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Prices vs. Quantities: Incentives for Renewable Power Generation - Numerical Analysis for the European Power Market

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Prices vs. Quantities: Incentives for renewable power generation[☆] - numerical analysis for the European power market -

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Abstract

In recent years, many countries have implemented policies to incentivize renewable power generation. This paper outlines the effects of weather uncertainty on investment and operation decisions of electricity producers under a feed-in tariff and renewable quota obligation. Furthermore, this paper tries to quantify the sectoral welfare and investments risks under the different policies. For this purpose, a spatial stochastic equilibrium model is introduced for the European electricity market. The numerical analysis suggests that including the electricity market price in renewable policies (wholesale price + x) reduces the loss of sectoral welfare due to a renewable policy by 11-20 %. Moreover, investors face an only slightly higher risk than under fixed price compensations. However, electricity producers face a substantially larger investment risk when introducing a renewable quota obligation without the option of banking and borrowing of green certificates. Given the scenario results, an integration of the hourly market price in renewable support mechanisms is mandatory to keep the financial burden to electricity consumers at a minimum. Additionally, following the discussion of a European renewable quota after 2020, the analysis indicates the importance of an appropriate banking and borrowing mechanism in light of stochastic wind and solar generation.

Keywords: RES-E policy, price and quantity controls, mixed complementarity problem

JEL classification: C61, L50, Q40

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1. Introduction

Partly due to concerns about global warming, many countries are trying to reduce CO₂ emissions from power generation by increasing the proportion of electricity generation from renewable energy sources. As power generation from renewable energy sources is usually more costly than conventional power generation, at least when ignoring external effects, many European countries have implemented various support schemes to promote renewable energies in recent years.

One established policy instrument is a feed-in tariff (FIT) for renewable power generation. Renewable producers are offered a long-term contract with guaranteed tariffs for each unit of electricity fed into the grid. Feed-in tariffs have led to a sharp increase in the share of renewable power generation, for example, in Spain +12 % and Germany +11 % from 2001 to 2010 (Eurostat, 2012). An alternative policy instrument is a renewable quota, demanding electricity consumers (or utility companies) to procure a certain share of their electricity from renewable sources. This gives rise to a market for ‘green certificates’ issued by renewable-based electricity producers. In either system, feed-in tariffs and quota obligation, renewable-based electricity producers may either be remunerated by the offered feed-in tariff (or certificate price) or by the hourly market price and an additional bonus (or green certificate price). The latter will be referred to as ‘market integration’ throughout this paper, because producers of renewable-based electricity are exposed to the hourly market price under such policies.

In general, there is no difference between a feed-in tariff policy (price-based control) and a quota obligation (quantity-based control) because for each instrument there is a corresponding way to implement the other in order to achieve the same results. For instance, subsidizing less mature technologies by technology-differentiated feed-in tariffs, i.e. based on the generation costs of each technology, could also be achieved by technology-specific generation quotas, resulting in several certificate markets with different certificate prices. However, price-based or quantity-based control mechanisms are not equivalent in markets with uncertainties (Weitzman, 1974).

The envisaged transition to a low-carbon and mostly renewable-based electricity supply implies a substantial increase in generation from wind and solar technologies due to the limited economic potential of dispatchable renewables in Europe. Unlike most conventional power plants, the feed-in from wind and solar technologies depends on local weather conditions and is therefore stochastic. Thus, weather uncertainty is likely to become increasingly important in power markets. Hence, I explore how the various support schemes are affected by increasing weather uncertainty. Moreover, I try to quantify the policy-related investment risks for electricity producers under these renewable policies.

This paper outlines the effects of a feed-in tariff and quota obligation, with and without market integration, on the investment and operation decisions of electricity producers under weather uncertainty. To quantify the effects of these renewable policies on the overall electricity market and the policy-related risk for electricity producers, a spatial stochastic equilibrium model for the European electricity market is introduced. The model is formulated as three separate optimization problems. First, a representative European electricity producer, acting as a price taker, maximizes its profit by selling electricity to the domestic markets. Second, an international electricity trader acts as an arbitrageur, representing the linkage between model regions (grid investments are exogenous). Third, a transmission system operator regulates the curtailment of wind and solar generation. Uncertainty concerning the annual generation from wind and solar technologies is modeled based on empirical data. In general, the scenario analysis attempts to quantify the performance of several existing renewable policies rather than finding the optimal renewable support mechanism.

The main findings of this analysis include that integrating the market price in renewable support mechanisms becomes increasingly important to keep consumer costs at a minimum. Furthermore, it is concluded that electricity producers face larger investment risks under quantity-based support schemes if banking and borrowing of certificates is not allowed. Given limited cost-efficient electricity storage options, the value of electricity depends on a specific point in time. When integrating the hourly price signal in renewable support mechanisms, profit maximizing investors will consider the hourly value of electricity and the production profiles of technologies with intermittent power generation, rather than simply minimize levelized costs of electricity. The resulting electricity supply will in turn be more efficient because of the more technologically and geographically diversified renewable mix. As the transition of the European electricity supply leads to a large deployment of wind and solar technologies with intermittent generation and negligible variable costs, wholesale prices will arguably become more volatile. As a result, integrating the hourly price signal in renewable support mechanisms becomes increasingly important. The simulation results suggest that welfare losses in the power sector due to a renewable target can be reduced by about 11 to 20 % when introducing a market integrated renewable support scheme. Given uncertainty about the annual wind and solar generation, green certificate prices vary substantially between weather years under quantity-based support schemes in the simulation. Thus, renewable electricity producers face a 15 to 20 times larger deviation (standard deviation) from the expected profits when banking and borrowing of certificates does not fully compensate these fluctuations. Therefore, an appropriate banking and borrowing mechanism is necessary when introducing quantity-based support schemes in order to reduce risk for renewable producers.

The main contribution of this paper to the existing literature is an application of the classical analysis by Weitzman (1974) to the case of subsidizing renewable power generation. The developed model approach allows a comparison of quantitative differences between price-based and quantity-based support mechanisms by accounting for stochastic annual full load hours of wind and solar technologies. Moreover, the analysis provides a quantitative comparison of price-based and quantity-based renewable support policies with and without market integration in a common framework.

Relative benefits and risks of price-based or quantity-based control mechanisms following Weitzman (1974) have been discussed in many contexts. Most prominently, the question received early and large interest in environmental economics in the context of controlling greenhouse gas emissions. Montgomery (1972) shows that an equilibrium exists in certificate markets, achieving an externally given standard at least cost. Other research fields in which this question is of interest include food and agriculture (e.g., Jensen and Vestergaard (2003)), international economics (e.g., Bhagwati (1965)) and airport congestion management (e.g., Brueckner (2009)).

Several articles discuss the performance of renewable policies by comparing the implementation in different countries (e.g. Butler and Neuhoff (2008), Verhaegen et al. (2009) or Bergek and Jacobsson (2010)). For example, Butler and Neuhoff (2008) compare support schemes for renewable energies in the United Kingdom and Germany. They observe lower consumer costs and a larger renewable deployment under the feed-in tariff system in Germany than the quota obligation in the United Kingdom due to lower project risks and a stronger competition among renewable sites. Menanteau et al. (2003) examine the efficiency of price-based and quantity-based approaches from a theoretical perspective and discuss practical experiences by analyzing the implementation in several European countries. However, these studies usually compare a feed-in tariff system (without market integration) and quota obligations (with market integration). The analysis in this paper helps to understand the empirical differences among policy implementations, by providing a welfare comparison of price-based and quantity-based renewable support policies with and without market integration.

Another active field of research concerns the associated risk for investors under different renewable policies (e.g., Berry (2002), Lemming (2003) or Dinica (2006)). Quantity-based support mechanisms are usually associated with a higher risk due to potentially fluctuating green certificate prices. However, Lemming (2003) argues that negatively correlated fluctuations in production of intermittent renewables and green certificate prices may actually reduce the financial risk. As most renewable technologies are dominated by fixed costs, Kildegaard (2008) discusses the risk of over-investments and the resulting periods of low

certificate prices. This paper adds to these discussions by providing a quantitative comparison of investment risks accompanying price-based or quantity-based support mechanisms under weather uncertainty.

The remainder of this paper is structured as follows: In Section 2, the role of renewable promotion schemes in power plant investments and their profitability are discussed. Section 3 describes the numerical analysis, including a detailed description of the model and input parameters. Conclusions are drawn in Section 4, along with an outlook of possible further research.

2. Promotion of renewable power generation

Total electricity generation from renewable energy sources has increased worldwide from approximately 2,317 TWh in 1990 to 4,207 TWh in 2010 (IEA, 2012). In the European electricity sector, the renewable share of total gross electricity generation has increased from 12 % in 1990 to 21 % in 2010 (IEA, 2012). The large deployment of renewable energies in Europe within the last decades is driven by national support programs specifically for electricity generation from renewable energy sources. It is debatable whether a separate renewable target is necessary in addition to the existing European Union Emissions Trading System (EU ETS). A discussion with a focus on efficiency losses for a separate renewable target, can be found in Böhringer et al. (2008).¹ Despite conflicting opinions, renewable support mechanisms are currently in place in many European countries.²

Many different policies exist to incentivize power generation from renewable energies. One established policy instrument is a feed-in tariff for renewable power generation. An alternative policy instrument is a renewable quota, demanding electricity consumers (or utility companies) to procure a certain share of their electricity from renewable sources. This gives rise to a market for ‘green certificates’ issued by renewable-based electricity producers. In either system, feed-in tariffs and quota obligation, renewable-based electricity producers may either be remunerated by the offered feed-in tariff (or certificate price) or by the hourly market price and an additional bonus (or green certificate price).

Table 1 categorizes renewable support mechanisms according to these characteristics and lists simplified versions of the electricity producers’ maximization problem under the different policies. The optimization problem, defined by the pay-off function and respective constraints, refrains from regional, technological and temporal effects to simply illustrate the impact of different renewable policies on the investment and

¹Moreover, several articles focus on the interplay between renewable and CO₂ emission policies (e.g., Morthorst (2001), Jensen and Skytte (2002), Amundsen and Mortensen (2001) and Böhringer et al. (2007)).

²An overview of implemented renewable policies can be found in Reiche and Bechberger (2004).

generation decisions of electricity producers. For the simplified model, a market with one electricity producer acting as a price taker is assumed. The model considers one conventional and one renewable technology. It is further assumed that renewable power generation is more expensive than conventional generation in terms of capital costs, with $ic_r \geq ic_c \geq 0$, and variable costs, with $vc'_c(S_c) > 0$, $vc''_c(S_c) > 0$ and $vc'_r(S_r) > vc'_c(S_c)$. As temporal effects are not considered, investment and generation decisions take place simultaneously. The simplified model also assumes a price inelastic electricity demand (d).

Table 1: Overview of incentives for renewable power generation

		price control	quantity control		
without market integration	① <i>'feed-in tariff'</i>	PF: $\max \pi = S_c \cdot (\phi - vc_c(S_c)) + S_r \cdot (fit - vc_r(S_r)) - C_c \cdot ic_c - C_r \cdot ic_r$ s.t. $C_c - S_c \geq 0$ (α_c) $C_r - S_r \geq 0$ (α_r) MC 1: $d - S_c - S_r = 0$ (ϕ)	③ <i>'quota w/out integration'</i> PF: $\max \pi = S_c \cdot (\phi - vc_c(S_c)) + S_r \cdot (\psi - vc_r(S_r)) - C_c \cdot ic_c - C_r \cdot ic_r$ s.t. $C_c - S_c \geq 0$ (α_c) $C_r - S_r \geq 0$ (α_r) MC 1: $d - S_c - S_r = 0$ (ϕ) MC 2: $S_r - qu \cdot d \geq 0$ (ψ)		
	② <i>'fixed bonus'</i>	PF: $\max \pi = S_c \cdot (\phi - vc_c(S_c)) + S_r \cdot (\phi + bo - vc_r(S_r)) - C_c \cdot ic_c - C_r \cdot ic_r$ s.t. $C_c - S_c \geq 0$ (α_c) $C_r - S_r \geq 0$ (α_r) MC 1: $d - S_c - S_r = 0$ (ϕ)	④ <i>'green certificate market'</i> PF: $\max \pi = S_c \cdot (\phi - vc_c(S_c)) + S_r \cdot (\phi + \psi - vc_r(S_r)) - C_c \cdot ic_c - C_r \cdot ic_r$ s.t. $C_c - S_c \geq 0$ (α_c) $C_r - S_r \geq 0$ (α_r) MC 1: $d - S_c - S_r = 0$ (ϕ) MC 2: $S_r - qu \cdot d \geq 0$ (ψ)		
π	profit	S_c	conventional generation	S_r	renewable generation
C_c	conventional capacity	C_r	renewable capacity	ϕ	electricity price
ψ	green certificate price	vc_c	conventional variable costs	vc_r	renewable variable costs
fit	feed-in tariff	d	electricity demand	qu	renewable quota
bo	bonus payment	α_c	dual variable capacity conventional	α_s	dual variable capacity renewable

Fixed price compensations for renewable generation without market integration are commonly referred to as *'feed-in tariff'* ①. The electricity producer receives the offered feed-in tariff (fit) for each renewable generated unit (S_r) and the wholesale price (ϕ) for each conventional generated unit (S_c). An electricity producer invests in renewables as long as capital costs can be recovered under the offered feed-in tariff.

Thus, the wholesale price has an impact neither on investment nor generation decisions for renewable energies.³ In the equilibrium, the residual load ($d - S_r$) is met by conventional generation satisfying the clearing condition for the power market (MC 1), with the dual variable representing the wholesale price of electricity (ϕ). A price control with market integration is often referred to as ‘*fixed bonus*’ ②. Under a bonus support, renewable producers receive a fixed price compensation in addition to the market price ($\phi + bo$). Thus, renewable producers consider the market price of electricity when making investment and generation decisions.

Under quantity support mechanisms, electricity producers (or utilities) are required to procure a certain share of their electricity from renewable energy sources. This gives rise to a market for green certificates, implemented as market clearing condition 2 in the example in Table 1. Renewable producers sell certificates to electricity consumers according to their exogenous renewable obligation ($qu \cdot d$). In the equilibrium, the certificate price (ψ) represents the marginal generation costs of the last renewable unit to achieve the political target ($qu \cdot d$). Under a ‘*quota w/out integration*’ ③, renewable producers receive the certificate price (ψ) that represents the full marginal generation costs of the last renewable technology. According to the feed-in tariff policy, the wholesale price thus has an impact neither on investment nor generation decisions for renewable energies. Instead, under a ‘*green certificate market*’ ④ (often also referred to as ‘*renewable portfolio standard*’) the certificate price corresponds to the needed markup to the wholesale price ($\phi + \psi$) such that the last renewable capacity can recover its’ capital costs.

In addition to these characteristics, incentives for renewable power generation can be implemented in different ways: technology-neutral policies, rather than technology-specific incentives, are cost-efficient as renewable technologies are competing against each other in achieving a renewable target. Intra-regional incentives, as opposed to regional differentiated policies, allow the competition between renewable sites. Renewable payments can be guaranteed or only provided when electricity is integrated into the power grid. Additionally, payments can be neutral or differentiated based on the installation year of the renewable technology. However, these aspects are beyond the scope of this paper, as the analysis concentrates on the differences between a price-based and quantity-based renewable policies and the benefits of a market integration.

³Unless the wholesale price is higher than the offered feed-in tariff.

Difference between price and quantity control instruments given uncertain wind and solar generation

In general, price-based and quantity-based control mechanisms can be implemented in corresponding ways to achieve the same results. Thus, no difference exists between feed-in tariffs and a quota without market integration ($\textcircled{1} \equiv \textcircled{3}$) or between a bonus support and a green certificate market ($\textcircled{2} \equiv \textcircled{4}$) when assuming perfect foresight. However, price-based or quantity-based control mechanisms are not equivalent in markets with uncertainties (Weitzman, 1974). Many uncertainties which influence the marginal cost curve of renewables exist: uncertain technological development (e.g., technology leaps), uncertain deployment of renewables (e.g., construction offshore wind parks) and weather effects (e.g., generation profiles of wind and solar technologies). As political plans usually foresee a strong deployment of wind and solar technologies, uncertainty about the annual generation of wind and solar technologies may strongly influence the (annual) marginal cost curve of renewables. For example, in years with low wind and solar generation, the renewable marginal cost curve becomes steeper because more costly biomass technologies are used. Thus, price-based and quantity-based support mechanisms to incentivize renewable power generation result in different levels of sectoral welfare and investment risks.⁴

Under a feed-in tariff support (price control), a fixed price is granted for renewable generation in all weather years. Given a symmetric deviation of full load hours, annual power generation differs but the expected amount of renewable generation over all weather years remains the same. Thus, uncertainty concerning annual full load hours of intermittent renewables (if deviation is symmetric) neither affects the investment decision nor the generation decision of a risk-neutral electricity producer. Due to the fixed price compensation (*fit*), producers invest in renewable technologies simply based on a comparison between the levelized cost of electricity and the offered feed-in tariffs ($fit - vc_r + ic_r \geq 0$). As the total amount and structure of renewable feed-in differs between weather years, conventional generators adjust their power generation to meet electricity demand. Therefore, the wholesale price of electricity varies between years depending on the marginal cost curve of conventional generation. However, renewable producers do not consider the value of electricity in different weather years, as the wholesale price does not appear in their profit maximization problem. The related risk for investors in renewable energies is purely based on the volatility of their renewable generation. Therefore, annual cash-flows of renewable producers vary according to the volatility of renewable generation as prices are fixed.

Under a quota policy (quantity control), targeted renewable generation is defined for a certain period,

⁴The maximization problem and related first-order conditions for electricity producers under the consideration of uncertain weather years can be found in Appendix 4.

often one year in electricity markets. As the annual cost curve for renewable generation varies between weather years, the necessary certificate price (ψ^w) to achieve the targeted renewable generation within a period also differs. In periods with high generation from wind and solar technologies, certificate prices may drop to zero as short-term marginal costs of these technologies are negligible. On the contrary, certificate prices are relatively high in years with low wind and solar generation. Specific targets over a certain period and the resulting volatile certificate prices have two important aspects. First, quantity control, without the option to trade certificates over multiple periods, incentivizes the achievement of the renewable target (or overachievement) in every single period (e.g., every year). This is also the case for periods with high renewable costs due to the low availability of wind and solar power. Thus, given several renewable technologies with different production profiles, such as negatively correlated wind and solar power, a greater mix of renewable technologies may be induced by a strict annual target. Moreover, forcing renewable producers to achieve the target in every single period increases system costs. Second, volatile certificate prices may have a positive or negative impact on the investment risk of renewable producers compared to the risk under a fixed price compensation. As certificate prices vary between weather years, quantity-based support policies are usually associated with higher risks for the electricity producer than under feed-in tariff policies. However, Lemming (2003) argues that negatively correlated fluctuations between the production of intermittent renewables and the prices of green certificate may actually reduce the financial risk.

Both aspects can be reduced or even resolved by allowing banking and borrowing of green certificates over multiple periods. With tradable green certificates, the renewable target is extended and reduces the volatility of certificate prices. However, one could argue that the risk of early investments in renewable technologies increases as the trading period is extended due to uncertain technological and political developments. For example, if costs for a renewable technology significantly decrease due to technological progress, certificate prices may drop within the trading period. In this case, early investments (with higher costs) will not be able to recover their capital costs. In summary, the main focus of the numerical analysis in Section 3 will be:

- How volatile are green certificate prices and consequently how important is a banking and borrowing scheme for green certificates?
- To what extent do the profits of electricity producers deviate from the expected profit under various renewable policies?

Effects of the market integration of renewable energies

As depicted in Table 1, renewable targets can be achieved by renewable support schemes, with and without an integration of the hourly market price. However, renewable incentives integrating the market price signal can reduce welfare losses in the power sector, due to ambitious renewable targets, compared to policies without market integration (Andor et al., 2012).

When oversimplifying the electricity market to only one dispatch situation, i.e. an annual electricity demand level, no differences exist in terms of capacity, generation and social welfare between renewable support policies with market integration (*'bonus'* ②) and without market integration (*'feed-in tariff'* ①). To achieve the same renewable target, feed-in tariffs have to be equal to the electricity price plus bonus (fit = $\psi + bo$) thus allowing electricity producers to face the same optimization problem.

In reality, load situations differ with regard to the level of electricity demand. Given several demand levels, feed-in tariffs and bonus payments may lead to different incentives and therefore to different investment and generation decisions. Under feed-in tariffs, the electricity producer will invest in renewable technologies if the expected total marginal revenues (based on FIT) are greater than the capital costs. As the generation decision purely depends on the offered feed-in tariff, producers will generate at full capacity during all load levels independent of the wholesale price of electricity. Given technology-neutral tariffs, electricity producers will strictly invest in the renewable technology with the lowest levelized cost of electricity as different production profiles of renewable technologies and different hourly electricity prices are not considered. In contrast, under bonus support policies, the actual renewable generation depends on the combination of market price and bonus. Producers will generate electricity if marginal revenues exceed variable costs at each load level $-(\phi^l + bo) + vc_{r_1} + \alpha_{r_1}^l \geq 0$.⁵ Additionally, electricity producers consider the different hourly feed-in structures of intermittent renewables and therefore consider the price lowering effect of wind and solar feed-in. Hence, electricity producers may invest in a mix of renewable technologies in order to maximize their profits. Concerning the market integration of renewables, the numerical analysis in Section 3 will focus on the following question.

- To what extent can the hourly price signal in support mechanisms reduce welfare losses resulting from an ambitious renewable target?

Given uncertainty about annual full load hours and different feed-in structures of intermittent renewables, all four policies perform differently in terms of sectoral welfare and investment risks for electricity producers.

⁵The dual variable of the capacity constraint ($\alpha_{r_1}^l$) is zero unless the capacity constraint is binding.

Moreover, allowing banking and borrowing of certificates over multiple periods is one option to reduce differences between price-based and quantity-based support mechanism. The numerical analysis in Section 3 attempts to quantify how the various support schemes are affected by increasing weather uncertainty.

3. Numerical analysis

In this section, the numerical analysis of the primary differences between renewable policies with regard to social welfare and investment risks is presented. The analysis is based on a stochastic spatial inter-temporal equilibrium model for the European electricity market. The model considers the uncertainty of annual full load hours of wind and solar technologies. In Subsection 3.1, the electricity market model developed for this analysis is described and the model assumptions are presented in Subsection 3.2. The performance of renewable policies is analyzed based on the model results in Subsection 3.3.

3.1. Model description

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

The electricity market model developed for this analysis is formulated as three separate optimization problems. First, a representative European electricity producer (acting as a price taker⁶) maximizes its profit by selling electricity to the domestic market. Second, an international electricity trader acts as an arbitrageur, representing the linkage between model regions (grid investments are exogenous). Third, a transmission system operator regulates the curtailment of wind and solar generation. The model is formulated as a mixed complementary problem by deriving the Karush-Kuhn-Tucker (first-order) conditions for the European electricity producer's, the arbitrageur's and the transmission system operator's maximization

⁶Given the oligopolistic structure of most electricity markets, the competitiveness of power markets, including the European power market, may be questioned (Borenstein et al., 1999; Newberry, 2002). An analysis of how various renewable support schemes are affected by market power is an interesting question but is beyond the scope of this paper.

problem. The model is programmed in GAMS and run with the PATH solver (Dirkse and Ferris, 1995; Ferris and Munson, 1998).

The time horizon of the model is $T = 2010, 2013, 2020, 2030, \dots, 2050$ on a ten-year basis up to 2050.⁷ The model consists of several electricity market regions $r \in R$ where electricity demand and supply must be balanced. All common power generation technologies $a \in A$ (conventional, renewable and storages) are implemented in the model. The set A can be divided into two subsets $A \equiv N \cup Q$, where $n \in N$ is a conventional or storage technology (not subsidized) and $q \in Q$ is a renewable-based technology (potentially subsidized). To distinguish between storage and non-storage technologies, an additional subset $b \in B \in A$ is added. Different electricity demand levels during a single year are represented by several load levels $l \in L$. An overview of all sets, decision variables and parameters can be found in Table 2.

Representative European electricity producer's maximization problem: power supply

The supply side is modeled by an aggregation of all producers to a single price taking European electricity producer. The European electricity producer maximizes its discounted pay-off function, defined as the revenues from sales and capacity payments minus costs for electricity production, recharging storages, fixed operation and maintenance costs as well as investment costs. In reality, power plant investors face many uncertainties that influence the profitability of their investments. Among others, the electricity demand development, future capital costs, fuel prices, political developments and future competition are uncertain. Another source of uncertainty is the stochastic annual generation of wind and solar technologies. Empirical data shows that full load hours vary by a magnitude of more than 20 % from the long-term average. The volatility of annual wind and solar generation has a large impact in electricity systems with a high share of wind and solar technologies (Nagl et al., 2013). In the presented model, the stochasticity as well as the negative correlation of wind and solar power are represented by a low wind/high solar year (w_1), an average wind/average solar year (w_2) and a high wind/low solar year (w_3). The European electricity producer is assumed to be risk-neutral⁸ and thus maximizes expected profit.

The model allows different renewable support schemes: ① ‘*feed-in tariff*’ ($bf=1$), ② ‘*fixed bonus*’ ($bp=1$), ③ ‘*quota w/out integration*’ ($bq=1$) and ④ ‘*green certificate market*’ ($bg=1$). It is important to note that all support schemes are technology-neutral, independent of the installation year and implemented across Europe (harmonized European policy). In all support mechanisms, payments are guaranteed even if generation

⁷To account for different technical lifetimes of technologies, the years 2060 and 2070 are additionally modeled but not interpreted.

⁸In many economic situations, firms seem to act rather risk-averse (Mas-Colell et al., 1995). Nevertheless, the analysis assumes a risk-neutral electricity producer to simply quantify investment risks under various support schemes rather than analyze how producers react to uncertainty, given their risk preference.

cannot be integrated into the grid (energy is curtailed by the transmission system operator). Renewable generator have to make an annual decision whether to receive the renewable subsidy or the market price. Furthermore, it is assumed that the European renewable policy is already implemented in 2013. As only one renewable support scheme can be in place at a time, $bf + bp + bq + bg = [0;1]$.

The pay-off function Π_f can be written as shown in (1a) to (1k). Line (1a) defines the annual revenues gained from electricity sales generated in conventional and storage plants (non-subsidized). Sales ($S_{t,r,l,f,a,w}$) are rewarded by the domestic electricity price ($\phi_{t,r,l,w}$) at the specific load level multiplied by the number of hours (h_l). Line (1b) defines the revenues from renewable-based sales (subsidized generation) depending on the specific support mechanism: ① Under a fixed price compensation, the producer receives the offered feed-in tariff (fit_t), ② under a bonus support, he receives the fixed bonus additionally to the market price ($\phi_{t,r,l,w} + bo_t$), ③ under a quota w/out market integration, he receives the green certificate price ($\psi_{t,w}$) and ④ under a green certificate market, he receives the certificate price additionally to the market price ($\phi_{t,r,l,w} + \psi_{t,w}$).⁹ Line (1c) defines the revenues from the reserve market that firms can achieve by offering securely available capacity to the market (technology-specific capacity factor ca_a). Due to the simplification to a few dispatch situations per model year, potential peak demand is not considered as a dispatch situation. The modeled capacity market simply ensures that sufficient investments in back-up capacities are made to meet potential peak demand. However, such investments could also be triggered in an energy-only market in the event of price peaks.¹⁰ Line (1d) defines the variable production costs, including fuel and CO₂ emission costs, for the generated electricity for each technology. Storage technologies can be recharged ($P_{t,r,l,f,a,w}$), but electricity has to be bought on the market as stated in line (1e). Line (1f) defines the fixed operation and maintenance costs. Line (1g) defines investment costs, which are annualized with an interest rate (ir) and occur until the end of the plant's technical lifetime. An earlier decommissioning of power plants is not considered in the model.

Profit maximization of the European electricity producer is constrained by a set of restrictions for production capacities and storage limits, as defined in line (1h) - (1k). The variables in parentheses on the right hand side of each constraint are the Lagrange multipliers used when developing the first-order conditions. Line (1h) states that available capacity (considering outages and revisions) has to be greater or equal to

⁹The variable ($\psi_{t,w}$) is used as the certificate price for a demanded renewable generation under a quota w/out market integration and the green certificate market. In the first model year (2010), no renewable support is modeled and therefore all technologies receive the market price.

¹⁰Based on the International Energy Agency, 'markets in which marginal pricing of electricity is the only remuneration are often called energy-only markets' (IEA, 2007). It is an ongoing debate whether sufficient incentives to invest in generation capacity exist in energy-only markets (Joskow (2008), Cramton and Stoft (2005) and Cramton and Stoft (2008)). Implementing a capacity market in this model is purely a result of the chosen model approach.

generation at all times. Line (1i) ensures that electricity charging is at least as high as generation from storage capacities on an annual basis. Line (1j) restricts the capacity potential for all technologies. Line (1k) states the typical non-negativity constraints.

Table 2: Model sets, variables and parameters

Sets		
$a \in A$	technologies for power generation	
$b \in B \in A$	storage technologies	
$q \in Q \in A$	renewable technologies	
$n \in N \in A$	not subsidized technologies	
$f \in F$	electricity producer	
$l, l' \in L$	load levels	
$r, r' \in R$	regions	
$t, t' \in T$	time periods	
$w \in W$	weather years	
Boolean policy		
bf	boolean indicating feed-in tariffs as support	[0;1]
bg	boolean indicating green certificate market as support	[0;1]
bp	boolean indicating bonus payments as support	[0;1]
bq	boolean indicating quota w/out market integration as support	[0;1]
Primal variables		
$\Pi_{f/ARB/TSO}$	profit of producer, arbitrageur or transmission operator	EUR ₂₀₁₀
$I_{t,r,f,a}$	capacity investments	MW
$E_{t,r,l,r',w}$	electricity exchange	MW
$S_{t,r,l,f,a,w}$	domestic sales / generation	MW
$P_{t,r,l,f,a,w}$	charging storage	MW
$M_{t,r,l,w}$	renewable curtailment	MW
Dual variables		
$\alpha_{t,r,l,f,a,w}$	shadow price of capacity constraint	EUR ₂₀₁₀ /MW
$\beta_{t,r,f,a,w}$	shadow price of annual storage constraint	EUR ₂₀₁₀ /MW
$\gamma_{t,r,f,a}$	shadow price of capacity potential	EUR ₂₀₁₀ /MW
$\phi_{t,r,l,w}$	shadow price of power equation (electricity price)	EUR ₂₀₁₀ /MWh
$\chi_{t,r,l,r',w}$	shadow price of transfer constraint (congestion price)	EUR ₂₀₁₀ /MWh
$\psi_{t,w}$	shadow price of renewable constraint (certificate price)	EUR ₂₀₁₀ /MWh
$\omega_{t,r}$	shadow price of peak capacity constraint (reserve price)	EUR ₂₀₁₀ /MW
Parameters		
$ai_{t,r,f,a,t'}$	boolean indicating technical lifetime (t' =periods after t)	[0;1]
$av_{r,l,a,w}$	capacity availability	MW/MW _{inst.}
bb_a	boolean indicating storage technologies	[0;1]
$bc_{t,a}$	fuel costs	EUR ₂₀₁₀ /MWh _{th}
$bi_{t,r,f,a,t'}$	boolean investments in previous periods (t' =periods before t)	EUR ₂₀₁₀ /MWh
bo_t	fixed bonus payment	[0;1]
ca_a	percentage of securely available capacity	MW/MW _{inst.}
$cp_{t,r,f,a}$	capacity potential	MW
$d_{t,r,l}$	electricity load	MW
$dp_{t,r}$	peak electricity demand	MW
dr_t	discount factor	%
$ec_{t,r,f,a}$	existing capacity	MW
ef_a	emission factor	t CO ₂ /MWh _{th}
et_t	tax on CO ₂ emissions	EUR ₂₀₁₀ /t CO ₂
η_a	net efficiency of power plants	MWh _{el} /MWh _{th}
$fc_{t,a}$	yearly fixed operation and maintenance costs	EUR ₂₀₁₀ /MWa
fit_t	feed-in tariff	EUR ₂₀₁₀ /MWh
$fp_{t,r,r'}$	net transfer capacity	MW
hl	number of hours	h
$ic_{t,a}$	investment costs	EUR ₂₀₁₀ /MW
ir	interest rate	%
lh_b	losses in storage charging	%
$lo_{r,r'}$	transfer losses	%
$pl_{a,w}$	boolean for technologies receiving market price	[0;1]
pr_w	probability of weather realizations	%
qu_t	demanded RES-E share	%
qq_a	boolean indicating renewable technologies	[0;1]
tl_a	technical lifetime of technologies	a
tr_t	number of years	-
$vc_{t,a}$	variable costs	EUR ₂₀₁₀ /MW
$\bar{Y}_{t,r,f,a}$	natural inflow storage technologies	MWh
$\bar{\phi}$	minimal price for curtailment (helping parameter)	EUR ₂₀₁₀ /MWh

Optimization problem of European electricity producer: electricity supply

$$\max_{I_{t,r,f,a}; S_{t,r,l,f,a,w}; P_{t,r,l,f,a,w}} \Pi_f = \sum_{t \in T} dr_t \cdot tr_t \cdot \left[\sum_{r \in R} \sum_{l \in L} \sum_{a \in N} \sum_{w \in W} (pr_w \cdot h_l \cdot \phi_{t,r,l,w} \cdot S_{t,r,l,f,a,w}) \right] \quad (1a)$$

$$+ \sum_{r \in R} \sum_{l \in L} \sum_{a \in Q} \sum_{w \in W} (pr_w \cdot h_l \cdot S_{t,r,l,f,a,w} \cdot (bf \cdot fit_t + bp \cdot (\phi_{t,r,l,w} + bo_t) + bq \cdot \psi_{t,w} + bg \cdot (\phi_{t,r,l,w} + \psi_{t,w}))) \quad (1b)$$

$$+ \sum_{r \in R} \sum_{a \in A} (\omega_{t,r} \cdot ca_a \cdot (ec_{t,r,f,a} + \sum_{t' \in T} (bi_{t,r,f,a,t'} \cdot I_{t,r,f,a}))) \quad (1c)$$

$$- \sum_{r \in R} \sum_{l \in L} \sum_{a \in A} \sum_{w \in W} (pr_w \cdot h_l \cdot \frac{bc_{t,a} + efa \cdot et_t}{\eta_a} \cdot S_{t,r,l,f,a,w}) \quad (1d)$$

$$- \sum_{r \in R} \sum_{l \in L} \sum_{a \in B} \sum_{w \in W} (pr_w \cdot h_l \cdot \phi_{t,r,l,w} \cdot P_{t,r,l,f,a,w}) \quad (1e)$$

$$- \sum_{a \in A} (fc_{t,a} \cdot (ec_{t,r,f,a} + \sum_{t' \in T} (bi_{t,r,f,a,t'} \cdot I_{t,r,f,a}))) \quad (1f)$$

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

s.t.

$$S_{t,r,l,f,a,w} + P_{t,r,l,f,a,w} - av_{r,l,a,w} \cdot \left(ec_{t,r,f,a} + \sum_{t' \in T} (bi_{t,r,f,a,t'} \cdot I_{t,r,f,a}) \right) \leq 0 \quad (\alpha_{t,r,l,f,a,w}) \quad \forall t, r, l, f, a, w. \quad (1h)$$

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

$$\left(ec_{t,r,f,a} + \sum_{t' \in T} (bi_{t,r,f,a,t'} \cdot I_{t,r,f,a}) \right) - cp_{t,r,f,a} \leq 0 \quad (\gamma_{t,r,f,a}) \quad \forall t, r, f, a. \quad (1j)$$

$$I_{t,r,f,a}; S_{t,r,l,f,a,w}; P_{t,r,l,f,a,w} \geq 0 \quad (1k)$$

The next step in developing the model is to derive the Karush-Kuhn-Tucker conditions from the Lagrangian \mathcal{L}_f of the original optimization problem. Equation 2 defines the equilibrium condition for electricity sales. Electricity is generated as long as the expected revenues are greater than production ($vc_{t,a}$) and capacity costs ($\alpha_{t,r,l,f,a,w}$).¹¹ Electricity generation from renewable sources receive additional payments depending on the support scheme. Electricity generation from storage technologies also consider the shadow price of the annual storage equilibrium condition ($h_t \cdot \beta_{t,r,f,a,w}$).¹²

$$\begin{aligned} \frac{\partial \mathcal{L}_f}{\partial S_{t,r,l,f,a,w}} : & \quad dr_t \cdot tr_t \cdot h_l \cdot pr_w \cdot (-pl_{a,w} \cdot \phi_{t,r,l,w} - bf \cdot fit_t \\ & - bp \cdot (\phi_{t,r,l,w} + bo_t) - bq \cdot \psi_{t,w} - bg \cdot (\phi_{t,r,l,w} + \psi_{t,w}) + vc_{t,a}) \\ & + \alpha_{t,r,l,f,a,w} + bb_a \cdot h_l \cdot \beta_{t,r,f,a,w} \geq 0 \quad \perp S_{t,r,l,f,a,w} \quad \forall t, r, l, f, a, w. \end{aligned} \quad (2)$$

Equation 3 defines the equilibrium condition for charging storage technologies. Storage operators charge their storages as long as the market price is lower than the marginal price of the annual storage equilibrium condition ($\beta_{t,r,f,a,w}$), while considering losses during charging operations ($1-lh_b$) and the capacity limit ($\alpha_{t,r,l,f,a,w}$).

$$\begin{aligned} \frac{\partial \mathcal{L}_f}{\partial P_{t,r,l,f,a,w}} : & \quad dr_t \cdot tr_t \cdot h_l \cdot pr_w \cdot \phi_{t,r,l,w} + \alpha_{t,r,l,f,a,w} \\ & - h_l \cdot (1 - lh_b) \cdot \beta_{t,r,f,a,w} \geq 0 \quad \perp P_{t,r,l,f,a,w} \geq 0 \quad \forall t, r, l, f, w, a \in B. \end{aligned} \quad (3)$$

Equation 4 defines the equilibrium condition for investments in new power plants and storage facilities. Investments are made as long as the sum of marginal benefits of additional capacity is greater than fixed operation and maintenance costs, investment costs and the marginal price of the capacity potential constraint ($\gamma_{t,r,f,a}$) over the total lifetime.

$$\begin{aligned} \frac{\partial \mathcal{L}_f}{\partial I_{t,r,f,a}} : & \quad - \sum_{t' \in T} (ai_{t,r,f,a,t'} \cdot dr_{t'} \cdot tr_{t'} \cdot \omega_{t,r}) + \sum_{t' \in T} (ai_{t,r,f,a,t'} \cdot dr_{t'} \cdot tr_{t'} \cdot fc_{t,a}) \\ & + \sum_{t' \in T} \left(ai_{t,r,f,a,t'} \cdot dr_{t'} \cdot tr_{t'} \cdot ic_{t,a} \cdot \frac{(1+ir)^{tl_a} \cdot ir}{(1+ir)^{tl_a} - 1} \right) + \sum_{t' \in T} (ai_{t,r,f,a,t'} \cdot \gamma_{t,r,f,a}) \\ & - \sum_{l \in L} \sum_{w \in W} av_{r,l,a,w} \cdot \sum_{t' \in T} (ai_{t,r,f,a,t'} \cdot \alpha_{t,r,l,f,a,w}) \geq 0 \\ & \perp I_{t,r,f,a} \geq 0 \quad \forall t, r, f, a, w. \end{aligned} \quad (4)$$

¹¹The dual variable of the capacity constraint ($\alpha_{t,r,l,f,a,w}$) is zero unless the capacity constraint is binding.

¹²Under a feed-in tariff system or quota w/out market integration, renewable technologies with lower variable costs than the offered feed-in tariff/certificate price generate electricity at full available capacity at all times. If the offered feed-in tariff is equally high as the variable costs, the first-order condition for electricity generation is then fulfilled for zero to maximal generation (no unique solution). To force the model to reach an unique solution, negligible increasing variable costs are modeled. Hence, the first-order condition with regard to electricity generation is actually: $dr_t \cdot tr_t \cdot h_l \cdot pr_w \cdot (-pl_{a,w} \cdot \phi_{t,r,l,w} - bf \cdot fit_t - bp \cdot (\phi_{t,r,l,w} + bo_t) - bq \cdot \psi_{t,w} - bg \cdot (\phi_{t,r,l,w} + \psi_{t,w}) + (vc_{t,a} + \epsilon \cdot S_{t,r,l,f,a,w})) + \alpha_{t,r,l,f,a,w} + bb_a \cdot h_l \cdot \beta_{t,r,f,a,w} \geq 0$.

Arbitrageur's maximization problem: linkage between model regions

Model regions are linked by introducing an arbitrageur who takes advantage of different price levels across regions. The pay-off function of the arbitrageur Π_{ARB} can be written as shown in (5a) to (5c). Line (5a) defines the revenues gained from trading electricity across regions ($E_{t,r,l,r',w}$), considering transmission losses ($lo_{r,r'}$). Transmission losses are assumed to be linear, depending on the average distance between regions. Transmission capacities ($fp_{t,r,r'}$) are restricted as defined in (5b). Line (5c) is the typical non-negativity constraint.

$$\max_{E_{t,r,l,r',w}} \Pi_{ARB} = \sum_{t \in T} dr_t \cdot tr_t \cdot pr_w \quad (5a)$$

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

s.t.

$$E_{t,r,l,r',w} - fp_{t,r,r'} \leq 0 \quad (\chi_{t,r,l,r',w}) \quad \forall t, r, l, r', w. \quad (5b)$$

$$E_{t,r,l,r',w} \geq 0 \quad (5c)$$

The Karush-Kuhn-Tucker condition from the Lagrangian \mathcal{L}_{ARB} of the arbitrageur's maximization problem with regard to electricity transports is shown in Equation 6. The arbitrageur transports electricity between two regions if the market price of the import region accounting for transmission losses is greater than or equal to the market price in the export region plus the congestion fee ($\chi_{t,r,l,r',w}$). The congestion fee is zero until the transmission line operates at full capacity.

$$\begin{aligned} \frac{\partial \mathcal{L}_{ARB}}{\partial E_{t,r,l,r',w}} : & -dr_t \cdot tr_t \cdot h_l \cdot pr_w \cdot (lo_{r,r'} \cdot \phi_{t,r',l,w} - \phi_{t,r,l,w}) + \chi_{t,r,l,r',w} \\ & \perp E_{t,r,l,r',w} \geq 0 \quad \forall t, r, l, r', w. \end{aligned} \quad (6)$$

Transmission system operator's maximization problem

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

From a modeling perspective, there is no difference between a transmission operator absorbing the electricity surplus and renewable-based producers reducing generation. Renewable curtailment ($M_{t,r,l,w}$) is modeled by giving the transmission system operator an incentive to take care of surplus electricity in these situations. The transmission system operator receives the price difference between the defined minimum electricity price ($\bar{\phi} \leq 1.0 \cdot E^{-5}$) and the actual wholesale price per curtailed unit. In other words, the transmission system operator increases the electricity demand until the wholesale price increases to the defined minimum. Given no further restrictions, the transmission system operator's profit is zero in all possible scenarios as the price difference converges to zero in the equilibrium ($\bar{\phi} - \phi_{t,r,l,w} = 0$). It is important to note that electricity generators receive the renewable subsidy for their generation. The resulting profit function is stated in Line (7a). Line (7b) is the typical non-negativity constraint.

$$\max_{M_{t,r,l,w}} \Pi_{TSO} = \sum_{t \in T} dr_t \cdot tr_t \cdot pr_w \cdot \left[\sum_{r \in R} \sum_{l \in L} (h_l \cdot pr_w \cdot (\bar{\phi} - \phi_{t,r,l,w}) \cdot M_{t,r,l,w}) \right] \quad (7a)$$

s.t.

$$M_{t,r,l,w} \geq 0 \quad (7b)$$

The Karush-Kuhn-Tucker condition from the Lagrangian \mathcal{L}_{TSO} of the transmission system operator's maximization problem with regard to renewable curtailment ($M_{t,r,l,w}$) is shown in Equation 8. From a modeling perspective, the transmission system operator absorbs electricity (or in other words, increases electricity demand) as long as the wholesale price is below the defined limit ($\bar{\phi} \leq 1.0 \cdot E^{-5}$) for the electricity price.

$$\frac{\partial \mathcal{L}_{TSO}}{\partial M_{t,r,l,w}} : \phi_{t,r,l,w} - \bar{\phi} \geq 0 \quad \perp \quad M_{t,r,l,w} \geq 0 \quad \forall t, r, l, w. \quad (8)$$

Market clearing conditions

In addition to the derived first-order conditions of the European electricity producer, the arbitrageur and the transmission system operator, three market clearing conditions define the equilibrium of the market. Equation 9 ensures that the hourly regional electricity demand ($d_{t,r,l}$) is satisfied by domestic or foreign electricity supply. Electricity demand is assumed to be price inelastic as real-time elasticity of electricity demand seems to be rather low.¹³ The charging of storages ($P_{t,r,l,f,a,w}$) and renewable curtailment ($M_{t,r,l,w}$) increase the fixed electricity demand at the specific load level.

$$d_{t,r,l} + \sum_{f \in F} \sum_{a \in B} (P_{t,r,l,f,a,w}) + M_{t,r,l,w} - \sum_{f \in F} \sum_{a \in A} (S_{t,r,l,f,a,w}) - \sum_{r' \in R} (l_{o,r,r'} \cdot E_{t,r,l,r',w}) + \sum_{r' \in R} (E_{t,r',l,r,w}) = 0 \quad \phi_{t,r,l,w} \text{ free} \quad \forall t, r, l, w. \quad (9)$$

Equation 10 is the market clearing condition for the green certificate market. When renewables are subsidized by a quota w/out market integration or green certificate market, this condition defines the demanded RES-E generation and sets a market price for green certificates (ψ_t). The demanded renewable target refers to the total renewable generation in all regions (Europe-wide). It is important to note that a higher renewable generation than demanded leads to certificate prices equal to zero. Moreover, curtailed energy does not contribute to the renewable generation target.

$$\sum_{r \in R} \sum_{l \in L} \sum_{f \in F} \sum_{a \in Q} (h_l \cdot S_{t,r,l,f,a,w}) - \sum_{r \in R} \sum_{l \in L} (h_l \cdot M_{t,r,l,w}) - q_{u_t} \cdot \sum_{r \in R} \sum_{l \in L} (h_l \cdot d_{t,r,l}) \geq 0 \quad \perp \psi_{t,w} \geq 0 \quad \forall t, w. \quad (10)$$

Equation 11 is the market clearing condition for the capacity reserve market. It ensures that a politically defined amount of securely available capacity ($dp_{t,r}$) is installed in each region. Given limited cross-border transmission capacities, the almost simultaneous occurrence of peak loads across Europe and the need for regional flexible generation to control the grid frequency, it is unclear to what extent capacities in other regions are able to contribute to the securely available capacity. Thus, it is assumed that only regional power plants can participate in the regional capacity reserve markets.

$$\sum_{a \in A} \left(ca_a \cdot \left(ec_{t,r,f,a} + \sum_{t' \in T} (bi_{t,r,f,a,t'} \cdot I_{t,r,f,a}) \right) \right) - dp_{t,r} \geq 0 \quad \perp \omega_{t,r} \geq 0 \quad \forall t, r. \quad (11)$$

¹³Price elasticity of demand is defined as the percentage change in quantity demanded given a one percent change in price ($\eta = \frac{dQ/Q}{dP/P}$). Empirical data on real-time elasticity of electricity demand can be found in Lijesen (2007).

The model is defined by the first-order conditions (2 - 4) and restrictions (1h - 1k) of the European electricity producer; the first-order condition (6) and the restrictions (5b - 5c) of the arbitrageur, the first-order condition (8) and the restriction (7b) of the transmission system operator as well as the market clearing conditions (9 - 11). Modeling eight regions and ten technologies up to 2070 in ten year time steps, the model contains of about 32,000 variables/constraints. The PATH solver tends to not converge when modeling a renewable policy. Hence, the solution of the system with no support is always used as a first starting point. Then, tariffs or quotas are increased over up to 100 iterations, each time using the previous solution as new starting point.

3.2. Assumptions

The model results are based on many assumptions including the regional electricity demand development, net transfer capacities between regions, existing power plants, technical and economic parameters for power plant investments and fuel and CO₂ prices. It is clear that the scenario setting chosen for this analysis is only one possible development and should not be interpreted as a forecast. The assumptions are based on several databases such as IEA (2011), Prognos/EWI/GWS (2010), ENTSO-E (2011) and EWI (2011).

Net electricity demand

The scenarios assume a similar demand development as described in EWI (2011). Yearly net electricity demand is assumed to increase in all regions until 2050. A strong increase, 0.7-1.95 % per year, is assumed until 2020, in particular due to the further economic development in Southern Europe. In the long term, growth rates are assumed to decrease to 0-1.35 % per year, among others, due to the application of energy efficient technologies. Two load levels (base and peak) are modeled based on the structure of the load duration curve in 2009 (ENTSO-E, 2011). In the scenarios, peak load is defined as the average of the 10 % highest electricity load levels. The demand structure, referring to the ratio between peak and base load, is assumed to remain as in 2009. Thus, base demand (l_1) occurs in 7970 hours and peak demand (l_2) in 790 hours each year. Table 3 depicts the two assumed load levels, absolute peak demand and the resulting annual electricity consumption for each region from 2020 to 2050.

Table 3: Electricity loads [GW] and annual (net) electricity demand [TWh]

			ATCH	BNL	FR	GER	IB	IT	SCAN	UK
2020	l ₁	GW	15.5	26.0	57.7	68.0	42.1	43.2	48.0	49.4
	l ₂	GW	21.5	33.6	83.2	90.2	56.1	57.2	67.6	69.5
	dp	GW	23.7	37.0	91.5	99.2	61.8	62.9	74.4	76.5
	annual	TWh	140.2	233.9	525.4	613.6	379.5	389.8	435.8	448.4
2030	l ₁	GW	16.5	27.7	61.5	70.1	48.4	42.1	51.2	52.6
	l ₂	GW	22.9	35.8	88.7	92.9	64.6	56.1	72.1	74.1
	dp	GW	25.2	39.4	97.5	102.2	71.0	61.8	79.3	81.6
	annual	TWh	149.4	249.3	560.1	632.1	436.6	379.5	464.6	478.0
2040	l ₁	GW	17.5	29.4	65.2	70.1	55.4	48.4	54.3	55.8
	l ₂	GW	24.3	38.0	94.1	92.9	73.9	64.6	76.5	78.7
	dp	GW	26.8	41.8	103.5	102.2	81.3	71.0	84.1	86.5
	annual	TWh	158.5	264.5	594.3	632.1	499.8	436.6	492.9	507.1
2050	l ₁	GW	18.5	31.1	68.9	70.1	63.1	55.4	57.3	58.9
	l ₂	GW	25.7	40.1	99.3	92.9	84.3	73.9	80.7	83.0
	dp	GW	28.3	44.2	109.2	102.2	92.7	81.3	88.8	91.3
	annual	TWh	167.4	279.3	627.4	632.1	569.6	499.8	520.4	535.4

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

Technologies and generation costs

The model includes nuclear, conventional, renewable and storage technologies. The regional existing power plant fleet is based on the power plant database of the Institute of Energy Economics at the University of Cologne. Power plant data including net capacity, efficiency factors and location has been collected from a multitude of different sources (including company reports and Platts database 2012). Table 4 gives an overview of the technical and economic parameters of the modeled technologies. The assumptions are based on different databases such as IEA (2011), Prognos/EWI/GWS (2010) and EWI (2011). Additionally, it is assumed that lignite-fired power plants emit $0.406 \text{ t CO}_2 / \text{MWh}_{th}$, hard-coal plants $0.335 \text{ t CO}_2 / \text{MWh}_{th}$ and natural gas-fired plants $0.201 \text{ t CO}_2 / \text{MWh}_{th}$.

Table 4: Technical and economic parameters of generation technologies

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

Compared to today, investment costs of renewable technologies, and particularly of photovoltaics, are assumed to decrease significantly until 2050. To determine the annual capital costs, as described in line (1g) of the electricity producer’s maximization problem, a technology-independent interest rate of 10 % is assumed. Table 5 shows the assumed development of investment costs for the different technologies.

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

Table 5: Investment costs of technologies [EUR₂₀₁₀/kW]

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

The fluctuating feed-in of wind and solar technologies is approximated by different availability factors at each load level, as shown in Table 6. At each load level, a low and high wind and solar availability is modeled based on the empirical data of 2007-2010, in total four dispatch situations.¹⁴ The low availability represents the 30 % quantile and the high value represents the 70 % quantile at the respective load level. Varying regional renewable conditions are reflected by different full load hours. In addition, uncertainty concerning annual full load hours of wind and solar technologies is represented by a low-average-high wind (solar) year. In the low (high) wind year, full load hours are 20 % lower (higher) than in the average year. The negative correlation between wind and solar power is approximated by assuming 10 % higher (lower) full load hours of solar technologies in the low (high) wind year. It is further assumed that the average weather year (w_2) occurs with a probability of 60 % and the weather years w_1 and w_3 with a probability of 20 %.

Table 6: Availability of fluctuating renewables for $w_1/w_2/w_3$ [% or MW/MW_{inst.}]

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

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

¹⁴The assumed full load hours are based on hourly wind speeds and solar radiation from EuroWind (2011).

The assumed fuel prices are based on international market prices and transportation costs to the power plants. The price for hard coal is assumed to increase from 11.9 EUR₂₀₁₀/MWh_{th} in 2010 to 12.7 EUR₂₀₁₀/MWh_{th} in 2050. For domestic lignite a constant price of 1.4 EUR₂₀₁₀/MWh_{th} is assumed. Despite the current excess supply and low prices of natural gas, a significant increase up to 25.3 EUR₂₀₁₀/MWh_{th} is assumed for the long term. The price for biomass is assumed to increase up to 37.5-85.1 EUR₂₀₁₀/MWh_{th}. In addition to the modeled renewable target, an increasing tax on CO₂ emissions of up to 20.0 EUR₂₀₁₀/t CO₂ in 2050 is assumed. Table 7 shows the assumed development of fuel prices for thermal power plants in the scenarios.

Table 7: Fuel [EUR₂₀₁₀/MWh_{th}] and CO₂ prices [EUR₂₀₁₀/t CO₂]

	2020	2030	2040	2050
Nuclear	3.3	3.3	3.3	3.3
Lignite	1.4	1.4	1.4	1.4
Hard-coal	11.5	11.7	12.2	12.7
Natural gas	18.2	22.3	23.7	25.3
Biomass	0.1-27.7-67.2	0.1-34.9-72.9	0.1-35.1-78.8	0.1-37.7-85.1
CO ₂ price [EUR ₂₀₁₀ /t CO ₂]	15.0	17.5	20.0	20.0

Net transfer capacities

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

However, the model considers transfer restrictions between model regions based on net transfer capacities. In the scenarios, a similar extension of cross-border transmission capacities as described in EWI (2011) is assumed. In 2050, total cross-border capacities are assumed to be more than five times as large as today's levels. Table 8 lists assumed net transfer capacities between model regions.

Table 8: Assumed net transfer capacities between model regions [GW]

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

3.3. Simulation results

In this section, the model results for a scenario with no renewable support and the discussed renewable policies ① ‘*feed-in tariff*’, ② ‘*fixed bonus*’, ③ ‘*quota w/out integration*’ and ④ ‘*green certificate market*’ are presented. First, the development of the electricity market based on the capacity and generation mix as well as prices (wholesale, renewable and capacity prices) are analyzed. Second, welfare effects between the scenario with no renewable support and the policy scenarios are discussed. Third, the risk for electricity producers under the different policies is analyzed by comparing the distribution of the producer profit. All numerical data can be found in Tables 9 and 10.

Effects on the electricity mix

If no renewable support mechanism is in place, the capacity mix remains relatively similar to today. Base-load generation takes place in nuclear (limited as per political assumption) and lignite power plants (limited due to fuel availability). The assumed increasing electricity demand is mainly met by additional hard-coal power plants. Open cycle gas turbines are installed as back-up capacities, which only achieve about 600-700 full load hours per year but are nonetheless profitable because of the capacity payments. A few investments in wind turbines (onshore) at the most favorable sites in the United Kingdom take place in 2040 due to the assumed capital cost reduction as well as increasing CO₂ and fuel prices for conventional plants. These investments in wind turbines are profitable without any subsidies. Given the increasing electricity demand, the share of renewable generation, mainly in already existing hydro plants, decreases to about 15-17 % in 2050. Annual generation from fluctuating renewables differs between years and is balanced by conventional technologies (mainly gas-fired plants). As a result, wholesale prices for electricity

vary throughout the weather years. However, the effect is rather small in the scenario with no renewable support due to the limited deployment of these technologies. Electricity prices rise in all regions up to 2050 due to the assumed increase in electricity demand as well as CO₂ and fuel prices. Price differences across regions tend to decrease due to the further development of the European transmission network and the increase in demand (both assumptions). Long-term price differences occur in spatial markets when technologies with marginal cost differences are available in only some regions and transport capacities are limited (or significant transport losses/costs occur). A few such resources exist in the European power sector: large hydro facilities (Austria, Switzerland and Scandinavia), large nuclear capacities (France) and lignite-fired plants (Germany). Given the scenario assumptions, open-cycle gas turbines are the cheapest option to provide additional securely available capacity. However, also a switch, for example, from wind to conventional capacities can be an option to increase the securely available capacity due to the low capacity credit of wind power. Hence, regional capacity prices range from 39 to 87 EUR₂₀₁₀/kWa.¹⁵ Particularly remarkable is the capacity situation in Germany in 2020. Due to the phase-out of nuclear power in Germany (the scenarios assumes no nuclear power in 2020), substantial investments in securely available capacities are needed. In 2030, these capacities have been commissioned and old wind and solar capacities¹⁶ are replaced by coal capacities. Therefore, the capacity situation is less tense in 2030 compared to 2020. As a result, capacity prices are high in 2020 and relatively low in 2030.

Under all renewable policies, the achievement of a 60 % renewable share of the total electricity generation in 2050 (2020: 30 %, 2030: 40 % and 2040: 50 %) leads to a stepwise reduction in traditional base-load capacities such as nuclear and hard-coal power plants. The remaining non-renewable generation takes place mostly in combined and open cycle gas turbines due to decreasing full load hours of conventional plants and a more favorable operating/capital cost ratio. In 2020, the demanded RES-E generation comes from hydro facilities (about 50 %) and onshore wind turbines (about 40 %). In the long term, the renewable generation is more technologically and geographically diversified: offshore wind in the United Kingdom and the Benelux (about 25 %); onshore wind in France, United Kingdom and Germany (about 25 %); solar power plants in Italy, Spain and France (about 25 %), hydro in Scandinavia and Austria (about 20 %) and biomass in Germany, France and Italy (about 5 %). Due to the limited potential of cost-efficient storage options and limited cross-border transmission capacities (assumption), wind and solar generation is shut-off in hours with large availability and low demand. In the scenarios, renewable curtailment takes place

¹⁵The common capacity price of 74 EUR₂₀₁₀/kWa represents the annualized fixed costs of an open cycle gas turbine over 20 years.

¹⁶These capacities were built under the feed-in tariff support before 2012 and reach their technical lifetime before 2030.

mainly in Scandinavia and the Benelux. Electricity prices (wholesale prices) decrease over time due to the price lowering effect of renewable energies (merit order effect). Large wind and solar capacities, a result of subsidies, push the merit order to the right as marginal costs of these technologies are negligible. Hence, technologies with lower marginal costs are price setting in more hours. In 2050, wholesale prices are about 25 % lower than in the scenario with no renewable support. In the policy scenarios, the stochastic annual generation has large influence with respect to generation, electricity prices and renewable curtailment due to the large deployment of wind and solar technologies.

In quantity-based support mechanisms without the option of banking and borrowing of green certificates ($\textcircled{3a}$ ‘*quota w/out integration (no BaB)*’ and $\textcircled{4a}$ ‘*green certificate market (no BaB)*’), the renewable target is expected to be reached in all weather years. Hence, more renewable capacities and a greater mix of technologies are deployed so the target can be achieved even in weather years with low generation from fluctuating renewables. Due to the stochastic generation of wind and solar capacities, green certificate prices vary significantly between weather years. As wind power is the dominant renewable technology and hence largely deployed under the scenario assumptions, certificate prices are low or even zero in high wind years (w_3). In the low wind year (w_1), green certificate prices are higher due to the utilization of more costly biomass technologies. Moreover, certificate prices are above short-term marginal costs when an additional capacity must be built in order to achieve the renewable target within the specific period.

Given the possibility of banking and borrowing of green certificates and assuming that intermittent renewable generation is balanced over a decade (uncertainty resolved), price and quantity control mechanisms are equivalent ($\textcircled{3b}$ ‘*quota w/out integration (BaB)*’ \equiv $\textcircled{1}$ ‘*feed-in tariff*’ and $\textcircled{4b}$ ‘*green certificate market (BaB)*’ \equiv $\textcircled{2}$ ‘*fixed bonus*’). Under feed-in tariffs or a quota without market integration, the renewable target is achieved over a decade even though the RES-E generation (and RES-E share) differs between weather years. Operators of non-subsidized technologies (nuclear, conventional and storages) react to the higher or lower annual renewable generation. Thus, electricity generation, renewable curtailment, electricity prices and electricity transports vary among weather years depending on the availability of wind and solar generation.

The hourly and regional price signals in price-based and quantity-based support mechanisms with market integration ($\textcircled{2}$ ‘*fixed bonus*’ and $\textcircled{4a}/\textcircled{4b}$ ‘*green certificate market with or without BaB*’) lead to a more efficient mix of renewable capacities. Given limited cost-efficient electricity storage options, the value of electricity depends on a specific point in time. When integrating the hourly price signal in renewable support mechanisms, investors consider the hourly value of electricity and compare it to the production

profiles of technologies with intermittent power generation, rather than simply minimize levelized costs of electricity. In contrast, under feed-in tariffs renewable operators make their investment and generation decisions purely based on the expected revenues from the renewable market, which offers revenues even in hours with wholesale prices equal to zero. Therefore, support mechanisms with market integration lead to a more efficient electricity supply.

Table 9: Overview model results I – capacities and annual generation in Europe for weather years $w_1/w_2/w_3$

	Net capacities [GW]			Net generation (adjusted by curtailment) [TWh]						
	2020	2030	2040	2020	2030	2040	2050			
① 'no subsidy'	Nuclear	104	79	118	132	771/771/771	583/583/583	874/874/874	978/978/978	
	Hard-coal	82	158	223	257	626/626/624	1207/1207/1207	1702/1702/1702	1955/1955/1937	
	Lignite	18	18	18	18	140/140/140	140/140/140	140/140/140	140/140/140	
	Natural gas	289	295	241	242	1065/1051/1040	1007/1007/1007	346/314/283	243/211/196	
	Storages	33	33	33	33	14/14/14	14/14/14	14/14/14	14/14/14	
	Wind	39	1	50	50	64/81/97	3/4/4	130/163/195	130/163/195	
	Solar	24	5	0	0	29/26/24	7/7/6	0/0/0	0/0/0	
	Biomass	15	8	2	2	20/20/20	15/15/15	14/14/14	14/14/14	
	Hydro	124	124	124	124	444/444/444	444/444/444	444/444/444	444/444/444	
	RES-E share [%]	124	124	124	124	18/18/18	14/14/14	16/17/18	15/16/17	
	③ a 'quota w/out integration (no BaB)'	Nuclear	104	79	28	16	749/735/730	559/568/567	187/192/202	117/117/117
		Hard-coal	82	38	30	35	567/560/576	251/247/246	202/205/206	178/182/186
		Lignite	18	18	18	18	135/135/135	136/136/136	136/136/136	140/140/140
Natural gas		281	401	488	536	763/793/786	1113/1117/1114	1319/1312/1303	1129/1129/1140	
Storages		33	33	33	33	14/16/17	17/21/18	21/21/21	14/14/18	
Wind		176	200	289	356	368/460/489	419/524/627	545/681/818	715/894/1073	
Solar		24	271	468	796	29/26/24	424/386/297	679/618/556	1001/910/819	
Biomass		15	11	23	25	109/20/0	80/14/0	171/88/14	190/102/14	
Hydro		124	124	124	124	444/444/437	444/444/444	444/444/444	444/444/444	
RES-E share [%]		104	79	43	31	30/30/30	40/40/40	50/50/50	60/60/60	
③ a 'green certificate market (no BaB)'		Nuclear	104	79	43	31	750/737/731	583/583/567	320/320/320	231/231/231
		Hard-coal	82	38	29	37	569/559/539	264/247/245	186/197/194	175/232/200
		Lignite	18	18	18	18	135/135/135	140/140/136	136/136/136	140/140/136
	Natural gas	280	398	477	506	759/786/759	1059/1045/984	1199/1188/1146	1026/959/1020	
	Storages	33	33	33	33	14/14/17	14/14/18	19/20/20	16/14/18	
	Wind	171	259	314	373	358/448/524	506/632/759	583/729/875	772/965/1158	
	Solar	24	220	456	640	29/26/24	343/312/281	663/603/543	853/776/698	
	Biomass	16	10	19	38	119/32/20	75/14/14	141/55/21	281/165/50	
	Hydro	124	124	124	124	444/444/444	444/444/444	444/444/444	444/444/444	
	RES-E share [%]	104	79	43	31	30/30/32	40/41/44	50/50/51	60/60/60	
	① 'feed-in tariff' ≡ ③ b 'quota w/out integration (BaB)'	Nuclear	104	79	19	6	749/731/731	559/548/516	131/131/132	47/47/47
		Hard-coal	82	47	43	52	596/572/541	333/319/312	309/309/294	295/304/297
		Lignite	17	17	18	17	128/128/128	131/131/128	136/136/136	127/127/124
Natural gas		281	389	498	545	820/785/758	1150/1070/997	1318/1207/1111	1090/978/911	
Storages		33	33	33	33	15/14/14	17/21/21	21/21/21	19/18/19	
Wind		147	273	345	510	315/394/454	528/660/792	682/853/1023	1094/1271/1426	
Solar		24	165	434	618	29/26/24	236/220/205	640/582/524	832/756/681	
Biomass		17	10	4	2	86/86/86	43/43/43	14/14/14	14/14/14	
Hydro		124	124	124	124	444/444/444	444/444/444	444/444/444	444/444/444	
RES-E share [%]		124	124	124	124	28/30/32	37/40/43	49/52/55	61/63/65	
② 'fixed bonus' ≡ ④ b 'green certificate market (BaB)'		Nuclear	104	79	35	23	771/761/747	583/583/567	260/260/260	168/168/168
		Hard-coal	82	39	33	36	578/555/526	298/277/268	230/230/230	235/186/193
		Lignite	18	18	18	18	135/135/135	140/140/136	139/140/140	140/136/134
	Natural gas	282	398	497	547	795/753/723	1100/1020/954	1374/1273/1180	1178/1076/1002	
	Storages	33	33	33	33	14/14/17	14/14/18	16/14/15	14/15/22	
	Wind	157	273	321	424	330/412/495	528/660/792	604/756/907	930/1163/1395	
	Solar	24	178	400	589	29/26/24	277/252/227	596/542/487	803/730/657	
	Biomass	15	8	2	3	84/81/81	43/43/42	14/14/14	21/21/21	
	Hydro	124	124	124	124	444/444/444	444/444/444	444/444/444	444/444/444	
	RES-E share [%]	124	124	124	124	28/30/33	38/41/44	45/48/51	56/60/62	

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

Table 10: Overview model results II – wholesale, capacity and RES-E prices for weather years $w_1/w_2/w_3$

		Wholesale prices [EUR ₂₀₁₀ /MWh]				Capacity price [EUR ₂₀₁₀ /kW _a]			
		2020	2030	2040	2050	2020	2030	2040	2050
⑩ 'no subsidy'	ATCH	46/43/42	66/54/51	67/55/55	65/62/59	69	69	68	68
	BNL	45/42/42	65/53/50	71/55/53	62/59/55	74	72	74	74
	FR	43/41/41	67/54/51	70/54/52	60/57/53	73	72	74	74
	GER	48/45/44	70/57/53	69/54/55	62/61/56	87	39	74	72
	IB	45/45/42	64/55/56	70/56/58	65/61/59	53	61	63	74
	IT	51/47/47	67/53/57	68/54/57	62/59/55	63	60	74	74
	SCAN	48/45/45	68/54/50	67/54/54	61/58/56	74	74	74	74
	UK	44/42/41	67/54/50	70/54/51	60/57/53	74	74	74	74
	RES-E price	0/0/0	0/0/0	0/0/0	0/0/0				
	③a 'quota w/out integration (no BaB)'	ATCH	41/42/43	52/58/51	50/52/67	55/57/50	69	70	71
BNL		41/42/48	53/57/50	56/58/68	53/50/46	74	73	74	74
FR		38/32/28	43/41/34	39/39/50	55/55/49	74	74	74	74
GER		42/44/51	55/61/54	54/57/71	54/53/46	85	42	74	74
IB		45/45/45	28/42/48	30/38/53	47/57/59	49	74	74	74
IT		45/47/53	46/57/53	51/55/73	60/57/63	65	74	74	74
SCAN		29/27/29	50/54/34	54/57/68	50/50/43	74	74	74	74
UK		41/38/40	53/57/50	57/57/66	55/54/48	74	74	74	74
RES-E price		295/69/0	340/63/0	340/88/41	346/94/31				
④a 'green certificate market (no BaB)'		ATCH	41/43/43	55/57/51	58/53/60	52/51/61	70	70	71
	BNL	41/42/47	56/56/50	67/56/61	51/49/56	74	74	74	74
	FR	38/33/31	51/48/34	58/41/43	51/50/64	74	74	74	74
	GER	42/45/51	58/58/52	64/56/63	51/50/56	81	55	74	74
	IB	45/45/42	57/49/46	59/39/39	52/51/71	53	74	74	74
	IT	45/48/50	48/56/53	58/55/62	59/53/75	66	74	74	74
	SCAN	29/27/23	55/52/34	65/54/62	48/48/50	74	74	74	74
	UK	41/38/38	57/56/50	67/55/51	61/53/63	74	74	74	74
	RES-E price	272/27/0	283/0/0	274/33/0	288/47/0				
	① 'feed-in tariff' ≡ ③b 'quota w/out integration (BaB)'	ATCH	44/43/43	66/53/51	74/58/54	51/47/45	69	70	71
BNL		44/42/42	68/52/50	73/56/48	33/28/28	74	74	74	74
FR		41/40/40	58/36/32	56/38/34	61/48/45	73	74	74	74
GER		48/45/44	68/54/52	73/59/54	43/43/43	80	57	74	74
IB		45/45/45	40/28/28	53/38/35	67/50/50	49	74	74	74
IT		49/48/47	63/54/54	70/55/52	62/58/58	63	68	74	74
SCAN		29/26/22	65/49/32	73/59/50	27/22/4	74	74	74	74
UK		41/38/38	68/53/48	72/56/48	71/59/53	74	74	74	74
RES-E price		89/89/89	105/105/105	119/119/119	131/131/131				
② 'fixed bonus' ≡ ④b 'green certificate market (BaB)'		ATCH	44/42/42	66/54/51	74/57/53	63/50/42	70	69	71
	BNL	44/42/41	66/52/50	73/57/54	62/39/31	74	74	74	74
	FR	39/37/31	64/45/32	67/52/42	71/50/39	74	74	74	74
	GER	52/44/44	68/54/52	73/57/54	61/48/41	80	57	74	73
	IB	45/44/42	68/51/44	59/45/40	72/52/50	58	74	74	74
	IT	51/47/47	61/53/53	70/55/52	70/55/57	65	74	74	74
	SCAN	31/29/28	65/49/33	73/57/49	57/36/31	74	74	74	74
	UK	41/38/38	68/53/48	73/56/48	77/52/38	74	74	74	74
	RES-E price	55/55/55	57/57/57	64/64/64	87/87/87				

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

Welfare effects of renewable policies

Within the electricity market model, total welfare is defined as the sum of the producer profit, arbitrageur surplus, incomes from the CO₂ emission policy and the consumer surplus under the consideration of renewable and capacity payments. Given this definition of sectoral welfare, potential benefits of renewable policies such as fewer emissions, positive employment effects as well as lower imports of fossil fuels are not considered. Thus, the welfare effect of all modeled renewable policies is, by definition, negative compared to the 'no support scenario'. However, the analyzed renewable policies perform differently with regard to sectoral welfare. Given the scenario assumptions – technology-neutral and Europe-wide renewable policies starting from 2013; decreasing renewable costs, extensive grid extensions and reducing the challenge of balancing supply and demand to four dispatch situations per year – the accumulated welfare loss over the next 50 years ranges between 194 to 265 bn. EUR₂₀₁₀. Table 11 depicts the total discounted welfare effect (assumed discount rate of 10 %) between the indicated policy and the 'no support scenario'.

Under quantity-based mechanisms without a banking and borrowing scheme ($\textcircled{3a}$ ‘*quota w/out integration (no BaB)*’ and $\textcircled{4a}$ ‘*green certificate market (no BaB)*’), the renewable target must be reached in every year. As power generation from wind and solar technologies varies substantially between years, the costs to reach an annual target differ among weather years. Thus, expecting the renewable target to be reached in every single year increases the policy costs and reduces sectoral welfare. Given the scenario assumptions, longer time frames (e.g. allowing banking and borrowing) reduce the loss of sectoral welfare by about 9-18 %. However, periods that allow banking and borrowing of certificates have to be long enough that fluctuations of wind and solar generation are balanced.

Furthermore, the loss of sectoral welfare associated with a renewable policy can be reduced by a market-based support mechanism. As discussed in the previous section, the electricity mix is more efficient when renewable investors and operators take the hourly and regional market price signal into account. Given the scenario assumptions, a market integration reduces the sectoral welfare loss by about 11-20 %.

Table 11: Total discounted welfare effect between indicated renewable policy and the ‘no support scenario’ [bn. EUR₂₀₁₀]

	price control or quantity control with banking and borrowing	quantity control without banking and borrowing	Benefit of periods for renewable targets
without market integration	$\textcircled{1}$ <i>feed-in tariff</i> $\textcircled{3b}$ <i>quota w/out integration (BaB)</i> - 217	$\textcircled{3a}$ <i>quota w/out integration (no BaB)</i> - 265	+ 48 (18 %)
with market integration	$\textcircled{2}$ <i>fixed bonus</i> \equiv $\textcircled{4b}$ <i>green certificate (BaB)</i> - 194	$\textcircled{4a}$ <i>green certificate (no BaB)</i> - 213	+ 18 (9 %)
Benefit of market integration	+ 23 (11 %)	+ 52 (20 %)	

To illustrate the effects over time (i.e. the influence of a higher renewable share) and the magnitude of each category, Figure 1 shows the welfare effects (not discounted) between the indicated renewable scenario and the ‘no support scenario’ per category and decade.

The general idea of a renewable subsidy is that the payment, electricity producers from renewable energy sources receive, should recover the extra costs for renewable generation compared to conventional power generation. However, as discussed in Bergek and Jacobsson (2010)), technology-neutral payments (i.e., renewable support not based on the cost structure of technologies) allow some technologies to achieve additional rents, often referred to as ‘*windfall or swindle profits*’ (Verbruggen, 2008). Within the model environment, the representative electricity producer is able to achieve additional rents from low-cost renew-

able technologies with limited fuel (i.e., biomass) or space potential (i.e., wind technologies). While in a conventional-dominated electricity market, only nuclear and lignite-fired plants are such limited technologies, all renewable generation options are either restricted based on their capacity or their fuel potential. Thus, the producer profit is higher in all policy scenarios than in the ‘no support scenario’.¹⁷

Total consumer surplus is determined by the wholesale price of electricity, necessary RES-E payments (i.e., subsidies for renewables) and capacity payments (i.e., payments for sufficient back-up capacity). Lower wholesale prices in all renewable policy scenarios, due to the merit order effect, have a positive impact on consumer surplus. However, necessary renewable and capacity payments surmount this benefit. Therefore, total consumer surplus is lower in all policy scenarios compared to the ‘no support scenario’.¹⁸

The actual distribution of rents (between producers and consumers) highly depends on the renewable support scheme. For example, when excluding renewable technologies from the support program that are already cost-efficient, producer profit decreases and consumer surplus increases. A discussion of how renewable costs should be allocated is beyond the scope of this paper. However, it should be noted that adjustments in renewable policy (e.g. reducing windfall profits by excluding technologies or introducing taxes) should not influence the cost-efficient deployment of renewables.

Furthermore, the graph indicates the performance of the analyzed renewable policies dependent on the size of the renewable share. Differences between renewable policies become more obvious in the long term due to the increasing share of renewable energies. For example, a market integration of renewable energies becomes more important as it substantially reduces the amount of necessary subsidies to achieve the renewable target. Within the last decade modeled (2050-2059), a market integrated renewable support (reduces the loss of sectoral welfare by about 350 bn. EUR (not discounted)).

¹⁷The scenario results may give an indication of the extent to which producers can gain additional profits, mostly from large hydro facilities and relatively low-cost wind sites. However, one should keep in mind that the additional rents highly depend on the assumed potential for hydro and wind technologies.

¹⁸Given the assumption of a price-inelastic electricity demand, the depicted effects on the consumer surplus refer to the difference in consumer expenses for electricity.

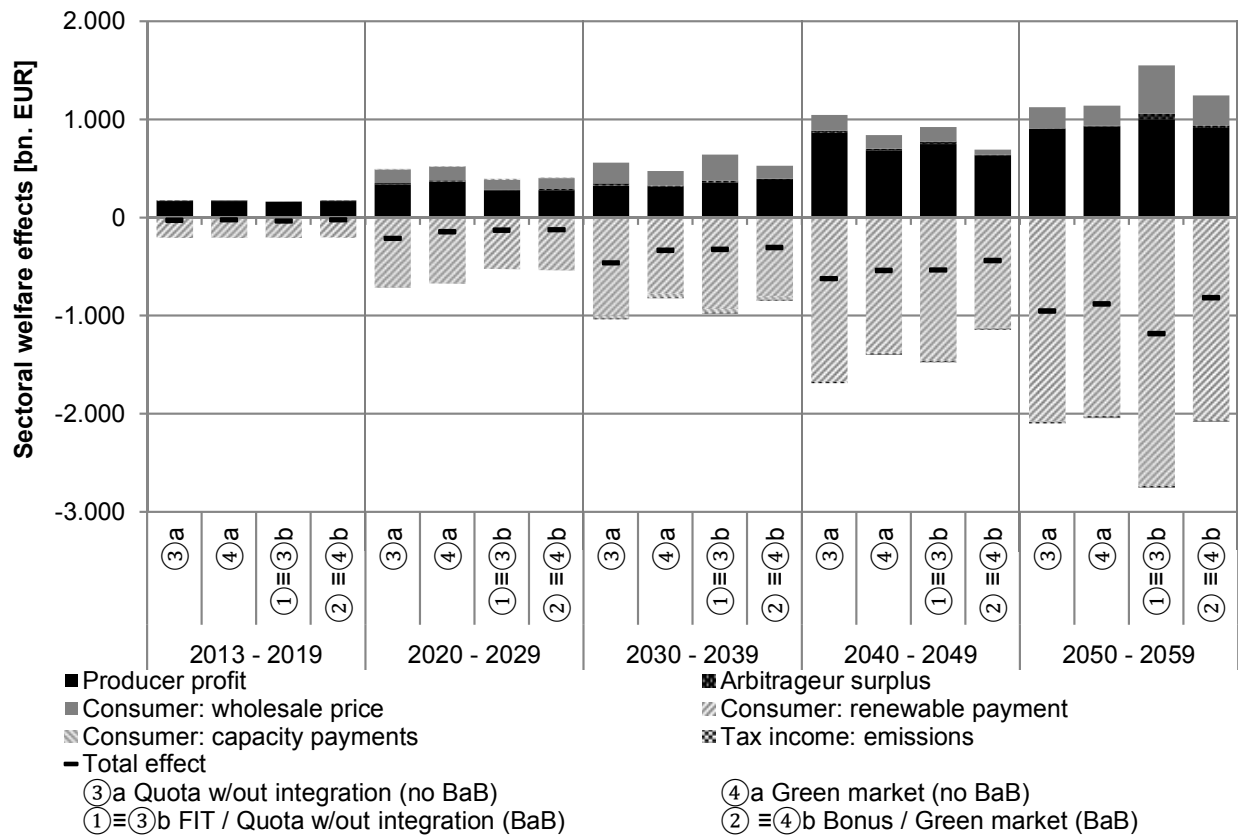


Figure 1: Welfare effects between indicated policy and no support scenarios [bn. EUR]

Investment risk under the analyzed renewable policies

As described above, the electricity producer is able to make profits within the model environment due to restricted fuel availability (i.e., lignite and biomass fuels) or capacity potentials (e.g., potential for wind sites). Additionally, the producer is able to make profits from existing, already depreciated power plants. Thus, the expected profit is positive in all scenarios. However, the profit level is of minor interest in this paper and depends highly on the renewable policy implementation and the assumed capacity limits.

More interesting is the investment risk of electricity producers, measured by the distribution of producer profits, under the various renewable policies. If weather differs from the assumed distribution (i.e., the expected distribution of weather years), actual profit varies from the expected profit due to the resulting substantially different cash-flows. For the purpose of estimating the probability function of the producer profits, annual cash-flows for the different weather years are calculated and 10,000 different weather realizations over the next 50 years are chosen (sampling with replacement). Figure 2 shows box plots for the producer profit including the potential minimum, 25 % quantile, 75 % quantile and the potential maximum

under the different policies.

In the case of no renewable support, the electricity mix remains similar to today and the stochastic wind and solar generation has little impact on the probability function of the producer profit. As a result, the potential deviation from the expected profit is relatively small. Renewable support to achieve a 60 % share of the total electricity generation in 2050 (2020: 30 %, 2030: 40 % and 2040: 50 %) leads to a stepwise reduction of conventional power plants, which are replaced mainly by intermittent renewables. Hence, stochastic full load hours of intermittent renewables have a large influence on prices and rents under the different policies.

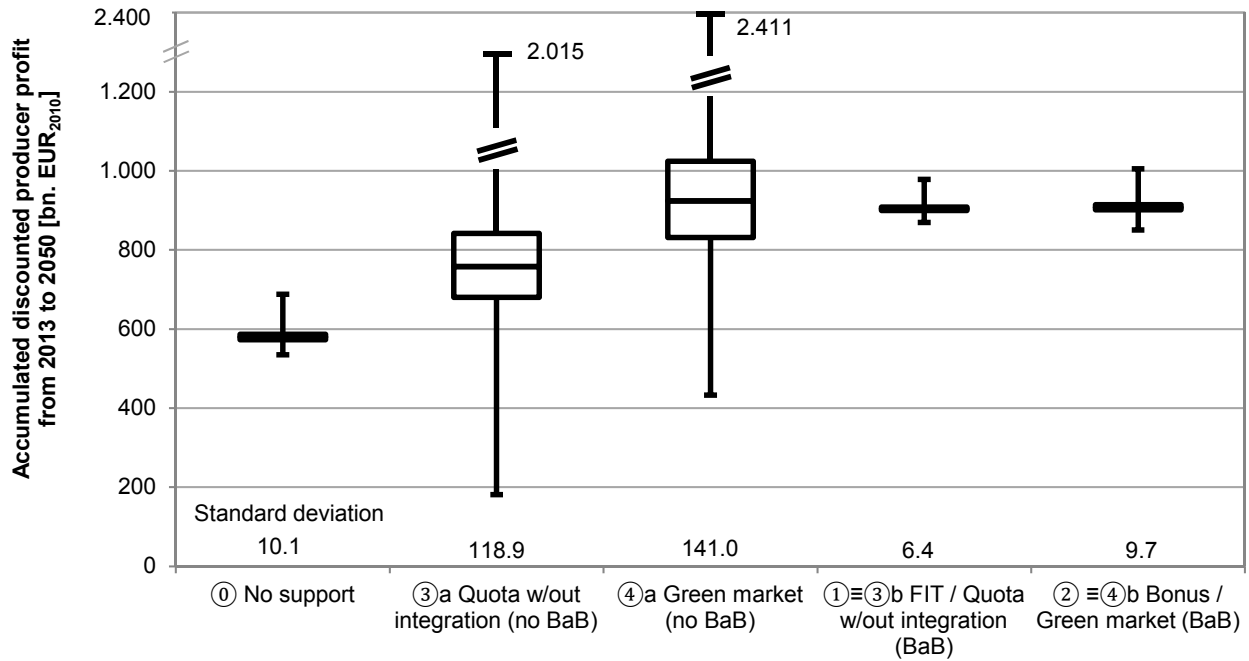


Figure 2: Deviation from expected profit depending on RES-E policy [bn. EUR₂₀₁₀]

Under price-based support mechanisms (① ‘*feed-in tariff*’ and ② ‘*fixed bonus*’) or quantity-based support mechanisms with banking and borrowing mechanisms fully compensating fluctuations (③b ‘*quota w/out integration (BaB)*’ and ④b ‘*green certificate market (BaB)*’), the electricity producer faces volatile marginal returns from intermittent renewables due to the volatile generation and fixed prices. However, total yearly cash-flows of subsidized and non-subsidized technologies are almost balanced under these policies. This is the case because non-subsidized technologies realize higher (lower) cash-flows in years with low (high) generation of intermittent renewables because of higher utilization rates as well as wholesale prices.

Under quantity-based support mechanisms without banking and borrowing (③a ‘*quota w/out integration (no BaB)*’ and ④a ‘*green certificate market (no BaB)*’), the large variance in marginal returns from sub-

sidized technologies (due to a large variance in certificate prices) dominates the balancing effect between subsidized and non-subsidized technologies. Thus, electricity producers with a large share of renewables face a large deviation from expected producer profit. Indeed, the deviation from expected producer profit is about 15-20 times larger (standard deviation) under the quantity-based mechanisms than under fixed price compensations.

Lemming (2003) argues that negatively correlated fluctuations in production of intermittent renewables and green certificate prices may actually reduce the financial risk. In the scenarios, electricity producers face a larger deviation from expected profits under quantity-based support mechanisms rather than under price-based support mechanisms due to the uncertainty about the annual full load hours of wind and solar technologies. Given the cost structure of most renewable energies (capital-intensive), certificate prices vary substantially between weather years and the volatility of certificate prices dominates the realized producer profit. Thus, the simulation results lead to a different conclusion than argued in Lemming (2003). However, it should be noted that the approximation of weather uncertainty by three years limits the robustness of this result.

A market integration is often associated with larger investment risks for renewable investors than under a feed-in tariff support scheme. However, the described scenario results show similar profit distributions under renewable policies with and without market price signal. Thus, this indicates that a market integration of renewables does not lead to a substantially higher financial risk for renewable producers.

4. Conclusion

In recent years, many countries have implemented policies to incentivize renewable power generation. The numerical analysis suggests that integrating the market price signal in renewable support mechanisms reduces the loss of sectoral welfare by 11-20 %. Moreover, investors face an only slightly higher risk than under fixed price compensations. Furthermore, the simulation suggests that electricity firms face a 15 to 20 times larger (standard) deviation from expected profits in quantity-based supports when banking and borrowing is not allowed.

These findings are important for policy discussions which have recently tended to favor feed-in tariffs potentially due to the large progress of renewable energy deployment in countries such as Germany or Spain. However, the analysis shows that the lack of price signals, as under feed-in tariffs, significantly reduces the welfare in the power sector. Additionally, following the discussion of a European renewable quota after 2020, the analysis indicates the importance of an appropriate banking and borrowing mechanism in light of

a greater penetration of stochastic wind and solar generation.

The analysis neglected a few important aspects: First, it neglects regulatory risks by setting prices (e.g., feed-in tariffs) for renewable power generation. Given uncertainty of the actual costs of renewable power generation, regulators are likely to over- or underestimate the costs, causing a large deployment of renewables and high consumer costs (or an under-achievement). Moreover, the analysis identifies different investment risks under the various support schemes but does not account for these risks when determining capital costs. Thus, it would be desirable to quantify the regulatory risk and compare it to the risk of renewable producers under the analyzed support mechanisms. Second, the analysis assumes risk-neutral investors but Ehrenmann and Smeers (2011) show that the risk-neutral analysis may miss a shift towards less capital-intensive technologies that may result from risk aversion. This is particularly interesting due to the capital intensity of most renewable technologies. Third, it would be desirable to explicitly model the policy option of ‘banking and borrowing’ of certificates as an instrument to reduce investment risks in quantity-based support mechanisms. In particular, determining how long banking periods would have to be in order to significantly reduce the investment risks would be an interesting research question.

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Appendix

4.1. Price-based versus quantity-based support mechanism

To analyze the effect of uncertain annual full load hours of intermittent renewables under a price and quantity control, the simple illustration in Table 1 is extended by introducing two renewable technologies $R=\{r_1; r_2\}$ and three weather years $W=\{w_1; w_2; w_3\}$, with probabilities pr^w . It is further assumed that renewable technology r_2 has higher capital ($ic_{r_2} > ic_{r_1}$) as well as variable costs ($vc_{r_2} > vc_{r_1}$). Variable costs of both renewable technologies are constant. It is assumed that the availability of intermittent renewables (av_r^w) depends on the weather year, with $av_{r_1}^{w_1} < av_{r_1}^{w_2} < av_{r_1}^{w_3}$ and $av_{r_2}^{w_1} > av_{r_2}^{w_2} > av_{r_2}^{w_3}$. Furthermore, it is assumed that electricity producers can chose between the renewable subsidy and the market price. Thus, producers receive the maximum of the market price (ϕ) and the renewable payment (fit or ψ). The max-function is not differentiable and should not occur in the first-order conditions. However, it is kept simple for a better illustration.

<i>Feed-in tariff</i>	
$\begin{aligned} \max \pi = & \sum_{w \in W} (pr^w \cdot S_c^w \cdot (\phi^w - vc_c(S_c^w))) \\ & + \sum_{w \in W} (pr^w \cdot S_{r_1}^w \cdot (\max(\phi^w; fit) - vc_{r_1})) \\ & + \sum_{w \in W} (pr^w \cdot S_{r_2}^w \cdot (\max(\phi^w; fit) - vc_{r_2})) \\ & - C_c \cdot ic_c \\ & - C_{r_1} \cdot ic_{r_1} \\ & - C_{r_2} \cdot ic_{r_2} \end{aligned}$	$\begin{aligned} \frac{\partial \mathcal{L}}{\partial S_c^w} : & pr^w \cdot (-\phi^w + vc_c(S_c^w)) + \alpha_c^w \geq 0 \\ \frac{\partial \mathcal{L}}{\partial S_{r_1}^w} : & pr^w \cdot (-\max(\phi^w; fit) + vc_{r_1}) + \alpha_{r_1}^w \geq 0 \\ \frac{\partial \mathcal{L}}{\partial S_{r_2}^w} : & pr^w \cdot (-\max(\phi^w; fit) + vc_{r_2}) + \alpha_{r_2}^w \geq 0 \\ \frac{\partial \mathcal{L}}{\partial C_c} : & -\sum_{w \in W} (av_c^w \cdot \alpha_c^w) + ic_c \geq 0 \\ \frac{\partial \mathcal{L}}{\partial C_{r_1}} : & -\sum_{w \in W} (av_{r_1}^w \cdot \alpha_{r_1}^w) + ic_{r_1} + \beta_{r_1} \geq 0 \\ \frac{\partial \mathcal{L}}{\partial C_{r_2}} : & -\sum_{w \in W} (av_{r_2}^w \cdot \alpha_{r_2}^w) + ic_{r_2} + \beta_{r_2} \geq 0 \end{aligned}$
<p>s.t.</p> $\begin{aligned} av_c \cdot C_c - S_c^w & \geq 0 & (\alpha_c^w) \\ av_{r_1}^w \cdot C_{r_1} - S_{r_1}^w & \geq 0 & (\alpha_{r_1}^w) \\ av_{r_2}^w \cdot C_{r_2} - S_{r_2}^w & \geq 0 & (\alpha_{r_2}^w) \\ cp_{r_1} - C_{r_1} & \geq 0 & (\beta_{r_1}) \\ cp_{r_2} - C_{r_2} & \geq 0 & (\beta_{r_2}) \end{aligned}$	

<i>Quota without market integration</i>	
$\begin{aligned} \max \pi = & \sum_{w \in W} (pr^w \cdot S_c^w \cdot (\phi^w - vc_c(S_c^w))) \\ & + \sum_{w \in W} (pr^w \cdot S_{r_1}^w \cdot (\max(\phi^w; \psi^w) - vc_{r_1})) \\ & + \sum_{w \in W} (pr^w \cdot S_{r_2}^w \cdot (\max(\phi^w; \psi^w) - vc_{r_2})) \\ & - C_c \cdot ic_c \\ & - C_{r_1} \cdot ic_{r_1} \\ & - C_{r_2} \cdot ic_{r_2} \end{aligned}$	$\begin{aligned} \frac{\partial \mathcal{L}}{\partial S_c^w} : & pr^w \cdot (-\phi^w + vc_c(S_c^w)) + \alpha_c^w \geq 0 \\ \frac{\partial \mathcal{L}}{\partial S_{r_1}^w} : & pr^w \cdot (-\max(\phi^w; \psi^w) + vc_{r_1}) + \alpha_{r_1}^w \geq 0 \\ \frac{\partial \mathcal{L}}{\partial S_{r_2}^w} : & pr^w \cdot (-\max(\phi^w; \psi^w) + vc_{r_2}) + \alpha_{r_2}^w \geq 0 \\ \frac{\partial \mathcal{L}}{\partial C_c} : & -\sum_{w \in W} (av_c^w \cdot \alpha_c^w) + ic_c \geq 0 \\ \frac{\partial \mathcal{L}}{\partial C_{r_1}} : & -\sum_{w \in W} (av_{r_1}^w \cdot \alpha_{r_1}^w) + ic_{r_1} + \beta_{r_1} \geq 0 \\ \frac{\partial \mathcal{L}}{\partial C_{r_2}} : & -\sum_{w \in W} (av_{r_2}^w \cdot \alpha_{r_2}^w) + ic_{r_2} + \beta_{r_2} \geq 0 \end{aligned}$
<p>s.t.</p> $\begin{aligned} av_c \cdot C_c - S_c^w & \geq 0 & (\alpha_c^w) \\ av_{r_1}^w \cdot C_{r_1} - S_{r_1}^w & \geq 0 & (\alpha_{r_1}^w) \\ av_{r_2}^w \cdot C_{r_2} - S_{r_2}^w & \geq 0 & (\alpha_{r_2}^w) \\ cp_{r_1} - C_{r_1} & \geq 0 & (\beta_{r_1}) \\ cp_{r_2} - C_{r_2} & \geq 0 & (\beta_{r_2}) \end{aligned}$	

4.2. Effects of a market integration

	PF: $\max \pi = \sum_{l \in L} (S_c^l \cdot (\phi - vc_c(S_c^l)))$ $+ \sum_{l \in L} (S_{r1}^l \cdot (fit - vc_{r1}))$ $+ \sum_{l \in L} (S_{r2}^l \cdot (fit - vc_{r2}))$ $- C_c \cdot ic_c$ $- C_{r1} \cdot ic_{r1}$ $- C_{r2} \cdot ic_{r2}$	$\frac{\partial \mathcal{L}}{\partial S_c^l} : -\phi^l + vc_c(S_c^l) + \alpha_c^l \geq 0$ $\frac{\partial \mathcal{L}}{\partial S_{r1}^l} : -fit + vc_{r1} + \alpha_{r1}^l \geq 0$ $\frac{\partial \mathcal{L}}{\partial S_{r2}^l} : -fit + vc_{r2} + \alpha_{r2}^l \geq 0$
Feed-in tariff	s.t. $av_c^l \cdot C_c - S_c^l \geq 0$ $av_{r1}^l \cdot C_{r1} - S_{r1}^l \geq 0$ $av_{r2}^l \cdot C_{r2} - S_{r2}^l \geq 0$ $cp_{r1} - C_{r1} \geq 0$ $cp_{r2} - C_{r2} \geq 0$	$\frac{\partial \mathcal{L}}{\partial C_c} : -\sum_{l \in L} (av_c^l \cdot \alpha_c^l) + ic_c \geq 0$ $\frac{\partial \mathcal{L}}{\partial C_{r1}} : -\sum_{l \in L} (av_{r1}^l \cdot \alpha_{r1}^l) + ic_{r1} + \beta_{r1} \geq 0$ $\frac{\partial \mathcal{L}}{\partial C_{r2}} : -\sum_{l \in L} (av_{r2}^l \cdot \alpha_{r2}^l) + ic_{r2} + \beta_{r2} \geq 0$ (α_c^l) (α_{r1}^l) (α_{r2}^l) (β_{r1}) (β_{r2})

	PF: $\max \pi = \sum_{l \in L} (S_c^l \cdot (\phi - vc_c(S_c^l)))$ $+ \sum_{l \in L} (S_{r1}^l \cdot ((\phi^l + bo) - vc_{r1}))$ $+ \sum_{l \in L} (S_{r2}^l \cdot ((\phi^l + bo) - vc_{r2}))$ $- C_c \cdot ic_c$ $- C_{r1} \cdot ic_{r1}$ $- C_{r2} \cdot ic_{r2}$	$\frac{\partial \mathcal{L}}{\partial S_c^l} : -\phi^l + vc_c(S_c^l) + \alpha_c^l \geq 0$ $\frac{\partial \mathcal{L}}{\partial S_{r1}^l} : -(\phi^l + bo) + vc_{r1} + \alpha_{r1}^l \geq 0$ $\frac{\partial \mathcal{L}}{\partial S_{r2}^l} : -(\phi^l + bo) + vc_{r2} + \alpha_{r2}^l \geq 0$
Bonus	s.t. $av_c^l \cdot C_c - S_c^l \geq 0$ $av_{r1}^l \cdot C_{r1} - S_{r1}^l \geq 0$ $av_{r2}^l \cdot C_{r2} - S_{r2}^l \geq 0$ $cp_{r1} - C_{r1} \geq 0$ $cp_{r2} - C_{r2} \geq 0$	$\frac{\partial \mathcal{L}}{\partial C_c} : -\sum_{l \in L} (av_c^l \cdot \alpha_c^l) + ic_c \geq 0$ $\frac{\partial \mathcal{L}}{\partial C_{r1}} : -\sum_{l \in L} (av_{r1}^l \cdot \alpha_{r1}^l) + ic_{r1} + \beta_{r1} \geq 0$ $\frac{\partial \mathcal{L}}{\partial C_{r2}} : -\sum_{l \in L} (av_{r2}^l \cdot \alpha_{r2}^l) + ic_{r2} + \beta_{r2} \geq 0$ (α_c^l) (α_{r1}^l) (α_{r2}^l) (β_{r1}) (β_{r2})
