Electricity Markets Working Papers

WP-EM-30

Economic Interactions between Electricity Reserve Markets and Wholesale Electricity Markets

Lars Wieschhaus and Hannes Weigt

October 2008

TECHNISCHE UNIVERSITÄT DRESDEN

EE²

Dresden University of Technology

Chair for Energy Economics and Public Sector Management

Economic Interactions between Electricity Reserve Markets and Wholesale Electricity Markets[1]

Lars Wieschhaus and Hannes Weigt

Corresponding author:

Hannes Weigt
Dresden University of Technology
Department of Business Management and Economics
Chair of Energy Economics
D – 01069 Dresden
Germany
Phone: +49-(0)351-463-39764
Fax: +49-(0)351-463-39763
hannes.weigt@tu-dresden.de

Abstract:

This paper analyzes the interdependence of reserve and spot markets for electricity applying equilibrium models. We develop a Cournot model to analyze the impact of different pricing mechanisms at the reserve market (uniform and pay-as-bid) on spot market prices. Furthermore, we show how the demand requirement for reserve capacities can drive prices in the spot market. The models are tested using a dataset of the German electricity market. One result is that a more competitive reserve market helps to keep prices on the spot market low.

Key words: electricity, reserve market, Cournot, pay-as-bid, Germany
JEL-code: L94

[1] This paper is based on the diploma thesis by Lars Wieschhaus, “Economic Interactions between Electricity Reserve Markets and Wholesale Electricity Markets - Cournot Equilibrium Modeling and Application”, extending the results of the thesis. We thank Christian von Hirschhausen for helpful comments and suggestions.

1 Introduction

The process of deregulation in electricity industries around the world leads to new challenges of how to create efficient markets for electricity. Specific characteristics of electric power, such as non-storability, the necessity to balance supply and demand in real time, capacity constraints on generation and transmission, and low demand elasticities give rise to market design questions. Beside wholesale markets the market(s) for reserves capacity are of particular concern. Reserve capacity has to be provided by the system operator to supply a previously unknown amount of reserve energy (Swider 2007). Forward markets for electricity reserve procurement are installed in many liberalized electricity markets, though they differ in the actual design and timing (ETSO, 2003). Since reserve requirements are determined by the system operator demand is usually fixed and practically price inelastic. Blocking generation capacity for balancing purposes may prevent a more efficient allocation of this capacity in the auction for real-time electricity. Hence the decision to offer capacity in the reserve market actually competes with the alternative to offer generation capacity in the electricity wholesale market.

The aim of this paper is to implement equilibrium modeling techniques to analyze economic interactions between wholesale electricity markets and reserve markets. We assume oligopolistic market structures and strategic firm behavior and test the models on a dataset of the German market. Each firm is modeled as an entity with multiple generation units and decides about bidding capacity either in the wholesale market and/or in the reserve market. We apply two different market clearing processes for the reserve market: uniform and pay-as-bid pricing. Market clearing on the spot market is always considered as uniform pricing. First the uniform pricing approach is analyzed where strategic firms act simultaneously on both markets maximizing their profit. The actual reserve market in Germany however has a fixed demand requirement which would lead to infeasible results in a Cournot approach. Therefore, we approximate a fixed demand by a highly inelastic demand function. In a second approach, we apply the pay-as-bid clearing process as a Bayesian approach in a sequential three stage process: first, the firms bid capacity for the reserve market, second the system operator clears the reserve market, and third, the firms compete on the spot market with their remaining capacity. The latter approach resembles the current German setting with uniform pricing in the spot and pay-as-bid with a fixed demand level in the reserve market. Both models are coded in GAMS. We find that a more competitive reserve market helps to keep prices at the spot market down, and thus increases welfare.

The remainder of the paper is structured as follows. Section 2 gives an overview on electricity market design, auction mechanisms, and reserve markets. In section 3 the mathematical formulation of the two models and the underlying data is presented. In Section 4 the scenarios and results are described. Section 5 draws conclusions from the findings and gives an outlook.

2 Market Overview

Liberalized electricity markets can be differentiated in wholesale markets, retail markets and balancing markets (Moselle et al., 2006). We will focus on short term wholesale and balancing markets to estimate the interdependence of market prices in an oligopolistic framework. Wholesale markets consist of generators offering electricity to retailers such as local utilities and distribution companies. Research on electricity wholesale markets is largely focused on design issues and the integration of technical constraints (see e.g. Stoft, 2002, Hogan 1992, Joskow, 2007) or the analysis of the competitiveness, strategic company behavior and market power issues in recent liberalized electricity markets (e.g. Joskow and Kahn (2002) for California, Green and Newberry (1992) for the UK, and Weigt and Hirschhausen (2008) for Germany). Wholesale markets are typically further subdivided into long term and short term forward contract markets and real-time markets. In most European wholesale segments the day-ahead market is called spot market, and it is most influential in terms of setting short-run and long-run price signals.

Balancing markets on the other hand provide ancillary services, essential to match demand and supply in real time to maintain system stability including frequency stability and voltage control. Accurate frequency control is most crucial for the stability of electricity systems. Deviations from optimal values are due to imbalances of generation and load. These imbalances can be caused either by stochastic fluctuations and incorrect load prognoses or unavailability of supply due to technical breakdowns of generation units (Swider, 2007). In liberalized electricity markets, ancillary services can be either procured by commercial or by mandatory means. If procurement is on a mandatory basis, mostly large generators are obliged to contribute to system stability. However, we will focus on market based mechanisms.

The most important part of ancillary services is electricity reserve defined as a certain fraction of capacity that is kept in reserve to keep the system in a steady state in case of a mismatch between generation and load. In Europe the balancing process occurs in three so-called control levels according the terminology of the Union for Co-ordination of Transmission of Electricity (UCTE). The control levels are separated by time frame and are basically defined by the needed amount of capacity and the necessary ramp rate. Hence there are three kinds of electricity reserves, (primary, secondary and tertiary reserves) which are provided as incremental and decremental reserve power. A detailed description of the common international terms and technical specifications of reserve services is given by Rebours and Kirschen (2005) and technical details are represented in UCTE (2004), an overview about the development of reserve markets in Germany is presented in Riedel and Weigt (2007), and experiences from the Nordic markets are presented in Amundsen and Bergman (2007). As electricity markets become more liberalized, market based procurement of ancillary services such as electricity reserves becomes more important. Oren (2001) remarks that adequate product definition and market design are most crucial in terms of efficiency and liquidity of such markets which in turn has impacts on system stability and reliability.

As we focus on the price interdependence between the different market segments the pricing mechanism is of particular concern. Within the broad range of possible auctions (see Klemperer, 1999) two types of auctions are relevant for multi unit products such as electricity: the first-price-sealed-bid auction and the second-price-sealed-bid auction. In the context of multi-unit auctions these types of auctions are often denoted uniform price (or system marginal price) auction and pay-as-bid price (or discriminatory price) auction. The revenue equivalence theorem does not hold for multi-unit-auctions, when demand is uncertain such as in electricity markets.[2] Hence the issue which pricing rule is more efficient and which one leads to more competition-like outcomes is an issue of debate. Kahn et al. (2001) argue against the discriminatory pricing rule in the case of the California power exchange day-ahead markets. The authors state that switching from uniform to pay-as-bid pricing would also change bidding behavior of market participants. This effect would cause new inefficiencies and higher costs for generation companies, weaken the competition level and last but not least slow down essential capacity expansions. Federico and Rahmann (2001) analyze two reference cases, namely monopoly and perfect competition under demand uncertainty, to show consequences of changing the pricing rule from uniform to pay-as-bid. They demonstrate that the introduction of pay-as-bid pricing can lead to price and output reduction in the competitive environment, but also tends to decrease efficiency. The results of the monopolistic case show that the exercise of market power is more difficult under the pay-as-bid pricing rule, but this may provoke inefficient reactions by firms with market power. The oligopolistic case is not considered.

Regarding pricing mechanisms in reserve markets Chao and Wilson (2002) present an approach in which the system operators purchase electricity reserves in a one-sided procurement auction. Therein generators submit two-part bids, one for capacity provision and one for incremental energy supply. The authors show that this market design is incentive compatible in a competitive environment, whereas efficiency depends much on the scoring rule to award bids and the settlement rule to compensate accepted bids. In terms of the settlement rule Oren (2004) compares uniform pricing and pay-as-bid pricing applied to multiproduct markets suggesting a pay-as-bid settlement rule in case of markets, which exhibit “a high degree of product fragmentation” such as electricity reserve markets.

3 Model and Data

3.1 Model formulation

We develop two different model formulations and use a dataset from the German electricity market to analyze uniform and pay-as-bid pricing mechanisms. The first model consists of a Cournot approach with firms bidding on two separated market segments (wholesale and reserves) given limited generation capacities that they have to allocate to both segments. We assume that both markets are

[2] The revenue equivalence theorem states that the four types of auctions, namely English, Dutch, Vickrey and sealed bid auction, yield the same revenue for the bidders in case of private value (Soft, 2002).

cleared via a uniform pricing mechanism given a linear demand function.[3] In the second approach we assume pay-as-bid pricing on the reserve market and uniform pricing on the spot market.[4] Firms decide about which capacity to bid at which price in the reserve market and then play Cournot with the remaining capacity on the spot market.

For the first approach with uniform pricing on both markets we assume that each firm i has a given number of generation units j with a maximum capacity of s_{ij}. The firm has to decide which fraction of its generation capacity it will bid on the reserve market (q^r) and on the spot market (q^s). As reserve capacities have to satisfy a technical pre-qualification process only a limited number of generation units can be bid on the reserve market (r_{ij}). The profit of the firm consist of the earning on the spot market ($p^s q^s$) and the earning on the reserve market ($p^r q^r$) minus the costs to provide energy ($c^s q^s$) and reserve capacity ($c^r q^r$):

$$max\ \pi_i = p^s \sum_{j=1}^{n_i} q_{ij}^s + p^r \sum_{j=1}^{n_i} q_{ij}^r - \sum_{j=1}^{n_i} c_{ij}^s \cdot q_{ij}^s - \sum_{j=1}^{n_i} c_{ij}^r \cdot q_{ij}^r \qquad \textit{profit} \qquad (1)$$

$$s.t. \qquad s_{ij} \geq q_{ij}^s + q_{ij}^r \qquad \textit{total capacity} \qquad (2)$$

$$r_{ij} \geq q_{ij}^r \qquad \textit{reserve capacity} \qquad (3)$$

The uniform prices on the spot and reserve market depend on the quantity supplied by all firms. We assume a linear demand behavior:

$$p^s = a - b \cdot \sum_{i=1}^{m} \sum_{j=1}^{n} q_{ij}^s \qquad \textit{spot market demand function} \qquad (4)$$

$$p^r = f - g \cdot \sum_{i=1}^{m} \sum_{j=1}^{n} q_{ij}^r \qquad \textit{reserve market demand function} \qquad (5)$$

Deriving the first order conditions yields the equilibrium problem firm i has to solve:

$$\frac{\partial L}{\partial q_{ij}^s} = a - b \cdot (2q_{ij}^s + 2 \cdot \sum_{\substack{l=1 \\ l \neq j}}^{n} q_{il}^s + \sum_{\substack{k=1 \\ k \neq i}}^{m} \sum_{l=1}^{n} q_{kl}^s) - c_{ij}^s \quad \perp \quad q_{ij}^s \geq 0 \qquad \textit{FOC } q^s \qquad (6)$$

$$\frac{\partial L}{\partial q_{ij}^r} = f - g \cdot (2q_{ij}^r + 2 \cdot \sum_{\substack{l=1 \\ l \neq j}}^{n_i} q_{il}^r + \sum_{\substack{k=1 \\ k \neq i}}^{m} \sum_{l=1}^{n_i} q_{kl}^r) - c_{ij}^r \quad \perp \quad q_{ij}^r \geq 0 \qquad \textit{FOC } q^r \qquad (7)$$

$$\frac{\partial L}{\partial \lambda_{ij}} = q_{ij}^s + q_{ij}^r - s_{ij} \quad \perp \quad \lambda_{ij} \geq 0 \qquad \textit{FOC } \lambda \qquad (8)$$

$$\frac{\partial L}{\partial \mu_{ij}} = q_{ij}^r - r_{ij} \quad \perp \quad \mu_{ij} \geq 0 \qquad \textit{FOC } \mu \qquad (9)$$

For the second approach with pay-as-bid pricing on the reserve market we adopt a Bayesian approach. The Bayesian approach is based on the assumption that each firm's behavior is subject to a probability distribution function of the market clearing price which specifies the probability of bid acceptance.

[3] This assumption is necessary to conduct a market clearing on the reserve market under Cournot. The fixed demand on reserve market would otherwise lead to infeasible results.
[4] Pay-as-bid on the reserve market allows keeping the demand fixed but requires a Bayesian model approach.

Thereby the market clearing price describes the price of the last accepted bid and the probability distribution function represents the bidding behavior of the competitors and the long term market demand consisting of market data of previous bidding periods. An early approach to apply a Bayesian strategy to game theory in terms of a single unit sealed bid first price auction was presented in Lavalle (1967). The method was applied later to multi unit auctions, especially in electricity pay-as-bid markets in studies by Green and McDaniel (1999) and Federico and Rahmann (2001) who assume competitive markets and obtain market equilibria. More recently, Sadeh et. al. (2007) also took risk into consideration. Swider (2007) considers the German reserve market and presents an approach considering the decision processes of system operators and generators, but without regarding the market clearing process.

Contrary to the Cournot model our second approach is a sequential market clearing process. We assume that each power plant *j* belonging to firm *i* bids its capacity price p_{ij}^r into the reserve market and is accepted with a certain probability. Furthermore, each firm has knowledge of this probability based on publicly accessible market data. The probability function that specifies whether a firm's bid price p_{ij}^r is greater than the highest bid price p_m^r is denoted by $F(p_{ij}^r)$. Consequently the probability that the bid is accepted is $P(p_{ij}^r \le p_m^r) = 1 - F(p_{ij}^r)$. Subsequently each firm's earnings can be expressed in terms of an n-step profit function:

$$\pi_i = \sum_{j=1}^{n} (p_{ij}^r - c_{ij}^r) \cdot \bar{q}_{ij}^r \cdot (1 - F(p_{ij}^r)) \qquad \textit{profit under pay-as-bid} \qquad (10)$$

where $\bar{q}_{ij}^r$ represents the bid quantity and c_{ij}^r its marginal costs. For simplicity we assume that the bid quantity $\bar{q}_{ij}^r$ is fixed and equal to the available capacity $\bar{q}_{ij}^r = r_{ij}$. The actual quantity, which is provided by each winning plant, is determined afterwards by the market demand, i.e. by the system operator. The first order condition is given by:

$$\frac{\partial \pi_{ij}^r}{\partial p_{ij}^r} = q_{ij}^r \cdot (1 - F(p_{ij}^r)) - q_{ij}^r \cdot (p_{ij}^r - c_{ij}^r) \cdot \frac{\partial F(p_{ij}^r)}{\partial p_{ij}^r} = 0 \qquad \textit{FOC } p^r \qquad (11)$$

Given that $\frac{\partial F(p_{ij}^r)}{\partial p_{ij}^r}$ is the density function $f(p_{ij}^r)$ and rearranging equation 11 yields:

$$p_{ij}^r = c_{ij}^r + \frac{1 - F(p_{ij}^r)}{f(p_{ij}^r)}, \qquad \textit{FOC } p^r \qquad (12)$$

which represents the optimal bid price of firm *i*'s power plant *j*.

In order to derive the optimal bidding strategy the firm has to know the price distribution on the market. If expected prices are assumed to be uniformly distributed a range of prices can be determined, where p^{max} denotes the maximum expected and p^{min} the minimum expected price, and the actual last accepted bid price lies within the range p^{max}- p^{min}. Hence the density function and the distribution function can be defined as follows:

$$f(p_{ij}^{r}) = \frac{1}{p^{\max} - p^{\min}} \qquad \textit{uniform density} \qquad (13)$$

$$\Leftrightarrow \qquad F(p_{ij}^{r}) = \int_{p^{\min}}^{p_{ij}^{r}} f(\rho)d\rho \; = \ldots = \frac{p_{ij}^{r} - p^{\min}}{p^{\max} - p^{\min}} = 1 - \frac{p^{\max} - p_{ij}^{r}}{p^{\max} - p^{\min}} \qquad \textit{uniform probability} \qquad (14)$$

Insertion of (13) and (14) in (12) and rearranging yields the specification of the optimal bid price:

$$p_{ij}^{r} = \frac{c_{ij}^{r} + p^{\max}}{2} \qquad \textit{optimal bid price} \qquad (15)$$

Thus each generator chooses a markup that depends on the difference between the expected highest price and its marginal costs.

In a second step the system operator clears the reserve market by minimizing procurement costs C_{SO} given a fixed demand for reserve capacity q_{SO}^{rdem} :

$$\begin{aligned} & C_{SO} = \sum_{i=1}^{m} \sum_{j=1}^{n} p_{ij}^{r} \cdot q_{ij}^{r} \\ & s.t. \quad \sum_{i=1}^{m} \sum_{j=1}^{n} q_{ij}^{r} = q_{SO}^{rdem} \\ & \qquad \tau_{ij} q^{r,\min} \leq q_{ij}^{r} \\ & \qquad \tau_{ij} \overline{q}_{ij}^{r} \geq q_{ij}^{r}, \quad \tau_{ij} \in \{0,1\} \end{aligned} \qquad \textit{reserve market clearing} \qquad (16)$$

The price p_{ij}^{r} is taken as an exogenous input variable from the generators' price setting problem. If a bid is accepted (τ_{ij} =1) the awarded bid quantity q_{ij}^{r} has to be within the minimum bid size $q^{r,\min}$ and each firm's capacity bid $\overline{q}_{ij}^{r}$.

After generators solved their price setting problem and the system operator minimized his costs by choosing the cost-efficient dispatch for reserve provision, the clearing of the reserve market is finished and generators have the opportunity to bid their non-committed reserve capacity as well as their further generation capacities into the spot market:

$$\max \quad \pi_i^{s} = (a - b \cdot \sum_{i=1}^{m} \sum_{j=1}^{n} q_{ij}^{s}) \cdot \sum_{j=1}^{n} q_{ij}^{s} - \sum_{j=1}^{n} c_{ij}^{s} q_{ij}^{s} \qquad \textit{spot market profit} \qquad (17)$$

$$s.\ t. \quad q_{ij}^{s} \leq s_{ij}$$

The cost minimization problem is implemented and solved as a mixed integer problem (MIP), the profit maximizing models as mixed complementarity problem (MCP).

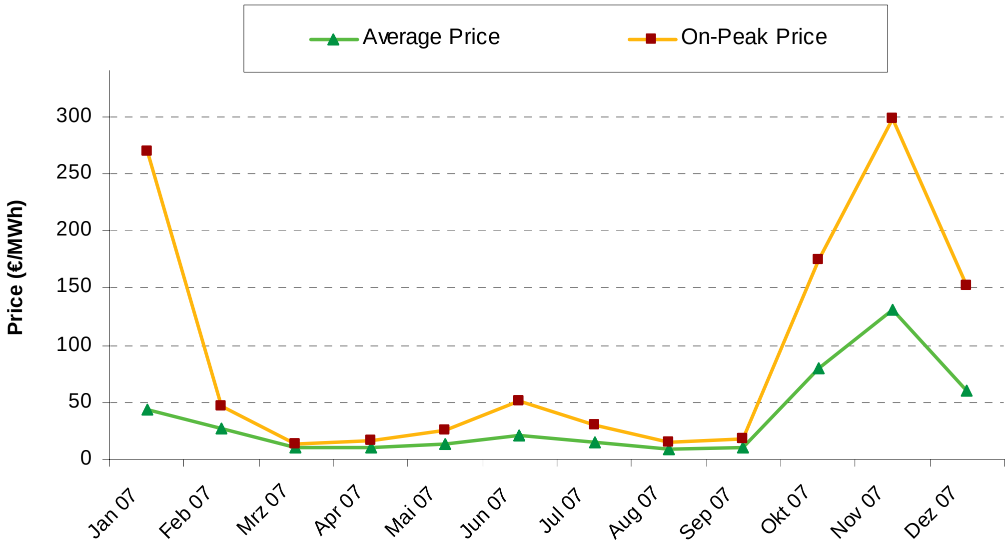
3.2 Dataset

We use a dataset of the German electricity market. The German market is dominated by four large suppliers. Beside there are about 74 large generators, who hold capacity of more than 200 MW, and 910 local distributors (Meller, 2007). The market itself is characterized by a large fraction of bilateral contracts and over the counter transactions. The benchmark for spot and future prices is given by the European Energy Exchange (EEX). The reserve market is separated into primary, secondary and tertiary electricity reserves. Until December 2006 the reserves were auctioned for each of the four control zones separately and on four different IT-based markets, each one operated by a different system operator. Since December 1st 2006 the markets for tertiary reserve power and since December 1st 2007 also the markets for primary and secondary reserves are consolidated and reserves are procured via one single market platform. However, the system operator of each control area is still entitled to auction a fraction of the required reserves just for balancing purposes inside his own control area, the so called core proportion, as long as this is necessary to maintain the security of supply in the respective area (VDN, 2005).

The procedure of bidding for the particular type of electricity reserves is organized separately. While primary and secondary reserve power are procured every six month, tertiary reserves are procured on a daily basis as incremental and decremental reserve power. Within the tendering process each day is divided in six time slots, and hence tertiary reserve power is tendered in six four hour blocks, where the minimum bid capacity is 15 MW. All offers have to be placed until 11 a.m., one hour before the EEX gate closure. The intention of this sequence of clearing the markets is to ensure liquidity in reserve markets, since generators have not committed their generation units for the spot market when the reserve auction takes place. Each bid is a two-part bid which consists of a capacity bid and an energy bid referring to a previously unknown amount of megawatt hours to be delivered. We only take account of the capacity bid.

The amount of reserve capacity to be tendered is determined by the system operator according to UCTE recommendations and is thus inelastic to bid prices. In 2007 the average demand per four hour block was 3,185 MW and 3,223 MW in on-peak hours (VDN, 2008). The average bid price for reserve capacity in 2007 was 36.04 €/MW per four hour block and the average reserve energy rate was 287.45 €/MWh. On-peak times featured significantly higher reserve capacity bids and the average on-peak price matched 92.66 €/MW (Figure 1).

Figure 1: Average and on-peak bid prices for reserve capacity



Source: VDN (2008)

For our numerical analysis we use a stylized model of the German electricity wholesale spot and reserve market. The available generation capacity and cost data from 2006 refers to 315 power plants based on VGE (2006). The strategic firms are represented by the four major utilities, which have a joint market share of 78.5 % and hold a generation capacity of 70.53 GW (Table 1). There is also a cluster of fringe firms consisting of about 100 generators, who hold an average generation capacity of 190 MW and make up roughly one fifth of the whole market capacity. We consider eight types of generation plants: hydro power, pump storage power, nuclear power, open cycle gas turbines, combined cycle gas turbines, natural gas and oil based steam plants, hard coal plants, and lignite plants.

Basically, every firm included in the model is supposed to be able to bid in the spot market. However, the number of market participants who are able to bid in the reserve market is relatively small as there are only a limited number of generation technologies capable to provide reserves. Due to limited public available information about participating firms in the reserve market we assume that the 10 major firms can bid in the reserve market, according to their capacity. The prequalification process for reserve auction participation is not considered specifically and it is simply assumed that pumped storage, open cycle gas turbines, combined cycle gas turbines, and natural gas and oil based steam generation are ready to provide reserve capacity.

Since the products offered in the markets are different there are different types of marginal costs, too. The reserve market is considered as a pure capacity market, where the capacity is accounted as the decision variable. Hence firms actually decide about capacity expansion in this model (€/MW), which is an abstraction of reality. Since in the German market tertiary reserve capacity is tendered (and thus blocked) for a time horizon of four hours, the measure is actually (€/MW*4h). For the spot market marginal cost of generation are considered (€/MWh).

Capacity costs are based on specific overnight costs and the expected economic lifetime of the different generation technologies taken from Eberhard et al. (2000) given in Table 2. The four-hourly capital costs are calculated by utilizing the Capital Asset Pricing Model (CAPM) an estimating the weighted average cost of capital (WACC) based on parameters for investments in generation capacity as in Riedel and Weigt (2006).

Table 1: Modeled market structure

Company	Market share (%)	Capacity (GW)	Number of plants
E.ON	24.40	21.92	80
EnBW	12.00	10.78	48
RWE	26.82	24.09	52
Vattenfall	15.31	13.75	35
Fringe	21.47	19.28	100
Total	**100.00**	**89.82**	**315**

Source: VGE (2006)

Table 2: Assumptions for Estimation of Capital Costs

Generation Technology	Investment Cost (€/kW)	Typical Lifetime (years)	€/MW*4h
Natural Gas Based Steam	815	27.5	29.42
Gas Turbine	285	27.5	10.33
Gas Steam Combined Cycle	520	22.5	20.45
Pumped Storage	1,490	65.0	44.92
Oil Based Steam	585	25.0	21.86

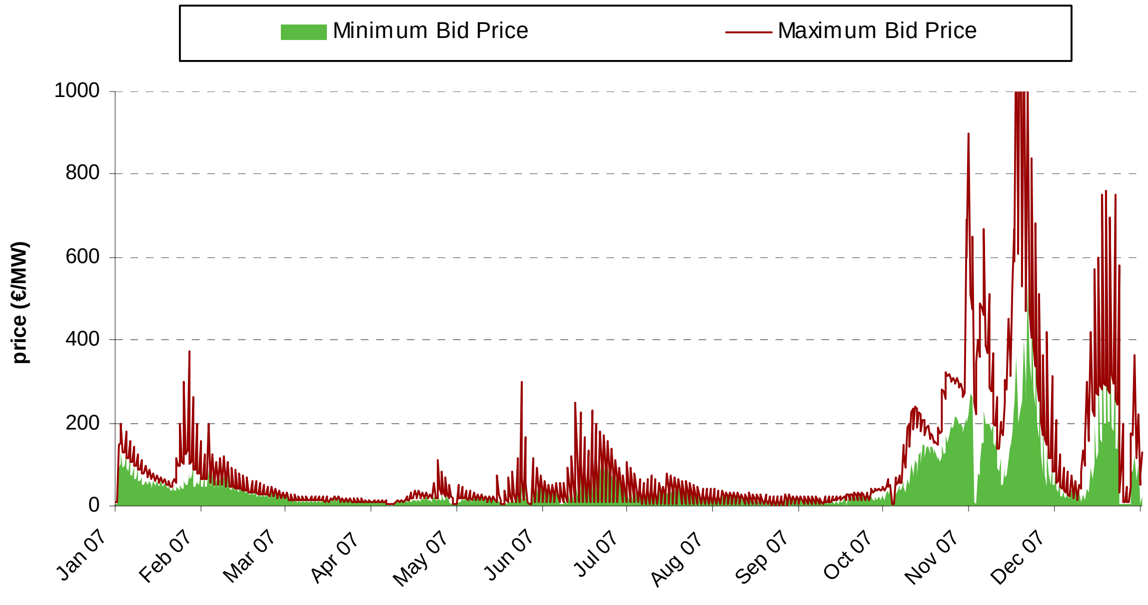
Source: Eberhard et.al. (2000)

In the spot market we assume a linear demand function in both approaches. To get an estimation of the slope and the intercept, publicly available on-peak consumption data provided by the UCTE and on-peak price data provided the EEX is used to obtain a reference point with average peak demand (66 GW) and price level (56.09 €/MWh) of 2007. The demand elasticity is derived from several sources averaging to -0.2 at the reference point.[5]

For the first model approach we also have to assume a linear demand function in the reserve market in order to apply the Cournot approach. As a basis for the parameter estimation, the average peak demand and price are calculated from public by available data provided by the system operators; we use 3,223 MW and 92.66 €/MW, respectively. Furthermore, we assume that demand in the reserve market is rather inelastic compared to the spot market. Thus, an elasticity value of -0.05 is applied, which is the lower boundary of elasticity values for short term electricity demand found in the literature. For the second approach with a pay-as-bid clearing system only the total demand and expected prices are necessary. We observe an average maximum bid price of 99.08 €/MW and an average minimum bid price of 51.16 €/MW during on-peak times in 2007 (Figure 2). Demand is fixed at 3,223 MW.[6]

[5] In his investigation of the California electricity crisis Sweeney (2002) gives an approximation of short term price elasticities between 0.1 and 0.3, Bushnell, Day et. al. (1999) find values between 0.05 and 0.5, and Bentzen and Engsted (1993) estimate 0.135 for short term energy demand.

Figure 2: Maximum and Minimum Bid Prices for Tertiary Reserve Capacity in 2007



Source: VDN. 2008

Fringe firms participating in the spot market are divided into two categories. One part is assumed to act as price takers and the others act strategically. The latter group is defined via the reserve market bidder group. Thus, the six largest fringe firms that are also assumed to be active in the reserve market are considered within the strategic fringe group. This group is later extended as part of a scenario analysis. The residual demand curve for the strategic firms is derived by subtracting the quantity supplied by the price taking fringe.

4 Results

First we compare the above described model approaches to a simple competitive benchmark. Therefore, we apply the uniform pricing two market approach of the Cournot model but without any strategic company behavior. The results are summarized in Table 3. For both strategic models we observe higher prices and lower quantities in the spot and reserve market. The spot market results of both models are quite similar: prices are above 100 €/MWh and thus significantly higher than the competitive ones, and the supply is about 10 GW lower. For the reserve market both approaches produce different outcomes. In the uniform pricing Cournot model prices are about 216 €/MW, well above competitive results although supply is only 360 MW lower. This is due to the steeper demand function assumed for the reserve market. In the pay-as-bid case demand is fixed and the bidding behavior of firms is based on the historic price information of the real market. Thus the resulting price level, about 55 €/MW is significant lower than in the elastic demand case.

[6] For simplicity we assume a uniform price distribution on the reserve market (see equations 13 and 14).

In a second step we want to analyze the impact of the degree of competition in the reserve market on the spot market prices. Abstracting from the basic market structure, we assume that every generator who holds the appropriate generation technology is able to offer reserve capacity. We add those firms to the strategic fringe group active on the reserve and spot market. The lower two columns in Table 3 show the competitive results. The high pressure of competitive fringe firms brings the price level down compared to the base case for both models and both markets. In the Cournot model reserve prices go down to 95 €/MW and spot prices decrease by 6 €/MWh. In the Baysian model the effect on the reserve market is less striking as prices are already significantly below the Cournot model. Spot prices also decrease by about 6 €/MWh.

Table 3: Basic model results

Scenario	Spot Market Price (€/MWh)	Reserve Market Price (€/MW)	Spot Market Supply (GW)	Reserve Market Supply (MW)
Competitive Benchmark	52.7	10.3	65.2	3,370
Cournot	108.2	216.5	54.9	3,010
Pay-As-Bid	105.8	55.4	55.4	3,220
Cournot (competitive reserve)	102.1	95.3	56.1	3,220
Pay-As-Bid (competitive reserve)	99.9	54.7	56.5	3,220

In a third step we estimate the impact the actual demand requirement for reserve capacity has on spot market prices. While the demand of tertiary reserve power currently ranges between 3,000 and 3,400 MW, the demand may increase in the future years.[7] However, there are also reasons why the current level of reserve capacity may be too high. First, the actual usage of reserve capacity is rather low (about 6.3 % in 2006, see BNA, 2007). This raises the question whether the current reserve capacity is overestimated by the system operators, or even withdrawn from the wholesale market, as suspected by Richmann (2006). Second, the current amount of reserve capacity is based on the four control areas. An integration of those four areas to a single balancing zone would reduce the reserve capacity needed.

To analyze interactions between the wholesale spot market and the reserve market we model a demand shift in the reserve market, while spot market demand is kept fixed. Thereby, reserve demand is varied over a range of demand levels by altering the intercept parameter in the case of the Cournot based models and, respectively, the fixed demand parameter in the case of the pay-as-bid model.[8] Demand levels are varied within the range between 1,000 MW and 8,000 MW. Figure 3 shows the prices on the spot market for the different reserve demand levels. We observe that in the two uncompetitive reserve market scenarios the price on the spot market is relatively similar for low reserve demand levels. If the

[7] The German Energy Agency (DENA) conducted a study concerning the development of the transmission and distribution grid in Germany in terms of the integration of on-shore and off-shore wind power. They estimate an additional amount of tertiary reserve power of approximately 2,000 MW until 2010 and 3,000 MW until 2015 which is caused by the volatility of wind-power (DENA, 2005).

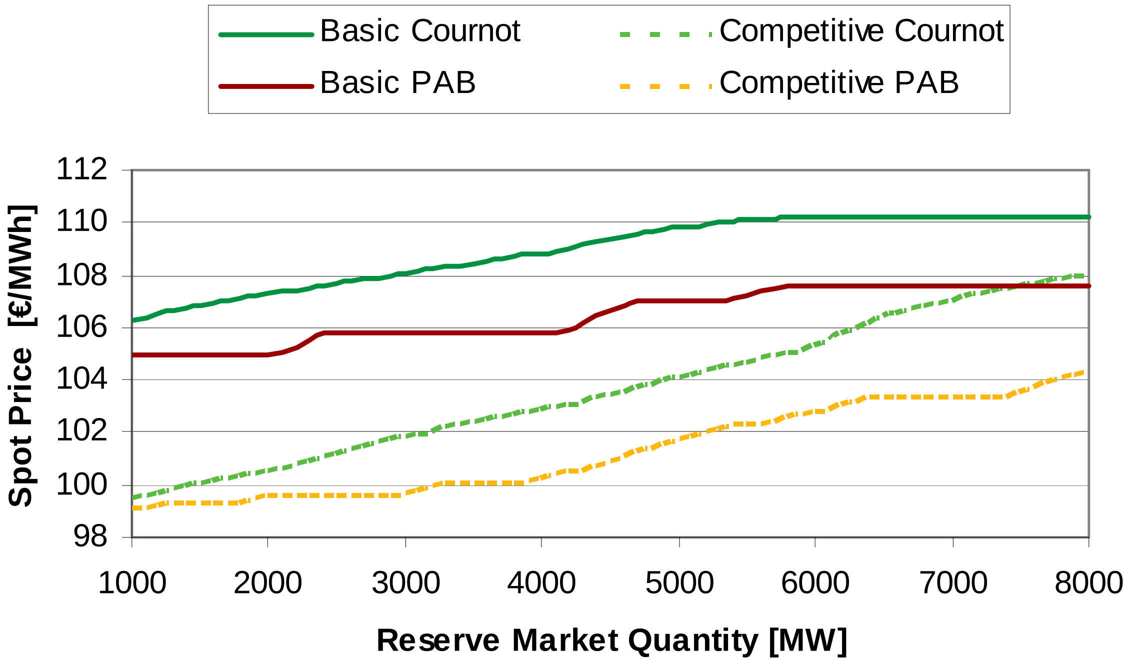
[8] We do not change the assumptions on maximum and minimum bid prices which biases the results of the pay-as-bid model.

demand requirement is increased the spot prices increase as well. Overall a price increase of 3 to 4 €/MWh is observable which is relatively small compared to the price level of about 100 €/MWh.

In case of the more competitive market setting with a significant increase of competitors on the reserve market prices in the spot market are about 6 €/MWh lower for small demand requirements but increase as well if reserve demand is raised. In the Counrot model the price difference between the basic and competitive case decreased to 2 €/MWh for a reserve demand of 8 GW. In the pay-as-bid case this difference is greater even for high demand requirement. The results indicate that an overestimation of reserve demand can lead to higher spot prices although the relative impact is small for the given dataset.

The prices on the reserve market remain nearly constant for the pay-as-bid model in both the basic and the competitive case averaging about 55 €/MW. However, this is mainly due to the fact that the underlying reference price range for the Baysian approach has not been altered with the demand increase. For the basic Cournot approach reserve prices range from 210 €/MW for low up to 300 €/MW for high reserve requirements. These prices are significantly lower in the competitive Cournot model but still range between 80 and 125 €/MW.

Figure 3: Prices on the spot market by varying reserve demand



5 Conclusion

In this paper we analyze the interdependence of reserve and spot markets for electricity using equilibrium models. We apply a Cournot based model using multi-product companies bidding their capacities simulations on the spot and reserve market and a Bayesian approach applying pay-as-bid pricing on the reserve market. Both models are tested using a dataset of the German market.

We show that the design of the reserve market affects spot market outcomes: a uniform priced reserve market is subject to strategic company behavior and thus prices on the reserve as well as the spot market are the highest. If we apply the pay-as-bid approach prices on both markets are lower. We then test whether a more competitive market structure on the reserve market also reduces prices on the spot market. By increasing the number of companies active on the reserve market we increase the residual demand elasticity faced by strategic companies and thus can bring prices down. Furthermore, prices on the spot market are also affected by this assumption although the actual impact is rather low compared to the price level.

In the next step, we vary the demand for reserve capacity between 1 and 8 GW. Prices increase with a higher demand for reserves. However, the results for the uniform priced Cournot approach show a higher price increase than the pay-as-bid model. Furthermore, if we assume a larger fraction of competitive bidders in the reserve market the impact on spot prices can be reduced. Thus a too high demand level in reserve markets can have negative impacts on wholesale prices if the market structure is already characterized by oligopolies.

The models make simplifying assumption regarding company behavior. In particular the pay-as-bid approach depends on historic market data and thus adjustments to the model may not be tractable in real markets. Further research is necessary to validate these first results and improve the modeling approaches when interacting markets are analyzed.

References

Amundsen, E. S., Bergman, L., 2007: Provision of Operating Reserve Capacity: Principles and Practices on the Nordic Electricity market, *Competition and Regulation in Network Industries,* Vol. 8, pp. 73.

Bentzen, J., Engsted, T, 1993: Short and Long-run Elasticities in Energy Demand – A Cointegration Approach, *Energy Economics,* Vol. 15, No. 1, pp. 9-16.

Chao, H., Wilson, R., 2002: Multi-Dimensional Procurement Auctions of Power Reserves: Incentive-Compatible Scoring and Settlement Rules, *Journal of Regulatory Economics*, Vol. 22, No. 2, pp. 161-183.

DENA, 2005: *Energiewirtschaftliche Planung für die Netzintegration von Windenergie in Deutschland an Land und Offshore bis zum Jahr 2020,* Version of February, 2005.

Eberhard, A., Lazarus, M. et. al., 2000: *Electricity Supply and Demand Side Management Options - Annexes and Appendices*, World Commission on Dams (WCD) Thematic Review, Version of November 2000, Cape Town, South Africa.

ETSO, 2003: *Current State of Balance Management in Europe,* European Transmission SystemOperators, http://www.etso-net.org/upload/documents/BalanceManagemeninEurope.pdf, retrieved: 31.05.2008, 20:20.

Federico, G., Rahmann, D., 2001: *Bidding in an Electricity Pay-as-Bid Auction*, Working Paper, Version of April 2001, Nuffield College, Oxford, UK, and University of California, Los Angeles.

Green, R., McDaniel, T., 1999: Modelling RETA: *A Model of Forward Trading and the Balancing Mechanism,* Version of May 1999, Working Paper, University of Cambridge, Cambridge.

Green R; Newbery D. 1992: Competition in the British electricity spot market. *Journal of Political Economy*; Vol. 100; No. 5, pp. 929-953.

Hogan, W., 1992: Contract Networks for Electric Power Transmission, *Journal of Regulatory Economics*, Vol. 4, No. 3, pp. 211-242.

Joskow P. 2007: *Lessons Learned from Electricity Market Liberalization*, MIT.

Joskow, P, Kahn, E., 2002: A Quantative Analysis of Pricing Behavior in California`s Wholesale Electricity Market During Summer 2000. *The Energy Journal,* Vol. 23, No. 4.

Kahn, E., 2001: Uniform Pricing or Pay-as-Bid Pricing: A Dilemma for California and Beyond, *The Electricity Journal*, Vol. 14, No. 6, pp. 70-79.

Klemperer, P., 1999: Auctiom Theory: A Guide to the Literature, *Journal of Economic Surveys,* Vol. 13, No. 3, pp. 227-286.

Lavalle, I. H., 1967: A Bayesian Approach to an Individual Player's Choice of Bid in Comepetitive Sealed Auctions, *Management Science*, Vol. 13, No. 7, pp. 584-597.

Meller, E., 2007: *Libralisation of the German Electricity Market*, Version of March 2007, VDEW, Berlin.

Moselle, B., Newberry, D., Harris, D., 2006: *Factors Affecting Geographic Market Definition and Merger Control for the Dutch Electricity Sector*. The Brattle Group, Brussels.

Oren, S., 2001: *Design of Ancillary Service Markets,* University of Calfornia, Berkley.

Oren, S., 2004: When is Pay-as-Bid Preferable to Uniform Price in Electricity Markets, *Power Systems Conference and Exposition*, Vol. 13, No. 10, pp. 1618-1620

Rebours, J., Kirschen, D., 2005: *A Survey of Definitions and Specifications of Reserve Services*, University of Manchester.

Richmann, A., 2006: *Gibt es strategisches Verhalten auf den Strommärkten?*, Version of December 2006, Berlin.

Riedel, S., Weigt, H., 2007: *German Electricity Reserve Markets,* Electricity Markets Working Papers, WP-EM-20, Technical University of Dresden.

Sadeh, J. et. al., 2007: *A Risk-based Approach for Bidding Strategy in an Electricity Pay-as-Bid* A*uction*, Version of November 2007, European Transactions on Electrical Power.

Stoft, S., 2002: *Power System Economics: Designing Markets for Electricity*, Wiley-IEEE Press.

Sweeney, J. L., 2002: *The California Electricity Crisis*, Hoover Institution Press, Stanford.

Swider, J. D., 2007: *Handel and Regelenergie- und Spotmärkten: Methoden zur Entscheidungsunterstützung für Netz- und Kraftwerksbetreiber*, Deutscher Universitäts-Verlag, Wiesbaden.

UCTE, 2004: *Load Frequency Control and Performance*. http://www.ucte.org/_library/ohb/policy1_v22.pdf, retrieved: 19.04.2008, 12:39

VDN, 2005: *Beschaffung von Regelleistung und -energie in Deutschland*. http://www.vdn-berlin.de/global/downloads/Netz-Themen/Regelenergie/Regelenergiemarkt_dt_2005-07-07.pdf, retrieved: 26.06.2008, 23.33

VDN, 2008: *Internetplatform for Electricity Reserves Tendering*. https://www.regelleistung.net, retrieved: 22.05.2008, 22:07

VGE, 2006: *Jahrbuch der europäischen Energie- und Rohstoffwirtschaft 2006.* Essen,Verlag Glückauf GmbH.

Weigt, H., v. Hirschhausen, Ch., 2008: Price Formation and Market Power in the German Wholesale Electricity Market in 2006, *Energy Policy*, Vol. 36, No. 11, pp. 4227-4234.