Essays on the Economics of Renewable Energy Policy

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Contents

List of Figures

List of Tables

Nomenclature

a	Annum
AT	Austria
avail	availability
BE	Belgium
BG	Bulgaria
BMU	Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit (German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety)
BMWi	Bundesministerium für Wirtschaft und Technologie (German Federal Ministry of Economics and Technology)
bn	Billion
BSW	Bundesverband Solarwirtschaft (German Solar Industry Association)
CAES	Compressed air energy storage
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CDM	Clean Development Mechanism
CH	Switzerland
CHP	Combined heat and power
CO_2	Carbon dioxide
coop	cooperative
CSP	Concentrating solar power
ct	Cent
CZ	Czech Republic
DE	Germany

Dena	Deutsche Energie-Agentur (German Energy Agency)
diff	difference
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)
DK	Denmark
EC	European Commission
EE	Estonia
EEA	European Environment Agency
EEX	European Energy Exchange
EIA	Energy Information Administration
ENTSO-E	European Network of Transmission System Operators for Electricity
EREC	European Renewable Energy Council
ES	Spain
EU	European Union
EU ETS	European Union Emissions Trading System
EUR	Euro
EVPI	Expected Value of Perfect Information
EWI	Energiewirtschaftliches Institut an der Universität zu Köln (Institute of Energy Economics at the University of Cologne)
FI	Finland
FOM	Fixed operation and maintenance costs
FR	France
GAMS	General algebraic modeling system
GDP	Gross domestic product
GJ	Gigajoule
GR	Greece
GW	Gigawatt
GWh	Gigawatt hour
GWS	Gesellschaft für Wirtschaftliche Strukturforschung mbH
h	Hour

HU	Hungary
HVDC	High voltage direct current
IE	Ireland
IEA	International Energy Agency
innov	innovative
IT	Italy
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)
LT	Lithuania
LU	Luxembourg
LV	Latvia
m	Meter
m^2	Square meter
Mio	Million
MS	member state
MW	Megawatt
MW_{el}	Megawatt electric
MW_{th}	Megawatt thermal
MWh	Megawatt hour
MWh_{el}	Megawatt hour electric
MWh_{th}	Megawatt hour thermal
NL	Netherlands
NO	Norway
NREAP	National Renewable Energy Action Plan
NTC	Net transfer capacities
OCGT	Open cycle gas turbine
PL	Poland
PT	Portugal
PV	Photovoltaics
RES	Renewable energy sources
RES-E	Renewable energy sources for electricity generation
RO	Romania

s	Second
SE	Sweden
SK	Slovakia
SL	Slovenia
t	(Metric) tonne
TES	Thermal energy storage
TGC	Tradable green certificates
TWh	Terawatt hour
TWh_{el}	Terawatt hour electric
TWh_{th}	Terawatt hour thermal
TYNDP	Ten-Year Network Development Plan
U.S.	United States
UK	United Kingdom
VSS	Value of the Stochastic Solution
W	Watt

Chapter 1

Introduction

1.1 Background and Motivation

Renewable energies are considered to play an important role in achieving greenhouse gas emission reduction targets. In addition, the European Commission states that the promotion of renewable energies contributes to "promoting the security of energy supply, promoting technological development and innovation and providing opportunities for employment and regional development (...)" (EU Directive 2009/28/EC). For these reasons, the share of renewable energy in primary energy consumption and, in particular, in electricity consumption should increase in the coming years and decades, according to political plans. Up to 2020, binding targets for the renewable energy share in electricity (RES-E) consumption have been defined in all member states of the European Union, in compliance with Directive 2009/28/EC. Overall, on a European level, the RES-E share is set to increase up to 34% by 2020, compared to 19.9% in 2010 (BMU (2012) and EREC (2011)). Post 2020, RES-E targets have only been defined in some European countries thus far. For example, Germany envisages reaching a RES-E share of 80% by 2050 (BMWi/BMU (2010)). In addition, renewable energies may potentially play an important role in realizing European decarbonization plans up to 2050 (EC (2011b) and Jägemann et al. (2013)).

Two major challenges come along with an increasing RES-E share. First, most renewable energies are not (yet) competitive with other energies and would not be built without support mechanisms. Thus, with an increasing RES-E share, support expenditures also increase. For example, in Germany, support expenditures increased from 0.9 bn. EUR in 2000, when the German renewable energy support system (EEG) was introduced, up to

15.4 bn. EUR in 2012 (Übertragungsnetzbetreiber (2012)).[1] Second, renewable energies have to be integrated in the electricity system. In particular, many renewable energies, such as wind and solar, depend on hourly meteorological conditions. The intermittency of renewable energy infeed has important consequences on the electricity system. First, hourly residual demand becomes more volatile and the balancing of hourly demand and supply becomes more challenging than in electricity systems with mainly dispatchable power plants. Second, the yearly utilization times that can be achieved by thermal power plants are affected by an increasing RES-E share (e.g., de Miera et al. (2008)): In many hours of the year, a large part of demand is met by renewable energies, while in some hours residual demand remains high when the wind is not blowing and the sun is not shining. Depending on their yearly utilization times, different power plant types (characterized by different capital/operation cost ratios) are cost-efficient. Therefore, an increasing RES-E penetration affects optimal investment decisions of thermal power plants (e.g., Nicolosi (2012)). Moreover, a further challenge of RES-E integration is to physically connect supply and demand because many favorable renewable energy sites are located far from demand centers and have to be connected to the electricity grid.

From an economic point of view, these challenges should be tackled by building and using those technologies in those regions which allow reaching the political target at lowest system costs. In the context of renewable energy deployment in the European Union, RES-E plants have thus far mainly been built in countries with high promotion payments rather than in regions where meteorological conditions are favorable and generation costs are low (EWI (2010)). In fact, given large variances in RES-E generation costs across different European regions, the national 2020 RES-E targets do not necessarily have to be reached by national RES-E production only. Instead, Directive 2009/28/EC explicitly provides the option of reaching the national targets through cooperation between different member states or with third countries. These cooperation mechanisms defined by the Directive include joint projects, joint support systems and statistical transfers of renewable energy generation. Cooperation between European countries would significantly reduce the costs of increasing the RES-E share in the European electricity system (e.g., EWI (2010) and Aune et al. (2012)). Nevertheless, cooperation mechanisms have been hardly used thus far.

This conflict between the potential economic benefits of cooperation on the one hand and the observed reluctance to cooperate on the other hand motivates the first main topic of this thesis. Within three essays, the benefits and challenges of cross-border cooperation in RES-E support are investigated. In doing so, the impact of cooperation is analyzed both on the electricity system level and on the level of individual groups. In fact, as

[1] In the same period, the renewable energy share in gross electricity consumption increased from 6.8% in 2000 to 23.5% in 2012 (BMU (2013)).

also shown in general trade theory, an overall cost-efficient measure does not necessarily result in the best outcome from the single groups' perspectives. Consequently, financial redistribution effects resulting from an overall economic efficient measure (such as the introduction of trade or cooperation, which can be interpreted as a trade in RES-E targets) can be an obstacle to the implementation of this measure. Therefore, in this thesis, the economic benefit of cooperation is further investigated compared to previous analyses. In addition, redistribution effects arising from cooperation are analyzed both theoretically and numerically.

The second main topic of this thesis deals with optimal investment and dispatch decisions of conventional power plants and storage units under uncertainty about future renewable energy deployment paths. The motivation for this part of the thesis is that RES-E deployment paths have been difficult to forecast in the past and that a broad range of scenarios and forecasts exists regarding future developments. For example, due to social acceptance issues and uncertainties about technological developments of renewable energies and the progress of grid extensions, the pace of future RES-E deployment paths is difficult to predict. In addition, political uncertainty about future developments in renewable energy promotion can render future RES-E penetration levels uncertain. As the RES-E penetration level in an electricity system affects the optimal capacity mix of dispatchable power plants, unknown future RES-E deployment paths induce uncertainty about optimal investment decisions of thermal power plants and storage units. In the second part of this thesis, a dynamic stochastic optimization model is developed to optimize investment and dispatch decisions given that future renewable energy deployment paths are unknown.

To summarize, this thesis sheds further light on the question, how an increasing renewable energy share in the European power system can be cost-efficiently reached. In particular, this thesis investigates two aspects of this question: First, it investigates the benefit of cooperation in European RES-E deployment as well as resulting redistribution effects, which are possible obstacles to the practical implementation of cooperation. Second, it analyzes the optimal development of the conventional power plant fleet, given that future RES-E deployment paths cannot be perfectly foreseen.

1.2 Methodological approach of this thesis

In order to analyze cost-efficient RES-E deployment and integration pathways as well as redistribution effects of cooperation in RES-E support different methodologies could be applied: On the one hand, theoretical models can be used to determine the signs of effects under quite general assumptions. On the other hand, based on numerical analyses, the magnitude of effects can be quantified. Furthermore, if effects are undetermined in theoretical models based on general assumptions, the sign of the effects can be determined in numerical analyses based on real-world data. Important numerical analysis methods in energy economics are empirical methods as well as optimization and equilibrium models, covering the technological and economic fundamentals of energy markets in large detail.[2] Empirical analyses are mostly used for an ex-post quantification of effects. Optimization and equilibrium models, in contrast, are widely used for modeling future developments of, e.g., the electricity system.

The aim of this thesis is to analyze the benefits of European cooperation in achieving high renewable energy shares in electricity consumption, the resulting redistribution effects between different groups and the optimal investment and dispatch decisions under uncertainty about future RES-E penetration levels. In Chapter 2 of this thesis, the benefits of cooperation in RES-E support are calculated, in terms of a decrease in total system costs. In doing so, an electricity optimization model of the European power system is used, allowing for the quantification of the magnitude of this benefit and its robustness with regard to various developments in the electricity system. In Chapter 3, redistribution effects of cooperation are theoretically investigated using a mathematical two-country model, and in Chapter 4, these effects are numerically analyzed by applying the same optimization model of the European electricity system as in Chapter 2. In Chapter 5, a stochastic optimization model is developed to investigate the impact of uncertain renewable energy deployment paths on optimal investment decisions in the conventional power market. First, a simplified version of the model is used to investigate general effects of this uncertainty. Next, the detailed model, parameterized for the Central European power market, is used to quantify the magnitude of effects in a real-world electricity market setting.

To summarize, in this thesis, I use optimization under perfect foresight, stochastic optimization and a theoretical model of cross-border cooperation in RES-E support. In the following, general principles of optimization and, in particular, of stochastic optimization are briefly outlined. In addition, economic principles of efficiency and distribution are recaptured.

[2]In optimization models, one target function is minimized or maximized (while satisfying additional restrictions), while equilibrium models require a set of conditions to be satisfied in an equilibrium. This set of equations, which has to be satisfied in equilibrium, can for example represent the target functions of different market participants. Note that an optimization model can be reformulated as an equilibrium model. In fact, equilibrium models generalize optimization models (Gabriel et al. (2013), Minot (2009)).

Optimization

Optimization methods generally minimize or maximize a target function under several restrictions. In this thesis, I use linear optimization models, which imply that all variables in the target function and the restriction equations are linear (Neumann and Morlock (2002)). The main advantage of linear optimization is that problems are easier to computationally solve and thus applicable to large-scale models, including a large number of variables. However, using linear optimization also implies, e.g., that demand has to be assumed to be inelastic and that perfect competition as well as exogenous cost developments have to be assumed. As will be discussed in Chapter 3, demand in electricity markets is relatively inelastic, especially in the short term. The degree of competitiveness, and the right instruments to measure it in electricity markets, is a contentious issue (Newberry (2009)). Furthermore, the impact of learning curve effects on the investment cost developments of power plants is controversial. The learning curve concept suggests that with each doubling of the world-wide installed capacity of a technology, the costs of this technology are reduced by a certain percentage. As discussed in Jägemann et al. (2013), a caveat to the learning curve concept is that past trends are extrapolated to the future, which is not always appropriate. Moreover, when regional electricity systems (and not the world-wide electricity system) are optimized, including endogenous learning curves is difficult and requires an assumption about the relation between regional and world-wide technology expansions.

In stochastic optimization, a target function is also minimized or maximized under certain restrictions. In addition to deterministic optimization, stochastic optimization takes into account that the realization of one or several parameters is uncertain. In electricity systems, investment decisions for new power plants are typically characterized by long planning, construction, amortization and technical lifetimes. Future revenues and production costs are, however, unknown because, e.g., the development of fuel costs, electricity demand and political decisions is uncertain from an investor's perspective (Weber (2005)). The aim of stochastic optimization is to find an optimal decision (e.g., for a power plant investment) given that the future is uncertain. This optimal decision may include postponing decisions until new information is revealed or hedging against realizations of the random parameters, for example, by considering a more balanced technology mix than the one which is optimal given perfect foresight (see e.g., Gardner (1996), Gardner and Rogers (1999), Hobbs and Maheshwari (1990) and Patino-Echeverri et al. (2009)). In general, the optimal solution under uncertainty differs from the optimal solution(s) given perfect foresight and, in particular, also from the optimal solution given an average realization of the random parameter. In fact, a solution which is optimal when assuming an expected value of the uncertain parameter may be very costly once extreme values of the uncertain parameter are realized (Birge (1997), Conejo et al. (2010)).

In order to take into account uncertainty in an optimization model, an assumption on the distribution of the uncertain parameters is needed (Birge (1997)). Within the stochastic optimization process, perfect information about the distribution of uncertainty is assumed. Making an adequate assumption about the distribution of the uncertain parameter(s) is challenging in many cases. Only in some cases, e.g., when modeling uncertainty about realizations of meteorological phenomena, such as wind speeds and solar radiation, can the distributions be estimated based on historical data. In contrast, when modeling uncertainty about the development of demand, fuel costs and, in particular, technological progress or political decisions, occurrence probabilities of different realizations of the random parameters are difficult to estimate. Therefore, when interpreting the results of a stochastic optimization model, it is important to keep in mind which kind of uncertainty has been taken into account and which assumptions on the probability distributions have been made in the modeling process.

In stochastic programming, uncertainty is often taken into account either by two-stage or by multi-stage stochastic programs.[3] In two-stage programs, a decision for the so-called 'first-stage' or 'here-and-now' variables has to be made first under uncertainty about the realization of the random parameters. In the second stage, information about the uncertain parameters is revealed and the so-called 'second-stage' or 'wait-and-see' variables are optimized as a best response to this revealed information (Birge (1997) and Conejo et al. (2010)). For example, in investment planning, the first-stage variables are the investment variables and the second-stage variables the dispatch variables. In a multi-stage program, decisions under uncertainty are made in several subsequent stages, taking into account that the transition probabilities between different nodes as well as the realization of the random parameters in different stages are interdependent. For example, in the context of weather uncertainty, a two-stage stochastic program is applied by Nagl et al. (2013) and a multi-stage stochastic program by Sun et al. (2008). Nagl et al. (2013) analyze the impact of weather uncertainty on investment decisions and electricity system costs. In their model, investment decisions have to be made in the first stage without knowing the weather realization during the lifetime of the plants. Thus, only one decision under uncertainty has to be made, before constructing a plant. In contrast, Sun et al. (2008) analyze the influence of short-term uncertainties surrounding the infeed of wind in a stochastic dispatch optimization model. In their model, decisions under uncertainty have to be made in each state, taking into account that wind infeed

[3]An additional strand of stochastic optimization is chance-constrained programming. Chance-constrained programming is applied if certain constraints should "hold with some probability or reliability level" and can not be applied if all constraints have to hold under all possible outcomes of the random parameters (Birge (1997)).

levels between different stages are strongly correlated. In a similar fashion, Chapter 5 of this thesis presents how a multi-stage stochastic program is developed to account for implementation risks in RES-E deployment when optimizing the development of the conventional power plant fleet. By using a multi-stage model, it is taken into account that the installed RES-E capacities (and therefore the RES-E penetration level) in one stage depends on the deployment realized in previous stages. Moreover, the multi-stage model represents the fact that more and more information about the progress in RES-E deployment is revealed over time.

One challenge facing stochastic optimization is that problems can become very large and difficult to solve (Sen (2001), Birge (1997)). Due to high computational times of stochastic models, not all parameters which are uncertain in reality can also be represented as uncertain parameters in the model. Thus, one aim of stochastic modeling is to identify the direction and the magnitude of the effect of including the uncertain nature of different parameters. Thereby, those parameters can be identified which have a large effect on model results and thus should be included as uncertain parameters in optimization calculus (Hobbs and Maheshwari (1990)). Moreover, knowledge about the impact of different uncertainties on optimal decisions can help the results of deterministic optimization models to be interpreted more accurately (e.g., as lower bounds for cost calculations).

Measures to analyze the impact of uncertainty on model results are the Expected Value of Perfect Information (EVPI) and the Value of the Stochastic Solution (VSS). The EVPI estimates the costs induced by uncertainty or, expressed differently, the “value of knowing the future with certainty” (Birge (1997)). It is calculated as the additional costs resulting from stochastic optimization, compared to the probability-weighted additional costs resulting from the deterministic optimization problems, given perfect foresight, of different realizations of the parameter. Thus, the EVPI measures the impact of uncertainty given that stochasticity is taken into account in the optimization process (see Figure 1.1).

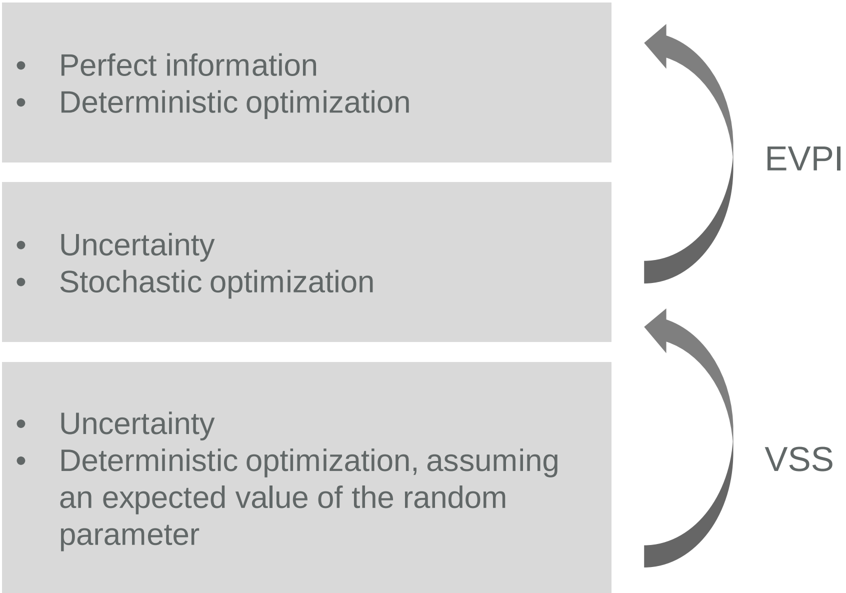

Figure 1.1: The calculation of EVPI and VSS
Source: Own illustration. If not indicated otherwise, all figures in this thesis are own illustrations.

In contrast, the VSS measures the benefit of using stochastic programming when the future is uncertain. The VSS is calculated as the probability-weighted additional costs, arising under different realizations of the random parameter, if the optimization is performed assuming the expected value of the random parameter is realized, compared to the costs arising under stochastic planning. A large VSS indicates that it is worth it to use stochastic optimization because the optimization for the expected value of the random parameter leads to significantly different results (Birge (1997)). Both measures, the EVPI and the VSS, help to identify those uncertain parameters, which have a large impact on model results (Hobbs and Maheshwari (1990)).

Efficiency and distributional effects

The objective of the electricity market optimization models used in this thesis (namely, the newly developed multi-stage model in Chapter 5 and the deterministic optimization model DIMENSION in Chapters 2 and 4) is to minimize total costs of electricity supply under the restriction of meeting electricity demand as well as under a set of additional restrictions (e.g., environmental targets). Under the assumption of a price-inelastic electricity demand, this cost minimization problem is equivalent to the welfare maximization problem of the social planner (Sauma and Oren (2005)).

Weakening restrictions in the optimization model implies that overall welfare can be increased and that electricity demand can be satisfied at lower costs. However, welfare of individual groups does not necessarily increase. As an example, the introduction or facilitation of trade between different regions in the electricity system corresponds to a weakening of trading restrictions. Without the possibility of trade (e.g., trading of electricity, CO_2 -emission certificates or RES-E targets), demand or political targets have to be met in each region individually. When trade is possible, differences in generation costs or CO_2 mitigation costs between regions can be exploited. Figure 1.2 illustrates the effects of electricity trade between two regions with different supply curves for electricity generation. It can be seen that overall welfare increases compared to the situation under autarky (by $c+e+f$). However, due to the convergence of electricity prices, consumers in region A, the 'low price region' before trade, are worse off than without trade (consumer rents decrease by $a+b$), while producers benefit from trade (producer rents increase by $a+b+c$). In contrast, in region B, the 'high price region' before trade, consumer rents increase by $(d+e+f)$ and producer rents decrease by d.

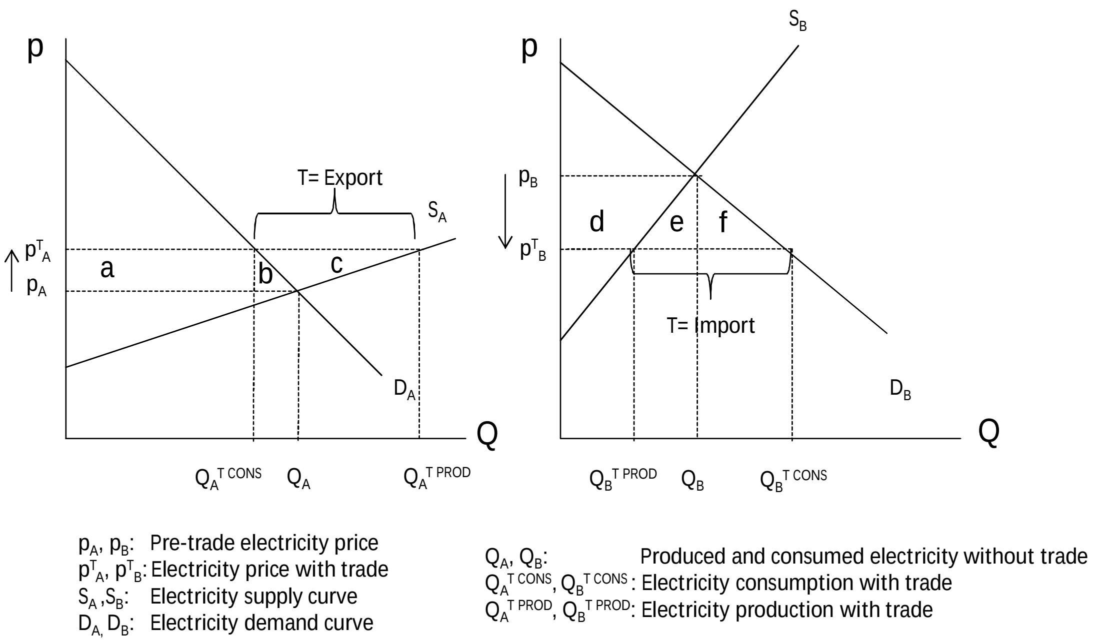

FIGURE 1.2: Welfare effects of electricity trade
Source: Adapted from Kapff and Pelkmans (2010).

Likewise, in general trade theory, it has been shown that international trade increases overall welfare but is not beneficial for all groups. For example, in the neoclassical trade theory model of Heckscher and Ohlin, it is shown that trade between regions with a different factor endowment increases overall welfare (see, e.g., Krugman and Obstfeld (2009)). The model assumes that different goods have different input factor intensities. When international trade is possible, regions specialize in the production of the good which is intensive in the factor that is relatively abundant in comparison to the other factor. Figure 1.3 illustrates the effect of different factor endowments on the production possibility frontier (PPF) in two regions, as well as the effect of trade on the welfare in both regions.[4] Assume that the production of product A is intensive in the input factor 1, which is relatively abundant in country A. Vice versa, assume that the product B is intensive in the input factor 2, which is relatively abundant in country B. With the possibility of trade, country A will specialize in the production of product A, country B in the production of product B. The relative output prices of the two products converge on the international level and, in both countries, a higher community indifference curve (CIC*) can be reached (and thus, also overall welfare increases).

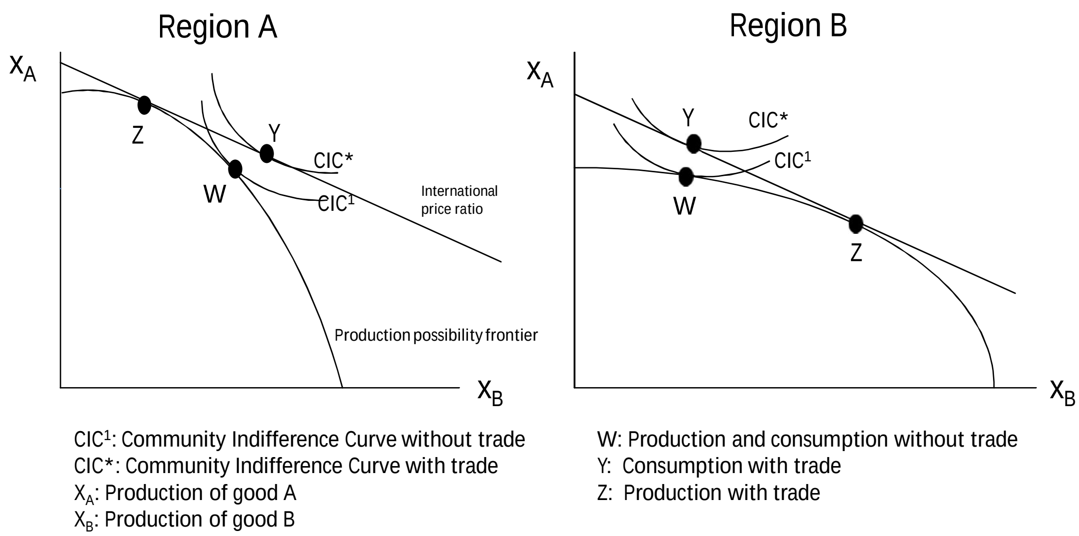

FIGURE 1.3: Effects of international trade in the Heckscher-Ohlin model
Source: Based on Ströbele and Wacker (1995) and Zweifel and Heller (1992).

However, as shown in the Stolper-Samuelson theorem, the output price changes also affect the relative factor prices in both countries such that owners of the factor which is relatively abundant (scarce) in a country benefit (lose) from trade (see, e.g., Zweifel and Heller (1992)).[5] Consequently, the introduction of trade is normally not a pareto-improvement, which would require that at least one individual benefits from trade while no individual is worse off than without trade (Breyer (2004)). However, if the winners are able to compensate the losers and would still be better off than without trade, the introduction of trade, accompanied with transfers, could potentially be a pareto-improvement ('Kaldor-Hicks criteria'; see, e.g., Gravelle and Rees (2004)). In other terms, as pointed out by Sauma and Oren (2005), whether an increase of social welfare is a pareto-improvement essentially depends on the "availability of adequate and

[4] A production possibility frontier (PPF) represents the opportunity costs of producing one good in terms of sacrificing output of the other good. As all input factors available in the economy are completely used for all production combinations of the two goods, which are located on the PPF, a higher production of one good necessarily leads to a lower production of the other good (see, e.g., Breyer (2004)).

[5] In the context of electricity systems, different regions have different endowments, e.g., in sites with high wind speeds or different production possibilities for conventional electricity, e.g., due to different endowments in lignite.

costless (without transaction costs) transfer mechanisms". In practice, such compensation mechanisms are difficult to implement (Breyer (2004), Gravelle and Rees (2004), Sauma and Oren (2005)). Thus, redistribution effects, which come along with policies that improve overall welfare, play an important role in their practical implementation. Therefore, in Chapters 3 and 4, I theoretically and numerically analyze redistribution effects resulting from the introduction of cross-border cooperation in RES-E support, which can essentially be interpreted as a cross-border trade of renewable energy targets.

1.3 Thesis outline

This thesis consists of four essays, dealing with two main topics. Chapters 2, 3 and 4 analyze the effects of cross-border cooperation in the support of renewable energies and Chapter 5 analyzes optimal investment and dispatch decisions of conventional power plants under uncertain future renewable energy deployment paths.

While each chapter of this thesis can be read separately, Chapters 2, 3 and 4 are closely interrelated. In Chapter 2, the effect of European-wide cooperation in renewable energy support on electricity system costs is quantified for the period 2020 to 2030. In addition, this chapter qualitatively investigates why European member states mostly rely on national renewable energy production in order to achieve their renewable energy targets instead of cooperating with other countries. As a result from this qualitative analysis, we find that undesired redistribution effects resulting from cross-border cooperation seem to be a major reason impeding the use of cooperation mechanisms in practice. Therefore, within Chapters 3 and 4, redistribution effects arising from cross-border cooperation are analyzed in-depth. Chapter 3 provides a theoretical analysis of redistribution effects, taking into account effects of different regional RES-E deployments on regional power markets and regional renewable energy markets. Chapter 4 directly builds on the theoretical analysis in Chapter 3 and quantifies the effects shown in the theoretical model for the case of the European power system.

Chapter 5 deals with a distinctive subject, namely the optimization of power plant investments under uncertainty. In the following, the content of each chapter is briefly summarized.

1.3.1 Promotion of electricity from renewable energy in Europe post 2020 - the economic benefits of cooperation

The analysis presented in Chapter 2 quantifies the economic benefits of European-wide cooperation in RES-E support and qualitatively investigates obstacles to the implementation of cooperation mechanisms. It has been published in the Working Paper Series of the Institute of Energy Economics at the University of Cologne (Fürsch and Lindenberger (2013)). The paper has been written in co-authorship with Dietmar Lindenberger and I am the leading author of this paper. The motivation for this paper is that the availability of renewable energies differs significantly across European regions. Consequently, European cooperation in the deployment of renewable energy potentially yields substantial efficiency gains. However, for achieving the 2020 renewable energy targets, most countries purely rely on domestic production. In this paper, we analyze the benefits of cooperation compared to continuing with national renewable energy support after 2020. We use an optimization model of the European electricity system and find that compared to a 2030 CO_2 -only target (-40% compared to 1990), electricity system costs increase by 5 to 7% when a European-wide renewable energy target for electricity generation (of 55%) is additionally implemented. However, these additional costs are 41 to 45% lower than the additional costs which would arise if the renewable energy target was reached through national support schemes (without cooperation). Furthermore, the cost reduction achieved by cooperation is quite robust with regard to the assumptions on interconnector extensions and investment cost developments of renewable energy technologies. In practice, however, administrative issues and questions concerning the fair sharing of costs and benefits between the member states represent major obstacles that need to be tackled in order to reach renewable energy targets at the lowest possible cost.

1.3.2 Redistribution effects resulting from cross-border cooperation in support for renewable energy

In Chapter 3, I theoretically analyze redistribution effects resulting from cross-border cooperation in support for renewable energy. This analysis has not yet been published and I am the sole author of this analysis. The background for this analysis is that international cooperation in achieving renewable energy targets, e.g., via a common tradable green certificate market, increases overall welfare. However, cooperation in the support of electricity from renewable energy sources also leads to regional price effects, from which some groups benefit while others lose. On a regional level, the introduction of cross-border cooperation in RES-E support generally has an opposite effect on support expenditures and wholesale electricity prices, as long as grid congestion between the different regions exists. In this paper, the redistribution effects resulting from cooperation in RES-E support are analyzed in terms of consumer rents and producer profits per country. A theoretical model is used to show under which conditions different groups benefit or suffer from the introduction of cooperation. Findings of the analysis include that effects on consumers and total producers per country can only be clearly determined if no grid congestions between the countries exist. If bottlenecks in the transmission system exist, the relationship between the slopes of the renewable and the non-renewable marginal generation cost curves for electricity generation as well as the level of the RES-E target essentially determine whether these groups benefit or lose from the introduction of green certificate trading. In contrast, system-wide welfare always increases once cooperation in RES-E support is introduced. Similarly, welfare on the country level always increases (compared to a situation without RES-E cooperation) if the countries are perfectly or not at all physically interconnected. In the case of congested interconnectors, the sum of producer and consumer rents in a country may also decrease under certain conditions. However, in this case the level of congestion rents is also influenced by the introduction of RES-E cooperation. Therefore, in this case, there always exists a possible distribution of congestion rents between the countries which ensures that each country benefits from the introduction of certificate trade.

1.3.3 Who benefits from cooperation? - A numerical analysis of redistribution effects resulting from cooperation in European RES-E support

In Chapter 4, I numerically quantify redistribution effects potentially arising from cooperation in RES-E support in the European power system. This analysis has not yet been published and I am the sole author of this analysis. The quantification of redistribution effects builds on the theoretical analysis presented in Chapter 3. A dynamic investment and dispatch optimization model of the European electricity system is used to investigate which groups potentially benefit from cooperation and which groups would be worse off compared to a situation in which national RES-E targets are reached solely by domestic RES-E production. In the analysis, cooperation in RES-E support is implemented as a European-wide green certificate trading scheme. Main findings of the analysis include that in the European electricity system, effects of the change in the certificate price in most countries would overcompensate for the effects of the change in the wholesale electricity price. Thus, in most countries with comparatively high (low) generation costs for renewable energies, consumer rents increase (decrease) due to cooperation and producers yield lower (higher) profits. In addition, it is found that the magnitude of redistribution effects between the individual groups is quite large: In some countries, the change in consumer rents or producer profits resulting from cooperation is nearly twice as high as the overall welfare effect of cooperation in the whole European electricity system. Moreover, the benefit different countries have from cooperation varies substantially. In our analysis, we find that Germany would by far have the largest (absolute) benefit of cooperation, achieved by significant reductions of RES-E target compliance costs via certificate imports. Finally, we find that the sign of redistribution effects is quite robust to different developments of interconnector extensions, the CO_2 price and RES-E investment costs. The magnitude of redistribution effects, in contrast, is in some countries sensitive to these assumptions (especially with regard to the assumption on the CO_2 price).

1.3.4 Optimization of power plant investments under uncertain renewable energy deployment paths: A multi-stage stochastic programming approach

The analysis presented in Chapter 5 has been published in Fürsch et al. (2013b). The essay has been written in co-authorship with Stephan Nagl and Dietmar Lindenberger and I am the leading author of the paper. The paper investigates the impact of uncertain renewable energy deployment paths on investment planning for conventional power plants and storage units. Electricity generation from renewable energy sources (RES-E) is planned to increase significantly within the coming decades. However, due to uncertainty surrounding the progress of necessary infrastructure investments, public acceptance and cost developments of renewable energies, the achievement of political plans is unclear. Implementation risks of renewable energy targets are challenging for investment planning, because different shares of RES-E fundamentally change the optimal mix of dispatchable power plants. Specifically, uncertain future RES-E deployment paths induce uncertainty about the level and the steepness of the residual load duration curve and the hourly residual load structure. In this paper, we show how uncertain future RES-E penetration levels impact the electricity system and try to quantify effects for the Central European power market. We develop a multi-stage stochastic investment and dispatch model to analyze effects on investment choices, electricity generation and system costs. Our main findings include that uncertainty about the achievement of RES-E targets significantly affects optimal investment and dispatch decisions. In particular, plants with a medium capital/operating cost ratio have a higher value under uncertainty. We find that this technology choice is mainly driven by the uncertainty about the level rather than about the structure of the residual load. Furthermore, given larger investments in plants with medium capital/operating cost ratio under uncertainty, optimal investments in storage units are lower than under perfect foresight. In the case of the Central European power market, costs induced by the implementation risk of renewable energies are rather small compared to total system costs.

Chapter 2

Promotion of electricity from renewable energy in Europe post 2020 - the economic benefits of cooperation

2.1 Introduction and background

For the year 2020, the European Union (EU) has agreed upon a target of 20% for the share of renewable energy sources (RES) in gross final energy consumption, comprising the electricity, heating and cooling and transportation sectors. A sectoral breakdown of the national targets was defined by each EU member state in the National Renewable Energy Action Plans (NREAP). In addition, the member states were asked to notify via their NREAPs, whether they plan to make use of the cooperation mechanisms defined in the European Directive 2009/28/EC. The purpose of these cooperation mechanisms is to facilitate a cost reduction in achieving national targets by promoting RES in a different member state or in a third country in which generation costs are lower. Across different European regions, full load hours of fluctuating renewables such as wind and solar technologies vary by factors up to 100% (Fürsch et al. (2013a)) such that substantial potential benefits from cross-border cooperation arise (see, e.g., EWI (2010)). Nevertheless, the national schemes for target achievement stated in the NREAPs rely almost purely on domestic RES production and hardly envisage the use of cooperation mechanisms.

Beyond 2020, a European renewable energy target has not yet been defined. However, in October 2009, the European Council agreed upon the target to reduce greenhouse gas emissions by 80-95% by 2050 compared to 1990 levels. Within the European "Roadmap for moving to a competitive low carbon economy in 2050" an emission reduction of 40% by 2030 was identified as an important milestone (EC (2011a)). Furthermore, in the EU Energy Roadmap, possible decarbonization pathways to reach the 2050 target were analyzed. All decarbonization pathways outlined in the Roadmap include substantial deployments of renewable energies within the coming decades, reaching RES-E shares between 50% and 60% in 2030 (EC (2011b)).

In this paper, we analyze the benefits of a larger use of cooperation mechanisms beyond 2020, compared to effects of continuing with national RES support as currently envisaged by almost all member states for the period up to 2020. We focus on the electricity sector and use a large-scale linear optimization model of the European power system, including investment and dispatch decisions for thermal, renewable and storage technologies. This modeling approach allows us to take into account the interdependencies between regional renewable deployment and its effects on the power system. On the one hand, cooperation may possibly lead to higher RES-E integration costs because of a higher regional concentration of RES-E generation on sites with favorable meteorological conditions, which, however, are often located far from demand centers. On the other hand, in electricity systems with grid congestions between market regions, cooperation may possibly also induce cost-savings in the non-RES-E sector. In this case, cooperation in RES-E support enables an overall optimization of electricity generation, including renewable and non-renewable sources. Furthermore, we analyze the robustness of cooperation gains with regard to interconnector capacity extensions and RES-E investment cost developments, which has thus far been neglected in almost all numerical analyses of cooperation gains. Interconnector extensions in Europe currently progress very slowly (EWI and energynautics (2011)). If planned interconnector extensions are not realized, gains from cooperation may be lower since electricity cannot be transported from favorable sites to demand centers. Also, cooperation gains may be sensitive to RES-E investment cost developments, especially in terms of the resulting cost-difference between RES-E technologies available in all countries (e.g., biomass, photovoltaics) and those renewable energy sources that are regionally concentrated (e.g., wind offshore).

Our main findings include that compared to a CO_2 -only target for 2030 (-40% compared to 1990 emission levels), electricity system costs increase by 5 to 7% when a European-wide renewable energy target for electricity generation (of around 55%) is additionally implemented. However, these additional costs are 41 to 45% lower than the additional electricity system costs which would arise if the renewable energy target was reached through national support systems (without cooperation). Furthermore, we find that the cooperation gains (i.e., the cost reduction achieved by cooperation) are quite robust. Though the optimal regional and technological generation mix is influenced by different levels of interconnector extensions and varying investment costs for RES-E technologies, cooperation gains decrease only slightly when interconnectors are not further extended (compared to today) and depend only slightly on assumptions on investment cost developments of renewable energy technologies. With regard to the practical implementation of cooperation, however, unclear administrative issues and questions concerning the fair sharing of costs and benefits between the member states represent major obstacles that need to be tackled in order to reach renewable energy targets at the lowest possible cost.

The remainder of the paper is structured as follows: In Section 2.2 we provide an overview of related literature. In Section 2.3 we describe the methodological approach of our analysis and present the most important assumptions underlying the scenario analysis. Section 2.4 covers model results and interpretations. In Section 2.5 we address possible obstacles to cooperation, which need to be tackled in order to increase cooperation between member states. Conclusions are drawn in Section 2.6.

2.2 Related literature and contribution of the current work

The discussion surrounding stronger cooperation in renewable energy support in Europe has a history spanning more than a decade. Already in the context of the 2001 EU Renewables Directive (2001/77/EC), which defines (indicative) renewable targets for 2010, have many authors discussed the potential benefits of European-wide harmonized support systems (e.g., Voogt et al. (2001) and Del Río (2005)) or the suitability of different support scheme designs for a harmonized approach (e.g., Lauber (2004), Munoz et al. (2007) and Söderholm (2008)). For the target year 2020, possible gains from harmonization have been quantified, e.g., by Ragwitz et al. (2007), EWI (2010), Capros et al. (2011), Aune et al. (2012) and Jägemann et al. (2013). Although the authors use different model types, which in turn have different regional and technological coverage, all authors find that cooperation in RES may yield substantial cost savings. An overview of the models used for these analyses and the quantified cooperation gains is provided in Table 2.1.

Table 2.1: Overview of related literature

Authors	Model used	Cooperation gains are quantified in terms of:	Resulting cooperation gains
Voogt et al. (2001)	REBUS	additional costs of RES-E supply	- 15 to - 70% (depending on target distribution)
Ragwitz et al. (2007)	Green-X	support expenditures for RES-E (EUR/MWh)	- 33 to - 37% or up to + 12% (depending on support design)
EWI (2010)	LORELEI & DIME	total costs of RES-E generation	-20% (cumulated 2008-2020)
Capros et al. (2011)	PRIMES	total energy system costs	-16 to -25% (depending on other policy options, e.g., the implementation of CDM)
Aune et al. (2012)	LIBEMOD	additional energy system costs (due to RES target)	-70% (yearly costs)
Jägemann et al. (2013)	DIMENSION	total costs of electricity generation	- 10% (cumulated 2010-2050)

While Voogt et al. (2001) quantify the benefits of a EU-wide cooperation for the achievement of the 2010 RES-E targets, all other papers analyze cooperation gains in the context of the 2020 targets. Voogt et al. (2001) and EWI (2010) analyze cooperation gains in terms of cost savings for electricity supply from RES, either in terms of absolute costs (EWI (2010)) or in terms of additional costs with regard to electricity market prices (Voogt et al. (2001)). In contrast, Ragwitz et al. (2007) compare support expenditures for RES-E under different promotion systems. Capros et al. (2011) and Aune et al. (2012) apply multi-market models and determine cost savings in terms of energy system costs, including electricity supply costs as well as costs in other energy markets (e.g., natural gas). Jägemann et al. (2013) use a large-scale dynamic optimization model of the European electricity generation sector, which covers thermal, renewable and storage technologies. The authors determine the excess costs of technology-specific national RES-E targets for 2020, as defined in the NREAPs, compared to a technology-neutral European-wide RES-E target for 2020.

We use the same general modeling framework as Jägemann et al. (2013) to determine the benefits of European cooperation in the decade 2021 to 2030 and to analyze the robustness of cooperation gains with regard to interconnector extensions and RES-E investment costs. Cooperation gains in the decade 2021 to 2030, a period that is currently in the focus of the political debate, have thus far hardly been analyzed. To our knowledge, only one other analysis of cooperation gains arising in the period post 2020 has been published. The study conducted by Booze & Company et al. (2013) mainly deals with the effects of larger European electricity and gas market integration in general. In addition, Booze & Company et al. (2013) calculate the cost savings achieved by a reallocation of photovoltaic and wind capacities (that are installed in the year 2030 in a scenario taken from the EU Energy Roadmap (EC (2011b))) to regions where higher load factors can be achieved.[6] In their analysis, generation levels taken from the EU Roadmap scenario are held constant when reallocating the photovoltaic and wind capacities. A cost reduction is achieved, because less capacities are required to generate the same amount of wind-based and photovoltaic-based electricity (compared to the original allocation of capacities). In contrast, our approach of optimizing investment and dispatch decisions of power plants, both in the cases with and without cooperation, takes into account that not only a different regional allocation but also a different technological generation mix may be optimal when European-wide cooperation is possible.

In addition, the influence of different interconnector capacity restrictions and of different RES-E investment cost developments on possible gains from cooperation has thus far been neglected in almost all numerical analyses of cooperation gains. To our knowledge, only Booze & Company et al. (2013) indicate a range of cost savings from using favorable renewable energy production sites in Europe, depending on different photovoltaic costs.[7] Moreover, the influence of limited interconnector extensions on coordinated RES-E supply has recently been addressed in a theoretical two-country model by Laffont and Sand-Zantman (2012). Their key finding is that the optimal level of coordination in RES-E support depends on the level of transmission capacity between the two countries. Moreover, Saguan and Meeus (2012) analyze the interaction between cooperation in renewable energy support and cooperation in transmission planning in a two-region

[6] Note also that Booze & Company et al. (2013) refer to a Siemens AG presentation in which cost savings from a reallocation of wind and photovoltaics capacities in the period 2012-2030 are shown. However, no further information on the applied methodology or the assumed input parameters is provided in this presentation.

[7] In the analysis of Booze & Company et al. (2013), the level of photovoltaic investment costs influences the magnitude of the cost savings, because it determines the value of the photovotaic capacities which can be reduced through reallocation. In contrast, in our analysis, different investment cost assumptions influence the optimal generation and capacity levels of various renewable energy technologies (both in the cases with and without cooperation).

modeling example. However, for a real-world electricity system, the influence of interconnector extensions on the level of cooperation gains, to our knowledge, has not yet been quantified.

2.3 Methodological approach and assumptions

We use a dynamic linear dispatch and investment model for Europe incorporating thermal, storage and renewable technologies. The model is an extended version of the long-term investment and dispatch model DIMENSION of the Institute of Energy Economics (University of Cologne), as presented in Richter (2011). The model in its extended version has been recently applied, e.g., by Fürsch et al. (2013a) (who provide a detailed model description).[8] In the following, we briefly summarize the main model characteristics (Section 2.3.1) and give an overview of the input parameters chosen for the analysis presented (Section 2.3.2).

2.3.1 Model description

The model minimizes total discounted system costs of the European electricity system. These costs comprise investment, fixed operation and maintenance, variable production and ramping costs.[9] Costs are minimized subject to the conditions of meeting hourly electricity demand in each market region and of ensuring security of supply. For the latter condition, securely available generation capacities must be sufficient to cover peak demand (increased by a security margin). In addition, European-wide CO_2 emissions are limited by an emission cap. RES-E targets must be met either on a national or on a EU-wide level, depending on the scenario. Furthermore, the electricity infeed and/or the amount of construction of certain technologies is restricted due to meteorological conditions (such as wind speed, solar radiation and water inflows to hydro reservoirs), space potentials (e.g., for wind parks), fuel potentials (e.g., for biomass or lignite) or political restrictions (such as nuclear phase-out plans). Curtailment of renewable energy infeed is endogenously chosen by the model as long as this option reduces system costs (e.g., because ramping costs can be avoided). Electricity import and export streams are limited by exogenously defined net transfer capacity values between market regions.

[8]The DIMENSION model is based on the DIME model of the Institute of Energy Economics (Bartels (2009)). DIME has been applied, e.g., by Nagl et al. (2011b), Paulus and Borggrefe (2011), Grave et al. (2012) and Fürsch et al. (2012). The extended version of the DIMENSION model, as presented in Fürsch et al. (2013a), includes most elements of the renewable energy investment model LORELEI (Wissen (2011)).

[9]In contrast, combined heat and power plants can earn incomes from the heat market, which are deducted from the objective value. Thus, the objective value only includes costs induced by the supply of electricity.

Within market regions, grid copper plates are assumed. Further model elements are described in Richter (2011).

Within this analysis, we model all member states of the European Union (with the exception of Malta and Cyprus), Switzerland and Norway. Different wind and solar conditions throughout Europe are captured by modeling 47 wind onshore regions, 42 wind offshore regions and 38 photovotaic regions, which are determined according to meteorological data (EuroWind (2011)).[10] The different hourly, daily and seasonal characteristics of renewable infeed and electricity demand are captured by modeling four typical days per model year.

The model incorporates thermal, renewable and storage technologies. The existing European power plant fleet is represented by different vintage classes, which account for different technical properties such as conversion efficiencies. Thermal power plants can be equipped with combined-heat-power-technology (CHP) and/or carbon-capture-and-storage (CCS) (from 2030 onwards). We assume that, before 2025, only nuclear plants already under construction today can be commissioned. However, existing plants can be retrofitted to increase plant lifetime by 10 years. Endogenous storage investments are only possible for compressed-air-storage technology (CAES), as pump storage and hydro storage potentials are already largely used and further investments are often difficult due to environmental concerns. Renewable technologies covered by the model include photovoltaics (base and roof), concentrated solar power (CSP), onshore wind, offshore wind (deep and shallow water), biomass (solid and gas), hydro (run-of-river and storage) and geothermal power. In addition, different wind turbine classes, available at different points in time, are modeled to represent technological progress (see Wissen (2011) and EWI and energynautics (2011)).

2.3.2 Assumptions

Table 2.2 depicts the assumed final electricity demand development per country up to 2030. Up until 2020, the demand development is based on the 'additional energy efficiency' scenario of the NREAPs (Beurskens et al. (2011)).[11] For the development after 2030, electricity demand growth rates are based on EWI and energynautics (2011). In addition, the potential heat generation in CHP plants per country is depicted (based on EURELECTRIC (2008) and Capros et al. (2010); see also EWI and energynautics (2011)).

[10] For an overview of these regions, see EWI and energynautics (2011).

[11] For Norway and Switzerland, which do not have a NREAP, electricity demand growth rates based on EWI and energynautics (2011) have been applied.

TABLE 2.2: Final electricity demand [TWh_{el}] and potential heat generation in CHP plants [TWh_{th}]

	2010		2020		2030	
Austria (AT)	66	(40.7)	74	(41.2)	80	(41.5)
Belgium (BE)	97	(14.5)	111	(14.7)	119	(14.8)
Bulgaria (BG)	36	(6.8)	37	(6.9)	41	(7.0)
Czech Republic (CZ)	70	(54.0)	84	(55.1)	95	(55.7)
Denmark (DK)	36	(54.0)	38	(54.7)	43	(55.1)
Estonia (EE)	10	(1.4)	11	(1.4)	12	(1.4)
Finland (FI)	88	(64.4)	102	(65.2)	109	(65.7)
France (FR)	533	(31.2)	546	(31.6)	585	(31.8)
Germany (DE)	604	(191.0)	562	(192.4)	562	(192.9)
Greece (GR)	59	(17.1)	68	(17.4)	79	(17.7)
Hungary (HU)	43	(13.9)	51	(14.2)	58	(14.4)
Ireland (IE)	29	(3.2)	33	(3.2)	35	(3.3)
Italy (IT)	357	(166.1)	375	(169.2)	433	(171.7)
Latvia (LV)	7	(6.4)	9	(6.5)	10	(6.6)
Lithuania (LT)	7	(4.7)	9	(4.8)	10	(4.9)
Luxembourg (LU)	6	(0.9)	7	(0.9)	7	(0.9)
Netherlands (NL)	124	(112.8)	136	(114.3)	146	(115.1)
Norway (NO)	104	(3.6)	119	(3.6)	127	(3.6)
Poland (PL)	141	(91.5)	170	(93.3)	191	(94.4)
Portugal (PT)	55	(13.6)	65	(13.9)	75	(14.1)
Romania (RO)	62	(91.5)	74	(93.3)	83	(94.4)
Slovakia (SK)	29	(16.7)	33	(17.0)	38	(17.2)
Slovenia (SL)	14	(1.2)	16	(1.2)	18	(1.2)
Spain (ES)	291	(57.9)	375	(59.0)	433	(59.9)
Sweden (SE)	152	(28.9)	155	(29.3)	166	(29.5)
Switzerland (CH)	59	(0.7)	67	(0.7)	72	(0.7)
United Kingdom (UK)	369	(67.2)	377	(68.1)	404	(68.6)

Table 2.3 depicts the investment cost development up to 2030. Assumptions are based on EWI and energynautics (2011) with the exception of photovoltaic investment costs, which have been adapted in order to account for recent cost degressions (BSW (2011)). Furthermore, investment costs for concentrating solar plants have been adapted according to data from IRENA (2012), Turchi et al. (2010) and Hinkley et al. (2011).

Table 2.3: Investment costs [EUR_{2010}/kW]

	2020	2030		2020	2030
Nuclear	3,157	3,157	Biomass gas	2,398	2,395
Nuclear Retrofit	300	300	Biomass gas - CHP	2,597	2595
Hard Coal	1,500	1,500	Biomass solid	3,297	3,293
Hard Coal - innov.	2,250	1,875	Biomass solid - CHP	3,497	3,493
Hard Coal - CCS	-	2,000	Geothermal (hot dry rock)	10,504	9,500
Hard Coal - innov. CCS	-	2,475	Geothermal (high enthalpy)	1,050	950
Hard Coal - innov. CHP	2,650	2,275	PV ground	1,440	990
Hard Coal - innov. CHP & CCS	-	2,875	PV roof	1,600	1,100
Lignite	1,850	1,850	Concentrated solar power	3,423	2,926
Lignite - innov.	1,950	1,950	Wind onshore 6 MW	1,221	-
Lignite - innov. CCS	-	2,550	Wind onshore 8 MW	-	1,161
OCGT	700	700	Wind offshore 5 MW (shallow)	2,615	-
CCGT	1,250	1,250	Wind offshore 8 MW (shallow)	-	2,512
CCGT - CCS	-	1,550	Wind offshore 5 MW (deep)	3,105	-
CCGT - CHP	1,500	1,500	Wind offshore 8 MW (deep)	-	2956
CCGT - CHP & CCS	-	1,700			
Pump storage	-	-			
Hydro storage	-	-			
CAES	850	850			

Table 2.4 shows the conversion efficiencies, CO_2 emission factors, technical availability, operational and maintenance costs and the technical lifetime for conventional plants (taken from EWI and energynautics (2011)).

Table 2.4: Economic-technical parameters for conventional and storage technologies

Technologies	$\eta(gen)$ [%]	$\eta(load)$ [%]	CO_2 factor [t CO_2 /MWh_{th}]	avail [%]	FOM costs [EUR_{2010}/kW]	Lifetime [a]
Nuclear	33.0	-	0.0	84.50	96.6	60
Hard Coal	46.0	-	0.335	83.75	36.1	45
Hard Coal - innov.	50.0	-	0.335	83.75	36.1	45
Hard Coal - CCS	42.0	-	0.034	83.75	97.0	45
Hard Coal - innov. CCS	45.0	-	0.034	83.75	97.0	45
Hard Coal - CHP	22.5	-	0.335	83.75	55.1	45
Hard Coal - CHP & CCS	18.5	-	0.034	83.75	110.0	45
Lignite	43.0	-	0.406	86.25	43.1	45
Lignite - innov.	46.5	-	0.406	86.25	43.1	45
Lignite - innov. CCS	43.0	-	0.041	86.25	103.0	45
OCGT	40.0	-	0.201	84.50	17.0	25
CCGT	60.0	-	0.201	84.50	28.2	30
CCGT - CHP	36.0	-	0.201	84.50	40.0	30
CCGT - CCS	53.0	-	0.020	84.50	88.2	30
CCGT - CHP & CCS	33.0	-	0.020	84.50	100.0	30
Pump storage	87.0	83.0	0.0	95.00	11.5	100
Hydro storage	87.0	-	0.0	90.00	11.5	100
CAES	86.0	81.0	0.0	95.00	9.2	40

Table 2.5 reports technological and economic characteristics for renewable energy technologies (taken from EWI and energynautics (2011)). The availabilities of fluctuating renewable energy technologies vary on an hourly level and between the different meteorological regions throughout Europe, and are thus not able to be depicted in Table 2.5. The secured capacity corresponds to the share of capacity that can be assumed to be securely available at peak demand (see EWI and energynautics (2011)).

Table 2.5: Economic-technical parameters for renewable technologies

Technologies	Efficiency [%]	Availability [%]	Secured capacity [%]	FOM costs [EUR_{2010}/kW]	Lifetime [a]
Biomass gas	40.0	85	85	120	30
Biomass gas - CHP	30.0	85	85	130	30
Biomass solid	30.0	85	85	165	30
Biomass solid - CHP	22.5	85	85	175	30
Geothermal (HDR)	22.5	85	85	300	30
Geothermal	22.5	85	85	30	30
PV ground	-	-	0	15	25
PV roof	-	-	0	17	25
Concentrated solar power	-	-	40	120	25
Wind offshore 6MW (deep)	-	-	5	152	25
Wind offshore 8MW (deep)	-	-	5	160	25
Wind offshore 6MW (shallow)	-	-	5	128	25
Wind offshore 8MW (shallow)	-	-	5	136	25
Wind onshore 6MW	-	-	5	41	25
Wind onshore 8MW	-	-	5	41	25
Run-of-river hydropower	-	-	50	11.5	100

Table 2.6 depicts the assumed fuel price development up to 2030. Assumptions are based on IEA (2011) and EWI and energynautics (2011). The CO_2 price is determined endogenously in the model by imposing a CO_2 emission reduction (in the power sector) of 20% (40%) compared to 1990 levels by 2020 (2030).

Table 2.6: Fuel costs in EUR_{2010}/MWh_{th}

	2008	2020	2030
Nuclear	3.6	3.3	3.3
Coal	17.28	12.5	12.8
Lignite	1.4	1.4	1.4
Natural gas	25.2	28.1	28.3
Biomass (solid)	15.0-27.7	15.7-34.9	16.7-35.1
Biomass (gas)	0.1-70.0	0.1-67.2	0.1-72.9

2.4 Scenario Analysis

2.4.1 Scenario definition

We compare the costs of achieving a European RES-E share of 55% by 2030 using national RES-E support to the costs of achieving the target under EU-wide cooperation.[12] The RES-E share of 55% was chosen in line with the decarbonization pathways of the EU Roadmap, including RES-E shares between 50% and 60% in 2030 (see Section 2.1). Both national and EU-wide coordinated RES-E support is modeled as a technology-neutral support, implying that technologies with lowest costs are chosen first - either on a national or on an EU-wide level. Moreover, in both cases, the technology-specific national NREAP targets are reached in 2020 (see Beurskens et al. (2011) for an overview), whereas possible gains from cooperation only refer to the subsequent timeframe 2021-2030. We analyze possible gains from EU-wide cooperation in RES-E support for different national target settings as well as for different assumptions regarding interconnector extensions and RES-E investment cost developments. The setting of the national targets is crucial in determining the magnitude of the cooperation gains as the distribution of the targets dictates the reference costs against which the cooperation gains are calculated. The availability of interconnector capacities restricts the use of favorable RES-E sites in regions with low electricity demand and thus presumably also influences the magnitude of the cooperation gains. Similary, the development of RES-E investment costs presumably influences the magnitude of the cooperation gains because cost differences vary between the generation options available in all countries and those that are regionally concentrated. Table 2.7 provides an overview of the modeled scenarios.

Table 2.7: Overview of modeled scenarios

		Energy Economic Assumptions			
		Reference	Without TYNDP	lower wind offshore costs	lower phovoltaic costs
Target Setting	Equal Share Extrapolation Flatrate Growth	national RES-E support vs. EU-wide cooperation			

With regard to the setting of national targets, we model the following cases:

- ‘Equal share’: Each member state must increase its RES-E share up to 55% by 2030.

[12] As the electricity systems of Switzerland and Norway are embedded in the European power system, these two countries are included in the calculation even though the countries are not part of the EU. Norway and Switzerland can therefore contribute in reaching the common RES-E target in the cooperation case. However, we assume that, regardless of the national target setting for the EU member states, the targets for Switzerland and Norway remain close to today´s RES-E shares, which significantly exceed the EU average.

- 'Extrapolation': The RES-E deployment of each country, as stated by its NREAP 2020 target, is extrapolated to 2030.[13]

- 'Flatrate growth': Each member state must increase its 2020 RES-E share by 20 percentage points by 2030.

The different settings of national targets cover a broad range of possible effort sharing agreements. The 'Equal share' target setting results in a large effort for countries that have low RES-E shares in 2020, while other countries (such as Sweden and Austria) already exceed the 55% share in 2020 and thus would not require a further increase in their share. In the 'Extrapolation' case, the greatest effort is demanded from those countries which also made the greatest effort in the 2010-2020 decade. However, these are mostly countries with a high GDP per capita and/or favorable RES-E potentials, as these components were used to determine the 2020 target distribution. The 'Flatrate growth' target setting poses the same burden on all countries as far as the percentage increase is concerned. However, also in this case, the slope of the RES-E merit order curve and the demand development in each country essentially determine the burden imposed by the national targets. An overview of the assumed national RES-E targets can be found in Appendix A.[14]

With regard to interconnector extensions and RES-E investment cost developments, we model the following reference case and sensitivity analyses:

- 'Reference': Interconnectors are extended according to ENTSO-E´s Ten-Year-Network-Development-Plan (TYNDP, see ENTSO-E (2010)). Assumed investment costs for RES-E correspond to those depicted in Table 2.3.

- 'w/o TYNDP': Interconnectors are not extended. Net transfer capacities (NTC) remain at today´s level. All other assumptions are identical to the 'Reference' case.

- 'Lower Offshore Wind Costs': Investment costs for offshore plants are 10% lower than depicted in Table 2.3. All other assumptions are identical to the 'Reference' case.

[13]Note that in order to ensure that a EU-wide target of around 55% is reached by all national target settings the 'Extrapolation' case includes a flatrate increase of 5 percentage points in each country in addition to the extrapolation.

[14]Note that we assume a linear pathway for achieving the 2030 targets and thus also set 2025 RES-E (and CO_2) targets. These 2025 targets are determined as a linear interpolation between the 2020 and the 2030 targets.

- 'Lower Photovoltaic Costs': Investment costs for photovotaic systems are 10% lower than depicted in Table 2.3. All other assumptions are identical to the 'Reference' case.

We model sensitivities with regard to interconnector extensions and to offshore wind and photovoltaic investment costs for two reasons: First, both network extensions and cost degressions of renewables are subject to high uncertainty - either because, e.g., opposition from the local population often leads to delays of planned network extensions or because technological progress is uncertain. Second, both aspects potentially have a high influence on the extent of cooperation gains. Lower interconnector capacities presumably lead to lower gains from cooperation because the best RES-E sites in Europe can be used to a lesser extent. In contrast, lower costs of offshore wind presumably increase the benefit from cooperation, as favorable potentials for offshore wind are regionally concentrated in Northern Europe and can be used to a larger extent in a cooperative European support system. The benefit of using these resources further increases if investment costs of offshore plants are low. Lower investment costs for photovoltaic, on the one hand, may similarly increase the benefit from cooperation due to the increased opportunity of using sites with high solar radiation in the Mediterranean region. On the other hand, potentials (however not necessarily favorable ones) for photovoltaic systems exist in all countries, such that this generation option may be used to a larger extent under a national target scheme. Thus, given lower photovoltaic costs, the achievement of national targets may be less costly.
In the following, we present results for the reference case (Section 2.4.2) and discuss the influence of interconnector extensions and RES-E investment cost developments on potential cooperation gains (Section 2.4.3 and Section 2.4.4, respectively).

2.4.2 Results - Reference case

Table 2.8 depicts differences between the national and the EU-wide RES-E support scenarios in 2030 in terms of European electricity generation and European generation capacities. Regardless of the national target setting (Equal Share, Extrapolation or Flatrate Growth), generation from coal plants, photovoltaic systems and biomass plants is higher when RES-E targets are achieved on a national level, while generation from nuclear plants as well as from on- and offshore wind plants is higher when RES-E support is coordinated on the European level. Capacity differences reflect varying technological and regional generation patterns under national and cooperative RES-E support. On average, photovoltaic systems and wind plants (onshore and offshore) have lower energy outputs in the national support scenarios, because sites with comparatively low solar radiation and low wind speeds are also used in achieving national targets. Thus, e.g., onshore wind capacities in the 'Equal Share' and the 'Flatrate Growth' scenarios are lower when RES-E support is coordinated, although wind onshore generation is higher. In the following differences between the generation and capacity levels under national and cooperative support are discussed in more detail.

Table 2.8: Differences in European electricity generation [TWh] and generation capacities [GW] between national support and cooperation in 2030 (Reference)

Generation [TWh]	Equal Share			Extrapolation			Flatrate Growth		
	national	coop.	**diff.**	national	coop.	**diff.**	national	coop.	**diff.**
Nuclear	866	968	**-102**	978	1011	**-34**	947	1000	**-54**
Lignite	370	362	**7**	366	367	**-1**	369	366	**4**
Coal	480	399	**81**	473	427	**46**	439	413	**26**
Gas	48	56	**-8**	42	67	**-25**	63	61	**3**
Oil	0	0	**0**	0	0	**0**	0	0	**0**
Storage	78	87	**-9**	84	81	**3**	78	85	**-7**
Hydro	551	552	**0**	552	552	**0**	552	552	**0**
Biomass	208	174	**34**	178	170	**8**	186	172	**14**
Wind onshore	706	711	**-5**	689	705	**-16**	704	707	**-3**
Wind offshore	299	359	**-61**	299	335	**-37**	244	345	**-101**
PV	370	325	**45**	324	270	**54**	393	291	**102**
CSP	49	47	**1**	49	48	**0**	49	47	**1**
Geothermal	94	94	**0**	94	93	**1**	94	94	**1**
Others	56	56	**0**	56	56	**0**	56	56	**0**

Capacity [GW]	Equal Share			Extrapolation			Flatrate Growth		
	national	coop.	**diff.**	national	coop.	**diff.**	national	coop.	**diff.**
Nuclear	141	151	**-10**	149	154	**-5**	147	153	**-6**
Lignite	57	56	**2**	56	57	**-1**	57	56	**1**
Coal	73	65	**8**	73	66	**7**	69	65	**3**
Gas	147	147	**-1**	147	147	**0**	151	147	**4**
Oil	5	5	**0**	5	5	**0**	5	5	**0**
Storage	78	82	**-3**	78	76	**2**	74	79	**-4**
Hydro	154	155	**-1**	155	155	**0**	155	155	**0**
Biomass	29	24	**5**	25	24	**1**	26	24	**2**
Wind onshore	315	311	**4**	301	308	**-6**	310	309	**2**
Wind offshore	89	91	**-2**	82	85	**-3**	69	87	**-19**
PV	311	251	**60**	273	205	**68**	330	223	**108**
CSP	11	11	**0**	11	11	**0**	11	11	**0**
Geothermal	13	13	**0**	13	13	**0**	13	13	**0**
Others	11	11	**0**	11	11	**0**	11	11	**0**

Generation from photovoltaic systems, biomass plants and coal plants is higher in the national support scenarios. The reason for higher photovoltaic generation is a higher generation at sites with low solar radiation (e.g, in Belgium, Germany and even in Sweden when a national target of 83% must be reached in the 'Flatrate Growth' scenario) which overcompensates for lower generation at sites with high solar radiation (e.g., in Spain and Portugal), which are used to a higher extent in the cooperative support scenarios. Higher biomass generation in the national support scenarios can be mainly attributed to additional generation in Finland and in the Equal Share scenario also to higher biomass generation in Hungary and Italy. Higher coal generation in the national support scenarios essentially replaces nuclear generation. Generation from nuclear plants is lower on a European level because, in the national support scenarios, RES-E generation in countries with existing nuclear plants or political plans to construct nuclear plants (FR, BG, CZ, PL, SK, RO) is usually higher than in the cooperative scenarios. Due to limited interconnector capacities - despite extensions according to the TYNDP - high nuclear in addition to high RES-E generation would exceed regional demand and export possibilites in these countries. The largest difference between nuclear and coal generation occurs when each country is required to reach a 55% RES-E share ('Equal Share'). This target distribution leads to the highest RES-E generation in France, which impedes the use of French nuclear plants. Generation from wind plants, especially from offshore wind plants, is substantially higher in the scenarios with cooperative RES-E support because wind generation at sites with high wind speeds is associated with comparatively low generation costs. Additional offshore generation in the cooperative (compared to the national) support scenarios mainly comes from Skandinavia, the Netherlands and Ireland. However, offshore generation in the national support scenarios is higher in Germany and, depending on the national target setting, in France and the United Kingdom.

In addition, total RES-E generation is higher in the national support scenarios because RES-E generation exceeds national targets in countries with favorable meteorological conditions for wind- or solar-based electricity generation and low national targets compared to their RES-E potential (e.g., in Portugal and Ireland). This additional RES-E generation contributes to a cost-efficient achievement of the CO_2 emission reduction target. In the cooperative support scenarios, RES-E generation from these favorable sites replaces RES-E generation in other regions and the CO_2 emission reduction target is achieved by a higher generation from nuclear plants.

Additional results of the cost-efficient regional RES-E deployment in the cooperative support scenarios and the respective deviations in the national support scenarios are provided in Table 2.9.[15] The table depicts the RES-E generation per country, depending on the different settings of national targets, both for the national and for the co-operative support scenarios. In Table 2.9, only about half of the countries modeled are depicted. The countries listed are those countries which yield the greatest deviation in RES-E generation from their national targets, when a European-wide cooperation is implemented.

Table 2.9: RES-E generation in national and cooperative support scenarios in 2030 in selected countries [TWh]

	Equal Share			Extrapolation			Flatrate Growth		
	national	coop.	**diff.**	national	coop.	**diff.**	national	coop.	**diff.**
Group A									
Belgium	53	32	**21**	50	32	**18**	49	32	**17**
Finland	60	38	**22**	49	34	**15**	58	34	**24**
Germany	309	258	**51**	364	256	**108**	329	258	**72**
Group B									
France	322	265	**57**	254	252	**3**	275	254	**21**
Czech Republic	52	24	**28**	25	23	**1**	33	24	**8**
Greece	43	46	**-2**	56	42	**14**	47	44	**3**
Poland	105	68	**37**	68	68	**0**	75	68	**7**
Sweden	105	110	**-5**	126	110	**16**	137	110	**27**
United Kingdom	222	210	**13**	234	199	**36**	206	205	**1**
Group C									
Ireland	23	47	**-23**	27	46	**-19**	30	47	**-17**
Netherlands	80	121	**-41**	103	121	**-18**	83	121	**-38**
Norway	127	204	**-77**	127	193	**-65**	127	195	**-68**
Portugal	43	70	**-27**	55	65	**-10**	56	65	**-9**
Spain	238	297	**-59**	244	295	**-51**	260	297	**-37**
Group D									
Italy	238	198	**40**	169	180	**-11**	201	189	**12**

The countries depicted have been clustered into four groups: Countries in the 'A' group are characterized by higher RES-E generation in the national support scenarios compared to the cooperative support scenarios, regardless of the national target setting. Countries in the 'B' group are also characterized by a higher RES-E generation in the national support scenarios under most scenario settings; however, for at least one target setting, hardly a deviation from the cost-efficient generation in the cooperative support scenarios occurs. In countries, belonging to the 'C' group, RES-E generation in the

[15] Note that we use the term 'cost efficient' in the context of a European-wide RES-E target - with a CO_2 emission reduction target only, a smaller share of RES-E would be cost-efficient. In our scenario settings, a European RES-E share of 46% is achieved in 2030 if no additional RES-E target is modeled after 2020. However, this share also includes RES-E generation from plants that were built in order to achieve the NREAP in 2020.

national support scenarios is always lower than in the cooperative support scenarios. These countries are characterized by high wind speeds or high solar radiation. Italy ('D' group) is a special case because, depending on the target setting, RES-E generation in the national support scenarios is either significantly lower or significantly higher than in the cooperative support scenarios.

As a result of the suboptimal regional and technological RES-E generation in the national support scenarios (compared to the cooperative support scenarios), the costs of achieving a RES-E share of 55 % by 2030 are significanty higher in the national support scenarios. Table 2.10 shows the additional electricity system costs in the decade 2021-2030 that are induced by national and EU-wide 2030 RES-E targets as opposed to a 2030 CO_2 target only (-40% compared to 1990 levels). Moreover, the resulting gains from cooperation are shown, expressed as the difference in additional costs of the 2030 RES-E target (compared to the CO_2 target only) with national and with cooperative support. All costs are cumulated from 2021 to 2030 and discounted by 5% (to the base year 2020).

Table 2.10: Additional costs induced by the 2030 RES-E target and cooperation gains (2021-2030)

	Equal Share	**Extra-polation**	**Flatrate Growth**
Additional costs of 2030 RES-E target - national support (bn. EUR_{2010})	166	125	133
Additional costs of 2030 RES-E target - cooperative support (bn. EUR_{2010})	93	68	79
Gains from cooperation (bn. EUR_{2010})	73	57	54
Gains from cooperation (%)	44	45	41

Additional electricity system costs induced by the 2030 RES-E target vary between 68 and 93 bn. EUR_{2010} if the RES-E target is cost-efficiently reached by using efficient technologies and sites throughout Europe. The cost differences between the different cooperative support scenarios result from slightly different 2030 RES-E shares. The 'Extrapolation' and the 'Flatrate Growth' target distribution result in a European RES-E target of approximately 55 % (54.5% and 55.4%, respectively). The 'Equal Share' target distribution results in a higher European RES-E target (56.8%) because some countries already exceed the 55% share in their 2020 NREAP targets. However, it becomes clear that, given our assumptions, the European RES-E merit order curve is relatively steep given RES-E shares of approximately 55%: While the RES-E share in the 'Flatrate Growth' scenario is 0.9 percentage points higher than in the 'Extrapolation' scenario (corresponding to 1.6% higher RES-E generation), additional costs of achieving the 2030

RES-E target increase by 16%.[16] Comparing the additional electricity system costs of the 2030 RES-E target of the national versus the cooperative support scenarios, gains from cooperation amount to 54-73 bn. EUR_{2010}. In other words, the additional costs induced by the (national) RES-E targets can be reduced by 41 to 45 % when the best sites throughout Europe can be used. It is important to note that these cost differences refer to electricity system costs and not only to the costs of RES-E production. For example, more regionally concentrated RES-E generation in the cooperative support scenarios may increase the need for system flexibility. In the Equal Share and the Flatrate Growth target setting scenarios, it can be seen that more storage units are deployed given cooperative rather than national support. The gains from cooperation thus already include the indirect costs of RES-E support, i.e., the costs of RES-E integration in terms of flexibility and security of supply requirements.[17] Note also that, as described above, not exactly the same RES-E quantities are reached under national and cooperative support. Some countries surpass their targets in the national support scenarios and thereby contribute to the achievement of the European CO_2 emission reduction target.[18] The gains from cooperation thus include both the cost advantage of using best sites throughout Europe to achieve the European RES-E target and the advantage of using low-cost emission reduction possibilities in the overall electricity sector to achieve the European CO_2 target.

2.4.3 The influence of interconnector extensions on cooperation gains

Table 2.11 depicts the difference in generation between national support and cooperative support scenarios in 2030, both when interconnectors are extended according to the TYNDP (left columns, see also Table 2.8) and when interconnectors are not extended (right columns). The overall picture is similar for the scenarios with and without interconnector extensions: In the national support scenarios, generation from photovoltaic systems and fossil-fuel power plants is higher, whereas in the cooperative support scenarios, generation from nuclear and wind plants is higher. However, the absence of interconnector extensions has two major consequences: First, lower import and export possibilities impede the use of low-cost electricity generation options throughout Europe.

[16] Similarly, while the RES-E share in the 'Equal Share' scenario is 1.4 percentage points higher than in the 'Flatrate Growth' scenario (corresponding to 2.5% higher RES-E generation), additional costs of the 2030 RES-E target increase by 18%.

[17] In contrast, costs of the electricity grid are not included in the calculation. However, Fürsch et al. (2013a) show that substantial extensions of the transmission grid are beneficial in order to access favorable RES-E sites and that the induced grid extension costs are rather small compared to cost differences occurring in the generation system.

[18] RES-E generation in 2030 is around 1% higher for national compared to cooperative support. In 2025, differences amount to around 5%.

This includes renewable generation options (i.e., offshore wind) and non-renewable generation options (i.e., existing nuclear and lignite). Second, lower interconnector capacities limit the possibility to balance regional demands and fluctuating RES-E infeed. Thus, the requirement for flexible generation or demand on a national level increases.

Table 2.11: Differences in European electricity generation [TWh] between national and cooperative support scenarios in 2030 (with and without TYNDP)

	TYNDP			w/o TYNDP		
	national	cooperative	**difference**	national	cooperative	**difference**
Equal Share						
Nuclear	866	968	**-102**	755	890	**-135**
Lignite	370	362	**7**	362	357	**5**
Coal	480	399	**81**	451	421	**30**
Gas	48	56	**-8**	171	108	**62**
Oil	0	0	**0**	0	0	**0**
Storage	78	87	**-9**	78	105	**-28**
Hydro	551	552	**0**	552	552	**0**
Biomass	208	174	**34**	208	193	**16**
Wind onshore	706	711	**-5**	699	704	**-5**
Wind offshore	299	359	**-61**	311	332	**-20**
PV	370	325	**45**	374	344	**30**
CSP	49	47	**1**	49	46	**3**
Geothermal	94	94	**0**	94	94	**0**
Others	56	56	**0**	56	56	**0**
Extrapolation						
Nuclear	978	1011	**-34**	859	913	**-54**
Lignite	366	367	**-1**	356	361	**-5**
Coal	473	427	**46**	453	429	**24**
Gas	42	67	**-25**	174	156	**18**
Oil	0	0	**0**	0	0	**0**
Storage	84	81	**3**	78	87	**-9**
Hydro	552	552	**0**	552	552	**0**
Biomass	178	170	**8**	181	189	**-8**
Wind onshore	689	705	**-16**	683	696	**-13**
Wind offshore	299	335	**-37**	303	303	**0**
PV	324	270	**54**	324	293	**31**
CSP	49	48	**0**	49	46	**3**
Geothermal	94	93	**1**	94	94	**0**
Others	56	56	**0**	56	56	**0**
Flatrate Growth						
Nuclear	947	1000	**-54**	842	906	**-64**
Lignite	369	366	**4**	362	360	**3**
Coal	439	413	**26**	431	433	**-2**
Gas	63	61	**3**	172	132	**40**
Oil	0	0	**0**	0	0	**0**
Storage	78	85	**-7**	79	96	**-17**
Hydro	552	552	**0**	552	552	**0**
Biomass	186	172	**14**	191	192	**-1**
Wind onshore	704	707	**-3**	692	699	**-7**
Wind offshore	244	345	**-101**	254	311	**-56**
PV	393	291	**102**	387	314	**73**
CSP	49	47	**1**	49	46	**3**
Geothermal	94	94	**1**	95	94	**0**
Others	56	56	**0**	56	56	**0**

We identify the following effects of interconnector capacities on the optimal generation mix in the cooperative RES-E support scenarios, compared to national support:

- The best wind availabilities across Europe are better exploited under cooperative RES-E support. This advantage is greater when interconnector capacities are larger. Thus, the difference in wind generation between cooperative and national support is larger if the TYNDP is realized.
- Photovoltaic generation is lower given cooperative support because only best solar sites are competitive with other RES-E generation options throughout Europe. When interconnector capacities are larger, more favorable RES-E generation options across Europe (i.e., wind in Northern Europe) can be used and solar generation at sites with medium solar generation in Central Europe is smaller. Thus, the difference in solar generation between cooperative and national support is larger if the TYNDP is realized.
- Nuclear generation is higher given cooperative support because the use of renewable and non-renewable generation options can be optimized on a European-wide level. With cooperative support, RES-E generation in countries with existing nuclear plants or the political will to construct nuclear plants is lower compared to national support. Thus, a larger use of nuclear generation is possible. When interconnectors are larger, this relative advantage of the cooperative RES-E support decreases. With larger interconnectors, a higher nuclear, in addition to a high RES-E generation, is possible on a national level. Thus, the difference in nuclear generation between cooperative and national support is smaller if the TYNDP is realized.
- When interconnector capacities are larger, international power flows contribute significantly to balance demand and fluctuating RES-E infeed. Thus, the need for flexibility on a national level is smaller, both under cooperative and national RES-E support. In the cooperative RES-E support scenarios, storage generation in countries with a high wind penetration is smaller when interconnector capacities are larger. In the national support scenarios, a large share of non-renewable generation is coal rather than gas based when interconnector capacities are larger. Thus, the difference in generation from storage units between cooperative and national support is smaller if the TYNDP is realized. Furthermore, a lower generation from nuclear plants under national compared to cooperative support is replaced by coal rather than by gas when interconnector capacities are larger.

Differences in regional generation patterns between national and cooperative support scenarios do not fundamentally change given an absence of interconnector extensions.

Countries with favorable meteorological conditions also generate more RES-E in cooperative than in national support scenarios, however, generally to a lower extent. For example, the cost-efficient wind generation in Ireland, Norway and Denmark is lower due to limited export possibilites. In contrast, e.g., solar generation in Spain in the cooperative support scenarios is hardly reduced when the TYNDP is not realized, because the additional solar generation in the cooperative (compared to the national) support scenarios mainly replaces non-renewable based generation in Spain and is not exported to other countries.

With regard to gains from cooperation, the absence of interconnector extensions has, as expected, a decreasing effect. However, gains from cooperation remain at a significant magnitude of 47 to 62 bn EUR_{2010} (cumulated from 2021 to 2030) which translates to a reduction of the additional costs induced by the (national) RES-E targets by 36% to 37%.

2.4.4 The influence of RES-E investment costs on cooperation gains

Table 2.12 depicts the additional costs induced by the 2030 RES-E target under national and cooperative RES-E support systems, as well as the associated cooperation gains when investment costs for photovoltaic systems or for offshore wind plants are 10% lower than in the reference case. Numbers in brackets indicate the difference compared to the reference case (either in bn. EUR_{2010} or in percentage points).

TABLE 2.12: Effect of RES-E investment costs on additional costs induced by the 2030 RES-E target and cooperation gains (2021-2030)

Photovoltaic Costs - 10%	**Equal Share**	**Extra-polation**	**Flatrate Growth**
Additional costs of 2030 RES-E target - national support (bn. EUR_{2010})	156 (-10)	115 (-10)	124 (-9)
Additional costs of 2030 RES-E target - cooperative support (bn. EUR_{2010})	90 (-3)	68 (0)	76 (-3)
Gains from cooperation (bn. EUR_{2010})	65 (-8)	47 (-10)	48 (-6)
Gains from cooperation (%)	42 (-2)	41 (-4)	39 (-2)
Offshore Wind Costs - 10%			
Additional costs of 2030 RES-E target - national support (bn. EUR_{2010})	160 (-6)	121 (-4)	131 (-2)
Additional costs of 2030 RES-E target - cooperative support (bn. EUR_{2010})	91 (-2)	67 (-1)	76 (-3)
Gains from cooperation (bn. EUR_{2010})	69 (-4)	55 (-2)	54 (0)
Gains from cooperation (%)	43 (-1)	45 (0)	42 (+1)

Lower costs for photovoltaic systems (compared to the reference case) mainly lead to higher photovoltaic and to lower offshore wind-based generation under either national or cooperative RES-E support. Given national RES-E support, the switch from offshore- to photovoltaic-based generation mostly occurs in countries characterized by medium wind speeds and medium solar radiation as opposed to the best sites throughout Europe (e.g., France and Germany). Under cooperative RES-E support, e.g., photovoltaic generation in Italy is higher than in the reference case, while offshore generation in the United Kingdom is lower. In contrast, generation at the best sites for offshore wind (e.g., in the Netherlands and Denmark) is not affected by lower photovoltaic costs. Also, generation from other generation options such as onshore wind, is hardly affected by lower photovoltaic costs. In contrast, the overall costs of reaching the 2030 RES-E target is reduced by lower investment costs for photovoltaic systems, both given national and cooperative RES-E support. The cost reducing effect is, however, more pronounced in the national support scenarios, in which photovoltaic capacities are largely higher, such that gains from cooperation decrease to 47 - 65 bn. EUR_{2010} (to 39 - 42 %).

Lower investment costs for offshore wind plants also lead to generation switches between offshore wind- and photovoltaic-based generation. In addition, in the cooperative RES-E support scenarios, higher offshore wind-based generation partly replaces biomass-based generation. Contrary to the hypothesis made in Section 2.4.1, gains from cooperation do not increase with decreasing offshore wind costs. In absolute terms, gains from cooperation either do not change ('Flatrate Growth' scenario) or decrease slightly. In relative terms, gains from cooperation do not change, decrease or increase in a negligible order of magnitude. Although offshore wind-based *generation* is significantly higher in the cooperative support scenarios, *capacities* are only slightly higher (but deployed at sites with higher full load hours). Consequently, lower investment costs for offshore plants affect approximately the same number of offshore wind plants in the national and in the cooperative support scenarios. In terms of offshore wind generation costs, absolute reductions due to decreasing investment costs are, however, larger in the national support scenarios because full load hours are lower on average. Thus, in the 'Equal Share' and 'Extrapolation' scenarios, additional costs induced by the 2030 RES-E target decrease more when RES-E is supported on a national level. In the 'Flatrate Growth' scenarios, the highest difference in offshore wind capacity between national and cooperative support occurs (8 GW in the reference case, 18 GW when offshore wind costs are lower). In this case, cost reductions in the national and the cooperative support scenario are in the same order of magnitude: The effect of higher offshore wind capacities in the cooperative scenario balances the effect of a larger absolute reduction of generation costs in the national scenario.

2.5 Possible obstacles to cooperation in RES-E support

In Section 2.4, we have shown that stronger cooperation in RES-E support yields substantial cost savings in the period after 2020 and that these cost savings are relatively robust to different developments of the grid infrastructure and RES-E investment costs. As discussed in Section 2.2, several authors have already quantified cost savings from cooperation in achieving the 2020 target. However, currently hardly any member states plan to use cooperation mechanisms in order to reach their national 2020 targets.[19] One exception is the joint support system of Sweden and Norway that was implemented in 2012. In addition, Italy and Luxembourg both intend to profit from RES sources outside their national borders in order to achieve their targets. This section addresses possible obstacles to a cooperative RES-E support that need to be tackled in order to reduce the costs of increasing the European RES-E share. In the following, we analyze the main obstacles facing the implementation of cooperation mechanisms, as stated in the individual member states' NREAPs (see EC (2010)), and thereby provide further insights on political measures required to increase cooperation among member states (MS).

- **Uncertainty surrounding national RES-E deployment paths**
  Future RES-E deployment is not exactly predictable, especially in countries with a price-based RES-E promotion system. MS explain within their NREAPs that they are interested in statistical transfers in the case their national target is surpassed, but would also like to be assured that their own target is met (see, e.g., NREAP Ireland and NREAP Germany).

- **Uncertainty surrounding RES-E deployment in third countries**
  Even more than RES-E deployment on national territories, the progress of joint projects between MS and third countries is difficult to foresee. For example, many MS are involved in initiatives to import RES-E from the North African countries. However, Italy is the only country that states within its NREAP that it aims to fulfill a part of its target through imports from third countries. In contrast, e.g., France explains that the current status of the project does not allow for the quantification of the amounts of RES-E that could be imported within the target period of the Directive.

- **Administrative issues**
  Another obstacle hindering the use of cooperation mechanisms are unclear administrative issues. Within the NREAPs, the MS were requested to describe national

[19]Cooperation mechanisms defined within the European Renewables Directive include statistical transfers, joint projects and joint support systems between member states. In addition, targets can be achieved through cooperation mechanisms with non-EU member states under certain conditions. For more detailed information, see EC (2012).

procedures for arranging statistical transfers or joint projects. Most countries declared that no procedures have yet been established and that there is no clear common understanding of how cooperation mechanisms could work in practice (see, e.g., NREAP Ireland). In addition, there is a lack of information concerning the potential for joint projects in other MS or third countries (see, e.g., NREAP Slovakia or NREAP Spain).

- **Sharing of integration costs**
  Several MS state that the implementation of statistical transfers or joint projects is only eligible if integration costs of a higher RES-E share are borne by all participating member states. These integration costs include, e.g., costs for reinforcing the national grid and interconnectors as well as balancing costs (see, e.g., NREAP Ireland and NREAP Germany). Obviously, it is not evident how, for example, grid enforcement costs induced by renewable energies can be clearly distinguished from those induced by other power plants or changes in the demand structure (Dena (2010)). To quantify the integration costs induced only by those RES quantities needed for cooperation mechanisms is even less straightforward.

- **Insufficient interconnector capacities**
  Besides the unclear cost distribution of grid investments, an important issue for the implementation of cooperation mechanisms is the actual realization of grid enhancements, especially regarding interconnectors. Thus, administrative issues or issues of public acceptance that hinder grid extensions can be an obstacle to the use of cooperation mechanisms. Spain explains in its NREAP that participation in joint projects would be "senseless" for Spain if interconnectors between Spain and France (and the rest of the European Union) are not enforced. Furthermore, the Spanish NREAP states that the interconnectors between the European Union and the North African countries are insufficient with regard to the envisaged RES-E imports from North Africa. Portugal´s NREAP declares that it could easily go beyond its own RES target given an extension of the interconnector capacity between France and Spain.

- **Influence on the conventional power market**
  A rising RES-E share has significant effects on the conventional power system. Portugal explains that the Portuguese electricity market currently has surplus capacity and therefore does not intend to produce more RES-E than required for national target achievement. A rising amount of RES-E would lead to shrinking full load hours of thermal power plants and thus affect their profitability.

- **Other political targets**
  Finally, some governments also pursue political targets that can only be achieved

by domestic RES promotion. For example, the Netherlands have set a higher target for themselves than the mandatory target of the EU directive, which, in addition, should be achieved through domestic production. Germany states in its NREAP that the benefits from cooperation mechanisms have to be balanced with the benefits from local RES production (such as local employment).

In summary, a sharing of costs and benefits between member states is challenging, and unclear administrative procedures, a lack of information about RES-E potentials in other countries and uncertainty about the progress of RES-E projects may hinder the use of cooperation mechanisms. Potential drawbacks of cooperation have also been addressed in the literature. Del Río (2005) states that harmonization may be in conflict with national socioeconomic and environmental objectives, e.g., if a country wants to increase employment by creating green jobs. Klessmann et al. (2010) point out that a quantification of indirect costs and benefits resulting from cooperation mechanisms is hardly possible. These indirect costs include, e.g., grid integration costs or environmental costs (e.g., impact on the landscape) whereas potential benefits listed by Klessmann et al. (2010) include, e.g., local job creation and innovation. Pade et al. (2012) also identify the distribution of costs and benefits as a major challenge. In addition, the authors discuss in detail barriers that are specific to the implementation of the different cooperation mechanisms. When implementing a joint support scheme, countries have to agree on a common support system design, which can be very difficult in practice. Joint projects are more easily to implement; however, Pade et al. (2012) point out that transaction costs can be an important barrier for small size projects. Moreover, the authors explain that uncertainty surrounding the setting of RES targets in the period post 2020 is a barrier to cooperation because countries with low-cost RES potentials may not be willing to exploit their potentials given uncertainty about the development of future targets.

2.6 Conclusions

Generation costs of fluctuating renewables vary substantially throughout Europe due to different meteorological conditions. Thus, any RES-E support system that does not incentivize the use of best sites across Europe induces high extra costs. In this analysis, we have shown that continuing with national support systems after 2020 would increase the additional cost of a 2030 RES-E target substantially. Furthermore, we find that the economic benefit of cooperation, in terms of cost savings in the electricity system, is quite robust: The cost savings decrease only slightly when interconnectors are not further extended (compared to today) and depend only slightly on assumptions about the developments of RES-E investment costs.

In order to benefit from cooperation in practice, prevailing obstacles facing cooperation need to be tackled. Based on an analysis of the NREAP documents, we find that a sharing of costs and benefits between member states is challenging and that unclear administrative procedures, a lack of information about RES-E potentials in other countries and uncertainty surrounding the progress of RES-E projects may hinder the use of cooperation mechanisms. However, the example of the joint support system of Norway and Sweden shows that these obstacles can be overcome.[20] Moreover, the European Commission is currently working on the development of guidelines on the implementation of cooperation mechanisms to provide information on legal conditions and on possible methodologies to share costs and benefits (EC (2012)).[21] Moreover, hybrid support systems (as opposed to pure national or pure cooperative support systems) may yield a large part of possible cooperation gains while limiting the distributional effects. For example, Jansen (2011) proposes a bottom-up harmonization in which joint renewable quota systems can be supplemented with national support measures in order to take into account national concerns. Pade et al. (2012) also propose 'technology or geographically specific joint support schemes' (e.g., only for offshore wind) as a short- to medium-term solution. The advantage of this approach would be that these specific joint support schemes could coexist with national support schemes. Thereby, some barriers to cooperation would be removed, such as the difficulties in agreeing on a common support system or the pursuit of different objectives the member states have with regard to RES-E support. The authors state that while full harmonization would lead to the highest efficiency gains, it is difficult to implement in the short term. In the context of European cooperation in transmission system planning, Buijs (2011) investigates how different forms of collaboration affect overall and country-wise economic welfare and discusses the impact of different compensation mechanisms. Further research in this area is clearly required in order to avoid large excess costs of achieving national targets without cooperation.

[20] Klessmann et al. (2010) explain that the idea of a joint support system between Norway and Sweden was first abolished in 2006 because "it was very hard to find a final agreement how to share the costs and benefits in such a system".

[21] The analysis presented in this chapter has been published in the EWI Working Paper Series in August 2013. In November 2013, the European Commission published its guidelines "on the use of renewable energy cooperation mechanisms" (EC (2013)). These guidelines clarify administrative procedures for the implementation of different cooperation mechanisms and describe different practical design options for statistical transfers, joint projects and joint support schemes. Moreover, indirect costs and benefits arising in the host and the off-taking countries are named. However, the guidance also states that a quantification of these indirect costs and benefits is difficult.

Chapter 3

Redistribution effects resulting from cross-border cooperation in support for renewable energy

3.1 Introduction and background

International trade increases overall welfare. However, trade also results in redistribution effects such that different groups may be better or worse off with or without trade. These general findings of international trade theory (see, e.g., Krugman and Obstfeld (2009) or Bhagwati et al. (1998)) also apply to cross-border cooperation in achieving political targets for electricity generation from renewable energy sources (RES-E). Due to favorable meteorological conditions (e.g., high wind speeds or high solar radiation) or large resource availabilities (e.g., of hydro reservoirs), some regions have cost advantages in RES-E generation. Political targets for RES-E generation are, however, often not linked to the resource potential of a region. Cooperation between regions with different supply functions of RES-E generation thus increases system-wide welfare because less costly generation options can be used. However, this cooperation also leads to regional price effects from which some groups (e.g., consumers or producers in a particular region) benefit while other groups lose compared to a situation without cooperation. While the effect of increasing welfare resulting from cooperation in RES-E support has been studied quite extensively (e.g., by Ragwitz et al. (2007), EWI (2010) and Aune et al. (2012)), the associated redistribution effects have received little attention in literature thus far. This is intriguing as redistribution effects seem to be one of the main reasons that cooperation in RES-E support among member states of the European Union has been impeded thus far (Fürsch and Lindenberger (2013)).

With this paper, we try to fill the existing gap in literature. We analyze redistribution effects resulting from cooperation in a theoretical two-country electricity system model in which RES-E support is implemented via a tradable green certificate system. In a green certificate system, consumers or distributors of electricity are obliged to present an amount of 'green certificates' corresponding to a politically-defined percentage share of their electricity demand. Thereby, a market for the 'green value' of RES-E generation is created (see Section 3.3). The green certificate market is closely linked to the wholesale electricity market for two reasons. First, the certificate price is paid on top of the wholesale electricity price, such that the RES-E investor has two sources of incomes from which he covers his costs. Therefore, if the electricity price level is high, the investor will bid at low prices on the certificate market and vice versa. Second, an increase in renewable-based electricity generation leads to a decrease in non-renewable-based electricity generation (ceteris paribus). Therefore, as long as grid congestions between different regions exist, varying regional allocations of RES-E also affect regional wholesale electricity markets. Consequently, welfare and redistribution effects resulting from RES-E cooperation are significantly influenced by the degree of physical interconnection between different regional power systems. In this paper, we explicitly distinguish between different grid interconnections, in analyzing under which conditions different groups benefit or lose from the introduction of cooperation.

Main findings of this analysis include that the effects on consumers and total producers per country resulting from cooperation can only be clearly determined if no grid congestions between the countries exist. If bottlenecks in the transmission system exist, the relationship between the slopes of the renewable and the non-renewable marginal generation cost curves for electricity generation as well as the level of the RES-E target essentially determine whether these groups benefit or lose from the introduction of cross-border trading in green certificates. In contrast, system-wide welfare always increases once cooperation in RES-E support is introduced. Similarly, welfare on the country level always increases (compared to a situation without RES-E cooperation) if the countries are perfectly or not at all physically interconnected. In the case of congested interconnectors, the sum of producer and consumer rents in a country may also decrease under certain conditions. However, in this case the level of congestion rents is also influenced by the introduction of RES-E cooperation. Therefore, in this case, there always exists a possible distribution of congestion rents between the countries which ensures that each country benefits from the introduction of certificate trade.

The remainder of the article is structured as follows: In Section 3.2, an overview of the related literature and the contribution of the current work is presented. In particular, the relationship between cooperation in RES-E support and international trade theory is highlighted. Section 3.3 covers the theoretical analysis of redistribution effects. In Section 3.4, we draw conclusions and provide an outlook for further research.

3.2 Related literature and contribution of the current work

To our knowledge, the redistribution effects resulting from RES-E cooperation have not yet been analyzed in a theoretical framework. However, our analysis is related to two strands of literature. First, as pointed out in the introduction, the question of welfare and redistribution effects resulting from RES-E cooperation is closely related to international trade theory. Second, our analysis builds on the literature on the interaction between renewable support and the competitive wholesale market for electricity. A part of the latter literature also includes an investigation of cross-border cooperation in RES-E support, however, these investigations do not analyze redistribution effects.

3.2.1 Relation to international trade theory

International trade theory shows that trade between different regions increases welfare for two main reasons: First, because differences between the regions (e.g., in terms of different resource availabilities) can be exploited and second, because trade enables economies of scale to be achieved (Krugman and Obstfeld (2009)). The classical and neoclassical trade theory (Smith, Ricardo, Heckscher and Ohlin) is founded on differences between the countries, whereas the new trade theory focuses on reasons for trade between similar countries, e.g., on the achievement of economies of scale and the reinforcement of competition through increasing market sizes (Mejía (2011)). The analysis presented in this paper can be best related to classical and neoclassical trade theory, as cooperation in our model occurs between regions with different RES-E generation costs.

In 1776, Adam Smith showed that trade between regions with an absolute cost advantage in the production of different goods increases overall welfare. The Ricardian model (developed by David Ricardo in 1817) states that trade increases welfare even if a region has higher production costs for all goods. In the Ricardian model, countries specialize in the production of the good in which they have a comparative advantage (Krugman and Obstfeld (2009)). In both the models of Smith and Ricardo, labor is the only production factor and trade occurs due to differences in regional labor productivities. Trade is beneficial for both countries, which reach higher aggregate consumption levels than in autarky. In addition, trade is beneficial for all individuals within the countries because productivities and real wages increase in both countries (Mejía (2011)).[22] Redistribution effects resulting from trade were first addressed in the context of the Heckscher-Ohlin model. Heckscher and Ohlin analyze trade between regions with different factor endowments. Their model consists of two countries, two output goods and - in contrast to Smith and Ricardo´s model - two input factors. Each of the output goods is intensive in one of the input factors (i.e., it requires more of one of the input factors than of the other) and each of the input factors is relatively abundant in one of the two countries. The Heckscher and Ohlin model states that countries specialize in the production of the good that is intensive in the input factor that is relatively abundant in the specific country. As in the models of Smith and Ricardo, trade increases overall consumption and, thus, welfare in both countries (Krugman and Obstfeld (2009)). However, as shown in the Stolper-Samuelson theorem, changes in the output price, induced by trade, also affect the relative factor prices in both countries, such that owners of the relatively abundant factor, benefit from trade, whereas owners of the relatively scarce factor, lose compared to the pre-trade situation (see, e.g., Zweifel and Heller (1992)).

Our analysis of cooperation in RES-E support is closest related to the theory of Heckscher and Ohlin. The motivation for cooperation in RES-E, e.g., implemented as a cross-border green certificate trading scheme, is that regions have different resource availabilities, such as sites with high wind speeds, hydro reservoirs or lignite mines. Furthermore, as will be shown in Section 3.3, cross-border green certificate trading leads to regional price effects which in turn lead to income distribution effects between different groups within a country. A difference between the analysis in this paper and the models of Smith, Ricardo and Heckscher-Ohlin is that our model covers only the electricity system (partial equilibrium model) and not the economy as a whole (general equilibrium model). In addition, the general equilibrium models of Smith, Ricardo and Heckscher and Ohlin assume that all factors are fully used, both before and after trade (which implies, e.g., that no unemployment exists). Therefore, no country will export or import both goods. An export of both goods would simply not be possible and an import of both goods would lead to unused resources and, thus, to inefficiencies. In our partial equilibrium model of the electricity system, it is not assumed that all input factors are fully used.[23] Therefore, it is possible that a country is an importer or an exporter of both green certificates and electricity. As will be shown in Section 3.3, in this case, and under the additional condition that the interconnector between the two countries is congested, it is possible that the sum of consumer rents and producer profits in a country decreases

[22] Note that the Ricardian model assumes free and costless mobility of labor between the sectors within a country. Also, the productivity of all workers in a country is assumed to be identical.

[23] In a partial equilibrium model, such an assumption would not be sensible. For example, agricultural land can be used either for producing energy crops or for producing food. As the food sector is not included in the model of the electricity system, it would not be reasonable to assume that all available production sites are fully used for producing energy crops.

once cooperation is introduced. However, if interconenctors are congested, cooperation not only affects the welfare of producers and consumers, but also impacts congestion rents. Including changes of the congestion rents, we find that, analogous to general trade theory, overall international system-wide welfare always increases when trade is possible. Moreover, similar to the Heckscher-Ohlin model, in which trade is beneficial for all countries, we find that there always exists a possible redistribution of congestion rents between the countries which ensures that sectoral welfare in the electricity systems of all countries increases.

3.2.2 Interaction between RES-E support and the competitive wholesale electricity market

The influence of RES-E support on the wholesale electricity market, i.e., in terms of wholesale electricity prices, has been studied e.g., by Amundsen and Mortensen (2001), Jensen and Skytte (2002) and Fischer (2010). These authors either use one-country models or models with electricity trading, in which, however, RES-E is only supported in one country. Models with a common support scheme for renewable energies in two or more countries are investigated by e.g., Bye (2003), Amundsen and Nese (2009), Sun (2012), Aune et al. (2012) and Laffont and Sand-Zantman (2012). Except for Laffont and Sand-Zantman (2012), all authors study the effects of RES-E support via a green certificate market. Bye (2003) studies volume and price effects of an increasing RES-E percentage requirement in a model under autarky, a model with only electricity trading and a model with both electricity and green certificate trading. Amundsen and Nese (2009) investigate the impact of the RES-E percentage requirement and CO_2 emission prices on RES-E generation and total electricity production, both under autarky and with cross-border certificate trading. Aune et al. (2012) show that a common certificate market ensures the cost-efficient allocation of production across countries as long as the countries aim to increase their share of renewable energy in aggregate energy consumption. Sun (2012) builds on the two-country model presented in Aune et al. (2012) and investigates welfare effects of a socially-optimal RES-E percentage requirement under a joint renewable support system. Laffont and Sand-Zantman (2012) study the optimal degree of coordination in RES-E support in a two-country model with potentially limited transmission capacity. Their key finding is that the optimal degree of coordination depends on the level of transmission capacity.

In summary, while theoretical two-country models with common renewable promotion systems have been studied by several authors, these analyses do not include redistribution effects.[24] Our contribution to literature is thus to theoretically determine the redistribution effects resulting from cooperation in RES-E support, which to the best of our knowledge has not yet been performed.

3.3 Theoretical analysis

In analyzing the redistribution effects resulting from cooperation in RES-E support, we use a theoretical two-country model with a wholesale electricity market and a market for green certificates. A system of tradable green certificates (TGC) is a support mechanism for RES-E generation that is currently implemented in e.g., Poland, Great Britain, Norway and Sweden.[25] Of course, other support mechanisms also exist (see www.res-legal.eu for an overview of current RES-E support mechanisms across Europe) and cooperation in RES-E support is not restricted to a common TGC market. In this analysis, we chose to focus on the TGC system because, as outlined in Section 3.2, most literature that theoretically analyze RES-E support mechanisms, focus on this support mechanism.

In the model, producers sell electricity from renewable and non-renewable energy sources on the wholesale electricity market. Most renewable electricity sources are currently not competitive with non-renewable electricity sources. It is assumed that a certain RES-E target is decided politically and expressed as a percentage share of electricity demand, and that RES-E generation is incentivized by a green certificate system. In a green certificate system, the electricity consumer, or the electricity utility providing the consumer with electricity, is usually obliged to present a certain amount of certificates per unit of electricity demand. Producers of renewable energy usually receive green certificates for each generated unit of RES-E (from the regulatory body). Thus, they sell their produced electricity on the wholesale electricity market and the 'green value' of the electricity on the green certificate market. Therefore, producers of renewable energy have two sources of income and - in competitive markets - will offer green certificates at a price which compensates for the additional costs of renewable generation compared to the wholesale electricity price. For more information on the functioning of TGCs, the interested reader is referred to, e.g., Amundsen and Mortensen (2001), Menanteau et al. (2003) and Agnolucci (2007).

[24] The paper of Aune et al. (2012) also includes a numerical analysis in which welfare effects of cooperation on country levels are shown. However, redistribution effects between different groups within the countries are analyzed neither in their theoretical nor in their numerical model.

[25] The term 'tradable' generally does not refer to trade between different countries, but simply to the fact that green certificates can be traded between different market actors and often also across different time periods.

The RES-E percentage requirements in the model are set on the national level and may or may not be identical in the two countries. Without cooperation in renewable support between the two countries, the national RES-E targets have to be achieved by domestic RES-E production only. With cooperation, implemented in our analysis as a cross-border green certificate trading system, imported green certificates can also contribute to national target achievement. Note that cross-border trade in green certificates is also possible without electricity trading because the green value, and not necessarily the green electricity itself, is traded across borders. In the following, we analyze the welfare effects of introducing a cross-border green certificate trading scheme in two cases. In the first case, we assume that the grid connection between the two countries is unlimited ('copper plate'). Neglecting transmission losses, the two countries in this case have a common wholesale price of electricity that is not affected by the regional distribution of RES-E generation.[26] In the second case, we assume that the interconnector linking the two countries is congested or that, in the extreme case, the two countries are not at all physically connected ('limited grid'). Therefore, in this case, the regional distribution of RES-E generation affects regional wholesale electricity markets.

In Section 3.3.1, we present the theoretical model. In Sections 3.3.2 and 3.3.3 we discuss welfare and redistribution effects resulting from cross-border green certificate trading for the case of a copper plate and the case of limited grid connection, respectively. In Section 3.3.4, the determinants for the results in the 'limited grid' case are discussed in more detail and in Section 3.3.5, we present numerical examples to illustrate how different assumptions (e.g., on the supply curves) influence welfare and redistribution effects shown in the theoretical model.

3.3.1 The theoretical model

As a starting point for our analysis, we take the model presented in Amundsen and Nese (2009), which is a theoretical two-country model with a wholesale electricity market and a green certificate market. However, the research question of this paper is completely different to the one of Amundsen and Nese (2009). Amundsen and Nese (2009) use the model to investigate whether it is possible to derive clear results on the level of RES-E generation resulting from a) an increase in the RES-E percentage requirement and of b) an increase in the CO_2 -price. We use the model to investigate welfare effects of

[26]Note that the (common) wholesale price for electricity could be affected by a different regional distribution of RES-E generation if the impact of the demand *structure* is taken into account. Assume, for example, that the introduction of cross-border green certificate trading leads to a reduction of photovoltaic generation in country A, which is then replaced by a higher wind generation in country B. In this case, the total amount of RES-E generation remains unchanged; however the structure of the renewable infeed has changed. A possible influence on the wholesale electricity market resulting from a different renewable energy mix is neglected in this analysis.

cross-border green certificate trading, under different assumptions about the physical interconnection between different regions. In contrast to Amundsen and Nese (2009), we do not consider the market for CO_2 emissions and assume that electricity demand is inelastic. Unlike in other markets, demand in electricity markets is characterized by a relatively low elasticity, especially in the short term (Erdmann and Zweifel (2008)).[27] Thus, we believe that, for our research question, the assumption of a perfectly inelastic demand is appropriate as an approximation for a low demand elasticity.[28]

Table 3.1 presents the parameters and variables of the two-country model, where the index i denotes the country i $\in \{A, B\}$ (and where i´ is an alias of i).

TABLE 3.1: Notation of the theoretical model (partly based on Amundsen and Nese (2009))

s_i	price of green certificate
q_i	wholesale price of electricity
x_i	total consumption of electricity
y_i	production of conventional electricity
g_i	production of renewable electricity
α_i	RES-E percentage requirement
z_i	national RES-E target [with $z_i = \alpha_i \cdot x_i$]
$C_i(y_i)$	costs for conventional electricity with $\frac{\partial C}{\partial y} > 0; \frac{\partial C^2}{\partial y^2} \geq 0$
$h_i(g_i)$	costs for RES-E with $\frac{\partial h}{\partial g} > 0; \frac{\partial h^2}{\partial g^2} \geq 0$
π_i	profit function of all producers
π_i^R	profit function of renewable electricity producers
π_i^C	profit function of conventional electricity producers
CR_i	consumer rent
CE_i	consumer expenditures (expenditures for meeting electricity demand)
W_i	welfare
$T_{i,i'}$	traded green certificates
$M_{i,i'}$	interconnector capacity
$E_{i,i'}$	congestion rent

We assume that country B has a large potential of RES-E generation options with comparatively lower costs than country A (e.g., due to favorable meteorological conditions). More specific, we assume that in the market equilibrium without certificate trading, the price of green certificates in country B (at the certificate demand level corresponding to

[27] An overview of electricity demand estimations is, e.g., provided by Simmons-Süer et al. (2011) and Liejesen (2007). In general, electricity demand of industrial consumers is more elastic than of household customers. Furthermore, electricity demand is more elastic in the long term than in the short term. Simmons-Süer et al. (2011) determine average household electricity demand elasticities to be -0.2 in the short term (up to one year) and -0.6 in the long term (ten years or more), based on a literature review. Real-time price elasticity of electricity demand is estimated to be close to zero (Liejesen (2007)).

[28] In contrast, the main finding of Amundsen and Nese (2009), namely that the effect of an increasing percentage requirement on RES-E generation is indeterminate, relies on the assumption of an elastic electricity demand. With elastic electricity demand, an increasing percentage requirement can lead to a decreasing electricity demand such that the percentage requirement can also be achieved without an increase in RES-E generation.

the national RES-E target z_B) is lower than in country A. Technologies and resource availabilities for the generation of non-renewable electricity may or may not be identical in both countries. Analogous to Amundsen and Nese (2009), we assume perfect competition in all markets.

3.3.2 Welfare effects with unlimited grid connection ('copper plate')

In the case of unlimited grid connection between countries A and B, the introduction of cross-border green certificate trading only affects the certificate market and not the wholesale electricity market. In the absence of grid congestions non-renewable power generation is optimally distributed between countries A and B even if green certificate trading is not possible and the regional distribution of RES-E generation is not optimal. Neglecting grid losses, a change in the regional distribution of renewable energy generation has no influence on the optimal regional distribution of non-renewable generation. Thus, the outcome of the wholesale electricity market (in terms of the common power price q and the regional levels of conventional electricity generation y_i) is not affected by the trading of green certificates.[29] With the possibility to trade green certificates, country A (with comparatively higher generation costs of RES-E) will import an amount T of certificates instead of fulfilling the national renewable target (z_A) using only local RES-E production. In country B, a higher RES-E generation is generated than needed to fulfill domestic demand for certificates (z_B), such that an amount T of certificates can be exported to country A. Equation (3.1) shows the profit function of conventional electricity producers in countries A and B. Equations (3.2) and (3.3) show the profit functions of renewable electricity producers in countries A and B, respectively.

$$\pi_i^C = q \cdot y_i - C(y_i); \quad i \in \{A, B\} \tag{3.1}$$

$$\pi_A^R = [q + s_A][z_A - T] - h_A(z_A - T) \tag{3.2}$$

$$\pi_B^R = [q + s_B][z_B + T] - h_B(z_B + T) \tag{3.3}$$

Analogous to Billette de Villemeur and Pineau (2010), who analyze the impact of a marginal increase in cross-border *electricity* trade on producer profits, consumer rents and total welfare, we analyze the welfare effects of a marginal increase in cross-border

[29]In addition, as explained in footnote 26, this proposition relies on the assumption that the cost function for non-renewable electricity generation C_i only depends on the level of non-renewable electricity generation and thus only on the level of demand minus the level of RES-E infeed. The possible influence of a different structure of RES-E infeed, which may result from certificate trading, is neglected. Furthermore, wholesale electricity price effects can occur if the RES-E quota in country B is not binding. In this case, overall RES-E production in countries A and B would be lower than without the possibility of certificate trading. This case is discussed via a numerical example in Section 3.3.5.

certificate trade T from country B to country A. The case $T = 0$ corresponds to the case where trading of green certificates is not allowed. In this case, by assumption, the price of green certificates in country A is larger than in country B ($s_A(z_A) > s_B(z_B)$). In the market equilibrium without certificate trading, the price of green certificates in each country corresponds to the additional marginal costs of renewable energy production, associated with a RES-E production of $g_i = z_i$, compared to the wholesale electricity price: $s_i = h_i'(z_i) - q$.[30] If green certificate trading is allowed, T is increased until the prices of green certificates in both countries converge ($s_A = s_B$). As the wholesale electricity price is identical in both countries and not affected by trading green certificates (meaning that q and y_i are independent of T), the convergence of green certificate prices is reached when the marginal costs of RES-E generation in both countries are equal ($h_A^{'}(z_A - T) = h_B^{'}(z_B + T)$). Thus, the optimal certificate trade T* is reached when $s_A = h_A^{'}(z_A - T^*) - q = h_B^{'}(z_B + T^*) - q = s_B$, and arbitrage is no longer possible.

Lemma 3.1 states that an increase in the trading of green certificates increases welfare in both countries, as long as $0 < T < T^*$ (implying $h_A^{'} > h_B^{'}$) and under the condition that the interconnector is not congested. While consumers in country A benefit from trading, producers of renewable electricity are worse off. Contrarily, RES-E producers in country B profit from trading, whereas consumers are worse off (for proof, see Appendix B).[31] In both countries, producers of conventional electricity are not affected by cross-border certificate trading.

[30]The equilibrium condition in the certificate market (i.e., the certificate price corresponds to the marginal generation costs of RES-E minus the wholesale electricity price) results from differentiating the profit function of RES-E producers with regard to RES-E production g_i (i.e., to the first-order condition of profit maximization of the RES-E producers) (see Amundsen and Nese (2009)).

[31]To be precise, price effects (and thus also most redistribution and welfare effects) on country-levels are only non-negative and not strictly positive or negative, as indicated in Lemma 3.1.

Lemma 3.1. *If* $0 < T < T^*$ *and* M *is unlimited then*

$$\frac{dCR_A}{dT} = -\frac{ds_A}{dT} \cdot \alpha_A x_A = -\frac{ds_A}{dT} \cdot z_A \geq 0 \tag{3.4}$$

$$\frac{d\pi_A^R}{dT} = \frac{ds_A}{dT} \cdot [z_A - T] \leq 0 \tag{3.5}$$

$$\frac{d\pi_A^C}{dT} = 0 \tag{3.6}$$

$$\frac{dW_A}{dT} = -\frac{ds_A}{dT} \cdot T \geq 0 \tag{3.7}$$

$$\textit{with} \quad \frac{ds_A}{dT} = -h_A''(z_A - T) \leq 0 \tag{3.8}$$

$$\frac{dCR_B}{dT} = -\frac{ds_B}{dT} \cdot \alpha_B x_B = -\frac{ds_B}{dT} \cdot z_B \leq 0 \tag{3.9}$$

$$\frac{d\pi_B^R}{dT} = \frac{ds_B}{dT} \cdot [z_B + T] \geq 0 \tag{3.10}$$

$$\frac{d\pi_B^C}{dT} = 0 \tag{3.11}$$

$$\frac{dW_B}{dT} = \frac{ds_B}{dT} \cdot T \geq 0 \tag{3.12}$$

$$\textit{with} \quad \frac{ds_B}{dT} = h_B''(z_B + T) \geq 0 \tag{3.13}$$

$$\frac{dW}{dT} = \frac{dW_A}{dT} + \frac{dW_B}{dT} = [-\frac{ds_A}{dT} + \frac{ds_B}{dT}] \cdot T \geq 0 \tag{3.14}$$

In country A, the trading of green certificates leads to a decreasing price in green certificates (Eq. (3.8)), which is beneficial for consumers (Eq. (3.4)) and worse for RES-E producers compared to a situation without trade (Eq. (3.5)). The price decrease refers to the quantity z_A for the consumers, but only to the quantity $(z_A - T)$ for the RES-E producers. Producers of conventional electricity are not affected by certificate trade (Eq. (3.6)). Thus, total welfare in country A increases (Eq. (3.7)). In country B, in contrast, the trade in green certificates leads to an increasing price in green certificates (Eq. (3.13)), which is beneficial for RES-E producers (Eq. (3.10)) and worse for consumers compared to a situation without trade (Eq. (3.9)). In this case, the price increase refers to the quantity $(z_B + T)$ for the RES-E producers, but only to the quantity z_B for the consumers. Thus, total welfare in country B increases (Eq. (3.12)). The change in total system-wide welfare corresponds to the sum of the welfare changes in A and B and is therefore also positive (Eq. (3.14)).

Consequently, when grid connections are unlimited, it can be clearly shown that total welfare in both countries increases. Furthermore, it can be seen that in the country with a cost advantage for RES-E production (country B), producers are better and consumers are worse off than without trade. The opposite holds true in country A. The magnitude of the overall welfare and distributional effects essentially depends on the slope of the RES-E generation cost curves, which in turn determine the optimal certificate trade T^* and the changes in certificate prices.

3.3.3 Welfare effects with limited interconnection ('limited grid')

We now consider the case in which the electricity systems of countries A and B are not perfectly physically interconnected. Either, the interconnector between the two countries is congested, or, in the extreme case, the two regional electricity markets are not physically linked at all. Under this assumption, the different regional allocation of renewable energy generation capacities, resulting from the introduction of green certificate trading, has an influence on national wholesale electricity prices. If country A imports green certificates and thus reduces its domestic RES-E production, (inelastic) electricity demand in country A has to be met by increasing generation from conventional plants. Similarly, in country B, an increasing production of renewable energy leads to a decreasing production of electricity from conventional energy sources. This effect is the larger, the smaller electricity trading possibilities are. In the extreme case of no physical interconnection between the countries, the amount of lower (higher) RES-E generation in country A (B) has to be completely compensated by higher (lower) domestic conventional electricity generation.

The profit functions of electricity producers (for renewable and conventional electricity) in countries A and B are given by Eq. (3.15) - Eq. (3.20).[32] Equations (3.15) and (3.16) both present the profit function of conventional electricity producers in country A - once for the case that country A is an importer of electricity and once for the case that it exports electricity. Country A may be an importer both of certificates and of electricity, e.g., if countries A and B have the same production costs for conventional electricity or if country A has higher costs both for the generation of green and of conventional electricity. In contrast, if country A has a cost advantage for the generation of conventional electricity compared to country B, it may be an importer of certificates but an exporter of electricity. Similarly, Country B is an exporter of green certificates and may either be an importer or an exporter of electricity (Eq. (3.18) and Eq. (3.19)). Note that we only consider the case, when the interconnector is congested and a complete electricity price convergence between the two regional electricity markets cannot be

[32] Note that the intermittent character of RES-E technologies such as wind and solar, is not taken into account in the model. This becomes apparent in Equations (3.15), (3.16), (3.18) and (3.19) as the total costs of conventional electricity generation (C_A and C_B) directly depend on the level of the residual demand (= demand - RES-E generation). Additional integration costs that occur in the conventional power system when RES-E shares increase (e.g., due to increasing balancing requirements or in ensuring security of supply during hours of low RES-E infeed) are not taken into account.

achieved. Thus, total electricity imports or exports correspond to the interconnector capacity M. Setting M=0 corresponds to the case that the two countries are not at all interconnected.

$$\pi_A^C = q_A \cdot [x_A - z_A + T - M] - C_A(x_A - z_A + T - M) \quad \text{[A imports electricity]} \quad (3.15)$$
$$\pi_A^C = q_A \cdot [x_A - z_A + T + M] - C_A(x_A - z_A + T + M) \quad \text{[A exports electricity]} \quad (3.16)$$
$$\pi_A^R = [q_A + s_A] \cdot [z_A - T] - h_A(z_A - T) \quad (3.17)$$
$$\pi_B^C = q_B \cdot [x_B - z_B - T + M] - C_B(x_B - z_B - T + M) \quad \text{[B exports electricity]} \quad (3.18)$$
$$\pi_B^C = q_B \cdot [x_B - z_B - T - M] - C_B(x_B - z_B - T - M) \quad \text{[B imports electricity]} \quad (3.19)$$
$$\pi_B^R = [q_B + s_B] \cdot [z_B + T] - h_B(z_B + T) \quad (3.20)$$

As in the ‘copper plate’ case, certificates are traded until certificate prices converge. However, in this case, convergence implies that the *additional* marginal generation costs of RES-E are identical in both countries ($(h_A^{'} - C_A^{'}) = (h_B^{'} - C_B^{'})$). Lemma 3.2 defines welfare and redistribution effects resulting from the trading of green certificates (for $0 < T < T^*$; meaning that $(h_A^{'} - C_A^{'}) > (h_B^{'} - C_B^{'})$), given that country A (B) is not only a certificate but also an electricity importing (exporting) country.

Lemma 3.2. *If* $0 < T < T^*$*,* $M > 0$ *but limited and* A *(*B*) is an electricity importer (exporter), then:*

$$\frac{dCR_A}{dT} = \underbrace{-\frac{ds_A}{dT} \cdot z_A}_{\geq 0} \underbrace{-\frac{dq_A}{dT} \cdot x_A}_{\leq 0} \tag{3.21}$$

$$\frac{d\pi_A}{dT} = \underbrace{\frac{ds_A}{dT} \cdot [z_A - T]}_{\leq 0} + \underbrace{\frac{dq_A}{dT} \cdot [x_A - M]}_{\geq 0} \tag{3.22}$$

$$\frac{d\pi_A^R}{dT} = [\frac{ds_A}{dT} + \frac{dq_A}{dT}] \cdot [z_A - T] \leq 0 \tag{3.23}$$

$$\frac{d\pi_A^C}{dT} = \frac{dq_A}{dT} \cdot [x_A - z_A + T - M] \geq 0 \tag{3.24}$$

$$dW_A = \underbrace{-\frac{ds_A}{dT} \cdot T}_{\geq 0} \underbrace{-\frac{dq_A}{dT} \cdot M}_{\leq 0} \tag{3.25}$$

$$\textit{with} \quad \frac{ds_A}{dT} = - h_A^{''}(z_A - T) - C_A^{''}(x_A - z_A + T - M) \leq 0 \tag{3.26}$$

$$\textit{and} \quad \frac{dq_A}{dT} = C_A^{''}(x_A - z_A + T - M) \geq 0 \tag{3.27}$$

$$\frac{dCR_B}{dT} = -\frac{dCE_B}{dT} = \underbrace{-\frac{ds_B}{dT} \cdot z_B}_{\leq 0} \underbrace{-\frac{dq_B}{dT} \cdot x_B}_{\geq 0} \tag{3.28}$$

$$\frac{d\pi_B}{dT} = \underbrace{\frac{ds_B}{dT} \cdot [z_B + T]}_{\geq 0} + \underbrace{\frac{dq_B}{dT} \cdot [x_B + M]}_{\leq 0} \tag{3.29}$$

$$\frac{d\pi_B^R}{dT} = [\frac{ds_B}{dT} + \frac{dq_B}{dT}] \cdot [z_B + T] \geq 0 \tag{3.30}$$

$$\frac{d\pi_B^C}{dT} = \frac{dq_B}{dT} \cdot [x_B - z_B - T + M] \leq 0 \tag{3.31}$$

$$\frac{dW_B}{dT} = \frac{d\pi_B}{dT} + \frac{dCR_B}{dT} = \underbrace{\frac{ds_B}{dT} \cdot T}_{\geq 0} + \underbrace{\frac{dq_B}{dT} \cdot M}_{\leq 0} \tag{3.32}$$

$$\textit{with} \quad \frac{ds_B}{dT} = h_B^{''}(z_B + T) + C_B^{''}(x_B - z_B - T + M) \geq 0 \tag{3.33}$$

$$\textit{and} \quad \frac{dq_B}{dT} = - C_B^{''}(x_B - z_B - T + M) \leq 0 \tag{3.34}$$

$$\frac{dE_{A,B}}{dT} = [\frac{dq_A}{dT} - \frac{dq_B}{dT}] \cdot M \geq 0 \tag{3.35}$$

$$\frac{dW}{dT} = \frac{dW_A}{dT} + \frac{dW_B}{dT} + \frac{dE_{A,B}}{dT} = [-\frac{ds_A}{dT} + \frac{ds_B}{dT}] \cdot T \geq 0 \tag{3.36}$$

In country A, the trading of green certificates leads to a decreasing price of green certificates (Eq. (3.26)) but to an increasing wholesale electricity price (Eq. (3.27)). The change in the wholesale electricity price is always (in absolute values) smaller than, or equal to, the change in the green certificate price. Thus, profits of renewable electricity producers decrease (Eq. (3.23)) and profits of conventional electricity producers increase (Eq. (3.24)). However, effects on consumer rents and on total producer profits cannot be clearly determined without making further assumptions. With regard to consumer rents, the smaller change in the wholesale electricity price refers to total electricity demand (x_A), while the larger change in the green certificate price only affects a fraction of electricity demand (namely ($z_A = x_A \cdot \alpha_A$)). With regard to producer profits, the change in the wholesale electricity price refers to ($x_A - M$), which is likely to be larger than the quantity ($z_A - T$) that is affected by the change in the certificate price.[33]

In country B, the trading of green certificates leads to an increasing price of green certificates (Eq. (3.33)) but to a decreasing wholesale electricity price (Eq. (3.34)). Thus, profits of renewable electricity producers increase (Eq. (3.30)), while profits of conventional electricity producers decrease (Eq. (3.31)). However, as in country A, the effects on consumer rents and on total producer profits are not clear. Again, the change in the wholesale electricity price (in absolute values) is smaller than, or equal to, the change in the green certificate price and affects total electricity demand (x_B) for consumers and ($x_B + M$) for producers. The change in the certificate price, in contrast, affects only ($z_B = x_B \cdot \alpha_B$) for consumers and ($z_B + T$) for producers.

The change in total welfare in countries A and B depends on the change in the green certificate price and, in contrast to the 'copper plate' case, also on the change in the wholesale electricity price (Eq. (3.25) and Eq. (3.32)). If country A is an electricity importer and the wholesale electricity price increases once cooperation is introduced, consumers pay a higher wholesale electricity price for their total demand (x_A), while producers only profit from the higher price for the quantity ($x_A - M$). Therefore, the welfare change in country A, defined as the sum of changes in producer profits and consumer rents, depends on ($\frac{ds_A}{dT} \cdot T$) and on ($\frac{dq_A}{dT} \cdot M$), and can without further assumptions on the slopes of the marginal generation cost curves only be clearly determined if either one of the price effects is zero or if $T > M$.[34] Similarly, if country B is an electricity exporting country, the decreasing wholesale electricity price affects producers to a larger extent ($x_B + M$) than consumers (x_B), such that it is unclear, whether total welfare in country B increases or decreases.

[33] As ($x_A > z_A$), M would need to be substantially larger than T in oder to let ($x_A - M$) be smaller than ($z_A - T$). At the same time, when assuming that the interconnector is congested, it is unlikely that M is substantially larger than T.

[34] As $|\frac{ds_A}{dT}| > |\frac{dq_A}{dT}|$, it follows that, if $T > M$, $|\frac{ds_A}{dT} \cdot T| > |\frac{dq_A}{dT} \cdot M|$ (independent of the slopes of the marginal cost curves).

In contrast, if either the two countries are not at all interconnected (M=0) or if country A (B) is an electricity exporting (importing) country, the welfare changes in A and B are always positive. In the latter case, Equation (3.25) is transformed to $\frac{dW_A}{dT} = -\frac{ds_A}{dT} \cdot T + \frac{dq_A}{dT} \cdot M$ and Equation (3.32) to $\frac{dW_B}{dT} = \frac{ds_B}{dT} \cdot T - \frac{dq_B}{dT} \cdot M$. These equations are always non-negative.

The change in total system-wide welfare corresponds to the sum of the welfare changes in countries A and B and to the change in the congestion rents. If the interconnector between A and B is congested, the changes in the regional wholesale electricity prices affect the price difference between the countries and thus, in turn, the congestion rents. If country A is an electricity importing country (and correspondingly, country B is an electricity exporting country), the price difference between A and B increases when certificate trade is possible (Eq. (3.35)). In contrast, if country A (B) is an electricity exporting (importing) country, then the difference in the wholesale electricity price between A and B decreases with an increasing T, since the wholesale electricity price in A is lower than in B without certificate trading. In both cases, total system-wide welfare increases in T. If country A (B) imports (exports) electricity, then the increasing congestion rents compensate for the negative components in $\frac{dW_A}{dT}$ and $\frac{dW_B}{dT}$ (Eq. (3.36)). If country A (B) exports (imports) electricity, the decreasing congestion rent compensates for the additional welfare increasing effects in A and B based on the changing wholesale electricity prices (see Appendix B). Thus, the change in total system-wide welfare always only depends on the change in the certificate price in both countries and on T, and is always positive. Therefore, even if the welfare in one country, defined as the sum of consumer rents and producer profits, decreases in T, congestion rents can always be redistributed in a way that all countries benefit from certificate trading. In fact, in the European Union congestion rents have to be used for one or several of the three following purposes: (1) guaranteeing the actual availability of the allocated capacity, (2) for network investments maintaining or increasing interconnector capacities or (3) for reducing network tariffs (Art. 6 of the Regulation (EC) 1228/2003; see also Kapff and Pelkmans (2010)). Therefore, if congestion rents are used for purposes (2) or (3), increasing congestion rents have a welfare increasing effect on the country level. If interconnector capacities are increased, ceteris paribus, the welfare in both countries increases - either because of increasing producer profits that overcompensate decreasing consumer rents or, vice versa, because increasing consumer rents dominate (e.g., Kapff and Pelkmans (2010)). If network tariffs are reduced, endconsumer electricity prices decrease and consumer rents increase, which also has a welfare increasing effect. Therefore, if for example congestion rents are used for a network tariff reduction, there exist possible distributions of the network tariff reduction between the two countries, which ensure that welfare in both countries increases once certificate trade is introduced.

In summary, we find that both when the two countries are perfectly interconnected or if bottlenecks exist, system-wide welfare always increases in T (as long as $T < T^*$). Also, welfare on the country-levels always increases either if the two countries form a copper plate or if the countries are not at all interconnected. If bottlenecks exist, congestion rents can always be redistributed in a way, that both countries benefit from the introduction of certificate trading. In contrast, redistribution effects arise between different groups within the two countries, such that the introduction of certificate trade is not beneficial for all groups. Producers of renewable energy yield lower profits in country A (characterized by relative higher generation costs of renewable energy), while profits of RES-E producers in country B increase. If bottlenecks exist, the opposite holds true for producers of conventional electricity. In the copper plate case, producers of conventional electricity are not affected by the introduction of certificate trading. Effects on consumer rents and total producer profits (renewable and conventional) can, however, not be determined, except for the copper plate case. Table 3.2 provides an overview of the price, welfare and redistribution effects resulting from trading of green certificates.

TABLE 3.2: Price, welfare and redistribution effects resulting from cross-border trading of green certificates

	Copper plate	Limited interconnection	
		M>0 but limited	M=0
ds_A	≤ 0	≤ 0	≤ 0
ds_B	≥ 0	≥ 0	≥ 0
dq_A	$=$	≥ 0	≥ 0
dq_B	$=$	≤ 0	≤ 0
dCR_A	≥ 0	?	?
dCR_B	≤ 0	?	?
$d\pi_A^C$	$=$	≥ 0	≥ 0
$d\pi_B^C$	$=$	≤ 0	≤ 0
$d\pi_A^R$	≤ 0	≤ 0	≤ 0
$d\pi_B^R$	≥ 0	≥ 0	≥ 0
$d\pi_A$	≤ 0	?	?
$d\pi_B$	≥ 0	?	?
dW_A	≥ 0	?	≥ 0
dW_B	≥ 0	?	≥ 0
$dE_{A,B}$	$=$	?	$=$
$dW_A + dW_B + dE_{A,B}$	≥ 0	≥ 0	≥ 0

In the next section, the influence factors for those effects marked by a question mark in Table 3.2 are discussed.

3.3.4 Determinants of the redistribution effects in the case of limited interconnection

In this section, determinants of redistribution effects of cooperation, arising in the case of limited interconnection, are investigated in more detail. In the following, it will be shown that the sign of the changes of consumer rents and producer profits essentially depends on the relationship between the slopes of the generation cost curves for renewable-based and conventional electricity and on the level of the RES-E quota.

For this purpose, Equation (3.21), which defines the change in consumer rents in country A due to an increase in T, can be rewritten as follows:
$\frac{dCR_A}{dT} = -(-h''_A(z_A - T) - C''_A(x_A - z_A + T - M)) \cdot z_A - (C''_A(x_A - z_A + T - M) \cdot x_A)$.
Thereby, it can be seen that the change in consumer rents depends on the slopes of the generation cost curves of renewable and non-renewable electricity generation (h''_A and C''_A) and on the RES-E percentage requirement (z_A). While the slopes of the supply curves determine the magnitude of the price effects (resulting from cooperation) on the certificate and on the wholesale electricity market, the level of the RES-E percentage requirement determines how large the part of electricity demand is that is affected by the change in the green certificate price. If the slopes of the two marginal generation cost curves are identical (in the relevant areas) and the RES-E quota is exactly 50%, then the effect of the change in the certificate price exactly compensates for the effect of the change in the wholesale electricity price. In this case, consumer rents are not affected by certificate trading. The upper part of Table 3.3 shows how consumer rents in country A change in T, depending on the relationship between the slopes of the two marginal generation cost curves and the level of the RES-E quota. Generally, consumers in country A benefit from certificate trading, if the RES-E marginal generation cost curve is relatively steep compared to the conventional one ($h''_A \geq C''_A$) and/or the RES-E quota is high.

TABLE 3.3: Changes in consumer rents and producer profits in country A (case II, 'limited grid') depending on the slopes of the marginal generation cost curves and the level of the RES-E quota

$\mathbf{dCR_A/dT}$			
	$h''_A = C''_A$	$h''_A > C''_A$	$h''_A < C''_A$
$z_A = 0.5x_A$	0	> 0	< 0
$z_A < 0.5x_A$	< 0	?	< 0
$z_A > 0.5x_A$	> 0	> 0	?
$\mathbf{d\pi_A/dT}$			
	$h''_A = C''_A$	$h''_A > C''_A$	$h''_A < C''_A$
$z_A = 0.5(x_A - M)$	> 0	?	> 0
$z_A < 0.5(x_A - M)$	> 0	?	> 0
$z_A > 0.5(x_A - M)$	?	?	?

The lower part of Table 3.3 shows how the change in total producer profits in country A depends on the slopes of the marginal generation cost curves, on the RES-E quota and on the size of the interconnector capacity.[35] As defined in Equation (3.23), the change in the certificate price refers to the quantity $(z_A - T)$ for the producers. Thus, the change in total producer profits shown in Table 3.3 cannot be determined in many cases because the level of T is also necessary to determine whether the sum of producers benefit or lose from certificate trading. Generally, if the slope of the marginal generation cost curve for conventional electricity is relatively steep and the RES-E target is low, the wholesale electricity price effect is likely to be dominant, implying that producers in country A benefit from certificate trading.

Table 3.4 depicts the changes in consumer rents and total producer profits in country B depending on the slopes of the renewable and the conventional marginal generation cost curves and the level of the RES-E quota. The effects shown in Table 3.4 mirror the ones depicted in Table 3.3: Under the same conditions as in country A, either the certificate price effect or the wholesale electricity price effect is dominant. However, as price effects in country A and B are opposite, a dominant certificate price effect implies increasing consumer rents in country A and decreasing consumer rents in country B.[36]

[35]Note that the depicted changes in producer profits correspond to the case that country A is not only a certificate but also an electricity importing country. If A is an electricity exporting country, $(x_A - M)$ has to be replaced by $(x_A + M)$.

[36]Note that the depicted changes in producer profits correspond to the case that country B is not only a certificate but also an electricity exporting country. If B is an electricity importing country, $(x_B + M)$ has to be replaced by $(x_B - M)$.

TABLE 3.4: Changes in consumer rents and producer profits in country B (case II, 'limited grid') depending on the slopes of the marginal generation cost curves and the level of the RES-E quota

$\mathbf{dCR_B/dT}$			
	$h''_B = C''_B$	$h''_B > C''_B$	$h''_B < C''_B$
$z_B = 0.5x_B$	0	< 0	> 0
$z_B < 0.5x_B$	> 0	?	> 0
$z_B > 0.5x_B$	< 0	< 0	?
$\mathbf{d\pi_A/dT}$			
	$h''_B = C''_B$	$h''_B > C''_B$	$h''_B < C''_B$
$z_B = 0.5(x_B + M)$	> 0	> 0	?
$z_B < 0.5(x_B + M)$	?	?	?
$z_B > 0.5(x_B + M)$	> 0	> 0	?

Table 3.5 shows under which conditions (i.e., the slopes of the marginal cost curves and the relation between T and M) welfare in country A decreases or increases, given that A is an importer both of certificates and of electricity.[37] Generally, if the amount of certificates traded is large compared to the amount of electricity traded, and if the marginal cost curves of RES-E are relatively steep compared to the marginal cost curves of conventional electricity, then welfare on the country level increases. In contrast, if the amount of certificates traded is relatively small and the conventional marginal generation cost curves are relatively steep, then the wholesale electricity price effect dominates and welfare, defined as the sum of producer profits and consumer rents, decreases. Remember however, that, as explained in Section 3.3.3, congestion rents increase in T if A is electricity importer. These congestion rents can be distributed between A and B in a way which ensures that welfare in both countries always increases in T.

TABLE 3.5: Change in welfare in country A (case II, M>0, but limited) depending on the slopes of the marginal generation cost curves and the relation between certificate and electricity trading

$\mathbf{dW_A/dT}$			
	$h''_A = C''_A$	$h''_A > C''_A$	$h''_A < C''_A$
$T = 0.5M$	0	> 0	< 0
$T < 0.5M$	< 0	?	< 0
$T > 0.5M$	> 0	> 0	?
$T > M$	> 0	> 0	> 0

[37]Note that the welfare effects in country B are identical to the ones depicted in Table 3.5 when h''_A is replaced by h''_B and C''_A by C''_B.

Summarizing, the relation between the slopes of the RES-E supply curve and the supply curve for conventional electricity has a high influence on welfare and redistribution effects resulting from cooperation. Whether in real-world power systems the supply curve of RES-E is steeper or flatter than the one of non-renewable-based electricity cannot be generally said and depends, for example, on available country-specific potentials for different power plant types. For this reason, a determination of redistribution effects in real-world power systems needs to be based on quantitative modeling analyses and is an important subject for future research. In the next section, the role of the supply curves´ slopes and the RES-E percentage requirement is further demonstrated, using numerical examples.

3.3.5 Numerical examples

In this section, we construct two simple numerical examples in order to highlight the effect of the degree of physical interconnection between the two countries, the slopes of the RES-E and the conventional supply curves and the RES-E quota requirement on welfare and redistribution effects induced by cooperation in RES-E support. Table 3.6 provides an overview of the assumptions made in the two numerical examples.

TABLE 3.6: Assumptions made in the numerical examples

	Example 1	Example 2
Demand		
x_A	10	10
x_B	10	10
RES-E target		
z_A	5	4
z_B	5	4
Cost curves		
C_A	$0.5y_A^2$	$0.75y_A^2 + 2y_A$
C_B	$0.5y_B^2$	$0.5y_B^2$
h_A	$2g_A^2$	$0.75g_A^2 + 5g_A$
h_B	g_B^2	$0.5g_B^2 + 3g_B$

In the first numerical example, a 50% RES-E share of electricity demand has to be reached in both countries and costs for conventional electricity generation are identical in both countries. In contrast, country B has a cost advantage in the production of renewable-based electricity compared to country A. Furthermore, in both countries, the slope of the RES-E supply curve is steeper than the slope of the conventional supply curve ($h''_A(g_A) = 4 > C''_A(y_A) = 1$ and $h''_B(g_B) = 2 > C''_B(y_B) = 1$).

Table 3.7 shows the results of this first numerical example for three different interconnector settings: M=0 ('no grid'), M=1 ('limited grid') and M unlimited ('copper plate'). It can be seen that the optimal amount of certificate trade (T*) increases with an increasing level of interconnection between the two countries and that the common certificate price with certificate trading (s*) decreases when M increases. Furthermore, overall welfare gains of certificate trading ($W_A + W_B + E_{A,B}$) increase when M, and therefore T*, increases.

TABLE 3.7: Effects of cooperation in RES-E support:
Results from numerical example 1

		M = 0 ('no grid')			**M = 1** ('limited grid')			**M unlimited** ('copper plate')		
	T*	1.25			1.5			1.67		
	s*	8.75			8.5			8.33		
		T=0	**T=T***	**diff.**	**T=0**	**T=T***	**diff.**	**T=0**	**T=T***	**diff.**
A	s_A	15.00	8.75	-6.25	15.00	8.50	-6.50	15.00	8.33	-6.67
	q_A	5.00	6.25	1.25	5.00	5.50	0.50	5.00	5.00	0.00
	π_A^R	50.00	28.12	-21.88	50.00	24.50	-25.50	50.00	22.22	-27.78
	π_A^C	12.50	19.53	7.03	12.50	15.13	2.63	12.50	12.50	0.00
	π_A	62.50	47.66	-14.84	62.50	39.63	-22.88	62.50	34.72	-27.78
	CE_A	125.00	106.25	-18.75	125.00	97.50	-27.50	125.00	91.67	-33.33
	CR_A			18.75			27.50			33.33
	W_A			3.91			4.63			5.55
B	s_B	5.00	8.75	3.75	5.00	8.50	3.50	5.00	8.33	3.33
	q_B	5.00	3.75	-1.25	5.00	4.50	-0.50	5.00	5.00	0.00
	π_B^R	25.00	39.06	14.06	25.00	42.25	17.25	25.00	44.44	19.44
	π_B^C	12.50	7.03	-5.47	12.50	10.13	-2.38	12.50	12.50	0.00
	π_B	37.50	46.09	8.59	37.50	52.38	14.88	37.50	56.94	19.44
	CE_B	75.00	81.25	6.25	75.00	87.50	12.50	75.00	91.67	16.67
	CR_B			-6.25			-12.50			-16.67
	W_B			2.34			2.38			2.77
	$E_{A,B}$	0.00	0.00	0.00	0.00	1.00	1.00	0.00	0.00	0.00
	$W_A + W_B + E_{A,B}$			6.25			8.00			8.32

Note that, due to the assumption of an inelastic electricity demand, no absolute values for consumer rents and welfare levels can be calculated. However, the differences in expenditures that consumers pay for meeting their electricity demand (CE) (multiplied by (-1)) correspond to the change in consumer rents (CR).

Regardless of the size of the interconnector capacity M, the certificate price effect is always dominant in this example. Therefore, consumers in country A and total producers in country B benefit from certificate trading, while consumers in country B and total producers in country A are worse off than without certificate trading. On the country level, the change in welfare is positive in A and B. However, trade gains are unequally distributed between the two countries. In all three interconnector settings, the welfare increase in country A is larger than in country B. When the two countries form a copper plate, the welfare gain in country A makes up even two thirds of the overall welfare gain. The reason is, that, as shown in Lemma 2, the welfare change on the country-level depends on the changes in the green certificate and in the wholesale electricity price

($dW = |\frac{ds}{dT} \cdot T| + |\frac{dq}{dT} \cdot M|$). As the slopes of the conventional electricity supply curves are the same in both countries, it follows that $|\frac{dq_A}{dT}| = |\frac{dq_B}{dT}|$. In contrast, the RES-E supply curve is steeper in A than in B, such that the certificate price effect in A is larger than in B ($|\frac{ds_A}{dT}| > |\frac{ds_B}{dT}|$). Consequently, the welfare change in A is larger than in B ($\frac{dW_A}{dT} > \frac{dW_B}{dT}$).

In the second example, it is assumed that countries A and B have different cost curves for RES-E as well as for conventional electricity generation. In contrast to the first example, the slopes of the RES-E and the conventional supply curves in each country are identical ($h''_A(g_A) = C''_A(y_A) = 1.5$ and $h''_B(g_B) = C''_B(y_B) = 1$). Moreover, in contrast to the first example, the RES-E quotas in both countries are assumed to be 40% instead of 50%.

Table 3.8 shows price, welfare and redistribution effects occurring in this second example due to certificate trading. First of all, it needs to be noted that under the assumptions made in this example, country A is not always a certificate importing country. When M=0 and certificate trading is not possible, the certificate price in A is lower than in country B. The reason is that country A has higher costs for RES-E *and* conventional electricity generation compared to country B. Therefore, the certificate price in country A is lower than in B, due to a high wholesale electricity price. When electricity trading is possible (M=1 or M unlimited), country A is an electricity importing country, both when certificate trade is and is not possible. Therefore, the wholesale electricity price in country A is lower than without the possibility of electricity trading and the pre-certificate trading certificate price is higher in country A than in B. Thus, when M=1 or when M is unlimited, country A imports electricity and green certificates.

Table 3.8: Effects of cooperation in RES-E support:
Results from numerical example 2

		M = 0 ('no grid')			**M = 1** ('limited grid')			**M unlimited** ('copper plate')		
	T*	0.2			0.3			1.6		
	s*	0.6			0.6			0.6		
		T=0	**T=T***	**diff.**	**T=0**	**T=T***	**diff.**	**T=0**	**T=T***	**diff.**
A	s_A	0.00	0.60	0.60	1.50	0.60	-0.90	3.38	0.60	-2.78
	q_A	11.00	10.70	-0.30	9.50	9.95	0.45	7.63	8.00	0.38
	π_A^R	12.00	13.23	1.23	12.00	10.27	-1.73	12.00	4.32	-7.68
	π_A^C	27.00	25.23	-1.77	18.75	21.07	2.32	10.55	12.00	1.45
	π_A	39.00	38.46	-0.54	30.75	31.34	0.59	22.55	16.32	-6.23
	CE_A	110.00	109.40	-0.60	101.00	101.90	0.90	89.75	82.40	-7.35
	CR_A			0.60			-0.90			7.35
	W_A			0.06			-0.32			1.12
B	s_B	1.00	0.60	-0.40	0.00	0.60	0.60	0.00	0.60	0.60
	q_B	6.00	6.20	0.20	7.00	6.70	-0.30	7.63	8.00	0.38
	π_B^R	8.00	7.22	-0.78	8.00	9.25	1.25	10.69	15.68	4.99
	π_B^C	18.00	19.22	1.22	24.50	22.45	-2.06	29.07	32.00	2.93
	π_B	26.00	26.44	0.44	32.50	31.69	-0.81	39.76	47.68	7.92
	CE_B	64.00	64.40	0.40	70.00	69.40	-0.60	76.25	82.40	6.15
	CR_B			-0.40			0.60			-6.15
	W_B			0.04			-0.21			1.77
	$E_{A,B}$	0.00	0.00	0.00	2.50	3.25	0.75	0.00	0.00	0.00
	$W_A + W_B + E_{A,B}$			0.10			0.22			2.89

As in the first example, the optimal amount of certificates traded and the welfare gains increase with an increasing interconnection between the two countries.[38] In contrast to the first example, however, the common certificate price when certificate trading is possible (s*) does not vary with different levels of M. As shown in Lemma 2, the certificate price effect depends on the slopes of the RES-E and the conventional electricity supply curve. On the one hand, an increase in M leads to an increase in T* and therefore, ceteris paribus, to an increasing certificate price effect. On the other hand, the larger the interconnector capacity is, the smaller the wholesale electricity price effect becomes. As the change in the wholesale electricity price reinforces the certificate price effect, a larger interconnector capacity also has a decreasing effect on changes in the certificate price. Under the assumptions of equal slopes of the two supply curves, these two effects exactly compensate for each other.

[38]Note that the overall welfare gain is significantly higher when M is unlimited compared to the case when M=1, as shown in the third column of Table 3.8. The reason is that without certificate trading the RES-E quota in country B is not binding (i.e., the certificate price would be negative when producing only 4 units of RES-E). Thus, the overall amount of RES-E produced is lower when certificate trading is possible because a part of the certificates traded from country B to country A corresponds to RES-E generation that exceeds the RES-E quota even without certificate trade. Consequently, some of the traded certificates do not induce extra costs in country B. Moreover, for this reason, the wholesale electricity price increases both in countries A and B when certificate trading is possible.

Regarding redistribution effects, the certificate price effect in this example clearly dominates if M is unlimited. In contrast, it can be seen that if M=1, the wholesale electricity price effect is dominant both with regard to changes in consumer rents and with regard to changes in producer profits in the two countries. As the slopes of the RES-E and the conventional electricity supply curves are identical in this example, the change in the certificate price is twice as high as the change in the wholesale electricity price in both countries. However, as the RES-E quota is lower than 50%, the wholesale electricity price effect dominates.

Regarding welfare effects on the country-level, it can be seen that welfare in countries A and B decreases if M=1. As stated in Table 3.5, welfare on the country level decreases if the slopes of the RES-E and the conventional supply curves are identical and if $T < 0.5M$, which is satisfied in this example. In this case, the increase in the wholesale electricity price in country A leads to increasing end-consumer electricity prices for all consumers in country A, while producers in country A only partly benefit from this price increase because a part of the consumed electricity is imported. Similarly in country B, the decrease in the wholesale electricity price affects producers to a larger extent than consumers because electricity generation is higher than electricity demand due to exports. However, if M=1, congestion rents increase by 0.75 once cooperation is introduced and consequently, welfare on the system-level increases. Moreover, in this case, e.g., an equal distribution of the additional congestion rents between the two countries would ensure that both countries benefit from the introduction of certificate trade.

3.4 Conclusion

As shown in neoclassical trade theory, trade between regions characterized by different resource availabilities increases overall welfare. However, due to trade-induced changes in prices, some individuals benefit from trade while others are worse off compared to a situation in autarky. This paper is motivated by findings of trade theory and analyzes cooperation in RES-E support between regions that are characterized by different supply functions of RES-E generation. The paper shows that cooperation in RES-E support also increases overall welfare and creates winners and losers compared to a situation in which each country achieves its RES-E target by local production only.

Our analysis shows that, due to opposing price effects of cooperation on the wholesale electricity market and on the green certificate market, the determination of winners and losers of cooperation is not straightforward as long as the different regions are not perfectly physically interconnected. Whether consumers or producers in a country benefit or are worse off essentially depends on the relation between the slopes of the RES-E and the conventional electricity supply curves as well as on the level of the RES-E target and on the degree of physical interconnection between the different countries. In contrast, system-wide welfare always increases once cooperation in RES-E support is introduced. Similarly, welfare on the country level always increases (compared to a situation without RES-E cooperation) if the countries are perfectly or not at all physically interconnected. In the case of congested interconnectors, the sum of producer and consumer rents in a country may also decrease under certain conditions. However, in this case the level of congestion rents is also influenced by the introduction of RES-E cooperation. Therefore, in this case, there always exists a possible distribution of congestion rents between the countries which ensures that each country benefits from the introduction of certificate trade.

Redistribution effects have a high relevance in political decisions surrounding the implementation of cooperation in RES-E support. In most real-world electricity systems, bottlenecks in the transmission lines between different countries exist currently. Our analysis shows that, in this case, the determination of redistribution effects is not straightforward and needs to be based on thorough quantitative analyses of real-world electricity systems. In particular, the interaction between the support for renewable energy and the wholesale electricity market needs to be taken into account. Moreover, important influence factors of redistribution effects can change over time, e.g., when interconnectors are expanded, when the RES-E targets increase over time or when cost degressions of different technologies lead to changing supply curves.

It is also important to take these considerations into account when discussing the sharing of costs and benefits of cooperation mechanisms. In this context, two important questions arise: First, who should or would need to be compensated in order to enhance cooperation between different regions? And second, how should compensation payments be determined? Regarding the first question, our analysis shows that in most cases cooperation increases welfare on the country level. Thus, compensation mechanisms on the country level would be hardly needed if countries are not concerned about domestic redistribution effects or unequally high benefits among participating countries. However, while the analysis includes effects resulting form cooperation on RES-E support expenditures and on the wholesale electricity market, effects on regional grid enhancement costs and other integration costs are neglected. Furthermore, the theoretical model assumes that producer profits are clearly allocated to the country in which the electricity is produced. For example, in the European electricity system, large international companies operating in several countries play an important role in electricity production. Thus, a clear association between producer profits and countries can be difficult in practice.

Regarding the second question, direct and indirect costs and benefits of cooperation have already been assessed in literature, e.g., by Klessmann et al. (2010) and Pade et al. (2012). These costs and benefits include, e.g., a reduction of RES-E target compliance costs, grid reinforcement and grid expansion costs, power market effects, effects on the technological development of power plants, employment effects and regional environmental effects. In particular, Pade et al. (2012) state that compensation mechanisms should include power market effects and that barriers to cooperation between countries with a common electricity market are lower because, in this case, RES-E deployment leads to similar power market effects in the cooperating countries. Our analysis confirms that power market effects can have a significant influence on redistribution effects resulting from cooperation. However, thorough quantitative analysis based on real-world data is needed to determine the magnitude of these power market effects. In summary, further research, is needed to further investigate redistribution effects and possible measures to enhance cooperation.

Chapter 4

Who benefits from cooperation? - A numerical analysis of redistribution effects resulting from cooperation in European RES-E support

4.1 Introduction

An important target in European energy policy is to increase the share of renewable energy sources (RES) in primary energy consumption, mainly for reasons of environmental protection and security of supply (EU (2001), EC (2009)). The electricity sector plays an important role in reaching this target. By 2020, the overall RES share in primary energy consumption should reach 20%, whereas the renewable energy share in electricity consumption (RES-E) is targeted to increase up to 34%.[39] The contribution of the individual member states of the European Union (EU) in achieving this target has been agreed upon based on the member states´ GDP, their RES level in 2005 and their resource potentials for renewable energy generation (EC (2009)). As the resource potential is only one among several factors which influenced the target distribution, a cost-efficient regional allocation of RES-E production across Europe is not reached if the

[39]Directive 2009/28/EC defines the contribution of each member state to reach the 20% RES target in primary energy consumption. This target includes the electricity, transportation and heating and cooling sectors. The sector-specific distribution of the targets were defined by the member states in their National Renewable Energy Action Plans (NREAP). An aggregation of the targets for the electricity sector of all member states leads to a EU-wide RES-E target of 34% by 2020 (EC (2012)).

national targets are achieved purely by domestic production (e.g., EWI (2010), Aune et al. (2012)). Thus, in order to reduce target compliance costs, the European Directive 2009/28/EC on the promotion of renewable energy establishes the possibility of using cooperation mechanisms, including statistical transfers, joint projects and joint support schemes.

The use of cooperation mechanisms potentially enables the member states to benefit from low-cost generation options across Europe, either because support payments can be reduced (in member states with small potentials of low-cost generation options compared to their targets) or because additional revenues can be acquired (in member states with large potentials of low-cost generation options). Despite these potential benefits from cooperation, almost all member states plan to reach their 2020 targets solely by domestic RES-E production (Beurskens et al. (2011)). One reason why member states are reluctant to implement cooperation mechanisms is that cooperation induces redistribution effects (Fürsch and Lindenberger (2013)). For example, Portugal states in its National Renewable Energy Action Plan (NREAP) that it could easily produce more RES-E than required for achieving its national target if the interconnector between the Iberian Peninsula and France would be expanded. Without interconnector expansions, a larger RES-E share would devaluate the existing power plant fleet of Portugal (Portuguese Republic (2010)). Furthermore, in the history of the joint quota system of Norway and Sweden, redistribution effects played an important role. This joint RES-E support system was introduced in 2012 and is one of the few exceptions of a cooperation mechanism in use. An earlier attempt to establish the joint support scheme, however, failed in 2006 because the different parties could not agree on a sharing of costs and benefits (Klessmann et al. (2010)).

While the overall benefit of cooperation in RES-E support has been quantified in prior research, e.g., by Voogt et al. (2001), Ragwitz et al. (2007), EWI (2010), Capros et al. (2010) and Aune et al. (2012), the effects of cooperation on individual groups such as consumers or producers in individual countries have, to our knowledge, not yet been quantified.[40] However, in a theoretical analysis, this research question has recently been addressed by Unteutsch (2014), who relates cross-border cooperation in RES-E support

[40]Moreover, redistribution effects of other policies in the electricity system have been subject to prior research, however, to our knowledge, we are the first to numerically analyze redistribution effects of cooperation in RES-E support. For example, Huang et al. (2005) and Billette de Villemeur and Pineau (2010) show effects of electricity trading on overall sectoral welfare, consumer rents and producer rents. Bauer et al. (2008) analyze redistribution effects of electricity transfers from North Africa to Europe. Hirth and Ueckerdt (2012) analyze redistribution effects between consumers and producers induced by support schemes for renewable energies and by CO_2 emission reduction policies. Neuhoff et al. (2013) investigate the distributional effects of increasing RES-E support payments in Germany on different household types and discuss different compensation mechanisms to lower the burden carried by low-income households.

to international trade theory and shows in a theoretical two-country model that cooperation in RES-E support increases overall welfare but is not beneficial for all groups. The author shows that as long as cooperating countries are not perfectly physically interconnected, cooperation has opposite effects on regional wholesale electricity prices and prices for green certificates.[41] For this reason, the net effect of cooperation on consumers and producers per country is theoretically not clear as long as grid congestions between different countries exist. Moreover, while the system-wide welfare always increases if cooperation is implemented, the net welfare effect of cooperation on the country level can be undetermined under certain conditions (including that a country is importer or exporter both of electricity and of green certificates). Therefore, redistribution effects resulting from cooperation depend on data that is specific to each electricity system and need to be determined by numerical analyses using real-world data.

The paper presented numerically analyzes the effects shown in Unteutsch (2014) for the European electricity system up to 2020. The purpose of this paper is to analyze the direction, magnitude and robustness of redistribution effects that could be induced in the European electricity system in reaching the 2020 RES-E targets by EU-wide cooperation (via cross-border trading of green certificates) rather than by national approaches. The analysis is carried out using the investment and dispatch optimization model DIMENSION of the Institute of Energy Economics, which captures the European electricity system in great detail. As shown in Unteutsch (2014), the degree of physical interconnection and the slopes of the RES-E and the conventional electricity supply curves have a large influence on the direction and the magnitude of redistribution effects. Therefore, we model different scenarios with regard to interconnector capacity extensions between European regions as well as with regard to factors influencing the slopes of the supply curves (such as CO_2 - prices and RES-E investment costs).

Main findings of this paper include that, in the European electricity system, effects of a change in the green certificate price in most countries would overcompensate for the effects of a change in the wholesale electricity price. Thus, in most countries with comparatively high (low) generation costs for renewable energies, consumer rents increase (decrease) due to cooperation and producers yield lower (higher) profits. In addition, we find that the magnitude of redistribution effects between the individual groups is quite large: In some countries, the change in consumer rents or producer profits resulting from cooperation is nearly twice as high as the overall welfare effect of cooperation in the whole European electricity system. Moreover, the benefit different countries have from cooperation varies substantially. In our analysis, we find that Germany would by

[41] In Unteutsch (2014), cooperation in RES-E support is implemented as a cross-border green certificate trading scheme. A green certificate system is one of several RES-E support systems currently implemented in European member states. See Section 4.2 for a brief description.

far have the largest (absolute) benefit of cooperation, achieved by significant reductions of RES-E target compliance costs via certificate imports. Finally, we find that the sign of redistribution effects is quite robust to different developments of interconnector extensions, the CO_2 price and RES-E investment costs. The magnitude of redistribution effects, in contrast, is in some countries sensitive to these assumptions (especially with regard to the assumption on the CO_2 price).

The remainder of the article is structured as follows: In Section 4.2, findings of Unteutsch (2014) are briefly summarized in order to provide the theoretical background for the analysis carried out in this paper. Section 4.3 outlines the modeling approach and covers the results of the numerical analysis. In Section 4.4, we draw conclusions and provide an outlook for future research.

4.2 Theoretical background

As described in the introduction, this paper directly builds on the theoretical analysis of redistribution effects by Unteutsch (2014), whose results are briefly summarized in this section. Unteutsch (2014) analyzes the impact of cooperation in RES-E support in a theoretical two-country electricity system model in which RES-E support is implemented as a green certificate system. In a green certificate system, a market for the green value of renewable electricity is created by obligating consumers or distributers of electricity to certify that a certain share of the electricity produced or consumed comes from renewable energy sources (see Amundsen and Mortensen (2001), Menanteau et al. (2003) or Agnolucci (2007) for a detailed description).

In the model presented by Unteutsch (2014), it is assumed that a country A has higher RES-E generation costs compared to a country B, whereas generation costs of conventional electricity in A can be equal, higher or lower than in B. Each country has a national RES-E target, expressed as a percentage share of (inelastic) electricity demand. Without cross-border trading of green certificates, the national RES-E target has to be achieved solely by domestic RES-E production. When trading of green certificates is possible, country B produces a higher RES-E amount than needed for national target achievement and exports certificates to country A until the certificate prices in the two countries converge. Note that the trading of green certificates is also possible without physical trading of electricity.

In this analytical framework, effects of cooperation in RES-E support (via cross-border green certificate trading) on consumer rents, producer profits and total welfare in both countries are analyzed for two different cases of physical interconnection between the two countries, i.e., the 'copper plate' case and the 'limited interconnection' case. The 'copper plate' case assumes that no grid congestion between the countries exist and that, consequently, the two regional electricity markets are perfectly interconnected. In the 'limited interconnection' case, electricity trade between the two countries is restricted - either because the interconnector is congested (the interconnector capacity M is > 0 but limited such that no complete electricity price convergence between the two markets is possible) or because no interconnector exists (M=0). Table 4.1 summarizes the results from the analysis by Unteutsch (2014).

Table 4.1: Price, welfare and redistribution effects resulting from cross-border trading of green certificates

	Copper plate	Limited interconnection M>0 but limited	M=0
Green certificate price in A (ds_A)	≤ 0	≤ 0	≤ 0
Green certificate price in B (ds_B)	≥ 0	≥ 0	≥ 0
Wholesale electricity price in A (dq_A)	=	≥ 0	≥ 0
Wholesale electricity price in B (dq_B)	=	≤ 0	≤ 0
Consumer rents in A (dCR_A)	≥ 0	?	?
Consumer rents in B (dCR_B)	≤ 0	?	?
Profits of conventional elec. producers in A ($d\pi_A^C$)	=	≥ 0	≥ 0
Profits of conventional elec. producers in B ($d\pi_B^C$)	=	≤ 0	≤ 0
Profits of renewable-based elec. producers in A ($d\pi_A^R$)	≤ 0	≤ 0	≤ 0
Profits of renewable-based elec. producers in B ($d\pi_B^R$)	≥ 0	≥ 0	≥ 0
Total producer profits in A ($d\pi_A$)	≤ 0	?	?
Total producer profits in B ($d\pi_B$)	≥ 0	?	?
Welfare in A (dW_A)	≥ 0	?	≥ 0
Welfare in B (dW_B)	≥ 0	?	≥ 0
Congestion rent ($dE_{A,B}$)	=	?	=
System-wide welfare ($dW_A + dW_B + dE_{A,B}$)	≥ 0	≥ 0	≥ 0

Source: Unteutsch (2014)

In all cases, the certificate price in country A (with comparatively higher RES-E generation costs) decreases when cross-border cooperation in RES-E support is possible (s_A), whereas the certificate price in country B (s_B) increases. The opposite holds true for the wholesale electricity prices (q_A and q_B), except for the 'copper plate' case in which a different regional allocation of RES-E production does not affect the common wholesale electricity market. In country A, producers of conventional electricity yield higher profits (π_A^C) than without cooperation in RES-E support (due to the increased wholesale electricity price), while producer profits gained with conventional electricity generation decrease in country B (π_B^C) (except for the 'copper plate' case in which producer profits from conventional electricity generation are not affected by cooperation). Producer profits of RES-E (π_A^R, π_B^R), in contrast, increase in country B and decrease in country A. Except for the 'copper plate' case, the net effect on consumers (CR_A, CR_B) and total producers (π_A, π_B) in countries A and B cannot be determined without making further assumptions. While the decreasing green certificate price in country A is beneficial for consumers in this country, the increasing wholesale electricity price has an end-consumer price increasing effect. Similarly, in country B, the increasing certificate price leads to increasing end-consumer prices (ceteris paribus), while the decreasing wholesale electricity market price has an opposite effect. Welfare on the country level (W_A, W_B) always increases due to cooperation, except under certain conditions in the 'limited grid' case (as further discussed below). However, given the conditions under which welfare on the country level can decrease, congestion rents ($E_{A,B}$) increase such that overall system-wide welfare ($W_A + W_B + E_{A,B}$) always increases once cooperation in RES-E support is introduced. Moreover, these additional congestion rents could potentially be distributed between the two countries in a way which ensures that all countries benefit from the introduction of certificate trade.

Moreover, for the cases in which effects on consumers, producers and welfare per country cannot be determined (marked by a '?' in Table 4.1), Unteutsch (2014) shows under which conditions the effects are unambiguous, particular with respect to the slopes of the supply curves and the level of the RES-E targets. Generally, if the conventional electricity supply curve is relatively steep compared to the RES-E supply curve and the RES-E target is rather low, then the wholesale electricity price effect resulting from cooperation is likely to be dominant. In this case, producers in country A and consumers in country B benefit from cooperation, while producers in country B and consumers in country A lose compared to a situation in which each country achieves its RES-E target without cooperation. Similarly, if the RES-E supply curve is relatively steep compared to the conventional electricity supply curve and the RES-E target is rather high, the certificate price effect is likely to be dominant. In this case, cooperation is beneficial for consumers in country A and for producers in country B. Total welfare in country A and B always increases when cooperation in RES-E support is introduced and the two countries are not at all or perfectly interconnected. If, however, a bottleneck in the interconnector exists and country A is an importer of both certificates and electricity (and country B an exporter of certificates and electricity), welfare on the country level (defined as the sum of consumer rents and producer profits) can decrease under certain conditions. For example, the amount of certificates traded may be relatively small compared to the amount of electricity traded and the conventional electricity supply curve may be relatively steep compared to the RES-E supply curve. In this case, higher electricity import costs or lower revenues from electricity exports resulting from cooperation can overcompensate the benefit from certificate trading in terms of reduced RES-E production costs or additional incomes from certificate trading.

In summary, Unteutsch (2014) shows that redistribution effects of cooperation depend on the level of interconnection between the different countries as well as on the slopes of the supply curves and the level of the RES-E target(s). These factors are specific to each electricity system and can also change over time, e.g., when interconnectors are expanded or when fuel, CO_2 prices or investment costs change, leading to changing supply curves. Therefore, in order to determine the direction and the magnitude of redistribution effects in real-world electricity systems, a quantification based on real-world data is needed. In this paper, we analyze which redistribution effects would occur in the European electricity system up to 2020, if the 2020 targets were reached with EU-wide cooperation in RES-E support rather than with national RES-E support. As in the theoretical analysis presented in Unteutsch (2014), the model-based scenario analysis is built on the assumption that the RES-E targets are either cost-efficiently reached within national borders (when cooperation is not possible) or by using low-cost generation options throughout Europe (via cooperation).

4.3 Numerical analysis

We numerically analyze redistribution effects in the European electricity system that may potentially arise when reaching RES-E targets for 2020 with European-wide cooperation rather than by national approaches. According to the European Directive 2009/28/EC, the renewable energy share in the European Union´s (EU) final energy consumption (including the electricity, transportation and heating and cooling sectors) should increase to 20% by 2020. The contribution of each country to the European-wide target has also been defined in Directive 2009/28/EC, while the sector-specific breakdown of the national targets has been stated by each member state within its National Renewable Energy Action Plan (NREAP). Overall, the achievement of the national RES-E targets would lead to an EU-wide RES-E share of approximately 34% by 2020 (EC (2010)). Despite the possibilities to cooperate across borders in order to achieve the national targets, given by the Directive 2009/28/EC, most member states almost purely rely on national approaches. As described in the introduction (Section 4.1), one impediment of stronger cooperation seems to be (politically undesired) redistribution effects.

Therefore, we compare consumer rents, producer profits and total welfare per country in the event that the 2020 RES-E targets are reached either on a national level or with EU-wide cooperation. In both cases, we assume that targets are reached with a technology-neutral support system. It is important to note that, in reality, many EU countries currently have technology-specific support systems.[42] Thus, we do not quantify redistribution effects that would arise when changing from the currently implemented

[42]See www.res-legal.eu for an overview of renewable energy support system designs currently implemented in European countries.

country-specific support systems to a cooperative support design. Instead, we show which effects would arise when changing from purely national, technology-neutral support systems to a system in which RES-E is supported as technology-neutral *and* with European-wide cooperation. Thereby, we quantify the effects that have been theoretically shown by Unteutsch (2014) for the European power system up to 2020 and focus on the welfare and redistribution effects explicitly induced by cross-border cooperation. In contrast, we do not take into account effects which could arise from inefficient national support systems. In specific, the numerical analysis in this paper aims at investigating the following questions:

1. Who benefits and who loses when the 2020 RES-E targets in Europe are achieved with cross-border cooperation in RES-E support?
2. How large are these redistribution effects?
3. How robust are these redistribution effects (in terms of their sign and magnitude) with regard to different developments of interconnector extensions and with regard to changes in the CO_2 price, fuel prices or investment costs, which influence the slope of electricity supply curves?

In Section 4.3.1, we define the scenarios to analyze and provide information on the most important assumptions. In Section 4.3.2, the modeling approach is described. In Section 4.3.3, we describe and analyze the model results.

4.3.1 Scenario definition and assumptions

As discussed in Unteutsch (2014), the level of grid interconnection between countries influences the optimal amount of certificates traded as well as the redistribution and welfare effects resulting from cooperative RES-E support. Therefore, the numerical analysis presented in this paper also distinguishes between different grid interconnection settings. The current European power system is, on the one hand, already deeply intermeshed and is, on the other hand, still subject to substantial bottlenecks between some regions. Interconnector extensions are planned but often delayed (EWI and energynautics (2011)). Thus, we model two main scenarios that differ with regard to the progress in interconnector extensions. In the first scenario, we assume that interconnectors are not extended at all from today onwards. In the second scenario, we assume that all planned interconnector extensions, as stated in the Ten-Year Network Development Plan (TYNDP; see ENTSO-E (2010)), are realized.

Moreover, as discussed in Unteutsch (2014), price effects, which in turn induce redistribution effects, depend on the slopes of the supply curves for renewable and conventional electricity generation. Thus, we run sensitivities with regard to three factors which influence the slopes of the supply curves. First, we analyze the effects of a higher CO_2 price than in the reference case (30 EUR/t compared to 20 EUR/t in 2020). Second, we analyze the effects of lower photovoltaic investment costs and third, of lower offshore wind investment costs (- 10 % compared to the investments costs in the reference case).[43] In all sensitivity runs, we assume that the TYNDP is realized. Table 4.2 provides an overview of the main scenarios and the sensitivities.

TABLE 4.2: Overview of modeled scenarios

		Interconnector extension	
		no extension	TYNDP
Reference assumptions		x	x
Sensitivities	higher CO price		x
	lower photovoltaic costs		x
	lower offshore wind costs		x

All scenarios depicted in Table 4.2 are modeled twice: Once assuming purely national RES-E support systems and once with EU-wide cooperation. RES-E targets in 2020 and electricity demand in 2020 are depicted in Table 4.3. Electricity demand is assumed to develop according to the 'additional energy efficiency' scenario of the NREAPs (see Beurskens et al. (2011)).[44]

[43]The investment costs in the reference case correspond to those costs which are also assumed in the analysis presented in Chapter 2 of this thesis (see Table 2.3).

[44]The analysis covers the EU-27 countries (with the exception of Cyprus and Malta), Norway and Switzerland. As Norway and Switzerland are not part of the European Union and have no NREAP, assumptions on electricity demand are based on EWI and energynautics (2011). RES-E targets are assumed to be slightly above historical RES-E generation in 2010.

TABLE 4.3: Final electricity demand and NREAP target in 2020 [TWh_{el}]

	electricity demand	RES-E target
Austria (AT)	74	52
Belgium (BE)	111	23
Bulgaria (BG)	37	8
Czech Republic (CZ)	84	12
Denmark (DK)	38	21
Estonia (EE)	11	2
Finland (FI)	102	33
France (FR)	546	155
Germany (DE)	562	217
Greece (GR)	68	27
Hungary (HU)	51	6
Ireland (IE)	33	14
Italy (IT)	375	99
Latvia (LV)	9	5
Lithuania (LT)	9	3
Luxembourg (LU)	7	1
Netherlands (NL)	136	50
Norway (NO)	119	114
Poland (PL)	170	32
Portugal (PT)	65	36
Romania (RO)	74	31
Slovakia (SK)	33	8
Slovenia (SL)	16	6
Spain (ES)	375	150
Sweden (ES)	155	97
Switzerland (CH)	67	45
United Kingdom (UK)	377	117

Table 4.4 depicts the assumed fuel price developments up to 2020, based on Prognos/EWI/GWS (2010) and EWI and energynautics (2011) (biomass solid and biogas). In addition, CO_2 emission factors are shown. The CO_2 price is assumed to increase up to 20 EUR_{2010}/t in 2020.

TABLE 4.4: Fuel prices [EUR_{2010}/MWh_{th}] and CO_2 emission factor [t CO_2 /MWh_{th}]

	Fuel price		CO_2 factor
	2008	2020	
	[EUR_{2010}/MWh_{th}]		[t CO_2 /MWh_{th}]
Nuclear	3.6	3.3	0
Coal	17.28	10.1	0.335
Lignite	1.4	1.4	0.406
Natural gas	25.2	23.1	0.201
Biomass (solid)	15.0-27.7	15.7-34.9	0
Biomass (gas)	0.1-70.0	0.1-67.2	0

Assumptions on technical and economic parameters of power plants correspond to those described in Chapter 2 of this thesis (see Tables 2.3, 2.4 and 2.5).

4.3.2 Model description

For the numerical analysis, we use the dynamic investment and dispatch optimization model DIMENSION developed at the Institute of Energy Economics at the University of Cologne. The model minimizes total costs required to meet an inelastic hourly electricity demand in each market region. Hourly demand is represented by a typical day approach, reflecting typical demand and RES-E feed-in structures on a weekday and a weekend-day in autumn/winter and in spring/summer. Different meteorological conditions throughout Europe are taken into account by modeling different wind speed conditions in 47 onshore and 42 offshore wind regions. Different levels of solar radiation throughout Europe are captured by modeling 38 photovoltaic regions. Meteorological data is taken from EuroWind (2011). Hourly dispatch decisions include ramping procedures of thermal power plants, pumping and generation operations in storage units and import and export streams between market regions. Furthermore, RES-E infeed can be curtailed if this option is beneficial for minimizing total costs, e.g., when curtailment is cost-optimal compared to ramping procedures of thermal power plants. The model optimizes investment and dispatch decisions of thermal power plants (possibly equipped with combined-heat-power technology (CHP)), storage units and renewable plants. The existing power plant fleet is taken into account by several vintage classes, representing typical technological characteristics (e.g., conversion efficiencies) of power plants build at different points in time. Renewable technologies covered by the model include: onshore wind, offshore wind (shallow and deep water), biomass solid, biogas, concentrated solar power (equipped with thermal energy storage), geothermal and photovoltaics (ground and roof). The generation in biomass or biogas plants is restricted by yearly fuel potentials. Investments in wind- and solar-based technologies are restricted by area potentials. The technological progress of wind turbines is taken into account by modeling different technology classes which can be deployed at different future time periods. The option of repowering is also included in the modeling.

A detailed documentation of the basic model is provided by Richter (2011). In this analysis, we use an extended model version including the option of endogenous investments in renewable energy plants. For a documentation of this extended model version, the reader is referred to Jägemann et al. (2012) and Fürsch et al. (2013a).

In this paper, we use the DIMENSION model to analyze redistribution effects of EU-wide cooperation compared to national RES-E support. Equations (4.1) to (4.4) show how redistribution effects in terms of consumer rents, producer profits as well as welfare on the country level and on the European electricity system level are determined. A list of the abbreviations used in the equations for model sets, parameters and variables, is provided in Table 4.5. The difference in consumer rents (in country i and year y) between EU-wide cooperation and national RES-E support is defined by Eq. (4.1), i.e., the difference in expenditures that consumers pay to meet their electricity demand multiplied by (-1).[45] These expenditures include costs for buying electricity on the wholesale electricity market, RES-E support expenditures and costs for ensuring security of supply. In the model, 'security of supply' is defined by the requirement that an amount of 'securely available' electricity generation capacity exists that is sufficient to meet peak demand including during times of low wind infeed and low solar radiation (see, e.g., Fürsch et al. (2013a)).[46] Producers may earn incomes on the wholesale electricity market, for selling green certificates on the certificate market and by providing securely available generation capacities. In addition, producers can earn incomes by selling heat that is generated by combined-heat-and-power plants on the heat market. Producer profits are determined as the sum of these incomes, from which the following costs are deducted: variable generation costs (including fuel and CO_2 costs), additional variable costs arising from ramping procedures, costs for pumping electricity into storage units, fixed operation and maintenance costs and annualized investment costs. Equation (4.2) shows the difference in producer profits between cooperative and national RES-E support. The difference in the national welfare of country i is defined as the sum of differences in consumer rents and in producer profits in this country (Eq.(4.3)). Differences in the overall European-wide welfare are determined as the sum of differences of all national welfares and of the congestion rents that the transmission system operators (TSO) earn (Eq.(4.4)). Congestion rents cannot be allocated to a particular TSO of a specific country. In reality, often agreements regarding the allocation of these rents exist (see, e.g., Nordpool Spot (na)). However, as these agreements can change over time, we do not allocate congestion rents to specific countries.

[45] As DIMENSION is a linear optimization model, no absolute values for consumer rents can be determined. However, we are only interested in differences of consumer rents between scenarios with cooperative and national RES-E support. Assuming an inelastic electricity demand, these differences in consumer rents correspond to the differences in expenditures that consumers pay to meet their demand.

[46] Due to limited computed hours in the model, not all combinations of demand and RES-E infeed that may occur with some probability can be explicitly modeled. Thus, in this modeling approach, investments that are only required to meet security of supply are incentivized by a capacity price. Note that, in real-world electricity markets, investments in plants which are only necessary for a few hours can also be incentivized by price peaks in the electricity wholesale market (see Nagl (2013)).

$$
\begin{aligned}
dCR_{i,y} =& \phi_y \cdot (-1) \cdot [\sum_h (q^{CO}_{i,h,y} - q^{N}_{i,h,y}) \cdot x_{i,h,y} && (4.1)\\
&+(s^{CO}_y - s^{N}_{i,y}) \cdot \alpha_{i,y} \cdot \sum_h x_{i,h,y} \\
&+\omega_a(\sum_a C^{CO}_{i,a,y} \cdot \gamma^{CO}_{i,y} - \sum_a C^{N}_{i,a,y} \cdot \gamma^{N}_{i,y}) \\
d\pi_{i,y} =& \phi_y \cdot [\sum_{h,a} (q^{CO}_{i,h,y} \cdot Z^{CO}_{a,i,h,y} - q^{N}_{i,h,y} \cdot Z^{N}_{a,i,h,y}) && (4.2)\\
&+(s^{CO}_y \cdot \sum_{r,i,h,y} Z^{CO}_{r,i,h,y} - s^{N}_{i,y} \cdot \sum_{r,i,h,y} Z^{N}_{r,i,h,y}) \\
&+\omega_a(\sum_a C^{CO}_{i,a,y} \cdot \gamma^{CO}_{i,y} - \sum_a C^{N}_{i,a,y} \cdot \gamma^{N}_{i,y})] \\
&+h_y(\sum_{d,h} H^{CO}_{d,i,h,y} - \sum_{d,h} H^{CO}_{d,i,h,y})] \\
&-(\sum_{h,a} v_{a,y} \cdot (Z^{CO}_{a,i,h,y} - Z^{N}_{a,i,h,y})) \\
&-(\sum_{h,a} vr_{a,y}(R^{CO}_{a,i,h,y} - R^{N}_{a,i,h,y})) \\
&-(q^{CO}_{i,h,y} \cdot P^{CO}_{p,i,h,y} - q^{N}_{i,h,y} \cdot P^{N}_{p,i,h,y}) \\
&-\sum_a (C^{CO}_{i,a,y} - C^{N}_{i,a,y}) \cdot fom_{a,y} \\
&-\sum_a (I^{CO}_{i,a,y} - I^{N}_{i,a,y}) \cdot ann_{a,y} \\
dW_{i,y} =& dCR_{i,y} + d\pi_{i,y} && (4.3)\\
dW_y =& \sum_i dW_{i,y} + \phi_y \cdot [[(q^{CO}_{i,h,y} \cdot (1-\lambda_{i,i'}) - q^{CO}_{i',h,y}) \cdot M^{CO}_{i,i',h,y}]] && (4.4)\\
&-[(q^{N}_{i,h,y} \cdot (1-\lambda_{i,i'}) - q^{N}_{i',h,y}) \cdot M^{N}_{i,i',h,y}]
\end{aligned}
$$

Table 4.5: Model abbreviations including sets, parameters and variables

Abbreviation	Dimension/Unit	Description
indices		
a		Technology
p	Subset of a	Storage technology
r	Subset of a	RES-E technology
d	Subset of a	Combined-heat-and-power technology
i,i’		Countries
h		Hour
y		Year
CO		Coordinated Support
N		National Support
Model parameters		
$\mathrm{ann}_{a,y}$	$\mathrm{EUR}_{2010}/\mathrm{MW}$	Annuity for technology specific investment costs
$\mathrm{x}_{i,h,y}$	MW_{el}	Demand
ϕ_y	%	Discount rate
$\mathrm{fom}_{a,y}$	$\mathrm{EUR}_{2010}/\mathrm{MW}$	Fixed operation and maintenance costs
$\mathrm{v}_{a,y}$	$\mathrm{EUR}_{2010}/\mathrm{MWh}_{th}$	Variable generation costs
$\mathrm{vr}_{a,y}$	$\mathrm{EUR}_{2010}/\mathrm{MWh}_{th}$	Additional variable costs for ramping
ω_a	%	Capacity factor
$\alpha_{i,y}$	%	Quota on RES-E generation
$\lambda_{i,i'}$	%	Transmission losses
Marginal values		
$\mathrm{q}^{N}_{i,h,y}$,$\mathrm{q}^{CO}_{i,h,y}$	$\mathrm{EUR}_{2010}/\mathrm{MWh}_{el}$	Power price (marginal on power balance)
$\mathrm{s}^{N}_{i,y}$,$\mathrm{s}^{N}_{i,y}$	$\mathrm{EUR}_{2010}/\mathrm{MWh}_{el}$	Green certificate price (marginal on RES-E quota)
$\gamma^{N}_{i,y}$, $\gamma^{CO}_{i,y}$	$\mathrm{EUR}_{2010}/\mathrm{MWh}_{el}$	Capacity price (marginal on peak capacity constraint)
h_y	$\mathrm{EUR}_{2010}/\mathrm{MWh}_{th}$	Heat price
Model variables		
$\mathrm{Z}^{N}_{a,i,h,y}$,$\mathrm{Z}^{N}_{a,i,h,y}$	MW_{el}	Electricity generation
$\mathrm{R}^{N}_{a,i,h,y}$, $\mathrm{R}^{CO}_{a,i,h,y}$	MW_{el}	Capacity which is ramped up in hour h
$\mathrm{M}^{N}_{i,i',h,y}$, $\mathrm{M}^{CO}_{i,i',h,y}$	MW_{el}	Net electricity trade between regions
$\mathrm{C}^{N}_{i,a,y}$,$\mathrm{C}^{CO}_{i,a,y}$	MW_{el}	Installed capacity
$\mathrm{I}^{N}_{i,a,y}$,$\mathrm{I}^{CO}_{i,a,y}$	MW_{el}	Capacity Additions
$\mathrm{P}^{N}_{p,i,h,y}$, $\mathrm{P}^{CO}_{p,i,h,y}$	MW_{el}	Consumption in storage operation
$\mathrm{H}^{N}_{d,i,h,y}$, $\mathrm{H}^{CO}_{d,i,h,y}$	MW_{th}	Heat generation in combined-heat-and-power plants
Variables calculated ex-post		
$\mathrm{dCR}_{i,y}$	EUR_{2010}	Difference in consumer rents
$\mathrm{d}\pi_{i,y}$	EUR_{2010}	Difference in producer profits
$\mathrm{dW}_{i,y}$	EUR_{2010}	Difference in country-wise sectoral welfare
dW_y	EUR_{2010}	Difference in overall sectoral welfare

4.3.3 Model results

In this section, we present results from our scenario analysis with regard to price, redistribution and welfare effects of EU-wide cooperation in reaching the 2020 RES-E targets. First, we present model results of the main scenarios (Section 4.3.3.1). Second, we discuss the results of the sensitivity analysis (Section 4.3.3.2).

4.3.3.1 Analysis of the main scenarios

As described in Section 4.3.1, the main scenarios differ with regard to the assumed level of physical interconnection between European regions. For the two different grid extension scenarios ('no extension', 'TYNDP'), we compare consumer rents, producer profits and welfare in reaching the 2020 RES-E targets with either (technology-neutral) national support or (technology-neutral) cooperative RES-E support. In addition, before discussing welfare and redistribution effects, the general effects of cooperation on the optimal technological and regional generation and capacity mix in the European power system are briefly presented.

Effects of cooperation on generation patterns and welfare
Table 4.6 shows electricity generation and capacity differences by energy source on the European level, resulting from the introduction of cooperation. It can be seen that in 2020, European generation from onshore wind plants and concentrated-solar-power (CSP) plants is higher with cooperation, while biomass-based electricity generation is lower compared to the case where each country achieves its national target on its own. Generation from onshore wind plants mainly increases because sites with high load factors in Poland, the Czech Republic and Ireland can be used to a larger extent (note that the installed European onshore wind capacities are identical with and without cooperation). The higher CSP generation is mainly of Spanish origin and the lower biomass generation is mainly driven by a reduction in German biomass generation. Moreover, offshore wind generation is higher with cooperation when the TYNDP can be realized, because in this case offshore generation in Norway and Denmark is significantly higher with cooperation and clearly overcompensates for a lower offshore wind generation in Germany. In contrast, if the TYNDP is not realized, the favorable offshore wind sites in Northern Europe can only be used to a smaller extent. Therefore, if the TYNDP is not realized, European wind offshore generation decreases once cooperation is introduced because the effect of lower offshore wind generation in Germany dominates.[47] Photovoltaic generation is mainly higher in Spain and lower in Italy, when cooperation is introduced. The increase in Spanish photovoltaic generation resulting from cooperation is higher when the TYNDP is not realized because in this case offshore wind generation from Northern Europe can be used to a lesser extent to achieve the European RES-E

[47] In the model, grid connection costs (as well as grid extension and other grid related costs) have not been included. In the case of offshore wind plants, grid connection costs are substantially higher compared to other technologies and depend on the shore distance of the wind parks. In Germany, potential wind offshore areas are located relatively far from shore (Skiba and Reimers (2012)). Therefore, when including offshore grid connection costs, the benefit of cooperation achieved by replacing German offshore wind generation by less costly generation options may, ceteris paribus, increase.

target cost-efficiently. Therefore, photovoltaic-based electricity generation on the European level increases once cooperation is introduced when the TYNDP is not realized and decreases in the TYNDP case.

TABLE 4.6: Generation and capacity differences between cooperative and national RES-E support scenarios in the year 2020 [TWh and GW] on the European level (in the TYNDP and in the 'w/o TYNDP' scenario)

	Generation differences		Capacity differences	
	TYNDP	w/o TYNDP	TYNDP	w/o TYNDP
Nuclear	-4.3	2.6	-0.5	0.6
Lignite	0.2	-1.5	0.6	-0.2
Gas	50.2	9.7	5.4	-1.1
Coal	-41.5	-9.3	-3.9	-1.0
Storage	-0.4	-1.0	0.0	0.0
Hydro	0.0	0.0	-0.4	-2.7
Biomass	-29.2	-19.6	-4.5	-3.1
Onshore Wind	14.0	12.8	0.0	0.0
Offshore Wind	31.8	-14.8	4.3	-6.2
Photovotaics	-8.5	9.2	-6.9	5.2
CSP	8.0	10.4	1.7	2.3
Geothermal	-17.5	1.3	-2.4	0.2

Positive (negative) values indicate that electricity generation or generation capacities are higher (lower) once cooperation is introduced.

Taking a look at generation differences of non-renewable-based electricity sources, a switch from coal to gas-based electricity generation can be observed, once cooperation is introduced. Coal-based electricity generation is lower in Spain and Poland, where, in turn, RES-E generation is significantly higher with cooperation. In the TYNDP case, gas-based electricity generation increases significantly in Italy, which is an importer of green certificates once cooperation is introduced. An overview of changes in the generation and capacity mixes on country level is provided in Table C.2 in Appendix C for the largest certificate importing and exporting countries, which are also analyzed in the following.

In Table 4.7, certificate trade streams in 2020 for the largest certificate importing and exporting countries are shown. The amount of certificates traded is, in some countries, independent of the level of interconnection between countries (e.g., in Germany, Poland and Italy). In these countries, the trade in green certificates mainly leads to a switch between domestic renewable and conventional electricity generation. Moreover, Germany is already today well interconnected with neighboring electricity markets. In other countries, e.g., in Denmark and Norway, the enforcement of interconnectors is a critical factor in determining to what extent sites with high wind speeds can be used to generate more RES-E than required for national target achievement. For example, in Norway, most electricity generation comes from renewable energy sources. Thus, due to low conventional generation that could be reduced, an increase in RES-E generation has to be exported. Furthermore, in Spain, the amount of exported certificates significantly depends on whether the TYNDP is realized or not. As explained above, in Spain certificate exports are substantially lower when the TYNDP is realized because, in this case, many other and more cost-efficient RES-E generation options (e.g., offshore wind in Norway) are accessible.

Taking a look at the amount of certificates traded by the individual countries, it can be seen that Germany is the largest importer, with certificates corresponding to 91 TWh of green electricity and making up 42% of its NREAP target. Similarly, Finland and Greece import large amounts of certificates and cost-efficiently fulfill one third or more of their national target by using cooperation mechanisms (in the TYNDP case). Large exporters of certificates are mainly countries with large potentials of sites with high wind speeds, either for onshore or for offshore wind. In relation to its national target, Denmark is the largest exporter of certificates (204% when the TYNDP is realized, 83% when interconnectors are not enforced).

Table 4.7: Green certificate trade streams in 2020 [TWh and % of NREAP targets], overall welfare gain from cooperative RES-E support [bn. EUR_{2010}, cumulated 2010-2020 and discounted by 5 %] and certificate price in 2020 [EUR_{2010}/MWh] in the scenarios 'TYNDP' and 'w/o TYNDP'

	TYNDP		**w/o TYNDP**	
Certificate trade of largest certificate importing countries [TWh]	TWh	% of target	TWh	% of target
Finland (FI)	-11	33%	-5	14%
Germany (DE)	-91	42%	-91	42%
Greece (GR)	-8	37%	-3	10%
Italy (IT)	-9	9%	-9	9%
Portugal (PT)	-7	20%	-3	8%
Sweden (SE)	-10	10%	-9	10%
United Kingdom (UK)	-6	5%	-4	3%
Certificate trade of largest certificate exporting countries [TWh]				
Czech Republic (CZ)	9	80%	9	80%
Denmark (DK)	28	204%	11	83%
France (FR)	5	3%	11	7%
Ireland (IE)	7	50%	6	44%
Norway (NO)	51	45%	21	18%
Poland (PL)	19	60%	19	60%
Spain (ES)	23	15%	38	25%
Overall welfare gain [bn. EUR_{2010}]	12		10.6	
European certificate price [EUR_{2010}/MWh]	47.4		52.1	

In addition, Table 4.7 depicts the overall welfare gain of cooperation as well as the European certificate price (in the case that cooperation is possible), depending on the level of interconnection between regions. Generally, stronger interconnections between the European regions facilitate the use of low-cost generation options throughout Europe as well as the balancing of supply and demand over large distances (Fürsch et al. (2013a)). Therefore, the European-wide benefit of cooperative, compared to purely national, RES-E support increases because sites with high wind speeds or high solar radiation are more easily accessible (see also Fürsch and Lindenberger (2013)). The overall welfare gain of introducing cooperation is 12 bn. EUR_{2010} when the TYNDP is realized and 10.6 bn. EUR_{2010} when interconnector capacities are not extended. Note that the results in terms of cost figures presented in this section refer to the period 2010-2020 and are discounted by 5%. As we use a dynamic model and amortization times of power plants are long (typically around 20 years, depending on the technology), these costs do not include all costs induced by the 2020 target (and vice versa, the presented welfare gains do not include the total long-term benefit of introducing cooperation in the achievement of the 2020 target).

The largest welfare gain of cooperation on the country level is achieved in Germany, as can be seen in Table 4.8 which depicts welfare differences per country between cooperative and national RES-E support scenarios (cumulated from 2010 to 2020).

Table 4.8: Country-wise welfare differences between cooperative and national RES-E support scenarios [bn. EUR_{2010}, cumulated 2010-2020, discounted by 5%]

Certificate importing countries	TYNDP	w/o TYNDP
Finland (FI)	0.1	0.3
Germany (DE)	5.3	4.3
Greece (GR)	0.1	0.0
Italy (IT)	0.1	0.2
Portugal (PT)	0.0	0.0
Sweden (SE)	0.4	-0.1
United Kingdom (UK)	0.0	0.1
Certificate exporting countries		
Czech Republic (CZ)	0.8	0.9
Denmark (DK)	0.1	0.1
France (FR)	0.3	0.1
Ireland (IE)	-0.1	0.1
Norway (NO)	0.6	0.1
Poland (PL)	0.7	1.0
Spain (ES)	1.3	0.3

Positive (negative) values indicate that welfare is higher (lower) once cooperation is introduced.

On the country level, welfare generally increases with cooperation because either increasing consumer rents overcompensate for decreasing producer profits or vice versa. The country that benefits (in absolute terms) most from cooperation is Germany. It is the country with the highest electricity demand and the highest RES-E target (see

Table 4.3) and also trades the highest amount of certificates (see Table 4.7). Certificate exporting countries which benefit most from cooperation are Poland, the Czech Republic and, if the TYNDP is realized, Spain and Norway. In relation to their electricity demand, countries which benefit most from cooperation are smaller countries such as Latvia and Luxembourg.

In some few countries, however, welfare decreases. In Ireland (if the TYNDP is realized) and Sweden (if the TYNDP is not realized), cumulated welfare up to 2020 is lower under cooperation. In these two countries, the welfare decreasing effect is temporary and occurs because not all costs and incomes from electricity generation are realized in the same period.[48] In contrast, in Portugal and France (in the TYNDP scenario), welfare decreases in the long term. As shown theoretically by Unteutsch (2014), the change in welfare on the country level, resulting from cooperation, can be negative if a) a country is an exporter of both electricity and certificates, and the additional incomes gained from certificate exports do not outweigh lower incomes gained from the export of electricity or if b) a country is an importer of both electricity and certificates and the cost savings, in terms of renewable energy production, do not outweighed higher electricity import costs. In this numerical analysis, welfare decreases in Portugal, an importer of both electricity and certificates, and in France, an exporter of electricity and certificates (in the TYNDP scenario).

While the overall European-wide benefit of cooperation increases if countries are better interconnected (Table 4.7), the effect of interconnector extensions on the welfare change is ambiguous on the country level. In Germany, the benefit of cooperation is larger if the TYNDP is realized and certificates can be imported at a comparatively low price. In contrast, in Poland, the benefit of cooperation is larger without interconnector extensions because, in this case, the European certificate price is higher and higher revenues from certificate exports can be gained.

In the following, we discuss how the introduction of cross-border trading of green certificates influences prices, consumer rents and producer profits in the different European countries.

Effects of cooperation on price changes

Unteutsch (2014) shows that cross-border trading of green certificates leads to an increase (decrease) of green certificate prices in countries with comparatively low (high) RES-E generation costs, while opposite price effects occur on the regional wholesale electricity markets. Table 4.9 depicts green certificate prices and wholesale electricity

[48] In these countries, cumulated welfare up to 2020 decreases; however, cumulated welfare up to the end of the modeled period increases. In order to account for long amortization and lifetimes of power plants, the optimization model runs up to 2040.

prices in 2020 for both the cooperative and the national RES-E support scenarios in selected European countries.

Table 4.9: Green certificate prices and wholesale electricity prices in 2020 (with national and with cooperative RES-E support), [EUR_{2010}/MWh]

	TYNDP						w/o TYNDP					
	Certificate price			**Wholesale electr. price**			**Certificate price**			**Wholesale electr. price**		
Certificate importers	Nat	Coop	Diff.	Nat	Coop	Diff.	Nat	Coop	Diff.	Nat	Coop	Diff.
FI	36.9	47.4	10.5	47.8	46.9	-0.9	35.0	52.1	17.1	47.4	46.7	-0.7
DE	87.6	47.4	-40.1	46.6	49.5	3.0	87.6	52.1	-35.5	46.3	49.5	3.2
GR	44.7	47.4	2.7	50.5	53.4	2.7	45.6	52.1	6.5	51.1	52.7	1.7
IT	40.7	47.4	6.7	56.8	58.4	1.6	42.4	52.1	9.7	55.4	56.7	1.3
PT	34.3	47.4	13.1	54.5	52.6	-1.9	34.2	52.1	17.9	55.8	52.6	-3.1
SE	61.9	47.4	-14.4	46.4	43.8	-2.6	64.7	52.1	-12.6	45.2	41.5	-3.7
UK	113.7	47.4	-66.3	49.4	50.7	1.3	110.0	52.1	-58.0	50.5	52.4	1.9
Certificate exporters												
CZ	14.3	47.4	33.2	45.9	47.8	1.9	13.6	52.1	38.5	46.1	47.3	1.2
DK	0.0	47.4	47.4	46.6	44.0	-2.6	0.0	52.1	52.1	46.2	42.5	-3.7
FR	14.7	47.4	32.7	45.7	46.1	0.4	16.2	52.1	35.9	44.8	45.1	0.4
IE	0.0	47.4	47.4	51.7	48.2	-3.4	4.6	52.1	47.4	53.6	46.2	-7.4
NO	0.0	47.4	47.4	46.0	40.6	-5.4	0.0	52.1	52.1	45.6	36.5	-9.0
PL	0.0	47.4	47.4	47.2	48.8	1.6	0.0	52.1	52.1	47.1	47.9	0.9
ES	23.8	47.4	23.7	52.2	51.0	-1.2	22.1	52.1	30.0	54.2	49.6	-4.6

In all certificate exporting countries, green certificate prices increase with cooperation, while the opposite generally holds true in the certificate importing countries. However, in some certificate importing countries, the green certificate price *in 2020* also increases (FI, PT, IT, GR). In these countries, the certificate prices in the period post 2020 decrease given cooperation. Therefore, from a dynamic perspective, for these countries it is cost-efficient to import certificates. Note that the range of certificate price changes is identical in many exporting countries (NO, PL, DK and IE in the 'TYNDP' case). In these countries, the national certificate price is zero because the national target is not binding. The certificate price changes thus correspond to the different certificate prices occurring with cooperation (see Table 4.7). The largest certificate price change occurs in the United Kingdom. As shown in Table 4.7, the amount of certificates imported is comparatively low (3% and 5% without and with the realization of the TYNDP, respectively). However, the high certificate price in the national RES-E scenarios shows that it is very costly to reach the national target completely by domestic production.

The wholesale electricity price increases in most certificate importing countries. Exceptions occur in Portugal, Finland and Sweden. In these countries, the wholesale electricity prices decrease because the RES-E generation in neighboring countries increases (Spain and Norway). In most certificate exporting countries, wholesale electricity prices are lower with cooperation (DK, IE, NO, ES). In other certificate exporting countries, which today are already well interconnected with certificate importing countries, wholesale electricity prices increase (CZ, FR and PL).

In general, it can be seen that, in most countries, the change in the green certificate price far exceeds the change in the wholesale electricity price. Unteutsch (2014) shows that, in general, the change in green certificate prices is larger than the change in wholesale electricity prices but affects a smaller quantity than the change in the wholesale electricity price. Thus, the net effect of cross-border cooperation on consumer rents and total producer profits per country is theoretically unclear and needs to be determined by numerical analyses.

Effects on consumers rents and producer profits

Results of the numerical analysis in terms of consumer rents and producer profits per country are depicted in Table 4.10. The upper part of the table depicts the change of discounted, cumulated consumer rents and producer profits up to 2020 that result from cross-border green certificate trading. Percentage changes are depicted in the lower part of the table.[49] Consumer rents are only affected by cooperation via changes in the green certificate prices and in the wholesale electricity prices, assuming an inelastic demand. Producer profits, in contrast, are affected by cooperation via price and quantity effects as the amount of electricity produced and/or the electricity mix within a country also changes.

[49]Due to the assumption of an inelastic electricity demand, absolute values for consumer rents with either national or cooperative RES-E support cannot be determined. Thus, the percentage change of consumer rents between cooperative and national RES-E support can also not be determined. While absolute differences in the expenditures of consumers in meeting their electricity demand (multiplied with -1) correspond to absolute difference in consumer rents, percentage changes cannot be determined. Thus, the lower part of Table 4.10 depicts the percentage change in expenditures of consumers as well as the percentage changes of producer profits between cooperative and national RES-E support.

TABLE 4.10: Differences in consumer rents and producer profits between cooperative and national RES-E support, cumulated up to 2020 and discounted by 5% [bn. EUR_{2010} and %-changes]

changes in bn. EUR_{2010}				
	TYNDP		w/o TYNDP	
Certificate importing countries	Consumer rent changes (Coop-Nat)	Changes of producer profits (Coop-Nat)	Consumer rent changes (Coop-Nat)	Changes of producer profits (Coop-Nat)
FI	-1.0	1.2	-1.9	2.2
DE	20.0	-14.7	18.1	-13.8
GR	-0.4	0.5	-0.6	0.6
IT	-4.2	4.3	-3.8	3.9
PT	-1.1	1.1	-1.5	1.6
SE	5.2	-4.8	5.4	-5.4
UK	20.8	-20.8	18.2	-18.1
Certificate exporting countries				
CZ	-1.7	2.5	-1.5	2.5
DK	-2.6	2.7	-2.8	2.9
FR	-13.0	13.3	-14.9	15.1
IE	-1.7	1.6	-1.3	1.4
NO	-13.9	14.5	-13.7	13.7
PL	-5.6	6.3	-5.2	6.2
ES	-13.6	14.8	-14.6	14.9
% changes				
Certificate importing countries countries	Changes in consumer expenditures (Coop-Nat)	Changes of producer profits (Coop-Nat)	Changes in consumer expenditures (Coop-Nat)	Changes of producer profits (Coop-Nat)
FI	2.4	7.9	4.5	14.9
DE	-7.3	-13.5	-6.6	-12.7
GR	1.3	4.3	1.9	5.2
IT	2.3	7.5	2.1	7.0
PT	3.6	9.5	5.0	13.1
SE	-6.3	-7.5	-6.5	-8.6
UK	-11.3	-36.3	-9.9	-31.5
Certificate exporting countries				
CZ	5.8	17.7	5.1	17.2
DK	17.1	42	18.3	45
FR	5.0	9.2	6.0	11.2
IE	13.5	85	10.1	78
NO	34.3	38	34.2	37
PL	9.3	60	8.6	59
ES	8.6	28	9.2	28

Positive (negative) values indicate that consumer rents, consumer expenditures or producer profits are higher (lower) once cooperation is introduced.

It can be seen that, in those countries which are exporters of certificates, consumer rents decrease and producer rents increase when changing from a national to a cooperative support system. Results for countries that are importers of certificates are more ambiguous. In some certificate importing countries, the effect of the change in the certificate price overcompensates for the effect of the change in the wholesale electricity price (e.g., in DE, GB and SE), such that consumer rents increase and producer profits decrease. However, in other certificate importing countries, the wholesale electricity price effect dominates such that producers make higher profits (especially from the utilization of existing conventional plants) and consumers are worse off with cooperation (e.g., PT). In Italy and Greece, both the certificate and the wholesale electricity price in 2020 increase such that consumers rents decrease and producer profits increase.

The largest effects of cooperation on consumer rents (in terms of percentage changes) occur in Norway, Denmark, Ireland and the United Kingdom. In these countries, the certificate price effect resulting from cooperation is very large and, in addition, the RES-E targets are comparatively high, such that the change in the certificate price has a large influence on the electricity bill of end consumers. Regarding the change in producer profits, cooperation substantially increases profits in Ireland, Poland, Denmark and Norway. These countries export large amounts of certificates and are characterized by high changes in the certificate prices. Moreover, it can be seen that redistribution effects are generally large compared to the overall welfare gain resulting from cooperation on the European level. For example, the changes in consumer rents and producer profits in the United Kingdom, Germany, Spain, Norway and France far exceed the overall change in European-wide welfare (see Table 4.7).

Comparing changes in consumer rents and producer profits in the scenarios with and without the realization of the TYNDP, it can be seen that the effects of cooperation are of a similar order of magnitude in both settings. Even in Norway, which exports certificates corresponding to 51 TWh RES-E generation when the TYNDP is realized and less than half as much when interconnectors are not enforced, the effect of cooperation on consumer rents and producer profits hardly differs. Consumer rents are not directly affected by the amount of certificates traded but only by the changes in prices. In Norway, the combined effect of cooperation on the wholesale electricity price and the certificate price are of the same order of magnitude with and without realization of the TYNDP. In addition, due to the assumed high RES-E target in Norway, both price changes affect nearly the same amount of electricity for consumers. Moreover, the effect of cooperation on producer profits is hardly influenced by different grid extensions because (as discussed in more detail in the following) producer profits in Norway mainly increase with cooperation as the incomes of existing hydro plants increase. Additional incomes from those capacities that are only built to export green certificates (in the cooperative support scenarios), in contrast, are comparatively low.

A closer look on producer profits

Tables 4.11 through 4.13 present a closer look on changes in producer profits. Table 4.11 depicts differences in producer profits between the national and the cooperative support scenarios by fuel type and Tables 4.12 and 4.13 highlight effects of cooperation in RES-E support on producer profits per country for conventional power plants and renewable energy plants, respectively. In all three tables, only changes in producer profits realized using plants from the currently existing European power plant fleet are shown. Thus, to be specific, producer *rents* (and not *profits*) of existing plants are depicted because investment costs of existing power plants are considered as stranded costs.

Examining the changes in producer rents of the existing power plant fleet is interesting for two main reasons. First, in contrast to new power plant investments, existing plants are not mobile. Investment decisions for the existing power plant fleet have been made in the past without anticipating European-wide cooperation (and possibly also without anticipating a strong RES-E expansion in general). If producer rents realized by these plants would decrease due to a shift in politics towards more cooperation in RES-E support, cooperation plans would presumably face strong opposition from the respective plant owners.[50] Second, it may be questioned as to whether it is appropriate to determine country-wise producer profits in light of international capital markets. While this question also concerns the existing power plant fleet, since large international stock companies generate a large part of electricity in many countries, this question becomes even more important for new investments. While the current ownership structure of the European power plant fleet is known, it is unclear which companies would build new capacities. Furthermore, in some countries, the state owns a large part of the existing power plant fleet.

Table 4.11 shows that, on a European level, producer rents gained from electricity generation by existing lignite, coal, gas and hydro plants are larger with cooperative than with national RES-E support. In contrast, rents gained from generation by existing biomass, offshore wind and photovoltaic plants decrease once cooperation is introduced. Rents gained from existing nuclear plants are larger with cooperative RES-E support if the TYNDP is realized but lower with national RES-E support if interconnectors are not enforced. The owners of existing onshore wind plants, in contrast, benefit in sum

[50] In fact, Portugal, for example, states in its National Renewable Energy Action Plan (NREAP) that it would be interested in surpassing its own target and make use of cooperation mechanisms, given that the interconnector between Spain and France is expanded. Without a stronger interconnection of the Iberian Peninsula to Central Europe, the impact of a higher RES-E share on the existing conventional power plant fleet in Portugal would be strong (see Portuguese Republic (2010) and Fürsch and Lindenberger (2013)).

(on a European level) from cooperation if interconnectors are not enforced but are worse off in the cooperation case if the TYNDP is realized.

Producer rents realized with lignite-based, gas-based and coal-based electricity generation increase because wholesale electricity prices in those countries, in which large capacities of lignite, gas and coal plants are located, increase once cooperation is introduced. Large lignite plants exist in Germany, Poland and the Czech Republic. Lignite production in these countries is hardly affected by the introduction of cooperation in RES-E support, whereas wholesale electricity prices in these three countries increase (Table 4.9). Producer rents of existing coal plants mainly increase because wholesale electricity prices in Germany and Italy increase. Producer rents realized by existing gas plants increase mainly due to increased generation and electricity prices in Germany, the United Kingdom, Italy and - especially in the TYNDP case - the Netherlands.

The effect of cooperation on producer rents gained from electricity generation by existing nuclear plants is rather small because generation levels are hardly affected by the introduction of cooperation. In addition, existing nuclear plants are located both in countries in which the wholesale electricity price increases with cooperation (e.g., FR) and in countries where the wholesale electricity price decreases (e.g., ES and FI). Therefore, the net effect on overall producer rents from existing nuclear plants on the European level is small.

Hydro rents are substantially larger with cooperative RES-E support because most hydro power plants are competitive without support payments. For example, the national green certificate price (without cooperation) is zero in Norway, where large hydro power resources are located. Thus, a shift towards a cooperative RES-E support system, in which hydro power producers gain revenues from selling green certificates at the European certificate prices, increases hydro rents substantially.[51] The increase in hydro rents is larger if the TYNDP is not realized because, in this case, the European certificate price is higher.

Producer rents realized using existing biomass plants, offshore wind plants and photovoltaic systems decrease once cooperation is introduced because a large part of these plants were built in countries that are importers of certificates if cooperation is possible (e.g., Germany, Finland, Sweden, United Kingdom, Italy). In most of these countries, the certificate price is lower with cooperation than with national RES-E support.

Existing onshore wind capacities are mainly located in Germany and Spain. While the certificate price in Germany decreases once cooperation is introduced, the opposite

[51]Of course, hydro may also be excluded from the support system, depending on the specific support design. For example, in Germany, large hydro power plants are currently excluded from the RES-E support system.

price effect resulting from cooperation is observed for Spain. If the TYNDP is realized, onshore rents on a European level decrease because the effect of lower rents gained in Germany is dominant. In contrast, if interconnectors are not enforced, the increase in the certificate price resulting from cooperation in Spain is higher than if the TYNDP is realized and onshore wind rents increase on a European level.

TABLE 4.11: Differences in producer rents gained from electricity generation of existing power plants (by fuel type) between cooperative and national RES-E support, cumulated up to 2020 and discounted by 5% [bn. EUR_{2010} and %-changes]

	TYNDP		w/o TYNDP	
	bn. EUR_{2010}	%	bn. EUR_{2010}	%
Nuclear	1.1	0.6	-0.8	-0.5
Lignite	1.4	4.6	0.6	2.0
Coal	4.8	12.2	4.2	10.5
Gas	3.3	8.3	0.6	1.4
Storage	0.2	3877.4	0.5	-337.5
Hydro	23.7	9.4	31.3	12.5
Biomass	-3.6	-74.4	-1.9	-42.1
Onshore Wind	-0.9	-1.7	0.7	1.4
Offshore Wind	-0.5	-18.6	-0.3	-12.1
Photovoltaics	-1.0	-6.1	-0.7	-4.3

Positive (negative) values indicate that producer rents are higher (lower) once cooperation is introduced.

Tables 4.12 and 4.13 depict changes in producer rents on the country level. The changes in producer rents gained from generation by existing conventional power plants (Table 4.12) mostly reflect the changes in wholesale electricity prices (see Table 4.9). An exception is Spain, where producer rents increase despite of decreasing wholesale electricity prices in 2020. However, the wholesale electricity price in 2015 is higher given cooperative rather than national RES-E support. The largest benefit (in absolute values) from cooperation in terms of producer rents of existing conventional power plants is realized in Germany (+ 5.1 bn. EUR_{2010} in the TYNDP scenario), followed by Spain (+ 1.9 bn. EUR_{2010}) and United Kingdom (+ 1.3 bn. EUR_{2010}).

Table 4.12: Differences in producer rents gained from electricity generation by existing conventional power plants (per country) between cooperative and national RES-E support, cumulated up to 2020 and discounted by 5% [bn. EUR_{2010} and %-changes]

	TYNDP		w/o TYNDP	
Certificate importing countries	bn. EUR_{2010}	%	bn. EUR_{2010}	%
Finland (FI)	0.1	0.7	0.0	0.1
Germany (DE)	5.1	14.1	4.3	12.0
Greece (GR)	0.1	1.9	0.1	1.5
Italy (IT)	0.7	8.2	0.1	1.8
Portugal (PT)	-0.1	-2.9	-0.1	-2.8
Sweden (SE)	-0.6	-3.8	-1.0	-6.7
United Kingdom (UK)	1.3	9.5	1.1	7.1
Certificate exporting countries				
Czech Republic (CZ)	0.6	4.3	0.2	1.6
Denmark (DK)	-0.1	-2.3	-0.1	-2.3
France (FR)	-1.0	-0.9	-1.1	-1.1
Ireland (IE)	0.1	35.3	0.1	103.9
Norway (NO)	0.0	23.4	0.0	135.7
Poland (PL)	0.5	4.4	-0.1	-0.6
Spain (ES)	1.9	7.4	1.1	4.4

Positive (negative) values indicate that producer rents are higher (lower) once cooperation is introduced.

Existing RES-E plants make up approximately one third of the currently existing European power plant capacity. Producer rents realized up to 2020 using currently existing RES-E plants are higher given cooperative RES-E support, in particular, in countries that are characterized by large hydro power resources and in which, in addition, the certificate price increases once cooperation is introduced (NO, FR, ES, IT). Lower producer rents under cooperative RES-E support are mainly realized in Germany and the United Kingdom, where the certificate price decreases with cooperation. In many other European countries, very few RES-E capacities currently exist.

Table 4.13: Differences in producer rents gained from electricity generation by existing RES-E plants (per country) between cooperative and national RES-E support, cumulated up to 2020 and discounted by 5% [bn. EUR_{2010} and %-changes]

	TYNDP		w/o TYNDP	
Certificate importing countries	bn. EUR_{2010}	%	bn. EUR_{2010}	%
Finland (FI)	0.7	11.7	1.3	21.3
Germany (DE)	-14.5	-23.0	-12.8	-20.3
Greece (GR)	0.1	1.9	0.2	4.0
Italy (IT)	1.8	5.0	3.8	10.0
Portugal (PT)	0.7	8.0	1.0	10.9
Sweden (SE)	-4.3	-9.3	-4.5	-9.8
United Kingdom (UK)	-6.2	-34.7	-5.3	-30.3
Certificate exporting countries				
Czech Republic (CZ)	1.0	94.0	1.1	104.2
Denmark (DK)	1.5	93.8	1.8	120.0
France (FR)	5.8	17.9	6.7	21.8
Ireland (IE)	0.4	35.9	0.4	30.4
Norway (NO)	15.8	38.1	18.6	44.4
Poland (PL)	0.6	77.5	0.7	84.5
Spain (ES)	6.4	22.6	7.7	27.5

Positive (negative) values indicate that producer rents are higher (lower) once cooperation is introduced.

4.3.3.2 Sensitivity Analysis: The influence of CO_2 emission prices and RES-E investment cost developments on welfare and redistribution effects

As shown by Unteutsch (2014), the slopes of the electricity supply curves (for RES-E and conventional electricity) determine the magnitude of the price changes and thereby also the magnitude of redistribution effects induced by certificate trade. Therefore, we run sensitivities with regard to three parameters that influence the slopes of the supply curves and investigate whether findings of the main scenarios are robust to these changes. We run sensitivities for the development of the CO_2 emission price, photovoltaic investment costs and offshore wind investment costs, which are all subject to great uncertainty. In the sensitivity analysis, we assume that the CO_2 emission price in 2020 is higher (by 10 EUR/t) and that photovoltaic and offshore wind investment costs in 2020 are lower (by 10% each) compared to the assumptions made in the main scenarios.

An increasing CO_2 emission price and decreasing RES-E investment costs have a common impact on the electricity system: Generation cost differences between RES-E plants and conventional plants decrease. Thus, the costs of achieving RES-E targets also decrease - both on a national level and under cooperation. The overall European system-wide benefit of cooperation decreases ('lower photovoltaic costs') or increases ('lower offshore costs' and 'higher CO_2 price'), depending on whether costs in the national or in the cooperative RES-E support scenarios are more affected by an increasing CO_2 emission price/decreasing RES-E investment costs. Table 4.14 provides an overview of European-wide welfare effects and the European green certificate price in the 'reference' case, corresponding to the 'TYNDP' scenario of the main scenarios, as well as in the sensitivity scenarios. In addition, certificate trade streams, price changes, redistribution and welfare effects in selected countries are presented.

TABLE 4.14: The influence of the CO_2 price and RES-E investment cost developments on model results [[bn. EUR_{2010}], cumulated 2010-2020 and discounted by 5 %; [EUR_{2010}/MWh] in 2020 or [TWh] in 2020]

		Reference	Higher CO_2 price	Lower wind offshore costs	Lower photovoltaic costs
Overall welfare gain [bn. EUR_{2010}]		12	13.4	12.4	11.3
European certificate price [EUR_{2010}/MWh]		47.4	34.2	45.6	42.4
Results for selected countries					
Certificate price change [EUR_{2010}/MWh] and (wholesale electricity price change)	DE	- 40.1 (+ 2.9)	- 30.8 (+ 1.4)	- 42 (+ 3.2)	- 33.6 (+ 3.4)
	DK	+ 47.4 (- 2.6)	+ 34.2 (- 2.5)	+ 45.6 (- 3.7)	+ 42.4 (- 0.8)
	ES	+ 23.7 (- 1.2)	+ 15.1 (- 2.2)	+ 21.9 (- 0.5)	+ 16.0 (+ 0.2)
	IE	+ 47.4 (- 3.4)	+ 34.2 (- 3.3)	+ 45.6 (- 4.2)	+ 42.4 (- 2.9)
	IT	+ 6.7 (+ 1.6)	- 2.8 (+ 0.3)	+ 4.9 (+ 1.7)	+ 10 (+ 1.6)
	NO	+ 47.4 (- 5.4)	+ 34.2 (- 5.5)	+ 45.6 (- 5.5)	+ 42.4 (- 3.9)
	PL	+ 47.4 (+ 1.6)	+ 34.2 (- 0.8)	+ 45.6 (+ 1.8)	+ 42.4 (+ 1.9)
Certificate trade [TWh]	DE	-91	-91	-91	-91
	DK	28	21	34	21
	ES	23	20	19	36
	IE	7	7	9	7
	IT	-9	-9	-9	3
	NO	51	50	51	51
	PL	19	17	19	17
Consumer rent change [bn. EUR_{2010}] and (changes in producer profits [bn. EUR_{2010}])	DE	+ 20.0 (- 14.7)	+ 19.9 (- 9.8)	+ 20.6 (- 15.5)	+ 15.4 (- 8.8)
	DK	- 2.6 (+ 2.7)	- 1.8 (+ 1.6)	- 2.4 (+ 2.4)	- 2.5 (+ 2.5)
	ES	- 13.6 (+ 14.8)	- 6.8 (+ 7.5)	- 12.9 (+ 14.3)	- 9.9 (+ 10.4)
	IE	- 1.7 (+ 1.6)	- 1.1 (+ 1.3)	- 1.6 (+ 1.5)	- 1.5 (+ 1.3)
	IT	- 4.2 (+ 4.3)	+ 1.4 (- 0.7)	- 4.1 (+ 4.2)	- 5.4 (+ 5.1)
	NO	- 13.9 (+ 14.5)	- 9.5 (+ 8.9)	- 13.3 (+ 14.3)	- 12.7 (+ 12.7)
	PL	- 5.6 (+ 6.3)	- 2.4 (+ 3.4)	- 5.5 (+ 6.1)	- 5.1 (+ 5.7)
Changes in country-wise welfare [bn. EUR_{2010}]	DE	5.3	7.1	5	6.7
	DK	0.1	-0.2	0	0
	ES	1.3	0.7	1.4	0.5
	IE	-0.1	0.2	-0.2	-0.2
	IT	0.1	0.7	0.1	-0.4
	NO	0.6	-0.7	1	0
	PL	0.7	1	0.6	0.6

In many countries, the amount of certificates traded is not sensitive to changes in the CO_2 emission price or RES-E investment costs. For example, the amount of certificates traded by Germany and by Norway is (approximately) the same in the reference and all sensitivity scenarios. In the case of lower investment costs for offshore wind plants, Denmark and Ireland export a higher amount of certificates, while exports from Spain decrease compared to the 'reference' case. In the case of lower photovoltaic costs, countries in the Mediterranean region (Spain and Italy) produce more RES-E, while offshore wind generation in the North Sea region is reduced. In fact, Italy is a certificate importing country in all scenarios except for the 'lower photovoltaic' sensitivity scenario. A higher CO_2 price reduces the overall amount of traded certificates in Europe by around 10%. Due to a higher CO_2 price, the relative costs of generating power and heat in geothermal plants compared to the costs of generating heat and power in hard coal CHP plants decrease in some countries. Therefore, in some countries which are certificate importers in the 'reference' scenario, the optimal amount of domestic RES-E production increases.

Furthermore, the sign of the redistribution effects determined in the main scenarios is, in most countries, robust to changes in the supply curves assumed in the sensitivity scenarios. In most certificate importing countries, such as Germany, the certificate price decreases and the wholesale electricity price increases. In addition, in most certificate importing countries, the certificate price effect overcompensates for the wholesale electricity price effect such that consumers are better and producers are worse off than in a situation with purely national RES-E support systems. The opposite holds true for most certificate exporting countries, such as Norway and Ireland.

In contrast, the magnitude of price and redistribution effects highly depends on the assumptions varied in the sensitivity scenarios. The European certificate price is lower by around 28% when assuming a CO_2 price of 30 EUR/t (instead of 20 EUR/t). A decrease in offshore wind investment costs (photovoltaic costs) by 10% reduces the European green certificate price by around 4% (11%) compared to the 'reference case'. In countries where the national RES-E target is not binding, the European certificate price directly corresponds to the certificate price change resulting from cooperation (e.g., in Ireland and Norway). In these countries, a lower European certificate price reduces the benefit of cooperation for producers and attenuates the effect of decreasing consumer rents. For example, in the sensitivity scenario 'higher CO_2 price', the benefit that producers receive from cooperation decreases compared to the 'reference' case by 32% in Norway (19% in Ireland). Furthermore, the effect of increasing expenditures for consumers to meet their electricity demand decreases compared to the 'reference' case (-32% in Norway, -35% in Ireland). In other countries, the change in the certificate price depends on the relation between the national and the European certificate price, which both depend on changes in CO_2 emission prices and/or RES-E investment costs. For example, in Germany, lower photovoltaic costs have a larger impact on the national than on the European certificate price. Thus, both the benefit consumers have from cooperation and the negative impact cooperation has on producer profits substantially decrease compared to the reference case (by 23% for consumers, by 40% for producers). Moreover, the effect that lower photovoltaic costs have on the redistribution effects between individual groups within the countries is significantly larger than the effect of lower photovoltaic costs on the total system-wide welfare change resulting from cooperation (- 6% compared to the reference case).

In summary, the sensitivity analysis shows that the sign of the redistribution effects of cooperation and the magnitude of the overall European-wide welfare effect are quite robust to different assumptions which influence the slope of the electricity supply curves. However, the magnitude of price changes and thus also of redistribution effects is sensitive to different developments of RES-E investment costs and the CO_2 emission price.

4.3.4 Critical discussion of the numerical results

This paper numerically analyzes welfare and redistribution effects potentially resulting from the introduction of cooperation in European RES-E support. While the modeling represents the European power system by including European data about e.g., electricity demand, resource potentials, wind speed and the existing power plant fleet, some important differences between the current real-world European power system and the modeled situation exist. Therefore, in this section we discuss which model specifics have to be kept in mind when drawing conclusions from the model results presented in Section 4.3.3.

Probably the largest difference between the modeled scenarios and the real-world European power system stems from the assumption of technology-neutral RES-E support in all countries, both in the cases with and without cross-border cooperation. As stated in the introduction of this section, currently a variety of country-specific RES-E support systems exists in Europe and many countries have implemented technology-specific support systems, generally not leading to a cost-optimal generation mix. This current real-world situation is not taken into account in the analysis presented in Section 4.3.3. Therefore, in this paper, we do not quantify welfare and redistribution effects induced by a change from the currently implemented country-specific RES-E support systems to a RES-E support system with European-wide cooperation. Instead, we analyze the effects of introducing European-wide cooperation starting from a (hypothetical) situation of country-specific technology-neutral RES-E support. Thereby, we explicitly determine the separate welfare and redistribution effects of cooperation and exclude the effects which could also be achieved by optimizing national RES-E policies.

Note also that a complete change from purely national RES-E support to European-wide cooperation represents an extreme shift of politics that is very unlikely to occur before 2020. A first step towards European-wide cooperation would be the use of bilateral and multilateral cooperation mechanisms. Our analysis shows that especially Germany would have a large benefit from cooperation - even under the assumption of a cost-efficient domestic RES-E generation mix. Also, the analysis identifies potential cooperation partners such as Poland or Spain. However, the magnitude of redistribution effects resulting from different bilateral or multilateral engagements would have to be calculated in separate model analyses as the magnitude of price effects would be different compared to the case when changing from purely national support to complete European-wide cooperation. Nevertheless, this analysis shows that in the European power system effects of cooperation arising in the RES-E market would in most countries (such as Germany) be dominant compared to effects in the electricity market and that the sign of redistribution effects is in most countries very robust. Therefore, the results from this analysis provide a general idea of the impact different cooperation agreements would have on individual groups within the participating countries.

In addition, the magnitude of redistribution effects would in reality also depend on a variety of additional political decisions. For example, grandfathering rules could apply for existing renewable energy power plants. In this case, owners of existing RES-E plants would not be affected by the introduction of cooperation and consumers in countries with comparatively expensive existing RES-E plants would benefit to a smaller extent from cooperation. Moreover, as stated in footnote 51, renewable energies which are competitive without subsidies, such as large hydro power plants, might be excluded from the RES-E support system. In this case, countries with large hydro power resources would benefit less from cooperation.

In summary, the exact magnitude of redistribution effects resulting from different cooperation mechanisms in reality depends on many design specifics of the RES-E support systems and the cooperation mechanisms themselves. Conclusions which can be drawn from this analysis for the European electricity system are presented in the next section and include that the effects of cooperation in the RES-E market overcompensate in most countries for the effects occurring in the wholesale electricity market - even if interconnectors are not further extended compared to today.

4.4 Conclusion

Due to different meteorological conditions and resource availabilities across Europe, cooperation in the support of renewable energies would increase overall welfare in the European electricity sector. However, just like international trade in general, cooperation in the achievement of national RES-E targets, e.g., via cross-border green certificate trading, is not beneficial for all groups but creates winners and losers.

We find that in the European electricity system, effects of the change in the certificate price in most countries would overcompensate for the effects of the change in the wholesale electricity price. Thus, in most countries with comparatively high (low) generation costs for renewable energies, consumer rents increase (decrease) due to cooperation and producers yield lower (higher) profits. In addition, we find that the magnitude of redistribution effects between the individual groups is quite large: In some countries, the change in consumer rents or producer profits resulting from cooperation is nearly twice as high as the overall welfare effect of cooperation in the whole European electricity system. Moreover, the benefit different countries have from cooperation varies substantially. In our analysis, we find that Germany would by far have the largest (absolute) benefit of cooperation, achieved by significant reductions of RES-E target compliance costs via certificate imports. Finally, we find that the sign of redistribution effects is quite robust to different developments of interconnector extensions, the CO_2 price and RES-E investment costs. The magnitude of redistribution effects, in contrast, is in some countries sensitive to these assumptions (especially with regard to the assumption on the CO_2 price).

Therefore, this analysis shows that cooperation indeed has a significant influence on the welfare of different groups and thereby sheds further light to the question why it has been difficult to implement cooperation mechanisms thus far. Although on a country level the benefit of cooperation is generally positive, large inner-country redistribution effects may occur and those groups which potentially are worse off once cooperation is introduced may have a large influence on political decisions about the implementation of cooperation. The question, how these redistribution effects should be dealt with, however, is not straightforward. According to international trade theory, winners of trade can always compensate losers such that no group is worse off than without trade. However, in reality such compensation mechanisms can be complicated to design. First, it would need to be clarified who should be compensated by whom. Considering only consumers, cross-country compensation mechanisms could be implemented between those consumers who benefit from trade and those who pay higher prices once cooperation is introduced. But which group would, for example, compensate owners of conventional power plants in a country where the power price decreases once cooperation is introduced? Implementing compensation mechanisms for producers is especially difficult because many companies in the electricity sector operate in several countries and may therefore in some countries benefit from cooperation and lose revenues in other countries. Moreover, companies may also own both conventional and renewable power plants. Finally, even a clear distinction between producers and consumers can be difficult in practice, e.g., in the field of household photovoltaic installations. Second, the quantification of adequate compensation payments can be difficult ex-ante to the implementation of cooperation. As shown in this analysis, the exact magnitude of redistribution effects is specific to economic and technological developments in the power system, which are often subject to uncertainty. Finally, many other policies in the European power sector also induce redistribution effects, for which no compensation mechanisms exist. Examples are the European CO_2 emission trading system, the initial implementation of RES-E targets and the plan to create a single European electricity market. Thus, the question of welfare and redistribution effects resulting from cooperation in RES-E support comes back to the general question of trade and cooperation: To what extent should individual groups be protected and how far should overall welfare be increased?

This analysis has several shortcomings which could be addressed by future research. First, no sensitivities regarding the particular design of (national and cooperative) RES-E support systems have been made. This, for example, includes the question of how welfare and redistribution effects of cooperation depend on a technology-neutral (versus a technology-specific) and a quantity-based (versus a price-based) support. Moreover, in this analysis, we neglected that in practice grandfathering rules may apply for existing RES-E technologies. Second, in this analysis, we aggregated producer profits and consumer rents on country levels. While this seems appropriate for consumers as well as for some electricity producers, this procedure may be questioned for many electricity producers that are large international stock companies, operating in several countries. Further research analyzing the impact of cooperation on firm levels may be interesting. Third, this analysis is based on a purely deterministic approach and neglects, e.g., the stochastic nature of wind and solar in-feed. Nagl et al. (2013) show that including weather uncertainties in optimization models influences the value of different power plant types. In particular, Nagl et al. (2013) find that the value of fluctuating renewables such as wind decreases compared to deterministic modeling approaches. Consequently, including weather uncertainties would also affect the optimal generation mixes both when cooperation is and when it is not possible. Including stochastics therefore would lead to a more accurate determination of welfare and redistribution effects. Fourth, in this analysis, only the impact of an EU-wide cooperation in comparison to pure national RES-E support systems is analyzed. A first step towards European-wide cooperation would be the use of cooperation mechanisms between two or more countries via a common support system, joint projects or statistical transfers. Our analysis shows that in all scenarios the benefit of cooperation would be particularly large for Germany. Therefore, an engagement in bilateral or multilateral cooperation mechanisms would be an important measure to increase cost-efficiency in German RES-E support. The analysis of welfare and redistribution effects resulting from cooperation between Germany and different potential cooperation partners would be an interesting subject for further research.

Chapter 5

Optimization of power plant investments under uncertain renewable energy deployment paths: a multi-stage stochastic programming approach

5.1 Introduction

In order to reduce CO_2 emissions and the dependency from imported fuels, many countries established ambitious targets to increase electricity generation from renewable energy sources (RES-E). European member states agreed to increase the European RES-E share from 15.6% in 2007 to 34% in 2020. Although long-term targets (after 2020) have not been defined on a European level, individual member states, such as Germany, aim at increasing their RES-E shares continously up to 80% in 2050.

However, the implementation of political plans can be uncertain, even if reliable targets exist, for four principal reasons. First, many RES-E technologies are relatively new, implying that technological and cost developments are uncertain and/or that limited experiences exist for construction and maintenance. Second, favorable RES-E sites are often located far from demand centers and therefore the electricity network has to be adapted. Third, local opposition may hinder the construction of new sites or transmission lines due to visual or environmental concerns. Fourth, when RES-E is supported by a price-based promotion system, such as by a feed-in-tariff system, resulting RES-E quantities are inherently uncertain.

Uncertainty of the achievement of RES-E targets is challenging for investment planning because different shares of RES-E fundamentally change the optimal mix of dispatchable power plants. Specifically, uncertain future RES-E deployment paths induce uncertainty about the level and the steepness of the residual load duration curve and the structure of the hourly residual load. Thus, the optimal mix of (dispatchable) peak-, mid- and baseload plants is uncertain. In addition, it is uncertain how flexible the power plant fleet should optimally be and how valuable storage units are for the system. Consequently, the optimal investment planning for power plants with long construction times, amortization times and technical lifetimes is difficult.

In this paper, we show in a first part how uncertain future RES-E penetration levels impact the electricity system and in a second part try to quantify this impact from a social welfare perspective for the electricity systems of Germany and its neighboring countries. For the second part, we assume that a continuous increase in the RES-E share up to 2050 is a reliable target, which is however submitted to risks concerning the progress of necessary infrastructure investments, public acceptance and cost developments of RES-E. We use a multi-stage stochastic investment and dispatch model to quantify effects on investment choices, electricity generation and system costs.

Our main findings include that uncertainty about the achievement of RES-E targets significantly affects optimal investment and dispatch decisions. In particular, plants with a medium capital/operating cost ratio have a higher value under uncertainty. We find that this technology choice is mainly driven by the uncertainty about the level rather than about the structure of the residual load. Furthermore, given larger investments in plants with medium capital/operating cost ratio under uncertainty, optimal investments in storage units are lower than under perfect foresight. In the case of the Central European power market, costs induced by the implementation risk of renewable energies are rather small compared to total system costs.

The remainder of the article is structured as follows: The next section provides an overview of related literature and the contribution of the current work. Section 5.3 describes the modeling approach and gives an overview of assumed input parameters. In Section 5.4 we theoretically discuss the impact of uncertain future RES-E penetration levels and highlight the most important effects in an illustrative modeling example. In Section 5.5 we quantify the impact of uncertain RES-E target achievements for the electricity systems of Germany and its neighboring countries. In Section 5.6 we draw conclusions and provide an outlook for further research.

5.2 Related literature

The analysis of uncertainties using stochastic optimization models can be traced back to the 1950´s (Dantzig (1955)). Applications to electricity investment planning models often focus on the effects of demand, fuel or CO_2 emission price uncertainties. In recent years, the influence of intermittent renewable infeed on investment decisions for conventional power plants has also been analyzed with stochastic optimization models.

The influence of demand uncertainty on investment decisions was first shown in the 1980´s, for example by Murphy et al. (1982) and Mondiano (1987). Using multi-stage optimization models, Gardner (1996) and Gardner and Rogers (1999) analyze the effect of demand uncertainty in dynamic contexts.[52] Gardner (1996) shows that the value of technologies with short lead times, short lifetimes and/or a low capital/operating cost ratio increases in an uncertain environment. Gardner and Rogers (1999) analyze, in more detail, the effect of short lead times when dealing with demand uncertainty.

Fuel cost uncertainty has been addressed e.g., by Hobbs and Maheshwari (1990), who show that the expected costs of neglecting uncertainty of fuel prices in investment planning is lower than those of disregarding demand uncertainties. Reinelt and Keith (2007) use a stochastic dynamic model to analyze generation technology choices and optimal timing in investment when future CO_2 and natural gas prices are uncertain. Roques et al. (2006) evaluate investment decisions in nuclear and CCGT plants under uncertainty of natural gas prices, CO_2 emission prices and electricity prices, by applying a multi-stage stochastic program. Effects of uncertain future CO_2 regulations are also addressed by Patino-Echeverri et al. (2009) who apply a stochastic dynamic model and analyze the effect of uncertainty on investment strategies, social costs and CO_2 emissions.

Short-term uncertainties concerning the infeed of intermittent renewables have been analyzed in stochastic investment and dispatch models e.g., by Swider and Weber (2007) and Sun et al. (2008). Swider and Weber (2007) use a stochastic model to estimate the integration costs of intermittent wind and show that larger investments into thermal capacities are required when short-term stochastics of wind infeed are taken into account. This result is confirmed by Sun et al. (2008), who find that neglecting short-term wind infeed uncertainty leads to an undervaluation of the operational flexibility and results in insufficient investments in thermal power plants.

In contrast to the analysis of short-term uncertain renewable infeed, we analyze the influence of long-term uncertain renewable penetration levels induced by uncertainty as to whether political RES-E targets can be achieved. To our knowledge, the impact of

[52]Dynamic stochastic electricity optimization models have been developed earlier for different applications, e.g., by Manne and Richels (1978).

long-term uncertain residual load developments on the power system has not yet been analyzed. Other long-term uncertainties, e.g., demand, fuel or CO_2 emission price uncertainties, either primarily correspond to uncertainty as to how much capacity should be optimally constructed (demand) or induce uncertainty concerning the optimal technology mix (fuel and CO_2 emission prices). In the context of uncertain future RES-E penetration levels, both the optimal amount of dispatchable generation capacities and the optimal technology mix are uncertain because the level and the slope of the future residual load duration curve as well as the volatility of the hourly residual load curve are unknown.

5.3 Model description and assumptions

In this section, we describe the stochastic optimization model (5.3.1) and present the major assumptions underlying the scenario analyses (5.3.2).

5.3.1 Model description

We develop a linear multi-stage stochastic investment and dispatch model for electricity markets. The model covers thermal power plants and storage units. In each model period, different nodes account for different possible realizations of the residual load. In the following, we present the basic model equations and describe how uncertainty is captured in the model. Abbreviations used for model sets, parameters and variables are shown in Table 5.1.[53]

[53]The table only shows sets, parameters and variables used in the equations listed within this chapter. In addition, the model comprises variables necessary for ramping or storage equations such as the hourly storage level in a storage unit. Ramping and storage equations are modeled as described in Richter (2011).

TABLE 5.1: Model abbreviations including sets, parameters and variables

Abbreviation	Dimension	Description
Model sets		
d		Day
h		Hour
n		Node
n1	alias of n	Node (direct ancestor of n)
n2	alias of n	Node (direct or indirect ancestor of n)
r		Region
r1	alias of r	Neighboring region of r
res		RES-E technology
s	Subset of t	Storage technology
t		Technology
y	Subset of n	Node (associated with a certain model year)
Model parameters		
ad	MW	Exogenous capacity commissions
annuity	EUR_{2010}/MW	Technology specific investment costs (annuity)
attc	EUR_{2010}/MWh_{th}	Attrition costs for ramp-up operation
co	$EUR_{2010}/t\ CO_2$	CO_2 emissions prices
cres	MW	RES-E capacities
dsc	%	Discount factor
f	EUR_{2010}/MWh_{th}	Fuel prices
fomc	EUR_{2010}/MW	Fixed operation and maintenance costs
heatpr	EUR_{2010}/MWh_{th}	Heating price for end consumers
heatratio	MWh_{th}/MWh_{el}	Ratio for heat extraction
p	%	Occurence probability of node
β	%	Minimum generation level of power plants
η	%	Net efficiency
$\eta_{partload}$	%	Net efficiency in partload operation
ρ	MW	Residual demand
θ	MW	Peak demand
τ	%	Capacity factor
γ	%	Capacity factor (RES-E plants)
ω	$t\ CO_2\ /MWh_{th}$	CO_2 emissions per fuel consumption
ξ	[0;1]	Indicates if a technology has reached its lifetime
Model variables		
C	MW	Installed capacity (net)
CADD	MW	Capacity commissions (net)
CRTO	MW	Capacity which is ready to operate (net)
CSUB	MW	Capacity decommissions (net)
CUP	MW	Ramped-up capacity (net)
G	MW	Electricity generation (net)
NI	MW	Net imports
S	MW	Consumption in storage operation
Z	EUR_{2010}	Total system costs (objective value)

The objective of the model is to minimize total discounted system costs (eq. 5.1) while satisfying hourly (residual) demand (eq. 5.2) and ensuring that peak demand can be met by securely available capacities in each node (eq. 5.3). Equation 5.4 determines the capacity in each node, which depends on investment decisions made in previous periods, and which is thus chosen under uncertainty about the level and the structure of the residual load.

$$
\begin{aligned}
min\ Z = \sum_{n} \Bigg[p(n) \cdot dsc(y) \cdot \sum_{t,r} \Bigg[\Bigg[\sum_{n2} annuity(t) \cdot CADD(t, n2, r) \Bigg] \\
+ C(t,n,r) \cdot fomc(t) \\
+ \Bigg[\sum_{d,h} G(d,h,n,t,r) \Bigg] \cdot \Bigg[\frac{f(y,t) + co(y) \cdot \omega(t)}{\eta(t)} \Bigg] \\
+ \Bigg[\sum_{d,h} CUP(d,h,n,t,r) \Bigg] \cdot \Bigg[\frac{f(y,t) + co(y) \cdot \omega(t)}{\eta(t)} + attc(t) \Bigg] \\
+ \Bigg[\sum_{d,h} (CRTO(d,h,n,t,r) - G(d,h,n,t,r)) \Bigg] \cdot \\
\Bigg[\frac{f(y,t) + co(y) \cdot \omega(t)}{\eta_{partload}(t)} - \frac{f(y,t) + co(y) \cdot \omega(t)}{\eta(t)} \Bigg] \cdot \frac{\beta}{1 - \beta} \\
- \sum_{d,h} heatpr(y) \cdot heatratio(t) \cdot G(d,h,n,t,r) \Bigg] \Bigg]
\end{aligned}
\tag{5.1}
$$

s.t.

$$
\sum_{t} G(d,h,n,t,r) + \sum_{r1} NI(d,h,n,r,r1) - \sum_{s} S(d,h,n,s,r) = \rho(d,h,n,r) \tag{5.2}
$$

$$
\tau \cdot C(t,n,r) + \gamma \cdot cres(res,n,r) \geq \theta(n,r) \tag{5.3}
$$

$$
\begin{aligned}
C(t,n) = C(t,n1) + CADD(t,n1) + ad(t,y) - CSUB(t,n) \\
- \sum_{n2} \Bigg[(CADD(t,n2) + ad(t,n2)) \cdot \xi(t,n,n2) \Bigg]
\end{aligned}
\tag{5.4}
$$

Total system costs comprise fixed costs (investment and fixed operation and maintenance costs), variable production costs (including fuel and CO_2 costs), ramp-up costs and costs arising due to efficiency losses in part-load operation. We simulate ramp-up costs in this linear approach by referring to power plant vintage classes and setting a minimal load restriction. Also, additional costs for ramping-up (attrition (*attc*) and extra fuel costs) are taken into account (as in Richter (2011) and Nagl et al. (2013)). In part-load operation, fuel costs of power plants are higher due to lower efficiency values, which is taken into account by a linear approximation (as in Swider and Weber (2007)).

A heat remuneration for electricity generation in co-generation mode is subtracted from total system costs. As in Nagl et al. (2013), we assume that the heat remuneration corresponds to the "assumed gas price (divided by the conversion efficiency of the assumed reference heat boiler) which roughly represents the opportunity costs for households and industries". Heat generation in co-generation plants is restricted by a maximum heat potential per model region. The inflexibility of electricity generation in co-generation mode is accounted for by longer ramping times (as in Nagl et al. (2013)). All cost parameters are taken into account with the occurrence probability $p(n)$ of the node n in which the costs arise.

The hourly residual demand per country and node, inflows to storage units and electricity exports have to be met by generation from thermal and storage plants and/or by electricity imports (eq. 5.2). The dispatch within each node is calculated for four typical days, representing a weekday and a weekend-day in autumn/winter and in spring/-summer. These typical days capture typical seasonal, weekly and diurnal patterns of demand, wind speeds, solar radiation and inflow into hydro storages. Note that the model includes only long-term uncertainties about the deployment of RES-E capacities and no short-term uncertainty about the hourly infeed of renewables. The dispatch of generation and demand is realized under perfect foresight.

Peak demand (augmented by a security margin) per country and node has to be ensured by installed capacities which are securely available (eq. 5.3).[54] Thermal and storage capacities are adjusted by a factor incorporating possible outages (in the range of 85-90%; see Section 5.3.2). Fluctuating RES-E contribute with a relatively low capacity credit (5% for wind, 0% for photovoltaics).

Equation 5.4 determines the capacity in node n depending on the installed capacity and the investment decisions made in its ancestor node n1. In addition, the installed capacity in node n is augmented by exogenous capacity commissions (representing thermal and storage power plants that are already under construction or in an advanced planning process) and reduced by capacity decommissions, before or at the end of the technical lifetime of plant t. Thus, the model takes into account that power plant investments have long planning times, construction times, amortization times and technical lifetimes. Long planning times and construction times are represented by the fact that investment decisions have to be made one period before their commissioning, and thus under uncertainty about the state of the world at commissioning time. Long amortization times and technical lifetimes in uncertain environments are represented by the fact that at the time at which an investment decision for a power plant is made, the state of the world in each period up to the end of its lifetime is uncertain.

[54] Peak demand corresponds to the highest demand before subtraction of fluctuating RES-E infeed.

In addition to the equations presented in this section, the model incorporates common elements of linear dispatch models such as storage equations, ramping and minimum load restrictions, net transfer possibilities and the possibility of RES-E curtailment, as presented in Richter (2011) and Fürsch et al. (2013a).

5.3.2 Assumptions

In the following, we present the major assumptions underlying the scenario analyses. For the illustrative example (Section 5.4), cost assumptions for the year 2020 are used. For the analysis of RES-E implementation risks on the electricity systems of Germany and its neighboring countries (Section 5.5), we model Germany, Benelux (covering Belgium, the Netherlands and Luxembourg), Denmark, Czech Republic and Poland (‘CZ + PL’), Switzerland and Austria (‘CH + AT’) and France.

5.3.2.1 Electricity demand and potential heat generation in combined-heat-and-power (CHP) plants

We assume that in the long term, increasing energy efficiency will counterbalance any further increase in electricity demand driven by economic or population growth. Thus, we assume that electricity demand will increase until 2030 and stagnate afterwards. In addition to electricity demand values, Table 5.2 reports values for heat demand, based on data for electricity production in co-generation reported in EURELECTRIC (2008). In order to reduce computational time, the option to generate electricity in combined-heat-and-power (CHP) plants is restricted to countries in which CHP-based electricity generation makes up a major part of today´s electricity generation.

TABLE 5.2: Net electricity demand in TWh_{el} and (potential heat generation in CHP Plants in TWh_{th})

	2020		2030		2040		2050	
Benelux	226.2	(128)	241.7	(128)	241.7	(128)	241.7	(128)
CH + AT	140	(-)	149.5	(-)	149.5	(-)	149.5	(-)
CZ + PL	233.9	(146)	260.4	(146)	260.4	(146)	260.4	(146)
Denmark	43.1	(54)	46	(54)	46	(54)	46	(54)
Germany	611	(191)	628	(191)	628	(191)	628	(191)
France	523.6	(-)	558.3	(-)	558.3	(-)	558.3	(-)

5.3.2.2 Power plants

Table 5.3 depicts assumed investment costs for thermal and storage technologies (based on EWI and energynautics (2011) and EWI/Prognos/GWS (2010)). In addition to the listed technologies, the model comprises several technology classes to account for existing power plants. Investments into nuclear, hard coal, lignite, open-cycle-gas-turbines (OCGT), combined-cycle-gas-turbines (CCGT) and compressed-air-storages (CAES) are possible. Investments into nuclear plants are restricted to countries that already have existing nuclear power plants and that did not agree on a political phase-out of nuclear power. In addition, we account for long planning and construction times of nuclear plants. Therefore, no endogenous nuclear investments are possible before 2020, and afterwards investments are restricted to a maximum of 3 GW per 5-year-period and model region. For hard coal and lignite, state-of-the-art and innovative power plants are considered in the model. Innovative hard coal plants are equipped with "improved materials and processing techniques" and thus able to run at higher temperatures (700 degrees Celsius) and higher pressures (350 bars) (EWI and energynautics (2011)). The efficiency is assumed to increase by about 4 percentage points to 50% due to these improvements (EWI and energynautics (2011)). Investment costs are higher than the costs of state-of-the-art technologies but are decreasing due to learning effects by around one third by 2050. 'Innovative' lignite technologies use a more efficient drying process than existing plants and can therefore increase their efficiency to 46.5% (see EWI and energynautics (2011) and EWI/Prognos/GWS (2010)). Hard coal, lignite and CCGT plants can also be build as CHP technologies. Endogeneous investments in pump storage and hydro storage plants are not considered, because the existing space potentials are already used to a large extent.

TABLE 5.3: Investment costs of thermal and storage technologies in EUR_{2010}/kW

Technologies	2020	2030	2040	2050
Nuclear	3,157	3,157	3,157	3,157
Hard Coal	1,500	1,500	1,500	1,500
Hard Coal - innovative	2,250	1,875	1,750	1,650
Hard Coal - innovative CHP	2,650	2,275	2,150	2,050
Lignite - innovative	1,950	1,950	1,950	1,950
Lignite - innovative CHP	2,350	2,350	2,350	2,350
OCGT	400	400	400	400
CCGT	800	800	800	800
CCGT-CHP	1,100	1,100	1,100	1,100
Pump storage	-	-	-	-
Hydro storage	-	-	-	-
CAES	850	850	850	850

TABLE 5.4: Economic-technical parameters of thermal and storage technologies

Technology	η (η_{load}) [%]	η_{min} [%]	availability [%]	FOM-costs [EUR_{2010}/kW]	Lifetime [a]
Nuclear	33.0	28.0	84.5	96.6	50
Hard Coal	46.0	41.0	83.75	36.1	40
Hard Coal - innov.	50.0	45.0	83.75	36.1	40
Hard Coal - innov. CHP	22.5	17.5	83.75	55.1	40
Lignite - innov.	46.5	41.5	86.25	43.1	40
OCGT	40.0	20.0	84.5	17	20
CCGT	60.0	50.0	84.5	28.2	30
CCGT-CHP	36.0	26.0	84.5	40	30
Pump storage	87.0 (83.0)	87.0	95.25	11.5	100
Hydro storage	87.0	87.0	90.75	11.5	100
CAES	86.0 (81.0)	86.0	95.25	9.2	30

Table 5.4 shows the conversion efficiencies (at optimal operation and when operating at minimum load level), technical availability, operational and maintenance costs and the technical lifetime of conventional plants (mainly based on EWI and energynautics (2011) and EWI/Prognos/GWS (2010)). The efficiency grades depicted correspond to those of newly constructed plants. CHP plants have lower electrical but higher total efficiency grades than plants without the co-generation option (EWI and energynautics (2011)). The availability factor accounts for planned and unplanned shut-downs of the plants, e.g., because of inspections (EWI and energynautics (2011)). In addition, the availability factor determines the contribution of thermal and storage plants to the securely available capacity at times of peak demand. For renewable plants treated exogenously, we assume a contribution of 5% for wind and 0% for solar plants to securely available capacity. Biomass and geothermal capacities are dispatchable plants and assigned a capacity credit of 80%.
Assumed CO_2 factors (in t CO_2 /MWh_{th}) are 0.406 for lignite-fired plants, 0.335 for hard-coal fired plants and 0.201 for gas-fired plants.

We assume that yearly lignite generation is restricted to 350 TWh_{th} in Germany and to 249 TWh_{th} in the region 'Czech Republic + Poland'. In the other model regions, lignite is not a generation option because its low calorific value leads to prohibitively high transportation costs.

5.3.2.3 Fuel and CO_2 emission prices

Table 5.5 lists the assumed development of fuel prices (including transportation costs to the power plants) as well as historical prices. After the high price year of 2008, fuel prices came down rapidly before beginning to rebound afterwards. Assumptions concerning the fuel price development are mainly based on EWI and energynautics (2011). Regarding CO_2 prices, we assume that more restrictive quotas will lead to increasing prices, while an increasing RES-E share attenuates this effect. Overall, we assume that the CO_2 price increases up to 45 EUR_{2010}/t CO_2 by 2050.

TABLE 5.5: Fuel costs in EUR_{2010}/MWh_{th} and CO_2 emission costs in EUR_{2010}/t CO_2

	2008	2020	2030	2040	2050
Oil	44.6	99.0	110.0	114.0	116.0
Coal	17.28	13.4	13.8	14.3	14.7
Natural Gas	25.2	28.1	30.1	32.1	34.1
Lignite	1.4	1.4	1.4	1.4	1.4
Uranium	3.6	3.3	3.3	3.3	3.3
CO_2	22	25	35	40	45

5.3.2.4 Net transfer capacities

Table 5.6 depicts the assumed net transfer capacities (NTC), restricting imports and exports between model regions. Assumptions are based on ENTSO-E (2010). For model regions representing several countries, such as Benelux, the NTC-values of the represented countries have been summed.

TABLE 5.6: Net transfer capacities [MW]

	DE	FR	Benelux	CH+AT	CZ+PL	DK
DE	-	3050	4830	3100	1600	1500
FR	2600	-	2900	3000	-	-
Benelux	3980	1300	-	-	-	-
CH+AT	4800	1100	-	-	600	-
CZ+PL	3200	-	-	800	-	-
DK	2050	-	-	-	-	-

5.4 Theoretical discussion of effects and illustrative example

In this section, we discuss the influence of RES-E infeed on the optimal electricity capacity mix, the effects of uncertain future RES-E penetration levels and means to measure these effects (Section 5.4.1). In addition, we highlight the impact of uncertain future RES-E deployment paths via an illustrative modeling example (Section 5.4.2).

5.4.1 Theoretical discussion of results

Uncertain future RES-E penetration levels lead to uncertainty about the residual demand, required to be met by thermal power plants or by storage units. Figure 5.1 illustrates the influence of RES-E infeed on the optimal mix of dispatchable power plants. The upper graph depicts an hourly load curve without and after subtraction of RES-E infeed. The middle graph shows the corresponding (residual) load duration curves and the lower graph depicts the optimal mix of peak-, mid- and baseload plants under the simplifying assumption that only their yearly utilization times are decisive for the determination of the optimal capacity mix.[55] Even though the load duration curve approach provides a good approximation of the optimal capacity mix, it is important to note that in addition to yearly utilization times, the hourly variability of demand influences the optimal capacity mix. In the following we first discuss the influence of RES-E infeed on the optimal capacity mix under a load duration curve consideration. Then, we discuss the influence of the changing hourly variability of demand on the optimal capacity mix.

[55] An electricity load duration curve ranks load levels in a descending order of magnitude. The integral under the load duration curve shows how much electricity is demanded for how many hours per year. For the fraction of demand, that is needed in nearly all hours of the year, plants with high fixed and low variable costs (baseload plants) are cost-efficient while demand peaks are cost-efficiently met by peakload plants, characterized by high variable but low fixed costs (see e.g. Stoft (2002)).

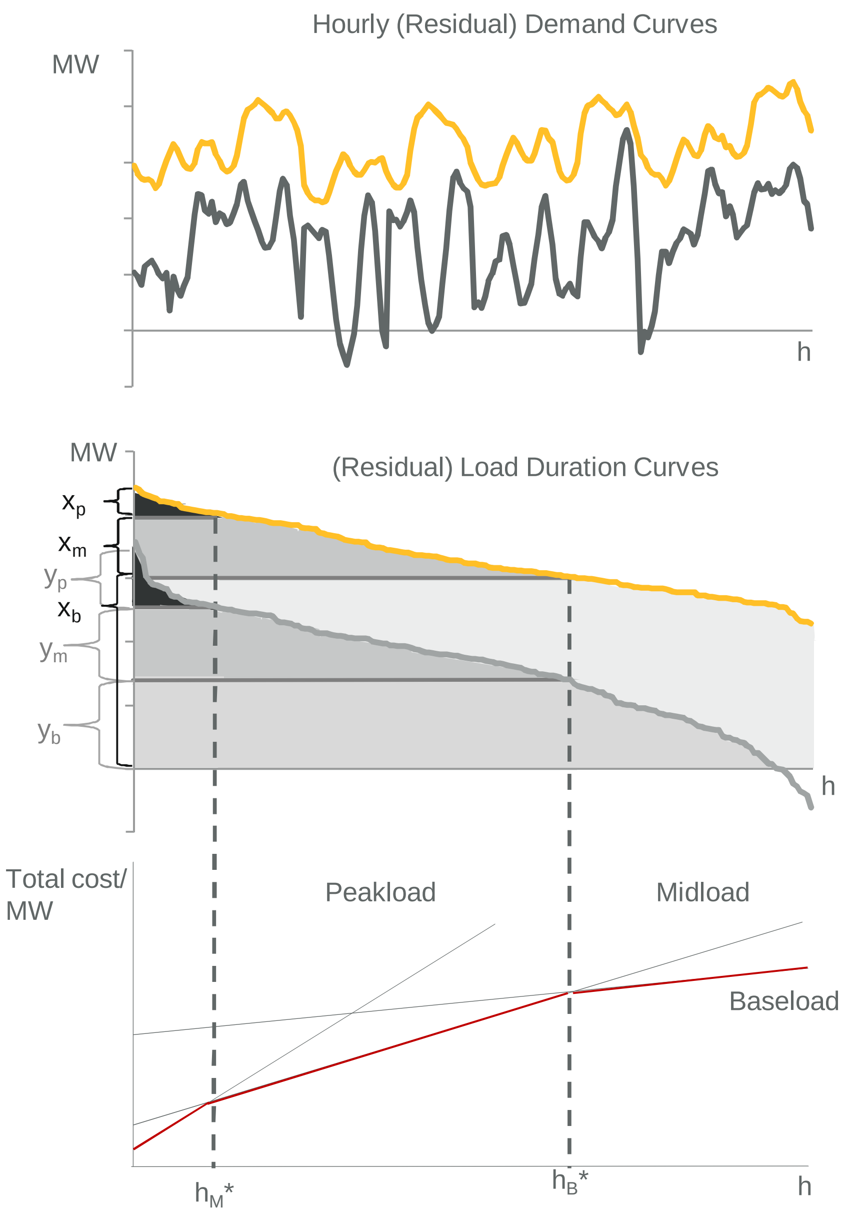

FIGURE 5.1: Effects of RES-E infeed on the optimal capacity mix
Source: Own illustration based on Nabe (2006) and de Miera et al. (2008).

Given high infeed of renewables, the residual load duration curve becomes steeper.[56] In many hours, a large part of the (residual) demand is met by renewables with negligible variable generation costs. Thus, the (residual) demand fraction, which is high in almost all hours of the year, shrinks. Consequently, the optimal capacity mix comprises less baseload plants, which need high utilization times in order to be cost-efficient ($y_b < x_b$). In addition, these baseload plants achieve lower utilization times than without RES-E

[56]While an increasing RES-E share generally increases the steepness of the residual load curve, this is not necessarily the case for small shares of renewables whose infeed matches well with demand. In these cases, an increasing RES-E share (up to a certain level) can even flatten the residual load duration curve. For example, small shares of solar based generation can flatten the electricity demand curve in countries with demand peaks at noon.

infeed due to a steeper residual load curve in the area where utilization times are higher than h_B^*. On the other hand, fluctuating RES-E such as wind and solar plants are not necessarily available at times of high demand. Thus, high electricity demand still needs to be met by dispatchable power plants. Consequently, the optimal capacity mix comprises a larger amount (or at least a larger share) of peak- and midload capacities ($y_p > x_p$ and $y_m > x_m$) when RES-E shares are high (see also Lamont (2008) and De Jonghe et al. (2011)). This effect is further amplified when considering security of supply requirements (not depicted in Figure 5.1). Due to low capacity credits of fluctuating RES-E, a large share of dispatchable generation capacities are also needed in electricity systems with high RES-E penetration, in order to ensure that peak demand can be met with securely available capacities (see, e.g., Dena (2008) and Weigt (2009)).

In addition, the volatility of the hourly residual load curve increases with a higher RES-E share (upper graph). Consequently, with an increasing RES-E share, the economic value of power plants with short ramping times, and/or low costs for ramping or part load operation, increases. Plants with a high capital/operating ratio are also those plants characterized by long ramping times, while plants with a low capital/operation cost ratio, such as open cycle gas turbines, can be ramped up and down within short time-frames. In addition, plants with a high capital/operating cost ratio typically have high minimum load requirements. Consequently, the increasing demand volatility induced by an increasing RES-E share also impacts optimal investment decisions of fossil fuel plants (De Jonghe et al. (2011)). Of course, also the economic value of storage units is significantly influenced by demand volatility (see, e.g., Nagl et al. (2011a)).

For these reasons, under uncertain future RES-E penetration levels, it is uncertain whether the optimal electricity mix should comprise large shares of baseload or rather large shares of peakload plants and storage units. The impact of this uncertainty on electricity system costs can be measured with the expected value of perfect information (EVPI) and with the value of the stochastic solution (VSS). The EVPI determines the expected additional costs induced by uncertainty, when the uncertainty is taken into account by a stochastic optimization procedure. The VSS corresponds to the additional costs (compared to the stochastic solution) arising when investments are planned for the average realization of the random parameters (here: residual load curves), without taking into account uncertainty. Thereby, the VSS measures how effectively stochastic optimization can help to mitigate the effects of uncertainty (Birge (1997)).

5.4.2 Illustrative example

In this section, we present an illustrative modeling example in order to highlight the effects of uncertain future RES-E deployment paths on optimal investment choices (5.4.2.1) and system costs (5.4.2.2). We consider one model region without an existing power plant fleet and only two time periods. Furthermore, for reasons of simplicity, we assume in this example that the contribution of RES-E to security of supply requirements is zero.[57]

5.4.2.1 Effects of uncertainty on the optimal technology mix

In this illustrative example, investment decisions have to be made in period 0 under uncertainty concerning the RES-E penetration in period 1, when RES-E shares of 0% (S1), approximately 25% (S2) and approximately 50% (S3) can be realized with equal probability. Investments can be made into hard coal, CCGT and OCGT plants, representing a baseload, a midload and a peakload technology, respectively. In addition, investments into storage units are possible.

Figure 5.2 depicts the residual load duration curves in S1, S2 and S3 as well as the stochastic residual load duration curve that corresponds to the probability weighted horizontal aggregation of the residual load curves of the three scenarios. It can be clearly seen that the stochastic residual load duration curve differs from all three deterministic load duration curves and, in particular, also from the average residual load duration curve (S2). In contrast to the average, the stochastic residual load duration curve takes into account that all extremely low or extremely high demand levels within the three scenarios can be realized with some probability. In Figure 5.2, it is also apparent, which power plant technologies are cost-efficient depending on their yearly utilization times (analogue to Figure 5.1). Considering only the load duration curve, OCGT plants are the cost-efficient choice to cover the demand levels occurring in fewer than h_M^* (full load) hours (- given our cost assumptions). For yearly full load hours larger than h_M^* (h_B^*), CCGT (hard coal) plants are cost-efficient. Of course, the hourly volatility of demand also determines the cost-efficient technology mix and especially the investments into storage units. However, abstracting in a first step from the hourly volatility, it can be seen that the residual load duration curve of S1 is comparatively flat, implying that a large share of hard coal plants should be cost-efficient. The residual load duration curve of S2 is also relatively flat except for the area of low utilization times. Since we

[57] As described in Section 5.3.2, the contribution of fluctuating RES-E to security of supply requirements is close to zero, because peak demand can occur when neither sun nor wind power is securely available, e.g., during night hours. In this illustrative scenario, we assume a capacity credit of 0% of all RES-E, as this assumption simplifies the calculation of the VSS in Section 5.4.2.2.

assume in this illustrative scenario that the contribution of RES-E to security of supply requirements is zero, all residual load curves start at the same demand level. Thus, the residual load curve of S2 and S3 are steep in the area where full load hours are below h_M^*. S3 generally has a steeper residual load curve than S1 and S2, indicating that a large share of OCGT plants should be cost-efficient. The stochastic residual load duration curve is flatter than S2 and S3 in the areas of very low utilization times but steeper than all deterministic scenarios between h_M^* and h_B^*. Thus, a large share of CCGT plants should be cost-efficiently deployed under stochastic optimization.

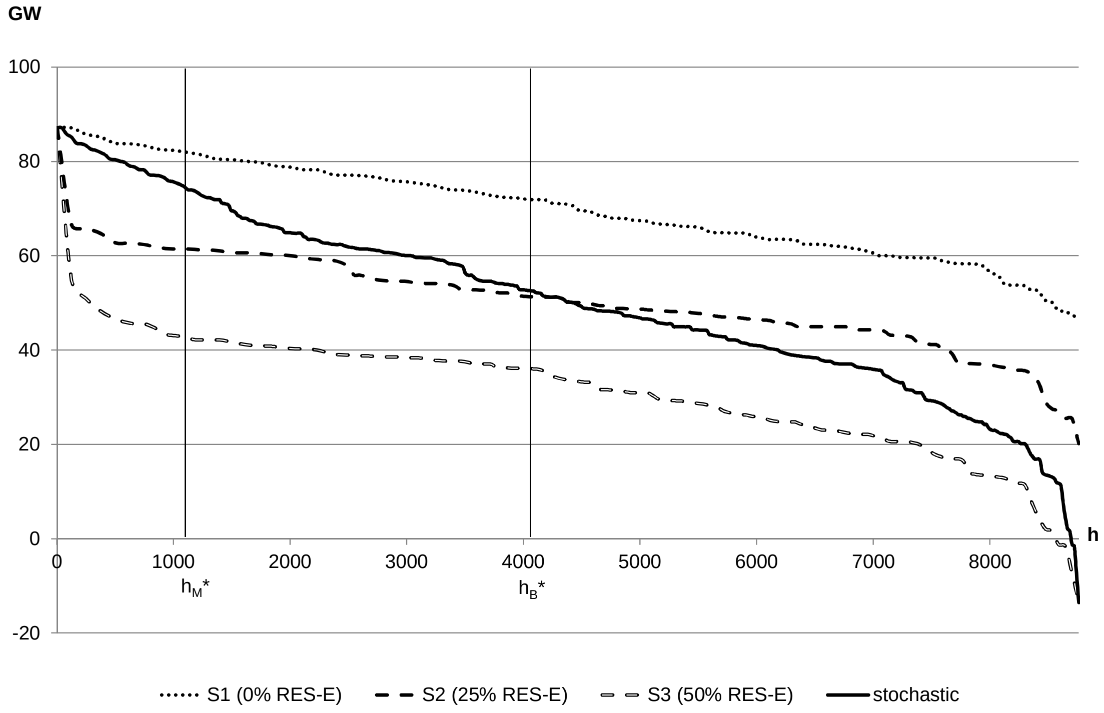

Figure 5.2: Residual load duration curves - deterministic and stochastic
Remark: Note that the load duration curve approach only provides an approximation of the optimal capacity mix. In addition, the optimal capacity mix is influenced by hourly demand variability.

In addition to yearly utilization times, optimal investment choices depend on the hourly variability of demand, which in turn determines the flexibility required from the power plant fleet. In particular, optimal investment decisions for storage units depend on the hourly variability of demand and cannot be determined by a load duration curve approach. Table 5.7 shows the maximum, minimum and average variations of residual demand from one hour to the next hour in the different scenarios. It can be seen that demand volatility significantly increases with an increasing RES-E share.[58] In

[58] As described in Section 5.3.1, we use a typical day approach to represent seasonal, daily and hourly variability of demand and infeed structures of fluctuating RES-E. Generally, this approach allows us to take into account typical residual demand situations resulting, e.g., from situations in which high RES-E infeed and low demand or low RES-E infeed and high demand occur at the same time. However, weather situations such as several weeks of calm wind cannot be captured by the limited number of typical days. Thus, including these weather phenomenons, e.g., by including a larger number of typical days or an

the stochastic optimization, both the maximum variation and the minimum variation of the three scenarios are taken into account. The average demand variation in the stochastic optimization is higher than in the average deterministic scenario (S2), because the extreme variations of S3 are also included.

TABLE 5.7: Hourly variation of residual demand - maximum, minimum and average values [MW]

	S1	S2	S3	stochastic
Max variation	10128	31026	53581	53581
Min variation	128	2	126	2
Average variation	2213	3646	6265	4254

Results of the power plant fleet optimization for the different residual demand curves are depicted in Table 5.8. The table shows the investment decisions for each of the three scenarios given perfect information about their realizations and the stochastic solution given uncertainty concerning RES-E penetration in period 1. In addition, utilization times are depicted. Table 5.9 depicts the power balances under deterministic and stochastic planning and provides information on the electricity demand of storage units and on the curtailed RES-E generation.

TABLE 5.8: Investments [GW] and utilization times [h] with deterministic and stochastic planning

	deterministic						stochastic			
	S1 (0%)		S2 (25%)		S3 (50%)		S1-S3	S1	S2	S3
	GW	h	GW	h	GW	h	GW	h		
Coal	83	6969	61	6811	41	6469	50	7111	6985	5393
CCGT	11	3321	9	3057	4	4096	36	6455	2792	230
OCGT	2	124	26	74	46	51	13	2248	0	0
Storage	8	1191	7	1163	15	1189	5	1280	647	581

TABLE 5.9: Power balances with deterministic and stochastic planning [TWh_{el}]

	deterministic			stochastic		
	S1	S2	S3	S1	S2	S3
End consumer electricity demand	611	611	611	611	611	611
Electricity consumption in storage units	14	11	25	8	4	4
Gross electricity demand	625	622	636	619	615	615
Generation of non-RES-E plants	625	452	298	619	445	279
Generation of RES-E plants	-	170	340	-	170	340
RES-E curtailment	-	-	2	-	-	4
Gross electricity generation	625	622	636	619	615	615

8760h approach, would lead to a lower average variation of hourly residual demand than depicted in Table 5.7.

It can be clearly seen that the optimal deterministic power plant mixes vary significantly between the scenarios. In scenario S1, without RES-E infeed, the capacity mix is dominated by coal capacities, while in scenario S3, with a 50% RES-E share, OCGT plants make up the largest share of capacities.[59] Storage capacities are deployed to the largest extent in scenario S3, characterized by the most volatile residual load.[60] Taking into account these uncertainties using a stochastic optimization approach, resulting investments yield more CCGT plants than in all deterministic scenarios.[61] Investments into coal, OCGT and storage capacities are lower than on average within the deterministic scenarios. As discussed above, the optimal capacity mix under stochastic optimization should comprise a large share of CCGT capacities because the stochastic residual load duration curve is relatively steep between h_M^* and h_B^* (Figure 5.2). But why is it cost-optimal to optimize for the stochastic residual load curve and thus build a large share of CCGT capacities when it is uncertain whether S1, S2 or S3 will be realized? Under the assumed investment, fuel and CO_2 prices, CCGT plants have a medium capital/operating cost ratio compared to coal and OCGT plants. When investment decisions are made under uncertainty and a high RES-E penetration (S3) is realized, CCGT plants have a low utilization and replace a part of the OCGT plants built under the deterministic planning of S3. In this case, additional total costs of CCGT plants are relatively low compared to additional costs arising if coal plants would be build and only run few hours per year. When a low RES-E penetration (S1) is realized, CCGT plants have a high utilization and substitute a part of the coal generation, which would be cost-efficient under the deterministic planning of S1. In this case, additional generation costs of CCGT plants are relatively low compared to additional costs arising if a large part of demand would have to be met by OCGT generation.

Investment decisions for storage units are driven by differences in electricity prices between periods of high and low (residual) demand. Electricity price volatility is high if (residual) demand is volatile and if differences in marginal generation costs of the price-setting technologies during high and low demand periods are large. Given perfect information, investments into storage units are highest in Scenario S3. Residual demand in S3 comprises, on the one hand, hours with negative residual demand during which electricity can be pumped into storage units for free. On the other hand, it comprises hours during which demand is relatively high and electricity generation from storage

[59] A large part of these OCGT capacities is only required to ensure security of supply, i.e., to meet demand in the peak demand hour if renewable infeed is not available. However, even if RES-E infeed would be 100% secure, 15 GW OCGT would be build in S3 - a significantly larger amount than in S1.

[60] It may seem surprising that the optimal storage capacities in Scenario S2 are lower than in S1 even though the RES-E share is higher. The reason is that a large part of the RES-E infeed in S2 matches demand and even flattens demand peaks at noon due to photovoltaic infeed.

[61] In the stochastic optimization approach, 36 GW CCGT capacities are built in period 0. In period 1, 2 GW CCGT are decommissioned in S2 and S3 in order to save fix operation and maintenance costs for capacities which are neither required for meeting demand nor for ensuring security of supply.

units can avoid high variable production costs by substituting generation from OCGT plants. Under uncertainty concerning the realization of S1, S2 or S3, a comparatively low amount of storage units is built. In combination with an - under uncertainty - optimally large deployment of CCGT plants, the value of storage units is, especially in S3, rather low. Under stochastic planning, the optimal capacity mix comprises more coal and CCGT plants than in the deterministic S3 scenario, and OCGT plants are not dispatched at all, when S3 is realized. Thus, under stochastic planning, the value for storage units is low in S3 because electricity prices have a lower volatility than under deterministic investment planning.[62] In addition, it is important to note that the model incorporates the option for cost-efficient RES-E curtailment. Thus, a smaller amount of storage units installed under uncertainty does not necessarily increase the ramping requirements for thermal power plants. In this example, RES-E curtailment in Scenario S3 is 4 TWh in the stochastic solution, while a curtailment of 2 TWh is cost-efficient in the case of deterministic investment planning. Furthermore, flexibility can be provided by part-load operation in addition to, or instead of, ramping procedures. In fact, the option of part-load operation is substantially used in Scenario S3, when investment decisions are made under uncertainty.

It should be noted that the setting of this illustrative scenario is rather extreme. First, the difference in RES-E infeed between the two extreme scenarios S1 and S3 is rather large. Second, only three scenarios are taken into account to represent this uncertainty. Increasing the number of scenarios representing an RES-E infeed between the two extremes of 0% and 50% flattens the stochastic residual load duration curve, as extreme values are taken into account with decreasing probabilities (see Figure D.1 in Appendix D). Consequently, the effect that technologies with a medium capital/operating cost ratio have a higher value under uncertainty is - although robust - less pronounced when the number of scenarios is increased. Table 5.10 depicts the optimal investment choice under uncertainty of RES-E infeed between 0% and 50% - either represented by three scenarios (0%, 25%, 50%) or represented by 50 scenarios (0%, 1%, 2%, ..., 50%). In addition, the result for the average scenario (25%) is shown again. It can be seen that the result from the stochastic optimization differs less from the optimal capacity mix in the average scenario if uncertainty is represented by 50 instead of 3 scenarios. However, the optimal capacity mix under uncertainty will never be identical to the optimal capacity mix for the average scenario. As shown in Figure 5.2, the residual load duration curve of S1 (with 0% RES-E infeed) consists of many high load levels, which never occur in the average S2 scenario. Furthermore, the residual load duration curve of S3 (with 50% RES-E infeed) consists of many low load levels, which never occur in the average S2

[62] In contrast, in Scenario S1, stochastic planning leads to a high OCGT generation compared to the deterministic case. Electricity prices have a higher volatility than under deterministic planning and the 5 GW storage capacity, installed under uncertainty, consequently has the highest utilization time in S1.

scenario. In the stochastic residual load duration curve, however, all load levels occuring in at least one of the scenarios are taken into account, also those that are higher or lower than in S2.

Table 5.10: Investments under uncertainty (3 vs 50 scenarios) and under average planning [GW]

	stochastic		average
	3 scenarios	50 scenarios	25% RES-E
Coal	50	54	61
CCGT	36	26	9
OCGT	13	19	26
Storage	5	5	7

In addition, it is important to note that the value of midload plants under uncertainty, compared to perfect foresight modeling, depends on the relative steepness of the stochastic residual load duration curve in the area h_M^* - h_B^* compared to the steepness of the deterministic residual load duration curves in the same area. Thus, given a higher steepness of, e.g, the average deterministic residual load duration curve in the area h_M^* - h_B^*, the difference between the stochastic solution and the average deterministic solution (shown in Table 5.10) would ceteris paribus be smaller.[63] Steeper deterministic residual load duration curves in the area h_M^* - h_B^* could for example result from different RES-E infeed patterns than those represented in our typical days (e.g, if a situation of several weeks of calm wind would be additionally taken into account). Using hourly historical data for RES-E infeed and demand on an 8760h basis instead than a typical day approach for constructing residual load duration curves (see Figure D.2 in Appendix D), we find that the curves with RES-E infeed (S1 and S2) are steeper in the area h_M^* - h_B^* compared to the curves which have been constructed on the basis of the typical day RES-E infeed structure (see Figure 5.2). Thus, also the relative difference in the steepness of the stochastic compared to the average residual load duration curve decreases. Thus, both using a typical day approach and using hourly historical data for RES-E infeed and demand on an 8760h basis, we find that in the area h_M^* - h_B^*, the stochastic residual load duration curve is steeper than the average deterministic residual load duration curve. The magnitude of this effect, however, is smaller when using the historical 8760h RES-E infeed structures.

[63] A higher steepness of the deterministic residual load duration curves in the area h_M^* - h_B^* would also affect the stochastic residual load duration curve, however, not necessarily for utilization times of h_M^* or h_B^* and even not necessarily in the area h_M^* - h_B^*. More specifically, if the steepness of a deterministic residual load duration curve changes in an area, where the level of the deterministic curve is lower than the value of the stochastic residual load duration curve in h_B^*, the stochastic residual load duration curve is affected by these changes only in the area of utilization times which are higher than h_B^*.

Against this background, a further investigation of the drivers for the steepness of the stochastic residual load duration curve is interesting. As described in Section 5.4.1, uncertainty concerning the RES-E penetration in an electricity system leads to uncertainty about the level and the slope of the residual load duration curve and about the hourly variability of residual demand. Thus, the amount of capacities needed to meet demand and the optimal capacity mix, in terms of utilization times and flexibility requirements, is uncertain. In order to further investigate the drivers for the steepness of the stochastic residual load duration curve, we compare the stochastic residual load duration curves if i) only the level of demand is uncertain or if ii) the level and the structure of the residual demand are uncertain. In Figure 5.3, the two stochastic and three deterministic (residual) load duration curves are depicted. The deterministic curves correspond to a) no RES-E infeed or a high demand level (≡ S1), b) to a RES-E infeed that makes up approximately 50% of yearly demand (≡ S3) and c) a demand level that corresponds to 50% of the highest demand level (assuming the same hourly demand pattern of the different yearly demand levels). The stochastic (residual) load curves take into account either uncertainty about the level of demand only (high versus low demand) or uncertainty about the level and the structure of residual demand (0% RES-E versus 50% RES-E).

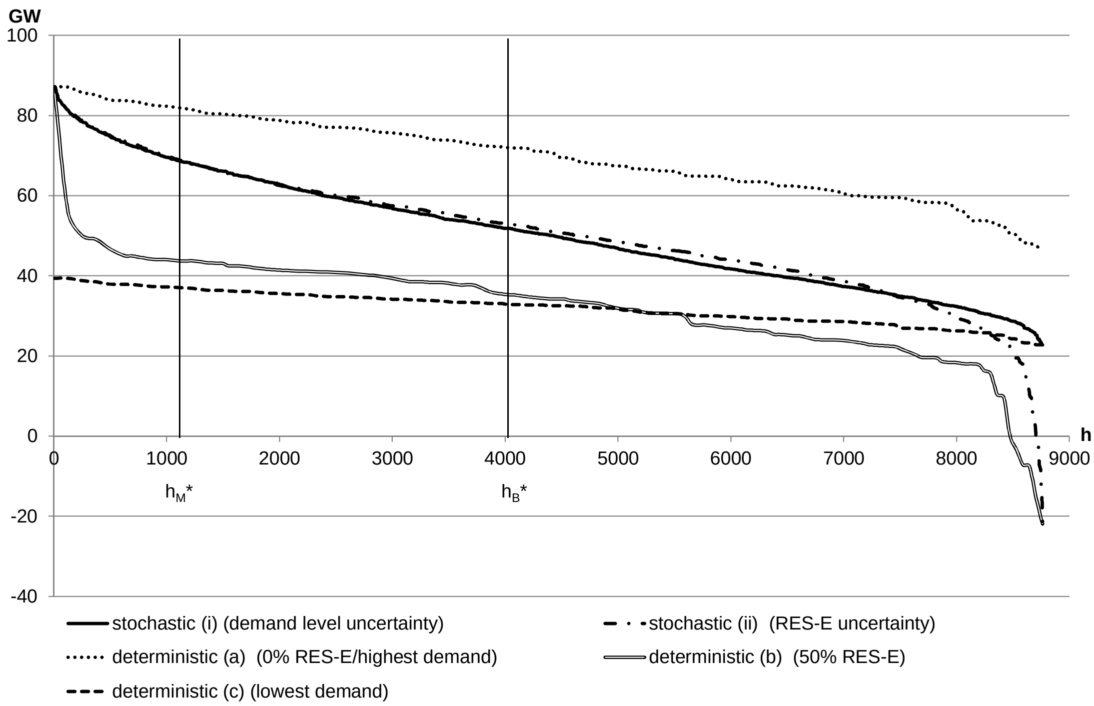

FIGURE 5.3: The influence of demand level uncertainty on the steepness of the stochastic load duration curve

Remark:Note that the load duration curve approach only provides an approximation of the optimal capacity mix. In addition, the optimal capacity mix is influenced by hourly demand variability.

However, both stochastic curves are quite similar except for the area of very high utilization times. In the area of very low utilization times, the two curves are overlapping because highest demand arises in the deterministic (a) scenario, which is taken into account in both stochastic curves.[64] The deterministic scenarios with a low demand (c) and with a high RES-E share (b) have significantly different slopes (- although their yearly (residual) demand levels are identical). These different slopes of the (residual) load duration curves have a high impact on the optimal capacity mix given perfect foresight.[65] However, in the area h_M^* - h_B^*, the effect of these different slopes of the *deterministic* curves on the slopes of the *stochastic* curves is rather low (in fact, the stochastic load duration curve given RES-E uncertainty lies only slightly above the stochastic load duration curve given demand uncertainty). The effect of a higher value of midload plants under uncertainty is thus mainly driven by the uncertainty about the level of the demand, while the *additional* uncertainty about the slope of the demand even slightly attenuates this effect. Furthermore, with increasing demand level differences between the scenarios, the steepness of the stochastic residual load duration curve increases (see Figure D.3 in Appendix D).

Moreover, the effect that midload plants have a higher value under uncertainty depends on the distance between h_M^* and h_B^*, i.e. the utilization time for which midload plants (here: CCGT plants) are cost-efficient. For example if we would include the possibility to invest into lignite in addition to OCGT, CCGT and hardcoal plants, the distance between h_M^* and h_B^* would approximately be divided in half (given our cost assumptions). Thus, in general, the magnitude of the effect that technologies with a medium capital/-operating cost ratio have a higher value under uncertainty first depends on the steepness of the stochastic residual load duration curve between h_M^* and h_B^* (in comparison to the steepness of the deterministic load duration curves). This steepness is essentially driven by the uncertainty about the level of demand (Figure 5.3) and by the probability with which the 'extreme' scenarios are taken into account (Table 5.10/ Figure D.1). Second, the magnitude of the effect depends on the distance between h_M^* and h_B^*, which is influenced by the choice of technologies considered in the modeling and the assumptions on investment, fuel and CO_2 costs.

[64]The stochastic load duration curves in Figure 5.3 have been calculated based on twelve scenarios that represent the range of demand or residual demand between the deterministic a and the deterministic b or c scenarios. Twelve scenarios, instead of only three scenarios, have been chosen because the scenario with the highest demand(/lowest RES-E infeed) is identical in both stochastic (residual) load duration curves. Thus, in order to limit the influence of this scenario on the slopes of the stochastic residual load duration curves, twelve scenarios have been chosen.

[65]For example, the optimal deterministic capacity mixes in the high and low demand scenarios in Figure 5.3 comprise the same shares of base-, mid- and peakload capacities. In contrast, the optimal deterministic capacity mixes with high and low RES-E shares differ significantly, as shown in Table 5.8.

5.4.2.2 Effects of uncertainty on system costs

Table 5.11 depicts system costs (excluding costs for RES-E generation) arising in this illustrative scenario when the future is perfectly known (deterministic planning), in the case of uncertainty under stochastic planning and in the case of uncertainty when the uncertainty is not taken into account within the investment planning process (average planning).

In this scenario setting, average planning principally refers to an optimization of investment capacities for Scenario S2, characterized by an average RES-E infeed. This capacity mix is then fixed in all scenarios and only the dispatch of these capacities can be optimized according to the actual RES-E infeed. Due to the peak-capacity constraint (and the simplifying assumption in this illustrative scenario that the contribution of RES-E to security of supply requirements is zero), capacities built in Scenario S2 are sufficient to meet peak demand in all scenarios. However, due to different structures of the residual load curves and thus different ramping requirements, it is not guaranteed that these capacities are sufficient to meet demand in all scenarios in every single hour. Thus, we optimize capacities for the average residual load (S2) under the additional constraint that demand also needs to be met in all other possible scenarios.[66] This optimization results in a slightly different capacity choice compared to the original Scenario S2. Thus, costs in S2 are slightly higher with average planning than with deterministic planning.

TABLE 5.11: System costs (excluding costs for RES-E generation) in Mio EUR, EVPI and VSS

	deterministic planning	stochastic planning	average planning
S1 (0% RES-E)	41,166	42,040	43,966
S2 (25% RES-E)	31,253	31,736	31,285
S3 (50% RES-E)	21,960	23,269	23,105
average costs	31,460	32,348	32,785
EVPI	889		
EVPI (% of det costs)	2.82%		
VSS	437		
VSS (% of det costs)	1.39%		

In all scenarios, total system costs are higher under stochastic planning than under deterministic planning (given perfect foresight). In scenarios S1 and S2, a lower coal generation than under deterministic planning leads to increasing variable generation

[66] In this auxiliary optimization of S2, only dispatch costs arising in S2 are taken into account. However, chosen capacities have to be sufficient in order to meet demand in all scenarios.

costs. However, capital costs are lower, such that in sum total system costs increase by 1.5 - 2%. In Scenario S3, total system costs under uncertainty are 6% higher than given perfect foresight because lower variable costs do not outweigh additional capital costs. The EVPI, corresponding to the probability weighted additional costs arising in all scenarios under stochastic compared to deterministic planning, amounts to 889 Mio EUR and to 2.82%, expressed as percentage of average deterministic system costs. The VSS evaluates the benefit of solving the stochastic solution and corresponds to the probability weighted additional costs arising in all scenarios under average planning compared to stochastic planning. The VSS amounts to 437 Mio EUR, representing 1.39% of average deterministic system costs. Expressed differently, system costs are higher by 1326 Mio EUR compared to a situation of perfect foresight, if RES-E deployment paths are uncertain and investment decisions are made for an average realization of the residual load. These additional costs can be reduced by approximately one third, by taking into account the existance of uncertainty by a stochastic investment planning approach.[67]

5.5 Analysis of uncertain RES-E deployment paths in Germany and neighboring countries

In the previous chapter, we have shown how uncertainty about future RES-E deployment paths changes optimal investment plans for thermal power plants and storage units and that this uncertainty induces additional costs. However, the remaining question is how significant these effects are in real-world electricity systems. In this context, it is important to exactly define the source of uncertainty to be analyzed and to determine the possible bandwidth of realizations of the uncertain parameters according to this definition. Specifically, uncertain future RES-E deployment paths have two potential sources: political uncertainty and uncertainty about the implementation of political plans. Political uncertainty arises when political targets are unclear or when it is uncertain, whether targets will be changed, e.g., after governmental elections. The implementation of political plans can be uncertain even if reliable targets exist, for four principal reasons. First, many RES-E technologies are relatively new technologies, implying that technological and cost developments are uncertain and/or that limited experiences exist for construction and maintenance. Second, favorable RES-E sites are often located far from demand centers and therefore the electricity network has to be adapted. Third, local opposition may hinder the construction of new sites or transmission lines due to visual or environmental concerns. Fourth, when RES-E is supported by a price-based promotion system,

[67] As shown in Table 5.10, when uncertainty is represented by a larger number of scenarios, the stochastic investment solution is closer to the optimal capacity mix under average planning. Thus, the cost advantage of the stochastic compared to the average planning (i.e., VSS) also depends on the specific representation of uncertainty in the model.

such as by a feed-in-tariff system, resulting RES-E quantities are inherently uncertain. In the following, we try to quantify effects of uncertainty concerning the implementation of reliable long-term political RES-E targets for Germany and its neighboring countries. We assume that a continuous increase of RES-E until 2050 is a politically agreed and reliable target for Germany and its neighboring countries.[68] Thus, we assume that the RES-E share increases within each model year and that only the magnitude of the increase is uncertain because the progress of necessary infrastructure investments, public acceptance, cost and technological developments of renewable energy technologies cannot be perfectly foreseen.
In this chapter we describe the scenario tree representing uncertainty about the implementation of political RES-E targets (Section 5.5.1) and present model results with regard to investment decisions, electricity generation and system costs (Section 5.5.2).

5.5.1 Representation of the RES-E implementation risk

In order to represent the RES-E implementation risk in the model, we estimate possible bandwidths of RES-E deployments within the next decades based on the targeted growth rates indicated in the National Renewable Energy Action Plans (NREAP)[69], the actual trends regarding the achievement of these targets, the possible obstacles to RES-E deployment and the space potential restrictions per technology and country.

The first model year considered in the analysis is 2015, when investment decisions have to be made for power plants commissioning in 2020. The model year 2020 is represented by three nodes, taking into account that the NREAP can be exactly reached but also be surpassed or not be reached. Lower RES-E deployments than targeted represent a case in which slow progress in grid and plant construction, local opposition to new power plant construction and/or a lack of funds hinders RES-E deployment. In particular, the achievement of offshore wind targets has been questioned recently because of slow progress in grid and plant construction. In contrast, higher than targeted RES-E deployments represent a case in which there exist hardly any obstacles to plant and grid construction and/or cost degressions of RES-E plants are higher than foreseen. For example, photovoltaic targets are easily surpassed in price-based RES-E support systems

[68]It is important to notice that political uncertainty about future RES-E deployment paths also exists. Binding RES-E targets on a European level have only been formulated until 2020. In Germany, RES-E targets until 2050 have been additionally formulated (Energiekonzept (2010)). Not all other European countries have long-term RES-E strategies yet. In addition, changes in political targets could occur with some probability. These risks are not incorporated in our model calculations.

[69]Within the National Renewable Energy Action Plans, the member states of the European Union defined how the national 2020 RES targets, according to the 2009 EU Directive on the promotion of renewable energy sources, are broken down into targets for the transporting, the heating and cooling and the electricity sectors.

except for very low promotion payment levels, because the support of the local population is often high and the space potential is vast.
Table 5.12 depicts the RES-E capacities in 2010, the foreseen deployment in GW between 2010 and 2020 (according to the NREAP) and the installed RES-E capacities in 2020 (when the NREAP is exactly reached, surpassed or not reached). Historical capacities in 2010 are based on the NREAP documents (Beurskens et al. (2011)), EURELECTRIC (2009) and BMU (2011).

Table 5.12: RES-E capacities in 2010 and 2020 [GW]

Region	Technology	**2010**	**growth NREAP**	**NREAP 2020**	**> NREAP 2020**	**< NREAP 2020**
Germany	wind onshore	27	9	36	40	30
	wind offshore	0	10	10	12	3
	photovoltaics	17	34	52	60	35
	biomass	7	2	9	10	8
	geothermal	0	0	0	1	0
Benelux	wind onshore	3	8	10	12	6
	wind offshore	0	5	5	7	2
	photovoltaics	0	2	2	4	1
	biomass	2	3	5	6	5
	geothermal	0	0	0	0	0
France	wind onshore	6	13	19	25	10
	wind offshore	0	6	6	8	1
	photovoltaics	1	4	5	10	2
	biomass	1	2	3	4	2
	geothermal	0	0	0	0	0
CH + AT	wind onshore	1	2	3	4	2
	wind offshore	0	0	0	0	0
	photovoltaics	0	0	0	1	0
	biomass	1	0	1	2	1
	geothermal	0	0	0	0	0
CZ+ PL	wind onshore	1	5	6	9	3
	wind offshore	0	1	1	1	0
	photovoltaics	2	0	2	2	2
	biomass	0	3	3	4	0
	geothermal	0	0	0	0	0
Denmark	wind onshore	3	0	3	3	3
	wind offshore	1	1	1	2	1
	photovoltaics	0	0	0	0	0
	biomass	1	2	3	4	2
	geothermal	0	0	0	0	0

For the time-frame after 2020, we estimate possible bandwidth for a high or a moderate RES-E deployment pace based on the same considerations. For the case of favorable investment conditions, we assume that the deployment between 2010 and 2020 (according to the NREAP) is carried forward in the coming decades, while in the presence of obstacles to RES-E deployment, the deployment is assumed to be one half of this growth. For offshore wind, we deviate slightly from this procedure, because experiences with offshore plants are few and unused space potential is still vast in all considered countries. Thus, for offshore wind, the deployment at a high pace is assumed to be twice the development in the NREAP between 2010 and 2020, while a deployment at moderate pace is assumed to be the same as within the NREAP. In addition, we take into account that (space or fuel) potential restrictions (see Table D.1 in Appendix D) need to be respected and that the maximal yearly RES-E production of all RES-E technologies reaches at most 90% of the annual country-specific electricity demand.

Figure 5.4 recaptures the resulting structure of the scenario tree representing the RES-E implementation risk for Germany and its neighboring countries. We assume that factors favoring and factors hindering a high RES-E deployment pace are realized with the same probability such that all nodes depicted in Figure 5.4 have the same occurrence probability. Also, with the chosen approach, we implicitly assume that different risks associated with the deployment of different RES-E technologies are positively correlated in all model regions.[70] In addition, we assume that most uncertainties about technological and cost developments and about grid construction progress are resolved from 2040 onwards.[71]

[70]Possible negative correlations could both increase or attenuate the effects of the RES-E implementation risk. For example, the combination of high offshore wind and low photovoltaic penetration can lead to a more volatile residual load than high penetration of both technologies. Thus, including paths with high offshore and low photovoltaic penetrations may even increase the possible bandwidth of residual load curves captured in the scenario tree and increase effects of uncertainty. On the other hand, including paths with high offshore and low onshore wind penetrations and vice versa may lead to increasing probabilities for these 'medium' paths such that effects of uncertainty may decrease to some extent.

[71]In our analysis, we focus on investments decisions until 2020 and the corresponding dispatch decisions until 2025. In order to include effects of long-term uncertainties on investment decisions with long amortization times and technical lifetimes, we however include nodes until 2060. Overall, the chosen scenario tree consists of 24 branches and 94 nodes.

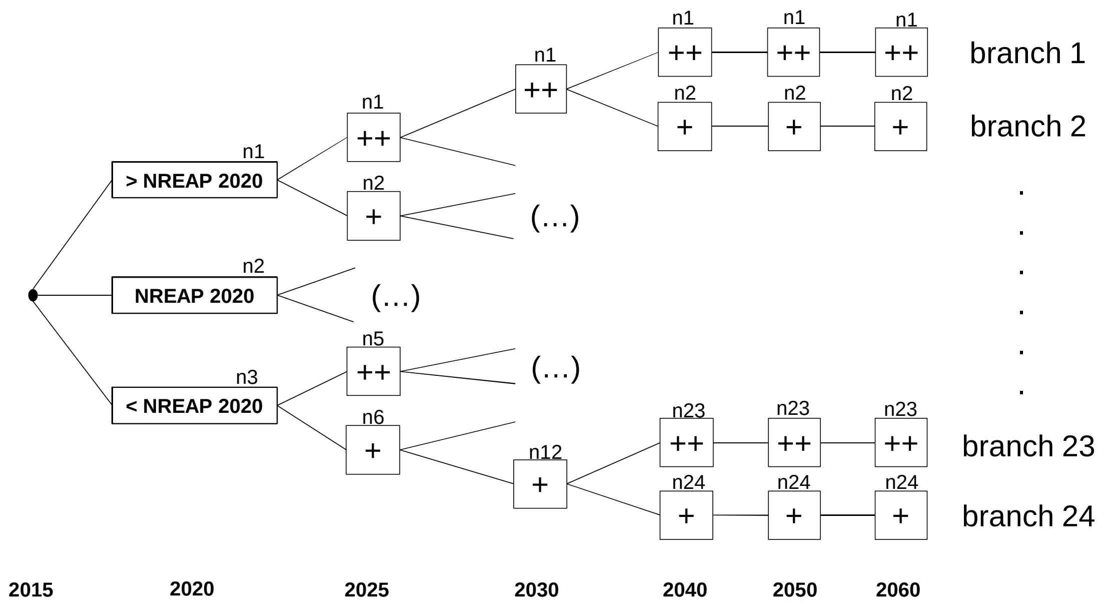

FIGURE 5.4: Structure of the scenario tree representing the RES-E implementation risk

Resulting RES-E capacities per node for the model years 2030 and 2050 can be found in Appendix D. For example, in Germany in the year 2030, RES-E capacities vary between 109 GW and 187 GW (see Table D.2 in Appendix D). In terms of RES-E generation, bandwidths are between 225 TWh and 383 TWh, which make up 37% and 63%, respectively, of the assumed electricity demand in 2030. In 2050, the maximum assumed bandwidths for Germany are between 141 GW and 244 GW (see Table D.3 in Appendix D), resulting in RES-E shares of 47% and 78%, respectively, given our assumed demand development.[72]

5.5.2 Model results

In the following, we analyze the effects of the RES-E implementation risk on investment and dispatch decisions (Section 5.5.2.1) as well as on system costs (Section 5.5.2.2). In addition, we compare the results for the European power system with the results of the illustrative example in Section 5.4.2 (Section 5.5.2.3).

[72]For Germany, an estimation of possible bandwidths of RES-E generation in a 5-year period can also be found in the medium-term RES-E generation forecast (IE Leipzig (2011)). As a lower bound for promoted RES-E generation in 2016, about 130 TWh are indicated and as a higher bound about 210 TWh. Although this bandwidth is based on both possible ranges for RES-E deployment and for different wind and water infeed assumptions, it clearly confirms that even within a short time horizon, RES-E developments can be quite uncertain.

5.5.2.1 Effects of RES-E implementation risks on investment and dispatch decisions

Table 5.13 depicts investment decisions made in 2015 for the sum of all modeled countries. Within branch 1, characterized by the highest possible RES-E penetration in all model years (surpassed NREAP in 2020 and fast-pace growth in each following period), only lignite and OCGT plants are constructed. In branch 24, with the lowest possible RES-E generation, coal and CCGT plants are also chosen. Lignite investments are identical in all branches because lignite generation is characterized by very low variable costs and is also restricted to local fuel potentials. Note that nuclear is not an investment option in the first model year.

Table 5.13: Investments in 2015 in all model regions [GW]

	deterministic			stochastic
	Max RES-E Branch 1	Min RES-E Branch 24	average of branches 1-24	
Lignite	3	3	3	3
Coal		10	2	
CCGT		3	2	3
OCGT	18	12	18	23
CHP-Coal				
CHP-Gas				
Nuclear				
Storage				
sum	21	28	25	29

Under uncertainty, no investments into coal plants take place. In contrast, CCGT and especially OCGT investments are higher than on average under certainty. The result of lower coal and higher CCGT investments reflects the effect discussed in the illustrative modeling example (Section 5.4): As coal is only cost-efficient in some scenarios, investments with lower capital/operating cost ratios are chosen under uncertainty in order to hedge against the risk of high investment expenditures for plants that may only run for few hours. In contrast, higher OCGT investments under uncertainty are only cost-efficient because of an existing power plant fleet. In the illustrative modeling example, lower OCGT investments are chosen under uncertainty because a high utilization of these capacities, in the case of low RES-E penetration, would induce high costs. Due to the existing power plant fleet of the Central European power market (now taken into account), the additional OCGT capacities built under uncertainty are not needed to meet demand in 2020. Even in the scenario with the lowest RES-E penetration (branch 24), demand can be met by a different dispatch of existing power plants such that the additional OCGT plants built under uncertainty only serve as backup capacities in all scenarios. Specifically, the utilization of existing CCGT plants in branch 24 is higher under uncertainty. In addition, generation in lignite-CHP plants is reduced such that generation in non-CHP lignite plants can be increased (due to the lignite fuel bound, only a limited amount of lignite can be used per year). CHP generation from lignite plants is replaced by a higher utilization of gas-CHP and coal-CHP plants. In addition, the utilization of pump storage plants is higher than under investment planning given perfect foresight. Due to a higher utilization of pump storage plants, the utilization of existing baseload plants can be increased compared to the deterministic case, in which more investments into baseload plants are made in 2015. In branch 1, characterized by the highest RES-E penetration, the different optimal investment plan under uncertainty leads to a higher amount of total installed capacities and to a larger share of CCGT capacities in 2020. Consequently, a larger share of demand in 2020 is met by CCGT plants instead of old coal plants, which have higher variable costs than new built CCGT plants due to low efficiency values.

These generation differences are recaptured in Figure 5.5. Interestingly, although in branch 1 and 24 uncertainty leads to a replacement of coal by CCGT generation, this generation difference leads to lower variable costs in branch 1 compared to the deterministic case, while variable costs in branch 24 are comparatively higher. Whereas in branch 1, CCGT generation replaces coal generation in old existing coal plants, differences in branch 24 occur because new efficient coal plants built in the deterministic case are not available under uncertainty.

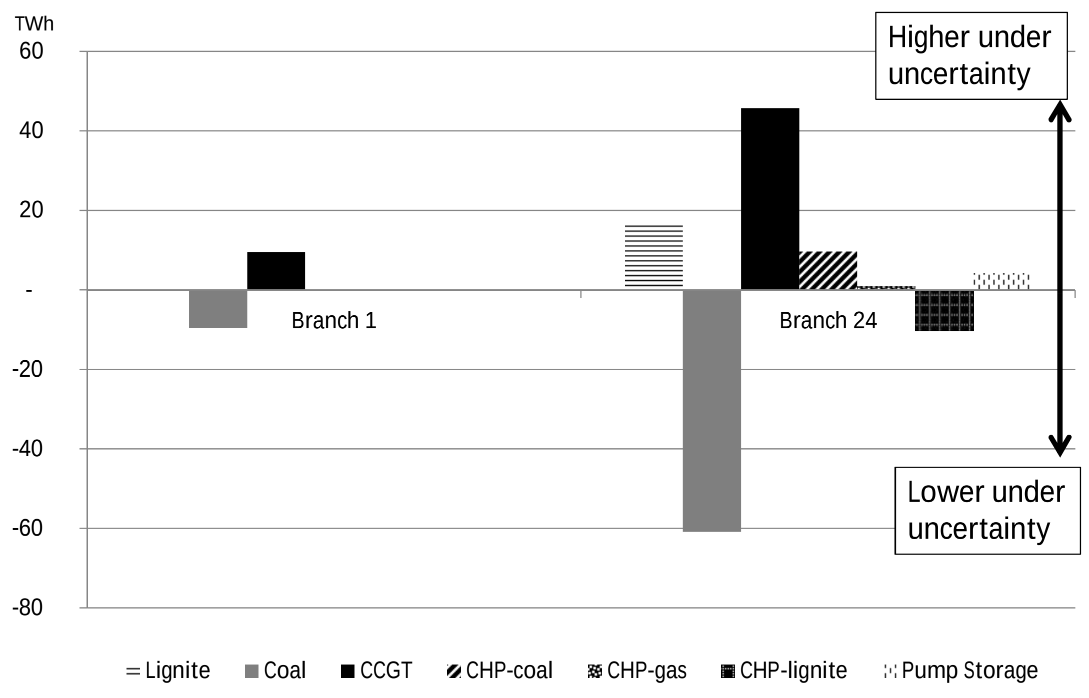

FIGURE 5.5: Generation differences in 2020 between the deterministic and the stochastic case [TWh]

Investment choices in 2020 differ between the stochastic and the deterministic solutions, mainly because the power plant fleet in the stochastic approach is adapted to newly available information about future RES-E deployments. Table 5.14 depicts investment decisions in branches 1 and 24, given perfect foresight, the average values for all eight deterministic branches passing through node n1 and node n3, respectively, and the stochastic values for nodes n1 and n3. Nuclear investments are identical in all deterministic and stochastic cases because generation costs are comparatively low and investments are restricted (see Section 5.3). Lignite investments are also identical in all branches passing through the same 2020 node such that investments into lignite plants are not subject to uncertainty.

TABLE 5.14: Investments in 2020 in all model regions [GW]

	Branch 1	av (n1)	stoch (n1)	Branch 24	av (n3)	stoch (n3)
Lignite	7	7	7	10	10	10
Coal						
CCGT	13	17	13	35	31	42
OCGT	34	31	28	15	17	8
CHP-Coal						
CHP-Gas						
Nuclear	6	6	6	6	6	6
Storage						
sum	60	61	54	66	64	66

Considering node n1 (characterized by a surpassed NREAP), it can be seen that under uncertainty, less investments in CCGT and OCGT plants are made compared to the average investments in the deterministic scenario calculations. Lower investments are cost-efficient because under uncertainty, more CCGT and OCGT plants are constructed in the period before 2020. Considering branch 1, CCGT investments in 2020 are identical in the stochastic and deterministic case. Thus, due to the higher CCGT investments in 2015 under uncertainty, installed CCGT capacities in 2025 are higher than in the deterministic case. Consequently, in branch 1, differences in the dispatch decisions between the deterministic and the stochastic optimization in 2025 hardly differ from those in 2020. Under uncertainty, a larger part of demand is met by CCGT plants, while generation from coal plants is lower than under perfect foresight.

Node n3 (low RES-E share) is characterized by substantially larger CCGT investments under uncertainty. OCGT investments are, in contrast, lower than in the deterministic case. Additional CCGT capacities are built in order to compensate for lower base- and midload plant investments (coal and CCGT) made in 2015. CCGT, rather than coal plants, are chosen to compensate for lower baseload investments because increasing CO_2 prices and RES-E shares over time lead to an increasing relative value of CCGT plants compared to coal plants. Fewer investments in OCGT plants are cost-efficient under uncertainty in 2020 because the capacity mix already comprises larger OCGT shares than under certainty due to the 2015 investments. Resulting dispatch decisions (branch 24) in 2025 are again characterized by higher CCGT and pump storage generation and by lower coal generation than under certainty. Results for later model years generally reflect the same effects and are thus not discussed in more detail.

5.5.2.2 Effects of RES-E implementation risks on system costs

Figure 5.6 depicts additional capital costs, additional variable costs and additional total costs arising in each of the 24 branches due to the uncertainty about the magnitude and the pace of future RES-E deployments in Germany and its neighboring countries. Depicted costs are discounted with a 5 % rate and accumulated until 2060. In branches with high RES-E shares, such as branch 1, investment planning under uncertainty induces additional capital costs (+ 9 bn EUR_{2010} by 2060 in branch 1) because many mid- and baseload plants built under uncertainty are not cost-efficient for these branches. However, variable generation costs decrease due to the availability of generation options with low variable costs (- 4 bn EUR_{2010}). In contrast, in branches with low RES-E shares, such as branch 24, additional variable costs are high (+ 11 bn EUR_{2010} by 2060 in branch 24), while capital costs are lower than in the deterministic case (- 9 bn EUR_{2010}).

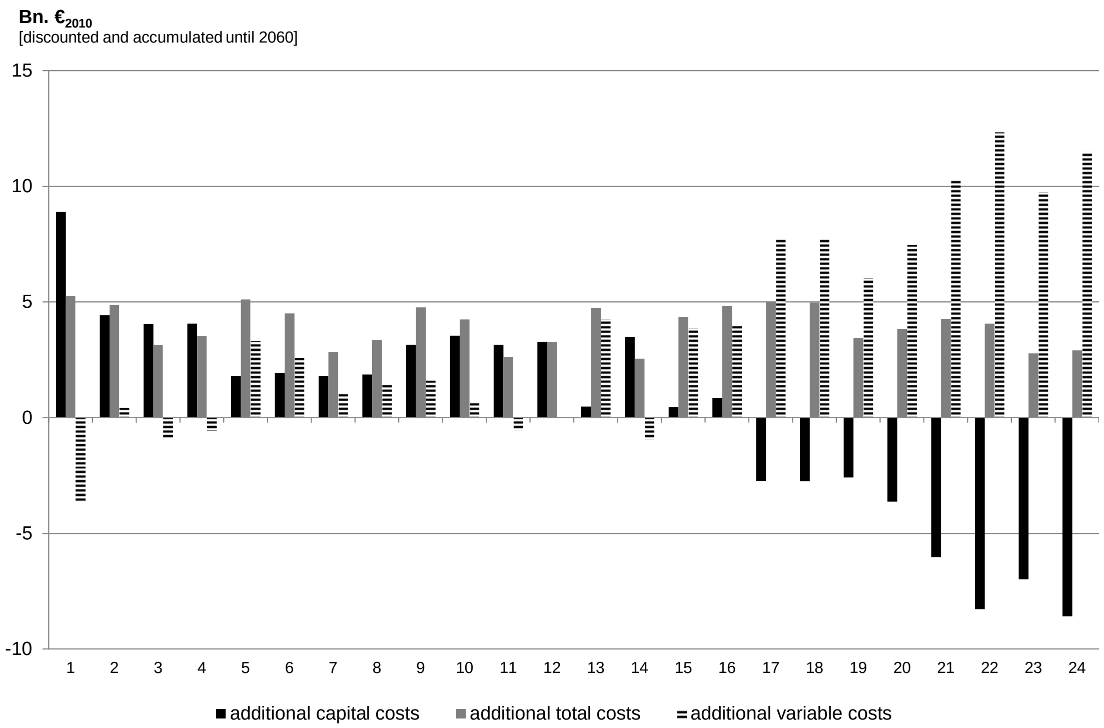

FIGURE 5.6: Additional costs induced by the RES-E implementation risk (per branch) [bn EUR_{2010}]

Total additional costs induced by uncertainty amount to 4 bn EUR_{2010} on average. Compared to total average deterministic costs, these costs however represent only 0.3%. One reason is that investment requirements are low in those periods when uncertainty is highest.[73] Investment decisions are exposed the most to uncertainty in 2015, when RES-E penetration levels up to 2060 are unknown. Besides exogenous commissions of power plants that are already in the construction process today, investment requirements to meet demand in 2020 are low. Endogenous investment decisions in 2015 amount to between 21 and 29 GW - representing approximately 7% of total installed capacities. In addition, due to an existing power plant fleet, not all of the new investments are necessarily needed to meet demand. For example, in branch 24, stochastic investment planning in 2015 does not lead to a higher OCGT generation in 2020; although from a capacity point of view, some of the OCGT plants replace coal plants, built under perfect foresight. Thus, the existing power plant fleet permits some investment decisions to be postponed to a period when more information is available. Another reason for relatively low additional costs is that not all capacity investments are exposed to risk. Lignite and nuclear plants are built in all paths either nearly (lignite) or exactly (nuclear) to the same amount. Both technologies have low variable costs and are additionally restricted by natural resource or political constraints.

5.5.2.3 Comparison of findings for the European power system with findings in the illustrative modeling example (Section 5.4.2)

In the illustrative modeling example (Section 5.4.2), we find that CCGT plants, characterized by a medium capital/operating cost ratio compared to hard coal and OCGT plants, have a higher value under uncertainty than given perfect foresight about future RES-E penetration levels. Given higher investments in CCGT plants under uncertainty, optimal investments in storage units are lower than under perfect foresight. In the case of the European power system, the finding that investments in CCGT plants are higher under uncertainty is confirmed. The magnitude of this effect is, however, rather small in comparison to the illustrative scenario. One major reason is that the difference between the highest and the lowest possible realization of RES-E penetration is very large in the illustrative scenario (0% versus 50% RES-E). Indeed, the difference between the assumed minimum and maximum realizations of RES-E shares in the European power system for 2050 is also large (e.g., for Germany: 47% versus 78%). However, investment decisions relevant for 2050 do not have to be made all in 2015. The difference in the

[73] In a quite different context, Manne (1974) finds that the expected value of perfect information about the time at which nuclear breeder technology becomes available is very low (0.04% of average deterministic costs), because decisions can be defererred to periods when uncertainty is at least partly resolved. In his calculation, a sufficient amount of old power plants exists, such that only few investments are required in the period when uncertainty is highest.

possible RES-E penetrations from one investment period to the next, in contrast, are comparatively small, because we assume that a long-term increase in the RES-E share is reliable and that only the magnitude and the pace of the increase are uncertain. Furthermore, as described above, investment requirements in the short term, when uncertainty is highest, are rather small. The result of lower investments in storage units, found in the illustrative example, can be neither confirmed nor disproved by the modeling results for the European power system. In the European power system, a large amount of pump storage units exist already and other storage options are not cost-efficient in the short and medium term. Analogue to the smaller magnitude of the effects, uncertainty has on the optimal capacity choice, also the impact of uncertainty on system costs of the European power system is comparatively small.

5.6 Conclusions

Uncertain future RES-E deployment paths induce uncertainty about the level and the slope of the residual load that needs to be met by dispatchable power plants and storage units. We find that uncertainty about the achievement of RES-E targets significantly affects optimal investment and dispatch decisions. Under plausible assumptions, plants with a medium capital/operating cost ratio have a higher value under uncertainty. Furthermore, given higher investments in plants with a medium capital/operating cost ratio under uncertainty, optimal investments in storage units are lower than under perfect foresight. Finally, the impact of uncertain RES-E deployment paths on system costs is rather small if we assume that a long-term increase in the RES-E share is reliable and that only the magnitude and the pace of the increase are uncertain.

Based on our analysis, the following implications can be drawn for optimal investment planning and policy: Firstly, it is important to take into account possible implementation risks associated with RES-E targets because a different technology choice or a different point of time may be beneficial for the investment. Secondly, many old power plants, whose decommissioning may seem cost-efficient based on deterministic optimization models, are valuable under uncertainty. Thirdly, reliable long-term political targets are crucial in order to limit uncertainty. Fourthly, the effects of RES-E implementation risks need to be considered in the ongoing debate concerning the necessity of capacity payments in the context of an increasing RES-E share. From deterministic model calculations, it is known that an increasing RES-E share requires a large amount of backup capacities, which however only run for very few hours. The capacity payment debate focuses on the question, as to whether investment incentives for these plants are high enough without additional payments (e.g., Cramton and Ockenfels (2012), Joskow

(2008), Cramton and Stoft (2008), Cramton and Stoft (2005)). Our analysis shows that under uncertainty about the pace of future RES-E deployments, power plants are needed that are only dispatched if RES-E deployment plans progress slowly. We analyze the effects of RES-E implementation risks from the perspective of a risk-neutral central planner, who recovers all costs on average. However, in some scenarios, electricity prices are not sufficient to cover investment expenditures. Whether risk-averse investors would invest within this uncertain environment without additional incentives is an interesting area of further research. Moreover, we have focused on only one source of uncertainty associated with the envisaged transformation process towards a low-carbon and mainly renewable-based European electricity system. However, this transformation process relies on three pillars: an increasing share of renewable energy, increasing energy efficiency and a reduction of CO_2 emissions. In this context, future CO_2 prices and the progress of energy efficiency measures are additional sources of uncertainty about the optimal capacity mix of conventional power plants and storage units. A combined analysis of these uncertainties provides an interesting area of further research and would contribute to a better understanding of optimal power plant investment planning within the context of the envisaged transformation process.

Appendix A

Supplemental data for Chapter 2

Table A.1: RES-E shares in 2010 and 2020 (according to NREAPs) and assumed RES-E targets for 2030 in the scenarios 'Equal Share', 'Extrapolation' and 'Flatrate Growth'

	2010 (NREAP)	**2020** (NREAP)		**2030**	
			Equal Share	**Extra-polation**	**Flatrate Growth**
	[%]	[%]	[%]	[%]	[%]
Austria	73	71	71	76	91
Belgium	5	21	55	42	41
Bulgaria	11	21	55	36	41
Czech Republic	7	14	55	26	34
Denmark	34	52	55	75	72
Estonia	2	5	55	13	25
Finland	26	33	55	45	53
France	16	27	55	44	47
Germany	17	39	55	65	59
Greece	13	40	55	71	60
Hungary	7	11	55	20	31
Ireland	20	43	55	70	63
Italy	19	26	55	39	46
Latvia	45	60	60	80	80
Lithuania	8	21	55	39	41
Luxembourg	4	12	55	25	32
Netherlands	9	37	55	70	57
Poland	8	19	55	36	39
Portugal	41	55	55	74	75
Romania	27	43	55	63	63
Slovakia	19	24	55	34	44
Slovenia	32	39	55	51	59
Spain	29	40	55	56	60
Sweden	55	63	63	76	83
United Kingdom	9	31	55	58	51
Switzerland*	55	n/a	57	57	57
Norway*	90	n/a	100	100	100

*2010 share according to Eurostat

Appendix B

Supplemental data for Chapter 3

Proof of Welfare effects in case 1 ('copper plate')

In the first case, it is assumed that the two countries form a copper plate, implying that the common wholesale electricity market price is not affected by cross-border trading of green certificates.

Country A (certificate importing country):

- Effects on producers:
  Producer profits are defined as:

$$\pi_A^C = q \cdot y_A - C(y_A) \tag{B.1}$$

$$\pi_A^R = [q + s_A][z_A - T] - h_A(z_A - T) \tag{B.2}$$

A marginal increase of T changes producer profits as follows:

$$\frac{d\pi_A^C}{dT} = 0 \tag{B.3}$$

$$\frac{d\pi_A^R}{dT} = \frac{ds_A}{dT}[z_A - T] - q - s_A + h'_A(z_A - T) \tag{B.4}$$

The first order condition of profit maximization of RES-E producers ($\frac{d\pi_A^R}{dg_A}$ with $g_A = z_A - T$) implies that the certificate price corresponds to the additional marginal costs of renewable energy compared to the wholesale electricity price (see also Amundsen and Nese (2009)) $s_A = h'_A(z_A - T) - q$. It follows that:

$$\frac{d\pi_A^R}{dT} = \frac{ds_A}{dT} \cdot [z_A - T] \leq 0 \tag{B.5}$$

$$\text{with} \quad \frac{ds_A}{dT} = -\, h''_A(z_A - T) \leq 0 \tag{B.6}$$

- Effects on consumers:
  Due to the assumption of an inelastic electricity demand, changes in consumer rents correspond to the changes in expenses for consumers in meeting their electricity demand (eq. (B.7)), multiplied by (-1). Thus, the effects of cross-border trading of green certificates on consumer rents is defined by Equation (B.8).

$$\text{Consumer expeditures} = CE_A = q \cdot x_A + s_A \cdot \alpha_A \cdot x_A \tag{B.7}$$

$$\frac{dCR_A}{dT} = -\frac{dCE_A}{dT} = -\frac{ds_A}{dT} \cdot \alpha_A x_A = -\frac{ds_A}{dT} \cdot z_A \geq 0 \tag{B.8}$$

- Effects on total welfare in country A:

$$\frac{dW_A}{dT} = \frac{d\pi_A}{dT} + \frac{dCR_A}{dT} = -\frac{ds_A}{dT} \cdot T \geq 0 \tag{B.9}$$

Country B (certificate exporting country):

- Effects on producers:
  Producer profits are defined as:

$$\pi_B^C = q \cdot y_B - C(y_B) \tag{B.10}$$

$$\pi_B^R = [q + s_B][z_B + T] - h_B(z_B + T) \tag{B.11}$$

A marginal increase in T changes producer profits as follows:

$$\frac{d\pi_B^C}{dT} = 0 \tag{B.12}$$
$$\frac{d\pi_B^R}{dT} = \frac{ds_B}{dT}[z_B + T] + q + s_B - h'_B(z_B + T) \tag{B.13}$$

Using $s_B = h'_B(z_B + T) - q$, changes in producer profits correspond to:

$$\frac{d\pi_B^R}{dT} = \frac{ds_B}{dT} \cdot [z_B + T] \geq 0 \tag{B.14}$$
$$\text{with} \quad \frac{ds_B}{dT} = h''_B(z_B + T) \geq 0 \tag{B.15}$$

- Effects on consumers:

$$CE_B = q \cdot x_B + s_B \cdot \alpha_B \cdot x_B \tag{B.16}$$
$$\frac{dCR_B}{dT} = -\frac{dCE_B}{dT} = -\frac{ds_B}{dT} \cdot \alpha_B x_B = -\frac{ds_B}{dT} \cdot z_B \leq 0 \tag{B.17}$$

- Effects on total welfare in country B:

$$\frac{dW_B}{dT} = \frac{d\pi_B}{dT} + \frac{dCR_B}{dT} = \frac{ds_B}{dT} \cdot T \geq 0 \tag{B.18}$$

Proof of Welfare effects in case 2 ('limited interconnection')

In the second case, it is assumed that the two countries are not perfectly physically interconnected. Either, an interconnector exists which is congested, or the two regional electricity systems are not physically interconnected at all. In both cases, the trading of green certificates also influences the regional wholesale electricity markets. Note that setting the interconnector capacity M=0 corresponds to the case of no interconnection.

Country A (certificate importing country):
In the following, it is first assumed that country A is not only a certificate, but also an electricity importing country.

- Effects on producers:
  Producer profits are defined as:

$$\pi_A^C = q_A \cdot [x_A - z_A + T - M] - C_A(x_A - z_A + T - M) \tag{B.19}$$
$$\pi_A^R = [q_A + s_A] \cdot [z_A - T] - h_A(z_A - T) \tag{B.20}$$

  A marginal increase in T changes producer profits as follows:

$$\frac{d\pi_A^C}{dT} = \frac{dq_A}{dT} \cdot [x_A - z_A + T - M] + q_A - C_A^{'}(x_A - z_A + T - M) \tag{B.21}$$
$$\frac{d\pi_A^R}{dT} = \frac{dq_A}{dT} \cdot [z_A - T] + \frac{ds_A}{dT} \cdot [z_A - T] - q_A - s_A + h_A^{'}(z_A - T) \tag{B.22}$$

  Again, the certificate price corresponds to the additional marginal costs of renewable energy compared to the wholesale electricity price ($s_A = h_A'(z_A - T) - q_A$) and the wholesale electricity price corresponds to the marginal costs of meeting residual demand (=total electricity demand - RES-E production - electricity imports) with electricity from conventional energy sources ($C_A^{'}(x_A - z_A + T - M) = q_A$). It follows that:

$$\frac{d\pi_A^C}{dT} = \frac{dq_A}{dT} \cdot [x_A - z_A + T - M] \geq 0 \tag{B.23}$$

$$\frac{d\pi_A^R}{dT} = [\frac{ds_A}{dT} + \frac{dq_A}{dT}] \cdot [z_A - T] \leq 0 \tag{B.24}$$

$$\frac{d\pi_A}{dT} = \underbrace{\frac{ds_A}{dT} \cdot [z_A - T]}_{\leq 0} + \underbrace{\frac{dq_A}{dT} \cdot [x_A - M]}_{\geq 0} \tag{B.25}$$

$$\text{with} \quad \frac{ds_A}{dT} = -h_A''(z_A - T) - C_A''(x_A - z_A + T - M) \leq 0 \tag{B.26}$$

$$\text{and} \quad \frac{dq_A}{dT} = C_A''(x_A - z_A + T - M) \geq 0 \tag{B.27}$$

- Effects on consumers:

$$CE_A = q_A \cdot x_A + s_A \cdot \alpha_A \cdot x_A \tag{B.28}$$

$$\frac{dCR_A}{dT} = -\frac{dCE_A}{dT} = \underbrace{-\frac{ds_A}{dT} \cdot z_A}_{\geq 0} \underbrace{-\frac{dq_A}{dT} \cdot x_A}_{\leq 0} \tag{B.29}$$

- Effects on total welfare in country A:

$$\frac{dW_A}{dT} = \frac{d\pi_A}{dT} + \frac{dCR_A}{dT} = \underbrace{-\frac{ds_A}{dT} \cdot T}_{\geq 0} \underbrace{-\frac{dq_A}{dT} \cdot M}_{\leq 0} \tag{B.30}$$

If country A is a certificate *importing* as well as an electricity *exporting* country, the profits gained from conventional generation and total producer profits in country A change as follows:

$$\pi_A^C = q_A \cdot [x_A - z_A + T + M] - C_A(x_A - z_A + T + M) \tag{B.31}$$

$$\frac{d\pi_A^C}{dT} = \frac{dq_A}{dT} \cdot [x_A - z_A + T + M] \geq 0 \tag{B.32}$$

$$\frac{d\pi_A}{dT} = \underbrace{\frac{ds_A}{dT} \cdot [z_A - T]}_{\leq 0} + \underbrace{\frac{dq_A}{dT} \cdot [x_A + M]}_{\geq 0} \tag{B.33}$$

Thus, if country A is a certificate importing as well as an electricity exporting country, welfare in country A changes as follows:

$$\frac{dW_A}{dT} = -\frac{ds_A}{dT} \cdot T + \frac{dq_A}{dT} \cdot M \geq 0 \tag{B.34}$$

Country B (certificate exporting country):
In the following, it is first assumed that country B is not only a certificate but also an electricity exporting country.

- Effects on producers:
  Producer profits are defined as:

$$\pi_B^C = q_B \cdot [x_B - z_B - T + M] - C_B(x_B - z_B - T + M) \tag{B.35}$$

$$\pi_B^R = [q_B + s_B] \cdot [z_B + T] - h_B(z_B + T) \tag{B.36}$$

A marginal increase in T changes producer profits as follows:

$$\frac{d\pi_B^C}{dT} = \frac{dq_B}{dT} \cdot [x_B - z_B - T + M] - q_B + C_B^{'}(x_B - z_B - T + M) \tag{B.37}$$

$$\frac{d\pi_B^R}{dT} = \frac{dq_B}{dT}(z_B + T) + \frac{ds_B}{dT}(z_B + T) + q_B + s_B - h_B^{'}(z_B + T) \tag{B.38}$$

Using that $s_B = h_B'(z_B - T) - q_B$ and $C_B^{'}(x_B - z_B - T + M) = q_B$, we find that:

$$\frac{d\pi_B^C}{dT} = \frac{dq_B}{dT} \cdot [x_B - z_B - T + M] \leq 0 \tag{B.39}$$

$$\frac{d\pi_B^R}{dT} = [\frac{ds_B}{dT} + \frac{dq_B}{dT}] \cdot [z_B + T] \geq 0 \tag{B.40}$$

$$\frac{d\pi_B}{dT} = \underbrace{\frac{ds_B}{dT} \cdot [z_B + T]}_{\geq 0} + \underbrace{\frac{dq_B}{dT} \cdot [x_B + M]}_{\leq 0} \tag{B.41}$$

$$\text{with} \quad \frac{ds_B}{dT} = h_B^{''}(z_B + T) + C_B^{''}(x_B - z_B - T + M) \geq 0 \tag{B.42}$$

$$\text{and} \quad \frac{dq_B}{dT} = -C_B^{''}(x_B - z_B - T + M) \leq 0 \tag{B.43}$$

- Effects on consumers:

$$CE_B = q_B \cdot x_A + s_B \cdot \alpha_B \cdot x_B \tag{B.44}$$

$$\frac{dCR_B}{dT} = -\frac{dCE_B}{dT} = \underbrace{-\frac{ds_B}{dT} \cdot z_B}_{\leq 0} \underbrace{-\frac{dq_B}{dT} \cdot x_B}_{\geq 0} \tag{B.45}$$

- Effects on total welfare in country B:

$$\frac{dW_B}{dT} = \frac{d\pi_B}{dT} + \frac{dCR_B}{dT} = \underbrace{\frac{ds_B}{dT} \cdot T}_{\geq 0} + \underbrace{\frac{dq_B}{dT} \cdot M}_{\leq 0} \tag{B.46}$$

If country B is a certificate *exporting* as well as an electricity *importing* country, the profits which can gained from conventional generation and total producer profits in country B change as follows:

$$\pi_B^C = q_B \cdot [x_B - z_B - T - M] - C_B(x_B - z_B - T - M) \tag{B.47}$$

$$\frac{d\pi_B^C}{dT} = \frac{dq_B}{dT} \cdot [x_B - z_B - T - M] \leq 0 \tag{B.48}$$

$$\frac{d\pi_B}{dT} = \underbrace{\frac{ds_B}{dT} \cdot [z_B + T]}_{\geq 0} + \underbrace{\frac{dq_B}{dT} \cdot [x_B - M]}_{\leq 0} \tag{B.49}$$

$$\tag{B.50}$$

Thus, if country B is a certificate exporting as well as an electricity importing country, welfare in country B changes as follows:

$$\frac{dW_B}{dT} = \frac{ds_B}{dT} \cdot T - \frac{dq_B}{dT} \cdot M \geq 0 \tag{B.51}$$

Congestion rents:

If the interconnector is congested, congestion rents, corresponding to the price difference between the two regions multiplied by the amount of electricity traded, are also affected by certificate trading.

- If country A is an electricity importing country and country B an electricity exporting country, congestion rents increase in T. Country A (B) imports (exports) electricity (even in the absence of certificate trading) if the wholesale electricity price in A is higher than in B. With an increasing T, the wholesale electricity price in A increases further, while the wholesale electricity price in B decreases. Thus, the price difference, and thereby the congestion rent, increases. If electricity trades are zero in the absence of certificate trading, congestion rents are also zero. In this case, the price difference also increases once certificate trading is introduced and congestion rents increase from zero to a positive value.

$$\frac{dE_{A,B}}{dT} = [\frac{dq_A}{dT} - \frac{dq_B}{dT}] \cdot M \geq 0 \tag{B.52}$$

- If country A is an electricity exporting country and country B an electricity importing country, congestion rents decrease in T. Country A exports electricity if the wholesale electricity price in A is lower than in B. When certificate trading is possible and wholesale electricity prices in A (B) increase (decrease), the price difference decreases.

$$\frac{dE_{A,B}}{dT} = [\frac{dq_B}{dT} - \frac{dq_A}{dT}] \cdot M \leq 0 \tag{B.53}$$

Overall welfare:

- If country A is an electricity importing country and country B an electricity exporting country, the increasing congestion rent compensates exactly for the sum of the negative components in the change in welfare in countries A and B, such that system-wide welfare increases and only depends on the changes in certificate prices.

$$\frac{dW}{dT} = \frac{dW_A}{dT} + \frac{dW_B}{dT} + \frac{dE_{A,B}}{dT} = \underbrace{-\frac{ds_A}{dT} \cdot T}_{\geq 0} \underbrace{-\frac{dq_A}{dT} \cdot M}_{\leq 0} + \underbrace{\frac{ds_B}{dT} \cdot T}_{\geq 0} \tag{B.54}$$

$$\underbrace{+\frac{dq_B}{dT} \cdot M}_{\leq 0} + \underbrace{[\frac{dq_A}{dT} - \frac{dq_B}{dT}] \cdot M}_{\geq 0} = [-\frac{ds_A}{dT} + \frac{ds_B}{dT}] \cdot T \geq 0$$

- If country A is an electricity exporting country and country B an electricity importing country, the decreasing congestion rent compensates exactly for the sum of the wholesale price effects in the changes in welfare of country A and B (which in this case are positive).

$$\frac{dW}{dT} = \frac{dW_A}{dT} + \frac{dW_B}{dT} + \frac{dE_{A,B}}{dT} = \underbrace{-\frac{ds_A}{dT} \cdot T}_{\geq 0} \underbrace{+\frac{dq_A}{dT} \cdot M}_{\geq 0} + \underbrace{\frac{ds_B}{dT} \cdot T}_{\geq 0} \tag{B.55}$$

$$\underbrace{-\frac{dq_B}{dT} \cdot M}_{\geq 0} + \underbrace{[\frac{dq_B}{dT} - \frac{dq_A}{dT}] \cdot M}_{\leq 0} = [-\frac{ds_A}{dT} + \frac{ds_B}{dT}] \cdot T \geq 0$$

Appendix C

Supplemental data for Chapter 4

TABLE C.1: Generation and capacity differences between cooperative and national RES-E support in the year 2020 [TWh and GW] in the largest certificate importing countries (in the TYNDP and in the 'w/o TYNDP' scenario)

		Generation differences		Capacity differences	
		TYNDP	w/o TYNDP	TYNDP	w/o TYNDP
FI	non RES-E	-4.3	-0.3	0.9	0.1
	biomass	-3.5	0.1	-0.5	0.0
	onshore wind	-4.9	-4.9	-2.6	-2.6
	offshore wind	0.0	0.0	0.0	0.0
	pv/csp	0.0	0.0	0.0	0.0
DE	non RES-E	40.1	49.3	-0.1	-0.6
	biomass	-30.5	-30.5	-4.1	-4.1
	onshore wind	-26.0	-26.0	-15.1	-15.1
	offshore wind	-32.2	-32.2	-10.0	-10.0
	pv/csp	0.0	0.0	0.0	0.0
GR	non RES-E	5.1	3.0	0.5	0.3
	biomass	-0.4	0.0	-0.1	0.0
	onshore wind	-0.7	-0.7	-0.4	-0.4
	offshore wind	0.0	0.0	0.0	0.0
	pv/csp	-4.8	-1.2	-2.8	-0.3
IT	non RES-E	12.8	8.3	0.0	0.9
	biomass	0.0	0.0	0.0	0.0
	onshore wind	-0.2	-0.2	-0.1	-0.1
	offshore wind	0.0	0.0	0.0	0.0
	pv/csp	-8.8	-8.8	-6.1	-6.1
SE	non RES-E	2.2	1.8	0.8	0.7
	biomass	-7.6	-7.1	-0.5	-0.5
	onshore wind	-0.7	-0.7	-0.3	-0.3
	offshore wind	0.0	0.0	0.0	0.0
	pv/csp	0.0	0.0	0.0	0.0
UK	non RES-E	-1.4	3.5	0.3	0.0
	biomass	-0.6	-0.5	0.0	0.0
	onshore wind	0.0	0.0	0.0	0.0
	offshore wind	-3.4	-3.4	-0.9	-0.9
	pv/csp	0.0	0.0	0.0	0.0

Positive (negative) values indicate that generation levels or capacities are higher (lower) once cooperation is introduced.

TABLE C.2: Generation and capacity differences between cooperative and national RES-E support in the year 2020 [TWh and GW] in the largest certificate exporting countries (in the TYNDP and in the 'w/o TYNDP' scenario)

		Generation differences		Capacity differences	
		TYNDP	w/o TYNDP	TYNDP	w/o TYNDP
CZ	non RES-E	-0.6	0.4	0.2	0.2
	biomass	1.0	1.4	0.0	0.0
	onshore wind	8.2	7.8	3.8	3.6
	offshore wind	0.0	0.0	0.0	0.0
	pv/csp	0.0	0.0	0.0	0.0
DK	non RES-E	0.0	0.0	-0.3	0.0
	biomass	2.0	1.8	0.0	0.0
	onshore wind	0.0	0.0	0.0	0.0
	offshore wind	19.2	2.8	4.5	0.6
	pv/csp	0.0	0.0	0.0	0.0
IE	non RES-E	-2.2	-5.5	-0.2	-0.5
	biomass	0.0	0.0	0.0	0.0
	onshore wind	6.4	6.1	2.5	2.7
	offshore wind	0.0	0.0	0.0	0.0
	pv/csp	0.0	0.0	0.0	0.0
NO	non RES-E	-0.1	-1.1	0.0	-0.1
	biomass	0.0	0.0	0.0	0.0
	onshore wind	5.9	5.9	2.4	2.4
	offshore wind	45.0	14.9	10.0	3.3
	pv/csp	0.0	0.0	0.0	0.0
PL	non RES-E	-21.6	-16.8	0.3	0.3
	biomass	2.0	2.0	0.3	0.3
	onshore wind	17.0	17.0	6.8	6.8
	offshore wind	0.0	0.0	0.0	0.0
	pv/csp	0.0	0.0	0.0	0.0
ES	non RES-E	-14.3	-29.4	-1.4	-1.7
	biomass	2.2	2.1	0.3	0.3
	onshore wind	-0.7	-1.2	-0.4	-0.6
	offshore wind	0.0	0.0	0.0	0.0
	pv/csp	21.8	34.4	9.3	17.6

Positive (negative) values indicate that generation levels or capacities are higher (lower) once cooperation is introduced.

Appendix D

Supplemental data for Chapter 5

TABLE D.1: Assumed potential restrictions [based on EWI and energynautics (2011)]

Technology	Germany	Benelux	France	CH + AT	CZ + PL	Denmark
Wind Onshore [km^2]	2174	497	3215	252	2429	300
Wind Offshore [km^2]	7200	11054	4050	-	1410	8520
Biomass [TWh_{th}]	177	44	356	42	141	34

Table D.2: RES-E capacities in 2030 [GW]

Region	Technology	n1	n2	n3	n4	n5	n6	n7	n8	n9	n10	n11	n12
Germany	wind onshore	48.5	46.4	46.4	44.3	44.3	42.2	42.2	40.0	38.5	36.4	36.4	34.3
	wind offshore	31.7	26.8	26.8	21.9	29.7	24.8	24.8	19.9	22.7	17.8	17.8	12.9
	photovoltaics	94.4	85.8	85.8	77.2	86.2	77.6	77.6	69.0	69.4	60.8	60.8	52.2
	biomass	11.7	11.2	11.2	10.6	11.0	10.5	10.5	9.9	10.2	9.7	9.7	9.1
	geothermal	0.8	0.7	0.7	0.6	0.6	0.5	0.5	0.4	0.3	0.2	0.2	0.2
Benelux	wind onshore	15.0	15.0	15.0	15.0	15.0	15.0	15.0	14.0	13.5	11.7	11.7	9.8
	wind offshore	17.2	14.7	14.7	12.1	15.6	13.0	13.0	10.5	12.2	9.7	9.7	7.1
	photovoltaics	5.7	5.3	5.3	4.9	3.9	3.5	3.5	3.0	2.7	2.3	2.3	1.9
	biomass	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
	geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
France	wind onshore	38.5	35.1	35.1	31.7	32.5	29.1	29.1	25.7	23.5	20.1	20.1	16.7
	wind offshore	20.0	17.0	17.0	14.0	18.0	15.0	15.0	12.0	13.0	10.0	10.0	7.0
	photovoltaics	14.4	13.3	13.3	12.2	9.2	8.1	8.1	7.0	6.4	5.3	5.3	4.2
	biomass	6.0	5.5	5.5	5.0	5.0	4.5	4.5	4.0	4.0	3.5	3.5	3.0
	geothermal	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0
CH + AT	wind onshore	5.6	5.2	5.2	4.8	4.2	3.8	3.8	3.4	3.6	3.2	3.2	2.8
	wind offshore	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	photovoltaics	1.2	1.2	1.2	1.1	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.4
	biomass	3.3	3.0	3.0	2.6	2.6	2.2	2.2	1.9	2.3	2.0	2.0	1.6
	geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CZ+ PL	wind onshore	14.0	12.8	12.8	11.5	11.3	10.1	10.1	8.8	8.0	6.8	6.8	5.5
	wind offshore	2.0	1.8	1.8	1.5	1.5	1.3	1.3	1.0	1.0	0.8	0.8	0.5
	photovoltaics	2.0	2.0	2.0	2.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
	biomass	6.3	5.6	5.6	4.9	5.8	5.1	5.1	4.4	3.1	2.4	2.4	1.7
	geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Denmark	wind onshore	2.7	2.8	2.8	2.8	2.3	2.4	2.4	2.5	2.3	2.4	2.4	2.5
	wind offshore	2.3	2.3	2.3	2.2	1.7	1.6	1.6	1.5	1.3	1.3	1.3	1.2
	photovoltaics	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	biomass	3.9	3.8	3.8	3.7	3.2	3.1	3.1	3.0	1.9	1.8	1.8	1.7
	geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

TABLE D.3: RES-E capacities in 2050 [GW]

Region	Technology	n1	n2	n3	n4	n5	n6	n7	n8	n9	n10	n11	n12	n13	n14	n15	n16	n17	n18	n19	n20	n21	n22	n23	n24
Germany	wind onshore	50.0	50.0	50.0	50.0	50.0	50.0	50.0	48.5	50.0	48.6	50.0	46.4	50.0	46.4	48.6	44.3	47.1	42.8	45.0	40.7	45.0	40.7	42.8	38.5
	wind offshore	50.0	41.6	46.5	36.6	46.5	36.6	41.6	31.7	49.4	39.6	44.5	34.6	44.5	34.6	39.6	29.7	42.4	32.6	37.5	27.6	37.5	27.6	32.6	22.7
	photovoltaics	128.9	111.6	120.3	103.0	120.3	103.0	111.6	94.4	120.6	103.4	112.0	94.8	112.0	94.8	103.4	86.2	103.9	86.6	95.3	78.0	95.3	78.0	86.6	69.4
	biomass	13.9	12.8	13.4	12.3	13.4	12.3	12.8	11.7	13.3	12.1	12.7	11.6	12.7	11.6	12.1	11.0	12.4	11.3	11.9	10.8	11.9	10.8	11.3	10.2
	geothermal	1.1	0.9	1.0	0.9	1.0	0.9	0.9	0.8	0.9	0.7	0.8	0.7	0.8	0.7	0.7	0.6	0.6	0.4	0.5	0.4	0.5	0.4	0.4	0.3
Benelux	wind onshore	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	13.5
	wind offshore	27.4	22.3	24.9	19.8	24.9	19.8	22.3	17.2	25.8	20.7	23.2	18.1	23.2	18.1	20.7	15.6	22.4	17.3	19.9	14.8	19.9	14.8	17.3	12.2
	photovoltaics	7.4	6.6	7.0	6.1	7.0	6.1	6.6	5.7	5.6	4.7	5.2	4.3	5.2	4.3	4.7	3.9	4.4	3.6	4.0	3.1	4.0	3.1	3.6	2.7
	biomass	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
	geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
France	wind onshore	51.9	45.2	48.6	41.8	48.6	41.8	45.2	38.5	45.9	39.2	42.6	35.8	42.6	35.8	39.2	32.5	36.9	30.2	33.6	26.8	33.6	26.8	30.2	23.5
	wind offshore	30.0	26.0	29.0	23.0	29.0	23.0	26.0	20.0	30.0	24.0	27.0	21.0	27.0	21.0	24.0	18.0	25.0	19.0	22.0	16.0	22.0	16.0	19.0	13.0
	photovoltaics	18.7	16.5	17.6	15.4	17.6	15.4	16.5	14.4	13.6	11.4	12.5	10.3	12.5	10.3	11.4	9.2	10.7	8.5	9.6	7.4	9.6	7.4	8.5	6.4
	biomass	7.9	6.9	7.4	6.4	7.4	6.4	6.9	6.0	6.9	5.9	6.4	5.5	6.4	5.5	5.9	5.0	5.9	4.9	5.4	4.4	5.4	4.4	4.9	4.0
	geothermal	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
CH + AT	wind onshore	6.0	6.0	6.0	6.0	6.0	6.0	6.0	5.6	5.7	4.9	5.3	4.6	5.3	4.6	4.9	4.2	5.1	4.4	4.7	4.0	4.7	4.0	4.4	3.6
	wind offshore	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	photovoltaics	1.5	1.3	1.4	1.3	1.4	1.3	1.3	1.2	0.9	0.7	0.8	0.7	0.8	0.7	0.7	0.6	0.8	0.6	0.7	0.6	0.7	0.6	0.6	0.5
	biomass	4.6	3.9	4.2	3.6	4.2	3.6	3.9	3.3	3.8	3.2	3.5	2.9	3.5	2.9	3.2	2.6	3.6	2.9	3.2	2.6	3.2	2.6	2.9	2.3
	geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CZ+ PL	wind onshore	19.0	16.5	17.8	15.3	17.8	15.3	16.5	14.0	16.3	13.8	15.1	12.6	15.1	12.6	13.8	11.3	13.0	10.5	11.8	9.3	11.8	9.3	10.5	8.0
	wind offshore	3.0	2.5	2.8	2.3	2.8	2.3	2.5	2.0	2.5	2.0	2.3	1.8	2.3	1.8	2.0	1.5	2.0	1.5	1.8	1.3	1.8	1.3	1.5	1.0
	photovoltaics	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.0	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.7
	biomass	9.2	7.8	8.5	7.0	8.5	7.0	7.8	6.3	8.6	7.2	7.9	6.5	7.9	6.5	7.2	5.8	6.0	4.6	5.3	3.8	5.3	3.8	4.6	3.1
	geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Denmark	wind onshore	2.4	2.5	2.5	2.6	2.5	2.6	2.5	2.7	2.0	2.2	2.1	2.2	2.1	2.2	2.2	2.3	2.0	2.2	2.1	2.2	2.1	2.2	2.2	2.3
	wind offshore	2.6	2.5	2.5	2.4	2.5	2.4	2.4	2.3	1.9	1.8	1.8	1.7	1.8	1.7	1.8	1.6	1.6	1.5	1.5	1.4	1.5	1.4	1.4	1.3
	photovoltaics	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	biomass	4.2	4.1	4.1	3.9	4.1	3.9	3.9	3.8	3.4	3.3	3.3	3.2	3.3	3.2	3.2	3.1	2.2	2.1	2.1	1.9	2.1	1.9	1.9	1.8
	geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

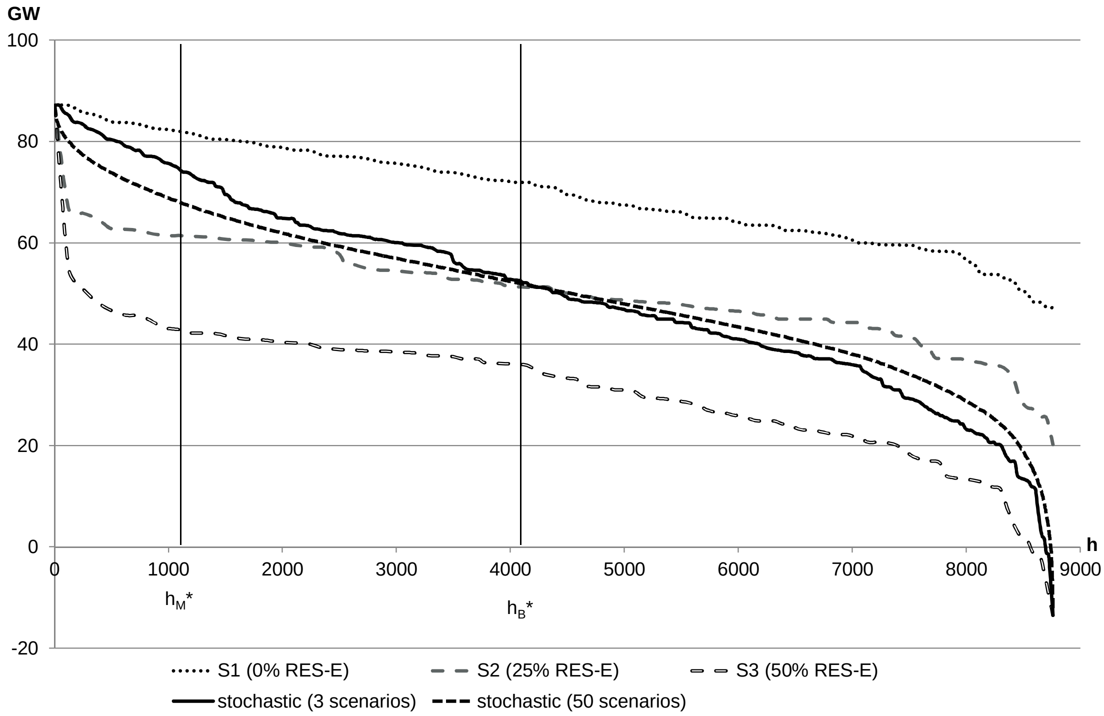

Figure D.1: The influence of representing uncertainty by a different number of scenarios

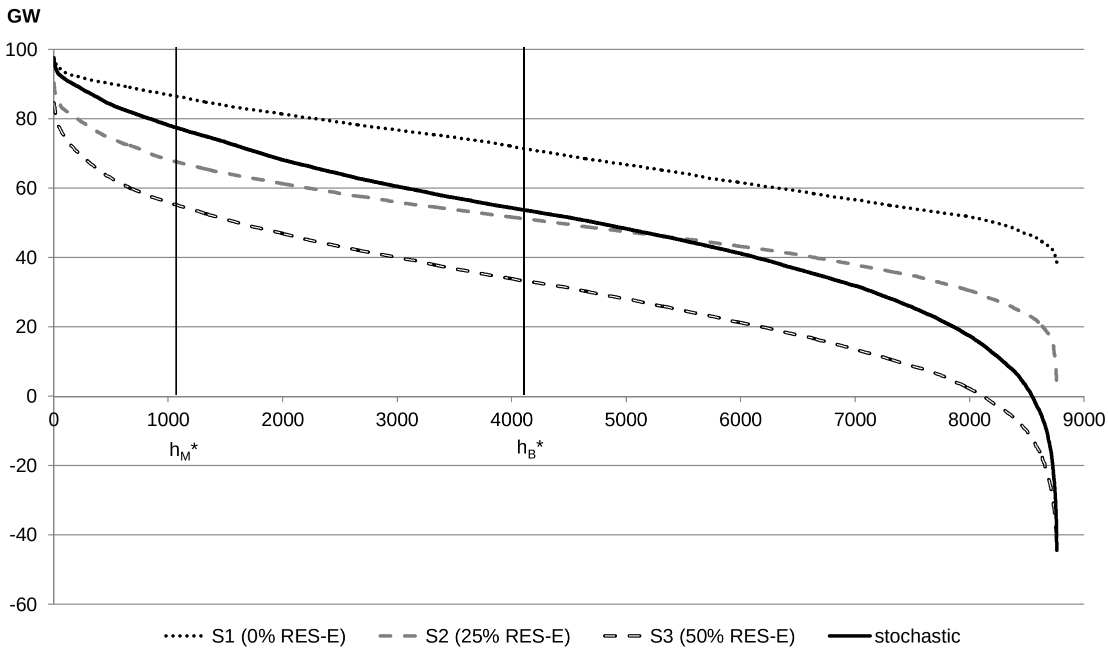

Figure D.2: Residual load duration curves - deterministic and stochastic (using 8760h of demand and RES-E infeed data instead of a typical day approach as in Figure 5.2)

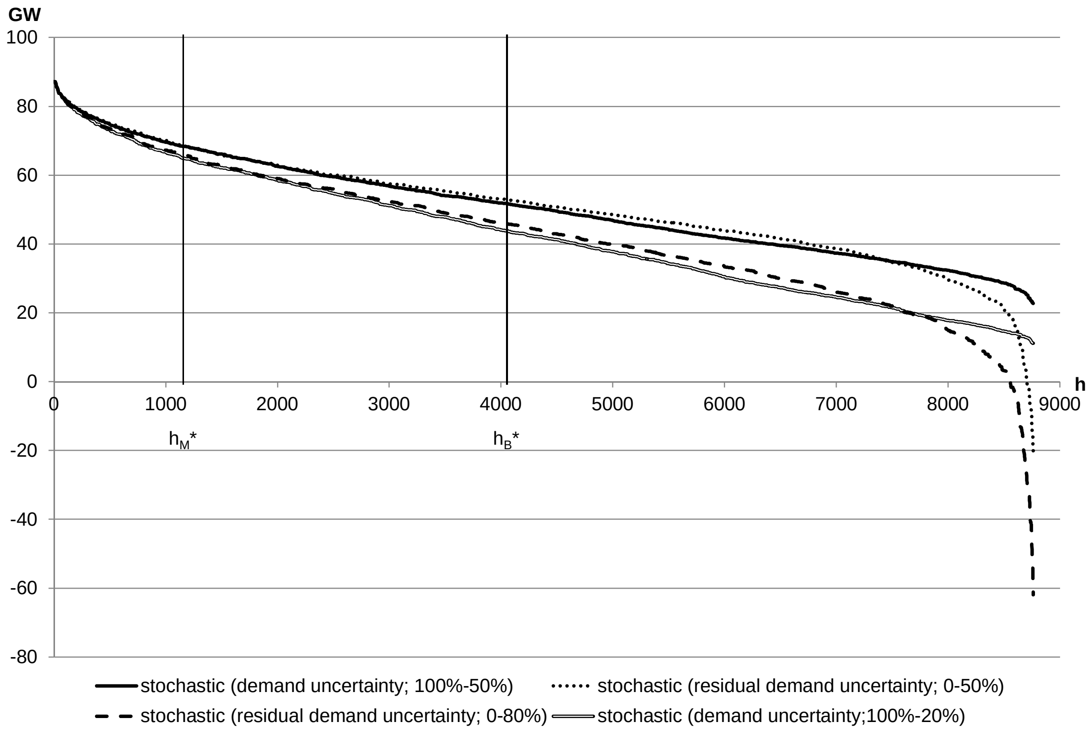

FIGURE D.3: The influence of demand level uncertainty on the steepness of the stochastic load duration curve II

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