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Why higher price sensitivity of consumers may increase average prices – an analysis of the European electricity market

Tobias Paulun,* Eberhard Feess† and Reinhard Madlener‡

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Abstract

We develop a model of the European electricity market that allows analyzing the impact of consumers' price sensitivity, defined as the willingness to change energy providers, on equilibrium prices. The model is parameterized with publicly available data on total demand, marginal costs and capacity constraints of power generators. Comparably precise data on the price sensitivity is not available, so that we analyze its impact in a range of simulations. Contrary to apparently straightforward expectations, we find that a higher price sensitivity *increases* average prices under reasonable assumptions. The reason is that, when price sensitivity is high, the most efficient energy providers can attract sufficiently many consumers for operating at full capacity, even when price differences to their less efficient competitors are small. Hence, incentives to reduce prices are higher when the price sensitivity is low. We conclude that the widespread view that high electricity prices can (partially) be attributed to a low willingness of consumers to change their providers is flawed.

Keywords: Electricity Market, Price Sensitivity, Heterogenous Oligopoly, Price Competition, Capacity Constraints

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1. Introduction

In the political discussion on energy markets, it is often argued that power generating firms benefit from a low willingness of consumers to change their electricity providers. The argument is based on the apparently straightforward assumption that a higher price sensitivity would lead to heightened competition, and thereby to lower prices.[1] Based on a parameterizable model of the European electricity market, we analyze the impact of the price sensitivity of customers on equilibrium prices by exploiting publicly available data bases such as the transparency platforms of ENTSO-E[2] and EEX.[3] We simulate the model with different degrees of price sensitivity, and we find that a higher price sensitivity leads to *higher* equilibrium prices in plausible scenarios. Although the quantitative results of our model vary considerably with the assumptions on the price sensitivity, the qualitative result is robust.

Our finding is due to the specificities of the electricity market's supply side. First, for the most efficient power plants in the actual market, capacity constraints are binding in equilibrium, at least in times of high demand. Second, power plants have constant, but highly different marginal costs, and are utilized in an ascending order with respect to their marginal costs (merit order). To see the impact of these features on equilibrium prices, consider a power generator with low marginal costs, thus having high incentives for fully utilizing its capacity. If the price sensitivity is close to zero, then this generator has no incentive at all to undercut its competitors, as it will not be able to attract new consumers anyway. Hence, prices will be high, and this is the negative impact of a low price sensitivity emphasized in the public discussion. If the price sensitivity increases slightly, then attracting new customers becomes profitable. Due to the low price sensitivity, this generator needs to undercut its competitors to a large extent in order to attract a sufficiently large number of individual customers. This leads to lower prices and confirms the intuition of the benefits of price sensitivity. However, suppose now that the price sensitivity becomes more pronounced. Then, even small differences in offer prices are sufficient for attracting new customers, and reducing prices further is unprofitable due to binding capacity constraints. Calibrating our model with the existing data shows that, for a wide and plausible range of parameter constellations, equilibrium offer prices are indeed likely to increase in the price sensitivity.

[1] See for instance European Commission (2007), EUREC (2006) or ERGEG (2007). An overview on the development of actual switching rates in the European Union can be found in European Commission (2009), table 2.1.

[2] http://www.entsoe.net from 11 November 2010.

[3] http://transparency.eex.com from 11 November 2010.

Our model is as simple as possible, but captures those stylized facts of the electricity market that are most important in our context. On the *supply side*, we assume that each firm has multiple power plants with constant, but different marginal costs. Each power plant has capacity constraints given in the period considered, and plants are utilized according to the merit order. The firms considered in parameterizing our model are those actually in the market, and the data used for estimating marginal costs and capacity constraints will be described in section 3.

On the *demand side*, we assume that total demand is exogenously given, and that prices determine solely the division of output among the different electricity suppliers. In particular, we assume that each firm gets a fraction $1/n$ of total demand if prices are identical, and the individual demand is then higher (lower) than average demand if the individual price is below (above) the average price. This model can be considered as a simplified version of a heterogenous oligopoly with price competition, and is convenient for parameterizing the electricity market. If the objective of our paper were purely theoretical, we could easily rationalize a positive impact of consumers' price sensitivity for instance in a Salop-model with capacity constraints and different marginal costs. In such a model, the low cost provider has an incentive to attract many consumers in order to fully utilize its capacities. If the preferences for one supplier are high[4], i. e. if the price sensitivity is low, then the low cost provider needs to largely undercut the less efficient firm, so that a lower price sensitivity will induce lower prices.

The assumption that total demand is given is clearly simplified, but seems to be acceptable for four reasons. First, empirical studies show that total electricity consumption is characterized by a low price elasticity of demand. Second and most importantly, our model is parameterized for a period of one hour, since this is a time domain for which demand and supply data are usually available in publicly accessible databases. For such a short period, total demand can reasonably be considered as exogenously given.[5] Third, we are interested in the impact of the consumers' willingness to switch suppliers due to price differences, and for focussing on this aspect, total demand is less interesting. Fourth, any realistic model of the European electricity market is necessarily

[4]In the Salop-model, this is captured by transportation costs.

[5]Most empirical studies find a substantial difference between short- and long-run elasticities due to the involvement of durable energy-using appliances (see e. g. Stoft, 2002). Lijesen (2007) finds a low value for the real-time price elasticity of total peak demand relative to spot market prices, even when correcting for the possible bias that arises from the fact that not all electricity consumers observe the spot market price; see also Nakajima and Hamori (2010). Accordingly, Halvorsen and Larsen (2001) attribute the low price elasticity of demand mainly to a lack of energy substitutes for electric household appliances.

highly complex, and dropping the assumption that total demand is given would lead to serious formal complications.[6]

In relating our paper to the literature, it first needs to be emphasized that we had to develop a new model of the European electricity market since the existing technical-economic models could not have been used. These models realistically take limited transmission capacities of the European power grid into account, and they are very useful for a rough estimation of interdependencies between different market aspects like power generation and transmission grid planning.[7] Furthermore, they can be utilized for evaluating different policy options, and for estimating the likely development of the European electricity market.[8] However, as a result of taking technical boundary conditions into account, all of these models have in common that they cannot be solved analytically. Moreover, equilibrium configurations cannot be found with reasonable computational effort. Therefore, these kinds of models are not suitable for analyzing fundamental market characteristics as intended in our paper.[9]

There are a few other game-theoretical models analyzing the strategic interdependency in the price setting of power generators. Compared to our paper, these models are more sophisticated concerning the demand function. However, the number of players in all papers we are aware of is far too limited to allow for simulating the conditions on the real European electricity market with reasonable data. In particular, Ferrero et al. (1997) analyze a model with three power generators and a finite number of pricing strategies. Cruz Jr. and Tan (2004) restrict attention to two competitors and linear demand functions, and the paper by Boom (2003), which focuses on investment decisions of power generators, is also restricted to monopoly and duopoly situations. Li et al. (2002) focus on price strategies, but the impact of price sensitivity cannot be analyzed in their model. The reason is the assumption that the power generators sell power to end consumers by using a single central agent, and this agent decides on the division of demand among

[6] Due to the non-continuous cost functions, the Nash Equilibrium of the price game cannot be derived by solving a system of reaction functions. Moreover, we cannot calculate the vector of profit-maximizing prices by Newton's method, so that a new calculation method, described in Appendix A.2, had to be developed.

[7] See e. g. ten Cate and Liejsen (2004), Lise and Hobbs (2005), Leuthold et al. (2008), and Lohwasser and Madlener (2009). A comprehensive overview on data until 2005 is provided by Cosijns and D'haeseleer (2006).

[8] Detailed analyses of potential developments of the European market are published on a regular basis by ETSO (2008) and its predecessor UCTE (2008) as System Adequacy Reports.

[9] Other model types simulate the world-wide energy market, thereby also taking the interdependencies between different market segments into account (see Roques and Sassi, 2007). In order to reduce the complexity, the behavior of individual power generators is not analyzed, so that these models do not fit our purposes.

the competing power generators.

The remainder of our paper is organized as follows: Section 2 presents our simple game-theoretical model that is used for the simulation. Section 3 describes the data. Section 4 explains the procedure for our simulations and the most important results. We conclude in section 5, thereby also discussing the importance of our simplified assumptions.

2. The model

In this section, we develop a simple model that can be parameterized with data for the European electricity market. On the supply side, the model captures two specificities of the electricity market: Each power generator has several power plants to produce with, and these power plants will be used in the order of their marginal costs of electricity provision (merit order). The discontinuity of cost functions arising from the merit order makes it impossible to calculate the equilibrium prices by solving a system of reaction functions. When simulating the market, equilibrium prices will be found by making use of an algorithm explained in the Appendix.

Technology. In our model, there are n firms with m power plants each. Each power plant has constant marginal costs, and marginal costs in power plant j of firm i are denoted by c_i^j. Power plants of each firm can be sorted according to their marginal costs, i.e. $c_i^1 < c_i^2 ... < c_i^m$.

Maximum capacity for generating electricity in power plant j of firm i is denoted as $\overline{y}_i^j$, and total maximum capacity of firm i as $\overline{y}_i \equiv \sum_{j=1}^m \overline{y}_i^j$. For any total amount of power generated, firm i will switch to power plant $k+1$ if and only if capacities of all plants indexed $j \leq k$ are exhausted (merit order). We denote by c_i^k the marginal costs of the last plant utilized. Finally, total capacity in the market is denoted $\overline{\mathbf{y}} \equiv \sum_{i=1}^n \overline{y}_i$.

Demand. For the reasons discussed in the introduction, we assume that total demand for electricity is exogenously given by $\overline{y}^D$. Still, demand for individual providers, y_i^D, depends on the price vector $\mathbf{p} = (p_1, ..., p_n)$. We assume that y_i^D is given by

$$y_i^D = \frac{\overline{y}}{n} - m \cdot f(\Delta_i) \;\; \forall i \tag{1}$$

with $m > 0$ and with $f'(\Delta_i) > 0$. Thereby, $\Delta_i \equiv \sum_{j=1}^n x \cdot (p_i - p_j)^s$ where $x = 1$ (-1) if $p_i - p_j > 0$ $(p_i - p_j < 0)$. Thus, the difference between the price charged by firm i and the price of each competitor is weighted with an exponential price sensitivity s, and then added up over all competitors. This short-cut for individual demand is convenient as it allows analyzing the impact of price sensitivity on equilibrium prices by varying the parameters m and s.[10]

The reason why we do not simply consider the difference between the price charged by firm i and the *average* in the Δ_i-function is that a single (large) price difference to the price charged by one other power generator may be much more important for the customers' awareness about potential cost savings from switching their supplier than several small price differences to a large number of competitors.

Prices and profits. We consider static competition in prices. Depending on the price vector actually chosen and the price sensitivity, we distinguish three regions:

Region 1: The demand for power by provider i (weakly) exceeds its total capacities, i.e. $y_i^D(\underline{\Delta}_i, \mathbf{p}) \geq \overline{y}_i$ (region 1 in figure 1.) Assuming that total capacity is sold, profits in region 1 are[11]

$$\Pi_{i1} = p_i \overline{y}_i - C_i(\overline{y}_i) \tag{2}$$

which yields constant marginal profits of

$$\frac{\partial \Pi_{i1}}{\partial p_i} = \overline{y}_i > 0. \tag{3}$$

Realistically, we assume that prices in region 1 are below average costs, so that *total* profits are negative. In other words, in equilibrium, no firm can increase prices without losing at least one customer.[12]

Region 2: In this region, the individual price p_i is so high that, for a price vector $\mathbf{p}_{-i}$ and a price sensitivity-function $f(\Delta_i)$ given, demand is below the firm's capacity constraint. There is a discontinuous upwards jump in marginal profits when moving from region 1 to region 2 as marginal production costs decrease due to the merit order. The only difference between regions 2a and 2b is that marginal profits are positive in region 2a, but negative in region 2b. In other words, the boundary between regions 2a and 2b is given by the point where the positive price effect is just equilibrated by the

[10] From a theoretical point of view, one would clearly prefer to derive the individual demand functions endogenously from consumer preferences in a heterogenous oligopoly. However, our main purpose is calibrating a realistic model of the European electricity market, and to this end it is useful to work directly with the $f(\Delta_i)$-function (see section 4).

[11] Subscript $i1$ denotes region 1.

[12] The assumption that profits are negative in region 1 holds in any realistic parameterization of the model.

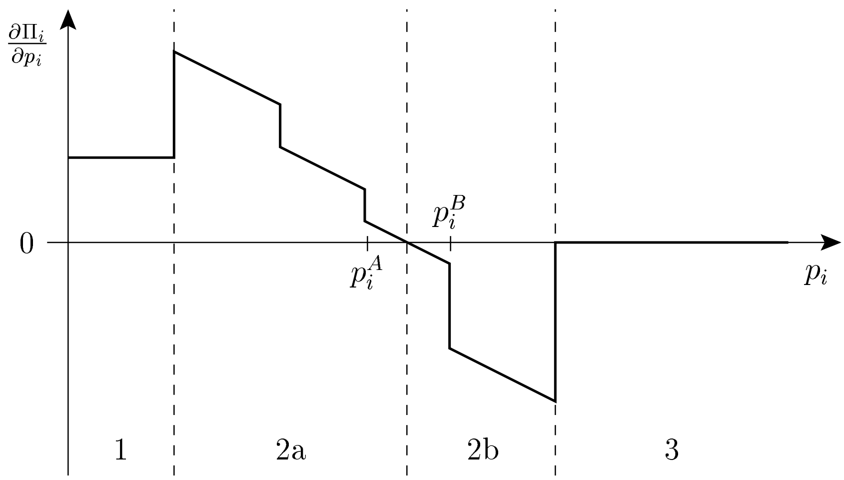

Figure 1: *Marginal profits of power generator i*

negative demand effect.

As demand in region 2 depends on the own price, profits in the continuous parts of the profit function are

$$\Pi_{i2}(\mathbf{p}) = p_i y_i(\mathbf{p}) - C_i(y_i(\mathbf{p})), \tag{4}$$

and marginal profits are thus

$$\frac{\partial \Pi_{i2}(\mathbf{p})}{\partial p_i} = \frac{\partial y_i(\mathbf{p})}{\partial p_i} p_i + y_i - c_i^k \frac{\partial y_i}{\partial p_i}$$

where c_i^k are constant marginal costs of the last power plant used in the merit order. Note that, for realistic parameterization of the model, *total* profits need to switch sign in region 2a. Hence, profits are negative for low prices (close to region 1), but positive for high prices (close to region 2b). This must be the case as total profits are negative in region 1 and decrease in region 2b since this part of region 2 is defined by negative marginal profits. Hence, the profit maximum is in region 2a.

Region 3: Here, prices are so high that no consumer prefers firm i to any other power generator. Then, demand is given by $y_i^D = \max(0, \overline{y}^D - \sum_{j \neq i}^n \overline{y}_j)$ as firm i faces only positive demand when all capacity constraints are reached. In figure 1, we assume that total demand is below total capacities which is realistic for the market considered in our paper. Then, both total and marginal profits are zero.

Due to the non-continuous cost functions, the Nash Equilibrium of the price game cannot be derived by solving a system of reaction functions.[13] As we cannot calculate the vector of profit-maximizing prices by Newton's method, we have developed a new calculation method described in Appendix A.2.

3. Data

Our model provides a framework for simulating the impact of customer price sensitivity on equilibrium offer prices of power generators. For parameterizing the supply side, we need the number of power generators, the maximum generating capacities per power generator, and marginal costs according to the merit order. For the demand side, we need data on total demand within a specific period and, due to a lack of data, we need to introduce assumptions for simulating the price sensitivity of consumers.

For several reasons, we restrict attention to the central-western part of the ENTSO-E-network[14]. Electricity markets in these countries are closely linked in terms of transmission capacities and, even more importantly, that these countries share similar market rules. Since 2007, there are several ongoing projects aiming at a close coupling of national markets through implicit auctions of electricity and transmission capacities. Because of this and due to the fact that European energy politics are currently aiming at improving transmission capacities between countries in this area, it is to be expected that national markets will become more and more a single European market with only small differences between national market prices.[15] Our country data set is shown in table 1.[16]

As discussed in the introduction, total demand can be considered as exogenously given in the short run, whereas electricity demand will clearly react to prices in the long run. Furthermore, our model treats capacities and marginal costs according to the merit order as given, and does therefore not incorporate investment decisions of power generators. For these reasons, the period considered for parameterizing the model needs

[13] Restrictive assumptions, such as one power plant only for each energy provider, would allow standard solutions, but at the expense of deriving realistic results of the impact of price sensitivity on energy prices in the European energy market, which is at the heart of our analysis.

[14] ENTSO-E stands for "European Network of Transmission System Operators for Electricity"; see http://www.entsoe.eu from 12 November, 2010.

[15] http://ec.europa.eu/energy/infrastructure/index_en.htm from 12 November, 2010.

[16] Our model does not account for restrictions given by the electrical transmission network, e. g. multiple market areas connected by limited transmission capacities. This simplification does not adulterate our results since significant differences between electricity wholesale prices in different market areas of the central-western European region are limited to a small number of hours per year. Electricity wholesale prices can be compared through the websites of power exchanges, e. g. APX-Endex (http://www.apxendex.com), European Energy Exchange (http://www.eex.com) and Nord Pool Spot (http://www.nordpoolspot.com).

Table 1: *Number of power generators and power plants per country (simplified) and total demand*

Country	Number of power generators	Number of power plants	Total demand [MWh/h]
Austria	14	98	9,233
Belgium	5	50	13,820
Denmark (West)	5	18	3,552
France	11	196	87,897
Germany	60	440	79,925
Italy	9	91	53,562
Luxembourg	4	7	878
Netherlands	6	57	16,064
Portugal	5	21	9,052
Spain	7	102	43,238
Switzerland	28	57	9,539
Total	154	1137	326,760

to be sufficiently short. Consequently, the model is parameterized for a period of one hour, since this is a time domain for which demand and supply data are usually available in publicly accessible databases. Specifically, we parameterize our model by using the maximum demand on the third Wednesday of December, since this day is commonly used as an indicator for yearly peak load.[17] Furthermore, our data refers to the year 2007, since this is the last year for which a complete and consistent data set is publicly available. Total demand for this day is shown in column 4 of table 1.

Whereas total demand can be taken from the data, there are no studies allowing to quantify the price sensitivity of consumers in a reliable way. Hence, we shall need to consider different scenarios in section 4 in order to get a realistic picture about the impact of the price sensitivity on the equilibrium offer prices.

As to the supply side, the number of power generators, the respective capacity constraints, and the marginal cost of production per power generator are taken from data collected by the Institute of Power Systems and Power Economics (IAEW) at RWTH Aachen University.[18] This data has been derived from publicly available sources during the last years and can be considered as a reasonable approximation for the current status of the European electricity market.

[17] See e. g. UCTE (2008), ETSO (2008).
[18] See `http://www.iaew.rwth-aachen.de` and Paulun (2009).

In most European countries, power plants with a generating capacity of at least 100 MW are listed in public databases.[19] Usually, the year of construction, the dominating primary energy carrier, the available generating capacity, and the owner of the power plants are published. This data is sufficient to calculate the parameters required for parameterizing our model.

First, the ownership structure of the power plants is analyzed and simplified to fit our needs. Following the majority principle, the dominating owner is identified for all power plants that are operated by more than one company. Based on this simplification, power plants operated by companies belonging to, or controlled by, one single entity are all assigned to one power generator who is then seen as a player when solving the model. The so defined number of power generators, and the number of power plants used for the simulation are shown in columns 2 and 3 of table 1, respectively.

Second, the merit order needs to be defined for each power generator. Whereas the capacity of each power plant is publicly available, this is not the case for marginal production costs which are kept confidential. To estimate production costs, we make use of the fact that these are mainly determined by the costs for providing primary energy at the location of the power plant and by the power plant's efficiency factor. Both parameters can be estimated to a reasonable degree of accuracy by using public databases in addition to the data already known per power plant:

- Costs for providing primary energy at a given location depend on prices for the required energy carrier on international markets and on transportation costs. International prices for primary energy carriers such as nuclear fuel, hard coal, lignite, natural gas and oil can be obtained from official statistics.[20] Transportation costs depend on the distance between the power plant and the origin of the primary energy carrier, and on the mode of transportation (e. g. ship or train for hard coal).[21] At IAEW, the geographical position of every power plant has been identified and evaluated in terms of its characteristics.[22] Thereby, total costs for providing primary energy for each power plant can be reasonably approximated.

[19] See in particular http://www.transparency.eex.com and http://en.wikipedia.org/wiki/List_of_power_stations_in_Europe.

[20] A good overview on international markets is provided by the U. S. Energy Information Administration (EIA).

[21] Specific charges (e. g. per kilometer and ton) have been taken from the Bureau of Transportation Statistics (BTS) and from the Research and Innovative Technology Administration (RITA), coordinator of the U. S. Department of Transportation's research programs, see http://www.rita.dot.gov and http://www.bts.gov.

[22] For an overview on the geographical position of major power plants in Germany, see http://www.transparency.eex.com/en/Information/reporting-companies.

- The efficiency factor of a power plant defines the ratio between the amount of electrical energy produced and the amount of primary energy used. This factor depends on the installed generation technology. For example—depending on technical characteristics of the power plant— the efficiency factor of newly constructed gas-fired power plants varies between 42 % and 59 %, whereas the efficiency factor of power plants based on lignite is lower with a range between 35 % and 52 %. Efficiency factors for individual power plants are usually not published, but they can roughly be approximated by the year of construction as the efficiency factors of all generating technologies have been improved over the last decades due to technological changes. The year of construction is publicly available for most power plants, and the range of efficiency factors over time for different generation technologies is shown in table 2.

Table 2: *Range of conversion efficiency for different generation technologies*

Generation technology	Conversion efficiency [%]
Nuclear	31 – 38
Hard coal	30 – 53
Lignite	30 – 52
Natural gas	38 – 59
Oil	35 – 42

Based on the costs for providing energy and the efficiency factors, the marginal costs per MWh electrical energy vary from zero (e. g. run-of-river hydroplants) to approx. € 80 for the power plants listed in table 1. These values will be used in our simulations.

A specific problem for our simulation is caused by renewable energies. For these power plants, the approximation method just described cannot be applied since the efficiency factors of generators based on renewable energy have not been continuously improved over several decades to an extent that is comparable to conventional technologies. And as significant amounts of renewable generating capacities are installed in some European countries, they cannot be neglected in our model.

In handling this problem, it needs to be taken into account that, in some European countries such as Germany, a priority dispatch for feed-in of electricity generated from renewable energies has been defined. In our model, we take care of this by simply assigning zero marginal costs to renewable energies. This results in a must-run situation where the power generator owning the corresponding power plants always generates at least the amount of electricity equal to the capacity constraints. This resembles what happens in reality.

4. Simulation results

As seen in section 3, all parameters except the price sensitivity can reasonably be deduced from the data. Hence, for calculating equilibrium offer prices for the model developed in section 2 we need to consider different price sensitivity-functions in order to get a realistic picture about its impact on the price vector. As for this, we consider both a *linear* and an *exponential* price sensitivity.

We start by assuming a linear price sensitivity. In our model, this means that $s = 1$, so that the price sensitivity depends only on m. Table 3 and figure 2 show the bandwidth and the average equilibrium prices of all power generators in the range $1 \leq m \leq 100$.

Table 3: *Offer prices at equilibrium depending on linear price sensitivity* m *(*$s = 1$*)*

Price sensitivity	Prices [€/MWh]		
m	Minimum	Maximum	Average
1	101.81	202.75	180.30
2	53.80	107.14	95.92
3	38.60	76.89	69.40
4	30.98	61.71	56.10
5	26.81	53.65	48.89
6	24.99	53.65	46.03
7	23.55	53.65	43.71
8	23.63	53.65	42.30
9	23.99	53.65	41.43
10	24.20	53.65	40.91
20	25.17	53.65	42.08
50	32.83	53.65	45.91
100	39.75	53.65	49.32

The figure and the table illustrate that, with the parameterization from section 3, both the price dispersion and average prices are initially decreasing in the price sensitivity. This is the natural case one would expect expressing that a higher impact of prices on demand leads to higher competition, and thereby do a downward shift of the equilibrium price vector.

Note, however that the minimum offer price any power generator is willing to set

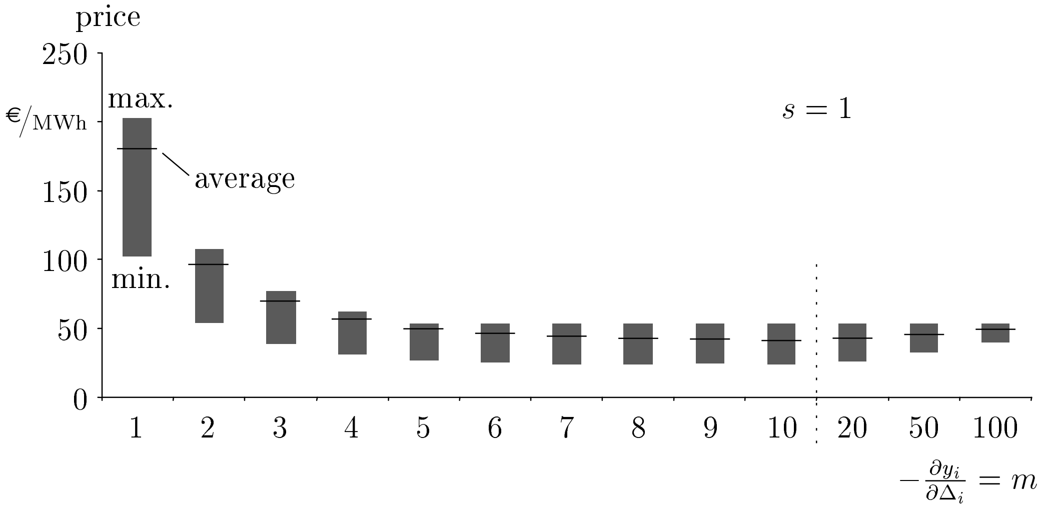

Figure 2: *Offer prices at equilibrium depending on linear price sensitivity* m *(*$s = 1$*)*

is equal to its marginal costs. This implies that the highest price in the price vector (i. e. the maximum in table 3) keeps constant if the price sensitivity—and hence the competitive pressure on inefficient power generating companies—is so high that at least one company offers at its marginal cost price. Consequently, table 3 shows that the highest offer price is always given by 53.65 €/MWh for all $m \geq 5$.

The lowest price in the price spectrum (i. e. the minimum in table 3) decreases for small price sensitivities, but increases for price sensitivities $m > 6$. The reason why the minimum price is initially decreasing in m is the following: If the price sensitivity is too small, then even power generators with large generating capacities and low variable production costs have no incentive to attract many new customers by underbidding their competitors, as this would require very low offer prices. If the price sensitivity increases, then attracting new customers becomes worthwhile. Still, the price sensitivity is relatively low in this range, so that large price differences between the different power generators occur. This leads to a decline in the lowest price charged by the most efficient power generator. However, if the price sensitivity increases further, then the efficient power generators can attract new customers even by only marginally underbidding their competitor's offer prices. And as the efficient power generators face binding capacity constraints, the lowest price charged is then increasing in the price sensitivity. As a consequence, the average price in the total electricity market considered is first decreasing, but then increasing in the price sensitivity of consumers.

As expected, the results become more pronounced when we allow for an exponential price sensitivity. Table 4 and figure 3 show the results for $m = 2$ and an increasing exponential price sensitivity expressed by s.

Table 4: *Offer prices at equilibrium depending on exponential price sensitivity s ($m = 2$)*

Price sensitivity	Prices [€/MWh]		
s	Minimum	Maximum	Average
1	53.80	107.14	95.92
2	22.29	53.65	41.01
3	41.69	53.65	48.45
4	46.54	53.65	50.52
5	48.57	53.65	51.43
6	49.67	53.65	51.95
7	50.34	53.65	52.28
8	50.78	53.65	52.50
9	51.09	53.65	52.64
10	51.31	53.65	52.75

As for the case with a linear price sensitivity, the maximum offer price remains constant at 53.65 €/MWh when the price sensitivity is sufficiently high. This boundary value is given by the variable production costs of the available power plants. Again for reasons similar to the case with a linear price sensitivity, the minimum price is first decreasing and then increasing in the price sensitivity. The main difference is that, with an exponential price sensitivity, the switching point where both minimum and average prices is now already reached for $s \geq 2$. This is due to the fact that for high values of s, offer prices just below prices of competitors are sufficient to obtain a large number of customers. Since the maximum available generating capacity is limited, further underbidding of competitors is not reasonable. As a consequence, with increasing price sensitivities, the offer prices of all power generators converge against the variable production costs of the most expensive power plant utilized for generation. Thus, some customers need to pay more and the consumer surplus declines if the average price sensitivity increases.

We now turn to the demand situation with exponential price sensitivtiy.[23] Qualitatively, this case just confirms the linear case that a higher price sensitivity leads initially to lower average prices, but will raise average prices when poaching customers from competitors becomes too easy. Of course, these results when varying s are robust for other values of m.

[23]Based on data from an electricity provider in Austria, Madlener et al. (2010) indeed find that the price sensitivity is disproportionately increasing in price differences.

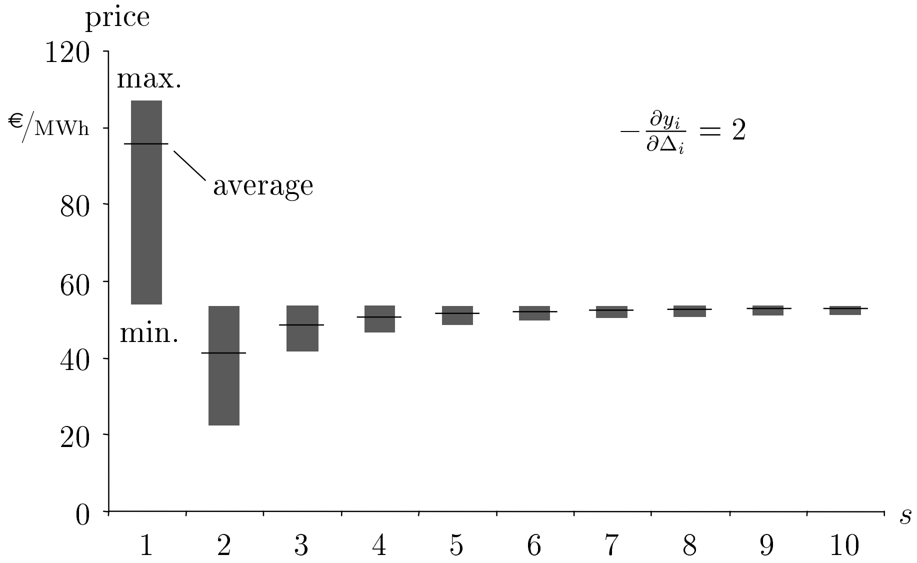

Figure 3: *Offer prices at equilibrium depending on exponential price sensitivity* s *(*$m = 2$*)*

For our examples considered with $s = 1$ (see figure 2) and $m = 2$ (see figure 3), the average equilibrium offer prices decline sharply in the price sensitivity for very low values, and increase afterwards to levels of around 50 €/MWh. In the real European electricity market, prices of around 60 €/MWh are observed on the wholesale market during peak load hours which have been considered for parameterization of the model (cf. section 3).

Of course, we could generate results closer to the prices actually observed by considering somewhat more complicated price sensitivity functions, but this would, in our view, be senseless due to the fact that our stylized assumptions are not suitable for a quantitative forcast of prices. We do believe, however, that they are sufficiently realistic for identifying the qualitative impact of the price sensitivity on prices.

5. Conclusion

We develop a model of the European electricity market allowing to study the impact of the degree of price sensitivity of consumers on equilibrium prices. The publicly available data allows us to parameterize the supply side of the model relatively accurately. The key factors for the supply side are the set of power generators, and the marginal costs and capacity constraints of their different power plants. On the demand side, we treat total demand as exogenously given, and due to data availability, we use the maximum demand on the third Wednesday of December 2007, since this day is commonly used as an indicator for yearly peak load.

Whereas supply conditions and total demand can be taken from the data, sufficiently precise information on the price sensitivity is not available. Hence, we have performed many simulations with linear and exponential price sensitivities, and we find a qualitatively very robust result: Up to some critical level which depends crucially on the cost functions and the capacity constraints, higher price sensitivity reduces average prices. Afterwards, however, higher price sensitivity leads to higher average prices due to the fact that the most efficient power generators can operate at full capacity even with prices relatively close to those of less efficient electricity providers.

Compared to other approaches, an important advantage of our framework is that the supply structure is modeled in a rather disaggregated way. Accounting for different power generators facing capacity constraints, and operating with several power plants with different marginal costs, are indispensable features for analyzing the impact of the price sensitivity on equilibrium prices, and we have sufficient decent information for parameterizing the model in a reasonable way. Our model of the supply side allows estimating the merit order of each single firm actually operating in the market, and this leads to a rich picture of the electricity market.

As for any model of the electricity market, however, we are aware that our model is highly stylized and simplified in several respects. One essential premise for our findings is that total demand is assumed as exogenously given, and hence completely price inelastic. Although this may come close to reality in the short period used to parameterize our model, power generators will account for the long-term effects on total demand when setting their prices, and this leads to countervailing incentives which mitigate the detrimental impact of higher price sensitivity. In this respect, we view our model as one for analyzing the impact of the willingness to change providers on the equilibrium price configuration, for any total price elasticity of demand given.

Other serious simplifications include that limited transmission capacities between market areas are neglected, and that the calculation of the variable costs for the different plants of power generators ignores factors such as risk premiums. Finally, we introduce the degree of price sensitivity without any reference to the data. Estimating the price sensitivity empirically requires to account for the manifold possibilities of purchasing electricity such as short- and long-term trading on the wholesale market or individualized full supply contracts. Because of this, empirical studies have been limited to certain customer groups, e. g. household or industrial customers. Although the large number of studies analyzing price sensitivity of customers provides a good overview on realistic figures, a more complex model than the model presented in this paper is needed in order to take individual preferences of customer groups into account.

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A. Appendix

A.1. Limits of Newton's method

In principle, zero points of non-linear functions can be determined by means of Newton's well-known method. This method can be applied to single- and multi-dimensional functions and is based on an iterative search for zero points and a linearization of the function under consideration. In order to determine zero points of the profit function presented in section 2, a starting point $\vec{p}^0$ with offer prices needs to be defined at first[24].

In every iteration, the partial derivatives of function $\mathrm{f}(\vec{p})$ are calculated as shown in (5), and a vector with correction values $\vec{x}^k$ is computed corresponding to (6).

$$\mathrm{f}'(\vec{p}) = \begin{pmatrix} \frac{\partial \mathrm{f}_1}{\partial p_1} & \frac{\partial \mathrm{f}_1}{\partial p_2} & \cdots & \frac{\partial \mathrm{f}_1}{\partial p_n} \\ \frac{\partial \mathrm{f}_2}{\partial p_1} & \frac{\partial \mathrm{f}_2}{\partial p_2} & \cdots & \frac{\partial \mathrm{f}_2}{\partial p_n} \\ \vdots & \vdots & \ddots & \vdots \\ \frac{\partial \mathrm{f}_n}{\partial p_1} & \frac{\partial \mathrm{f}_n}{\partial p_2} & \cdots & \frac{\partial \mathrm{f}_n}{\partial p_n} \end{pmatrix} \tag{5}$$

$$\mathrm{f}'(\vec{p}^0) \cdot \vec{x}^k = -\mathrm{f}(\vec{p}^0) \tag{6}$$

[24] Superscript indices indicate iteration numbers.

Once the vector $\vec{x}^k$ is known, an improved estimation for the zero point follows from (7). The iteration process is terminated if the value of function f is smaller than a boundary value, since the actual value of $\vec{p}^k$ is close enough to a zero point of the function.

$$\vec{p}^{k+1} = \vec{p}^k + \vec{x}^k \tag{7}$$

Sometimes Newton's method does not converge against a zero point of the function under consideration. In some of those cases, the distance to the real zero point increases beyond any boundaries. In other cases, the method starts to oscillate, meaning that the absolute distance between $\vec{p}^k$ and the real zero point stays constant over several iterations. Reasons for such a behavior may be inappropriate values for the starting vector $\vec{p}^0$ or characteristics of the function f itself. When Newton's method is applied to function Π_i, the jump discontinuities of this function are particularly critical, as shown in figure 4.

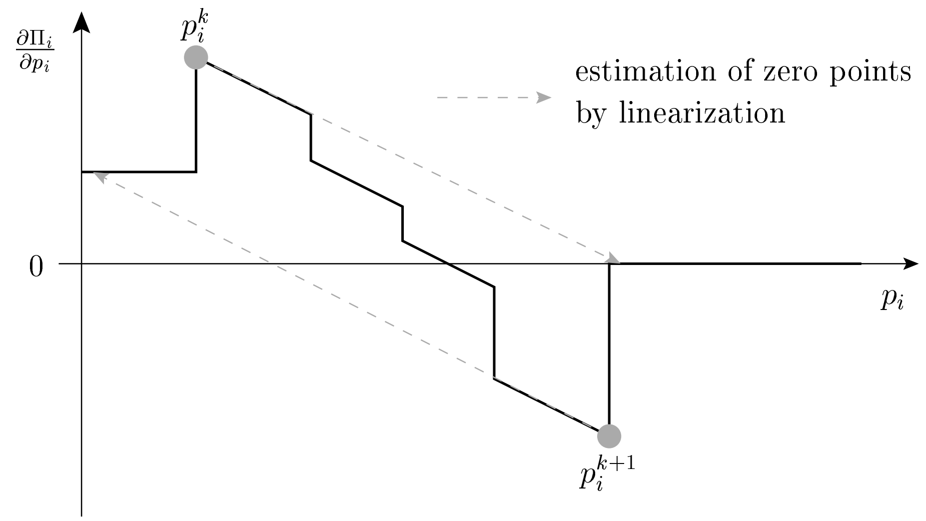

Figure 4: *Iterative search for zero points using Newton's method*

Newton's method linearises function f at point $\vec{p}^k$, which is given by the estimation of the optimal offer prices in iteration k. On the basis of this linearization, a new estimate for the offer prices is calculated. Due to the jump discontinuities in function f, the exact zero point is usually over- or underestimated. If the new estimate lies outside of regions 2a and 2b in figure 1, the value needs to be corrected inside the iteration procedure. Yet for $s = 1$, the gradient of f at the new estimate $\vec{p}^{k+1}$ is equal to the gradient in the iteration before. Thus the exact value of the optimal offer prices is over-or underestimated in the next iteration again. Therefore, after implausible estimates have been corrected again, $\vec{p}^{k+2} = \vec{p}^{k}$ applies. Thus Newton's method oscillates around the zero point that should be identified. For $s > 1$, the cycles of the method are different, since the gradient of the derivative of the profit function is not constant in regions 2a and 2b. However, jump discontinuities result in a divergence of Newton's method in such cases as well.

A.2. Newly developed iteration method

In order to develop a method for detecting zero points of the function under consideration, the behavior of a power generator is analyzed at first. Specifically, it is important how the optimal offer price p_i^* of a given power generator changes if competitors increase or decrease their offer prices.

According to section 2, the amount of power sold y_i increases with increasing offer prices p_j for $j \neq i$, given that power generator i has enough generating capacities to supply the additional load. Since the zero point of the profit function's derivative corresponding to the maximum functional value of Π (cf. figure 1) always lies between region 2a and region 2b, offer prices inside section 1 do not maximize the profit of the power generator and thus do not need to be considered any further in the following.

Therefore, the amount of power sold by power generator i, who sets the optimal offer price p_i^* for given offer prices of all competitors increases, if competitors increase their offer prices. This may lead to higher marginal costs of production for generator i, if the power plant with the highest variable costs is already used at full capacity. As a consequence, the offer price which was optimal before competitors increased their prices, does now lie below marginal costs of production and thus does not maximize the generator's profit. In figure 1, this modification corresponds to a shift of the function to the right, since the old offer price p_i^* lies now inside region 2a.

Thus a power generator always increases his offer prices if the marginal production costs have increased due to an increase of competitor's offer prices. This coherence can be used for determining the zero points of the profit function's derivative in an iterative manner. In this iteration method, the zero points are identified by approaching the exact value from the left. For this, $p_i^0 = 0$ is chosen as a starting value for all offer prices. Afterwards, the optimal offer price p_i^{*1} is calculated for every power generator, given that all competitors stick to their initial offer prices. Since $p_i^{*1} \geq p_i^0$ applies for all power generators, this procedure can be repeated until no power generator has an incentive to increase his offer price any further. The resulting vector $\vec{p}^*$ is an equilibrium of the model.

Figure 5 gives an overview of the newly developed iteration method.

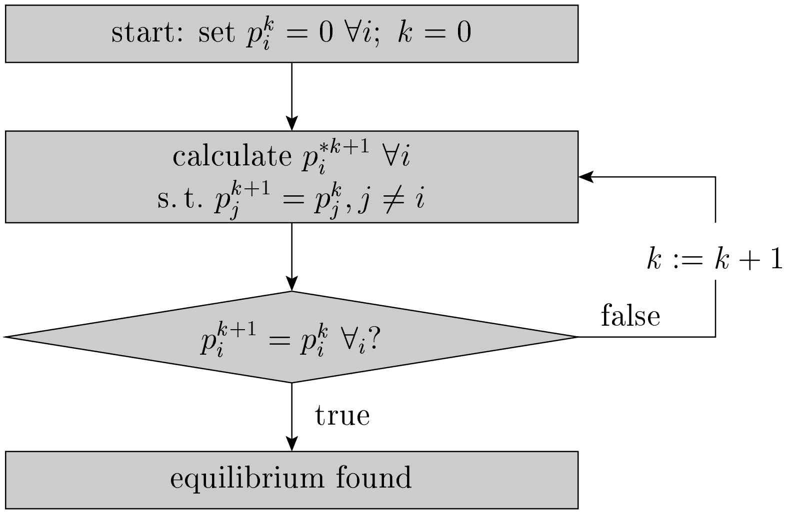

Figure 5: *Iterative search for zero points by successive adjustment of the working point*

If the offer prices of all competitors are given, the optimal offer price p_i^* of a power generator can be determined by calculating the function values at the jump discontinuities of the profit function's derivative. The zero point to be identified is positioned between the discontinuity $p_{i,1}$, with the highest value p_i and a positive function value, and the discontinuity $p_{i,2}$, with the lowest value p_i and a negative function value. In case $s = 1$, the zero point between $p_{i,1}$ and $p_{i,2}$ can be computed analytically. For $s \neq 1$, Newton's method is used for determining the exact value of the zero point inside this range, since the variable costs of production are constant in this area and no jump discontinuities need to be considered.

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