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Referent	Prof. Dr. Felix Höffler
Korreferent	PD Dr. Christian Growitsch
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Contents

1 Introduction

The liberalization of the European electricity markets has a number of consequences. First, the shift away from government-controlled monopolist regimes results in the need to rethink how to ensure security of supply. A possible approach lies in employing capacity mechanisms to ensure adequate generation capacity. However, the need for such mechanisms is a rather controversial topic currently being discussed by policymakers as well as researchers.

The arguments in favor of the necessity of capacity mechanisms are mainly based on the specific behavior of electricity markets: Electricity markets are often characterized by a fluctuating price-inelastic demand and limited storage possibilities for electricity, resulting in high volatility of prices and the ability for players to exercise market power. Thus, in order to prevent the exercise of market power, price caps (or related measures) are being discussed or have already been implemented in many liberalized markets. Binding price caps, however, reduce (spot market) revenues and may therefore lead to insufficient investments in new generation capacities in the long term. This problem is known as the "missing money problem".

The market design debate concerning capacity mechanisms motivates Chapter 2. In this chapter, the impact of price caps and capacity mechanisms on the market structure is analyzed. Many electricity markets consist of one or a small group of large incumbent firms, often former monopolists, who competes with a large number of small competitive new market entrants. We investigate such markets by using a theoretical model in which dominant firms face a competitive fringe of small firms that can freely enter the market and act as price takers. In static models, lower price caps have the effect of reducing the potential to exercise market power. We show that in our dynamic model with endogenous investments, lower price caps result in an increase in market concentration, a higher frequency of capacity withholding and larger profits for the dominant firms.

In the European countries, market design questions regarding capacity mechanisms are typically dealt with on a national basis. However, in a liberalized market framework, the opening of national electricity markets into a larger Internal Energy Market creates a need to investigate cross-border effects as the choice of capacity mechanism can affect neighboring countries.

Chapter 3 addresses this issue by analyzing the cross-border effects of different capacity mechanisms in neighboring countries. For the analysis of cross-border effects, we consider a model defined by two connected countries that only differ in the regulators' choices on capacity mechanisms, namely strategic reserves and capacity payments. Strategic reserves are generation capacities procured and controlled by a regulator and reserved for cases of capacity scarcity, i.e., strategic reserves are withheld from the market. Capacity payments are fees that are paid for generation capacity; the fees can be quantified by a regulator or, alternatively, determined in capacity markets in which the target capacity is fixed. In contrast to strategic reserves, capacity payments do not limit the participation in the market. In both countries, competitive firms can freely enter the market, invest in generation capacities and sell electricity on the spot market. Market equilibria are determined, and it is shown that different capacity mechanisms lead to redistribution effects such that the country with strategic reserves is worse off; the consumers' costs are higher in this country.

The liberalized electricity market also impacts the realization of policy objectives such as an increase in the share of electricity generation from renewable energies. Until now, fluctuating renewable energy technologies have benefited from support mechanisms (e.g., by fixed feed-in-tariff systems) in order to give incentives for investing. However, there may at some point be a fully integration of renewables in the market. Thus, it becomes increasingly important to understand the interaction between renewable energy generation and electricity markets.

The need to understand the interrelation between renewable energies and electricity spot markets is the motivation for Chapter 4. In this chapter, we analyze the value of wind power and, more specifically, the impact of the spatial dependencies of wind power on its market value. Wind power has been growing significantly during the last decade and increasingly affects electricity spot prices: Since its marginal generation costs are close to zero, wind power replaces other generation technologies when the wind blows and hence leads to generally lower spot market prices. Furthermore, prices become more volatile due to the stochastic nature of wind. However, it is clear that the market value of a specific wind turbine depends on whether it produces when other turbines also produce or, in contrast, generates electricity when production from wind power is generally low. In this chapter, we create a stochastic simulation model for electricity spot prices that captures the full spatial dependence structure of wind power by using copulas. We then calibrate the model to German data. It is shown that the specific location of a turbine, i.e., its spatial dependence with respect to the aggregated wind power in the system, is very important for its value. Many of the locations analyzed show an upper tail dependence that adversely impacts the market value.

The three chapters address different research questions that require different methodologies. Chapters 2 and 3 deal with market design issues. In both studies, we analytically derive market equilibria and analyze comparative statics. In Chapter 2, in addition to competitive firms, strategic players are considered and hence game theoretical methods are employed, while in Chapter 3 all players are assumed to be competitive. Chapter 4 constitutes a quantitative analysis on the value of wind power. For this analysis, we apply econometric methods. More precisely, we introduce copulas and develop a stochastic simulation model.

The remaining part of the introduction consists of the extended abstracts to provide a non-technical overview of the three papers presented in this thesis.

Chapter 2: Capacity Mechanisms and Effects on Market Structure (based on Elberg and Kranz (2014))

In this chapter, the impact of price caps and capacity mechanisms on the market structure is analyzed, as specified by the market shares, the profits of dominant and competitive firms as well as the frequency of capacity withholding. The chapter is based on the working paper by Elberg and Kranz (2014) to which both authors contributed equally.

For our analysis we choose a model with a fluctuating price-inelastic electricity demand, where a (strategically operating) *dominant firm* faces a *competitive fringe* of small firms that can freely enter the market and act as price takers. In the first stage, firms invest in capacity and than, in a second stage, sell electricity on the spot market.

The regulator imposes a spot market price cap, defines the security of supply target and procures the corresponding capacity in a (descending-bid) *capacity auction* that yields a uniform capacity payment (per capacity unit) to each firm providing capacity. Afterwards, the firms offer electricity on the spot market on which pricing is as follows: If the sum of the fringe capacity and the dominant firm's offered electricity exceeds demand, competition of the fringe firms drives prices down to marginal generation costs. Otherwise, electricity is considered scarce, and the price rises to the price cap.

We find the following main result: A reduction of the price cap increases the profits and the market share of the dominant firm, as well as the frequency of capacity withholding on the spot market. The intuition for this result is as follows: To earn higher spot market profits, the dominant firm holds back capacity to increase spot market prices, thus having on average lower capacity utilization in peak price periods than the competitive firms. Hence, if the spot market price cap is lowered, then spot market revenues per capacity unit of the dominant firms are reduced to a lesser extent than those of the fringe firms. To reach the fixed capacity target, a reduction in spot market revenues must lead to higher capacity payments from the capacity auction. Since both the dominant firm and the competitive fringe receive equal capacity payments per capacity unit, the dominant firm benefits from this revenues shift from the spot market to the capacity mechanism.

We extend our model in two dimensions. First, we show the robustness of our result for *alternative capacity mechanisms*: subsidies and strategic reserves. If *capacity subsidies* are paid, the regulator chooses the subsidy level such that the equilibrium capacities of the dominant firm and the fringe firms sum up to the target capacity level. The intuition for why our main result also applies to this capacity mechanism is similar to that of the auction case: The regulator compensates for the reduction in the price cap by increasing subsidies, which benefits the dominant firm. A comparison of the dominant firm's profits under capacity auctions and capacity subsidies shows that the dominant firm earns weakly higher profits under capacity auctions than under subsidies.

Strategic reserves are generation capacities procured and controlled by a regulator and are only used in times of scarcity, i.e., if a supply shortage occurs or if the price exceeds a trigger price (that equals the maximum price in our model). The regulator procures strategic reserves such that these together with the equilibrium capacities of the dominant firm and fringe firms sum up to the target capacity level. We show that for the case of no price cap (i.e., the price rises up to infinity), the dominant firm's capacity and profits decrease to zero.

The second extension addresses the case of *multiple dominant firms*. We show that our main result holds for the case of multiple dominant firms, namely that the dominant firms market share and profits as well as the frequency of capacity withholding decrease in the price cap. We prove that in the case of capacity auctions, an equilibrium exists in which the actions of the dominant firms are "collusive" i.e., the result for one dominant firm is replicated by an arbitrary (finite) number of dominant firms. Furthermore, we show that this result also carries over for the case of capacity subsidies and strategic reserves.

Chapter 3: Cross-Border Effects of Capacity Mechanisms in Electricity Markets

In this chapter, the effects resulting from different choices of capacity mechanisms in neighboring countries are investigated. I am the sole author of this study, which has not yet been published.

For the analysis, a model is chosen with two countries, *connected* by some given cross-border transmission capacity, that are *symmetric* in the sense that they face the same fluctuating price-inelastic electricity demand and ensure the same reliability level of electricity. In both countries, *competitive firms* can freely enter the market, build up generation capacities and sell electricity on the spot market. Both countries only differ in their capacity mechanisms: *strategic reserves* or *capacity payments*.

Strategic reserves are generation capacities procured by a regulator to achieve the capacity level that corresponds to the target reliability level of electricity. These capacities are withheld from the market and only used in times of scarcity. *Capacity payments* are fees that are paid for capacity to incentivize sufficient investments in order to meet the predefined capacity target. In contrast to strategic reserves, capacities that receive capacity payments participate in the spot market.

The spot market prices deviate from the firms' marginal generation costs only in times of scarcity, when the high scarcity (maximum) price is reached. Cross-border trading leads to equal prices in both markets when the transmission capacity is non-binding; otherwise, the prices in both markets may differ from one another.

Market equilibria are determined and yield the following main result: Although in isolation both types of capacity mechanisms induce identical costs, in interconnected countries the choice of capacity mechanisms leads to redistribution effects that leave the country with strategic reserves in a relatively worse position; the consumers' costs in this country are higher compared to the country with capacity payments.

The main effect driving this result comes from the fact that strategic reserves are only used in case of scarcity. In these situations, prices are high and attract electricity imports from the other country. Hence, a part of the high payments for electricity consumption by consumers from the country with strategic reserves leaks to the other country with capacity payments. The imports reduce the average capacity utilization and, consequently, the average revenues of the strategic reserves. This negatively impacts the consumers' costs in the country with strategic reserves. At the same time, the additional payments from exporting electricity implicitly benefits the consumers of the country with capacity payments.

The model is extended to the case of two technologies, base and peak load. It is shown that the amount of base load technology is independent of whether capacity mechanisms are introduced. Capacity mechanisms only increase the amount of peak load technologies. The main result carries over to the case of two technologies: If the two different capacity mechanisms are introduced in neighboring countries, the country with strategic reserves is worse off since its consumer costs are higher. In contrast, the country with capacity payments benefits from this situation.

Chapter 4: Spatial Dependencies of Wind Power and Interrelations with Spot Price Dynamics (based on Elberg and Hagspiel (2013))

In this chapter, we examine the value of wind power at different locations and, in particular, how the spatial dependencies of wind power affect its value. This chapter is based on the working paper by Elberg and Hagspiel (2013); both authors contributed equally to all aspects of the study.

To investigate the value of wind power, we develop a stochastic simulation model capturing the spatial dependencies of wind power by using *copulas* that are incorporated into a *supply- and demand-based model* for electricity spot prices. More precisely, we model the interrelation between the wind power of a single turbine at some specific location and the spot market prices for electricity; to this end, we establish the relationship of the aggregated wind power in the system, to the spot market prices as well as to the single turbine's wind power.

In a first step, we develop a supply- and demand-based model for spot prices that incorporates the aggregated wind power. Since the marginal generation costs of wind power are close to zero, wind power (if available) replaces generation from other technologies. We use hourly spot market prices, electricity demand and the aggregated amount of wind power to establish a functional relationship between spot prices and the residual demand, defined as the difference of total demand and wind power. We feed the price process with series of the aggregated wind power and add a stochastic spot price component in order to account for additional price movements caused by random events, such as, e.g., unplanned power plant outages.

In a second step, we link the aggregated wind power to the wind power of single turbines to determine the value of wind power at different locations. To capture the entire stochastic dependence structure, we use *copulas*. With the help of copulas, we can account for symmetric or asymmetric dependence structures as well as for no tail, upper or lower tail dependencies.

We calibrate the model with German data since Germany already shows a high share of wind power in the generation mix. We use hourly wind speeds for many stations in Germany over a period of more than two decades to derive synthetic wind power curves describing the electricity generation that the currently installed wind capacities would have produced in the last decades. With this model, we then derive the revenue distribution and the market value for a turbine, i.e., the weighted average spot price that the turbine is able to collect by selling electricity on the spot market.

We find that taking the complete dependence structure between the aggregated wind power and a single turbine's generation into account is indeed necessary; simply using the correlation coefficient or linear measures would lead to incorrect conclusions regarding the market value of a turbine. Since many of the stations analyzed show an upper tail dependence that adversely impacts the market value, linear measures would systematically overestimate the market value in these cases. Some of the locations do not show an upper tail dependence and therefore have a relatively higher market value.

For the 19 stations analyzed in Germany, we find that the expected market value is up to 8 Euro/MWh lower than the average spot price level of 49.80 Euro/MWh for the year 2011 and varies by up to 6 Euro/MWh for the different locations.

Furthermore, we investigate the market value of wind power for changing wind power penetration levels. Our results show that for the case of increasing wind power penetration levels, the adverse impact of an upper tail dependence structure could become even more important.

2 Capacity Mechanisms and Effects on Market Structure

Liberalized electricity markets are characterized by fluctuating price-inelastic demand of non-storable electricity, often defined by a substantial market share held by one or few incumbent firms. These characteristics have led to a controversial discussion concerning the need for and the design of capacity mechanisms, which combine some form of capacity payments with price caps in the spot market. The purpose of this study is to understand the effects of capacity mechanisms on the market structure. We consider a model with dominant firms and a competitive fringe and investigate the impact of price caps and capacity payments on investment incentives and market concentration. While lower price caps reduce the potential for the exercise of market power in static models, we find that in the dynamic model with endogenous investments, lower price caps result in an increase in market concentration, the frequency of capacity withholding and the profits of the dominant firms.

2.1 Introduction

The need for and the design of capacity mechanisms have been controversially discussed during recent years. Researchers as well as policymakers are concerned that there may not be sufficient investment incentives for adequate generation capacity on the wholesale market.[1] As the European Commission (2012) summarizes, "ensuring generation adequacy in electricity markets has become an increasingly visible topic in the policy discussion".

The reason for the concerns and the subsequent debate about capacity mechanisms is often based on the following line of argument: Electricity markets are characterized by a fluctuating price-inelastic demand and limited storage possibilities, which can cause high price volatility and facilitate the exercise of market power.[2] There-

[1]See, for example, Joskow (2008), Cramton and Stoft (2005), Finon and Pignon (2008).

[2]Market power in electricity markets has been studied, for example, by Borenstein et al. (2002) and Wolfram (1999).

fore, price caps or related measures are often proposed or are already implemented to reduce the potential of market power in the spot market. However, binding price caps reduce spot market revenues and may therefore lead to a lack of investments in the long term. This problem is often referred to as the "missing money" problem and is intensively discussed in economic literature, e.g., by Hogan (2005), Cramton and Stoft (2006) or Joskow (2008). For this reason, capacity mechanisms have been introduced or are currently being debated in many liberalized electricity markets. Typically, capacity mechanisms consist of some form of capacity payments and come along with price caps or similar measures to address the missing money and the market power problems.

The purpose of this paper is to analyze the effects of capacity mechanisms on the market structure. In many electricity markets, the market structure is given by a small group of large incumbent firms (or a single large firm) which competes with many small competitive firms. We investigate such markets using a model with fluctuating price-inelastic electricity demand, in which dominant firms face a competitive fringe of small firms that can freely enter the market and act as price takers. Investments take place in the first stage, followed by firms selling electricity on the spot market. We analyze how the level of price caps and capacity mechanisms affect the market structure, specified by the resulting market shares, the profits of the dominant and competitive firms as well as the frequency of capacity withholding on the spot market.[3] Focus is centered on three common forms of capacity mechanisms: capacity auctions, subsidies and strategic reserve.[4]

We find the following main result, which holds robustly for different forms of capacity mechanisms: if the price cap decreases, the market share and profits of the dominant firms increase and the frequency of capacity withholding in the spot market also increases. This means that even though lower price caps reduce the potential for static market power exertion, there is a robust counter-veiling force such that a reduction of price caps increases market concentration as long as total capacity is fixed by a capacity mechanism. The main intuition is as follows: when fixing a target level of total capacity, a lower price cap means that spot market revenues decrease

[3]Besides price caps, other control methods to reduce market power and price volatility exist, e.g., reliability options or bid caps on the spot market see Cramton and Stoft (2008); Joskow (2008). All three of these methods lead to a reduction of the generators' profits in times of scarcity. For our analysis, only this impact is important; therefore we do not distinguish between the different methods.

[4]Capacity markets with capacity auctions have been introduced in many electricity markets in the US as well as in Central and South America. Examples include the Forward Capacity Market (ISO New England), the Reliability Pricing Model (PJM) and the Colombia Firm Energy Market. Strategic reserves are used in Sweden and Finland. Capacity subsidies are paid in Spain and Portugal.

and a larger fraction of firm revenues must come from the capacity mechanism. This shift in revenue streams benefits the dominant firms relative to the competitive fringe for the following reason: in order to raise spot market profits, dominant firms hold back capacity to increase spot market prices, thus having a lower capacity utilization in peak price periods. As a consequence the average revenue per capacity on the spot market of the dominant firms is lower than that of the competitive firms. On the other hand, a dominant firm and a competitive firm benefit equally from the capacity payments. When fixing a target level of total capacity, a lower price cap means that energy market revenues decrease and a larger fraction of firm revenues must come from the capacity mechanism. This shift in revenue streams benefits the dominant firms relative to the competitive fringe for the following reason: The dominant firms have on average a lower capacity utilization during peak price periods due to the fact that they hold back capacity to increase spot market prices. Therefore, the average revenue per capacity on the spot market of the dominant firms is lower than that of the competitive firms. On the other hand, a dominant firm and a competitive firm benefit equally from the capacity payments.

The effects of price caps on investments, market outcomes and market power have been studied by Zoettl (2011) and Fabra et al. (2011). Zoettl (2011) analyzes the impact of reduced scarcity prices on investment decisions of strategic firms in base-load and peak-load technologies. He shows that an appropriately set price cap can increase investments in peak-load capacity without reducing base-load investments. Fabra et al. (2011) extend the analysis of Fabra et al. (2006) by analyzing strategic investment incentives in electricity markets in a duopoly model. They compare the impact of uniform-price vs. discriminatory auction formats and price caps on investment incentives. They find that although prices are lower in discriminatory auctions, the aggregated capacity is the same for both auction formats. Grimm and Zoettl (2013) analyze strategic investment decisions and compare different spot market designs. They find that investment incentives decrease if spot markets are designed in a more competitive fashion. Our main contribution to this literature is that we explicitly consider capacity mechanisms and their effects on the market structure.

The remainder of this paper is structured as follows: In Section 2.2, we describe the model defined by a single dominant firm and a competitive fringe and discuss the main results for a capacity auction. Section 2.3 illustrates robustness of the results for different capacity mechanisms. Section 2.4 shows that the results also apply for multiple dominant firms. Section 2.5 concludes. Proofs are relegated to the Appendix, Section 2.6.

2.2 The Model

We consider a model with a strategic dominant firm m and a competitive fringe f consisting of many small firms that act as price takers. There are two stages: In the first stage, firms perform long-term capacity investments. In the second stage, firms compete in the electricity spot market, which is characterized by fluctuating price-inelastic electricity demand.

During the investment stage, the dominant firm and fringe firms build up their capacities $x_m \in [0,1]$ and $x_f \in [0,1]$, respectively. The structure of the investment game varies between the different capacity mechanisms described below. The fixed costs per unit of capacity (including investment and fixed operation costs) are denoted by k_m and k_f. We allow the dominant firm to have a fixed cost advantage due to expert knowledge or economies of scale, i.e., $k_m \leq k_f$.[5] Variable per unit costs of electricity generation are identical for all firms and denoted by c.

2.2.1 Spot Market Behavior

We first describe the spot market and characterize its outcome. Electricity demand is given by a non-negative random variable D with distribution function G and a continuously differentiable density function g. There is a maximum level of demand, which we normalize to 1. We assume that $g(D)$ is strictly positive for all $D \in [0,1]$. One can interpret G as the distribution of demand over a large number of hours in which spot market competition with given capacities takes place.

After observing realized demand, the dominant firm chooses an output level q_m with $q_m \leq x_m$.[6] If the sum of the fringe capacity and the dominant firm's chosen output exceeds total demand D, competition by fringe firms will drive the spot market price down to the variable costs c. Otherwise, electricity is scarce and a maximal price

[5] Expert knowledge and economies of scale are important factors in electricity markets due to the very high investment costs and the corresponding risk that needs to be assessed accordingly, i.e., for large incumbent firms with power plant portfolios or small new entrants. In addition, the locational advantage of incumbent firms is of particular importance: Existing power plants can be extended or replaced by new power plants, which reduces location and infrastructure costs. As shown below, a strict cost advantage is crucial for the existence of market power in our model with free entry.

[6] We would obtain the same results if the dominant firm offered supply functions that specify price-quantity schedules.

$\bar{P} > c$ is reached.[7] $\bar{P}$ corresponds either to a price cap determined by the regulation or to the value of lost load (VOLL), which indicates the amount that customers are willing to pay to avoid a power outage. Written compactly, the spot market prices satisfy

$$P\left(q_m, x_f, D\right) = \begin{cases} \bar{P} & \text{if } D \geq q_m + x_f \\ c & \text{if } D < q_m + x_f. \end{cases} \tag{2.1}$$

When demand is below the total capacity of the competitive fringe x_f, the spot market price always equals the variable generation costs c. The dominant firm then cannot influence the price level. When demand exceeds the fringe capacity, the dominant firm always has an incentive to withhold just enough capacity that scarcity drives the price up to $\bar{P}$, i.e. it then optimally chooses

$$q_m = min\left\{D - x_f, x_m\right\}.$$

For fixed x_f, the equilibrium prices on the spot market are therefore independent of the dominat firm's capacity x_m and given by

$$P = \begin{cases} \bar{P} & \text{if } D > x_f \\ c & \text{if } D \leq x_f. \end{cases} \tag{2.2}$$

Positive spot market profits are only achieved in periods with a peak price $P = \bar{P}$. To avoid uninteresting case distinctions, we restrict attention to the case that $x_f + x_m \leq 1$.[8] The expected variable spot market profits per capacity unit of the dominant firm and the competitive fringe are given by

$$\pi_m^s = (\bar{P} - c)\left(\left(1 - G(x_f + x_m)\right) + \int_{x_f}^{x_f + x_m} \frac{D - x_f}{x_m} g(D)\, dD\right) \tag{2.3}$$

$$\pi_f^s = (\bar{P} - c)\left(1 - G\left(x_f\right)\right). \tag{2.4}$$

To avoid uninteresting case distinctions, we henceforth make

Assumption 1. *The maximum spot market markup $\bar{P} - c$ is strictly larger than the fringe firm's fixed cost of capacity k_f.*

[7] We assume that if electricity demand exceeds total supply, there is a partial blackout. The network operator cuts off exactly so many consumers from the electricity supply that total consumption equals the given supply.

[8] In our model, there is no need for a regulator to design a capacity mechanism that yields a total capacity above the maximum demand.

From Assumption 1 and Equation (2.4), it follows that the competitive fringe builds a positive capacity $x_f > 0$. We denote the average capacity utilization (capacity factor) of the dominant firm in periods with peak price by:

$$\phi_m = \mathbb{E}_D \left[\frac{q_m}{x_m} \middle| D > x_f \right].$$

We can then compactly write its expected spot market profits as

$$\pi_m^s = (\bar{P} - c)\left(1 - G\left(x_f\right)\right)\phi_m. \tag{2.5}$$

If fringe capacity is below the maximum demand, there are always some demand realizations in which capacity withholding is optimal for the dominant firm, which implies

$$\phi_m < 1.$$

In contrast, the fringe firms always utilize their whole capacity in peak price periods. Hence, while the dominant firm benefits from capacity withholding on the spot market, a fringe firm benefits even more. We therefore directly find

Proposition 1. *If $x_m > 0$ and $x_f < 1$, the dominant firm's expected spot market profits per capacity unit are strictly below those of a fringe firm and satisfy*

$$0 < \pi_m^s = \phi_m \pi_f^s.$$

2.2.2 Investments and Capacity Auctions

We assume that the regulator imposes a spot market price cap $\bar{P}$ but at the same time wants to ensure a reliability level ρ, which measures the probability that no blackout takes place due to insufficient supply, i.e.,

$$\rho \equiv \mathbb{P}(D \leq x_m + x_f).$$

In our model, fixing a reliability level is equivalent to fixing a total capacity

$$x_T \equiv x_m + x_f.$$

We investigate a market design in which the desired capacity x_T is procured in an auction that yields a uniform capacity payment to each firm that is willing to provide capacity. Capacity auctions exist in many electricity markets in the USA as well as in Central and South America. Examples include the Forward Capacity Market (ISO New England) and the Colombia Firm Energy Market (see, e.g., Cramton (2006) or Cramton (2007)). We consider a multi-unit descending bid auction. Ausubel and Cramton (2006) discuss this auction type and its application for capacity procurement. The auctioneer starts by announcing a high initial capacity payment (auction price) that is offered for each unit of capacity. At each price level, firms simultaneously announce the capacities that they are willing to build. The price is continuously decreased as long as the offered supply of capacity exceeds the demand for capacity x_T.[9] At any given price, firms can at most offer the same amount of capacity that they had previously offered at a higher price, i.e., offered capacity levels must weakly decrease during the auction. The resulting uniform capacity payment will be the infimum of those auction prices at which the capacity offered was at least as high as capacity demand.[10] Consider an auction outcome with capacities x_m, x_f and capacity payments z. A fringe firm's expected profits per capacity unit, including spot market profits, fixed cost and capacity payments, are then given by

$$\pi^f = \left(\bar{P} - c\right)\left(1 - G\left(x_f\right)\right) - k_f + z.$$

Hence, fringe profits are zero whenever fringe capacity and capacity payments satisfy the following relationship

$$z = k_f - \left(\bar{P} - c\right)\left(1 - G\left(x_f\right)\right). \tag{2.6}$$

Consistent with the assumption that fringe firms act as price takers and there is free entry, we assume that for any offered capacity payment z during the auction, total fringe supply is such that the zero profit condition (2.6) exactly holds. As capacity payments decrease during the auction, the offered fringe capacity also decreases. Figure 2.1 illustrates this zero profit curve as a fringe supply curve for different capacity payments.

If the dominant firm bids in all rounds some constant capacity $x_m \in [0, 1]$, we have the following auction outcome: the dominant firm receives the capacity x_m, the fringe capacity is $x_f = x_T - x_m$ and the capacity payments z are determined by the zero profit curve (2.6). Given the competitive bidding of the fringe firms, the dominant firm has no alternative bidding strategies that could lead to different auction outcomes than the simple strategy of bidding a constant x_m. This means

[9] It is a common simplification in theoretical models to assume that prices decrease in a continuous fashion, even though in real world auctions discrete bid decrements are often used.

[10] In case of excess supply at this price, capacity is randomly allocated.

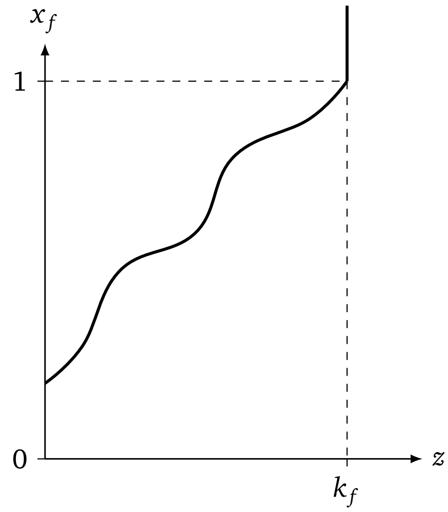


Figure 2.1: Illustration of the fringe capacity as function of capacity payment derived from the fringe's zero profit curve

that the dominant firm influences the auction outcome and the resulting capacity payments in its choice of x_m. However, its ability to exert market power in the auction is limited by the competitive behavior of the fringe who determines the auction price corresponding to each choice of x_m. By substituting the values for z and x_f, the dominant firm's expected total profits

$$\begin{aligned}\Pi^m &= \left(\pi^s_m + z - k_m\right) x_m \\ &= \left(\left(\phi_m\left(x_m\right) - 1\right)\left(\bar{P} - c\right)\left(1 - G\left(x_T - x_m\right)\right) + k_f - k_m\right) x_m\end{aligned} \tag{2.7}$$

can be written as a function of the desired level of x_m. The dominant firm simply maximizes these profits over x_m. Without imposing further (quite strong) assumptions on the demand distribution G, the dominant firm's profit function is not concave in general. This means that the first order condition of zero marginal profits is not sufficient for an optimal capacity choice, and we cannot rely on the implicit function theorem for comparative statics. Nevertheless, using methods of monotone comparative statics (Milgrom (2004)), we can establish the following general result.

Proposition 2. *If a fixed total capacity x_T is procured in a multi-unit descending bid auction, the dominant firm's total profits Π^m, its capacity x_m and market share, as well as the frequency of capacity withholding in the spot market decrease if the price cap $\bar{P}$ increases.*

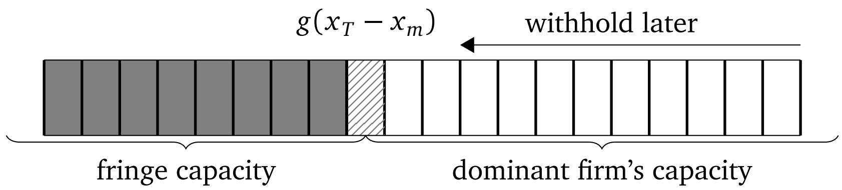


Figure 2.2: Illustrating the effect of a marginal capacity expansion of the dominant firm

Main intuition for why the dominant firm's profits decrease in the price cap $\bar{P}$: Even though at first thought it may seem counter-intuitive that the dominant firm's expected profits are decreasing in the price cap, there is a nice economic intuition for this result. Ceteris-paribus, i.e., holding capacities x_m and x_f fixed, an increase in the price cap $\bar{P}$ increases the spot market profits of both the fringe firms and the dominant firm. Since the capacity payment z in the auction is determined by the fringe firm's zero profit, it adjusts downwards accordingly. This means that an increase in the price cap $\bar{P}$ induces a shift in the revenues from the capacity market to the spot market that is profit-neutral for fringe firms. Recall that the dominant firm makes lower expected spot market profits per capacity unit than the competitive fringe since, due to capacity withholding, the dominant firm has a lower capacity utilization $\phi_m < 1$ in times of peak prices than fringe firms. On the other hand, the dominant firm benefits as much per capacity unit from the capacity payment z as a fringe firm. Hence, a revenue shift from capacity market to spot market that is profit neutral for fringe firms reduces expected total profits of the dominant firm. Reversely, a reduction of the spot market price cap $\bar{P}$ causes a revenue shift from spot markets to capacity markets that benefits the dominant firm. This intuition is quite robust: Even if we had elastic electricity demand, the dominant firm would make lower average profits on the spot market than a fringe firm and therefore prefer revenue shifts from the spot market to the capacity market.

More detailed intuition: To gain a deeper intuition of Proposition 2, consider the derivative of the dominant firm's total profits (2.7) with respect to its constant auction bid x_m, taking all effects into account. It can be compactly written as[11]

$$\frac{\partial \Pi^m}{\partial x_m} = (k_f - k_m) - g(x_T - x_m)(\bar{P} - c)x_m. \tag{2.8}$$

To interpret this marginal profit function, consider Figure 2.2. Each box illustrates

[11] See the appendix for a derivation.

a small capacity unit, with the shaded box indicating the unit which has transferred from the fringe to the dominant firm in the event the dominant firm marginally increases its capacity x_m. If the dominant firm performs capacity withholding on the spot market, we assume w.l.o.g. that it first withholds capacity units that are more to the right in Figure 2.2. Since the newly acquired capacity unit is the last unit that is withheld, the dominant firm earns approximately the same expected spot market profit from this unit as the competitive fringe. Given that the fringe firms' profits from the last capacity unit are internalized in the capacity payment z, the dominant firm has a gross benefit from this extra unit equal to its fixed cost advantage $k_f - k_m$, which appears as the first term in the marginal profit function.

A marginal increase in the dominant firm's capacity x_m marginally decreases the fringe capacity x_f and therefore increases expected spot market revenues, which causes capacity payments to fall. This shift from capacity market revenues to spot market revenues decreases the dominant firm's total profits due to the intuition explained above.

This negative impact is captured by the term $-g(x_T - x_m)(\bar{P} - c)x_m$ in the marginal profit function. To understand this term, consider the case in which realized spot market demand is just slightly above the new fringe capacity, so that the dominant firm withholds all its capacity including the newly acquired capacity unit. The density $g(x_T - x_m)$ can be interpreted as a measure for the "probability" of this event occurring. The fringe firms then earn a spot market profit of $(\bar{P} - c)$ per unit, which they would not have made if the dominant firm had not expanded its capacity. This increase in fringe firms' expected spot market profits translates into a lower auction price, which reduces the capacity payments for all x_m inframarginal capacity units of the dominant firm.

This negative effect in the marginal profit function is ceteris paribus increasing in the price cap $\bar{P}$. Intuitively, this is because a higher price cap means that an increase in the dominant firm's capacity causes a stronger revenue shift from capacity markets to spot markets. For this reason the dominant firm's equilibrium capacity is decreasing in the price cap $\bar{P}$.

Necessity of fixed cost advantage for market power: We also see from (2.8) that it can only be profitable for the dominant firm to build a positive capacity if it has a fixed cost advantage, i.e. $k_m < k_f$. Given that a firm with market power gains fewer spot market profits than a competitive firm, it is clear that market power can only arise if the dominant firm has a cost advantage.

Welfare

Proposition 2 has the following implication on total welfare:

Corollary 1. *Given completely inelastic demand, total welfare is decreasing in the price cap $\bar{P}$.*

To understand the result, note that in our model with capacity markets, a higher market share of the dominant firm corresponds to a larger welfare level. This is because of the following reasons:

i) The total capacity x_T, and thus the frequency of blackouts, is exogenously fixed.

ii) The dominant firm has a positive capacity $x_m > 0$ if and only if it has a cost advantage over the competitive fringe. This means a higher market share of the dominant firm implies lower total costs of electricity production.

iii) Due to the perfectly inelastic electricity demand, there are no deadweight losses from the capacity withholding of a dominant firm.

On the other hand, our assumption of perfectly inelastic electricity demand is a simplification rather than an exact description of reality. In reality, some deadweight losses from capacity withholding are very plausible, which would lead to ambiguous welfare results. Ambiguous welfare results could also result if we maintain the assumption of perfectly inelastic demand but extend the model to account for uncertainty in predicted electricity demand. If the dominant firm underestimates demand, capacity withholding may cause blackouts or require excessive procurement of balancing energy from network operators. Corollary 1 illustrates, however, that an increase in market concentration is not necessarily connected to a reduction in welfare.

2.3 Alternative Capacity Mechanisms

This section studies the robustness of our results by considering two alternative capacity mechanisms: subsidies and strategic reserves.

2.3.1 Subsidies

Assume that before investments take place, the regulator fixes a uniform capacity subsidy s to encourage sufficient capacity levels. The regulator fixes a price cap $\bar{P}$ and chooses the subsidy such that the resulting equilibrium capacity x_f^* and x_m^* add up to a target level of total capacity x_T.

The total profits per unit of capacity for a fringe firm are given by

$$\pi_f = \pi_f^s - k_f + s. \tag{2.9}$$

We assume that fringe firms enter the market until profits are driven down to zero. This zero profit condition can be written as

$$s = k_f - (\bar{P} - c)\left(1 - G\left(x_f^*\right)\right). \tag{2.10}$$

For $s < k_f$, this condition uniquely determines the fringe capacity x_f^*, which is increasing in the per unit subsidies s. The fringe's equilibrium capacity does not depend on the dominant firm's capacity x_m. This is because the dominant firm always withholds sufficient capacity to drive prices up to $\bar{P}$ when $D > x_f^*$. Therefore the frequency of high prices ($P = \bar{P}$) only depends on the fringe's capacity and the distribution of demand. Consequently, it does not matter whether the dominant firm invests before, at the same time or after the competitive fringe: the resulting equilibrium capacities are the same. The dominant firm's expected profits are given by

$$\Pi^m = \left(\pi_m^s + s - k_m\right) x_m. \tag{2.11}$$

The dominant firm's equilibrium capacity x_m^* maximizes total profits Π^m, given the fringe's equilibrium capacity x_f^* and the previously fixed subsidy s. In contrast to the auction, the capacity payments are no longer a function of the dominant firm's capacity choice. The dominant firm's first order condition for an interior solution is given by

$$\frac{\partial \Pi^m}{\partial x_m}\left(x_m^*\right) = (\bar{P} - c)\left(1 - G\left(x_f^* + x_m^*\right)\right) - \left(k_m - s\right) = 0. \tag{2.12}$$

The term $k_m - s$ simply describes the net cost of an additional capacity unit. The term $(\bar{P} - c)\left(1 - G\left(x_f^* + x_m^*\right)\right)$ captures the effect of a marginal capacity expansion on spot market profits. In situations in which demand exceeds the total capacity, the additional marginal unit is sold with a markup of $\bar{P} - c$.

Independent of the form of the demand distribution G, the dominant firm's expected profits are strictly concave in x_m. Hence, the fringe's zero profit condition and the dominant firm's first order condition uniquely determine equilibrium investments for any given pair of subsidies s and price cap $\bar{P}$. It follows from (2.12) that for any fixed total capacity $x_T < 1$, the subsidies s must increase if the price cap $\bar{P}$ decreases. In the special case of a 100% reliability level, i.e., $x_T = 1$, subsidies must always be equal to the dominant firm's fixed cost k_m.[12]

Even though the dominant firm's first order condition is quite distinct from the one in the auction case, we find qualitatively the same comparative static results with respect to the price cap.

Proposition 3. *If the regulator uses subsidies s to fix a reliability level $\rho \in [0,1]$, the dominant firm's total profits Π^m, its capacity x_m and market share, as well as the frequency of capacity withholding in the spot market decrease if the price cap $\bar{P}$ increases.*

The intuition for this result is similar to that in the auction case. The regulator must compensate a reduction in the price cap by a higher subsidy level. The dominant firm benefits from the shift in spot market revenues to capacity subsidies since it has a lower capacity utilization at peak prices than fringe firms.

Comparison of dominant firm's profit under capacity subsidies and capacity auctions

While the competitive fringe's zero profit conditions for the auction and subsidy case are basically identical, the dominant firm's first order conditions differ. We can generally establish

Proposition 4. *For a given price cap $\bar{P}$ and desired total output x_T, the dominant firm earns weakly higher profits under a capacity auction than under capacity subsidies.*

The intuition is as follows: The dominant firm can replicate the profits by simply bidding the equilibrium quantity under capacity subsidies in the auction. However, since its first order conditions differ, it generally has more profits under the capacity auction.

[12] Yet, for $s = k_m$, the dominant firm is indifferent between all capacity levels. Clearly, an auction is advantageous for targeting a specific capacity goal.

While we can generally rank the two mechanisms based on the the dominant firm's expected profits, ranking based on the dominant firm's market share and the frequency of capacity withholding is subject to the distribution of demand and the total capacity level. For the special case of uniformly distributed demand, the outcomes under an auction and subsidies are equivalent, as we will discuss in Subsection 2.3.3.

2.3.2 Strategic Reserves

Strategic reserves are generation capacity controlled by a regulator and are only used in the case of a supply shortage or when spot market prices rise above a previously determined trigger price. In some liberalized electricity markets, strategic reserves exist in addition to the wholesale market.[13] The strategic reserves can be used to implement a desired reliability level without using capacity payments. Assume the trigger price of the strategic reserve is equal to the price cap $\bar{P}$ and the regulator procures a strategic reserve of size x_r that satisfies $x_r + x_f^* + x_m^* = x_T$ for a specified total capacity level. The strategic reserve is only used in the case of shortage and does not push prices below the cap $\bar{P}$, i.e.,

$$q_r = \min\left\{x_r, \max\left\{0, D - x_f - qm_m\right\}\right\}.$$

Given this usage policy, the strategic reserve then has no influence over the distribution of spot market prices. Correspondingly, the equilibrium investments and profits of the dominant firm and the competitive fringe are independent of the size of the strategic reserve. The equilibrium capacities x_m^* and x_f^* are given by the solution of the zero profit condition (2.10) and the first order condition (2.12) of the previous subsection for the case of a zero subsidy $s = 0$. In particular, the fringe firms' capacity does not depend on the dominant firm's capacity. We find the following limit result for changes in the price cap.

Proposition 5. *Consider an electricity market with strategic reserves and the limit $\bar{P} \to \infty$. The equilibrium capacities of the dominant firm and the competitive fringe then satisfy $x_f \to 1$ and $x_m \to 0$.*

The intuition for this proposition is as follows: The frequency of high prices $P = \bar{P}$ only depends on the fringe's capacity and on the distribution of demand. Therefore, the higher the maximal price $\bar{P}$, the higher the expected spot market profits of the

[13]For example, strategic reserves exist in Sweden and Finland.

fringe firms and the higher the equilibrium capacity x_f^*. The dominant firm faces countervailing effects: On the one hand, a higher maximal price $\bar{P}$ leads to higher spot market profits if demand exceeds the fringe's capacity. On the other hand, the fringe's capacity is increasing in $\bar{P}$ and therefore reduces the frequency of high prices and the dominant firm's average share in production if prices are high. In contrast to the previously discussed capacity mechanisms, there is no shift in revenues from the spot market to a capacity market if $\bar{P}$ decreases. Hence, it is not clear as to whether the dominant firm's expected spot market profits as well as its equilibrium capacity are increasing or decreasing in $\bar{P}$. However, the limit result holds true since the fringe's capacity is strictly increasing in $\bar{P}$ and there is no incentive to build capacity greater than the maximal demand (i.e., $x_f^* + x_m^* \leq 1$).

2.3.3 Equivalent Equilibrium Outcomes under Uniformly Distributed Demand

Interestingly, for the special case of uniformly distributed demand, fixed total capacity x_T and price cap $\bar{P}$, we find that the dominant firm's equilibrium capacity and expected profits are the same under all three capacity mechanisms:

$$x_m^* = \frac{k_f - k_m}{\bar{P} - c} \quad \text{and} \quad \Pi^m \left(x_m^*\right) = \frac{\left(k_f - k_m\right)^2}{2\left(\bar{P} - c\right)}. \tag{2.13}$$

The dominant firm's equilibrium capacity is then independent of the total capacity x_T and simply given by the ratio of the fixed cost advantage to the difference in price cap and variable costs. Furthermore, fringe capacity and the distribution of spot market prices are the same for capacity auctions and subsidies. Under strategic reserves, fringe capacity is generally lower, however, and replaced by reserve capacity. Consequently, under strategic reserves, there is a larger fraction of periods in which the spot price peaks. This result does not necessarily extend to more general demand functions, however.

Entry Barriers

Free entry by competitive firms substantially limits the dominant firm's scope of market power. The dominant firm may attempt to restrict the competitive pressure by building entry barriers. In this subsection, we analyze how the dominant firm's incentive to build entry barriers by raising the fringe firms' fixed costs depends on the spot market price cap. See Salop and Scheffman (1983) and Salop and Scheffman (1987) for a classical treatment on raising rivals' costs. Assume that at an initial stage, the dominant firm can pick an intensity level $b \in \left[0, \bar{b}\right]$ of anti-competitive practices and the resulting fringe firm's fixed costs are given by

$$k_f = k_m + \Delta + b.$$

The parameter Δ measures a natural fixed cost benefit of the dominant firm. For simplicity, we assume that demand is uniformly distributed and that the dominant firm has quadratic costs of anti-competitive practices

$$\psi(b) = \gamma b^2.$$

The dominant firm's total expected profits as a function of the sabotage intensity then satisfy

$$\Pi^m\left(x_m^*\right) = \left(\frac{(\Delta + b)^2}{2\left(\bar{P} - c\right)} - \gamma b^2\right).$$

By solving for the optimal level of b, we directly find the following result:

Proposition 6. *In equilibrium, the intensity of anti-competitive practices b to build entry barriers is decreasing in the price cap; i.e., the incentive to build entry barriers is reduced.*

The intuition is as follows: A higher price cap causes a revenue shift from the capacity market to the spot market, reducing the expected profits that the dominant firm can reap from a fixed cost advantage. Therefore, the dominant firm has less incentive to gain such a cost advantage by raising rivals cost.

2.4 Multiple Dominant Firms and a Competitive Fringe

In this section, we analyze the robustness of our insights for the case with n dominant firms, indexed by $i = 1, ..., n$, and a competitive fringe f. Again, all firms face the same variable cost c per unit of capacity and the dominant firms have weakly lower per unit fixed costs than the fringe firms, i.e., $k_m \leq k_f$. In this extension, we restrict attention to the case in which electricity demand D is uniformly distributed on $[0, 1]$. We establish that for the case of uniform demand, the joint market shares and profits of all dominant firms, capacity payments and distribution of market prices are independent of the number of dominant firms n. This means that our comparatively static results of the main model carry over to the case of multiple dominant firms.

2.4.1 Spot Market Behavior

In the first step, we analyze the production choices on the spot market for a given vector of capacities $x = \left(x_1, .., x_n, x_f\right)$ and realized demand D. Since the maximal demand level is normalized to 1, we restrict our analysis to the interesting case that $x_f + X_d \leq 1$, with $X_d := \sum_{j=1}^{n} x_j$. In order to simplify the exposition, we assume w.l.o.g. that dominant firms are sorted increasingly in their capacities, i.e., $x_1 \leq x_2 \leq ... \leq x_n$. All dominant firms simultaneously choose their spot market outputs $q_i \in [0, x_i]$ and fringe firms act as price takers. We denote the resulting output vector by $q = \left(q_1, ..., q_n, q_f\right)$, the output of all dominant firms by $Q_d := \sum_{i=1}^{n} q_i$ and the total output by $Q := Q_d + q_f$. As before, the spot market price as a function of Q and D is given by

$$P(Q,D) = \begin{cases} \bar{P} & \text{if } Q \leq D \\ c & \text{otherwise.} \end{cases}$$

If the demand is below the total capacity of the fringe firms, i.e., $D \leq x_f$, the perfect competition of the fringe drives down prices to marginal cost c. Consider the case $D > x_f$. Since demand is perfectly inelastic, each dominant firm would always find it profitable to unilaterally reduce its output q_i such that total output satisfies $Q = D$ and spot market prices jump to the price cap $\bar{P}$. Consequently, there remains a unique equilibrium spot market price that is determined in the same fashion as for a single dominant firm (see equation 2.2). However, there is a multitude of spot market equilibria that differ by the distribution of capacity withholding among dominant firms: If demand exceeds the fringe's capacity, $D > x_f$, then all (and only those) feasible output vectors $q = \left(q_1, ..., q_n, x_f\right)$ for which dominant firms' total output satisfies $Q_d = min\left\{D - x_f, X_d\right\} \equiv Q_d^*$ constitute a spot market equilibrium.

Since we consider our perfectly inelastic demand function as an approximation only for very inelastic demand functions, it seems sensible to pick equilibrium quantities that correspond to the limit of equilibria quantities from a sequence of elastic demand functions converging to our inelastic demand function. We define the capacity-constrained, symmetric distribution of the dominant firms' total output $Q_d^* > 0$ as the unique vector $q_d^* = (q_1^*, ..., q_n^*)$ that satisfies the following conditions.

The first $l \in \{1, ..., n\}$ dominant firms that are capacity constrained produce

$$q_i^* = x_i \text{ for } i = 1, ..., l.$$

The remaining firms that are not capacity-constrained split the remaining excess demand equally, i.e.,

$$q_i^* = \frac{D - x_f - \sum_{j=1}^{l} x_j}{n - l} \text{ for } i = l + 1, ..., n.$$

In Cournot models with a smooth and (possibly just slightly) elastic inverse demand function and common constant marginal cost, equilibrium outputs usually distribute total output in such a symmetric fashion.[14] Correspondingly, we find the following result:

Lemma 1. *Fix $D > x_f$ and consider any sequence of continuously differentiable concave inverse demand functions $\left(P^l(Q)\right)_{l \in \mathbb{N}}$ that converges to our inelastic inverse demand function. Then the corresponding sequence $\left(q_d^l\right)_{l \in \mathbb{N}}$ of dominant firms' equilibrium output vectors converges to the symmetric output vector q_d^*.*

In light of this result, we base the subsequent analysis on the following assumption:

Assumption 2. *If $D > x_f$, the spot market equilibrium with the capacity-constrained symmetric output vector $q^* = (q_1^*, ..., q_n^*, x_f)$ is selected.*

2.4.2 Investments in Capacity

In this subsection, we prove that our comparative static results of the main model carry over to the case of multiple dominant firms.

Capacity Auctions

Assume the regulator procures the total capacity $x^T = X_d + x_f$ in a multi-unit descending bid auction. Let x_m^* be the equilibrium capacity of a monopolistic firm and let z^* be the resulting capacity payment. The bidding function $x_f(z)$ of the fringe is

[14] See, e.g., Zoettl (2011). For the unconstrained Cournot equilibrium: If an inverse demand function $P^l(Q, D)$ is twice continuously differentiable in Q and the first and second derivatives are negative, then the unconstrained Cournot equilibrium is unique and symmetric. See, e.g., Vives (2001), pp. 97/98.

determined by its zero profit condition

$$z = k_f - \left(\bar{P} - c\right)\left(1 - x_f\right). \tag{2.14}$$

Let z_0 be the lowest capacity payment at which it would still be profitable for a monopolist to offer a capacity of $x_T - x_f(z)$ instead of stopping to bid and letting the auction fail.

Consider the following symmetric bidding strategy of the n dominant firms in the descending bid auction:

$$\mathbf{x}^*(z) = \begin{cases} \frac{1}{n} x_m^* & \text{if } z \geq z^* \\ \frac{1}{n}\left(x_T - x_f(z)\right) & \text{if } z_0 \leq z \leq z^* \\ 0 & \text{if } z < z_0 \end{cases}$$

The first line states that all firms start bidding one n'th of the equilibrium quantity of a monopolistic firm, causing the auction to end with a resulting auction price of z^* and a total capacity of the dominant firms of $nx^*(z^*) = x_m^*$. The other two lines are mainly important to correctly specify the behavior of off the equilibrium path in order to have a subgame perfect equilibrium in the descending bid auction: If an auction price $z < z^*$ were to be reached in the descending bid auction, firms would immediately finish the auction by offering the total capacity $nx^*(z) = x_T - x_f(z)$. Even if an auction price below z_0 were to be reached, the dominant firms would stop bidding and the auction would fail.

Proposition 7. *The symmetric bidding strategies $\mathbf{x}^*(z)$ form a symmetric subgame perfect equilibrium in the descending bid auction with multiple dominant firms. The equilibrium auction price z^*, the total capacity and the total profits of all dominant firms are independent of the number of dominant firms n and equal to the results for a monopolistic firm.*

A rough intuition for this result is that the completely inelastic demand causes the oligopolistic dominant firms to act in the same fashion as a monopolistic dominant firm. For a more detailed insight, we refer the reader to the proof in the Appendix.

Subsidies and Strategic Reserve

Assume the regulator fixes a uniform capacity subsidy s such that the resulting equilibrium capacities $X_d^* = \sum_{i=1}^n x_i^*$ and x_f^* add up to the target level x^T. The fringe's capacities do not depend on the dominant firms' capacity because spot market prices rise up to $\bar{P}$ whenever $D > x_f^*$. For $s < k_f$, the fringe's equilibrium capacities x_f^* are therefore uniquely determined by the zero profit condition:

$$s = k_f - (\bar{P} - c)\left(1 - x_f^*\right).$$

The dominant firms choose their equilibrium capacities $x_d^* = \left(x_1^*, ..., x_n^*\right)$ to maximize their profits for given fringe capacities x_f^* and previously fixed subsidies s. We find the following proposition.

Proposition 8. *For fixed capacity subsidies s, the total equilibrium capacities as well as the total profits of all dominant firms are independent of the number of dominant firms and equal to the equilibrium capacities x_m^* and profits $\Pi^m\left(x_m^*\right)$ for a monopolistic dominant firm. Furthermore, the equilibrium capacities and profits of the dominant firms are symmetric.*

Let us consider a market in which the regulator procures a strategic reserve to obtain the total capacity level $x^T = x_r + X_d^* + x_f^*$. As in subsection 2.3.2, the strategic reserve is only used in times of shortage and does not influence the distribution of spot market prices. This means that the equilibrium capacities of the dominant firms and the competitive fringe are the same as in the previously considered market but with zero subsidies, i.e., $s = 0$. Since the dominant firms' equilibrium capacities are independent of the total capacity x_T (and s) see subsection 2.3.3, we directly find

Corollary 2. *If the regulator procures a strategic reserve to obtain the total capacity level x^T, the total equilibrium capacities as well as the total profits of all dominant firms are independent of the number of dominant firms and equal to the equilibrium capacities and profits for a monopolistic dominant firm. Furthermore, the equilibrium capacities and profits of the dominant firms are symmetric.*

2.5 Conclusion

It has been the purpose of this study to understand the effects of price caps and capacity mechanisms on the market structure. For our analysis, we have chosen a model with fluctuating price-inelastic electricity demand in which a dominant firm faces competitive firms that can freely enter the market and act as price takers. Firms invest in capacity in the first stage and afterwards sell electricity on the spot market. We have found the following main result: A higher price cap reduces the profits and the market share of the dominant firm, as well as the frequency of capacity withholding in equilibrium. This result is very robust and we have shown that it holds true for different types of capacity mechanisms as well as for multiple dominant firms.

The intuition is as follows: Fringe firms make higher average spot market profits per capacity unit than a dominant firm since a dominant firm has (on average) a lower capacity utilization in peak price periods due to the fact that it holds back capacity to increase spot market prices. In contrast, a dominant firm and a competitive firm benefit equally from capacity payments. When fixing a target level of total capacity, a lower price cap means that wholesale market revenues decrease and a larger fraction of firms' revenues must come from the capacity mechanism. This shift in revenue streams benefits the dominant firm relative to the competitive fringe.

The result is quite robust and its intuition has more general implications: First, dominant firms benefit from policy measures that reduce spot market revenues if capacity mechanisms exist. A lower price cap is one such measure, although we would see similar effects with alternative policy interventions. For example, a dominant firm would also benefit from a law that explicitly forbids capacity withholding on the spot market. Second, even if we had an elastic electricity demand, a dominant firm would have lower spot market profits per capacity unit than a fringe firm and therefore prefer revenue shifts from the spot market to the capacity market.

Especially in light of the present debate surrounding the future design of electricity markets, price caps and capacity mechanisms, the results we established are quite interesting. In this discussion, one should take into account that a reduction of price caps and the resulting shift in revenues from the spot market to the capacity market could lead to an increasing market share for the large incumbent electricity generators. The actual purpose of reducing price caps to reduce the exercise of market power may fail.

In our analysis, we have focused on the effects of changes in price caps and capacity payments on the market structure. We only briefly discussed the differences between the capacity mechanisms with regard to the dominant firms' market share and the frequency of capacity withholding in Section 2.3.3. Further research could address these differences, requiring stronger assumptions on demand. Furthermore, the model could be extended by adding base-load and peak-load technologies to investigate whether capacity mechanisms yield efficiency losses or gains in the generation mix.

2.6 Appendix

The appendix contains all proofs of the paper. Note that by the assumptions on G and g, and by the assumption that $x_m + x_f \leq 1$, the profit function $\Pi^m\left(x_m, \bar{P}\right)$ is twice continuously differentiable in x_m and $\bar{P}$. The same applies for the profit functions Π^l that we use in the proofs of propositions 7 and 8.

Proof of Proposition 2.

We prove this proposition in two steps: In part (i), we show that the dominant firm's profits are a decreasing function of the price cap. In part (ii), we prove that the dominant firm's equilibrium capacities are a decreasing function of the price cap. From (ii) it follows immediately that capacity withholding is also decreasing in the price cap since the total capacity is fixed and therefore the fringe's equilibrium capacity is increasing in the price cap.

(i) Profits. By the assumption that the total supply of the competitive fringe for each capacity payment z is such that its total profits π_f are zero, the equilibrium capacity payment z^* has to fulfill the following condition:

$$z^* = -\pi_f^s + k_f.$$

The dominant firm's profits are therefore given by

$$\begin{aligned}\Pi^m &= \left(\pi_m^s + z^* - k_m\right) x_m \\ &= \left(\pi_m^s - \pi_f^s + k_f - k_m\right) x_m \\ &= \left(-\left(\bar{P} - c\right)\left(1 - G\left(x_T - x_m\right)\right)\left(1 - \phi_m\right) + k_f - k_m\right) x_m.\end{aligned} \tag{2.15}$$

Taking the first derivative of equation (2.15) with respect to $\bar{P}$ directly leads to the following lemma:

Lemma. *If the dominant firm's capacity x_m is fixed, Π^m is strictly decreasing in $\bar{P}$.*

This lemma does not state that the dominant firm's total profits are decreasing in the price cap since generally x_m depends on $\bar{P}$. We consider two different price caps $\bar{P}_L$ and $\bar{P}_H$, $\bar{P}_L < \bar{P}_H$. Let

$$\begin{aligned}x_m^L &\in argmax_{x_m} \Pi^m\left(\bar{P}_L, x_m\right) \\ x_m^H &\in argmax_{x_m} \Pi^m\left(\bar{P}_H, x_m\right)\end{aligned}$$

denote optimal capacity selections of the dominant firm given $\bar{P}_L$ and $\bar{P}_H$, respectively. By optimality of x_m and the lemma above, the following inequalities hold:

$$\Pi^m\left(\bar{P}_L, x_m^L\right) \geq \Pi^m\left(\bar{P}_L, x_m^H\right) > \Pi^m\left(\bar{P}_H, x_m^H\right).$$

We have therefore shown that the dominant firm's total profits Π^m are strictly decreasing in the price cap $\bar{P}$.

(ii) Capacities. We show that x_m^* is a decreasing function of $\bar{P}$. The dominant firm's profit function is given by

$$\begin{aligned}\Pi^m &= \left(\pi_m^s + z^* - k_m\right) x_m \\ &= \left(\bar{P} - c\right)\left(x_m\left(1 - G\left(x_T\right)\right) + \int_{x_T - x_m}^{x_T}\left(D - x_T + x_m\right) g(D) dD\right) \\ &\quad + z^* x_m - k_m x_m.\end{aligned} \tag{2.16}$$

The auction price is determined by the fringe's zero profit condition. Plugging $z^* = k_f - \left(\bar{P} - c\right)\left(1 - G(x_T - x_m)\right)$ into equation (2.16) leads to

$$\begin{aligned}\Pi^m &= \left(\bar{P} - c\right)\left(x_m\left(1 - G\left(x_T\right)\right) + \int_{x_T - x_m}^{x_T}\left(D - x_T + x_m\right) g(D) dD\right) \\ &\quad + \left(k_f - \left(1 - G\left(x_T - x_m\right)\right)\left(\bar{P} - c\right)\right) x_m - k_m x_m.\end{aligned}$$

The first derivative with respect to x_m is then given by

$$\frac{\partial \Pi^m}{\partial x_m} = k_f - k_m - g\left(x_T - x_m\right)\left(\bar{P} - c\right) x_m.$$

By taking the derivative with respect to $\bar{P}$, we get

$$\frac{\partial \partial \Pi^m}{\partial x_m \partial \bar{P}}(x) = -g\left(x_T - x_m\right) x_m < 0$$

since $g > 0$. We can apply an analogue of the "Monotone Selection Theorem" to show that x_m^* is a strictly decreasing function of the price cap $\bar{P}$.

Theorem. *(Analogue of the Monotone Selection Theorem) Assume that the function Π^m has strictly decreasing differences (SDD). Then every optimal selection $x_m^*\left(\bar{P}\right) \in argmax_{x_m} \Pi^m\left(x_m, \bar{P}\right)$ is strictly decreasing in $\bar{P} \in [0, \infty)$.*[15]

[15] For the Monotone Selection Theorem, see Milgrom (2004), p.102. Since $\Pi^m(\cdot,\cdot)$ is sufficiently smooth, SSD is equivalent to $\frac{\partial \partial \Pi^m}{\partial x_m \partial \bar{P}} < 0$ for all $\left(x_m, \bar{P}\right) \in [0,1] \times [0, \infty)$

Proof. Let us fix arbitrary $\bar{P}_L, \bar{P}_H \in [0, \infty)$ satisfying $\bar{P}_L < \bar{P}_H$. Let us again denote optimal selections by

$$x_m^L \in argmax_{x_m} \Pi^m \left(\bar{P}_L, x_m\right)$$
$$x_m^H \in argmax_{x_m} \Pi^m \left(\bar{P}_H, x_m\right)$$

Let us assume that $x_m^L \leq x_m^H$. We bring this assumption to a contradiction. By definition of x_m^H and x_m^L, it holds that

$$\Pi^m \left(x_m^L, \bar{P}_L\right) \geq \Pi^m \left(x_m^H, \bar{P}_L\right) \text{ and } \Pi^m \left(x_m^H, \bar{P}_H\right) \geq \Pi^m \left(x_m^L, \bar{P}_H\right).$$

This implies that

$$\Pi^m \left(x_m^L, \bar{P}_L\right) + \Pi^m \left(x_m^H, \bar{P}_H\right) \geq \Pi^m \left(x_m^H, \bar{P}_L\right) + \Pi^m \left(x_m^L, \bar{P}_H\right),$$

which is equivalent to

$$\Pi^m \left(x_m^L, \bar{P}_L\right) - \Pi^m \left(x_m^L, \bar{P}_H\right) \geq \Pi^m \left(x_m^H, \bar{P}_L\right) - \Pi^m \left(x_m^H, \bar{P}_H\right). \tag{2.17}$$

However, by assumption $x_m^L \leq x_m^H$, the SDD property of Π^m yields a contradiction to (2.17). Hence, $x_m^L > x_m^H$, i.e., x_m^* is strictly decreasing in $\bar{P}$.

Proof of Proposition 3.

We prove this proposition in two steps: In part (i), we show that the dominant firm's profits are a decreasing function of the price cap. In part (ii), we prove that the dominant firm's equilibrium capacities are a decreasing function of the price cap. From (ii), it follows immediately that capacity withholding is also decreasing in the price cap since the total capacity is fixed and therefore the fringe's equilibrium capacity is increasing in the price cap.

(i) Profits. Due to the competitive fringe's zero profit condition, subsidies have to satisfy the following condition:

$$s^* = k_f - \pi_f^s.$$

The dominant firm's profits are therefore given by

$$\Pi^m = \left(\pi_m^s + s^* - k_m\right) x_m = \left(\pi_m^s - \pi_f^s + k_f - k_m\right) x_m.$$

For the rest of the proof, we refer to part (i) of the proof of Proposition 2.

(ii) Capacities. We show that x_m^* is strictly decreasing in $\bar{P}$. Due to the dominant firm's first-order condition (2.12), subsidies have to satisfy the following condition

$$s^* = k_m - \left(\bar{P} - c\right)\left(1 - G(x_T)\right).$$

Plugging s^* into the fringe's zero profit condition (2.10) leads to

$$x_f^* = G^{-1}\left(G(x_T) - \frac{k_f - k_m}{\bar{P} - c}\right).$$

Therefore, by adjusting s such that the reliability level ρ and the total capacity x_T are kept constant, we find that x_f is an increasing function of $\bar{P}$ by taking the first derivative $\frac{\partial x_f^*}{\partial \bar{P}}$. Since $x_T = x_f^* + x_m^*$ is kept constant, x_m^* is a decreasing function of $\bar{P}$.

Proof of Proposition 4.

Let s^* be the subsidy that implements the total output x_T. Let x_f^* and x_m^* be the resulting fringe and dominant firm capacity, respectively. Note that due to the same zero profit condition, x_f^* is also the fringe supply in the capacity auction for an auction price of $z = s^*$. Therefore, the dominant firm can replicate the same outcome in the auction as in the subsidy case by bidding a constant quantity of x_m^* in the auction. The resulting capacity payment is $z = s^*$, the fringe's capacity is x_f^* and the dominant firm's capacity is x_m^*.

Proof of Proposition 5.

The equilibrium capacities in a market with strategic reserves are given by the solution of the zero profit condition (2.10) and the first order condition (2.12) for the case of a zero subsidy $s = 0$. For $\bar{P} \to \infty$, it follows from the fringe's zero profit condition that $x_f \to 1$. Since $x_f + x_m \leq 1$ and $x_m \geq 0$, it follows that $x_m \to 0$.

Proof of Proposition 6.

By solving the first order condition

$$\frac{\partial \Pi_m}{\partial b} = \frac{1}{\bar{P} - c} 2\left(b + \Delta\right) - 2\gamma b = 0$$

and accounting for corner solutions, we find that the dominant firm's optimal level of anti-competitive practices a^* is by

$$b^* = \begin{cases} \frac{\Delta}{(\bar{P}-c)\gamma - 1} & \text{if } (\bar{P}-c)\gamma > 1 \\ \bar{b} & \text{otherwise.} \end{cases}$$

The result follows immediately.

Proof of Lemma 1.

Assume $D \in \left(x_f, 1\right)$. We consider any sequence $\left(P^l(Q,D)\right)_{l\in\mathbb{N}}$ in which each item of the sequence is twice continously differentiable and concave in Q and $P^l(Q,D) \to \bar{P}$ for $l \to \infty$. For $x_1, ..., x_n \in (0,1)$, the equilibrium quantities $q_1^{l*}, ..., q_n^{l*}$ are given by

$$q_i^{l*} := argmax_{0\leq\tilde{q}\leq x_i, \sum_{i=1}^n q_i \leq D - x_f} \left[P^l\left(\tilde{q} + Q_{-i}^* + x_f, D\right)\tilde{q} - c\tilde{q}\right].$$

Since the inverse demand function is given by P^l, which is twice continuously differentiable and concave, the unconstrained Cournot equilibrium is unique and symmetric, i.e., $q_1^{l*} = ... = q_n^{l*}$.[16] We consider the case in which all firms are unconstrained. Due to the fact that the equilibrium quantities are symmetric, we have the following constraint: $q_i^{l*} \leq \frac{D-x_f}{n}$.

We choose $\epsilon > 0$ and $N \in \mathbb{N}$ such that $||P^l - \bar{P}|| < \epsilon$ for all $l \geq N$. With $\delta := \bar{P} - c > 0$, it follows that

$$\left(P^l - c\right)\tilde{q} = \begin{cases} \leq & (\delta+\epsilon)\tilde{q} \\ \geq & (\delta-\epsilon)\tilde{q} \end{cases}$$

for all $l \geq N$ and $\tilde{q} \in [0,1]$. The function for which we consider the argmax is therefore bounded from above by the linear function with the slope $\delta + \epsilon$ and bounded from below by the linear function with the slope $\delta - \epsilon$ for all $\tilde{q} \in \left[0, \frac{D-x_f}{n}\right]$. For ϵ sufficiently small, we have $\delta - \epsilon > 0$ and the function for which we consider the argmax has the maximum in the interval $\left[\frac{\delta-\epsilon}{\delta+\epsilon}\frac{D-x_f}{n}, \frac{D-x_f}{n}\right]$. For $\epsilon > 0$ sufficiently small, the quantity is close to $\frac{D-x_f}{n}$.

If the first $m \in \{1, ..., n\}$ firms are capacity constrained, the arguments from above hold true for the remaining $n-m$ unconstrained firms. For the equilibrium quantities q_i^{l*}, $i \in \{n-m, ..., n\}$, we then have the following constraint: $q_i^{l*} \leq \frac{D-x_f-\sum_{j=1}^m x_j}{n-m}$.

[16]See, for example, Vives (2001), pp. 97/98.

Proof of Proposition 7.

The number of firms that are capacity constrained is weakly increasing in the demand level D. The critical demand level above which the i'th dominant firm becomes capacity constrained on the spot market is given by

$$\tilde{D}_i = x_f + (n-i)\, x_i + \sum_{j=0}^{i} x_j,$$

where we define $x_0 := 0$. The expected variable spot market profits per capacity unit of the competitive fringe and a dominant firm l are then given by:

$$\begin{aligned} \pi_f^s &= \left(\bar{P}-c\right)\left(1-x_f\right) \\ \pi_l^s &= \frac{1}{x_l}\left(\bar{P}-c\right)\left(\sum_{i=0}^{l-1}\int_{\tilde{D}_i}^{\tilde{D}_{i+1}} \frac{D-x_f-\sum_{j=0}^{i} x_j}{n-i}\,dD + \int_{\tilde{D}_l}^{1} x_l\,dD\right). \end{aligned}$$

Let $x^* = \mathbf{x}^*(z^*) = \frac{1}{n}x_m^*$. Consider first that after some history with price $z > z^*$, firm l would have a profitable deviation in his bidding function that results at an equilibrium to an auction price $\hat{z} > z^*$. The resulting equilibrium output of firm l is then given by

$$\hat{x} = x_T - x_f(\hat{z}) - (n-1)x^*.$$

Since the fringe firm's supply is increasing in z, we must have $\hat{x} < x^*$. Let

$$\Delta = x^* - \hat{x} \geq 0$$

denote the reduction of the deviating firm's output compared to its equilibrium output. Since other dominant firms offer a constant amount, the fringe output under the deviation satisfies

$$\hat{x}_f = x_f^* + \Delta$$

and the resulting auction price satisfies

$$\hat{z}(\Delta) = k_f - \left(\bar{P}-c\right)\left(1-\left(x_f^*+\Delta\right)\right).$$

The resulting spot market equilibrium with asymmetric capacities yields the following expected spot market profit for the deviating firm:

$$
\begin{aligned}
(x^* - \Delta)\hat{\pi}_l^s(\Delta) &= \left(\bar{P} - c\right) \int_{x_f^* + \Delta}^{x_f^* + nx^* - (n-1)\Delta} \frac{D - \left(x_f^* + \Delta\right)}{n} dD \\
&\quad + \left(\bar{P} - c\right) \int_{x_f^* + nx^* - (n-1)\Delta}^{1} \left(x^* - \Delta\right) dD.
\end{aligned}
$$

Firm l's expected total profits under this deviation are given by

$$\hat{\Pi}^l(\Delta) = (x^* - \Delta)(\hat{z}(\Delta) - k_d) + (x^* - \Delta)\hat{\pi}_l^s(\Delta)$$

Tedious but straightforward algebra shows that

$$\frac{\partial \hat{\Pi}^l}{\partial \Delta} = -\left(\bar{P} - c\right) n\Delta,$$

which is negative for all $\Delta \geq 0$. This means that a deviation that yields an auction price $\hat{z} > z^*$ cannot be profitable after any history.

To check that there are no other profitable deviations, let $\pi_m(z)$ denote the profits of a monopolist who offers the amount $x_m(z)$ that leads to an auction price z. This profit function is strictly concave (at least for uniformly distributed demand) and maximized at z^*. Recall that for all $z \in [z_0, z^*]$, the bids of the equilibrium strategies are given by

$$\mathbf{x}^*(z) = \frac{1}{n} x_m(z)$$

and the resulting profits of each dominant firm are given by $\frac{1}{n} x_m(z)$. Also, if firm i performs any deviation $\hat{\boldsymbol{x}}$ at some history with $z \geq z^*$ that yields an auction price $\hat{z} \in [z_0, z^*)$, then firm i's resulting capacity is always $\frac{1}{n} x_m(\hat{z})$ and its equilibrium profits are $\frac{1}{n}\pi_m(\hat{z})$. Yet, given that $\pi_m(z)$ is maximized for $z = z^*$, such a deviation cannot be profitable. Due to the concavity of $\pi_m(z)$, it is also strictly optimal to follow the equilibrium strategy in any continuation equilibrium in which the current auction price is $z \in [z_0, z^*)$, i.e., to immediately stop the auction. By the definition of z_0 as the lowest capacity payment under which a monopolist would be willing to supply $x_T - x_f(z)$, it is also clear that there can never be a profitable deviation that leads to an auction price $z \leq z_0$.

Proof of Proposition 8.

As already discussed in the proof of Proposition 7, the number of firms that are capacity constrained is weakly increasing in the demand level D. The critical demand level above which the i'th dominant firm becomes capacity constrained on the spot market is given by

$$\tilde{D}_i = x_f + (n-i)\, x_i + \sum_{j=0}^{i} x_j,$$

where we define $x_0 := 0$. The expected variable spot market profits per capacity unit of the competitive fringe and a dominant firm l are then given by:

$$\begin{aligned}
\pi_f^s &= \left(\bar{P} - c\right)\left(1 - x_f\right) \\
\pi_l^s &= \frac{1}{x_l}\left(\bar{P} - c\right)\left(\sum_{i=0}^{l-1} \int_{\tilde{D}_i}^{\tilde{D}_{i+1}} \frac{D - x_f - \sum_{j=0}^{i} x_j}{n-i} dD + \int_{\tilde{D}_l}^{1} x_l dD\right).
\end{aligned}$$

Hence, the dominant firm l's total profits are given by

$$\Pi^l = \left(\pi_l^s + s - k_m\right) x_l.$$

The first derivative of the dominant firm l's profit function is given by

$$\frac{\partial \Pi^l(x)}{\partial x_l} = \left(\bar{P} - c\right)\left(1 - x_f - (n-l)\, x_l - \sum_{j=0}^{l} x_j\right) - \left(k_m - s\right).$$

In part (i), we show that a symmetric equilibrium exists and that the equilibrium capacities are uniquely determined by

$$0 = \left(\bar{P} - c\right)\left(1 - x_f - n x^*\right) - \left(k_m - s\right)$$

(which states that x^* is exactly $\frac{1}{n}$'th of x_m^*). In part (ii), we show the uniqueness of this result.

(i) Existence. To show the existence of an equilibrium, it is sufficient to show quasiconcavity of firm l's profits $\Pi^l\left(x_l^*, \tilde{x}_{-l}\right)$, given the symmetric capacities $\tilde{x}$ of the other dominant firms.[17] If all other dominant firms choose a symmetric capacity

[17]See, for example, Vives (2001) page 16.

$\tilde{x}$, then the derivative of l's profit function is given by

$$\frac{\partial \Pi^l}{\partial x_l} = \begin{cases} (\bar{P}-c)\left(1-x_f-nx_l\right)-\left(k_m-s\right) & \text{if } x_l \leq \tilde{x} \\ (\bar{P}-c)\left(1-x_f-(n-1)\tilde{x}-x_l\right)-\left(k_m-s\right) & \text{if } x_l \geq \tilde{x}. \end{cases}$$

When other firms choose $\tilde{x} = x_l^*$, then this derivative is zero for $x_l = x_l^*$. The derivative $\frac{\partial \Pi^l(x_l,\tilde{x}_{-l})}{\partial x_l}$ is differentiable and $\frac{\partial \partial \Pi^l(x_l,\tilde{x}_{-l})}{\partial x_l \partial x_l} < 0$. Hence, the profit function is concave in firm l's profits (and thus quasiconcave).

(i) Uniqueness. Due to strict concavity, no other symmetric equilibrium exists. In the following, we show by contradiction that no asymmetric equilibrium exist: Assume an asymmetric equilibrium exists. In this case, we can order the equilibrium capacities $x_1^* \leq ... \leq x_n^*$, where at least one inequality has to hold strictly, i.e., $x_1^* < x_n^*$. The first order condition of firm n is given by

$$\frac{\partial \Pi^n(x)}{\partial x_n} = (\bar{P}-c)\left(1-x_f-\sum_{j=0}^{n} x_j\right)-\left(k_m-s\right).$$

Obviously $\frac{\partial^2 \Pi^n}{\partial x_n^2} < 0$. Therefore firm n's profit function is concave and any asymmetric equilibrium has to fulfill the condition $\frac{\partial \Pi^n}{\partial x_n} = 0$. However, whenever $\frac{\partial \Pi^n}{\partial x_n} = 0$ holds, firm 1's profits are increasing in x_1:

$$\begin{aligned} \frac{\partial \Pi^1(x)}{\partial x_1} &= (\bar{P}-c)\left(1-x_f-nx_1\right)-\left(k_m-s\right) \\ &> (\bar{P}-c)\left(1-x_f-\sum_{j=0}^{n} x_j\right)-\left(k_m-s\right) = 0. \end{aligned}$$

The inequality holds due to $x_1 < x_n$. Therefore, any asymmetric equilibrium cannot exist.

3 Cross-Border Effects of Capacity Mechanisms in Electricity Markets

To ensure security of supply in liberalized electricity markets, different types of capacity mechanisms are currently being debated or have recently been implemented in many European countries. The purpose of this study is to analyze the cross border effects resulting from different choices on capacity mechanisms in neighboring countries. We consider a model with two connected countries that differ in the regulator's choice on capacity mechanism, namely strategic reserves or capacity payments. In both countries, competitive firms invest in generation capacity before selling electricity on the spot market. We characterize market equilibria and find the following main result: While consumers' costs may be the same under both capacity mechanisms in non-connected countries, we show that the different capacity mechanisms in interconnected countries induce redistribution effects. More precisely, we find that consumers' costs are higher in countries in which reserve capacities are procured than in countries in which capacity payments are used to ensure the targeted reliable level of electricity.

3.1 Introduction

Ensuring adequate generation capacity to meet high security of supply targets in liberalized electricity markets is of major concern to many policymakers. To improve security of supply, different forms of capacity mechanisms are currently being debated or have recently been implemented in many European countries. Capacity mechanisms are mainly chosen on a national basis; however, the implementation of the Internal Energy Market in Europe has opened up national markets and induced increasing interdependence, allowing for neighboring countries to be affected by such interventions.[1] Therefore, the European Commission (2013) claims: "Any back-up capacity mechanism should not be designed having only the national market in mind but the European perspective."

[1] In February 2014, the day-ahead market coupling in the North-West region of Europe began covering 75% of the European power market. Since then, 15 European countries have become closely interlinked. See, e.g., Agency for the Cooperation of Energy Regulators (2014).

The need for capacity mechanisms has been controversially discussed in the literature on electricity market regulation.[2] The main arguments for why security of supply may be endangered in liberalized electricity markets are as follows: First, the price-inelasticity of the fluctuating electricity demand may cause blackouts if capacity becomes scarce. Second, the specific price volatility in electricity markets and market rules such as price caps lower the prospect of price signals leading to sufficient investments in capacity. Hence, different capacity mechanisms are intensively discussed to overcome such imperfections in electricity markets.[3] Although capacity mechanisms take many forms, we merge them into two main groups: strategic reserves and capacity payments. Strategic reserves are generation capacities procured and controlled by a regulator and are only used in times of scarcity. This means that strategic reserves are withheld from the market and only used in case of supply shortages or are alternatively bid into the market at a (high) trigger price.[4] Capacity payments are fees that are paid for capacity to ensure sufficient investments. These fees can either be fixed directly by the regulator or be determined in capacity markets in which the target capacity is fixed.[5] In contrast to strategic reserve capacities, these capacities participate in the wholesale market.

The purpose of this paper is to understand the cross-border effects of different capacity mechanisms in neighboring countries. We investigate such effects by considering a model with two countries, interconnected by some given transmission capacity, that are symmetric in the sense that both countries face the same fluctuating price-inelastic electricity demand. Competitive firms can freely enter the market and invest in generation capacities before selling electricity on the spot market. Spot market prices deviate from marginal generation costs only in times of scarcity; however scarcity prices are too low to allow for a full recovery of fixed costs of that amount of capacities that is necessary to ensure an exogenously determined reliability level of electricity. To overcome the resulting "missing money problem", one country employs strategic reserves, while the other country uses capacity payments. We find the following main result: Even though in isolation both forms of capacity mechanisms lead to an efficient generation mix and identical costs in both

[2] See, for example, Hogan (2005), Joskow (2008) and Cramton and Stoft (2005).

[3] See, for example, De Vries and Neuhoff (2004), De Vries (2007), Finon and Pignon (2008), Cramton and Stoft (2008) and Cramton and Ockenfels (2012).

[4] Strategic reserves are used, for example, in Sweden and Finland.

[5] Different forms of capacity markets exist. In some capacity markets, the required target capacity is centrally fixed and procured (e.g., by the regulator) in an auction. The uniform auction price then corresponds to the capacity payments. Alternatively, suppliers may be obliged to buy certificates of previously certified generation capacities. In that case, the certificate price corresponds to the capacity payments. Capacity markets are in a planning stage, for example, in Great Britain, Italy and France.

countries, in interconnected countries the different capacity mechanisms result in redistribution effects such that the country with strategic reserves is worse off. More precisely, the consumers' costs are higher in the country with strategic reserves than in the country that uses capacity payments to ensure the capacity target.

The main intuition for this result is as follows: For a fixed target capacity, firms' revenue streams to cover total costs must either come from the capacity mechanism or from the spot market, i.e., any profits that firms earn on the spot market reduce the amount that consumers need to pay via a capacity mechanism. Capacity payments do not limit the participation of firms on the spot markets, while strategic reserves are withheld from the market and only used in times of scarcity. Consider demand realizations such that demand can be satisfied across both countries, but in doing so, some - but not all - capacity from the strategic reserves is required. As a result, prices are high in at least the country with strategic reserves and trigger electricity imports. Hence, a part of the high payments for electricity consumption by the consumers in the country with strategic reserves is not earned by the country's own firms but "leaks" over the other country with capacity payments and contributes to the financing of the other country's firms, hence reducing its consumers' costs.

Investments in capacity in competitive electricity markets and capacity mechanisms have been studied by Joskow and Tirole (2007) and Borenstein and Holland (2005). Joskow and Tirole (2007) discuss optimal prices and investments in electricity systems in which load serving entities can commit to price-contingent rationing contracts with (price-insensitive) retail consumers. They analyze the effects of price caps, capacity obligations and capacity prices in such markets. They find that price caps may lead to underinvestment, while capacity obligations in combination with capacity payments can restore investments. Borenstein and Holland (2005) also analyze investments in markets in which many consumers face flat-rate prices and hence do not react to real-time prices. They discuss the effect of capacity subsidies and demonstrate that they do not lead to the (second-best) market optimum. The effects of capacity mechanisms on the market structure, i.e., on the market shares of dominant and competitive firms, have been discussed by Elberg and Kranz (2014). Similarities to their model are given by the pricing on the spot market and the consideration of free entry in our model; however we only consider competitive firms. We contribute to this existing literature by analyzing cross-border effects of capacity mechanisms in competitive electricity markets.

The remainder of this paper is structured as follows: In Section 3.2, we introduce the model. In Section 3.3 we discuss a simple numerical example to provide some basic intuition for key effects of the model. Cross-border effects of capacity mechanisms on market equilibria and the distribution of costs are discussed in Section 3.4. In Section 3.5, we show the robustness of the results for the case of two (base and peak load) technologies. Section 3.6 concludes. Proofs are relegated to the Appendix, Section 3.7.

3.2 The Model

We consider a model with two countries A and B that are connected by (exogenously) given cross-border transmission capacity $\alpha \geq 0$. In both countries, competitive firms can freely enter the market and invest in generation capacity, anticipating the price-inelastic fluctuating electricity demand, and thereafter compete in the electricity spot market.

Firms in countries A and B build up their capacities $x_A \in [0,1]$ and $x_B \in [0,1]$, respectively. The constant fixed costs per unit of capacity are denoted by $k \in \mathbb{R}^+$, and the variable costs of production are given by $c \in \mathbb{R}^+$.

The electricity demand is given by non-negative random variables D_A and D_B for countries A and B, respectively. The joint electricity demand is given by $D := D_A + D_B$, with the corresponding joint distribution function G and continuously differentiable density function g. We normalize the random variable D to the unit interval and assume that $g(D) > 0$ for all $D \in [0,1]$. One can think of G as the distribution of demand over a large period of time in which spot market competition with given capacities takes place.

Since we want to focus our analysis on the effect of the choice of different capacity mechanisms, we assume that both countries are perfectly symmetric in the sense that they face identical demand for electricity, $D_A = D_B = \frac{D}{2}$, and target the same reliability level of electricity, i.e., the probability that no power outage ("blackout") occurs due to insufficient capacity. In our model, fixing a reliability level is equivalent to fixing the corresponding capacity in the market. Both countries ensure the same capacity level $x_A^T = x_B^T \in \left[0, \frac{1}{2}\right]$. The countries A and B only differ in the choice of capacity mechanism: Strategic reserves are procured in country A, while capacity payments are used in country B to ensure this capacity target.

Strategic reserves are generation capacities procured and controlled by a regulator and are only used in case of scarcity, i.e., when a supply shortage occurs or the spot market price rises above a previously determined trigger price. Strategic reserves are used to fill the gap between the capacity that is built (and participate) in the market x_A and the target capacity x_A^T. In country A, the regulator procures strategic reserves of size x_A^R that satisfy

$$x_A^T = x_A + x_A^R.$$

Capacity payments z are fees that are uniformly paid according to each capacity unit to achieve the capacity target. The regulator in B fixes capacity payments

$$x_B^T = x_B(z).$$

The total capacity for both countries is then given by $x^T = x_A^T + x_B^T$.

Firms offer electricity on the spot market, knowing the realization of demand. When there is sufficient capacity available to cover the demand, competition drives prices down to marginal costs c. Otherwise, electricity is scarce and the maximum price $\bar{P} > c$ is reached.[6,7] The maximum price $\bar{P}$ refers either to a price cap fixed by a regulator or to the value of lost load (VOLL) that denotes the maximal amount customers are willing to pay for electricity.

Cross-border trading impacts the spot market prices as follows: When the transmission capacity α is non-binding, cross-border trading leads to equal prices in both markets, i.e., either there is sufficient capacity to cover the demand in A and B or scarcity prices occur in both markets. However, if α is a binding restriction, the prices in A and B may differ.

We assume that the trigger price of the strategic reserves equals the maximum price $\bar{P}$, i.e., strategic reserves do not push prices below the maximum price. Strategic reserves are only used if there is not sufficient (generation or transmission) capacity participating in the market to cover demand.

3.2.1 Spot Market Competition and Investments

We start by analyzing the spot market and its outcome. Since both countries target the same capacity level $x_A^T = x_B^T$, but country A's strategic reserves x_A^R do not participate in the spot market while in B the whole capacity $x_B^T = x_B$ participates, we

[6] We assume that a partial blackout occurs, if electricity demand exceeds supply. In this case, there will be exactly so many consumers cut off from the electricity supply such that the remaining consumption equals the given supply.

[7] We assume that scarcity prices occur if and only if capacity is equal to or less than demand. One could expect scarcity prices to occur if there is just enough capacity, i.e., ϵ more than needed. However, in this case, the given capacity would change by the constant amount ϵ and our results would be the same.

restrict our attention to the case that $x_A \leq x_B$. The spot market prices behave as follows: When demand is less than the domestic firms' capacities in both countries, the spot market prices equal the marginal costs c. Moreover, even if the demand exceeds the domestic firms' capacities in A, the prices equal marginal costs c in both countries if the total capacity of both countries exceeds the total demand D and α is sufficiently large, i.e., $\frac{D}{2} - x_A < \alpha$. In contrast, if the total demand D exceeds the total capacities, the price equals the maximum price $\bar{P}$ in A - and if, in addition, $x_B - \frac{D}{2} \leq \alpha$, the price also rises to $\bar{P}$ in B. Obviously, scarcity prices occur in both countries when the demand exceeds the domestic capacities in both countries. More comprehensively, the spot market prices in A are given by

$$P_A = \begin{cases} \bar{P} & \text{otherwise} \\ c & \text{if } D < x_A + x_B \text{ and } \frac{D}{2} - x_A < \alpha. \end{cases} \tag{3.1}$$

The spot market prices in B are given by

$$P_B = \begin{cases} \bar{P} & \text{if } D \geq x_A + x_B \text{ and } x_B - \frac{D}{2} \leq \alpha \\ c & \text{otherwise.} \end{cases} \tag{3.2}$$

We assume that firms in both countries always receive the domestic price for selling electricity, and consumers in both countries always pay the domestic price for electricity consumption. Congestion rents, which occur when a limited α results in price differences between two markets, are shared between (the transmission system operators of) both countries equally.[8] Hence, implicitly, consumers of both countries benefit equally from congestion rents.

To avoid uninteresting case distinctions, we restrict our attention to the case $x_A + x_B \leq 1$. Independent from the realization of demand, it follows from equations (3.1) and (3.2) that α is always non-binding if $x_B - x_A \leq 2\alpha$.[9] Hence, dependent on x_A, x_B and α, we distinguish between two possible outcomes for the expected variable spot market profits per capacity unit in both countries:

Case 1. If α is at least sometimes binding, i.e., $x_B - x_A > 2\alpha$, the expected variable spot market profits per capacity unit for firms in A and B differ and are given by

[8] This is basically how congestion rents resulting from market coupling are shared, e.g., in the Central West Europe region, see CWE MC Project Group (2010).

[9] The following relationship holds: $x_A + x_B \leq 2x_A + 2\alpha \Leftrightarrow x_B - x_A \leq 2\alpha \Leftrightarrow 2x_B - 2\alpha \leq x_A + x_B$. If $x_B - x_A \leq 2\alpha$ holds, $P_A(D) = P_B(D)$ for all $D \in [0,1]$. If $x_B - x_A > 2\alpha$ holds, $P_A = \bar{P}$ if $D \geq 2x_A + 2\alpha$ and $P_B = \bar{P}$ if $D \geq 2x_B - 2\alpha$.

$$\pi_A^S = \left(\bar{P}-c\right)\left[1-G\left(2x_A+2\alpha\right)\right] \quad (3.3)$$
$$\pi_B^S = \left(\bar{P}-c\right)\left[1-G\left(2x_B-2\alpha\right)\right], \quad (3.4)$$

respectively.

Case 2. If α is always non-binding, i.e., $x_B - x_A \leq 2\alpha$, the firms' expected variable spot market profits per capacity unit are the same in both countries A and B and are given by

$$\pi_A^S = \pi_B^S = \left(\bar{P}-c\right)\left[1-G\left(x_A+x_B\right)\right]. \quad (3.5)$$

Remark 1. *If α is (sometimes) binding, the expected variable spot market profits per capacity unit are higher in country A than in country B. Moreover, π_A^S is decreasing in α and π_B^S is increasing in α.*

Since we consider competitive markets, firms enter the market until profits are driven down to zero.[10] The firms' zero profit condition in A is then given by

$$0 = k - \pi_A^S. \quad (3.6)$$

In B the capacity payments z that are paid for each unit of capacity impact the firms' investments. The firms' zero profit condition in B can be written as

$$z = k - \pi_B^S. \quad (3.7)$$

The strategic reserves are only used in times of scarcity and as mentioned above the trigger price equals the maximum price $\bar{P}$. Hence, the usage policy follows

$$q_A^R = \min\left\{x_A^R, \max\left\{0, \frac{D}{2} - x_A - \alpha, D - x_A - x_B\right\}\right\},$$

where we define q_A^R as the amount of electricity produced by the reserve capacities. Strategic reserves are given by the difference $x_A^R = x_A^T - x_A$, i.e., strategic reserves are capacities that are not worth building in the market because they would earn negative profits. Additional payments are necessary that are born by the consumers, as we discuss below.

[10]We assume that regulators want to increase the reliability level of electricity, i.e., they choose a target capacity that is at least as large as the capacity that would have been built in the market without any capacity mechanism. To make sure that $x_A^R \geq 0$ and $z \geq 0$, we assume that $\frac{k}{\bar{P}-c} > 1 - G\left(x^T\right)$.

To avoid uninteresting case distinctions, we assume that $x^T \geq 2\alpha$.[11] In addition, we make the following

Assumption 1. *The maximum spot market mark-up $\bar{P} - c$ is strictly larger than the fixed costs of capacity k.*

3.2.2 Consumers' Costs

The consumers' costs can be split into two parts: First, consumers pay (spot market prices) for their electricity consumption. Second, the consumers have to bear the costs incurred by the capacity mechanisms, i.e., they pay for the reliability level.[12] The consumers' costs CC_A and CC_B in A and B, respectively, are given by

$$CC_A = CC_A^S + CC_A^{SR} \quad \text{and} \quad CC_B = CC_B^S + CC_B^Z, \tag{3.8}$$

where we define CC_A^S and CC_B^S as the costs incurred on the spot markets, CC_A^{SR} as the strategic reserves' costs and CC_B^Z as the costs arising from capacity payments. While the costs from capacity payments are simply given by

$$CC_B^Z = z x_B,$$

the costs of the strategic reserves depend on the usage of the strategic reserves:

$$CC_A^{SR} = k x_A^R - \left(\bar{P} - c\right) \mathbb{E}\left[q_A^R\left(D, x_A, x_A^R, x_B, \alpha\right)\right].$$

The consumers pay the procurement costs (defined as the fixed costs) of the strategic reserves and the generation costs. At the same time, spot market revenues generated by strategic reserve capacities are used to partially offset these costs and hence benefit the consumers.

Furthermore, congestion rents may benefit consumers by lowering their costs. These rents are shared equally between the two countries. Since we are not interested in the magnitude of consumers' costs but rather in the cost differential between

[11] In our model, there is no need to consider transmission capacity that is larger than the maximum generation capacity in one of the two countries.

[12] Furthermore, blackout costs occur if sufficient capacity is not available to cover demand. The blackout price is at least as high as the maximum price $\bar{P}$ that occurs on the spot market (and is always finite). However, since both countries have identical demand for electricity and the same reliability level, the blackout costs are the same in both countries. We are not interested in the absolute amount of consumer cost but rather in the cost difference between the two countries; therefore we neglect these costs in our analysis.

consumers of both countries, we do not specify the congestion rent in our model. In the following, the consumers' costs in both countries are analyzed.

Benchmark: Isolated countries

In order to compare both capacity mechanisms, let us consider the case in which there does not exist any transmission capacity between A and B, i.e., $\alpha = 0$.

Proposition 1. *The target reliability level is reached by capacity payments and strategic reserves. The consumers' costs are the same for both mechanisms.*

The intuition is as follows: In our model with competitive firms and free entry, firms enter the market until profits are driven down to zero. This happens regardless of where the revenue streams come from. Hence, in both countries, the consumers pay the exact amount that is necessary to reach the previously determined capacity level.

3.3 A Simple Numerical Example

We discuss a simple numerical example in order to highlight some effects resulting from different capacity mechanisms in neighboring countries. Consider the two symmetric countries A and B that are connected by transmission capacity $\alpha = 0.05$. The maximum price for electricity is given by $\bar{P} = 1000$ and the firms can produce electricity at costs $c = 100$. The fixed costs are given by $k = 9$. The regulators of both countries target the same capacity level $x_A^T = x_B^T = 0.5$, i.e., total capacity is given by $x^T = 1$. While the regulator in A procures strategic reserves to reach the capacity target, the regulator in B determines capacity payments that are paid for each unit of capacity.

For the fixed target capacity, firms' revenue streams to cover total costs must either come from the spot market or from the capacity mechanism. In country A, in equilibrium the spot market revenues earned by capacity x_A are exactly as large as the firms' total costs. The costs of the strategic reserves x_A^R are born by the consumers and given by the difference between the sum of procurement (defined by the fixed costs) and generation costs and the spot market revenues. Hence, the higher the spot market revenues of the strategic reserves become, the lower the costs of the strategic reserves will be. In country B, the total costs of capacity $x_B^T = x_B$ are exactly covered by the sum of spot market revenues and capacity payments. Hence, the costs of the capacity mechanisms strongly depend on the variable spot market profits. The firms' variable spot market profits, in turn, depend not only on the domestic electricity demand but also on cross-border transmission capacity between both countries. Let us assume that in A, firms build up capacities $x_A = 0.3$ and hence the regulator procures $x_A^R = 0.2$ as strategic reserves. We split the possible spot market outcomes into three different cases:

- If demand is sufficiently small, i.e., $D < 0.7$, the spot market price equals marginal generation costs in both countries since sufficient generation capacity is built in the market or transmission capacity is available to cover total demand. In these hours, firms in both countries do not earn any profits to cover their fixed costs.
- If $0.7 \leq D < 0.9$, the prices in both countries differ. Suppose demand is given by $D = 0.8$. In country A, the price rises up to $\bar{P}$ and in country B, the price equals marginal generation costs c. To cover the demand in A, the capacities that are built in the market $x_A = 0.3$ are fully utilized, electricity is imported from country B according to the transmission capacity $\alpha = 0.05$ and the strategic reserves are used, which amounts to $q_A^R = 0.05$. Even though consumers pay the high price for $\frac{D}{2} = 0.4$, only $x_A + q_A^R = 0.35$ of A's capacity is used and profits from the high prices. The congestion rent, which results from the electricity import, is shared between both countries equally.[13] Consumers in country A pay $\bar{P}$ for each unit of electricity. However, only a fraction of the corresponding revenues is earned by the country's own firms, allowing for the reduction of ex ante payments for strategic reserve capacities. For the exports from B to A, part of the payments for electricity consumption "leaks" over country B and contributes to the financing of B's firms.
- If $0.9 \leq D < 1$, the maximum price is reached in both countries. Suppose demand is given by $D = 0.95$. In that case, B's total capacities $x_B = 0.5$ are fully utilized, while in A the capacities that are built in the market $x_A = 0.3$ are fully utilized but the strategic reserves do not operate at full capacity, $q_A^R = 0.15$. Although consumers from both countries pay the same for electricity consumption, the costs of the capacity mechanisms are reduced more in B than in A.

Hence, in this example, the consumers' costs are higher in A than in B. So far, we have not proved whether the capacities in A are equilibrium capacities, i.e., we do

[13] If the congestion rent had been completely given to country A, the additional costs on the spot market due to higher prices would equal the cost reduction by the congestion rent.

not know whether $x_A = 0.3$ would have been built in the market for given assumptions on $\bar{P}, c, k$ and α. To solve the problem, one has to specify the distribution of demand. Suppose the demand is beta-distributed, $D \sim Beta(2,5)$; then $x_A^* \approx 0.3$ and $x_A^{R*} \approx 0.2$ are indeed equilibrium outcomes.

In the following section, we determine equilibrium outcomes for any arbitrary choice of $\bar{P}$, c, α, x^T and distribution of demand G. Furthermore, we show that the result from our example always holds, i.e., the consumers' costs for A are always higher than those for B.

3.4 Cross-Border Effects on Market Equilibria

In this section, we investigate cross-border effects resulting from different capacity mechanisms in the two connected countries. We henceforth assume that $\alpha > 0$. In particular, we are interested in the size of the strategic reserves, the capacity that is built in the market, the amount of capacity payments and the effects on consumers' costs. We can generally establish the following

Proposition 2. *Assume countries A and B use different capacity mechanisms, namely strategic reserves and capacity payments, to ensure the same reliability level. For every given combination of $\bar{P}$, c, k, any distribution of demand G, transmission capacity α and target capacity x^T, a unique market equilibrium exists. The equilibrium capacities x_A^*, x_A^{R*} and capacity payments z^* are characterized as follows:*

(i) If $1 - G(2\alpha) > \frac{k}{\bar{P}-c}$ *and* $1 - G\left(x^T - 2\alpha\right) < \frac{k}{\bar{P}-c}$,

$$x_A^{R*} > 0, \quad x_A^* > 0 \quad and \quad z^* > 0.$$

(ii) If $1 - G(2\alpha) \leq \frac{k}{\bar{P}-c}$ *and* $2\alpha < \frac{x^T}{2}$,

$$x_A^{R*} = \frac{x^T}{2}, \quad x_A^* = 0 \quad and \quad z^* > 0.$$

In (i) and (ii), Case 1 holds; i.e., α is sometimes binding.

(iii) If $1 - G\left(\frac{x^T}{2}\right) > \frac{k}{\bar{P}-c}$ *and* $1 - G\left(x^T - 2\alpha\right) \geq \frac{k}{\bar{P}-c}$,

$$x_A^{R*} > 0, \quad x_A^* > 0 \quad and \quad z^* = 0.$$

(iv) If $1 - G\left(\frac{x^T}{2}\right) \leq \frac{k}{\bar{P}-c}$ *and* $2\alpha \geq \frac{x^T}{2}$,

$$x_A^{R*} = \frac{x^T}{2}, \quad x_A^* = 0 \quad \textit{and} \quad z^* > 0.$$

In (iii) and (iv), Case 2 holds; i.e., α *is always non-binding.*[14]

Let us first discuss (i) and (ii), i.e., the cases in which the transmission capacity α is binding. Depending on whether or not $\mathbb{P}(D > 2\alpha) > \frac{k}{\bar{P}-c}$, the equilibrium capacities in A that are built in the market are either positive or zero. The threshold value $\frac{k}{\bar{P}-c}$ can be interpreted as a measure of how severe the missing money problem is: The higher the difference between the maximum spot market mark-up $\bar{P} - c$ and the fixed costs k is, the less severe the missing money problem becomes (for a given capacity target x^T). Given the distribution of demand G and transmission capacity α, a lower threshold value leads to an equilibrium in which (positive) capacities are built in the market in A. In contrast, if the difference between the maximum spot market mark-up and the fixed costs is sufficiently small, all capacities in A are procured as strategic reserves. In cases (iii) and (iv), the arguments are similar. The difference in these cases is that the capacity level x^T, instead of the transmission capacity α, is crucial. Depending on whether or not the probability of demand exceeding A's target capacity is greater than the threshold value, capacity that is built in the market is positive or zero.

The intuition of this proposition is as follows: The amount of capacity that is built in A depends on the value of the spot market mark-up relative to the fixed costs and on the frequency in which high prices occur. If the maximum spot market mark-up is relatively high, sufficient variable spot market profits can be earned in peak price periods to cover the fixed costs of capacities and therefore, (positive) capacities are built in A.

Note that for case (iii) in which α is always non-binding and thus the spot market prices are always the same in both countries, some capacities are procured as strategic reserves in A, while the capacity payments in B are zero. This means that only consumers in A pay for the capacity mechanism while consumers from both countries benefit from the same reliability level and pay exactly the same amount for electricity consumption. In the following, we investigate the redistribution effects that are induced by different capacity mechanisms.

[14]See the proof of Proposition 2 for the equilibrium capacities in the Appendix.

Redistribution Effects

The effects of different capacity mechanisms in two connected countries on consumers' costs can be characterized as follows:

Proposition 3. *Assume the regulator in A procures strategic reserves x_A^R while the regulator in B uses capacity payments z to ensure a total capacity level $x_A^T = x_B^T$. If $\alpha > 0$, the expected consumers' costs are higher in A than in B, i.e., $CC_A > CC_B$.*

Intuition for why the consumers' costs in A are higher than in B: Given a fixed capacity target x_B^T, higher expected variable profits π_B^S lead to a reduction of capacity payments z and vice versa. That is, firms in B earn profits if $P = \bar{P}$, and the amount of capacity payments is reduced exactly by the amount of profits that firms earn during these peak price periods. Accordingly, the capacity payment costs for consumers in B are reduced. Similarly, the strategic reserve costs for consumers in A are reduced by the amount of profits of the strategic reserves. Since both countries have the same amount of capacity and, in country A a part of its capacities are procured as strategic reserves, peak price periods occur either in both countries or only in country A. If the peak price occurs only in country A, electricity is imported from country B according to the transmission capacity α and congestion rents are split equally, i.e., country B benefits from the congestion rents that are paid by A's consumers. If peak prices occur, in both countries which is, e.g., the case if α is non-binding, the capacities x_A and x_B are both fully utilized. However, if demand is less than total capacity $x^T = x_A^T + x_B^T$, the strategic reserves x_A^R by definition do not operate at full capacity. It follows that the average utilization of capacity in B is higher than in A during peak price periods. If α is non-binding, consumers in both countries pay the same for electricity consumption. Consumers in B benefit from peak prices due to reduced capacity payments, while the costs of the strategic reserves in A decrease to a lesser extent. Hence, on average, the consumers' costs in A are higher than in B.

This intuition is quite robust: Even if we had an elastic electricity demand the expected variable spot market profits per capacity unit would be higher in the country with capacity payments than in the country with strategic reserves during peak price periods. This intuition also holds true if demand for electricity varies between both countries. If prices are high the strategic reserves is still the last resort that is used to cover demand. This negatively impacts the consumer costs of the country with strategic reserves.

Remark 2. *Proposition 3 shows that different capacity mechanisms in two connected countries induce redistribution effects and hence impact the welfare of each country. However, total welfare does not change: Regardless of whether both countries choose strategic reserves, capacity payments, or one chooses capacity payments and the other procures strategic reserves, the total welfare remains the same.*

3.5 Base and Peak Load Technologies

This section studies the robustness of our results regarding the redistribution effects of different capacity mechanisms for the case of two technologies. Firms in both countries A and B invest in two different technologies $x_A, x_B \in [0,1]$ and $x_A^1, x_B^1 \in [0,1]$, i.e., base and peak load technologies, respectively. The investment and marginal generation costs are denoted by $k, c \in \mathbb{R}^+$ and $k^1, c^1 \in \mathbb{R}^+$ for base load (BL) and peak load (PL) technologies, respectively. Base load technologies are characterized by higher fixed costs and lower marginal generation costs compared to peak load technologies, i.e., $k > k^1$ and $c < c^1$. Investments into a generation mix are reasonable due to the fluctuating demand: While base load capacities produce relatively cheaply but have to run many hours to cover the high investment costs, peak load capacities are cheap to build but have high marginal generation costs and hence operate only in times of high demand. To avoid uninteresting case distinctions, we restrict our attention to the case in which it is worth investing in both technologies and henceforth make the following

Assumption 2. *The maximum spot market mark-up $\bar{P} - c^1$ is strictly larger than the fixed costs of the peak load capacity k^1, and the difference in marginal generation costs $c^1 - c$ of both technologies is strictly larger than the difference in fixed costs $k - k^1$. In order to ensure that it is reasonable to invest in a generation mix, $\frac{k-k^1}{c^1-c} > \frac{k^1}{\bar{P}-c}$ must hold.*

In this extension, we restrict our analysis to the case in which the transmission capacity α is sufficiently large such that it is always non-binding.

We start by characterizing the spot market and its outcome. Firms offer electricity on the spot market knowing the realized demand. When there is sufficient base load capacity available to cover demand, competition drives prices down to marginal costs c. Correspondingly, when demand exceeds the base load capacity but is less than the sum of the base and peak capacities, the price $c^1 > c$ is reached. If capacity is scarce, the maximum price $\bar{P} > c^1$ occurs. Since we assume that there is sufficient transmission capacity α, the spot market prices are always the same in both markets and characterized by

$$P_A = P_B = \begin{cases} c & \text{if } D < x_A + x_B \\ c^1 & \text{if } x_A + x_B \leq D < x_A + x_B + x_A^1 + x_B^1 \\ \bar{P} & \text{otherwise.} \end{cases} \tag{3.9}$$

The spot market profits per capacity unit for base and peak load capacities are then given by

$$\begin{aligned} \pi^s_{BL_A} = \pi^s_{BL_B} &= \left(\bar{P} - c\right) - \left(\bar{P} - c_1\right) G\left(x_A + x_B + x_A^1 + x_B^1\right) - \left(c_1 - c\right) G\left(x_B + x_A\right) \\ \pi^s_{PL_A} = \pi^s_{PL_B} &= \left(\bar{P} - c_1\right)\left(1 - G\left(x_A + x_B + x_A^1 + x_B^1\right)\right), \end{aligned}$$

respectively.

As in the main model, we assume that both countries encourage the same capacity level $x_A^T = x_B^T \in \left[0, \frac{1}{2}\right]$, and total capacity is given by $x^T = x_A^T + x_B^T$. The regulator in A procures strategic reserves $x_A^R \geq 0$, while the regulator in B fixes capacity payments $z \geq 0$ to ensure the capacity level.[15] The total capacities in A and B are then given by

$$x_A^T = x_A + x_A^1 + x_A^R \quad \text{and} \quad x_B^T = x_B\left(z\right) + x_B^1\left(z\right).$$

Since we consider competitive markets, firms enter the market until profits are driven down to zero. The firms' zero profit conditions in A for base and peak load technologies are given by

$$\begin{aligned} 0 &= k - \pi^s_{BL_A} \\ 0 &= k^1 - \pi^s_{PL_A}, \end{aligned}$$

respectively. The firms' zero profit conditions in B for base load and peak load technologies are given by

$$\begin{aligned} 0 &= k - \pi^s_{BL_B} - z \\ 0 &= k^1 - \pi^s_{PL_B} - z, \end{aligned}$$

[15] We assume that the regulators want to increase the reliability level of electricity, i.e., they choose a target capacity that is at least as large as the capacity that would have been built in the market without any capacity mechanism. To make sure that $x_A^R \geq 0$ and $z \geq 0$, we assume that $\frac{k^1}{\bar{P} - c^1} > 1 - G\left(x^T\right)$.

respectively.

Benchmark: One capacity mechanism for both countries.

In order to compare both capacity mechanisms, let us consider the case in which regulators of both countries choose the same capacity mechanism.

Proposition 4. *Assume the regulators choose the same capacity mechanism. Both capacity mechanisms are efficient in the sense that they ensure the target capacity level with minimal costs. The total equilibrium base load capacity is given by*

$$x_A^* + x_B^* = G^{-1}\left(1 - \frac{k - k^1}{c^1 - c}\right).$$

The consumers' costs are the same for both mechanisms.

Interestingly, the equilibrium base load capacity $x_A^* + x_B^*$ neither depends on the target capacity level x^T, nor on the choice of capacity mechanism, nor on the maximum price $\bar{P}$. The efficient amount of base load capacity is solely determined by the relation between fixed costs and variable generation costs between base and peak load technologies. The reason is as follows: Since we assume that it is worth it to invest in both technologies (by Assumption 2), peak load capacity is needed that operates so infrequently that its fixed cost advantage over base load capacity dominates the disadvantage of higher generation costs. If the regulators want to increase the reliability level of electricity and fix a capacity target $x^T = x_A^T + x_B^T$, the additional capacity units are used even less and hence peak load capacities are built to reach the target. This holds for both mechanisms. Since the total capacity is fixed and the firms' profits are zero, the consumers' costs remain the same.

Cross-border effects of capacity mechanisms in neighboring countries.

From now on, we investigate cross-border effects resulting from different capacity mechanisms in the two fully connected countries. We can establish the following

Proposition 5. *Assume the regulator in A procures strategic reserves x_A^R, while the regulator in B uses capacity payments z to ensure the capacity level $x_A^T = x_B^T$, and both countries are fully connected. The equilibrium capacities are characterized as follows:*

(i) If $1-G\left(\frac{x^T}{2}\right) > \frac{k^1}{\bar{P}-c^1}$,

$$x_A^{R*} > 0, \quad x_A^* + x_A^{1*} > 0 \quad and \quad z^* = 0.$$

(ii) If $1-G\left(\frac{x^T}{2}\right) \leq \frac{k^1}{\bar{P}-c^1}$,

$$x_A^{R*} = \frac{x^T}{2}, \quad x_A^* = x_A^{1*} = 0 \quad and \quad z^* > 0.$$

In (i) and (ii), the total base load capacity is independent of the total capacity level x^T *and the maximum price* $\bar{P}$ *and is given by* $x_A^* + x_B^* = G^{-1}\left(1 - \frac{k-k^1}{c^1-c}\right)$.

As in Proposition 4, the total equilibrium base load capacity is independent of the choice of capacity mechanism: It is exactly equal to the amount of base load capacity that would have been built in the market without any capacity mechanism. However, the amount of peak load capacity depends on the target capacity level. Depending on whether or not $\mathbb{P}\left(D > \frac{x^T}{2}\right) > \frac{k^1}{\bar{P}-c^1}$, the equilibrium capacities in A that are built in the market are positive or zero. The threshold value $\frac{k^1}{\bar{P}-c^1}$ indicates how severe the missing money problem is, i.e., the maximum spot market mark-up $\bar{P} - c^1$ relative to the fixed costs of the peak capacity k^1 is crucial for the amount of capacity that is procured as strategic reserves. Given the distribution of demand and the target capacity x^T, a higher threshold value leads to the case in which the whole capacity in A has to be procured as strategic reserves.

Note, that in case (ii), each unit of the total base load capacity receives capacity payments. In both cases, only peak load capacity is procured as strategic reserve. The redistribution effects that are induced by the choice of different capacity mechanisms in connected countries can be characterized as follows:

Proposition 6. *Assume the regulator in A procures strategic reserves* x_A^R*, while the regulator in B uses capacity payments z to ensure the capacity level* $x_A^T = x_B^T$*, and both countries are fully connected. The expected consumers' costs are higher in A than in B.*

The intuition for this result is similar to that in the case of one technology: In peak price periods, the total capacity $x_B^T = x_B + x_B^1$ and the capacities x_A, x_A^1 that are built in the market are fully utilized. However, if demand is less than total capacity, the strategic reserves x_A^R do not operate at full capacity in these periods. Even though the electricity consumption costs are equal, firms' expected variable spot market profits per capacity unit are higher in B than in A. Hence, the consumers' costs from strategic reserves are higher than capacity payment costs.

Corollary 3. *Regardless of whether regulators of both countries choose strategic reserves, capacity payments or one chooses capacity payments and the other procures strategic reserves, the joint welfare remains the same.*

3.6 Conclusion

It has been the purpose of this study to understand the cross-border effects of different capacity mechanisms in neighboring countries. For our analysis, we have chosen a model with two symmetric countries that are connected by some given transmission capacity. Both countries only differ in their regulator's choice of capacity mechanisms, namely strategic reserves or capacity payments. In both countries, competitive firms can freely enter the market and invest in generation capacities before selling electricity on the spot market, which is characterized by fluctuating price-inelastic electricity demand. We have characterized different market equilibria and found the following main result: Even if both forms of capacity mechanisms lead to an efficient generation mix and induce the same consumer costs in isolated countries, different capacity mechanisms lead to redistribution effects for interconnected countries. The country with strategic reserves is worse off; more precisely, the consumers' costs are higher in the country with strategic reserves than in the country with capacity payments. We have shown that this result holds robustly for the case of two technologies.

The main effect that drives this result comes from the fact that strategic reserves are used only if electricity import is limited by transmission capacity or no sufficient (other) capacities are available. Hence, in times of scarcity when demand is less than total capacity, part of the high payments for electricity consumption in the country with strategic reserves are not earned by the country's own firms but "leaks" over to the country with capacity payments and implicitly benefits its consumers. In our model, we have chosen completely symmetric countries in order to point out the effects resulting from different capacity mechanisms. However, this effect should have more general implications: First, even if we had an elastic electricity demand or demand varied between both countries, the average capacity utilization during peak price periods in which the transmission capacity is non-binding would be higher for the country with capacity payments than in the country with strategic reserves. Second, even if the maximum price varied between the two countries and was, e.g., lower in the country with capacity payments, the consumers who pay capacity payments would benefit from the fact that strategic reserves are only used as a last resort. In our model, we assume that both countries (agree to) ensure the same reliability level of electricity. We have not analyzed the effects resulting from choosing different reliability levels of electricity. Obviously, due to cross-border trading, the reliability level in one country depends on the reliability level of the other country and vice versa. Hence, different choices may also impact the consumers' costs in both countries.

The result we established may be informative for the policy debate surrounding the design of capacity mechanisms and the effects for the internal market in Europe. In this discussion, one should take into account that such policy interventions may lead to redistribution effects. Redistribution may affect the choice of capacity mechanism as well as the cooperation between different countries. It is clear that cross-border trading can be beneficial for the countries involved and reduce consumers' costs, e.g., through increased competition or a better technology mix that lowers the costs of production. However, the cross-border effects resulting from the choice of different capacity mechanisms can induce negative welfare effects for individual countries, as shown in our analysis.

In our analysis, we have chosen a theoretical model to investigate the cross-border effects of different capacity mechanisms in neighboring countries to clearly point out the factors that drive these effects. Further research could quantify the equilibrium investments and the redistribution effects for an existing market. This would be very interesting in light of the recently introduced market coupling in the North-West region of Europe and the different capacity mechanisms that are currently being implemented.

3.7 Appendix

The Appendix contains all proofs of the paper.

Proof of Proposition 1.

From equation (3.6) follows that the firms' zero profit condition in A is given by

$$0 = \left(\bar{P} - c\right)\left(1 - G\left(2x_A\right)\right) - k.$$

The unique equilibrium capacity is then given by $x_A^* = \frac{1}{2}G^{-1}\left(1 - \frac{k}{\bar{P}-c}\right)$ since x_{A}^*

is the unique solution of the firms' zero profit condition and $x_A^* > 0$. The target capacity is given by $x_A^T = \frac{x^T}{2}$. The difference $x_A^T - x_A^* = x_A^{R*}$ determines the reserve capacity. The electricity consumption costs are given by

$$CC_A^S = c\int_0^{2x_A^*} \frac{D}{2} g(D)\, dD + \bar{P}\left(\int_{2x_A^*}^{x^T} \frac{D}{2} g(D)\, dD + \frac{x^T}{2}\left(1 - G\left(x^T\right)\right)\right). \quad (3.10)$$

The costs from the strategic reserves are given by

$$CC_A^{SR} = kx_A^{R*} - (\bar{P} - c)\left(\int_{2x_A^*}^{x^T}\left(\frac{D}{2} - x_A^*\right) g(D)\, dD + x_A^R\left(1 - G\left(x^T\right)\right)\right). \quad (3.11)$$

The consumers' costs are given by $CC_A = CC_A^S + CC_A^{SR}$. Plugging x_A^* into equations (3.10) and (3.11) leads to

$$CC_A = c\left(\int_0^{x^T} \frac{D}{2} g(D)\, dD + \frac{x^T}{2}\left(1 - G\left(x^T\right)\right)\right) + k\frac{x^T}{2}.$$

Let us consider country B. For a given capacity level $x_B^T = \frac{x^T}{2}$, we can argue from equation (3.7) that the capacity payments are given by

$$z = k - (\bar{P} - c)\left(1 - G\left(x^T\right)\right).$$

The electricity consumption costs are given by

$$CC_B^S = \frac{c}{2}\int_0^{x^T} Dg(D)\, dD + \bar{P}\frac{x^T}{2}\left(1 - G\left(x^T\right)\right).$$

The capacity payment costs are given by

$$CC_B^Z = zx_B = \left(k - (\bar{P} - c)\left(1 - G\left(x^T\right)\right)\right)\frac{x^T}{2}.$$

The consumers' costs are given by $CC_B = CC_B^S + CC_B^Z$. Summing up leads to

$$CC_B = \frac{c}{2}\left(\int_0^{x^T} Dg(D)\, dD + x^T\left(1 - G\left(x^T\right)\right)\right) + k\frac{x^T}{2}.$$

Hence, we have shown that $CC_A = CC_B$ holds.

Proof of Proposition 2.

For the proof of Proposition 2, we show first the following

Lemma. *For every choice of $\bar{P}$, c, k, G, α and x^T, one and only one of the following conditions holds:*

(i) $1 - G(2\alpha) > \frac{k}{\bar{P}-c}$ *and* $1 - G\left(x^T - 2\alpha\right) < \frac{k}{\bar{P}-c}$

(ii) $1 - G(2\alpha) \leq \frac{k}{\bar{P}-c}$ *and* $2\alpha < \frac{x^T}{2}$

(iii) $1 - G\left(\frac{x^T}{2}\right) > \frac{k}{\bar{P}-c}$ *and* $1 - G\left(x^T - 2\alpha\right) \geq \frac{k}{\bar{P}-c}$

(iv) $1 - G\left(\frac{x^T}{2}\right) \leq \frac{k}{\bar{P}-c}$ *and* $2\alpha \geq \frac{x^T}{2}$.

Proof. First, we show that only one of the four conditions can hold: Obviously, only one of the conditions (i) and (ii), one of the conditions (i) and (iii), one of the conditions (ii) and (iv), as well as only one of the conditions (iii) and (iv) can hold. Hence, we have to show that only one of the conditions (i) and (iv) as well as only one of the conditions (ii) and (iii) can hold: From (i) follows that $1-G(2\alpha) > \frac{k}{\bar{P}-c} > 1 - G\left(x^T - 2\alpha\right) \Rightarrow x^T - 2\alpha > 2\alpha \Rightarrow \frac{x^T}{2} > 2\alpha$. Hence, (iv) does not hold. From (iv) follows that $1 - \frac{k}{\bar{P}-c} \leq G\left(\frac{x^T}{2}\right) \leq G(2\alpha) \Rightarrow 1 - G(2\alpha) \leq \frac{k}{\bar{P}-c}$. Hence, (i) does not hold. From (ii) follows that $G\left(\frac{x^T}{2}\right) > G(2\alpha) \geq 1 - \frac{k}{\bar{P}-c} \Rightarrow \frac{k}{\bar{P}-c} \geq 1 - G\left(\frac{x^T}{2}\right)$. Hence, (iii) does not hold. From (iii) follows that $G\left(\frac{x^T}{2}\right) < 1 - \frac{k}{\bar{P}-c}$. If, in addition, $1 - \frac{k}{\bar{P}-c} \leq G(2\alpha)$ holds, $2\alpha < \frac{x^T}{2}$ can not hold. Hence, (ii) does not hold. Thus, we have shown that only one of the four conditions above can hold.

Second, we prove that always one of the four conditions holds by showing that no further cases exist. By considering all possible combinations of (a), (b), (c) and (d)

$$\text{(a) } 1 - G(2\alpha) > (\leq) \frac{k}{\bar{P}-c}, \qquad \text{(b) } 1 - G\left(\frac{x^T}{2}\right) > (\leq) \frac{k}{\bar{P}-c},$$

$$\text{(c) } 1 - G\left(x^T - 2\alpha\right) < (\geq) \frac{k}{\bar{P}-c}, \qquad \text{(d) } 2\alpha < (\geq) \frac{x^T}{2}$$

it follows directly that in 14 out of these 16 cases, either (i), (ii), (iii) or (iv) occurs.

We only have to analyze the following two cases:

$$\begin{aligned}
I \quad : \quad & \text{(a) } 1-G(2\alpha) > \frac{k}{\bar{P}-c}, && \text{(b) } 1-G\left(\frac{x^T}{2}\right) \leq \frac{k}{\bar{P}-c}, \\
& \text{(c) } 1-G\left(x^T-2\alpha\right) \geq \frac{k}{\bar{P}-c}, && \text{(d) } 2\alpha < \frac{x^T}{2}. \\
II \quad : \quad & \text{(a) } 1-G(2\alpha) \leq \frac{k}{\bar{P}-c}, && \text{(b) } 1-G\left(\frac{x^T}{2}\right) > \frac{k}{\bar{P}-c}, \\
& \text{(c) } 1-G\left(x^T-2\alpha\right) < \frac{k}{\bar{P}-c}, && \text{(d) } 2\alpha \geq \frac{x^T}{2}.
\end{aligned}$$

In case I, the conditions (a), (c) and (d) lead to

$$G\left(\frac{x^T}{2}\right) = G\left(x^T - 2\alpha - \left(\frac{x^T}{2} - 2\alpha\right)\right) < G\left(x^T - 2\alpha\right) \leq 1 - \frac{k}{\bar{P}-c}.$$

This is a contradiction to (b). Hence, case I does not occur. In case II, the conditions (a), (b) and (c) lead to

$$1 - \frac{k}{\bar{P}-c} > G\left(\frac{x^T}{2}\right) = G\left(x^T - 2\alpha - \left(\frac{x^T}{2} - 2\alpha\right)\right) > G\left(x^T - 2\alpha\right).$$

This is a contradiction to (c). Hence, case II can not occur. Therefore, we have shown that for any choice of $\bar{P}$, c, k, G, α and x^T, exactly one of the conditions (i), (ii), (iii) or (iv) occurs.

From the lemma above, we can argue that if we find for each of the four cases (i)-(iv) unique equilibrium capacities, then there always exists an equilibrium that is unique for given $\bar{P}$,k, c, G, α and x^T. The firms' capacity in equilibrium has to fulfill one of the following two conditions: (I) The firms' capacity in equilibrium is positive and their profits are zero. (II) The firms' capacity is zero and the profits are negative or zero.

Case (i): $1 - G\left(x^T - 2\alpha\right) < \frac{k}{\bar{P}-c}$ and $1 - G(2\alpha) > \frac{k}{\bar{P}-c}$. The unique equilibrium capacity x_A^* that is built in the market in A and the capacity payments z^* that are paid in B are given by

$$x_A^* = \frac{1}{2} G^{-1}\left(1 - \frac{k}{\bar{P}-c}\right) - \alpha \quad \text{and} \quad z^* = k - (\bar{P}-c)\left(1 - G\left(x^T - 2\alpha\right)\right),$$

for the following reasons: (1.) $z^* > 0$, (2.) $x_A^* > 0$, (3.) z^* and x_A^* are the unique solutions for the firms' zero profit conditions

$$\begin{aligned} 0 &= \left(\bar{P}-c\right)\left(1-G\left(2x_A+2\alpha\right)\right)-k, \\ 0 &= \left(\bar{P}-c\right)\left(1-G\left(x^T-2\alpha\right)\right)+z-k, \end{aligned}$$

and (4.) $x_B^*-x_A^*=\frac{x^T}{2}-\frac{1}{2}G^{-1}\left(1-\frac{k}{\bar{P}-c}\right)-\alpha>2\alpha$.

Case (ii): $2\alpha<\frac{x^T}{2}$ and $1-G(2\alpha)\leq\frac{k}{\bar{P}-c}$. These inequalities lead to

$$1-\frac{k}{\bar{P}-c}\leq G(2\alpha)\leq G\left(\frac{x^T}{2}\right)=G\left(x^T-2\alpha-\left(\frac{x^T}{2}-2\alpha\right)\right)<G\left(x^T-2\alpha\right),$$

i.e., $1-\frac{k}{\bar{P}-c}<G\left(x^T-2\alpha\right)$. The unique equilibrium capacity x_A^* and capacity payments z^* are then given by

$$x_A^*=0 \quad \text{and} \quad z^*=k-\left(\bar{P}-c\right)\left(1-G\left(x^T-2\alpha\right)\right),$$

for the following reasons: (1.) $z^*>0$, (2.) $x_A^*=0$,(3.) the profits for x_A^* are negative or zero

$$\left(\bar{P}-c\right)(1-G(2\alpha))-k\leq\left(\bar{P}-c\right)\left(1-\left(1-\frac{k}{\bar{P}-c}\right)\right)-k=0,$$

and z^* is the unique solution for the zero profit condition of B's firms

$$0=\left(\bar{P}-c\right)\left(1-G\left(x^T-2\alpha\right)\right)+z-k,$$

and (4.) $x_B^*-x_A^*=\frac{x^T}{2}>2\alpha$. The total capacity $x_A^T=\frac{x^T}{2}$ is procured as strategic reserve.

Case (iii): $1-G\left(x^T-2\alpha\right)\geq\frac{k}{\bar{P}-c}$ and $1-G\left(\frac{x^T}{2}\right)>\frac{k}{\bar{P}-c}$. The unique equilibrium capacity x_A^* and capacity payments z^* are then given by

$$x_A^*=G^{-1}\left(1-\frac{k}{\bar{P}-c}\right)-\frac{x^T}{2} \quad \text{and} \quad z^*=0,$$

for the following reasons: (1.) $z^*=0$, (2.) $x_A^*>0$, (3.) z^* and x_A^* are the unique solutions for the firms' zero profit conditions

$$\begin{aligned} 0 &= \left(\bar{P}-c\right)\left(1-G\left(x_A+\frac{x^T}{2}\right)\right)-k \\ 0 &= \left(\bar{P}-c\right)\left(1-G\left(x_A+\frac{x^T}{2}\right)\right)+z-k, \end{aligned}$$

and (4.) $x_B^* - x_A^* = x^T - G^{-1}\left(1-\frac{k}{\bar{P}-c}\right) \leq 2\alpha$.

Case (iv): $2\alpha \geq \frac{x^T}{2}$ and $1-G\left(\frac{x^T}{2}\right) \leq \frac{k}{\bar{P}-c}$. The unique equilibrium capacity x_A^* and capacity payments z^* are then given by

$$x_A^* = 0 \text{ and } z^* = k - \left(\bar{P}-c\right)\left(1-G\left(\frac{x^T}{2}\right)\right),$$

for the following reasons: (1.) $z^* \geq 0$, (2.) $x_A^* = 0$, (3.) the profits for x_A^* are negative or zero

$$\left(\bar{P}-c\right)\left(1-G\left(\frac{x^T}{2}\right)\right)-k \leq \left(\bar{P}-c\right)\left(\frac{k}{\bar{P}-c}\right)-k=0,$$

and x_A^* and z^* are the unique solution for the zero profit condition of B's firms

$$0 = \left(\bar{P}-c\right)\left(1-G\left(\frac{x^T}{2}\right)\right)+z-k,$$

and (4.) $x_B^* - x_A^* = \frac{x^T}{2} \leq 2\alpha$. The total capacity x_A^T is procured as strategic reserve. Hence, we have proven Proposition 2.

Proof of Proposition 3.

The consumers' costs are given by equation (3.8).

Case 1: Let us first consider the case in which α is sometimes binding and in which the expected variable spot market profits per capacity unit in A and B are given by equations (3.4) and (3.4). The electricity consumption costs in A and B are then given by

$$CC_A^S = c\int_0^{2x_A+2\alpha}\frac{D}{2}g\left(D\right)dD + \bar{P}\left(\int_{2x_A+2\alpha}^{x^T}\frac{D}{2}g\left(D\right)dD + \frac{x^T}{2}\left(1-G\left(x^T\right)\right)\right)$$

and

$$CC_B^S = c\int_0^{2x_B-2\alpha} \frac{D}{2} g(D)\, dD + \bar{P}\left(\int_{2x_B-2\alpha}^{x^T} \frac{D}{2} g(D)\, dD + \frac{x^T}{2}\left(1-G\left(x^T\right)\right)\right),$$

respectively. The costs from the strategic reserves are given by

$$\begin{aligned} CC_A^{SR} &= kx_A^R - (\bar{P}-c)\int_{2x_A+2\alpha}^{x^T-2\alpha}\left(\frac{D}{2}-x_A-\alpha\right) g(D)\, dD \\ &\quad - (\bar{P}-c)\int_{x^T-2\alpha}^{x^T}\left(D-x_A-\frac{x^T}{2}\right) g(D)\, dD \\ &\quad - (\bar{P}-c)\, x_A^R\left(1-G(x_T)\right). \end{aligned}$$

The capacity payment costs are given by

$$CC_B^Z = zx_B = \left[k-(\bar{P}-c)\left(1-G\left(x^T-2\alpha\right)\right)\right]\frac{x^T}{2}.$$

The difference in consumers' costs is given by:

$$\begin{aligned} CC_A - CC_B &= CC_A^S - CC_B^S + CC_A^{SR} - CC_B^Z \\ &= (\bar{P}-c)\int_{2x_A+2\alpha}^{x^T-2\alpha}\frac{D}{2} g(D)\, dD + \left(k-(\bar{P}-c)\left(1-G(x_T)\right)\right) x_A^R \\ &\quad - (\bar{P}-c)\int_{2x_A+2\alpha}^{x^T-2\alpha}\left(\frac{D}{2}-x_A-\alpha\right) g(D)\, dD \\ &\quad - (\bar{P}-c)\int_{x^T-2\alpha}^{x^T}\left(D-x_A-\frac{x^T}{2}\right) g(D)\, dD \\ &\quad - \left[k-(\bar{P}-c)\left(1-G\left(x^T-2\alpha\right)\right)\right]\frac{x^T}{2} \\ &> \left(k-(\bar{P}-c)\left(1-G(x_T)\right)\right) x_A^R \\ &\quad + (\bar{P}-c)(x_A+\alpha)\left(G\left(x^T-2\alpha\right)-G(2x_A+2\alpha)\right) \\ &\quad - (\bar{P}-c)\left(x^T-x_A-\frac{x^T}{2}\right)\left(G\left(x^T\right)-G\left(x^T-2\alpha\right)\right) \\ &\quad - \left[k-(\bar{P}-c)\left(1-G\left(x^T-2\alpha\right)\right)\right]\frac{x^T}{2} \\ &= (\bar{P}-c)\left(\alpha G\left(x^T-2\alpha\right)-(x_A+\alpha)\, G(2x_A+2\alpha)+x_A\right)-kx_A \end{aligned}$$

and the inequality holds due to $\int_{x^T-2\alpha}^{x^T} Dg(D)\, dD < x^T\left(G\left(x^T\right)-G\left(x^T-2\alpha\right)\right)$.

If $1-G(2\alpha) > \frac{k}{\bar{P}-c}$ and $1-G\left(x^T-2\alpha\right) < \frac{k}{\bar{P}-c}$, A's equilibrium capacity x_A^* is given by $x_A^* = \frac{1}{2}G^{-1}\left(1-\frac{k}{\bar{P}-c}\right)-\alpha$ (see proof of Proposition 2). Using $1-\frac{k}{\bar{P}-c} < G\left(x^T-2\alpha\right)$ and plugging x_A^* into the inequality leads to

$$\begin{aligned} CC_A - CC_B &> \left(\bar{P}-c\right)\left(\alpha G\left(x^T-2\alpha\right)-\left(x_A+\alpha\right)G\left(2x_A+2\alpha\right)+x_A\right)-kx_A \\ &> \left(\bar{P}-c\right)\left(x_A+\alpha\right)\left(1-G\left(2x_A+2\alpha\right)\right)-\left(x_A+\alpha\right)k \\ &= 0. \end{aligned}$$

If $1-G(2\alpha) \leq \frac{k}{\bar{P}-c}$ and $2\alpha < \frac{x^T}{2}$, A's equilibrium capacity is given by $x_A^* = 0$. Plugging x_A^* into the inequality leads to

$$\begin{aligned} CC_A - CC_B &> \left(\bar{P}-c\right)\left(\alpha G\left(x^T-2\alpha\right)-\left(x_A+\alpha\right)G\left(2x_A+2\alpha\right)+x_A\right)-kx_A \\ &= \left(\bar{P}-c\right)\alpha\left(G\left(x^T-2\alpha\right)-G\left(2x_A+2\alpha\right)\right) \\ &> 0. \end{aligned}$$

Hence, we have proven that in cases (i) and (ii) of Proposition 2, $CC_A > CC_B$ holds.

Case 2: Let us consider the case in which α is always non-binding and in which the expected variable spot market profits per capacity unit in A and B are given by equation (3.5). The electricity consumption costs in A and B are the same, and we only have to analyze the difference between CC_A^{SR} and CC_B^{Z}. The costs from the strategic reserves are given by

$$CC_A^{SR} = kx_A^R - \left(\bar{P}-c\right)\left(\int_{x_A+x_B}^{x^T}\left(D-x_A-x_B\right)g\left(D\right)dD + x_A^R\left(1-G\left(x^T\right)\right)\right).$$

The capacity payment costs are given by

$$CC_B^Z = zx_B = \left[k-\left(\bar{P}-c\right)\left(1-G\left(x_A+x_B\right)\right)\right]\frac{x^T}{2}.$$

Let us show that $CC_A^{SR} > CC_B^Z$:

$$\begin{aligned}
& CC_B^Z - CC_A^{SR} \\
= \;& kx_A \\
& - (\bar{P} - c)\left(x_A + x^T G\left(x^T\right) - \left(x^T + x_A\right) G\left(x_A + \frac{x^T}{2}\right)\right) \\
& - (\bar{P} - c)\left(-\int_{x_A + \frac{x^T}{2}}^{x^T} Dg(D)\, dD\right) \\
> \;& \left(k - (\bar{P} - c)\left(1 - G\left(x_A + \frac{x^T}{2}\right)\right)\right) x_A
\end{aligned}$$

and the inequality holds due to $\int_{x_A+\frac{x^T}{2}}^{x^T} Dg(D)\, dD < x^T \left(G\left(x^T\right) - G\left(x_A + \frac{x^T}{2}\right)\right)$.

If $1 - G\left(\frac{x^T}{2}\right) > \frac{k}{\bar{P}-c}$ and $1 - G\left(x^T - 2\alpha\right) \geq \frac{k}{\bar{P}-c}$, the capacity payments are zero and

$$z^* = k - (\bar{P} - c)\left(1 - G\left(x_A + \frac{x^T}{2}\right)\right) = 0$$

holds (see proof of Proposition 2). Hence, $CC_B^Z - CC_A^{SR} > 0$.

If $1 - G\left(\frac{x^T}{2}\right) \leq \frac{k}{\bar{P}-c}$ and $2\alpha \geq \frac{x^T}{2}$, equilibrium capacity in A is given by $x_A^* = 0$. Thus, $CC_B^Z - CC_A^{SR} > 0$.

Proof of Proposition 4.

We define $x := x_A + x_B$ and $x^1 := x_A^1 + x_B^1$. If both regulators choose strategic reserves to ensure the target capacity level, the equilibrium capacities are given by $x^* = G^{-1}\left(1 - \frac{k-k^1}{c^1-c}\right)$ and $x^{1*} = G^{-1}\left(1 - \frac{k^1}{\bar{P}-c^1}\right) - x^*$ since both capacities are positive and the following zero profit conditions of both technologies are fulfilled:

$$\begin{aligned}
BL: \quad & 0 = (\bar{P} - c) - \left(\bar{P} - c^1\right) G\left(x + x^1\right) - \left(c^1 - c\right) G(x) - k \\
PL: \quad & 0 = \left(\bar{P} - c^1\right)\left(1 - G\left(x + x^1\right)\right) - k^1.
\end{aligned}$$

The strategic reserves are then given by

$$x^R = x^T - G^{-1}\left(1 - \frac{k^1}{\bar{P} - c^1}\right).$$

If both regulators choose capacity payments, the equilibrium capacities are given by $x^* = G^{-1}\left(1 - \frac{k-k^1}{c^1-c}\right)$ and $x^{1*} = G^{-1}\left(1 - \frac{k^1-z}{\bar{P}-c^1}\right) - x^*$ since both capacities are positive and the following zero profit conditions of both technologies are fulfilled:

$$\begin{aligned} BL: \quad & z = k - (\bar{P} - c) + \left(\bar{P} - c^1\right) G\left(x + x^1\right) + \left(c^1 - c\right) G(x) \\ PL: \quad & z = k^1 - \left(\bar{P} - c^1\right)\left(1 - G\left(x + x^1\right)\right). \end{aligned}$$

The capacity payments are given by $z^* = k^1 - \left(\bar{P} - c^1\right)\left(1 - G\left(x^T\right)\right)$. Since the equilibrium capacities are the same for both mechanisms it follows directly that the consumers' costs are the same for both mechanisms.

Proof of Proposition 5.

The firms' capacity in equilibrium has to fulfill one of the following two conditions: (I) The firms' capacitiy in equilibrium is positive and their profits are zero. (II) The firms' capacity is zero and the profits are negative or zero.

If $1 - G\left(\frac{x^T}{2}\right) > \frac{k^1}{\bar{P} - c^1}$, each vector $x^* = \left(x_A, x_B, x_A^1, x_B^1\right)$ with $x_A > 0$, $x_B > 0$, $x_A^1 > 0$ and $x_B^1 > 0$ for which $x_A + x_B = G^{-1}\left(1 - \frac{k - k^1}{c^1 - c}\right)$, $x_A^1 + x_B^1 = G^{-1}\left(1 - \frac{k^1}{\bar{P} - c^1}\right) - G^{-1}\left(1 - \frac{k - k^1}{c^1 - c}\right)$ and $x_B + x_B^1 = \frac{x^T}{2}$ holds constitute a market equilibrium in which $z^* = 0$ holds. The reason is that all capacities are positive and the following zero profit conditions of both technologies in both countries are fulfilled:

$$\begin{aligned} BL_B: \quad 0 &= (\bar{P} - c) - \left(\bar{P} - c^1\right) G\left(x_A + x_B + x_A^1 + x_B^1\right) \\ &\quad - \left(c^1 - c\right) G\left(x_B + x_A\right) + z - k \\ PL_B: \quad 0 &= \left(\bar{P} - c^1\right)\left(1 - G\left(x_A + x_B + x_A^1 + x_B^1\right)\right) + z - k^1 \\ BL_A: \quad 0 &= (\bar{P} - c) - \left(\bar{P} - c^1\right) G\left(x_A + x_B + x_A^1 + x_B^1\right) \\ &\quad - \left(c^1 - c\right) G\left(x_B + x_A\right) - k \\ PL_A: \quad 0 &= \left(\bar{P} - c^1\right)\left(1 - G\left(x_A + x_B + x_A^1 + x_B^1\right)\right) - k^1. \end{aligned}$$

Furthermore, the following combinations of x_A, x_B, x_A^1, x_B^1 constitute market equilibria in which $z^* = 0$ holds:

$$\begin{aligned} I: x_B^* &= \frac{x^T}{2} - G^{-1}\left(1 - \frac{k^1}{\bar{P} - c^1}\right) + G^{-1}\left(1 - \frac{k - k^1}{c^1 - c}\right), \\ x_B^{1*} &= G^{-1}\left(1 - \frac{k^1}{\bar{P} - c^1}\right) - G^{-1}\left(1 - \frac{k - k^1}{c^1 - c}\right), \\ x_A^* &= G^{-1}\left(1 - \frac{k^1}{\bar{P} - c^1}\right) - \frac{x^T}{2}, \\ x_A^{1*} &= 0 \end{aligned}$$

$$
\begin{aligned}
II: x_B^* &= G^{-1}\left(1-\frac{k-k^1}{c^1-c}\right), \\
x_B^{1*} &= \frac{x^T}{2} - G^{-1}\left(1-\frac{k-k^1}{c^1-c}\right) \\
x_A^* &= 0, \\
x_A^{1*} &= G^{-1}\left(1-\frac{k^1}{\bar{P}-c^1}\right) - \frac{x^T}{2} \\
III: x_B^* &= \frac{x^T}{2}, \\
x_B^{1*} &= 0 \\
x_A^* &= G^{-1}\left(1-\frac{k-k^1}{c^1-c}\right) - \frac{x^T}{2}, \\
x_A^{1*} &= G^{-1}\left(1-\frac{k^1}{\bar{P}-c^1}\right) - G^{-1}\left(1-\frac{k-k^1}{c^1-c}\right) \\
IV: x_B^* &= 0, \\
x_B^{1*} &= \frac{x^T}{2} \\
x_A^* &= G^{-1}\left(1-\frac{k-k^1}{c^1-c}\right), \\
x_A^{1*} &= G^{-1}\left(1-\frac{k^1}{\bar{P}-c^1}\right) - G^{-1}\left(1-\frac{k-k^1}{c^1-c}\right) - \frac{x^T}{2}.
\end{aligned}
$$

The reason is that the capacities are either positive and the zero profit conditions are fulfilled, or they are zero and the profits are zero or negative for these capacities. The strategic reserves are given by $x_A^{R*} = x^T - x_A^* > 0$.

If $1 - G\left(\frac{x^T}{2}\right) \leq \frac{k^1}{\bar{P}-c^1}$, the unique market equilibrium is given by

$$
\begin{aligned}
& x_B^* = G^{-1}\left(1-\frac{k-k^1}{c^1-c}\right), x_B^{1*} = G^{-1}\left(1-\frac{k^1-z}{\bar{P}-c^1}\right) - G^{-1}\left(1-\frac{k-k^1}{c^1-c}\right), \\
& x_A^* = 0, x_A^{1*} = 0
\end{aligned}
$$

and

$$
z^* = k_1 - \left(\bar{P}-c^1\right)\left(1-G\left(\frac{x^T}{2}\right)\right),
$$

since x_B^* and x_B^{1*} fulfill the zero profits conditions and the profits for $x_A^* = x_A^{1*} = 0$ are zero or negative. By checking the equilibrium conditions for all other combinations of (a), (b), (c) and (d),

$$\text{(a) } x_B > (=)\, 0, \quad \text{(b) } x_B^1 > (=)\, 0, \quad \text{(c) } x_A > (=)\, 0, \quad \text{(d) } x_A^1 > (=)\, 0,$$

we find that no further equilibrium exists.

Proof of Proposition 6.

If $z = 0$ and $x_A^R > 0$, the consumers' costs are obviously higher in A than in B. When the equilibrium capacities and capacity payments are given by $x_A^{*1} = x_A^* = 0$ and $z^* = k_1 - \left(\bar{P} - c\right)\left(1 - G\left(\frac{x^T}{2}\right)\right)$, the costs from the strategic reserves are given by

$$CC_A^{SR} = k^1 \frac{x^T}{2} - \left(\bar{P} - c\right)\left(\int_{x_B^1 + x_B}^{x^T} \left(D - \frac{x^T}{2}\right) g\left(D\right) dD + \frac{x^T}{2}\left(1 - G\left(x^T\right)\right)\right).$$

The capacity payment costs are given by

$$CC_B^Z = z x_B = \left[k^1 - \left(\bar{P} - c\right)\left(1 - G\left(\frac{x^T}{2}\right)\right)\right]\frac{x^T}{2}.$$

The difference is given by

$$CC_B^Z - CC_A^{SR} = \left(\bar{P} - c\right)\left(x^T\left(G\left(x^T\right) - G\left(\frac{x^T}{2}\right)\right) - \int_{\frac{x^T}{2}}^{x^T} D g\left(D\right) dD\right),$$

which is positive since $x^T \int_{\frac{x^T}{2}}^{x^T} g\left(D\right) dD > \int_{\frac{x^T}{2}}^{x^T} D g\left(D\right) dD$.

4 Spatial Dependencies of Wind Power and Interrelations with Spot Price Dynamics

Wind power has seen strong growth over the last decade, increasingly affecting electricity spot prices. In particular, prices are more volatile due to the stochastic nature of wind, such that more generation of wind energy yields lower prices. Therefore, it is important to assess the value of wind power at different locations not only for an investor but for the electricity system as a whole. In this paper, we develop a stochastic simulation model that captures the full spatial dependence structure of wind power by using copulas, incorporated into a supply- and demand-based model for the electricity spot price. This model is calibrated with German data. We find that the specific location of a turbine, i.e., its spatial dependence with respect to the aggregated wind power in the system, is of high relevance for its value. Many of the locations analyzed show an upper tail dependence that adversely impacts the market value. Therefore, a model that assumes a linear dependence structure would systematically overestimate the market value of wind power in many cases. This effect becomes more important as levels of wind power penetration increase and may render the large-scale integration into markets more difficult.

4.1 Introduction

The amount of electricity generated by wind power plants has increased significantly during recent years. Due to the fact that wind power is stochastic, its introduction into power systems has caused changes in electricity spot price dynamics: Prices have become more volatile and exhibit a correlated behavior with wind power fed into the system. In times of high wind, spot prices are observed to be generally lower than in times with low generation from wind power plants. Empirical evidence of this effect has been demonstrated for different markets characterized by high wind power penetration, e.g., by Jónsson et al. (2010) for Denmark, Gelabert et al. (2011) for Spain, Woo et al. (2011) for Texas or Cutler et al. (2011) for the Australian market. Due to the cost-free availability of wind energy, wind power plants are subject to marginal costs of generation that are lower than for other types of power plants such as coal or gas. Hence, when the wind blows, wind power replaces other types of generation and thus leads to lower spot market prices in such hours. As a consequence, power plants are faced with increasingly difficult conditions and an additional source of price risk when participating in the market. Until now, fluctuating renewable energy technologies (including wind power itself) have often been exempted from this price risk by support mechanisms (e.g., by fixed feed-in-tariff systems) in order to incentivize investments.[1] However, their price risk draws more and more attention as they start to make up an increasing share of the generation mix and may at some point be fully integrated into the liberalized power market. In this case, wind power plant operators would be obliged to refinance their investments by selling wind power on the market. Therefore, for an individual investor as well as for a social planner, it becomes increasingly important to understand the value of wind power and how it depends on the location of the wind turbine.

The purpose of this paper is to derive revenue distributions and the market value of wind power, i.e., the weighted average spot price wind power is able to achieve when selling its electricity on the spot market, at specific locations. It is clear that the market value of a wind turbine at a specific location depends on whether it tends to produce when many other wind turbines at other locations can also produce, or whether it is one out of few producers at a given time. To capture the full stochastic dependence structure of wind power, we use copulas and incorporate the stochastic generation in a supply- and demand-based model for electricity prices. We calibrate the model with German data since Germany already has a high share of wind power.

We find that taking the entire spatial dependence structure into account is indeed necessary, and that considering only correlations between a specific turbine and the aggregate wind power would be misleading. Even if the correlation of a specific turbine is lower compared to another, the resulting market value may be lower due to a non-linear, asymmetric dependence structure. In fact, we find a pronounced upper tail dependence that adversely impacts the market value for many of the locations analyzed. Therefore, a model solely based on linear dependence measures would systematically overestimate the market value of wind power in many cases. Moreover, it is shown that this effect becomes increasingly important for higher levels of wind power penetration.

To derive these results, we take the following two steps. In a first step, we develop

[1] For a comprehensive overview of different renewable support mechanisms including their economic implications, e.g., refer to Green and Yatchew (2012).

a stochastic simulation model for electricity spot prices that incorporates the aggregated wind power as one of the determinants. Electricity spot prices are very volatile and follow daily, weekly and seasonal patterns due to a very price-inelastic fluctuating demand and limited storage possibilities of electricity. The market is designed as such that in a competitive environment, suppliers who can offer electricity at lowest marginal generation costs will cover the demand. If demand increases, those capacities characterized by higher marginal generation costs are needed and generally lead to higher electricity prices. Since the marginal costs of wind power are close to zero, available production quantities will always cover some part of the demand as long as prices are non-negative. This is why we use the residual demand, given by the difference between total demand and aggregated wind power, to establish the relationship between wind power and spot prices. In our model, we approximate this relationship by a function estimated from hourly spot prices, demand and wind power. We then feed the price formation process with aggregated wind power series and add a stochastic component in order to cover additional stochastic price movements caused, e.g., by unplanned power plant outages, scarcity prices and speculation.

In the second step, we link the market's aggregated wind power to the wind power of single turbines in order to quantify their market value and the revenues depending on their specific location.[2] We use copulas to model this interrelation. The reason why copulas are necessary is illustrated by the following thought experiment: Let there be two turbines *A* and *B* characterized by equal availability factors and equal correlation coefficients between their own generation and the aggregated generation of the turbines in the market. Turbine *A* follows the production pattern of all other turbines very closely at low generation levels but is much less dependent at high generation levels and can therefore realize high prices when producing at full power. In contrast, turbine *B* faces the adverse situation of having a particularly high probability that every time it runs at full power, a large share of all the other turbines in the system is also running (i.e., a high correlation in the upper tail). Hence, weighted average prices gained by turbine *B* will be lower.

Our paper contributes to three lines of literature. First, our paper builds on the literature on demand and supply models. Within this class of models, Bessembinder and Lemmon (2002) were among the first to study the importance of demand and pro-

[2]Note that our analysis of a single turbine is representative for one or multiple turbines at this specific location. Due to the fact that wind speed conditions can be assumed to be equal for all turbines at this specific location, the market value is independent of the number of turbines, whereas revenue can simply be scaled by the amount of installed capacity.

duction costs for electricity prices. They develop a theoretical model for electricity derivatives and show that the level and variance of the electricity demand impact the forward premium. Motivated by these theoretical foundations, Longstaff and Wang (2004) provide empirical evidence for a significant forward premium in the PJM market. Barlow (2002) presents a different approach to model electricity prices based on an Ornstein-Uhlenbeck model for the demand process and a functional dependence between prices and demand. The model developed by Burger et al. (2006) follows the same conceptual approach by including a non-linear functional dependence of the electricity spot price on a stochastic demand process as well as long-term non-stationarity. Their model is used to price derivatives via Monte Carlo simulation. Howison and Coulon (2009) employ a stochastic electricity bid stack, i.e., detailed information on the supply curve. They further extend the number of state variables explaining the electricity spot price by including fuel prices. We extend this literature by including stochastic production quantities of wind power that may impact the supply side and hence electricity prices.

Secondly, we build on the literature using copulas. Copulas were first identified by Papaefthymiou (2006) to be a suitable tool in modeling multivariate dependencies of wind power. Grothe and Schnieders (2011) model spatial dependencies of wind speeds in order to allocate wind farms in Germany such that an optimal reduction of power output fluctuations is achieved. Hagspiel et al. (2012) model European wind power based on copula theory and use the simulated data as an input for a probabilistic load flow analysis. In contrast to the existing literature, we apply conditional copulas to model the dependence structure between the generation of specific turbines and the aggregated wind power. The latter, in turn, is needed as an input for the spot price model.

Finally, our paper complements ongoing research on the valuation of power generation assets. So far, this line of research has mainly focused on conventional power (e.g., Thompson et al. (2004), Porchet et al. (2009) or Falbo et al. (2010)) and the optimization of hydro power schedules (e.g., García-González et al. (2007) or Densing (2013)). Furthermore, a number of papers have valued wind power based on historical data (e.g., Green and Vasilakos (2012)). However, we know of no study presenting a model that fully captures the stochastic of wind power and interrelations with spot price dynamics.

The remainder of this article is organized as follows: Section 4.2 provides a short introduction to copula modeling with a particular focus on conditional copula sampling, which we apply in our model. The model itself is presented in Section 4.3.

Section 4.4 reports the results of the methodology applied to the case of wind power in Germany, namely the revenues and the market value of specific wind turbines. Section 4.5 concludes.

4.2 Stochastic Dependence Modeling using Copulas

In this section, we briefly discuss the modeling of stochastic dependencies with the help of copulas, as used in our model. Specifically, we discuss the different copula models that we consider and describe the conditional sampling procedure with respect to our application. A more general introduction to copulas is provided, e.g., in Joe (1997), Nelsen (2006) or Alexander (2008). For a comprehensive literature review of the current status and applications of copula models, the interested reader is referred to Genest et al. (2009), Durante and Sempi (2010) and Patton (2012).

4.2.1 Copulas and Copula Models

A copula is a cumulative distribution function with uniformly distributed marginals on $[0,1]$. Sklar's theorem is the main theorem for most applications of copulas, stating that any joint distribution of some random variables is determined by their marginal distributions and the copula (Sklar (1959)). The bivariate form of Sklar's theorem is as follows: For the cumulative distribution function $F : \mathbb{R}^2 \to [0,1]$ of any random variables X, W, with marginal distribution functions F_X, F_W, there exists a copula $C : [0,1]^2 \to [0,1]$ such that

$$F(x,w) = C\left(F_X(x), F_W(w)\right). \tag{4.1}$$

The copula function is unique if the marginals are continuous.[3] Conversely, if C is a copula and F_X and F_W are continuous distribution functions of the random variables X, W, then (4.1) defines the bivariate joint distribution function. From Sklar's theorem, it follows that copulas can be applied with any marginal distributions. Particularly, marginal distributions may differ for each of the random variables considered.

In our application we are interested in the dependence structure of the market's aggregated wind power W and a single turbine wind power X. The copula captures the complete dependence structure of X and W. The selection of an appropriate

[3] Sklar's theorem also holds for the multivariate case of $n > 2$ dimensions.

copula model can be made independent from the choice of the marginal distribution functions. Taking advantage of this, the joint distribution of W and X is determined in a two stage process: First, the marginal distribution functions F_W and F_X are determined, followed by the selection of the most appropriate copula model.

Copula functions are mostly determined in a parametric way. There are different types of parametric copula models that can be used to capture the pairwise dependence. In many applications – such as ours – it is particularly important to differentiate between symmetric or asymmetric, tail or no tail, and upper or lower tail dependence structures. Therefore, one can test several parametric copula models that are able to capture these characteristics: The Gaussian copula is symmetric and has zero or weak tail dependence (unless the correlation is 1). In contrast, the symmetric Student-t copula has a relatively strong symmetric tail dependence. Whereas the Frank copula is another symmetric copula with particularly low tail dependence, Clayton and Gumbel copulas incorporate an asymmetric tail dependence. Lower tail dependence is captured by the Clayton copula, while the Gumbel copula incorporates an upper tail dependence.[4] These copulas are listed in Table 4.1.[5]

Table 4.1: Copula models

Copula family	Copula function $C(u,v)$
Gaussian	$\Phi_\Sigma\left(\Phi^{-1}(u),\Phi^{-1}(v)\right)$
Student-t	$t_{\Sigma,v}\left(t_v^{-1}(u),t_v^{-1}(v)\right)$
Clayton	$\left(\max\left\{u^{-\theta}+v^{-\theta}-1,0\right\}\right)^{-1/\theta}$
Frank	$\frac{-1}{\theta}\ln\left(1+\frac{\left(e^{-u\theta}-1\right)\left(e^{-v\theta}-1\right)}{e^{-\theta}-1}\right)$
Gumbel	$e^{-\left((-\ln(u))^\theta+(-\ln(v))^\theta\right)^{1/\theta}}$

The copula parameters can be estimated based on observed data by optimizing the log-likelihood function:

$$\hat{\theta}=\max_\theta\sum_t \ln c\left(F_X\left(x_t\right),F_W\left(w_t\right);\theta\right) \tag{4.2}$$

[4] Gaussian and Student-t copulas belong to the group of Elliptical copulas, whereas Frank, Gumbel and Clayton copulas belong to the group of Archimedian copulas. For a more extensive discussion of different copula families, see, e.g., Nelsen (2006)

[5] u and v can be interpreted as $F_X(x)$ and $F_W(w)$, respectively. Φ_Σ denotes the multivariate normal distribution function with covariance matrix Σ and $t_{\Sigma,v}$ the multivariate Student-t distribution with v degrees of freedom and covariance matrix Σ.

where θ denotes the parameter vector and c the copula density. The selection of the most appropriate copula model can then be determined based on the Akaike Information Criteria (AIC).

4.2.2 Conditional Copula and Simulation Procedure

Like any ordinary joint distribution function, copulas have conditional distribution functions. The conditional copula can be calculated by taking first derivatives with respect to each variable, i.e., for $u = F_X(x)$ and $v = F_W(w)$ we have

$$C(u|v) = \frac{\partial C(u,v)}{\partial v} \quad \text{and} \quad C(v|u) = \frac{\partial C(u,v)}{\partial u}. \tag{4.3}$$

For the application presented in this paper, there is one inherent advantage of using conditional copulas rather than sampling directly from the bivariate copula distribution: Samples can be conditioned on time series that may serve as inputs to the simulation procedure.[6] The time series characteristics can thus be preserved during the simulation process.

We consider the stochastic processes $(X_t)_{t\in\mathbb{N}}$ and $(W_t)_{t\in\mathbb{N}}$. $F_{X_t}(X_t), F_{W_t}(W_t)$ are uniformly distributed random variables on $[0,1]$. For random variables $U_t, V_t \sim U(0,1)$, $F_{X_t}^{-1}(U_t)$ and $F_{W_t}^{-1}(V_t)$ thus follow the distributions of X_t and W_t, respectively. It is important to notice that by applying the inverse distribution functions, the dependence structure is not influenced, i.e., U_t and V_t as well as $F_{X_t}(X_t)$ and $F_{W_t}(W_t)$ have the same copula C.

The conditional sampling procedure can be summarized as follows:

1. Apply the marginal distribution function F_{W_t} to the time series of the market's aggregated wind power $(w_1, w_2, w_3, ...)$ in order to get $\left(v_1^*, v_2^*, v_3^*, ...\right)$.
2. Simulate $(u_1, u_2, u_3, ...)$ from independent uniformly distributed random variables.
3. For each observation $F_{W_t}(w_t) = v_t^*$, apply the inverse conditional copula $C^{-1}_{F_{W_t}(W_t),F_{X_t}(X_t)}\left(\cdot|v_t^*\right)$ to translate u_t into u_t^* by:

$$u_t^* = C^{-1}_{F_{W_t}(W_t),F_{X_t}(X_t)}\left(u_t|v_t^*\right) \tag{4.4}$$

[6] We use time series of the market's aggregated wind power as an input variable for the spot price model.

4. Apply the inverse marginal distribution functions to $\left(u_1^*, u_2^*, u_3^*, \ldots\right)$ in order to obtain the corresponding simulations of the random variable X_t: $\left(F_{X_1}^{-1}\left(u_1^*\right), F_{X_2}^{-1}\left(u_2^*\right), F_{X_3}^{-1}\left(u_3^*\right), \ldots\right)$.

This sampling procedure is one of the main parts of our model that is described in detail in the following section.

4.3 The Model

We develop a stochastic simulation model for the single turbine wind power and electricity spot prices, including a precise representation of their interrelations. The interrelation is established by the aggregated wind power that is related to both the electricity spot prices as well as the single turbine wind power. Hence, we set up a model that represents these two relationships: First, a supply and demand based model that takes the aggregated wind power as an input. Second, a stochastic dependence model that links the single turbine wind power to the aggregated wind power. These two parts of the model can be summarized by the following two equations:

$$
\begin{aligned}
S_t &= h_t\left(D_t - W_t\right) + Z_t && (4.5)\\
X_t &= F_{X_t}^{-1}\left(C^{-1}_{F_{X_t}(X_t), F_{W_t}(W_t)}\left(U_t | F_{W_t}\left(W_t\right)\right)\right) && (4.6)
\end{aligned}
$$

where S_t is the hourly stochastic spot price and X_t the hourly single turbine wind power, for $t \in \mathbb{N}$.

The spot price S_t is determined by two components: First, the function h_t describes the dependence of the spot price on the residual demand that is determined by the difference of the electricity demand level D_t and the stochastic aggregated wind power W_t. Second, a short term stochastic component adds to the spot price that is denoted by Z_t. As operators of wind power plants are able to curtail their power output in case of negative spot prices, their price is non-negative, i.e., $S_t^W = \max\left\{0, S_t\right\}$.

The second part of the model links the hourly single turbine wind power X_t to the hourly aggregated wind power W_t. F_{X_t} and F_{W_t} denote the corresponding marginal distribution functions. The joint distribution function of these two random variables is determined by the corresponding copula, i.e., $F_{X_t, W_t}\left(x_t, w_t\right) = C_{F_{X_t}(X_t), F_{W_t}(W_t)}\left(F_{X_t}\left(x_t\right), F_{W_t}\left(w_t\right)\right)$. Due to the copula's ability to separate marginal distribution functions and the dependence structure, the joint distribution function can be modeled in a two-step process: First, the marginal distribution functions $F_{X,t}$ and $F_{W,t}$ are determined. Second, the appropriate copula $C_{F_{X_t}(X_t),F_{W_t}(W_t)}$ is selected and estimated. We deploy the conditional copula in order to keep the time series properties of the stochastic process $(W_t)_{t\in\mathbb{N}}$. For the simulation procedure, independent $[0,1]$-uniformly random variables U_t are needed. Note that the marginal distribution functions are the same within a month m, i.e., $F_{X_i} = F_{X_j}$ if $i, j \in m$. The same holds for F_{W_t}, h_t and $C_{F_{X_t}(X_t),F_{W_t}(W_t)}$.

Based on Equations (4.5) and (4.6), the amount of hourly wind power produced by a single turbine and the spot prices can be simulated. We sample from these model equations using a Monte Carlo simulation ($n = 10000$) in order to investigate the market value and revenue distributions as well as the relevance of the dependence structure with the aggregated wind power for single turbines at different locations.

While the revenue is simply the sum of the products of electricity generation and prices, the market value of a wind turbine is the average spot price weighted with the electricity generation of the respective wind turbine:

$$MV = \frac{\sum_t X_t S_t}{\sum_t X_t}. \tag{4.7}$$

In the following subsections, we explain the input parameters and the different parts of the model in more detail.

4.3.1 The Data

Different data sets are deployed in order to calibrate and estimate the different parts of the model. In the following, we explain the content and origin of these sets, as well as the way in which the data are preprocessed.

Expected generation by the German aggregated wind power: For the estimation of the appropriate copula (C) as well as for the supply and demand model (represented by h_t in Equation (4.5)), data is needed on the day-ahead expected generation of the German aggregated wind power in 2011. This is provided by the transmission system operators and published on the EEX Transparency Platform (EEX Transparency Platform (2012)). Note that the day-ahead expectations – and not the actual aggregated wind power – is used, since this is the relevant information for the day-ahead market (Jónsson et al. (2010)).

Wind speeds: Hourly mean wind speeds for various measurement stations in Germany are provided via the national climate monitoring of the German Weather Service for the years 1990-2011 (Deutscher Wetterdienst (DWD) (2012)). The measurement data for 19 locations are used in this project to determine the corresponding power output series of wind turbines.[7] Wind speeds are scaled to the hub height of currently installed wind turbines (100 meters).[8]

Wind power capacities: The development of currently installed wind power capacities per federal state between 1995 and 2011 is available from the German Wind Energy Association (German Wind Energy Association (BWE) (2012)). In 2011, installed wind power capacities in Germany amounted to 27.1 GW.

Electricity demand levels: Hourly electricity demand levels for the German market in 2011 — used as one of the explaining variables for spot prices and denoted by D_t in Equation (4.5) — are provided by ENTSO-E (2012).

Spot prices: EPEX day-ahead prices from 2011 are deployed for the calibration of the spot price model (Equation (4.5)). The EPEX day-ahead market is organized by an auctioning process that matches supply and demand curves once a day, thus determining prices at which electricity is exchanged in each respective hour.

4.3.2 Derivation of Synthetic Aggregated Wind Power

As an important input for the model, curves are needed that describe the wind power that the currently installed wind power capacities would have produced during the last decades (i.e., the long-term stochastic behavior of aggregated wind power in the power system). In the model, the curve is needed for the estimation of the marginal distribution $F_{W,t}$ of the aggregated wind power W_t. It is important to notice that this curve has to be derived synthetically, as wind power capacities changed significantly during the last years.

Based on wind speeds and wind power capacities, the synthetic German aggregated wind power is generated as follows: By applying a power curve capturing the characteristics of the transformation process from wind energy to electrical power, electricity generation profiles of a wind turbine can be derived. In this study, the power

[7] Missing data are interpolated based on the previous and next available value if the missing gap is not exceeding 12 hours. If the gap is longer, the values are replaced by data of the same station and same hours of the previous year.

[8] As wind speeds are measured only a few meters above the ground, they are scaled to the hub height of modern wind turbines (100 meters) assuming a power law: $v_{h_1} = v_{h_0}(h_1/h_0)^{\alpha}$, where h_0 is the measurement height, h_1 the height of interest and α the shear exponent. According to Firtin et al. (2011), α is assumed to be 0.14.

curve is assumed to be one of a GE 2.5 MW turbine (General Electric (2010)), that represents a typical wind turbine. The transformation is based on a look-up table derived from the power curve and linear interpolation. Furthermore, electrical output is determined as a ratio of installed wind power capacity (i.e., scaled to $[0, 1]$). Multiplying this ratio with the wind power capacity installed in the corresponding federal state yields the wind power. The above steps are repeated for 16 locations (one for each federal state) and all available years (1990–2011), resulting in a time series for what would have been produced during the last 22 years with current wind power capacities. In order to check the plausibility of this approach, historical wind power time series and volumes can be compared to the model estimates. The comparison for the 2011 time series yields high conformity with an R^2 of 0.84. Another check of consistency is done by calculating the accumulated aggregated wind power volumes for the past 10 years from the synthetically generated curves, and comparing them to the overall wind power as reported in Eurostat Database (2012). We find the deviations to be less than 12%.

4.3.3 Supply- and Demand-Based Model for the Electricity Spot Price

We develop a supply- and demand-based model to derive electricity spot prices dependent on the level of wind power. A similar approach has been applied in Burger et al. (2006). The main difference between our and their approach is that we use the residual demand instead of total demand. We are therefore able to integrate the effect of wind power on spot prices.

We describe the non-linear relationship between residual demand and spot prices (i.e., h_t in Equation (4.5)) by a function estimated from historical hourly spot prices, demand and wind power data. To derive a functional form for h_t, we use spline fits that are suitable to capture the non-linearities in the demand-price dependence.[9] The parameters of h_t are estimated from historical data for the reference year 2011 on a monthly basis in order to capture seasonal differences and variations on the supply side that occur, e.g., because of planned outages or variations in fuel costs.

Note that if demand were totally price-inelastic, the function h_t would approximate the supply curve (excluding wind energy) that is often referred to as the merit

[9] A spline is a function that is constructed piece-wise from polynomial functions. It is smooth at the places where the polynomial pieces connect (i.e., the knots) and aims at fitting a smooth curve to a set of noisy observations. Based on the R^2, we find cubic splines with three knots to be the best configuration for our data.

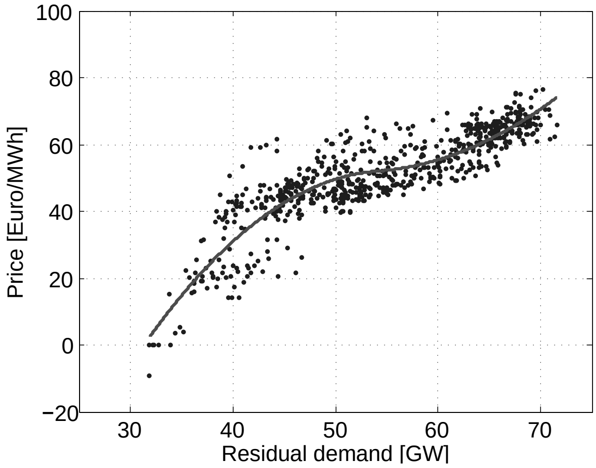


Figure 4.1: Demand-price dependence in February 2011 and spline fit

order.[10] Even though electricity demand is generally very inelastic, there may be some price-response of demand. Hence, our function h_t should not be seen as an unbiased estimator of the merit order. However, for our purpose the impact of supply and residual demand elasticities on the observed market-clearing prices is irrelevant as long as the elasticities of residual demand and supply do not vary with changing wind power.[11] The reason is that the wind power is the only quantity we change in our simulation procedure.

The data and the corresponding spline fit for h_t are shown in Figure 4.1 for the month of February 2011. All other months of 2011 are presented in Figure 4.10 in the Appendix. As can be observed, the dependence between residual demand levels and prices is characterized by steep ends and a comparatively flat part in between (i.e., for the residual demand ranging between 40 and 70 GW). Rather moderate price increases in the upper tail may be interpreted by prevailing excess capacity in the German power market, leading to very few instances at which scarcity prices occur.

Besides the functional dependence on (residual) demand, additional stochastic factors influence spot market prices such as speculation, unplanned power plant outages or scarcity prices. In the following, we aim at finding a model for Z_t that is capable of capturing the characteristics observed in the data. We can derive the

[10] I.e., the supply curve that represents all available sources of electricity generation ranked in ascending order of their short-run marginal generation costs.

[11] Note that we hereby assume that supply from conventional power plants and electricity demand do not change with wind power. This assumption should not be critical since variations in the conventional generation capacities can be assumed to remain equal within a month and we do not change installed wind power capacities.

observed residual short-term stochastic component based on h_t, the observations of residual demand and spot prices from $z_t = s_t - h_t$, and use the result for the calibration of the stochastic process $(Z_t)_{t\in\mathbb{N}}$. The time series z_t is visually observed to be stationary within the considered time frame, which is confirmed by an augmented Dickey-Fuller test that indicates that the null hypothesis of a unit root can be rejected at the 95% level.

The empirical auto-correlation function of z_t decays slowly, however, with an apparent dependence at a lag of 24 hours. We therefore choose to model Z_t as a seasonal ARIMA (SARIMA) model with 24 hour seasonality. In order to do so, the ARIMA model needs to be extended to include non-zero coefficients at lag s, where s is the identified seasonality period. We use a multiplicative form of SARIMA models, resulting in a more parsimonious model than the additive option.[12]

As the Engle's ARCH test indicates that there is conditional heteroscedasticity in the data, we extend the SARIMA by a GARCH component. GARCH-type models are able to capture conditional heteroscedasticity by splitting the error term ϵ_t into a stochastic component η_t and a time-dependent standard deviation σ_t. The latter can then be expressed dependent on lagged elements of ϵ and σ_t.

Various specifications of SARIMA-GARCH models are estimated and evaluated. Based on the AIC, a GARCH(1,1)-SARIMA(2,0,2)$\times$(1,0,1)$_{24}$ model is found to perform best. The inclusion of additional parameters hardly improves the fit. Note that no constant needs to be added to the model of Z_t due to the fact that the process has already been centered by applying a spline fit.

Comparing the residual's distribution to the normal distribution yields unsatisfactory results (Figure 4.2, left hand side). Thus, alternatively, the error term can be specified as a t-distribution, which leads to an improved match of the distributional shapes (Figure 4.2, right hand side). Instead of $\eta_t \sim \mathcal{N}(\mu, \sigma^2)$ we therefore use $\eta_t \sim t(\nu)$, with ν being the t-distribution's degrees of freedom that are estimated from the data.

[12] For more details about SARIMA models, the reader is referred to, e.g., Box et al. (2008).

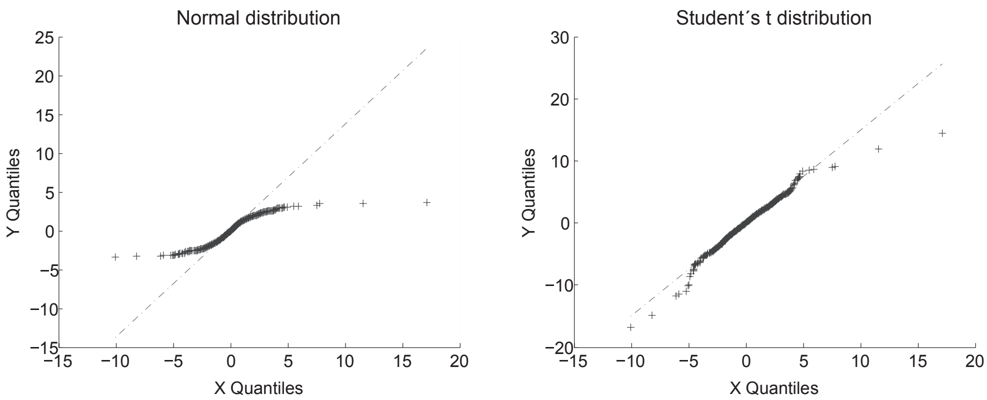


Figure 4.2: QQ-plots of the year 2011 residuals compared against a normal distribution and a Student-t distribution

Written explicitly, the model for Z_t now takes the following form:

$$\begin{aligned} Z_t =& \phi_1 Z_{t-1} + \phi_2 Z_{t-2} + \Phi_1 Z_{t-24} + \Phi_1(\phi_1 Z_{t-25} - \phi_2 Z_{t-26}) \\ &+ \epsilon_t + \theta_1 \epsilon_{t-1} + \theta_2 \epsilon_{t-2} + \Theta_1 \epsilon_{t-24} + \Theta_1(\theta_1 \epsilon_{t-25} - \theta_2 \epsilon_{t-26}) \end{aligned} \tag{4.8}$$

$$\epsilon_t = \sigma_t \eta_t \tag{4.9}$$

$$\sigma_t^2 = \alpha + \beta_1 \epsilon_{t-1}^2 + \gamma_1 \sigma_{t-1}^2 \tag{4.10}$$

$$\eta_t \sim t(\nu) \tag{4.11}$$

The parameters for the above model are estimated from the time series z_t by optimizing the log-likelihood function. Estimates and standard errors are presented in Table 4.2. The estimates of Φ_1 and Θ_1 are particularly high, confirming the relevance of the seasonal components. Furthermore, the coefficient of γ_1 indicates relatively persistent volatility clustering. Note that all standard errors are low with respect to their estimates.

Table 4.2: Parameter estimates for the short-term stochastic process model

Parameter	ϕ_1	ϕ_2	Φ_1	θ_1	θ_2
Estimate	0.366	0.359	0.965	0.566	0.074
Std. Error	(0.146)	(0.120)	(0.002)	(0.146)	(0.019)
Parameter	Θ_1	α	β_1	γ_1	ν
Estimate	-0.845	2.955	0.295	0.466	3.610
Std. Error	(0.005)	(0.032)	(0.027)	(0.272)	(0.156)

4.3.4 Estimation and Selection of Copula Models

In this section, we select and estimate models for the joint distribution of a single turbine wind power and the German aggregated wind power for 19 wind power stations in Germany[13]. We apply the two-stage process introduced in Section 4.2: First, the marginal distributions are determined, followed by the selection and estimation of the copula model that best describes the dependence structure.

In order to determine the marginal distributions, we consider the hourly synthetic wind power data for the years 1990–2011 for the different stations as well as for the German aggregated wind power. The yearly data is split into monthly intervals in order to capture seasonal differences. We thus obtain 22x12 subsamples from which we get 22x12 empirical distribution functions. With 22 years, the data covers a wide range of weather uncertainties that largely determine the quantity risk of wind power. Furthermore, the extensive database allows us to use the empirical distribution functions as marginal distribution functions (F_{W_t}, F_{X_t}) of the two variables of interest, namely the single turbine wind power and the aggregated wind power.

In contrast to the marginal distribution functions, the copula model $C_{F_{X_t}(X_t),F_{W_t}(W_t)}$ is estimated from the data of the day-ahead expected generation of the German aggregated wind power in 2011 and the corresponding hourly single turbine wind power. Even though 22 years would be available when using the synthetic aggregated wind power, we argue that for estimating, the copula model it is important to rely on observed rather than synthetically generated data. This is motivated as follows: First, a source of imprecision would be incorporated due to the fact that the synthetic aggregated wind power represents the actual power delivery, whereas the day-ahead expected generation is the relevant quantity for the spot market activities. Even though wind power forecasts have become more reliable over the last years, we want to avoid this imprecision in the estimation of the copula models. Second, subsamples consisting of approximately 700 observations are sufficiently large for a reliable estimation of the copula parameters. Just as the empirical distribution functions, the copula models are selected and estimated on a monthly basis.

To find the most appropriate copula model, various types are fitted to the data based

[13]We determine the models for the joint distribution functions between the German aggregated wind power and the following stations: Aachen, Angermünde, Augsburg, Bremen, Dresden, Emden, Erfurt-Weimar, Idar-Oberstein, Kahler Asten, Kleiner Feldberg, Konstanz, Leipzig-Halle, Magdeburg, Münster-Osnabrück, Oldenburg, Potsdam, Rostock, Saarbrücken and Schleswig.

on the procedure introduced in Section 4.2.1.[14] Table 4.5 in Appendix 4.6 report the copulas that provide the best fit to the data in terms of AIC for all stations that are considered in this paper. In the following, we first concentrate on particular stations (namely *Bremen*, *Kleiner Feldberg* and *Augsburg*) in order to point out the most important aspects with respect to the dependence structure and the effect on the results. *Bremen* is located in northern Germany where most of the current wind capacity is installed due to generally high average wind speeds. *Kleiner Feldberg* is a mountain in central Germany, also characterized by comparatively favorable wind speeds but less surrounded by other wind turbines. Finally, we analyze *Augsburg*, which is located in southern Germany and far away from most wind power capacities. *Augsburg* has the fewest full load hours among the three stations considered. Table 4.3 lists the copulas providing the best fit to the data (in terms of AIC) for these three locations in every month.[15] For *Bremen* and *Augsburg*, the copula that provides the best fit in almost every month is the Gumbel copula. For these locations, there is a distinctive asymmetric upper tail dependence in the dependence structure of the single turbine wind power and the aggregated wind power. In contrast, there is hardly any tail dependence for the turbine located at *Kleiner Feldberg*. Here, most of the copulas that best fit the data are symmetric (Gaussian, Student-t and Frank copula).

Table 4.3: Copula selection for the three stations of interest

Month	Augsburg	Bremen	Kleiner Feldberg
January	Gaussian	T40	Gaussian
February	Gumbel	Gumbel	Gaussian
March	Gumbel	Gumbel	Frank
April	Gumbel	Gumbel	Frank
May	Gumbel	Gumbel	Frank
June	Gumbel	Gumbel	Clayton
July	Frank	Gumbel	Frank
August	Gumbel	Gumbel	Frank
September	Gumbel	Gumbel	T10
October	Gumbel	Gumbel	Gaussian
November	Gumbel	Gumbel	Frank
December	Frank	T10	Gaussian

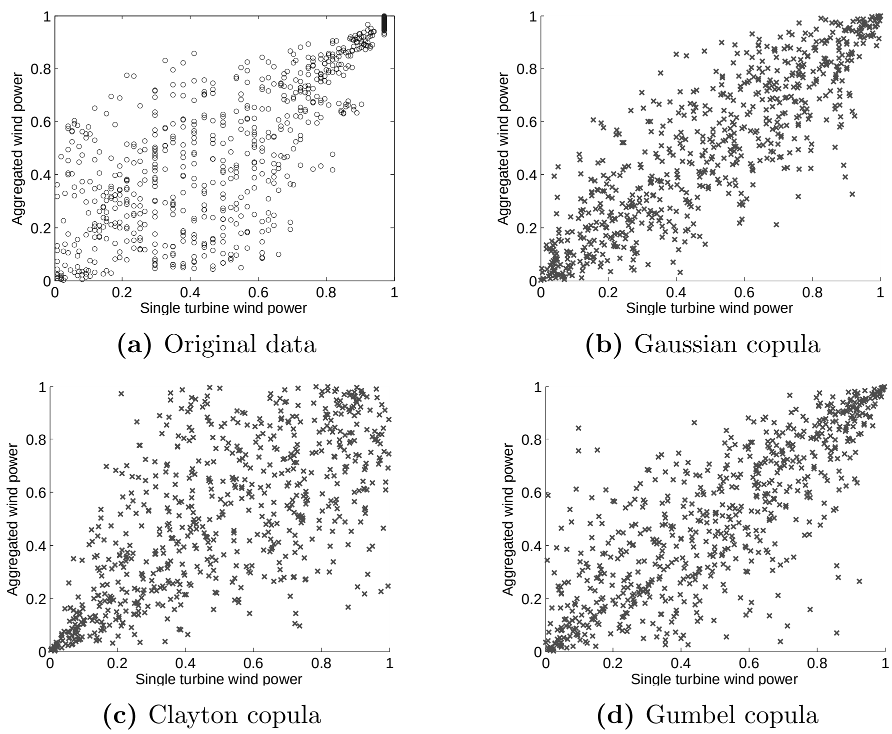
Once the marginal distributions and copulas are estimated, the conditional copula

[14] The following copula models are tested: Gaussian copulas, Frank copulas, Clayton copulas, Gumbel copulas and Student-t copulas for ν=1,2,3,4,5,10,20,30,40,50.

[15] The tables reporting the AIC values for all months and all copulas fitted to the data of the three stations considered is provided in Appendix 4.6.

model can be used to simulate the single turbine wind power conditional on the German aggregated wind power, based on the the sampling procedure that was introduced in Section 4.2.2. We loop through the 22 years and the 12 months of data and draw $n = 10000$ samples of the single turbine wind power for each point of the aggregated wind power curve, while applying the corresponding single turbine marginal distribution out of the 22x12 available.

Example: Figure 4.3 shows the dependence structure of the original data as well as simulations from three different types of copula models for a wind turbine in *Bremen*. Visually, the Gumbel copula provides the best fit to the data, which is confirmed by the comparison of the AIC. It can be observed that there is a distinctive upper tail dependence between the single turbine wind power and the German aggregated wind power. It should be noted that this type of dependence is generally undesirable for wind turbines selling their electricity on the spot market, as there is a high probability that spot prices are low in case of high electricity generation.



(a) Original data
(b) Gaussian copula
(c) Clayton copula
(d) Gumbel copula

Figure 4.3: Dependence structure of the original data and simulations from three copula models

Figure 4.4 shows the original data together with simulations from the Gumbel copula for the single turbine wind power located in *Bremen* and the aggregated wind power, transformed back to their marginal distributions.[16]

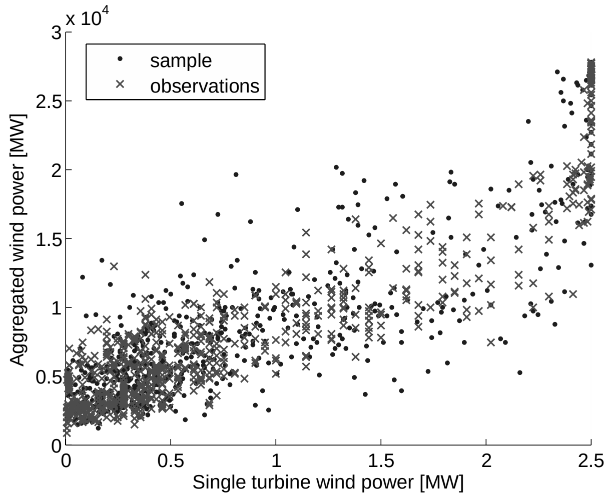


Figure 4.4: Observations and sample of the single turbine wind power and the aggregated wind power

4.4 Results

This section presents the results of our simulation with respect to revenue distributions and market values at different locations. In particular, we demonstrate the relevance of the dependence structure for the market value in today's context as well as under higher wind power penetration levels.

Figure 4.5 presents the yearly revenue distribution for a wind turbine located in *Bremen* selling its power at the spot market, together with the 5% value at risk. The expected revenue amounts to 82000 Euro/MW/a, with a standard deviation of 3800 Euro/MW/a and a slightly negative skew. The 5% value at risk is found to be 75000 Euro/MW/a. Note that the distribution of absolute revenue is determined by both the number of full load hours that can be achieved at the specific site of interest and the corresponding market value. However, the scope of this paper lies on the dependence structures of different sites and their impact on the market value, as shown in the following analysis.

[16]The turbine is assumed to be a GE 2.5 MW.

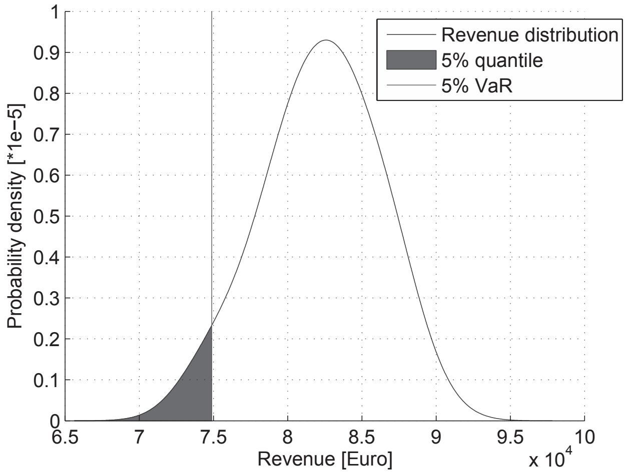


Figure 4.5: Yearly revenue distribution of the *Bremen* station and the 5% value-at-risk

4.4.1 Market Value of Different Wind Turbines

To quantify the effect arising from the dependence structures, distribution functions of the market value are determined and compared for the three stations *Augsburg*, *Bremen* and *Kleiner Feldberg*. Table 4.4 lists the main results for these three stations for the month of February. The expected average spot price of the simulations is 48.52 Euro/MWh. In contrast, the expected market value of the wind turbines is much lower for all turbines due to the dependence between the single turbine wind power and the aggregated wind power, which in turn has a price damping effect. From only the correlation coefficient ρ, one would have anticipated the expected market value of a turbine in *Augsburg* ($\rho = 0.37$) to be much higher than the expected market value of a turbine in *Kleiner Feldberg* ($\rho = 0.51$) which in turn should have a higher market value than a turbine in *Bremen* ($\rho = 0.75$). However, this is not the case: Although the correlation coefficient for a turbine in *Kleiner Feldberg* is much higher than that of a turbine in *Augsburg*, the expected market value is also higher. The reason lies in the dependence structure. As shown in Section 4.3.4, the dependence structure for *Augsburg* in February is best described by a Gumbel copula, thus incorporating an upper tail dependence between the single turbine wind power and the aggregated wind power. In contrast, the dependence structure between the single turbine wind power in *Kleiner Feldberg* and the aggregated wind power is modeled most accurately by a symmetric Gaussian copula. Therefore, *Kleiner Feldberg* benefits from an advantageous dependence structure when selling its wind power at the spot market.

Table 4.4: Main results for the month of February

	Augsburg	Bremen	Kleiner Feldberg
Expected average spot price [Euro/MWh]	48.52	48.52	48.52
Correlation coefficient	0.37	0.75	0.51
Selected copula model	Gumbel	Gumbel	Gaussian
Expected market value [Euro/MWh]	43.10	41.31	44.33
Standard deviation [Euro/MWh]	5.98	6.63	5.63

The distributions of the yearly market value for the three stations considered are shown in Figure 4.6. Following the same logic as discussed for the specific month of February, the yearly market value of a turbine in *Kleiner Feldberg* is higher than the market value for *Augsburg*. As can be seen in Table 4.3, the dependence structure for *Augsburg* is modeled with a copula incorporating an upper tail dependence in almost every month, whereas the one for *Kleiner Feldberg* is mostly symmetric. Consequently, for the three distributions that are shown in Figure 4.6, the dependence structure reduces the expected yearly market value of the turbines by 3.54, 4.97 and 2.63 Euro/MWh, respectively, compared to the expected average spot price level (49.80 Euro/MWh).

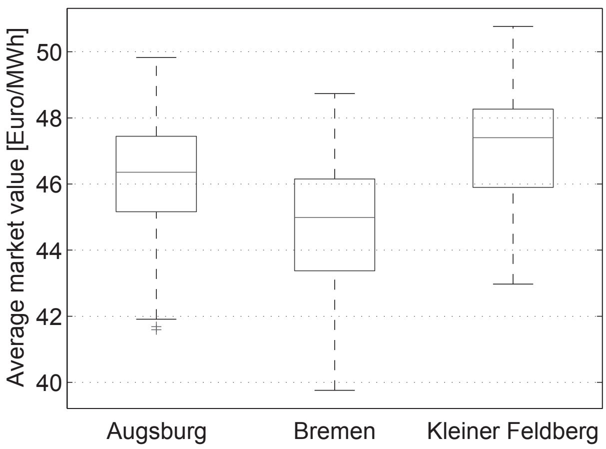


Figure 4.6: Yearly market value of the three turbines

4.4.2 Market Value Variations in Germany

Germany is characterized by a surface area of 357,021 km^2 and a maximum horizontal width and vertical length of 642 km and 833 km, respectively. Furthermore, there are several diverse geographical regions, suggesting that meteorological conditions may vary substantially when analyzing different locations throughout the country.

With the model developed, we analyze the market value for 19 different stations in Germany, as depicted in Figure 4.7. As the analyzed stations differ with respect to their exact location (and thus with respect to their dependence structure related to the aggregated German wind power), we expect market values to differ as well. Specifically, we expect the market value to be lowest for the stations that are closest to the majority of installed wind power capacities. Figure 4.7 shows the expected market value of the stations that were considered.

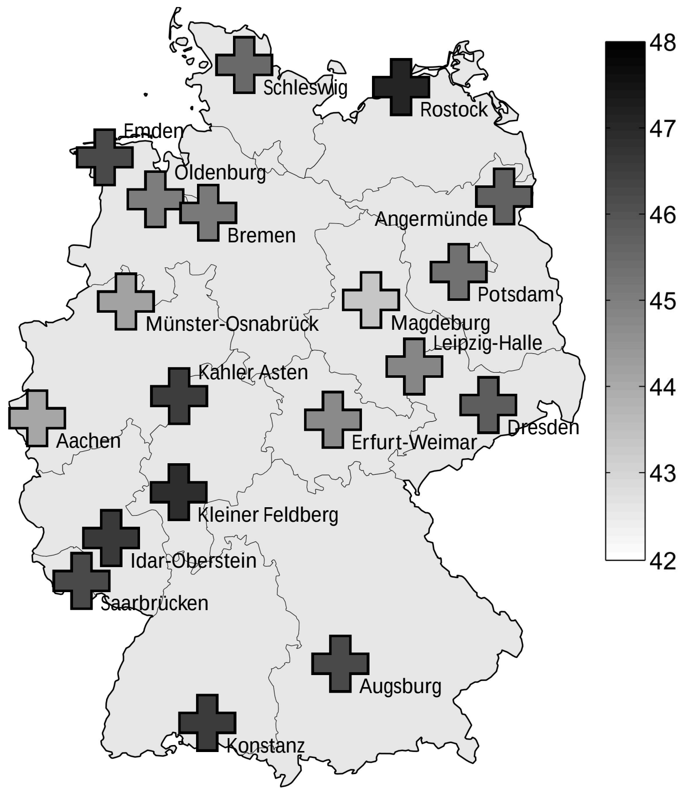


Figure 4.7: Expected yearly market value for 19 stations in Germany (in Euro/MWh)

Results indicate that the expected market value ranges from 42 to 48 Euro/MWh for the analyzed stations, compared to an expected average spot price level of 49.80

Euro/MWh. Hence, the market value lies between 6 and 15% lower than the average spot price. As expected, lowest values are found for the stations that are closest to the majority of currently installed wind power capacities, i.e., mainly in the area of *Magdeburg* and *Münster-Osnabrück*. For stations in this area, the dependence structure shows a pronounced asymmetric upper tail dependence. It is observed that expected market values are similar for all stations located in the so called 'North German Plain', which is a geographical region in Northern Germany characterized by constant lowlands and hardly any hills. Note that *Aachen* is at the far end of the North German Plain and, as such, equally characterized by comparatively low expected market values of 43.47 Euro/MWh. In contrast, *Kahler Asten* is located in Germany's Central Uplands, where meteorological conditions are different (e.g., due to pronounced thermals), which is reflected by higher values. Other stations in or south of the Central Uplands show higher expected market values as there are very few installed wind power capacities.

Kahler Asten and *Kleiner Feldberg* are special cases, as they are characterized by advantageous, symmetric dependence structures, resulting in expected market values that are the highest compared to the other stations considered. Similarly, *Emden* and *Rostock* – both located at the seashore – show higher values, compared to other stations in the North German Plain, due to comparatively advantageous dependence structures.

4.4.3 The Impact of Changing Wind Power Penetration Levels

In the previous section, model parameters were set and estimated to reflect the current environment with respect to the physical generation mix and the market conditions. In this section, some of the model parameters are modified to analyze their impact on the outcome. As has been clarified, the effect of wind power on spot market prices largely depends on the quantities of wind power being integrated in the market. With the help of the model presented in this paper, the aforementioned effect is quantified for the case of changing wind power penetration levels in Germany. First, we scale up the wind power penetration up to two times the capacity that is currently installed. Note that this is roughly in line with targets envisaged by the German government, which wants to further extend wind power to 45.8 GW in 2020 (installed capacity was 27.1 GW in 2011). Second, we compare the impact of today's wind power penetration to a situation with no wind power capacities installed. For the analysis, installed wind power capacities are scaled-up stepwise and simulation runs are repeated for each of these steps. The underlying assumptions of this approach are as follows:

- The proportionate geographic distribution of wind power capacities within Germany remains the same. Note that due to the linear up-scaling, the dependence structure is preserved. Alternatively, region-specific changes in installed capacities could be implemented, e.g., for testing the effect of an increased wind power extension in some specific area.
- The functional dependence between residual demand levels and spot prices is again estimated from 2011 data, as explained in Section 4.3.3. This is certainly a strong assumption, as the conventional power sector will dynamically develop with increasing wind power penetration. However, it should be kept in mind that current wind power capacities are being rapidly expanded, whereas the conventional power sector seems to be behind in terms of capacity adjustments. Also note that the functional dependence could also be altered (e.g., by shifting or assuming a different shape). However, this was not implemented in order to focus on the specific impact of the wind power penetration levels.
- The parameter estimates for the short-term stochastic spot price process remain the same. Here again, the model could be adjusted in order to represent expectations regarding future short-term stochastic price movements.

The resulting distributions of the yearly market value for the station of *Bremen* under increasing wind power penetration ranging from 100-200% are shown in Figure 4.8. As can be observed, the local market value distribution is highly affected both in average level and variance. While the expected local market value is at 44.83 Euro/MWh at 100% scaling, it decreases to 30.13 Euro/MWh at a scaling of 200%. At the same time, its standard deviation increases from 1.94 to 3.40 Euro/MWh, respectively.

To achieve further insights regarding the effect of the wind power penetration level, we repeat the simulation for all three stations considered in Section 4.4.1 and a wind penetration level ranging from 0-200%. The relative change in expected values of the resulting market value distributions are presented in Figure 4.9. For completeness, the expected average spot price level is also included. Compared to an expected average spot price of 56.70 Euro/MWh at 0% scaling, the level is reduced by 12% to 49.80 Euro/MWh for today's penetration level. Hence, provided that the rest of the system remains the same, the spot price level would be 7 Euro/MWh higher with no wind power penetration. In this case, resulting market

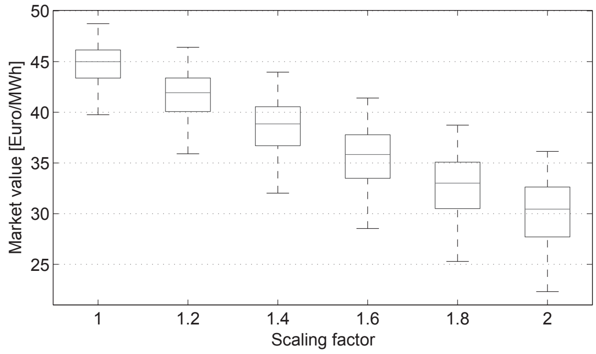


Figure 4.8: Yearly market value of the *Bremen* station under increasing wind power penetration

values are above average spot price levels (due to higher wind power infeeds during wintertime when overall demand as well as prices tend to be also higher) and almost equal for any single wind turbine as spot prices are only marginally affected by wind power. Just as average spot price levels, expected market values decrease as the penetration level increases, however, at very different slopes. Whereas the average spot price itself is affected the least, the expected market value decreases corresponding to their dependence structure. They drop below average spot price levels at penetration levels as low as around 30% of today's capacities. A scaling of 100% corresponds to the current situation described in detail in Section 4.4.1. As can be observed, the difference between the average spot price and the market value further increases as the scaling factor approaches 200%, reaching levels of 8.34, 11.63, and 6.20 Euro/MWh for *Augsburg*, *Bremen* and *Kleiner Feldberg*, respectively.

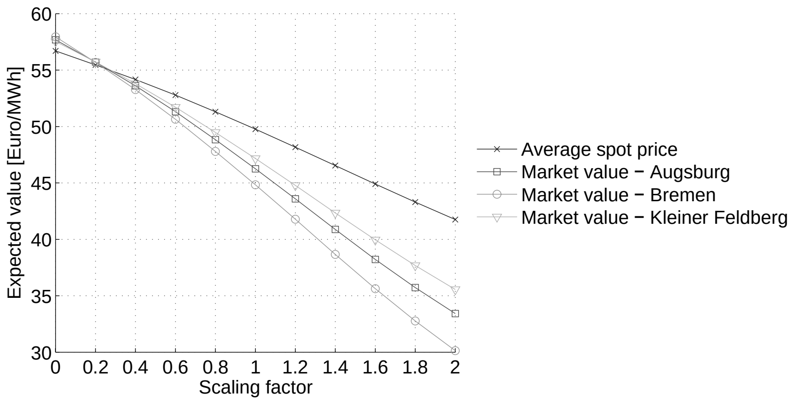


Figure 4.9: Relative change in expected values of the spot price and the market value under changing wind power penetration levels

4.5 Conclusion

The purpose of this paper has been to derive the value of wind power at different locations. In particular, the impact of the dependence structure of wind power on its value has been analyzed. This analysis becomes increasingly important as shares of wind power in electricity markets rise. We therefore developed a model for the simulation of single turbine wind power and electricity spot prices, including a precise representation of their interrelations. Copula theory has been applied to model single turbine wind power and aggregated wind power, thus allowing us to decouple their dependence structure from their marginal distributions. The formation of prices has been formulated as a function of the aggregated wind power in a supply- and demand-based model. As such, the model extends formerly known modeling approaches through its ability to simulate and quantify the price effect of wind power and hence to determine market values.

We find that the market value highly depends on the specific location and the corresponding dependence structure between the wind power of a single turbine at this location and the aggregated wind power. Whereas most locations are found to be characterized by rather adverse asymmetric dependence structures, some of the locations analyzed are identified as being related to the aggregated wind power such that their realizable selling prices are comparatively high. For the nineteen locations in Germany that we have analyzed in detail, we have shown that the expected market value is reduced by up to 8 Euro/MWh compared to average spot price levels and varies by up to 6 Euro/MWh for the different locations.

Moreover, our results indicate that, in case of increasing wind power capacities, the adverse upper tail dependence structure of many locations has a negative impact on the market value, which makes market integration of wind power even more difficult. Nevertheless, integrating wind power into the market would allow market prices to reveal their key function by indicating the actual value of electricity and thus triggering investments in wind power projects characterized by high realizable spot prices. These projects would deploy balancing potentials much better and reduce the volatility in the electricity spot market as well as in the physical system.

Although a powerful tool to analyze the market value of wind power in a predefined setting, the model reveals its limitations in not being able to determine the dynamic reaction of the power system development in response to changing levels of wind power penetration. Further research could be done by extending the model in order to use it as a forecasting and derivative pricing tool, or by applying the modeling approach developed in this paper to other forms of renewable energy, e.g., solar power.

4.6 Appendix

Demand-price dependence

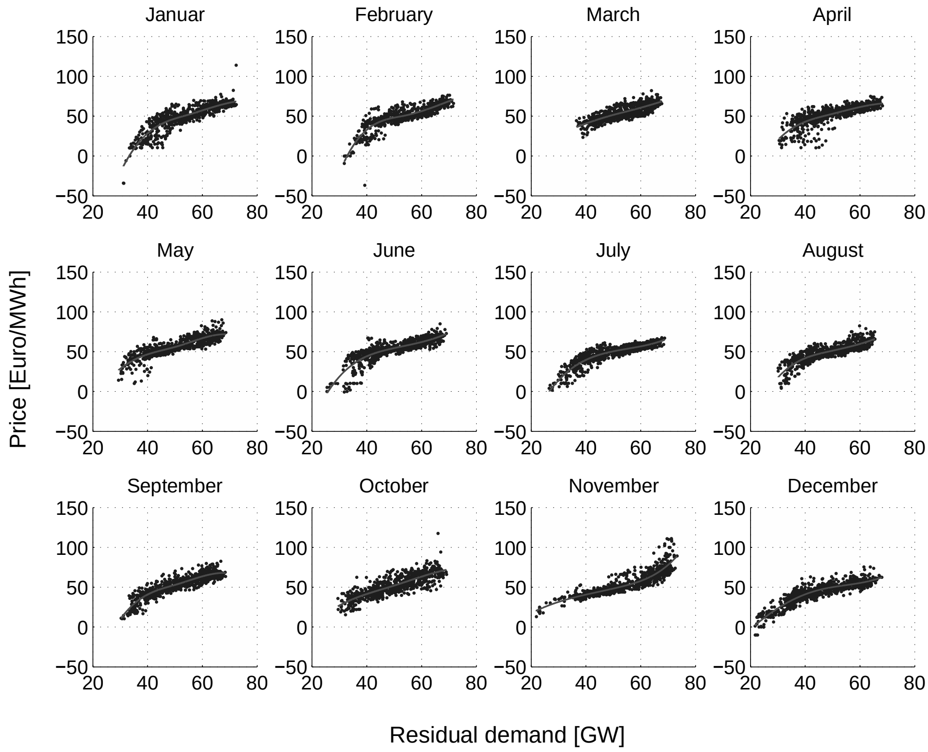


Figure 4.10: Demand-price dependence and spline fits for all months of the year 2011

Table 4.5: Selected copula models and rank correlation coefficients

Station	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Aachen	Frank	Gumbel	Gumbel	Frank	Gaussian	Gumbel	Frank	Frank	Gumbel	Gumbel	Gumbel	T30
	0.63	0.54	0.55	0.53	0.69	0.44	0.58	0.57	0.69	0.61	0.51	0.65
Angermünde	Gumbel	Gumbel	Gaussian	Gumbel	T10	Frank	Gumbel	Gumbel	Gumbel	Gaussian	Gumbel	Gaussian
	0.58	0.61	0.56	0.57	0.49	0.52	0.64	0.59	0.58	0.67	0.53	0.66
Augsburg	Gaussian	Gumbel	Gumbel	Gumbel	Gumbel	Gumbel	Frank	Gumbel	Gumbel	Gumbel	Gumbel	Frank
	0.23	0.37	0.28	0.39	0.37	0.46	0.30	0.35	0.30	0.44	0.26	0.50
Bremen	T40	Gumbel	Gumbel	Gumbel	Gumbel	Gumbel	Gumbel	Gumbel	Gumbel	Gumbel	Gumbel	T10
	0.71	0.75	0.70	0.79	0.73	0.61	0.80	0.71	0.78	0.78	0.78	0.81
Dresden	Frank	Gumbel	Frank	Gumbel	T10	Gumbel	Frank	Gumbel	Gumbel	Gaussian	Frank	Clayton
	0.68	0.64	0.59	0.63	0.50	0.58	0.72	0.67	0.61	0.61	0.55	0.60
Emden	Gaussian	Gumbel	Gaussian	Gumbel	Gaussian	Gumbel	Frank	Gumbel	Gumbel	Gaussian	Gumbel	Gaussian
	0.62	0.50	0.68	0.67	0.70	0.49	0.76	0.61	0.73	0.72	0.71	0.68
Erfurt-Weimar	Frank	Gumbel	Gumbel	Gumbel	Gumbel	Gumbel	Frank	Gumbel	Gumbel	Gumbel	Gumbel	T50
	0.74	0.67	0.61	0.70	0.64	0.61	0.78	0.70	0.81	0.74	0.55	0.75
Idar-Oberstein	Frank	Gumbel	Gumbel	Gumbel	Gumbel	Gumbel	Frank	Gumbel	Gumbel	Gumbel	Gumbel	Frank
	0.42	0.55	0.49	0.37	0.46	0.35	0.39	0.47	0.55	0.57	0.40	0.68
Kahler Asten	Frank	Gaussian	Gumbel	Frank	Frank	T50	Frank	Frank	Frank	T20	Gumbel	Frank
	0.72	0.69	0.65	0.82	0.76	0.71	0.80	0.74	0.76	0.80	0.72	0.74
Kleiner Feldberg	Gaussian	Gaussian	Frank	Frank	Frank	Clayton	Frank	Frank	T10	Gaussian	Frank	Gaussian
	0.34	0.51	0.50	0.53	0.61	0.49	0.52	0.39	0.35	0.46	0.33	0.56
Konstanz	Frank	Gumbel	Gaussian	Gumbel	Gumbel	Gumbel	Frank	Gumbel	Gumbel	Gumbel	T30	Frank
	-0.06	0.22	0.19	0.21	0.24	0.39	0.25	0.27	0.41	0.35	0.14	0.37
Leipzig-Halle	Frank	T40	Gumbel	Gumbel	T40	Gumbel	Frank	Gumbel	Gumbel	Gaussian	Gumbel	T5
	0.80	0.78	0.71	0.75	0.70	0.69	0.83	0.77	0.79	0.80	0.70	0.70
Magdeburg	Gumbel	Gumbel	Gumbel	Gumbel	Gumbel	Gumbel	Gumbel	Gumbel	Gumbel	Gumbel	Gumbel	Gaussian
	0.72	0.72	0.63	0.66	0.57	0.65	0.76	0.71	0.67	0.70	0.65	0.76
Münster-Osnabrück	Frank	Gumbel	Gumbel	Gumbel	Gumbel	Gumbel	Frank	Gumbel	Gumbel	Gumbel	Gumbel	T40
	0.67	0.63	0.56	0.66	0.62	0.53	0.73	0.59	0.74	0.74	0.66	0.80
Oldenburg	Gaussian	Gumbel	Gumbel	Gumbel	Gumbel	Gaussian	Gumbel	Gumbel	Gumbel	Gumbel	Gumbel	Gaussian
	0.63	0.56	0.64	0.69	0.65	0.48	0.75	0.56	0.69	0.69	0.75	0.71
Potsdam	Frank	Gumbel	Gaussian	Gumbel	T30	T20	Frank	Frank	Frank	Frank	Gaussian	Gaussian
	0.83	0.76	0.78	0.82	0.72	0.76	0.85	0.81	0.82	0.84	0.78	0.69
Rostock	Gumbel	Gumbel	Clayton	Gumbel	Gaussian	Gaussian	Gaussian	T40	Frank	Frank	Gumbel	Clayton
	0.30	0.52	0.36	0.61	0.56	0.39	0.55	0.43	0.57	0.66	0.70	0.47
Saarbrücken	Gumbel	Gumbel	Gaussian	Gumbel	Gumbel	Gumbel	Frank	Gumbel	Gumbel	Gumbel	Gumbel	Frank
	0.27	0.42	0.48	0.06	0.47	0.39	0.34	0.35	0.47	0.56	0.28	0.64
Schleswig	Frank	Gumbel	Gumbel	Gumbel	Gaussian	Frank	Frank	Gumbel	Gumbel	Gaussian	Gumbel	Gumbel
	0.66	0.60	0.58	0.73	0.63	0.53	0.66	0.58	0.72	0.72	0.71	0.54

Table 4.6: Copula model selection based on AIC for the Station *Augsburg*.

Copula	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Clayton	-13.7	-49.4	-15.9	-20.5	-55.5	-103.7	-36.0	-10.8	-6.2	-73.0	-20.9	-112.0
Frank	-34.7	-99.9	-54.8	-107.4	-103.4	-168.5	-67.1	-80.8	-55.8	-145.9	-46.3	-198.2
Gumbel	-19.4	-145.4	-65.1	-172.3	-135.9	-194.0	-43.4	-133.4	-111.4	-163.3	-83.5	-146.6
Gaussian	-36.6	-109.1	-64.2	-117.5	-120.0	-182.5	-59.2	-95.0	-66.7	-156.5	-55.0	-174.0
T1	482.0	48.2	432.2	154.4	191.2	101.1	402.3	245.2	221.6	197.6	167.4	306.7
T2	158.2	-102.8	109.4	-54.8	-40.9	-112.3	92.9	1.9	3.2	-43.8	-26.2	-13.7
T3	77.8	-124.9	32.9	-95.2	-87.3	-155.7	21.0	-49.1	-39.2	-98.4	-58.0	-89.9
T4	43.5	-129.5	1.6	-108.7	-103.6	-170.8	-7.6	-67.8	-53.6	-119.9	-66.4	-120.5
T5	24.8	-129.9	-14.8	-114.5	-111.0	-177.6	-22.2	-76.8	-59.9	-130.9	-68.8	-136.2
T10	-8.4	-124.8	-42.7	-120.4	-120.0	-185.2	-45.3	-89.5	-67.2	-147.8	-67.2	-160.7
T20	-23.1	-118.5	-54.3	-120.3	-121.4	-185.4	-53.5	-93.2	-68.1	-153.5	-62.8	-169.0
T30	-27.7	-115.8	-57.8	-119.7	-121.3	-184.8	-55.7	-94.0	-67.9	-154.8	-60.6	-171.1
T40	-30.0	-114.3	-59.4	-119.3	-121.1	-184.4	-56.7	-94.3	-67.7	-155.4	-59.4	-172.0
T50	-31.3	-113.3	-60.4	-119.0	-120.9	-184.1	-57.3	-94.5	-67.5	-155.7	-58.6	-172.5

Table 4.7: Copula model selection based on AIC for the Station *Bremen*.

Copula	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Clayton	-370.7	-309.2	-263.6	-273.2	-309.4	-193.8	-292.3	-247.0	-224.9	-357.1	-390.3	-652.9
Frank	-511.6	-538.0	-502.5	-641.1	-530.0	-329.1	-685.1	-498.5	-596.2	-664.1	-640.0	-787.9
Gumbel	-539.1	-700.2	-610.7	-746.7	-604.6	-420.5	-692.0	-667.4	-702.0	-727.5	-788.9	-826.3
Gaussian	-554.9	-594.2	-533.6	-614.4	-560.9	-377.4	-637.5	-547.3	-571.0	-668.8	-698.1	-867.0
T1	-333.6	-480.8	-322.3	-402.2	-305.6	-143.3	-283.6	-368.5	-303.5	-435.9	-563.0	-708.9
T2	-477.1	-576.0	-469.5	-565.0	-480.3	-303.6	-500.5	-497.6	-488.1	-591.4	-666.7	-815.8
T3	-514.1	-594.2	-505.8	-602.7	-521.8	-339.2	-559.5	-526.3	-532.2	-631.2	-689.8	-846.6
T4	-530.1	-600.0	-520.4	-616.6	-538.3	-353.3	-585.6	-537.3	-549.6	-647.8	-698.2	-860.1
T5	-538.6	-602.2	-527.6	-622.7	-546.6	-360.5	-599.8	-542.5	-558.2	-656.3	-701.9	-867.1
T10	-551.9	-602.4	-536.8	-627.7	-558.8	-371.7	-623.6	-549.3	-570.0	-668.5	-705.1	-875.8
T20	-555.4	-599.7	-537.5	-624.5	-561.6	-375.4	-632.3	-549.9	-572.3	-670.9	-703.5	-875.1
T30	-555.8	-598.2	-536.8	-622.1	-561.9	-376.3	-634.5	-549.5	-572.3	-670.8	-702.2	-873.6
T40	-555.8	-597.4	-536.2	-620.5	-561.9	-376.7	-635.4	-549.2	-572.2	-670.6	-701.4	-872.4
T50	-555.8	-596.8	-535.8	-619.5	-561.8	-376.8	-636.0	-548.9	-572.0	-670.3	-700.9	-871.6

Table 4.8: Copula model selection based on AIC for the Station *Kleiner Feldberg*.

Copula	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Clayton	-76.5	-142.7	-158.9	-142.0	-252.9	-235.2	-202.5	-79.8	-94.8	-141.6	-77.6	-230.5
Frank	-88.3	-189.8	-194.6	-231.9	-308.9	-187.9	-211.1	-110.1	-96.9	-166.3	-80.7	-269.4
Gumbel	-58.2	-164.3	-115.3	-187.4	-197.9	-89.1	-101.3	-60.1	-114.1	-142.5	-32.4	-285.1
Gaussian	-88.7	-199.8	-192.3	-227.0	-288.8	-188.8	-181.4	-100.4	-115.7	-192.4	-70.7	-318.5
T1	288.9	136.8	321.1	173.3	190.2	238.2	286.6	405.0	123.2	275.6	327.8	-1.8
T2	24.8	-79.2	6.0	-80.3	-106.3	-36.4	-20.4	78.8	-65.7	-15.5	56.7	-209.5
T3	-32.8	-131.8	-75.0	-143.6	-181.9	-103.6	-94.8	-0.5	-101.1	-88.0	-5.1	-257.5
T4	-54.6	-153.9	-110.2	-170.5	-214.5	-131.7	-125.2	-33.2	-112.6	-119.2	-29.4	-277.2
T5	-65.4	-165.8	-129.5	-184.9	-232.2	-146.5	-140.9	-50.5	-117.3	-136.3	-41.6	-287.6
T10	-81.2	-185.9	-163.9	-209.4	-263.5	-171.5	-166.2	-79.5	-121.2	-166.8	-60.5	-305.3
T20	-86.1	-193.8	-178.9	-219.2	-276.9	-181.3	-175.3	-91.0	-120.0	-180.2	-66.8	-312.6
T30	-87.3	-196.1	-183.6	-222.1	-281.1	-184.1	-177.7	-94.4	-118.9	-184.4	-68.4	-314.7
T40	-87.7	-197.1	-185.8	-223.4	-283.1	-185.4	-178.8	-96.0	-118.3	-186.5	-69.1	-315.7
T50	-88.0	-197.7	-187.2	-224.2	-284.3	-186.1	-179.4	-96.9	-117.8	-187.7	-69.5	-316.3

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