Four Essays on the Economics of Renewable Power Markets

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Nomenclature

CO_2	Carbon dioxide
a	Annum
BMWi	Bundesministerium für Wirtschaft und Technologie (Federal Ministry of Economics and Technology)
bn	Billion
CAES	Compress air energy storage
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CDU	Christlich Demokratische Union (Christian Democratic Union)
CHP	Combined heat and power
CSP	Concentrating solar power
CSU	Christlich Soziale Union (Christian Social Union)
ct	Cent
DIME	Dispatch and investment model for electricity markets in Europe (of the Institute of Energy Economics at the University of Cologne)
DIMENSION	Dispatch and investment model for electricity markets in Europe (new version of the electricity market model of the Institute of Energy Economics at the University of Cologne)
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
EPEX	European power exchange - spot market
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)
FB	Fixed bonus
FDP	Freie Demokratische Partei (Free Democratic Party)
FIT	Feed-in tariff
FOM	Fixed operation and maintenance costs
GAMS	General algebraic modeling system
GJ	Gigajoule
GW	Gigawatt
GWh	Gigawatt hour
GWS	Gesellschaft für Wirtschaftliche Strukturforschung mbH
h	Hour
HVDC	High voltage direct current
IEA	International Energy Agency
kW	Kilowatt
kWh	Kilowatt hour
LORELEI	Linear optimization model for renewable electricity integration in Europe (of the Institute of Energy Economics at the University of Cologne)
m	Meter
m^2	Square meter
MC	Market clearing condition
MCP	Mixed complementarity problem
mio	Million
MW	Megawatt
MW_{el}	Megawatt electric
MW_{th}	Megawatt thermal
MWh	Megawatt hour
MWh_{el}	Megawatt hour electric
MWh_{th}	Megawatt hour thermal
NREL	National Renewable Energy Laboratory
NTC	Net transfer capacities
OCGT	Open cycle gas turbine

OMEL	Operador del Mercado Ibérico de Energía
PV	Photovoltaics
RES-E	Renewable energy sources for electricity generation
s	Second
SWITCH	Solar, wind, hydro, conventional generators and transmission model
t	(Metric) tonne
TES	Thermal energy storage
TGC	Tradable green certificates
TWh	Terawatt hour
TWh_{el}	Terawatt hour electric
TWh_{th}	Terawatt hour thermal
U.S.	United States
W	Watt

Chapter 1

Introduction

1.1 Motivation

Many countries are trying to increase the proportion of electricity generation from renewable energy sources (RES-E). By definition of the International Energy Agency (IEA), renewable energies[2] are 'naturally replenishing but flow limited. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time' (IEA, 2007a). The vision of a highly efficient and partly renewable-based electricity supply of industrialized countries was first developed during the world oil crisis in the 1970s (e.g., Carter (1977) or Krause et al. (1980)). In the last two decades, the fear of severe consequences from climate change led to an increased effort to integrate renewables in the power sector.

The European Union (EU) chose to lead the way in demonstrating a possible transition to a low-carbon and mostly renewable-based electricity supply. From 1990 to 2010, the share of renewable power generation has been increased from 12 to 21 % of the total electricity supply in Europe, representing 20 % of the worldwide increase of renewable power generation in the same time frame (IEA, 2012). What is remarkable is the large deployment of technologies with intermittent power generation[3], such as wind and solar plants, accounting for more than 45 % of the additional renewable generation in the European Union. In 2010, 43 % of the worldwide existing wind turbine capacity and 79 % of the worldwide existing solar capacity were installed within the European Union

[2]'Renewable energy sources include: biomass, hydro, geothermal, solar, wind, ocean thermal, wave action and tidal action' (IEA, 2007a).

[3]By definition of the U.S. Energy Information Administration, intermittent generation refers to an 'electric generating plant with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements. Intermittent output usually results from the direct, non-stored conversion of naturally occurring energy fluxes such as solar energy, wind energy, or the energy of free-flowing rivers' (EIA, 2012).

and wind and solar generation already contributed to more than 5 % of the European electricity generation (close to 0 % in 1990).

However, the increase in renewable power generation came along with several technical as well as economic challenges compared to a conventional-dominated electricity supply: First, unlike conventional power plants, the availability of wind and solar technologies depends on local weather situations and thus securely available capacity is required as back-up. Second, favorable renewable sites are often distant from load centers and require grid extensions. Third, power generation from renewable energy sources is usually more costly than conventional power generation and therefore a high proportion of renewables increases consumer costs. Fourth, the costs of wind and solar generation are almost entirely up-front as variable costs are negligible. Due to these characteristics and the absence of large transmission capacities across Europe as well as cost-efficient storage facilities, the deployment of renewables has already caused remarkable market results. For example, negative spot prices for electricity occurred in 166 hours from 2008 to 2012 under the current renewable subsidy program due to the large supply of wind energy in Germany (EEX, 2012b).[4]

Political plans in Europe foresee a further deployment of renewable energies for power generation. In 2010, each member state of the European Union defined a technology-specific target for capacity and electricity generation from renewable energies in 2020 as stated in the National Renewable Action Plans (approximately 25 % of the European electricity consumption depending on the electricity demand). Given the objective of the European Union to reduce greenhouse gas emissions by 80-95 % in 2050 compared to 1990 levels (EC, 2009), a further increase of renewable power generation is envisaged. Moreover, a large share of total electricity generation can be expected to come from intermittent renewables due to the limited potential of hydro and biomass technologies.

Several questions regarding the economics of power markets arise from the further deployment of renewable energies, which will be investigated in the scope of this thesis. First, what would a cost-efficient transition to a low-carbon and mostly renewable-based power sector in Europe resemble? The resulting scenarios, including an assessment of technologies and system costs, can be used as political guidance to develop a long-term energy strategy. Second, how does weather uncertainty influence the power market? As most power generation will likely come from intermittent technologies in a mostly renewable-based electricity supply in Europe, weather uncertainty may have a substantial impact on the electricity mix and the related system costs. Third, how do subsidy programs for renewable energies perform with regard to social welfare and investment risks considering weather uncertainty? The results from this analysis can support the

[4]A discussion of negative wholesale prices for electricity can be found in Nicolosi (2010).

harmonization process to a consolidated renewable policy in the European Union by providing a quantitative comparison of established support policies.

The analyses in this thesis are carried out for the European electricity system. However, the results can be useful for the assessment of a transition to a low-carbon and mostly renewable-based electricity system in other regions as well.

1.2 Analyzing the economics of renewable power markets

In the scope of this thesis, potential pathways to a low-carbon European electricity supply with a large share of intermittent renewables are analyzed. In today's European electricity market, more than 90 % of all power plants are dispatchable (2010: 95 % based on IEA (2012)), which means that these capacities can be used to generate electricity when needed apart from planned revisions and outages. The envisaged transition of the European electricity market implies a substaintial increase of wind and solar power due to the limited potential of dispatchable renewable energies.[5] Unlike most conventional power plants, the availability of wind and solar technologies depends on local weather conditions and is therefore stochastic. As depicted in Figure 1.1, the feed-in of these technologies can be extremely voltaile and is therefore unreliable. In particular, the feed-in from wind turbines can change substantially within minutes due to alternating wind speeds. As a result, securely available capacities are needed for situations with minimum wind and solar generation. Moreover, electricity supply and demand has to be flexible enough to cope with these fluctuations.

The lack of empirical data limits the application of econometric analyses to understand the challenges arising from a large share of intermittent renewables in the European power market. The European Union is the first industrialized region implementing policies to significantly reduce CO_2 emissions by increasing the share of renewables in the power sector. Hence, empirical data of comparable international power markets on system costs and the performance of technologies in such an environment do not yet exit. Some isolated regions or islands, characterized by low population densities and limited grid connection, use a mix of photovoltaics (PV) or wind turbines, batteries as storage and gasoline engines as back-up (Lefale and Lloyd, 1993). However, data from these systems can hardly be compared to the well-connected European power sector with large load centers. The experiences with the integration of renewable energies in the European electricity sector in recent years, such as facing forecast errors for wind and solar generation or increasing subsidy payments, indicate some arising challenges from an

[5] Some power generation from renewable energy sources, such as biomass, hydro or geothermal power, is dispatchable. However, the potential of these technologies is relatively limited in Europe.

increased renewable share. However, wind and solar power still contributes substantially less than 10 % of the annual electricity generation in Europe (2010: 5 % based on IEA (2012)) and problems with the integration of intermittent power generation are likely to become more important.

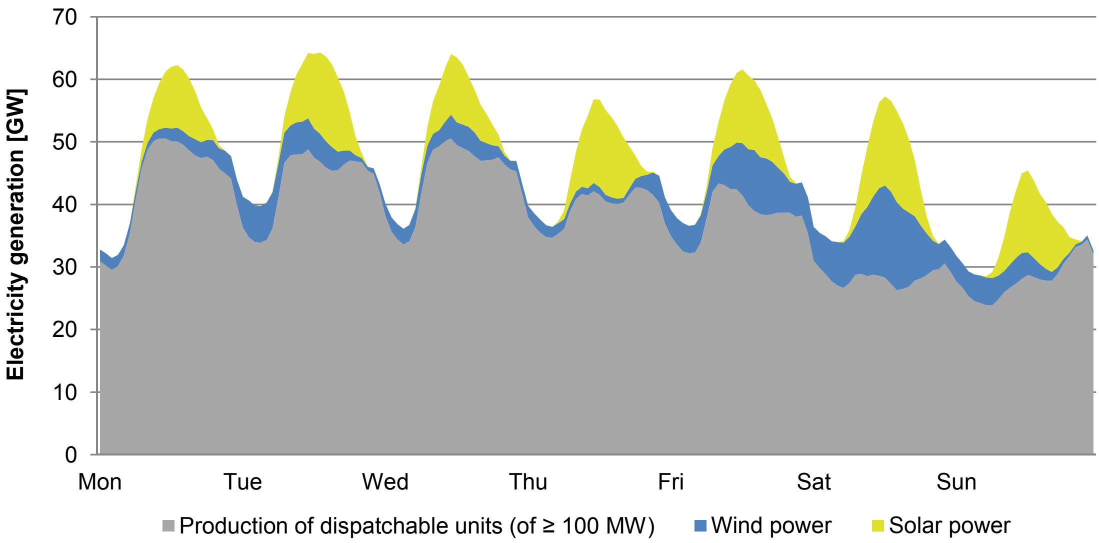

FIGURE 1.1: Electricity generation in Germany, June 4^{th} - June 11^{th} 2012 [GW]
Source: Own illustration based on EEX (2012a). Unless explicitly stated otherwise, figures in this thesis represent own illustrations.

Optimization and complementarity models, capturing the fundamental economic and technical characteristics of power markets, can be useful tools to analyze arising challenges of intermittent power generation. Such models have been applied to economic and engineering problems in various industries and academic fields. For power markets, system costs to achieve climate protection targets can be derived by applying cost-minimizing optimization models, as stated below on the left hand side, where s_i^{max} is the capacity constraint of technology i, d is the fixed electricity demand, c_i are the technology-specific generation costs and s_i the generation per technology. Given the Duality Theorem for linear programs (Murty, 1983), the minimization problem (in this case called primal problem) is associated with the maximization problem (dual problem) with each variable in the dual problem corresponding to a specific constraint in the primal problem and each constraint in the dual problem corresponding to a variable in the primal problem. The results of a cost-minimizing electricity market model are equivalent to welfare maximization when assuming a price inelastic electricity demand (Samuelson, 1952), reflecting the outcome of a perfectly competitive market.[6] In today's

[6]A perfectly competitive market refers to a market with 1. homogeneous good, 2. each firm attempts to maximize profits, 3. each firm is a price taker, 4. perfect information and 5. transactions are costless (Snyder and Nicholson, 2008).

electricity markets, real-time elasticity of electricity demand seems to be rather low.[7] Thus, a fixed electricity demand is often assumed when modeling electricity markets to reduce computational complexity.

Optimization models are limited as the model formulation is restricted to a single optimization problem, representing the objective of a single player or several players with the same objective function. In general, every optimization model can also be stated as complementarity model[8]. The formulation as a complementarity model allows the consideration of several players with different objective functions. Thus, the original optimization model can also be expressed as below on the right hand side, where an overall electricity producer is maximizing net profit by selling electricity to the market at the price ϕ, which represents the dual variable of the market clearing condition. For the case of renewable power markets, the formulation as a complementarity model allows the simulation of specific renewable policies on electricity producer decisions (further discussed in Chapter 4).

Optimization model (deterministic)		*Complementarity model (deterministic)*	
$\min_{s_i}$	$\sum_i (s_i \cdot c_i)$	Producer:	$\max_{s_i} \quad \sum_i (s_i \cdot (\phi - c_i))$
s.t.	$\sum_i s_i = d; \quad s_i \leq s_i^{max}; \quad s_i \geq 0$		s.t. $\quad s_i \leq s_i^{max} \quad (\alpha_i); \quad s_i \geq 0$
		Market clearing:	$\sum_i s_i = d \quad (\phi)$

Many of the existing optimization and complementarity models for power markets underestimate the challenges arising from a large share of intermittent renewables. Most existing investment and dispatch optimization models[9] have been developed to primarily analyze conventional-dominated power markets. Thus, these models simulate the dispatch of generation and demand for just a few demand levels per year. When adding renewable energies to these models, the resulting comparison of technologies is misleading because differences in the production profiles of intermittent and dispatchable generating technologies are not taken into account (Joskow, 2011). However, simply increasing the number of dispatch situations (typical feed-in pattern) is insufficient as the feed-in from wind and solar technologies is not only volatile but also generation patterns and correlations between sites are stochastic.

Uncertainty about the hourly or yearly generation from wind and solar technologies can be incorporated in stochastic optimization and complementarity models. Methodologies

[7] Price elasticity of demand is defined as the percentage change in quantity demanded given a one percent change in price ($\eta = \frac{dQ/Q}{dP/P}$). In electricity markets, it is often distinguished between real-time, short-term and long-term price elasticity (Simmons-Süer et al., 2011). Empirical data on real-time elasticity of electricity demand can be found in Lijesen (2007).

[8] An introduction to complementarity models, including many examples for energy markets, can be found in Gabriel et al. (2013).

[9] An overview of different optimization models for power markets can be found in Chapter 3.

incorporating uncertainty in optimization models were developed by Dantzig (1955).[10] They were applied to electricity generation planning problems to analyze the impact of demand uncertainty for the first time in the 1980s (Murphy et al. (1982) and Modiano (1987)). Given mostly conventional-dominated electricity systems, the research focus has been on demand uncertainty and fossil-fuel price uncertainty. As stated in the model formulation below, stochastic models with recourse consider uncertainty ω about one or several parameters, for example the maximum available capacity $s_{i,\omega}^{max}$ may differ with the probability p_ω. Thus, uncertainty about the production capacity leads to a more complex optimization problem, in particular when determining investment strategies.

Optimization model (stochastic)

$\min_{s_{i,\omega}} \sum_{i,\omega}(p_\omega \cdot s_{i,\omega} \cdot c_i)$

s.t. $\sum_i s_{i,\omega} = d_\omega; \quad s_{i,\omega} \leq s_{i,\omega}^{max}; \quad s_{i,\omega} \geq 0$

Complementarity model (stochastic)

Producer: $\max_{s_{i,\omega}} \sum_{i,\omega}(p_\omega \cdot s_{i,\omega} \cdot (\phi_\omega - c_i))$

s.t. $s_{i,\omega} \leq s_{i,\omega}^{max}; \ (\alpha_{i,\omega}); \ s_{i,\omega} \geq 0$

Market clearing: $\sum_i s_{i,\omega} = d_\omega \quad (\phi_\omega)$

Even though optimization and complementarity models are helpful tools to analyze power markets, model results should always be carefully interpreted. At best, such models depict the fundamental technical and economic characteristics of power markets with an appropriate technological, geographical and timely resolution to analyze a specific research question. When comparing the results of a cost-minimizing electricity market model to real market data, one has to keep in mind the restrictive model assumption of a perfectly competitive market. Given uncertainties and the oligopolistic structure of most power markets, model results, such as system costs, should be seen as a lower bound. In particular, long-term analyses suffer from a large number of necessary assumptions to develop scenarios for the power system. One way to identify the most important input parameters and their impact on the model results are sensitivity analyses by comparing model results with variations of input parameters. Another possibility to account for the uncertainty about input parameters is the application of stochastic models. However, even then only a limited number of parameters can be considered as uncertain. Additionally, all potential developments of input parameters as well as the respective probabilities have to be known. In general, fundamental market models for power systems are useful tools when considering these limitations.

[10] A broad overview of different stochastic modeling approaches can be found in Birge and Louveaux (1997).

1.3 Thesis outline

The main part of the thesis consists of four essays analyzing several challenges that arise from an increasing share of renewable energies in the European power sector. Each chapter consists of an essay that can be read independently.

The first part of the thesis focuses on a cost-efficient pathway and the related system costs of a mostly renewable-based electricity supply in Europe. Chapter 2 covers energy policy scenarios to reach challenging climate protection targets in the German electricity sector by 2050. It was published in *Utilities Policy* (Nagl et al., 2011b) and I am a co-author of the paper. Chapter 3 is an analysis of the additional system costs due to the stochastic availability of wind and solar technologies for the European electricity market. It was accepted for publication in *The Energy Journal* (Nagl et al., 2013) and I am the leading author of the paper.[11]

The second part of the thesis focuses on the efficiency of various renewable support policies. The analysis in Chapter 4 outlines the effect of weather uncertainty on the risk for green electricity producers under the most common renewable support policies. It was published in the *EWI Working Paper Series* (Nagl, 2013) and I am the sole contributor. Chapter 5 discusses the inefficient incentive – arising from flat feed-in tariffs for renewable power generation – to invest in thermal energy storages in concentrated solar plants in today's electricity markets. It was published in the *EWI Working Paper Series* (Nagl et al., 2011a) and I am a co-author of the paper.

The main body of the thesis is organized as follows: In Chapter 2, the essay ENERGY POLICY SCENARIOS TO REACH CHALLENGING CLIMATE PROTECTION TARGETS IN THE GERMAN ELECTRICITY SECTOR UNTIL 2050, we demonstrate how challenging greenhouse gas reduction targets of up to 95 % by 2050 can be achieved in the German electricity sector. In the coalition agreement for the 17th legislative period, the political parties CDU, CSU and FDP settled on a greenhouse gas reduction target of 40 % by 2020 compared to emissions in 1990. For 2050, the agreement is loose but states that greenhouse gas reduction in Germany should be in line with international agreements envisioning a reduction of at least 80 % compared to 1990 values. In order to develop a long-term energy concept to achieve these targets, the German government commissioned a scenario analysis for the energy sector up to 2050. Chapter 2 describes these scenarios with a focus on the main requirements to reach such challenging targets in the German electricity sector. The scenarios were developed by applying several optimization models in an iterative way to account for interdependencies between the

[11]This article is copyrighted and reprinted by permission from the International Association for Energy Economics. The article first appeared in The Energy Journal, Vol. 34, No. 4. Visit The Energy Journal online at http://www.iaee.org/en/publications/journal.aspx.

electricity market and the rest of the economy. For the electricity sector, we use the cost-minimizing investment and dispatch optimization models of the Institute of Energy Economics, DIME (Bartels, 2009) and LORELEI (Wissen, 2012), to analyze the effects of different electricity demand developments and runtimes (as well as retrofit costs) for existing nuclear plants. The main finding of the analysis is that a long-term transition towards a low-carbon and mostly renewable-based energy supply in Germany does not necessarily lead to a large increase in electricity prices. However, this requires several highly challenging preconditions: First, a mandatory international climate protection agreement must be put in place to provide similar conditions for all industries in a globalized business environment. Second, several technological breakthroughs in the performance of renewable and storage technologies are required, leading to a reduction of generation costs. Third, a well coordinated European energy policy is necessary, in particular to build an efficient transmission grid throughout Europe and to establish a harmonized European renewable policy. As a result of the scenario findings, the German government introduced several measurements in the fall of 2010, including a prolongation of nuclear power plants, to reach the defined climate protection targets. However, Germanys' nuclear policy was once again reconsidered due to the nuclear catastrophe in Fukushima in March 2011. In 2011, an accelerated nuclear phase-out, i.e. shut down of eight reactors immediately and the shut down of the last nuclear plant by 2022, has been decided. Thus, the essay in Chapter 2 is supplemented by a scenario analysis up to 2030 (Fürsch et al., 2012) with regard to shorter lifetimes of nuclear power plants in Germany.

In Chapter 3, the essay The costs of electricity systems with a high share of fluctuating renewables - a stochastic investment and dispatch optimization model for Europe, we analyze the impact of the stochastic availability of wind and solar energy on the cost-minimal power plant mix and the related system costs. Renewable energies are meant to cover a large share of the future electricity demand in Europe. However, the availability of wind and solar power depends on local weather conditions, which may or may not be favorable in terms of meeting the hourly electricity demand. Moreover, weather situations, such as longer time frames with e.g., minimal wind power feed-in, need to be considered. From a system perspective, it may be cost-efficient to only focus on the best renewable sites in Europe, i.e. locations with the highest full load hours on average. As installation costs are similar across Europe, levelized electricity costs for wind power are about 50 % lower in Northern Europe as in Southern Europe at relatively similar conditions. However, a distribution of wind turbines and solar systems could be cost-efficient, as the hourly European-wide total power generation from these technologies would be more stable due to the existence of positive and negative availability correlations between technologies (e.g., negative correlation between photovoltaics and wind power) and between regions (e.g., wind in Great Britain and Italy). However, the extent of the correlation between technologies and between regions also differs between years and is therefore uncertain. Analysis tools to back national long-term energy strategies usually neglect these uncertainties. Thus, the optimal capacity mix (conventional, renewable and storage technologies) may be different than developed in these strategies and total system costs of a mostly renewable-based electricity supply could be significantly higher than estimated. To estimate the additional system costs and the impact on the cost-efficient capacity mix, we develop a stochastic investment and dispatch optimization model that considers uncertainty of hourly and yearly availability of wind and solar resources and apply it to the European electricity market. The stochastic feed-in of wind and solar power is taken into account by varying feed-in profiles with regard to the annual full load hours and correlations. We find that fluctuating renewables are overvalued in deterministic optimization models and hence, dispatchable renewable energies such as biomass or geothermal sites, even considering high investment or fuel costs, are underestimated for a mostly renewable-based electricity supply. Furthermore, solar technologies are, relative to wind power, underestimated when neglecting the negative correlation between wind and solar power. The results also indicate that the total system costs for a mostly renewable-based electricity supply are underestimated when neglecting the stochastic availability of wind and solar technologies. Sensitivity analyses on the capital costs of wind and solar technologies, as well as on the development of the transmission grid, show that the optimal technology mix and system costs highly depend on these parameters. However, the identified additional costs due to the stochastic availability of wind and solar technologies (as percentage of the system costs) are fairly robust to variations in these parameters. The scenario analysis does not question the renewable targets but rather shows that the economic burden resulting from a high share of renewable energies in power systems is likely to be higher than expected.

In Chapter 4, the essay THE EFFECT OF WEATHER UNCERTAINTY ON THE FINANCIAL RISK OF GREEN ELECTRICITY PRODUCERS UNDER VARIOUS RENEWABLE POLICIES, we analyze the variance in profits of renewable-based electricity producers due to weather uncertainty under a 'feed-in tariff' policy, a 'fixed bonus' incentive and a 'renewable quota' obligation. Under a 'feed-in tariff' policy, renewable-based electricity producers are offered a long-term contract with guaranteed tariffs for each unit of electricity fed into the grid. As prices are fixed, revenues vary according to the volatility in generation. Under a 'fixed bonus' incentive, renewable-based electricity producers receive the wholesale price of electricity and, in addition, a fixed bonus payment. As the feed-in from intermittent renewables has a price-lowering effect on the wholesale market, producers may face negatively correlated fluctuations in production and wholesale prices. Thus, the integration of renewables into the power market may actually cause the financial risk to be reduced under a fixed bonus policy compared to feed-in tariffs. Under a 'renewable quota' obligation, electricity producers (or utilities) are required to procure a certain share of their electricity from renewable energy sources. This gives rise to a market for green certificates issued by renewable-based electricity producers. In line with the discussion concerning a potential balancing effect between fluctuations in production and wholesale prices, certificate prices are also negatively correlated with the production of intermittent electricity generation. Thus, renewable-based electricity producers may face a higher or lower risk compared to a feed-in tariff or fixed bonus policy. We analyze the effect of weather uncertainty in a simple analytical framework and find that the variance in revenues highly depends on the slope of the supply curve of dispatchable plants when integrating renewables in the power market. To analyze the variance in profits under the different policies, the size of the balancing effects and how different renewable energies are affected by weather uncertainty, we apply a spatial stochastic equilibrium model to the European electricity market. The results of the numerical analysis suggest that wind producers benefit from market integration, whereas producers from biomass and solar plants face a larger variance in profits. Furthermore, the simulation indicates that highly volatile green certificate prices occur when introducing a renewable quota obligation without the option of banking and borrowing. Thus, all renewable producers face a higher variance in profits, as the price effect of weather uncertainty on green certificates overcompensates the negatively correlated fluctuations in production and prices. It is an ongoing debate as to if and how renewable energies should be promoted in Europe once the envisaged national renewable targets of the National Renewable Energy Action Plans in 2020 have been achieved. Following the discussion of a European renewable quota after 2020, the analysis indicates the importance of an appropriate banking and borrowing mechanism to reduce the risk for producers in light of a greater penetration of stochastic wind and solar generation.

In Chapter 5, the essay THE ECONOMIC VALUE OF STORAGE IN RENEWABLE POWER SYSTEMS – THE CASE OF THERMAL ENERGY STORAGE IN CONCENTRATING SOLAR PLANTS, we analyze the inefficiency arising from flat feed-in tariffs to subsidize renewable power generation for the special case of concentrating solar power plants. One major challenge in the transition to a low-carbon and mostly renewable-based power sector 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 are concentrating solar power plants equipped with thermal storage units. In these plants, the sun's heat is absorbed by collectors and concentrated to heat a fluid that is then used to generate electricity in a steam turbine.

Specific to concentrating solar power systems is the inherent option to integrate a thermal energy storage capacity, used to generate electricity in hours with low or no solar radiation. Dependent on the technology and the site characteristics, thermal energy storages can reduce the sites production costs (per kilowatt hour) due to a higher usage of the capital intensive power plant block. However, electricity demand has a midday peak when solar radiation is also highest in today's European electricity sector. Thus, electricity prices are above average when solar plants can directly feed into the grid. As power generation from renewable energies 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 through fixed feed-in tariffs, independent of the hourly market price. Thus, investors maximize their profit by simply minimizing the average production costs. Given a reduction in average generation costs by installing a thermal energy storage, investors have an incentive to install a storage capacity without considering the hourly price curve under a feed-in tariff scheme. In order to investigate the relationship at the system level, we apply a bottom-up system optimization model allowing, among others, a choice between concentrating solar systems with different thermal energy storage sizes. Our simulation shows that thermal storage units are not cost-efficient from a system perspective in today's electricity systems as electricity prices are above average when concentrating solar plants can directly feed into the grid. Hence, we argue that flat feed-in tariffs would currently set an inefficient incentive to invest in thermal storage units by neglecting hourly price signals. However, the value of storage increases in electricity systems with higher shares of fluctuating renewable generation. Therefore, concentrating solar plants with integrated thermal storages may play a significant role in mostly renewable-based electricity systems in the future.

Chapter 2

Energy policy scenarios to reach challenging climate protection targets in the German electricity sector until 2050

2.1 Introduction

Many countries are trying to reduce CO_2 emissions in the energy sector due to the fear of uncontrollable consequences from climate change. In particular, Germany increased its effort in the last decades. However, a long-term energy strategy to reach climate protection targets was not considered.

Within the coalition agreement for the 17^{th} legislative period of the German Federal Parliament, the political parties CDU, CSU and FDP settled on a greenhouse gas reduction target of 40 % by 2020 compared to emission levels in 1990. For 2050, the agreement is loose but states that greenhouse gas reduction in Germany should be in line with international agreements envisioning a reduction of at least 80 % compared to 1990 values. The coalition agreement furthermore emphasizes the need for improvements in energy efficiency and states that renewable energies should be expanded continuously in order to play the expected predominant role in the future energy mix. Regarding conventional power plants, the usage of carbon capture and storage (CCS) technologies is encouraged. Furthermore, the coalition agreement considers the option of a prolongation of nuclear power plants in Germany within the transformation process to a low-carbon emission energy system.[12] Moreover, other targets such as economically justifiable energy prices and a secure energy supply should be achieved. On the basis of the coalition agreement, the Federal Government commissioned a scenario analysis in order to identify ways of a technological and structural transformation process to reach the envisaged climate targets.

This article describes the scenario analysis of the electricity sector and the interdependencies between the electricity, heating and transportation sectors in Germany. We analyze four scenarios (I–IV) in which a CO_2 emission reduction in the overall energy sector of at least 40 % by 2020 and of 85 % is achieved up to 2050. An overview of the scenario framework is given in Table 2.1.

Table 2.1: Scenario framework

	Reference	I A/B	II A/B	III A/B	IV A/B
Greenhouse gas emission reduction targets		40 % (2020) 85 % (2050)	40 % (2020) 85 % (2050)	40 % (2020) 85 % (2050)	40 % (2020) 85 % (2050)
Nuclear power extension	-	4 years	12 years	20 years	28 years
Energy efficiency p.a.	endog.	1.7-1.9 %	2.3-2.5 %	2.3-2.5 %	endog.
Renewable energies					
- gross electricity share	$\geq$ 16 %	$\geq$ 18 %	$\geq$ 18 %	$\geq$ 18 %	$\geq$ 18 %
- primary energy share	$\geq$ 50 %	$\geq$ 50 %	$\geq$ 50 %	$\geq$ 50 %	$\geq$ 50 %

For the electricity sector, the CO_2 reduction target is higher (95 % in 2050) than in other sectors because of the (expected) relatively low CO_2 abatement costs. Within the reference scenario, we extrapolate observable trends and do not include an explicit CO_2 emission reduction target. While in the reference scenario the operational times of nuclear power plants are not extended, an extension of 4/12/20/28 years is possible in the scenarios I to IV with an explicit CO_2 emission target. The extension of nuclear power generation is an option in the determination of the overall cost-minimizing electricity mix. The influence of different retrofit costs on the extension of operational times is taken into account by comparing the effects in scenarios I A to IV A with scenarios I B to IV B, which consider higher retrofit costs as suggested by the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety. However, even considering an extension in operating time of 28 yeary, electricity generation by nuclear power is only a negligible option in the target year 2050. In all scenarios, demand for electricity decreases substantially due to assumed improvements in energy efficiency.

[12] The prohibition of building new nuclear power plants according to the nuclear law remains enacted and is not questioned in the current coalition agreement (Atomgesetz, 2009). An extension of the remaining operational lifetimes for existing nuclear plants that have been determined in 2002 ('Atomkonsens') is described as an option in the coalition agreement (Atomkonsens, 2002).

For the analysis of the electricity and co-generation system, we apply the investment and dispatch optimization models for electricity markets (conventional and renewable) of the Institute of Energy Economics at the University of Cologne. The main finding of the analysis is that a long-term transition towards a low-carbon and mostly renewable-based energy supply in Germany does not necessarily lead to a large increase in system costs. However, this requires several highly challenging preconditions: First, several technological breakthroughs in the performance of renewable and storage technologies are required and will lead to a reduction of generation costs. Second, a well-coordinated European energy policy is necessary to build an efficient transmission grid throughout Europe and to establish harmonized European renewable policy. Moreover, a mandatory international climate protection agreement must be put in place to provide similar conditions for industries in a globalized business environment.

The remainder of the paper is structured as follows: Section 2.2 provides an overview of the relevant literature. Sections 2.3 and 2.4 describe the methodological approach and the assumptions of the model calculations. In Sections 2.5 and 2.6, we discuss the model results for the target year 2050 and for the transformation process up to 2050, respectively. Section 2.7 summarizes and draws conclusions.

2.2 Literature overview

In recent years, a number of studies analyzed possible transformations to a more-or-less carbon free energy usage in Europe. These studies often focus on the electricity sector. Most of them assume high CO_2 emission targets or a target for electricity generation by renewables, optimistic developments of investments in energy efficiency, high potentials and cost reductions for renewable energies over time. The published studies can be distinguished by the time horizon (e.g., 2030 or 2050), the methods used to model the power market and by the criteria whether or not total costs are evaluated.[13] However, the main difference between the studies is the analytical approach: feasibility studies demonstrating that challenging climate protection targets can be technically achieved or economic scenario analysis determining the cost-efficient transformation to a low-carbon energy system.

Studies that mainly focus on the technical feasibility of a significant CO_2 reduction include Öko-Institut et al. (2009), Hulme et al. (2009) or ICCS (2010). For example, Öko-Institut et al. (2009) develop policy scenarios with a reduction of greenhouse gas emissions of 178 mio. t CO_2 by 2030 (- 17.8 % compared to 2005). Erdmenger

[13] Keles et al. (2011) classified the studies/scenarios into three main groups: 'moderate', 'climate protection' and 'resource scarcity and high fossil fuel prices'.

et al. (2009) present measures and instruments for Germany to substantially reduce CO_2 emissions up to 2020. In both studies, a reduction of energy consumption by improving energy efficiency is illustrated as the most important measure. Due to the long-term effects of decisions in the energy sector and due to the political targets or visions for 2050, several institutes present long-term scenarios with a 80-100 % energy supply by renewables (EREC, 2010, Klaus et al., 2010). However, total system costs of electricity supply in the developed scenarios are not estimated in these studies. Ackermann and Tröster (2009) is another example for a study that focuses on the technical feasibility of a 100 % power supply by renewables in 2050 that explicitly takes transmission constraints of the electricity grid into account. Results of this study include: the need for a significant grid extension and the feasibility of a 100 % renewable-based electricity supply in Europe in order to reach 2050 goals.

Prognos/EWI (2007) model cost-efficient transformations to a low-carbon energy system up to 2030. The study demonstrates among others how the usage of nuclear power plants can reduce economic costs while reducing CO_2 emissions. DLR/IWES/IFNE (2009) as well as Prognos/Öko-Institut (2009) calculate scenarios with high renewable shares and a reduction of greenhouse gas emissions of at least 80 % up to 2050. The studies draw different conclusions concerning the effects of challenging CO_2 reduction targets on prices and total costs. DLR/IWES/IFNE (2009) calculate increasing prices until 2024 and decreasing prices afterwards, due to a decrease of costs of renewable energy technologies after 2024. Prognos/Öko-Institut (2009) estimate higher electricity prices among others as a result of climate protection measures.

In our study, we simulate cost-efficient transformations of the German electricity system with greenhouse gas reductions between 80 % and 95 % until 2050. The results are based on long-term investment and dispatch optimization models for the European electricity market (see Section 2.3). Feedback loops and interdependencies between the electricity market and the rest of the economy are taken into account.

2.3 Methodical approach

Greenhouse gases are emitted in several sectors of an economy: households, industries, trade and commerce and the transportation sector. An analysis on the reduction of greenhouse gas emissions in an economy while maintaining cost-efficiency requires a simultaneous consideration of all sectors. Reasons are differing CO_2 abatement costs in sectors as well as the efficient allocation of scarce input factors (e.g. biomass fuels).

In this study, several simulation models are used to analyze the effects in the specific sectors (Distelkamp et al., 2004, Prognos/EWI/GWS, 2010). For the computations of the electricity and co-generation system, we use the long-term investment and dispatch model for the European electricity market of the Institute of Energy Economics at the University of Cologne, DIME (Bartels, 2009). Cost-based developments for the deployment of renewable energies in Europe up to 2050 are constructed by applying the linear optimization model for renewable electricity integration in Europe, LORELEI (Wissen, 2012), of the Institute of Energy Economics at the University of Cologne.

Interdependencies between the electricity sector and the rest of the economy are taken into account using an iterative approach. In order to find a consistent solution for achieving challenging greenhouse gas reduction targets, relevant variables are interchanged between the different models. For modeling the electricity and co-generation market, variables are iterated between the demand estimation models (Prognos/EWI/GWS, 2010) and DIME. In DIME, the demand for electricity and co-generation is used as a fixed input parameter. Some DIME results including electricity prices, district and process heat generation and the German import and export balance of electricity generation are analogically used as input parameters to model the demand developments. This approach accounts for the interdependency between electricity prices and demand (long-term price elasticity). The macroeconomic effects resulting from the developments in the electricity sector are modeled based on the determined investments and electricity prices in DIME.

Investment and dispatch model for conventional technologies

DIME is a linear optimization model for the conventional European electricity market. It is applied to simulate the hourly dispatch of conventional generation and demand leading to investment decisions regarding the supply side of the electricity sector. The objective of the model is to minimize total discounted system costs subject to meeting electricity demand in all hours. The time frame of the model is from 2008 to 2050 in five-year steps. The dispatch of each year is represented by three typical days (each day consists of 24 hours) per season considering load and renewable generation. A detailed model description can be found in Bartels (2009).

Input parameters can be divided into three groups: demand side, supply side and political parameters. The demand met by conventional generation is called residual demand, which essentially is given by total demand minus the RES-E generation.[14] Important input parameters for the supply side include the costs of generation (investment costs, operation and maintenance costs as well as fuel prices), technical parameters of conventional generation technologies (including minimum load, net efficiency and start-up

[14]To be precise, electricity generation from waste and small-scale combined heat and power (CHP) technologies are also treated exogenously.

times) and the amount of already existing conventional capacities in Europe. Cross-country electricity transmission is constrained by net transfer capacities (NTC) as exogenous model parameters. Political input parameters include decisions on nuclear policy or the availability of carbon capture and storage in the European countries. Important model outputs are the structure of electricity generation and investments in new power plants. Furthermore, electricity prices are estimated on the basis of the dual variables of the equilibrium conditions.[15]

Investment model for renewable energies

LORELEI is a linear optimization model for the deployment of renewable energies in Europe under different support policies. Under a quota obligation, capacities of a specific RES-E technology are constructed as long as the sum of marginal revenues from selling electricity (hourly electricity price) and green certificates (price derived from quota obligation) exceed the generation costs of the specific RES-E technology. Under a feed-in-tariff policy, the investment decision for RES-E capacities is simply made by comparing the feed-in tariff for a technology and the generation costs in a specific country. Important input parameters include the technical RES-E potential in every country, current and prospective RES-E generation costs and the amount and structure of already existing RES-E capacities within each country. LORELEI outputs are the RES-E capacities built in every country, as well as the corresponding electricity generation. A detailed model description can be found in Wissen (2012).

2.4 Political and economic assumptions for the electricity sector

2.4.1 Electricity demand and potential for co-generation

Net electricity demand is assumed to decrease in all scenarios. In the reference scenario, the reduction amounts to 6 % until 2050. In the scenarios I A–IV B, net demand is reduced by 20 % (scenario IV A) to 24 % (scenario I B), which reflects the underlying assumption that the expected increase in electricity consumption due to the extensive usage of electric mobility is overcompensated by the effects of the supposed investments in more efficient technologies of households as well as industries.[16] Table 2.2 shows the assumed net as well as gross electricity demand for the different scenarios.

[15] Given the model approach, cost-minimization from a central planner perspective, the derived electricity prices represent a lower bound.

[16] The electricity demand is modeled bottom-up by Prognos as described in Prognos/EWI/GWS (2010).

Table 2.2: Development of net and (gross) electricity demand [TWh_{el}]

Scenario	2008	2020	2030	2040	2050
Reference	537.6 (614.0)	507.1 (596.2)	497.6 (556.0)	503.3 (562.4)	503.7 (555.1)
I A	537.6 (614.0)	495.4 (552.7)	458.1 (507.8)	433.2 (475.0)	408.1 (440.6)
II A	537.6 (614.0)	496.3 (550.3)	468.2 (514.9)	448.9 (491.9)	427.5 (459.2)
III A	537.6 (614.0)	496.9 (551.4)	469.5 (514.1)	450.0 (491.7)	426.6 (459.2)
IV A	537.6 (614.0)	496.2 (551.0)	467.9 (512.2)	448.2 (488.1)	427.7 (463.1)
I B	537.6 (614.0)	491.7 (548.7)	457.6 (508.0)	432.8 (476.9)	406.7 (440.7)
II B	537.6 (614.0)	493.2 (548.6)	467.7 (515.9)	449.5 (492.8)	426.0 (458.0)
III B	537.6 (614.0)	495.8 (552.6)	468.3 (515.7)	450.0 (494.3)	426.7 (459.5)
IV B	537.6 (614.0)	489.0 (546.8)	458.0 (505.7)	443.0 (486.7)	429.0 (463.3)

The shift to a mostly renewable-based electricity generation leads to a significant reduction of the total internal consumption of power plants (- 92 %). The power losses in other conversion sectors decrease mainly due to the reduced coal extraction. Therefore, gross electricity demand decreases even more than net electricity demand.

The assumed demand for district heating decreases in the scenarios over time (- 60 to 63 %) as well as process heat in industries (- 4 to 12 %). For district heating, the usage of energy-efficient technologies leads to a lower demand for heat in general. This holds true especially for the trade and commerce sector with 80 % lower heating demand in 2050 compared to 2008. In 2050, industries account for 47-57 %, the trade and commerce sector for 13 % and private households for 30-40 % of the potential district heating. The potential demand for process heat decreases due to the supposed structural change and progress in efficiency of material usage. Table 2.3 shows the potential for co-generation in the scenarios for Germany.

Table 2.3: Potential for co-generation (district and process heating) [TWh_{th}]

Scenario	2008	2020	2030	2040	2050
Reference	129.8 (202.9)	124.6 (193.4)	118.0 (195.6)	108.9 (203.3)	99.3 (214.1)
I A	129.8 (202.9)	117.9 (196.5)	95.5 (192.7)	72.0 (191.8)	51.9 (194.4)
II A	129.8 (202.9)	114.8 (194.6)	94.3 (187.3)	73.3 (182.1)	54.9 (180.9)
III A	129.8 (202.9)	114.9 (196.6)	94.3 (187.3)	73.3 (182.1)	54.9 (180.8)
IV A	129.8 (202.9)	113.1 (194.0)	87.1 (188.3)	64.4 (185.0)	47.2 (180.1)
I B	129.8 (202.9)	117.9 (196.8)	95.5 (193.4)	72.0 (192.7)	51.9 (195.2)
II B	129.8 (202.9)	114.8 (194.6)	94.3 (187.6)	73.3 (182.6)	54.9 (181.6)
III B	129.8 (202.9)	114.9 (194.5)	94.3 (187.2)	73.3 (182.2)	54.9 (180.9)
IV B	129.8 (202.9)	113.7 (194.1)	87.7 (188.4)	65.0 (184.6)	47.1 (178.8)

2.4.2 Extension of grid infrastructure in Germany and Europe

The scenarios are based on the assumption that the national electricity grids (transmission and distribution) as well as cross-border transmission capacities in Europe will be expanded significantly in the next decades. An expansion of the European electricity grid is pivotal to achieve a single European electricity market, supports the integration of renewable technologies, as well as the overall stability of the German and European electricity system. Table 2.4 gives an overview of the assumed expansion of the net transfer cross-border capacities in Europe.[17]

TABLE 2.4: Cross-border extensions (net transfer capacities) from 2008 to 2050 [MW_{el}]

NTC < 1,500 MW	1,500 MW ≤ NTC ≤ 4,000 MW	NTC > 4,000 MW
Austria–Croatia	Belarus–Poland	Austria–Germany
Austria–Czech Republic	Belgium–France	Austria–Italy
Austria–Hungary	Belgium–United Kingdom	France–Germany
Austria–Slovakia	Denmark–Norway	France–Italy
Belgium–Germany	France–Switzerland	France–Spain
Belgium–Netherlands	Germany–Poland	France–United Kingdom
Croatia–Italy	Germany–Sweden	Germany–Switzerland
Czech Republic–Germany	Lithuania–Poland	Italy–Switzerland
Czech Republic–Poland	Poland–Ukraine	
Denmark–Germany		
Poland–Slovakia		
Poland–Sweden		
Portugal–Spain		

The main focus of grid expansion in the scenarios is the connection of Scandinavia and the United Kingdom to central Europe, the enhancement of net transfer capacities between the Iberian Peninsula and France as well as the interconnections between Italy and the Alps region. In total, net transfer cross-border capacities in Europe are assumed to triple until 2050 which is similar as in Ackermann and Tröster (2009). Additionally, a significant improvement of the national grids is supposed. The assumed Europe-wide network enables electricity transfer from solar sites at the Mediterranean and wind turbines in Northern Europe to the large load centers in Central Europe. This allows compensating or supporting conventional generation by imports from wind and solar power stations in periods with high demand across Europe. Hence, the grid extension contributes to assure sufficient capacity to meet peak demand in the different countries.

2.4.3 Technical and economic parameters for conventional technologies

Several assumptions are made regarding the development of investment costs and technical parameters such as the lifetime or efficiencies of conventional power plants. A few technologies, not in use today, are assumed: An 'innovative' hard-coal plant with 4 %-points higher net efficiency factors than state of the art power stations from today; an 'innovative' lignite plant with novel drying processes resulting in a net efficiency of 48 % and CCS-technologies being available starting from 2025 (lower net efficiencies

[17]We assume the same capacity limits for both flow directions.

than technologies without CCS). Table 2.5 shows the assumed investment costs for new conventional power plants over time. Further techno-economic assumptions for conventional power plants can be found in Appendix A.

TABLE 2.5: Investment costs for conventional power plants [EUR_{2008}/kW]

	2020	2030	2040	2050
Lignite	1,850	1,850	1,850	1,850
Lignite (‘innovative’)	1,950	1,950	1,950	1,950
Hard-coal	1,300	1,300	1,300	1,300
Hard-coal (‘innovative’)	2,250	1,875	1,763	1,650
Combined cycle gas turbine	950	950	950	950
Open cycle gas turbine	400	400	400	400
Integrated gasification combined cycle-CCS	-	2,039	1,985	1,781
Combined cycle gas turbine-CCS	-	1,173	1,132	1,020
Hard-coal-CCS	-	1,848	1,800	1,751
Hard-coal-CCS (‘innovative’)	-	2,423	2,262	2,101
Lignite-CCS	-	2,498	2,450	2,402

The scenarios I–IV are computed with two different sets of retrofit costs for nuclear power plants. In the scenarios ‘A’, retrofit costs are assumed to be 25 EUR_{2008}/kW per additional year of operational time extension. In the scenarios ‘B’, retrofit costs for nuclear power plants are specific to the plant. Table 2.6 presents the retrofit costs in the scenarios ‘A’ and (‘B’).

TABLE 2.6: Retrofits costs for nuclear plants in A and (B) scenarios [EUR_{2008}/kW]

	Scenario I 4 years	Scenario II 12 years	Scenario III 20 years	Scenario IV 28 years
Biblis A	100 (86)	300 (514)	500 (1,457)	700 (2,142)
Biblis B	100 (81)	300 (484)	500 (1,371)	700 (2,016)
Brokdorf	100 (438)	300 (1,241)	500 (1,825)	700 (2,409)
Brunsbüttel	100 (130)	300 (778)	500 (2,335)	700 (3,372)
Emsland	100 (451)	300 (1,354)	500 (1,956)	700 (2,558)
Grafenrheinfeld	100 (78)	300 (941)	500 (1,569)	700 (2,196)
Gundremmingen B	100 (78)	300 (1,012)	500 (1,636)	700 (2,259)
Gundremmingen C	100 (466)	300 (1,087)	500 (1,708)	700 (2,329)
Grohnde	100 (441)	300 (1,176)	500 (1,765)	700 (2,353)
Isar 1	100 (114)	300 (683)	500 (1,936)	700 (2,847)
Isar 2	100 (429)	300 (1,286)	500 (1,857)	700 (2,429)
Krümmel	100 (449)	300 (1,273)	500 (1,873)	700 (2,472)
Neckarwestheim 1	100 (0)	300 (764)	500 (2,038)	700 (3,057)
Neckarwestheim 2	100 (920)	300 (1,533)	500 (2,146)	700 (2,759)
Philippsburg 1	100 (112)	300 (674)	500 (2,022)	700 (2,921)
Philippsburg 2	100 (431)	300 (1,149)	500 (1,724)	700 (2,299)
Unterweser	100 (74)	300 (446)	500 (1,338)	700 (1,933)

2.4.4 Potential, costs and full load hours of renewable technologies

The development of renewable energies respects the different technical as well as economic potentials throughout Europe. In Germany, the potential for additional hydro power capacities is limited to the already existing capacities. The utilization of biomass fuels for electricity generation is assumed to be bounded (41 TWh_{th}) due to the consumption of liquid biomass as a substitute for oil in the transportation sector. In the scenarios, no potential limit for solar-based electricity generation is assumed. Since the most favorable onshore wind sites are already utilized in Germany, re-powering of existing wind turbines plays an important role.

Table 2.7 shows the assumed development of investment costs for renewable energies. Due to more efficient production processes and technology improvements (assumptions), investment costs for renewable energies decrease over time. In particular, the investment costs for offshore wind parks and photovoltaics are assumed to decrease substantially.

TABLE 2.7: Investment costs for renewable technologies [EUR_{2008}/kW]

	2020	2030	2040	2050
Large hydro power	3,850	4,180	4,950	5,500
Small hydro power	2,750	2,970	3,080	3,190
Onshore wind sites	1,030	985	960	950
Offshore wind sites	2,400	1,670	1,475	1,350
Photovoltaics	1,375	1,085	1,015	1,000
Biomass	2,300	2,200	2,125	2,075
Geothermal power	10,750	9,500	9,000	9,000
Concentrated solar power	4,188	3,677	3,064	2,554

The scenarios assume increasing full load hours of wind and solar technologies due to technological progress (e.g., higher hub heights for wind turbines). As listed in Table 2.8, achievable full load hours of wind technologies in Germany are slightly below the European average and solar technologies in Germany achieve relatively low full load hours.

TABLE 2.8: Average full load hours of wind and solar technologies in Europe [h]

	Average in countries with unfavorable sites	Average in Germany	Average in countries with best sites
Today			
Wind onshore	1,200	1,680	2,800
Wind offshore	2,000	2,600	4,200
Photovoltaics	800	845	1,100
Target year 2050			
Wind onshore	1,400	2,200	3,800
Wind offshore	3,000	4,000	5,500
Photovoltaics	900	1,000	1,500

Source: EWI (2010).

2.4.5 Fuel and CO_2 emission prices

The assumed fuel prices are based on international market prices and include transportation costs to the power plants. Table 2.9 shows the fuel prices assumed for power generation and the price for CO_2 emissions in the scenarios. The price for hard coal is assumed to decrease in the midterm but to increase in the long run up to 3.9 EUR_{2008}/GJ. For domestic lignite a constant price of 0.4 EUR_{2008}/GJ is assumed. Despite the currently existing excess supply and low prices of natural gas, we assume a significant increase up to 8.8 EUR_{2008}/GJ in 2050. The price for biomass fuels is assumed to increase to 13.9 EUR_{2008}/GJ due to a higher demand in the scenarios. Total CO_2 emissions depend on various drivers such as RES-E feed-in, utilization of nuclear power, electricity demand and fossil fuel generation mix. Consequently, CO_2 prices differ slightly between the scenarios (I A–IV B).

Table 2.9: Fuel prices [EUR_{2008}/GJ] and CO_2 prices [EUR_{2008}/t CO_2]

	2008	2020	2030	2040	2050
Hard coal	4.8	2.8	3.0	3.3	3.9
Lignite	0.4	0.4	0.4	0.4	0.4
Natural gas	7.0	6.4	7.2	8.0	8.8
Biomass	8.3	12.0	13.9	13.9	13.9
CO_2 price (ref. scenario)	22.0	20.0	30.0	40.0	50.0
CO_2 price (I A–IV B)	22.0	18.6-23.3	35.7-42.8	55.3-58.8	74.1-75.6

2.5 Scenario results for the target year 2050

The challenging climate protection targets lead to a structural change of the German and European electricity generation mix. This section highlights selected results for the target year 2050 in comparison to 2008.

Total share of electricity generation by conventional power plants decreases from 84 % in 2008 to 19 to 24 % in the scenarios I to IV in 2050. Electricity generation based on fossil fuels takes mainly place in highly efficient coal-fired power plants with carbon capture and storage in 2050. These plants are designed for combined heat and power generation to achieve higher overall fuel efficiency levels. Furthermore, it allows for an increase in plant utilization, as revenue streams from electricity generation alone may not be sufficient to cover the significant investment costs of such plants.

The contribution of renewable technologies increases significantly, especially in the scenarios I to IV. This leads to a gross electricity share of renewables of 77 to 81 % in the scenarios I to IV (reference scenario: 54 %). In the long term, the deployment of wind energy is the main driver for a higher generation by renewables in Germany. The potential of biomass fuels is limited by different land usage opportunities as well as future settlement dispersion. The available potential also faces usage opportunities. The bulk of biomass is required in the mobility sector where other substitution options are scarce. All remaining biomass fuels are used for electricity generation. Due to the assumed continuance of national renewable policies in Europe until 2020, the electricity generation from photovoltaics increases (continuance of a feed-in-tariff system) in Germany in the first ten years of the modeled horizon. Afterwards, the assumed cost-efficient European renewable support scheme leads to very low growth rates for photvoltaics in Germany, as specific costs of solar-based energy generation are significantly lower in Mediterranean countries. Figure 2.1 shows the electricity generation mix in Germany in 2050 for the different scenarios.

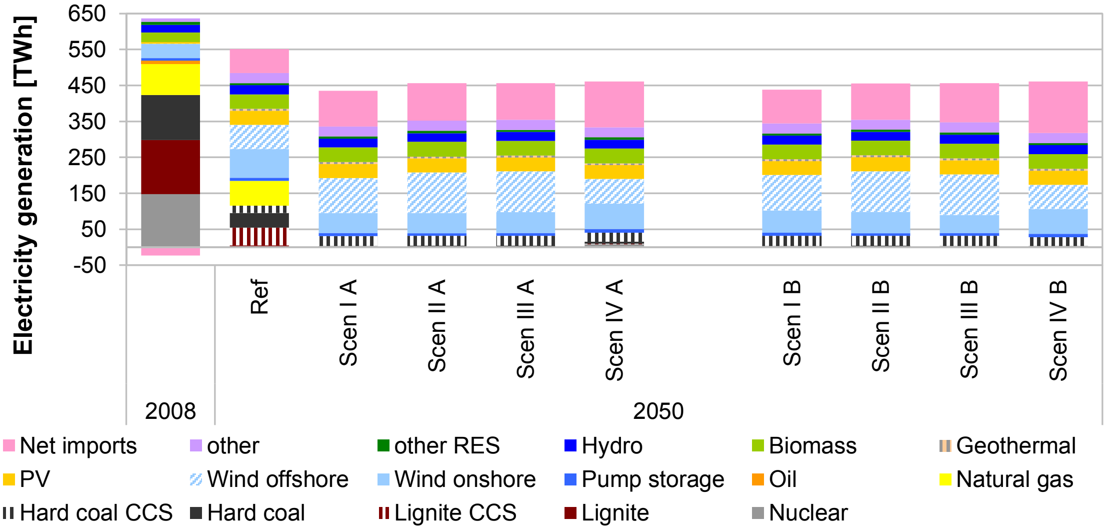

FIGURE 2.1: Electricity generation by fuel in 2050 compared to 2008 [TWh]
Sources: Electricity generation 2008 based on BMWi (2012).

In all scenarios, net imports of Germany increase significantly compared to the year 2008. In the scenarios I to IV, the share of net imports accounts for 22 to 31 % in 2050 (reference scenario: 12 %). The imports result from the cost-efficient approach to reach reduction targets in the European power sector in the long term and are based on two main assumptions: the supposed coordinated extension of the European electricity grid and the European cost-efficient renewable support policy beginning by 2020.

Both assumptions lead to a different spatial electricity generation pattern compared to today. Marginal cost-wise, the cheapest conventional generation option is nuclear power and the cheapest renewable generation option is wind energy along the coastlines in Northern Europe and solar technologies in Southern Europe. Due to the nuclear phase-out and relatively high cost renewable options in Germany, the cheapest generation options (nuclear and renewable) are not available in Germany in 2050. This leads to a situation in which a significant part of the German electricity demand is met by imports from European countries with more cost-efficient generation options.

The shift to a mostly renewable-based electricity generation mix leads to a significant reduction of CO_2 emissions in the German electricity sector (96 to 97 % in the scenarios I to IV). Main reasons for the reduction of CO_2 emissions in Germany beside the increase in renewable feed-in are:

- reduced electricity demand especially in Germany, but also a slow-down of demand-growth in the other European countries;
- change in fossil fuel-based generation (e.g., CCS-technologies);
- an increase of net imports (mainly nuclear power and renewables).

In the reference scenario, the higher CO_2 and fuel prices (assumptions) and the larger share of renewables lead to an increase of electricity generation costs. In the scenarios I to IV, wholesale prices are lower than in the reference scenario for several reasons: First, as electricity demand is assumed to be lower in all of Europe in 2050, the need for covering peak demand spikes is reduced. Second, the strong increase in renewable energy feed-in leads to many periods in which renewables are price setting in the wholesale market, which means that wholesale prices are often zero during hours with large wind and solar feed-in. Third, the large-scale expansion of the European transmission grid makes it possible that the different renewable sources can partly balance each others intermittent feed-in characteristics. This portfolio effect enables that the remaining fossil plants can be dispatched more efficiently than today, which reduces their long-run marginal costs. However, retail prices in the scenarios I to IV are slightly higher than the prices in the reference scenario.[18] This is mainly due to higher costs for renewable support, which outweighs the positive price effects in the wholesale market.

2.6 The transformation of the electricity market until 2050

The challenging climate protection targets lead to a structural change of power plant capacities over the next 40 years. Despite decreasing electricity demand, gross capacity installed increases in the short and medium term. This development is due to the transformation to a renewable-based and Pan-European power mix (25 % RES-E in 2008 and 67-70 % in 2050).

[18] Exceptionally, the retail price for large industries is lower due to the high influence of wholesale prices for these industries (considering exceptional rules).

2.6.1 The impact of operating time extensions for nuclear power plants

The main difference between the scenarios I–IV A is the extension of the operating time for nuclear power plants in Germany. In scenario I A, all German nuclear power plants have been decommissioned in 2030 whereas in scenario IV A some nuclear power plants may still be utilized in 2050. Due to the different operating time for nuclear power plants, the power plant mix, capacity utilization and the gross electricity generation differs between the scenarios. Nuclear power plants are the cheapest option for base-load electricity generation, thus the maximum possible prolongation of operational time is always used in these scenarios. In this setting retrofit costs of 25 EUR_{2008} per kW and operational year are assumed.

Renewable energies, especially wind and solar technologies, contribute less to cover peak demand than conventional power plants. Therefore, back-up capacities are needed to ensure that demand can always be met. Consequently, total installed capacity increases in the medium term and stagnates or slightly decreases in the long term (lower demand per assumption). The phase-out of nuclear power plants causes an additional need for capacity in the short and medium term in the respective scenarios. In general, these capacity requirements are either met by longer economic lifetimes of existing installations or the commissioning of new gas-fired power plants. Both, decreased net exports of electricity and increased domestic generation from fossil fuel-based power stations contribute to the substitution of nuclear power. Figure 2.2 shows the development of (gross) installed capacities in the reference scenario and the scenarios I–IV A from 2008 to 2050.

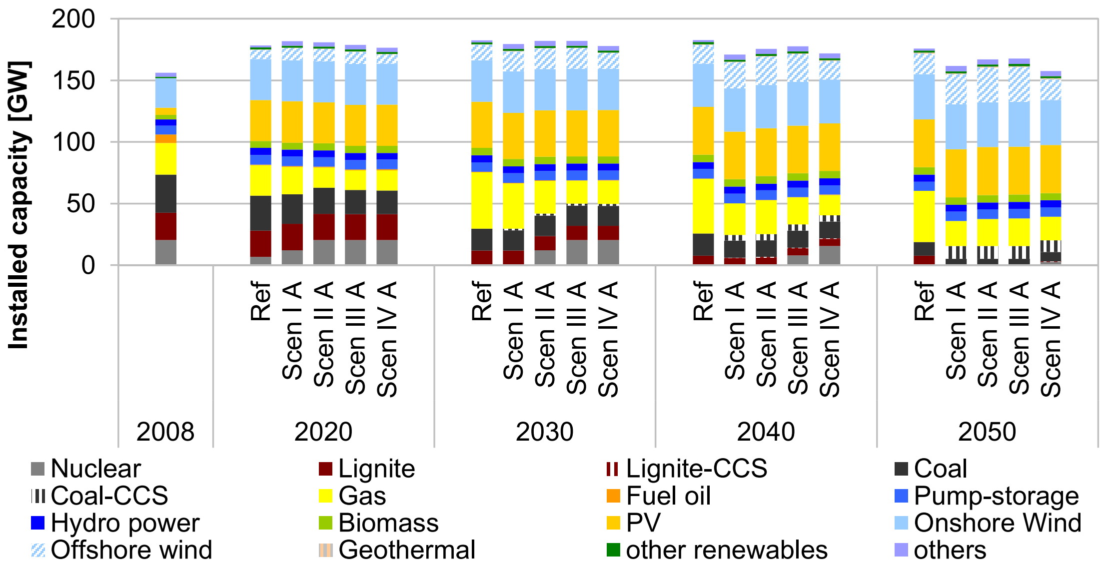

FIGURE 2.2: Development of installed capacities by fuel from 2008 to 2050 [GW]
Sources: Capacities 2008 based on BMWi (2012).

In the scenarios I–IV, electricity generation by conventional power plants decreases continuously until 2050 due to the high feed-in of RES-E into the European power system. While gas and lignite play a minor role in electricity generation in the long run, a certain amount of coal plants remain profitable. Coal-fired plants gain a cost advantage compared to gas and lignite in the long run for a number of reasons: relatively low hard-coal prices; lignite has a disadvantage compared to hard-coal in CHP generation due to the location of mine-mouth lignite plants[19]; high carbon prices penalize lignite-fired plants stronger as CO_2 capture rates of CCS plants are below 100 %. Electricity generation from renewable energies significantly over time. Until 2020, a national support scheme for RES-E in Germany is assumed resulting in an expansion of PV and wind capacities. From 2030 onwards, the assumed coordination of European RES-E policies leads to a strong increase of wind generation in the United Kingdom and solar power at the Mediterranean. In Germany, the majority of domestic RES-E is wind power: both onshore and offshore. Due to the expansion of the European transmission network, increasing amounts of electricity can be imported. While Germany is still a net exporter of electricity in 2020, significant amounts of electricity are imported in 2030. Shorter prolongations of nuclear power lead to fewer net exports in the short and medium term. Furthermore, gas-fired plants increase their utilization in scenarios with shorter operation times of nuclear power stations (i.e., scenarios I A and II A).

Utilization rates of fossil fuel-based plants depend on the prolongation times of nuclear power in Germany in the short and medium term. Old hard-coal and lignite power stations are used as back-up option and therefore realize low utilization rates. On the other hand the utilization rate of newly installed coal and lignite plants with CCS is above average. Although gas-fired power plants contribute significantly to the substitution of nuclear power in the short term, their utilization rate decreases over time and only operate in a few hours in the long run. This is due to two effects: the clean spark spread becomes increasingly unfavorable for gas plants (assumption) and the volatile feed-in of renewables requires large amounts of back-up capacity, which is provided by cheap gas turbines. These plants recover their investment costs because of a peak load or capacity price mechanism. Such a mechanism is implemented in the used electricity market model: In periods when capacity is scarce, i.e. the restriction of required minimum capacity for peak load coverage is binding, securely available capacities earn a scarcity rent. This rent corresponds to the shadow price of the peak load capacity constraint in this period. The cost minimization mechanism consistently assigns shadow prices according to the input involved. Therefore, the capacity scarcity rent is exactly

[19]The transport of lignite is usually not cost-efficient due to its low calorific value.

high enough to remunerate investment costs of the least utilized peak load plant over the plant lifetime.[20]

The wholesale price (including the described capacity payment) allows conventional power plants to recover their capital costs but this is not the case for renewable energies. The additional costs for renewable energies, representing the difference between the full costs for renewables and the wholesale price, are allocated to end-consumers as levy additional to the wholesale price. Hence, the RES-E levy highly depends on the development of the wholesale price. The necessary levy for RES-E imports is calculated respectively by comparing the full costs of renewables and wholesale prices in Europe. Figure 2.3 depicts the development of wholesale prices and RES-E levies in the scenarios. When comparing the reference scenario with the scenarios I–IV, one has to keep in mind the different assumptions about the electricity demand development and the availability of nuclear power in Germany.

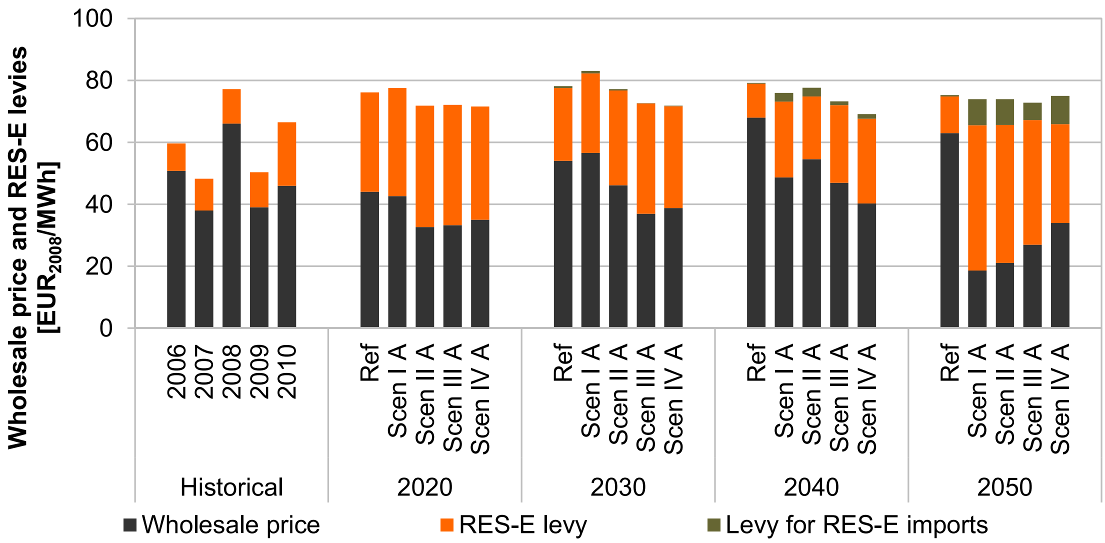

FIGURE 2.3: Development of wholesale prices and RES-E levies [EUR_{2008}/MWh]
Sources: Historical data based on EEX (2012b) and BDEW (2012).

Figure 2.4 shows the resulting retail prices for households, trade and commerce, industries and energy intensive industries in the developed scenarios. End-consumer prices consist of the wholesale and sales component, a grid usage tariff, a levy for additional renewable costs and taxes. The differences between the end-consumer groups depend on the amount of consumed electricity, the demand structure and different regulations

[20]There are various market designs that could support such capacity payments. One example could be market-driven price spikes, whose duration, height and frequency lead to investment cost recovery for all plants in the long run, subject to potential competition with new entrants. Another example could be regulated capacity markets, e.g., auctioning the required minimum capacity to securely cover expected peak load. The issue of choosing an optimal market design to support efficient investment in generation capacity is clearly a field where additional research is needed (Finon and Pignon, 2008, Moreno et al., 2010).

concerning taxes and levies in Germany. For example, a limit for the RES-E levy applies for energy-intensive industries.

The retail prices for all consumer groups increase in the scenarios until 2030 and then decrease up to 2050 to a similar level as in 2008. In the short run, retail prices increase due to the much higher generation costs for renewable energies compared to fossil fuels. In the long run, the import option and assumed cost reductions of renewable energies lead to a price decrease until 2050.

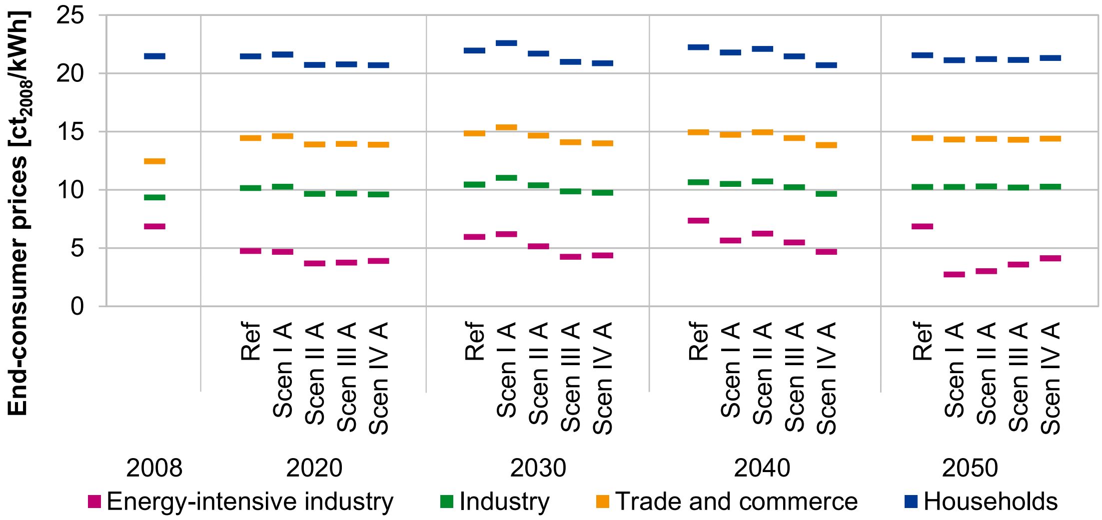

FIGURE 2.4: Electricity prices for end-consumer [ct_{2008}/kWh]
Sources: Electricity prices in 2008 based on Eurostat (2010b).

In general, shorter operational times of nuclear power plants lead to higher electricity prices particularly in the short and medium term. In the long run, prices are similar in all scenarios but highest in scenario IV A due to catch-up effects concerning the substitution of nuclear power.

2.6.2 The impact of different retrofit costs for nuclear plants

The scenarios I–IV are computed with two different sets of retrofit costs as shown in Table 2.6 (Subsection 2.4.3). In the scenario I–IV A, the option to prolong the operational times for nuclear power plants is taken for each nuclear power plant. For higher retrofit cost this is not the case. Figure 2.5 depicts the maximal possible extension and the installed capacities (retrofit option taken) in the scenarios I–IV B.

The analysis of the impact of different retrofit costs shows similarities with the analysis of different operational times. The nuclear power capacities decommissioned due to the higher retrofit costs in the scenarios I–IV B are also substituted by coal and gas capacities. In the short term, a higher utilization of conventional power plants substitute the generation by nuclear power plants. This is backed by additional electricity imports and fewer exports (in 2020).

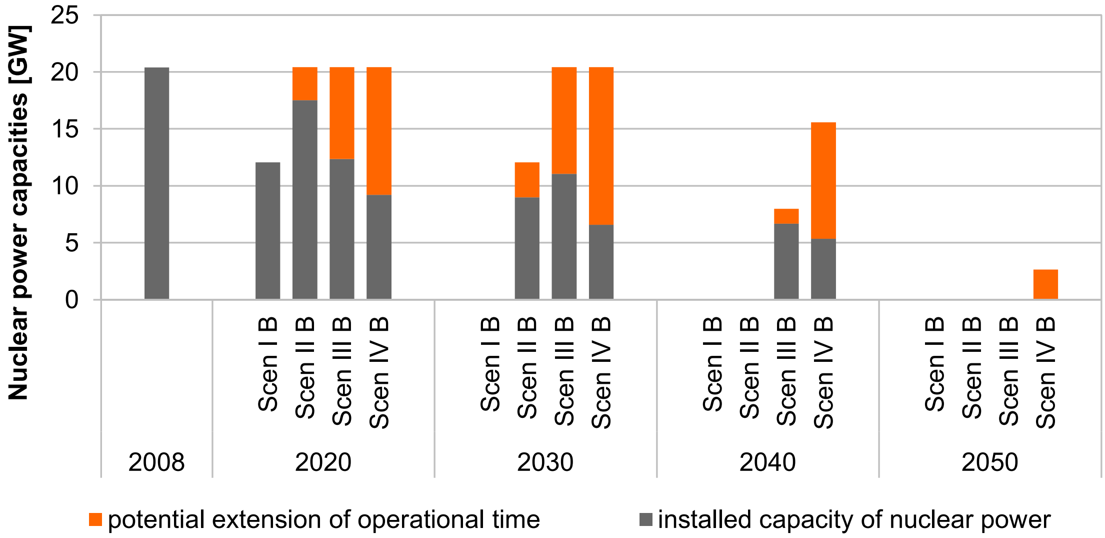

FIGURE 2.5: Installed capacities of nuclear power plants [GW]

Higher retrofit costs and therefore less prolonged nuclear power stations have several inflating impacts on wholesale prices (as compared to scenarios I–IV A). Decommissioned nuclear power plants need to be replaced by either investments in new power plants, a higher utilization of existing capacities or imports (or lower exports as in 2020). Furthermore, retrofit investments have to be recovered by nuclear plants and thus increase long-run marginal costs of this technology. Due to the merit order effect, power stations with higher marginal costs are more often price setting and therefore the wholesale price is higher. As discussed above, nuclear power generation is substantially replaced by additional natural gas-based generation. This leads to higher marginal costs due to relatively high variable costs of natural gas power stations.

2.7 Conclusions

The CO_2 reduction targets are achieved as required by political request in the scenarios I–IV A/B and electricity prices remain relatively stable over time. Although prices increase in the long run due to the ambitious CO_2 reduction targets, the increment is surprisingly low. Thereby, the power system needs to change substantially from a national to a supranational- and from a fossil fuel-based to a renewable-based energy system. However, the extension of the European electricity grid, an international climate protection agreement as well as the European coordination of renewable policies are major conditions for the transformation of the electricity market as described in this paper. Each single one of them is undeniably a great challenge.

An international climate protection agreement in the short or medium term is important to provide similar conditions for industries in a globalized business environment. A reliable decision on the operational time of nuclear power plants in Germany is needed to provide planning reliability for investors in power plants as the political uncertainty causes higher generation costs due to higher market risks. Pricing mechanisms need to focus more on back-up and balancing capacities as well as the integration of renewable energies. An expansion of the European electricity grid is key to achieve a single European electricity market. Moreover, the transmission grid supports the integration of renewable technologies and contributes to the overall stability of the German and European electricity system. A coordinated development of renewable energies in the European Union is important to minimize the additional costs of renewable generation. The technical, legal and political requirements for a commercial use of power plants with carbon capture and storage need to be resolved. A decreasing energy demand over all sectors in Europe is crucial to achieve CO_2 reduction targets and political action is needed to initiate energy efficiency investments and behavior.

The realization of such a long-term ambitious energy concept requires coordinated political and economic actions. However, perhaps even more important is a social consensus about the need of an environment-friendly energy system with economically justifiable prices and a secure supply. Without such social consensus, it is inconceivable that society would be willing to accept such extraordinary burdens and risks to achieve climate protection targets.

Chapter 3

The costs of electricity systems with a high share of fluctuating renewables - a stochastic investment and dispatch optimization model for Europe[21]

3.1 Introduction

As an attempt to fight global warming, many countries try to reduce CO_2 emissions from electricity generation by significantly increasing the proportion of renewables. The cost-efficient transformation from a fossil fuel-based to a primarily renewable-based electricity system is often analyzed by applying deterministic investment and dispatch models for single countries or regions. Model results often suggest that wind power, photovoltaics and biomass will replace fossil fuel generation and total system costs will only moderately increase due to assumed cost reductions for renewable energies.

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However, even considering significant capital cost reductions for renewables these model results may be questioned because unlike conventional power plants the availability of fluctuating renewables such as wind and PV power depends on local weather conditions and is therefore stochastic. The availability may or may not be favorable in terms of meeting the hourly electricity demand and weather situations, such as longer time frames with e.g., minimal wind power feed-in, need to be considered. As shown by Joskow (2011), cost comparisons between intermittent and dispatchable generating technologies based on expected levelized cost of electricity fail because differences in the production profiles and the associated large variations in the market value of electricity are not taken into account. Deterministic investment and dispatch models consider these aspects by simulating dispatch realizations for several days and therefore seem to be a more appropriate method to estimate the costs for an electricity system with a high share of renewables.[22] However, deterministic investment and dispatch models do not capture the uncertainty of the availability of fluctuating renewables by modeling typical wind and solar structures, average full load hours of wind and solar systems and average correlations between wind and solar availability.

As regional wind speeds and solar radiation differ significantly between years, the amount of yearly generated electricity by wind turbines and solar panels is uncertain.[23] Due to the existence of positive and negative availability correlations between technologies (e.g., negative correlation between PV and wind power) and between regions (e.g., wind in Great Britain and Italy) a mix of wind and solar technologies as well as geographical distributed RES-E capacities, together with a large extension of the electricity grid, is often suggested (Heide et al., 2010). However, the extent of the correlation between technologies and between regions also differs between years and is therefore uncertain. Due to these uncertainties, the optimal capacity mix (conventional, renewable and storage technologies) may be different than determined in deterministic investment and dispatch models and total system costs for high RES-E systems could be significantly higher than estimated so far.

In this paper, we try to quantify the additional system costs and the impact on the cost-efficient capacity mix when accounting for the uncertainty of the availability of wind and solar plants. We develop a stochastic investment and dispatch optimization model which considers uncertainty of hourly and yearly availability of wind and solar resources and apply it to the European electricity market.[24] The stochastic feed-in of wind and

[22] Some models neglect ramp-up constraints and optimize the capacity mix and generation for a given load duration curve.

[23] Data can be found in Table B.2 in Appendix B.

[24] We divide Europe into several zones in order to limit computational times: Austria (AT), Benelux (BeNeLux), Switzerland (CH), Czech Republic (CZ), Denmark (DK), Eastern Europe (EE), France (FR), Germany (GER), Iberian Peninsula (IB), Italy (IT), Poland (PL), Scandinavia (SCA), United Kingdom (UK).

solar power technologies as well as stochastic full load hours are taken into account by different feed-in structures reflecting the empirical data.[25]

We find that fluctuating renewables are overvalued in deterministic optimization models and hence, dispatchable renewable energies such as biomass or geothermal sites, even considering high investment or fuel costs, are underestimated in high RES-E scenarios. Furthermore, solar technologies are, relative to wind power, underestimated when neglecting the negative correlation between wind and solar power. The results also indicate that the total system costs for high RES-E electricity systems are significantly underestimated when neglecting the stochastic availability of wind and solar technologies. The cost difference increases with a higher share of fluctuating RES-E generation and amounts to 14.2 EUR_{2010}/MWh which represents about 12.3 % of the average costs in the case of a system with 95 % generation from renewables in 2050. Sensitivity analyses on the capital costs of wind and solar technologies, as well as on the development of the transmission grid, show that the optimal technology mix and system costs highly depend on these parameters. However, the identified additional costs due to the stochastic availability of wind and solar technologies (as percentage of the system costs) are fairly robust to variations in these parameters.

The remainder of the paper is structured as follows: Section 3.2 sketches literature of models which account for the stochastic availability of wind and solar power. In Section 3.3, we analyze the availability of wind and solar power and present a re-sampling method to generate Europe-wide combined regional wind and solar feed-in structures. In Section 3.4, the stochastic optimization model is presented and model results are discussed. Conclusions are drawn in Section 3.5 providing an outlook of further possible research.

3.2 Literature review and contributions of the current work

Several models have been developed to identify the optimal combination of renewable and conventional resources on a large scale. Short et al. (2010) divide the United States into 356 wind regions and model the cost-efficient installations and operation of wind

[25]The model simulates the dispatch of electricity generation and demand for 30 days on an hourly basis (scaled to 8760 hours). Modeling the dispatch for 30 days allows the consideration of typical demand characteristics such as a peak around midday or higher demand levels on weekdays. The volatile generation from wind and solar technologies is modeled by regional feed-in structures (different hourly feed-in availability). The availability parameter represents the maximal generation by a wind turbine or solar panel in a specific hour as a ratio of the installed capacity. The regional feed-in structures differ across the scenarios in terms of annual as well as hourly generation in the stochastic model. However, we assume perfect foresight within each dispatch realization as such short-term uncertainties e.g. short noticed power plant outages or forecast errors are not modeled and therefore system costs are higher in reality.

farms and conventional generators from 2000 through 2050. DeCarolis and Keith (2006) develop an optimization model for one investment period in 2020 based on five years of hourly wind and load data. Considering the assumed costs of wind turbines, their simulation indicates that supplying 50 % of the electricity demand by wind power adds about 1-2 ct/kWh to the costs of electricity generation. Rosen et al. (2007) couple a long-term energy system model with a temporally highly resolved simulation model for power plant scheduling. The long-term model is used to determine the cost-optimized capacity development and generation for 25 European regions between 2000 and 2020. Neuhoff et al. (2008) divide the United Kingdom into seven regions and optimize investments and dispatch choices for new and existing natural gas, coal and wind generators during four five year investment periods. The SWITCH model at the University of California, Berkeley (Fripp, 2008) concentrates on California and optimizes the combination of more than 229 wind, 464 solar sites and conventional resources considering investment and operational costs. Heide et al. (2010) model the optimal mix of wind and PV capacities for Europe by minimizing needed storage capacities subject to the constraint that all renewable energy is used (independent of total system costs). In case of supplying 100 % electricity by wind and solar technologies, the optimal mix is found to be 55 % wind and 45 % solar power generation. Mount et al. (2011) use a 30-bus test network and analyze it for different wind levels to show that the social value of storage and controllable load increases when intermittent sources of generation are added to a network. The DIMENSION model of the Institute of Energy Economics at the University of Cologne (EWI, 2011) simulates in five year time steps the cost-efficient European capacity development and dispatch for twelve typical days of conventional, renewable and storage technologies until 2050. Due to modeling deterministic feed-in structures and average full load hours of wind and solar technologies, all of these models neglect uncertainty of hourly availability of renewable energy.

Methodologies incorporating uncertainty in optimization models were developed by Dantzig (1955). They were applied to electricity generation planning problems to analyze the impact of demand uncertainty for the first time in the 1980s (Modiano, 1987, Murphy et al., 1982). In recent years, among others Hobbs and Maheshwari (1990), Birge and Louveaux (1997), Sen and Higle (1999), Fleten et al. (2002), Weber (2005) and Conejo et al. (2010) analyzed uncertainties and their impacts in energy markets. A broad overview of different stochastic modeling approaches for electricity markets can be found in Möst and Keles (2010).

The economic value of wind power, taking into account the volatility of wind velocity, was analyzed by Beenstock (1995). The method is based on the intuition that one can immunize the output of a wind turbine against fluctuations in wind speed by investing in back-up capacities. The costs of necessary back-up investments may be regarded as the costs of wind volatility. Papaefthymiou et al. (2006) present a Monte Carlo simulation technique to model the extremes of stochastic wind generation in power systems by sampling wind turbines with similar generation patterns. Swider and Weber (2006) apply a stochastic fundamental electricity market model to estimate the integration costs of wind based on the changed system operation and investments in Germany. The simulation indicates that the value of fluctuating renewables is overestimated when applying a static, deterministic model. In particular, investment planning under uncertainty, considering power plant outages and fluctuating renewable feed-in, was analyzed in Sun et al. (2008). By applying a stochastic mixed-integer optimization model for power plant investment planning to the German electricity market, Sun et al. (2008) show how ignoring short-term uncertainties significantly undervalues the needed operational flexibility and can result in insufficient investments. However, in these models, the deployment of RES-E capacities is not part of the optimization problem and therefore the optimal mix of conventional, storage and renewable technologies in high RES-E scenarios is not determined.

In this paper, we present a stochastic investment and dispatch optimization model for electricity markets that accounts for the uncertain feed-in of wind and solar technologies to determine the optimal mix of conventional, renewable and storage capacities for prescribed European renewable generation targets (technology-neutral, Europe-wide targets). The difference between the stochastic model results and the deterministic solution based on averages in wind speeds and solar radiation can be interpreted as the impact of the stochastic availability of wind and solar power. To our knowledge, a stochastic electricity market model with as much detail concerning the different local RES-E conditions and the uncertain feed-in of fluctuating renewables has not appeared before.

3.3 Generation of combined wind and solar feed-in structures

Wind and solar technologies are meant to produce a large share of the future electricity demand. However, the availability of these technologies depends on local weather conditions and therefore weather characteristics must be considered when optimizing the future electricity mix. Regional weather characteristics lead to different local RES-E conditions throughout Europe, stochastic amounts of yearly generated electricity of wind and solar sites as well as positive or negative correlations between the availability in different regions or between technologies. In this section, we highlight the most important characteristics of wind speeds and solar radiation in Europe for the power sector based on hourly wind speed and solar radiation data from EuroWind (2011) for the years 2006-2010.[26] Furthermore, we show how representative feed-in structures as input parameters for the stochastic optimization model are selected.

3.3.1 Characteristics of wind speeds and solar radiation in Europe

Wind speed distributions reflect that, in most regions, strong winds are rare and moderate winds occur most often. Due to seasonal characteristics, the average wind speed is usually higher in winter and autumn than in the summer months. Table 3.1 shows summarizing statistics for some of the selected wind regions in Europe. As wind speeds are usually higher in Northern Europe, the average wind speed at 30 meters was 6.74 m/s in Northern Ireland compared to 3.59 m/s in Southern Italy for the years 2006-2010. Higher wind speeds often result in a higher variance, as can be seen by comparing the variance of the wind speed in the Southern part of the Iberian Peninsula (9.02) and offshore wind in the United Kingdom (18.81). Due to generally short distances between European regions, the same general weather situations occur between these regions. Hence, the hourly wind speeds in Europe are, to some extent, correlated. Closer regions have a stronger correlation, e.g., Pearson correlation factor of 0.587 between on- and offshore wind in the United Kingdom. However, some wind regions in Europe are not very correlated or even negatively correlated (e.g., United Kingdom and Iberian Peninsula with -0.026). A table with the correlation factors of all analyzed regions can be found in Appendix B.

The values in Table 3.1 represent the average of several years. However, as weather situations differ between years, the yearly average wind speed varies as well (depicted in Table 3.2 for the years 2006-2010). The average wind speed in the United Kingdom in 2008 was significantly higher with 7.26 m/s than the 5.93 m/s in 2010. Even considering just a few years, the difference of more than 1 m/s represents about 20 % of the average over the five years. Similar to the yearly average wind speed, the correlation between wind regions differs as well. The Pearson correlation factor for wind in the United Kingdom (northern to central) of 0.587 in 2006 indicates a rather strong correlation, however in some years the correlation is less distinctive (Pearson correlation factor of 0.451 in 2010). Naturally, data for five years does not represent the long-term average of wind speeds as it does not sufficienctly capture the variance between years.

[26] Meteorological data for 242 measure stations of the German Weather Service for the years 2000-2010 and the European solar radiation from Satel-Light for the years 1996-2000 confirms the listed characteristics in the dataset from EuroWind (2011).

TABLE 3.1: Summarizing statistics for some of the selected wind regions [m/s]

	UK (on) west	IB (on) south	GER (on) central	PL (on) north	IT (on) south	UK (off) north	IB (off) west
Mean [m/s]	6.74	4.80	4.89	6.33	3.59	8.82	5.03
- summer [m/s]	5.95	4.40	4.38	5.49	3.44	7.45	4.52
- winter [m/s]	7.65	5.03	5.47	7.22	3.67	10.26	5.30
Median [m/s]	6.28	4.12	4.54	5.92	3.10	8.28	4.27
Variance	10.48	9.02	5.51	9.24	4.34	18.81	10.23
10%-Quantile	2.97	1.73	2.18	2.80	1.42	3.55	1.71
90%-Quantile	11.15	8.90	8.13	10.36	6.48	14.85	9.60

Remark: A list of abbreviations can be found in Footnote 24.
Source: EuroWind (2011).

TABLE 3.2: Average wind speed in 2006-2010 [m/s]

	UK (on) west	IB (on) south	GER (on) central	PL (on) north	IT (on) south	UK (off) north	IB (off) west
Mean [m/s]							
2006	6.90	4.49	4.86	6.07	3.49	8.80	4.81
2007	6.73	4.72	5.35	6.74	3.50	9.04	4.95
2008	7.26	4.94	5.08	6.66	3.63	9.54	5.19
2009	6.89	4.75	4.81	6.15	3.69	8.97	4.97
2010	5.93	5.11	4.34	6.03	3.61	7.74	5.26

Remark: A list of abbreviations can be found in Footnote 24.
Source: EuroWind (2011).

Global radiation depends on the location, daytime, season and local weather conditions. Hence, the yearly radiation in Southern Europe is higher than in Northern Europe and the average solar radiation is generally higher in summer than winter. The times of sunrise and sunset also depend on the season and hence the duration of daily solar radiation varies throughout the year. Table 3.3 shows summarizing statistics for some of the analyzed solar regions in Europe. Due to the same general weather conditions in Europe, solar radiation in different European regions is correlated on an hourly basis. The Pearson correlation factors for solar radiation in different regions are rather high (even considering only daytime) due to the distinguished solar structure with a peak at midday. Some regions have a stronger correlation, e.g., 0.730 between Southern France and Southern Italy compared to 0.643 between Poland and the United Kingdom. A table with the correlation factors of all analyzed regions can be found in Appendix B.

Table 3.4 depicts the yearly average solar radiation for the years 2007 to 2010. Average solar radiation of 222 W/m^2 in Italy in 2008 was significantly higher than the 206 W/m^2 in 2010. The difference of more than 16 W/m^2 represents about 7 % of the average over the four years. Similar to the yearly average solar radiation, the correlation between solar availability in European regions differs as well. The Pearson correlation factor between the hourly solar radiation in Southern France and Southern Italy of 0.865 in

2008 indicates a strong correlation but with 0.802 in 2007 the correlation can also be lower in a specific year. Naturally, data for four years does not represent the long-term average of solar radiation as it does not capture the variance between years.

TABLE 3.3: Summarizing statistics for some of the selected solar regions [W/m^2]

	UK central	IB south	FR south	GER central	SCA south	PL north	IT south
Mean [W/m^2]	139	228	191	138	138	152	214
- summer [W/m^2]	231	314	283	233	247	250	309
- winter [W/m^2]	75	172	130	70	61	81	150
Maximum [W/m^2]	953	1,021	997	909	834	886	976
Variance	44,884	88,594	68,087	44,537	43,124	48,356	75,138
90%-Quantile	490	746	575	496	497	534	690

Remark: A list of abbreviations can be found in Footnote 24.
Source: EuroWind (2011).

TABLE 3.4: Average solar radiation in 2007-2010 [W/m^2]

	UK central	IB south	FR south	GER central	SCA south	PL north	IT south
Mean [W/m^2]							
2007	134	228	195	133	135	154	213
2008	136	231	185	141	141	149	222
2009	143	231	196	137	141	156	213
2010	144	223	190	143	133	149	206

Remark: A list of abbreviations can be found in Footnote 24.
Source: EuroWind (2011).

Solar radiation and wind speeds are influenced by similar local weather characteristics such as air pressure, sunshine, degree of cloudiness and rain. As higher wind speeds usually occur when the sky is cloudy and sunshine is low, wind speed and solar radiation are to some extent negatively correlated. Table 3.5 shows the correlation factors between wind speed and solar radiation for the years 2007-2010 during daytime. The data reflects that solar radiation and wind speed within the same region are negatively correlated, with a Pearson correlation factor between -0.004 in the Iberian Peninsula (north) and -0.231 in the United Kingdom (central).

However, the extent of the negative correlation between the availability of wind and solar power differs between years. Table 3.6 depicts the different correlation factors for hourly wind speed and solar radiation for the years 2007 to 2010. As can be seen in the example of Poland, the Pearson correlation factors vary between -0.077 (2009) and -0.188 (2008) among these years.

Table 3.5: Correlation matrix of wind and solar radiation for selected regions (only daytime)

		Wind							
		UK central	IB north	IB south	FR south	GER central	PL north	CZ central	IT north
Solar	UK central	-0.230	-0.053	-0.187	-0.195	-0.098	-0.137	-0.008	-0.089
	IB north	-0.176	-0.045	-0.200	-0.163	-0.043	-0.090	0.013	-0.047
	IB south	-0.158	-0.057	-0.140	-0.096	0.018	-0.093	0.045	-0.033
	FR south	-0.164	-0.107	-0.192	-0.231	-0.040	-0.076	0.026	-0.131
	GER central	-0.230	-0.045	-0.140	-0.231	-0.228	-0.141	-0.198	-0.269
	PL north	-0.195	-0.105	-0.182	-0.190	-0.124	-0.141	-0.156	-0.176
	CZ central	-0.196	-0.086	-0.195	-0.191	-0.184	-0.159	-0.198	-0.164
	IT north	-0.189	-0.139	-0.219	-0.248	-0.102	-0.104	-0.069	-0.269

Remark: A list of abbreviations can be found in Footnote 24.
Source: EuroWind (2011).

Table 3.6: Regional correlation between wind and solar in 2007-2010 (daytime)

	UK central	IB north	FR south	GER central	PL north	CZ central	IT north
2007	-0.186	0.035	-0.146	-0.278	-0.162	-0.233	-0.224
2008	-0.241	-0.021	-0.214	-0.196	-0.188	-0.243	-0.205
2009	-0.221	-0.108	-0.290	-0.215	-0.077	-0.106	-0.289
2010	-0.270	-0.083	-0.284	-0.212	-0.135	-0.206	-0.353

Remark: A list of abbreviations can be found in Footnote 24.
Source: EuroWind (2011).

Based on the described wind and solar characteristics, three aspects influence the optimal electricity mix: First, from a system perspective it may be cost-efficient to focus on the best European sites i.e. locations with the highest full load hours on average. Based on the data, more than twice as much electricity can be produced on average from the same wind turbine in Ireland than in Italy. As installation costs are similar across Europe, levelized electricity costs for wind power are about 50 percent lower in Northern Europe as in Southern Europe at relatively similar conditions. Second, particularly in electricity systems with a high share of fluctuating RES-E generation a distribution of wind turbines and solar systems may be cost-efficient as the hourly European-wide total power generation from these technologies would be more stable. A regional concentration may also need significant grid extensions from wind and solar sites to large load centers. Third, the optimal electricity mix has to consider uncertainty of the yearly availability of wind and solar power – resulting from high as well as low wind/solar years – as well as uncertainty of the correlation between wind and solar power. Hence, there should exist an optimum between focusing on the best sites and the distribution throughout Europe.

3.3.2 Extraction of feed-in structures from the data

As the empirical data of combined wind speed and solar radiation is available for four years for this analysis, we only have an indication of the variance for yearly full load hours for each region and for the yearly correlation between regions or technologies. Therefore, we use a bootstrapping approach to develop feed-in structures for wind and solar feed-in with different full load hours and correlations between regions and technologies.[27] As a necessary condition for the bootstrap method, the original data needs to reflect the underlying distribution. This leads to two critical assumptions for this analysis: First, we assume that the hourly data for wind speeds and solar radiation of the four years represent the full spectrum of possible weather situations. Second, as we create consistent wind and solar structures for a future year, we need to assume that weather conditions will stay similar as the patterns today. It is clear that the data does not contain all possible weather situations in Europe but it can be assumed that four years of hourly wind speed and solar radiation give a broad spectrum. Taking into account the effects of climate change on stochastic regional solar and wind availabilities in energy optimization models clearly remains a challenge, but is beyond the scope of this paper.

To account for the previously described seasonal characteristics for wind and solar availability, we divide the dataset into two blocks: months from April to August as spring and summer; months from September to March as autumn and winter. We randomly pick 30 days of wind and solar radiation data over all regions in three day-blocks (actual observed days) and repeat 2000 times.[28] By taking blocks (each block contains three days of hourly data) rather than single hours, typical hourly changes and daily structures of wind speeds and solar radiation are reflected. Another advantage of picking blocks rather than single days is that common general weather situations, such as a storm traveling from Western to Eastern Europe, are, to some extent, considered. Naturally, due to picking three-day blocks, common weather situations lasting for more than three days are not reflected in the bootstrapped data.[29] The possible feed-in of wind power and PV sites in different regions in Europe is computed based on the hourly wind speed and

[27]The bootstrap approach is a resampling method that can be used to assess the properties of a distribution underlying a sample and the parameters of interest that are derived from this distribution (Efron, 1979).

[28]Due to computational constraints, the dispatch in the optimization model is simulated for 720 instead of 8760 hours. To account for the seasonal differences, we pick 3·3 days from autumn/winter; 4·3 days from spring/summer and again 3·3 days from autumn/winter.

[29]As solar radiation is zero at night, the change from one block to another does not induce an unrealistic change in solar radiation at midnight. The situation is different for wind speeds and therefore we average wind speeds for the hours between 9 pm to 3 am to smooth the break around midnight. We find that taking the moving average of four hours leads to a realistic change of wind speeds.

solar radiation of the 30 days (720 hours), as well as the assumed technical parameters of state-of-the-art wind and solar technologies.[30]

The resulting regional wind speed and solar radiation structures have similar characteristics as the original data (including mean and variance). Hence, we argue that this approach provides consistent feed-in structures of wind and solar technologies for several European regions. Figure 3.1 depicts the distribution of full load hours for two solar (Southern part of the Iberian Peninsula and Northern Germany) and two wind regions (Central France and Central part of the United Kingdom) in the 2000 created scenarios. As can be seen, the variance of full load hours for wind turbines is significantly larger than for solar power.[31]

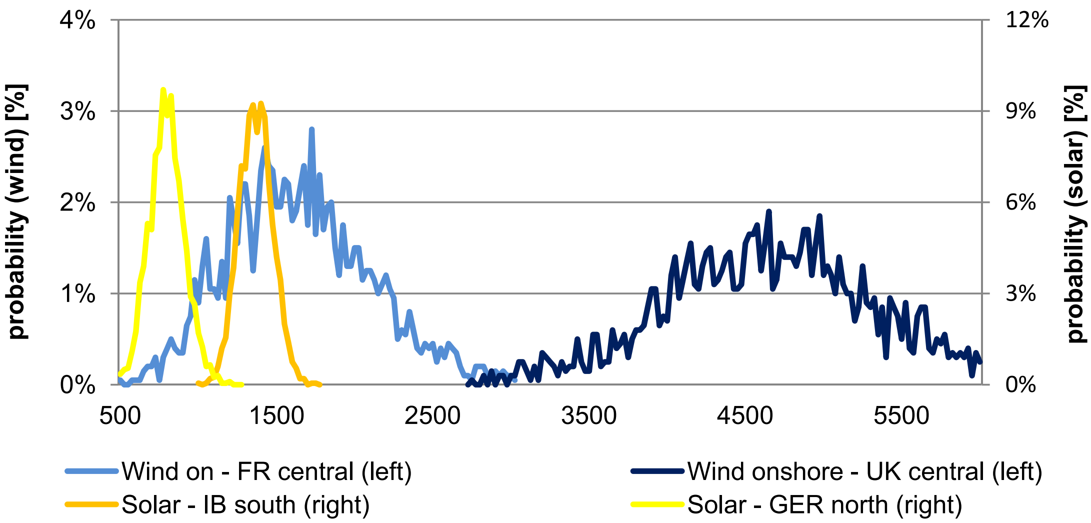

FIGURE 3.1: Distribution of full load hours in two wind and solar regions [%]

Due to computational constraints, not all 2000 created feed-in structures can be used as input data in the stochastic electricity market model. Therefore, representative feed-in structures are selected, which are supposed to consider the characteristics of wind and

[30] Power generation of wind turbines [per region (reg), hours (h) and scenario (s)] is calculated as a ratio of the installed capacity for the specific wind turbine. All capacities are normalized to 1 MW units. The power output of wind turbines is a function of air density (ρ), rotor area ($\pi \cdot r^2$), power coefficient (c_p), wind speed (v) and efficiency (η_{total}): $P_{el}(reg,h,s) = 1/P_{nom} \cdot 1/2 \cdot \rho \cdot \pi \cdot r^2 \cdot c_p \cdot v^3(reg,h,s) \cdot \eta_{total}$. A typical power curve for wind turbines (pitch control) is assumed with no generation at wind speeds lower than 3 m/s and a shutdown at more than 25 m/s to avoid damages. To scale wind speeds from 30 meters to the assumed turbine height, the standard logarithmic conversion is used. The conversion of wind speeds in reference height to turbine height are computed by a scaling factor, which is a function of turbine height, reference height and the roughness parameter of the region. The roughness parameter takes the different surface conditions into account. $v_{normh}(reg,h,s) = v(reg,h,s) \cdot [\ln \frac{normh}{rough(reg)} / \ln \frac{refh}{rough(reg)}]$. The power generation by the assumed state-of-the-art photovoltaic system is computed based on the net efficiency (η_{total}), the surface area (A) and solar radiation (radiation). This implies standard configurations of PV systems directed towards the south and with an angle of 30 degrees in order to achieve the highest yearly energy output. $P_{el}(reg,h,s) = 1/P_{nom} \cdot \eta_{total} \cdot A \cdot radiation(reg,h,s)$.

[31] As the estimation of yearly full load hours is based on resampling 30 instead of 365 days, it is possible that the variance of full load hours is overestimated. To account for a possible overestimation, we exclude the 10 % quantile on each side.

solar feed-in availability throughout Europe. For this purpose, we define an indicating value for the yearly availability of wind power and an indicating value for the yearly availability of solar power in Europe. The importance of a specific wind or solar site for an electricity system is mainly defined by the area potential and the expected power generation (full load hours). Therefore, we define the indicating values as the average availability of the most important wind (solar) sites in Europe in terms of these two factors. For wind power, we calculate the average full load hours of onshore wind in the Northern part of the United Kingdom, Germany, the Iberian Peninsula and Poland and wind sites on the Atlantic coast of France as well as offshore wind on Norway's coastline. For solar power, we select the Southern part of Italy, the Iberian Peninsula, France and Germany. From the distribution of the indicating values, we pick ten feed-in structures with the following characteristics: S1 extremely low wind year; S2 low wind year; S3 average wind year; S4 high wind year; S5 extremely high wind year; S6 extremely low solar year; S7 low solar year; S8 average solar year; S9 high solar year; S10 extremely high solar year. Apart from the yearly amount of electricity generation, the selected feed-in structures consider different hourly correlations between regions and between technologies (wind and PV). The bounds (lowest and highest full load hours) for each category are chosen such that the probability for the extreme scenarios amounts to 2.5 %, the low and high scenario to 10 % and the average scenario to 25 %. As the probablility for an extremely high wind year is lower than an average wind year, the different dispatches in the stochastic optimization model are weighted by the specific probability factor. The resulting full load hours in the selected scenarios can be found in Table B.7 in the Appendix B.

3.4 Optimization of the European electricity mix for different levels of RES-E

We develop a two-stage stochastic investment and dispatch model to determine the cost-minimal electricity mix and dispatch considering the uncertain feed-in structures of wind and solar technologies in 59 regions for a political target year e.g., 2050. One can interpret the first stage as the time frame before 2050 where investments can be made and the second stage as the usage of these technologies to supply the electricity demand in the target year (greenfield approach).[32]

By using a stochastic model the investment decision has to be made under uncertainty about the local feed-in structure, the amount of yearly generated electricity of wind and

[32]The greenfield approach neglects potential costs due to an adaption process to a low-carbon electricity system. On the other hand existing conventional power plants may be a cost-efficient option to provide back-up capacities for fluctuating renewable energies.

solar technologies and the correlation between regions and technologies.[33] It is clear that many uncertainties exist, including the future electricity demand, fuel prices or the development of investment costs. Stochastic models have often been used to analyze the effect of demand uncertainty on the optimal power mix (such as Murphy et al. (1982) and Modiano (1987)). In our analysis, we concentrate on the uncertainty on the supply side by modeling stochastic feed-in structures for wind and solar technologies.[34] In this section, the electricity market model is described and the results of the stochastic model are discussed and compared to the deterministic results.

3.4.1 Model description

The model includes possible investments in conventional, renewable and short- as well as long-term storage technologies in Europe. The realized dispatch respects technical constraints e.g., ramp-up restrictions, renewable curtailment and transmission limits between regions based on net transfer capacities. The model sets, parameters and variables are shown in Table 3.7.

Key model elements

The model has to ensure that electricity supply meets the hourly (fixed) demand in all modeled countries for each feed-in structure of wind and solar technologies.[35] Demand can be met by electricity generation in power plants within the country or by imports from other countries. Apart from the physical power supply the model has to build enough securely available capacity to assure electricity supply at peak demand.

$$\sum_a \left[G_{a,c,h,s} \cdot \eta_a \right] + \sum_e \left[I_{c,e,h,s} \cdot \left(1 - \delta_{c,e} \cdot \beta \right) - E_{c,e,h,s} \right] - \sum_{st} \left[S_{st,c,h,s} \right] = \rho_{c,h,s} \quad (3.1)$$

$$\sum_a \left[C_{c,a} \cdot \tau_a \right] \geq \theta_c \quad (3.2)$$

[33]For clarification, we assume perfect foresight within each dispatch realization as such short-term uncertainties, e.g. short-notice power plant outages, of forecast errors for fluctuating RES-E generation are not modeled and therefore system costs are in reality higher. However, the underestimation occurs in the deterministic as well as in the stochastic model and it can be assumed that is has a similar impact in both models.

[34]The model optimizes investments based on a dispatch simulation for 30 days on an hourly basis (720 hours) per scenario. A typical demand structure with a peak around midday is modeled and correlations between the hourly electricity load with solar or wind power are taken into account.

[35]As typical in stochastic models the uncertainty is reflected by modeling different scenarios weighted by their specific probability.

TABLE 3.7: Model abbreviations including sets, parameters and variables

Abbreviation	Dimension	Description
Model sets		
a ∈ A		Technologies
c ∈ C (alias: e)		Regions
h ∈ H		Hours
res ∈ RES ∈ A		Renewable energies
s ∈ S		Scenarios
st ∈ ST ∈ A		Storage technologies
Model parameters		
$annuity_a$	EUR_{2010}/MW	Technology specific investment costs (annuity)
$attc_a$	EUR_{2010}/MWh_{th}	Attrition costs for ramp-up operation
$avail_{c,a,h,s}$	%	Availability of generation units
$facCO_a$	$t\ CO_2\ /MWh_{th}$	CO_2 emissions per fuel consumption
$fomc_a$	EUR_{2010}/MW	Fixed operation and maintenance costs
$fuelpr_a$	EUR_{2010}/MWh_{th}	Fuel price
hpr	EUR_{2010}/MWh_{th}	Remuneration per generated heat unit
htp_a	MW_{th}/MW_{el}	Heat-to-power ratio
prCO	$EUR_{2010}/t\ CO_2$	Price for CO_2 certificates
$prob_s$	%	Scenario probability
β	MW/km	Average transmission loss per kilometer
$\delta_{c,e}$	km	Distance between two regions
κ_a	%	Own consumption of thermal power plants
η_a	%	Net efficiency
$\rho_{c,h,s}$	MW	Model demand
θ_c	MW	Peak demand
τ_a	%	Factor for securely available capacity
ψ	%	Conversion efficiency for heat generation
ω	%	RES-E quota on gross electricity demand
Model variables		
$C_{c,a}$	MW_{el}	Installed capacity (net)
$CUP_{c,a,h,s}$	MW_{el}	Ramping capacity (net)
$E_{c,e,h,s}$	MW_{el}	Exports
$G_{a,c,h,s}$	MW_{el}	Electricity generation (net)
$I_{c,e,h,s}$	MW_{el}	Imports
$S_{st,c,h,s}$	MW_{el}	Consumption in storage operation
TCOST	EUR_{2010}	Total system costs

The objective of the model is to minimize total system costs, which are defined by investment, fixed operation and maintenance costs, variable costs including fuel as well as CO_2 and costs due to ramping thermal power plants. The investment and fixed operation and maintenance costs depend on the chosen capacities in the first-stage decision. Due to the model approach, we use annualized investment costs which include financial costs.[36] The fixed operation and maintenance costs represent staff costs, insurance charges and fixed maintenance costs. The variable system costs for electricity generation depend on the cost-minimized dispatch of conventional, renewable and storage

[36]The depreciation time is assumed to be the technical lifetime for all technologies (10 percent interest rate).

technologies for the different feed-in structures of fluctuating renewable energies. Variable costs are determined by fuel prices, CO_2 emission factors, CO_2 price, net efficiencies and the generation of all technologies weighted by the scenario probability. Modeling ramp-up restrictions and ramping costs of thermal power plants is difficult in linear optimization models. To actually account for technical restrictions, a mixed-integer optimization model is needed, which increases the computational time significantly. We simulate ramp-up costs by referring to the power plant blocks and by setting a minimal load restriction similar to the method described in Richter (2011). Depending on the minimum load and start-up time of thermal power plants, additional costs for ramping occur (attrition and extra fuel costs).

$$\begin{aligned} minimize\, TCOST = \sum_{c,a} \left[C_{c,a} \cdot \left[annuity_a + fomc_a \right] \right] \\ + \sum_{c,a,h,s} \left[prob_s \cdot G_{c,a,h,s} \cdot \left[\frac{fuelpr_a + facCO_a \cdot prCO)}{\eta_a} \right] \right] \\ + \sum_{c,a,h,s} \left[prob_s \cdot CUP_{c,a,h,s} \cdot \left[\frac{fuelpr_a + facCO_a \cdot prCO + attc_a}{\eta_a} \right] \right] \\ - \sum_{c,a,h,s} \left[prob_s \cdot G_{c,a,h,s} \cdot \left[\frac{htp_a \cdot hpr}{\psi} \right] \right] \end{aligned} \tag{3.3}$$

Apart from the basic cost equations, the model incorporates all common elements of linear dispatch models such as storage restrictions, net transfer possibilities and restrictions for combined heat and power generation. The possibility for combined heat and power generation is simulated by a maximum potential for heat generation in CHP power plants specific to each region. The inflexibility of CHP power plants is represented by longer ramp-up times. The generated heat is remunerated by the assumed gas price (divided by the conversion efficiency of the assumed reference heat boiler - 90 %), which roughly represents the opportunity costs for households and industries. The availability of conventional, nuclear, dispatchable renewable energies and storage capacities is reduced by possible outages (planned or not planned).

Modeling stochastic feed-in structures of renewable energies

The model includes the following renewable energy technologies: PV (roof and ground), wind (on- and offshore), biomass (solid and gas), biomass CHP (solid and gas), geothermal and hydro (storage and run-of-river) technologies. Biomass, geothermal and hydro technologies are modeled as dispatchable renewables. The availability of fluctuating renewable energies (wind and solar technologies) highly depends on the different scenarios (weather years) and hours within the scenario (weather years). The availability parameter represents the (maximal possible) feed-in of wind and solar plants. This allows the possibility of wind and solar curtailment when not needed due to low demand and full storages, or when total system costs can be reduced due to lower ramping costs of thermal power plants.[37] The generation of renewable energies has to at least equal on average (average of all modeled scenarios) a pre-defined European RES-E quota on the gross electricity demand. Gross electricity demand includes net electricity demand, storage consumption, own consumption of thermal power plants and transmission losses (Equation 3.5).[38,39]

$$G_{c,a,h,s} \leq avail_{c,a,h,s} \cdot C_{c,a} \tag{3.4}$$

$$\sum_{c,res,h,s} G_{c,res,h,s} \geq \omega \cdot \left[\sum_{c,a,h,s} \left[\rho_{c,h,s} + S_{c,st,h,s} + G_{c,a,h,s} \cdot \frac{1}{(1-\kappa_a)} \right] + \sum_{c,e,h,s} \left[E_{c,e,h,s} \cdot \delta_{c,e} \cdot \beta \right] \right] \tag{3.5}$$

3.4.2 Scenario assumptions

In this section, the economic and technical assumptions for the target year 2050 are described. Apart from the assumed electricity demand, economic and technical parameters for generation units, the European transmission grid (net transfer capacities), fuel and CO_2 prices are presented. The assumptions are based on several databases such as EEA (2009), IEA (2010c), EWI (2010), Prognos/EWI/GWS (2010), EWI (2011), ENTSO-E (2011b). It is clear that the scenario setting chosen for this analysis is only one possible outcome. Hence, we will carry out a sensitivity analysis on some parameters to identify the most important assumptions and their influence on the model results.

[37] 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 used low variable costs for offshore wind and even lower ones for onshore wind sites. Therefore, the model chooses offshore wind curtailment first.

[38] Due to the constraint of an average electricity generation by renewable energies of all modeled scenarios, it is not obvious how to apply decomposition methods such as Benders Decomposition (Benders, 1962) to divide the optimization problem into a master (investment) and subproblems (dispatch). Therefore, only a limited amount of scenarios can be considered in the extended version of this model.

[39] The model runs on the basis of net values: net electricity generation or net capacities. Equation 3.5 gives a lower bound for the share of RES-E generation on gross electricity demand. The difference between gross and net electricity demand represents transmission losses, own consumption of thermal power plants and charging of storage technologies. Transmission losses within each region are exogenous and are assumed to be similar as today. Transmission losses for power exchange between regions are endogenous and depend on the amount of power exchange and the distance (1 % power loss per 100 km distance). The electricity used in thermal power plants can be calculated by dividing the net electricity generation by one minus the plant-specific own consumption share $[G_{c,a,h,s}/(1-\kappa_a)]$.

Electricity demand is primarily driven by economic and population growth, improvements in energy efficiency and the emergence of new technologies (such as electric cars). For this scenario analysis, we assume net electricity demand to be 25 percent lower in each region in 2050 compared to today: the largest consumption regions remain in Central Europe (Germany 396.6 TWh; France 316.4 TWh; BeNeLux 146.0 TWh; Switzerland 43.2 TWh and Austria 43.0 TWh) followed by Northern Europe (United Kingdom 273.9 TWh; Scandinavia 240.8 TWh and Denmark 26.7 TWh). In Southern Europe, electricity demand amounts to 220.3 TWh in the Iberian Peninsula and 225.5 TWh in Italy. In Eastern Europe, the combined electricity demand of the Baltic countries (Slovakia, Slovenia, Hungary, Romania and Bulgaria) is assumed to be 119.2 TWh, 86.6 TWh in Poland and 43.2 TWh in the Czech Republic. The hourly load structures – midday peak, weekly and seasonal characteristics as well as regional differences – are assumed to be as today (based on ENTSO-E (2011b)).

The model includes conventional (potentially equipped with CCS or combined heat generation), nuclear, renewable and storage technologies. The development of technical characteristics or future investment costs – especially for relatively new technologies such as photovoltaics or CCS plants – is highly uncertain. Compared to the values today, we assume investment costs, especially for renewables, to decrease significantly until 2050. For conventional power plants, higher efficiency factors are assumed due to the deployment of improved materials and processing techniques. As storage technologies are an important option to balance the stochastic feed-in of renewables and demand, we model short- and long-term storage technologies. Due to larger storage volumes, hydrogen storages may be a cost-efficient option to overcome periods with low feed-in of fluctuating renewables. In addition to traditional storages, demand side management (e.g., thermal storage) may reduce the challenges of balancing the stochastic generation and demand in high RES-E systems. This accounts especially for short-term fluctuations acting within a few hours (Paulus and Borggrefe, 2011). However, the model does not include demand side management processes as an investment option. The most important technical and cost-related parameters are shown in Table 3.8 (based on IEA (2010c) and Prognos/EWI/GWS (2010)).

Although the necessity of transmission grid extensions for the cost-efficient transformation towards a low-carbon and renewable-based electricity system has been mostly accepted, construction of new lines is progressing very slowly in Europe. Cross-border infrastructure projects often face significant delays due to the local public acceptance, technical issues and authorization procedures (Buijs et al., 2011). In the scenario analysis, cross-border capacities are assumed to be expanded by 20 % compared to today's capacities (based on ENTSO-E (2011a)). Table 3.9 shows the assumed net transfer capacities between the modeled European regions.

TABLE 3.8: Technical and economic parameters for generation technologies in 2050

Technology	Investment costs [EUR_{2010}/kW]	FOM costs [EUR_{2010}/kWa]	Lifetime [a]	$\eta\,(\eta_{load})$ [%]
Nuclear	3,160	97	60	33.0
Lignite	1,950	43	45	46.5
Lignite-CCS	2,450	103	45	37.0
Lignite-CHP	2,600	70	45	22.5
Hard-coal	1,650	36	45	50.0
Hard-coal-CCS	1,850	97	45	40.5
Hard-coal-CHP	2,050	55	45	22.5
CCGT	950	28	30	60.0
CCGT-CCS	1,088	88	30	52.0
CCGT-CHP	1,500	40	30	36.0
OCGT	400	17	25	40.0
Pump-Storage	2,300	12	100	87.0 (83.0)
Hydro-Storage	2,300	12	100	87.0
CAES-Storage	850	10	30	86.0 (81.0)
Hydrogen-Storage	3,500	10	20	45.0 (65.0)
Biomass gas	2,400	120	30	40.0
Biomass gas-CHP	2,600	130	30	22.5
Biomass solid	3,300	165	30	30.0
Biomass solid-CHP	3,500	175	30	22.5
Geothermal	9,050	300	30	-
Hydro river	4,500	12	100	-
PV base	1,080	30	25	-
PV roof	1,260	35	25	-
Wind onshore	1,100	41	25	-
Wind offshore (shallow)	2,400	136	25	-
Wind offshore (deep)	2,800	160	25	-

TABLE 3.9: Assumed net transfer capacities in 2050 [GW]

	AT	BNL	CH	CZ	DK	EE	FR	GER	IB	IT	PL	SCA	UK
AT	-	-	1.20	0.96	-	1.44	-	1.92	-	0.08	-	-	-
BNL	-	-	-	-	-	-	3.48	4.62	-	-	-	0.84	-
CH	0.65	-	-	-	-	-	3.60	1.80	-	1.73	-	-	-
CZ	0.72	-	-	-	-	1.20	-	0.96	-	-	2.40	-	-
DK	-	-	-	-	-	-	-	1.68	-	-	-	3.52	-
EE	1.56	-	-	2.04	-	-	-	-	-	0.14	0.72	0.42	-
FR	-	1.56	1.32	-	-	-	-	3.66	0.60	1.04	-	-	2.40
GER	1.92	3.60	3.84	2.52	2.46	-	3.12	-	-	-	1.32	0.72	-
IB	-	-	-	-	-	-	1.4	-	-	-	-	-	-
IT	0.24	-	4.15	-	-	0.40	2.88	-	-	-	-	-	-
PL	-	-	-	0.96	-	0.60	-	0.96	-	-	-	-	-
SCA	-	0.84	-	-	4.07	0.42	-	0.72	-	-	-	-	-
UK	-	-	-	-	-	-	2.40	-	-	-	-	-	-

Remark: A list of abbreviations can be found in Footnote 24.

Trade market prices for fossil fuels depend on production capacities, development of input factor prices to mining, transport infrastructure such as port facilities and demand. For 2050, we assume slightly higher prices for hard coal 14.7 EUR_{2010}/MWh_{th} as a result of increasing material, transport and labor costs (IEA, 2010c). For lignite, we assume that better productivity offsets increasing cost factors and consequently prices are assumed to remain at the same level as in 2008 (1.4 EUR_{2010}/MWh_{th}). For natural gas, we assume a price of 30.0 EUR_{2010}/MWh_{th}. Prices of biomass are assumed to slightly increase compared to their levels today (gas 0.1-60.0 EUR_{2010}/MWh_{th} and solid 22.4 EUR_{2010}/MWh_{th}) because of a high demand for biomass fuels in the scenarios. As a political target year is modeled, a relatively high price of 40.0 $EUR_{2010}/t\ CO_2$ for emissions is assumed.

3.4.3 Simulation results

In this section, we discuss the stochastic model results including optimal capacities, generation and average costs for electricity generation. Then, these model results are compared to the deterministic model results – average full load hours and correlations – to analyze the effects of the stochastic feed-in of wind and solar technologies. In the second part of this section, sensitivity simulations regarding the assumed capital costs of wind and solar technologies, as well as the European cross-border capacities, are discussed.

3.4.3.1 The influence of stochastic full load hours and uncertain correlations between regions and technologies

Stochastic model results

The optimal capacity mix and average generation costs for Europe depend on the prescribed RES-E generation quota (technology-neutral, Europe-wide target) as shown in Figure 3.2.[40] Due to the lower availability of fluctuating RES-E capacities compared to conventional power plants, the total capacity increases when modeling high RES-E scenarios. Due to the negatively correlated feed-in structures, a mix of wind and solar technologies is cost-efficient from a system point of view, even though additional wind capacities with lower average generation costs are available when modeling a high RES-E share. In general, a mix of technologies is cost-efficient due to different capital/operating cost ratios across generation technologies, limited transfer capacities between regions and limited capacity and fuel potentials. Due to the limited potential for low-cost renewable options and the integration costs for renewables such as additional costs for back-up capacities, total system costs increase significantly when modeling high RES-E quotas (greater than 60-70 %).

[40] Average generation costs are defined as the yearly total system costs (annualized investment costs, yearly fixed operation and maintenance costs, variable costs including ramping costs of thermal power plants and the remuneration for generated heat in CHP plants) divided by the assumed net electricity consumption.

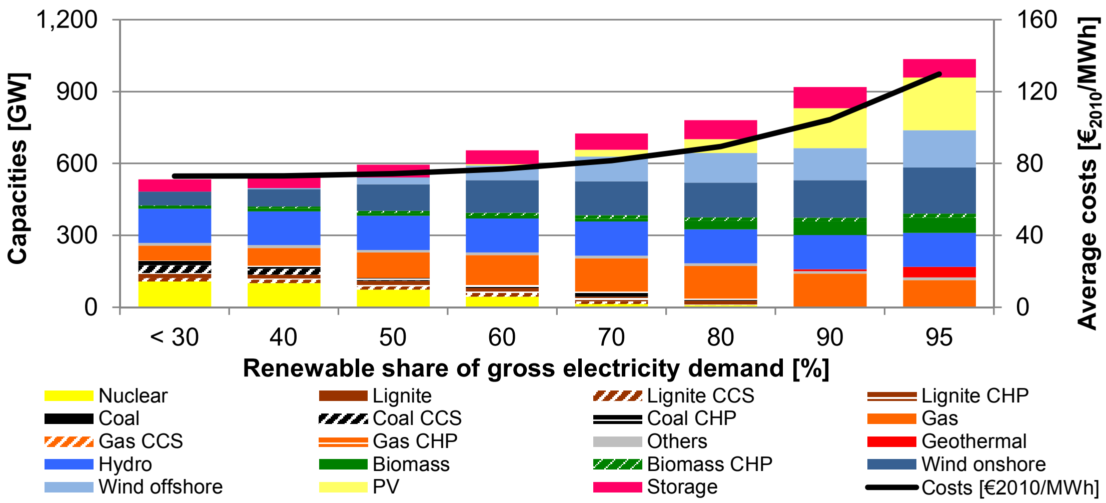

FIGURE 3.2: Optimal capacities [GW] and average costs [EUR_{2010}/MWh] in Europe

No RES-E quota leads to about 35 % generation by renewable energies (hydro 57 %; wind 24 %; biomass 12 % and others 7 %), which are cost-efficient given the assumed investment and fuel costs. Hence, a share of 35 % generation by renewable energies would not require additional payments for renewables (certificate price is zero). Base-load generation takes place in nuclear as well as lignite-fired power plants equipped with CCS-technology, mid-load is generated in coal capacities and the balancing of wind generation and demand is mainly realized by gas-fired power plants. A higher RES-E quota (up to 60 %) leads to higher investments in onshore wind turbines, especially in in the United Kingdom and France; offshore wind mainly in Germany, France and Italy; and short-term storage capacities in the United Kingdom. The storage capacities help to overcome short periods with lower wind generation. For conventional power plants, fewer investments take place in coal (Germany and Italy) and nuclear power (United Kingdom and France) but more flexible gas capacities are built (especially in Germany, United Kingdom and Italy) due to fewer full load hours of conventional plants and the additional needed flexibility. A higher RES-E quota of up to 80 % brings out a mix of photovoltaics in Italy, the Iberian Peninsula and Southern France; more wind on- and offshore capacities are seen in Germany, the United Kingdom, and Poland; and high-cost biomass capacities appear in France and the Iberian Peninsula. To integrate the fluctuating renewables more storage capacities are installed mainly in Germany, France and Poland. Almost no base-load capacities, such as nuclear, lignite and coal capacities equipped with CCS, are installed. An even higher RES-E quota also leads to significantly higher investments in onshore wind capacities (at less favorable sites), biomass capacities and geothermal sites. Also, more investments in photovoltaics, especially on the Iberian Peninsula, Italy and Germany, are cost-efficient even though more wind sites with lower levelized costs are available within these countries.

The average generation costs for the European electricity system highly depend on the implied RES-E quota. When no RES-E quota is modeled, average generation costs amount to 72.9 EUR_{2010}/MWh. Due to the conventional power-dominated generation mix, variable costs make up almost 30 % of the system costs. A higher demanded RES-E quota of up to 60 % leads to a small increase in the average generation costs to 76.9 EUR_{2010}/MWh. Due to the transformation to a primarily renewable-based generation mix, system costs are then dominated by investment and fixed operation and maintenance costs, which make up almost 90 %. Considering the model assumptions, a higher RES-E quota leads to a significant increase in total costs (89.4 EUR_{2010}/MWh for 80 % RES-E and 104.3 EUR_{2010}/MWh for 90 % RES-E) due to the limited potential of low-cost RES-E options and high integration costs of fluctuating RES-E generation.

The generation (utilization rate) of technologies highly depends on the availability of fluctuating RES-E generation and therefore on the specific year (scenario). Large wind and photovoltaic capacities lead to a more fluctuating generation structure and a more volatile yearly generation (absolute figures). Due to the marginal generation costs, fluctuating RES-E technologies are used when available and when an integration into the electricity grid is possible. Figure 3.3 shows the maximal, minimal and average yearly generation of fuels for the different feed-in structures of wind and solar technologies when implying a 60 % (left side) and a 80 % (right side) RES-E quota.[41]

Figure 3.3 shows the generation of conventional technologies that depends sensitively on the specific feed-in of wind and solar technologies: If a 60 % RES-E quota has to be reached, lignite capacities generate on average 265 TWh (7,300 full load hours), coal capacities 77 TWh (6,500 full load hours) and gas-fired power plants 316 TWh (2,500 full load hours). However, depending on the availability of wind and solar generation, the realized full load hours of conventional power plants vary significantly between years (scenarios). Due to relatively low investment costs, gas-fired power plants are used as back-up capacities to balance the stochastic wind and solar generation. In a high wind and solar year (scenario), gas-fired power plants only generate about 262 TWh (lower than 2,100 full load hours) but are highly used in a low wind and solar year with almost 402 TWh (3,300 full load hours). The increasing amount of fluctuating wind and solar generation also leads to a higher utilization of storage capacities. When a 60 % RES-E quota has to be reached, pump storage facilities in Germany achieve on average 1100 full load hours (485-1700 h across the scenarios) but in the case of 80 % RES-E generation, utilization rates increase to 1500 full load hours on average (1000-1850 h across the scenarios). A higher RES-E quota leads to an electricity system that is primarily based

[41]The maximal and minimal generation by wind turbines and photovoltaics are extreme values which only occur by a probability of 2.5 %. However, the electricity system also needs to be able to meet demand cost-efficiently in these extreme years.

on fluctuating RES-E capacities. Differences in the utilization rates of the conventional and storage power plants are even greater among the scenarios.

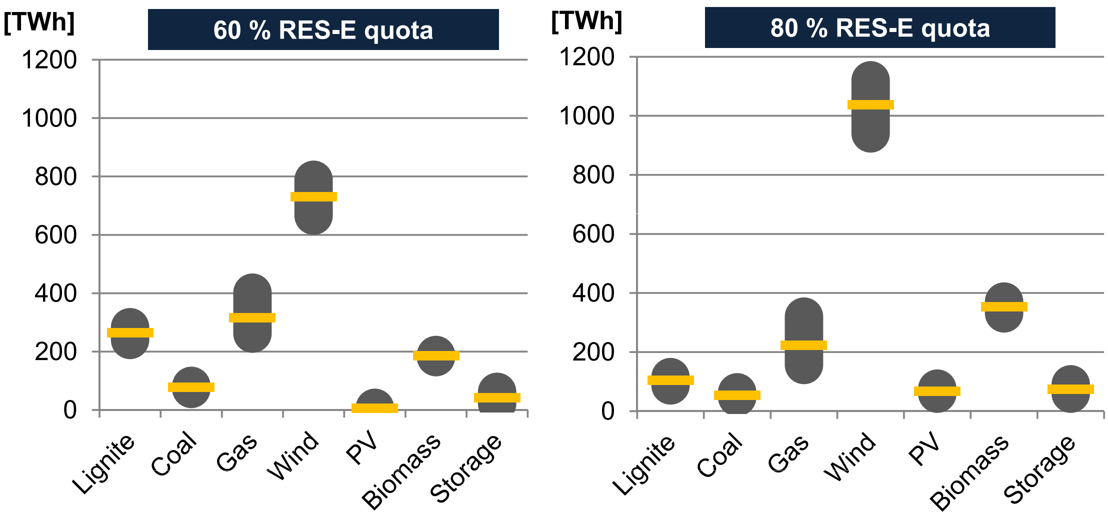

FIGURE 3.3: Range of generation by fuels depending on RES-E generation [TWh]

Comparison of stochastic to deterministic model results

The previously discussed results of the stochastic optimization model are compared to the deterministic model results to quantify the deviation with regard to the cost-efficient capacity mix and system costs, depending on the share of RES-E generation when neglecting the stochastic availability of wind and solar plants. We use the feed-in structures of wind (on- and offshore) and solar sites of the average wind scenario (scenario 3) as input data in the deterministic model. The feed-in structures represent average yearly full load hours as well as average correlations between regions and technologies. Figure 3.4 shows the optimal capacities as well as average generation costs that result when modeling deterministic full load hours and correlations (left side) and compares these values to the stochastic model results (right side; + means higher values in the stochastic model). In general, a similar development of capacities can be seen in the comparison when the uncertainty of the availability of wind and solar power is considered. However, the results show that the value of fluctuating renewable technologies are overestimated and generation costs are underestimated when neglecting the stochastic availability of these technologies by applying deterministic investment and dispatch models. Furthermore, the value of solar technologies, relative to wind turbines, is underestimated when neglecting the negative correlation between wind speed and solar radiation.

In the stochastic model, when no RES-E quota has to be reached, more base-load capacities, specifically nuclear and coal, are built instead of wind turbines. As the value of wind turbines is lower due to the uncertain yearly availability, less on- and offshore wind capacities at relatively low costs sites in the United Kingdom and Norway are installed. When modeling RES-E quotas of 40-50 %, less coal plants equipped with CCS are installed and are mainly replaced by more flexible as well as less capital-intensive, gas-fired power plants. RES-E quotas higher than 60 % are reached with more onshore wind capacities, mainly in Germany and the Iberian Peninsula; solar plants in Italy, Germany and the United Kingdom, and biomass as well as geothermal capacities. More wind and solar capacities are needed for two reasons: First, as better or worse wind and solar years are considered, more capacities are needed to ensure the achievement of the RES-E target. Second, as uncertainty of regional availability and uncertainty of the correlation between regions and technologies are considered, the capacity mix cannot be optimized for one specific year.

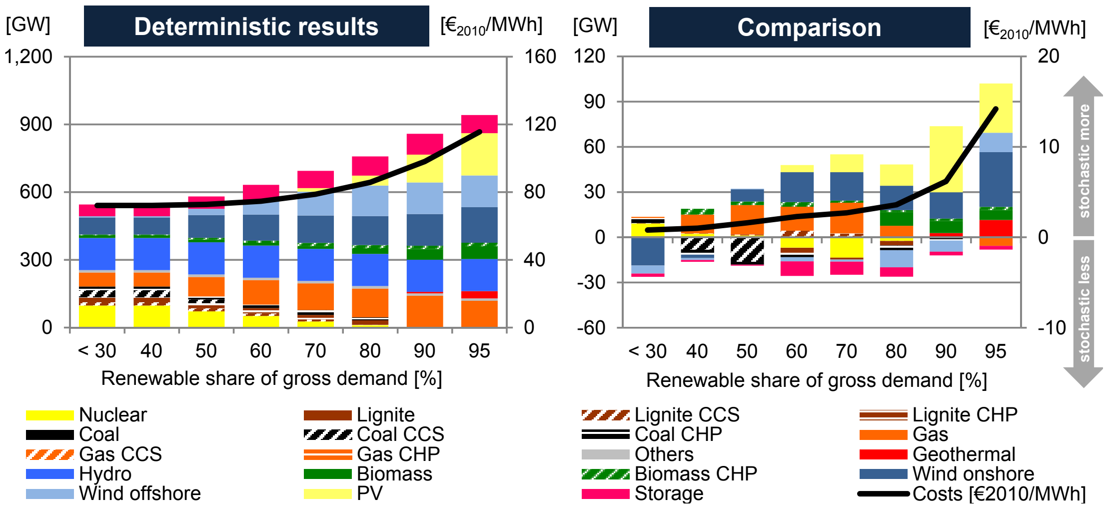

FIGURE 3.4: Comparison of stochastic to deterministic results [GW and EUR_{2010}/MWh]

Total system costs are higher in the stochastic model due to the uncertainty of the availability of wind and solar power. In the stochastic model, the power plant mix is optimized under consideration of different wind and solar availabilities. Therefore, the power plant fleet is a robust solution for the long-term power plant mix but not optimal in each specific year. When neglecting the stochastic availability of wind and solar power, the capacity mix and utilization can be optimized for an average wind and solar year. Hence, average generation costs are lower when modeling deterministic full load hours as well as correlations. Table 3.10 shows the average generation costs in EUR_{2010}/MWh for the stochastic and deterministic model, as well as the comparison in absolute and relative values (as percentage of the deterministic solution).

Table 3.10: Average generation costs depending on the RES-E quota [EUR_{2010}/MWh]

	50 %	60 %	70 %	80 %	90 %	95 %
Stochastic model [EUR_{2010}/MWh]	74.3	76.9	81.5	89.4	104.3	129.8
Deterministic model [EUR_{2010}/MWh]	72.7	74.6	78.8	85.8	98.1	115.6
Difference						
- absolute [EUR_{2010}/MWh]	1.6	2.3	2.7	3.6	6.2	14.2
- percent of deterministic model [%]	2.2 %	3.1 %	3.4 %	4.2 %	6.3 %	12.3 %

In the case of a 50 % RES-E quota, average generation costs of the modeled electricity system amount to 72.7 EUR_{2010}/MWh compared to 74.3 EUR_{2010}/MWh in the stochastic model. The cost difference of 1.6 EUR_{2010}/MWh represents about 2.2 % of the deterministic model result. Up to a RES-E quota of 70 %, total system costs, as well as the difference between the two models, increase almost linearly. As fluctuating renewables play a more important role in high RES-E electricity systems and as the impact of the uncertain availability becomes more significant, the cost difference increases with higher RES-E quotas. For a 95 % RES-E share, the cost difference between the stochastic compared to the deterministic model amounts to 14.2 EUR_{2010}/MWh, which represents about 12.3 % of the average generation costs.

3.4.3.2 Sensitivity analysis

From the simulation, two assumptions seem to have a strong impact on the model results: First, the assumed investment costs for wind and solar technologies are notable due to their large deployment. Second, the available cross-border capacities are important due to the possibility or necessity to balance the regional stochastic generation and demand throughout Europe. The analysis focuses on the additional costs – the difference between the stochastic and the deterministic model – rather than on the effect of different scenario assumptions on the cost-efficient electricity mix.

Investment costs of wind and solar technologies

The development of investment costs for wind (on- and offshore) and solar technologies over the next decades is highly uncertain. Therefore, we simulate a scenario with 20 % lower and 20 % higher capital costs compared to the original data (compared to Table 3.8). In general, investment costs of wind and solar technologies have a strong influence on the system costs due to the large deployment of these technologies in the scenarios. The 20 % variation in investment costs leads to about 3 % higher (lower) average generation costs in the case of a RES-E quota of 60 % when compared to the original simulation. The effect increases with a higher RES-E share to 6 % as these technologies are largely deployed. Table 3.11 depicts the average generation costs in EUR_{2010}/MWh depending on the demanded renewable generation quota for both sensitivity scenarios (stochastic and deterministic).

When comparing the stochastic to deterministic results, we also find the switch from wind and solar technologies to dispatchable renewables in both sensitivity scenarios. Furthermore, more solar plants are built rather than additional wind turbines. Additional costs due to the stochastic availability of wind and solar power – measured by the difference between the stochastic to deterministic results – remain at a similar level as in the original simulation. When modeling a 50 % RES-E quota, the additional average costs vary from 2.3 to 2.5 EUR_{2010}/MWh and in the case of a 95 % RES-E quota, from 13.1 to 15.2 EUR_{2010}/MWh.

TABLE 3.11: Average generation costs depending on capital costs of wind and solar technologies and RES-E quota [EUR_{2010}/MWh]

		40 %	50 %	60 %	70 %	80 %	90 %	95 %
Low investment costs	stochastic	72.2	72.6	74.1	77.5	84.4	98.0	122.0
	deterministic	70.9	71.0	72.0	75.1	80.8	92.1	108.9
	absolute difference	1.2	1.6	2.1	2.5	3.6	5.9	13.1
	relative difference	1.7 %	2.2 %	2.8 %	3.3 %	4.5 %	6.4 %	12.0 %
High investment costs	stochastic	73.8	76.0	79.5	85.2	93.9	110.3	137.1
	deterministic	72.9	74.2	77.1	82.4	90.1	103.6	122.0
	absolute difference	0.9	1.7	2.5	2.8	3.8	6.7	15.2
	relative difference	1.3 %	2.3 %	3.2 %	3.4 %	4.2 %	6.5 %	12.5 %

Development of cross-border capacities

The assumed transmission grid may have a significant influence on the model results due to the necessity to balance the regional stochastic generation and demand throughout Europe. Hence, we simulate a scenario with no additional cross-border lines, compared to the situation today, and a scenario with no transmission constraints in addition to the original simulation, with an assumed increase of 20 % in all cross-border capacities (depicted in Table 3.9). Major export regions across the scenarios are Denmark, Benelux, Scandinavia and the United Kingdom mainly due to favorable on- and offshore wind sites. The largest import region is by far Germany due to the relatively limited favorable renewable potential compared to its electricity demand. When transmission capacities are limited to today's extent, less favorable renewable sites are used to achieve the renewable target. This includes more wind turbine installations in Southern Germany, Eastern France and Southern Poland, rather than on the coastlines of Northern Europe, and increased solar technologies in Northern France, Central Germany and Northern Italy. Average generation costs highly depend on the assumptions made about the transmission grid, as can be seen by the costs reported in Table 3.12. In the case of a system with 95 % generation from renewables, average generation costs are 47.6 EUR_{2010}/MWh (35 %) lower when electricity exchange is not limited compared to the simulation with transmission capacities from today.[42]

Additional costs due to the stochastic availability of wind and solar power – measured by the difference between the stochastic and deterministic results – remain at a similar level as in the original simulation. In the scenarios with no cross-border extensions, the relative cost difference tends to be higher – compared to the original simulation – as it becomes more challenging to balance the stochastic generation and demand with less transmission capacities. In the scenarios with no transmission constraints, the relative cost difference is also higher compared to the original simulation when modeling high RES-E quotas. Due to the stochastic generation of wind and solar technologies, the optimal mix is relatively diversified (extent depends on cost assumptions) although more low cost wind sites in Northern Europe are available and transmission is not limited. However, in the corresponding deterministic simulation, it is cost-efficient to mainly focus on these low cost sites as the annual generation is relatively stable (average full load hours) and electricity can be transported throughout Europe. Hence, the resulting relative cost difference is even larger than in the other scenarios in which the electricity mix is already diversified due to limited cross-border capacities.

Table 3.12: Average generation costs depending on cross-border capacities and RES-E quota [EUR_{2010}/MWh]

		40 %	50 %	60 %	70 %	80 %	90 %	95 %
No NTC extension	stochastic	73.3	74.6	77.2	82.2	90.4	106.5	140.7
	deterministic	72.3	72.9	74.9	79.5	86.7	100.0	122.4
	absolute difference	1.0	1.7	2.3	2.7	3.7	6.5	18.2
	relative difference	1.4 %	2.3 %	3.1 %	3.4 %	4.2 %	6.5 %	14.9 %
No NTC limits	stochastic	69.9	70.6	73.0	76.3	80.1	86.7	93.1
	deterministic	69.3	69.3	69.9	71.5	73.7	77.2	80.4
	absolute difference	0.6	1.4	3.1	4.9	6.4	9.5	12.7
	relative difference	0.9 %	2.0 %	4.5 %	6.8 %	8.7 %	12.3 %	15.8 %

Based on the simulation results, it is likely that total system costs for high RES-E systems are significantly higher than estimated in many studies. This applies especially for decentralized electricity power systems with a limited grid infrastructure, because balancing the fluctuating generation from renewables and demand becomes more difficult. When estimating additional costs for high RES-E systems compared to mostly conventional generation, one has to consider the uncertain availability of wind and solar power. The analysis shows that the additional costs are higher than estimated in deterministic models and that the difference increases significantly when implementing RES-E quotas of more than 70-80 %.

[42]The reported numbers represent average cost of electricity generation and do not include additional costs for the electricity grid.

3.5 Conclusion

We have shown that the stochastic feed-in and different cost structures of wind and solar technologies compared to conventional power plants lead to different requirements for the determination of the optimal electricity mix development. In this paper, an approach is presented to incorporate the stochastic feed-in of renewable energies in an investment and dispatch optimization model for electricity markets and applied to the European electricity system. The simulation results show that fluctuating renewables are significantly overvalued and hence dispatchable renewable energies such as biomass or geothermal sites - even considering high investment or fuel costs - are underestimated in deterministic electricity market models. Furthermore, solar technologies are - relative to wind turbines - underestimated when neglecting the negative correlation between wind speed and solar radiation. The simulation also shows that total system costs are significantly underestimated and this effect increases with higher RES-E shares. Hence, the simulation indicates that total system costs of a primarily renewable-based European electricity system will be significantly higher than estimated in many studies.

The analysis approach could be improved and extended in several ways. It would be desirable to also include short-term uncertainties such as wind and solar power forecast errors or power plant outages by using continuous planning techniques. As already shown in Sun et al. (2008), ignoring short-term uncertainties significantly undervalues the needed operational flexibility and can even result in insufficient investments. As the effects of stochastic yearly availability seem to be similar as short-term uncertainties a combined analysis may bring out interesting results. It would then be interesting to analyze the cost-efficient European pathway to a primarily renewable electricity system considering the stochastic feed-in of fluctuating renewables. The impact of the stochastic availability of wind and solar technologies and the appropriate consideration of long-term electricity market models provide interesting areas of further research.

Chapter 4

The effect of weather uncertainty on the financial risk of green electricity producers under various renewable policies

4.1 Introduction

Partly due to concerns about global warming, many countries are attempting to reduce CO_2 emissions from power generation by increasing the proportion of electricity generated from renewable energy sources. As power generation from renewable energy sources is usually more costly than conventional power generation, at least when ignoring external effects, many European countries have implemented various support schemes to promote renewable energies in recent years.

One established policy instrument is a *'feed-in tariff'* (FIT) for renewable power generation. Renewable producers are offered a long-term contract with guaranteed tariffs for each unit of electricity fed into the grid. To promote a broad mix of renewable energies, tariffs are usually differentiated by technologies representing the differences in generation costs. Feed-in tariff policies have led to a sharp increase in the share of renewable power generation in Spain (+12 %) and Germany (+11 %) from 2001 to 2010 (Eurostat, 2012). An alternative policy instrument is a *'fixed bonus'* (FB), which electricity producers receive in addition to the hourly market price for each unit of renewable energy (e.g., in Denmark and the Netherlands). Producers of renewable-based electricity are then exposed to the hourly market price, which is usually referred to as 'market integration'. Another common policy instrument is a *'renewable quota'* (often also referred to as *'renewable portfolio standard'*), demanding utility companies (or electricity consumers) to procure a certain share of their electricity from renewable sources within a defined period. This gives rise to a market for green certificates (TGC) issued by renewable-based electricity producers, which allows revenues in addition to the revenues from the wholesale market for electricity. A green certificate market is currently the main promotion scheme for renewable energies in Sweden and Poland.

It is an ongoing debate as to if and how renewable energies should be promoted in Europe once the envisaged national renewable targets of the National Renewable Energy Action Plans in 2020 have been achieved (EC, 2013). If the European Union or individual Member States make the decision to continue incentivizing renewable power generation, the promotion system should be cost-efficient in achieving this target. From a purely economic perspective, the support scheme should be technology-neutral, be implemented across Europe and include the hourly wholesale price for electricity. A technology-neutral policy, rather than technology-specific incentives, are cost-efficient as renewable energies with different generation costs and generation pattern are competing against each other. A harmonized RES-E policy would allow competition between European sites, which is particularly important for wind and solar technologies. Moreover, integrating renewables in the power market drives cost-efficient investments, as green electricity producers consider the hourly value of electricity in their investment and production decisions. Thus, the introduction of a European bonus system or renewable quota, with the above mentioned characteristics, is currently being discussed for the time frame after 2020.

However, one could question such policies, as the investment risk for electricity producers may be significantly higher than under a feed-in tariff support. A higher risk for producers may increase the costs of renewable-based electricity in particular due to the higher capital-to-operating cost ratio (compared to conventional power plants). Under a feed-in tariff system, electricity producers are remunerated by the fixed tariff and thus the produced quantity represents the only source of uncertainty. When exposing renewables to the power market, as under a bonus system, revenue streams are affected by uncertainty about the production as well as the future market price of electricity. Under a quota obligation, the produced amount of electricity, the market price and the price of green certificates are uncertain.

In this case, the effect of weather uncertainty is of particular interest mainly because of the increasing impact of intermittent generation on wholesale prices of electricity. The envisaged transition to a low-carbon and mostly renewable-based electricity supply implies a substantial increase in generation from wind and solar technologies due to the limited economic potential of dispatchable renewables (i.e., biomass or hydro power) in Europe. As variable generation costs of intermittent renewables are negligible, the feed-in of these technologies has a decreasing effect on wholesale prices. Thus, renewable-based electricity producers may face negatively correlated fluctuations in production and wholesale prices. Therefore, integrating renewables in the power market may actually reduce the variance in revenues.

This paper outlines the effect of weather uncertainty on the variance in profits of green electricity producers under the three most common renewable policies. We concentrate on the risk for green electricity producers (partial analysis) and refrain from an analysis on the risk sharing between renewable and conventional-based electricity producers. Moreover, an analysis on the risk for regulators when setting prices under feed-in tariff support or quantities under a renewable quota is beyond the scope of this paper.[43] In a first step, we discuss the price effects of fluctuations in the feed-in from intermittent renewables and their impact on the risk for renewable-based electricity producers. As potential balancing effects (negatively correlated fluctuations in production and wholesale prices) depend on the slope of the supply curve of dispatchable plants, we analyze the variance in revenues under the three renewable policies depending on the slope of the supply curve in a simple analytical framework. In a second step, we numerically solve the problem by applying a spatial stochastic equilibrium model to the European electricity market. The simulation results allow us to discuss the variance in profits under the different renewable support mechanisms, the size of the described balancing effects and how different technologies are affected by weather uncertainty.

The main findings of this analysis include that the effect of weather uncertainty on the risk for green electricity producers, under the three described renewable policies, highly depends on the slope of the supply curve (dispatchable power plants). For example, in the case of a supply curve with a relatively low slope, intermittent renewables profit from market integration due to negatively correlated fluctuations in production of intermittent renewables and the wholesale price. However, the price effect overcompensates the fluctuations in production if the supply curve is rather steep. Moreover, given any slope, only some technologies benefit from the described balancing effect. For example, biomass plants are likely to achieve high (low) full load hours in years with low (high) intermittent generation and thus high (low) prices. Thus, biomass plants face a higher risk when integrated into the power market due to the positive correlation of production

[43] In general, there is no difference between a bonus incentive (price-based control) and a quota obligation (quantity-based control) because for each instrument there is a corresponding way to implement it as the other in order to achieve the same results. However, price-based or quantity-based control mechanisms are not equivalent in markets with uncertainties (Weitzman, 1974). It is an interesting question whether price or quantity controls are preferable to promote renewables in power markets, but it is beyond the scope of this paper.

and prices. The results of the numerical analysis for the European power market suggest that wind producers benefit from market integration, but producers from biomass and solar plants face a larger variance in profits. Furthermore, the simulation indicates highly volatile green certificate prices when introducing a renewable quota obligation without the option of banking and borrowing. Thus, all renewable producers face a higher variance in profits, as the price effect of weather uncertainty on green certificates overcompensates the negatively correlated fluctuations in production and prices. However, one should keep in mind that a well-functioning banking and borrowing scheme may reduce the variance in certificate prices considerably and thus the variance in profits of green electricity producers.

The main contribution of this paper to existing literature is the illustration of the impact of weather uncertainty on the risk for green electricity producers under the three most common renewable policies. The literature concerning risks for green electricity producers has so far mainly concentrated on green certificate markets (e.g., Berry (2002), Lemming (2003), Dinica (2006) and Kildegaard (2008)). Berry (2002) discusses the price mechanism and the management of risks associated with using the tradable credits market. Amundsen et al. (2006) discuss the price volatility of green certificates due to strong fluctuations in wind power production by using a simulation model to show that the introduction of a banking scheme may considerably reduce price volatility. Moreover, banking and borrowing leads to increased social welfare but not necessarily to higher profits of green producers. As most renewable energies are dominated by fixed costs, Kildegaard (2008) points out that there exists a risk of over-investments and resulting periods of low certificate prices. Thus, banking and borrowing plays an important role in green certificate markets. Lemming (2003) argues that negatively correlated fluctuations in the production of intermittent renewables and the pricing of green certificate may actually reduce the financial risk for renewable-based electricity producers. This analysis adds to the discussion on the impact of weather uncertainty on the risk for green electricity producers in Lemming (2003) by comparing the most common renewable policies. Moreover, the impact on different technologies is discussed along with a numerical analysis for the European power market.

The remainder of this paper is structured as follows: In Section 4.2, the influence of weather uncertainty on the risk of green electricity producers is discussed. Section 4.3 describes the numerical analysis, including a detailed description of the model, input parameters and results. Conclusions are drawn in Section 4.4, along with an outlook of possible further research.

4.2 Analytical analysis

Many different policies exist to incentivize power generation from renewable energies. Most commonly applied are *'feed-in tariffs'*, *'fixed bonus'* incentives and *'renewable quota'* obligations, or slight variations of these policies.[44] Thus, we analyze these three renewable policies. Concerning the renewable quota obligation, we consider the case of a certificate market without the option of banking and borrowing (referred to as *'renewable quota (no BaB)'*). As discussed in Amundsen et al. (2006), the introduction of a banking scheme may considerably reduce the price volatility of green certificates. Moreover, in case of a perfectly well-functioning banking and borrowing mechanism such that weather uncertainty is resolved, the risk for green electricity producers equals the risk in the case of a fixed bonus incentive (referred to as *'renewable quota (perf. BaB)'*).

We assume an electricity market where intermittent generation (i.e., wind or solar power) makes up a significant share of the renewable supply. Due to the stochastic nature of wind and solar power, electricity generation of intermittent renewables (Q_w) varies among years with equal probability $Q_1 < Q_2 < Q_3$. We are looking at a single renewable-based electricity producer with power generation $q_1 < q_2 < q_3$ that is perfectly correlated with all other intermittent renewable generation in the market. The renewable policies are designed such that the expected profit equals the capital costs and thus $E(R_{fit}) = E(R_{bonus}) = E(R_{quota}) = K$. Figure 4.1 schematically depicts the revenues of the renewable-based electricity producer under the three policies.

Under a *'feed-in tariff'* policy, the renewable-based electricity producer is offered a long-term contract with guaranteed tariffs (fit) for each unit of electricity fed into the grid. Consequently, electricity producers invest in renewables as long as capital costs can be recovered under the offered feed-in tariff. As such, renewable-based electricity producers do not consider the market price for electricity in their investment decision. Since prices are fixed under a feed-in tariff system, revenues vary according to the volatility in generation. As depicted, the renewable-based electricity producer can expect high revenues ($R_{fit,3} = [0, FIT, o', q_3]$) in years with large generation but substantially lower revenues ($R_{fit,1} = [0, FIT, o, q_1]$) in years with low generation. Hence, the related risk for the renewable-based electricity producer is purely based on the volatility in generation.

Under a *'fixed bonus'* incentive, renewable-based electricity producers receive the wholesale price of electricity and, in addition, a fixed bonus payment ($p_e + b$). As variable

[44] As we concentrate on the effect of weather uncertainty on the risk of green electricity producers under these three policies, we refrain from a discussion on the benefits of a price (i.e., feed-in tariffs or bonus payments) or quantity control instrument (i.e., quota obligation) from a social welfare perspective (including the risk of regulators and conventional power generators).

generation costs of intermittent renewables are negligible, the feed-in of intermittent renewables reduces the residual load ($d - Q_w$) that has to be met by dispatchable plants. Thus, the feed-in of intermittent renewables has a price lowering effect on the wholesale market ($p_{e,1} \geq p_{e,2} \geq p_{e,3}$). Furthermore, renewable-based electricity producers may face negatively correlated fluctuations in production and wholesale prices, which may actually reduce the financial risk under a fixed bonus policy compared to feed-in tariffs. However, the balancing effect highly depends on the marginal supply curve of the dispatchable plants. In the case of a very steep merit order, the feed-in from intermittent renewables may have such a large effect on prices that it overcompensates for the fluctuation in production.

Under a *'renewable quota (no BaB)'* obligation, utility companies (or electricity consumers) are required to procure a certain share of their electricity from renewable energy sources within a defined period. This gives rise to a market for green certificates issued by renewable-based electricity producers. In the equilibrium, the certificate price corresponds to the difference in marginal costs between renewable and conventional power generation. The renewable-based electricity producer faces fluctuations in production, wholesale/green certificate prices. In addition to the potential balancing effect between fluctuations in production and wholesale prices, certificate prices ($p_{c,1} \geq p_{c,2} \geq p_{c,3}$) are also negatively correlated with the production of intermittent electricity generation (Lemming, 2003). Thus, renewable-based electricity producers may face a higher or lower risk compared to a feed-in tariff or fixed bonus policy.

In summary, weather uncertainty affects the risk for renewable-based electricity producers under the three policies differently. Due to the negatively correlated fluctuations in production and wholesale/certificate prices, renewable-based electricity producers may face a lower risk when integrating renewables into the power market or creating a green certificate market. Next, we introduce a simple analytical example to depict the impact of the supply function on the risk for green electricity producers in light of weather uncertainty.

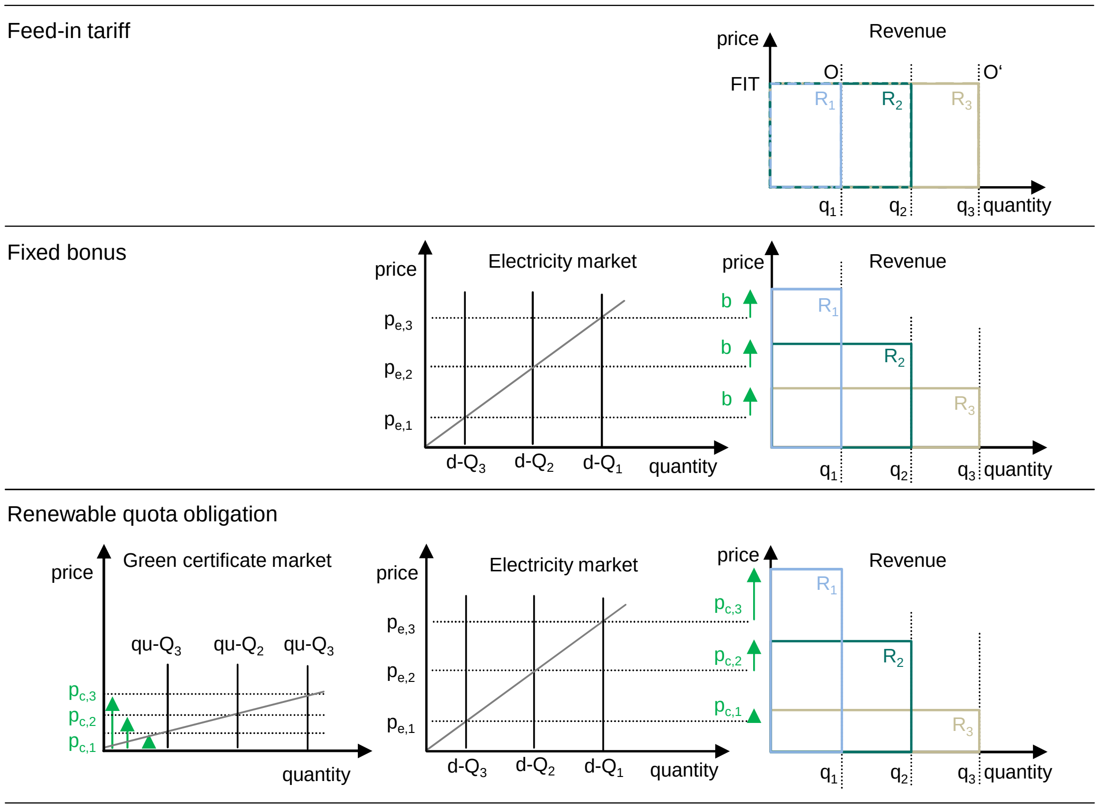

FIGURE 4.1: Effect of weather uncertainty on the variance in revenues of green electricity producers

Let us assume a technology with total capital costs $K = 2500$ and intermittent renewable-based electricity generation $q_w = \{14; 15; 16\}$ with equal probability $p = 1/3$. Total electricity demand (inelastic) is $d = 20$ and the marginal cost curve of dispatchable plants (conventional and renewable) is given by $C'_d = \alpha_d \cdot q_d^2 + \gamma_d$ with $\gamma_d = 10$.[45] The rather flat part of the supply function represents the marginal costs of already existing plants (i.e., based on short-term marginal costs). The strong increase in generation costs, due to the quadratic form, depicts the high costs when additional investments are needed (i.e., long-run marginal costs). The variable α_d represents the steepness of the supply function. Given the first-order conditions for electricity producers, the electricity price is equal to the marginal costs in the equilibrium ($p_e = C'_d = \alpha_d \cdot (d - q_w)_d^2 + 10$). Thus, electricity prices vary due to the fluctuating generation of intermittent renewables with $p_1 = 36 \cdot \alpha_d + 10$; $p_2 = 25 \cdot \alpha_d + 10$ and $p_3 = 16 \cdot \alpha_d + 10$. Under all renewable policies, the expected revenue should equal to total capital costs $E(R_w) = K$ (zero profit condition).

Under a *'feed-in tariff'* policy, the renewable-based electricity producer is offered a long-term contract with guaranteed tariffs (fit) for each unit of electricity fed into the grid. In our example, the feed-in tariff needs to be $fit = \frac{500}{3}$ to allow the renewable-based

[45]Other functions may actually be a better approximation of a typical merit order of dispatchable plants. We pick a quadratic supply curve mainly to keep the example as simple as possible.

electricity producer to recover (on average) the capital costs. The variance in revenues simply depends on the volatility in generation and is thus fixed in this framework. Numerically, this is stated as:

Zero profit condition: $\frac{1}{3} \cdot (14 + 15 + 16) \cdot fit = 2500$

$$\Rightarrow fit = \frac{500}{3}$$

thus $R_{fit,1} = \frac{7000}{3}$, $R_{fit,2} = \frac{7500}{3}$ and $R_{fit,3} = \frac{8000}{3}$

and $Var_{fit} = \frac{(R_{fit,1}-K)^2+(R_{fit,2}-K)^2+(R_{fit,3}-K)^2}{3} = 18518\ \frac{14}{27}$

Under a *'fixed bonus'* incentive, renewable-based electricity producers receive the wholesale price and, in addition, a fixed bonus payment $(p_e + b)$. The necessary bonus can be determined through the zero profit condition and amounts to $b = \frac{470}{3} - \frac{227}{9} \cdot \alpha_d$.[46] The variance in revenues depends on the slope of the supply function: A relatively low slope of the supply curve leads to a lower variance in revenues, whereas a steep supply curve leads to a greater variance in revenues compared to the case of a feed-in tariff. Numerically, this is stated as:

Zero profit condition: $\frac{1}{3} \cdot [14 \cdot (36 \cdot \alpha_d + 10 + b) + 15 \cdot (25 \cdot \alpha_d + 10 + b)$

$$+16 \cdot (16 \cdot \alpha_d + 10 + b)] = 2500$$

$$\Rightarrow b = \frac{470}{3} - \frac{227}{9} \cdot \alpha_d$$

thus $R_{b,1} = \frac{7000}{3} + \frac{1358}{9} \cdot \alpha_d$, $R_{b,2} = \frac{7500}{3} - \frac{10}{3} \cdot \alpha_d$ and $R_{b,3} = \frac{8000}{3} - \frac{1328}{9} \cdot \alpha_d$

and $Var_b = 14850\ \frac{98}{243} \cdot \alpha_d^2 - 33160\ \frac{40}{81} \cdot \alpha_d + 18518\ \frac{14}{27}$

Under a *'renewable quota (no BaB)'* obligation, producers receive a green certificate for each unit of renewable-based electricity fed into the grid. Thus, renewable-based electricity producers generate revenues on the wholesale market and the green certificate market $(p_d + p_c)$. The residual supply curve of green certificates represents the marginal cost difference between dispatchable renewables q_r (i.e., biomass) and dispatchable conventional power generation $(p_c = C_r'(q_r) - C_d'(q_d))$. For our example, we assume a green certificate supply curve (residual) with $p_c = \alpha_c \cdot q_r^2 + \gamma_c$ $(\gamma_c > \gamma_d)$. The renewable target $(qu = 18)$ is expected to be achieved independently of the weather realization. Thus, green certificate prices are given by $p_c = \alpha_c \cdot (qu - q_w)^2 + \gamma_c$: $p_{c,1} = 16 \cdot \alpha_c + \gamma_c$; $p_{c,2} = 9 \cdot \alpha_c + \gamma_c$ and $p_{c,3} = 4 \cdot \alpha_c + \gamma_c$. The resulting function for the variance $Var_{qu}(\alpha_d, \alpha_c)$ indicates that low slopes of the supply curves (α_d and α_c) reduce the variance but high slopes increase it due to the quadratic form. Numerically, this is stated as:

[46] As the bonus is expected to be positive $(b \geq 0)$, the slope of the supply curve of dispatchable plants has an upper bound with $\alpha_d \leq \frac{1410}{227}$ in this example.

Zero profit condition: $\frac{1}{3} \cdot (14 \cdot (36 \cdot \alpha_d + 10 + 16 \cdot \alpha_c + \gamma_c) + 15 \cdot (25 \cdot \alpha_d + 10$

$+9 \cdot \alpha_c + \gamma_c) + 16 \cdot (16 \cdot \alpha_d + 10 + 4 \cdot \alpha_c + \gamma_c)) = 2500$

$\Rightarrow \gamma_c = \frac{470}{3} - \frac{227}{9} \cdot \alpha_d - \frac{47}{5} \cdot \alpha_c$

thus $R_{q,1} = \frac{1358}{9} \cdot \alpha_d + \frac{462}{5} \cdot \alpha_c + \frac{7000}{3}$, $R_{q,2} = -\frac{10}{3} \cdot \alpha_d - 6 \cdot \alpha_c + \frac{7500}{3}$ and

$R_{q,3} = -\frac{1328}{9} \cdot \alpha_d - \frac{432}{5} \cdot \alpha_c + \frac{8000}{3}$

$Var_q = 14850\,\frac{98}{243} \cdot \alpha_d^2 + 5346\,\frac{6}{25} \cdot \alpha_c^2 + 17807\,\frac{13}{45} \cdot \alpha_d \cdot \alpha_c$

$-33160\,\frac{40}{81} \cdot \alpha_d - 19866\,\frac{2}{3} \cdot \alpha_c + 18518\,\frac{14}{27}$

The variance in revenues under the three renewable policies are affected differently by variations in the slope of the supply function of the power market and the green certificate market (Var_{fit}, $Var_b(\alpha_d)$ and $Var_q(\alpha_d, \alpha_r)$). Figure 4.2 shows the variance in revenues under the three policies depending on the slope of the power market's supply function. For the variance under a renewable quota obligation, two different cases for the slope of the supply function of green certificates are depicted ($\alpha_c = 1$ and $\alpha_c = 3$).

For the special case of a flat supply curve of dispatchable plants (conventional and renewable with $\alpha_d = 0$), fluctuations in intermittent renewable generation have no effect on the wholesale price. Thus, renewable-based electricity producers face the same variance in revenues under all renewable policies, which represents the fluctuations in power generation.

In power markets with a rather low slope of the supply curve ($0 < \alpha_d < 1.1$), meaning that the power plant mix has similar generation costs, fluctuations in intermittent generation lead to slightly higher (lower) prices in years with low (high) feed-in from intermittent renewables. Thus, the variance in revenues is reduced under bonus support due to slightly higher (lower) revenues in years with low (high) intermittent generation compared to the feed-in tariff support. An increase in the steepness of the supply curve results in more balanced revenues due to the negatively correlated fluctuations in production and wholesale prices. In fact, at a specific steepness ($\alpha_d = 1.1$) the variance in revenues actually becomes zero.

However, in power markets with a rather steep supply curve of dispatchable plants ($\alpha_d > 1.1$), wholesale prices vary substantially due to fluctuations in intermittent power generation. This could be the case in power markets with large base-load capacities that are supplemented by only peak capacities rather than a mix of mid and peak capacities. Due to the large price effect, renewable-based electricity producers achieve large revenues in years with low generation and low revenues in years with high generation. In other words, the price effect overcompensates for the fluctuation in generation and, as a result, the variance becomes relatively large.

A similar effect can be observed under a renewable quota obligation. A relatively low slope of the power market and the green certificate market helps to balance the revenues. However, large price effects on both markets can overcompensate for the fluctuations in production such that the variance in revenues becomes relatively large.

Considering today's power markets in Europe, the most relevant case seems to be a relatively low slope of the supply curve of the power market but a rather steep supply curve of the green certificate market. A large mix of conventional technologies with slightly different efficiency factors (due to the different installation years) and fuel costs usually results in a merit order with a relatively low slope. The supply curve becomes relatively steep once new capacity is needed to cover demand (representing long-term marginal costs). The situation is different for the supply curve of renewable energies. At first, marginal generation costs are zero, as variable generation costs of (existing) wind, solar and hydro plants are negligible. The second part is relatively flat as the costs represent short-term marginal generation costs of (existing) dispatchable plants (mainly biomass plants). Thereafter, the merit order becomes relatively steep, representing the long-term marginal costs of new capacities.

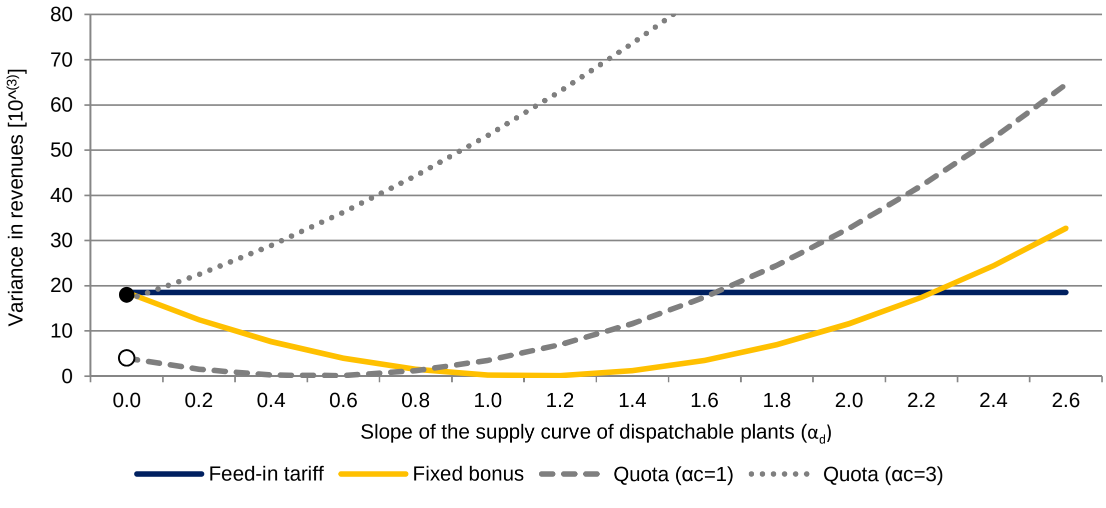

FIGURE 4.2: Variance in revenues depending on the slope of the supply curves [10^3]

The effect of weather uncertainty on the risk for renewable-based electricity producers under the most common renewable policies is not obvious. The simple analytical example has shown that the effect depends on the function of the conventional and the renewable supply curves. Furthermore, there remain a few important aspects that have not yet been considered in this simple framework.

First, the simple framework assumes one period of power supply, thus ignoring dynamic effects. Second, we look at the case of one intermittent renewable-based electricity producer (marginal technology) with power generation that is perfectly correlated to all other intermittent renewable generation. It is shown that negatively correlated generation and wholesale/certificate prices may reduce the financial risk. However, taking the example of dispatchable renewables (e.g., biomass), generation can be positively correlated with wholesale/certificate prices. Another example could be negatively correlated generation of wind and solar technologies. Thus, some renewable energies face a higher risk when integrated into the power market due to the positive correlation of production and prices.

As the analytical framework allows us only limited arguments for a policy discussion about a suitable renewable promotion scheme for Europe after 2020, we solve this problem numerically by applying a stochastic simulation model to the European electricity market. The stochasticity as well as the negative correlation of wind and solar power are modeled by three different wind and solar years. The model is not exactly comparable to the analytical example, as several renewable energies and periods are modeled. However, the simulation results allow us to discuss the variance in profits under the different renewable support mechanisms (via a ranking of support mechanisms), the size of the described balancing effects and how different technologies are affected by weather uncertainty.

4.3 Numerical analysis for the European power market

In this section, the numerical analysis of the financial risk for green electricity producers under weather uncertainty is presented. The analysis is based on a stochastic spatial inter-temporal equilibrium model for the European electricity market. The model considers the uncertainty of annual full load hours of wind and solar technologies. In Subsection 4.3.1, the electricity market model developed for this analysis is described and the model assumptions are presented in Subsection 4.3.2. The performance of renewable policies is analyzed based on the model results in Subsection 4.3.3.

4.3.1 Model description

The model developed for this analysis is a stochastic spatial inter-temporal equilibrium model for liberalized electricity markets. Economic analyses on spatial markets date back to Samuelson (1952), who developed a framework to describe the equilibrium by modeling marginal inequalities as first-order conditions. Takayama and Judge (1964) reformulated the Samuelson model as a quadratic programming problem and presented a computational algorithm to find the optimal solution for such problems. Spatial equilibrium models have been used to analyze investments under uncertainty or firms with non-competitive market behavior for various energy markets in recent years: coal markets (e.g., Haftendorn and Holz (2010), Paulus and Trüby (2011)); natural gas markets (e.g., Haurie et al. (1988), Hecking and Panke (2012), Zhuang and Gabriel (2008)) and electricity markets (e.g., Hobbs (2001), Lise and Kruseman (2008), Metzler et al. (2003), Neuhoff et al. (2005), Vespucci et al. (2009) as well as Ehrenmann and Smeers (2011)).

The electricity market model developed for this analysis is similar to the perfect competition case of the electricity market model described in Traber and Kemfert (2013). It is formulated as three separate optimization problems. First, a representative European electricity producer (acting as a price taker[47]) maximizes its profit by selling electricity to the domestic market. Second, an international electricity trader acts as an arbitrageur, representing the linkage between model regions (grid investments are exogenous). Third, a transmission system operator regulates the curtailment of wind and solar generation. The model is formulated as a mixed complementary problem by deriving the Karush-Kuhn-Tucker (first-order) conditions for the European electricity producer's, the arbitrageur's and the transmission system operator's maximization problem. The model is programmed in GAMS and run with the PATH solver (Dirkse and Ferris, 1995, Ferris and Munson, 1998).

The time horizon of the model is T = 2010, 2013, 2020, 2030,...t,... 2050 on a ten-year basis up to 2050.[48] The model consists of several electricity market regions r $\in$ R where electricity demand and supply must be balanced. All common power generation technologies a $\in$ A (conventional, renewable and storages) are implemented in the model. The set A can be divided into two subsets $A \equiv N \cup Q$, where n $\in$ N is a conventional or storage technology (not subsidized) and q $\in$ Q is a renewable-based technology (potentially subsidized). To distinguish between storage and non-storage technologies, an additional subset b $\in$ B $\in$ A is added. Different electricity demand levels during a single year are represented by several load levels l $\in$ L. An overview of all sets, decision variables and parameters can be found in Table 4.1.

Representative European electricity producer's maximization problem: power supply

The supply side is modeled by an aggregation of all producers to a single price taking European electricity producer. The European electricity producer maximizes its

[47] Given the oligopolistic structure of most electricity markets, the competitiveness of power markets, including the European power market, may be questioned (Borenstein et al., 1999, Newberry, 2002). An analysis of how various renewable support schemes are affected by market power is an interesting question but is beyond the scope of this paper.

[48] To account for different technical lifetimes of technologies, the years 2060 and 2070 are additionally modeled but not interpreted.

discounted pay-off function, defined as the revenues from sales and capacity payments minus costs for electricity production, recharging storages, fixed operation and maintenance costs as well as investment costs. In reality, power plant investors face many uncertainties that influence the profitability of their investments. Among others, the electricity demand development, future capital costs, fuel prices, political developments and future competition are uncertain. Another source of uncertainty is the stochastic annual generation of wind and solar technologies. Empirical data shows that full load hours vary by a magnitude of more than 20 % from the long-term average. The volatility of annual wind and solar generation has a large impact in electricity systems with a high share of wind and solar technologies (Nagl et al., 2013). In the presented model, the stochasticity as well as the negative correlation of wind and solar power are represented by a low wind/high solar year (w_1), an average wind/average solar year (w_2) and a high wind/low solar year (w_3). The European electricity producer is assumed to be risk-neutral[49] and thus maximizes expected profit.

The model allows different renewable support schemes: *'feed-in tariff'* (bf=1), *'fixed bonus'* (bp=1) and *'renewable quota obligation'* (bg=1). It is important to note that all support schemes are technology-neutral, independent of the installation year and implemented across Europe (harmonized European policy). In all support mechanisms, payments are guaranteed even if generation cannot be integrated into the grid (energy is curtailed by the transmission system operator). Renewable generator have to make an annual decision whether to receive the renewable subsidy or the market price. Furthermore, it is assumed that the European renewable policy is already implemented in 2013. As only one renewable support scheme can be in place at a time, bf + bp + bg = [0;1].

The pay-off function Π_f can be written as shown in (4.1a) to (4.1k). Line (4.1a) defines the annual revenues gained from electricity sales generated in conventional and storage plants (non-subsidized). Sales ($\mathrm{S}_{t,r,l,f,a,w}$) are rewarded by the domestic electricity price ($\phi_{t,r,l,w}$) at the specific load level multiplied by the number of hours ($\mathrm{h_l}$). Line (4.1b) defines the revenues from renewable-based sales (subsidized generation) depending on the specific support mechanism.[50] Line (4.1c) defines the revenues from the reserve market that firms can achieve by offering securely available capacity to the market (technology-specific capacity factor ca_a). Due to the simplification to a few dispatch situations per model year, potential peak demand is not considered as a dispatch situation. The modeled capacity market simply ensures that sufficient investments in back-up capacities

[49]In many economic situations, firms seem to act rather risk-averse (Mas-Colell et al., 1995). Nevertheless, the analysis assumes a risk-neutral electricity producer to simply quantify investment risks under various support schemes rather than analyze how producers react to uncertainty, given their risk preference.

[50]In the first model year (2010), no renewable support is modeled and therefore all technologies receive the market price.

are made to meet potential peak demand. However, such investments could also be triggered in an energy-only market in the event of price peaks.[51] Line (4.1d) defines the variable production costs, including fuel and CO_2 emission costs, for the generated electricity for each technology. Storage technologies can be recharged ($P_{t,r,l,f,a,w}$), but electricity has to be bought on the market as stated in line (4.1e). Line (4.1f) defines the fixed operation and maintenance costs. Line (4.1g) defines investment costs, which are annualized with an interest rate (ir) and occur until the end of the plant's technical lifetime. An earlier decommissioning of power plants is not considered in the model.

Profit maximization of the European electricity producer is constrained by a set of restrictions for production capacities and storage limits, as defined in line (4.1h) - (4.1k). The variables in parentheses on the right hand side of each constraint are the Lagrange multipliers used when developing the first-order conditions. Line (4.1h) states that available capacity (considering outages and revisions) has to be greater or equal to generation at all times. Line (4.1i) ensures that electricity charging is at least as high as generation from storage capacities on an annual basis. Line (4.1j) restricts the capacity potential for all technologies. Line (4.1k) states the typical non-negativity constraints.

[51] Based on the International Energy Agency, 'markets in which marginal pricing of electricity is the only remuneration are often called energy-only markets' (IEA, 2007b). It is an ongoing debate whether sufficient incentives to invest in generation capacity exist in energy-only markets (Joskow (2008), Cramton and Stoft (2005) and Cramton and Stoft (2008)). Implementing a capacity market in this model is purely a result of the chosen model approach.

Table 4.1: Model sets, variables and parameters

Sets		
a ∈ A	technologies for power generation	
b ∈ B ∈ A	storage technologies	
q ∈ Q ∈ A	renewable technologies	
n ∈ N ∈ A	not subsidized technologies	
f ∈ F	electricity producer	
l, l' ∈ L	load levels	
r, r' ∈ R	regions	
t, t' ∈ T	time periods	
w ∈ W	weather years	
Boolean policy		
bf	boolean indicating feed-in tariffs as support	[0;1]
bp	boolean indicating bonus payments as support	[0;1]
bg	boolean indicating green certificate market as support	[0;1]
Primal variables		
$\Pi_{f/ARB/TSO}$	profit of producer, arbitrageur or transmission operator	EUR_{2010}
$I_{t,r,f,a}$	capacity investments	MW
$E_{t,r,l,r',w}$	electricity exchange	MW
$S_{t,r,l,f,a,w}$	domestic sales / generation	MW
$P_{t,r,l,f,a,w}$	charging storage	MW
$M_{t,r,l,w}$	renewable curtailment	MW
Dual variables		
$\alpha_{t,r,l,f,a,w}$	shadow price of capacity constraint	EUR_{2010}/MW
$\beta_{t,r,f,a,w}$	shadow price of annual storage constraint	EUR_{2010}/MW
$\gamma_{t,r,f,a}$	shadow price of capacity potential	EUR_{2010}/MW
$\phi_{t,r,l,w}$	shadow price of power equation (electricity price)	EUR_{2010}/MWh
$\chi_{t,r,l,r',w}$	shadow price of transfer constraint (congestion price)	EUR_{2010}/MWh
$\psi_{t,w}$	shadow price of renewable constraint (certificate price)	EUR_{2010}/MWh
$\omega_{t,r}$	shadow price of peak capacity constraint (reserve price)	EUR_{2010}/MW
Parameters		
$ai_{t,r,f,a,t'}$	boolean indicating technical lifetime (t'=periods after t)	[0;1]
$av_{r,l,a,w}$	capacity availability	$MW/MW_{inst.}$
bb_a	boolean indicating storage technologies	[0;1]
$bc_{t,a}$	fuel costs	EUR_{2010}/MWh_{th}
$bi_{t,r,f,a,t'}$	boolean investments in previous periods (t'=periods before t)	EUR_{2010}/MWh
bo_t	fixed bonus payment	[0;1]
ca_a	percentage of securely available capacity	$MW/MW_{inst.}$
$cp_{t,r,f,a}$	capacity potential	MW
$d_{t,r,l}$	electricity load	MW
$dp_{t,r}$	peak electricity demand	MW
dr_t	discount factor	%
$ec_{t,r,f,a}$	existing capacity	MW
ef_a	emission factor	t CO_2 /MWh_{th}
et_t	tax on CO_2 emissions	EUR_{2010}/t CO_2
η_a	net efficiency of power plants	MWh_{el}/MWh_{th}
$fc_{t,a}$	yearly fixed operation and maintenance costs	EUR_{2010}/MWa
fit_t	feed-in tariff	EUR_{2010}/MWh
$fp_{t,r,r'}$	net transfer capacity	MW
h_l	number of hours	h
$ic_{t,a}$	investment costs	EUR_{2010}/MW
ir	interest rate	%
lh_b	losses in storage charging	%
$lo_{r,r'}$	transfer losses	%
$pl_{a,w}$	boolean for technologies receiving market price	[0;1]
pr_w	probability of weather realizations	%
qu_t	demanded RES-E share	%
qq_a	boolean indicating renewable technologies	[0;1]
tl_a	technical lifetime of technologies	a
tr_t	number of years	-
$vc_{t,a}$	variable costs	EUR_{2010}/MW
$y_{t,r,f,a}$	natural inflow storage technologies	MWh
$\bar{\phi}$	minimal price for curtailment (helping parameter)	EUR_{2010}/MWh

Optimization problem of European electricity producer: electricity supply

$$\max_{I_{t,r,f,a};S_{t,r,l,f,a,w};P_{t,r,l,f,a,w}} \Pi_f = \sum_{t\in T} dr_t \cdot tr_t \cdot [\sum_{r\in R}\sum_{l\in L}\sum_{a\in N}\sum_{w\in W}(pr_w \cdot h_l \cdot \phi_{t,r,l,w} \cdot S_{t,r,l,f,a,w}) \tag{4.1a}$$

$$+\sum_{r\in R}\sum_{l\in L}\sum_{a\in Q}\sum_{w\in W}(pr_w \cdot h_l \cdot S_{t,r,l,f,a,w} \cdot (bf \cdot fit_t + bp \cdot (\phi_{t,r,l,w} + bo_t) + bg \cdot (\phi_{t,r,l,w} + \psi_{t,w}))) \tag{4.1b}$$

$$+\sum_{r\in R}\sum_{a\in A}(\omega_{t,r} \cdot ca_a \cdot (ec_{t,r,f,a} + \sum_{t'\in T}(bi_{t,r,f,a,t'} \cdot I_{t,r,f,a}))) \tag{4.1c}$$

$$-\sum_{r\in R}\sum_{l\in L}\sum_{a\in A}\sum_{w\in W}(pr_w \cdot h_l \cdot \frac{bc_{t,a} + ef_a \cdot et_t}{\eta_a} \cdot S_{t,r,l,f,a,w}) \tag{4.1d}$$

$$-\sum_{r\in R}\sum_{l\in L}\sum_{a\in B}\sum_{w\in W}(pr_w \cdot h_l \cdot \phi_{t,r,l,w} \cdot P_{t,r,l,f,a,w}) \tag{4.1e}$$

$$-\sum_{a\in A}(fc_{t,a} \cdot (ec_{t,r,f,a} + \sum_{t'\in T}(bi_{t,r,f,a,t'} \cdot I_{t,r,f,a}))) \tag{4.1f}$$

$$-\sum_{a\in A}(ic_{t,a} \cdot \frac{(1+ir)^{tl_a} \cdot ir}{(1+ir)^{tl_a} - 1} \cdot \sum_{t'\in T}(bi_{t,r,f,a,t'} \cdot I_{t,r,f,a}))] \tag{4.1g}$$

s.t.

$$S_{t,r,l,f,a,w} + P_{t,r,l,f,a,w} - av_{r,l,a,w} \cdot \left(ec_{t,r,f,a} + \sum_{t'\in T}\left(bi_{t,r,f,a,t'} \cdot I_{t,r,f,a}\right)\right) \leq 0 \qquad (\alpha_{t,r,l,f,a,w}) \qquad \forall t,r,l,f,a,w. \tag{4.1h}$$

$$\sum_{l\in L}(h_l \cdot S_{t,r,l,f,a,w}) - y_{t,r,f,a} - \sum_{l\in L}(h_l \cdot P_{t,r,l,f,a,w} \cdot (1 - lh_b)) \leq 0 \qquad (\beta_{t,r,f,a,w}) \qquad \forall t,r,f,a,w. \tag{4.1i}$$

$$\left(ec_{t,r,f,a} + \sum_{t'\in T}\left(bi_{t,r,f,a,t'} \cdot I_{t,r,f,a}\right)\right) - cp_{t,r,f,a} \leq 0 \qquad (\gamma_{t,r,f,a}) \qquad \forall t,r,f,a. \tag{4.1j}$$

$$I_{t,r,f,a};\ S_{t,r,l,f,a,w};\ P_{t,r,l,f,a,w} \geq 0 \tag{4.1k}$$

The next step in developing the model is to derive the Karush-Kuhn-Tucker conditions from the Lagrangian $\mathcal{L}_f$ of the original optimization problem. Equation 4.2 defines the equilibrium condition for electricity sales. Electricity is generated as long as the expected revenues are greater than production ($\mathrm{vc}_{t,a}$) and capacity costs ($\alpha_{t,r,l,f,a,w}$).[52] Electricity generation from renewable sources receive additional payments depending on the support scheme. Electricity generation from storage technologies also consider the shadow price of the annual storage equilibrium condition ($h_t \cdot \beta_{t,r,f,a,w}$).[53]

$$\begin{aligned} \frac{\partial \mathcal{L}_f}{\partial S_{t,r,l,f,a,w}} :\quad & dr_t \cdot tr_t \cdot h_l \cdot pr_w \cdot (-pl_{a,w} \cdot \phi_{t,r,l,w} - bf \cdot fit_t \\ & -bp \cdot (\phi_{t,r,l,w} + bo_t) - bg \cdot (\phi_{t,r,l,w} + \psi_{t,w}) + vc_{t,a}) \\ +\alpha_{t,r,l,f,a,w} + bb_a \cdot h_l \cdot \beta_{t,r,f,a,w} \geq 0 \quad & \perp S_{t,r,l,f,a,w} \qquad \forall t, r, l, f, a, w. \end{aligned} \tag{4.2}$$

Equation 4.3 defines the equilibrium condition for charging storage technologies. Storage operators charge their storages as long as the market price is lower than the marginal price of the annual storage equilibrium condition ($\beta_{t,r,f,a,w}$), while considering losses during charging operations (1-lh_b) and the capacity limit ($\alpha_{t,r,l,f,a,w}$).

$$\begin{aligned} \frac{\partial \mathcal{L}_f}{\partial P_{t,r,l,f,a,w}} :\quad & dr_t \cdot tr_t \cdot h_l \cdot pr_w \cdot \phi_{t,r,l,w} + \alpha_{t,r,l,f,a,w} \\ -h_l \cdot (1 - lh_b) \cdot \beta_{t,r,f,a,w} \geq 0 \quad & \perp P_{t,r,l,f,a,w} \geq 0 \qquad \forall t, r, l, f, w, a \in B. \end{aligned} \tag{4.3}$$

Equation 4.4 defines the equilibrium condition for investments in new power plants and storage facilities. Investments are made as long as the sum of marginal benefits of additional capacity is greater than fixed operation and maintenance costs, investment costs and the marginal price of the capacity potential constraint ($\gamma_{t,r,f,a}$) over the total lifetime.

[52] The dual variable of the capacity constraint ($\alpha_{t,r,l,f,a,w}$) is zero unless the capacity constraint is binding.

[53] Under a feed-in tariff system or quota w/out market integration, renewable technologies with lower variable costs than the offered feed-in tariff/certificate price generate electricity at full available capacity at all times. If the offered feed-in tariff is equally high as the variable costs, the first-order condition for electricity generation is then fulfilled for zero to maximal generation (no unique solution). To force the model to reach an unique solution, negligible increasing variable costs are modeled. Hence, the first-order condition with regard to electricity generation is actually: $dr_t \cdot tr_t \cdot h_l \cdot pr_w \cdot (-pl_{a,w} \cdot \phi_{t,r,l,w} - bf \cdot fit_t - bp \cdot (\phi_{t,r,l,w} + bo_t) - bg \cdot (\phi_{t,r,l,w} + \psi_{t,w}) + (vc_{t,a} + epsilon \cdot S_{t,r,l,f,a,w})) + \alpha_{t,r,l,f,a,w} + bb_a \cdot h_l \cdot \beta_{t,r,f,a,w} \geq 0$.

$$\begin{aligned}\frac{\partial \mathcal{L}_f}{\partial I_{t,r,f,a}}: \quad & -\sum_{t' \in T} \left(ai_{t,r,f,a,t'} \cdot dr_{t'} \cdot tr_{t'} \cdot \omega_{t,r} \right) + \sum_{t' \in T} \left(ai_{t,r,f,a,t'} \cdot dr_{t'} \cdot tr_{t'} \cdot fc_{t,a} \right) \\ + \sum_{t' \in T} & \left(ai_{t,r,f,a,t'} \cdot dr_{t'} \cdot tr_{t'} \cdot ic_{t,a} \cdot \frac{(1+ir)^{tl_a} \cdot ir}{(1+ir)^{tl_a} - 1} \right) + \sum_{t' \in T} \left(ai_{t,r,f,a,t'} \cdot \gamma_{t,r,f,a} \right) \\ & - \sum_{l \in L} \sum_{w \in W} av_{r,l,a,w} \cdot \sum_{t' \in T} \left(ai_{t,r,f,a,t'} \cdot \alpha_{t,r,l,f,a,w} \right) \geq 0 \\ & \perp I_{t,r,f,a} \geq 0 \qquad \forall t, r, f, a, w.\end{aligned} \tag{4.4}$$

Arbitrageur's maximization problem: linkage between model regions

Model regions are linked by introducing an arbitrageur, as described in Traber and Kemfert (2013), who takes advantage of different price levels across regions. Modeling an arbitrageur, rather than allowing producers to export electricity to another region, is purely due to computational reasons (reducing the amount of variables). The pay-off function of the arbitrageur Π_{ARB} can be written as shown in (4.5a) to (4.5c). Line (4.5a) defines the revenues gained from trading electricity across regions ($\mathrm{E}_{t,r,l,r',w}$), considering transmission losses ($\mathrm{lo}_{r,r'}$). Transmission losses are assumed to be linear, depending on the average distance between regions. Transmission capacities ($\mathrm{fp}_{t,r,r'}$) are restricted as defined in (4.5b). Line (4.5c) is the typical non-negativity constraint.

$$\max_{E_{t,r,l,r',w}} \Pi_{ARB} = \sum_{t \in T} dr_t \cdot tr_t \cdot pr_w \cdot \tag{4.5a}$$

$$\sum_{r \in R} \sum_{l \in L} \sum_{r' \in R} \sum_{w \in W} \left(\left(h_l \cdot pr_w \cdot (\phi_{t,r',l,w} \cdot lo_{r,r'} - \phi_{t,r,l,w} \right) \cdot E_{t,r,l,r',w} \right)$$

s.t.

$$E_{t,r,l,r',w} - fp_{t,r,r'} \leq 0 \qquad (\chi_{t,r,l,r',w}) \qquad \forall t, r, l, r', w. \tag{4.5b}$$

$$E_{t,r,l,r',w} \geq 0 \tag{4.5c}$$

The Karush-Kuhn-Tucker condition from the Lagrangian $\mathcal{L}_{ARB}$ of the arbitrageur's maximization problem with regard to electricity transports is shown in Equation 4.6. The arbitrageur transports electricity between two regions if the market price of the import region accounting for transmission losses is greater than or equal to the market price in the export region plus the congestion fee ($\chi_{t,r,l,r',w}$). The congestion fee is zero until the transmission line operates at full capacity.

$$\begin{aligned}\frac{\partial \mathcal{L}_{ARB}}{\partial E_{t,r,l,r',w}}: \quad & -dr_t \cdot tr_t \cdot h_l \cdot pr_w \cdot (lo_{r,r'} \cdot \phi_{t,r',l,w} - \phi_{t,r,l,w}) + \chi_{t,r,l,r',w} \\ & \perp E_{t,r,l,r',w} \geq 0 \qquad \forall t, r, l, r', w.\end{aligned} \tag{4.6}$$

Transmission system operator's maximization problem

The transmission system operator monitors the curtailment of fluctuating renewable generation. Due to the renewable support, renewable producers may generate electricity even if the market price is zero. The wholesale price drops to zero if the regional electricity demand is met and transfer capacities, as well as storage capacities, are operating at their capacity limit. In practice, transmission system operators order renewable generators to reduce their generation (e.g., turning wind turbines) in the event of such a situation. However, in some support schemes, renewable producers still receive the subsidy payment despite the needed curtailment.

From a modeling perspective, there is no difference between a transmission operator absorbing the electricity surplus and renewable-based producers reducing generation. Renewable curtailment ($M_{t,r,l,w}$) is modeled by giving the transmission system operator an incentive to take care of surplus electricity in these situations. The transmission system operator receives the price difference between the defined minimum electricity price ($\bar{\phi} \leq 1.0 \cdot E^{-5}$) and the actual wholesale price per curtailed unit. In other words, the transmission system operator increases the electricity demand until the wholesale price increases to the defined minimum. Given no further restrictions, the transmission system operator's profit is zero in all possible scenarios as the price difference converges to zero in the equilibrium ($\bar{\phi} - \phi_{t,r,l,w} = 0$). It is important to note that electricity generators receive the renewable subsidy for their generation. The resulting profit function is stated in Line (4.7a). Line (4.7b) is the typical non-negativity constraint.

$$\max_{M_{t,r,l,w}} \Pi_{TSO} = \sum_{t \in T} dr_t \cdot tr_t \cdot pr_w \cdot \left[\sum_{r \in R} \sum_{l \in L} (h_l \cdot pr_w \cdot \left(\bar{\phi} - \phi_{t,r,l,w}\right) \cdot M_{t,r,l,w}) \right] \quad (4.7a)$$

$$s.t.$$

$$M_{t,r,l,w} \geq 0 \quad (4.7b)$$

The Karush-Kuhn-Tucker condition from the Lagrangian $\mathcal{L}_{TSO}$ of the transmission system operator's maximization problem with regard to renewable curtailment ($M_{t,r,l,w}$) is shown in Equation 4.8. From a modeling perspective, the transmission system operator absorbs electricity (or in other words, increases electricity demand) as long as the wholesale price is below the defined limit ($\bar{\phi} \leq 1.0 \cdot E^{-5}$) for the electricity price.

$$\frac{\partial \mathcal{L}_{TSO}}{\partial M_{t,r,l,w}} : \quad \phi_{t,r,l,w} - \bar{\phi} \geq 0 \quad \perp M_{t,r,l,w} \geq 0 \qquad \forall t, r, l, w. \quad (4.8)$$

Market clearing conditions

In addition to the derived first-order conditions of the European electricity producer, the arbitrageur and the transmission system operator, three market clearing conditions define the equilibrium of the market. Equation 4.9 ensures that the hourly regional electricity demand ($\mathrm{d}_{t,r,l}$) is satisfied by domestic or foreign electricity supply. Electricity demand is assumed to be price inelastic as real-time elasticity of electricity demand seems to be rather low.[54] The charging of storages ($\mathrm{P}_{t,r,l,f,a,w}$) and renewable curtailment ($\mathrm{M}_{t,r,l,w}$) increase the fixed electricity demand at the specific load level.

$$\begin{aligned} d_{t,r,l} + \sum_{f \in F} \sum_{a \in B} \left(P_{t,r,l,f,a,w}\right) + M_{t,r,l,w} - \sum_{f \in F} \sum_{a \in A} \left(S_{t,r,l,f,a,w}\right) \\ - \sum_{r' \in R} \left(lo_{r,r'} \cdot E_{t,r,l,r',w}\right) + \sum_{r' \in R} \left(E_{t,r',l,r,w}\right) = 0 \quad \phi_{t,r,l,w} \ free \qquad \forall t,r,l,w. \end{aligned} \tag{4.9}$$

Equation 4.10 is the market clearing condition for the green certificate market. When renewables are subsidized by a quota obligation, this condition defines the demanded RES-E generation and sets a market price for green certificates (ψ_t). The demanded renewable target refers to the total renewable generation in all regions (Europe-wide). It is important to note that a higher renewable generation than demanded leads to certificate prices equal to zero. Moreover, curtailed energy does not contribute to the renewable generation target.

$$\begin{aligned} \sum_{r \in R} \sum_{l \in L} \sum_{f \in F} \sum_{a \in Q} \left(h_l \cdot S_{t,r,l,f,a,w}\right) - \sum_{r \in R} \sum_{l \in L} \left(h_l \cdot M_{t,r,l,w}\right) \\ -qu_t \cdot \sum_{r \in R} \sum_{l \in L} \left(h_l \cdot d_{t,r,l}\right) \geq 0 \quad \perp \psi_{t,w} \geq 0 \qquad \forall t,w. \end{aligned} \tag{4.10}$$

Equation 4.11 is the market clearing condition for the capacity reserve market. It ensures that a politically defined amount of securely available capacity ($\mathrm{dp}_{t,r}$) is installed in each region. Given limited cross-border transmission capacities, the almost simultaneous occurrence of peak loads across Europe and the need for regional flexible generation to control the grid frequency, it is unclear to what extent capacities in other regions are able to contribute to the securely available capacity. Thus, it is assumed that only regional power plants can participate in the regional capacity reserve markets.

$$\begin{aligned} \sum_{a \in A} \left(ca_a \cdot \left(ec_{t,r,f,a} + \sum_{t' \in T} \left(bi_{t,r,f,a,t'} \cdot I_{t,r,f,a}\right)\right)\right) - dp_{t,r} \geq 0 \\ \perp \omega_{t,r} \geq 0 \qquad \forall t,r. \end{aligned} \tag{4.11}$$

[54] Price elasticity of demand is defined as the percentage change in quantity demanded given a one percent change in price ($\eta = \frac{dQ/Q}{dP/P}$). Empirical data on real-time elasticity of electricity demand can be found in Lijesen (2007).

The model is defined by the first-order conditions (4.2 - 4.4) and restrictions (4.1h - 4.1k) of the European electricity producer; the first-order condition (4.6) and the restrictions (4.5b - 4.5c) of the arbitrageur, the first-order condition (4.8) and the restriction (4.7b) of the transmission system operator as well as the market clearing conditions (4.9 - 4.11). Modeling eight regions and ten technologies up to 2070 in ten year time steps, the model contains of about 32,000 variables/constraints. The PATH solver tends to not converge when modeling a renewable policy. Hence, the solution of the system with no support is always used as a first starting point. Then, tariffs or quotas are increased over up to 100 iterations, each time using the previous solution as new starting point.

4.3.2 Assumptions

The model results are based on many assumptions including the regional electricity demand development, net transfer capacities between regions, existing power plants, technical and economic parameters for power plant investments and fuel and CO_2 prices. It is clear that the scenario setting chosen for this analysis is only one possible development and should not be interpreted as a forecast. The assumptions are based on several databases such as IEA (2011), Prognos/EWI/GWS (2010), ENTSO-E (2011b) and EWI (2011).

Net electricity demand

The scenarios assume a similar demand development as described in EWI (2011). Yearly net electricity demand is assumed to increase in all regions until 2050. A strong increase, 0.7-1.95 % per year, is assumed until 2020, in particular due to the further economic development in Southern Europe. In the long term, growth rates are assumed to decrease to 0-1.35 % per year, among others, due to the application of energy efficient technologies. Two load levels (base and peak) are modeled based on the structure of the load duration curve in 2009 (ENTSO-E, 2011b). In the scenarios, peak load is defined as the average of the 10 % highest electricity load levels. The demand structure, referring to the ratio between peak and base load, is assumed to remain as in 2009. Thus, base demand (l_1) occurs in 7970 hours and peak demand (l_2) in 790 hours each year. Table 4.2 depicts the two assumed load levels, absolute peak demand and the resulting annual electricity consumption for each region from 2020 to 2050.

TABLE 4.2: Electricity loads [GW] and annual (net) electricity demand [TWh]

			ATCH	BNL	FR	GER	IB	IT	SCAN	UK
2020	l_1	GW	15.5	26.0	57.7	68.0	42.1	43.2	48.0	49.4
	l_2	GW	21.5	33.6	83.2	90.2	56.1	57.2	67.6	69.5
	dp	GW	23.7	37.0	91.5	99.2	61.8	62.9	74.4	76.5
	annual	TWh	140.2	233.9	525.4	613.6	379.5	389.8	435.8	448.4
2030	l_1	GW	16.5	27.7	61.5	70.1	48.4	42.1	51.2	52.6
	l_2	GW	22.9	35.8	88.7	92.9	64.6	56.1	72.1	74.1
	dp	GW	25.2	39.4	97.5	102.2	71.0	61.8	79.3	81.6
	annual	TWh	149.4	249.3	560.1	632.1	436.6	379.5	464.6	478.0
2040	l_1	GW	17.5	29.4	65.2	70.1	55.4	48.4	54.3	55.8
	l_2	GW	24.3	38.0	94.1	92.9	73.9	64.6	76.5	78.7
	dp	GW	26.8	41.8	103.5	102.2	81.3	71.0	84.1	86.5
	annual	TWh	158.5	264.5	594.3	632.1	499.8	436.6	492.9	507.1
2050	l_1	GW	18.5	31.1	68.9	70.1	63.1	55.4	57.3	58.9
	l_2	GW	25.7	40.1	99.3	92.9	84.3	73.9	80.7	83.0
	dp	GW	28.3	44.2	109.2	102.2	92.7	81.3	88.8	91.3
	annual	TWh	167.4	279.3	627.4	632.1	569.6	499.8	520.4	535.4

Remark: Austria-Switzerland (ATCH); BeNeLux (BNL); France (FR); Germany (GER); Iberian Peninsula (IB); Italy (IT); Scandinavia (SCAN) and United Kingdom (UK).

Technologies and generation costs

The model includes conventional, renewable and storage technologies. The regional existing power plant fleet is based on the power plant database of the Institute of Energy Economics at the University of Cologne. Power plant data including net capacity, efficiency factors and location has been collected from a multitude of different sources (including company reports and Platts database 2012). Table 4.3 gives an overview of the technical and economic parameters of the modeled technologies. The assumptions are based on different databases such as IEA (2011), Prognos/EWI/GWS (2010) and EWI (2011). Additionally, it is assumed that lignite-fired power plants emit 0.406 t CO_2 /MWh_{th}, hard-coal plants 0.335 t CO_2 /MWh_{th} and natural gas-fired plants 0.201 t CO_2 /MWh_{th}.

Table 4.3: Technical and economic parameters of generation technologies

Technology	FOM costs [EUR_{2010}/kWa]	Lifetime [a]	Efficiency (η_{load}) [%]	Capacity factor [%]
Nuclear	97	60	33.0	85
Lignite	43	40	42.5	87
Hard-coal	36	40	47.0	87
CCGT	28	30	57.0	87
OCGT	17	20	27.0	87
Pump-Storage	12	100	87.0 (83.0)	70
CAES-Storage	10	30	86.0 (81.0)	50
Hydro resevoir and river	12	100	-	50
Biomass	120	30	40.0	85
Photovoltaics	30	20	-	0
Wind onshore	41	20	-	5
Wind offshore	150	20	-	5

Compared to today, investment costs of renewable technologies, and particularly of photovoltaics, are assumed to decrease significantly until 2050. To determine the annual capital costs, as described in line (4.1g) of the electricity producer's maximization problem, a technology-independent interest rate of 10 % is assumed. Table 4.4 shows the assumed development of investment costs for the different technologies.

Due to the limited potential, hydro reservoirs, run-of-river and pump storage facilities are not considered as an investment option. Investments in nuclear power plants are restricted to the countries already using nuclear power today. Moreover, total regional nuclear capacity is bounded by today's existing capacity. In Germany, nuclear power generation is prohibited due to the nuclear phase-out starting from 2020 (actually planned for 2022). Furthermore, fuel bounds apply for lignite and biomass plants. Additionally, regional wind and solar capacities are bounded by regional space potentials.

Table 4.4: Investment costs of technologies [EUR_{2010}/kW]

	2020	2030	2040	2050
Nuclear	3,300	3,300	3,300	3,300
Lignite	1,850	1,850	1,850	1,850
Hard-coal	1,500	1,500	1,500	1,500
CCGT	950	950	950	950
OCGT	400	400	400	400
CAES-Storage	850	850	850	850
Biomass (gas)	2,400	2,400	2,400	2,400
Biomass (solid)	3,000	3,000	3,000	3,000
Photovoltaics	1,300	950	800	750
Wind onshore	1,350	1,150	1,100	1,100
Wind offshore	3,150	2,950	2,850	2,800

The fluctuating feed-in of wind and solar technologies is approximated by different availability factors at each load level, as shown in Table 4.5. At each load level, a low and high wind and solar availability is modeled based on the empirical data of 2007-2010, in total four dispatch situations.[55] The low availability represents the 30 % quantile and the high value represents the 70 % quantile at the respective load level. Varying regional renewable conditions are reflected by different full load hours. In addition, uncertainty concerning annual full load hours of wind and solar technologies is represented by a low-average-high wind (solar) year. In the low (high) wind year, full load hours are 20 % lower (higher) than in the average year. The negative correlation between wind and solar power is approximated by assuming 10 % higher (lower) full load hours of solar technologies in the low (high) wind year. It is further assumed that the average weather year w_2 occurs with a probability of 60 % and the weather years w_1 and w_3 with a probability of 20 %.

TABLE 4.5: Availability of fluctuating renewables for $w_1/w_2/w_3$ [% or MW/MW$_{inst.}$]

		base		peak		
		low	high	low	high	full load hours
Solar						
	ATCH	5/5/4	23/21/19	1/1/1	11/10/9	1155/1050/945
	BNL	5/4/4	19/17/15	1/1/1	6/6/5	963/875/788
	FR	4/3/3	28/26/23	2/2/1	12/11/10	1320/1200/1080
	GER	5/4/4	20/18/16	1/1/1	9/8/7	1018/925/833
	IB	4/4/3	34/31/28	3/3/2	18/16/14	1595/1450/1305
	IT	4/3/3	33/30/27	3/3/2	17/15/14	1540/1400/1260
	SCAN	5/4/4	17/16/14	0/0/0	2/2/2	880/800/720
	UK	4/4/3	19/17/16	1/1/1	6/5/5	946/860/774
Wind onshore						
	ATCH	10/12/15	20/24/29	2/2/3	26/33/39	1280/1600/1920
	BNL	12/15/18	32/40/47	9/12/14	36/45/54	1920/2400/2880
	FR	12/15/18	29/37/44	13/16/20	35/44/53	1840/2300/2760
	GER	11/13/16	23/28/34	6/8/9	21/26/31	1440/1800/2160
	IB	13/16/19	21/27/32	10/13/15	27/34/41	1520/1900/2280
	IT	10/12/15	16/20/24	8/9/11	21/26/31	1140/1425/1710
	SCAN	7/9/11	41/51/61	15/18/22	45/56/67	2160/2700/3240
	UK	16/19/23	44/55/66	17/21/26	42/52/63	2600/3250/3900
Wind offshore						
	BNL	21/26/31	53/66/79	23/29/35	46/57/69	3200/4000/4800
	FR	17/21/26	41/51/61	25/31/37	40/50/60	2560/3200/3840
	GER	19/24/29	40/50/61	17/21/25	28/35/42	2560/3200/3840
	IB	14/17/21	23/28/34	14/17/21	24/30/36	1600/2000/2400
	IT	12/15/19	20/25/31	12/16/19	22/27/33	1440/1800/2160
	SCAN	27/34/40	45/56/68	30/37/45	53/67/80	3200/4000/4800
	UK	17/21/25	49/61/73	27/34/41	41/51/62	2880/3600/4320

Remark: Austria-Switzerland (ATCH); BeNeLux (BNL); France (FR); Germany (GER); Iberian Peninsula (IB); Italy (IT); Scandinavia (SCAN) and United Kingdom (UK).

The assumed fuel prices are based on international market prices and transportation costs to the power plants. The price for hard coal is assumed to increase from 11.9

[55]The assumed full load hours are based on hourly wind speeds and solar radiation from EuroWind (2011).

EUR_{2010}/MWh_{th} in 2010 to 12.7 EUR_{2010}/MWh_{th} in 2050. For domestic lignite a constant price of 1.4 EUR_{2010}/MWh_{th} is assumed. Despite the current excess supply and low prices of natural gas, a significant increase up to 25.3 EUR_{2010}/MWh_{th} is assumed for the long term. The price for biomass is assumed to increase up to 37.5-85.1 EUR_{2010}/MWh_{th}. In addition to the modeled renewable target, an increasing tax on CO_2 emissions of up to 20.0 EUR_{2010}/t CO_2 in 2050 is assumed. Table 4.6 shows the assumed development of fuel prices for thermal power plants in the scenarios.

TABLE 4.6: Fuel [EUR_{2010}/MWh_{th}] and CO_2 prices [EUR_{2010}/t CO_2]

	2020	2030	2040	2050
Nuclear	3.3	3.3	3.3	3.3
Lignite	1.4	1.4	1.4	1.4
Hard-coal	11.5	11.7	12.2	12.7
Natural gas	18.2	22.3	23.7	25.3
Biomass	0.1-27.7-67.2	0.1-34.9-72.9	0.1-35.1-78.8	0.1-37.7-85.1
CO_2 price [EUR_{2010}/t CO_2]	15.0	17.5	20.0	20.0

Net transfer capacities

Due to computational constraints, only a limited number of regions can be modeled. Within each region, limited transmission capacities cannot be considered. Hence, in all modeled scenarios a substantial increase of transmission capacities in Europe is assumed. For example, grid extensions have to be large enough within the United Kingdom to transport large amounts of wind energy along the northern and western coastlines to central England.

However, the model considers transfer restrictions between model regions based on net transfer capacities. In the scenarios, a similar extension of cross-border transmission capacities as described in EWI (2011) is assumed. In 2050, total cross-border capacities are assumed to be more than five times as large as today's levels. Table 4.7 lists assumed net transfer capacities between model regions.

Table 4.7: Assumed net transfer capacities between model regions [GW]

		2020	2030	2040	2050
Austria-Switzerland (ATCH)	France (FR)	3.0	3.0	3.0	3.2
Austria-Switzerland (ATCH)	Germany (GER)	3.2	3.2	3.2	5.9
Austria-Switzerland (ATCH)	Italy (IT)	1.4	1.4	2.4	5.0
BeNeLux (BNL)	France (FR)	3.2	3.2	4.2	4.2
BeNeLux (BNL)	United Kingdom (UK)	1.0	1.0	1.0	1.0
BeNeLux (BNL)	Germany (GER)	3.9	5.8	5.8	6.7
BeNeLux (BNL)	Scandinavia (SCAN)	0.7	2.8	2.8	2.8
France (FR)	United Kingdom (UK)	2.6	3.6	3.6	3.6
France (FR)	Germany (GER)	3.1	3.1	3.1	3.1
France (FR)	Iberian Peninsula (IB)	1.2	3.5	3.5	4.7
France (FR)	Italy (IT)	2.4	3.0	3.0	4.0
Germany (GER)	Scandinavia (SCAN)	2.1	2.6	4.2	14.2
Scandinavia (SCAN)	United Kingdom (UK)	0.0	1.4	1.4	1.4

4.3.3 Simulation results

In this section, the model results for the scenario with *'no renewable support'*, as well as the renewable policies *'feed-in tariff'*, *'fixed bonus'* and *'renewable quota obligation'* to achieve a renewable share of 60 % in 2050 (2020: 30 %, 2030: 40 % and 2040: 50 %) are presented. First, the development of the electricity market based on the capacity and generation mix as well as the prices (wholesale, renewable and capacity) are presented. Second, the financial risk for renewable-based electricity producers under the different policies is analyzed by comparing the variance in profits. All numerical data can be found in Tables 4.8 and 4.9.

Effects on the electricity mix

If no renewable support mechanism is in place, the capacity mix remains relatively similar to today. Base-load generation takes place in nuclear (limited as per political assumption) and lignite power plants (limited due to fuel availability). The assumed increasing electricity demand is mainly met by additional hard-coal power plants. Open cycle gas turbines are installed as back-up capacities, which only achieve about 600-700 full load hours per year but are nonetheless profitable because of the capacity payments. A few investments in wind turbines (onshore at the most favorable sites in the United Kingdom) take place in 2040 due to the assumed capital cost reduction as well as increasing CO_2 and fuel prices of conventional plants. These investments in wind turbines are profitable without any subsidies. Given the increasing electricity demand, the share of renewable generation, mainly in already existing hydro plants, decreases to about 15-17 % in 2050. Annual generation from fluctuating renewables differs between years and is balanced by conventional technologies (mainly gas-fired plants). As a result, wholesale prices of electricity vary throughout the weather years. However, the effect is rather small in the scenario with no renewable support due to the limited deployment of these technologies. Moreover, electricity prices rise in all regions up to 2050 due to the assumed increase in electricity demand as well as CO_2 and fuel prices. Price differences across regions tend to decrease due to the further development of the European transmission network and the increase in demand (both assumptions).[56] Regional capacity prices range from 39 to 87 EUR_{2010}/kWa.[57] Given the scenario assumptions, open-cycle gas turbines are the cheapest option to provide additional securely available capacity.

Under all renewable policies, the achievement of a 60 % renewable share of the total electricity generation in 2050 (2020: 30 %, 2030: 40 % and 2040: 50 %) leads to a stepwise reduction in traditional base-load capacities such as nuclear and hard-coal power plants.[58] The remaining non-renewable generation is provided mostly by combined and open cycle gas turbines due to decreasing full load hours of conventional plants and a more favorable operating/capital cost ratio. In 2020, the demanded RES-E generation is provided by hydro facilities (about 50 %) and onshore wind turbines (about 40 %). In the long term, the renewable generation is more technologically and geographically diversified: offshore wind in the United Kingdom and the Benelux (about 25 %); onshore wind in France, United Kingdom and Germany (about 25 %); solar power plants in Italy, Spain and France (about 25 %); hydro in Scandinavia and Austria (about 20 %) and biomass in Germany, France and Italy (about 5 %). Electricity prices (wholesale) decrease over time due to the price lowering effect of renewable energies (merit order effect). Large wind and solar capacities, a result of subsidies, push the merit order to the right as marginal costs of these technologies are negligible. Hence, technologies with lower marginal costs are price setting in more hours. In 2050, wholesale prices are about 25 % lower than in the scenario with no renewable support. In the policy scenarios, the increase in intermittent generation, has a large influence with respect to generation, electricity prices and renewable curtailment due to the large deployment of wind and solar technologies.

[56]Long-term price differences occur in spatial markets when technologies with marginal cost differences are available in only some regions and transport capacities are limited (or significant transport losses/-costs apply). A few such resources exist in the European power sector: large hydro facilities (Austria, Switzerland and Scandinavia), large nuclear capacities (France) and lignite-fired plants (Germany).

[57]The common capacity price of 74 EUR_{2010}/kWa represents the annualized fixed costs of an open cycle gas turbine over 20 years. Particularly remarkable is the capacity situation in Germany in 2020. Due to the phase-out of nuclear power in Germany (the scenarios assume no nuclear power in 2020), substantial investments in securley available capacities are needed. In 2030, these capacities have been commissioned and old wind and solar capacities (capacities that were built under the feed-in tariff support before 2012 and reached their technical lifetime before 2030) are replaced by coal capacities. Therefore, the capacity situation is less tense in 2030 compared to 2020. As a result, capacity prices are high in 2020 and relatively low in 2030.

[58]The renewable policies are designed such that the last capacity to achieve the renewable target can remunerate its capital costs. The resulting feed-in tariffs, bonus payments and certificate prices are depicted in Table 4.9.

Under a *'feed-in tariff'* policy, the renewable electricity mix is simply optimized based on levelized costs of electricity. Operators of non-subsidized technologies (nuclear, conventional and storages) react to the higher or lower annual renewable generation. Thus, electricity generation, renewable curtailment, electricity prices and electricity transports vary among weather years depending on the availability of wind and solar generation. Reaching the renewable target through feed-in tariffs reduces the sectoral welfare[59] by about 217 bn. EUR_{2010} compared to the scenario with *'no renewable support'*.

The hourly and regional price signals under a *'fixed bonus'* policy lead to a more efficient mix of renewable capacities. Given limited cost-efficient electricity storage options, the value of electricity depends on a specific point in time. When integrating the hourly price signal into renewable support mechanisms, investors consider the hourly value of electricity and compare it to the production profiles of technologies with intermittent power generation, rather than simply minimize levelized costs of electricity. Reaching the renewable target through a fixed bonus policy reduces the sectoral welfare by about 194 bn. EUR_{2010} compared to the scenario with *'no renewable support'*.

Under a *'renewable quota obligation'* without the option of banking and borrowing, the renewable target is expected to be reached in all weather years. Hence, more renewable energies and a greater mix of technologies are deployed, allowing the target to be achieved even in weather years with low generation from fluctuating renewables. Due to the stochastic generation of wind and solar capacities, green certificate prices vary significantly between weather years. As wind power is the dominant renewable technology (and hence largely deployed under the scenario assumptions), certificate prices are low or even zero in high wind years (w_3). In the low wind year (w_1), green certificate prices are relatively high due to the utilization of more costly biomass technologies. Moreover, certificate prices are greater than short-term marginal costs if an additional capacity must be built in order to achieve the renewable target within the specific period. Thus, expecting the renewable target to be reached in every single year increases the policy costs and reduces sectoral welfare. Given the scenario assumptions, reaching the renewable target through a renewable quota obligation, reduces the sectoral welfare by about 213 bn. EUR_{2010} compared to the scenario with *'no renewable support'*.

[59]Within the electricity market model, total welfare is defined as the sum of the producer profit, arbitrageur surplus and the consumer surplus (differences in electricity costs given fixed electricity demand) under the consideration of renewable and capacity payments. Given this definition of sectoral welfare, potential benefits of renewable policies such as fewer emissions, positive employment effects and lower imports of fossil fuels are not considered. Thus, the welfare effect of all modeled renewable policies is, by definition, negative compared to the *'no support scenario'*.

Table 4.8: Overview of model results I – capacities and annual generation in Europe for weather years $w_1/w_2/w_3$

		Net capacities [GW]				Net generation (adjusted by curtailment) [TWh]			
		2020	2030	2040	2050	2020	2030	2040	2050
'no subsidy'	Nuclear	104	79	118	132	771/771/771	583/583/583	874/874/874	978/978/978
	Hard-coal	82	158	223	257	626/626/624	1207/1207/1207	1702/1702/1702	1955/1955/1937
	Lignite	18	18	18	18	140/140/140	140/140/140	140/140/140	140/140/140
	Natural gas	289	295	241	242	1065/1051/1040	1007/1007/1007	346/314/283	243/211/196
	Storages	33	33	33	33	14/14/14	14/14/14	14/14/14	14/14/14
	Wind	39	1	50	50	64/81/97	3/4/4	130/163/195	130/163/195
	Solar	24	5	0	0	29/26/24	7/7/6	0/0/0	0/0/0
	Biomass	15	8	2	2	20/20/20	15/15/15	14/14/14	14/14/14
	Hydro	124	124	124	124	444/444/444	444/444/444	444/444/444	444/444/444
	RES-E share [%]					18/18/18	14/14/14	16/17/18	15/16/17
'feed-in tariff'	Nuclear	104	79	19	6	749/731/731	559/548/516	131/131/132	47/47/47
	Hard-coal	82	47	43	52	596/572/541	333/319/312	309/309/294	295/304/297
	Lignite	17	17	18	17	128/128/128	131/131/128	136/136/136	127/127/124
	Natural gas	281	389	498	545	820/785/758	1150/1070/997	1318/1207/1111	1090/978/911
	Storages	33	33	33	33	15/14/14	17/21/21	21/21/21	19/18/19
	Wind	147	273	345	510	315/394/454	528/660/792	682/853/1023	1094/1271/1426
	Solar	24	165	434	618	29/26/24	236/220/205	640/582/524	832/756/681
	Biomass	17	10	4	2	86/86/86	43/43/43	14/14/14	14/14/14
	Hydro	124	124	124	124	444/444/444	444/444/444	444/444/444	444/444/444
	RES-E share [%]					28/30/32	37/40/43	49/52/55	61/63/65
'fixed bonus' or *'renewable quota (perf. BaB)'*	Nuclear	104	79	35	23	771/761/747	583/583/567	260/260/260	168/168/168
	Hard-coal	82	39	33	36	578/555/526	298/277/268	230/230/230	235/186/193
	Lignite	18	18	18	18	135/135/135	140/140/136	139/140/140	140/136/134
	Natural gas	282	398	497	547	795/753/723	1100/1020/954	1374/1273/1180	1178/1076/1002
	Storages	33	33	33	33	14/14/17	14/14/18	16/14/15	14/15/22
	Wind	157	273	321	424	330/412/495	528/660/792	604/756/907	930/1163/1395
	Solar	24	178	400	589	29/26/24	277/252/227	596/542/487	803/730/657
	Biomass	15	8	2	3	84/81/81	43/43/42	14/14/14	21/21/21
	Hydro	124	124	124	124	444/444/444	444/444/444	444/444/444	444/444/444
	RES-E share [%]					28/30/33	38/41/44	45/48/51	56/60/62
'renewable quota (no BaB)'	Nuclear	104	79	43	31	750/737/731	583/583/567	320/320/320	231/231/231
	Hard-coal	82	38	29	37	569/559/539	264/247/245	186/197/194	175/232/200
	Lignite	18	18	18	18	135/135/135	140/140/136	136/136/136	140/140/136
	Natural gas	280	398	477	506	759/786/759	1059/1045/984	1199/1188/1146	1026/959/1020
	Storages	33	33	33	33	14/14/17	14/14/18	19/20/20	16/14/18
	Wind	171	259	314	373	358/448/524	506/632/759	583/729/875	772/965/1158
	Solar	24	220	456	640	29/26/24	343/312/281	663/603/543	853/776/698
	Biomass	16	10	19	38	119/32/20	75/14/14	141/55/21	281/165/50
	Hydro	124	124	124	124	444/444/444	444/444/444	444/444/444	444/444/444
	RES-E share [%]					30/30/32	40/41/44	50/50/51	60/60/60

Remark: Total net electricity generation varies among weather years and scenarios due to differing electricity exchanges (transportation losses) and storage utilizations (storage losses).

Table 4.9: Overview of model results II – wholesale, capacity and RES-E prices for weather years $w_1/w_2/w_3$

		Wholesale prices [EUR_{2010}/MWh] 2020	2030	2040	2050	Capacity price [EUR_{2010}/kWa] 2020	2030	2040	2050
'no subsidy'	ATCH	46/43/42	66/54/51	67/55/55	65/62/59	69	69	68	68
	BNL	45/42/42	65/53/50	71/55/53	62/59/55	74	72	74	74
	FR	43/41/41	67/54/51	70/54/52	60/57/53	73	72	74	74
	GER	48/45/44	70/57/53	69/54/55	62/61/56	87	39	74	72
	IB	45/45/42	64/55/56	70/56/58	65/61/59	53	61	63	74
	IT	51/47/47	67/53/57	68/54/57	62/59/55	63	60	74	74
	SCAN	48/45/45	68/54/50	67/54/54	61/58/56	74	74	74	74
	UK	44/42/41	67/54/50	70/54/51	60/57/53	74	74	74	74
	RES-E price	0/0/0	0/0/0	0/0/0	0/0/0				
'feed-in tariff'	ATCH	44/43/43	66/53/51	74/58/54	51/47/45	69	70	71	72
	BNL	44/42/42	68/52/50	73/56/48	33/28/28	74	74	74	74
	FR	41/40/40	58/36/32	56/38/34	61/48/45	73	74	74	74
	GER	48/45/44	68/54/52	73/59/54	43/43/43	80	57	74	74
	IB	45/45/45	40/28/28	53/38/35	67/50/50	49	74	74	74
	IT	49/48/47	63/54/54	70/55/52	62/58/58	63	68	74	74
	SCAN	29/26/22	65/49/32	73/59/50	27/22/4	74	74	74	74
	UK	41/38/38	68/53/48	72/56/48	71/59/53	74	74	74	74
	RES-E price	89/89/89	105/105/105	119/119/119	131/131/131				
'fixed bonus' or *'renewable quota (perf. BaB)'*	ATCH	44/42/42	66/54/51	74/57/53	63/50/42	70	69	71	71
	BNL	44/42/41	66/52/50	73/57/54	62/39/31	74	74	74	74
	FR	39/37/31	64/45/32	67/52/42	71/50/39	74	74	74	74
	GER	52/44/44	68/54/52	73/57/54	61/48/41	80	57	74	73
	IB	45/44/42	68/51/44	59/45/40	72/52/50	58	74	74	74
	IT	51/47/47	61/53/53	70/55/52	70/55/57	65	74	74	74
	SCAN	31/29/28	65/49/33	73/57/49	57/36/31	74	74	74	74
	UK	41/38/38	68/53/48	73/56/48	77/52/38	74	74	74	74
	RES-E price	55/55/55	57/57/57	64/64/64	87/87/87				
'renewable quota (no BaB)'	ATCH	41/43/43	55/57/51	58/53/60	52/51/61	70	70	71	71
	BNL	41/42/47	56/56/50	67/56/61	51/49/56	74	74	74	74
	FR	38/33/31	51/48/34	58/41/43	51/50/64	74	74	74	74
	GER	42/45/51	58/58/52	64/56/63	51/50/56	81	55	74	74
	IB	45/45/42	57/49/46	59/39/39	52/51/71	53	74	74	74
	IT	45/48/50	48/56/53	58/55/62	59/53/75	66	74	74	74
	SCAN	29/27/23	55/52/34	65/54/62	48/48/50	74	74	74	74
	UK	41/38/38	57/56/50	67/55/51	61/53/63	74	74	74	74
	RES-E price	272/27/0	283/0/0	274/33/0	288/47/0				

Remark: Austria-Switzerland (ATCH); BeNeLux (BNL); France (FR); Germany (GER); Iberian Peninsula (IB); Italy (IT); Scandinavia (SCAN) and United Kingdom (UK).

Investment risks under the analyzed renewable policies

To measure the financial risk of renewable-based electricity producers due to weather uncertainty, we analyze the variance in profits of investments in different renewable energies. For this purpose, we calculate annual revenues for the different weather years of an average wind turbine, photovoltaic system and biomass plant in Europe (average based on all modeled regions). We pick 10,000 different combinations of revenues considering the given weather probabilities over the technical lifetime (sampling with replacement) and subtract total capital as well as fixed operating and maintenance costs. Table 4.10 depicts the resulting variance in profits for each renewable policy.

The general idea of a renewable subsidy is that the payment that renewable-based electricity producers receive, should cover the extra costs for renewable generation compared to conventional power generation. However, as discussed in Bergek and Jacobsson (2010), technology-neutral payments (as modeled in this analysis) allow some technologies to achieve additional rents, often referred to as *'windfall or swindle profits'* (Verbruggen, 2008). Within the model environment, renewable-based electricity producers are able to achieve additional rents from low-cost renewable technologies with limited fuel (e.g., low cost biomass) or space potential (e.g., onshore wind).[60] Thus, the expected profit of the analyzed investments (average over all countries) is positive under all renewable policies. The data shows that the expected profit differs depending on the renewable policy, which makes it difficult to compare the investment risks. However, the effect of the different policies on the variance in profits is so large for most technologies that the effects seem to be clear.

TABLE 4.10: Variance in profits depending on the renewable policy [$TEUR_{2010}$/MW]

			Min	25%-Qu	Mean	Median	75%-Qu	Max	Var
Wind onshore	2020	FIT	198	404	426	427	450	657	$1.2 \cdot 10^4$
		Bo/quota (perf. BaB)	246	382	396	397	412	492	$5.2 \cdot 10^3$
		Quota (no BaB)	-110	408	581	566	745	2,588	$6.0 \cdot 10^5$
	2030	FIT	166	259	269	269	280	373	$2.5 \cdot 10^3$
		Bo/quota (perf. BaB)	188	224	227	227	230	244	$2.1 \cdot 10^2$
		Quota (no BaB)	-91	90	167	162	231	989	$1.0 \cdot 10^5$
	2040	FIT	86	126	131	131	135	176	$4.7 \cdot 10^2$
		Bo/quota (perf. BaB)	94	117	119	120	122	136	$1.1 \cdot 10^2$
		Quota (no BaB)	-12	72	99	97	122	380	$1.2 \cdot 10^4$
Wind offshore	2040	FIT	34	104	112	112	119	189	$1.4 \cdot 10^3$
		Bo/quota (perf. BaB)	56	95	101	101	107	155	$7.4 \cdot 10^2$
		Quota (no BaB)	-76	61	101	97	139	571	$3.4 \cdot 10^4$
PV	2030	FIT	90	120	123	123	126	156	$2.5 \cdot 10^2$
		Bo/quota (perf. BaB)	51	89	94	94	99	140	$5.3 \cdot 10^2$
		Quota (no BaB)	-109	33	102	99	168	849	$8.9 \cdot 10^4$
	2040	FIT	57	70	71	71	73	85	$4.7 \cdot 10^1$
		Bo/quota (perf. BaB)	36	49	50	50	52	65	$4.7 \cdot 10^1$
		Quota	-40	35	59	57	80	321	$1.1 \cdot 10^6$
Biomass	2020	FIT	138	138	138	138	138	138	0
		Bo/quota (perf. BaB)	80	160	176	175	191	397	$5.4 \cdot 10^5$
		Quota (no BaB)	-2,675	-435	301	224	954	9,406	$1.0 \cdot 10^9$
	2030	FIT	112	112	112	112	112	112	0
		Bo/quota (perf. BaB)	46	128	144	143	158	350	$5.0 \cdot 10^5$
		Quota	-937	-152	159	129	437	3,861	$1.8 \cdot 10^8$

The analytical analysis in Section 4.2 indicates that market integration may actually reduce the financial risk of investments in technologies with negatively correlated fluctuations in production and wholesale/certificate prices.

Effect of market integration (fixed bonus compared to feed-in tariffs)

In the scenarios, wholesale prices vary between weather years due to the different feed-in from intermittent renewables. As wind energy is largely deployed in the scenarios, wholesale prices are typically lower in years with large feed-in from wind producers. However, considering that annual generation from intermittent renewables ranges from 2000 TWh to 2500 TWh (the difference represents about 10 % of the annual demand) in 2050, wholesale prices remain relatively stable. This implies a rather low slope of the supply function on the power market. Concerning the analytical example in Section 4.2, this refers to the case on the left side of Figure 4.2. Thus, wind energy producers actually

[60] One should keep in mind that the additional rents highly depend on the assumed potential for these technologies. Given the scenario assumptions, onshore wind remains the cheapest renewable option, followed by low-cost biomass technologies. Thus, investments in these technologies are highly profitable due to the technology-neutral incentives.

face negatively correlated fluctuations in production and wholesale prices. Hence, the variance in profits is substaintially lower (about 60-90 %) for investments in wind power under a fixed bonus incentive than under a feed-in tariff policy.

The effect is reversed for investments in solar or biomass technologies, as wholesale prices are positively correlated with energy generation. As a result, variances in profits are larger than under a feed-in tariff policy. For solar technologies, the model assumes that annual full load hours are negatively correlated to wind energy generation. As annual full load hours are in reality not perfectly negatively correlated to wind generation, the increasing effect of market integration on the variance in profits is likely to be overestimated by the model. Furthermore, Table 4.10 depicts the variance for an average investment in a photovoltaic system (over all regions). In regions with large solar capacities (e.g., Southern Europe), wholesale prices react more to the availability of solar energy rather than wind energy. Thus, investors in photovoltaics on the Iberian Peninsula face a similar variance in profits under a feed-in tariff or bonus support.

Effects of a renewable quota obligation without banking and borrowing

The simulation indicates highly volatile prices of green certificates due to the fluctuations in wind and solar generation. This implies that the supply curve of renewable power generation is very steep. As marginal generation costs of wind and solar technologies are negligible, certificate prices become zero in years with large feed-in from wind and solar technologies (if banking and borrowing is not allowed). In years with limited feed-in from intermittent technologies, certificate prices are determined by the long-run marginal costs of wind and solar technologies and thus certificate prices are relatively high.

Because certificate prices vary significantly among weather years in the analyzed scenario, the price effect is relatively large compared to the fluctuations in electricity generation. Thus, the financial risk of investments in all renewable energies is higher under a quota obligation (without the option of banking and borrowing) compared to feed-in tariffs and bonus incentives. However, this remains the extreme case, as the renewable target has to be achieved in every single year independently of the availability of wind and solar technologies. An appropriate banking and borrowing mechanism may be able to reduce the price volatility considerably and, as such, reduce the financial risk of green electricity producers.

4.4 Conclusion

In recent years, many countries have implemented policies to incentivize renewable power generation. The analysis shows that renewable-based electricity producers face different risks under the various policies. The effect of weather uncertainty on the financial risk of green electricity producers is not obvious and depends on the function of the supply curve of dispatchable plants. The numerical simulation indicates a risk lowering effect of market integration for wind energy producers but higher risks for solar and biomass suppliers. Furthermore, all renewable-based electricity producers face larger variances in profits under a European renewable quota obligation when banking and borrowing is not an option.

It is an ongoing debate as to if and how renewable energies should be promoted in Europe once the envisaged national renewable targets of the National Renewable Energy Action Plans in 2020 have been achieved. Following the discussion of a European renewable quota after 2020, the analysis indicates the importance of an appropriate banking and borrowing mechanism to reduce the risk for producers in light of a greater penetration of stochastic wind and solar generation. Moreover, national renewable quotas, as opposed to a European quota, would be even more affected by fluctuations in intermittent renewable generation and could thus be questioned as the appropriate instrument to promote renewable energies.

The analysis neglects a few important aspects: First, we concentrate on the effect of weather uncertainty under various renewable policies. However, weather is obviously not the only source for uncertainty. Thus, it would be interesting to analyze the effect of other uncertainties on the investment risk under the different policies. Second, the analysis assumes risk-neutral investors, but Ehrenmann and Smeers (2011) show that the risk-neutral analysis may miss a shift towards less capital-intensive technologies that may result from risk aversion. This is particularly interesting due to the capital intensity of most renewable technologies. Third, it would be desirable to explicitly model the policy option of the 'banking and borrowing' of certificates as an instrument to reduce the investment risk under a renewable quota obligation. In particular, determining how long banking periods would have to be in order to significantly reduce the investment risks would be an interesting research question.

Chapter 5

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

5.1 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 renewables. 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 are concentrating solar power plants (CSP) equipped with thermal storage units (TES). 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 kilowatt hour due to a higher usage of the capital-intensive power plant block.

Today, demand in European electricity systems has a midday peak when solar radiation is also highest. Thus, electricity prices are above average when CSP plants can directly feed into the grid. When stored thermal energy is used to generate electricity, such as during night hours, electricity is often produced in hours with comparatively low prices.[61] However, the structure of the hourly price curve depends on the specific characteristics of the electricity system. Particularly, a higher share of solar technologies could reverse the midday peak. In line with the discussion in Joskow (2011), feed-in-tariffs may set an inefficient incentive in today's electricity markets to invest in thermal storage units for concentrating solar plants, as flat tariffs do not consider the hourly price curve and different feed-in structures of renewables.

In this paper, we analyze the value of solar power in today's electricity markets and thereupon discuss the efficiency of flat feed-in tariffs to promote renewable power generation. Furthermore, we estimate the value of thermal energy storages in CSP plants depending on the share of fluctuating renewables.

A number of studies analyze the technical, geographical and economical feasibility of solar energy to supply a significant share of the electricity demand. This includes the assessment of the technical feasibility of balancing demand and generation in high-solar scenarios as well as the economic value of 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 principle 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 photovoltaic and CSP plants in the long term. Horn et al. (2004) analyze specific CSP projects in Egypt and come to the conclusion that levelized cost of electricity of integrated solar combined cycle systems (3.1 US ct/kWh) are in the range of the costs of conventional power plants.

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 concentrating solar power 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

[61]TES can also be used to shift generation to early evening hours when, in some markets, demand and thus prices are even higher than at midday. However, electricity prices are on average higher in hours with high sun radiation.

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 power 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, this is the first paper analyzing the value of thermal energy storages as a function of the overall generation mix. Second, the simulation results indicate that flat feed-in tariffs to promote renewable power generation set an inefficient incentive to invest in thermal energy storages for CSP plants. To estimate the value of solar power in today's electricity markets, we compare the hourly wholesale prices of electricity to the solar radiation in France, Germany, Spain and Portugal from 2007 to 2010. To analyze the value of thermal energy storages as a function of the overall generation mix, we use a simulation approach, calibrating the use of CSP to the electricity market of the Iberian Peninsula. We see three potential advantages 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 compared to all other investment options that could contribute to meeting demand cost-efficiently. Third, the price curve within our electricity market model is endogenously determined and the influence of investments in generation or storage technologies is captured by the structure of the price curve.

We find that electricity prices are usually higher than average when CSP plants can directly feed into the grid. Therefore, thermal energy storages in concentrating solar power plants are not cost-efficient in today's electricity markets. Hence, we argue that flat feed-in tariffs to promote renewable power generation set an inefficient incentive to invest in thermal storages by neglecting market price signals. However, results of the simulation model show that integrated 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 renewables, electricity prices may vary substantially as a result of the volatile residual load. The results of the model simulation indicate that thermal storage capacities in CSP plants, in addition to other balancing options, may be able to balance generation from fluctuating renewables and demand in order to keep the residual load more or less constant in most hours.

The remainder of the paper is structured as follows: In Section 5.2, we compare the hourly wholesale prices of electricity to the solar radiation in France, Germany, Spain and Portugal from 2007 to 2010. In Section 5.3, the simulation approach analyzing the value of thermal energy storages as a function of the overall generation mix is presented with a detailed model description and assumptions. In Section 5.4, 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 5.5, providing an outlook of further possible research.

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

In liberalized electricity markets, wholesale prices represent the market result of supply and demand for a specific point in time. Given a large share of dispatchable power plants, the cost curve of electricity supply does not significantly differ between hours. Therefore, 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 peak (or early evening) when electricity demand is highest.

As solar radiation also has a midday peak, electricity prices are above average when solar systems are able to directly feed into the grid. Table 5.1 lists average electricity prices (spot market) compared to different levels of solar radiation for France, Germany, Spain and Portugal from 2007 to 2010. 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 EUR/MWh). Consequently, electricity prices were 88 EUR/MWh, about 34 % higher, in hours with highest solar radiation ($>$ 800 W/m^2). The data shows 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 due the typical feed-in during hours with high electricity demand.

TABLE 5.1: Average electricity prices [EUR/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]
FR	2007	41	40	44	48	42	42	41	39	40	42
	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
GER	2007	38	36	47	46	46	46	46	44	44	46
	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
ES	2007	39	38	37	40	42	44	41	40	41	45
	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
PT	2007	52	51	54	52	57	59	56	49	49	50
	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 C.
Abbreviations: FR - France; GER - Germany; ES - Spain and PT - Portugal.
Sources: EEX (2012b), 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. 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. Moreover, the technical characteristics of the collector field, storage unit and steam turbine of CSP plants are chosen independently from each other. Given the distinct midday peak of solar radiation, TES may reduce the average generation costs, depending on the CSP technology and the site characteristics, due to the higher usage of the capital-intensive power plant block. For example, in CSP systems without integrated thermal energy storage unit, the steam turbine would be off-line for more than half of the time, even considering a large collector field, due to the distinct daily curve for solar radiation. Given an integrated storage unit, the large amount of absorbed heat during midday can be stored, when the turbine runs already 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 from renewable energies 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 fixed feed-in tariffs. Under feed-in tariffs, operators of renewable plants receive a fixed remuneration for their power generation, independent of the hourly market price. Thus, investors maximize their profit by simply minimizing the average production costs. Given a reduction in average generation costs of a CSP plant through thermal energy storages, investors have an incentive to install thermal energy storage capacity without considering the hourly price curve.

However, today's electricity prices are usually above average when CSP plants are capable of directly feeding into the grid (listed in Table 5.1). Therefore, we argue that flat feed-in tariffs set an inefficient incentive, from a system perspective, to invest in thermal energy storages for CSP plants. Under renewable incentives, including a market price signal (e.g., bonus to the hourly wholesale price), investors in CSP plants would consider the higher value (on average) of electricity during midday and install CSP systems without storage units. Concerning the efficiency of flat feed-in tariffs, the numerical analysis in Section 5.3 will focus on the following question.

- Set flat feed-in tariffs for power generation from CSP plants an inefficient incentive to invest in thermal energy units in today's electricity markets?

However, given the further deployment of intermittent renewables with negligible marginal generation costs, electricity prices will mainly be influenced by the hourly feed-in of intermittent renewables rather than the level of electricity demand. 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 often volatile electricity generation from intermittent renewables. As a result, the value of storages will arguable increase with higher shares of intermittent renewable generation. Thus, concentrating solar plants with integrated thermal storages may play a significant role in primarily renewable-based electricity systems. Concerning the value of thermal energy storages in CSP plants, the numerical analysis in Section 5.3 will focus on the following question.

- Does the value of thermal storages in CSP plants increase with the share of intermittent renewable generation?

5.3 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 dynamic linear investment and dispatch model for the Iberian Peninsula until 2050. The analysis is conducted for the Iberian Peninsula for mainly two reasons: Firstly, Spain and Portugal are countries with an annually high solar radiation and secondly Spain has worldwide the highest installed capacity of CSP plants due to a feed-in tariff system for renewable energies. A significant number of plants recently commissioned or under construction include thermal storage units (NREL, 2011), which are profitable from an investor's perspective due to the offered flat feed-in tariff (time independent).[62] The scenario analysis provides information as to whether thermal energy storage units in CSP plants are cost-efficient in today's electricity system of the Iberian Peninsula from an overall system perspective.

5.3.1 Scenario framework

In general, CSP plants are mainly characterized by three independent components. The size of the collector's field determines the amount of energy to be absorbed by the sun. Thermal energy storage units give the opportunity to shift energy to later hours. The turbine size determines the maximum electricity that can be generated at a specific point in time. The modeled CSP technologies differ with respect to storage volume and size of collector surface. The following data refers to 1 MW systems: CSP A has a collector surface of 7,376 m^2 and no storage capacity. 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, but a different solar multiple, which indicates the extent to which the solar field is over-sized in relation to the turbine capacity.[63] As depicted in Table 5.2, the size of the collector field and storage unit has a significant impact on the plant's capital costs.

TABLE 5.2: Characteristics of modeled concentrated solar power plants

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

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

In the first scenario ('illustrative scenario'), we analyze the value of thermal energy storage units in CSP plants in today's electricity market and the impact of a higher intermittent RES-E generation. It is expected that CSP plants with TES will have higher cost reductions than CSP plants without thermal storage units due to learning curve effects in regards to the storage unit. To separately analyze the effect of an increasing

[62] A list of current CSP projects in Spain can be found in Appendix C.

[63] 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).

share of intermittent RES-E generation on the value of TES (apart from potential cost reductions), today's electricity system in the Iberian Peninsula is extrapolated with an increasing share of renewables until 2050. Thus, investment costs, electricity demand as well as fuel and CO_2 prices will remain as today's values in the 'illustrative scenario'. In order to analyze the effects of an increasing share of CSP and other fluctuating RES-E generation, the following RES-E and CSP quotas are incorporated (Table 5.3).

Table 5.3: Framework of the 'illustrative scenario'

		2020	2030	2040	2050
Net electricity demand (Iberian Peninsula)	[TWh]	316.5	316.5	316.5	316.5
RES-E quota (generation of net demand)	[%]	≥ 30	≥ 40	≥ 60	≥ 80
CSP quota (generation of net demand)	[%]	≥ 3.5	≥ 10	≥ 17.5	≥ 25
Investment costs for CSP plants					
CSP A	[EUR_{2010}/kW]	3,722	3,722	3,722	3,722
CSP B	[EUR_{2010}/kW]	6,794	6,794	6,794	6,794
CSP C	[EUR_{2010}/kW]	10,082	10,082	10,082	10,082

In the second scenario ('roadmap scenario'), we analyze the potential role of CSP plants with and without thermal storage units in a potential transition to a primarily renewable-based electricity system. In contrast to the 'illustrative scenario', an increasing electricity demand and decreasing investment costs of RES-E due to learning curve effects are assumed. Additionally, only a technology-neutral quota for RES-E generation and no CSP quota is modeled. Thus, this scenario incorporates two effects potentially favoring CSP plants with storage units in the long term: First, the share of intermittent RES-E generation increases due to the RES-E quota. Second, a decreasing cost-difference between CSP plants with and without storages occurs due to the assumed investment cost of the storage units. Table 5.4 gives an overview of the key assumptions in the 'roadmap scenario'.

Table 5.4: Framework of the 'roadmap scenario'

		2020	2030	2040	2050
Net electricity demand (Iberian Peninsula)	[TWh]	377.3	432.2	493.3	560.8
RES-E quota (generation of net demand)	[%]	≥ 30	≥ 40	≥ 60	≥ 80
CSP quota (generation of net demand)	[%]	-	-	-	-
Investment costs for CSP plants					
CSP A	[EUR_{2010}/kW]	2,220	1,700	1,400	1,290
CSP B	[EUR_{2010}/kW]	3,437	2,300	2,100	1,963
CSP C	[EUR_{2010}/kW]	5,500	3,800	3,100	2,693

It should be noted that the scenario setting (further assumptions are discussed in Section 5.3.3) 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.

5.3.2 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 5.1, is to minimize discounted total system costs while meeting demand at all times. An overview of all model sets, parameters and variables is given in Table 5.5. 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 represent staff costs, insurance charges and maintenance costs. Variable costs are determined by fuel and CO_2 prices, CO_2 emission factors, net efficiencies and the amount of generation per technology. 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, Sunday and a weekday) 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 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).

$$\begin{aligned} \min \quad TCOST = \sum_{y \in Y} \sum_{c \in C} \sum_{a \in A} \Bigg[dr_y \cdot \Bigg(& AD_{y,c,a} \cdot an_a + IN_{y,c,a} \cdot fc_a \\ & + \sum_{d \in D} \sum_{h \in H} \Bigg(GE^{d,h}_{y,c,a} \cdot \left(\frac{fp_{y,a} + cp_y \cdot ef_a}{\eta_a} \right) \\ & + CU^{d,h}_{y,c,a} \cdot \left(\frac{fp_{y,a} + cp_y \cdot ef_a}{\eta_a} + ac_a \right) \Bigg) \Bigg) \Bigg] \end{aligned} \tag{5.1}$$

TABLE 5.5: Model abbreviations including sets, parameters and variables

Abbreviation	Dimension	Description
Model sets		
$a \in A$		Technologies
$c \in C$		Countries
$d \in D$		Days
$h \in H$		Hours
$y \in Y$		Years
Model parameters		
ac_a	EUR_{2010}/MWh_{el}	Attrition costs for ramp-up operation
an_a	EUR_{2010}/MW	Annuity for technology specific investment costs
cp_y	$EUR_{2010}/t\ CO_2$	Costs for CO_2 emissions
dr_y	%	Discount rate
ef_a	$t\ CO_2\ /MWh_{th}$	CO_2 emissions per fuel consumption
fc_a	EUR_{2010}/MW	Fixed operation and maintenance costs
$fp_{y,a}$	EUR_{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
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
$INJ_{y,c,a}^{d,h}$	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., 2013). The model includes the following renewable energy technologies: roof and ground photovoltaic 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.[64] In addition, the model considers several wind and solar regions within the countries to account for local conditions.

To analyze the value of thermal storage units in CSP plants, we add CSP plants with respective storage restrictions to the model. In concentrating solar plants, the heat

[64]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 wind and even smaller ones for onshore wind sites. Therefore, the model chooses offshore wind curtailment first.

of the sun is absorbed by collectors and concentrated to heat a fluid, which is then used to generate electricity in a steam turbine. The heat can be saved in a storage unit and the electricity generation can take place later (Equation 5.2). The maximum storage level is determined by the volume factor, which is the ratio of storage to turbine capacity. Equation 5.3 shows the hourly power balance of a CSP system. The injection variable represents the solar energy which is absorbed by the collectors. CSP plants with storage 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. Efficiency losses over time for stored energy in the TES are negligible (Sioshansi and Denholm, 2010) and therefore are not incorporated in the model. The change in storage level (Equation 5.4) depends on the storage operation in the specific hour taking into account losses during the charging process.[65] As we focus in the analysis on the renewable energy generation of CSP plants, 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. Hence, co-firing with natural gas is, in most cases, an option to increase the economic value of CSP plants. The modeled technical restrictions are displayed in Equations 5.2 to 5.4.

$$SLEVEL_{y,c,a}^{d,h} \leq vc_a \cdot IN_{y,c,a} \tag{5.2}$$

$$INJ_{y,c,a}^{d,h} + SOUT_{y,c,a}^{d,h} \cdot \hat{\eta}_a - GE_{y,c,a}^{d,h}/\eta_a - SIN_{y,c,a}^{d,h} = 0 \tag{5.3}$$

$$SLEVEL_{y,c,a}^{d,h+1} - SLEVEL_{y,c,a}^{d,h} = SIN_{y,b,a}^{d,h} \cdot \check{\eta}_a - SOUT_{y,c,a}^{d,h} \tag{5.4}$$

5.3.3 Common scenario assumptions

In this section, the technical and economic assumptions underlying the scenario analysis are described. The assumptions are based on several databases such as ICCS (2010), IEA (2010c), IEA (2010b), IEA (2010a), Prognos/EWI/GWS (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 Prognos/EWI/GWS (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. Future hard-coal plants (‘hard-coal innovative’) are assumed to be able to run at 700 degrees Celsius and higher pressures (350 bars). Due to these

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

improvements, the net efficiency is assumed to increase by 4 percentage points to 50 %. Investment costs are above those of today's standard technologies but are assumed to decrease due to learning effects by about 1/3 by 2050. Future lignite technologies ('lignite innovative') use a more efficient drying process and can therefore increase their efficiency to 48 %. Investment costs are just above those of today's newest 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 5.6, 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.

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.[66]

[66]The regions are based on specific wind and solar data from Sperling and Hänsch (2009). The wind and solar regions are not identical.

Table 5.6: Investment costs of generation technologies [EUR_{2010}/kW]

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 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 due to the additional costs for the pipe and the storage system. Combined heat and power generation units have lower electrical but higher total efficiency factors. Operational and maintenance costs also include the costs for the heat extraction system. Table 5.7 shows the net efficiency factors, technical availability, operational and maintenance costs and the technical lifetime for conventional, renewable and storage technologies.

Table 5.7: Economic-technical parameters of generation technologies

Technologies	Efficiency generation [%]	Efficiency charging [%]	Avail-ability [%]	FOM-costs EUR_{2010} per 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

The assumed fuel prices are based on international market prices and transportation costs to the power plants. The coal price is assumed to increase from 11.9 EUR_{2010}/MWh_{th} in 2010 to 17.6 EUR_{2010}/MWh_{th} in 2050. For domestic lignite a constant price of 1.4 EUR_{2010}/MWh_{th} is assumed. Despite the current excess supply and low prices of natural gas we assume a significant increase up to 28.0 EUR_{2010}/MWh_{th} in the long term. As the model includes several biomass technologies, only a range for the price of biomass solid and gas is given in Table 5.8. The price for biomass solid is assumed to increase up to 37.5 EUR_{2010}/MWh_{th} and biomass gas up to 85.1 EUR_{2010}/MWh_{th}. The price of CO_2 emissions is assumed to increase from 14.0 EUR_{2010}/t CO_2 in 2010 to 40.0 EUR_{2010}/t CO_2 in 2050. Table 5.8 shows the fuel prices assumed for thermal power plants in the scenarios.

TABLE 5.8: Fuel prices [EUR_{2010}/MWh_{th}] and CO_2 price [EUR_{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 [EUR_{2010}/t CO_2]	14.0	20.0	25.0	30.0	40.0

5.4 Scenario results

5.4.1 '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. Firstly, due to learning curve effects of storage technologies, the cost difference between CSP plants with and without storage capacities is likely to decrease. Secondly, the value of thermal storage capacities is likely to increase with a higher share of fluctuating RES-E generation. 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. 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) generation 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 5.1 for the Iberian Peninsula until 2050. Given the large deployment of renewables, the total capacity increases due to lower capacity factors of wind and solar capacities compared to dispatchable plants. The conventional generation system is dominated by gas capacities, some equipped with CHP, as 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 generation quotas, mostly CSP plants and wind onshore sites are built. Existing photovoltaic capacities built under the current Spanish feed-in tariff system are not rebuilt endogenously in the model after their technical lifetime ends due to higher investment costs.

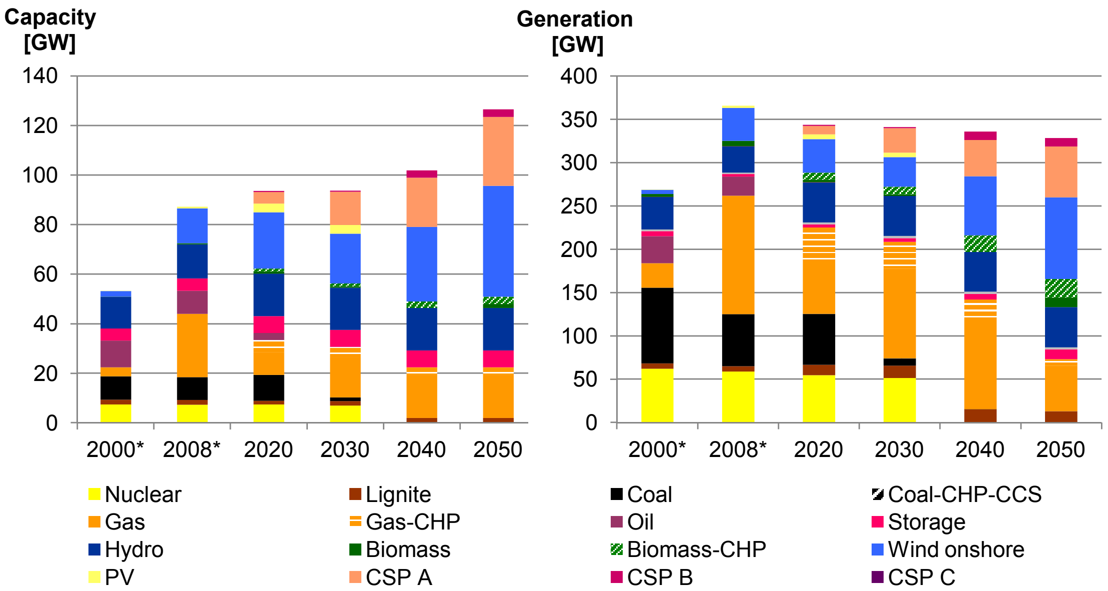

FIGURE 5.1: Capacities [GW] and generation [TWh] in the 'illustrative scenario'
Remarks: The data for 2000/2008 is based on Eurostat (2010a). CHP capacities (generation) are included in gas and coal capacities (generation) in 2000 and 2008.

In the short term, 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. The renewable generation is provided by CSP plants, onshore wind turbines, biomass and hydro plants. The generation in pump storages increases in the long term due to the feed-in of fluctuating renewables. In sum, gross electricity generation decreases over time (despite the constant demand) due to the transition to a renewable-based system. Although the increasing utilization of storage capacities leads to a higher gross electricity demand, the reduction of own consumption by thermal power plants (due to an increasing share of renewables) leads to an overall lower gross electricity demand.

CSP plants are built in order to fulfill the increasing generation quota over time.[67] In the short term, only CSP plants with no storage capacities (CSP A) are constructed. CSP plants with small storage capacities (CSP B) with the ability to shift generation to later hours are cost-efficient when the penetration of fluctuating RES-E generation exceeds a certain limit. In this scenario, about 10 % of the CSP plants are equipped with small storage capacities when the RES-E share reaches 80 % and when CSP generation makes up 25 % of total generation. The installed capacities of CSP plants are shown in Table 5.9.

[67]The CSP generation quota is binding in all years.

Table 5.9: 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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

The value of thermal storage units in CSP plants

The model results are based on the favorable feed-in structures of solar technologies in order to meet electricity demand. CSP plants and photovoltaics generate electricity when demand is usually high. Hence, at a low penetration of fluctuating RES-E, there is no benefit from having additional storage capacities and being able to shift electricity generation to later hours. Therefore, thermal storage units in CSP plants are not cost-efficient in electricity systems in the short term. Figure 5.2 shows the feed-in structures of fluctuating generation technologies (wind, photovoltaic and CSP plants), the model demand and the marginal of the power balance for the example of the Spanish electricity market.[68]

The marginal of the power balance can be interpreted as the value of electricity in a specific hour. In general, high generation by technologies with negligible variable generation costs, such as wind or solar lead to a lower marginal of the power balance. As can be seen in Figure 5.2, the marginal of the power balance is primarily influenced by the level of the model demand in today's electricity systems. Fluctuating renewables play a minor role in the short term because generation of wind turbines, photovoltaics and CSP plants is relatively low compared to the demand.

[68]The equilibrium condition 'power balance' assures the hourly balance of electricity generation and demand. The marginal of the power balance represents the partial derivative considering the total system costs.

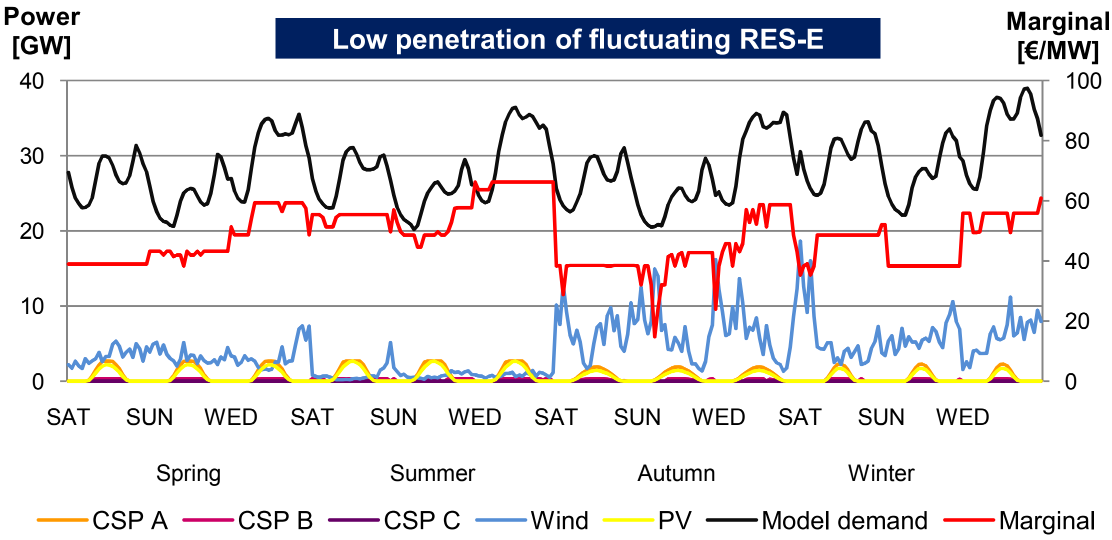

FIGURE 5.2: Low RES-E generation [GW] and power marginal [EUR_{2010}/MW]

Figure 5.3 shows the development of renewable generation and the marginal in an electricity system with medium penetration of fluctuating RES-E. The increasing generation of fluctuating renewable technologies leads to a more volatile marginal. As can be seen in Figure 5.3, additional CSP capacities (CSP A) with a relatively high generation at midday cause relatively low marginals in these specific hours.

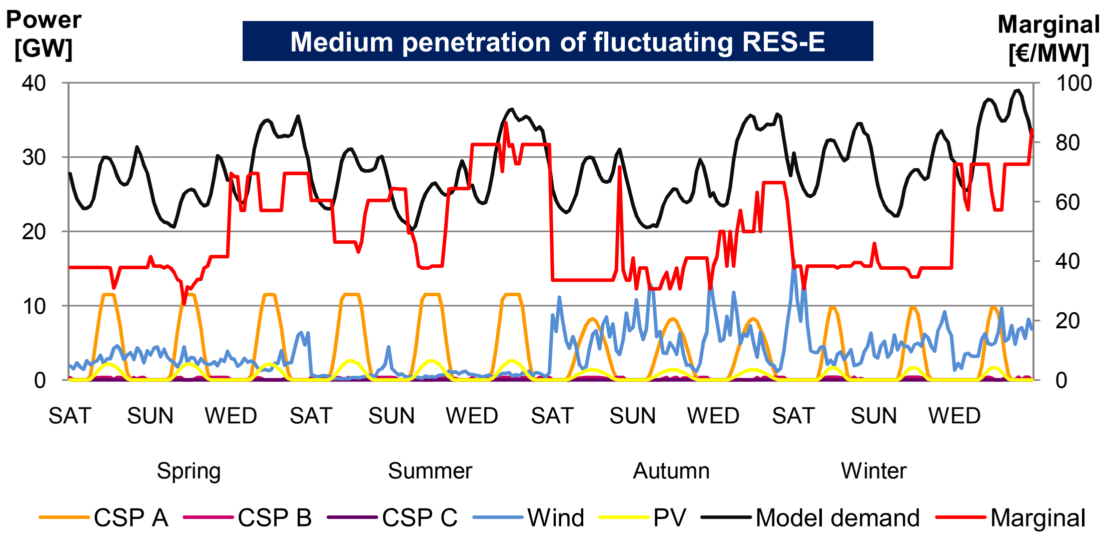

FIGURE 5.3: Medium RES-E generation [GW] and power marginal [EUR_{2010}/MW]

The influence of CSP generation on the marginal increases significantly due to the concentrated generation at midday in this scenario. Around midday, when generation by solar technologies is high, the marginal of the power balance - especially in summer - is often lower than at night. The structure of the marginal is almost reversed compared to today (especially in summer): Lower marginals occur when electricity demand is high around midday and higher marginals when electricity demand is low during the night.

Figure 5.4 shows the value of CSP storage units in a high fluctuating RES-E scenario. A high share of fluctuating RES-E capacities - especially solar - leads to a low value of additional generation around midday. Therefore, the value of storage options in CSP plants increases. This leads to investments in CSP plants with small storage capacities (CSP B) in order to shift generation to later hours. The CSP plants with storage units are able to balance the generation from fluctuating wind and CSP plants without storage units (CSP A) with the electricity demand.

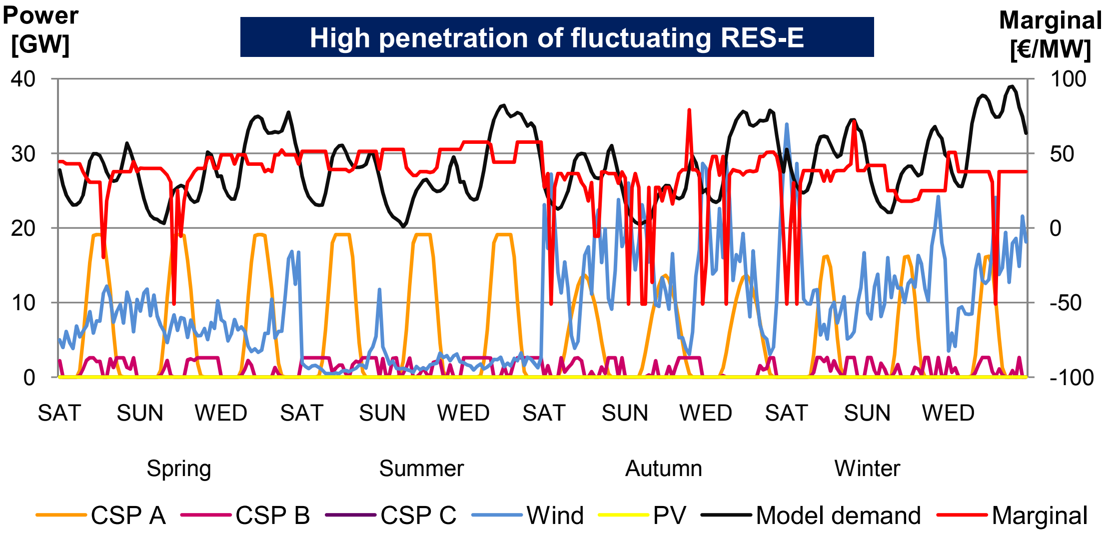

FIGURE 5.4: High RES-E generation [GW] and power marginal [EUR_{2010}/MW]

From the results of the 'illustrative scenario', we draw the following conclusions. Firstly, investments in CSP plants with storage units in today's electricity systems of Spain and Portugal are not cost-efficient from a system-integrated perspective. The growing investments in CSP plants with storage units in the Spanish market result from the specific design, flat feed-in tariffs, of the Spanish RES-E promotion system and do not reflect investment signals of the competitive electricity market, which would favor CSP plants without storage units. Secondly, 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 intermittent RES-E technologies increases. However, the share of intermittent RES-E technologies has to reach a substantial magnitude to cause an almost reverse structure of the marginal on the power balance, until CSP plants with storage units become cost-efficient.

5.4.2 '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 of the Iberian Peninsula. In contrast to the 'illustrative scenario', an increasing electricity demand and decreasing investment costs of RES-E technologies due to learning curve effects are assumed (as described in Subsection 5.3.3). At least 80 % of the electricity consumption has to be generated by renewable capacities starting from 2050 (40 % in 2020) but no additional CSP quota has to be reached.

Capacities and generation mix

The implied transformation of the electricity system results in a large extension of RES-E capacities until 2050. The generation of fluctuating RES-E depends on weather conditions and therefore the maximum yearly generation per unit is lower compared to conventional power plants. Due to this effect, the sum of capacities increases significantly. The demand in 2050 is twice as high as in 2000 while generation capacities triple until 2050. Figure 5.5 shows the installed capacities and generation in the 'roadmap scenario'.

To achieve the implied RES-E generation 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 storage capacities (CSP B) are constructed. Due to the scenario assumptions, the model chooses CSP systems over photovoltaics. In the long term, larger CSP plants with 15 hours of storage capacity (CSP C) have a comparative cost advantage compared to smaller CSP plants. Additionally, the value of thermal storage units in CSP plants increases in high RES-E electricity systems as shown in the 'illustrative scenario'.

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. Additionally, compressed air energy storages are constructed to integrate the fluctuating generation from wind and solar power. Power balances for Spain and Portugal can be found in Appendix C.

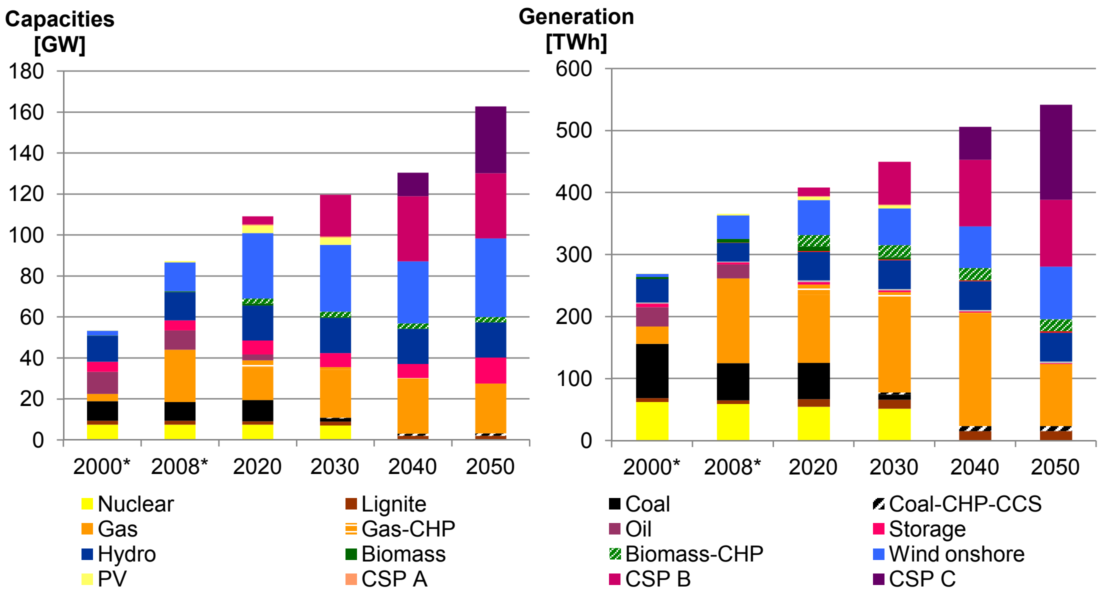

FIGURE 5.5: Capacities [GW] and generation [TWh] in the 'roadmap scenario'
Remarks: The data for 2000/2008 is based on Eurostat (2010a). CHP capacities (generation) are included in gas and coal capacities (generation) in 2000 and 2008.

The usage of storage units in the 'roadmap scenario'

A higher generation by fluctuating RES-E technologies leads to a more volatile residual electricity demand. This requires a higher share of flexible conventional generation such as combined cycle or open cycle gas turbines to balance generation and demand. The costs of ramping thermal power plants rises with higher generation of fluctuating RES-E capacities.

Figure 5.6 shows the model demand curves (black line), the model demand after subtracting the generation by fluctuating RES-E (blue line), the model demand after subtracting the generation by fluctuating RES-E and storage operations (yellow line) as well as the final residual demand (green line), that has to be met by thermal power plants for the Iberian Peninsula in 2020. The system is characterized by 10 % electricity generation by fluctuating RES-E and large hydro capacities (hydro and pump storage). Due to the large storage capacities, the residual demand is relatively constant compared to the model demand. As a result, quick changes in the generation of thermal power plants are rarely needed. However, a high generation by wind technologies in autumn leads to a more volatile residual demand, a higher usage of storage capacities in pump operation (yellow line is above the green line in Figure 5.6) and higher costs of ramping thermal power plants.

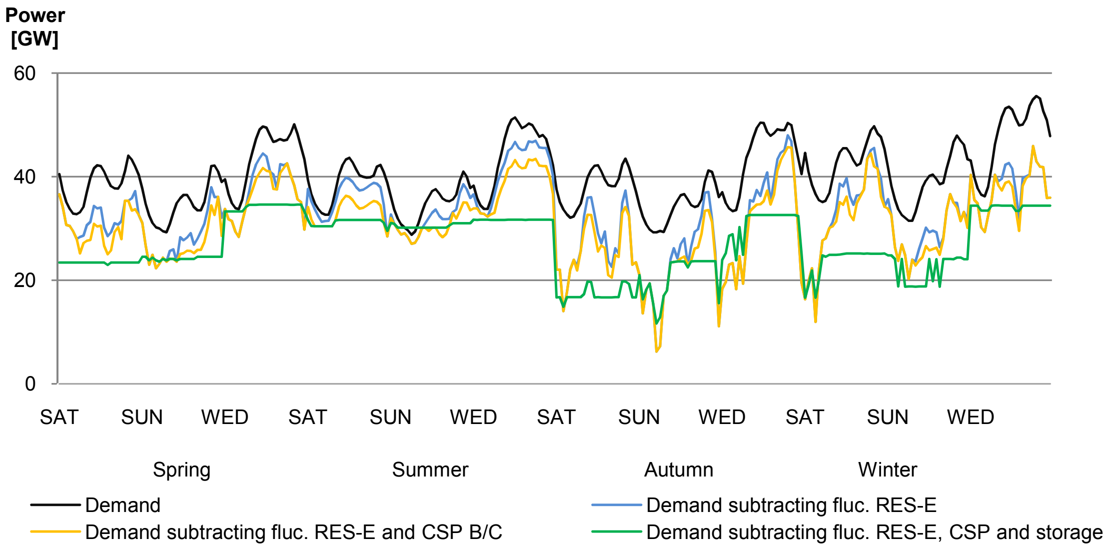

FIGURE 5.6: Different residual demands [GW] for the Iberian Peninsula in 2020

Figure 5.7 shows different residual demands for the Iberian Peninsula in 2050. A higher share of fluctuating RES-E technologies would lead to a more volatile residual demand and higher costs of ramping thermal power plants. This is best observed by comparing the demand after subtracting the fluctuating RES-E generation in 2020 (blue line in Figure 5.6) with the demand after subtracting the fluctuating RES-E generation in 2050 (blue line in Figure 5.7).

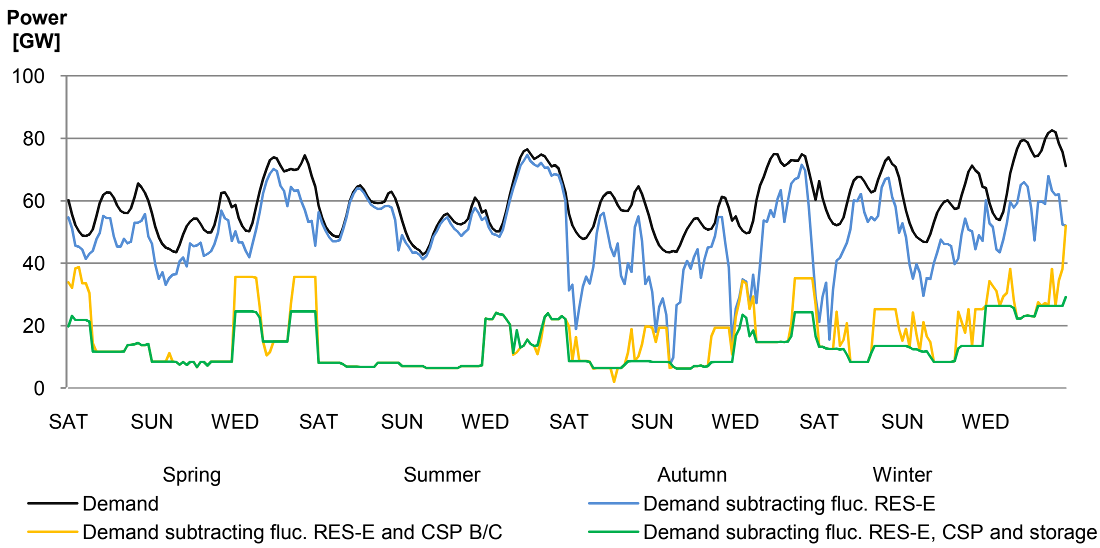

FIGURE 5.7: Different residual demands [GW] for the Iberian Peninsula in 2050

CSP technologies with storage units are able to shift generation from one hour to another and can therefore help to balance generation and demand. In connection with other storage capacities (hydro, pump and compressed air storages), the residual demand can be kept more or less constant in most hours. In the 'roadmap scenario', CSP technologies with storage units are built rather than additional wind technologies for several reasons:

The potential for cost-efficient onshore wind sites is limited, the investment costs for CSP plants with storage capacities decrease significantly until 2050 and the value of storage capacities increases as shown in the 'illustrative scenario'. As can be seen in Figure 5.7, CSP plants with the ability to shift electricity generation lead to a smoother residual demand, even considering the higher RES-E generation in 2050.

5.5 Conclusions

We have shown that thermal energy storage units in CSP plants in today's electricity systems of Spain and Portugal are 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 flat feed-in tariffs currently set an inefficient incentive to invest in thermal storage units by neglecting hourly price signals. The value of TES in CSP plants increases with a higher share of wind and solar generation, as storage technologies can help to balance fluctuating generation and demand. Due to specific learning curve effects in regard to the thermal storage unit, the cost difference between CSP plants with and without thermal storage is likely to decrease. Moreover, CSP plants play a potentially significant role in a transformation to a primarily renewable-based electricity system.

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 and Sioshansi, 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

Table A.1: Economic and technical parameters for conventional power plants

	Efficiency [%]	Technical lifetime [a]	Availability [%]	FOM costs [EUR_{2008}/kWa]	CO_2 costs [EUR_{2008}/MWh]
Lignite	44	45	86	37	-
Lignite ('innovative')	48	45	86	37	-
Hard-coal	46	45	84	24	-
Hard-coal ('innovative')	50	45	84	24	-
CCGT	60	30	84	20	-
OCGT	40	25	84	9	-
IGCC-CCS	45	40	84	75	10
CCGT-CCS	51	30	84	33	6
Coal CCS	37	45	84	59	13
Coal-CCS ('innovative')	41	45	84	59	11
Lignite-CCS	38	45	84	90	15

Table A.2: Fixed operation and maintenance costs of renewables [EUR_{2008}/kWa]

	2020	2030	2040	2050
Hydro power	50	50	50	50
Onshore wind sites	41	39	38	38
Offshore wind sites	132	92	81	74
Photovoltaics	29	28	27	26
Biomass	140	140	140	140
Geothermal power	380	360	340	320
Concentrated solar power	84	74	61	51

Appendix B

Supplemental data for Chapter 3

We divide Europe into several zones in order to limit computational times. Table B.1 lists the used abbreviations for the selected regions.

Table B.1: Abbreviations for selected regions

AT	Austria
BeNeLux	Benelux (Belgium, the Netherlands and Luxembourg)
CH	Switzerland
CZ	Czech Republic
DK	Denmark
EE	Eastern Europe (Slovakia, Slovenia, Hungary, Romania and Bulgaria)
FR	France
GER	Germany
IB	Iberian Peninsula (Portugal and Spain)
IT	Italy
PL	Poland
SCA	Scandinavia (Norway, Sweden and Finland)
UK	United Kingdom
C	Central
N	North
S	South
W	West

Table B.2: Full load hours of wind and solar technologies in Europe, 2006 to 2010 [h]

	UK-C		IB-S		GER-C		FR-S	
	Wind	PV	Wind	PV	Wind	PV	Wind	PV
2006	3,731	-	1,651	-	1,918	-	2,131	-
2007	3,781	824	1,893	1,395	2,380	813	2,461	1,198
2008	3,917	835	2,064	1,419	2,105	867	2,405	1,132
2009	3,416	879	1,898	1,418	1,792	837	2,433	1,202
2010	2,924	882	2,106	1,366	1,441	878	2,460	1,163

Source: Own calculations based on wind speed and solar radiation from EuroWind (2011).

Table B.3: Correlation matrix for modeled wind sites

	GER-C (on)	GER-S (on)	GER-N (on)	BeNeLux-N (on)	BeNeLux-S (on)	IB-C (on)	IB-S (on)	IB-N (on)	UK-C (on)	UK-S (on)	UK-W (on)	FR-C (on)	FR-S (on)	FR-N (on)	CH-C (on)	AT-C (on)	CZ-C (on)	PL-N (on)	PL-S (on)	DK-C (on)
GER-C (on)	1																			
GER-S (on)	0.651	1																		
GER-N (on)	0.573	0.355	1																	
BeNeLux-N (on)	0.610	0.476	0.355	1																
BeNeLux-S (on)	0.788	0.563	0.484	0.803	1															
IB-C (on)	-0.020	-0.048	-0.028	0.012	-0.003	1														
IB-S (on)	-0.031	-0.034	-0.039	-0.010	-0.036	0.309	1													
IB-N (on)	0.171	0.116	0.090	0.219	0.209	0.328	0.137	1												
UK-C (on)	0.211	0.164	0.269	0.258	0.256	-0.032	0.004	0.085	1											
UK-S (on)	0.470	0.346	0.330	0.733	0.620	0.005	-0.022	0.163	0.367	1										
UK-W (on)	0.204	0.153	0.159	0.307	0.276	-0.018	-0.026	0.085	0.327	0.353	1									
FR-C (on)	0.437	0.412	0.212	0.527	0.499	0.165	0.120	0.363	0.111	0.340	0.187	1								
FR-S (on)	0.101	0.119	0.068	0.086	0.074	0.179	0.302	0.202	0.044	0.045	0.011	0.220	1							
FR-N (on)	0.234	0.201	0.097	0.296	0.265	0.336	0.220	0.519	0.077	0.202	0.160	0.597	0.260	1						
CH-C (on)	0.269	0.240	0.151	0.209	0.246	0.186	0.116	0.282	0.074	0.161	0.077	0.331	0.320	0.306	1					
AT-C (on)	0.429	0.492	0.377	0.201	0.290	-0.044	-0.027	0.079	0.131	0.169	0.077	0.104	0.150	0.063	0.240	1				
CZ-C (on)	0.554	0.477	0.483	0.251	0.367	0.027	0.022	0.131	0.103	0.173	0.073	0.265	0.220	0.167	0.314	0.588	1			
PL-N (on)	0.289	0.204	0.557	0.151	0.231	-0.055	-0.014	0.029	0.192	0.162	0.143	0.083	0.024	0.054	0.047	0.264	0.323	1		
PL-S (on)	0.344	0.369	0.384	0.173	0.246	-0.025	-0.020	0.059	0.143	0.158	0.097	0.117	0.069	0.075	0.146	0.562	0.491	0.447	1	
DK-C (on)	0.385	0.219	0.646	0.352	0.402	-0.063	-0.060	0.060	0.362	0.378	0.206	0.150	-0.005	0.055	0.091	0.218	0.236	0.414	0.244	1
SCA-W (on)	0.122	0.092	0.105	0.154	0.166	0.013	0.054	0.157	0.191	0.143	0.188	0.153	0.036	0.155	0.108	0.059	0.033	0.113	0.081	0.168
SCA-S (on)	0.228	0.138	0.414	0.165	0.207	-0.031	0.015	0.061	0.209	0.188	0.134	0.092	0.033	0.082	0.071	0.166	0.181	0.549	0.228	0.386
IT-N (on)	-0.043	0.010	-0.070	-0.027	-0.043	0.091	0.230	0.071	-0.046	-0.030	-0.051	0.059	0.240	0.105	0.048	-0.019	0.050	-0.040	-0.015	-0.090
IT-S (on)	0.055	0.087	-0.003	0.073	0.049	0.165	0.256	0.200	0.039	0.058	0.015	0.164	0.320	0.260	0.275	0.101	0.140	0.014	0.048	-0.049
EE-C (on)	0.268	0.338	0.208	0.128	0.175	0.044	0.052	0.108	0.084	0.102	0.039	0.125	0.153	0.134	0.184	0.509	0.426	0.184	0.553	0.090
EE-N (on)	-0.045	0.003	-0.011	-0.039	-0.044	-0.002	0.080	0.043	0.034	-0.032	0.013	-0.001	0.086	0.031	0.012	0.045	0.028	0.005	0.006	-0.001
EE-S (on)	0.144	0.090	0.205	0.088	0.123	-0.059	0.024	-0.003	0.115	0.096	0.089	0.038	0.003	0.019	0.050	0.085	0.075	0.318	0.161	0.204
DE (off)	0.577	0.329	0.710	0.494	0.596	-0.040	-0.039	0.132	0.333	0.515	0.188	0.235	0.060	0.122	0.176	0.286	0.327	0.354	0.255	0.679
BeNeLux (off)	0.562	0.371	0.410	0.779	0.733	-0.035	-0.037	0.182	0.333	0.818	0.308	0.359	0.041	0.193	0.202	0.191	0.204	0.203	0.170	0.443
IB (off)	-0.024	-0.044	-0.029	0.004	-0.018	0.373	0.922	0.193	0.014	-0.003	-0.025	0.141	0.267	0.253	0.141	-0.032	0.015	-0.006	-0.025	-0.046
UK (off)	0.298	0.210	0.244	0.442	0.402	-0.062	-0.053	0.087	0.540	0.601	0.587	0.188	-0.005	0.112	0.095	0.114	0.073	0.178	0.135	0.334
FR (off)	0.222	0.149	0.110	0.404	0.320	0.147	0.059	0.387	0.139	0.372	0.382	0.429	0.057	0.468	0.171	0.035	0.069	0.076	0.056	0.119
PL (off)	0.405	0.246	0.797	0.264	0.363	-0.037	-0.012	0.063	0.257	0.270	0.141	0.148	0.043	0.082	0.090	0.260	0.342	0.659	0.322	0.632
DK (off)	0.407	0.233	0.542	0.451	0.465	-0.046	-0.039	0.119	0.424	0.552	0.236	0.194	0.034	0.096	0.139	0.197	0.212	0.296	0.199	0.763
SCA (off)	0.234	0.128	0.346	0.291	0.287	-0.012	-0.017	0.116	0.418	0.335	0.203	0.145	0.030	0.098	0.117	0.123	0.134	0.236	0.119	0.614
IT (off)	0.096	0.141	0.055	0.088	0.074	0.157	0.365	0.164	0.059	0.054	0.027	0.208	0.754	0.249	0.312	0.159	0.177	0.003	0.054	-0.012
EE (off)	0.405	0.246	0.797	0.264	0.363	-0.037	-0.012	0.063	0.257	0.270	0.141	0.148	0.043	0.082	0.090	0.260	0.342	0.659	0.322	0.632

Source: Own calculations based on wind speed data from EuroWind (2011).

Table B.4: Correlation matrix for modeled wind sites (continued)

continued

	SCA-W (on)	SCA-S (on)	IT-N (on)	IT-S (on)	EE-C (on)	EE-N (on)	EE-S (on)	DE (off)	BeNeLux (off)	IB (off)	UK (off)	FR (off)	PL (off)	DK (off)	SCA (off)	IT (off)	EE (off)
SCA-W (on)	1																
SCA-S (on)	0.178	1															
IT-N (on)	0.000	-0.033	1														
IT-S (on)	0.063	0.035	0.330	1													
EE-C (on)	0.037	0.074	0.166	0.212	1												
EE-N (on)	0.088	0.025	0.151	0.131	0.115	1											
EE-S (on)	0.131	0.408	0.004	0.012	0.023	-0.004	1										
GER (off)	0.142	0.322	-0.065	0.011	0.131	0.003	0.172	1									
BeNeLux (off)	0.179	0.228	-0.060	0.033	0.076	-0.018	0.134	0.660	1								
IB (off)	0.075	0.027	0.200	0.239	0.034	0.066	0.034	-0.019	-0.012	1							
UK (off)	0.204	0.188	-0.085	-0.002	0.037	-0.017	0.135	0.376	0.545	-0.039	1						
FR (off)	0.210	0.103	0.006	0.124	0.052	0.013	0.064	0.180	0.352	0.099	0.337	1					
PL (off)	0.116	0.534	-0.061	-0.001	0.127	0.007	0.233	0.604	0.354	0.003	0.249	0.120	1				
DK (off)	0.157	0.306	-0.070	-0.003	0.078	0.013	0.146	0.773	0.622	-0.019	0.442	0.193	0.502	1			
SCA (off)	0.205	0.254	-0.048	0.001	0.042	0.049	0.102	0.450	0.363	0.007	0.320	0.168	0.369	0.641	1		
IT (off)	0.063	0.055	0.255	0.327	0.154	0.109	0.021	0.078	0.068	0.303	0.028	0.084	0.060	0.045	0.043	1	
EE (off)	0.116	0.534	-0.061	-0.001	0.127	0.007	0.233	0.604	0.354	0.003	0.249	0.120	1.000	0.502	0.369	0.060	1

Source: Own calculations based on wind speed data from EuroWind (2011).

Table B.5: Correlation matrix for modeled solar sites - daytime

	GER-C	GER-N	GER-S	BeNeLux-C	IB-C	IB-N	IB-S	UK-C	FR-C	FR-N	FR-S	CH-C	AT-C	CZ-C	PL-C
GER-C	1														
GER-N	0.797	1													
GER-S	0.768	0.690	1												
BeNeLux-C	0.819	0.722	0.694	1											
IB-C	0.653	0.667	0.645	0.626	1										
IB-N	0.646	0.644	0.607	0.634	0.744	1									
IB-S	0.654	0.646	0.631	0.634	0.835	0.807	1								
UK-C	0.707	0.716	0.646	0.695	0.693	0.717	0.709	1							
FR-C	0.720	0.649	0.699	0.786	0.663	0.666	0.678	0.676	1						
FR-N	0.676	0.678	0.626	0.652	0.730	0.812	0.768	0.749	0.677	1					
FR-S	0.688	0.685	0.662	0.670	0.811	0.754	0.783	0.717	0.756	0.735	1				
CH-C	0.701	0.631	0.856	0.669	0.622	0.569	0.600	0.590	0.701	0.590	0.655	1			
AT-C	0.651	0.615	0.848	0.602	0.604	0.545	0.561	0.571	0.634	0.570	0.625	0.851	1		
CZ-C	0.786	0.743	0.765	0.665	0.622	0.573	0.579	0.639	0.609	0.615	0.617	0.666	0.694	1	
PL-C	0.714	0.710	0.720	0.622	0.636	0.558	0.584	0.643	0.603	0.595	0.633	0.640	0.668	0.782	1
DK-C	0.738	0.810	0.670	0.698	0.702	0.696	0.695	0.750	0.677	0.717	0.727	0.616	0.594	0.667	0.674
SCA-C	0.763	0.803	0.693	0.695	0.680	0.637	0.646	0.715	0.652	0.683	0.713	0.638	0.620	0.740	0.746
IT-C	0.729	0.733	0.744	0.680	0.768	0.688	0.730	0.711	0.696	0.700	0.798	0.718	0.699	0.700	0.729
IT-N	0.729	0.729	0.778	0.686	0.721	0.661	0.688	0.680	0.709	0.669	0.764	0.754	0.759	0.709	0.735
IT-S	0.683	0.693	0.682	0.622	0.714	0.620	0.670	0.653	0.636	0.649	0.730	0.650	0.649	0.681	0.723
EE-C	0.719	0.727	0.729	0.646	0.652	0.579	0.611	0.667	0.633	0.616	0.686	0.662	0.695	0.741	0.839
EE-N	0.703	0.739	0.650	0.626	0.626	0.568	0.577	0.666	0.603	0.606	0.677	0.592	0.601	0.689	0.722
EE-S	0.629	0.656	0.620	0.544	0.611	0.496	0.530	0.578	0.550	0.539	0.642	0.581	0.585	0.638	0.703

continued

	DK-C	SCA-C	IT-C	IT-N	IT-S	EE-C	EE-N	EE-S
DK-C	1							
SCA-C	0.786	1						
IT-C	0.750	0.755	1					
IT-N	0.722	0.752	0.841	1				
IT-S	0.711	0.728	0.836	0.771	1			
EE-C	0.710	0.773	0.776	0.800	0.766	1		
EE-N	0.739	0.807	0.717	0.720	0.703	0.741	1	
EE-S	0.667	0.716	0.742	0.705	0.771	0.751	0.690	1

Source: Own calculations based on solar radiation data from EuroWind (2011).

TABLE B.6: Correlation matrix for modeled solar and wind sites - daytime

		Wind														
		GER-C	GER-N	GER-S	BeNeLux-C	IB-C	IB-N	IB-S	UK	FR-C	FR-N	FR-S	CH-C	AT-C	CZ-C	PL-C
Solar	GER-C	**-0.228**	-0.175	-0.104	-0.262	-0.087	-0.045	-0.140	-0.230	-0.239	-0.064	-0.231	-0.211	-0.132	-0.198	-0.141
	GER-N	-0.205	**-0.175**	-0.205	-0.189	-0.042	-0.073	-0.192	-0.249	-0.152	-0.109	-0.200	-0.145	-0.185	-0.106	-0.186
	GER-S	-0.146	-0.223	**-0.104**	-0.149	-0.047	-0.100	-0.190	-0.166	-0.176	-0.203	-0.226	-0.230	-0.181	-0.140	-0.104
	BeNeLux-C	-0.247	-0.264	-0.170	**-0.262**	-0.061	-0.058	-0.215	-0.205	-0.252	-0.148	-0.270	-0.235	-0.167	-0.126	-0.128
	IB-C	0.003	-0.014	-0.034	-0.018	**-0.087**	-0.118	-0.137	-0.157	-0.045	-0.047	-0.112	-0.088	-0.035	0.042	-0.086
	IB-N	-0.043	-0.054	-0.035	-0.078	-0.076	**-0.045**	-0.200	-0.176	-0.108	-0.055	-0.163	-0.136	-0.030	0.013	-0.090
	IB-S	0.018	-0.020	-0.030	-0.007	-0.050	-0.057	**-0.140**	-0.158	-0.044	-0.039	-0.096	-0.114	-0.040	0.045	-0.093
	UK-C	-0.098	-0.087	-0.099	-0.171	-0.021	-0.053	-0.187	**-0.230**	-0.152	-0.085	-0.195	-0.166	-0.093	-0.008	-0.137
	FR-C	-0.141	-0.188	-0.103	-0.189	-0.106	-0.106	-0.206	-0.176	**-0.239**	-0.165	-0.298	-0.248	-0.081	-0.063	-0.071
	FR-N	-0.077	-0.080	-0.065	-0.111	-0.022	-0.039	-0.170	-0.202	-0.096	**-0.064**	-0.146	-0.124	-0.084	-0.002	-0.099
	FR-S	-0.040	-0.041	-0.045	-0.080	-0.156	-0.107	-0.192	-0.164	-0.147	-0.142	**-0.231**	-0.221	0.002	0.026	-0.076
	CH-C	-0.133	-0.213	-0.087	-0.158	-0.074	-0.120	-0.169	-0.153	-0.189	-0.204	-0.240	**-0.211**	-0.111	-0.100	-0.077
	AT-C	-0.118	-0.172	-0.076	-0.128	-0.086	-0.114	-0.185	-0.141	-0.159	-0.220	-0.216	-0.220	**-0.132**	-0.109	-0.069
	CZ-C	-0.184	-0.233	-0.171	-0.159	-0.052	-0.086	-0.195	-0.196	-0.154	-0.169	-0.191	-0.181	-0.286	**-0.198**	-0.159
	PL-C	-0.124	-0.175	-0.117	-0.121	-0.053	-0.105	-0.182	-0.195	-0.133	-0.172	-0.190	-0.167	-0.239	-0.156	**-0.141**
	DK-C	-0.125	-0.105	-0.138	-0.169	-0.040	-0.063	-0.205	-0.291	-0.146	-0.083	-0.203	-0.161	-0.087	-0.021	-0.149
	SCA-C	-0.146	-0.159	-0.169	-0.155	-0.047	-0.086	-0.198	-0.254	-0.139	-0.105	-0.201	-0.157	-0.167	-0.087	-0.200
	IT-C	-0.048	-0.085	-0.056	-0.091	-0.108	-0.141	-0.184	-0.167	-0.141	-0.145	-0.232	-0.171	-0.057	-0.015	-0.116
	IT-N	-0.102	-0.133	-0.080	-0.146	-0.134	-0.139	-0.219	-0.189	-0.176	-0.173	-0.248	-0.219	-0.104	-0.069	-0.104
	EE-C	-0.124	-0.161	-0.110	-0.130	-0.074	-0.106	-0.199	-0.182	-0.134	-0.167	-0.212	-0.195	-0.204	-0.121	-0.117
	EE-N	-0.134	-0.140	-0.157	-0.150	-0.086	-0.119	-0.188	-0.257	-0.146	-0.107	-0.206	-0.169	-0.138	-0.075	-0.218
	EE-S	-0.043	-0.075	-0.044	-0.099	-0.107	-0.128	-0.172	-0.175	-0.107	-0.124	-0.190	-0.122	-0.058	-0.022	-0.079

continued

		Wind						
		DK-C	SCA-C	IT-C	IT-N	EE-C	EE-N	EE-S
Solar	GER-C	-0.232	-0.301	-0.086	-0.269	-0.147	-0.161	-0.070
	GER-N	-0.201	-0.271	0.025	-0.118	-0.082	-0.136	-0.100
	GER-S	-0.111	-0.212	-0.051	-0.204	-0.127	-0.141	-0.059
	BeNeLux-C	-0.164	-0.230	0.030	-0.123	-0.108	-0.115	-0.088
	IB-C	-0.079	-0.251	0.026	-0.050	0.017	-0.085	-0.081
	IB-N	-0.073	-0.238	0.069	-0.047	-0.007	-0.102	-0.055
	IB-S	-0.066	-0.230	0.043	-0.033	0.002	-0.098	-0.068
	UK-C	-0.153	-0.234	0.065	-0.089	-0.032	-0.112	-0.087
	FR-C	-0.128	-0.217	0.010	-0.151	-0.060	-0.113	-0.090
	FR-N	-0.105	-0.249	0.076	-0.049	-0.019	-0.097	-0.084
	FR-S	-0.082	-0.263	0.026	-0.131	0.013	-0.080	-0.082
	CH-C	-0.104	-0.201	-0.088	-0.211	-0.090	-0.120	-0.062
	AT-C	-0.093	-0.187	-0.087	-0.233	-0.088	-0.121	-0.059
	CZ-C	-0.151	-0.238	-0.004	-0.164	-0.160	-0.149	-0.060
	PL-C	-0.139	-0.260	-0.032	-0.176	-0.189	-0.168	-0.074
	DK-C	**-0.232**	-0.299	0.047	-0.093	-0.035	-0.134	-0.114
	SCA-C	-0.202	**-0.301**	0.010	-0.133	-0.086	-0.163	-0.122
	IT-C	-0.099	-0.262	**-0.086**	-0.237	-0.042	-0.128	-0.095
	IT-N	-0.112	-0.260	-0.147	**-0.269**	-0.091	-0.129	-0.080
	EE-C	-0.127	-0.262	-0.024	-0.214	**-0.147**	-0.178	-0.069
	EE-N	-0.217	-0.313	-0.011	-0.153	-0.088	**-0.161**	-0.170
	EE-S	-0.095	-0.243	-0.055	-0.160	-0.057	-0.252	**-0.070**

Source: Own calculations based on wind speed and solar radiation from EuroWind (2011).

Table B.7: Full load hours of wind and solar technologies in the selected scenarios [h]

	S1	S2	S3	S4	S5	S6	S7	S8	S9	S10
			wind					solar		
	- -	-	+/-	+	++	- -	-	+/-	+	++
Ind. value 'wind'	**3,162**	**3,350**	**3,530**	**3,651**	**3,998**	**3,344**	**3,026**	**3,345**	**3,501**	**3,697**
Ind. value 'solar'	**1,103**	**1,180**	**1,159**	**1,162**	**1,037**	**1,010**	**1,053**	**1,174**	**1,234**	**1,285**
Probability [%]	**2.5**	**10.0**	**25.0**	**10.0**	**2.5**	**2.5**	**10.0**	**25.0**	**10.0**	**2.5**
Wind onshore										
GER-C	1,694	1,534	1,530	2,146	1,499	1,703	1,696	1,381	1,909	1,656
GER-S	1,657	1,945	1,531	1,848	730	1,244	1,643	1,600	1,789	1,657
GER-N	2,869	2,531	3,122	2,576	3,042	2,838	1,818	2,472	2,226	2,949
BeNeLux-N	2,039	2,012	1,941	2,889	2,187	2,084	2,220	2,693	2,995	2,769
BeNeLux-S	1,873	1,873	1,773	2,404	2,133	1,953	1,873	1,909	2,305	2,164
IB-C	913	641	618	826	1,139	746	1,274	964	471	873
IB-S	1,932	2,063	1,931	2,273	1,998	1,380	2,278	2,227	1,157	1,545
IB-N	4,245	3,057	3,870	4,258	4,839	3,353	3,841	3,094	3,756	3,384
UK-N	3,554	5,515	4,961	4,820	5,506	3,647	4,149	5,749	4,495	5,006
UK-C	2,843	2,855	3,915	3,126	3,176	3,373	3,251	3,812	3,263	3,030
UK-W	2,839	3,379	3,008	3,790	4,307	3,129	3,003	4,108	3,692	3,555
FR-C	1,998	1,329	748	1,777	1,799	1,264	1,571	1,053	1,588	2,278
FR-S	2,200	2,225	2,603	2,153	2,678	2,093	2,304	2,147	2,226	2,345
FR-W	2,591	2,154	1,547	3,065	3,155	2,462	2,428	2,154	2,400	2,629
CH-C	448	457	565	511	660	382	466	343	340	487
AT-C	1,261	1,804	1,484	1,256	1,404	1,748	1,355	1,297	1,210	1,501
CZ-C	1,444	1,292	1,211	1,015	1,287	1,412	1,634	1,159	1,097	1,452
PL-N	3,269	3,256	3,300	3,039	3,502	3,284	2,673	2,877	2,933	3,585
PL-C	1,321	1,519	1,639	1,234	1,442	1,795	1,744	1,352	1,275	1,492
DK-C	2,620	3,883	4,600	4,416	4,228	3,710	3,010	3,396	3,843	4,528
SCA-W	1,563	1,745	1,451	1,527	2,424	1,422	1,938	1,973	2,221	1,881
SCA-C	2,323	3,320	3,281	4,144	3,511	2,777	2,350	3,828	3,561	3,094
IT-N	803	557	1,093	1,162	1,111	776	1,832	974	692	656
IT-S	2,816	1,674	2,275	1,960	2,185	1,813	2,259	1,835	1,716	1,566
EE-C	1,237	1,228	1,368	1,066	1,058	1,380	1,642	1,246	1,001	1,311
EE-S	922	1,236	952	706	569	882	1,032	532	941	593
EE-N	2,352	2,754	2,159	3,612	2,639	2,515	2,550	2,934	2,703	3,255
Wind offshore										
GER-N	4,478	4,798	5,964	6,147	4,993	4,703	4,481	4,970	5,573	5,083
BeNeLux-N	3,973	4,251	5,613	5,369	5,397	4,488	5,208	5,387	5,742	4,648
IB-W	2,247	2,061	1,976	2,246	2,248	1,633	2,153	2,413	1,146	1,521
UK-W	4,425	5,390	5,100	5,482	5,444	4,731	4,604	5,395	5,385	4,812
FR-W	5,207	5,011	4,333	4,439	6,633	5,380	4,852	5,580	4,850	4,641
PL-N	4,671	4,583	5,198	6,142	5,717	4,809	3,887	4,667	4,048	4,931
DK-N	3,751	5,268	6,818	5,666	5,115	5,147	4,856	5,153	5,584	5,311
SCA-W	3,160	5,720	6,336	5,180	5,143	4,998	4,395	5,363	5,997	6,077
IT-W	4,620	4,811	4,920	4,579	3,824	4,722	4,518	5,442	4,763	4,293
EE-N	4,671	4,583	5,198	6,142	5,717	4,809	3,887	4,667	4,048	4,931
Solar power										
GER-C	823	744	805	842	703	720	742	890	843	905
GER-N	820	783	785	748	658	667	654	849	812	915
GER-S	870	903	917	823	747	766	881	938	932	1,024
BeNeLux-C	904	731	708	721	666	602	734	729	750	838
IB-C	1,126	1,257	1,202	1,324	1,153	1,168	987	1,281	1,268	1,297
IB-N	982	1,072	939	1,137	859	922	954	1,138	1,124	1,109
IB-S	1,337	1,436	1,306	1,505	1,284	1,246	1,270	1,442	1,439	1,540
UK-C	833	834	823	792	680	677	762	876	750	924
FR-C	975	936	927	735	799	658	870	928	944	1,012
FR-S	921	871	877	932	746	854	883	1,073	961	1,141
FR-W	1,020	1,076	1,162	1,197	1,041	1,004	1,006	1,185	1,239	1,343
CH-C	972	910	875	777	752	767	883	917	932	1,079
AT-C	889	996	840	779	649	746	831	833	925	1,105
CZ-C	665	764	868	868	741	680	685	838	847	890
PL-C	713	932	911	962	843	860	669	917	1,023	1,000
DK-C	921	857	807	809	642	619	725	887	764	958
SCA-C	824	885	812	789	681	628	715	762	775	908
IT-C	1,183	1,306	1,252	1,124	1,075	1,023	1,056	1,132	1,326	1,232
IT-N	973	1,127	1,087	1,038	878	920	929	1,069	1,142	1,294
IT-S	1,294	1,320	1,067	1,323	1,166	1,185	1,055	1,391	1,416	1,282
EE-C	930	1,092	1,043	978	934	950	774	931	1,178	1,104
EE-N	733	759	798	780	686	706	730	705	703	828
EE-S	1,100	1,314	1,033	1,280	1,117	1,094	970	1,287	1,096	1,297

Appendix C

Supplemental data for Chapter 5

TABLE C.1: Concentrated solar 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).

Table C.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]
FR	2007	41 (2445)	40 (3332)	44 (1388)	48 (1560)	42 (657)	42 (481)	41 (272)	39 (154)	40 (150)	42 (250)
	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)
GER	2007	38 (921)	36 (1017)	47 (1258)	46 (777)	46 (740)	46 (710)	46 (697)	44 (577)	44 (542)	46 (760)
	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)
ES	2007	39 (174)	38 (206)	37 (149)	40 (154)	42 (176)	44 (154)	41 (83)	40 (56)	41 (59)	45 (70)
	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)
PT	2007	52 (254)	51 (782)	54 (878)	52 (784)	57 (972)	59 (1044)	56 (937)	49 (643)	49 (615)	50 (657)
	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 (2012b), 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.

Table C.3: 'High RES-E 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 (2010a).

Table C.4: 'High RES-E 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 (2010a).

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CURRICULUM VITAE

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Diploma Business Administration with Electrical Engineering	**2003 - 2009**
Technical University Darmstadt	*Darmstadt, Germany*
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Université Montesquieu Bordeaux (12 months exchange program)	*Bordeaux, France*
University Entrance Examination (Abitur)	**2003**
Kepler Gymnasium Ulm	*Ulm, Germany*

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Research Associate	**2010 - 2013**
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REFEREED JOURNAL PUBLICATIONS

Fürsch, M., Hagspiel, S., Jägemann, C., Nagl, S., Lindenberger, D., Tröster, E. (2013). The role of grid extensions in a cost-efficient transformation of the European electricity system until 2050. *Applied Energy*, 104:642-652.

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