Modeling Accuracy in ex-ante Analyses - An Example of a Multi-Regional Two-Stage Cournot Model for Germany

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Abstract

In this paper impact of accuracy and assumptions in model based ex-ante analyses of market power is presented. Based on a multi-regional two-stage Cournot model developed for analyzing competition in the German wholesale electricity market, it is shown to what extent different assumption on crucial model parameters can influence results and the therefore estimation for market power potentials. The paper focuses on different supply side and demand side related aspects in Cournot type modeling.

Key words: Market power, ex-ante analyses, accuracy and assumption, Cournot model.

1 Introduction

Public and scientific debate regarding the exercise of market power in the German electricity market has become more intensive within the last years. Given the rising wholesale prices at the European Electricity Exchange (EEX), the oligopolistic market structure consisting of RWE Power AG, E.ON Energie AG, Vattenfall Europe AG and EnBW AG is assumed to provide a basis for strategic behavior. In particular RWE and E.ON holding a dominant market position are supposed to raise spot market prices by physically or economically withhold capacity and by pass-through the costs of CO_2 allowances.

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As the argument of unjustified pass-through of CO_2 costs is loosing importance, even in the political debate, due to the understanding and acceptance of inevitable price signals to establish environmental friendly power generation technologies, concerns about the possibilities of strategic behavior are more and more present. Suggestions for dealing with possible market power range from a state controlled price formation over the taxation of generators to collect profits up to the enforcement of horizontal and vertical divesture by generating companies. Considering these concerns, research has to provide adequate instruments, which can be used by policy to monitor competition and, if market power can be proven, to establish appropriate measures to mitigate the possibilities of detrimental strategic behavior.

Due to the specific conditions in electricity markets, the monitoring of market power is difficult and demands for sophisticated approaches. Therefore the primarily use of simple concentration measures like the CR_n concentration ratio or the Herfindahl-Hirschman Index (HHI) is widely opposed in economic research. Based on the limitations of these static indicators more advanced measures have been developed. Two examples can be found in the Residual-Supply Index (RSI) and the Pivotal-Supplier Indicator (PSI). Although these indices are much more detailed in considering the specific conditions in electricity markets, they only can provide a first indication for the possibilities of market power.

More appropriate instruments for monitoring competition and strategic behavior in electricity markets can be found in model based approaches. Depending on the model framework, a detailed representation of the technical, economical and behavioral conditions can be implemented. Given the different types of electricity market models, applications for *ex-post* and *ex-ante* analysis of market behavior can be found. Whereas *ex-post* analysis focuses of historical market results by monitoring e. g. price-cost margins, *ex-ante* analysis studies the potentials for exercising market power by simulating different types of strategic behavior within alternative market settings.

The analysis of market performance, e. g. realized wholesale prices by quantifying the price-cost margin for a selected time period is mainly based on fundamentally driven optimization models, which can basically represent electricity markets in great detail. The effectiveness to exactly measure the exercise of market power *ex-post* by comparing time varying market results with predicted system marginal costs considerably depends on the quantity and quality of available market data. At least for Germany, it can be questioned, if the currently data base is sufficient for this type of market power analyses.

Using game theoretic model approaches to analyze the potentials for strategic behavior *ex-ante*, problems are less based on the availability of market data, but on the assumptions made for modeling companies' behavior and the accuracy in representing market structure. Regarding the various options to model oligopolistic behavior in electricity market, *Cournot* type approaches are often used due to their comparatively straightforward implementation of firm's strategies. Moreover, in a *Cournot* model framework, different structural and institutional market conditions like time varying supply and demand patterns, constraints in generation and transmission capacity as well as forward market trading and interregional electricity exchange can be represented to show a more realistic picture of the actual market setting.

Notwithstanding the advantages of explicitly taking into account non-competitive market transaction, game theoretic oligopoly models suffer form two major problems. The first is the simplification of technical conditions in electrical power systems. Due to calculate robust *Nash* equilibria, e. g. dynamics in power plant dispatch like start-ups, pump storage optimization or reserve power supply have to be reduced. However, these inaccuracies appear in both the *Nash* and the reference competitive equilibrium. The second is the impact of crucial model parameters on the model results. Especially the type of demand functions used and the assumptions made on price elasticity of demand, the construction of companies' marginal cost functions, the implementation of different market segments and the possibilities for cross-border trade have considerable influence on the predicted market power potentials. Considering these aspects in *Cournot* type modeling, the paper focuses on the following issues:

(1) Interregional electricity exchange
(2) Forward market trading
(3) Marginal cost functions
(4) Demand functions
(5) Price elasticity of demand

The paper is organized as follows. In section 2 an overview of the multi-regional two-stage *Cournot* model is given. The impact of modeling accuracy and assumptions is described in Section 3. Therein it is discussed how interregional electricity exchange and forward market trading can influence the evaluation of market power potentials. Furthermore, different technical modeling aspects with emphasis on different types of marginal cost and demand functions as well as assumptions on price elasticity are described. Finally, conclusions are drawn in section 4.

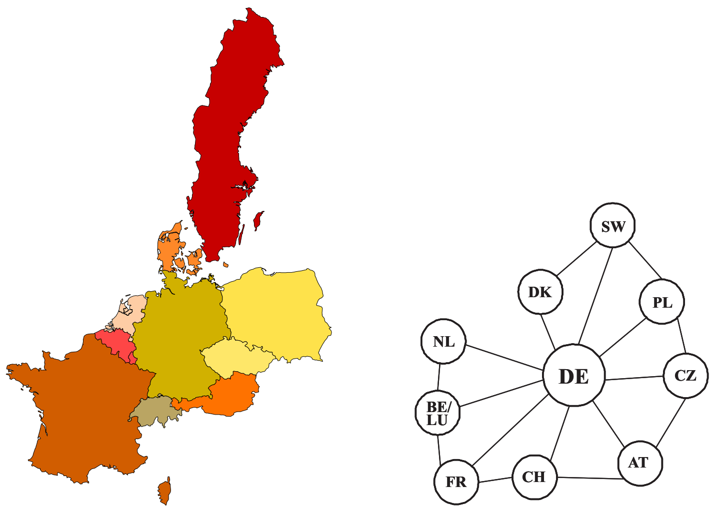
2 Model overview

For analyzing competition in the German electricity market, a multi-regional, two-stage *Cournot* model has been developed (cf. Ellersdorfer (2005) for details). The German electricity market is modeled as a four player oligopoly with a competitive fringe and at least one risk neutral speculators. Generating companies maximize their profit simultaneously within a two-stage market setting. In the first stage, the derivatives market, firms decide about the amount of electricity they want to sell or buy through forward contracts that call for delivery in the second stage. In the second stage generators trade on the spot market and physical production takes place. Fringe suppliers are assumed to behave as price takers.

Solving the second stage optimization problem, each oligopolistic supplier i maximizes its profit by determining the optimal electricity output s_i. The profit function of each player can be written as:

$$\max_{s_i} \Pi_i(s_i, f_i) = P(S)s_i + f_i(P^f - P(S)) - TC_i(s_i) \tag{1}$$

with $S = \sum_i s_i$ being aggregated supply by all generators. $TC_i(s_i)$ represents player's total generation costs of supplied quantity in the spot market. P^f is the price of forward contracts f_i and $f_i(P^f - P(S))$ being the profit from selling contracts in the forward market. Based on the assumption of at least one risk neutral speculator, P^f equals expected spot market price $E(P(S))$. Generators' physical output in the second stage is constrained by its maximum available production capacity $s_i^{\max}$.



(a) Regions (b) Interconnections

Fig. 1. Regional coverage in the electricity market model

As Germany is highly integrated in the European internal electricity market, the existing interconnection capacities to its neighboring countries have been implemented, allowing for interregional electricity exchange. Transmission capacities are supplied by a Single Transmission System Operator (TSO) and are based on average Net Transfer Capacities (NTC) for the years 2002 to

2005, provided by the European Electricity System Operators (ETSO). The TSO supplies transmission services at marginal congestion cost. Electricity markets within neighboring countries are assumed to be fully competitive. Figure 1 presents the covered regions (a) and the cross-border transmission lines (b) in the model.

As interregional electricity trade is possible, producers decide not only about the quantity they want to sell in their regional market, but also about the amount they want to export to neighboring countries. Due to the assumptions of fully competitive electricity markets in the neighboring countries, imports into the German market are possible to marginal generation costs.

The model is formulated in Mixed Complementarity Problem (MCP) format using GAMS and the PATH solver.

3 Impact of accuracy and assumptions

The application of game theoretic equilibrium models for *ex-ante* analyses of market power potentials in electricity market requires both a detailed representation of market conditions and a careful interpretation of model results. Some of the crucial aspects, that have to be considered, particularly in *Cournot* type models, are discussed in the following sections. In section 3.1 the influence of interregional electricity exchange on possible market outcome is described. Section 3.2 focuses on the competitive enhancing effect of forward markets and its implication for the evaluation of market power potentials in Germany. Two, more technical aspects of oligopoly modeling are discussed in sections 3.3 and 3.4. The first describes the impact of different marginal cost functions that can be used to approximate *merit-order* curves. The second is related to different types of demand functions. Finally, in section 3.5 the impact of different assumptions on price elasticity of demand is presented.

3.1 Interregional electricity exchange

Modeling the possibility of interregional electricity exchange, i. e. extending the options to optimize spot market decisions for the electricity suppliers, has a considerable impact on the estimation of market power potentials. As foreign generators can profit from market power induced price increases, electricity exports keep pressure on prices in the German wholesale market. As a consequence, price mark-ups due to capacity withholding by the four major players in Germany are reduced in comparison to a situation where cross-border trade is unconsidered. Figure 2 presents wholesale electricity prices in Germany for the perfectly competitive equilibrium and the two *Cournot* equilibria. Additionally the historical spot market prices at the European Energy Exchange for the year 2005/2006 are also included.

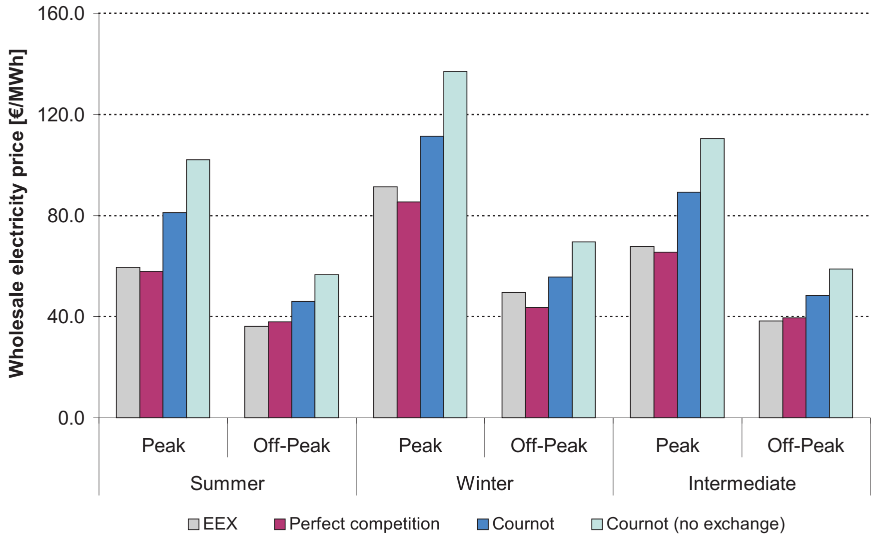


Fig. 2. Wholesale electricity prices considering interregional exchange

It can be observed that interregional electricity exchange forces down wholesale prices e. g. from 136.91 €/MWh (winter peak) in the *Cournot* equilibrium without cross-border trade to 111.27 €/MWh (winter peak) in the *Cournot* equilibrium with cross-border trade. Wholesale prices in the summer peak segment are reduced from 102.11 €/MWh to 81.15 €/MWh, whereas off-peak prices decrease from 56.60 €/MWh to 46.07 €/MWh. Market power induced prices in the intermediate peak times decrease from 110.52 €/MWh to 89.17 €/MWh and from 58.88 €/MWh to 48.29 €/MWh in off-peak times. Table 1 summarizes the computed price mark-ups due to capacity withholding with and without consideration of interregional electricity exchange.

Table 1
Change in wholesale prices due to capacity withholding compared to competitive level

Parameter	Unit	Summer		Winter		Intermediate	
		Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
Δ P(S) [a]	%	+76.4	+49.2	+60.6	+59.8	+68.9	+49.1
Δ P(S) [b]	%	+40.2	+21.4	+30.5	+27.7	+36.3	+22.3

[a] Interregional exchange not implemented
[b] Interregional exchange implemented

The analysis shows, that cross-border trade can have significant influence on the evaluation of market power potentials at least in the German electricity market. Model based analyses of oligopolistic behavior should therefore take aspect of interregional price adjustment and its ability to limit market power into account. If it remains unconsidered, market power potentials might be overestimated.

Beside the effects on the *Cournot* equilibria, another aspect related to accuracy in electricity market modeling for *ex-ante* analyses of market power should be mentioned. This aspect is related to the differences between the endogenously calculated competitive equilibrium prices and the empirical EEX prices. Although the model results show competitive prices being slightly lower than EEX prices in all peak load segments, this can not be interpreted as a *ex-post* evidence for the exercise of market power in Germany. Due to the nature of oligopoly models, which mainly focus on behavioral aspects, many technical conditions in power markets are addressed in reduced detail only. EEX prices are thus underestimated (peak load) and overestimated (off-peak load). However, as the possibility of historically exercised market power can not be negated for Germany, this type of model is not an adequate approach for its *ex-post* verification.

3.2 Forward market trading

Many established European electricity exchanges, like the European Energy Exchange, operate derivatives markets to provide instruments like futures, forwards and options, that can be used by market participants for risk hedging and speculation. As has been indicated before, the outcomes of both market stages can not be considered to be independent.

Given a non-competitive market environment, oligopolistic players maximize their profit in a sequential two-stage game, taking forward positions that call for delivery in the second stage, before spot market trading and actual production occurs. Moreover, optimal second stage output depends on first stage forward contacting. Beside risk hedging and speculation generators can thus use forward contracts strategically to improve their spot market position in the second stage.

This relation can be shown by second stage marginal revenue with forward contracts, which can be written as:

$$MR_i(s_i, f_i) = P'(S)\,(s_i - f_i) + P(S) \tag{2}$$

An additional unit of electricity sold forward has a positive effect on marginal revenue, i. e. forward contracts shift marginal revenue upwards. If generators aim to use forward contracts for strategy and additionally are risk averse regarding changes in spot market price, both motives call for a *short* position in the derivatives market. Consequently, forward selling leads to an increase in second stage supply and therefore a decrease in spot market price. Generating companies that have already sold much of their production quantity forward, do not have any strong incentives to withhold capacity in the second stage. Market power induced price increase does not have an effect on the already contracted forward quantity. In Figure 3 the impact of changing forward market strategies on wholesale prices in Germany is presented.

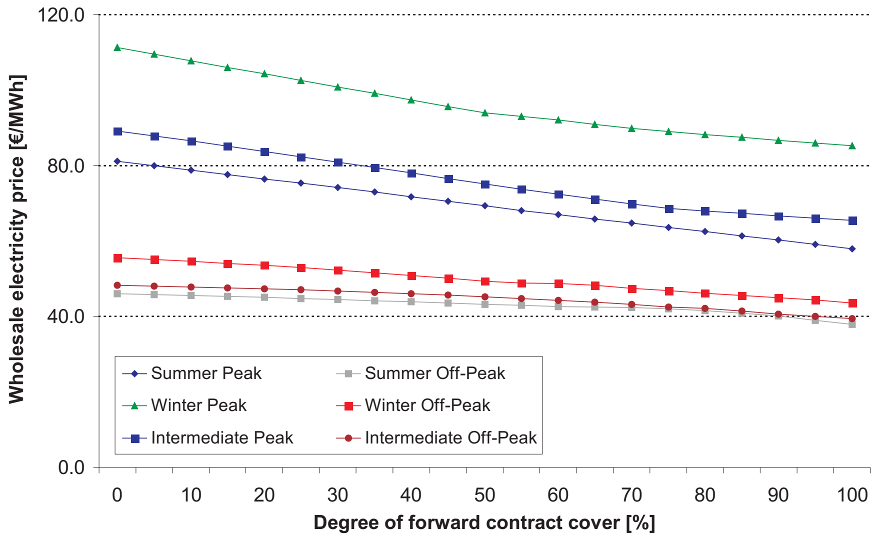


Fig. 3. Wholesale prices in Germany under forward market trading

If generators do not trade forward contracts, i. e. the degree of forward contract cover is 0 %, they play the pure *Cournot* game and have maximum market power potential to influence prices. If otherwise generators are fully contracted, i. e. they realize a degree of forward contract cover of 100 %, companies behave as price takers and the perfectly competitive equilibrium results. In this situation none of the oligopolists have any quantity left for exercising market power in the spot market.

Considering the amount of electricity traded through *day-ahead* spot market contracts at the European Energy Exchange of approximately 85 TWh in the year 2005, it can be concluded that almost 85 % of net electricity demand in Germany has been sold through forward or long-term contracts. Given this degree of forward contract cover, market power potentials are strongly reduced in the German wholesale market. This result is shown in Table 2 by the average Lerner-Index and the changes in wholesale prices due to capacity withholding at a degree of forward contract cover of 85 %.

Table 2
Average Lerner-Index (LI) and change in wholesale prices due to capacity withholding at 85 % degree of forward contract cover

Parameter	Unit	Summer		Winter		Intermediate	
		Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
∅ LI_i	-	0.10	0.07	0.13	0.10	0.11	0.08
Δ P(S)	%	+6.0	+7.9	+2.6	+4.6	+2.9	+4.8
Δ P(S)	€/MWh	+3.50	+2.99	+2.18	+2.01	+1.90	+1.91

As market power potentials in Germany were estimated to result in price increases of +21.4 % (summer off-peak) to +40.2 % (summer peak) without consideration of a forward market, calculated price mark-ups are reduced to +2.6 % (winter peak) to +7.9 % (summer off-peak). Strategic incentives to manipulate spot market price by withholding capacity are thus mitigated by forward trading. Whether oligopolists use forward contracts strategically or for risk hedging purpose, a forward contract cover of approximately 85 % as observed for Germany, enhances competition in the electricity spot market. Due to it strong impact on model results and the estimation of market power potentials, forward trading should be implemented in *ex-ante* analyses of oligopolistic behavior in electricity markets. Market power potentials might be overestimated, if it remains unconsidered.

3.3 Marginal cost functions

As a result of diversifying risk related to energy price development or other fundamental influences, generating companies aim to diversify their power plant portfolios. Particularly large companies like the major players in Germany control highly diversified generation capacities. Therefore, companies' *merit-oder* curves follow a step function with each step representing another generation technology representing different variable production costs. Figure 4 presents the *merit-order* curves of RWE Power AG, E.ON Energie AG, Vattenfall Europe AG, EnBW AG and the aggregated fringe generation capacities in Germany.

For implementing continuously differentiable marginal cost function in a oligopoly model which is formulated as a Mixed Complementarity Problem, the *merit-order* curves have to be approximated. One possibility is to construct strictly increasing polynomials that reflect the characteristics of the *merit-order* curve and additionally guaranty a unique model solution. A second option to model marginal cost functions for technologically diversified electricity

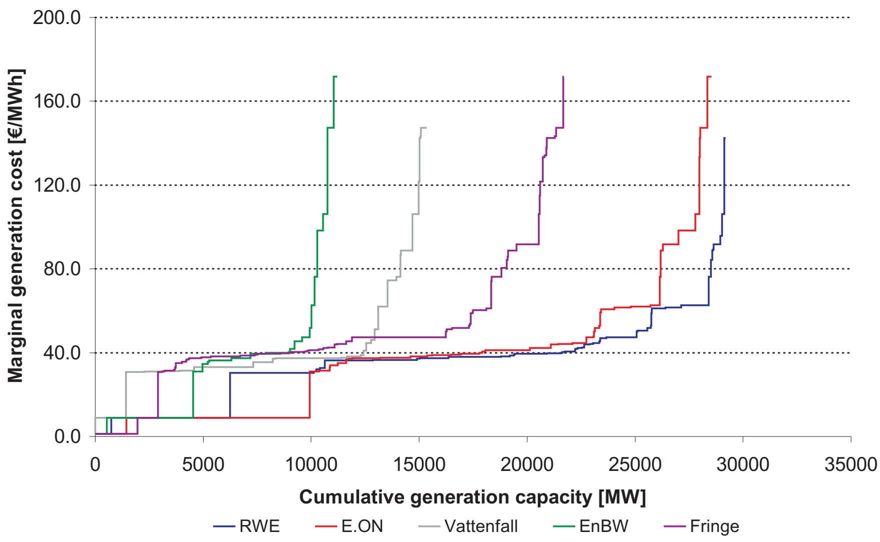


Fig. 4. Merit Order curves of generators and competitive fringe in Germany

generators is to simply use linear functions. For analyzing the impact on results due to different types of marginal cost functions in oligopoly models, both polynomial and linear forms have been considered.

First a polynomial of fourth degree is used to approximate the *merit-order* curves of each player and the competitive fringe. The marginal cost functions are of the form:

$$C_i(s_i) = c_1 s_i^4 + c_2 s_i^3 + c_3 s_i^2 + c_4 s_i + c_5 \tag{3}$$

where c_1 to $c_4 \in]-\infty, \infty[$ and $c_5 \in [0, \infty[$ are estimated by a least squares method algorithm. Generation by firm i, $s_i \in [0, s_i^{\max}]$ is constrained by firm's available capacity $s_i^{\max}$.

Simplifying Eq. 3 by setting $c_1 = c_2 = c_3 = 0$ leads to a linear approximation of the *merit-order* curves:

$$C_i(s_i) = c_4 s_i + c_5 \tag{4}$$

with c_4 and $c_5 \in [0, \infty[$, also estimated by a least square algorithm.

As both types of marginal cost functions can be found in the literature related to the analysis of market power, the following exercise presents how model results can thus be effected. Using the different marginal cost functions as defined above within the multi-reginal two-stage *Cournot* models of oligopolistic behavior in Germany, assuming identical market settings, changes in possible price mark-ups and therefore market power potentials can be observed. Table 3 represents wholesale electricity prices in Germany applying polynomial and linear cost functions.

Table 3
Wholesale prices assuming polynomial and linear marginal cost functions

Price	Unit	Summer		Winter		Intermediate	
		Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
EEX [a]	€/MWh	59.50	36.13	91.30	49.49	67.72	38.34
Polyn. PC [b]	€/MWh	57.89	37.94	85.27	43.53	65.44	39.48
Polyn. CC [c]	€/MWh	81.15	46.07	111.27	55.59	89.17	48.29
Linear PC [b]	€/MWh	71.81	51.13	83.89	60.82	75.84	54.03
Linear CC [c]	€/MWh	92.96	54.79	119.72	66.95	99.66	58.16

[a] Average spot market price
[b] PC: Perfect Competition
[c] CC: Cournot Competition

Because linear marginal cost functions overestimate variable generation costs for base load and for middle load power plants, calculated wholesale prices are to high. It can be observed that the estimated market prices in the competitive equilibrium are approximately 12 to 40 % overestimated. Due to this effect, price mark-ups in the pure *Cournot* equilibrium (no forward trading) differ from possible price mark-ups if polynomial marginal cost functions are used.

3.4 Demand functions

Electricity demand can basically be modeled in form of a load curve representing the sequential changes in system load over time or by load duration curves. In the *Cournot* model applied here, different load situations in the year are reflected by average system load within three time (Summer, Winter, Intermediate) and two load (Peak, Off-Peak) segments. Peak load contains demand values for weekdays from 08:00 a. m. to 08:00 p. m. whereas the Off-Peak load segment contains the hours on weekends and the hours from 08:00 p. m. to 08:00 a. m. on weekdays. Hence, Peak load covers 960 hours and Off-Peak load 1960 hours each time segment, respectively. Demand values are based on data provided by the Union for Co-ordination of Transmission for Electricity (UCTE) and have been scaled to represent regional net electricity demand in each country, whereas prices have been taken from regional power exchanges.

Although electricity demand is often assumed to by totaly price inelastic in the short run, prices curves published by the European Energy Exchange show still some price response. Hence the demand curves implemented in the multi-regional two-stage *Cournot* model are assumed to be price elastic. The values are 0.20 for peak load hours and 0.25 for off-peak Load hours, respectively. Another more technical reason for the assumption of price elastic demand functions can be seen in the nature of *Cournot* models, which can not be solved with totaly inelastic demand functions.

To model price elastic electricity demand in each country and each time and load segment, e. g. linear or isoelastic functions can be used. Demand functions are calibrated by using historical price and quantity data to represent a reference points. In principle, a linear function can be written:

$$P_r(S_r) = a_r - b_r S_r \tag{5}$$

where S_r is the overall quantity supplied by all generators in a country and a specific time and load segment, subsumed by the index r. The parameters a_r and b_r determine the location and the slope of the function. Price elasticity is not constant but changes at each equilibrium price-quantity pair. Linear demand functions are often used in *Cournot* models due to their technical convenience.

Isoelastic demand functions can also be used in oligopoly models. Here price elasticity ε is an exogenous defined constant value. This type of demand function can be formulated as follows:

$$P_r(S_r) = P_r^{\text{ref}} \left(\frac{S_r}{D_r^{\text{ref}}} \right)^{\frac{1}{\varepsilon}} \tag{6}$$

As isoelastic demand functions with low elasticities show strong price increases due to capacity withholding of oligopolistic generators if market conditions are narrow and fringe supply is highly constrained. Market power potentials might thus be overestimated, especially in peak load hours. This effect can be shown by comparing both types of demand functions and its impact on model results. Figure 5 presents wholesale electricity prices in different demand segments at changing forward market strategy of the four large players in Germany.

It can be observed that the use of an isoelastic demand function leads to higher price mark-ups in a pure *Cournot* solution without forward market trading (or assuming a forward contract cover of 0 %) than a model with linear demand functions would predict. Especially in peak times (winter and summer in Fig. 5) the price increase is much stronger. On the other hand, the competitive equilibrium (or assuming a full forward contract cover), differences in wholesale prices are negligible. Moreover, if the model is used to estimate the market power potentials of the four strategic players in Germany taking into account a 85 % degree of forward contract cover, results are quite similar

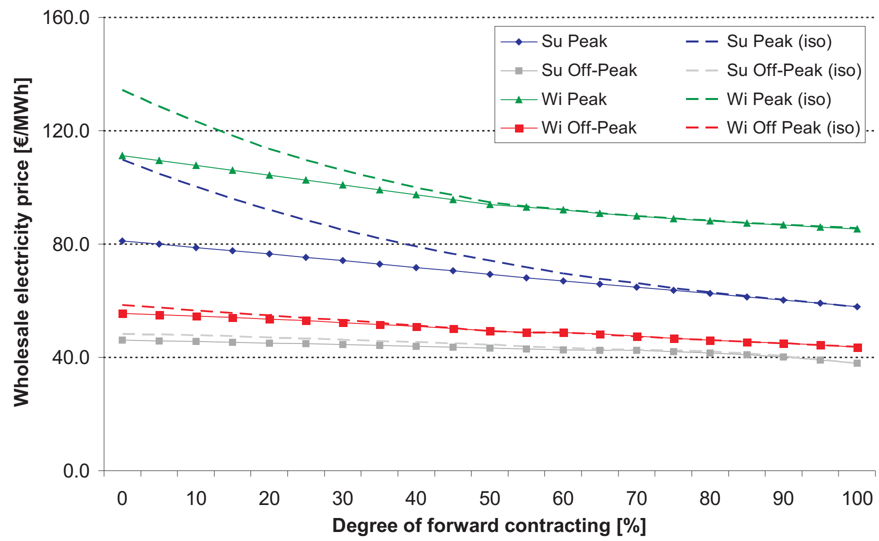


Fig. 5. Wholesale electricity prices assuming different demand functions

with isoelastic and linear demand functions.

3.5 Price elasticity of demand

Related to the type of demand function, another crucial parameter that has a strong impact on model results is the assumed price elasticity of demand. As price elasticity is an exogenously determined parameter that is constant for the entire isoelastic demand functions, it is variable within a linear demand function. For the discussion of the impact different assumptions on price elasticities have on model results, both linear and isoelastic demand functions have been implemented in the multi-regional two-stage *Cournot* model. By defining identical price elasticities of demand, that hold for the price-quantity pair at the reference point (not taking about how to estimate it), influence on market outcome can be shown.

As already described before, the demand functions are calibrated to historical observed market outcomes, and price elasticities of 0.20 in the peak load segments and 0.25 in the off-peak load segments have been assumed. For an *ex-ante* analysis of market power potential, given different structural or institutional market settings like investments in transmission capacity, mergers or divesture and the implementation of forward markets or obligations to commit to long-term delivery, the assumptions on price elasticities have to be kept constant and model results have to be compared.

For the exercise performed here, the assumptions on price elasticity of demand are changed from 0.20 to 0.10 in peak load and from 0.25 to 0.15 in off-peak load times. Table 4 describes the impact of strategic behavior, i. e. withholding capacity on wholesale electricity prices in Germany.

Table 4
Change in wholesale prices and average Lerner-Index (LI) due to capacity withholding assuming different price elasticities

Parameter	Unit	Summer		Winter		Intermediate	
		Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
Δ P(S) [a]	%	+40.2	+21.4	+30.5	+27.7	+36.3	+22.3
∅ LI_i [a]	-	0.44	0.27	0.53	0.34	0.46	0.28
Δ P(S) [b]	%	+95.9	+30.9	+91.7	+48.3	+92.3	+34.7
∅ LI_i [b]	-	0.59	0.37	0.67	0.46	0.62	0.38

[a] Price elasticity, Peak: 0.20, Off-Peak: 0.25
[b] Price elasticity, Peak: 0.10, Off-Peak: 0.15

The assumption on the price elasticity of demand has a significant impact on model results, at least in a *Cournot* model. Again, given the pure *Cournot* solution without forward market trading, prices mark-ups as well as Lerner-Indices are much higher assuming a price elasticity of 0.10 (0.15) than 0.20 (0.25). The price increases nearly triples in some of the peak load segments, whereas the changes in the off-peak hours are much smaller.

As was also shown concerning the type of demand function, different assumptions on price elasticity have a minor impact on model results if observable degree of forward contract cover (85 %) in Germany is taken into account. In this situation market power induced price increases are only 2.5 %-points (intermediate off-peak) to 7.7 %-points (summer peak) higher than assuming the more price elastic demand functions.

4 Conclusions

Game theoretic models for analyzing the impact of oligopolistic behavior in the German electricity market can be sophisticated tools for *ex-ante* evaluation of market power potentials. Given the possibility to comparatively analyze different market setting within one model framework, their application do not depend as much on the quantity and the quality of available market data as the *ex-post* analyses of exercised market power.

However, model results and therefore the estimation of market power potentials strongly depend on the accuracy in considering various structural and institutional aspect of the market. It has been shown, how accuracy in modeling market structure like the implementation of interregional electricity exchange, forward markets and the definition of marginal cost and demand functions can influence estimated market outcome.

It can be concluded, that *Cournot* models can be used to *ex-ante* predict the potentials to exercise market power in electricity market, but that model results have to be carefully interpreted due to their dependency on model assumptions. Market power analyses should therefore take a comprehensive look at real market structures.

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