annual CO_2 reduction targets. The effect can, for example, be seen when comparing Scenario 2-III-B with Scenario 2-I-B. If no restrictions on the use of nuclear power across Europe are implemented, then the marginal costs of compliance in 2050 amount to 78 $€_{2010}$/t CO_2 . However, if Europe pursues a complete nuclear phase-out by 2050, marginal costs increase to over 91 $€_{2010}$/t CO_2 in 2050.

Naturally, the marginal costs of compliance with the EU-wide CO_2 reduction targets also depend on the assumed economic framework conditions ('Low-cost', 'Base' and 'High-cost'). The less favorable the economic conditions are (towards achieving low costs of decarbonization), especially considering higher RES-E investment costs or total electricity demand, the higher the marginal costs of compliance with the annual CO_2 reduction targets will be, especially in the target year 2050.

After having analyzed the minimal costs of decarbonization under a stand-alone CO_2 target and the associated cost implications of both the economic framework conditions and the availability of nuclear power and CCS, we analyze the excess costs associated with the supplementary RES-E targets.

2.5.3 Excess costs of supplementary RES-E targets

Supplementary RES-E targets interfere with the least-cost idea of implementing a stand-alone CO_2 reduction target by exempting a particular CO_2 abatement option from the common benchmark price. Hence, supplementary RES-E targets may lead to excess costs. However, the actual amount of excess costs significantly depends on the availability of other low-carbon technologies such as nuclear power and CCS as well as the economic framework conditions.

[50] The decrease is due to the fact that both the investment costs of existing RES-E technologies decrease and more advanced RES-E technologies become available. For example, to account for technological progress expected in the wind power sector, 8 MW onshore and offshore wind turbines can be built from 2030 onwards, which are characterized by higher full load hours, lower specific investment costs and a lower space requirement per MW installed (km^2/MW).

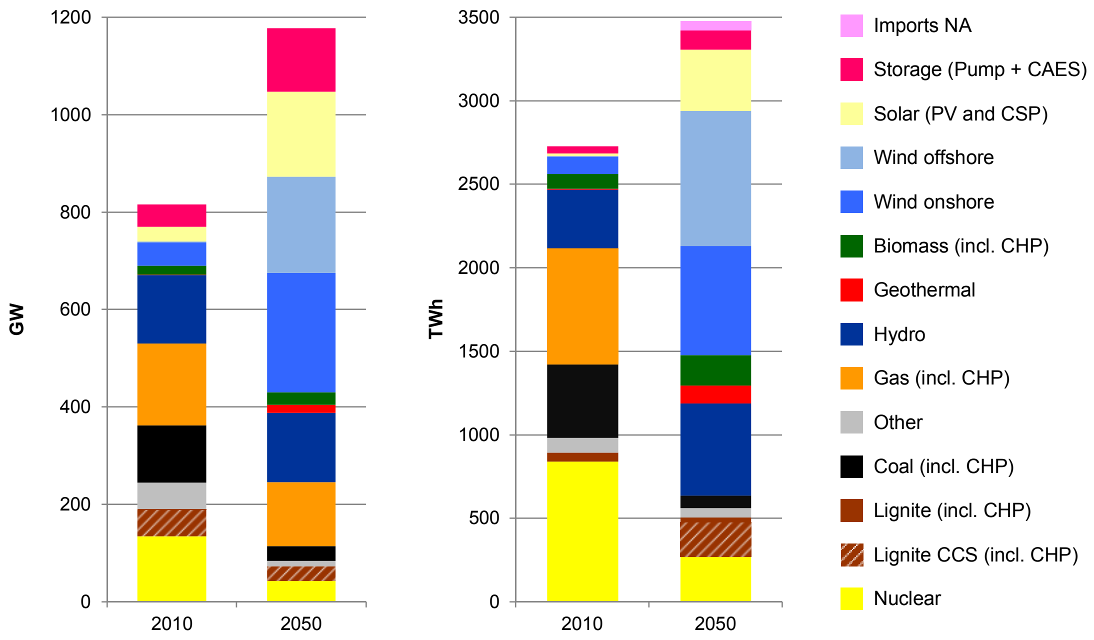


FIGURE 2.4: Capacity and generation mix in 2050 in Scenario 3-I-B
(The historical 2010 values are based on EURELECTRIC (2012).)

Our scenario analysis shows that the costs of decarbonization significantly increase – in comparison to a stand-alone CO_2 reduction target – if supplementary RES-E targets (of up to 85 % in 2050) are implemented and the use of nuclear power and CCS is not restricted. Overall, the costs of decarbonization increase to 408 bn €$_{2010}$ in Scenario 3-I-B, which corresponds to a plus of almost 140 % compared to the minimal costs of decarbonization under a stand-alone CO_2 target in Scenario 2-I-B (171 bn €$_{2010}$). Hence, given no politically implemented restrictions on nuclear power and CCS, supplementary RES-E targets lead to excess costs of over 237 bn €$_{2010}$ until 2050.[51] Interestingly, the excess costs of supplementary RES-E targets (237 bn €$_{2010}$) lay in the same range as the excess costs of a complete nuclear phase-out in Europe by 2050 (274 bn €$_{2010}$). This is due to the fact that in both cases, the decarbonization of Europe's power sector is largely achieved through the expansion of renewable energies by 2050.

As shown in Figure 2.2, renewables account for 978 Mt CO_2 or 91 % of total CO_2 savings in 2050 in Scenario 3-I-B. In comparison to Scenario 2-I-B, offshore wind turbines and solar power capacities are also deployed to achieve commitment with the RES-E targets (see Figure 2.4).[52] Overall, 245 GW of onshore wind turbines, 197 GW of offshore wind turbines, 121 GW of PV systems, 53 GW of CSP plants, 26 of GW biomass power plants (incl. CHP-plants) and 16 GW of geothermal power plants are installed

[51]However, given the fact that our cost assumptions for nuclear power account for the costs of nuclear waste disposal, but not for the risk costs of nuclear accidents, the excess costs of supplementary RES-E targets represent an upper bound estimate.

[52]However, unlike onshore wind, investments in offshore wind and solar power capacities do not take place before 2020.

by 2050 in Scenario 3-I-B. In comparison to Scenario 2-I-B, total installed capacities across Europe increase by 65 % in Scenario 3-I-B due to the large-scale expansion of fluctuating wind (onshore and offshore) and solar power (PV) plants with comparatively low full load hours per year. However, given the formulation of EU-wide (technology-neutral) RES-E targets, the deployment of capacities takes place at the most favorable sites across Europe. Onshore and offshore wind turbines are primarily deployed in northern European countries with good wind conditions such as Great Britain (97 GW), (northern) France (96 GW), Germany (78 GW), the Netherlands (36 GW) and Norway (23 GW). PV systems are primarily installed in southern European countries such as Italy (52 GW), Spain (17 GW) and (southern) France (20 GW). Moreover, 45 GW of CSP plants equipped with thermal storage devices are deployed across southern Europe by 2050 (mostly in Spain).

Table 2.7: Marginal costs of compliance with the annual CO_2 reduction targets [$€_{2010}$/t CO_2] (not discounted) given supplementary RES-E targets

Nuclear investment	CCS investment	Scenario	2020	2030	2040	2050
			'Low-cost'			
Option	Option	[3-I-L]	18	7	54	37
Option	No invest. option	[3-II-L]	18	17	68	37
No invest. option	Option	[3-III-L]	35	19	58	55
No invest. option	No invest. option	[3-IV-L]	35	43	79	72
			'Base'			
Option	Option	[3-I-B]	23	7	49	42
Option	No invest. option	[3-II-B]	22	12	68	42
No invest. option	Option	[3-III-B]	39	18	69	80
No invest. option	No invest. option	[3-IV-B]	38	46	95	97
			'High-cost'			
Option	Option	[3-I-C]	28	6	37	50
Option	No invest. option	[3-II-C]	27	13	66	55
No invest. option	Option	[3-III-C]	39	22	79	94
No invest. option	No invest. option	[3-IV-C]	38	54	104	159

In addition to the increase in the costs of decarbonization, the impact of supplementary RES-E targets can also be identified by a change in the marginal costs of compliance with the annual CO_2 reduction targets. Table 2.7 lists the marginal costs of compliance in $€_{2010}$/t CO_2 for the scenarios assuming supplementary RES-E targets. Overall, the supplementary RES-E targets – which increase from 36 % in 2020 to 85 % in 2050 – have a clear downward pressure on the marginal costs of compliance with the CO_2 reduction targets across the scenarios (compare Table 2.7 with Table 2.6).[53] Nevertheless, the marginal costs of compliance with the annual CO_2 reduction targets are always greater than zero, meaning the implied CO_2 reduction targets are binding in all years.

2.5.3.1 Implications of the economic framework

The excess costs associated with supplementary RES-E targets significantly depend on the assumed economic development. In the 'Base' economic scenario, excess costs amount to 237 bn €$_{2010}$ (increase of 140 % compared to the minimal costs of decarbonization), whereas excess costs amount to only 79 bn €$_{2010}$ (increase of 60 %) in the 'Low-cost' scenario (3-I-L) and to more than 291 bn €$_{2010}$ (increase of 170 %) in the 'High-cost' scenario (3-I-H). These results are primarily driven by the assumptions regarding the future development of RES-E investment costs. Obviously, excess costs of supplementary RES-E targets decrease as the level of RES-E investment costs decreases. Moreover, given a limited potential of favorable renewable energy sites across Europe, excess costs of supplementary RES-E targets decrease as the level of Europe's electricity demand decreases – given the assumption that the RES-E targets are formulated as a percentage of Europe's total electricity demand.

So far, we have shown that supplementary RES-E targets lead to significant excess costs in comparison to a stand-alone CO_2 target. However, the preceding analysis was based on the assumption that no politically implemented restrictions on the use of nuclear power and CCS exist up until the year 2050. In the following section, we show that supplementary RES-E targets may be redundant if the use of nuclear power and CCS is restricted. In such a scenario the overall costs of decarbonization are comparatively high, whereas the excess costs of supplementary RES-E targets are close to zero (in comparison to a stand-alone CO_2 reduction target).

2.5.3.2 Implications of restrictions on the use of nuclear power and CCS

The costs of decarbonization significantly increase (in comparison to a stand-alone CO_2 target) if supplementary RES-E targets and restrictions on the use of nuclear power and CCS are implemented. Specifically, the costs of decarbonization increase to 528 bn €$_{2010}$ in Scenario 3-IV-B, corresponding to a plus of almost 310 % in comparison to the minimal costs of decarbonization under a stand-alone CO_2 target (and no nuclear or CCS restrictions) in Scenario 2-I-B (171 bn €$_{2010}$). However, the excess costs

[53] This effect has also been shown by Tsao et al. (2011) for the California electricity market, by Unger and Ahlgren (2005) for the northern European electricity markets and by De Jonghe et al. (2009) for the Belgian, French and German electricity markets.

of supplementary RES-E targets amount to only 15 bn €$_{2010}$ (compare Scenario 3-IV-B with Scenario 2-IV-B), which can be explained by the fact that Europe's power sector will already be based on RES-E technologies to achieve the decarbonization target by 2050 – if the construction of new nuclear power plants and conventional power plants equipped with CCS technology is restricted. Hence, supplementary RES-E targets are quasi redundant.

This effect can also be seen when analyzing the marginal costs of compliance with the annual RES-E targets, which reflect the change in the total system costs associated with the supply of the last MWh of RES-E electricity production needed to achieve the RES-E target in a specific year. As shown in Table 2.8, the marginal costs of compliance with the annual RES-E targets significantly depend on the availability of alternative low-carbon technologies. For example, the marginal costs of compliance with the RES-E targets can drop to zero in scenarios that combine challenging CO_2 reduction targets with restrictions on the usage of nuclear power and CCS.[54] Thus, the additionally implemented RES-E targets are rendered non-binding. This is, for example, the case in Scenario 3-IV-L, 3-IV-B and 3-IV-C for the year 2050.

Moreover, the marginal costs of compliance with the RES-E targets also depend on the assumed economic scenario ('Low-cost', 'Base' and 'High-cost'). The less favorable the economic conditions (towards achieving low costs of decarbonization) are, the higher the marginal costs of compliance with the RES-E targets will be.

So far, we have shown that supplementary RES-E targets lead to higher costs of decarbonization in comparison to a stand-alone CO_2 target but that the excess costs associated with supplementary RES-E targets crucially depend on the availability of alternative low-carbon technologies such as nuclear power and CCS. The next section demonstrates that the excess costs of supplementary RES-E targets also depend on the specific formulation of the RES-E targets. Up to now, the analysis was based on the assumption that EU-wide technology-neutral targets are implemented, which increase from 36 % in 2020 to 85 % in 2050. For reasons of policy relevance, a sensitivity analysis of Scenario 3-I-B is simulated by considering national technology-specific RES-E targets instead of an EU-wide (technology-neutral) RES-E target in 2020.

[54]These findings are in line with De Jonghe et al. (2009), who show that at high CO_2 emission restrictions, the RES-E quota restriction becomes a non-binding constraint and thus yields a zero certificate price.

Table 2.8: Marginal costs of compliance with the RES-E targets per year [€$_{2010}$/MWh] (not discounted)

Nuclear investment	CCS investment	Scenario	2020	2030	2040	2050
			'Low-cost'			
Option	Option	[3-I-L]	18	33	19	31
Option	No option	[3-II-L]	17	32	12	28
No option	Option	[3-III-L]	2	23	9	3
No option	No option	[3-IV-L]	3	8	0	0
			'Base'			
Option	Option	[3-I-B]	18	49	71	60
Option	No option	[3-II-B]	18	46	60	56
No option	Option	[3-III-B]	6	36	51	2
No option	No option	[3-IV-B]	7	23	32	0
			'High-cost'			
Option	Option	[3-I-C]	0	55	95	71
Option	No option	[3-II-C]	0	54	80	72
No option	Option	[3-III-C]	0	38	63	20
No option	No option	[3-IV-C]	0	17	45	0

2.5.3.3 Implications of a national technology-specific RES-E targets in 2020

For the sensitivity analysis of Scenario 3-I-B, we assume that the EU member states achieve the national technology-specific RES-E targets specified in their National Renewable Energy Action Plans (NREAPs) for 2020 instead of an EU-wide (technology-neutral) RES-E target of 36 % in 2020. All other assumptions are kept constant. Specifically, we assume that the national technology-specific RES-E targets of the EU member states' NREAPs only exist until 2020 and are replaced by the EU-wide (technology-neutral) RES-E targets of Scenario 3-I-B from 2020 onwards. Hence, both scenarios achieve a 85 % RES-E target by 2050. They only differ with regard to the 2020 RES-E target.

Overall, the costs of decarbonization up until 2050 amount to 598 bn €$_{2010}$ in the 'Sensitivity' scenario of 3-I-B, which assumes that the EU member states achieve their national technology-specific NREAP targets instead of an EU-wide (technology-neutral) RES-E target of 36 % in 2020. In order to quantify the excess costs of the national technology-specific RES-E targets for 2020 in comparison to the EU-wide technology-neutral energy target of 36 % in 2020, the results of the 'Sensitivity' scenario need to be set in relation to the results of Scenario 3-I-B. Overall, the costs of decarbonization increase by 47 % from 408 bn €$_{2010}$ in Scenario 3-I-B to 598 bn €$_{2010}$ in the 'Sensitivity' scenario. Hence, the EU member states' NREAP targets are associated with excess costs of more than 190 bn €$_{2010}$.[55]

In comparison to the EU-wide (technology-neutral) RES-E target, the EU member states' technology-specific RES-E targets lead to excess costs for two reasons: First, technology-specific targets prevent the utilization of the least-cost RES-E technologies. Second, national targets prevent the allocation of RES-E technologies at the most favorable sites in Europe (with the highest full load hours).

The sub-optimal choice of RES-E technologies, in the case of the EU member states' NREAP targets, is reflected by a significant expansion of PV and offshore wind up to 2020, as shown in Figure 2.5.

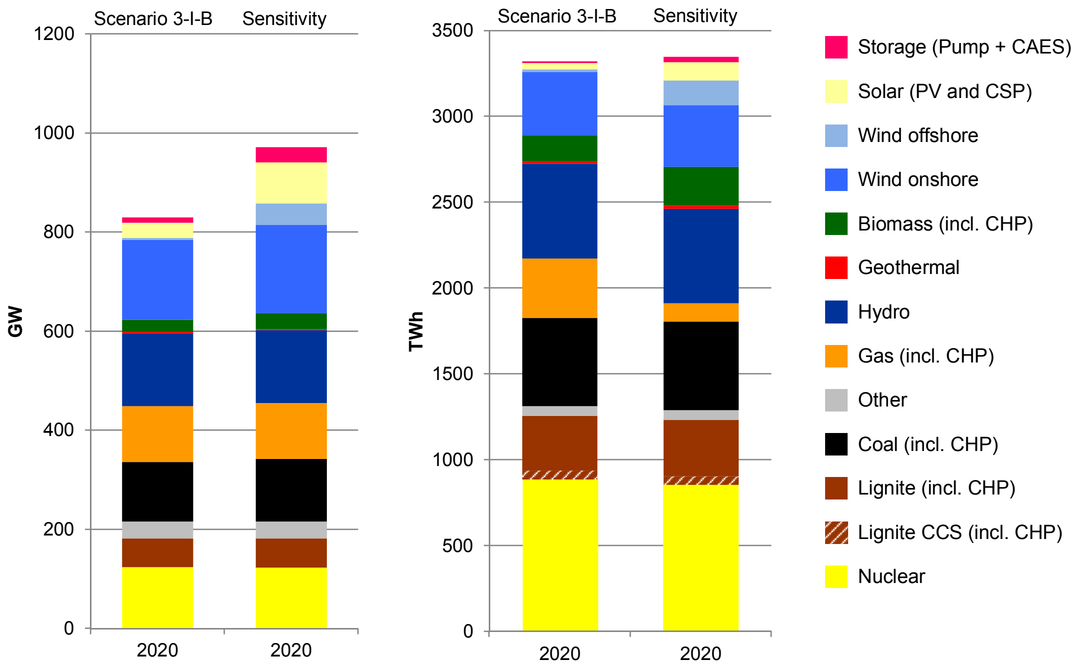


FIGURE 2.5: Scenario-specific capacity and generation mix in 2020, Scenario 3-I-B and 'Sensitivity'

While the EU member states' NREAPs forsee more than 83 TWh PV electricity generation in Europe by 2020 (41 TWh in Germany alone), PV electricity generation amounts to only 33 TWh in Scenario 3-I-B, assuming an EU-wide (technology-neutral) RES-E target of 36 % for 2020.[56] A similar case holds for offshore wind power. While the NREAP targets forsee a total offshore wind power generation of 142 TWh in 2020, only 15 TWh offshore wind power is generated in Scenario 3-I-B.

[55]For comparison, Aune et al. (2012), who apply a multi-market energy equilibrium model to analyze the cost implications of the EU's 20 % renewable energy target for the year 2020, estimate that a common renewable energy target for all member states alongside a EU-wide green certificates trading system may cut the EU's total cost of fulfilling the renewable target for 2020 by 70 % compared to a situation with differentiated national targets for each of the member states with domestic trade of certificates only.

[56]In Scenario 3-I-B, no additional PV capacities are installed by 2020. Only existing PV capacities (already installed in 2010) are used to generate power.

In addition to the sub-optimal choice of RES-E technologies, excess costs also occur due to an inefficient regional allocation of RES-E technologies. For example, although total onshore wind capacities in 2020 are 5 % lower in Scenario 3-I-B than in the 'Sensitivity' scenario with the NREAP targets, total onshore wind electricity generation is 5 % higher.[57] Unlike the national technology-specific NREAP targets, the EU-wide technology-neutral RES-E target ensures the deployment of wind power turbines at the most favorable sites in Europe until 2020. As a consequence, the average full load hours achieved by the onshore (offshore) wind turbines deployed across Europe in 2020 are 11 % (14 %) higher in Scenario 3-I-B than in the 'Sensitivity' scenario using the NREAP targets.

The sub-optimal choice of RES-E technologies and the inefficient regional allocation in the case of national technology-specific RES-E targets are also reflected by the marginal costs of compliance with the NREAP targets in 2020, which depict the related system costs for an additional MWh of a certain RES-E technology produced in a specific country in 2020. Table 2.9 lists the assumed country-specific onshore wind, offshore wind and PV targets for 2020, as well as the corresponding marginal costs of compliance.[58] The marginal costs of compliance with the national technology-specific (onshore and offshore) wind and PV targets increase with the target level, due to the fact that the national potential of favorable wind and solar sites (with high full load hours) is limited. Hence, wind turbines and PV systems may need to be deployed at less favorable sites within the country to achieve commitment with the technology-specific targets.[59] However, it should be noted that even in the absence of space potential restrictions, the marginal costs of compliance with the national technology-specific (onshore and offshore) wind and PV targets would increase as the target level increases. This is due to the fact that the marginal value of wind and solar power units (with no short-run marginal costs of power generation) decreases as the wind and solar power penetration increases, as explained in Chapter 3.[60]

Except for Italy and Portugal, the marginal costs of compliance with the national PV targets are significantly higher than for the national onshore wind targets in 2020, despite the fact that the national PV targets are significantly lower in all countries. In Germany, for example, the marginal costs of compliance with the national PV target in 2020 (41.4 TWh) amount to over 293 $€_{2010}$/MWh, whereas the marginal costs of

[57] In Scenario 3-I-B: 162 GW and 370 TWh, respectively; in 'Sensitivity' scenario with NREAP targets: 170 GW and 352 TWh, respectively. Note that the implied national technology-specific onshore wind targets in the 'Sensitivity' scenario for 2020 are exceeded in Denmark and Ireland.

[58] The assumed country-specific biomass, geothermal and CSP targets for 2020, as well as the corresponding average marginal costs of compliance, are listed in Table A.8 of the Appendix.

[59] As explained in Section 2.3.5, the deployment of wind and solar power technologies within a subregion is restricted by a space potential in km^2.

[60] The marginal value of wind and solar power units is defined as the revenue from selling electricity on the wholesale market during the unit's technical lifetime.

compliance with the national onshore wind target in 2020 (72.7 TWh) amount to only 97 €$_{2010}$/MWh. Moreover, the marginal costs of compliance with the national onshore wind targets are always lower than the marginal costs of compliance with the national offshore wind targets, although the national offshore targets are lower than the onshore wind targets (except for Belgium).[61] These differences reflect the sub-optimal choice of RES-E technologies.

Table 2.9: National technology-specific RES-E targets [TWh] for 2020 (EC (2010b)) and marginal costs of compliance [€$_{2010}$/MWh] (not discounted)

	Onshore wind		Offshore wind		PV	
	[TWh]	[€$_{2010}$/MWh	TWh]	[€$_{2010}$/MWh]	[TWh]	[€$_{2010}$/MWh]
Austria	4.8	88	-	-	0.3	268
Belgium	4.3	14	6.2	99	1.1	373
Bulgaria	2.6	262	-	-	0.4	273
Czech Republic	1.5	31	-	-	1.7	324
Denmark	6.4	0	5.3	141	-	-
Estland	1.0	48	0.6	227	-	-
Finland	3.5	31	2.5	210	-	-
France	39.9	38	18.0	156	5.9	204
Germany	72.7	97	31.8	125	41.4	293
Great Britain	34.2	31	44.1	77	2.2	367
Greece	16.1	187	0.7	411	2.9	217
Hungary	1.6	125	-	-	0.1	240
Ireland	10.2	0	1.7	71	-	-
Italy	18.0	127	2.0	328	9.7	113
Latvia	0.5	66	0.4	220	0.0	324
Lithuania	1.3	93	-	-	0.0	342
Luxemburg	0.2	75	-	-	0.1	339
Netherlands	13.4	84	19.0	69	0.6	340
Poland	13.2	18	1.5	211	0.003	325
Portugal	14.4	146	0.2	199	1.5	123
Romania	8.4	220	-	-	0.3	254
Slovakia	0.6	111	-	-	0.3	281
Slovenia	0.2	179	-	-	0.1	285
Spain	70.5	91	7.8	294	14.3	132
Sweden	12.0	22	0.5	219	-	-

The inefficient regional allocation of RES-E technologies is, for example, shown by the marginal costs of compliance with the offshore wind targets. While compliance with the German offshore wind target (31.8 TWh) is achieved at marginal costs of more

[61] Note that the marginal costs of compliance with the national wind onshore targets are 0 €$_{2010}$/MWh in Denmark and Ireland. Hence the implemented targets are non-binding and thus exceeded.

than 125 €$_{2010}$/MWh, compliance with the British offshore wind target (44.1 TWh) is achieved at marginal costs of less than 77 €$_{2010}$/MWh. Hence, given the comparatively good offshore wind conditions in Great Britain, total system costs could be lowered by reducing the offshore wind power target in Germany and increasing the offshore wind power target in Great Britain instead.

Overall, the scenario results show that the national technology-specific RES-E targets prevent the cost-efficient choice and allocation of RES-E technologies across Europe. Consequently, significant excess costs arise (190 bn €$_{2010}$). In the case of the EU member states' NREAP targets for 2020, the excess costs are primarily due to two reasons: First, the NREAP targets forsee a large-scale deployment of PV systems and offshore wind power turbines, which are characterized by comparatively high investment costs up to 2020. Second, the NREAP targets allocate wind power turbines (onshore and offshore) and PV systems at comparatively unfavorable sites across Europe.

2.6 Conclusion

The applied electricity system optimization model is a profound tool to derive a comprehensive set of technically feasible development pathways for Europe's power sector up to 2050. Specifically, the implications of alternative decarbonization pathways are accurately captured from an technical perspective, as the model encompasses current and future electricity generation technologies in detail, is characterized by a high regional resolution and accounts for increased flexibility requirements of electricity systems with high shares of fluctuating renewable energy sources. Our scenario analysis shows that the costs of decarbonizing Europe's power sector by 2050 may vary between 139 and 633 bn €$_{2010}$ depending on the implementation of supplementary RES-E targets, the availability of nuclear power and CCS technologies for power generation and the economic framework conditions. This corresponds to an increase of between 11 % and 44 % compared to the total system costs when no CO_2 reduction targets are implemented.

In line with economic theory, the decarbonization of Europe's power sector is found to be achieved at minimal costs under a stand-alone CO_2 reduction target, which ensures competition between all low-carbon technologies. If, however, renewable energies are exempt from competition via supplementary RES-E targets or if investments in new nuclear and CCS power plants are politically restricted, the costs of decarbonization rise by between 60 % and 270 % in the scenarios. The drastic cost increase highlights the necessity to base political interference with regard to supplementary RES-E targets or restrictions on the use of nuclear power and CCS on a comprehensive cost-benefit analysis. Only if the potential benefits associated with a renewable-based electricity system outweight the additional costs, political interference may be justified from an economic perspective.

However, it should be stressed that the scenario results are driven by a large number of parameters associated with uncertainty, such as the investment costs of CCS and nuclear power plants. Likewise it is to be noted that the model does not account for feedback effects between different markets with regard to fossil fuel prices and CO_2 abatement opportunities given its sector-specific nature. Moreover, the model assumes a price-inelastic electricity demand and abstracts from endogenous learning curve effects.

Future research could address the following issues: First, other methodological approaches could be applied – such as an iterative approach or an reformulation of the optimization problem as a mixed complementarity problem – to account for endogenous learning curve effects for non-mature technologies (such as RES-E and CCS technologies) in the model. Both approaches, however, require valid assumptions regarding the learning rates of non-mature technologies and their expansion across the world up to 2050. Second, instead of simulating three economic scenarios characterized by different developments in RES-E investment costs, electricity demand levels and fossil fuel prices, a probability function for the costs of decarbonization could be applied. In this case, a large number of scenarios would need to be simulated based on random draws (i.e., samples) of uncertain economic parameters up to 2050 – including not only RES-E investment costs, electricity demand levels and fossil fuel prices but also, e.g., investment costs of CCS and nuclear power plants or country-specific renewable energy space potentials. Third, while this paper provides evidence for the cost implications of supplementary RES-E targets, renewable energies are often mentioned to be associated with benefits (other than no CO_2 emissions) that could be quantified and compared to the respective costs. Most importantly, the use of local renewable energy sources may improve the security of energy supply in Europe, as the diversity in generation sources increases and the dependency on imported fuels from outside Europe decreases.

Chapter 3

The economic inefficiency of grid parity - The case of German photovoltaics

3.1 Introduction

In Germany, the consumption of self-produced electricity is exempt from paying taxes, levies and surcharges. Moreover, electricity consumers pay energy-related rather than capacity-related network tariffs, i.e., electricity consumers pay a fixed network tariff for each kWh purchased from the grid (see Figure 3.1). The exemption from additional charges and the current network tariff structure incentivize the consumption of self-produced rather than grid-supplied electricity. This paper analyzes the economic consequences of this indirect financial incentive for the case of residential photovoltaic (PV) systems – both from the single household's and the total system perspective.

Besides the exemption from taxes, levies and surcharges as well as the allocation of grid costs via energy- rather than capacity-related network tariffs, the government currently promotes investments in renewable energy technologies via a feed-in tariff system in which eligible renewable energy producers receive a fixed payment for the amount of electricity fed into the grid (over a period of 20 years). The additional costs associated with the promotion of renewable energies are passed on to electricity consumers via the renewable energy surcharge. Under the current feed-in tariff system, households typically maximize their profits by maximizing the amount of PV electricity fed into the electricity grid. However, in 2012, the German government decided to stop the direct financial incentives for PV electricity generation (feed-in tariff) once a cumulative

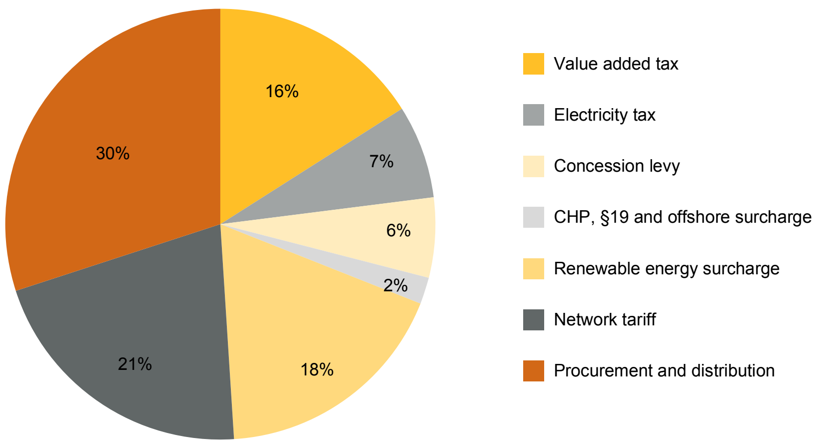


FIGURE 3.1: Composition of Germany's flat residential electricity tariff in 2013
Source: Own illustration based on BDEW (2013).

capacity of 52 GW is reached (Deutscher Bundestag (2012)), which corresponds to the German NREAP target for 2020.[62]

Meanwhile, 'PV grid parity' was recently reached on the household level in Germany (as a consequence of increasing residential electricity tariffs and falling PV system prices), which marked the point in time at which the levelized costs of electricity (LCOE) of rooftop PV systems have reached the level of the residential electricity tariff (Perez et al. (2012)).[63] Since then, the LCOE of rooftop PV systems (14 €ct/kWh - 16 €cent/kWh, Kost et al. (2012)) have fallen well below the flat residential electricity tariff (28.5 €ct/kWh, BDEW (2013)).

Both (i) the decrease of PV electricity generation costs below the flat residential electricity tariff and (ii) the exemption from taxes, levies and surcharges as well as the allocation of grid costs via energy- rather than capacity-related network tariffs in Germany, have made the consumption of a self-produced kWh cheaper than the consumption of a grid-supplied kWh from the single household's perspective. Hence, households are given a financial incentive to install rooftop PV systems, even without receiving any feed-in tariff.

If the residential electricity tariff further increases and the price of PV system further decreases, the financial incentive will also continue to increase in the years to come. Similary, the price of small-scale battery storage systems, such as lithium-ion batteries, is

[62]By the end of October of 2013, total installed PV capacity amounted to 35.3 GWp in Germany (BNetzA (2013)).

[63]Several studies have tried to identify the point in time at which PV grid parity will be reached in different countries (e.g., Bhandari and Stadler (2009) for Germany, Ayompe et al. (2010) for Ireland, and Denholm et al. (2009), Reichelstein and Yorston (2013) and Swift (2013) for the United States). An analyis of factors influencing the LCOE of PV (and thus the point of time at which PV grid parity is reached) is, for example, provided by Branker et al. (2011), Darling et al. (2011), Singh and Singh (2010) and Hernandez-Moro and Martinez-Duart (2013).

expected to further decrease, allowing an increased share of PV electricity generation to be consumed in-house. Overall, households will soon be able to significantly reduce their electricity costs by consuming self-produced PV electricity instead of grid-supplied electricity, rendering investments in rooftop PV systems combined with small-scale battery storage systems economically viable from the single household's perspective.

This paper analyzes the consequences of exempting in-house PV electricity consumption from taxes, levies and surcharges and allocating grid costs via energy- rather than capacity-related network tariffs from 2020 onwards – both from the single household and the total system perspective.[64] In a case study for Germany, a household optimization model is applied that minimizes the single households' electricity costs by determining (among others) the cost-optimal dimensioning of the combined PV and battery storage system, the amount of PV electricity generation consumed in-house or sold to the grid as well as the dispatch of the battery storage system. To best reflect the current situation, it is assumed that households pay a flat (time-independent) residential electricity tariff for the amount of electricity purchased from the grid. Moreover, households are assumed to receive the (time-dependent) wholesale electricity price for the amount of surplus PV electricity generation fed into the grid.

Our analysis complements a growing body of literature addressing the economic performance of both residential and commercial PV systems from the single customer's perspective. Darghouth et al. (2013), Ong et al. (2010), Mills et al. (2008) and Borenstein (2007) analyze the impact of the retail electricity tariff structures on the economic viability of residential PV systems from the customer's perspective. These papers find that time-varying retail tariffs (such as time-of-use rates or real-time prices), which reflect the utility's cost of generating (purchasing) electricity on the wholesale electricity market, lead to higher electricity bill savings from in-house PV electricity consumption than flat retail tariffs.[65] This is due to the generally positive correlation between the hourly solar power generation profile and the hourly wholesale electricity price profile in scenarios with low solar power penetration. However, as explained by Darghouth et al. (2013), electricity bill savings under time-varying retail tariffs may decrease with increased solar power penetration, as high amounts of PV electricity generation may cause the temporal profile of the hourly wholesale electricity price to become negatively correlated with the hourly PV electricity generation profile. More specifially, the

[64] Although investments in PV systems for in-house PV electricity consumption may already be economically viable today, we choose 2020 as starting year in our analysis as investments in PV systems are expected to be driven by the feed-in tariff until 2020, which will be paid until the target of 52 GW is achieved. Moreover, by 2020, the price of lithium-ion batteries is expected to have significantly fallen in comparison to today, rendering investments in small-scale storage capacities (to increase the amount of in-house PV electricity consumption) economically viable.

[65] While time-of-use rates set various prices for different periods (e.g., daytime vs. nighttime), real-time pricing forsees prices to change on an hourly basis depending on the hourly wholesale electricity price (Darghouth et al. (2013)).

more PV capacity is installed, the larger the short-term merit-order-effect becomes. PV electricity supply, having (almost) zero variable generation costs, reduces the wholesale electricity price and, as such, the (time-varying) retail tariff during sunny hours.[66] However, in Germany (and many other European countries), residential customers are traditionally charged a flat retail electricity tariff for the electricity taken form the grid – independent of the time of day that the electricity is used.

The applied household optimization model extends the modeling approach of recent analyses. While Colmenar-Santos et al. (2012), McHenry (2012), Ayompe et al. (2010) and Hernandez et al. (1998) analyze the profitability of investments in grid-connected PV systems (with an exogenously given capacity) from the single household's perspective, Ren et al. (2009) determine the cost-optimal capacity of a grid-connected PV system by minimizing the annual electricity costs of a given residential electricity consumer. Castillo-Cagigal et al. (2011), in contrast, abstract from costs and evaluate the supplementary installation of both a battery storage system and active demand side management in order to maximize the in-house consumption of self-produced PV electricity. Only Colmenar-Santos et al. (2012) and Castillo-Cagigal et al. (2011) analyze the option to install a battery storage system in combination with the PV system. However, none of the papers cited above jointly optimizes the size of the PV and battery storage system from the single household's perspective by minimizing the household's annual electricity costs.

Moreover, to the authors' knowledge, our analysis is the first to account for feedback effects of the single household's optimization behavior on the rest of the electricity system (and vice versa). In particular, an increased penetration of PV systems on the household level causes changes in the residual load (both in volume and structure), which in turn affects both the wholesale electricity price (via a change in the provision and operation of power plants and storage technologies on the system level) and the residential electricity tariff (primarily via changes in the wholesale electricity price and the renewable energy surcharge). We account for these feedback effects by running an iteration between the household optimization model and an electricity system optimization model. Finally, we are the first to quantify both redistributional effects and excess costs associated with the indirect financial incentive for in-house PV electricity consumption.

We find that households are able to reduce their electricity costs by investing in PV and storage battery capacities to meet part of their demand with self-produced electricity. However, while households reduce their annual electricity costs by consuming

[66]The effect of renewable energy penetration with no variable generation costs on the wholesale electricity price (short-term merit order effect) is, for example, analyzed in Gil et al. (2012), Jonsson et al. (2010), Munksgaard and Morthorst (2008), G. Saenz de Miera and P. del Rion Gonzalez and I. Vizcaino (2008) and Sensfuß et al. (2008).

self-produced instead of grid-supplied electricity, this indirect financial incentive yields two economic consequences:

Firstly, we find that the indirect financial incentive distorts competition of technologies, which causes excess costs to be born by the society. Due to the exemption from taxes, levies and surcharges for the amount of in-house PV consumption and the allocation of grid costs via energy- rather than capacity-related network tariffs, households are incentivized to undertake investments in small-scale PV and battery storage systems that are inefficient from an economic perspective, causing total system costs to rise.

Secondly, we find that the indirect financial incentive for the consumption of self-produced instead of grid-supplied electricity leads to a redistribution of financial resources. For example, as a consequence of an increased in-house PV electricity consumption on the household level, the amount of electricity purchased from the grid decreases. However, since the additional costs of promoting renewable energies are currently apportioned to the amount of electricity purchased from the grid, the renewable energy surcharge (to be paid by the residual electricity consumers) increases with the amount of in-house PV electricity consumption on the household level. Hence, the financial burden for residual electricity consumers rises in order to favor the electricity bill savings of households that meet part of their electricity demand with self-produced PV electricity.

In order to incentivize a cost-efficient development of the German electricity system, we argue that the consumption of self-produced electricity should be treated in the same manner as the consumption of grid-supplied electricity, i.e., the exemption from taxes, levies and other surcharges for the amount of self-produced PV electricity consumed in-house should be abolished. Alternatively, the residential electricity price could be reduced to the 'true' costs of electricity procurement. Moreover, since grid costs are primarily fixed costs, the traditional (energy-related) grid tariffs should be replaced by cost-reflecting tariffs that correspond primarily to grid connection capacity.

The remainder of the paper is structured as follows: Section 3.2 presents the applied methodology used to analyze the consequences of indirect financial incentives for in-house PV electricity consumption in Germany. Section 3.3 defines the scenarios und Section 3.4 summarizes the model results. Section 3.5 concludes and provides an outlook on possible further research.

3.2 Methodology and assumptions

In the following, we first explain the general logic of the applied methodological approach (Section 3.2.1), before the household optimization model (Section 3.2.2) and the electricity system optimization model (Section 3.2.3) are described in more detail.

3.2.1 Modeling approach

The general logic of the applied modeling approach used to analyze the consequences of the indirect financial incentive for in-house PV electricity consumption can best be described by defining two agents, each characterized by a specific optimization behavior. Agent A minimizes the single household's accumulated and discounted electricity costs subject to techno-economic constraints. Agent A can choose between meeting the single household's electricity demand with electricity supplied by the grid or with self-produced PV electricity. More specifically, he minimizes the single household's electricity costs by determining the optimal decisions with respect to the dimensioning of the combined PV and storage systems and the use of self-produced PV electricity. Hence, Agent A decides not only on the optimal size of the combined PV and storage capacities installed but also on the optimal dispatch of the single household's battery storage systems and the optimal amount of PV electricity generation that is to be consumed in-house or sold to the grid.

Agent B, in contrast, minimizes total system costs by making optimal investment and dispatch decisions with respect to generation and storage technologies on the system level. Accumulated and discounted system costs are minimized subject to techno-economic constraints, such as the necessity to meet the electricity demand at each point in time. Given the assumption of a price-inelastic electricity demand, the cost-minimization problem of Agent B corresponds to a welfare-maximization approach.

Moreover, both agents minimize costs under the assumption of perfect foresight.

As shown in Figure 3.2, the optimization behavior of Agent A influences the optimization behavior of Agent B and vice versa. The more PV and storage system capacities Agent A builds on the household level, the more PV electricity is produced and either consumed in-house or fed into the grid. As a consequence, the residual load to be supplied by generation and storage technologies on the system level changes (both in volume and structure). Agent B subsequently adapts the provision and operation of power plants and storage technologies on the system level to the new residual load, which in turn leads to changes in the wholesale electricity price and the residential electricity tariff. Changes in the wholesale electricity price and the residential electricity tariff, in turn,

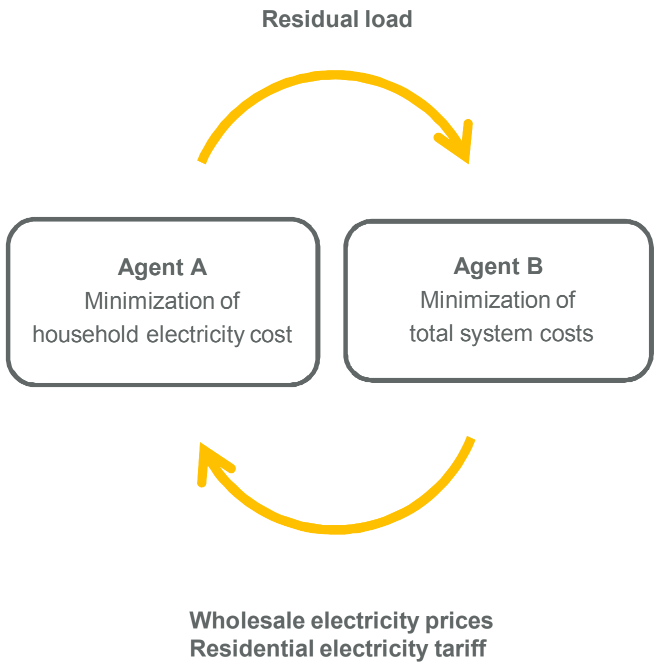


FIGURE 3.2: Interaction of the agents' optimization behaviors

affect the single household's optimization behavior. This is due to two facts: Firstly, we assume that households pay a fixed, i.e., time-independent, residential electricity tariff for each kWh purchased from the grid, as currently employed in Germany. Secondly, we assume that the amount of surplus (not self-consumed) PV electricity generation, which is sold to the grid, is remunerated by the wholesale electricity price.

Agent A and Agent B are assumed to determine their investment and dispatch decisions given the investment and dispatch decisions of the other agent. Hence, both agents adapt their optimal invest and dispatch decisions in response to the other agent's decision until the equilibrium is reached. In the equilibrium, Agent A no longer has an incentive to change his behavior, given the exogenously given behavior of Agent B and vice versa.

In order to determine the equilibrium solution, an iterative approach with two linear optimization models, (i.e., a linear household optimization model (Agent A) and a linear electricity system optimization model (Agent B)), is applied. Each model minimizes the respective agent's costs. The equilibrium is derived by iterating all interrelated variables (such as the wholesale electricity price, the renewable energy surcharge and the residual load) until convergence of results is reached. For this, a convergence criterion must to be defined. A natural possibility is to stop when the relative change in the interrelated variables is sufficiently small.

The linear programming environment has been proven to be suitable for solving large-scale problems such as these ones, which involve millions of variables that require extensive calculations. In fact, there are very effective algorithms which can efficiently and reliably solve large linear programming problems, such as the Simplex algorithm (e.g., Boyd and Vandenberghe (2004), Todd (2002) or Murty (1983)).[67] An alternative approach would be to formulate a non-linear optimization model that minimizes the sum of the respective agent's costs. In this case, however, the target function would become non-linear and thus the optimization problem may become difficult to solve since the algorithms for large-scale non-linear optimization problems are typically far less effective than the algorithms for linear optimization problems (Boyd and Vandenberghe (2004)). Another alternative would be to formulate an equilibrium model that solves each agent's optimization problem simultaneously within a complementarity system. However, just like in the case of the non-linear optimization model, the large complexity of the problem structure suggests that the model may be rather difficult to solve via a mixed complementarity problem algorithm (Li (2010)).

In the following, the household optimization model (Section 3.2.2) and the electricity system optimization model (Section 3.2.3), which are iterated to determine the market equilibrium, are described in more detail.

3.2.2 Household optimization model

The household optimization model determines (among others) the optimal investment in combined PV and storage systems from the single household's perspective by the year 2020 and calculates the optimal dispatch of the battery storage system in 5-year time steps up to 2050, i.e., over the entire lifetime of the PV system (which is assumed to be 30 years). Moreover, the model determines the optimal share of PV electricity to be consumed in-house, stored in the battery storage system or sold to the grid.

3.2.2.1 Model equations

The objective of the linear household optimization model is to minimize the accumulated discounted electricity costs of one- and two-family houses in Germany, given hourly solar radiation profiles, hourly household electricity consumption profiles, PV and battery storage system investment costs, hourly wholesale electricity prices and the residential

[67] Applications of iterative procedures to compute market equilibria can, for example, be found in Greenberg and Murphy (1985) and Wu and Fuller (1996). Specifically, the iterative procedure pursued in this paper is comparable to the PIES (Project Independence Evaluation System) algorithm, which essentially applies a linear programming model in combination with econometric demand equations to determine fuel prices and quantities (Ahn and Hogan (1982), Hogan (1975) and Gabriel et al. (2001)).

electricity tariff. Tables 3.1, 3.2 and 3.3 lists all sets, parameters and variables of the household optimization model.

TABLE 3.1: Sets and parameters of the household optimization model

Abbreviation	Dimension	Description
Model sets		
$h \in H$		Hour of the year, H = [1, 2, ..., 8760]
$y \in Y$		Year, Y = [2020,...,2050]
$i \in I$		Number of residents living in the household, I = [1,2,3,4,5]
$b \in B$		Region, B = [northern, central and southern Germany]
Model parameters		
$a_{h,b}$	[W/m^2]	Solar irradiance on tilted PV cell
$\overline{a}$	[W/m^2]	Solar irradiance under standard test conditions
an^P		Annuity factor for PV investment costs (5% interest rate)
an^S		Annuity factor for battery investment costs (5% interest rate)
c^P	[€$_{2011}$/kW]	PV investment costs
c^S	[€$_{2011}$/kWh]	Battery investment costs
$d_{y,h,i,b}$	[kWh]	Household electricity demand
$disc_y$		Discount factor (5% discount rate)
fc^P	[€$_{2011}$/kW]	PV fixed operation and maintenance costs
fc^S	[€$_{2011}$/kWh]	Battery fixed operation and maintenance costs
n	[1/h]	Relation of storage capacity [kW] to storage volume [kWh]
$p_{y,h}$	[€$_{2011}$/kWh]	Wholesale electricity price
ret_y	[€$_{2011}$/kWh]	Residential electricity tariff
t^P	[years]	PV lifetime
t^S	[years]	Battery lifetime
η	[%]	Efficiency of the battery storage
u	[%]	Interest rate for annuity and discount factor
$z_{i,b}$		Total number of one- and two-family houses
x		Sample households with residents i in region r
ω	[%]	PV performance ratio

Table 3.2: Variables of the household optimization model

Abbreviation	Dimension	Description
Model variables		
$AD^P_{y,i,b}$	[kW]	Commissioning of new PV systems
$AD^S_{y,i,b}$	[kWh]	Commissioning of new battery systems
$C^P_{y,i,b}$	[€$_{2011}$]	Annualized PV investment costs (5 % interest rate)
$C^S_{y,i,b}$	[€$_{2011}$]	Annualized battery investment costs (5 % interest rate)
$ECI^P_{y,h,i,b}$	[kWh]	Electricity consumed in-house supplied by the PV system
$ECI^S_{y,h,i,b}$	[kWh]	Electricity consumed in-house supplied by battery system
$ECI^G_{y,h,i,b}$	[kWh]	Electricity consumed in-house supplied by the grid
$ESG^P_{y,h,i,b}$	[kWh]	Electricity sold to the grid supplied by the PV system
$ESG^S_{y,h,i,b}$	[kWh]	Electricity sold to the grid supplied by battery system
$ESB^P_{y,h,i,b}$	[kWh]	Electricity stored in the battery system supplied by the PV system
$ESB^G_{y,h,i,b}$	[kWh]	Electricity stored in the battery system supplied by the grid
$K^P_{y,i,b}$	[kW]	Installed PV system capacity
$K^S_{y,i,b}$	[kWh]	Installed battery storage volume
$L^S_{y,h,i,b}$	[kWh]	Storage level
$M_{y,i,b}$	[€$_{2011}$]	Annual O&M cost
$P_{y,i,b}$	[€$_{2011}$]	Annual costs of purchasing electricity
$R_{y,i,b}$	[€$_{2011}$]	Annual revenue from selling electricity
$THHC$	[€$_{2011}$]	Accumulated and discounted total HH electricity costs

Table 3.3: Variables of the household optimization model calculated ex-post

Abbreviation	Dimension	Description
HHC_y	[€$_{2011}$]	Scaled costs of PV and battery storage capacities
$HHD_{y,h}$	[MW]	Scaled amount of household electricity demand
$HHES_{y,h}$	[MW]	Scaled amount of electricity sold to the grid
$HHGD_{y,h}$	[MW]	Scaled amount of grid-supplied electricity consumed in-house
HHI_y	[€$_{2011}$]	Scaled revenue from selling surplus PV electricity
$HHSC_{y,h}$	[MW]	Scaled amount of self-produced electricity consumed in-house

$$\min THHC = \sum_{i\in I}\sum_{b\in B}\sum_{y\in Y} disc_y \cdot (C^P_{y,i,b} + C^S_{y,i,b} + M_{y,i,b} + P_{y,i,b} - R_{y,i,b}) \cdot \frac{z_{i,b}}{x} \tag{3.1}$$

s.t.

$$C^P_{y,i,b} = c^P \cdot AD^P_{y,i,b} \cdot an^P \tag{3.2}$$

$$C^S_{y,i,b} = c^S \cdot AD^S_{y,i,b} \cdot an^S \tag{3.3}$$

$$M_{y,i,b} = fc^P \cdot K^P_{y,i,b} + fc^S \cdot K^S_{y,i,b} \tag{3.4}$$

$$P_{y,i,b} = \sum_{h\in H}(ECI^G_{y,h,i,b} + ESB^G_{y,h,i,b}) \cdot ret_y \tag{3.5}$$

$$R_{y,i,b} = \sum_{h\in H}((ESG^P_{y,h,i,b} + ESG^S_{y,h,i,b}) \cdot p_{y,h}) \tag{3.6}$$

$$K^P_{y,i,b} \cdot \omega \cdot (\frac{a_{h,b}}{\overline{a}}) = ECI^P_{y,h,i,b} + ESB^P_{y,h,i,b} + ESG^P_{y,h,i,b} \tag{3.7}$$

$$d_{y,h,i,b} = ECI^P_{y,h,i,b} + ECI^S_{y,h,i,b} + ECI^G_{y,h,i,b} \tag{3.8}$$

$$L^S_{y,h,i,b} \leq K^S_{y,i,b} \tag{3.9}$$

$$L^S_{y,h+1,i,b} - L^S_{y,h,i,b} = ((ESB^P_{y,h,i,b} + ESB^G_{y,h,i,b}) \cdot \eta) - ECI^S_{y,h,i,b} - ESG^S_{y,h,i,b} \tag{3.10}$$

$$ESB^P_{y,h,i,b} + ESB^G_{y,h,i,b} = l = K^S_{y,i,b} \cdot n \tag{3.11}$$

$$ECI^S_{y,h,i,b} + ESG^S_{y,h,i,b} = l = K^S_{y,i,b} \cdot n \tag{3.12}$$

The accumulated discounted (5 % discount rate) electricity costs of one- and two-family houses in Germany ($THHC$), as defined in Equations (3.1) - (3.6), are the sum of the single household's annualized PV system investment costs ($C^P_{y,i,b}$), the annualized storage system investment costs ($C^S_{y,i,b}$), the annual operation and maintenance (O&M) costs ($M_{y,i,b}$) and the annual costs for the amount of electricity purchased from the grid ($P_{y,i,b}$). Investment costs are annualized with a 5 % interest rate for the depreciation time, i.e., the technical liftetime of the PV and battery storage systems. O&M costs account for the replacement of the inverter. In addition, the electricity costs are decreased by the revenue acquired from selling surplus (not self-consumed) PV electricity to the grid ($R_{y,i,b}$), which is assumed to be remunerated by the wholesale electricity price ($p_{y,h}$).

The accumulated discounted electricity costs are minimized subject to several techno-economic constraints.

Power generation constraint (Eq. (3.7)): The power output of the single household's PV system, which depends on the solar radiation on the tilted PV cells ($a_{h,b}$) and the performance ratio of the PV system (ω), can either be directly consumed in-house

($ECI^P_{y,h,i,b}$), stored in the battery storage system ($ESB^P_{y,h,i,b}$) or sold to the electricity grid ($ESG^P_{y,h,i,b}$).[68]

Power balance constraint (Eq. (3.8)): The single household's electricity demand ($d_{y,h,i,b}$) needs to be met by electricity supplied by the PV system ($ECI^P_{y,h,i,b}$), the battery storage system ($ECI^S_{y,h,i,b}$) or the electricity grid ($ECI^G_{y,h,i,b}$).

Battery storage constraints (Eqs. (3.9), (3.10), (3.11) and (3.12)): The maximum storage level of the single household's battery system ($L^S_{y,h,i,b}$) is determined by the storage volume ($K^S_{y,i,b}$). Moreover, the hourly change in the storage level of the single household's battery system depends on the storage operation and the losses during the charging process. Note that the stored PV electricity may not only be used to meet the household's electricity demand ($ECI^S_{y,h,i,b}$) but also be fed into the electricity grid ($ESG^S_{y,h,i,b}$). Likewise, the battery storage system may not only be charged using electricity supplied by the PV system ($ESB^P_{y,h,i,b}$) but also using grid-supplied electricity ($ESB^G_{y,h,i,b}$).

Equations (3.13) - (3.18) quantify all variables calculated ex-post, which then serve as input parameters for the electricity system optimization model.

$$HHES_{y,h} = \sum_{i \in I} \sum_{b \in B} (ESG^P_{y,h,i,b} + ESG^S_{y,h,i,b}) \tag{3.13}$$

$$HHSC_{y,h} = \sum_{i \in I} \sum_{b \in B} (ECI^P_{y,h,i,b} + ECI^S_{y,h,i,b}) \tag{3.14}$$

$$HHGD_{y,h} = \sum_{i \in I} \sum_{b \in B} ECI^G_{y,h,i,b} \tag{3.15}$$

$$HHD_{y,h} = \sum_{i \in I} \sum_{b \in B} d_{y,h,i,b} = \sum_{i \in I} \sum_{b \in B} (HHGD_{y,h} + HHSC_{y,h}) \tag{3.16}$$

$$HHC_y = \sum_{i \in I} \sum_{b \in B} (C^P_{y,i,b} + C^S_{y,i,b} + M_{y,i,b}) \tag{3.17}$$

$$HHI_y = \sum_{i \in I} \sum_{b \in B} R_{y,i,b} \tag{3.18}$$

The total calculation time of the household optimization model amounts to 20 hours.

[68] We note that the curtailment of solar power generation is no option in the household optimization model.

3.2.2.2 Numerical assumptions

All country- and year-specific input parameters of the household optimization model (such as the solar radiation profiles, the single household's electricity demand profiles or PV and storage system investment costs) have been defined according to German levels.

Solar radiation profiles: The household optimization model considers three hourly solar radiation profiles (8760 h) for northern, central and southern Germany (based on historical solar radiation data of the year 2008 taken from EuroWind (2011)), which were converted from the horizontal to the tilted surface. The solar cells were assumed to be oriented to the south (azimuth of 180 *degree*) and tilted with an optimized angle of 37*degree* in southern Germany and 35.3*degree* in northern and central Germany.[69] Given these rather optimal conditions, a conservative performance ratio of 70 % was chosen to capture losses due to soiling and partial shadowing of rooftop PV systems. As a result, rooftop PV systems were assumed to exhibit a yield of 868 kWh/kWp per year in northern Germany, 923 kWh/kWp in central Germany and 1,022 kWh/kWp in southern Germany.[70]

Household's electricity demand profiles: The household optimization model accounts for 250 individual electricity demand profiles for 8760 h of the year, which were derived using a model developed by Richardson et al. (2010). The model creates synthetic electricity demand data for 24 h (with one-minute resolution) by simulating domestic appliance use dependent on the number of residents living in the house, the day of the week and the month of the year.[71] Deriving individual electricity demand profiles for 8760 h of the year – instead of using standard load profiles – is of major importance in order to adequately determine the cost-optimal PV and battery storage capacities from the single household's perspective. Individual electricity demand profiles account for both the high variability of the individual household's electricity demand and peak load situations. Standard load profiles for residential customers, in contrast, are based

[69] The chosen orientation and angle was derived via a PV electricity optimization model that maximizes the total annual electricity generation of the PV system depending on their location in Europe (in this case in northern, central or southern Germany) developed by the authors.

[70] The impact of the orientation of the PV system on both the total annual electricity generation and the daily profile of PV electricity supply is, for example, discussed in Tröster and Schmidt (2012), Blumsack et al. (2010), Mehleri et al. (2010) and Mondol et al. (2007). Note that the electricity generation output during the morning and evening can be increased by splitting the orientation of the PV panel arrays for an east-west orientation rather than a fixed southern orientation, as explained by Blumsack et al. (2010). This may be advantageous for residential electricity consumers if the electricity generation profile of the east-west orientated PV system matches more closely to the customer's demand profile. Such an orientation, however, assumes that the customer's goal is to maximize the in-house consumption of PV electricity generation. In contrast, if electricity consumers were to maximize revenues from net metering, they would need to consider the correlation between the PV systems electricity generation profile and the wholesale electricity price when deciding on the optimal orientation of the PV system (Blumsack et al. (2010)).

[71] The basic version of the domestic electricity demand model is distributed under https://dspace.lboro.ac.uk/2134/5786 and documented in Richardson et al. (2010).

on statistical average values. Hence, taking standard load profiles as an input parameter for the household optimization problem would not adequately represent the variability of individual household's demand and thus distort the results.

The domestic electricity demand model is configured to simulate the use of domestic appliances in Germany based on data from DESTATIS (2012a), DESTATIS (2012b), DESTATIS (2012c) and Statista (2012) for 8760 h of the year. The assumed proportions of households equipped with domestic appliances are shown in Table B.1 of the Appendix.

The model is used to simulate 250 electricity demand profiles, differing with regard to the number of residents living in the household (1-5 residents) and the household's configuration of domestic appliances, which are randomly assigned in the domestic electricity demand model (according to the assumptions shown in Table B.1 of the Appendix).[72] The average annual electricity demand of these consumption profiles is presented in Table 3.4.

Table 3.4: Average annual household electricity demand [kWh]

	min	max	average
1 Resident	1,840	5,649	2,888
2 Residents	2,086	6,556	3,871
3 Residents	2,539	9,217	4,200
4 Residents	3,057	8,698	4,519
5 Residents	3,339	10,379	4,833

By combining the 250 electricity demand profiles with the three different solar radiation profiles, we obtain 750 individual housholds each differing with regard to the number of residents living in the house (1-5 residents), the equipment (domestic appliances) and the location of the house. In the model, the 750 sample households are scaled-up by the actual number of one- and two-family houses in Germany, $z_{i,b}$ (see Table 3.5), in order to analyze the potential consequences of the indirect financial incentive for in-house PV electricity consumption for the case in which a large share of residential electricity consumers invests in combined PV and storage systems. In specific, only 90 % of the one- and two-family houses are used in scaling the results of the household optimization

[72] Specifically, 50 electricity demand profiles were generated for each of the five household types (with 1-5 residents), each of which differing with regard to the configuration of domestic appliances.

model, accounting for the fact that part of the rooftop PV potential of one- and two-family houses will already be used to achieve Germany's NREAP target for PV (52 GW).[73]

Note that scaled-up annual household electricity demand covered by the household optimization model amounts to 56 TWh. This corresponds to 9 % of the gross electricity demand assumed in the electricity system optimization model for Germany in 2020 (612 TWh).

TABLE 3.5: Number of one- and two-family houses located in Germany (90 %) based on data by DESTATIS (2008) and DESTATIS (2010)

	northern Germany	central Germany	southern Germany
1 Resident	835,086	1,817,500	1,176,311
2 Residents	1,261,675	2,462,942	1,562,837
3 Residents	528,596	1,016,977	643,481
4 Residents	491,342	942,537	596,034
5 Residents	171,152	326,388	206,157

Wholesale electricity prices and residential electricity tariff: The wholesale electricity price and the residential electricity tariff are taken from the electricity system optimization model (described in Section 3.2.3), which determines both input parameters based on optimal investment and dispatch decisions on the system level.

Other input parameters: All other input parameters of the household optimization model are listed in Table 3.6. In particular, PV system investment costs (c^P) are assumed to amount to 1,200 €$_{20112011}$/kWp in 2020 (based on Agora Energiewende (2013a) and Prognos AG (2013)). Moreover, stationary battery storage units are assumed to have investment costs (c^S) of 400 €$_{20112011}$/kWh and a technical lifetime (ts) of 15 years, which reflects expectations for lithium-ion batteries (see, e.g., Bost et al. (2011)).

3.2.3 Electricity system optimization model

The electricity system optimization model used in this analysis is a linear investment and dispatch model for Europe, incorporating conventional thermal, nuclear, storage and

[73] By scaling up the results of the household optimization model by the number of one- and two-family-houses located in Germany, market imperfections such as informational asymmetry, transaction costs or uncertainty are neglected. In particular, the scaling-up procedure abstracts from the so-called 'landlord-tenant' problem (Jaffe and Stavins (1994)), which describes the barriers for landlords in ensuring appropriate investment returns by including investment costs in the rent. The chosen scaling procedure serves the purpose of deriving the maximum potential of PV and battery storage systems that may be optimally deployed on top of one- and two-family-houses in Germany. Because the scaling-procedure includes all one- and two-family houses, the results should be interpreted as upper bound estimates and not as most likely estimates.

Table 3.6: Input parameters of the household optimization model for 2020

Input parameter	Unit	
c^P	[€$_{2011}$/kWp]	1,200
c^S	[€$_{2011}$/kWh]	400
m^P	[€$_{2011}$/kWp p.a.]	11
m^S	[€$_{2011}$/kWh p.a.]	6
n	[1/h]	0.6
t^P	[years]	30
t^S	[years]	15
η	[%]	95
u	[%]	5
x		50
ω	[%]	70
$\overline{a}$	[W/m^2]	1,000
ω	[%]	70

renewable technologies. The model is an extended version of the long-term investment and dispatch model of the Institute of Energy Economics (University of Cologne) as presented in Richter (2011). The possibility of endogenous investments in renewable energy technologies has been added to the investment and dispatch model, as described in Fürsch et al. (2013a), Jägemann et al. (2013a) and Nagl et al. (2011a).

In the following, an overview of the applied electricity system optimization model is given. The model has been adapted to accurately incorporate the feedback effects of the single households optimization behavior on the residual electricity system and to quantify the redistributional effects associated with the indirect financial incentive for in-house PV electricity generation.

3.2.3.1 Technological resolution

The model incorporates investment and generation decisions for all types of technologies: conventional (potentially equipped with carbon capture and storage (CCS)), combined heat and power (CHP), nuclear, renewable energy and storage (pump, hydro and compressed air energy (CAES)). In contrast to investments in generation and storage capacities, the extension of interconnector capacities, which limit the inter-regional power exchange, is exogenously defined. Today's power plant mix is represented by several vintage classes for hard coal, lignite and natural gas-fired power plants. With regard to renewable energy technologies, the model encompasses onshore and offshore wind turbines, roof and ground based PV systems, biomass (CHP-) power plants (solid and gas), hydro power plants, geothermal power plants and concentrating solar power (CSP) plants (including thermal energy storage devices).

3.2.3.2 Regional resolution

The model is configured to cover all countries of the European Union, except for Cyprus, Malta and Croatia, and includes Norway and Switzerland. To account for local weather conditions, the model considers 47 onshore wind, 42 offshore wind and 38 PV subregions, each differing with regard to both the level and the structure of the wind and solar power generation (based on historical hourly meteorological wind speed and solar radiation data from EuroWind (2011)). Given the focus of the analysis, the simulation was run for Germany and seven neighboring European market regions that were considered most relevant for dispatch and investment decisions in Germany (Figure 3.3).

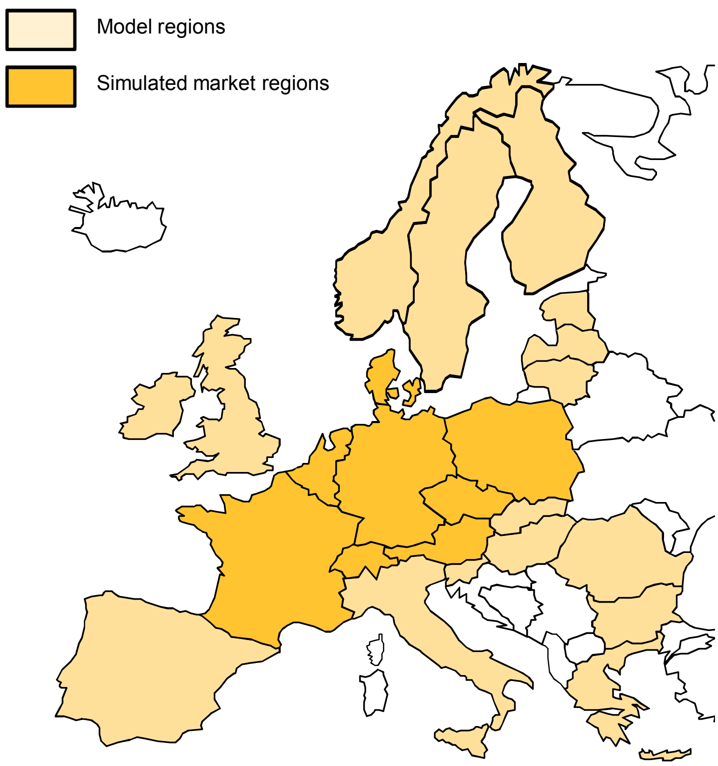


Figure 3.3: Simulated market regions

3.2.3.3 Temporal resolution

For our analysis, the simulation is carried out as a two-stage process: In the first step, investments in generation and storage capacities are simulated in 5-year time steps until

2050 by the investment and dispatch model. For reasons of computational efforts, the dispatch of generation and storage capacities is calculated in this step for eight typical days per year, which are then scaled to 8760 h in the model. Each typical day defines the electricity demand per country for 24 hours (h) of the day. Moreover, each typical day determines the hourly water inflow of hydro storages and the hourly electricity feed-in of wind and solar power plants per subregion (in $MW/MW_{installed}$). For each of the years simulated, the model determines both investments in new capacities and decommissionings of existing capacities. Moreover, the dispatch of power plants and storage technologies is simulated for each typical day and scaled to 8760 h of the year. In the second step, the capacity mix is fixed for each year and a (high resolution) dispatch is simulated. Instead of typical days, the dispatch is simulated on the basis of hourly load profiles (based on historical hourly load data by ENSTO-E (2012)) as well as the hourly electricity generation profiles of hydro, wind (on- and offshore) and solar power (PV and CSP) technologies for 8760 h per year (based on historical hourly wind and solar radiation data by EuroWind (2011)).

3.2.3.4 Model equations

An overview of all model sets, parameters and variables is given in Tables 3.7, 3.8 and 3.9.

The objective of the model (Eq. 3.19) is to minimize accumulated discounted (5 % discount rate) total system costs which include investment costs, fixed O&M costs, variable generation costs and costs due to ramping thermal power plants.[74]

Investment costs arise from new investments in generation and storage units ($\mathrm{AD}_{y,a,c}$) and are annualized with a 5 % interest rate for the depreciation time.[75] The fixed operation and maintenance costs (fc_a) represent staff costs, insurance charges, rates and maintenance costs.[76] Variable costs are determined by fuel prices ($\mathrm{fu}_{y,a}$), the net efficiency (η_a) and the total generation of each technology ($\mathrm{GE}_{y,h,a,c}$). Depending on the ramping profile, additional costs for attrition occur (ac_a). Combined heat and power (CHP) plants can generate revenue from the heat market, thus reducing the objective value. More specifically, the generated heat in CHP plants ($\mathrm{GE}_{y,h,a,c} \cdot \mathrm{hr}_a$) is remunerated by the assumed gas price divided by the conversion efficiency of the assumed reference heat boiler (hp_y), which roughly represents the opportunity costs for

[74]The model's optimization premise (minimization of accumulated discounted total system costs) implies a cost-based competition of electricity generation and perfect foresight.

[75]Note that the interest rate level significantly influences capital cost. However, the impact of the actual interest rate level (i.e., 3, 5 or 7 %) on the optimal investment mix is only minor.

[76]For CCS power plants, fixed operation and maintenance costs include fixed costs for CO_2 storage and transportation.

households and industries. However, only a limited amount of generation in CHP plants is compensated by the heating market.[77]

$$\min \ TSC = \sum_{y \in Y} \sum_{c \in C} \sum_{a \in A} (disc_y \cdot (AD_{y,a,c} \cdot an_a + IN_{y,a,c} \cdot fc_a \tag{3.19}$$

$$+ \sum_{h \in H} (GE_{y,h,a,c} \cdot (\frac{fu_{y,a}}{\eta_a}) + CU_{y,h,a,c} \cdot (\frac{fu_{y,a}}{\eta_a} + ac_a) - GE_{y,h,a,c} \cdot hr_a \cdot hp_y)))$$

s.t.

$$\sum_{a \in A} GE_{y,h,a,c} + \sum_{c' \in C} IM_{y,h,c,c'} - \sum_{s \in A} ST_{y,h,s,c} = d_{y,h,c} \tag{3.20}$$

$$GE_{y,h,a,c} \leq av_{d,h,a,c} \cdot IN_{y,a,c} \tag{3.21}$$

$$GE_{y,h,a,c} \geq ml_a \cdot av_{h,a,c} \cdot IN_{y,a,c} \tag{3.22}$$

$$CU_{y,h,a,b} \leq \frac{IN_{y,a,c} - CR_{y,h,a,c}}{st_a} \tag{3.23}$$

$$CR_{y,h,a,c} \leq av_{h,a,c} \cdot IN_{y,a,c} \tag{3.24}$$

$$\sum_{a \in A} (cr_{y,h,a,c} \cdot IN_{y,a,c}) \geq pd_{y,h,c} \tag{3.25}$$

$$\sum_{r \in A} sr_r \cdot IN_{y,r,c} \leq sp_{r,c} \tag{3.26}$$

$$\sum_{h \in H} \frac{GE_{y,h,a,c}}{\eta_a} \leq fp_{y,a,c} \tag{3.27}$$

$$\sum_{a \in A} \sum_{c \in C} \sum_{h \in H} \frac{GE_{y,h,a,c}}{\eta_a} \cdot ef_a \leq cc_y \tag{3.28}$$

$$IN_{y,r,c} \geq nr_{y,r,c} \tag{3.29}$$

[77] We account for a maximum potential for heat in co-generation within each country, which is depicted in Table B.5 of the Appendix.

Table 3.7: Sets and parameters of the electricity system optimization model

Abbreviation	Dimension	Description
Model sets		
a ∈ A		Technologies
s ∈ A	Subset of a	Storage technologies
r ∈ A	Subset of a	RES-E technologies
c ∈ C (alias c')		Market region
h ∈ H		Hours
y ∈ Y		Years
Model parameters		
ac_a	[€$_{2011}$ /MWh$_{el}$]	Attrition costs for ramp-up operation
an_a		Annuity factor (5 % interest rate)
$av_{h,a,c}$	[%]	Availability
$d_{y,h,c}$	[MW]	Total demand
$disc_y$		Discount factor (5 % discount rate)
cc_y	[t CO_2]	Cap for CO_2 emissions
ef_a	[t CO_2 /MWh$_{th}$]	CO_2 emissions per fuel consumption
fc_a	[€$_{2011}$/MW]	Fixed operation and maintenance costs
$fu_{y,a}$	[€$_{2011}$/MWh$_{th}$]	Fuel price
$fp_{y,a,c}$	[MWh$_{th}$]	Fuel potential
hp_y	[€$_{2011}$/MWh$_{th}$]	Heating price for end-consumers
hr_a	[MWh$_{th}$/MWh$_{el}$]	Ratio for heat extraction
ml_a	[%]	Minimum part load level
$nr_{y,r,c}$	[MW]	National technology-specific RES-E targets
$pd_{y,h,c}$	[MW]	Peak demand (increased by a security factor of 10 %)
$sp_{r,c}$	[km^2]	Space potential
sr_r	[MW/km^2]	Space requirement
st_a	[hours]	Start-up time from cold start
η_a	[%]	Net efficiency (generation)
$cr_{y,h,a,c}$	[%]	Securely available capacity
$\alpha_{a,h}$	[%]	Capacity factor
ϵ	[%]	Share of privileged end consumer
$RESpc$	[€$_{2011}$/kWh]	Renewable energy surcharge for privileged end consumers

Accumulated discounted total system costs are minimized, subject to several techno-economic constraints:

Power balance constraint (Eq. (3.20)): The match of electricity demand and supply needs to be ensured in each hour and country, taking storage options and inter-regional power exchange into account. In specific, the sum of a country's electricity generation

TABLE 3.8: Variables of the electricity system optimization model

Abbreviation	Dimension	Description
Model variables		
$\mathrm{AD}_{y,a,c}$	[MW]	Commissioning of new power plants
$\mathrm{CU}_{y,h,a,c}$	[MW]	Capacity that is ramped up within one hour
$\mathrm{CR}_{y,h,a,c}$	[MW]	Capacity that is ready to operate
$\mathrm{GE}_{y,h,a,c}$	[MW_{el}]	Electricity generation
$\mathrm{O}_{s,y,h,i}$	[MW]	Consumption in storage operation
$\mathrm{IM}_{y,h,c,c'}$	[MW]	Net imports
$\mathrm{IN}_{y,a,c}$	[MW]	Installed capacity
$\mathrm{ST}_{y,h,s,c}$	[MW]	Consumption in storage operation
TSC	[€$_{2011}$]	Accumulated discounted total system costs

TABLE 3.9: Model variables calculated ex-post and shadow variables of the electricity system optimization model

Abbreviation	Dimension	Description
Model variables calculated ex-post		
$CI_{y,h}$	[€$_{2011}$]	Revenues from the reserve market
REC_y	[€$_{2011}$]	Renewable energy compensation
RES_y	[€$_{2011}$/kWh]	Renewable energy surcharge
CP_y	[€$_{2011}$/kWh]	Back-up capacity payment
$dCONSR_y$	[€$_{2011}$]	Difference in consumer rents
$dPROSR_y$	[€$_{2011}$]	Difference in rents of 'HH producers and in-house consumers'
$d\pi_y$	[€$_{2011}$]	Difference in producer profits
dW_y	[€$_{2011}$]	Difference in sectoral welfare (excess costs)
Shadow variables		
$\mu_{y,h}$	[€$_{2011}$/MW]	Wholesale electricity price (shadow variable of the power balance constraint)
$\kappa_{y,h}$	[€$_{2011}$/MW]	Capacity price (shadow variable of the security of supply constraint)

($GE_{y,h,c,a}$), net imports ($IM_{y,h,c,c'}$) and electricity lost in storage operation ($ST_{y,h,s,c}$) needs to equal demand ($d_{y,h,c}$).

Capacity constraint (Eq. (3.21)): The maximum electricity generation by dispatchable power plants (thermal, nuclear, storage, biomass and geothermal power plants) per hour ($GE_{y,h,a,c}$) is restricted by their seasonal availability ($\mathrm{av}_{d,h,a,c}$), which is limited due to unplanned or planned shutdowns (e.g., because of repairs).[78] Unlike dispatchable power plants, the availability of wind and solar power plants is given by the maximum possible electricity feed-in per hour.[79] The maximum transmission capability per hour between two neighboring countries is given by the net transfer capacities.

Minimum load constraint (Eq. (3.22)): The minimum electricity generation per hour ($GE_{y,h,a,c}$) of dispatchable power plants (thermal, nuclear, storage, biomass and geothermal power plants) is given by their minimum part-load level (ml_a).

Ramp-up constraints (Eqs. (3.23) and (3.24)): The start-up time (st_a) of dispatchable power plants limits the maximum amount of capacity ramped up within an hour.

Security of supply constraint (Eq. (3.25)): Equation 3.25 captures system reliability requirements by ensuring that the historically observed peak demand level of each country is met by securely available capacities. Due to the simplification of the annual dispatch to eight typical days, potential peak demand is not considered as a dispatch situation in the investment part of the model. To nevertheless ensure security of supply at all times, i.e., also during times of low solar radiation and low wind infeed, the peak-capacity constraint is implemented in the model. Whereas the securely available capacity ($cr_{y,h,a,c}$) of dispatchable power plants within the peak-demand hour is assumed to correspond to the seasonal availability, the securely available capacity of onshore (offshore) wind power plants within the peak-demand hour (capacity credit) is assumed to amount to 5 % (10 %). Hence, 5 % (10 %) of the total installed onshore (offshore) wind power capacities within a region are assumed be securely available within the peak demand hour. In contrast, PV systems are assumed to have a capacity credit of 0 % due to the assumption that peak demand occurs during evening hours in the winter.[80] The modeled capacity market simply ensures that sufficient investments in back-up capacities are made to meet potential peak demand situations.[81]

Space potential constraint (Eq. (3.26)): The deployment of wind and solar power technologies is restricted by area potentials in km^2 per subregion ($sp_{r,c}$).

[78]The availability of dispatchable power plants is the same for each country, year and hour, but differs for each season. The infeed of storage technologies is additionally restricted by the storage capacity in use at a particular hour.

[79]We note that the electricity system optimization model allows for endogenous wind and solar power curtailment. Since wind sites are usually larger than solar sites, transaction costs for wind power curtailment are assumed to be lower than for solar sites. By using negligible small variable costs for offshore wind and even smaller ones for onshore wind sites, the model chooses offshore wind curtailment first (i.e., before onshore wind curtailment.

[80]This assumption is based on a detailed analysis of historical electrical load data (based on ENSTO-E (2012) and historical solar radiation data based on EuroWind (2011)) for all EU member states for the years 2007-2010 (Ackermann et al. (2013)).

[81]However, such investments could also be triggered in an energy-only market in the event of price peaks.

Fuel potential constraint (Eq. (3.27)): The fuel use is restricted to a yearly potential in MWh_{th} per country($fp_{y,a,c}$), with different potentials applying for lignite, solid biomass and gaseous biomass sources.

In addition to techno-economic constraints, politically implemented restrictions are also modeled:

CO_2 emission constraint (Eq. (3.28)): Equation (3.28) states that the accumulated CO_2 emissions of all modeled market regions may not exceed a certain CO_2 cap per year (cc_y). The approach of modeling a quantity-based regulation (CO_2 cap) rather than a price-based regulation (CO_2 price) ensures that the CO_2 emissions reduction target within Europe's power sector is met in all scenarios simulated – which allows the results to be compared to one another.

Renewable capacity constraint (Eq. (3.29)): Equation (3.29) formalizes the politically implemented restriction that each country must achieve the technology-specific RES-E targets ($nr_{y,r,c}$), as prescribed by the EU member states' National Renewable Energy Action Plans (NREAP's) for 2020.

The total calculation time of the electricity system optimization model amounts to two hours.

The most important assumptions of the electricity system optimization model (such as the gross electricity demand, investment costs and techno-economic parameters of conventional, storage and renewable technologies as well as fuel prices) are listed in Tables B.2 - B.10 of the Appendix.

3.3 Scenario definitions and quantification of redistributional effects

To capture the impact of the single household's optimization behavior on the residual electricity system, we iterate the household optimization model in conjunction with the electricity system optimization model until convergence of results is achieved. The results of the last iteration step represent the 'Grid Parity Scenario'. A more detailed description of the iterative approach and the convergent behavior of the interrelated variables can be found in the Appendix (see Figure B.1).

Moreover, to quantify the overall economic consequences of the single household's optimization behavior (such as redistributional effects and excess costs), we compare the results of the 'Grid Parity Scenario' with the results of a 'Reference Scenario', which assumes that the indirect financial incentive for in-house PV electricity consumption is abolished (Table 3.10). More specifically, households are assumed to meet their electricity demand with grid-supplied electricity in the 'Reference Scenario'. However, the NREAP targets for 2020 are achieved in both scenarios.

TABLE 3.10: Scenario definitions

	'Grid Parity Scenario' (GP)	'Reference Scenario' (REF)
Household optimization	Yes	No
Iterative approach	Yes	No
Achievement of 2020 NREAP targets	Yes	Yes
Achievement of CO_2 reduction targets	Yes	Yes

Redistributional effects of the household's optimization behavior are quantified for three different actors: (i) (pure) electricity producers, (ii) (pure) electricity consumers and (iii) household electricity consumers who meet part of their electricity demand with self-produced PV electricity generation in the 'Grid Parity Scenario', referred to as 'HH producers and in-house consumers' in the following. Note that in the 'Reference Scenario', the (former) 'HH producers and in-house consumers' become pure consumers, i.e., they no longer own a combined PV and battery storage system and meet their total electricity demand with grid-supplied electricity. Since we apply a linear electricity system optimization model with a price-inelastic electricity demand function, no absolute values for the consumer rent can be quantified. Instead, we focus on the change of the consumer rent as a consequence of the single household's optimization behavior, i.e., the difference in the consumer rent between the 'Grid Parity Scenario' and the 'Reference Scenario'. Welfare losses or excess costs due to the single household's optimization behavior are given by the accumulated change in the consumer rent, the rent of 'HH producers and in-house consumers' and the producer profit.

In the following, all parameters are discussed which are used to quantify redistributional effects.

Wholesale electricity prices: The shadow variable of the power balance (Equation (3.20)) serves as a proxy for the hourly wholesale electricity price in Germany ($\mu^{GP}_{y,h}$,$\mu^{REF}_{y,h}$).

Producer compensation for providing back-up capacity: The shadow variable of the security of supply constraint ($\kappa_{y,h}$) serves as a proxy for the capacity price which producers receive for their efforts in ensuring security of supply. More specifically, they are assumed to be compensated for providing back-up capacities. Equations (3.30) and

(3.31) define the revenue which producers receive from the reserve market by offering securely available capacity ($CI^{GP}_{y,h}$, $CI^{REF}_{y,h}$).

$$CI^{GP}_{y,h} = \sum_{a \in A} (\alpha_{a,h} \cdot IN^{GP}_{y,a} \cdot \kappa^{GP}_{y,h}) \tag{3.30}$$

$$CI^{REF}_{y,h} = \sum_{a \in A} (\alpha_{a,h} \cdot IN^{REF}_{y,a} \cdot \kappa^{REF}_{y,h}) \tag{3.31}$$

Back-up capacity payment: The costs for providing back-up capacities are assumed to be apportioned to electricity consumers and 'HH producers and in-house consumers'. Specifically, for each kWh electricity purchased from the grid, a capacity payment (CP_y) is incurred.

$$CP^{GP}_{y} = \frac{\sum_{h \in H} CI^{GP}_{y,h}}{\sum_{h \in H} (d_{y,h} - HHSC_{y,h})} \tag{3.32}$$

$$CP^{REF}_{y} = \frac{\sum_{h \in H} CI^{REF}_{y,h}}{\sum_{h \in H} d_{y,h}} \tag{3.33}$$

Producer compensation for providing renewable energy capacities: As prescribed by Equation 3.29, Germany is expected to achieve national, technology-specific renewable energy targets by 2020 (NREAP targets). To reflect the current renewable energy promotion system in Germany (feed-in tariff), we assume that renewable energy producers receive the additional costs, i.e., the difference between annual costs and revenue from selling renewable energy electricity on the wholesale market (REC^{GP}_{y}, REC^{REF}_{y}).[82] This compensation is assumed to be granted over a period of 20 years for renewable capacities built up to the year 2020.[83]

[82]The annual costs include annualized investment costs, fixed O&M costs and variable generation costs (for biomass technologies).

[83]The quantification of the producer compensation for providing renewable energy capacities and of the renewable energy surcharge builds on the data of EWI (2012).

$$REC_y^{GP} = \sum_{r\in R}(AD_{y,r}^{GP} \cdot an_{y,r}^{GP} + IN_{y,r} \cdot fc_r) + \sum_{h\in H}\sum_{r\in R}(GE_{y,h,r}^{GP} \cdot (\frac{fu_{y,r}}{\eta_r}) - \mu_{y,h}^{GP}) \tag{3.34}$$

$$REC_y^{REF} = \sum_{r\in R}(AD_{y,r}^{REF} \cdot an_{y,r}^{REF} + IN_{y,r} \cdot fc_r) + \sum_{h\in H}\sum_{r\in R}(GE_{y,h,r}^{REF} \cdot (\frac{fu_{y,r}}{\eta_r}) - \mu_{y,h}^{REF}) \tag{3.35}$$

Renewable energy surcharge: The difference between the producers' annual costs and their revenue from selling renewable energy electricity on the wholesale market is assumed to be apportioned to electricity consumers via the renewable energy surcharge (RES_y), which (non-privileged) electricity consumers pay for each kWh purchased from the grid (Eqs. 3.36 and 3.37).[84]

$$RES_y^{GP} = \frac{REC_y^{GP} - \epsilon \cdot \sum_{h\in H} d_{y,h} \cdot RESpc}{(1-\epsilon) \cdot \sum_{h\in H} d_{y,h} - \sum_{h\in H} HHSC_{y,h}} \tag{3.36}$$

$$RES_y^{REF} = \frac{REC_y^{REF} - \epsilon \cdot \sum_{h\in H} d_{y,h} \cdot RESpc}{(1-\epsilon) \cdot \sum_{h\in H} d_{y,h}} \tag{3.37}$$

Residential electricity tariff: The residential electricity tariff (ret_y) is comprised of endogenous and exogneous components. The base price (i.e., the average wholesale electricity price), which serves as a proxy for the average costs of electricity procurement, the renewable energy surcharge and the back-up capacity payment are the endogenous components, which are outputs of the electricity system optimization model.[85] The assumptions regarding exogenous components are listed in Table 3.11.

[84] This reflects the current situation in Germany, where the additional costs for promoting renewable energy investments via a fixed feed-in tariff scheme are apportioned to (non-privileged) electricity cosumers via the renewable energy surcharge. Note that the fixed feed-in tariff, which is granted over 20 years, corresponds approximately to the technology-specific electricity generation costs of renewables. Moreover, the share of priviliged electricity consumers ($\epsilon = 15$ %) pays a lower renewable energy surcharge ($RESpc$).

[85] Note that in reality, the average costs of electricity procurement do not exactly correspond to the base price. This is due to the fact that electricity supplied by conventional and renewable capacities is not only marketed via the wholesale electricity market but also via mid- and long-term contracts. Furthermore, unlike in the electricity system optimization model, market participants do not have perfect foresight in reality.

TABLE 3.11: Composition of the residential electricity tariff [€ct/kWh]

<table>
<tr><th></th><th></th><th>2020</th><th>2025</th><th>2030</th><th>2040</th><th>2050</th></tr>
<tr><td>Base price
Renewable energy surcharge
Back-up capacity payment
Value-added tax of 19 %</td><td>Endogenous</td><td colspan="5"></td></tr>
<tr><td></td><td></td><td>2020</td><td>2025</td><td>2030</td><td>2040</td><td>2050</td></tr>
<tr><td>Concession levy</td><td>Exogenous</td><td colspan="5">1.79</td></tr>
<tr><td>Offshore liability surcharge</td><td>Exogenous</td><td colspan="2">0.25</td><td colspan="3">-</td></tr>
<tr><td>Distribution (margin included)</td><td>Exogenous</td><td colspan="5">2.11</td></tr>
<tr><td>Electricity tax</td><td>Exogenous</td><td colspan="5">2.05</td></tr>
<tr><td>CHP surcharge</td><td>Exogenous</td><td colspan="5">0.31</td></tr>
<tr><td>§19 surcharge</td><td>Exogenous</td><td colspan="5">0.33</td></tr>
<tr><td>Network tariff</td><td>Exogenous</td><td>7.18</td><td>8.12</td><td colspan="3">9.19</td></tr>
</table>

Source: 50Hertz, Amprion, Tennet and Transnet BW (2012b), 50Hertz, Amprion, Tennet and Transnet BW (2012a), BNetzA (2012) and BDEW (2013).

After having defined the parameters, the quantification of the redistributional effects is explained in the following.

Change in producer profit: The difference in producer profits ($d\pi_y$) between the 'Grid Parity Scenario' and the 'Reference Scenario' is defined by Equation (3.38). Producers are assumed to earn revenue for providing electricity, heat and securely available generation capacities. Moreover, producers receive a renewable energy compensation payment. Producer profits are determined by deducting the annualized investment costs, fixed O&M costs, variable generation costs, additional variable costs for ramping operations and costs for pumping electricity into storage units from the sum of producer revenues.

$$
\begin{aligned}
d\pi_y = &\sum_{a\in A}\sum_{h\in H}(\mu_{y,h}^{GP} \cdot GE_{y,h,a,c}^{GP}) + \sum_{a\in A}\sum_{h\in H}(GE_{y,h,a}^{GP} \cdot hr_a \cdot hp_y) \\
&+CI_{y,h}^{GP} + REC_y^{GP} - \sum_{a\in A}(AD_{y,a}^{GP} \cdot an_a^{GP}) - \sum_{a\in A}(IN_{y,a}^{GP} \cdot fc_a^{GP}) \\
&-\sum_{a\in A}\sum_{h\in H}(GE_{y,h,a}^{GP} \cdot (\frac{fu_{y,a}}{\eta_a}) - \sum_{a\in A}\sum_{h\in H}(CU_{y,h,a}^{GP} \cdot (\frac{fu_{y,a}}{\eta_a} + ac_a)) \\
&-\sum_{s\in S}\sum_{h\in H}(O_{s,y,h}^{GP} \cdot \mu_{y,h}^{GP}) \\
&-\Bigg[\sum_{a\in A}\sum_{h\in H}(\mu_{y,h}^{REF} \cdot GE_{y,h,a,c}^{REF}) + \sum_{a\in A}\sum_{h\in H}(GE_{y,h,a}^{REF} \cdot hr_a \cdot hp_y) \\
&+CI_{y,h}^{REF} + REC_y^{REF} - \sum_{a\in A}(AD_{y,a}^{REF} \cdot an_a^{REF}) \\
&-\sum_{a\in A}(IN_{y,a}^{REF} \cdot fc_a^{REF}) - \sum_{a\in A}\sum_{h\in H}(GE_{y,h,a}^{REF} \cdot (\frac{fu_{y,a}}{\eta_a})) \\
&-\sum_{a\in A}\sum_{h\in H}(CU_{y,h,a}^{REF} \cdot (\frac{fu_{y,a}}{\eta_a} + ac_a)) - \sum_{s\in S}\sum_{h\in H}(O_{s,y,h}^{REF} \cdot \mu_{y,h}^{REF})\Bigg]
\end{aligned}
\tag{3.38}
$$

Change in consumer rent: The difference in the consumer rent ($dCONSR_y$) between the 'Grid Parity Scenario' and the 'Reference Scenario' is defined by Equation (3.39) as the difference in the consumers' expenditures for meeting their electricity demand. Since the costs for ensuring security of supply and for promoting renewables are apportioned to electricity consumers via energy-related payments, consumers' expenditures do not only include the costs for buying electricity on the wholesale market but also the costs for being provided with both securely available and renewable capacities.

$$
\begin{aligned}
dCONSR_y = (-1) \cdot \Bigg[&\sum_{h\in H}(\mu_{y,h}^{GP} \cdot (d_{y,h} - HHD_{y,h})) \\
&+\sum_{h\in H}(d_{y,h} - HHD_{y,h}) \cdot CP_y^{GP} + \epsilon \cdot \sum_{h\in H} d_{y,h} \cdot RESpc \\
&+((1-\epsilon) \cdot \sum_{h\in H} d_{y,h} - \sum_{h\in H} HHD_{y,h}) \cdot RES_y^{GP} \\
&-\Bigg[\sum_{h\in H}(\mu_{y,h}^{REF} \cdot d_{y,h}) + \sum_{h\in H} d_{y,h} \cdot CP_y^{REF} + \epsilon \cdot \sum_{h\in H} d_{y,h} \cdot RESpc \\
&+(1-\epsilon) \cdot \sum_{h\in H} d_{y,h} \cdot RES_y^{REF}\Bigg]\Bigg]
\end{aligned}
\tag{3.39}
$$

Change in the rent of 'HH producers and in-house consumers': Equation (3.40) defines the difference in the rent of 'HH producers and in-house consumers' ($dPROSR_y$) between the 'Grid Parity Scenario' and the 'Reference Scenario' as the difference in expenditures that households need to make in order to meet their electricity demand. As opposed to the 'Reference Scenario' in which households meet 100 % of their electricity demand ($HHD_{y,h}$) with grid-supplied electricity, households meet part of their electricity demand with self-produced PV electricity in the 'Grid Parity Scenario'. Note that in the 'Grid Parity Scenario' households pay investment and fixed O&M costs for their PV and battery storage capacities, but also earn revenue from selling surplus PV electricity generation.

$$\begin{aligned} dPROSR_y = (-1) \cdot \Bigg[\sum_{h \in H} (\mu_{y,h}^{GP} \cdot HHGD_{y,h}^{GP}) \\ + \sum_{h \in H} HHGD_{y,h} \cdot (CP_y^{GP} + RES_y^{GP}) + HHC_y^{GP} - HHI_y^{GP} \\ - \Bigg[\sum_{h \in H} (\mu_{y,h}^{REF} \cdot HHD_{y,h}) + \sum_{h \in H} HHD_{y,h} \cdot (CP_y^{REF} + RES_y^{REF}) \Bigg] \Bigg] \end{aligned} \tag{3.40}$$

Welfare loss: The welfare loss or excess costs associated with the single household's optimization behavior are defined by Equation (3.41) as the accumulated change in the consumer rent, the rent of 'HH producers and in-house consumers' and the producer profit between the 'Grid Parity Scenario' and the 'Reference Scenario'.

$$dW_y = d\pi_y + dCONSR_y + dPROSR_y \tag{3.41}$$

3.4 Scenario results

The changes in the optimal capacities of PV and storage systems which take place during the iterative process are shown in Figure B.2 of the Appendix. Convergence of results is achieved after nine iteration steps.[86] In the following sections, the results of the household and the electricity system optimization models of the last iteration step

[86]To demonstrate the robustness of results the iteration is repeated for alternative starting values, as shown in Figures B.3 and B.4 of the Appendix.

are analyzed, which are referred to as the results of the 'Grid Parity Scenario'. These results are then compared to the results of the 'Reference Scenario', which assumes that the indirect financial incentive for in-house PV electricity consumption is abolished and thus total system costs are minimized.

3.4.1 Household level

3.4.1.1 Cost-optimal PV and battery storage capacities

The average cost-optimal PV and battery storage capacities (as shown in Table 3.12) increase with the number of residents living in the household and the annual full load hours of the PV system, i.e., the further south the house is located, the larger the average cost-optimal PV and battery storage capacities become. Specifically, cost-optimal PV capacities built in 2020 vary between 1.7 kWp and 3.6 kWp, and cost-optimal battery storage capacities between 2.1 kWh and 5.3 kWh.[87]

Due to their lower technical lifetime of 15 years, battery storage capacities need to be replaced in 2036. The fact that the optimal average battery storage capacities are lower in 2036 than in 2020 illustrates the diminished economic value of battery storage capacities from the single household's perspective over time.[88]

3.4.1.2 PV electricity in-house consumption and grid feed-in

Table 3.13 shows the average share of the single household's annual PV electricity generation that is consumed in-house and the average share of the single household's annual electricity demand that is covered by self-produced PV electricity in 2020.[89]

Due to the optimal dimensioning of the single household's PV and storage system capacities, the average shares of the single household's annual PV electricity generation that is consumed in-house lie within a high and relatively narrow range between 72 % and 76 % for all configurations. Hence, only 20 - 24 % of the (average) annual PV electricity generation by households is fed into the grid.[90]

[87] As explained in Section 3.2.2.2, for each of the five household types (with 1-5 residents), 50 different electricity demand profiles were generated and taken as input parameters for the household optimization model. The results of each household type (with 1-5 residents) present the average values over 50 samples.

[88] The battery storage investment costs in 2036 are assumed to be the same as in 2020, i.e., 400 €$_{2011}$/kWh.

[89] The average shares achieved in the years 2025-2050 differ only marginally from the shares in 2020.

[90] Average storage losses lie between 3 % and 4 % of the average annual household PV electricity generation.

Table 3.12: Average cost-optimal PV and battery storage capacities in the 'Grid Parity Scenario'

	northern Germany	central Germany	southern Germany
	Average cost-optimal PV capacities [kWp]		
1 resident	1.7	1.9	2.1
2 residents	2.3	2.6	2.9
3 residents	2.5	2.8	3.2
4 residents	2.8	3.1	3.4
5 residents	3.0	3.3	3.6
	Average cost-optimal storage capacities [kWh] (replaced in 2036)		
1 resident	2.1 (1.8)	2.6 (2.3)	3.0 (2.8)
2 residents	3.0 (2.5)	3.6 (3.2)	4.1 (3.9)
3 residents	3.4 (2.9)	4.1 (3.7)	4.6 (4.4)
4 residents	3.7 (3.2)	4.4 (4.0)	5.0 (4.7)
5 residents	3.9 (3.4)	4.7 (4.2)	5.3 (5.0)

Table 3.13: Average PV in-house consumption and self-supply shares in the 'Grid Parity Scenario' (2020)

	northern Germany	central Germany	southern Germany
	Average share of annual PV electricity consumed in-house		
1 resident	75%	75%	73%
2 residents	75%	75%	72%
3 residents	76%	75%	73%
4 residents	76%	76%	73%
5 residents	76%	76%	74%
	Average share of annual household electricity demand supplied by PV electricity		
1 resident	38%	46%	54%
2 residents	39%	46%	56%
3 residents	40%	48%	57%
4 residents	40%	48%	57%
5 residents	41%	48%	57%

Moreover, given the cost-optimal dimensions of the PV and battery storage capacities, households cover on average between 38 % and 57 % of their annual electricity demand by self-produced PV electricity that was either directly consumed (at the moment of production) or supplied by the battery storage system at a later point in time. Hence, the annual amount of electricity purchased by the single household from the grid decreases on average by 38 - 57 %. However, over the course of the year, the average share of the household's electricity demand that is met using self-produced PV electricity significantly varies. As shown in Table 3.14, households cover 76 - 85 % of their electricity demand in June, but only 6 - 22 % in December due to the lower PV electricity generation and higher household electricity demand in the winter.

TABLE 3.14: Share of monthly household electricity demand met by self-produced PV electricity

	northern Germany	central Germany	southern Germany
January	6%	12%	31%
February	25%	40%	57%
March	39%	43%	45%
April	56%	54%	61%
May	73%	78%	78%
June	76%	84%	85%
July	74%	79%	81%
August	58%	75%	80%
September	47%	59%	61%
October	27%	39%	57%
November	10%	15%	35%
December	6%	11%	22%

Figure 3.4 and Figure 3.5 show exemplaric electricity demand and supply profiles of a household with three residents in central Germany for a rather extreme week in June and December 2020, respectively. In June, the household covers most of its electricity demand by self-produced PV electricity ('PV in-house consumption'). Moreover, a significant amount of the overall PV electricity generation is neither directly consumed in-house nor stored in the battery system, but instead fed into the electricity grid ('PV grid feed-in'). Given the high solar PV electricity generation and the possibility to store surplus electricity in the battery system, the amount of electricity purchased from the grid ('Electricity purchased') in June is comparatively small. Only during some night hours is part of the household's electricity demand met by using grid-supplied electricity. In December, in contrast, households meet almost all of their electricity demand with grid-supplied electricity due to very limited solar power generation. Moreover, all of the (very limited) PV electricity generation is consumed in-house. Hence, no PV electricity is fed into the grid by the household in this sample week in December.

3.4.1.3 Investment costs

Depending on the average cost-optimal PV and battery storage system capacities, total overnight investment costs to be paid by the households lie between 2,853 €$_{2011}$ and

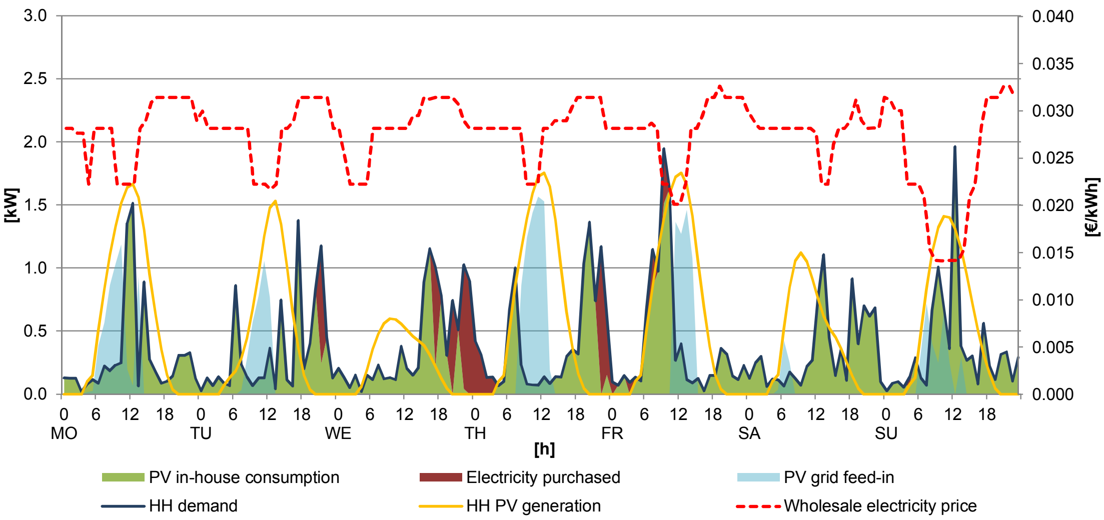


FIGURE 3.4: Sample week in June (2020): Profiles of a household with 3 residents in central Germany

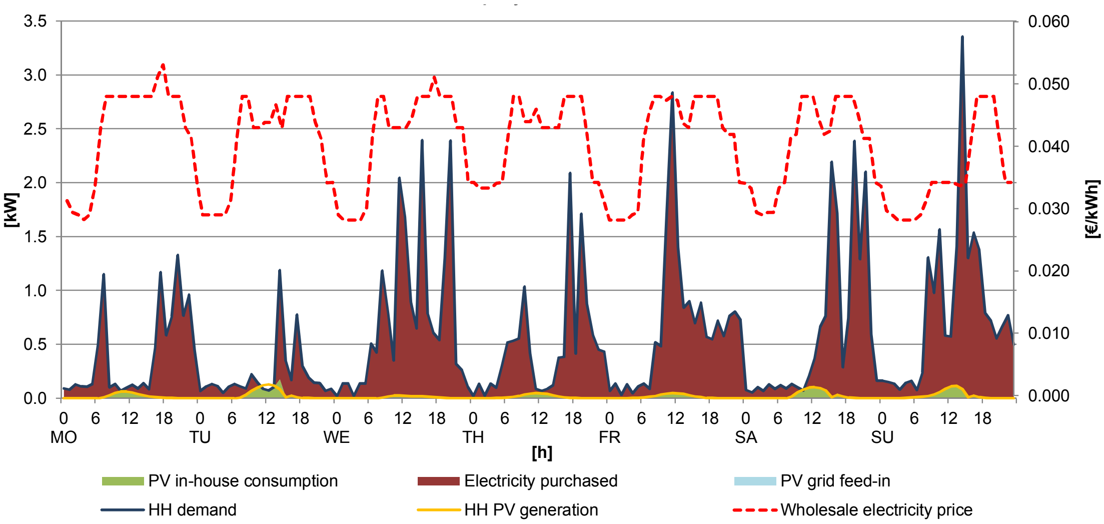


FIGURE 3.5: Sample week in December (2020): Profiles of a household with 3 residents in central Germany

6,485 €$_{2011}$ in 2020 (Table 3.15). On average, PV system costs account for more than two thirds (68 %) of total overnight investment costs.

Note that the upfront investment costs may pose a challenge for some households and may thus form an obstacle to the wide-scale deployment of PV and battery storage systems on the household level. As argued by R. Schleicher-Tappeser (2012) and Yang (2010), even if cost-effectiveness of PV systems on the household level is achieved, the commercial competitiveness may not be guaranteed for reasons of high upfront investment costs and unfamiliarity with the technology.

Table 3.15: Overnight investment costs of the average cost-optimal PV and battery storage capacities in the 'Grid Parity Scenario' (2020)

	northern Germany	central Germany	southern Germany
	PV investment costs [€$_{2011}$]		
1 resident	2,006	2,249	2,514
2 residents	2,786	3,085	3,485
3 residents	3,042	3,414	3,801
4 residents	3,314	3,671	4,086
5 residents	3,541	3,958	4,353
	Battery storage investment costs [€$_{2011}$]		
1 resident	847	1,059	1,208
2 residents	1,183	1,435	1,651
3 residents	1,372	1,637	1,855
4 residents	1,489	1,767	2,001
5 residents	1,573	1,876	2,132
	Total investment costs [€$_{2011}$]		
1 resident	2,853	3,308	3,722
2 residents	3,969	4,520	5,136
3 residents	4,414	5,051	5,656
4 residents	4,804	5,438	6,087
5 residents	5,115	5,834	6,485

3.4.1.4 Cost savings

In comparison to the 'Reference Scenario' in which households meet their total electricity demand with grid-supplied electricity, households save on average between 1,336 €$_{2011}$ and 4,012 €$_{2011}$ of their accumulated (2020-2050) and discounted (5 % discount rate) electricity costs as a consequence of the indirect financial incentive for in-house PV electricity consumption (Table 3.16). Hence, households avoid on average 10 % - 18 % of their accumulated discounted electricity costs over the PV system's liftime (30 years).

As can be seen in Table 3.16, the absolute cost savings in the 'Grid Parity Scenario' increase with the number of residents living in the house and the annual full load hours of the PV system, i.e., the further south the house is located, the larger the potential cost savings per household become.

The cost savings demonstrate that despite the costs of installing and operating the PV and battery storage systems, households are economically better off if they meet part of their electricity demand using self-produced PV electricity instead of completely using grid-supplied electricity. This is due to the fact that the consumption of self-produced

PV electricity – in contrast to the consumption of grid-supplied electricity – is exempted from the payment of taxes, levies, surcharges and network tariffs.

TABLE 3.16: Average cost savings (accumulated up to 2050 and discounted with 5 %)

	Accumulated and discounted electricity costs in the 'Reference Scenario' [€$_{2011}$]		
1 resident	13,222		
2 residents	17,702		
3 residents	19,160		
4 residents	20,542		
5 residents	21,874		
	northern Germany	central Germany	southern Germany
	Accumulated and discounted electricity costs in the 'Grid Parity Scenario' [€$_{2011}$]		
1 resident	11,886	11,509	10,887
2 residents	15,863	15,375	14,502
3 residents	17,191	16,628	15,690
4 residents	18,489	17,881	16,839
5 residents	19,655	18,976	17,862
	Accumulated and discounted electricity costs savings [€$_{2011}$ (%)]		
1 resident	1,336 (10 %)	1,713 (13 %)	2,335 (18 %)
2 residents	1,839 (10 %)	2,326 (13 %)	3,200 (18 %)
3 residents	1,969 (10 %)	2,532 (13 %)	3,470 (18 %)
4 residents	2,053 (10 %)	2,661 (13 %)	3,703 (18 %)
5 residents	2,219 (10 %)	2,898 (13 %)	4,012 (18 %)

3.4.1.5 Grid connection dimensioning

As a consequence of the in-house consumption of self-produced PV electricity, the average share of the household's annual electricity demand met by grid-supplied electricity decreases (from 100 %) to 38 % - 57 %. However, the maximum (peak) amount of electricity purchased from the grid (within a single hour) decreases by only 2 - 4 %, as shown in Table 3.17. Hence, if we assume that the single household's grid connection capacity was originally dimensioned to meet the household's peak demand, then the installation of the PV and battery storage capacity would not allow for the grid connection capacity to be reduced.

Table 3.17: Average reduction of the maximum amount of electricity purchased from the grid in the 'Grid Parity Scenario' (2020-2050)

	northern Germany	central Germany	southern Germany
1 Resident	-3%	-3%	-4%
2 Residents	-3%	-3%	-3%
3 Residents	-3%	-3%	-4%
4 Residents	-2%	-2%	-3%
5 Residents	-2%	-2%	-3%

3.4.2 System level

As explained in Section 3.2.2.2, the 750 sample households are scaled-up in order to analyze the potential consequences if a large share of residential electricity consumers invests in combined PV and storage systems for in-house PV electricity consumption.

As a result of the scaling procedure, 36 GW of rooftop PV capacities are installed on one- and two-family houses in Germany by 2020 in the 'Grid Parity Scenario'. Note that these capacities are deployed in addition to the 52 GW of PV capacities already built by 2020 under the feed-in tariff promotion system. Battery storage capacities built in combination with these rooftop PV systems amount to 50 GWh, corresponding to 125 % of currently installed pump storage capacities in Germany (40 GWh in the year 2010 (Mahnke and Mülenhoff (2012))). Note that the 50 GWh storage capacities built in 2020 are decomissioned and replaced in 2036, but with a smaller total capacity of 45 GWh. Moreover, the 50 GWh (45 GWh) storage capacity correspond to a nominal output of 30 GW (27 GW).

In the following, we analyze the consequences of the single household's optimization behavior on the rest of the electricity system. This is done by comparing the results of the electricity system optimization model for the 'Grid Parity Scenario' to those of the 'Reference Scenario'.

3.4.2.1 Changes in the capacity and generation mix

Figure 3.6 displays the capacity and generation mix per decade in the 'Grid Parity Scenario', as well as a comparison to the 'Reference Scenario'. Note that in both scenarios, German NREAP targets for 2020 are achieved, including the 52 GW target for PV.

In the 'Grid Parity Scenario', an additional 36 GW of PV systems in combination with 30 GW (50 GWh) battery storage capacities are installed on households in 2020 as a consequence of the indirect financial incentive for in-house PV electricity consumption.

In contrast, no additional PV and storage capacities (beyond the politically implemented target of 52 GW) are built before 2020 in the 'Reference Scenario', since these technologies are not a cost-efficient investment option from a total system perspective in 2020. However, due to further investment cost degressions, PV capacity investments become cost-efficient by 2030 in both scenarios. In the longer run (2040-2050), more wind power capacities with comparatively higher full load hours are installed in the 'Reference Scenario' to achieve commitment with more ambitious CO_2 reduction targets. Moreover, compressed air energy storage capacities ('electricity') are expanded in both scenarios only after 2040.

Regarding the generation mix, the scenario comparison reveals that the additional PV electricity generation on the household level induced by the indirect financial incentive for PV electricity in-house consumption displaces electricity produced by coal-, gas- and lignite fired power plants in 2020 and 2030. Moreover, net electricity exports from Germany to neighboring countries significantly increase in the 'Grid Parity Scenario' compared to the 'Reference Scenario'.

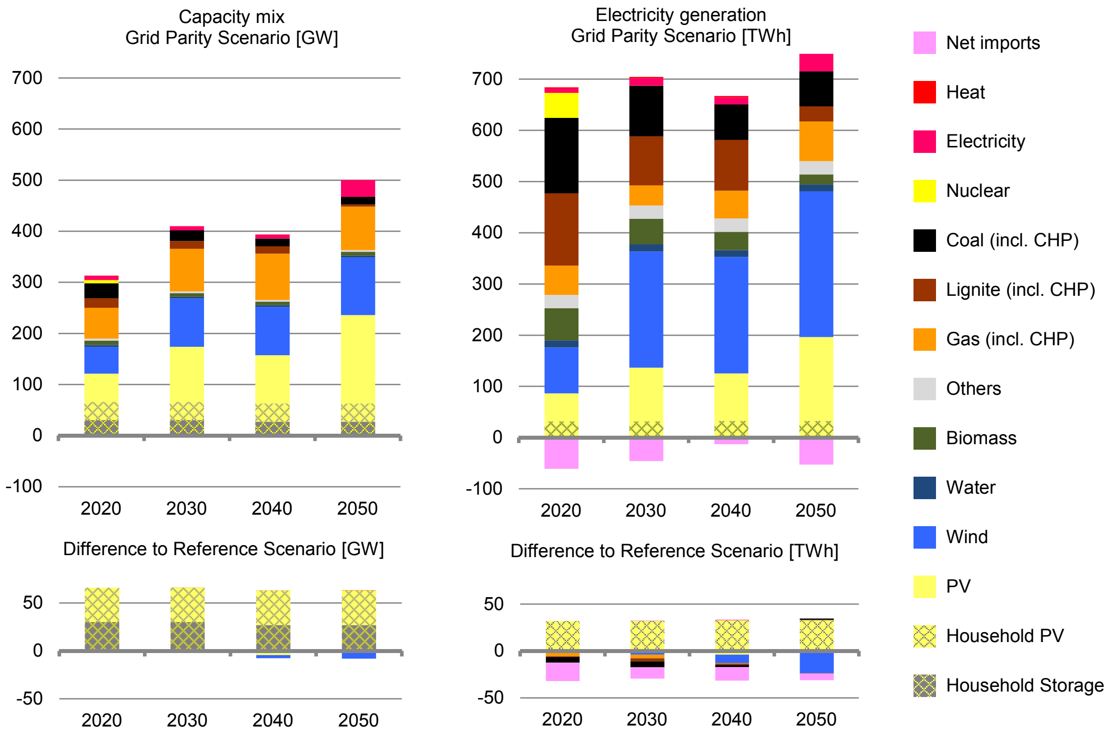


FIGURE 3.6: Capacity [GW] and generation [TWh] mix in the 'Grid Parity Scenario' and difference to the 'Reference Scenario'

3.4.2.2 Changes in the residual load to be supplied by the wholesale electricity market

The additional PV electricity generation on the household level in the 'Grid Parity Scenario' causes significant changes in the residual load and thus in the provision and operation of power plants on the system level.[91]

Figure 3.7 shows the average reduction of the total electricity demand (per hour and month) in 2020 that is supplied by the wholesale market due to the additional PV electricity generation on the household level, which is either consumed in-house or fed into the electricity grid.[92] As can be seen in Figure 3.7, the largest reductions in total electricity demand are observed during midday in the summer (up to 19 %) when PV electricity generation on the household level is highest. However, total electricity demand in the summer also decreases significantly in the evening hours due to the consumption of PV electricity that was stored in the battery system during the day.

	Month											
Hour	January	February	March	April	May	June	July	August	September	October	November	December
1	0%	-1%	-1%	-1%	-2%	-2%	-2%	-2%	-1%	-1%	0%	0%
2	0%	-1%	-1%	-1%	-2%	-2%	-2%	-1%	-1%	0%	0%	0%
3	0%	-1%	-2%	-1%	-2%	-2%	-2%	-1%	-1%	0%	0%	0%
4	0%	-1%	-3%	-2%	-3%	-3%	-2%	-2%	-2%	-1%	0%	0%
5	-1%	-1%	-1%	-2%	-3%	-4%	-3%	-2%	-2%	-1%	0%	0%
6	-1%	-2%	-2%	-4%	-8%	-8%	-7%	-6%	-3%	-1%	0%	0%
7	-2%	-4%	-5%	-8%	-13%	-13%	-11%	-9%	-8%	-5%	-1%	0%
8	-2%	-6%	-7%	-10%	-17%	-16%	-14%	-12%	-10%	-7%	-2%	-1%
9	-3%	-7%	-10%	-12%	-18%	-18%	-16%	-14%	-12%	-8%	-4%	-3%
10	-4%	-7%	-8%	-12%	-19%	-19%	-16%	-15%	-12%	-8%	-4%	-4%
11	-3%	-7%	-9%	-12%	-19%	-18%	-15%	-15%	-12%	-8%	-4%	-4%
12	-3%	-8%	-9%	-11%	-16%	-16%	-14%	-12%	-9%	-6%	-4%	-4%
13	-3%	-8%	-8%	-9%	-13%	-12%	-10%	-9%	-7%	-6%	-4%	-4%
14	-3%	-8%	-7%	-8%	-11%	-10%	-9%	-8%	-7%	-5%	-3%	-3%
15	-1%	-7%	-6%	-7%	-9%	-9%	-8%	-7%	-7%	-5%	-2%	-2%
16	-1%	-3%	-7%	-9%	-10%	-10%	-9%	-8%	-8%	-6%	-3%	-2%
17	-1%	-4%	-5%	-10%	-11%	-10%	-10%	-11%	-10%	-7%	-3%	-2%
18	-1%	-3%	-5%	-9%	-11%	-10%	-9%	-11%	-9%	-7%	-2%	-1%
19	-1%	-3%	-4%	-6%	-9%	-8%	-7%	-7%	-6%	-5%	-1%	0%
20	-1%	-3%	-3%	-5%	-8%	-9%	-7%	-6%	-4%	-3%	-1%	-1%
21	-1%	-3%	-3%	-4%	-8%	-9%	-8%	-6%	-3%	-2%	-1%	0%
22	-1%	-3%	-3%	-4%	-7%	-8%	-7%	-5%	-3%	-2%	0%	0%
23	-1%	-2%	-2%	-3%	-5%	-5%	-5%	-4%	-2%	-1%	0%	0%
24	0%	-1%	-1%	-1%	-2%	-2%	-2%	-1%	-1%	0%	0%	0%

FIGURE 3.7: Average reduction of total electricity demand to be supplied by the wholesale electricity market (2020)

3.4.2.3 Changes in the residential electricity tariff and its components

As explained in Section 3.3, the residential electricity tariff is derived by exogenous and endogenous components (see Table 3.11). While the exogenous components are the

[91]In the following, the residual load to be supplied by the wholesale electricity market is defined as the total electricity demand in Germany minus the scaled PV electricity in-house consumption and grid feed-in.

[92]Note that the average reduction of the total electricity demand in 2020 hardly differs from the average reduction in the years 2025-2050.

same for both scenarios, the endogenous components are scenario specific. Table 3.18 and Figure 3.8 illustrate the impact of the household's optimization behavior on the endogenous components of the residential electricity tariff.

TABLE 3.18: Endogenous components of the residential electricity tariff [€$_{2011}$ ct/kWh]

	'Reference Scenario'	'Grid Parity Scenario'
	Base price	
2020	3.2	3.1
2030	3.1	2.9
2040	4.1	4.0
2050	4.2	4.3
	Renewable energy surcharge	
2020	6.1	6.5
2030	2.9	3.1
2040	1.3	1.4
	Back-up capacity payment	
2020	1.6	1.7
2030	1.3	1.4
2040	1.2	1.3
2050	1.8	1.9
	Value-added tax	
2020	4.7	4.8
2030	4.4	4.4
2040	4.3	4.3
2050	4.1	4.2
	Residential electricity tariff	
2020	29.7	30.1
2030	27.4	27.6
2040	26.7	26.8
2050	25.9	26.1

Due to the additional PV electricity generation on the household level, the base price slightly decreases in 2020-2040. Specifically, as households consume self-produced instead of grid-supplied electricity, the residual load diminishes, and, as surplus PV electricity is fed into the grid, it displaces power plants with higher variable production costs (short-term merit order effect). Both effects cause the hourly wholesale electricity price and thus the base price to decline.[93] As a consequence of this so called merit-order effect, the marginal value and thus the overall economic attractiveness of additional solar power generation significantly decreases from the total system perspective. This is analyzed in more detail in Chapter 4 and 5.[94]

In 2050, in contrast, the base price slightly increases. This can be explained by the fact that in the 'Reference Scenario', more wind power (instead of PV power) is deployed in 2050 to achieve commitment with the long-term CO_2 reduction target (see Figure 3.6), which displaces conventional power plants at the steeper end of the merit-order curve (since wind generation is largest during the winter when the electricity demand is highest).

At the same time, however, the renewable energy surcharge increases as a consequence of the single household's optimization behavior. This is due to two factors: Firstly, the market value of the renewable energy generation – based on renewable capacities promoted via the feed-in tariff to achieve the 2020 NREAP targets – decreases with the additional PV electricity generation (short-term merit order effect). As a consequence, the additional costs, i.e., the difference between the producers' annual costs and their revenue from selling renewable energy electricity on the wholesale market, increase. Secondly, the total amount of grid-supplied electricity purchased by (non-privileged) electricity consumers – on which the additional costs are apportioned – decreases due to the increased in-house PV electricity consumption.

The decrease in the total amount of grid-supplied electricity purchased from electricity consumers in the 'Grid Parity Scenario' also explains the slight increase in the back-up capacity payment. Specifically, the costs for providing securely available capacities are apportioned to a lower share of electricity consumers (i.e., a lower amount of grid-supplied electricity purchased from electricity consumers) in the 'Grid Parity Scenario'.

Finally, the value-added tax payment also increases due to the fact that the value-added tax of 19 % is levied on the sum of all components, which is larger in the 'Grid Parity Scenario' than in the 'Reference Scenario'.

In sum, the increase in the renewable energy surcharge, the back-up capacity payment and the value-added tax payments compensates the decrease in the base price (which serves as a proxy for the average costs of electricity procurement). Thus, the residential electricity tariff increases.

[93]However, we note that the hourly wholesale prices do not drop below zero since the electricity system optimization model allows for endogenous curtailment of wind and solar power generation.

[94]See also Joskow (2011), who argues that comparing the economic attractiveness of fluctuating wind and solar power units to that of conventional dispatchable generation capacities based on the levelized costs of electricity (LCOE) is flawed since it fails to account for the fact that the value of electricity supplied (i.e., the wholesale price) varies over the course of the day and the year.

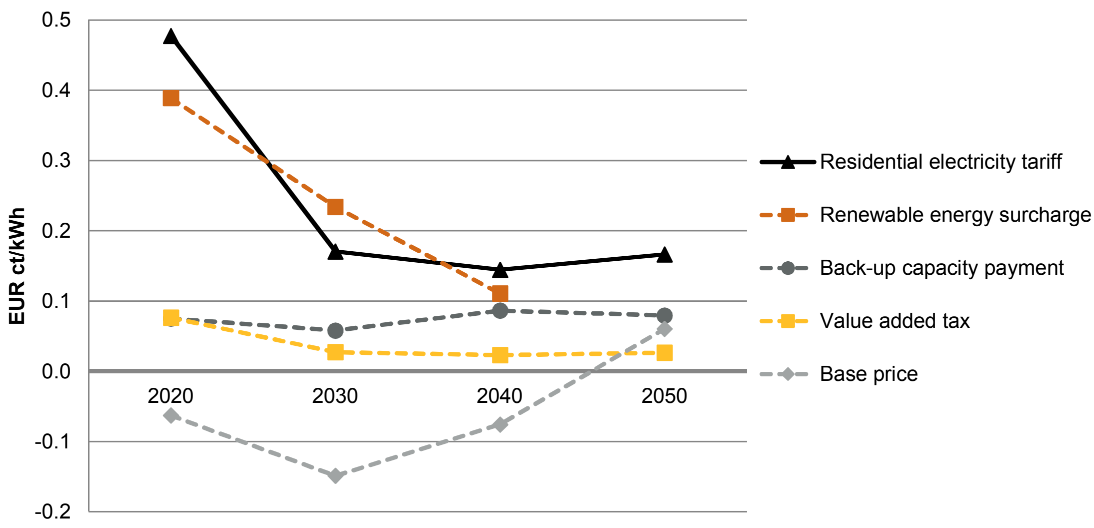


FIGURE 3.8: Impact of the single household's optimization on the residential electricity tariff [€$_{2011}$ ct/kWh]

Notably, the increase in the residential electricity tariff due to the additional PV electricity generation constitutes a self-reinforcing effect, since a higher residential electricity tariff in turn increases the attractiveness of consuming self-produced instead of grid-supplied electricity from the single household's perspective.

3.4.2.4 Welfare loss and redistributional effects associated with the household's optimization behavior

After having analyzed the impact of the single household's optimization behavior on the generation and capacity mix, the residual load and the residential electricity tariff, we quantify the welfare loss and redistributional effects associated with the in-house consumption of self-produced PV electricity generation on the household level.

Figure 3.9 illustrates the redistributional effects associated with the household's optimization behavior. Specifically, it shows the difference in the consumer rent, the rent of 'HH producers and in-house consumers', the producer profit, the payments of consumers to the public sector and network operators, the payments of 'HH producers and in-house consumers' to the public sector and network operators as well as the revenues of the public sector and network operators between the 'Grid Parity Scenario' and the 'Reference Scenario' accumulated up to 2050 in bn €$_{2011}$ (not discounted). Table 3.19, moreover, shows the change in the single components of the consumer rent, the rent of 'HH producers and in-house consumers' and producer profit accumulated up to 2050 in bn €$_{2011}$ (not discounted).

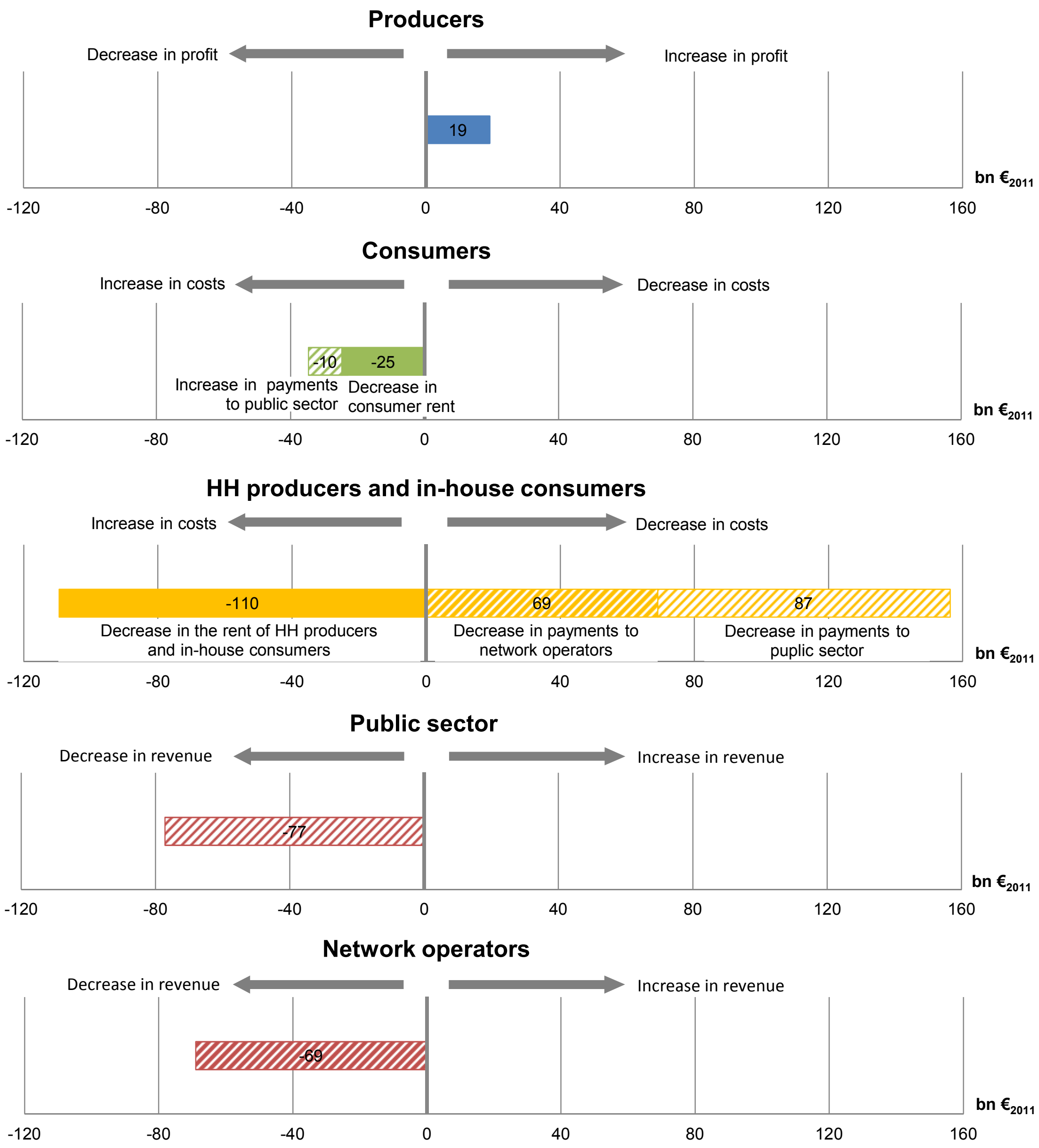


FIGURE 3.9: Redistributional effects accumulated up to 2050 (not discounted) [bn €$_{2011}$]

The producer rent increases by 19 bn €$_{2011}$ in the 'Grid Parity Scenario' since the decrease in the producer's costs exceeds the decrease in the producer's revenue (see Table 3.19). Specifically, the producer's revenue for providing electricity decreases by 25 bn €$_{2011}$, but annualized investment costs, variable generation costs and fixed O&M costs decrease by 22, 7 and 10 bn €$_{2011}$, respectively, in the 'Grid Parity Scenario'. Moreover, the producer's compensation for providing renewable energy capacity increases since the market value of the renewable energy generation (based on renewable capacities promoted via the feed-in tariff to achieve the 2020 NREAP targets) decreases (see Section 3.3).

Table 3.19: Change in the single components of the producer profit, the consumer rent and the rent of 'HH producers and in-house consumers' accumulated up to 2050 (not discounted) [bn €$_{2011}$]

Producers	
Decrease in the revenue for providing electricity	-25
Decrease in the revenue for providing heat	-2
Increase in the revenue for providing securley available capacities	2
Increase in the renewable energy compensation	6
Sum: Decrease in producer revenue	-20
Decrease in the annualized investment costs	22
Decrease in the variable generation costs (including fuel and CO_2 costs)	7
Decrease in the fixed operation and maintenance costs	10
Sum: Decrease in producer costs	39
Net effect: Increase in producer profit	19
Consumers	
Decrease in the costs for being provided with electricity (from the wholesale market)	9
Increase in the costs for being provided with securly available capacities	-13
Increase in the costs for being provided with renewable capacities	-21
Sum: Decrease in consumer rent	-25
HH producers and in-house consumers	
Increase in the revenue from the wholesale market	3
Sum: Increase in the revenue of HH producers and in-house consumers	3
Decrease in the costs for being provided with electricity (from the wholesale market)	26
Decrease in the costs for being provided with securely available capacities	12
Decrease in the costs for being provided with renewable capacities	13
Increase in the costs for PV and storage capacities	-163
Sum: Increase in costs of HH producers and in-house consumers	-113
Net effect: Decrease in the rent of HH producers and in-house consumers	-110

The consumer rent, in contrast, decreases by 25 bn €$_{2011}$ due to the single household's optimization behavior. Although the costs of being provided with electricity from the wholesale electricity market decreases by 9 bn €$_{2011}$ due to the higher PV electricity generation in the 'Grid Parity Scenario', the costs of being provided with renewable and securely available back-up capacities increase by 21 and 13 bn €$_{2011}$, respectively, for consumers. This is due to the fact that the (residual) consumers have to bear a higher share of both the (increased) additional costs of renewable energy and back-up capacities, as the total amount of grid-supplied electricity (on which these costs are apportioned) decreases.

Besides the consumer rent, the rent of 'HH producers and in-house consumers' also decreases by more than 110 bn €$_{2011}$ in the 'Grid Parity Scenario'. This is due to the high investment (and fixed O&M) costs for the households's PV and storage capacities of 157 bn €$_{2011}$, which compensate (i) the decrease in the costs of being provided with electricity from the wholesale electricity market (26 bn €$_{2011}$), (ii) the decrease in the costs of being provided with renewable and securely available capacities (13 and 12 bn €$_{2011}$, respectively) and (iii) the revenue from selling surplus PV electricity on the wholesale market (3 bn €$_{2011}$).

In sum, the single household's optimization behavior (induced by the indirect financial incentive for in-house PV electricity consumption) reduces overall economic welfare by 116 bn €$_{2011}$.[95] The welfare loss is due to the fact that the single household's PV and storage capacities are not yet cost-efficient investment options from the total system perspective in 2020.

However, despite the decrease in the rent of 'HH producers and in-house consumers', investments in PV and storage capacities are nevertheless profitable from the perspective of 'HH producers and in-house consumers', as illustrated in Figure 3.9. This is due to the fact that the in-house consumption of self-produced PV electricity allows 'HH producers and in-house consumers' to reduce their payments to the public sector and network operators. Overall, 'HH producers and in-house consumers' reduce their payments to the public sector by more than 87 bn €$_{2011}$ and to the network operators by more than 69 bn €$_{2011}$. This is because of the exemption from taxes, levies and surcharges for the amount of self-produced PV electricity generation consumed in-house and the allocation of grid costs via energy- rather than capacity-related network tariffs. In contrast, the consumers' payments to the public sector slightly increase by 10 bn €$_{2011}$, which is primarily explained by the fact that the total amount of value-added tax payments increase (see Section 3.3).

In total, 'HH producers and in-house consumers' save 47 bn €$_{2011}$ in the 'Grid Parity Scenario' compared to the 'Reference Scenario'. The financial burden of the (residual)

[95]The welfare loss (excess costs) corresponds to the accumulated change in the consumer rent, the rent 'HH producers and in-house consumers' and the producer profit between the 'Grid Parity Scenario' and the 'Reference Scenario' (see Equation (3.41) in Section 3.3).

electricity consumers, in contrast, increases by 35 bn €$_{2011}$. Moreover, the public sector and network operators face revenue losses of 77 and 69 bn €$_{2011}$, respectively.

Note that in our analysis, we capture feedback effects of the in-house consumption of self-produced PV electricity generation for four components of the residential electricity price: the base price (which serves as a proxy for the average costs of electricity procurement), the renewable energy surcharge, the back-up capacity payment and the value added tax (see Table 3.11). All other components of the residential electricity tariff are, in contrast, exogenously assumed and do not differ between scenarios.[96] This assumption aims at illustrating the potential revenue loss experienced by the public sector and the network operators as a consequence of an increased consumption of self-produced (instead of grid-supplied) electricity on the household level in Germany. However, if, contrary to our assumption, the public sector would raise the taxes and levies on electricity consumption or if the network operators would raise the (energy-related) network tariffs (to cover their revenue losses of 77 and 69 bn €$_{2011}$, respectively), the financial burden of the residual electricity consumers would further increase. Moreover, just like in the case of the renewable energy surcharge, an increase in public taxes and levies or network tariffs would constitute a self-reinforcing effect since a higher residential electricity tariff increases the attractiveness of consuming self-produced (rather than grid-supplied) electricity from the single household's perspective. Hence, our quantified welfare effects (excess costs of 116 bn €$_{2011}$) may be interpreted as lower-bound estimates.

In summary, the unequal treatment of grid-supplied and self-produced electricity with respect to public taxes, levies and surcharges as well as the allocation of grid costs via energy- rather than capacity-related network tariffs constitutes a considerable distortion of competition. Accumulated up to 2050, excess costs associated with the massive expansion of combined PV and storage capacities on the household level by 2020 amount to more than 116 bn €$_{2011}$, corresponding to 0.44 % of the German gross domestic product from 2012 (DESTATIS (2013)). These significant excess costs can be explained by the fact that PV systems in Germany become efficient from 2030 only (see Figure 3.6), once PV investment costs may have fallen further and CO_2 reduction targets become more ambitious. Likewise, electricity storage is not a cost-efficient flexibility option before 2040, i.e., not until the share of fluctuating renewable energy technologies has further increased. However, instead of small-scale battery storage capacities (on the household level), large-scale compressed air energy storage (CAES) capacities are installed in the Reference Scenario, which are characterized by higher investment costs but significantly higher technological lifetimes, rendering CAES storage a less costly

[96]The exogenously assumed components of the residential electricity tariff include the concession levy, the offshore liability surcharge, the costs of distribution (margin included), the electricity tax, the CHP surcharge, the §19 surcharge and the network tariff (see Table 3.11).

flexibility option than battery storage. Moreover, while the battery storage capacities on the household level are dispatched to minimize the single household's electricity costs, the CAES capacities are optimally dispatched from total system perspective.

3.5 Conclusion

The paper has analyzed the consequences of exempting in-house PV electricity consumption from taxes, levies and surcharges and allocating grid costs via energy- rather than capacity-related (cost-reflective) network tariffs in a case study for Germany up to 2050.

We find that single households are able to avoid on average 10 % - 18 % of their accumulated electricity costs up to 2050 by covering (on average) 38 - 57 % of their annual electricity demand with self-produced PV electricity. In total, cost savings on the household level amount to more than 47 bn €$_{2011}$ up to 2050 in our scenario analysis. However, while the installation of PV and battery storage capacities on the household level for the consumption of self-produced instead of grid-supplied electricity is beneficial from the single household's perspective, it is inefficient from the total system perspective. In total, the single household's optimization behavior is found to cause excess costs of 116 bn €$_{2011}$ accumulated up to 2050.

Moreover, we find that the single household's optimization behavior leads to redistributional effects that may be undesirable from the overall economic perspective. Specifically, the single household's optimization behavior raises the financial burden for the (residual) electricity consumers by more than 35 bn €$_{2011}$ up to 2050. In addition, it yields massive revenue losses on the side of the public sector and network operators of more than 77 and 69 bn €$_{2011}$, respectively.

In order to enhance the overall economic efficiency, we argue that the financial incentive for in-house PV electricity consumption should be abolished. This implies that either the consumption of self-produced electricity should be burdened with taxes, levies and other surcharges, as in the case of the consumption of grid-supplied electricity, or that the residential electricity price should be reduced to the 'true' costs of electricity procurement. Moreover, since grid costs are primarily fixed costs, the traditional energy-related network tariff should be replaced by a cost-reflective tariff corresponding primarily to the grid connection capacity. As a result, competition between PV and all other electricity generation technologies would be ensured and inefficient investments avoided.

Future research could address the following issues: Firstly, the consequences of a change in the network tariff structure from energy- to capacity-related tariffs on the overall single households optimization behavior and the overall welfare effects could be quantified.

Secondly, the effect of active demand side management measures could be analyzed. More specifical, the option to shift the deferrable electricity demand of households from the evening hours to the maximum PV electricity generation hours would be an interesting point of investigation. Thirdly, the implications of a time-dependent residential electricity tariff on the single household's optimization behavior could be analyzed. With increasing penetration of PV capacities, hourly solar generation and wholesale electricity prices may become negatively correlated. Thus cost savings from consuming self-produced instead of grid-supplied electricity may be lower under a time-varying residential electricity tariff (instead of a flat residential electricity tariff). All three aspects are assumed to lower the economic inefficiency associated with the indirect financial incentive for in-house PV electricity consumption.

Chapter 4

An illustrative note on the system price effect of wind and solar power - The German case

4.1 Introduction

The competitiveness of wind and solar power technologies is often evaluated in public debates by comparing levelized costs of electricity (LCOE). However, as argued by Joskow (2011), comparing the economic attractiveness of fluctuating wind and solar power units to that of conventional dispatchable generation capacities based on the LCOE is flawed since it fails to account for the fact that the value of electricity supplied (i.e., the wholesale market price) varies over the course of the day and the year. Similarly, renewable energy support schemes are often designed to incentivize investors to only account for the marginal costs (MC) but not for the marginal value (MV^{el}) of renewable energy technologies, i.e., the revenue from selling electricity on the wholesale market during their technical lifetime.

Whereas it is commonly recognized that dispatchable renewable energy technologies such as biomass power plants should be exposed to the price signal of the wholesale market, exposing fluctuating wind and solar power technologies to the market price signal is often argued to have no merit (e.g., Klessmann et al. (2008)). This statement is partly true from a short-term perspective since wind and solar power have no short-run marginal costs of power production, which incentivizes wind and solar power generators to produce electricity whenever the wind is blowing or the sun is shining – irrespective of the current market price signal (Hiroux and Saguan (2010)). On the other hand, exposing fluctuating renewables to the market price signal at least induces wind and solar power generators to voluntarily curtail their power generation in response to negative prices (e.g., Hiroux and Saguan (2010), Klessmann et al. (2008)) and to align their maintenance planning to hours in which their power generation is less valuable for the system (e.g., Gawel and Purkus (2013), Hiroux and Saguan (2010)). Most importantly, however, exposing wind and solar power to the market price signal allows for cost-efficient investment decisions, as it incentivices investors to account for the marginal value (MV^{el}) of renewable energy technologies (see also Chapter 6).

As shown by Lamont (2008), the MV^{el} of wind and solar power units depends on their penetration level. More specifically, the MV^{el} of wind and solar power units is a function of the respective unit's capacity factor and the covariance between its generation profile and the system marginal costs. The latter component of the MV^{el} (i.e., the covariance) declines as the wind and solar power penetration increases, displacing dispatchable power plants with higher short-run marginal costs of power production and thus reducing the system marginal costs in all generation hours. This so called 'system price effect' is analyzed in more detail in this paper.[97]

Our analysis complements the work Lamont (2008) in two regards. First of all, we derive an alternative expression for the MV^{el} of wind and solar power units, which shows that the MV^{el} of wind (solar) power technologies depends not only on their own penetration level but also on a variety of other parameters that are specific to the electricity system. Second, based on historical wholesale prices and wind and solar power generation data for Germany, we present a numerical 'ceteris paribus' example for Germany which illustrates the decrease in the MV^{el} of wind and solar power units as penetration increases (as a consequence of the system price effect).

The structure of the paper is as follows: Section 4.2 discusses the marginal value (MV^{el}) of wind and solar power from a theoretical perspective, before Section 4.3 numerically illustrates the system price effect of wind and solar power in Germany. Section 4.4 draws conclusions.

4.2 Theoretical analysis

In the following we first derive the characteristics of a cost-efficient renewable energy mix (Section 4.2.1), before we analyze the determinants of the marginal value (MV^{el})

[97] In contrast to Lamont (2008), Hirth (2013) and Nicolosi (2012) analyze the annual 'value factor' of wind and solar power in Northwestern Europe and Germany, respectively, which can be understood as a proxy/indicator for the MV^{el} of wind and solar power, as it is defined as the average hourly revenue of wind and solar power generators relative to the time-weighted average wholesale price (base-price) per year. Both papers apply a linear dispatch and investment model and find that the annual value factor of wind and solar power decreases with increasing penetration of these technologies.

of wind and solar power in more detail (Section 4.2.2).

4.2.1 What characterizes a cost-efficient renewable energy mix?

The analysis complements the work of Lamont (2008) in accounting for politically implemented renewable energy (RES-E) targets. Just as in Lamont (2008), the optimality condition for renewable energy expansions is analyzed for the example of fluctuating wind and solar power units. The focus on wind and solar power is motivated by the fact that they differ from conventional dispatchable power plants in the sense that their power production is weather dependent (i.e., it depends on the availability of wind and solar power resources, which differs between regions) and that they are associated with (almost) no short-run marginal costs of power production. Moreover, given limited potentials for hydro power and low-cost biomass resources in generating electricity, wind and solar power are expected to account for the largest share of renewable energy capacity additions in the coming years.

The optimality condition for the expansion of fluctuating wind and solar power units (C^f) with an hourly power output of $pf^f_{y,h}$ under a technology- and region-neutral RES-E target can be derived by minimizing total system costs (as demonstrated in Appendix C, see Eq. (C.1) - (C.8)).[98]

In the optimum, fluctuating renewable energy units (C^f) are expanded up to the point at which their marginal costs (MC) correspond to the sum of their marginal value of power supply (MV^{el}) and their marginal value of renewable energy supply (MV^{ren}), given a technology- and region-neutral RES-E target (see Eq. (4.1)).[99] This reflects a basic economic principle under perfect competition: Marginal profits are zero for the capacity level at which marginal costs equal marginal value, which implies that profits are maximized or (alternatively) costs are minimized.

In general, the competitive equilibrium is characterized by a market clearance and a zero profit condition. Market clearance refers to the condition that (i) a wholesale price for electricity ($\mu_{y,h}$) is established through competition such that the amount of electricity demanded is equal to the amount of electricity produced, and (ii) that a market price for 'green electricity' (green certificates) (ρ_y) is established such that the amount of 'green electricity' demanded (by the RES-E target) is equal to the amount of 'green electricity' produced. Moreover, in line with the zero profit condition, investments in

[98]Due to the assumption of perfect competition and a price-inelastic electricity demand the cost-minimization approach corresponds to a welfare-maximization approach. Alternatively, the optimality condition for the expansion of fluctuating wind and solar power units could be derived by maximizing profits (assuming perfect competition and a price-inelastic electricity demand).

[99]The term 'technology- and region-neutral' indicates that each kWh of renewable electricity produced contributes to achieving the RES-E target irrespective of the technology or the region of its deployment.

fluctuating renewable energy capacities (C^f) take place as long as investments break even, i.e., up until the point the sum of their marginal value of power supply (MV^{el}) and their marginal value of renewable energy supply (MV^{ren}) corresponds to the unit's marginal costs (MC). This corresponds to the result of Lamont (2008) who showed that the costs of an additional unit of wind and solar power capacity should be equal to the benefits that it provides to the system. However, in contrast to our analysis, Lamont (2008) only accounted for the benefits of meeting electricity demand (MV^{el}) but not for the benefit of meeting renewable energy targets, i.e., the benefit of supplying 'green electricity' (MV^{ren}).

$$\underbrace{\sum_{y \in Y} fc^f_y}_{MC_{Cf}} \stackrel{!}{=} \underbrace{\sum_{y \in Y} \sum_{h \in H} pf^f_{y,h} \cdot \mu_{y,h}}_{MV^{el}_{Cf}} + \underbrace{\sum_{y \in Y} \sum_{h \in H} pf^f_{y,h} \cdot \rho_y}_{MV^{ren}_{Cf}} \tag{4.1}$$

While the MC are defined as the unit's accumulated annualized investment costs (fc^f_y) over all years (Y) of its technical lifetime, the MV^{el} of wind and solar power units corresponds to the accumulated revenue from selling electricity ($pf^f_{y,h}$) at the wholesale market at price $\mu_{y,h}$ in all hours (H) and years (Y) of the unit's technical lifetime. Assuming perfect competition and a price-inelastic electricity demand, the shadow variable of the power balance constraint (see Eq. (C.4) and (C.7) of the Appendix) – which represents the system's marginal costs associated with meeting the hourly electricity demand at a specific point in time – serves as proxy for the wholesale price ($\mu_{y,h}$). Hence, the MV^{el} of wind and solar power units reflects the accumulated value of the good 'electricity' (wholesale price) supplied by wind and solar power units during their technical lifetime.

In contrast to the MV^{el}, the MV^{ren} of wind and solar power units represents the accumulated value of the good 'green electricity' supplied by wind and solar power units during their technical lifetime under politically implemented RES-E targets. RES-E targets can hardly be justified from a climate protection perspective, given the implementation of a CO_2 emission cap which limits the overall CO_2 emissions (see, e.g., Chapter 2 or Jägemann et al. (2013a)). However, if renewable energy targets are nevertheless implemented, they may reflect the society's preference for electricity generation from renewable energy sources over electricity generation from non-renewable sources (i.e., fossil fuels or nuclear power). As such, electricity produced from wind and solar power units may have an additional value for the society (compared to electricity produced from non-renewable sources), which is derived from its property of being 'green'.

Just as in the case of the good 'electricity', which is traded and priced on the wholesale electricity market, the good 'green electricity' can be traded and priced on a market for 'green electricity'. Such markets exist, for example, in countries where governments have implemented renewable energy quota obligations in combination with tradable green certificates (TGC) which generators receive from the government for each kWh of 'green electricity' produced.[100] In this case, the MV^{ren} of wind and solar power units corresponds to the accumulated revenue from selling TGC on the green certificate market. The price of TGC is given by ρ_y, which corresponds to the shadow variable of the renewable energy constraint (see Eq. (C.6) and (C.7) of the Appendix) and indicates the marginal system costs associated with the achievement of the politically implemented RES-E target. Overall, the MV^{ren} of wind and solar power units represent the part of the MC that cannot be covered by the revenue from selling electricity on the wholesale market during the unit's technical lifetime (i.e., the MV^{el}), as shown by Equation 4.2.

$$MV_{Cf}^{ren} = MC_{Cf} - MV_{Cf}^{el} \tag{4.2}$$

Summarizing, while the MC reflect the unit's capital costs, the MV^{el} of wind and solar power units is defined as the accumulated revenue from selling electricity on the wholesale market during the unit's technical lifetime. Hence, in contrast to the MC, the MV^{el} of wind and solar power units depends on a variety of parameters that are specific to the electricity system. In the next section we analyze the determinants of the MV^{el} of wind and solar power units to gain a better understanding of what drives the MV^{ren} of renewable energy technologies, i.e., the part of the MC that needs to be covered by renewable energy support payments to incentivice investments.

4.2.2 What determines the marginal value of power supply (MV^{el})?

In the following two alternative theoretical definitions of the marginal value of wind and solar power units (MV^{el}) are derived.

[100] Quota obligations in combination with tradable green certificates (TGC) fix the quantity of renewable electricity to be generated. The supply of TGC is ensured by giving producers a certificate for each unit of renewable energy sold. The demand for TGC is induced by transferring the politically implemented RES-E target to distribution companies (electricity suppliers), who are then required to prove that a certain proportion (quota) of the electricity supplied to their final consumers was generated from renewable energy sources.

4.2.2.1 Definition 1

The marginal value of power supply (MV^{el}) is defined as the accumulated revenue from selling electricity on the wholesale market at price $\mu_{y,h}$ in all hours (H) and years (Y) of the unit's technical lifetime (Eq. (4.3)).

$$MV^{el}_{Cf} = \sum_{y \in Y} \sum_{h \in H} pf^{f}_{y,h} \cdot \mu_{y,h} \tag{4.3}$$

Let us assume that the hourly power output of wind or solar power units ($G^{f}_{y,h}$) is given by the production factor (pf^{f}_{h}) in the equilibrium (Eq. (4.4)), which implies that no curtailment of wind and solar power generation takes place.

$$G^{f}_{y,h} = pf^{f}_{y,h} \cdot C^{f} \tag{4.4}$$

Hence, the equilibrium output of dispatchable generators ($\sum_{d \in D} G^{d}_{y,h}$), which corresponds to the residual load ($RL_{y,h}$), is given by Equation (4.5).

$$\sum_{d \in D} G^{d}_{y,h} = l_{h,y} - \sum_{f \in F} pf^{f}_{y,h} \cdot C^{f} = RL_{y,h} \tag{4.5}$$

In our modeling framework, dispatchable generators offer their output at a price equal to their short-run marginal costs of power production, which are assumed to be a linear function of the total dispatchable power output ($\sum_{d \in D} G^{d}_{y,h}$), see Equation (4.6).[101] The function represents a merit-order curve of dispatchable power plants with different short-run marginal costs of power production.[102]

[101] The assumption that dispatchable generators offer their output at a price equal to their short-run marginal costs of power production reflects the assumption of perfect competition.

[102] The assumption of a linear function is in line with Bode (2006). However, in reality, the shape of the merit-order curve is rather staircase-shaped. More specifically, with every generator bidding its total capacity at a price equal to its short-run marginal costs of power production, the aggregate supply is a staircase function.

$$\frac{dVC^d}{d\sum_{d\in D} G^d_{y,h}} = a + b \cdot \sum_{d\in D} G^d_{y,h} \tag{4.6}$$

The parameter a reflects the short-run marginal costs of power production from the dispatchable power plant with the lowest short-run marginal production costs. Moreover, given the linear approximation of the (staircase-shaped) merit-order curve, b reflects the difference in the short-run marginal production costs between the dispatchable power plant with the lowest and the highest short-run marginal production costs. Hence, the larger the difference between the short-run marginal production costs between the dispatchable power plants is, the higher the slope of the linear (approximated) merit-order curve becomes.

Since the short-run marginal costs of wind and solar power production are zero, the wholesale price ($\mu_{y,h}$) is assumed to always be set by a dispatchable generator.

$$\mu_{y,h} = a + b \cdot \sum_{d\in D} G^d_{y,h} \tag{4.7}$$

Thus, the equilibrium wholesale price ($\mu_{y,h}$) is given by Equation (4.8).

$$\mu_{y,h} = a + b \cdot (l_{h,y} - \sum_{f\in F} pf^f_{y,h} \cdot C^f) = a + b \cdot RL_{y,h} \tag{4.8}$$

Equation (4.9) (i.e., the derivative of the wholesale price function with respect to C^f) illustrates the short-term merit-order effect: The wholesale price decreases as (ceteris paribus) the penetration of fluctuating wind and solar power capacities (C^f) with no short-run marginal costs of power production increases.[103]

[103]The effects of wind and solar power generation with (almost) no variable generation costs on the wholesale price has been examined by, e.g., Gil et al. (2012), Woo et al. (2011), Jonsson et al. (2010), MacCormack et al. (2010), Munksgaard and Morthorst (2008), G. Saenz de Miera and P. del Rion Gonzalez and I. Vizcaino (2008) or Sensfuß et al. (2008), based on historical as well as simulated data. All papers confirm the decreasing effect of increased wind and solar power generation on the wholesale price (short-term merit-order effect).

$$\frac{d\mu_{y,h}}{dC^f} \leq 0 \tag{4.9}$$

Inserting Equation (4.8) in Equation (4.3) shows that the marginal value (MV^{el}) of fluctuating renewables (C^f) can generally be expressed as follows:

$$MV^{el}_{C^f} = \sum_{y\in Y}\sum_{h\in H}(pf^f_{y,h} \cdot \mu_{y,h}) = \sum_{y\in Y}\sum_{h\in H}(pf^f_{y,h} \cdot (a + b \cdot (l_{h,y} - \sum_{f\in F} pf^f_{y,h} \cdot C^f))). \tag{4.10}$$

The MV^{el} of wind (C^w) and solar (C^s) power capacities is given by Equations (4.11) and (4.12), respectively.

$$MV^{el}_{C^w} = \sum_{y\in Y}\sum_{h\in H}(pf^w_{y,h} \cdot (a + b \cdot (l_{h,y} - pf^w_{y,h} \cdot C^w - pf^s_{y,h} \cdot C^s))) \tag{4.11}$$

$$MV^{el}_{C^s} = \sum_{y\in Y}\sum_{h\in H}(pf^s_{y,h} \cdot (a + b \cdot (l_{h,y} - pf^s_{y,h} \cdot C^s - pf^w_{y,h} \cdot C^w))) \tag{4.12}$$

Equations (4.11) and (4.12) demonstrate that the MV^{el} of wind power and solar power units is a function of the penetration of wind and solar power capacities (i.e., the level of C^w and C^s), the wind and solar power production factor profiles ($pf^w_{y,h}$ and $pf^s_{y,h}$) and the load profile ($l_{y,h}$). Moreover, the MV^{el} depends on the shape of the wholsale price function (Eq. (4.8)), based on the level of a (intersection) and b (slope).[104]

Due to the short-term merit-order effect, the MV^{el} of wind power (ceteris paribus) decreases not only as wind power penetration increases but also as solar power penetration increases (and vice versa) (see Eq. (4.13) - (4.14)). Equally, the MV^{el} of wind and solar power (ceteris paribus) decreases as the hourly load ($l_{y,h}$) decreases. This result reflects a basic economic interdependence: Assets (i.e., in this case 'electricity') decrease in value as their scarcity decreases, i.e., if supply increases or demand decreases. Thus, an asset essentially has no value if it abundant.

[104]The wholsale price function corresponds to the merit-order curve of dispatchable power plants and reflects the short-run marginal costs of power production of the respective electricity system's dispatchable power plants

Moreover, the MV^{el} of wind and solar power (ceteris paribus) increases as the slope (b) of the wholesale price function (i.e., the merit-order curve) increases, meaning that the difference in the short-run marginal production costs between the single dispatchable power plant capacities increases.

$$\frac{\delta MV^{el}_{C^w}}{\delta C^w} \leq 0; \frac{\delta MV^{el}_{C^w}}{\delta C^s} \leq 0; \frac{\delta MV^{el}_{C^w}}{\delta l_{h,y}} \geq 0; \frac{\delta MV^{el}_{C^w}}{\delta b} \geq 0 \tag{4.13}$$

$$\frac{\delta MV^{el}_{C^s}}{\delta C^s} \leq 0; \frac{\delta MV^{el}_{C^s}}{\delta C^w} \leq 0; \frac{\delta MV^{el}_{C^s}}{\delta l_{h,y}} \geq 0; \frac{\delta MV^{el}_{C^s}}{\delta b} \geq 0 \tag{4.14}$$

To summarize, Equations (4.11) and (4.12) show that system effects are very relevant when discussing the MV^{el} of renewable energy technologies. Overall, the MV^{el} of wind power capacities decreases as their penetration (C^w) increases. However, the level of the MV^{el} of wind power units depends on the wind power production factor profile ($\mathrm{pf}^w_{y,h}$), the solar power penetration (C^s), the solar power production factor profile ($\mathrm{pf}^s_{y,h}$), the load level ($l_{y,h}$) and the structure of the marginal costs of the dispatchable capacity mix. The same holds true for the MV^{el} of solar power capacities.

4.2.2.2 Definition 2

An alternative expression for the MV^{el} of fluctuating wind and solar power units is derived by Lamont (2008). Equation (4.3) can be rewritten as follows:

$$MV^{el}_{C^f} = \sum_{y \in Y} H \cdot E(pf^f_{y,h} \cdot \mu_{y,h}) \tag{4.15}$$

As explained in Lamont (2008), the term $\mathrm{E}(pf^f_{y,h} \cdot \mu_{y,h})$ from Equation (4.15), which reflects an expected (average) value, is a component of the correlation between the hourly production factor of fluctuating renewable energy technologies ($pf^f_{y,h}$) and the wholesale price ($\mu_{y,h}$) (Eq. (4.16)). The correlation coefficient ($cor(pf^f_{y,h}, \mu_{y,h})$) is obtained by dividing the covariance of the two variables ($cov(pf^f_{y,h}, \mu_{y,h})$) by the product of their standard deviations ($\sigma_{pf^f_{y,h}} \cdot \sigma_{\mu_{y,h}}$).

$$cor(pf^f_{y,h}, \mu_{y,h}) = \frac{cov(pf^f_{y,h}, \mu_{y,h})}{\sigma_{pf^f_{y,h}} \cdot \sigma_{\mu_{y,h}}} = \frac{E(pf^f_{y,h} \cdot \mu_{y,h}) - E(pf^f_{y,h}) \cdot E(\mu_{y,h})}{\sigma_{\mu_{y,h}} \cdot \sigma_{pf^f_{y,h}}} \tag{4.16}$$

Thus, the MV^{el} of fluctuating renewable energy technologies (C^f) can alternatively be expressed by Equation (4.17).

$$MV^{el}_{C^f} = \sum_{y \in Y} H \cdot (\underbrace{E(pf^f_{y,h}) \cdot E(\mu_{y,h})}_{\text{First component}} + \underbrace{cor(pf^f_{y,h}, \mu_{y,h}) \cdot \sigma_{pf^f_{y,h}} \cdot \sigma_{\mu_{y,h}}}_{\text{Second component}}) \tag{4.17}$$

This expression (Eq. (4.17)) differs from the one originally derived by Lamont (2008) with regard to the second component. More specifically, we take the correlation coefficient between the production factor profile and the wholesale price (i.e., the system marginal costs) instead of the covariance. This is motivated by the fact that the covariance only shows the sign of the linear relationship between the two variables, while the normalized version of the covariance, i.e., the correlation coefficient, is indicative of the strength of the linear relationship. More specifically, in contrast to the covariance, the correlation coefficient shows the strength of the linear relation by its magnitude. As such, the correlation coefficients of alternative fluctuating renewable energy technologies can be better compared and interpreted than the covariances, which is advantageous for the numerical analysis in Section 4.3.

As explained by Lamont (2008), the first component of Equation (4.17) is a function of the capacity factor, i.e., the expected (average) production factor of the fluctuating renewable energy technology ($E(pf^f_{y,h})$) over all hours (H) of the year, and the base price, i.e., the expected (average) wholesale price (E($\mu_{y,h}$)) over all hours (H) of the year. This component is independent of the actual profile of the hourly power production of fluctuating renewable energy technologies and only reflects the technology's full load hours (FLH). It shows that the MV^{el} of a technology increases as (ceteris paribus) its capacity factor or number of FLH increases. The second component, however, is a function of the correlation between the hourly production factor profile ($pf^f_{y,h}$) and the wholesale price profile ($\mu_{y,h}$) and reflects the 'price matching' or 'residual-load matching' capability of a fluctuating power generation unit. Hence, the better the production factor profile of a wind (solar) power unit matches the residual load (and thus the hourly wholesale price) profile, the larger (ceteris paribus) the correlation and thus the higher the MV^{el} of the wind (solar) power unit becomes.

After having analyzed the MV^{el} of the wind (solar) power units in detail via a theoretical framework, we provide quantitative evidence for the theoretical results derived so far. Using historical data for Germany, we illustrate the change in the MV^{el} of wind and solar power technologies as a consequence of increased wind and solar power penetration in a 'ceteris paribus' example (i.e., keeping all other determinants/parameters constant).

4.3 Numerical illustration for Germany

4.3.1 Methodology

In the numerical example for Germany we use Equation (4.18) to determine the MV^{el} of wind and solar power technologies (i.e., the annual revenue from selling electricity on the wholesale market) for exogenously varied onshore wind and solar power capacities (C^f).

$$MV^{el} = \sum_{h=1}^{8760} (pf_{y,h}^{f} \cdot \mu_{y,h}) \tag{4.18}$$

The corresponding wholesale price ($\mu_{y,h}$) in €ct/kWh, which depends on the residual load ($RL_{y,h}$), is determined by Equation (4.19) (see also Eq. 4.8).

$$\mu_{y,h} = -1.37 + 1.31 \cdot 10^{-07} \cdot \underbrace{(l_{h,y} - pf_{y,h}^{w} \cdot C^{w} - pf_{y,h}^{s} \cdot C^{s})}_{RL_{y,h}} \tag{4.19}$$

The coefficients of the wholesale price function (Eq. (4.19)) are derived by an ordinary least squares (OLS) regression based on historical wholesale price data (EEX (2013c)) and residual load data for Germany in 2011 and 2012 (ENSTO-E (2013), EEX (2013a) and EEX (2013b)).[105] More specifically, we apply an OLS regression of the wholesale

[105] The restriction to the years 2011 and 2012 is due to the fact that solar power generation data from EEX (2013a) are only available from 2011 onwards.

price on the residual load (i.e., total electricity demand minus wind and solar power generation) which is assumed to serve as a proxy for the output of dispatchable power plants ($\sum_{d \in D} G^d_{y,h}$).[106] Modeling wind and solar power generation as a reduction from total electricity demand reflects the German renewable energy law which guarantees fixed feed-in tariffs (FIT) and implies a priority infeed of renewable generation.[107]

TABLE 4.1: Results of the OLS regression

Wholesale price ($\mu_{y,h}$)	Coefficient
Residual demand ($RD_{y,h}$)	1.31e-07***
	(7.21e-10)
Constant	-1.37***
	(0.034182)

Remarks: Robust standard errors are in parentheses; ***Significant at the 1 %-level; Number of observations: 17544; R-squared: 0.6526; Adjusted R-squared: 0.6526.

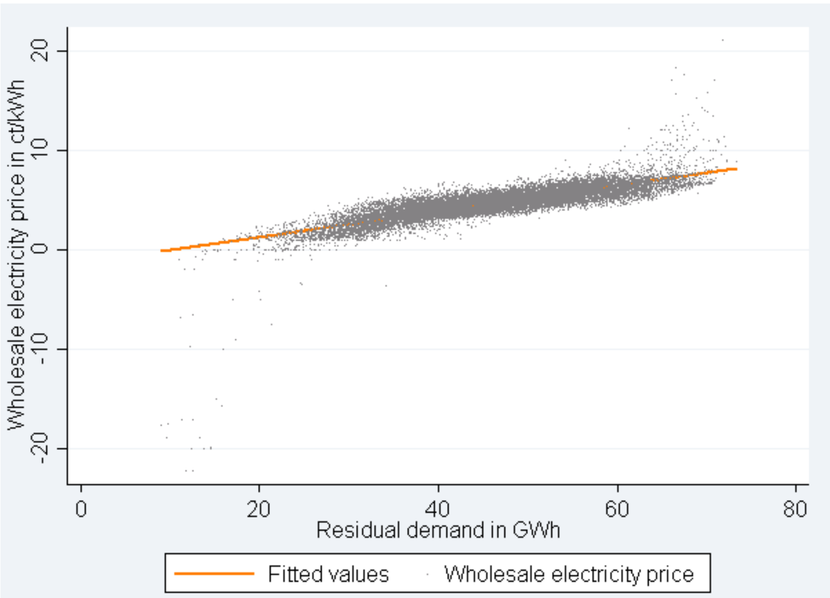


FIGURE 4.1: Scatter plot with linear regression line

The scatter plot of historical wholesale prices and residual load data (Figure 4.1) shows negative prices at very low residual load levels (below 20 GWh) due to the priority infeed of renewable generation under the German renewable energy law, and exponentially

[106] Another application of least-squares regressions of the wholesale price on the residual load can, for example, be found in Wagner (2012). Alternative empirical functions from hourly wholesale prices and (residual) load data are, for example, derived by Barlow (2002), Burger et al. (2006) and Elberg and Hagspiel (2013).

[107] We note that production from wind and solar power generation (with marginal production costs of zero) would be offered at a price of zero on the energy exchange if there was no such system. In this case, our approach would only be suitable when additionally assuming that no negative prices are allowed at the energy exchange.

increasing prices at very high residual load levels (above 65 GWh). Between those extremes, the plot suggest a fairly linear relation.

For reasons of model validation, historical wholesale prices (for 2011 and 2012) are compared to the simulated wholesale prices (on basis of the residual load in 2011 and 2012). As can be seen in Figure 4.2, which illustrates the annual price duration curve of the historical wholesale prices and the corresponding fitted values, wholesale prices are underestimated for very high residual load levels and overestimated for very low residual load levels in our model.[108]

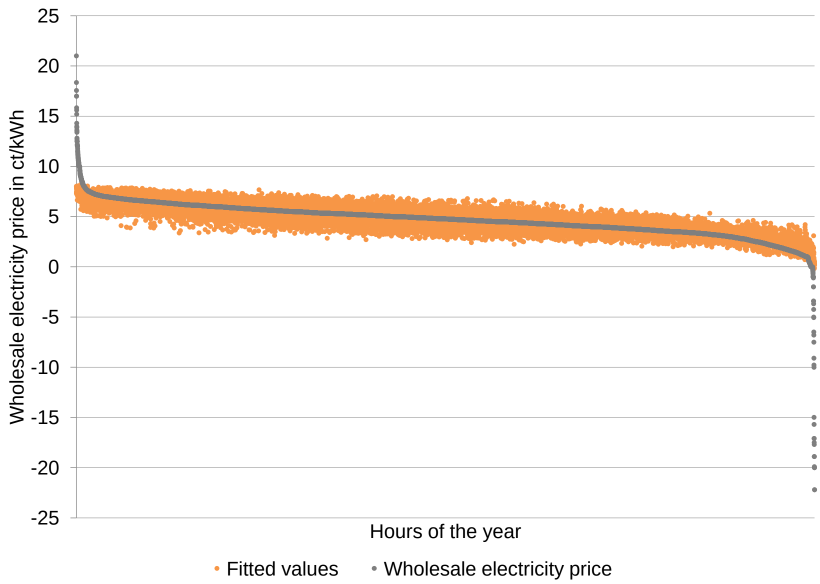


FIGURE 4.2: Annual price duration curves: Comparison of simulated and real wholesale prices in 2011 and 2012

Overall, however, the applied linear function provides a reasonable fit to the data. As illustrated in Table 4.1, the (adjusted) R-squared, which measures the quality of fit, amounts to 0.65. Hence, 65 % of the variation in the wholesale price can be explained by the residual load in our model.

We note that there might be a problem of endogeneity in OLS regressions which describes the circumstance that the independent variable (here the wholesale price) is correlated with the error term in the regression model and which implies that the regression coefficients are biased. Important sources of endogeneity are omitted explanatory variables and simultaneity. As explained in McMenamin et al. (2006), explanatory variables for electricity prices can basically be divided in two categories: The first set of explanatory factors is related to the demand-side. The hourly load reflects people's life-patterns and industrial production processes interacting, for example, with the day of the week or the weather. In our model hourly electricity demand ($l_{h,y}$, see Eq. (4.19)) is used

[108]This is primarily due to the application of a linear regression function.

as explanatory variable, rather than indirect variables for calendar and weather effects. The second set of explanatory factors refers to the supply-side. These factors include, for example, wind and solar power generation, fuel prices, generation unit availability and transmission constraints.[109] In this analysis only wind and solar power generation is included as explanatory variables ($pf_{y,h}^{w} \cdot C^{w}$ and $pf_{y,h}^{s} \cdot C^{s}$, see Eq. (4.19)). Other important supply-side factors, such as natural gas prices or un-/planned power plant outages, are not considered. However, omitted variables only cause problems of endogeneity (i.e., lead to biased regression coefficients) if they are correlated with at least one of the explanatory variables (i.e., the level of hourly demand or the level of hourly wind and solar power generation) which is arguably not the case in this analysis. More specifically, power plant outages and fossil fuel prices are assumed to be not correlated with the level of hourly demand or hourly wind and solar power generation. Hence, we argue that no problem of endogeneity exists in our analysis as a consequence of omitted variables. However, endogeneity problems might exist due to simultaneity, as the electricity demand itself might be dependent on the wholesale price if the electricity demand is price-elastic in the short-term. However, short-term price elasticity is found to be rather low in today's electricity system (see, e.g., Lijesen (2007)). Hence, we argue that the potential problem of endogeneity due to simultaneity is negligible in our analysis.

Besdies the potential problem of endogeneity, it should be stressed that the applied wholesale price function reflects the current capacity mix in Germany (as it was estimated based on historical data from 2011 and 2012) and thus does not account for an adaptation of the capacity mix as the renewable energy penetration increases (shift towards peak-load capacities). Therefore, the derived decrease in the MV^{el} as a consequence of increased wind and solar power penetration should be interpreted as an upper-bound estimate.

4.3.2 Results

In the numerical example for Germany we use Equations (4.18) and (4.19) to determine the MV^{el} of wind and solar power technologies (i.e., the annual revenue from selling electricity on the wholesale market) for exogenously varied onshore wind and solar power capacities (C^{f}) for three regions in Germany (north, central and south), taking the actual wind and solar power capacity mix in 2012 as a reference point.[110] The three regions

[109] Moreover, in periods of high demand the load levels in neighboring countries can have a significant impact on national electricity prices (McMenamin et al. (2006)).

[110] Appendix C provides a detailed discussion of the exogenous variation of wind and solar power capacities assumed in the numerical example (see also Table C.2).

differ with regard to the production factor profile of wind and solar power units ($pf^{f}_{y,h}$) and the number of full load hours (based on data for 2008 from EuroWind (2011)).

We note that the wind and solar power capacities are proportionally increased as to generate the same amount of electricity with each technology (between 19 TWh and 58 TWh) in the numerical example. Moreover, to illustrate the benefits of regional diversification, an average production factor profile is included for wind and solar power across the three regions. As such, the average production factor profile for wind/ solar power implicitly assumes an equal distribution of wind/ solar power capacities across the three regions.[111]

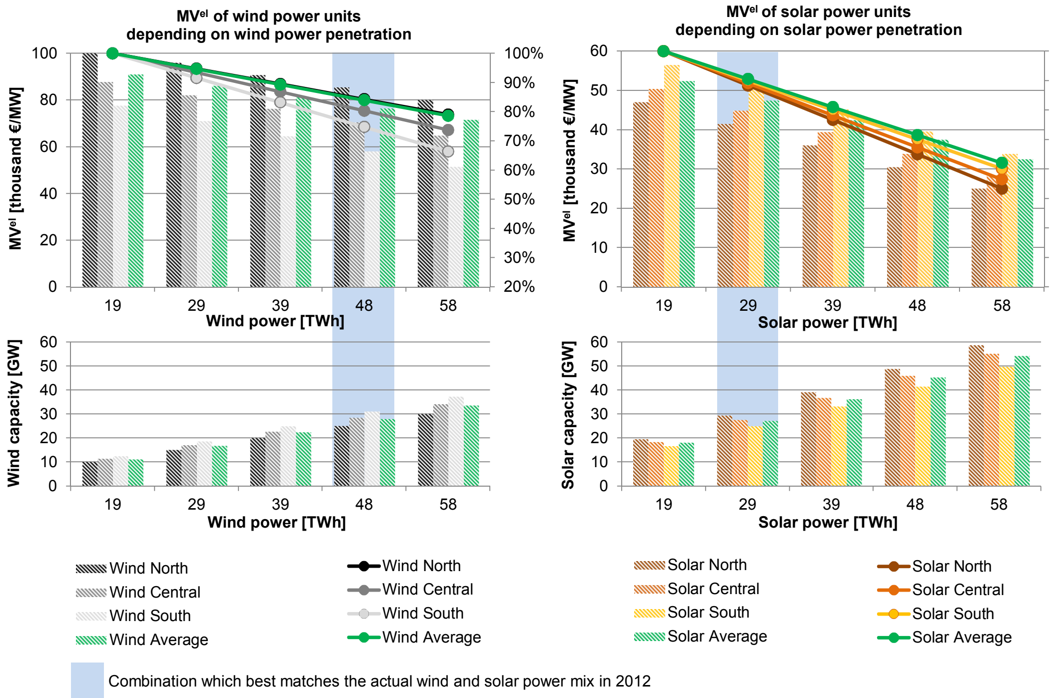


FIGURE 4.3: MV^{el} of wind and solar power units depending on their penetration level [€ /MW]

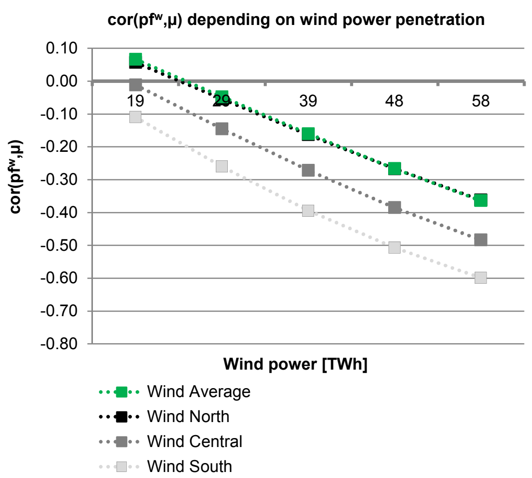
Figure 4.3 illustrates three effects: First, the MV^{el} of wind power and solar power units decreases (ceteris paribus) as their penetration increases. As shown in Figure 4.4, the decrease in the MV^{el} can be explained by the decrease in the correlation between the wind/ solar power production factor profile ($pf^{w}_{y,h}/pf^{s}_{y,h}$) and the wholesale price profile ($\mu_{y,h}$). The higher the penetration of wind or solar power units becomes the lower their price matching or residual-load matching capability will be.[112] In addition, the base

[111]The benefits of regional diversification with respect to the smoothing out of fluctuations in wind power generation are, for example, discussed in Liu et al. (2013), Grothe and Schnieders (2011) Katzenstein et al. (2010) and Roques et al. (2010).

[112]We note that the correlation between the wind/ solar power production factor profile and the wholesale price profile (illustrated in Figure 4.4) corresponds to the correlation between the wind/ solar power production factor profile and the residual load profile in the numerical analysis.

price (i.e., the time-weighted wholesale price $E(\mu_{y,h})$) also decreases, as shown in C (Figure C.1).[113]

Second, the decrease in the MV^{el} is more pronounced for solar power than for wind power units as penetration increases (see Figure 4.3). For example, while the MV^{el} of a wind power unit in central Germany decreases by only 26 % (to 74 %) as the overall wind power generation in central Germany increases from 19 to 58 TWh, the MV^{el} of a solar power unit in central Germany decreases by more than 44 % (to 56 %) as the overall solar power generation in central Germany increases from 19 to 58 TWh. This is due to the fact that the decrease in the correlation between the production factor profile and the wholesale price profile is more drastic for the case of solar power than for wind power (see Figure 4.4). More specifically, as a consequence of high solar power generation during midday, the residual load pattern reverses, as illustrated in Figure 4.5 (i) and (ii). The former midday-peak of the residual load curve (under moderate solar power penetration) becomes a trough. The wind power production factor profile, in contrast, is more volatile and follows no such distinct daily pattern like solar power (with zero output during the night and peak generation at midday). Hence, high wind power penetration does not result in such a pronounced structural change in the residual load curve, as shown in Figure 4.5 (i) and (iii). The effect can also be seen in Figure C.2 of the Appendix, which illustrates the impact of increased wind and solar power penetration on the annual residual load profile for 8760 hours of the year.



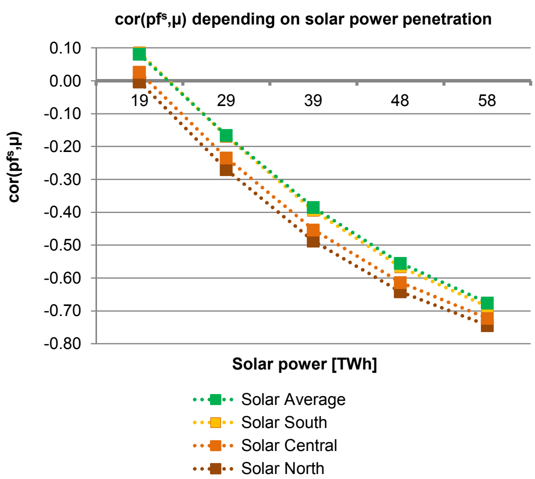


FIGURE 4.4: Correlation between the hourly wind/solar power production factor and the wholesale price

[113]The level of decrease in the MV^{el} of wind/ solar power units differs between the single regions due to differences in the correlation of the regional production factor profiles and the load profile, as illustrated in Table C.3 of the Appendix.

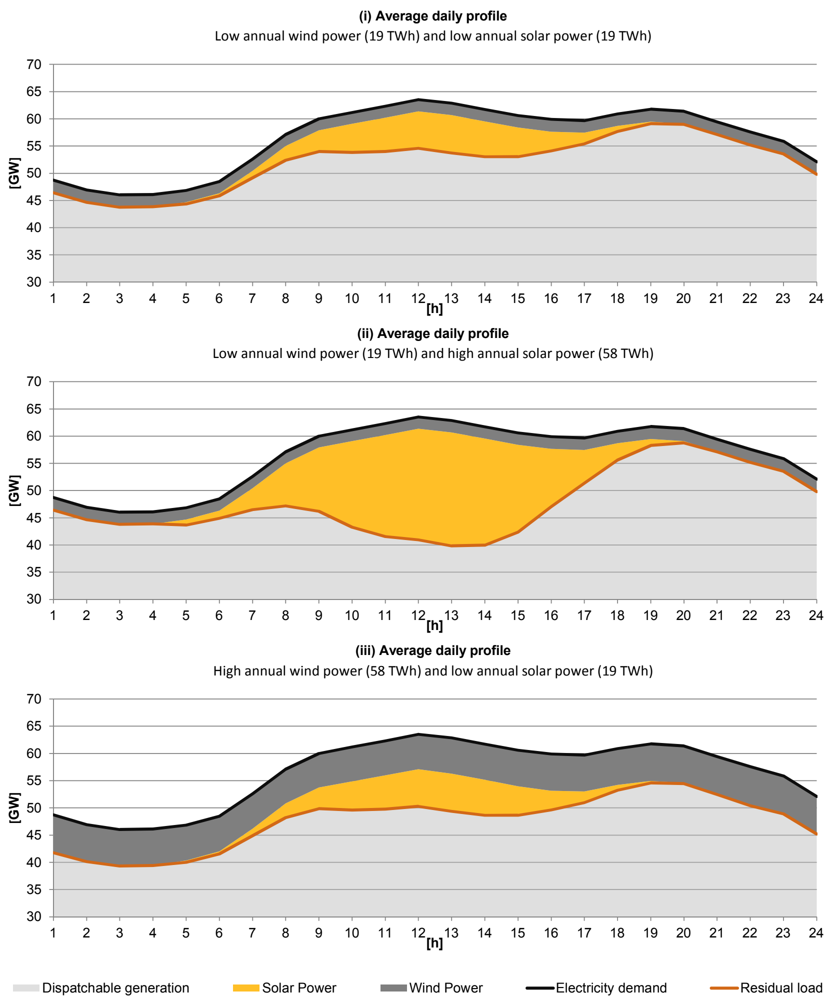


FIGURE 4.5: Impact of an increased wind and solar power penetration on the average daily residual load profile (based on 8760 h)

Third, there are benefits of regional diversification which become evident when comparing the full load hours (FLH) and the MV^{el} of units with region-specific production factor profiles and units with the average production factor profile. For example, the MV^{el} of a wind power unit with the average production factor profile is more than 10 % higher than the MV^{el} of a wind power unit in central Germany at a penetration level of 58 TWh (71.6 thousand € /MW vs. 64.9 thousand € /MW), although the wind power unit with the average production factor profile has only 2 % higher FLH than the wind power unit in central Germany in the numerical analysis.[114]

Moreover, when looking at the combination of wind and solar power generation which best matches the historical wind and solar power mix in 2012 in Figure 4.3, it becomes

[114]Equally, the MV^{el} of a solar power unit with the average production factor profile is more than 14 % higher than the MV^{el} of a solar power unit in central Germany at a penetration level of 58 TWh (32.6 thousand € /MW vs. 28.5 thousand € /MW), although the solar power unit with the average wind production factor profile has only 2 % higher FLH than the solar power unit in central Germany (1,072 h vs. 1,055 h).

evident that the system price effect of wind and solar power is already highly relevant for both wind and solar power in Germany. Hence, the MV^{el} of additional wind and solar power units in Germany has significantly decreased in recent years. As a consequence, the level of renewable energy support payments needed to incentivize further investments in wind and solar power technologies increases as (ceteris paribus) penetration increases, see Equation (4.2).

4.4 Conclusion

The marginal value (MV^{el}) of wind and solar power technologies depends on wide range of parameters that are electricity system specific. Most importantly, the MV^{el} of wind and solar power technologies decreases as penetration increases. The higher the overall installed capacity of wind and solar power becomes, the lower the correlation between the production factor profile and the wholesale electricity price and thus the marginal value of an additional unit of wind and solar capacity becomes. This so called system price effect is already highly relevant for both wind and solar power generation in Germany and suggests that renewable energy support payments needed to cover costs increase as (ceteris paribus) penetration increases.

Overall, the results highlight the need to expose wind and solar power to the market price signal if a cost-efficient renewable energy mix is to be achieved. Only if investors are incentivized to account for the marginal value (MV^{el}) of renewable energy technologies, they chose the technologies which are cost-efficient from the total system perspective. However, renewable energy support schemes are often designed to incentivize investors to only account for the marginal costs (MC) but not for the marginal value (MV^{el}) of renewable energy technologies. Future research could thus address the following research question: What are the excess costs if renewable energy support schemes fail to incentivize investments in those renewable energy technologies which are most attractive from the total system perspective?

Chapter 5

A note on the inefficiency of technology- and region-specific renewable energy support - The German case

5.1 Introduction

Renewable energy (RES-E) support schemes have to meet two requirements in order to lead to a cost-efficient renewable energy mix. First, RES-E support schemes need to expose RES-E producers to the price signal of the wholesale market, which incentivizes investors to account not only for the marginal costs (MC) but also for the marginal value (MV^{el}) of renewable energy technologies (see Chapter 4). Second, RES-E support schemes need to be technology- and region-neutral in their design (rather than technology- and region-specific). That is, the financial support may not be bound to a specific technology or a specific region.[115]

Germany, however, is committed to reach technology-specific targets for wind and solar power by 2020. Moreover, wind and solar power generation is currently incentivized via technology- (and region-)specific feed-in tariffs (FIT), which are coupled with capacity support limits. For example, in 2012, a photovoltaic (PV) capacity support limit of 52 GW was implemented in order to control escalating support costs. At this point, incentives will no longer be available for new PV projects in Germany. Moreover, the

[115]This is based on the assumption of imperfect information on the side of the government regarding the MC and MV^{el} of alternative technologies and regions, which prohibits the government to implement technology- and region-specific support schemes that lead to the cost-efficient renewable energy mix.

annual expansion of onshore wind capacities is forseen to take place along a predefined corridor of 2.5 GW per year (BMU (2014)), which would result in a total onshore wind power capacity of 50 GW installed by 2020.[116] With regard to offshore wind power, an overall capacity of 6.5 GW is targeted by 2020 (BMU (2014)).

While the level of the technology-specific FIT for PV generation is independent of the full load hours and the location of the PV system, the technology-specific FIT for onshore wind power generation is determined via a so called 'reference yield model'.[117] As such, the technology-specific FIT for onshore wind power generation is dependent on the annual output (full load hours) of the respective wind power project, which differs across regions. More specifically, under the current reference yield model, incentives for onshore wind power are designed in such a way as to only suffice the generation costs at sites with high full load hours (FLH), but not the generation costs at sites with less favorable wind resources (see, e.g., Frontier Economics (2012)). As such, Germany basically grants a region-specific FIT that incentivizes onshore wind investments at sites with the lowest marginal costs per kWh ($\overline{MC}$) (due to highest FLH) without accounting for differences in the marginal value per kWh ($\overline{MV^{el}}$) of onshore wind investments at different sites.

According to the coalition agreement of the German government from November 2013, financial support for onshore wind power should be decreased (CDU/CSU/SPD (2013)). However, favorable wind regions with a reference yield of 75 % to 80 % (of the benchmark) should still be operated profitably. This implies that investments in regions with less favorable wind resources (annual output below 75 % of the benchmark) are not attractive from the investor's perspective, although it may be beneficial from the total system perspective.

Summarizing, the current FIT in Germany (which is coupled with capacity support limits) fails to expose wind and solar power producers to the price signal of the wholesale market. Moreover, it is technology- and region-specific in its design, i.e., the support level for each kWh differs between wind and solar power technologies and the location of their deployment (at least for onshore wind power). As a consequence, excess costs occur which are burdened by society.

In the following, we illustrate the economic consequences associated with Germany's technology- and region-specific wind and solar power targets for 2020. By applying

[116] By the end of 2013, 32 GW of onshore wind power was installed in Germany (ISE (2014)).

[117] As explained, for example, in Deutsche Bank (2012), all onshore wind projects currently receive the same FIT level (initial payment) for the first five years of operation. Afterwards, sites with highest full load hours (FLH) are paid a lower FIT level for the remaining 15 years of the contract (base payment). Sites with lower FLH, in contrast, are paid the initial payment for a longer period of time before they decline to the base payment. The period for which wind turbines receive the initial payment is determined by comparing each project's FLH against a benchmark for the annual output (i.e., a reference yield).

an electricity system optimization model, we quantify the excess costs associated with (i) the technology-specific (but region-neutral) solar power target (of 52 GW), (ii) the technology-specific (but region-neutral) offshore wind power target (of 6.5 GW) and (iii) the technology- and region-specific target for onshore wind power in regions with comparatively high full load hours (of 50 GW).

The structure of the paper is as follows: Section 5.2 discusses the theoretical background regarding the cost-efficient achievement of renewable energy targets. Section 5.3 provides a numerical analysis of the economic inefficiency associated with Germany's renewable energy support scheme and its failure to incentivize renewable energy investments that are most attractive from an economic perspective. Section 5.4 draws conclusions and identifies a number of issues for further possible research.

5.2 Theoretical Background

Referring to the theoretical analysis of Chapter 4, fluctuating renewable energy units (C^f) are expanded up to the point at which their marginal costs (MC) correspond to the sum of their marginal value of power supply (MV^{el}) and their marginal value of renewable energy supply (MV^{ren}) in the optimum (see Eq. (5.1)).

$$MC_{C^f} = MV^{el}_{C^f} + MV^{ren}_{C^f} \tag{5.1}$$

While the MC are defined as the unit's accumulated annualized investment costs over all years of its technical lifetime, the MV^{el} of wind and solar power units corresponds to the accumulated revenue from selling electricity at the wholesale market in all hours and years of the unit's technical lifetime. The MV^{ren} of wind and solar power units, however, represents the accumulated value of the good 'green electricity' supplied by wind and solar power units during their technical lifetime under politically implemented RES-E targets. Alternatively, the MV^{ren} of wind and solar power units can be interpreted as the part of the MC that cannot be covered by the revenue from selling electricity on the wholesale market during the unit's technical lifetime (i.e., the MV^{el}) and thus need to be supplied by renewable energy support payments to incentivize investments. For the following discussion we define the difference between the MC and the MV^{el} as the net marginal costs NMC (see Eq. (5.2)).

$$MV^{ren}_{Cf} = MC_{Cf} - MV^{el}_{Cf} = NMC_{Cf} \tag{5.2}$$

Given a technology- and region-neutral RES-E target which prescribes the minimum amount of renewable energy generation (in kWh) (and not the minimum amount of renewable energy capacities (in kW)), the *NMC per kWh* are equalized across all renewable energy technologies and regions in the optimum (see Eq. (5.3)).[118] In the following, the *NMC per kWh* are denoted as $\overline{NMC}$. Equally, the *MC per kWh* are denoted as $\overline{MC}$ and the MV^{el} *per kWh* as $\overline{MV^{el}}$. [119]

$$\begin{aligned} &\overline{NMC}_{Cf1} = \overline{MC}_{Cf1} - \overline{MV^{el}}_{Cf1} \\ \overset{!}{=}\ &\overline{NMC}_{Cf2} = \overline{MC}_{Cf2} - \overline{MV^{el}}_{Cf2} \end{aligned} \tag{5.3}$$

Figure 5.1 (i) illustrates the cost-efficient renewable energy mix, which is achieved when the $\overline{NMC}$ are equalized across technologies and regions. For reasons of clarity, note that in Figure 5.1 (i) power generation of technology 1 (in region 1) increases from left to right, while power generation of technology 2 (in region 2) increases from right to left. While the $\overline{MC}$ are independent of the respective technology's penetration, the $\overline{NMC}$ increase with penetration. This is due to the fact that the $\overline{MV^{el}}$ decreases as the technology's penetration increases, which is shown in Chapter 4.[120] Technology 1 (in region 1) is associated with lower $\overline{MC}$ than technology 2 (in region 2) due to both lower investment costs and higher full load hours (FLH) than technology 2. However, the higher the penetration of technology 1 becomes, the lower its $\overline{MV^{el}}$ and thus the higher its $\overline{NMC}$ are. At some point of penetration of technology 1, technology 2 is thus associated with lower $\overline{NMC}$ than technology 1. Hence, even though technology 2 is associated with higher $\overline{MC}$ than technology 1, the cost-efficient renewable energy mix includes technology 2. The optimum, when $\overline{NMC}$ are equalized across technologies (and

[118] The term 'technology- and region-neutral' indicates that each kWh of renewable electricity produced contributes to achieving the RES-E target irrespective of the technology or the region of its deployment.

[119] The unit €/kWh is derived by dividing the $NMC/MC/MV^{el}$ by the accumulated full load hours over all years of the unit's technical lifetime.

[120] The assumption that the $\overline{MC}$ are independent of the respective technology's penetration level implies that no space potential restrictions are binding, i.e., that favorable locations with high full load hours (FLH) are not limited. If, however, locations with high FLH are limited, the $\overline{MC}$ would increase as the penetration increases since wind turbines/ solar power system would need to be deployed at locations with lower FLH.

regions), is (for example) achieved under a (technology- and region-neutral) renewable energy quota obligation in combination with tradable green certificates.

Figure 5.1 (ii) illustrates the excess costs arising when investment decisions are based on $\overline{MC}$ rather than on $\overline{NMC}$. Since technology 1 (in region 1) is associated with lower $\overline{MC}$ than technology 2 (in region 2), only technology 1 would be expanded which causes excess costs. This would, for example, be the case if renewable energy investments were promoted via a (technology- and region-neutral) feed-in tariff (FIT) system that fixes a price paid for renewable electricity and thus fails to incentivize investors to account for the $\overline{MV^{el}}$ of renewables which differs between technologies and regions. Rather than choosing the technology (in that region) with the lowest $\overline{NMC}$, profit maximizing investors are incentivized to build that technology (in that region) with the lowest $\overline{MC}$ under a FIT system.

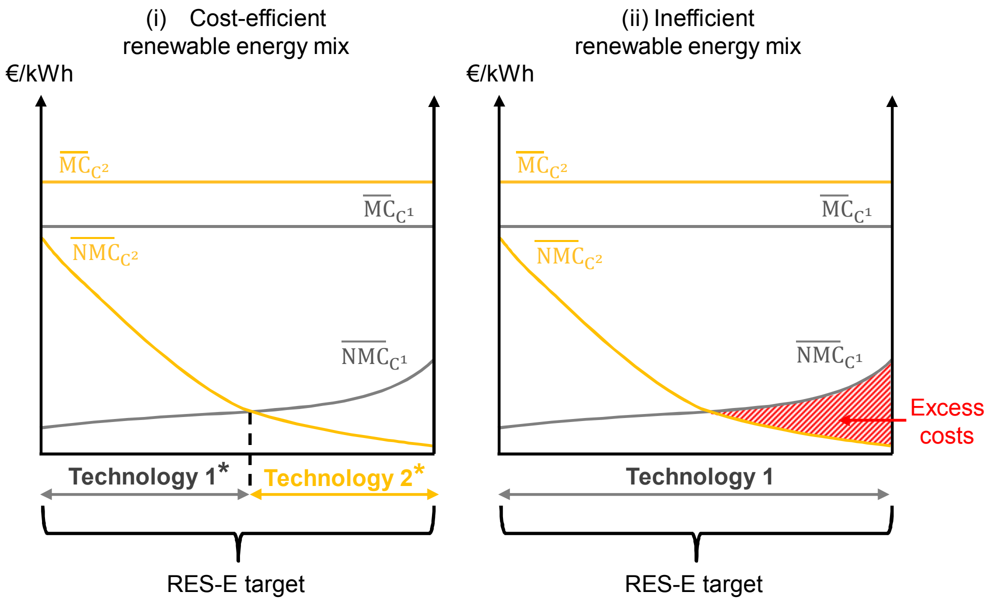


FIGURE 5.1: Cost-efficient renewable energy mix (i) vs. inefficient renewable energy mix (ii)

To summarize, politically implemented RES-E targets are achieved at minimal costs if the $\overline{NMC}$ across all renewable energy technologies and regions are equalized. Hence, we conclude that comparing the economic attractiveness of wind and solar power units (in different regions) on the basis of $\overline{MC}$ is incorrect, as doing so neglects the $\overline{MV^{el}}$ of the respective technology, which may be very different between technologies and regions. Instead, the economic attractiveness should be determined on the basis of the $\overline{NMC}$, i.e., the difference between the $\overline{MC}$ and the $\overline{MV^{el}}$. These results present an extension of the argumentation by Joskow (2011), who claims that comparing the economic attractiveness of fluctuating wind and solar power units to that of conventional dispatchable generation capacities based on the levelized costs of electricity (LCOE) is flawed since it fails to account for the fact that the value of electricity supplied (i.e., the wholesale price) varies over the course of the day and the year.

5.3 Numerical analysis for Germany

5.3.1 Electricity system optimization model

The electricity system optimization model used in this analysis is a linear investment and dispatch model, incorporating conventional, thermal, nuclear, storage and renewable technologies. The model is an extended version of the long-term investment and dispatch model of the Institute of Energy Economics (University of Cologne), as presented in Richter (2011). The possibility of endogenous investments in renewable energy technologies has been added to the investment and dispatch model through the work of Fürsch et al. (2013a), Jägemann et al. (2013a), Jägemann et al. (2013b) and Nagl et al. (2011a).

In the following, an overview of the applied electricity system optimization model is given, which has been adapted to accurately address the needs of the current analysis.

5.3.1.1 Technological resolution

The model incorporates investment and generation decisions for conventional power plants (potentially equipped with carbon capture and storage (CCS)), combined heat and power plants (CHP), nuclear, renewable energy and storage (pump, hydro and compressed air energy (CAES)). The expansion of interconnector capacities, which limit the inter-regional power exchange, is exogeneously defined. Several vintage classes for hard coal, lignite and natural gas-fired power plants represent today's power plant mix. With regard to renewable energy technologies, the model encompasses onshore and offshore wind power plants, PV systems, biomass (CHP-) power plants (solid and gas), hydro power plants, geothermal power plants and concentrating solar power (CSP) plants (including thermal energy storage devices). With respect to existing capacities of renewable energy technologies, the model considers all installations developed by the end of the year 2011.[121]

[121]Hence, all renewable energy capacity expansions after 2011 are endogenously determined by the model and do not necessarily correspond to the (real-world) capacity expansions actually realized in 2012 and 2013.

5.3.1.2 Regional resolution

The simulation is run for Germany and three neighboring countries that were considered most relevant for dispatch and investment decisions in Germany.[122] To account for local weather conditions, the model accounts for several subregions for wind and solar power within each country. In Germany, for example, two onshore wind, two offshore wind and two solar power subregions are modeled, each differing with regard to both the full load hours and the profile of the wind and solar power generation, as illustrated in Figure 5.2 and Table 5.1.[123]

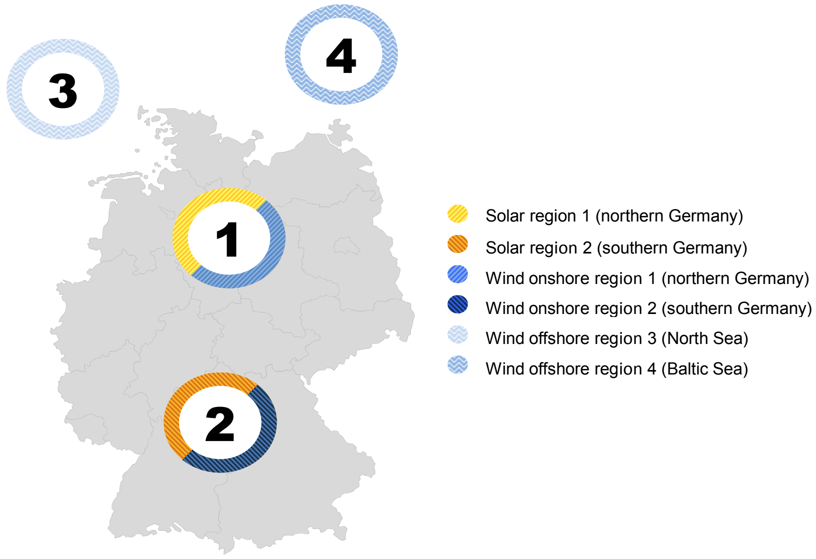


FIGURE 5.2: Modeled renewable energy regions

TABLE 5.1: Potential full load hours of wind and solar power plants

Solar power		Onshore wind power		Offshore wind power	
Region 1 (northern Germany)	Region 2 (southern Germany)	Region 1 (northern Germany)	Region 2 (southern Germany)	Region 3 (North Sea)	Region 4 (Baltic Sea)
992	1,084	1,528	1,448	3,423	3,349

Source: based on EuroWind (2011).

[122] Overall, we model Germany, Austria, France and the Netherlands. Given limited computational ressources, there is a trade-off between manageable calcualtion times on the one hand side and a high regional and temporal resolution on the other hand side. For the analysis of the marginal value of renewables, a high temporal resolution – which captures the fluctuating characteristic of wind and solar power supply – was considered more important than modeling a large number of countries (see Section 5.3.1.3).

[123] The wind and solar power generation profiles are based on historical hourly meteorological wind speed and solar radiation data from EuroWind (2011).

5.3.1.3 Temporal resolution

Investment and dispatch decisions are simulated in 5-year time steps until 2050. For the analysis, the daily and hourly temporal resolution of the model has been significantly increased. While previous analyses with this model (such as Jägemann et al. (2013a), Fürsch et al. (2013a) and Nagl et al. (2011a)) were based on 4-12 typical days per year (96-288 h) which were scaled to 365 days (8760 hours), the investment and dispatch decisions of this analysis are based on 42 typical days per year (or 1008 h), i.e., six weeks per year. The increased temporal resolution allows us to better capture the characteristics of the electricity demand and production factor profiles of wind and solar power units over the year, such as the correlation between the wind and the solar production factor profiles. At the same time, the chosen temporal resolution presents a trade-off between an accurate reproduction and manageable calculation times. Under the given regional and temporal resolution, the calculation time amounts to 44 hours.

The applied 42 days (i.e., six weeks) are based on historical hourly electricity demand profiles (ENSTO-E (2013)) as well as historical hourly electricity generation profiles of hydro, wind (on- and offshore) and solar power (PV and CSP) technologies for 8760 h per year (EuroWind (2011)). The six weeks were chosen as to reflect the following characteristics: the (potential) full load hours of wind and solar power turbines, the annual correlation between the wind and the solar production factor profiles as well as the annual correlation between the wind (solar) production profile and the demand profile.

5.3.1.4 Objective function and techno-economic constraints

The objective of the model is to minimize accumulated discounted total system costs, which include investment costs, fixed operation and maintenance (O&M) costs, variable production costs and costs due to ramping thermal power plants. The discount rate amounts to 5 % in the model.[124] Costs for new investments in generation and storage units and are annualized with a 5 % interest rate (nominal) for the depreciation time.

[124] The model's optimization premise (minimization of accumulated discounted total system costs) implies a cost-based competition of electricity generation and perfect foresight.

$$\min \quad TSC = \sum_{y\in Y}\sum_{c\in C}\sum_{a\in A}(disc_y \cdot (AD_{y,a,c} \cdot an_a \cdot ic_a + IN_{y,a,c} \cdot fc_a \tag{5.4}$$

$$+\sum_{h\in H}(GE_{y,h,a,c} \cdot (\frac{fu_{y,a}}{\eta_a}) + CU_{y,h,a,c} \cdot (\frac{fu_{y,a}}{\eta_a} + ac_a) - GE_{y,h,a,c} \cdot hr_a \cdot hp_y)))$$

$$disc_y = \frac{1}{(1+dr)^{y-y_{start}}} \tag{5.5}$$

$$an_a = \frac{(1+ir)^{dp_a \cdot ir}}{(1+ir)^{dp_a}-1} \tag{5.6}$$

The accumulated discounted total system costs are minimized, subject to several techno-economic constraints:

s.t.

$$\sum_{a\in A} GE_{y,h,a,c} + \sum_{c'\in C} IM_{y,h,c,c'} - \sum_{s\in A} ST_{y,h,s,c} = d_{y,h,c} \tag{5.7}$$

$$GE_{y,h,a,c} \leq av_{d,h,a,c} \cdot IN_{y,a,c} \tag{5.8}$$

$$GE_{y,h,a,c} \geq ml_a \cdot av_{h,a,c} \cdot IN_{y,a,c} \tag{5.9}$$

$$CU_{y,h,a,b} \leq \frac{IN_{y,a,c} - CR_{y,h,a,c}}{st_a} \tag{5.10}$$

$$CR_{y,h,a,c} \leq av_{h,a,c} \cdot IN_{y,a,c} \tag{5.11}$$

$$\sum_{h\in H} \frac{GE_{y,h,a,c}}{\eta_a} \leq fp_{y,a,c} \tag{5.12}$$

$$AD_{y,r,c} = \sum_{e\in E} AD_{y,r,c,e} \tag{5.13}$$

$$IN_{y,r,c} = \sum_{e\in E} IN_{y,r,c,e} \tag{5.14}$$

$$GE_{y,h,r,c} = \sum_{e\in E} GE_{y,h,r,c,e} \tag{5.15}$$

$$\sum_{h\in H}\sum_{r\in A}\sum_{e\in E} GE_{y,h,r,c,e} \geq x_{y,c} \tag{5.16}$$

$$\sum_{h\in H}\sum_{e\in E} GE_{y,h,r,c,e} \geq xx_{y,r,c} \tag{5.17}$$

$$\sum_{h\in H} GE_{y,h,r,c,e} \geq xxx_{y,r,c,e} \tag{5.18}$$

$$\sum_{a\in A}\sum_{c\in C}\sum_{h\in H} \frac{GE_{y,h,a,c}}{\eta_a} \cdot ef_a \leq cc_y \tag{5.19}$$

Table 5.2: Sets and parameters of the electricity system optimization model

Abbreviation	Dimension	Description
Model sets		
a ∈ A		Technologies
s ∈ A	Subset of a	Storage technologies
r ∈ A	Subset of a	RES-E technologies
c ∈ C (alias c')		Market region
e ∈ E		Subregion within a market region (for RES-E technologies)
h ∈ H		Hours
y ∈ Y		Years
y_{start} ∈ Y		Starting year (2010)
Model parameters		
ac_a	[€$_{2010}$ /MWh_{el}]	Attrition costs for ramp-up operation
an_a		Annuity factor for technology-specific investment costs
$av_{h,a,c}$	[%]	Availability
cc_y	[t CO_2]	Cap for CO_2 emissions
$d_{y,h,c}$	[MW]	Total demand
$disc_y$		Discount factor
dr	[%]	Discount rate (5 %)
dp_a	[years]	depreciation period
ef_a	[t CO_2 /MWh_{th}]	CO_2 emissions per fuel consumption
fc_a	[€$_{2010}$/MW]	Fixed operation and maintenance costs
$fu_{y,a}$	[€$_{2010}$/MWh_{th}]	Fuel price
$fp_{y,a,c}$	[MWh_{th}]	Fuel potential
hp_y	[€$_{2010}$/MWh_{th}]	Heating price for end-consumers
hr_a	[MWh_{th}/MWh_{el}]	Ratio for heat extraction
ir	[%]	Interest rate (5 %)
ic_a	[€$_{2010}$/MW]	Investment costs
ml_a	[%]	Minimum part load level
$x_{y,c}$	[MWh]	Technology- and region-neutral RES-E target
$xx_{y,r,c}$	[MWh]	Technology-specific but region-neutral RES-E target
$xxx_{y,r,c,e}$	[MWh]	Technology- and region-specificl RES-E target
st_a	[h]	Start-up time from cold start
η_a	[%]	Net efficiency (generation)
$\alpha_{a,h}$	[%]	Capacity factor

Power balance constraint (Eq. (5.7)): The match of electricity demand and supply needs to be ensured in each hour and country, taking storage options and inter-regional power exchange into account.

TABLE 5.3: Variables of the electricity system optimization model

Abbreviation	Dimension	Description
Model variables		
$AD_{y,a,c}$	[MW]	Commissioning of new power plants
$AD_{y,r,c,e}$	[MW]	Commissioning of a new RES-E technology r in subregion e
$CU_{y,h,a,c}$	[MW]	Capacity that is ramped up within one hour
$CR_{y,h,a,c}$	[MW]	Capacity that is ready to operate
$FLH_{y,r,c,e}$	[h]	(Actual) annual full load hours of a RES-E technology r in subregion e
$GE_{y,h,a,c}$	[MW_{el}]	Electricity generation
$GE_{y,h,r,c,e}$	[MW_{el}]	Electricity generation of a RES-E technology r in subregion e
$O_{s,y,h,i}$	[MW]	Consumption in storage operation
$IM_{y,h,c,c'}$	[MW]	Net imports
$IN_{y,a,c}$	[MW]	Installed capacity
$IN_{y,r,c,e}$	[MW]	Installed capacity of a RES-E technology r in subregion e
$ST_{y,h,s,c}$	[MW]	Consumption in storage operation
TSC	[€$_{2010}$]	Accumulated and discounted total system costs

Capacity constraint (Eq. (5.8)):The maximum electricity generation by dispatchable power plants (thermal, nuclear, storage, biomass and geothermal power plants) per hour is restricted by their seasonal availability (which is limited due to unplanned or planned shutdowns, e.g., because of repairs), while the availability of wind and solar power plants is given by the maximum possible electricity feed-in per hour. The maximum transmission capability per hour between two neighboring countries is given by the net transfer capacities.

Minimum load constraint (Eq. (5.9)): The minimum electricity generation per hour of dispatchable power plants is given by their minimum part-load level.

Ramp-up constraints (Eqs. (5.10) and (5.11)): The start-up time of dispatchable power plants limits the maximum amount of capacity ramped up within an hour.

Fuel potential constraint (Eq. (5.12)): The fuel use is restricted to a yearly potential in MWh_{th} per country, with different potentials applying for lignite, solid biomass and (low-cost) gaseous biomass sources.

In addition to techno-economic constraints, various politically implemented restrictions can be modeled:

Technology- and region-neutral renewable energy constraint (Eq. (5.16)): A certain amount of electricity per year y and market region c ($x_{y,c}$) needs to be supplied by renewable energy resources irrespective of the RES-E technology r used to produce electricity or the region of its deployment, i.e., the subregion e within the market region c.

Technology-specific but region-neutral renewable energy constraint (Eq. (5.17)): A certain amount of electricity per year y and market region c ($\mathrm{xx}_{y,r,c}$) needs to be supplied by a specific RES-E technology r irrespective of the region of its deployment, i.e., the subregion e within the market region c.

Technology- and region-specific renewable energy constraint (Eq. (5.18)): A certain amount of electricity per year y and market region c ($\mathrm{xxx}_{y,r,c,e}$) needs to be supplied by a specific RES-E technology r in a specific subregion e.

CO_2 emission constraint (Eq. (5.19)): The accumulated CO_2 emissions (of all modeled market regions c) may not exceed a certain CO_2 cap per year (cc_y).[125]

In contrast to other applications of the model (e.g., Jägemann et al. (2013a) and Jägemann et al. (2013b)), neither a space potential constraint for wind and solar power units nor a security of supply constraint is implemented in this analysis. The space potential constraint (which restricts the deployment of wind and solar power technologies per region by area potentials in km^2 per subregion) is disregarded in order to prevent any distortion of the model's economic investment calculus. For example, the switch between technologies (e.g., from wind to solar power) or regions (e.g., from northern Germany to southern Germany) should be driven solely by economic reasons (comparison of net marginal costs per kWh ($\overline{NMC}$)) rather than the fact that the maximum area potential of a specific technology within a region has been reached (which prohibits further capacity expansions).

The abandonment of the security of supply constraint is motivated by the aim to keep the analysis of the net marginal costs of wind and solar power capacity additions as close to the theoretical model as possible.[126] As explained in Jägemann et al. (2013b), the shadow variable of the security of supply constraint reflects the system's marginal costs associated with supplying securely available capacities. It typically serves as a proxy for the capacity price which producers receive for their efforts in ensuring security of supply. Given the usual assumption of a positive capacity credit of wind power

[125] The approach of modeling a quantity-based regulation (CO_2 cap) rather than a price-based regulation (CO_2 price) ensures that the CO_2 emissions reduction target is met in all scenarios simulated, which allows the results to be compared to one another. It reflects the market outcome of a CO_2 cap-and-trade system.

[126] The security of supply constraint prescribes that the peak demand level is met by securely available capacities. Whereas the securely available capacity of dispatchable power plants within the peak-demand hour is assumed to correspond to their seasonal availability, the securely available capacity of fluctuating wind and solar power plants within the peak-demand hour is assumed to amount to the unit's capacity credit, which typically varies between 0 % and 10 % (e.g., Jägemann et al. (2013b)).

plants (see, e.g., Jägemann et al. (2013a)), wind power generators would receive a third revenue stream from the reserve market by offering securely available capacity. Hence, in a addition to the marginal value of power supply (MV^{el}), the marginal value for offering securely available capacity would also need to be considered. Moreover, a security of supply constraint is typically only implemented in models in which the annual dispatch is simplified to a very limited amount of typical days, which leads to the problem that potential peak demand is not considered as a dispatch situation in the investment part of the model.[127] In this analysis, however, the investment and dispatch decisions are based on 42 typical days per year, which account for peak demand as a dispatch situation.

The numerical model assumptions are listed in Table D.2 - D.8 of the Appendix.

5.3.1.5 Quantification of variables used to illustrate the economic inefficiency associated with technology- and region-specific RES-E targets

In the following, we shortly describe how the $\overline{MC}$, the $\overline{MV^{el}}$ and the $\overline{NMC}$ are quantified, which are used to illustrate the economic inefficiency associated with technology- and region-specific RES-E targets for the example of wind and solar power in Germany.

- The $\overline{MC}$ of wind and solar power units r in subregion e of market region c are calculated by dividing the unit's accumulated and discounted ($disc_y$) annualized investment costs (ic_r) and fixed O&M costs (fc_r) by the unit's accumulated (actual) annual full load hours ($\mathrm{FLH}_{y,r,c,e}$) during all years of its technical lifetime (Eq. (5.20)). We note that the difference between the potential FLH (see Table 5.1) and the actual FLH (see Table 5.7) of wind and solar power units corresponds to the endogenous wind and solar power curtailment in the model. Hence, the higher the curtailment of wind and solar power units becomes, the lower their actual FLH and thus the higher their $\overline{MC}$ will be.

$$\overline{MC_{r,c,e}} = \frac{\sum_{y\in Y} disc_y \cdot AD_{y,r,c,e} \cdot (an_r \cdot ic_r + fc_r)}{\sum_{y\in Y} FLH_{y,r,c,e}} \tag{5.20}$$

- The $\overline{MV^{el}}$ of wind and solar power units r deployed in subregion e of market region c are calculated by dividing the unit's accumulated and discounted revenue from

[127]For example, the model applied in Jägemann et al. (2013a) and Jägemann et al. (2013b) accounts for a peak capacity constraint as it simulates the dispatch of only 4 and 8 typical days, respectively.

selling electricity ($GE_{y,h,r,c,e}$) on the wholesale market by the unit's accumulated (actual) annual full load hours ($\mathrm{FLH}_{y,r,c,e}$) during all years of its technical lifetime (Eq. (5.21)). The shadow variable of the power balance constraint (see Eq. (5.7)), which reflects the discounted system costs associated with supplying an additional unit of electricity at a specific point in time, serves as a proxy for the (discounted) hourly revenue, i.e., the (discounted) hourly wholesale price ($\mu_{y,h}$).[128]

$$\overline{MV^{el}_{r,c,e}} = \frac{\sum_{y \in Y} \sum_{h \in H} (GE_{y,h,r,c,e} \cdot \mu_{y,h})}{\sum_{y \in Y} FLH_{y,r,c,e}} \tag{5.21}$$

- The $\overline{NMC}$ of wind and solar power units deployed in Germany correspond to the difference between the $\overline{MC}$ and the $\overline{MV^{el}}$ (Eq. (5.22)). As such, the $\overline{NMC}$ reflect the (accumulated and discounted) markup on the $\overline{MV^{el}}$ that is needed in order for the last renewable energy capacity (that is built to achieve the RES-E target) to cover its costs. Under a technology- and region-neutral RES-E target, $\overline{NMC}$ are equalized across wind and solar power technologies and regions, which indicates that a cost-efficient renewable energy mix is achieved (see Section 5.2). In contrast, under a technology- and/ or region-specific RES-E target, $\overline{NMC}$ differ between technologies and regions, which implies that excess costs occur.[129]

$$\overline{NMC_{r,c,e}} = \overline{MC_{r,c,e}} - \overline{MV^{el}_{r,c,e}} \tag{5.22}$$

In the following, we quantify the excess costs associated with Germany's technology- and region-specific wind and solar power targets for 2020. Since this requires the consideration of all cost and revenue streams throughout the technical lifetime of the wind and solar power units deployed in Germany by 2020 the model is run up to the year 2050.[130]

[128] We note that the objective of the model is to minimize accumulated discounted total system costs.

[129] We note that under a technology- and region-neutral renewable energy RES-E target, the marginal of the technology- and region-neutral renewable energy constraint (Eq. (5.16)) corresponds to the $\overline{NMC}$. Equally, under a technology- and region-specific RES-E target, the marginal of the technology- and region-specific renewable energy constraint (Eq. (5.18)) corresponds to the $\overline{NMC}$ of the respective RES-E technology deployed in the respective subregion.

[130] The technical lifetime of both wind and solar power capacities is assumed to amount to 20 years in this analysis.

5.3.2 Scenario definitions

To analyze the economic inefficiency associated with Germany's technology-and region-specific wind and solar power targets for 2020, two scenarios are defined (see Table 5.6).

Both scenarios assume a CO_2 emission constraint (Eq. (5.19)), which limits the combined CO_2 emissions of all modeled countries per year (see Table 5.4) in order to incorporate the target of the European Union (EU) to reduce greenhouse gas (GHG) emissions by 80 % - 95 % in 2050 compared to 1990 levels (EU Council (2009)). As a consequence of the CO_2 emission constraint, the short-run marginal production costs of fossil-fuel fired (CO_2 -emitting) power plants increase.[131] This, in turn, leads to an increase in the shadow variable of the power balance constraint (see Eq. (5.7)), which indicates the system's marginal costs associated with meeting the hourly electricity demand and serves as a proxy for the (discounted) hourly wholesale price. As a consequence, the $\overline{MV^{el}}$ of renewable energy technologies increases in comparison to a scenario without a CO_2 emission constraint.

Moreover, in both scenarios, Germany is assumed to achieve the technology- and region-neutral RES-E targets for 2025 and 2035 defined in the coalition agreement from November 2013 (i.e., 40 - 45 % of gross electricity demand by 2025 and 55 - 60 % by 2035).[132]

Table 5.4: CO_2 reduction targets compared to 1990 levels

2020	2025	2030	2035	2040	2045	2050
30 %	40 %	50 %	58 %	65 %	73 %	80 %

Table 5.5: Technology- and region-neutral RES-E targets

2025	2030	2035
40 %	48 %	55 %

As illustrated in Table 5.6, the target year 2020 differs for each scenario. The 'EEG Scenario' reflects the current technology- and region-specific design of the German promotion scheme for wind and solar power technologies. It assumes technology-specific

[131] The increase in the short-run marginal costs of power production of fossil-fuel fired (CO_2 -emitting) power plants arises from incorporating the costs of emitting CO_2 , reflected by the price of CO_2 emission certificates.

[132] We note that the modeled technology- and region-neutral RES-E targets for 2025 (40 %) and 2035 (55 %) (see Table 5.5) cover wind and solar power generation only. This reflects the assumption that wind and solar power are expected to account for the largest share of renewable energy capacity additions up to 2035, given the limited potentials for hydro power and low-cost biomass resources in generating electricity. Moreover, we note that the modeled RES-E targets (40 % in 2025 and 55 % in 2035) are related to the net electricity demand, while the German RES-E targets for 2025 (40 - 45 %) and 2035 (55 - 60 %) are related to the gross electricity consumption (CDU/CSU/SPD (2013)).

(but region-neutral) solar and offshore wind power targets (56 TWh and 22 TWh, respectively), as well as technology- and region-specific onshore wind power targets for northern Germany (73 TWh) by 2020.[133] The technology- and region-specific onshore wind power targets for northern Germany (region 1) are motivated by the fact that under the current reference yield model, only projects in favorable wind regions (with high full load hours) can be operated profitably (CDU/CSU/SPD (2013)), which are primarily located in northern Germany.

Table 5.6: Scenario definitions: Targets for 2020 [TWh]

	EEG Scenario	Efficient Scenario
Technology-specific (but region-neutral) solar power target	56 TWh -	-
Technology-specific (but region-neutral) offshore wind power target	22 TWh	-
Technology- and region-specific onshore wind power target in northern Germany	76 TWh	-
Technology- and region-neutral RES-E target	-	154 TWh

In the 'Efficient Scenario', in contrast, a technology- and region-neutral RES-E target for 2020 is implemented. As illustrated in Table 5.6, the technology- and region-neutral RES-E target assumed for 2020 amounts to 154 TWh, which corresponds to the sum of the technology- and region-specific wind and solar power targets for 2020 assumed in the 'EEG Scenario'. As such, in both scenarios the same level of total wind and solar power generation (i.e., 154 TWh) is achieved in 2020. However, in contrast to the 'Efficient Scenario', the technological (and regional) mix of wind and solar power generation is predefined in the 'EEG Scenario' via technology-specific (and region-specific) wind and solar power targets.

The chosen scenario definition aims to quantify the economic inefficiency associated with Germany's technology- and region-specific wind and solar power targets for 2020. It needs to be stressed that the results derived by modeling technology- and region-neutral RES-E targets (i.e., by implementing renewable energy constraints as explained in Section 5.3.1.4) do not reflect the market result of a feed-in tariff system. For this, the applied electricity system model would need to maximize profits instead of minimizing total system costs. This can best be explained by the following example: Under a technology-specific FIT system and the choice between two regions, profit maximizing investors do not account for differences in the $\overline{MV^{el}}$ of the specific technology between

[133] The TWh targets are derived by multiplying the 2020 capacity targets for solar power (52 GW), onshore wind power (50 GW) and offshore wind power (6.5 GW) with the full load hours assumed in the model; see also Table D.1 of the Appendix.

two regions, but rather choose the region with the highest full load hours and thus the lowest $\overline{MC}$.[134] However, when modeling technology-specific RES-E targets in an electricity system optimization model that minimizes total system costs (rather than maximizing investors' profits), the investment decisions are always based on $\overline{NMC}$, i.e., on a comparison between the respective technology's $\overline{MC}$ and $\overline{MV^{el}}$. Hence, electricity system models that minimize total system costs are not capable of simulating the market result of feed-in tariff systems.

In the following, the scenario results are discussed.

5.3.3 Scenario results

Figure 5.3 illustrates the development of the capacity and generation mix in the 'EEG Scenario' and the 'Efficient Scenario' up to 2030.[135] In both scenarios, baseload capacities/ generation (lignite, coal and nuclear) decrease, while peak-load capacities/ generation (gas) increase, as the wind and solar power penetration increases.[136] Moreover, in both scenarios, the total dispatchable capacity stays essentially equal to the peak demand level, reflecting the model assumption of comparatively low wind and solar power generation (i.e., a low production factor) at times of peak demand. These results are in line with Lamont (2008) who showed that baseload capacities/generation decline in proportion to the increase in fluctuating wind and solar power capacities/ generation, while the intermediate capacity/ generation increases with increased wind and solar power penetration.[137]

In the 'EEG Scenario', Germany achieves commitment with its (region-neutral) solar and offshore wind power targets (56 TWh and 22 TWh, respectively) and its (region-specific) onshore wind power target for northern Germany (region 1) of 76 TWH by 2020. In the 'Efficient Scenario', which assumes a technology- and region-neutral RES-E target for 2020 (154 TWh), only onshore wind power investments in northern Germany (region 1) take place up to 2020, supplying in total 113 TWh in 2020. This highlights the comparative cost advantage of onshore wind power generation over offshore wind and solar power generation in reaching politically implemented RES-E targets by 2020.

[134] Note that the $\overline{MV^{el}}$ of a specific technology varies between the two regions because of both differences in the level of full load hours and differences in the production factor profile.

[135] The development of the capacity and generation mix up to 2050 is shown in Figure D.1 of the Appendix.

[136] We note that the nuclear capacities are exogenously decommissioned in the model by 2022 reflecting current legislation in Germany.

[137] Lamont (2008) applies an illustrative optimization model to determine the cost-efficient capacity mix for five technologies (baseload, intermediate and peaking generators along with wind and solar power) using a greenfield approach to examine the effects of increased wind and solar power penetration.

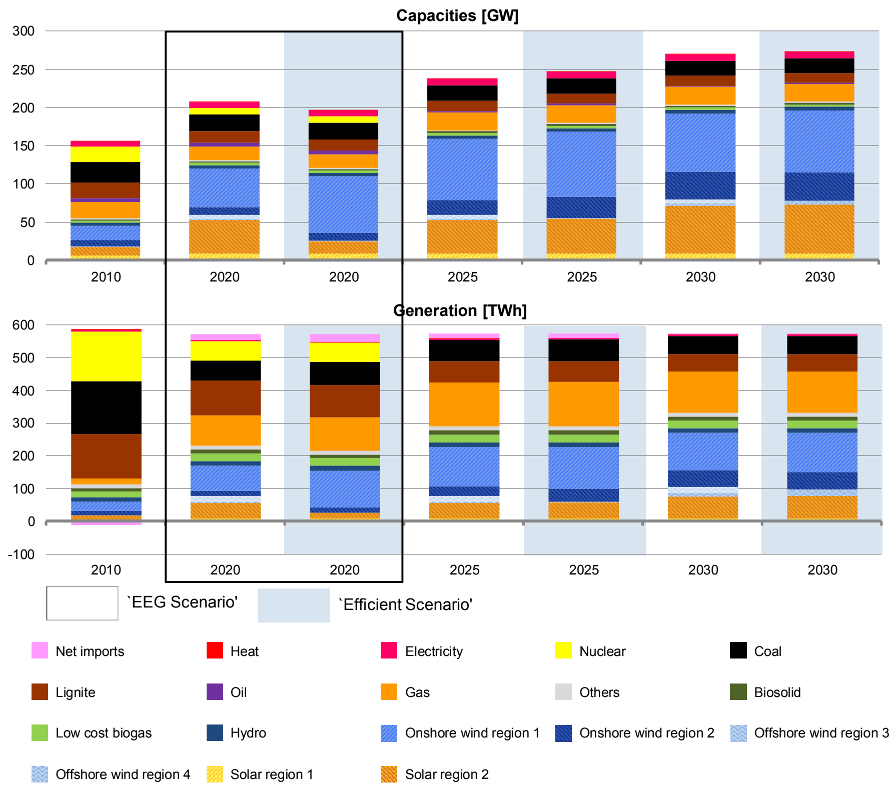


FIGURE 5.3: Development of Germany's capacity [GW] and generation [TWh] mix up to 2030

The high economic attractiveness of onshore wind power in comparison to solar power and offshore wind power up to 2020 also becomes evident when comparing the net marginal costs per kWh ($\overline{NMC}$). Figure 5.4 illustrates the $\overline{NMC}$ of all renewable energy capacities built in 2020, 2025 and 2030 in the 'EEG Scenario' and the 'Efficient Scenario'. We note that the scenarios differ only with regard to the RES-E targets for 2020, which are either technology- and region-specific ('EEG Scenario') or technology- and region-neutral ('Efficient Scenario'). For the years 2025 and 2030, however, both scenarios assume the same technology- and region-neutral RES-E target of 40 % and 48 % respectively (see Table 5.5).

In the 'EEG Scenario', $\overline{NMC}$ are not equalized across RES-E technologies and regions in 2020, which implies that the cost-efficient renewable energy mix is not achieved. As can be seen, all technologies differ with regard to both their $\overline{MC}$ – which depend on the technology's capital costs and full load hours – and their $\overline{MV^{el}}$ – which depends on the unit's revenue from selling electricity at the wholesale market. As such, the $\overline{MV^{el}}$ is driven by the unit's electricity generation profile or, more specifically, by the correlation between the unit's hourly production factor profile and the wholesale price profile (i.e., the unit's 'price matching' or 'residual-load matching' capability), see also Chapter 4 .

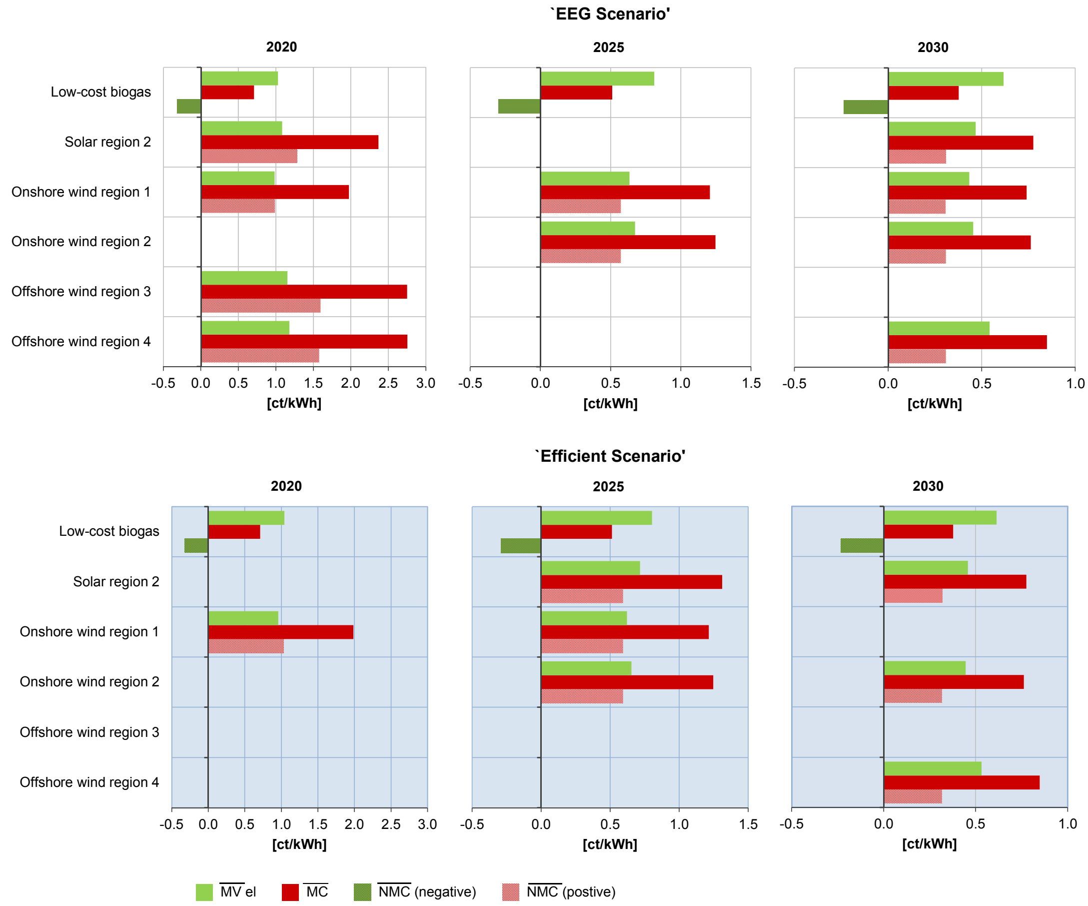


FIGURE 5.4: $\overline{MC}$, $\overline{MV^{el}}$ and $\overline{NMC}$ of RES-E technologies built in 2020, 2025 and 2030 (discounted with 5 %)

Offshore wind power (in the North Sea (region 3) and Baltic Sea (region 4)) exhibits by far the highest $\overline{MC}$ (2.75 €ct$_{2010}$/kWh), followed by solar power (2.37 €ct$_{2010}$/kWh in southern Germany (region 2)), onshore wind power (1.97 €ct$_{2010}$/kWh in northern Germany (region 1)) and low-cost biogas power plants (0.71 €ct$_{2010}$/kWh). However, offshore wind power is also characterized by the highest $\overline{MV^{el}}$ (1.15 €ct$_{2010}$/kWh in the North Sea and 1.18 €ct$_{2010}$/kWh in the Baltic Sea), followed by solar power in southern Germany and onshore wind power in northern Germany (1.08 €ct$_{2010}$/kWh and 0.98 €ct$_{2010}$/kWh, respectively). Dispatchable (low-cost) biogas power plants exhibit a $\overline{MV^{el}}$ of 1.03 €ct$_{2010}$/kWh. Overall, it can be seen that the difference in the $\overline{MC}$ between technologies (and regions) is more pronounced than the difference in the $\overline{MV^{el}}$ between technologies (and regions) in 2020. This effect, however, diminishes over time since wind and solar power capacities are assumed to realize investment cost reductions, which are relatively higher for the less mature technologies (solar power and offshore wind power) than for onshore wind power which is a comparatively mature technology (see also Table D.4 of the Appendix).[138]

In sum, offshore wind power capacities (built to achieve commitment with the offshore wind power target by 2020) are associated with the highest $\overline{NMC}$ (1.60 €ct$_{2010}$/kWh in the North Sea and 1.57 €ct$_{2010}$/kWh in the Baltic Sea), which arises from the comparatively high capital costs of offshore wind turbines which include the costs of the onshore grid connection (see Table D.4 of the Appendix). Solar power capacities (built in order to achieve the solar power target by 2020) exhibit the second highest $\overline{NMC}$ (1.28 €ct$_{2010}$/kWh in southern Germany), followed by onshore wind power (0.99 €ct$_{2010}$/kWh in northern Germany). Hence, the $\overline{NMC}$ of onshore wind power capacties (built to achieve commitment with the onshore wind power target for northern Germany by 2020) are 38 % lower than the $\overline{NMC}$ of offshore wind power units and 23 % lower than the $\overline{NMC}$ of solar power units. Interestingly, these differences in the $\overline{NMC}$ in the 'EEG Scenario' by 2020 are primarily driven by a comparatively wide divergence of the $\overline{MC}$ between the technologies (rather than by a wide divergence of the $\overline{MV^{el}}$).

In contrast to wind and solar power technologies, which face no space potential constraints in the model, biomass (low-cost biogas and biosolid) generation is restricted by a fuel potential constraint. As a consequence, low-cost biogas generators are able to earn (windfall) profits (i.e., negative $\overline{NMC}$ of -0.32 €ct$_{2010}$/kWh). As explained in Section 5.3.1.4, space potential constraints for wind and solar power are explicitly disregarded in the model in order to prevent distortions of the economic calculus. However, if we would have accounted for space potential constraints, also wind and solar power generators would be able to earn (windfall) profits in those regions where the space potential constraint is binding. As such, binding space potential constraints for wind and solar power would prevent an equalization of $\overline{NMC}$ across technologies and regions. More specifically, those technologies which are characterized by binding space potential constraints would be able to earn windfall profts, i.e., their $\overline{MV^{el}}$ would exceed their $\overline{MC}$.

In the 'Efficient Scenario', commitment with the technology- and region-neutral RES-E target for 2020 is achieved with onshore wind power capacity expansions in northern Germany. The $\overline{NMC}$ amount to 1.03 €ct$_{2010}$/kWh. The difference in the $\overline{NMC}$ of onshore wind power in northern Germany between the 'EEG Scenario' (0.99 €ct$_{2010}$/kWh) and the 'Efficient Scenario' (1.03 €ct$_{2010}$/kWh) by 2020 is due to the fact that the onshore wind power penetration in northern Germany is higher in the 'Efficient Scenario' (74 GW or 113 TWh) than in the 'EEG Scenario' (50 GW or 76 TWh), which implies that the $\overline{MV^{el}}$ of an additional onshore wind power unit in northern Germany is lower

[138]Between 2020 and 2050, solar power and offshore wind power investment costs are assumed to decrease by 31 % and 38 %, respectively, while onshore wind power investment costs are assumed to decrease by only 11 %.

in the 'Efficient Scenario' than in the 'EEG Scenario'. This result reflects the finding of the numerical 'ceteris paribus' example of Chapter 4 , i.e., the MV^{el} and thus also the $\overline{MV^{el}}$ of wind power decrease as penetration increases.

As can be seen in comparing the development of $\overline{MV^{el}}$ over time in Figure 5.4, the $\overline{MV^{el}}$ of wind and solar power capacities decreases as penetration increases. This is also in line with the results of the numerical 'ceteris paribus' example of Chapter 4. However, there are several differences between the numerical 'ceteris paribus' example of Chapter 4 and this scenario analysis, which are shortly described. First, in contrast to the numerical 'ceteris paribus' example which uses the revenue from selling electricity on the wholesale market within one year (8760 hours) as a proxy for the MV^{el} of wind and solar power units, the $\overline{MV^{el}}$ derived using the electricity system optimization model corresponds to the accumulated and discounted revenue per kWh from selling electricity on the wholesale market during all hours and years of the unit's technical lifetime (20 years). Second, the $\overline{MV^{el}}$ determined with the electricity system optimization model accounts for an optimal adaptation of the electricity system over time as wind and solar power penetration increases. Third, the scenario analysis examined with the electricity system optimization model also accounts for endogenous curtailment of wind and solar power generation, which also differentiates our scenario analysis from that of Lamont (2008).

As illustrated in Table 5.7, the actual full load hours (FLH) vary across the years in both scenarios.[139] In contrast to the potential FLH shown in Table 5.1, the actual FLH account for wind and solar power curtailment.

Interestingly, while onshore wind power investments up to 2020 are only located in northern Germany (region 1), onshore wind turbines built from 2020 onwards are primarily deployed in southern Germany (region 2), although southern Germany (region 2) is associated with lower (potential) full load hours (FLH) and thus higher $\overline{MC}$.[140] This illustrates the benefit of regional diversification. The significant expansion of onshore wind power in northern Germany in 2020 causes the $\overline{MV^{el}}$ of an additional onshore wind power unit in northern Germany to decrease.[141] As a consequence, the comparative cost advantage of onshore wind power in northern Germany over onshore wind power in southern Germany – which was originally driven by higher potential FLH and thus lower $\overline{MC}$ – diminishes. In fact, at some penetration level of onshore wind power in northern Germany, onshore wind power in southern Germany begins to have a comparative cost advantage over onshore wind power in northern Germany. Hence, investments in onshore

[139]The amount of wind and solar power curtailment in GWh is shown in Table D.9 of the Appendix.
[140]See Table 5.1 and Figure 5.3.
[141]We note that all wind turbines within a region are assumed to have the same production factor profile.

TABLE 5.7: Actual annual full load hours of wind and solar power plants [h]

	2020	2025	2030	2035	2040	2045	2050
	'EEG Scenario'						
Onshore wind power region 1	1,528	1,510	1,484	1,478	1,479	1,519	1,491
Onshore wind power region 2	1,440	1,448	1,446	1,445	1,445	1,448	1,444
Offshore wind power region 3	3,420	3,418	3,409	3,249	3,268		3,420
Offshore wind power region 4	3,349	3,349	3,344	3,345	3,342	3,349	3,348
Solar power region 1	992	991	990	962	964		
Solar power region 2	1,084	1,084	1,084	1,084	1,084	1,084	1,084
	'Efficient Scenario'						
Onshore wind power region 1	1,525	1,499	1,480	1,465	1,463	1,519	1,496
Onshore wind power region 2	1,448	1,448	1,447	1,444	1,444	1,448	1,444
Offshore wind power region 3	3,418	3,338	3,243	3,149			3,420
Offshore wind power region 4	3,349	3,234	3,344	3,341	3,343	3,349	3,347
Solar power region 1	992	988	980	943	957		
Solar power region 2	1,084	1,084	1,084	1,084	1,084	1,084	1,084

wind power turbines in southern Germany become efficient, although southern Germany exhibits lower potential FLH and thus higher $\overline{MC}$ than onshore wind power turbines in northern Germany.[142] This is due to the fact that the production factor profile of onshore wind turbines in southern Germany is characterized by a higher price-matching (or residual-load matching) capability than the production factor profile of onshore wind turbines in northern Germany – given the comparatively large penetration of onshore wind power in northern Germany and the associated short-term merit-order effect. As a consequence, the $\overline{MV^{el}}$ of onshore wind turbines in southern Germany exceeds the $\overline{MV^{el}}$ of onshore wind turbines in northern Germany, which compensates for the higher $\overline{MC}$ in southern Germany. A second factor which deteriorates the economic attractiveness of additional onshore wind power capacities in northern Germany (as penetration increases) is the increasing curtailment of onshore wind power in northern Germany, which reduces the actual FLH (see Table 5.7). As a consequence, the difference in the (actual) FLH between onshore wind power in northern and southern Germany diminishes. Moreover, the $\overline{MC}$ of onshore wind power in northern Germany increases.

In addition to onshore wind power, solar power is also expanded in southern Germany

[142]The potential FLH of onshore wind power plants in southern Germany are assumed to be more than 5 % lower than the potential FLH of onshore wind power in southern Germany.

(region 2) under the technology- and region-neutral RES-E target by 2025 despite comparatively high $\overline{MC}$ (see Figure 5.3). This reflects the benefit of technological diversification in reaching politically implemented RES-E targets. Overall, onshore wind and solar power capacity expansions in 2025 take place up to the point at which the $\overline{NMC}$ are equalized (see Figure 5.4), which is in line with the economic theory discussed in Section 5.2. The same holds true for the year 2030, in which the $\overline{NMC}$ are equalized across solar power, onshore wind power and offshore wind power units.

As a consequence of the technology- and region-specific RES-E targets for 2020 – which prevent the equalization of the $\overline{NMC}$ across renewable energy technologies and regions (see Figure 5.4) – excess costs of 6.6 Bn €$_{2010}$ occur. These are defined by the difference in accumulated discounted system costs between the 'EEG Scenario' and the 'Efficient Scenario'.

The comparison of $\overline{NMC}$ between technologies and regions in 2020 shows that excess costs are driven by the technology-specific offshore wind and solar power targets for 2020 (of 22 and 56 TWh, respectively). Although the onshore wind power penetration is much higher in 2020 than the offshore wind and solar power penetration in the 'EEG Scenario' (in terms of TWh), $\overline{NMC}$ of onshore wind power is significantly lower than the $\overline{NMC}$ of offshore wind and solar power (see Figure 5.4). This illustrates the low economic attractiveness of offshore wind and solar power in comparison to onshore wind power up to 2020.

Figure 5.5 shows the interdependence between the wind and solar power penetration (i.e., the annual wind and solar power generation) and the annual correlation (between the wind and solar power generation profile and the wholesale price profile) for both scenarios. Overall, the annual correlation tends to decrease as the annual wind and solar power generation increases, which is in line with the results derived in Chapter 4. This can, for example, be seen in the 'Efficient Scenario': Between 2015 and 2020, onshore wind power in northern Germany (region 1) is significantly expanded, which leads to a drop in the correlation (between the onshore wind power production factor profile in northern Germany (region 1) and the wholesale price profile). The same effect can be observed for solar power in southern Germany (region 2) between 2020 and 2025.

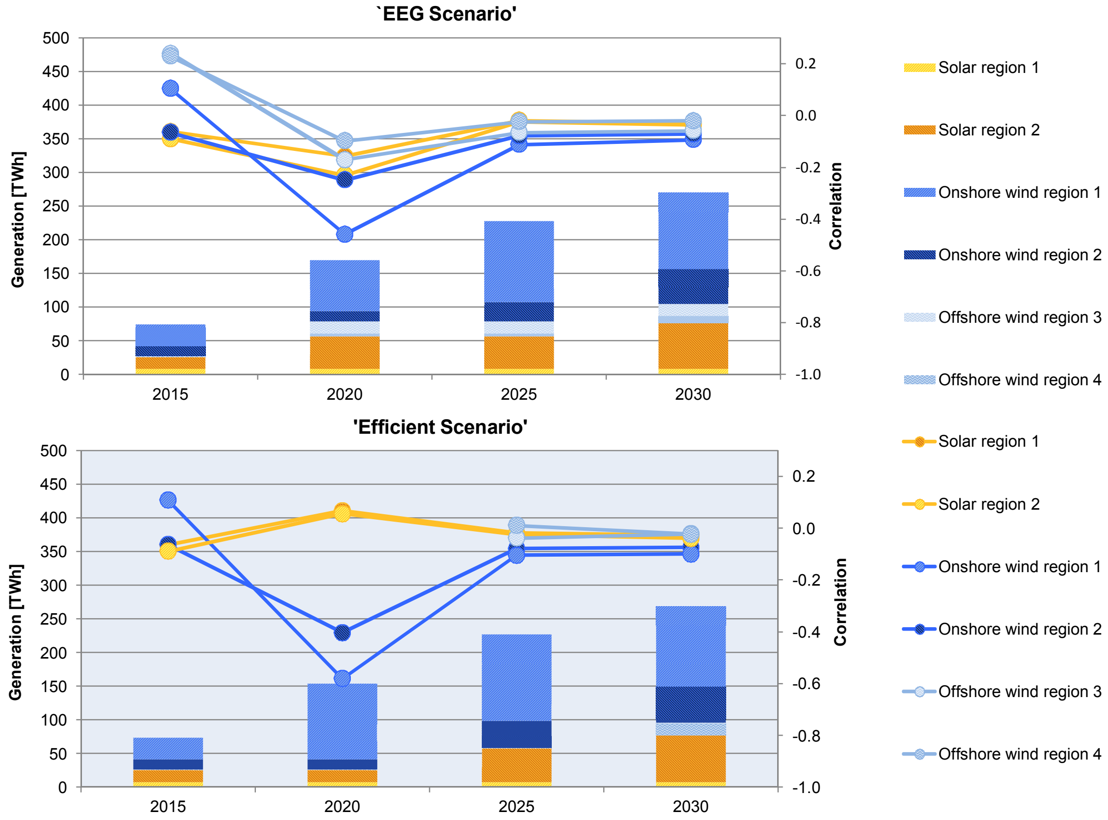


FIGURE 5.5: Annual generation [TWh] and annual correlation between the wind/solar power generation profile and the wholesale price profile

However, Figure 5.5 also illustrates the importance of cross-technological effects. For example, between 2020 and 2025, the correlation of onshore wind power in northern Germany (region 1) increases, although the penetration of onshore wind power in northern Germany slightly increases (from 74 GW in 2020 to 85 GW in 2025). This is due to the significant increase in solar power generation in southern Germany (region 2) which is negatively correlated with the onshore wind production factor profile in northern Germany (region 1). This is shown in Table 5.8.

Although the correlation between the onshore wind generation profile in northern Germany (region 1) and the wholesale price profile increases between the years 2020 and 2025, this does not mean that the onshore wind power units that were built in 2020 in northern Germany (region 1) are more profitable in 2025 than in 2020 – profitable in the sense that the revenue per MW from selling electricity on the wholesale market in 2025 exceeds the revenue in 2020. In contrast, the additional onshore wind and solar power in southern Germany (region 2) has a downward effect on the wholesale price in 2025, which lowers the annual revenue of onshore wind power turbines in northern Germany (region 1) that were built in 2020 (see Figure 5.6).

TABLE 5.8: Correlations between production factor profiles of wind and solar power technologies

	Solar region 1	Solar region 2	Onshore wind region 1	Onshore wind region 2	Offshore wind region 3
Solar region 2	0.8				
Onshore wind region 1	-0.2	-0.1			
Onshore wind region 2	-0.2	-0.2	0.5		
Offshore wind region 3	-0.3	-0.2	0.6	0.4	
Offshore wind region 4	-0.2	-0.2	0.5	0.4	0.6

Overall, the revenue earned from selling electricity on the wholesale market significantly varies across the years. The comparatively low revenue of onshore wind power turbines in northern Germany (region 1) in 2035 is due to the offshore wind power expansion in the Baltic Sea (region 4) by 2035, which exhibits a high positive correlation with onshore wind power in northern Germany of 0.5 (see Table 5.8). However, the increase in the revenue of onshore wind power in northern Germany by 2040 can be explained by a decrease in the onshore wind power penetration in northern and southern Germany. Betwen 2035 and 2040, more than 13 GW of onshore wind power capacities are decommissioned (9 GW in northern Germany and 4 GW in southern Germany), which are not replaced. Moreover, electricity generation from flexible gas-fired power plants increases. The increase in the annual revenue of wind and solar power plants in the longer run can also be seen in Figures D.2 and D.3 of the Appendix, which show the annual revenue of onshore wind, offshore wind and solar power plants that were built in 2025 and 2030. Hence, the optimal adaptation of the dispatchable power plant mix to a system with a higher share of flexible gas-fired (peak-load) power plants and a lower share of lignite-fired (base-load) power plants in Germany (see Figure D.1 of the Appendix) benefits wind and solar power generators in the long-run.

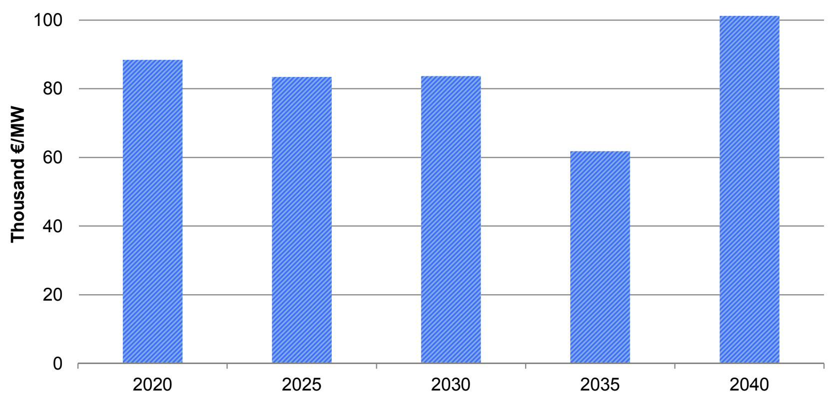


FIGURE 5.6: Development of the annual revenue from selling electricity on the wholesale market of an onshore wind power turbine built in region 1 in 2020 in the 'Efficient Scenario' [thousand € /MW] (not discounted)

In summary, the presented scenario results derived with the electricity system optimization model confirm the theoretical results derived in Chapter 4 and Section 5.2 and illustrate the economic inefficiency associated with Germany's technology- and region-specific RES-E targets for 2020. Due to the significantly higher $\overline{NMC}$ of offshore wind and solar power units compared to onshore wind power units in Germany up to 2020, the technology- and region-specific RES-E targets are associated with excess costs of more than 6.6 Bn €$_{2010}$ (accumulated and discounted).

However, the quantified excess costs of 6.6 Bn €$_{2010}$ should be interpreted as a lower bound estimate for the overall inefficiency associated with Germany's technology- and region-specific RES-E targets for 2020. This is due to the fact that power transfers between the regions within Germany, i.e., from northern to southern Germany and vice versa, face no transmission constraints.

More specifically, while power exchange between Germany and neighboring countries is limited by exogenously defined interconnection capacities, a copper-plate with no congestions is assumed for Germany. However, as soon as transmission capacity bottlenecks between two regions occur, the value of power supply (at a specific point in time) differs between the regions. As such, the marginal value (MV^{el}) of wind and solar power capacities between two regions may not only vary because of differences in the production factor profiles but also due to transmission capacity bottlenecks. The applied model, however, fails to account for the latter effect.

As such, the large expansion of onshore wind power in northern Germany up to 2020 (realized under the technology- and region-neutral RES-E target in the 'Efficient Scenario') may not be optimal (i.e., too large) when accounting for transmission capacity bottlenecks from northern to southern Germany, which already exist today and which are expected to increase as wind power supply in northern Germany rises. More specifically, onshore wind capacities are expected to become efficient in southern Germany already by 2020 when accounting for transmission capacity bottlenecks from northern to southern Germany, substituting part of the investments in northern Germany. Hence, we argue that the economic inefficiency associated with the region-specific onshore wind power target for northern Germany is underestimated with our model, which implies that the overall excess costs of 6.6 Bn €$_{2010}$ (accumulated and discounted) represent a lower bound estimate.

Moreover, the model is deterministic and not stochastic in its nature. Hence, no uncertainty about the hourly or yearly electricity generation of wind and solar technologies is incorporated. In stochastic models, the uncertainty of wind and solar power generation can be modeled by weighting different scenarios (which vary with regard to the wind and solar power production factor profiles) by their specific probability of occurence (Nagl et al. (2013)). As a means to reduce risk, the renewable energy mix determined by a stochastic model is expected to be more divers (both with regard to technologies and regions) than the renewable energy mix determined by a deterministic model (given a technology- and region-neutral RES-E target). However, unlike the impact of disregarding transmission capacity bottlenecks on the level of excess costs, the consequences of abstracting from uncertainty is not straight forward. Hence, it cannot be said a priori in which direction the excess costs of technology- and region-specific RES-E targets would change (in comparison to the present analysis) if a stochastic rather than a deterministic model would have been applied.

5.4 Conclusion

It has been shown that comparing the economic attractiveness of renewable energy technologies on the basis of marginal costs per kWh ($\overline{MC}$) is incorrect, as doing so neglects the marginal value per kWh ($\overline{MV^{el}}$) of the respective technology. Instead, the *net* marginal costs per kWh ($\overline{NMC}$) should serve as the reference when discussing the economic attractiveness of renewable energy technologies. Renewable energy support schemes that fail to incentivize investors to account for differences in the $\overline{MV^{el}}$ prevent an equalization of $\overline{NMC}$ across technologies and regions in the equilibrium and thus are associated with excess costs. For the case of Germany and its technology- and region-specific wind and solar power targets for 2020, excess costs amount to more than 6.6 Bn €$_{2010}$ (accumulated and discounted). These are driven by the comparatively high $\overline{NMC}$ of offshore wind and solar power in comparison to onshore wind power in Germany up to 2020. However, given the fact that we abstract from transmission capacity bottlenecks within Germany in the model, the quantified excess costs should be interpreted as a lower bound estimate.

Future research could address the following issues: First, the model could be extended to acount for both transmission capacity limitations within Germany and stochastic wind and solar power generation. Second, the technical granularity of wind and solar power systems could be increased to account for differences in the production factor profiles of wind and solar power units due to an alternative sizing of the wind power turbine or due to an alternative orientation of the PV system. This would allow us to analyze, for example, at which point in time (or at which penetration level) the $\overline{NMC}$ of PV systems that are tilted to the east or the west have lower $\overline{NMC}$ than PV systems that are tilted to the south. Third, an alternative model could be applied which maximizes investor's profits rather than minimizing total system costs. Fourth, as pointed out by Mitchell et al. (2006) and Klessmann et al. (2008), there is some trade-off associated with exposing renewable energy investors to market risk as it increases the project's capital costs, which may, in turn, deteriorate the (dynamic) efficiency of the support scheme. This is an important aspect if the goal is to bring new technologies into the market and gain experience. Meanwhile, however, renewables account for a comparatively large share of total electricity supply in many countries (e.g., 25 % in Germany in 2013 (Statista (2014))). Hence, efficiency gains due to the consideration of the market price signal in the generator's investment decisions are likely to balance potential efficiency losses due to higher risk premiums and higher required support payments. This could also be an interesting opportunity for further research.

Chapter 6

The economic value of storage in renewable power systems – The case of thermal energy storage in concentrating solar power plants

6.1 Introduction

In an attempt to fight global warming, many countries try to reduce CO_2 emissions from electricity generation by significantly increasing the proportion of renewable energy sources (RES-E). One major challenge in this transition is the balancing of fluctuating generation by wind or solar technologies and demand given limited cost-efficient electricity storage options. One technology that may contribute significantly in solving these problems in countries or regions with high direct normal irradiance (DNI), are concentrating solar power plants (CSP) equipped with thermal energy storage (TES) units. In CSP plants, the sun's heat is absorbed by collectors and concentrated to heat a fluid, which is then used to generate electricity in a steam turbine. Specific to CSP systems is the inherent option to integrate a TES capacity, used to generate electricity in hours with low or no solar radiation. Dependent on the CSP technology and the site characteristics, TES can even reduce the site's production costs per kWh due to a higher usage of the capital-intensive power plant block.

In electricity systems with low shares of fluctutaing renewable energy generation and price-inleastic electricity demand, the structure of the hourly electricity price curve follows the structure of the electricity demand curve. Hence, wholesale prices are highest when demand is highest. In today's electricity systems in Europe, electricity demand and wholesale prices have a midday peak when solar radiation is also highest. Thus, wholesale prices are above average during the time at which solar power plants can directly feed into the grid. As a consequence, the economic value of solar power generation is comparatively high in today's electricity systems.

However, many European member states, such as Germany, Spain and Italy, have implemented feed-in tariff (FIT) schemes to promote the deployment of renewable energy technologies. Under a FIT scheme, renewable energy generators receive a fixed payment per kWh independent of the actual wholesale price reflecting the economic value of electricity at a specific point in time. Hence, investors maximize profits by minimizing production costs per kWh. However, as a consequence of the fact that the price signal of the wholesale market is not taken into account, FIT schemes fail to guide efficient investments from a total system perspective. This is analyzed in the following using the example of thermal energy (TES) storage units installed in combination with CSP plants.

In the first part of the paper, we illustrate the value of solar power in today's electricity markets and discuss the inefficiency associated with FIT schemes to promote electricity generation from renewable energy sources (RES-E). In the second part, we analyze the value of thermal energy storages in CSP plants for the case of the Iberian Peninsula as a function of the share of fluctuating RES-E generation.

A number of studies have analyzed the technical, geographical and economical feasibility of solar energy to supply a significant share of the electricity demand – either provided by photovoltaic (PV) systems or concentrating solar power (CSP) plants. Analyses include the assessment of the technical feasibility of balancing demand and generation in high-solar scenarios as well as the economic value of PV, CSP and thermal energy storage technologies, both from an investor's perspective and for the economy as a whole. NREL (2003) and Pitz-Paal et al. (2005) describe the functional principles of different CSP technologies and thermal energy storage options and assess their future cost development. Fthenakis et al. (2009) and Wang (2010) investigate the technical, geographical and economical feasibility of solar energy and demonstrate that a significant percentage of electricity demand can be supplied by PV systems and CSP plants in the long term.

The value of electricity storage options has been analyzed in a number of papers, as described in Xi et al. (2011). One of the most common approaches is the so-called 'energy arbitrage', which essentially analyzes the option of charging storage when electricity prices are low and discharging when high (e.g., Graves et al. (1999), Sioshansi et al. (2009)). The value of thermal energy storage in CSP plants, from an investor's perspective, has been examined by Sioshansi and Denholm (2010), Laing et al. (2010) and Dominguez et al. (2012). Sioshansi and Denholm (2010) show that the addition of thermal energy storages increases the value of CSP plants both by allowing CSP generation to be shifted to hours with higher energy prices and by increasing the usage of thermal energy from a CSP plant's solar field. However, despite these benefits, their results suggest that at current investment costs, thermal energy storages cannot be economically justified on energy value alone: Only if the value of ancillary service sales and capacity are included do thermal energy storages in a number of cases become cost-effective. The value of concrete thermal energy storage options for parabolic trough CSP plants has been assessed by Laing et al. (2010). In contrast to Sioshansi and Denholm (2010), Laing et al. (2010) and Dominguez et al. (2012), who focus on the value of CSP systems from an investor's perspective, Poullikkas et al. (2010) investigate the economic costs of integrating parabolic trough CSP plants in isolated Mediterranean power systems using the example of Cyprus. By comparing scenarios that differ with respect to new investments in CSP plants (with and without thermal storage) and natural gas-fired power plants, the study comes to the conclusion that CSP plants with storage units are the most cost-effective investment option. However, the results may not be valid for other power systems, as Cyprus lacks, for example, other storage options such as large pump-storage plants.

This paper makes several contributions to the existing literature. First, we compare historical hourly wholesale prices of electricity to solar radiation data in France, Germany, Spain and Portugal from 2007 to 2010 to estimate the value of solar power in today's electricity markets with comparatively low shares of fluctuating RES-E generation. Second, we are the first to analyze the value of thermal energy storages in CSP plants as a function of the overall generation mix by using an electricity system optimization model of the Iberian Peninsula. We see three potential advantages of a simulation with an electricity system optimization model compared to an econometric 'energy arbitrage' analysis: First, empirical data of electricity systems with a large share of fluctuating renewables are limitedly available, making econometric analysis challenging. Second, by using an optimization model, the investment decision in TES is cost-efficient – compared to all other investment options that could contribute to meeting demand. Third, the price curve within our electricity market model is endogenously determined and the impact of investments in generation and storage technologies is captured by the price curve.

We find that electricity prices are usually higher than average when solar power plants can directly feed into the grid in today's electricity markets with low shares of fluctuating RES-E generation. Therefore, investments in thermal energy storages in CSP plants are not cost-efficient in today's electricity markets. Hence, we argue that feed-in tariffs to promote RES-E generation set an inefficient incentive to invest in thermal storages by neglecting market price signals. However, results of the optimization model show that thermal storage units in CSP plants may play a significant role in high RES-E and low-carbon electricity systems. Given a large share of fluctuating RES-E generation, electricity prices would vary substantially as a result of a volatile residual load. The results of the model simulation indicate that thermal storage capacities in CSP plants (in addition to other balancing options such as hydro and pump storage capacities), may be able to balance generation from fluctuating renewables and demand.

The remainder of the paper is structured as follows: In Section 6.2, we compare historical hourly wholesale prices of electricity to the solar radiation data in France, Germany, Spain and Portugal from 2007 to 2010. In Section 6.3, the simulation approach used to analyze the value of thermal energy storages in CSP plants as a function of the overall generation mix is presented with a detailed description of the model and the scenario setup. In Section 6.4, the scenario results concerning the value of thermal storages and the role of CSP with thermal storage in a high RES-E scenario are discussed. Conclusions are drawn in Section 6.5, providing an outlook of further possible research.

6.2 The value of solar energy in today's electricity markets

In liberalized electricity markets, wholesale prices represent the market result of supply and demand at a specific point in time. Given a large share of dispatchable power plants, electricity prices are mainly determined by the level of electricity demand in today's power markets. As a result, wholesale prices usually have a midday (or early evening) peak coinciding with the time that electricity demand is highest.

Since solar radiation also has a midday peak, electricity prices are above average when solar systems are able to directly feed into the grid. Table 6.1 lists average electricity prices (spot market) for France (FR), Germany (GER), Spain (ES) and Portugal (PT) from 2007 to 2010 (with comparatively low shares of solar power generation) in comparison to different levels of solar radiation (based on EEX (2012), EPEX (2012), OMEL (2012) and EuroWind (2011)). For example, in Germany in 2008, electricity prices had an average of 60 EUR/MWh in situations with low solar radiation (0-100 W/m^2) and were about 10 % lower than the yearly average (66 €/MWh). Consequently, electricity prices were 88 €/MWh, about 34 % higher, in hours with highest solar radiation (> 800 W/m^2). Overall, the data show higher electricity prices (on average) in situations with high solar radiation in all four listed countries and years. Hence, solar energy has a relatively high value in systems with low shares of fluctuating renewable generation due to the typical feed-in during hours with high electricity demand.

Table 6.1: Average electricity prices [€/MWh] in comparison to solar radiation [W/m^2]

		Annual [EUR/MWh]	0-100 [W/m^2]	100-200 [W/m^2]	200-300 [W/m^2]	300-400 [W/m^2]	400-500 [W/m^2]	500-600 [W/m^2]	600-700 [W/m^2]	700-800 [W/m^2]	> 800 [W/m^2]
	2007	41	40	44	48	42	42	41	39	40	42
FR	2008	69	63	73	73	78	81	87	89	87	97
	2009	43	39	43	51	53	61	46	45	47	48
	2010	48	46	50	50	49	52	50	51	50	54
	2007	38	36	47	46	46	46	46	44	44	46
GER	2008	66	60	75	76	78	80	83	85	86	88
	2009	39	37	45	46	46	45	45	45	44	45
	2010	44	43	49	49	49	49	49	49	49	50
	2007	39	38	37	40	42	44	41	40	41	45
ES	2008	64	62	63	64	65	67	69	69	71	72
	2009	37	36	36	36	37	39	37	39	39	39
	2010	37	35	36	37	38	39	40	41	42	43
	2007	52	51	54	52	57	59	56	49	49	50
PT	2008	70	69	69	70	72	72	73	74	72	73
	2009	38	37	36	37	38	39	39	39	39	40
	2010	37	36	37	38	37	39	39	40	42	43

Remarks: In Portugal, only data for the second half of the year 2007 was available. Moreover, additional data regarding the variance of electricity prices can be found in Appendix D (Table E.2).

Abbreviations: FR - France; GER - Germany; ES - Spain and PT - Portugal.

Source: EEX (2012), EPEX (2012), OMEL (2012) and EuroWind (2011).

In CSP plants, the sun's heat is absorbed by collectors and concentrated to heat a fluid which is then used to generate electricity in a steam turbine. Unlike photovoltaic systems, CSP plants use only the direct component of sunlight. Hence, CSP plants provide heat and power only in regions with high direct normal irradiance (DNI), such as North Africa or southern Europe. Specific to CSP systems is the inherent option to integrate a thermal energy storage capacity, which can then be used to generate electricity in hours with low solar radiation and/or high electricity demand.

The technical characteristics of the collector field, the thermal energy storage (TES) unit and the steam turbine of CSP plants are chosen independently from one another. Depending on the CSP technology and the site characteristics, TES units may reduce the average generation costs due to the higher usage of the capital-intensive power plant block. For example, in CSP systems without an integrated thermal energy storage unit, the steam turbine would be off-line for more than half of the time, regardless of the size of the collector field, due to the distinct daily solar radiation curve. Given an integrated storage unit, the large amount of heat absorbed during midday can be stored, even when the turbine is already running at full capacity. The stored energy can then be used to generate electricity in hours with little or no solar radiation.

As renewable power generation is usually more costly than conventional power generation, at least when ignoring external effects, many countries have implemented policies to incentivize renewable power generation. One common policy is the promotion of renewable power generation by feed-in tariffs. Under feed-in tariffs, operators of renewable energy plants receive a fixed remuneration for their power generation, independent of the market price. Thus, investors maximize their profit by simply minimizing the average production costs, without considering the economic value of electricity supply.

In the case of CSP plants, the installation of thermal energy storage (TES) units can reduce the average production costs per kWh, as they allow for a higher usage of the capital-intensive power plant block. As a consequence, investors may have an incentive to install a thermal energy storage capacity under a FIT scheme without considering the wholesale price curve and thus the market value of electricity at a specific point in time.

Today, however, electricity prices are usually above average during the time at which CSP plants are capable of directly feeding into the grid (see Table 6.1). Therefore, we argue that FIT schemes set an inefficient incentive, from a system perspective, to invest in thermal energy storages for CSP plants in today's electricity markets.

However, given the further deployment of fluctuating renewables with negligible marginal generation costs, electricity prices will mainly be influenced by the feed-in of fluctuating renewables rather than the level of electricity demand in the future. In particular, a large share of solar technologies may even inverse the electricity price curve, resulting in relatively low wholesale prices during midday. Moreover, electricity prices may vary substantially from one hour to another in future electricity markets due to the stochastic and volatile electricity generation from fluctuating renewables. As a result, the value of storages will arguable increase with higher shares of fluctuating RES-E generation. Thus, concentrating solar plants with integrated thermal storages may play a significant role in primarily renewable-based electricity systems.

Summarizing, the numerical analysis in Section 5.3 and 5.4 will focus on the following two questions:

- Set FIT schemes for power generation from CSP plants an inefficient incentive to invest in thermal energy units in today's electricity markets?
- Does the value of thermal energy storages in CSP plants increase with the share of fluctuating renewable energy generation?

6.3 Approach and model description

To analyze the value of thermal energy storage units in CSP plants, we simulate several CSP plants with different storage sizes in two scenarios, by applying a linear investment and dispatch model for the Iberian Peninsula until 2050. The analysis is conducted for the Iberian Peninsula for mainly two reasons: First, Spain and Portugal are countries with comparatively high direct normal irradiance (DNI) (see, e.g., Solargis (2014)); and second, Spain has the highest installed capacity of CSP plants worldwide due to a feed-in tariff (FIT) system for renewable energies that has been available for new projects up to the year 2013.[143] A significant number of CSP plants commissioned up to 2013 included thermal storage units (NREL, 2011), which are profitable from an investor's perspective due to the offered feed-in tariff.[144]

The following scenario analysis provides information as to whether thermal energy storage (TES) units in CSP plants are cost-efficient in today's electricity system for the Iberian Peninsula from an overall system perspective. Moreover, it illustrates the possible future role of CSP plants with TES units in primarily renewable energy based electricity systems.

6.3.1 Electricity market model

The model used in this analysis is an extended version of the long-term investment and dispatch model for conventional, storage and transmission technologies of the Institute of Energy Economics at the University of Cologne. The objective of the model, shown in Equation (6.1), is to minimize accumulated discounted (5 % dicount rate) total system costs while meeting demand at all times.[145] An overview of selected model sets, parameters and variables is given in Table 6.2.

Total system costs are defined by investment and fixed operational and maintenance costs, variable production costs and costs due to ramping thermal power plants. Investment costs occur for new investments in generation units and are annualized including a 5 % interest rate for the depreciation time. The fixed operation and maintenance costs (fc_a) represent staff costs, insurance charges and maintenance costs. Variable costs are determined by fuel prices ($\mathrm{fp}_{y,a}$) and CO_2 prices (cp_y), CO_2 emission factors (ef_a), net efficiencies (η_a) and the amount of generation per technology ($\mathrm{GE}^{d,h}_{y,c,a}$). Ramp-up costs are simulated by referring to the power plant blocks and by setting a minimal load restriction. Depending on the minimum load and start-up time of thermal power plants, additional costs for ramping occur. Demand characteristics are represented by modeling the dispatch for three days (Saturday (Sat), Sunday (Sun) and a weekday (Wd)) per season on an hourly basis (scaled to 8760 hours). Three days per season are used to account for the different demand structures on weekends and weekdays. Moreover, typical feed-in structures of each season for wind and solar technologies are

[143] Spain has suspended all feed-in tariff incentives for renewables in 2013 in response to the country's tight economic and financial situation (Brown (2013)).

[144] A list of current CSP projects in Spain can be found in Appendix D.

[145] The model's optimization premise (minimization of accumulated discounted total system costs) implies a cost-based competition of electricity generation and perfect foresight.

modeled, including very low and high wind days. Apart from the basic cost equations, the model incorporates all common elements of linear dispatch models such as storage equations, net transfer possibilities and restrictions due to local resource availabilities. A full description of the basic model can be found in Richter (2011).

Total system costs are minimized subject to several techno-economic constraints. For example, while minimizing total system costs, the model has to ensure that hourly electricity demand ($de_{y,c}^{d,h}$) within each market region is met ('power balance constraint', Eq. (6.2)) and that a minimum share (ω_y) of annual electricity demand ($de_{y,c}^{d,h}$) is met with renewable energy sources ('technology-neutral RES-E quota', Eq. (6.3)).[146] The marginal of the power balance constraint (Eq. (6.2)), i.e., the partial derivative with respect to the hourly electricity demand ($de_{y,c}^{d,h}$) considering the total system costs, is used as a proxy for the hourly wholesale price in the following.

A detailed description of all techno-economic constraints can be found in Fürsch et al. (2013a) and Jägemann et al. (2013b).

$$\begin{aligned}\min \ \ TCOST = \sum_{y\in Y}\sum_{c\in C}\sum_{a\in A}\Bigg[disc_y \cdot \Bigg(&AD_{y,c,a}\cdot an_a + IN_{y,c,a}\cdot fc_a \\ &+\sum_{d\in D}\sum_{h\in H}\Bigg(GE_{y,c,a}^{d,h}\cdot\left(\frac{fp_{y,a}+cp_y\cdot ef_a}{\eta_a}\right) \\ &+CU_{y,c,a}^{d,h}\cdot\left(\frac{fp_{y,a}+cp_y\cdot ef_a}{\eta_a}+ac_a\right)\Bigg)\Bigg)\Bigg]\end{aligned} \tag{6.1}$$

s.t.

$$\sum_{a\in A} GE_{y,c,a}^{d,h} + \sum_{c'\in C} IM_{y,c,c'}^{d,h} - \sum_{s\in A} GE_{y,c,s}^{d,h} = de_{y,c}^{d,h} \tag{6.2}$$

$$\sum_{c\in C}\sum_{r\in A}\sum_{d\in D}\sum_{h\in H} GE_{y,c,r}^{d,h} \geq \omega_y \cdot \sum_{c\in C}\sum_{d\in D}\sum_{h\in H} de_{y,c}^{d,h} \tag{6.3}$$

[146]The electricity demand is assumed to be price-inelastic. As a consequence, the cost minimization approach corresponds to a welfare-maximization approach. Moreover, we note that the model's optimization premise (minimization of accumulated discounted total system costs) implies a cost-based competition of electricity generation and perfect foresight.

Table 6.2: Model abbreviations including sets, parameters and variables

Abbreviation	Dimension	Description
Model sets		
a ∈ A		Technologies
r ∈ A	Subset of a	RES-E technologies
c ∈ C		Countries
d ∈ D		Days
h ∈ H		Hours
y ∈ Y		Years
Model parameters		
ac_a	[€ 2010/MWh_{el}]	Attrition costs for ramp-up operation
an_a		Annuity factor (5 % interest rate)
cp_y	[€ 2010/t CO_2]	Costs for CO_2 emissions
$de_{y,c}^{d,h}$	[MW]	Electricity demand
$disc_y$		Discount factor (5 % discount rate)
ef_a	[t CO_2 /MWh_{th}]	CO_2 emissions per fuel consumption
fc_a	[€ 2010/MW]	Fixed operation and maintenance costs
$fp_{y,a}$	[€ 2010/MWh_{th}]	Fuel costs
η_a	[%]	Net efficiency
$\check{\eta}_a$	[%]	Net efficiency of storage in charging operation
$\hat{\eta}_a$	[%]	Net efficiency of storage in discharging operation
vc_a	[MWh/MW]	Ratio of storage size and turbine capacity
ω_y	[%]	Quota on RES-E generation
Model variables		
$AD_{y,c,a}$	[MW]	Commissioning of new power plants
$CU_{y,c,a}^{d,h}$	[MW]	Ramped-up capacity
$GE_{y,c,a}^{d,h}$	[MW_{el}]	Electricity generation
$IM_{y,c,c'}^{d,h}$	[MW]	Net imports
$INJ_{y,c,a}^{d,h}$	[MW_{el}]	Absorbed solar power by collectors
$IN_{y,c,a}$	[MW]	Installed capacity
$SIN_{y,c,a}^{d,h}$	[MW_{el}]	Charging the storage unit
$SLEVEL_{y,c,a}^{d,h}$	[MWh_{el}]	Storage level
$SOUT_{y,c,a}^{d,h}$	[MW_{el}]	Discharging the storage unit
TCOST	[EUR_{2010}]	Total system costs

Endogenous investments in renewable energies were recently added to the model (Fürsch et al., 2013b). The model includes the following renewable energy technologies: roof and ground photovoltaic (PV) systems, wind (onshore and offshore), biomass (solid and gas), biomass CHP (solid and gas), geothermal, hydro (storage and run-of-river) and CSP technologies. Biomass, geothermal and hydro technologies are modeled as dispatchable renewables similar to conventional power plants. As the availability of fluctuating renewable energies (wind and solar technologies) highly depends on weather conditions, a maximum possible feed-in of wind and solar sites is modeled for each hour.[147] In addition, the model considers several wind and solar regions within the countries to account for local weather conditions.

To analyze the value of thermal storage units, the possibility to invest in CSP plants with and without thermal storage units has been added to the model. In CSP plants, the heat from the sun is absorbed by collectors and is concentrated to heat a fluid, which is then used to generate electricity in a steam turbine. The heat can be saved in a thermal energy storage (TES) unit, allowing for the electricity generation to take place later (Eq. (6.4)). The maximum storage level is determined by the volume factor (vc_a), which is the ratio of storage to turbine capacity. Equation (6.5) shows the hourly power balance of a CSP system. The injection variable ($INJ^{d,h}_{y,c,a}$) represents the solar energy which is absorbed by the collectors. CSP plants with TES units are able to shift the energy of the absorbed sun to hours with less or no solar radiation. Losses in storage processes occur due to energy consumption in pumps during charging and discharging processes, efficiency losses in heat exchangers and losses of stored energy over time. The latter, i.e., efficiency losses over time for stored energy in the TES, are negligible (Sioshansi and Denholm, 2010) and therefore not incorporated into the model. The change in storage level (Eq. (6.6)) depends on the storage operation in the specific hour taking into account losses during the charging process.[148]

$$SLEVEL^{d,h}_{y,c,a} \leq vc_a \cdot IN_{y,c,a} \tag{6.4}$$

$$INJ^{d,h}_{y,c,a} + SOUT^{d,h}_{y,c,a} \cdot \hat{\eta}_a - GE^{d,h}_{y,c,a}/\eta_a - SIN^{d,h}_{y,c,a} = 0 \tag{6.5}$$

$$SLEVEL^{d,h+1}_{y,c,a} - SLEVEL^{d,h}_{y,c,a} = SIN^{d,h}_{y,b,a} \cdot \check{\eta}_a - SOUT^{d,h}_{y,c,a} \tag{6.6}$$

As we focus on the renewable energy generation of CSP plants in the analysis, the option of co-firing with natural gas is not included in the model. Natural gas co-firing is another option to achieve a higher utilization rate of the capital-intensive power plant block and to increase the capacity factor of the plant.

In general, CSP plants are mainly characterized by three independent components: The size of the collector's field, which determines the amount of energy to be absorbed by

[147]This approach allows for the possibility of wind and solar curtailment when needed to meet demand or when total system costs can be reduced by avoiding ramping costs of thermal power plants. Wind sites are usually larger than solar sites and therefore transaction costs for solar curtailment are assumed to be higher than for wind sites. We use negligible small variable costs for offshore and onshore wind sites. Therefore, the model chooses wind curtailment first.

[148]The storage level is set to 10 % at the beginning of each model year, which has to be reached again in the last modeled hour.

the sun; the thermal energy storage (TES) units; and the turbine size, which determines the maximum electricity that can be generated at a specific point in time.

Overall, we model three CSP technologies (A/B/C), which differ with respect to the size of the collector surface and the storage volume, as shown in Table 6.3. In the following, all CSP parameters are given for a 1 MW system: CSP A has a collector surface of 7,376 m^2 and no storage capacity and thus the thermal energy has to be used to generate electricity at the time it is absorbed. CSP B represents plants with an average solar field of 11,384 m^2 and an average storage unit of 20 MWh, and CSP C has a large solar field of 15,887 m^2 and a storage unit of 40 MWh. All three CSP technologies have a common solar collector and turbine efficiency of 42 % and 37.7 %, respectively; however, each have a different solar multiple, which indicates the extent to which the solar field is over-sized in relation to the turbine capacity.[149] As depicted in Table 6.3, the size of the collector field and storage unit has a significant impact on the plant's capital costs.

TABLE 6.3: Characteristics of modeled concentrated solar power plants

	Collector surface [m^2]	Storage volume [MWh^{th}]	Efficiency solar field [%]	Efficiency turbine [%]	Efficiency load/unload [%]	Solar multiple [-]	Today's capital costs [€$_{2010}$/kW]
CSP A	7,376	0	42.0	37.7	-	1.3	3,722
CSP B	11,384	20 (7.5 h)	42.0	37.7	96.0/97.0	2.0	6,794
CSP C	15,887	40 (15.0 h)	42.0	37.7	96.0/97.0	2.8	10,082

Source: Modeled technologies based on Turchi et al. (2010) and Turchi (2010).

6.3.2 Scenario definitions

We simulate two scenarios for the Iberian Peninsula up to the year 2050 in order to analyze the value of thermal energy storage (TES) units in CSP plants. Both scenarios assume a technology-neutral renewable energy (RES-E) quota, which prescribes the minimum share of annual (net) electricity demand supplied by RES-E technologies and increases from 30 % in 2020 to 80 % in 2050 (see Table 6.4). The simulation of a RES-E quota serves the purpose of illustrating the effect of an increasing share of RES-E generation on the value of thermal energy storage (TES) units in CSP plants. The value of TES is derived from its ability to balance fluctuations in the electricity generation from solar (CSP and PV) and wind (onshore and offshore) power technologies.

[149] The solar multiple is defined as the ratio of the actual size of a CSP plant's solar field compared to the field size needed to feed the turbine at design capacity at a reference solar irradiance of about 1 kW/m^2 (IEA, 2010b).

TABLE 6.4: Technology-neutral RES-E quota common to both scenarios

2020	2030	2040	2050
30 %	40 %	60 %	80 %

The first scenario ('Illustrative Scenario') is for illustration purposes only. In addition to the technology-neutral RES-E quota, a CSP quota is modeled, which defines a minimum share of annual (net) electricity demand (for the Iberian Penisula) to come from CSP technologies. Moreover, the investment costs of all CSP technologies modeled (see Table 6.3) are assumed to remain at today's levels. Equally, (net) electricity demand as well as fuel and CO_2 prices are kept constant at 2010 levels (see Table E.5 of the Appendix). This allows us to isolate the impact of a higher fluctuating RES-E generation on the value of thermal energy storage (TES) units in CSP plants – irrespective of changes in other parameters.[150] Table 6.5 provides an overview of the assumptions made in the 'Illustrative Scenario'.

TABLE 6.5: Framework of the 'Illustrative Scenario'

	Unit	2020	2030	2040	2050
CSP quota	[%]	3.5 %	10 %	17.5 %	25 %
Constant capital costs of 'CSP A'	[€ $_{2010}$/kW]	3,722			
Constant capital costs of 'CSP B'	[€ $_{2010}$/kW]	6,794			
Constant capital costs of 'CSP C'	[€ $_{2010}$/kW]	10,082			
Constant (net) electricity demand	[TWh]	316.5			

In the second scenario ('Roadmap Scenario'), we analyze the potential role of CSP plants with thermal energy storage units in a potential transition to a primarily renewable-based electricity system. In contrast to the 'Illustrative Scenario', decreasing investment costs of CSP technologies due to learning curve effects are assumed (see Table 6.6). However, CSP plants with TES are assumed to have higher cost reductions than CSP plants without TES units due to higher learning curve effects in regard to the storage units. Moreover, in contrast to the 'Illustrative Scenario', no CSP quota is included, but increasing electricity demand, fuel and CO_2 prices are assumed (see also Table E.5). Thus, the 'Roadmap Scenario' incorporates two effects potentially favoring CSP plants with TES units in the long term: First, the share of fluctuating RES-E generation increases due to the RES-E quota (which is assumed in both scenarios, see Table 6.4). Second, a decreasing cost-difference between CSP plants with and without storages occurs due to the assumed investment cost of the storage units. Table 6.6 gives an overview of the key assumptions in the 'Roadmap Scenario'.

[150]These parameters include CSP investment costs, (net) electricity demand, fuel prices and CO_2 prices.

Table 6.6: Framework of the 'Roadmap Scenario'

	Unit	2020	2030	2040	2050
CSP quota	[%]	-	-	-	-
Decreasing capital costs of 'CSP A'	[€ $_{2010}$/kW]	2,220	1,700	1,400	1,290
Decreasing capital costs of 'CSP B'	[€ $_{2010}$/kW]	3,437	2,300	2,100	1,963
Decreasing capital costs of 'CSP C'	[€ $_{2010}$/kW]	5,500	3,800	3,100	2,693
Increasing (net) electricity demand	[TWh]	377.3	432.2	493.3	560.8

It should be noted that the setting of the 'Roadmap Scenario' is only one possible option for the Iberian Peninsula's electricity system and that it is neither a forecast nor the most likely outcome. We focus on the role of thermal storage units in CSP plants used to balance the fluctuating generation of solar and wind technologies.

Further assumptions, which are common to both scenarios, are discussed in the Appendix (see Tables E.3 - E.5).

6.4 Scenario results

6.4.1 'Illustrative Scenario': The value of thermal storage units in CSP plants

In the 'Illustrative Scenario', we analyze the value of thermal storage units in CSP plants depending on the share of fluctuating RES-E generation. In the future, CSP plants with thermal storage units may have a comparative advantage compared to CSP plants with no storage capacity for two reasons. First, due to learning curve effects of storage technologies, the cost difference between CSP plants with and without storage capacities is likely to decrease. Second, the value of thermal storage capacities is likely to increase with a higher share of fluctuating RES-E generation, as storage aids in balancing supply and demand. For the exclusive illustration of the later effect, i.e., the development of the value of thermal storage units as a function of the share of fluctuating RES-E generation, today's environment (e.g., investment costs for CSP plants, electricity demand and fuel prices) is extrapolated until 2050. Hence, the cost differences between CSP plants with and without storage capacities are kept constant at current levels. However, the share of renewable and especially CSP generation is increasing over time due to the modeled RES-E (80 % in 2050) and CSP (25 % in 2050) quota.

Overview of the generation system

An overview of the cost-efficient capacities and gross electricity generation in the 'Illustrative Scenario' is given in Figure 6.1 for the Iberian Peninsula up to 2050. Given the large deployment of renewables, total capacity increases due to lower capacity factors of wind and solar power plants compared to dispatchable power plants. The conventional generation system is dominated by gas capacities (some equipped with CHP), since nuclear plants are not considered as an investment option and the combination of fuel and CO_2 prices favors gas rather than coal power plants. To reach the RES-E and CSP quotas, mostly CSP plants without TES units (CSP A) and wind onshore capacities are built. Existing photovoltaic (PV) capacities deployed under the Spanish feed-in tariff system (granted up to 2013) are not endogenously rebuilt in the model after their technical lifetime ends due to higher investment costs.

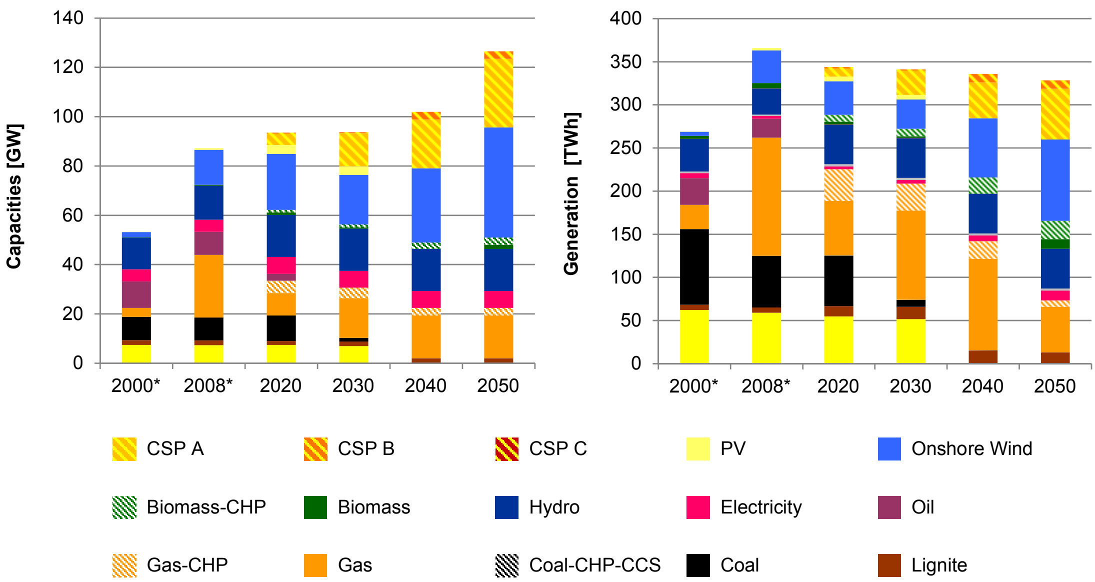


FIGURE 6.1: Capacities [GW] and generation [TWh] in the 'Illustrative Scenario'
Remarks: The data for 2000/2008 is based on Eurostat (2010). CHP capacities (generation) are included in gas and coal capacities (generation) in 2000 and 2008.

Up to 2030, electricity generation is similar to today's electricity mix. Base-load generation takes place in nuclear, lignite and coal capacities. After 2030, the conventional generation occurs mostly in gas-fired power plants and lignite capacities. Renewable generation is provided by CSP plants (CSP A and CSP B), onshore wind turbines, biomass and hydro power plants. The generation in pump storages ('Electricity') increases in the long term (by 2050) due to the feed-in of fluctuating renewables.

Despite the constant (net) electricity demand, gross electricity generation decreases over time due to the transition to a renewable-based electricity system. In particular, there are two opposing effects determining the development of gross electricity generation. On the one hand, increasing utilization of pump storage capacities leads to a higher gross electricity demand due to efficiency losses during pump operation. However, on the other hand, the reduction of the amount of electricity consumed by conventional power plants decreases due to an increased share of RES-E generation. Since the latter effect compensates for the former, the overall gross electricity generation decreases up to 2050.

CSP plants are built in order to fulfill the increasing CSP quota over time.[151] Table 6.7 shows the development of installed CSP capacities. Up to 2040, only CSP plants without thermal energy storage (TES) capacities (CSP A) are constructed. CSP plants with small TES capacities (CSP B), which have the ability to shift generation to hours with no solar radiation and/or higher demand, are cost-efficient from 2040 onwards, once the penetration of fluctuating RES-E generation has exceeded a certain limit. In this scenario, about 10 % of the CSP plants are equipped with small storage capacities in 2050 when the RES-E share reaches 80 % and when CSP generation makes up 25 % of total generation.

Table 6.7: Installed capacities of CSP technologies [GW]

	2010	2015	2020	2025	2030	2035	2040	2045	2050
CSP A	0.5	3.1	4.6	10.6	14.4	18.7	21.1	24.8	32.3
CSP B	0.4	0.4	0.4	0.4	0.4	0.0	3.4	3.4	3.4
CSP C	-	-	-	-	-	-	-	-	-

The value of thermal energy storage units in CSP plants

In the 'Illustrative Scenario', CSP technologies with thermal energy storage (TES) units are not built before 2040. This model result is based on the favorable feed-in structures of solar technologies (CSP and PV) in the short to medium term when fluctuating renewable energy supply is comparatively low and thus the residual demand matching capability of solar power technologies is comparatively high (see also Chapter 4).[152] Hence, at a low penetration of fluctuating RES-E technologies, there is no benefit from having additional storage capacities and being able to shift electricity generation to later hours.

Figure 6.2 shows the feed-in structures of fluctuating RES-E technologies (wind power, PV systems and CSP plants without TES (CSP A)), the model demand and the wholesale price (i.e., the marginal of the power balance constraint, see Eq. (6.2)) of the Spanish electricity market in 2015 and 2050 with a comparatively low (2015) and high (2050) penetration of fluctuating RES-E generation, respectively.

[151]The CSP quota is binding in all years.

[152]The residual demand is defined as total demand minus supply of fluctuating RES-E generation with (almost) no variable generation costs. It determines the amount total demand met with dispatchable generation technologies with variable generation costs.

In 2015, the wholesale price is primarily influenced by the level of total demand. This is due to the fact that generation from wind turbines, PV systems and CSP plants without TES units (CSP A) is still relatively low compared to the total demand.

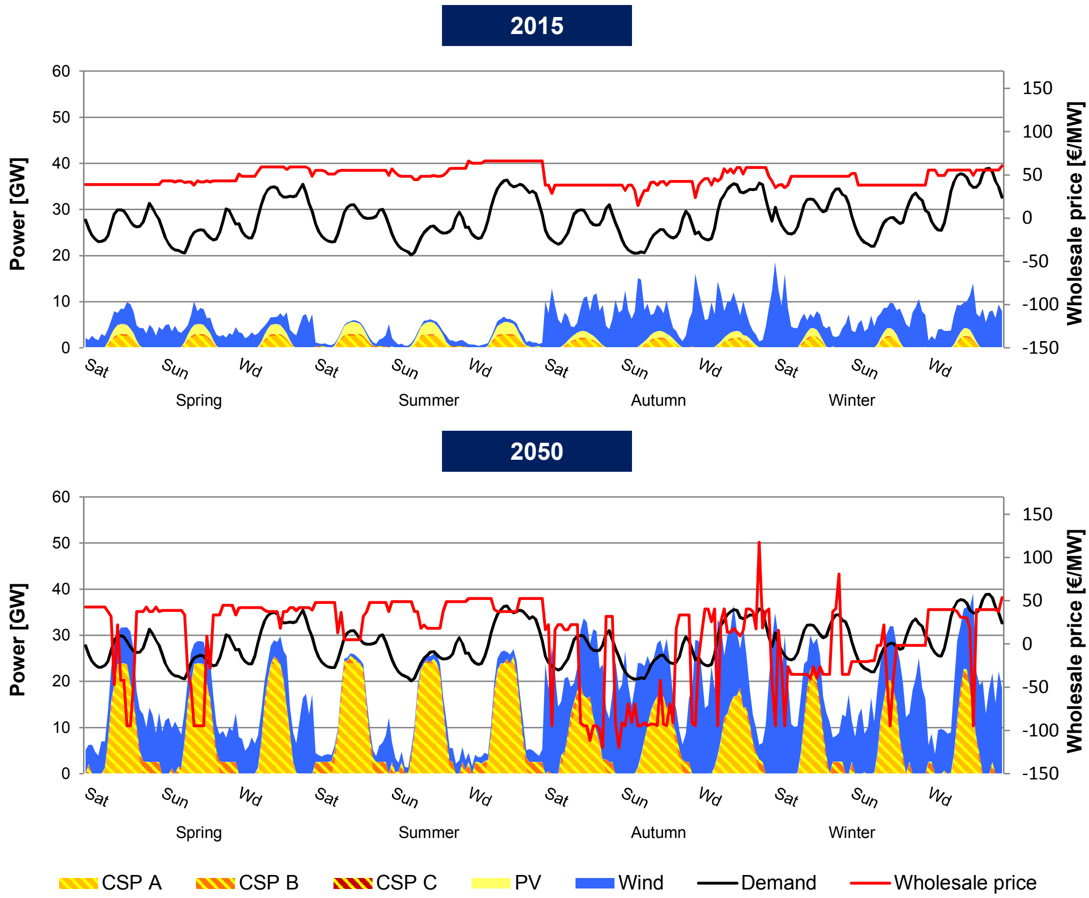


FIGURE 6.2: Spanish electricity market in 2015 and 2050: feed-in structures of fluctuating RES-E technologies, model demand and wholesale price

By 2050, however, the penetration of fluctuating RES-E generation has increased significantly, which leads to two effects with respect to the wholesale price curve (Figure 6.2): First, the wholesale price curve becomes more volatile and second, the structure of the wholesale price curve is almost reversed compared to today (especially in summer). Additional CSP capacities without thermal energy storage units (CSP A) and relatively high generation at midday cause a lower wholesale price during the noon hours.[153] Overall, it can be seen that lower wholesale prices occur when electricity demand is high (around midday), and, vice versa, that higher wholesale prices occur when electricity demand is low (during the night). Hence, the wholesale price is no longer primarily influenced by the level of demand, but the level of solar (and wind) power generation. In contrast

[153]This so called short-term merit-order effect of wind and solar power generation with (almost) no variable generation costs on the wholesale price has, for example, been examined by Gil et al. (2012), Woo et al. (2011), Jonsson et al. (2010), MacCormack et al. (2010), Munksgaard and Morthorst (2008), G. Saenz de Miera and P. del Rion Gonzalez and I. Vizcaino (2008) or Sensfuß et al. (2008).

to today, wholesale prices are higher in hours with no solar power generation than in hours with solar generation. Around midday, when solar power generation is highest, the wholesale price becomes even lower than at night, especially during the summer. As a consequence, the value of additional solar power generation during midday is very limited.[154]

Table 6.8: Development of correlations (Spanish electricity market)

	2015	2020	2030	2040	2050
Generation [TWh]					
CSP A	7	10	28	42	59
CSP B	1	1	1	10	10
Wind	34	34	29	58	79
Correlation between					
demand and wholesale price	0.55	0.54	0.48	0.28	0.23
wholesale price and solar production factor (CSP A)	0.06	0.02	-0.18	-0.23	-0.31

This can also be seen when analyzing the interdependence between solar (and wind) power generation and various correlation coefficients illustrated in Table 6.8. As fluctuating RES-E generation increases, the correlation between the demand profile and the wholesale price profile decreases from 0.55 to 0.23. Moreover, as solar power penetration increases (CSP A), the correlation between the wholesale price profile and the solar production factor profile (CSP A) decreases and even becomes negative.

Overall, it can be said that the economic attractiveness of CSP plants with TES units increases in comparison to CSP plants without TES units as solar (and wind) power penetration increases. This is due to the fact that storage capacities allow shifting solar electricity to hours with no solar radiation and thus comparatively high wholesale prices. As explained in Chapter 5, the economic attractiveness of renewable energy technologies is determined on the basis of the net marginal costs per kWh ($\overline{NMC}$), i.e., the difference between the marginal costs per kWh ($\overline{MC}$) and the marginal value ($\overline{MV^{el}}$).[155] This presents an extension of the argumention by Joskow (2011), who claims that comparing the economic attractiveness of fluctuating wind and solar power units to that of conventional dispatchable generation capacities based on the levelized costs of electricity (LCOE) is flawed since it fails to account for the fact that the value of electricity supplied (i.e., the wholesale price) varies over the course of the day and the year.

[154] See also Chapter 3 which demonstrates that the marginal economic value of solar power technologies decreases as penetration increases.

[155] $\overline{NMC} = \overline{MC}$ - $\overline{MV^{el}}$.

In contrast to the $\overline{MC}$ which reflect the unit's capital costs, the $\overline{MV^{el}}$ of an additional renewable energy unit is electricity system specific (see also Chapter 4) as it corresponds to the accumulated revenue from selling electricity on the wholesale market during the unit's technical lifetime.

Due to the additional costs for the thermal energy storage (TES) unit the $\overline{MC}$ of CSP technologies with TES units (CSP B/C) exceed the $\overline{MC}$ of CSP technologies with no TES units (CSP A). While the $\overline{MC}$ of all three CSP technologies (CSP A/B/C) are fixed for the simulation period in the 'Illustrative Scenario' (since investment costs are kept constant at today's levels, see Table 6.5), the $\overline{MV^{el}}$ of the different CSP technologies changes as the penetration of fluctuating wind and solar power capacities increases. This can be explained as follows: In electricity systems with low penetration of fluctuating RES-E generation, electricity prices are highest when solar power generation is highest. Hence, from total system perspective, there is (almost) no value from storing heat in order to shift electricity generation of CSP plants to hours with no solar radiation. Hence, the $\overline{MV^{el}}$ hardly differ between CSP plants with and without TES units (CSP B/C vs. CSP A). As a consequence, the $\overline{NMC}$ of CSP plants without TES units (CSP A) are lower than the $\overline{NMC}$ of CSP technologies with TES units (CSP B/C) in electricity systems with low shares of fluctuating RES-E generation. This, in turn, means that investments in CSP plants without TES units (CSP A) are more attractive from total system perspective than investments in CSP technologies with TES units (CSP B/C) in electricity systems with low RES-E shares.

However, as the share of wind and solar power generation rises, electricity prices are increasingly driven by the supply of fluctuating RES-E generation. More specifically, wholesale prices are lowest in hours with high wind and solar power generation. Since TES units allow shifting electricity generation to hours with high wholesale prices, the $\overline{MV^{el}}$ of CSP units with TES units (CSP B/C) increases in comparison to the $\overline{MV^{el}}$ of CSP plants with no TES units. As a consequence, the $\overline{NMC}$ of an additional CSP plant with a TES device (CSP B/C) are lower than the $\overline{NMC}$ of an additional CSP plant without a TES device (CSP A) at some penetration level of fluctuating RES-E generation (despite higher $\overline{MC}$ of CSP technologies with TES units (CSP B/C)). Thus, the increase in the value of thermal storage units in CSP plants as the share of fluctuating RES-E generation increases can be interpreted as a decrease in the $\overline{NMC}$ of CSP plants with a TES device (CSP B/C) in comparison to the $\overline{NMC}$ of CSP plants with no TES device (CSP A).

Summarizing, we draw the following conclusions from the results of the 'Illustrative Scenario'. First, investments in CSP plants with thermal energy storage (TES) units in today's electricity systems for Spain and Portugal are not cost-efficient from a system-integrated perspective. The historically observed investments in CSP plants with storage units in the Spanish electricity market up to the year 2012 resulted from the specific design of the Spanish RES-E promotion system: feed-in tariffs for solar-thermal electricity generation, as granted in Spain up to 2013, do not reflect investment signals of the competitive electricity market, which would have favored CSP plants without thermal storage units. Second, we come to the conclusion that the value of storage units in CSP plants increases when the share of electricity generation by CSP plants without storage units (and other fluctuating RES-E technologies) increases. However, the share of fluctuating RES-E technologies has to reach a substantial magnitude in order to cause an almost reverse structure of the wholesale price curve, until CSP plants with storage units to become cost-efficient.

6.4.2 'Roadmap Scenario': The role of CSP plants in a high RES-E scenario for the Iberian Peninsula

In the 'Roadmap Scenario', we analyze the role of CSP plants and thermal storage units in a possible transformation to a low-carbon and mostly renewable-based electricity system for the Iberian Peninsula. In contrast to the 'Illustrative Scenario', increasing electricity demand and decreasing investment costs of CSP technologies due to learning curve effects are assumed (as described in Subsection 6.3.2). At least 80 % of the electricity consumption has to be generated by RES-E capacities in 2050, but no additional CSP quota has to be reached.

Capacities and generation mix

The RES-E quota forces large expansions of RES-E capacities up to 2050, as illustrated in Figure 6.3. While the (net) electricity demand in 2050 is only twice as high as in the year 2000, the generation capacities triple by 2050. This is due to the low capacity factor of fluctuating RES-E technologies in comparison to conventional technologies.

To achieve the implied RES-E quota, mostly wind onshore sites are expanded (retrofit options are taken as well) and biomass capacities are used in the short term. Starting in 2020, CSP technologies with small (7.5 hours) storage capacities (CSP B) are constructed. Due to the scenario assumptions, the model chooses CSP over PV systems on the Iberian Peninsula. In the long term, i.e., from 2040 onwards, larger CSP plants with 15 hours of storage capacity (CSP C) are built.

The assumptions concerning the conventional generation technologies, fuel prices and flexibility requirements of the power plant mix lead to a gas-dominated conventional generation system. Lignite and hard-coal capacities (often equipped with CHP technology) replace nuclear capacities as base-load generation. In addition to large thermal storage units in combination with CSP plants (CSP C), compressed air energy storages (CAES) are constructed to integrate the large amount of fluctuating generation from wind and solar power technologies in 2050. Power balances for Spain and Portugal can be found in Appendix D.

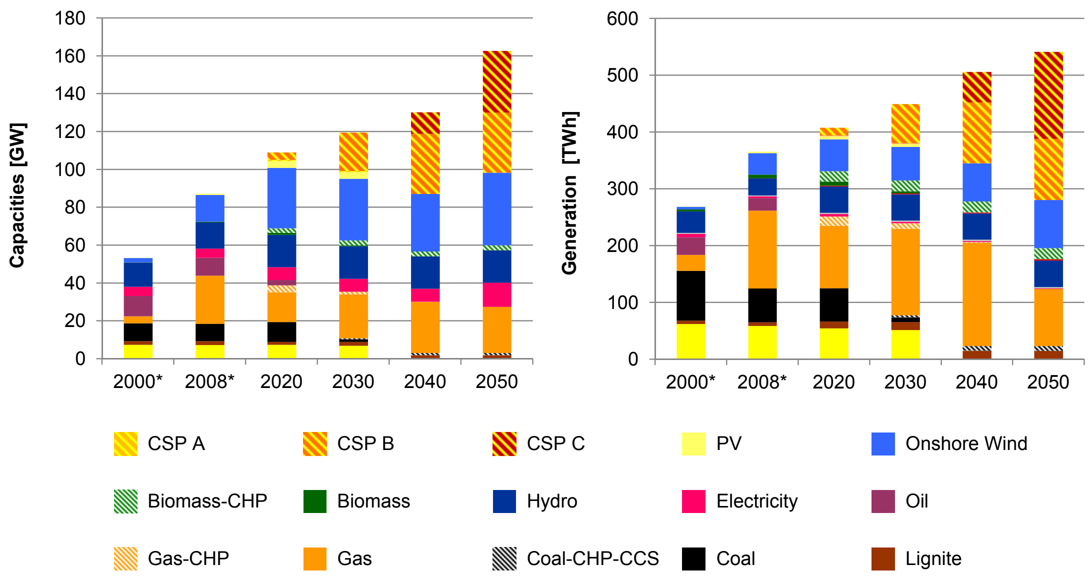


FIGURE 6.3: Capacities [GW] and generation [TWh] in the 'Roadmap Scenario'
Remarks: The data for 2000/2008 is based on Eurostat (2010). CHP capacities (generation) are included in gas and coal capacities (generation) in 2000 and 2008.

The usage of storage units in the 'Roadmap Scenario'

A higher generation by fluctuating RES-E technologies leads to a more volatile residual demand. This requires a higher share of flexible conventional generation such as combined cycle or open cycle gas turbines to balance generation and demand.

Figure 6.4 shows

- the model demand (black line),
- the model demand after subtracting the generation by fluctuating RES-E technologies, i.e., wind power, PV systems and CSP plants without thermal storage units (CSP A) (grey line) and
- the model demand after subtracting the generation by fluctuating RES-E technologies, CSP plants with thermal storage units (CSP B/C) and other storage capacities, i.e., hydro storage, pump storage and compressed air energy storage (CAES) (yellow line).

for the Iberian Peninsula (Spain and Portugal) in 2020 and 2050.

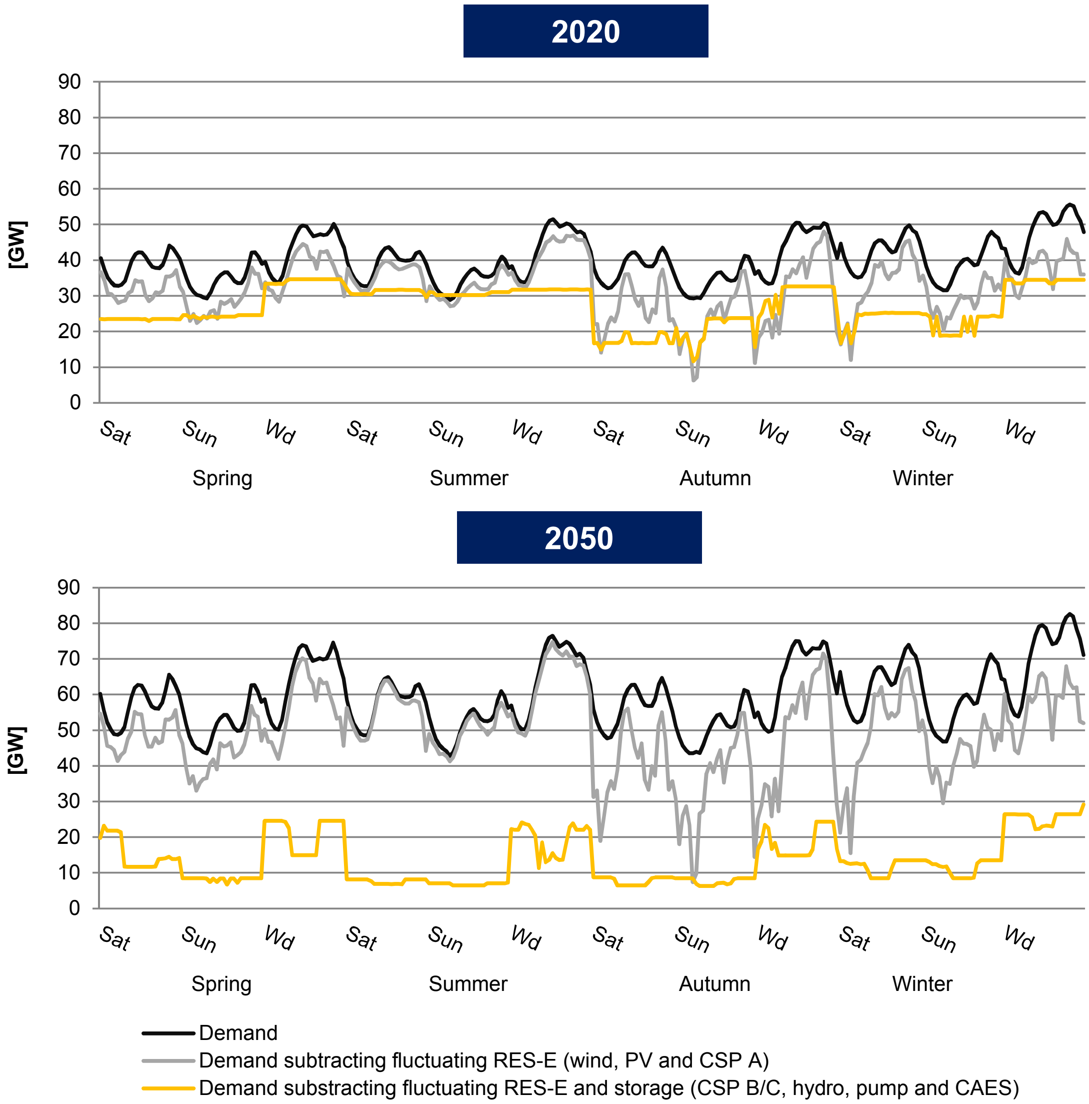


FIGURE 6.4: (Residual) demand [GW] for the Iberian Peninsula in 2020 and 2050

Note that the grey line reflects the share of total demand that would (hypothetically) need to be met by conventional power plants in the absence of storage capacities, while the yellow line represents the actual share of total demand that has to be met by conventional power plants taking storage operations (of TES in CSP plants, hydro, pump and CAES capacities) into account.

As illustrated in Figure 6.4, a higher share of fluctuating RES-E technologies would lead to a more volatile residual demand. This is best observed by comparing the grey line in 2050 with the grey line in 2020. As a consequence, the frequency of quick changes in the generation of thermal power plants would increase. Moreover, the residual load gradients would significantly increase as a consequence of a higher share of fluctuating

RES-E generation. Both effects would cause the ramping costs of thermal power plants to increase.

However, CSP technologies with storage units (CSP B/C) are able to shift generation from one hour to another and can therefore help to balance generation and demand in electricity systems with high shares of fluctuating RES-E generation. In connection with other storage capacities (hydro, pump and CAES), the residual demand (yellow line) is kept more or less constant in most hours in 2050.

Summarizing, the economic value of thermal storage units in CSP plants increases as the penetration of fluctuating RES-E technologies – and in specific solar power capacities – increases. This can be explained by two effects: First, the economic value of additional solar power generation at midday decreases as solar power penetration increases. This is reflected by a comparatively low wholesale price during midday, despite a comparatively high electricity demand. Hence, wholesale prices are increasingly decoupled from physical electricity demand and rather determined by the supply of wind and solar power with (almost) no variable production costs (i.e., the residual load). Thermal storage units installed in combination with CSP plants allow shifting electricity generation in hours with lower generation of fluctuating RES-E technologies and thus higher wholesale prices. Hence, CSP plants with thermal storage units have a higher economic value than CSP plants without thermal storage units under high penetration of fluctuating RES-E technologies from total system perspective. Second, as can be seen in Figure 6.4, CSP plants with thermal storage units (and thus the ability to shift electricity generation) lead to a smoother residual demand to be met by conventional power plants, even considering the higher shares of fluctuating RES-E generation. As a consequence, the need of quick changes in the generation of thermal power plants (due to high load gradients) decreases which helps limiting the costs of ramping.

6.5 Conclusion

We have shown that implementing CSP plants with thermal energy storage units in the current electricity system in Spain and Portugal is not cost-efficient (from a system integrated perspective) due to the relatively high demand at midday when solar radiation is highest. Hence, we argue that feed-in tariffs granted in Spain up to the year 2013 have set an inefficient incentive to invest in thermal energy storage (TES) units by neglecting wholesale price signals. TES can reduce the site's production costs per kWh due to a higher usage of the capital-intensive power plant block. Since investors maximize profits by minimizing production costs per kWh under a feed-in tariff system, CSP plants with TES may be more profitable from the investor's point of view than CSP plants without

TES. However, from a total system perspective, CSP plants with a TES unit, which also produce in hours with comparatively low electricity prices (in the evening or during the night), realize on average a lower revenue per kWh on the wholesale market than a CSP plant without a TES unit, which only generates during the day when demand and thus wholesale prices are highest.

However, the economic value of TES in CSP plants was shown to increase with a higher share of wind and solar power generation, as storage technologies can help to balance fluctuating RES-E generation and demand. For example, in systems with large penetration of solar power technologies, the economic value of additional solar power generation during midday is comparatively low. Shifting generation to hours with higher wholesale prices helps to limit the decrease in the economic value of solar power as its penetration increases. Hence, CSP plants with TES units may have a comparative cost advantage over CSP plants without TES units in electricity systems with high shares of fluctuating RES-E generation.

The analysis approach could be improved and extended in several ways. It would be desirable to include co-firing of natural gas as another option for a more complete understanding of the value of storage units in CSP plants. In addition, a more realistic mapping of the electricity system could be achieved by modeling transmission constraints. It would also be interesting to analyze the effects of different locations for energy storages on transmission requirements, which are expected to be lower if the energy storage is located closer to the (solar) power plant (Denholm et al., 2009). By neglecting uncertainty, forecast errors of wind and solar power or short notice power plant outages are not included in the model. Therefore, additional balancing services by thermal storage units in CSP plants are not fully considered. However, Black and Strbac (2006) or Sioshansi and Denholm (2010) show that it is preferable to integrate the balancing markets. The impact of uncertainty and balancing services on the value of thermal energy storages in CSP plants or other storage options from a system-integrated perspective provides an interesting area of further research.

Appendix A

Supplemental data for Chapter 2

Scenario-specific model parameters

TABLE A.1: Fuel prices [$€_{2010}$/MWh$_{th}$]

	Economic scenario	Nuclear	Lignite	Coal	Gas
2020	Low-cost	3.60	1.40	12.00	23.70
	Base	3.70	1.45	12.50	25.20
	High-cost	3.70	1.50	12.80	26.60
2030	Low-cost	3.60	1.40	12.10	25.60
	Base	3.70	1.45	12.80	28.30
	High-cost	3.90	1.50	13.50	30.50
2040	Low-cost	3.60	1.40	12.20	26.50
	Base	3.80	1.45	13.00	29.80
	High-cost	4.10	1.50	14.00	32.50
2050	Low-cost	3.60	1.40	12.20	27.40
	Base	3.90	1.45	13.10	31.30
	High-cost	4.20	1.50	14.50	34.60

Source: IEA (2011).

Table A.2: Overnight investment costs of renewable energy technologies per power output [€$_{2010}$/kW$_{el}$]

		Investment costs per year [€$_{2010}$/kW$_{el}$]				Investment costs degression rates [%]		
		2020	2030	2040	2050	2020-2030	2030-2040	2040-2050
Biomass gas*	Low-cost	2,306	2,249	2,225	2,224	-2%	-1%	-0.1%
	Base	2,353	2,324	2,313	2,312	-1%	-0.5%	-0.05%
	High-cost	2,400	2,400	2,400	2,400	-	-	-
Biomass gas - CHP	Low-cost	2,498	2,436	2,412	2,409	-2%	-1%	-0.1%
	Base	2,549	2,518	2,506	2,505	-1%	0%	-0.05%
	High-cost	2,600	2,600	2,600	2,600	-	-	-
Biomass solid*	Low-cost	3,170	3,092	3,061	3,058	-2%	-1%	-0.1%
	Base	3,235	3,196	3,181	3,179	-1%	-0.5%	-0.05%
	High-cost	3,300	3,300	3,300	3,300	-	-	-
Biomass solid - CHP	Low-cost	3,362	3,279	3,247	3,243	-2%	-1%	-0.1%
	Base	3,431	3,390	3,373	3,372	-1%	-0.5%	-0.05%
	High-cost	3,500	3,500	3,500	3,500	-	-	-
Geothermal (hot dry rock)	Low-cost	10,821	7,980	7,036	6,692	-26%	-12%	-5%
	Base	12,616	11,017	10,475	10,303	-13%	-5%	-2%
	High-cost	14,410	14,054	13,914	13,914	-2%	-1%	-
Geothermal (high enthalpy)	Low-cost	2,164	1,596	1,407	1,338	-26%	-12%	-5%
	Base	2,523	2,203	2,095	2,061	-13%	-5%	-2%
	High-cost	2,882	2,811	2,783	2,783	-2%	-1%	-
PV ground	Low-cost	1,234	739	574	546	-40%	-22%	-5%
	Base	1,571	1,276	1,185	1,171	-19%	-7%	-1%
	High-cost	1,907	1,813	1,795	1,795	-5%	-1%	-
PV roof	Low-cost	1,372	821	638	606	-40%	-22%	-5%
	Base	1,745	1,418	1,316	1,301	-19%	-7%	-1%
	High-cost	2,118	2,015	1,995	1,995	-5%	-1%	-
Concentrating solar power	Low-cost	3,319	2,206	1,803	1,715	-34%	-18%	-5%
	Base	4,484	3,858	3,629	3,585	-14%	-6%	-1%
	High-cost	5,649	5,510	5,455	5,455	-2%	-1%	-
Onshore wind	Low-cost	1,108	1,002	929	906	-10%	-7%	-2%
	Base	1,166	1,107	1,071	1,060	-5%	-3%	-1%
	High-cost	1,225	1,213	1,213	1,213	-1%	-	-
Offshore wind (deep)	Low-cost	2,453	1,809	1,595	1,517	-26%	-12%	-5%
	Base	2,860	2,497	2,374	2,335	-13%	-5%	-2%
	High-cost	3,266	3,186	3,154	3,154	-2%	-1%	-
Offshore wind (shallow)	Low-cost	2,236	1,649	1,454	1,383	-26%	-12%	-5%
	Base	2,607	2,277	2,165	2,129	-13%	-5%	-2%
	High-cost	2,978	2,905	2,876	2,876	-2%	-1%	-

Source: EWI (2010), EWI (2011), IEA (2010c) and IEA (2010b).

*Remarks: The difference in the investment costs of biomass gas and biomass solid power plants is due to the fact that biomass gas power plants are assumed to generate electricity via a gas turbine and biomass solid power plants via a steam turbine.

Table A.3: Electricity demand per country and year [TWh]

	2010	2020		2030		2040		2050	
		Low-cost	High-cost	Low-cost	High-cost	Low-cost	High-cost	Low-cost	High-cost
Austria	57.3	56.8	57.9	55.4	59.0	52.7	61.4	48.8	65.9
Belgium	81.4	80.6	82.2	78.6	83.9	74.8	87.3	69.3	93.6
Bulgaria	26.3	26.1	26.6	25.4	27.1	24.2	28.2	22.4	30.2
Czech Republic	57.6	57.1	58.2	55.7	59.4	52.9	61.8	49.1	66.2
Denmark	35.6	35.2	35.9	34.3	36.6	32.6	38.1	30.3	40.8
Estland	6.3	6.3	6.4	6.1	6.5	5.8	6.8	5.4	7.2
Finland	84.9	84.1	85.8	82.0	87.5	78.0	91.0	72.3	97.6
France	421.8	417.6	426.0	407.3	434.6	387.4	452.3	359.3	485.0
Germany	528.8	523.5	534.1	510.6	544.9	485.6	567.1	450.4	608.1
Great Britain	340.4	337.1	343.8	328.7	350.8	312.7	365.0	290.0	391.4
Greece	54.0	53.5	54.5	52.2	55.6	49.6	57.9	46.0	62.1
Hungary	33.0	32.7	33.3	31.9	34.0	30.3	35.4	28.1	37.9
Ireland	24.7	24.5	24.9	23.9	25.5	22.7	26.5	21.1	28.4
Italy	300.7	297.7	303.7	290.3	309.8	276.1	322.5	256.1	345.8
Latvia	5.9	5.8	6.0	5.7	6.1	5.4	6.3	5.0	6.8
Lithuania	8.1	8.1	8.2	7.9	8.3	7.5	8.7	6.9	9.3
Luxemburg	6.6	6.6	6.7	6.4	6.8	6.1	7.1	5.7	7.6
Netherlands	106.7	105.6	107.8	103.0	109.9	98.0	114.4	90.9	122.7
Norway	104.3	103.3	105.3	100.7	107.5	95.8	111.9	88.9	119.9
Poland	115.4	114.3	116.6	111.5	118.9	106.0	123.8	98.3	132.7
Portugal	46.3	45.8	46.8	44.7	47.7	42.5	49.7	39.4	53.2
Romania	41.0	40.6	41.4	39.6	42.2	37.7	44.0	34.9	47.1
Slovakia	24.8	24.5	25.0	23.9	25.6	22.8	26.6	21.1	28.5
Slovenia	13.4	13.3	13.5	12.9	13.8	12.3	14.4	11.4	15.4
Spain	247.4	244.9	249.9	238.9	254.9	227.2	265.3	210.7	284.5
Sweden	131.8	130.5	133.1	127.3	135.8	121.1	141.3	112.3	151.6
Switzerland	57.5	56.9	58.1	55.5	59.2	52.8	61.7	49.0	66.1
Total	2,962.4	2,932.9	2,991.7	2,860.4	3,052.0	2,720.6	3,176.3	2,523.3	3,405.8

Source: EC (2010a).

Remarks: As indicated in Section 2.3, the country-specific demand for electricity is not only defined on a yearly basis but also on a daily and hourly basis (via country-specific load curves for so-called 'typical days'). These load curves are based on historical hourly load data by ENSTO-E (2012) and capture the daily and seasonal characteristics of electricity demand as well as the different load structures among the various European countries. Scaled to 8760 hours, these load curves correspond to the yearly electricity demand listed in the table above.

Model parameters common to all scenarios

Table A.4: Maximum potential for heat generated in CHP plants [TWh]

	2020	2030	2040	2050
Austria	41.2	41.5	41.8	42.0
Belgium	14.7	14.8	14.9	14.9
Bulgaria	6.9	7.0	7.0	7.1
Czech Republic	55.1	55.7	56.4	57.0
Denmark	54.7	55.1	55.4	55.7
Estland	1.4	1.4	1.4	1.4
Finland	65.2	65.7	66.1	66.5
France	31.6	31.8	32.0	32.2
Germany	192.4	192.9	192.9	192.9
Great Britain	68.1	68.6	69.0	69.3
Greece	17.4	17.7	17.9	18.2
Hungary	14.2	14.4	14.5	14.7
Ireland	3.2	3.3	3.3	3.3
Italy	169.2	171.7	174.1	176.5
Latvia	6.5	6.6	6.7	6.7
Lithuania	4.8	4.9	4.9	5.0
Luxemburg	0.9	0.9	0.9	0.9
Netherlands	114.3	115.1	115.8	116.4
Norway	3.6	3.6	3.7	3.7
Poland	93.3	94.4	95.5	96.6
Portugal	13.9	14.1	14.3	14.5
Romania	93.3	94.4	95.5	96.6
Slovakia	17.0	17.2	17.4	17.6
Slovenia	1.2	1.2	1.3	1.3
Spain	59.0	59.9	60.7	61.5
Sweden	29.3	29.5	29.6	29.8
Switzerland	0.7	0.7	0.7	0.7
Total	1173.1	1184.0	1193.7	1203.1

Table A.5: Overnight investment costs of conventional, nuclear and storage technologies per power output [$€_{2010}/kW_{el}$]

Technologies	2010	2020	2030	2040	2050
CCGT	1,250	1,250	1,250	1,250	1,250
CCGT - CCS	-	-	1,550	1,500	1,450
CCGT - CHP	1,500	1,500	1,500	1,500	1,500
CCGT - CHP and CCS	-	-	1,700	1,650	1,600
Hard Coal	1,500	1,500	1,500	1,500	1,500
Hard Coal - innov	2,500	2,250	1,875	1,750	1,650
Hard Coal - CCS	-	-	2,000	1,900	1,850
Hard Coal - innov CCS	-	-	2,475	2,300	2,200
Hard Coal - innov CHP	2,650	2,650	2,275	2,150	2,050
Hard Coal - innov CHP and CCS	-	-	2,875	2,700	2,600
Lignite	1,850	1,850	1,850	1,850	1,850
Lignite - innov	1,950	1,950	1,950	1,950	1,950
Lignite - CCS	-	-	2,550	2,500	2,450
Nuclear	3,157	3,157	3,157	3,157	3,157
OCGT	700	700	700	700	700
CAES	850	850	850	850	850
Pump storage	-	-	-	-	-
Hydro storage	-	-	-	-	-

Source: IEA (2011), EWI (2011) and PROGNOS/EWI/GWS (2010).

Table A.6: Techno-economic parameters for conventional, nuclear and storage technologies

	Efficiency (generation) [%]	Efficiency (load) [%]	Efficiency (CO_2) [%]	CO_2 factor [t CO_2 /MWh_{th}]	Average saisonal availability [%]	FOM-costs [€$_{2010}$/kW]	Technical lifetime * [a]
CCGT	60.0	-	-	0.201	84.50	28.2	30
CCGT - CCS	53.0	-	90.0	0.020	84.50	40.0	30
CCGT - CHP	36.0	-	-	0.201	84.50	88.2	30
CCGT - CHP and CCS	36.0	-	85.0	0.030	84.50	100.0	30
Hard Coal	46.0	-	-	0.335	83.75	36.1	45
Hard Coal - innov	50.0	-	-	0.335	83.75	36.1	45
Hard Coal - CCS	42.0	-	90.0	0.034	83.75	97.0	45
Hard Coal - innov CCS	45.0	-	90.0	0.034	83.75	97.0	45
Hard Coal - innov CHP	22.5	-	-	0.335	83.75	55.1	45
Hard Coal - innov CHP and CCS	18.5	-	85.0	0.050	83.75	110.0	45
Lignite	43.0	-	-	0.406	86.25	43.1	45
Lignite - innov	46.5	-	-	0.406	86.25	43.1	45
Lignite - CCS	43.0	-	90.0	0.041	86.25	103.0	45
Nuclear	33.0	-	-	0.000	84.50	96.6	60
OCGT	40.0	-	-	0.201	84.50	17.0	25
CAES	86.0	82.0	-	0.0	95.00	9.2	40
Pump storage	87.0	83.0	-	0.0	95.00	11.5	100
Hydro storage	87.0	-	-	0.0	95.00	11.5	100

Source: IEA (2011), EWI (2011) and PROGNOS/EWI/GWS (2010).

*Remarks: The technical lifetimes of each technology (listed in Tables B.3 and B.4) represent the number of years that new generation and storage capacities (which are endogenously expanded by the model) can be operated before being decommissioned. As such, the technical lifetimes affect the value of investments in generation and storage capacities in the model.

Table A.7: Techno-economic parameters for RES-E technologies

	Efficiency (generation) [%]	Average saisonal availability [%]	Securely available capacity (peak demand) [%]	FOM costs [€$_{2011}$/kW]	Technical lifetime [a]
Biomass gas	40.0	85	85	120	30
Biomass gas - CHP	30.0	85	85	130	30
Biomass solid	30.0	85	85	165	30
Biomass solid - CHP	22.5	85	85	175	30
Concentrating solar power	-	-	40	120	25
Geothermal (hot dry rock)	22.5	85	85	300	30
Geothermal (high enthalpy)	22.5	85	85	30	30
PV ground	-	-	0	30	25
PV roof	-	-	0	35	25
Run-off-river hydropower	-	-	50	11.5	100
Offshore wind 5MW (deep water)	-	-	5	152	20
Offshore wind 8MW (deep water)	-	-	5	160	20
Offshore wind 5MW (shallow water)	-	-	5	128	20
Offshore wind 8MW (shallow water)	-	-	5	136	20
Onshore wind 6MW	-	-	5	41	20
Onshore wind 8MW	-	-	5	41	20

Source: EWI (2011), EWI (2010), IEA (2010c) and IEA (2010b).

Scenario results

Table A.8: National technology-specific RES-E targets [TWh] for 2020 and marginal costs of compliance [€$_{2010}$/MWh] (not discounted)

	Biomass		Geothermal		CSP	
	[TWh]	[€$_{2010}$/MWh]	[TWh]	[€$_{2010}$/MWh]	[TWh]	[€$_{2010}$/MWh]
Austria	5.2	70	-	-	-	-
Belgium	11.0	184	0.03	95	-	-
Bulgaria	0.9	20	-	-	-	-
Czech Republic	6.2	60	0.02	99	-	-
Denmark	8.9	159	-	-	-	-
Estland	0.4	1	-	-	-	-
Finland	12.9	77	-	-	-	-
France	17.2	58	0.5	88	1.0	536
Germany	49.5	99	1.7	69	-	-
Great Britain	26.2	188	-	-	-	-
Greece	1.3	60	0.7	133	0.7	213
Hungary	3.3	8	0.4	104	-	-
Ireland	1.0	0.3	-	-	-	-
Italy	18.8	119	6.8	-	1.7	150
Latvia	1.2	33	-	-	-	-
Lithuania	1.2	22	-	-	-	-
Luxemburg	0.3	26	-	-	-	-
Netherlands	16.6	163	-	-	-	-
Poland	14.2	79	-	-	-	-
Portugal	3.5	33	0.5	96	-	-
Romania	2.9	39	-	-	-	-
Slovakia	1.7	43	0.03	100	-	-
Slovenia	0.7	131	-	-	-	-
Spain	10.0	31	0.3	64	15.4	130
Sweden	6.0	61	-	-	-	-

Source: EC (2010b).

Table A.9: Scenario-specific capacity and generation mix in Europe by 2050

	1-I-L	1-I-B	1-I-H	1-II-L	1-II-B	1-II-H	1-III-L	1-III-B	1-III-H	1-IV-L	1-IV-B	1-IV-H
	Capacity [GW]											
Nuclear	0	0	0	0	0	0	1	1	1	1	1	1
Lignite (incl. CHP)	52	53	54	52	51	54	51	53	54	51	53	54
Lignite-CCS	0	0	0	0	0	0	0	0	0	0	0	0
Coal (incl. CHP)	234	284	340	234	234	340	234	284	340	234	284	340
Coal-CCS	0	0	0	0	0	0	0	0	0	0	0	0
Gas (incl. CHP)	32	42	54	32	32	54	32	41	54	32	41	54
Gas-CCS	0	0	0	0	0	0	0	0	0	0	0	0
Oil (incl. CHP)	0	0	0	0	0	0	0	0	0	0	0	0
Storage (Pump + CAES)	51	51	51	51	51	51	51	51	51	51	51	51
Hydro	133	136	139	133	134	139	134	136	139	134	136	139
Biomass (incl. CHP)	11	12	12	11	11	12	11	12	12	11	12	12
Onshore wind	72	85	102	72	72	102	72	87	102	72	87	102
Offshore wind	0	0	0	0	0	0	0	0	0	0	0	0
PV	1	0	0	1	1	0	1	0	0	1	0	0
CSP	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	3	3	3	3	3	3	3	3	3	3	3	3
Other	11	11	11	11	11	11	11	11	11	11	11	11
Total	600	677	766	600	600	766	600	678	767	600	678	767
	Generation [TWh]											
Nuclear	0	0	0	0	0	0	3	3	3	3	3	3
Lignite (incl. CHP)	385	397	405	385	397	385	382	395	405	382	395	405
Lignite-CCS	0	0	0	0	0	0	0	0	0	0	0	0
Coal (incl. CHP)	1,480	1,893	2,268	1,480	1,893	1,480	1,480	1,888	2,264	1,480	1,888	2,264
Coal-CCS	0	0	0	0	0	0	0	0	0	0	0	0
Gas (incl. CHP)	0	0	0	0	0	0	0	0	0	0	0	0
Gas-CCS	0	0	0	0	0	0	0	0	0	0	0	0
Oil (incl. CHP)	0	0	0	0	0	0	0	0	0	0	0	0
Storage (Pump + CAES)	5	25	34	5	25	5	5	23	33	5	23	33
Hydro	552	552	552	552	552	552	552	552	552	552	552	552
Biomass (incl. CHP)	84	87	87	84	87	84	84	87	87	84	87	87
Onshore wind	234	255	317	234	255	234	233	259	319	233	259	319
Offshore wind	0	0	0	0	0	0	0	0	0	0	0	0
PV	1	0	0	1	0	1	1	0	0	1	0	0
CSP	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	18	18	18	18	18	18	18	18	18	18	18	18
Other	56	56	56	56	56	56	56	56	56	56	56	56
Imports North Africa	0	0	0	0	0	0	0	0	0	0	0	0
Total	2814	3282	3737	2814	3282	2814	2814	3280	3736	2814	3280	3736

	2-I-L	2-I-B	2-I-H	2-II-L	2-II-B	2-II-H	2-III-L	2-III-B	2-III-H	2-IV-L	2-IV-B	2-IV-H
	Capacity [GW]											
Nuclear	152	221	273	183	258	300	1	1	1	1	1	1
Lignite (incl. CHP)	12	10	10	21	24	27	9	5	9	28	17	17
Lignite-CCS	53	55	57	0	0	0	55	55	59	0	0	0
Coal (incl. CHP)	26	32	40	25	25	25	18	10	10	7	5	3
Coal-CCS	0	0	0	0	0	0	0	0	2	0	0	0
Gas (incl. CHP)	51	45	58	57	61	83	164	234	258	198	272	300
Gas-CCS	0	0	0	0	0	0	0	0	0	0	0	0
Oil (incl. CHP)	0	0	0	0	0	0	0	0	0	0	0	0
Storage (Pump + CAES)	51	52	55	51	54	59	57	97	132	59	99	150
Hydro	138	135	138	139	135	138	145	142	146	144	142	146
Biomass (incl. CHP)	14	19	21	16	19	23	17	22	32	19	25	37
Onshore wind	152	130	163	183	134	205	296	244	385	347	258	397
Offshore wind	0	0	0	0	11	6	81	172	205	96	194	221
PV	12	0	0	19	0	0	149	136	124	224	209	199
CSP	0	0	0	3	0	0	55	40	40	66	60	59
Geothermal	15	15	13	16	15	15	16	16	16	17	17	16
Other	11	11	11	11	11	11	11	11	11	11	11	11
Total	688	726	837	725	747	891	1072	1185	1430	1217	1310	1558
	Generation [TWh]											
Nuclear	1,086	1,606	1,965	1,306	1,873	2,148	3	5	5	5	5	5
Lignite (incl. CHP)	8	6	6	45	44	49	0	0	0	110	5	0
Lignite-CCS	373	374	374	0	0	0	378	380	378	0	0	0
Coal (incl. CHP)	62	64	65	63	63	58	51	1	0	0	0	0
Coal-CCS	0	0	0	0	0	0	0	2	13	0	0	0
Gas (incl. CHP)	0	0	0	0	6	11	65	286	288	105	385	398
Gas-CCS	0	0	0	0	0	0	0	0	0	0	0	0
Oil (incl. CHP)	0	0	0	0	0	0	0	0	0	0	0	0
Storage (Pump + CAES)	32	46	49	38	52	59	36	43	58	32	42	64
Hydro	552	552	552	552	552	552	552	552	551	552	552	551
Biomass (incl. CHP)	90	125	134	101	127	139	117	155	216	132	172	252
Onshore wind	443	377	473	525	387	570	754	657	928	834	684	953
Offshore wind	0	0	0	0	52	30	340	700	831	404	780	881
PV	18	0	0	28	1	0	191	184	165	275	268	257
CSP	0	0	0	12	0	0	199	149	149	240	224	216
Geothermal	105	105	86	107	107	101	110	110	108	110	110	109
Other	56	56	56	56	56	56	56	56	56	56	56	56
Imports North Africa	35	0	0	36	3	0	31	48	47	22	45	63
Total	2860	3313	3761	2869	3322	3774	2882	3327	3794	2877	3327	3804

	3-I-L	3-I-B	3-I-H	3-II-L	3-II-B	3-II-H	3-III-L	3-III-B	3-III-H	3-IV-L	3-IV-B	3-IV-H
	Capacity [GW]											
Nuclear	34	43	58	57	70	85	1	1	1	1	1	1
Lignite (incl. CHP)	16	18	19	26	27	30	12	12	12	27	24	22
Lignite-CCS	29	30	34	0	0	0	52	56	59	0	0	0
Coal (incl. CHP)	32	31	40	28	25	30	30	32	30	9	7	8
Coal-CCS	0	0	0	0	0	0	0	0	0	0	0	0
Gas (incl. CHP)	110	131	148	112	129	147	141	166	216	193	231	277
Gas-CCS	0	0	0	0	0	0	0	0	0	0	0	0
Oil (incl. CHP)	0	0	0	0	0	0	0	0	0	0	0	0
Storage (Pump + CAES)	80	131	178	77	134	192	64	106	145	60	100	151
Hydro	141	143	143	141	142	142	145	145	147	144	144	146
Biomass (incl. CHP)	17	26	41	18	27	40	18	26	37	19	27	35
Onshore wind	311	245	390	328	246	390	320	245	391	356	257	394
Offshore wind	83	197	232	73	196	233	89	196	221	96	203	233
PV	154	121	99	150	127	110	148	142	145	228	198	188
CSP	56	53	30	61	51	29	54	58	37	67	67	62
Geothermal	15	16	15	16	16	15	16	16	16	17	17	16
Other	11	11	11	11	11	11	11	11	11	11	11	11
Total	1089	1196	1439	1096	1201	1453	1101	1211	1466	1227	1285	1542
	Generation [TWh]											
Nuclear	195	270	372	370	457	561	3	4	5	5	5	5
Lignite (incl. CHP)	0	0	5	9	5	22	4	0	0	111	31	0
Lignite-CCS	193	205	217	0	0	0	355	380	373	0	0	0
Coal (incl. CHP)	77	77	73	84	86	76	62	49	27	1	0	0
Coal-CCS	0	0	0	0	0	0	0	0	0	0	0	0
Gas (incl. CHP)	0	0	0	0	0	0	19	78	186	98	316	398
Gas-CCS	0	0	0	0	0	0	0	0	0	0	0	0
Oil (incl. CHP)	0	0	0	0	0	0	0	0	0	0	0	0
Storage (Pump + CAES)	74	116	223	67	106	196	43	52	76	34	46	67
Hydro	552	552	552	552	552	552	552	552	552	552	552	552
Biomass (incl. CHP)	120	180	257	126	190	255	120	181	229	130	186	235
Onshore wind	781	655	928	805	656	932	790	650	933	840	669	937
Offshore wind	352	806	945	314	800	939	371	793	890	402	817	919
PV	204	168	141	197	175	154	190	188	192	279	254	244
CSP	204	200	112	221	192	110	198	216	135	241	245	224
Geothermal	108	108	107	108	110	107	110	110	108	110	110	109
Other	55	55	56	55	54	54	55	56	56	56	56	56
Imports North Africa	32	57	60	30	51	55	22	36	63	22	47	64
Total	2946	3448	4048	2937	3434	4012	2895	3343	3825	2879	3333	3810

Appendix B

Supplemental data for Chapter 3

Assumptions of the household optimization model

Table B.1: Assumed equipment of households with domestic appliances in Germany

Domestic appliance type	Proportion of households equipped with appliance
Chest freezer	19 %
Fridge freezer	59 %
Refrigerator	40 %
Upright freezer	38 %
Answering machine	52 %
Cassette/ CD Player	79 %
Clock	73 %
Cordless telephone	93 %
Hi-Fi system	69 %
Iron	72 %
Vacuum	97 %
Fax	19 %
Personal computer	82 %
Printer	77 %
TV 1	96 %
TV 2	41 %
TV 3	9 %
VCR / DVD	71 %
TV Receiver box	48 %
Hob	46 %
Oven	62 %
Microwave	72 %
Kettle	85 %
Small cooking (group)	100 %
Dish washer	67 %
Tumble dryer	36 %
Washing machine	91 %
Washer dryer	4 %
Electric instantaneous water heater	20 %
Electric shower	0 %
Storage heaters	0 %
Other electric space heating	7 %
Lighting	100%

Source: DESTATIS (2012a), DESTATIS (2012b), DESTATIS (2012c) and Statista (2012).

Assumptions of the electricity system optimization model

Table B.2: National renewable energy targets for 2020 [MW]

	Onshore wind		Offshore wind		PV		Biomass	
	2015	2020	2015	2020	2015	2020	2015	2020
Austria	2.0	2.6	0.0	0.0	0.2	0.3	1.3	1.3
Belgium, Netherlands, Luxemburg	6.0	8.7	1.7	6.9	1.2	2.2	5.4	5.4
Czech Republic	0.5	0.7	0.0	0.0	2.0	1.7	0.3	0.4
Denmark	2.9	2.9	1.3	1.3	0.0	0.0	2.8	2.8
France	10.8	19.0	2.7	6.0	2.2	4.9	3.0	3.0
Germany	33.6	35.8	3.0	10.0	34.3	51.8	8.8	8.8
Poland	3.4	5.6	0.0	0.5	0.0	0.0	2.5	2.5
Switzerland	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Source: EC (2010b).

Table B.3: CO_2 reduction targets (in comparison to 1990 levels)

2020	2025	2030	2035	2040	2045	2050
30 %	45 %	60 %	68 %	75%	83 %	90 %

Table B.4: Gross electricity demand [TWh]

	2015	2020	2025	2030	2035	2040	2045	2050
Germany	611	612	621	631	631	631	631	631
Austria	71	78	78	78	80	82	85	87
Belgium, Netherlands, Luxemburg	247	259	259	259	267	275	283	290
Czech Republic	80	88	93	99	105	111	117	124
Denmark	40	41	41	41	43	44	45	46
France	575	599	621	643	662	682	701	721
Poland	178	202	202	202	214	227	240	253
Switzerland	61	65	65	65	67	69	71	73

Source: ECN (2011) (Reference scenario of the EU member states national renewable energy action plans).

Table B.5: Maximum potential for heat generated in CHP plants [TWh]

	2015	2020	2025	2030	2035	2040	2045	2050
Germany	191.7	192.4	192.7	192.9	192.9	192.9	192.9	192.9
Austria	41.0	41.2	41.4	41.5	41.7	41.8	41.9	42.0
Belgium, Netherlands, Luxemburg	129.0	129.9	130.3	130.8	131.2	131.5	131.9	132.3
Czech Republic	54.5	55.1	55.4	55.7	56.0	56.4	56.7	57.0
Denmark	54.4	54.7	54.9	55.1	55.3	55.4	55.6	55.7
France	31.4	31.6	31.7	31.8	31.9	32.0	32.1	32.2
Poland	92.4	93.3	93.9	94.4	95.0	95.5	96.0	96.6
Switzerland	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7

Table B.6: Overnight investment costs of conventional, renewable and storage technologies per power output [€$_{2011}$/kW$_{el}$]

Technologies	2015	2020	2025	2030	2035	2040	2045	2050
CCGT	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250
CCGT - CCS	-	-	-	1,550	1,525	1,500	1,475	1,450
CCGT - CHP	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
CCGT - CHP and CCS	-	-	-	1,700	1,675	1,650	1,625	1,600
Hard Coal	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
Hard Coal - innov		2,250	2,000	1,875	1,800	1,750	1,700	1,650
Hard Coal - innov CHP	2,650	2,650	2,400	2,275	2,200	2,150	2,100	2,050
Hard Coal - innov CHP and CCS	-	-	-	2,875	2,800	2,700	2,650	2,600
Lignite	1,850	1,850	1,850	1,850	1,850	1,850	1,850	1,850
Lignite - innov	1,950	1,950	1,950	1,950	1,950	1,950	1,950	1,950
Lignite - CCS	-	-	-	2,550	2,525	2,500	2,475	2,450
Nuclear	3,157	3,157	3,157	3,157	3,157	3,157	3,157	3,157
OCGT	700	700	700	700	700	700	700	700
CAES	850	850	850	850	850	850	850	850
Biomass gas	2,399	2,398	2,396	2,395	2,394	2,393	2,392	2,390
Biomass gas - CHP	2,599	2,597	2,596	2,595	2,594	2,592	2,591	2,590
Biomass solid	3,298	3,297	3,295	3,293	3,292	3,290	3,288	3,287
Biomass solid - CHP	3,498	3,497	3,495	3,493	3,491	3,490	3,488	3,486
CSP	4,494	3,989	3,709	3,429	3,266	3,102	2953	2805
Geothermal (hot dry rock)	12,752	10,504	10,002	9,500	9,268	9,035	9031	9026
Geothermal (high enthalpy)	1,275	1,050	1,000	950	927	904	903	903
Onshore wind	1,225	1,200	1,175	1,150	1,125	1,100	1,075	1,050
Offshore wind	2,650	2,200	2,050	1,900	1825	1,750	1,725	1,700
PV ground	1,260	1,100	900	810	765	720	675	630
PV roof	1,400	1,200	1,000	900	850	800	750	700

Source: Jägemann et al. (2013a), Fürsch et al. (2013a) and IEA (2011) and PROGNOS/EWI/GWS (2010).

Table B.7: Techno-economic parameters for conventional and storage technologies

	η [%]	β [%]	ef [t CO_2 /MWh$_{th}$]	av [%]	FOM-costs [€$_{2011}/kW$]	Lifetime [a]
CCGT	60.0	-	0.201	84.50	28.2	30
CCGT - CCS	53.0	-	0.020	84.50	40.0	30
CCGT - CHP	36.0	-	0.201	84.50	88.2	30
CCGT - CHP and CCS	36.0	-	0.030	84.50	100.0	30
Hard Coal	46.0	-	0.335	83.75	36.1	45
Hard Coal - innov	50.0	-	0.335	83.75	36.1	45
Hard Coal - innov CHP	22.5	-	0.335	83.75	55.1	45
Hard Coal - innov CHP and CCS	18.5	-	0.050	83.75	110.0	45
Lignite	43.0	-	0.406	86.25	43.1	45
Lignite - innov	46.5	-	0.406	86.25	43.1	45
Lignite - CCS	43.0	-	0.041	86.25	103.0	45
Nuclear	33.0	-	0.000	84.50	96.6	60
OCGT	40.0	-	0.201	84.50	17.0	25
CAES	86.0	82.0	0.0	95.00	9.2	40
Pump storage	87.0	83.0	0.0	95.00	11.5	100
Hydro storage	87.0	-	0.0	95.00	11.5	100

Source: Jägemann et al. (2013a), Fürsch et al. (2013a), IEA (2011) and PROGNOS/EWI/GWS (2010).

Table B.8: Techno-economic parameters for RES-E technologies

	η [%]	av [%]	Secured capacity [%]	Fixed O&M costs [€$_{2011}/kW$]	Lifetime [a]
Biomass gas	40.0	85	85	120	30
Biomass gas - CHP	30.0	85	85	130	30
Biomass solid	30.0	85	85	165	30
Biomass solid - CHP	22.5	85	85	175	30
Concentrating solar power	-	-	40	100	25
Geothermal (hot dry rock)	22.5	85	85	300	30
Geothermal (high enthalpy)	22.5	85	85	30	30
Offshore wind	-	-	5	93	25
Onshore wind	-	-	5	13	25
PV ground	-	-	0	12	30
PV roof	-	-	0	12	30
Run-off-river hydropower	-	-	50	11.5	100

Source: EWI (2010), Fürsch et al. (2013a), Jägemann et al. (2013a), IEA (2010c) and IEA (2010b).

Table B.9: Interconnection expansions between the modeled market regions [GW]

Import country	Export country	2015	2020	2025	2030
Austria	Germany		3.7		
Belgium, Netherlands, Luxemburg	Germany	1.9	1.0		
Czech Republic	Germany				1.9
Denmark	Germany				0.6
France	Switzerland				1.0
Germany	Austria		3.7		
Germany	Poland		1.9		1.7
Germany	Czech Republic				1.9
Germany	Belgium, Netherlands, Luxemburg	1.9	1.0		
Germany	Denmark		1.0		0.6
Poland	Germany		3.7		
Switzerland	France				1.0

Source: ENSTO-E (2012).

Table B.10: Fuel prices [€$_{2011}$/MWh$_{th}$]

	2015	2020	2025	2030	2035	2040	2045	2050
Coal	12.3	12.5	12.7	12.8	12.9	13.0	13.0	13.1
Gas	23.3	25.2	26.9	28.3	29.1	29.8	30.5	31.3
Lignite	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Nuclear	3.6	3.7	3.7	3.7	3.8	3.8	3.9	3.9
Oil	90.4	99.0	105.0	110.0	113.0	114.0	115.0	116.0

Source: IEA (2011) and PROGNOS/EWI/GWS (2010).

Iterative approach

From a total system perspective, an increased share of in-house PV electricity consumption causes changes in the residual load (both in volume and structure), which in turn affects both the wholesale electricity price (via a change in the provision and operation of power plants) and the residential electricity tariff (via changes in the wholesale electricity price and the renewable energy surcharge). The latter effect occurs due to the fact that under the current feed-in tariff system in Germany, the costs associated with the promotion of renewable energies are passed on to electricity consumers via the so-called 'renewable energy surcharge' as part of the residential electricity tariff (Figure

3.1).[156] As such, the level of the renewable energy surcharge increases if (ceteris paribus) the annual amount of electricity purchased from the grid by (non-privileged) electricity consumers decreases.

However, changes in the wholesale electricity price and the residential electricity tariff, in turn, influence the cost-optimal dimensioning of the PV and battery storage capacities from the single household's perspective. In particular, households are assumed to avoid the residential electricity tariff for the amount of self-produced PV electricity consumed in-house and receive the wholesale electricity price for the amount of surplus (not self-consumed) PV electricity that is fed into the grid. Hence, the amount of surplus PV electricity generation fed in to the grid is asssumed to be remunerated with its actual market value at a specific hour.

To capture this immanent interdependency, the results of the household optimization model are iterated with the results of an electricity system optimization model, which determines (among others) the hourly wholesale electricity prices and the residential electricity tariff per year for Germany until convergence of results is achieved (see below). Figure B.1 shows a schematic representation of the iterative process to quantify the consequences of both exempting in-house PV electricity consumption from taxes, levies and surcharges and allocating network cost to electricity customers via energy-related instead of capacity-related (cost-reflective) network tariffs. Overall, the iterative process can be divided into two seperate steps:

Step 1: Based on the single household's demand profiles (8760 h), solar radiation profiles (8760 h), the PV and battery storage system investment costs, the residential electricity tariff and the hourly wholesale electricity prices (8760 h), the household optimization model determines the cost-optimal PV and storage capacities from the single household's perspective (depending on the number of residents living in the house and the location of the house). Hourly system performance statistics, including the single household's PV electricity in-house consumption and grid feed-in profiles for 8760 h of the year, are also determined. The initial values for the wholesale electricity price, the renewable energy surcharge and the residential electricity tariff for the first iteration are shown in Table B.11.

[156]Specifically, the revenue from the renewable electricity sold on the power exchange is deducted from the cost associated with the payment of renewable energy feed-in tariffs. The remainder is passed on to (non-privileged) electricity consumers as the renewable energy surcharge. Hence, the renewable energy surcharge [in €$_{2011}$/kWh] corresponds to the difference between the annual sum of feed-in tariffs paid for the renewable energy supply and the annual revenues earned by selling the renewable energy supply at the wholesale electricity market [€$_{2011}$] divided by the annual amount of electricity purchased from the grid by (non-privileged) electricity consumers [kWh].

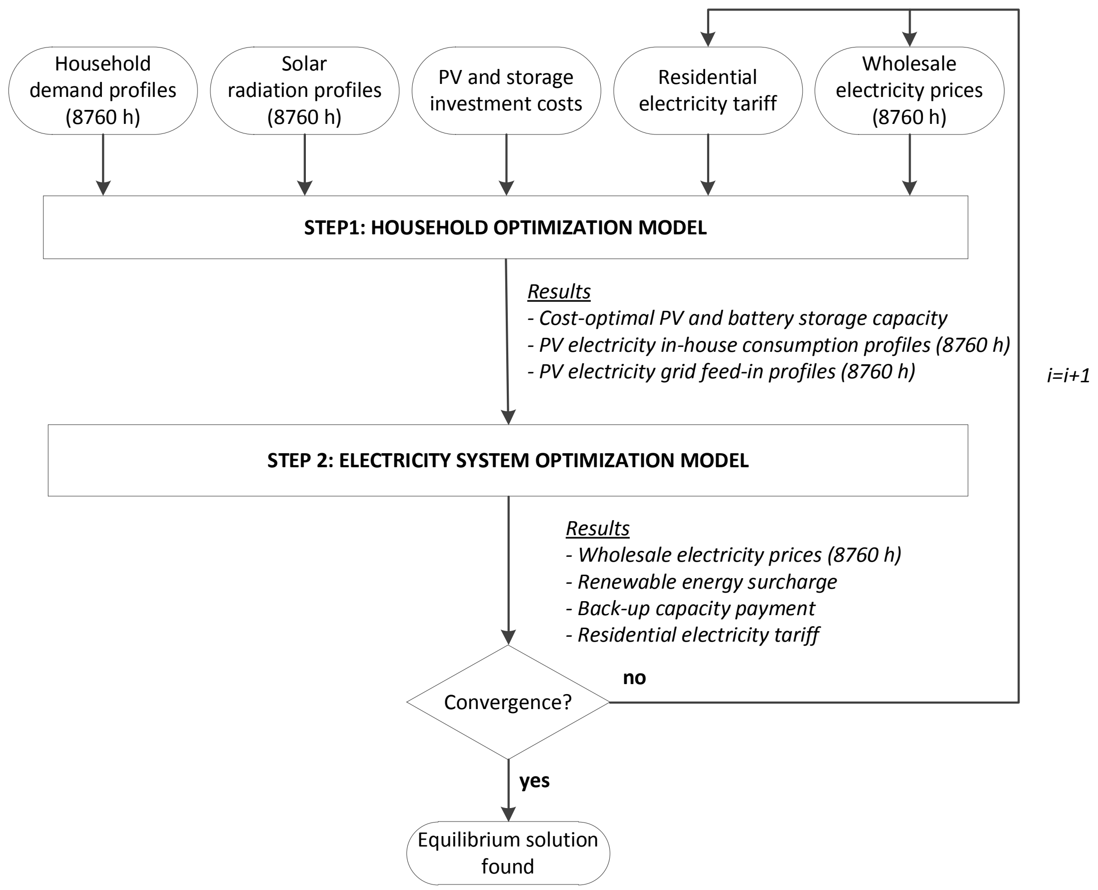


Figure B.1: Schematic representation of the iterative process

Table B.11: Initial assumptions for iteration step 1

	2020	2025	2030	2035	2040	2045	2050
Renewable energy surcharge [ct/kWh]	6.0	5.0	3.0	2.0	1.0	-	
Back-up capacity payment [ct/kWh]				1.5			
Average wholesale electricity price [ct/kWh]				5			

Step 2: The results of the household optimization model (i.e., the cost-optimal PV and battery storage capacities as well as the PV electricity in-house consumption and grid feed-in profiles for 8760 h) serve as input parameters for the electricity system optimization model.

Based on these input parameters, the electricity system optimization model determines (among others) the hourly wholesale prices, the renewable energy surcharge, the back-up capacity payment and the retail electricity tariff per year.

Subsequently, the wholesale electricity prices and the retail electricity tariff are again taken as input parameters for the household optimization model. Based on the new hourly wholesale electricity prices and the new retail electricity tariff, the household optimization model again determines the cost-optimal PV and storage capacities from the single household's perspective and the corresponding PV electricity in-house consumption and grid feed-in profiles for 8760 h of the year (Step 1).

This iterative process (Steps 1 - 2) is continued until convergence of results is achieved. Formally, the iterative process is stopped after the change in the cost-optimal PV and battery storage capacities from iteration i to iteration i+1 is smaller than 2 %.

Change in the optimal (scaled-up) capacities of PV and storage systems during the iterative process

Figure B.2 shows the development of the optimal (scaled-up) PV and storage capacities during the iterative process. Convergence of results is achieved after nine iteration steps. Both (scaled-up) PV capacities and storage capacities change by less than 2 % from iteration step 8 to iteration step 9.

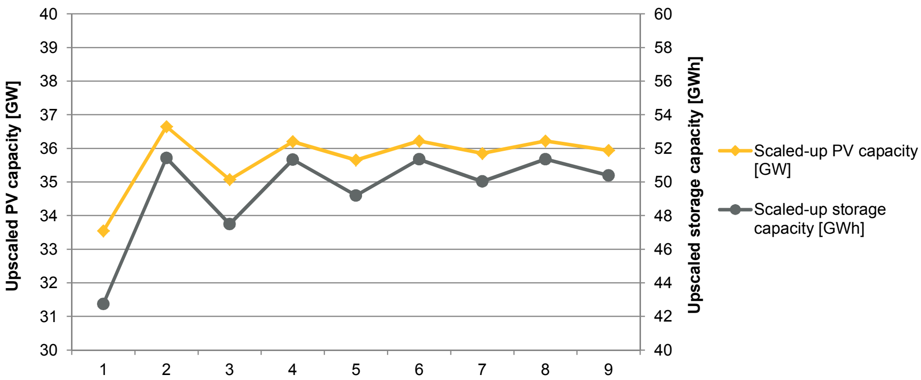


FIGURE B.2: Change in the optimal (scaled-up) PV and storage capacities during the iterative process

Sensitivity analysis and robustness of results

To demonstrate the robustness of results we repeat the iteration for two alternative starting values. In Sensitivity (i), we assume an initial average wholesale electricity price of 3 ct/kWh instead of 5 ct/kWh (see Table B.11), whereas in Sensitivity (ii), we assume an initial back-up capacity payment of 2.5 ct/kWh instead of 1.5 ct/kWh. The development of the optimal (scaled-up) PV and storage capacities during the iterative process for an initial average wholesale electricity price of 3 ct/kWh and an initial back-up capacity payment of 2.5 ct/kWh is shown in Figures B.3 and B.3. As can be seen, both the (scaled-up) PV and storage capacities converge to the same optimal capacities despite different initial values.

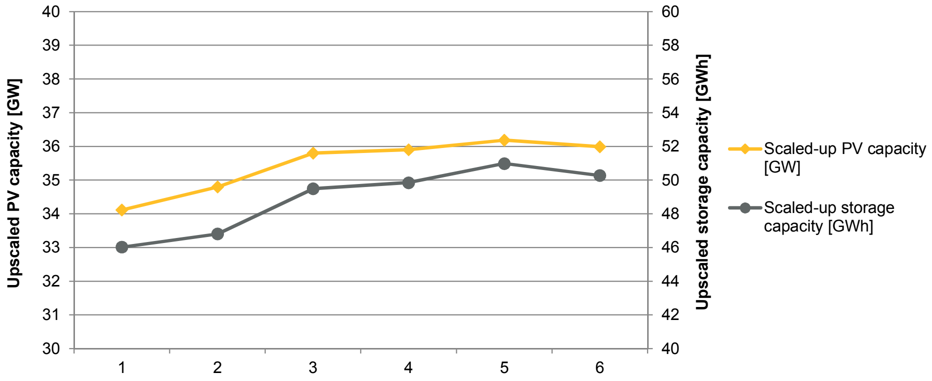


FIGURE B.3: Sensitivity (i) – Change in the optimal (scaled-up) PV and storage capacities during the iterative process

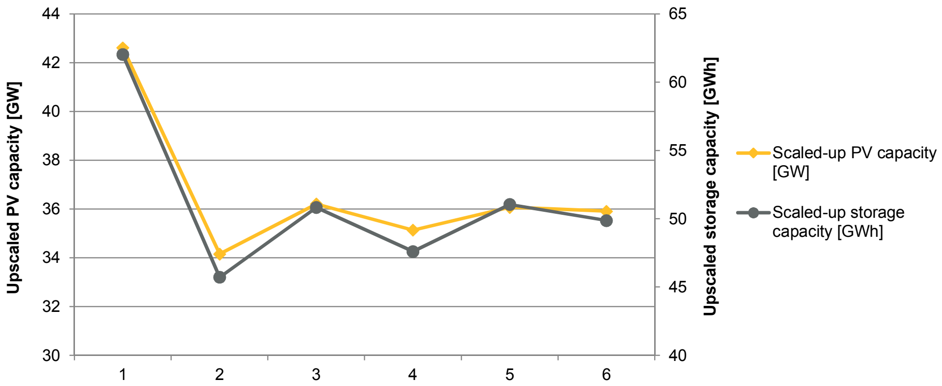


FIGURE B.4: Sensitivity (ii) – Change in the optimal (scaled-up) PV and storage capacities during the iterative process

Appendix C

Supplemental data for Chapter 4

Optimality condition for the expansion of wind and solar power units

Given a politically implemented (technology-neutral) RES-E target, the optimality condition for the expansion of fluctuating renewables can be derived by maximizing social welfare or by minimizing total system costs. The cost-minimization approach corresponds to the welfare-maximization approach given the assumption of perfect competition and a price-inelastic electricity demand.

In this analysis, we derive the optimality condition for the expansion of fluctuating renewable energy capacities (C^f) with no short-run marginal costs of power production and weather dependent production factor profiles ($pf^f_{y,h}$) by minimizing total system costs which are accumulated over all years (Y) and hours (H) of the capacities' technical lifetime (Eq. (C.1)). Assuming two kinds of generation technologies – i.e., dispatchable power plants and fluctuating renewable energy technologies – total system costs include annualized investment costs of dispatchable power plants (fc^d_y) and fluctuating renewable energy units (fc^f_y), as well as the variable generation costs (i.e., short-run marginal costs of power production) of dispatchable power plants (VC^d), which are a function of the dispatchable power plants' generation level ($G^d_{y,h}$).

Total system costs are minimized subject to several techno-economic constraints. Equations (C.2) - (C.3) restrict the hourly output of dispatchable power plants and fluctuating renewable energy units (capacity constraints), while Equation (C.4) ensures that demand ($l_{y,h}$) equals supply (power balance constraint). Equation (C.5) states that the accumulated CO_2 emissions may not exceed a certain CO_2 cap (co_y) per year (CO_2 emission constraint).[157] Moreover, Equation (C.6) defines the minimum share (x) of renewable

[157]The CO_2 emission constraint reflects a cap- and trade-system for CO_2 emission allowances.

energy generation in % of the annual electricity demand ($\sum_{h \in H} l_{y,h}$) (renewable energy constraint).[158]

Table C.1: Model sets, parameters and variables

Sets	
h in H	Hour H = [1,...,i]
d in D	Dispatchable power plants
f in F	Fluctuating renewable energy technologies (wind and solar power)
y in Y	Technical lifetime of fluctuating renewable energy technologies, Year Y = [1,...,j]
Parameters	
co_y	Cap for CO_2 emissions [t CO_2]
ef^d	CO_2 emissions per fuel consumption [t CO_2 /MWh_{th}]
η^d	Net efficiency (generation) [%]
fc_y^d	Annualized investment costs of dispatchable power plants [€ /kW]
fc_y^f	Annualized investment costs of fluctuating renewable energy technologies [€ /kW]
$l_{y,h}$	Price-inelastic electricity demand [kW]
pf_h^d	Production factor of dispatchable capacities [kW/kW_{inst} or %]
$pf_{y,h}^f$	Production factor of fluctuating renewable energy capacities [kW/kW_{inst} or %]
x	(Technology-neutral) renewable energy quota [%]
Variables	
C^d	Dispatchable capacities [kW]
C^f	Fluctuating renewable energy capacities [kW]
C^w	Fluctuating wind power capacities [kW]
C^s	Fluctuating sola power capacities [kW]
$G_{y,h}^d$	Generation of dispatchable capacities [kWh]
$G_{y,h}^f$	Generation of fluctuating renewable energy capacities [kWh]
$VC^d(G_{y,h}^d)$	Variable costs of dispatchable power generation [€]
$RL_{y,h}$	Residual Load [kW]
π	Profit [€ /kWh]
Shadow variables	
γ_y	Shadow variable of the CO_2 emission consraint [€ /t CO_2]
$\lambda_{y,h}^d$	Shadow variable of the dispatchable capacity constraint [€ /kW]
$\lambda_{y,h}^f$	Shadow variable of the fluctuating renewable energy capacity constraint [€ /kW]
$\mu_{y,h}$	Shadow variable of the power balance constraint [€ /kW]
ρ_y	Shadow variable of the fluctuating renewable energy constraint [€ /kW]
Variables calculated ex-post	
MV_{Cf}^{el}	Marginal value of power supply of fluctuating renewable energy capacities [€ /kW]
MV_{Cf}^{ren}	Marginal value of renewable electricity supply of fluctuating renewable energy capacities [€ /kW]
MC_{Cf}	Marginal costs of fluctuating renewable energy capacities [€ /kW]

The optimality condition for the cost-efficient expansion of fluctuating wind and solar power capacities (C^f) under a (technology-neutral) target for fluctuating renewable energy generation is derived by differentiating the Lagrangian function (Eq. (C.7)) with respect to C^f (Eq. (C.8)).

The variable $\mu_{y,h}$ corresponds to the shadow variable of the power balance constraint (Eq. (C.4)) and represents the system's marginal costs associated with meeting the hourly electricity demand ($l_{h,y}$). Assuming perfect competition and a price-inelastic electricity demand, the shadow variable of the power balance constraint ($\mu_{y,h}$) serves as a proxy for the wholesale price. The variable ρ_y, in contrast, corresponds to the shadow

[158] The renewable energy constraint reflects a (technology- and region-neutral) quota system for fluctuating rewewable energy generation in combination with tradable green certificates (TGC).

variable of the renewable energy constraint (Eq. (C.6)) and indicates the marginal system costs associated with the achievement of the renewable energy target. It may be interpreted as the price of tradable green certificates (TGC).[159] Moreover, $\lambda^d_{y,h}$ and $\lambda^f_{y,h}$ are the shadow variables of the capacity constraints (Eq. (C.2)-(C.3)). Following the explanation of Lamont (2008), $\lambda^d_{y,h}$ and $\lambda^f_{y,h}$ correspond to the amount of net revenue that dispatchable generators (C^d) and fluctuating renewable energy generators (C^f) receive per hour above their operating costs per unit of electricity produced (i.e., above their short-run marginal costs of power production), assuming that all generators receive a wholesale price equal to the system's marginal costs $\mu_{y,h}$. Hence, $\lambda^d_{y,h}$ and $\lambda^f_{y,h}$ are the difference between the generators' short-run marginal costs of power production and the system's marginal costs $\mu_{y,h}$. However, in contrast to dispatchable power plants, the short-run marginal costs of fluctuating renewable energy generation, i.e., of wind and solar power production, are zero. As a consequence, the net revenue wind and solar power generators receive per hour corresponds to the system's marginal costs $\mu_{y,h}$ (wholesale price). Hence, the optimality condition for the expansion of fluctuating renewable energy generation units – given a politically implemented technology- and region-neutral RES-E target – can be rewritten as follows:

$$\min \; TSC_{C^f} = \sum_{d\in D}\sum_{y\in Y} C^d \cdot fc^d_y + \sum_{f\in F}\sum_{y\in Y} C^f \cdot fc^f_y + \sum_{d\in D}\sum_{y\in Y}\sum_{h\in H} VC^d(G^d_{y,h}) \tag{C.1}$$

s.t.

$$G^d_{y,h} - pf^d_{y,h} \cdot C^d \leq 0 \tag{C.2}$$

$$G^f_{y,h} - pf^f_{y,h} \cdot C^f \leq 0 \tag{C.3}$$

$$l_{y,h} - \sum_{d\in D} G^d_{y,h} - \sum_{f\in F} G^f_{y,h} = 0 \tag{C.4}$$

$$\sum_{d\in D}\sum_{h\in H} \frac{G^d_{y,h}}{\eta^d} \cdot ef^d) \leq co_y \tag{C.5}$$

$$x \cdot \sum_{h\in H} l_{y,h} - \sum_{f\in F}\sum_{h\in H} pf^f_{y,h} \cdot C^f \leq 0 \tag{C.6}$$

[159] Alternatively, it may be interpreted as the optimal level of a bonus payment given the analogy of quantity- and price-based mechanisms under the assumption of perfect information. However, for reasons of completeness, note that in markets with uncertainties, price-based and quantity-based instruments are no longer equivalent (Weitzman (1974)).

$$
\begin{aligned}
\min \quad L_{Cf} = \sum_{d\in D}\sum_{y\in Y} C^d \cdot fc_y^d + \sum_{f\in F}\sum_{y\in Y} C^f \cdot fc_y^f + \sum_{d\in D}\sum_{y\in Y}\sum_{h\in H} VC^d(G_{y,h}^d) \quad \text{(C.7)}\\
+\sum_{d\in D}\sum_{y\in Y}\sum_{h\in H}(\lambda_{y,h}^d \cdot (G_{y,h}^d - pf_h^d \cdot C^d)) + \sum_{f\in F}\sum_{y\in Y}\sum_{h\in H}(\lambda_{y,h}^f \cdot (G_{y,h}^f - pf_{y,h}^f \cdot C^f))\\
+\sum_{y\in Y}\sum_{h\in H}(\mu_{y,h} \cdot (l_{h,y} - \sum_{d\in D} G_{y,h}^d - \sum_{f\in F} G_{y,h}^f))\\
+\sum_{y\in Y}\gamma_y \cdot (co_y - \sum_{d\in D}\sum_{h\in H}\frac{G_{y,h}^d}{\eta^d} \cdot ef^d)\\
+\sum_{y\in Y}\rho_y \cdot (x \cdot \sum_{h\in H} l_{y,h} - \sum_{f\in F}\sum_{h\in H} pf_{y,h}^f \cdot C^f)
\end{aligned}
$$

$$
dL/dC^f = \sum_{y\in Y} fc_y^f - \sum_{y\in Y}\sum_{h\in H} pf_{y,h}^f \cdot \lambda_{y,h}^f - \sum_{y\in Y}\sum_{h\in H} pf_{y,h}^f \cdot \rho_y = 0 \qquad \text{(C.8)}
$$

$$
\underbrace{\sum_{y\in Y} fc_y^f}_{MC_{Cf}} = \underbrace{\sum_{y\in Y}\sum_{h\in H} pf_{y,h}^f \cdot \mu_{y,h}}_{MV_{Cf}^{el}} + \underbrace{\sum_{y\in Y}\sum_{h\in H} pf_{y,h}^f \cdot \rho_y}_{MV_{Cf}^{ren}} . \qquad \text{(C.9)}
$$

Assumptions of the numerical example for Germany

Assumed variation of onshore wind and solar power capacities

For reasons of comparability, the onshore wind and solar power capacities across the three regions are varied in such a way that they produce the same overall power output (Table C.2).

The logic behind the exogenous variation of onshore wind and solar power capacities (across the different regions) is as follows: For example, when the impact of increased penetration of onshore wind power in northern Germany is analyzed, the onshore wind power capacities in the other two regions (central and southern Germany) are assumed to be zero, while the solar power capacities are assumed to amount to 33 GW (which is the historical installed capacity in 2012). Of these 33 GW solar power capacities one third is assumed to be located in central Germany and two thirds in southern Germany, producing a total of 37 TWh per year. Equally, when, for example, the impact of increased solar power penetration in southern Germany is analyzed, the solar power capacities in the other two regions (central and northern Germany) are assumed to be zero, while the onshore wind power capacities are assumed to amount to 32 GW (which is the historical installed capacity in 2012). Of these 32 GW wind power capacities two thirds are assumed to be installed in northern Germany and one third in central Germany, producing a total of 60 TWh per year.

Table C.2: Assumed variation of onshore wind and solar power capacities in Germany

Region	Full load hours [h]	Exogenous variation of capacities [GW]	Annual generation [TWh]
Onshore wind power			
North	1,938	10.0/15.0/20.0/25.0/30.0	19/29/39/48/58
Central	1,706	11.4/17.0/22.7/28.4/34.1	
South	1,560	12.4/18.6/24.8/31.1/37.3	
Average	1,950	11.2/16.8/22.3/27.9/33.5	
Solar power			
North	992	19.5/29.3/39.1/48.9/58.6	19/29/39/48/58
Central	1,055	18.4/27.6/36.8/45.9/55.1	
South	1,169	16.6/24.9/33.2/41.5/49.8	
Average	1,072	18.1/27.1/36.2/45.2/54.3	

Dependence of the time-weighted average wholesale price $\mathbf{E}(\mu_{y,h})$ on wind and solar power penetration

It should be noted that due to the assumed (linear) wholesale price function (Eq. (4.19)) the decrease in the time-weighted average wholesale price ($\mathrm{E}(\mu_{y,h})$) does not differ between the regions (see Figure C.1). However, the level of the time-weighted average wholesale price ($\mathrm{E}(\mu_{y,h})$) differs between technologies. This can be explained by the fact that the (historical) solar power capacities (33 GW/ 37 TWh), which are held constant when the wind penetration is increased, differ from the (historical) wind power capacities (32 GW/ 60 TWh), which are held constant when the wind penetration is increased.

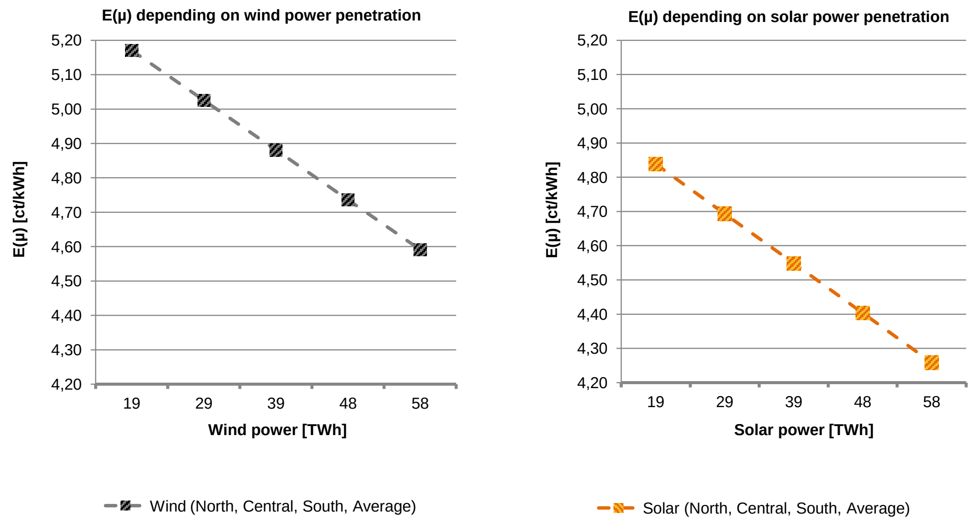


FIGURE C.1: Time-weighted average wholesale price E($\mu_{y,h}$)

Impact of increased wind and solar power penetration on the annual residual electricity demand profile (based on 8760 h)

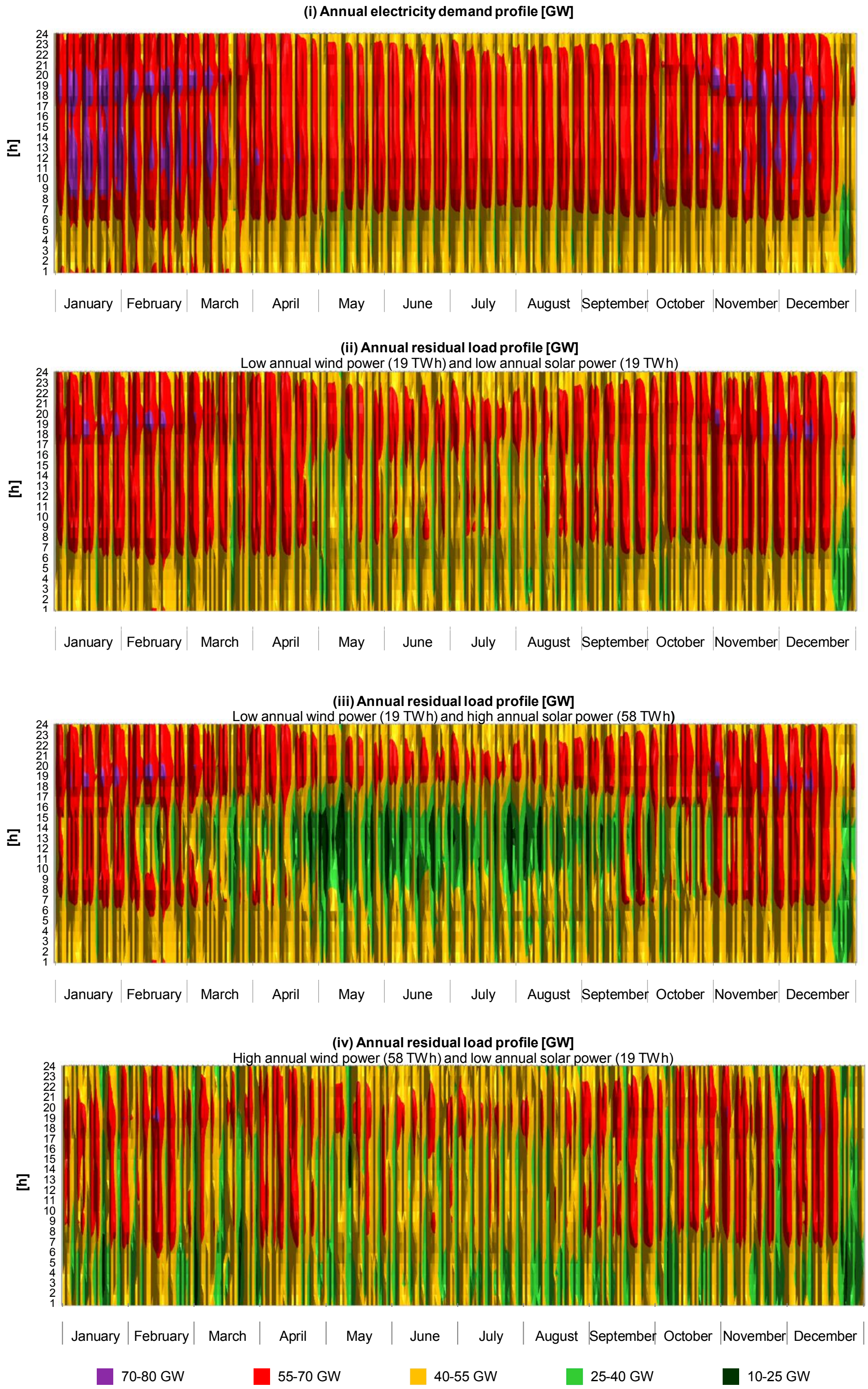


FIGURE C.2: Impact of increased wind and solar power penetration on the annual residual electricity demand profile (based on 8760 h)

Correlation between the demand profile and the production factor profile

TABLE C.3: Correlation between the demand profile and the production factor profile

wind north	0.19
wind center	0.17
wind south	0.08
wind average	0.17
solar north	0.21
solar center	0.23
solar south	0.28
solar average	0.26

Appendix D

Supplemental data for Chapter 5

Assumptions of the electricity system optimization model

Table D.1: Technology- and region-specific wind and solar power targets for 2020 assumed in the 'EEG-Scenario'

	Solar power (region-neutral)	Onshore wind power for northern Germany (region-specific)	Offshore wind power (region-neutral)
Target for 2020 [GW]	52	50	6.5
Assumed full load hours [h]	1,084	1,528	3,423
Modeled targets for 2020 [TWh]	56	76	22

Source: BMU (2014).

Table D.2: Annual net electricity demand [TWh] (2012 levels)

Germany	560
Austria	69
Netherlands	117
France	495

Source: ENTSO-E (2014).

Table D.3: Maximum potential for heat generated in CHP plants per year [TWh]

Germany	191
Austria	41
Netherlands	113
France	31

Table D.4: Overnight investment costs of conventional, renewable and storage technologies per power output [€$_{2010}$/kW$_{el}$]

Technologies	2015	2020	2025	2030	2035	2040	2045	2050
CCGT	1,175	1,175	1,175	1,175	1,175	1,175	1,175	1,175
CCGT - CCS	-	-	-	1,550	1,525	1,500	1,475	1,450
CCGT - CHP	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
CCGT - CHP and CCS	-	-	-	1,700	1,675	1,650	1,625	1,600
Hard Coal	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
Hard Coal - innovative		2,500	2,025	1,800	1,700	1,700	1,700	1,650
Hard Coal - innovative CHP	2,650	2,650	2,400	2,275	2,200	2,150	2,100	2,050
Hard Coal - innovative CHP and CCS	-	-	-	2,875	2,800	2,700	2,650	2,600
Lignite	1,850	1,500	1,500	1,500	1,500	1,500	1,500	1,500
Lignite - innovative	1,950	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Lignite - innovative CHP	4,100	4,100	4,100	4,100	4,100	4,100	4,100	4,100
Lignite - CCS	-	-	-	2,550	2,525	2,500	2,475	2,450
Nuclear	3,157	3,157	3,157	3,157	3,157	3,157	3,157	3,157
OCGT	700	700	700	700	700	700	700	700
CAES	1100	1100	1100	1100	1100	1100	1100	1100
Biomass gas	2,400	2,400	2,400	2,400	2,400	2,400	2,400	2,400
Biomass gas - CHP	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600
Biomass solid	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300
Biomass solid - CHP	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
CSP	4,494	3,989	3,709	3,429	3,266	3,102	2953	2805
Geothermal (hot dry rock)	12,752	10,504	10,002	9,500	9,268	9,035	9031	9026
Geothermal (high enthalpy)	1,275	1,050	1,000	950	927	904	903	903
Onshore wind	1,425	1,350	1,325	1,300	1,275	1,250	1,225	1,200
Offshore wind	4,500	4,000	3,500	3,000	2,875	2,750	2,625	2,500
PV	1,500	1,300	1,150	1,090	1,030	980	940	900

Source: The Crown Estate (2012), ISE (2013), Agora Energiewende (2013b), IEA (2011), EWI (2011) and PROGNOS/EWI/GWS (2010).

Table D.5: Fuel prices [€$_{2010}$/MWh$_{th}$]

	2015	2020	2025	2030	2035	2040	2045	2050
Nuclear	3.6	3.7	3.7	3.7	3.8	3.8	3.9	3.9
Lignite	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Oil	90.4	99.0	105.0	110.0	113.0	114.0	115.0	116.0
Coal	12.3	12.5	12.7	12.8	12.9	13.0	13.0	13.1
Gas	23.3	25.2	26.9	28.3	29.1	29.8	30.5	31.3

Source: IEA (2011) and PROGNOS/EWI/GWS (2010).

Table D.6: Techno-economic parameters for conventional and storage technologies

	η [%]	β [%]	ef [t CO_2 /MWh_{th}]	av [%]	FOM-costs [€$_{2010}$/kW]	Lifetime [a]
CCGT	60.0	-	0.201	84.50	28.2	30
CCGT - CCS	53.0	-	0.020	84.50	40.0	30
CCGT - CHP	36.0	-	0.201	84.50	88.2	30
CCGT - CHP and CCS	36.0	-	0.030	84.50	100.0	30
Hard Coal	46.0	-	0.335	83.75	36.1	45
Hard Coal - innovative	50.0	-	0.335	83.75	36.1	45
Hard Coal - innovative CHP	22.5	-	0.335	83.75	55.1	45
Hard Coal - innovative CHP and CCS	18.5	-	0.050	83.75	110.0	45
Lignite	43.0	-	0.406	86.25	43.1	45
Lignite - innovative	46.5	-	0.406	86.25	43.1	45
Lignite - CCS	43.0	-	0.041	86.25	103.0	45
Nuclear	33.0	-	0.000	84.50	96.6	60
OCGT	40.0	-	0.201	84.50	17.0	25
CAES	86.0	82.0	0.0	95.00	9.2	40
Pump storage	87.0	83.0	0.0	95.00	11.5	100
Hydro storage	87.0	-	0.0	95.00	11.5	100

Source: IEA (2011), EWI (2011) and PROGNOS/EWI/GWS (2010).

Table D.7: Techno-economic parameters for RES-E technologies

	η [%]	av [%]	Secured capacity [%]	Fixed O&M costs [€$_{2010}$/kW]	Lifetime [a]
Biomass gas	40.0	85	85	120	30
Biomass gas - CHP	30.0	85	85	130	30
Biomass solid	30.0	85	85	165	30
Biomass solid - CHP	22.5	85	85	175	30
Concentrating solar power	-	-	40	100	25
Geothermal (hot dry rock)	22.5	85	85	300	30
Geothermal (high enthalpy)	22.5	85	85	30	30
Offshore wind	-	-	5	93	25
Onshore wind	-	-	5	13	25
PV ground	-	-	0	12	30
PV roof	-	-	0	12	30
Run-of-river hydropower	-	-	50	11.5	100

Source: EWI (2011), EWI (2010), IEA (2010c) and IEA (2010b).

Table D.8: Interconnection expansions between the modeled market regions [GW]

Import country	Export country	2015	2020	2025	2030	2035
Austria	Germany		2.9	1.0	1.3	
Netherlands	Germany	1.9	1.0			1.0
France	Germany					1.9
Germany	Austria		2.9	1.0	1.3	
Germany	Netherlands	1.9	1.0			1.0
Germany	France					2.3

Source: ENTSO-E (2012).

Results of the electricity system optimization model

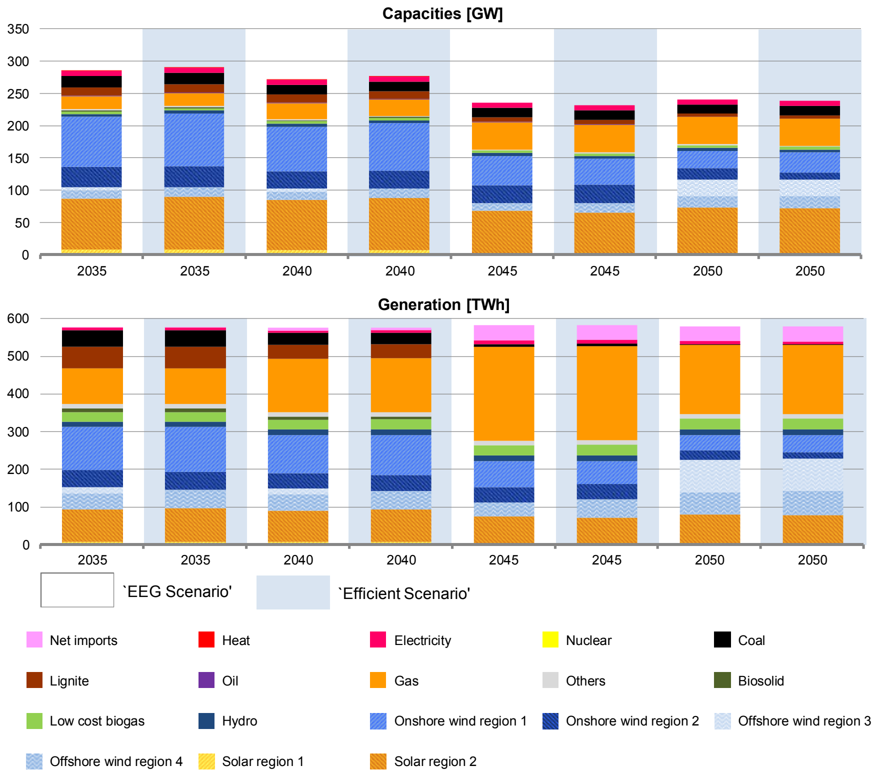


FIGURE D.1: Development of Germany's capacity [GW] and generation [TWh] mix up to 2050

TABLE D.9: Wind and solar power curtailment [GWh]

	2020	2025	2030	2035	2040	2045	2050
	Curtailment in the 'EEG Scenario' [GWh]						
Onshore wind power region 1		1493	3426	3906	3430	428	1020
Onshore wind power region 2	82	7	65	112	81		69
Offshore wind power region 3		14	57	886	755		
Offshore wind power region 4		0.3	15	53	87		17
Solar power region 1		11	16	251	214		
Solar power region 2		0.5	0.1		23	2	2
	Curtailment in the 'Efficient Scenario' [GWh]						
Onshore wind power region 1	239	2502	3895	5231	4776	395	1013
Onshore wind power region 2	3	16	39	145	125		42
Offshore wind power region 3	1	19	40	59			
Offshore wind power region 4	0.01	6	25	120	81		35
Solar power region 1	0.2	33	98	407	265		
Solar power region 2	0.2	0.5	1	0.2	13	2	2

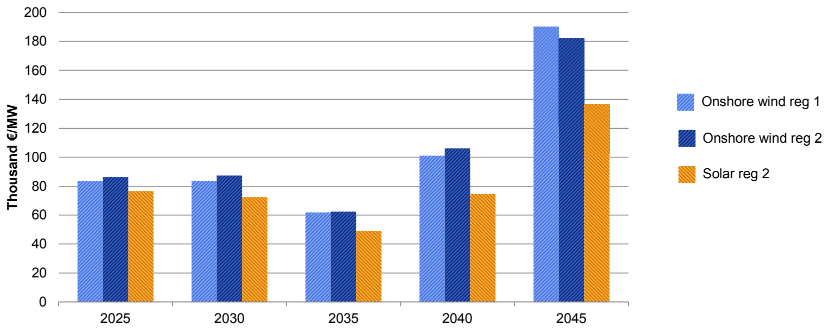


FIGURE D.2: Development of the annual revenue from selling electricity on the wholesale market of capacities built in 2025 in the 'Efficient Scenario' [thousand € /MW] (not discounted)

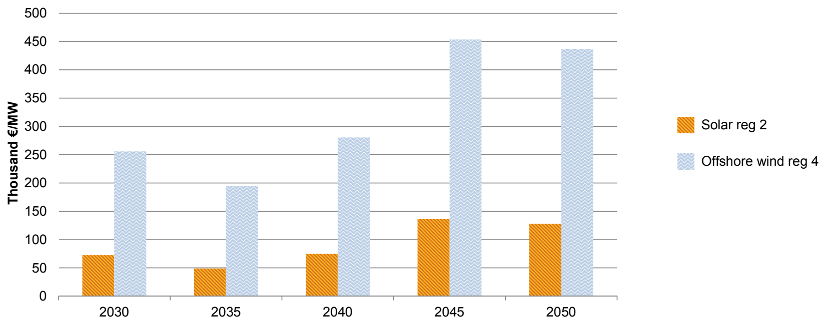


FIGURE D.3: Development of the annual revenue from selling electricity on the wholesale market of capacities built in 2030 in the 'Efficient Scenario' [thousand € /MW] (not discounted)

Appendix E

Supplemental data for Chapter 6

Concentrated solar power projects in Spain

Table E.1: Concentrated solar power projects in Spain

Project	Start Production	Turbine [MW]	Solar-Field [m^2]	Storage [h]
Alvarado I	2009	50	n.a.	0
Andasol-1 (AS-1)	2008	50	510,120	7.5
Andasol-2 (AS-2)	2009	50	510,120	7.5
Andasol-3 (AS-3)	2011	50	n.a.	7.5
Andasol-4 (AS-4)	2020	50	510,120	7.5
Arcosol 50 (Valle 1)	2010	49.9	n.a.	7.5
Central Solar Termoelectrica La Florida	2010	49.9	552,750	7.5
EL REBOSO II 50-MW	2011	50	319,057	0
EL REBOSO III 50-MW	2012	50	518,469	2.3
Extresol-1 (EX-1)	2010	50	510,120	7.5
Extresol-2 (EX-2)	2010	49.9	510,120	7.5
Extresol-3 (EX-3)	2010	49.9	510,210	7.5
Gemasolar Thermosolar Plant (Gemasolar)	2010	17	318,000	15.0
Helios I (Helios I)	n.a.	49.9	n.a.	0
Helios II (Helios II)	n.a.	49.9	n.a.	0
Ibersol Ciudad Real (Puertollano)	2009	50	287,760	0
La Dehesa	2011	49.9	552,750	7.5
Lebrija 1 (LE-1)	2010	49.9	412,020	0
Majadas I	2010	50	n.a.	0
Manchasol-1 (MS-1)	2011	49.9	510,120	7.5
Manchasol-2 (MS-2)	2010	49.9	510,120	7.5
Palma del Río I	2011	50	n.a.	0
Palma del Río II	2010	50	n.a.	0
Planta Solar 10 (PS10)	2007	11.02	75,000	1.0
Planta Solar 20 (PS20)	2009	20	150,000	1.0
Puerto Errado 1 Thermosolar Power Plant	2009	1.4	n.a.	n.a.
Puerto Errado 2 Thermosolar Power Plant	2012	30	n.a.	n.a.
Solnova 1	2009	50	300,000	0
Solnova 3	2009	50	300,000	0
Solnova 4	2009	50	300,000	0
Vallesol 50 (Valle 2)	2020	49.9	510,120	7.5

Source: Listed projects based on NREL (2011).

Average electricity prices in comparison to solar radiation

Table E.2: Average electricity prices [EUR/MWh]
and variance (in brackets) in comparison to solar radiation [W/m^2]

		Annual [EUR/MWh]	0-100 [W/m^2]	100-200 [W/m^2]	200-300 [W/m^2]	300-400 [W/m^2]	400-500 [W/m^2]	500-600 [W/m^2]	600-700 [W/m^2]	700-800 [W/m^2]	> 800 [W/m^2]
	2007	41 (2445)	40 (3332)	44 (1388)	48 (1560)	42 (657)	42 (481)	41 (272)	39 (154)	40 (150)	42 (250)
FR	2008	69 (817)	63 (679)	73 (795)	73 (750)	78 (786)	81 (819)	87 (876)	89 (900)	87 (943)	97 (1128)
	2009	43 (4416)	39 (391)	43 (456)	51 (16205)	53 (19315)	61 (46032)	46 (169)	45 (135)	47 (125)	48 (110)
	2010	48 (290)	46 (298)	50 (328)	50 (343)	49 (281)	52 (341)	50 (154)	51 (101)	50 (85)	54 (117)
	2007	38 (921)	36 (1017)	47 (1258)	46 (777)	46 (740)	46 (710)	46 (697)	44 (577)	44 (542)	46 (760)
GER	2008	66 (821)	60 (699)	75 (765)	76 (676)	78 (768)	80 (765)	83 (802)	85 (830)	86 (789)	88 (790)
	2009	39 (377)	37 (416)	45 (218)	46 (225)	46 (231)	45 (223)	45 (204)	45 (176)	44 (146)	45 (147)
	2010	44 (195)	43 (206)	49 (160)	49 (144)	49 (148)	49 (137)	49 (123)	49 (115)	49 (111)	50 (118)
	2007	39 (174)	38 (206)	37 (149)	40 (154)	42 (176)	44 (154)	41 (83)	40 (56)	41 (59)	45 (70)
ES	2008	64 (166)	62 (191)	63 (127)	64 (123)	65 (120)	67 (116)	69 (104)	69 (100)	71 (98)	72 (95)
	2009	37 (91)	36 (133)	36 (57)	36 (48)	37 (46)	39 (51)	37 (17)	39 (12)	39 (14)	39 (15)
	2010	37 (216)	35 (263)	36 (169)	37 (148)	38 (154)	39 (150)	40 (135)	41 (142)	42 (142)	43 (85)
	2007	52 (254)	51 (782)	54 (878)	52 (784)	57 (972)	59 (1044)	56 (937)	49 (643)	49 (615)	50 (657)
PT	2008	70 (116)	69 (128)	69 (100)	70 (101)	72 (99)	72 (101)	73 (92)	74 (85)	72 (81)	73 (85)
	2009	38 (81)	37 (115)	36 (53)	37 (57)	38 (56)	39 (43)	39 (32)	39 (16)	39 (16)	40 (15)
	2010	37 (216)	36 (259)	37 (173)	38 (151)	37 (162)	39 (162)	39 (144)	40 (166)	42 (129)	43 (111)

Sources: EEX (2012), EPEX (2012), OMEL (2012) and EuroWind (2011).
In Portugal, only data for the second half of the year 2007 was available.
Abbreviations: FR - France; GER - Germany; ES - Spain and PT - Portugal.

Common scenario assumptions

In the following, the technical and economic assumptions underlying the scenario analysis are described. The assumptions are based on several databases such as EC (2010a), IEA (2010c), IEA (2010b), IEA (2010a), Schlesinger et al. (2010) and EWI (2010). It is clear that the scenario setting chosen for this analysis is only one possible outcome.

Assumptions regarding investment costs and techno-economic characteristics of nuclear, conventional and storage power plants are based on IEA (2010c) and Schlesinger et al. (2010). Investment costs for already existing conventional technologies are assumed to be the same as today but learning effects lead to lower investment costs for new technologies. CCS technologies are assumed to be commercially available and applicable to hard-coal, lignite and combined-cycle gas power plants starting from 2030. As can be seen in Table E.3, standard and innovative technologies can be fitted with CCS and/or CHP technology. Investment costs of CHP plants also include additional costs for the grid and the extraction of heat. Due to limited potential, pump storage and hydro storage plants are not an investment option. Compressed air energy storage (CAES) technologies have investment costs of 850 EUR_{2010} per kW. Nuclear power plants are not considered as an investment option for the Iberian Penisula.

The modeled renewable energy technologies and their assumed specific investment costs over time are based on IEA (2010a) and EWI (2010). Investment costs are assumed to decrease over time, in particular for photovoltaics and offshore wind. To account for technological progress apart from cost reductions, we model 6 MW onshore (5 MW offshore) wind turbines until 2025 and 8 MW onshore (8 MW offshore) turbines starting from 2030. Since the annual generation and feed-in structure of wind and solar technologies depends on local weather conditions, values generally differ between various regions of a country. To account for these differences, the Iberian Peninsula is divided into five solar and five wind regions.[160]

TABLE E.3: Overnight investment costs of conventional, renewable and storage technologies per power output [€$_{2010}$/kW$_{el}$]

Technologies	2010	2020	2030	2040	2050
Lignite	1,850	1,850	1,850	1,850	1,850
Lignite - innovative	1,950	1,950	1,950	1,950	1,950
Lignite - CCS	-	-	2,550	2,500	2,450
Hard-coal	1,500	1,500	1,500	1,500	1,500
Hard-coal - innovative	2,500	2,250	1,875	1,750	1,650
Hard-coal - CCS	-	-	2,000	1,900	1,850
Hard-coal - innovative CCS	-	-	2,475	2,300	2,200
Hard-coal - innovative CHP	2,650	2,650	2,275	2,150	2,050
Hard-coal - innovative CHP and CCS	-	-	2,875	2,700	2,600
CCGT	1,250	1,250	1,250	1,250	1,250
CCGT - CCS	-	-	1,550	1,500	1,450
CCGT - CHP	1,500	1,500	1,500	1,500	1,500
CCGT - CHP and CCS	-	-	1,700	1,650	1,600
OCGT	700	700	700	700	700
Biomass gas	2,400	2,398	2,395	2,393	2,390
Biomass gas - CHP	2,600	2,597	2,595	2,592	2,590
Biomass solid	3,300	3,297	3,293	3,290	3,287
Biomass solid - CHP	3,500	3,497	3,493	3,490	3,486
Wind onshore 6 MW	1,350	1,221	-	-	-
Wind onshore 8 MW	-	-	1,161	1,104	1,103
Wind offshore 5 MW (shallow)	3,200	2,615	-	-	-
Wind offshore 8 MW (shallow)	-	-	2,512	2,390	2,387
Wind offshore 5 MW (deep)	3,800	3,105	-	-	-
Wind offshore 8 MW (deep)	-	-	2,956	2,811	2,808
Photovoltaics base	3,000	1,796	1,394	1,261	1,199
Photovoltaics roof	3,500	2,096	1,627	1,471	1,399
Hydro (run-of-river)	4,500	4,500	4,500	4,500	4,500
Geothermal power	15,000	10,504	9,500	9,035	9,026
CSP A	3,722	2,220	1,700	1,400	1,290
CSP B	6,794	3,437	2,300	2,100	1,963
CSP C	10,082	5,500	3,800	3,100	2,693
CAES	850	850	850	850	850

Net efficiency factors of nuclear, conventional and biomass power plants are based on the specifications of power plants in construction. For ‘innovative’ technologies, higher efficiencies are assumed due to the described technical developments. The generation efficiency of plants with CCS are assumed to be lower. Moreover, higher operational and maintenance costs occur for CCS power plants due to the additional costs for the pipe and the storage system. Combined heat and power (CHP) generation units have lower electrical but higher total efficiency factors. Operational and maintenance costs also include the costs for the heat extraction system. Table E.4 shows the net efficiency factors, technical availability, operational and maintenance costs and the technical lifetime for conventional, renewable and storage technologies.

[160] The regions are based on specific wind and solar data from Sperling and Hänsch (2009). The wind and solar regions are not identical.

TABLE E.4: Economic-technical parameters of generation technologies

Technologies	Efficiency generation [%]	Efficiency charging [%]	Availability [%]	FOM-costs [€$_{2010}$/kW]	Lifetime [a]
Nuclear	33.0	-	84.50	96.6	60
Lignite	43.0	-	86.25	43.1	45
Lignite - innovative	46.5	-	86.25	43.1	45
Lignite - CCS	43.0	-	86.25	103.0	45
Hard-coal	46.0	-	83.75	36.1	45
Hard-coal - innovative	50.0	-	83.75	36.1	45
Hard-coal - CCS	42.0	-	83.75	97.0	45
Hard-coal - innovative CCS	45.0	-	83.75	97.0	45
Hard-coal - innovative CHP	22.5	-	83.75	55.1	45
Hard-coal - inno. CHP/CCS	18.5	-	83.75	110.0	45
CCGT	60.0	-	84.50	28.2	30
CCGT - CCS	53.0	-	84.50	40.0	30
CCGT - CHP	36.0	-	84.50	88.2	30
CCGT - CHP/CCS	36.0	-	84.50	100.0	30
OCGT	40.0	-	84.50	17.0	25
Biomass gas	40.0	-	84.50	120.0	30
Biomass gas - CHP	36.0	-	84.50	130.0	30
Biomass solid	30.0	-	84.50	165.0	30
Biomass solid - CHP	22.5	-	84.50	175.0	30
Wind onshore	-	-	-	41.0	25
Wind offshore	-	-	-	130.0	25
Photovoltaics	-	-	-	30.0	25
Hydro (run-of-river)	-	-	-	45.0	100
Geothermal power	-	-	-	300.0	30
Concentrated solar power	-	-	-	70.0	30
Pump storage	87.0	83.0	95.00	11.5	100
Hydro storage	87.0	-	95.00	11.5	100
CAES	86.0	82.0	95.00	9.2	40

Table E.5 shows fuel prices assumed for thermal power plants in the scenarios, as well as CO_2 prices. The price of CO_2 emissions is assumed to increase from 14.0 €2010/t CO_2 in 2010 to 40.0 €2010/t CO_2 in 2050. The assumed fuel prices are based on international market prices and transportation costs to the power plants.

TABLE E.5: Fuel prices [€$_{2010}$/MWh$_{th}$] and CO_2 price [€$_{2010}$/t CO_2]

	2010	2020	2030	2040	2050
Nuclear	3.4	3.3	3.3	3.3	3.3
Lignite	1.4	1.4	1.4	1.4	1.4
Hard-coal	11.9	13.1	13.6	15.1	17.6
Natural gas	16.9	20.9	22.9	25.6	28.0
Biomass (solid)	27.7	27.7	34.9	35.1	37.5
Biomass (gas)	0.1-70.0	0.1-67.2	0.1-72.9	0.1-78.8	0.1-85.1
CO_2 price [€$_{2010}$/t CO_2]	14.0	20.0	25.0	30.0	40.0

Scenario results

Table E.6: 'Roadmap Scenario' - Power balance for Spain [TWh_{el}]

	2000	2008	2020	2030	2040	2050
Net electricity consumption	188.5	265.4	298.6	344.9	396.3	453.2
Transformation losses	19.0	20.0	27.1	26.1	18.4	14.7
Thermal plant consumption	14.0	15.0	22.2	21.1	15.9	9.2
other transformation	5.0	5.0	5.0	5.0	5.0	5.0
Grid losses	20.0	16.0	13.5	13.5	13.5	13.5
Storage consumption	2.6	1.1	4.4	2.6	1.7	1.5
Gross electricity consumption	230.1	302.5	342.7	387.1	432.4	482.4
Net imports	4.4	-11.0	-0.4	-0.8	1.3	-0.7
Gross electricity generation	225.6	313.5	344.1	387.8	431.1	483.1

Source: The years 2000 and 2008 are based on Eurostat (2010).

Table E.7: 'Roadmap Scenario' - Power balance for Portugal [TWh_{el}]

	2000	2008	2020	2030	2040	2050
Net electricity consumption	38.5	48.4	55.9	64.5	74.1	84.8
Transformation losses	2.3	2.4	3.6	3.4	5.4	3.7
Thermal plant consumption	1.7	1.8	3.0	2.8	4.8	3.1
other transformation	0.6	0.6	0.6	0.6	0.6	0.6
Grid losses	3.6	4.2	3.8	3.8	3.8	3.8
Storage consumption	0.2	0.2	0.9	0.8	1.0	0.2
Gross electricity consumption	44.6	55.2	64.1	72.5	84.2	92.5
Net imports	0.9	9.4	0.2	0.7	-1.4	0.6
Gross electricity generation	43.7	46.0	63.9	71.8	85.7	91.9

Source: The years 2000 and 2008 are based on Eurostat (2010).

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