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An Econometric Analysis of Utilities' Fuel Choice

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Firing the Furnace? –
An Econometric Analysis of Utilities' Fuel Choice

Harald Tauchmann*

Abstract

This paper attempts to predict the potential effects of CO_2 emissions trading on fuel choice in the German electric power industry. By analyzing panel data (1968–1998) of major utilities, we show that the fuel mix of electric utilities is price inelastic. As a consequence, the implementation of a CO_2 trading scheme will, if anything, only slightly induce interfuel substitution. Accordingly, low-carbon fuels will hardly replace lignite and hard coal through CO_2 emissions trading, as long as abatement targets are not extremely ambitious. However, one cannot rule out that fuel prices may become more important for the utilities' fuel mix as a result of deregulation in the German power sector.

JEL Classification: Q42, Q53

Keywords: fuel mix, high-carbon fuels, CO_2 emissions trading

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1 Introduction

It is widely accepted that CO_2 emissions are a potential threat to the world's climate. While the debate on the appropriate instruments to reduce CO_2 emissions continues, the European Union has already agreed on implementing a CO_2 trading scheme. Permit trading is a cost-efficient and, therefore, preferable policy instrument from an economist's perspective. Yet, there are serious concerns about the effects such a trading scheme might have on energy markets: hard coal and lignite, which are responsible for roughly half of current German electricity generation, may lose their competitiveness as a consequence of CO_2 emissions trading.

Whether or not the use of coal and lignite is going to be affected by CO_2 abatement is mainly determined by two factors: by the abatement target and the price sensitivity of the utilities' fuel demand. Obviously, the overall number of CO_2 allowances will determine the permit price and increase the costs of the various fuels proportionally to their carbon content. As the second decisive factor, the sensitivity of the utilities' fuel demand with respect to fuel costs will finally determine the genuine pressure on fuels due to CO_2 trading. While the amount of permits being issued is purely a political matter, the sensitivity of utilities to the price of fuel is a matter of factor demand and, ultimately, a matter of production technology. This paper attempts to estimate fuel price sensitivity in order to contribute to the assessment of the consequences of future CO_2 reduction policies.

The effects that the fuel prices have on the fuel mix and interfuel substitution are a wellestablished topic in the empirical literature. The majority of these papers, such as those written by Griffin (1977), Pindyck (1979), Jones (1996), and Söderholm (2000), rely on highly aggregated data at the industry or national level. Such approaches, however, appear to be questionable, since fuel mix decisions, involving investment and factor demand decisions, are typically made at the firm-level. Using aggregate data may not allow for modelling these complex decision problems at the micro-level; nevertheless, although micro-econometric analyses of fuel-mix decisions are not absent from the literature, almost all of these micro-level studies use data from US electric utilities, see e.g. Atkinson & Halvorsen (1976), and Seifi & McDonald (1986). Studies using non-US firm-level data, such as Bousquet & Ivaldi (1998), are rare in this field. To this author's best knowledge, only Tauchmann (2002) has analyzed German firm-level data. While Tauchmann (2002) dealt with data predominantly originating from small firms, this article focuses on the few major German utilities that represent the electricity sector well.

In order to predict the effects of future price changes induced by emissions trading, we must assume that firms in the electricity sector will not react to them in any other way than they have reacted to any past fuel prices changes. Yet, the electricity-generating sector in Germany has experienced various kinds of regulatory interventions until recently. Therefore, this paper has to investigate whether price-induced interfuel substitution can be identified in historic data at all. Additionally, we test whether or not changes in the regulatory framework have directly affected the fuel mix in this sector. This question is particularly interesting since future CO_2 emissions trading will operate in an increasingly deregulated electricity market.

The following section describes the relevant institutional and regulatory framework. Section 3 presents the model and its econometric specification. Section 4 describes the data, while Section 5 discusses the estimation results. Finally, conclusions are drawn in Section 6.

2 The Regulatory Framework

The electric power-generating sector is one of the most extensively regulated German industries. This can partially be explained by its history. When a comprehensive national power system was installed in the late 19th and early 20th centuries, regional monopolies were granted to utilities. By guaranteing monopoly profits, utilities were motivated to bear the enormous investments in the required infrastructure. On the other hand, prices were regulated and supervised, and utilities were obliged to provide power to any consumer within a monopoly region. Even more relevant in the context of this study is that not only the supply of electricity but also the production was subjected to regulatory intervention.

Two reasons explain the energy mix in power generation attracted political intervention. Firstly, German hard coal had been loosing its competitiveness on the world market since the late 1950s. Secondly, after the oil crises in 1973 and 1979 oil supply was regarded as unreliable. Consequently, increasing the use of hard coal in power generation became a corner stone of German and European energy policy, see Söderholm (1998). Since 1965, burning domestic hard coal has been subsidized. In 1974, the construction of medium and large power plants burning gas or oil was subjected to official approval, and the use of gas in existing plants was restricted. Finally, in 1974, and again in 1980, the German electricity producers were forced to burn fixed quantities of hard coal, for which they were compensated by an extra tax on electric power, the so-called "Kohlepfennig". Additionally, the employment of cheap coal from abroad was restricted. Parallel to the promotion of domestic coal, a nuclear power program started in the 1960s. Research in nuclear energy technology was heavily subsidized and numerous sites were built. Due to increasing influence of the anti-nuclear movement, the construction of new nuclear power plants stopped. In fact, the last reactor went into service in 1989.

In the 1990s, many regulations in power generation were relaxed or abandoned, others were introduced. In 1994, the "Kohlepfennig" was dismissed by the German supreme court. Even though German hard coal would still be subsidized, the scale of subsides had substantially been reduced. The restrictions on the use of gas and oil were abolished. The use of renewable energy has increasingly been promoted since the beginning of the 1990s. On the other hand, the German government had been trying to phaseout nuclear power since 1998. After intense negotiations in 2000 the nuclear power industry agreed to phaseout of nuclear power by 2030 at the latest. Finally, the EU agreed to liberalize the European electricity market in 1996. This general deregulation program is likely to at least indirectly affect fuel use decision of electricity generating firms, see Söderholm (1999).

3 Modelling Fuel Mix in Power Generation

Most econometric papers analyze the fuel mix in electric power generation on the basis of cost or profit function approaches, the standard tools of applied production analysis, see e.g. Cowing & Smith (1978) or Considine (2000). Estimation results are often provided in terms of structural parameters, such as elasticities of substitution.[1] For several reasons, though, one may doubt whether the structure of the data generating process is correctly specified by standard profit maximizing or cost minimizing models. First of all, since electricity markets are often highly regulated, the firms' optimization problem is subject to many more restrictions than those given by market prices and production technology. But even the assumption of given market prices may not be appropriate: for instance, utilities burning lignite often operate their own mines.

Conventional specifications of the underlying production technology may also be inappropriate. Firstly, static models do not catch specific features of the energy sector. Since electricity can hardly be stored, the utility must meet the instantaneous demand for power at any point in time at minimal costs. This issue has been intensely addressed

[1]One can dispute whether elasticities of substitution obtained from estimating standard – e.g. translog – models are informative measures at all. Frondel & Schmidt (2002) show that such estimates are almost exclusively determined by the sample means of cost-shares.

in energy science research with particular focus on daily and yearly fluctuations in power demand. From an econometric point of view, the identification of this complex production structure requires a quasi-continuous observation of the key variables or at least at many points in time. Yet, from the typically available quarterly, yearly, and snapshot cross-section data, it seems to be impossible to identify the true structure of the data generating process.[2]

3.1 The Modelling Strategy

Fuel substitution operates through quite different pathways. In the long run, the fuel mix is mainly determined by investments in different production techniques that use specific types of energy inputs. But even conditionally on existing production capacities electricity producers can still adjust their energy demand patterns. Multi-fuel burning boilers, for example, offer a very direct way of replacing one type of fuel with another. Mono-fuel plants also allow for substitution too, because a utility can choose the activity level for different mono-fuel plants that burn different fuel types. These distinct aspects could generally be integrated in a structural production model; however, the data requirements are likely to be very high, and strong restrictions may be necessary to identify the structural parameters.

Instead of a structural model, this study pursues a robust and simple non-structural approach to identify effects of price changes and regulatory interventions on the fuel mix in German electric power generation. For simplicity, we assume that each type of primary fuel is associated with a particular generation technique and use both terms as synonyms. Obviously, this does not apply to multi-fuel burners. We cope with this exceptional case by modelling "multi-fuel" as a separate generation technique, in addition to fuel-specific ones.

Our model addresses the long-term as well as the short-term dimension of utilities' fuel choice. Accordingly, an electricity producer's fuel mix decision is described as a two stage choice problem: In the first stage a long-term investment decision must be made about the capacities for each available generation technique[3]. In the second

[2] Stewart (1979) addresses this issue indirectly by arguing in favor of using multi-dimensional output measures for electric utilities.

[3] With respect to investment, two further aspects might be distinguished: firstly, the discrete decision about the pattern of techniques being used, and secondly the decision about the size of capacities, given the chosen pattern. In fact, only a few papers have modelled discrete fuel choice, e.g. Joskow & Mishkin (1977) and Ellis & Zimmerman (1982) an even smaller number has modelled both aspects, see Seifi & McDonald (1988) and Tauchmann (2000). Here, a somewhat different

stage, the amount of electricity actually generated by existing generation capacities must be determined, representing a short-term production decision. We firstly focus on the long-term dimension: While a structural modelling approach would lead to a rather complex system of equations, we formulate a non-structural reduced form representation that explains the optimal capacities as functions of exogenous and predetermined variables:

$$c_{lit} = \alpha_{li}^{cap} + \beta_l' x_{it'} + \upsilon_{lit} \qquad l = 1, \ldots, L. \tag{1}$$

The index l denotes the respective generation technique, which also reflects a certain fuel type; i stands for utility i, and index t indicates time. The parameter α_{li}^{cap} represents a utility-specific time-invariant effect, υ_{lit} the usual error term. c_{lit} denotes the fuel-specific generation capacities and $x_{it'}$ the vector of explanatory variables. It is assumed that the utilities adjust their capacities to changes in the exogenous variables with some delay. Therefore, lagged values of the exogenous variables enter $x_{it'}$, where $t' < t$ holds. Besides fuel prices, for instance, the demand for electricity enters $x_{it'}$. Additionally, time-specific indicators are included to capture changes in the regulatory framework. All explanatory variables are discussed in detail in Section 4.

3.1.1 Stationarity

Standard unit-root tests reveal that neither the dependent nor the explanatory variables are stationary, while first differences prove to be. In addition, joint panel unit root tests, see Maddala & Wu (1999), cannot reject the null-hypothesis of these series being jointly non-stationary for all utilities. In contrast, the same hypotheses are always rejected in the case of first differences. Because of these test results, the model is formulated in terms of first differences rather than in levels[4]:

$$\Delta c_{lit} = \widetilde{\alpha}_{li}^{cap} + \beta_l' \Delta x_{it'} + \widetilde{\upsilon}_{lit} \qquad l = 1, \ldots, L. \tag{2}$$

By taking this approach, we hope to avoid "spurious regression", which might cause misleading estimation results. In order to allow for utility-specific drifts, individual effects[5] are retained in the reformulated model (2).

approach is taken by explaining changes in capacities rather than capacities themselves, which may reflect either aspects of investment. See Section 3.1.3 for details.

[4]This approach is not free from measurement error problems, which are also a potential cause for bias and to be present in the data. The problem gets more severe if first differences or fixed effects are used, see Griliches & Hausman (1986). However, this does not apply in the case of autocorrelated measurement error, see Bound & Krueger (1991).

[5]Combining first differences with fixed effects may cause problems, since this removes a large share

3.1.2 Time Structure of Regressors

It is obvious that electricity-generating capacities react to changes in fuel prices with some delay. Because of long planning and construction periods, which are typical for power plants, a lag of just one year is certainly too short. Furthermore, the very recent past might be of very limited relevance, since firms cannot adjust their ongoing investments projects immediately. To allow for such a time lag structure within a "distributed lag" framework, the log-normal density serves as weighting function. In contrast, geometrically distributed lags, the most common approach, force the effect of changes in the explanatory variables to constantly fade away over time. Depending on the parameters μ_l and σ_l of the log-normal distribution, which are subject to estimation, the choice of a log-normal weighting function ω_{lj} allows for small weights on the recent past as well as the far past, while heavy weights can be allocated to the periods in between. Correspondingly, (2) can be reformulated as

$$\Delta c_{lit} = \widetilde{\alpha}_{li}^{cap} + \beta_l' \widetilde{x}_{lit} + \widetilde{v}_{lit} \qquad \textit{with} \quad \widetilde{x}_{lit} = \sum_{j=1}^{J} \omega_{lj} \left(j, \mu_l, \sigma_l \right) \Delta x_{i(t-j)}. \tag{3}$$

Obviously, the loss of many observations through the inclusion of numerous lags necessitates to restrict the number of lags. The actually chosen value, $J = 9$, represents a compromise of theory and data requirements.

3.1.3 A Discrete Model of Capacity Change

Besides non-stationarity, the data show another characteristic feature. Capacities change rarely, but spasmodically, and thus exhibit a discrete as well as continuous aspect of capacity adjustment. The discrete decision whether to extend, reduce, or leave capacities unchanged can be captured by a standard ordered choice model. Correspondingly, the following notation is chosen:

$$\Delta \widetilde{c}_{lit} = \begin{cases} 1 & \textit{if} \quad \Delta c_{lit} > 0 \\ 0 & \textit{if} \quad \Delta c_{lit} = 0 \\ -1 & \textit{if} \quad \Delta c_{lit} < 0. \end{cases} \tag{4}$$

Assuming the $\widetilde{v}_{lit}$ to be normally distributed, the likelihood function for the resulting

of variation, which in turn cannot be employed for the identification of causal effects. In an untypical panel, i.e large T but small N, as it is in our case, this problem is less severe than for typical panels.

ordered probit model can be written as follows:

$$
\begin{aligned}
&\Pr\left(\Delta\widetilde{c}_{lit}|\widetilde{x}_{lit}, c_{li(t-1)} > 0\right) = \\
&\quad \left(\Phi\left(-\widetilde{\alpha}_{li}^{cap} - \beta_l'\widetilde{x}_{lit}\right)\right)^{\frac{1}{2}\left((\Delta\widetilde{c}_{lit})^2 - \Delta\widetilde{c}_{lit}\right)} * \\
&\quad \left(\Phi\left(\theta_l - \widetilde{\alpha}_{li}^{cap} - \beta_l'\widetilde{x}_{lit}\right) - \Phi\left(-\widetilde{\alpha}_{li}^{cap} - \beta_l'\widetilde{x}_{lit}\right)\right)^{\left(1-(\Delta\widetilde{c}_{lit})^2\right)} * \\
&\quad \left(1 - \Phi\left(\theta_l - \widetilde{\alpha}_{li}^{cap} - \beta_l'\widetilde{x}_{lit}\right)\right)^{\frac{1}{2}\left((\Delta\widetilde{c}_{lit})^2 + \Delta\widetilde{c}_{lit}\right)}.
\end{aligned} \tag{5}
$$

The likelihood function explains the probability that an extension, a reduction or an unchanged capacity type l is observed. Threshold parameters are denoted by θ_l. Individual effects $\widetilde{\alpha}_{li}^{cap}$ are specified as fixed, rather than random. The "incidental parameters problem" is irrelevant in our context, since N is very small in comparison with T. Therefore, N-consistency cannot be a relevant criterion. For those firms with no capacities for a certain fuel, the model has to be modified slightly. Here, the model is reduced to a simple binary choice problem with the alternatives "extending capacities" and "leaving them unchanged":

$$
\begin{aligned}
&\Pr\left(\Delta\widetilde{c}_{lit}|\widetilde{x}_{lit}, c_{li(t-1)} = 0\right) = \\
&\quad \left(\Phi\left(\theta_l - \widetilde{\alpha}_{li}^{cap} - \beta_l'\widetilde{x}_{lit}\right)\right)^{(1-\Delta\widetilde{c}_{lit})} * \left(1 - \Phi\left(\theta_l - \widetilde{\alpha}_{li}^{cap} - \beta_l'\widetilde{x}_{lit}\right)\right)^{\Delta\widetilde{c}_{lit}}.
\end{aligned} \tag{6}
$$

Because of enormous numerical problems due to the simultaneous estimation of a system of ordered probit models, we have ignored the correlation of the error terms $\widetilde{v}_{lit}$ across the fuel type equations and have separately estimated ordered probit models.

In principle, in a second step, the continuous aspect of capacity adjustment could be explained on basis of a linear a regression that only accounts for those observations for which $\Delta c_{lit} \neq 0$ holds. However, ignoring observations that do not exhibit adjustment in capacities is likely to cause a typical sample selection problem. This problem could be addressed by a generalized Heckman-correction. Yet, since capacities are adjusted infrequently, the sample that could be used for this second-step analysis would be rather small. For this reason, we abstain from adding the second step and restrict the analysis to the discrete aspect.

3.2 A Continuous Model of Electricity Generation

Analogous to (1), a model explaining electricity generation by different fuels, given existing capacities, is formulated:

$$
\log\left(y_{lit}\right) = \alpha_{li}^{gen} + \gamma_l' z_{it} + \varepsilon_{lit}, \qquad l = 1, ..., L. \tag{7}
$$

Here, y_{lit} denotes the amount of electricity that is generated by utility i using fuel type l in period t. The model is formulated in logs rather than levels. Large differences in the utilities' size are a strong argument in favor of expressing marginal price effects in terms of elasticities. The vector z_{it} shares most of its elements with x_{it}, except for generation capacities that are additionally included, since electricity generation depends on existing capacities. We distinguish between "specific" capacities c_{lit}, i.e. capacities for burning fuel l, and "unspecific" ones $c_{l'it} \equiv c_{it} - c_{lit}$, i.e. capacities for burning fuels others than l. Choosing the fuel mix conditionally on existing generation capacities is a matter of short term factor demand. Accordingly, contemporaneous rather than lagged values of explanatory variables enter z_{it}. The intercept α_{li}^{gen} captures unobserved time-invariant and utility-specific heterogeneity.

3.2.1 Specification and Estimation

The series for fuel-specific electricity generation proved to be non-stationary. Correspondingly, the generation model is formulated in first differences, too. Unfortunately, by solely focusing on first differences, any information on possible long-term stationary equilibrium relationships between dependent and explanatory variables that might be comprised in the data is given away. Error-correction models, see e.g. Hamilton (1994), provide the opportunity to capture short-term relationships in first differences as well as long-term ones concerning the levels of variables. In our context, such long-term equilibrium relationships seem to be plausible at least between generation capacities and electricity generation. To test whether such co-integrating relationships can actually be found, Phillips-Ouliaris (1990) tests were applied. In the overwhelming number of series, these tests could not support the hypothesis of co-integrating relationships being present. Therefore, an error-correction model is not specified, and the model is characterized by the equations:

$$\Delta \log (y_{lit}) = \widetilde{\alpha}_{li}^{gen} + \gamma_l' \Delta z_{it} + \widetilde{\varepsilon}_{lit}, \qquad l = 1, ..., L. \tag{8}$$

To allow for utility-specific drifts, individual effects $\widetilde{\alpha}_{li}^{gen}$ were even included in the differenced model and were estimated as fixed effects. In contrast to the non-linear model (5), cross-equation correlation of the $\widetilde{\varepsilon}_{lit}$ can easily be accounted for in the linear model framework used here. Therefore, the coefficients of the linear system (8) are simultaneously estimated using the *SURE*-method, see Zellner (1963). Varying patterns of fuel types used – i.e. an observation-specific number of equations in the system – are accounted for by adequately correcting the estimated variance-covariance matrix. Bootstrapping was applied to obtain standard errors for the estimated coefficients.

4 The Data

Econometric analyses with German firm-level data are extremely rare, since such data are hardly available the public in Germany. The micro-data on German electric utilities used here were collected by the "Association of German Power Plants" (VDEW). The VDEW data comprise annual information on almost all electricity producers at the firm and plant level since the 1950s, specifically on capacities, peak loads, electricity output and losses, and the structure of the demand side within the monopoly regions.

Our analysis is concentrated on the period from 1968 to 1998[6]. We restrict our attention to only nine electric utilities[7], which dominated the German electricity market before its liberalization initiated. These monopolies were the largest[8] electricity producers, in terms of generation capacities as well as actual electricity generation. In 1995 they held a share of 65% in overall German generation capacities and 70% in electricity generation.

Since utility-specific price data are not available, aggregated data are used, provided by the OECD, the German Federal Statistical Office, and the "Statistics of Coal Economics"[9]. Therefore, our approach is not purely based on micro-data. Mergers of utilities as well as the restructuring of existing firms – e.g. the reallocation of business domains to subsidiary companies – appear as physical rather than organizational changes in the data. Wherever possible, the data were corrected for such effects. Moreover, power plants jointly held by several utilities are not reported in the data prior to 1975. For this reason, our panel is unbalanced.

In addition to "multi-fuel"[10], six fuel types are distinguished in our analysis: coal, lignite, gas, oil, nuclear power, and "others". The residual category "others" comprises several primary energy sources – primarily water power but also waste, wind and, solar power – all of which are relevant in the context of CO_2 abatement. However, each individual energy sources is of marginal importance.

[6]Even though a more recent wave has recently been published, the new data are hardly comparable due to the process of mergers in the German power sector.

[7]In detail, these utilities are: RWE, PreussenElektra, Bayernwerk, VEW, Badenwerk AG, Energieversorgung Schwaben AG (EVS), Bewag, Hamburgische Electricitätswerke (HEW), and VEAG, called the "Verbundunternehmen". Only four major utilities still exist: RWE took over VEW; PreussenElectra and Bayernwerk merged to E.ON; Energieversorgung Schwaben and Badenwerk merged to EnBW; and Vattenfall Europe took over Bewag, HEW, and VEAG.

[8]In fact, a small number of large producers does not belong to this group of utilities.

[9]Statistik der Kohlenwirtschaft e.V.

[10]Since "multi-fuel" is an generation technique and not fuel itself, this category is relevant only for generation capacities, but not for generation.

4.1 Generation Capacities

The development of fuel-specific capacities belonging to the nine dominating utilities can roughly be described as follows: The traditional dominance of lignite even increased as a consequence of German reunification, reflecting the fact that electricity is predominately generated from lignite in East Germany. The importance of gas has been declining since the 1970s; however, it seemed to recover in the late 1990s. Throughout the entire period, oil was of marginal importance. The relative importance of nuclear power rapidly increased up to the mid 1980s. Then the installed capacities for nuclear power remained constant. Finally, hard coal capacities were enlarged from the mid 1970s to the mid 1980s, thereafter they declined marginally.

Generation capacities are far from being evenly distributed across utilities. First of all, capacities substantially differ in size. For example, in 1995, the largest utility by far, RWE, held a share of 28.9% in total capacities, 17.9% and 18.7% were the shares of PreussenElektra and VEAG respectively, while those of all others utilities were substantially smaller. Similarly, fuel-specific capacities were also unevenly distributed. In particular, RWE and VEAG were dominant with respect to capacities for burning lignite. In fact, the majority of the remaining firms did not endure such capacities at all. Furthermore, gas capacities were concentrated on RWE and VEW.[11]

4.2 Electricity Generation

Total generation of all nine utilities constantly increased during the period in question. The period up to the mid 1980s was characterized by the expansion of nuclear power. Since the mid 1970s, generation from hard coal had also gained in absolute terms as well as relative terms. Generation from gas and oil had dramatically been reduced since the mid 1970s; however, it looks as though the use of gas has recovered in recent years. All other primary energy sources have only played a marginal role. The allocation of generation to the different fuels highly coincides with the distribution of fuel-specific capacities. Correspondingly, utilities' size differ similarly in terms of generation differed as in terms of capacities.[12]

[11] Considering all nine major utilities jointly, in 1995, both nuclear and lignite power plants accounted for 27.9%, while hard coal, gas, oil und other mono-fuel plants accounted for 9.7%, 5.7%, 6.7%, and for 6.9% of total capacities, respectively. The remaining 15.2% are multi-fuel plants.

[12] Considering all nine major utilities jointly, in 1995, nuclear power received a share of 37.5%, in electricity generation, while lignite accounted for 37.1%, hard coal for 19.6%, gas for 2.7%, oil for 0.7%, and finally other fuels for 2.4% of total generation.

4.3 Explanatory Variables

Aggregated fuel prices[13] are plotted in Figure 1, with electricity serving as nummeraire. The two oil crises in the 1970s shape the series, whereas oil and gas are much more affected than coal or lignite. Moreover, oil and gas prices are more volatile than coal or lignite prices. Unfortunately, fuel prices, especially those of oil and gas[14], are highly correlated, and this hampers the econometric analysis.

An optimal fuel mix is likely to be determined by the load demand curve, see section 3, which is not directly observed in our data. Nevertheless, the corresponding "load factor" LF_{it}[15] is included in the vectors $x_{it'}$ and z_{it}. It is defined as the actual demand for electricity d_{it}, divided by the demand that would have been accrued if the demand for electric load had stood at its peak PL_{it} for the hole year, i.e. 8760 hours:

$$LF_{it} \equiv \frac{d_{it}}{8760 * PL_{it}}.$$

The load factor is a non-dimensional variable, normalized to the unit-interval. Values close to one indicate an evenly distributed load demand, while values closed to zero indicate an unevenly distributed one. In the pooled sample, LF_{it} takes an average of 0.66. Along with the demand for electricity d_{it}, this variable characterizes the demand side within the utilities' regional monopolies.

Including a full set of time dummies is not operational, because time dummies and aggregated prices are highly correlated. Therefore, only one time-dependent dummy variable is included in the model. It takes the value one for the periods 1995 – 1998 and zero otherwise. This dummy can be interpreted as a deregulation indicator, capturing the effects of somewhat relaxed regulation of electricity production since the mid 1990s.

[13]Reliable price measures for nuclear fuel were not available. Some other generation techniques, namely wind and waterpower, have no variable fuel costs at all. Some specifications additionally consider costs of labor and capital. Unfortunately, only weak proxies for firm- and technique-specific costs were available. Moreover, the corresponding coefficients turned out to be insignificant. For this reason, results for these specifications are not presented.

[14]This might be explained by long-term contracts, which often peg the price of gas to the price of oil.

[15]The use of the load factor used as a regressor in an econometric analysis was introduced by Söderholm (2001).

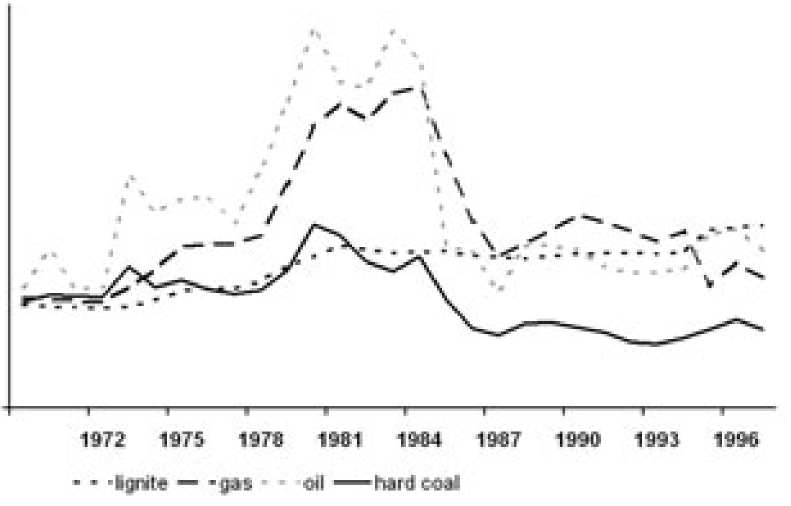

Figure 1: Relative prices of fossil fuels

Source: Statistik der Kohlenwirtschaft e.V. and own calculations

5 Estimation Results

Tables 1 and 3 display estimation results for the discrete capacity change model and the continuous generation model, respectively. Raw coefficients rather than marginal effects are presented, since our discussion focuses on significance and direction of effects. Additionally, Tables 2 and 4 display test results concerning the joint significance of groups of variables, such as prices, within single equations. Finally, Table 5 presents results concerning joint significance of individual explanatory variables across equations.

Table 1: **Capacities model: estimated parameters**

	coal	**lignite**	**gas**	**oil**	**nuclear**	**others**	**multi-fuel**
constant	1.095** (0.251)	0.572 (0.402)	–	1.731** (0.555)	3.218** (0.585)	1.806** (0.328)	–
RWE	–	–	2.276** (0.693)	–	–	–	–
Pr. Elektra	–	–	1.756* (0.862)	–	–	–	2.375** (0.620)
VEAG	–	–	–	–	–	–	–
Bayernwerk	–	–	–	–	–	–	1.515** (0.651)
VEW	–	–	1.539** (0.461)	–	–	–	1.120* (0.572)
EVS	–	–	3.251** (0.575)	–	–	–	1.847** (0.605)
Badenwerk	–	–	1.707* (0.845)	–	–	–	1.809** (0.503)
HEW	–	–	2.032** (0.481)	–	–	–	0.656 (0.577)
Bewag	–	–	1.715** (0.692)	–	–	–	1.743** (0.664)
price coal	8.795* (4.068)	1.378 (3.037)	−0.855 (3.148)	14.727* (7.110)	23.114** (8.102)	−0.826 (2.618)	0.489 (7.443)
price lignite	12.317 (7.084)	20.892* (9.167)	−8.951 (9.946)	0.238 (13.974)	−5.960 (17.070)	−2.550 (5.038)	−15.961 (14.78)
price gas	0.632 (3.261)	−6.484 (3.455)	−0.375 (3.800)	−0.828 (3.331)	0.681 (7.668)	−4.287** (1.660)	−0.370 (5.015)
price oil	−7.250** (2.698)	−0.430 (1.747)	0.227 (2.595)	−6.976* (3.221)	−9.469* (3.898)	2.671* (1.047)	2.800 (5.190)
load factor	−1.891 (6.001)	4.561 (7.132)	−8.863 (5.003)	−13.896 (9.816)	14.350 (10.963)	−1.413 (3.642)	−15.217 (9.656)
demand	2.022 (3.250)	−4.557* (2.223)	3.800 (2.694)	−2.014 (7.345)	2.290 (4.687)	0.162 (2.751)	3.347 (4.906)
dereg. ind.	0.310 (0.320)	2.124** (0.680)	0.446 (0.401)	−0.264 (0.485)	−0.512 (0.445)	−0.046 (0.412)	−0.352 (0.422)
threshold θ	2.295** (0.180)	3.820** (0.546)	3.250** (0.437)	3.231** (0.315)	3.494** (0.317)	3.080** (0.256)	2.572** (0.270)
L-norm. σ	0.296** (0.026)	0.078 (0.044)	0.182** (0.027)	1.105* (0.527)	0.350 (0.440)	0.779 (0.705)	0.262** (0.052)
L-norm. μ	1.373** (0.042)	1.374** (0.243)	1.082** (0.091)	0.907** (0.199)	1.528** (0.078)	−0.083 (1.342)	1.646** (0.063)

Note: Standard errors in parentheses
* indicates significance at the 0.05 level, ** at the 0.01 level.

5.1 Results for the Capacities Model

Fixed effects are only jointly significant for gas and multi-fuel. So, for the other generation techniques, Table 1 presents the results originating from specifications including a uniform constant. The log-normal weighting function's parameters σ_l and μ_l typically indicate a pronounced delay in the adaptation of capacities in response to changes in the exogenous variables, with oil and "other fuels" being the only exceptions from this rule. This result appears to be plausible, since the latter two techniques are typically characterized by small installations. The still rather moderate effect that the very distant past has on capacities for burning lignite, coal, and nuclear fuel comes somewhat as a surprise, since these techniques are characterized by very large plants, implying long planning and construction periods.

The load factor as well as the demand for electricity does not explain firms' investment behavior. For the load factor, none of the corresponding coefficients is significant. That is, the evenness of electricity demand does not seem to have any effects on utilities' investment decisions. Electricity demand has a significant effect only in the case of lignite; however, it bears a negative, i.e. the "wrong", sign. Therefore, there is no support for the hypothesis that utilities react to changes in electricity demand by adjusting their capacities for electricity generation.

Similarly, the estimated price effects do not suggest that fuel prices are decisive for utilities' fuel-specific investment decisions. A significant overall price effect cannot be recognized at all in the cases of lignite, gas, and multi-fuel, see Table 2. In the equations concerning the remaining fuels, prices are jointly significant, and the own-price effects are also significant, except for gas. However, these effects often bear the "wrong", i.e. positive, sign. Only for oil we do obtain the expected result, which is that the propensity to invest in oil-fired power plants is reduced by rising oil prices.

Table 2: **Capacities model: joint significance**

	coal	**lignite**	**gas**	**oil**	**nuclear**	**others**	**multi-fuel**
fixed effects	0.968	0.320	0.001	0.911	0.853	0.812	0.004
prices	0.000	0.081	0.509	0.025	0.001	0.003	0.511

Note: p-values for Wald-tests

The "deregulation indicator" is significant – and positive – only in the case of lignite. For this finding, it is hard to find an appealing explanation, because prior to 1995, lignite was less regulated than any other fuel.

Table 3: **Generation model: estimated parameters**

	coal	lignite	gas	oil	nuclear	others
constant	–	−0.305** (0.106)	–	–	–	–
specific capacities	0.201 (0.119)	0.328 (0.517)	0.846* (0.343)	1.970* (0.958)	0.411 (0.235)	1.049** (0.152)
unspecific capacities	−0.228 (0.150)	1.115 (0.862)	−1.013 (0.718)	1.030 (0.899)	−0.575 (0.584)	−0.084 (0.119)
price coal	−0.094 (0.189)	−0.6128 (0.898)	0.025 (0.750)	2.322** (0.850)	0.096 (0.512)	−0.350 (0.186)
price lignite	−1.035 (0.695)	2.356 (1.830)	−0.638 (1.491)	0.956 (2.689)	2.332 (1.468)	0.710 (0.547)
price gas	0.131 (0.144)	−0.478 (0.669)	−0.353 (0.540)	−1.734** (0.618)	−0.147 (0.333)	0.190 (0.130)
price oil	0.026 (0.099)	0.208 (0.341)	0.250 (0.421)	−0.757 (0.491)	−0.803 (0.503)	0.045 (0.100)
load factor	0.817** (0.314)	−0.447 (2.117)	0.234 (1.226)	−2.341* (1.207)	−1.169 (0.857)	−0.172 (0.244)
demand	1.196** (0.272)	1.610 (1.819)	0.454 (0.913)	−0.343 (1.119)	2.094 (1.131)	−0.018 (0.254)
dereg. indicator	0.067 (0.045)	0.503* (0.241)	−0.026 (0.117)	−0.790* (0.2830)	−0.041 (0.067)	−0.002 (0.041)

Note: Standard errors in parentheses
* indicates significance at the 0.05 level, ** at the 0.01 level.

5.2 Results for the Electricity Generation Model

Fixed effects are never significant. Furthermore, constants are also insignificant, with the equation for lignite being the only exception. Therefore, except for lignite, results for specifications without constant terms are presented.

Only a few estimated coefficients are individually significant, with specific capacities for burning gas, oil, and "other fuels" being among the significant ones. Moreover, the null-hypothesis that a one percent change in these capacities leads to a one percent change in electricity generated by them cannot be rejected. In contrast, no significant effects of capacities on the corresponding generation can be found in the case of lignite, nuclear power, and coal.

Individual unspecific capacities do not seem to have any effect. Jointly, however, i.e. by taking all six equations simultaneously into account, they are as significant as the specific ones. This leads us to conclude that the rather trivial hypothesis that existing generation capacities have an effect on the amount of electricity generated by them is weakly supported. Detailed insights on how changes in capacities affect the allocation of electricity production to different fuels, however, can hardly be inferred from our estimation results.

Similarly, the demand for electricity shows individually no effects, with the equation for coal being the only exception. Nevertheless, demand is jointly significant, see Table 5. In the cases of oil and coal, the load factor shows a significant effect, but estimated signs do not appear to stay in line with theory. Surprisingly, with respect to the canonical base load techniques (lignite and less pronounced coal) as well as their peak load counterpart (gas) no effects of the load factor can be recognized. Therefore, the importance of the load factor on the fuel choice seems to be rather weak. By jointly considering all six equations, its effect sails on the margin of statistical significance.

Table 4: **Generation: joint significance within single equations**

	coal	**lignite**	**gas**	**oil**	**nuclear**	**others**
fixed effects	0.898	0.285	0.813	0.811	0.472	0.755
constant	0.418	0.008	0.949	0.495	0.582	0.996
prices	0.210	0.720	0.951	0.028	0.315	0.418

Note: p-values for Wald-tests

The deregulation indicator displays significant effects only for lignite and oil. With respect to lignite, the downward trend apparently came to an end in 1995. This might reflect the political protection that East German lignite has received in recent years. With respect to oil, the estimated negative sign cannot easily be explained by deregulation. Simultaneously examining all six equations, joint insignificance of the deregulation indicators can just marginally be rejected. Therefore, a clear-cut effect of power sector deregulation on utilities' conditional fuel mix cannot be recognized yet.

Considering fuel prices, the hypothesis that there is no price effect at all – i.e. any price coefficient in any equation is equal to zero – cannot be rejected. The corresponding p-value is as high as 0.368. Moreover, examining each equation separately cannot contribute much evidence for rejecting the null-hypothesis either. The equation for electricity generation by oil turns out to be the only one that displays jointly significant price coefficients, see Table 4. Additionally, this equation shows individually significant prices alone, though the direct price effect is not among the significant ones. Therefore, no evidence is found in the data that supports the hypothesis that fuel-mix decisions, given existing capacities, are determined by prices of fossil fuels.

Table 5: **Generation: joint significance across equations**

	Wald-Statistic	**p-value**
specific capacities	66.731	0.000
unspecific capacities	14.715	0.023
price coal	10.414	0.108
price lignite	6.522	0.367
price gas	13.358	0.038
price oil	5.903	0.434
demand	28.259	0.000
load factor	12.987	0.043
deregulation indicator	12.821	0.046

5.3 Interpretation of Estimation Results

Persuasive evidence that fuel prices are pivotal determinants of utilities' fuel choice could not be found, neither in the case of generation capacities nor the case of electricity generation. This result might be explained by high regulatory pressure, making fuel choice a political matter rather than one of cost minimization and business management. If this interpretation is correct, it will appear to be a rather ambitious task to draw any conclusions about a less regulated future from estimation results that are based on data concerning a highly regulated past, especially, these estimation results were of limited use for predicting the future impact of CO_2 emissions trading on electric utilities' fuel mix.

Nevertheless, if by our estimation results technology, not regulation, is reflected, these results indicate that changing the fuel mix is a rather expansive CO_2 abatement measure. If this is the case, utilities' fuel choice will hardly react to a carbon reduction enforced by a cap on CO_2 emissions, and carbon abatement will operate through other channels.

6 Conclusions

In this paper, the attempt has been made to estimate the effects of fuel prices on the German utilities' fuel choice through the use of German firm-level data. Such estimates are required to predict the impact the scheduled European CO_2 trading may have on the fuel mix used for electricity generation. Estimation results do not indicate that in the past utilities have adjusted their fuel choice to changes in fuel prices, either in terms of fuel-specific combustion capacities or in terms of fuel use, given existing capacities.

During the period from 1968 to 1998, the German electricity market was subjected to various regulatory interventions. Recently, many of these regulations have been either relaxed or abolished. Therefore the estimated low fuel price sensitivity that might be due to past regulation may not tell much about future price effects induced by future CO_2 emissions markets.

If the insignificance of price effects is due to technological reasons rather than government intervention in the electricity markets, our estimation results indicate that prices of CO_2 permits may have no severe effects on utilities' fuel choice. Most importantly, high-carbon fuels like lignite and coal may still be used intensively under an emissions-trading regime.

In any case, more information is required about utilities, operating within a less regulated environment, in order to decide whether the future fuel mix will be as price inelastic as the past one and whether severe changes in the fuel mix have to be expected in the course of the European CO_2 allowance market.

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