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Electricity Prices, River Temperatures and Cooling Water Scarcity

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Electricity Prices, River Temperatures and Cooling Water Scarcity♣

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Abstract

Thermal-based power stations rely on water for cooling purposes. These water sources may be subject to incidents of scarcity, environmental regulations and competing economic concerns. This paper analyses the effect of water scarcity and increased river temperatures on German electricity prices from 2002 to 2009. Having controlled for demand effects, the results indicate that the electricity price is significantly impacted by both a change in river temperatures and the relative abundance of river water. An implication is that future climate change will affect electricity prices not only through changes in demand, but also via increased water temperatures and scarcity.

JEL Codes: Q25, Q41, Q5, C3

Key Words: Thermal-based power, water scarcity.

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1. Introduction

Many thermal-based power facilities, such as nuclear and coal-fired plants, are critically dependent on water for cooling purposes. In the case of inland plants, these cooling needs must be met by drawing water from a nearby river or lake. To illustrate, the thermal industry accounts for roughly 40 percent of all freshwater withdrawals in the United States – a figure that places it alongside the country's agricultural sector (USDOE, 2006). Unlike agriculture, however, the majority of these withdrawals are actually returned to their natural source. Nevertheless, discharging used cooling water back into the environment can raise the ambient temperature of the water source itself – to the possible detriment of aquatic plants and animals. Water temperatures at or above the mid-20s degree Celsius (°C) mark are considered particularly dangerous to aqueous plants and certain fish species, since this leads to reduced oxygen levels and raised concentrations of ammoniac (Langford, 1990). As a result, many countries have enacted environmental regulations, which place restrictions on the maximum allowable temperature of discharge water from power stations; otherwise known as "thermal pollution".[1]

A number of studies have sought to analyse how thermal-based power production might be affected by constraints in water resources, particularly given growing energy demands (see, for instance, Feeley *et al*., 2008; and USDOE/NETL, 2009a, 2009b, 2009c). Within this context, an emerging literature has focused on the adaptive strategies available to the thermal power industry in coping with the impacts of climate change. Synthesising several studies, the Fourth Assessment Report of Intergovernmental Panel on Climate Change (IPCC, 2007) suggests that future energy generation is vulnerable to higher temperatures and

[1] The vulnerability to water scarcity, as well as problems related to thermal pollution, varies according to fuel type and cooling technology. For example, the low thermal efficiencies of nuclear plants make them particularly susceptible to water-related issues (for example, see: USDOE, 2006).

a reduced availability of cooling water for thermal power stations. Citing effects from the 2003 European heat wave as a precautionary example: "[E]lectricity production was undermined by the facts that the temperature of rivers rose, reducing the cooling efficiency of thermal power plants (conventional and nuclear) and that flows of rivers were diminished" (*ibid*, p. 367).[2] In that vein, Koch and Vögele (2009) use an integrated water demand model to simulate the interconnected effects of changing water demand and supply on the thermal power industry, before applying it to various hypothetical climate scenarios. Similarly, Förster and Lilliestam (2010) simulate the effects of climate change on a single, large nuclear plant in Central Europe that is reliant on once-through cooling technology. Their results indicate that annual load losses could be as high as 11.8%, with annual plant losses upwards of €100 million for the worst case scenarios. Adopting a more empirical approach, Linnerud *et al*. (2011) use European data to analyse the impact that climate change may have on the nuclear industry, and find that an average temperature rise of 1°C reduces the supply of nuclear power by roughly half a percent. Kopytko and Perkins (2011) also highlight similar issues by discussing the vulnerability of nuclear power to climate change, drawing specific attention to cooling water scarcity as a key impediment to future investment in inland nuclear plants.[3]

The focus of this paper is to determine the impact that water scarcity and increased river temperatures have on electricity prices. Indeed, even though a large number of studies have sought to analyse the sensitivity of thermal-based electricity production technologies to

[2] Among other studies highlighting equivalent issues are Hurd and Harrod (2001), Arnell *et al*. (2005), Maulbetsch and DiFilippo (2006), Kirshen *et al*. (2008), Sovacool (2009), and Sovacool and Sovacool (2009).

[3] The link between thermal-based power and water has also received attention within popular media formats. This includes news stories of European power plants shutting down during heat waves of the last decade (cf. Gentleman, 2003; Godoy, 2006; Pagnamenta, 2009) and similar problems in the US (cf. AP, 2008; Sohn, 2011), as well as implications of the nuclear power sector's dependency on water and recurring incidents of drought (cf. Kanter, 2007; Dell'Amore, 2010). The linkage between power supply and water needs has also received increased attention in the wake of recent events at the Fukushima Daiichi nuclear plant in Japan (cf. Chellaney, 2011).

water scarcity, we are unaware of any that establish empirical evidence for an effect on electricity prices. Our paper therefore aims to quantify some of the direct economic costs that may arise due to the power industry's reliance on water.

The European heat waves of 2003 and 2006, which saw a spate of record summer temperatures across the continent, provide perhaps the most vivid example of how inadequate access to cooling water can directly impact electricity supply. Beyond the more tragic outcomes such as a large number of heat-related deaths, the scorching weather also resulted in spiking electricity prices. Some regions even experienced power outages as grid capacities strained under the pressure of increased electricity demand (for air-conditioning) and, in some cases, restrictions in supply due to insufficient cooling water. [4] This latter issue can be understood to have arisen either in absolute terms (i.e. there was a physical shortage of available cooling water), or legislative terms (i.e. there were environmental restrictions over the discharge of too hot water back into the ecosystem).

We use German data to analyse the impacts that high river temperatures and falling river levels have on thermal-based electricity supply, and thus also prices. There are several reasons why German data is appropriate for a study of this kind. First, it is a big country with a fairly diversified power portfolio. During the review period of this study (2002-2009), Germany derived approximately 60 percent of its electricity supply from fossil fuels (mostly coal), 25 percent from nuclear, and the remainder from a combination of renewables, including only a small contribution from hydropower.[5] Second, the availability of a wide series of relevant data, including wholesale electricity information and hydrological data,

[4] E.g. France, whose nuclear industry supplies approximately four fifths of the country's electricity needs, was eventually forced to shut or power down 17 inland nuclear reactors during the 2003 European heat wave, costing national electricity incumbent, Électricité de France, an estimated €300 million (Kantor, 2007).

[5] The role of nuclear power in Germany has been highly contested over the last several decades, with renewed public interest in the wake of the stricken Fukushima Daiichi plant in Japan. Following a period of political flip-flopping on the issue, the German government in 2011 committed to phasing out nuclear power by 2022.

makes it an amenable choice for conducting empirical analysis. Third, and most importantly, the country's electricity sector has proven vulnerable to incidences of water scarcity and compromised water quality; especially during very hot periods. For instance, Germany joined the likes of France and Spain in suffering from diminished production capacities during the 2003 and 2006 heat waves. A proximate cause of this outcome was the fact that river temperatures began to exceed the regulatory threshold imposed on thermal waste water pollution. German federal authorities initially provided emergency dispensation to power stations. However, officials were eventually forced to uphold the usual restrictions on discharging (used, hot) cooling water into the environment, so as to protect river fauna and flora. Overall, 15 thermal plants had to be shut down or entered into constrained production because of water-related issues during the summer of 2003 (Müller *et al*., 2007, 2008). Similarly, German energy providers once more had to throttle production during the 2006 heat wave in order to limit the discharge of thermal waste water into rivers. This time, 12 thermal plants were either temporarily closed or forced to operate at reduced capacity (*ibid*).

In this context our empirical results indicate that electricity prices are significantly impacted by both a change in the temperature and relative abundance of river water. In general, falling river levels are associated with a higher electricity price, while the price will also be driven higher once river temperatures breach a 25°C threshold.

The remainder of the paper is structured as follows. Section 2 presents the theoretical framework and discusses the empirical strategy. Section 3 describes the data. Section 4 presents the empirical findings, while Section 5 provides some concluding remarks.

2. Model Specifications and Econometric Strategy

We may model the profit, π, for plants depending on cooling water as follows

$$\pi = p\left(Q+F\right)Q - c\left(Q\right) - p_w\left(RL\right)\cdot W$$

where *p*(.) denotes the inverse demand function and total electricity demand is the sum of power produced by the analysed plants, *Q*, together with electricity imports and the other sources that aren't dependent on cooling water (e.g. wind power), *F*. The parameter, *c*(*Q*), captures the costs associated with the production of additional quantities of electricity. In addition to these standard production costs, the latter part of the expression, $p_w\left(RL\right)\cdot W$, reflects the fact that there are costs associated with drawing cooling water, *W*, from the external coolant (here: river). These are said to be a function of the river level, *RL*, such that $p_w' < 0$. We furthermore assume a simple production technology described as follows;

$$Q = A\left(T_{EW} - T\right)\cdot W .$$

In other words, the production of electricity is contingent on the difference in temperature between the cooling water at the intake point and the discharge water at the outlet point. Production will increase as this temperature difference increases, i.e. $A' > 0$.[6] This is a rather simplified model of the thermodynamic process, consisting of a closed steam circuit (where turbines are driven by the steam, which is generated by combusting fossil fuels or a reacting nuclear core), and a heat exchanger (where surplus heat from the closed circuit is removed by the external coolant). In our model we take as exogenous the former, and focus instead on the heat exchanger that uses cooling water to dump the surplus heat; thus leading to a higher

[6] An underlying assumption is that $T_{EW} \geq T$. In other words, there is a cooling effect due to the heat exchange that takes place in the plant condenser. The specification that we have used here is thus also indicative of the fact that the cooling effect becomes increasingly negligible as the temperature difference falls.

temperature of the discharge water. Importantly, the model also captures the possibly that thermal-based plants can use more cooling water, W, to compensate for a low temperature difference.

The production of electricity by thermal-based power stations is subject to the following constraint:

$$\frac{W}{S}\cdot T_{EW}+\left(\frac{S-W}{S}\right)\cdot T\leq\overline{T}$$

This constraint reflects the fact that environmental authorities set a cap, $\overline{T}$ on the temperature of the downstream river volume, S, which occurs as a result of the mixing between discharged cooling water, W, and the river water not used for cooling (S-W). Thus, $\frac{W}{S}$ is the share of total river water used for cooling. The constraint implies that – rather than undergoing a complete shutdown to meet the cap set by the authorities – the plant has the option of reducing the flow of discharge relative to the volume of downstream mixing water when the temperature of each unit of discharged water, T_{EW}, is relatively hot. However, as the temperature of the river water itself approaches the regulatory limit (e.g. during very hot summer months), the plant has little scope for manoeuvre and will likely have to run at less than full power.[7]

By substituting in the technology function for the water parameter, W, we are arrive at the following profit maximisation problem:

[7] Of course, environmental authorities will also typically impose limits on the temperature of the discharged water itself – let us say $\overline{T}_{EW}$ – and/or on the temperature differential between river water at the intake point and the discharge. In the interests of parsimony, however, we ignore these additional limits in our model. Indeed, one could argue that including a constraint, $\overline{T}$, on the temperature of the downstream river volume, S, already serves to capture these effects indirectly.

$$\pi = p\left(Q+F\right)Q - c\left(Q\right) - p_w\left(RL\right)\cdot\frac{Q}{A\left(T_{EW}-T\right)}$$

s.t.

$$\frac{Q}{S\cdot A(T_{EW}-T)}\cdot T_{EW} + \left(1-\frac{Q}{S\cdot A(T_{EW}-T)}\right)\cdot T \le \overline{T}$$

The first-order condition with regard to Q is

$$p^*\left(1-\frac{1}{\varepsilon}\right) = \frac{\partial c(Q^*)}{\partial Q} + p_w\left(RL\right)\cdot\frac{1}{A\left(T_{EW}-T\right)} + \lambda\cdot\frac{1}{S\cdot A(T_{EW}-T)}\cdot\left(T_{EW}(T)-T\right)$$

where Q^* is the optimal level of produced energy (with corresponding optimal price, p^*), λ is the shadow price of the constraint, and ε denotes the price elasticity where we have integrated out the demand effects for electricity provided by the other sources. For illustrative purposes, one could make the following simplification: $A(T_{EW}-T) \equiv A\cdot(T_{EW}-T)$. The last term of the optimal price and quantity equation will then become $\lambda\cdot\frac{1}{S\cdot A}$, where λ is the shadow price of the temperature cap.

Given that $p_w' < 0$, a reduced river level (RL) will have the same effect as a cost increase. To be specific, falling river levels will reduce the quantity of electricity and thereby lead to a price increase. As already stated, $A' > 0$ and $T_{EW} - T > 0$, such that a higher temperature difference increases the production. The magnitude of the price increase that follows a rise in river temperature (T) is thus contingent on the concomitant change in the temperature differential between the discharged water and normal river water ($T_{EW} - T$). More precisely, increased river temperatures will have a positive effect on the electricity price, but in a rather non-linear fashion. This can be shown by taking the first derivative of the optimal price with regard to river temperature (*T*):

$$\frac{\partial p^*\left(1-\frac{1}{\varepsilon}\right)}{\partial T}=p_w(RL)\cdot\frac{A'(T_{EW}-T)}{A(T_{EW}-T)^2}+\lambda\cdot\frac{1}{S\cdot A(T_{EW}-T)^2}\cdot\left(A'(T_{EW}-T)\cdot(T_{EW}-T)-A(T_{EW}-T)\right)$$

Since $A'(.) > 0$, the first term is positive. The last term is positive if $A'(T_{EW}-T)\cdot(T_{EW}-T) > A(T_{EW}-T)$. This would seem a reasonable assumption, not least because it is consistent with a production function that has diminishing returns to the temperature difference between the discharged water and the cooling water (see for instance, Kay and Nedderman, 1985). We are thus left with a positive, though non-linear, effect of river temperatures on electricity prices.

As a matter of convenience, we do not model the market or competition behaviour of the analysed plants explicitly.[8] Instead we focus on a reduced-form system of demand and supply equations. It is assumed that prices and quantities are set simultaneously through a market clearing process where a multitude of produces and consumers reach a single price-quantity combination. The process is repeated daily as the producers and consumers adjust to changes in their individual constraints, as well as utility and profit functions. Aggregate electricity demand is $Q = Q(P, W, u)$, where *P* denotes the price level (price per mega watt), *W* a vector of exogenous variables that affects downward sloping demand curve, and *u* is an error term capturing all information not captured by *P* and *W*. In contrast, the upward-slopping price equation takes the form $P = P(Q, X, u)$, where *Q* is the total quantity of

[8] This means that the model is encompassing as setting, where the representative plant is a price-taker (i.e. where $\varepsilon \to -\infty$), or where the plant can exercises market power. Of course, a plant's ability to react to changes in demand or marginal costs will depend on what type they are. For instance, nuclear power plants are built for baseload, while gas-fired plants are more flexible.

electricity purchased for that day in megawatts (MW), X is a vector of other factors determining the shape of the price schedule, and u is a disturbance term. The system of supply and demand equations – (1) and (2), respectively – is given as follows:

(1) $$\ln P_t = \beta_0 + \beta_1 \ln Q_t + \beta_2 \ln RiverLevel + \beta_3 \ln RiverTemp_t + \beta_4 lnF_t + \beta_T{}'\mathbf{T}_t + v_t$$

(2) $$\ln Q_t = \alpha_0 + \alpha_1 \ln P_t + \alpha_2 \ln HDD_t + \alpha_3 \ln CDD_t + \alpha_4 \ln NonWorkingDays_t + \alpha_T{}'\mathbf{T}_t + u_t$$

where

P	- Daily clearing price for electricity
Q	- Daily electricity consumption
RiverLevel	- The aggregated river level
RiverTemp	- River Temperature
F	- Fuel costs
HDD	- Heating degree-day (degrees below 18°C outside air)
CDD	- Cooling degree-day (degrees above 22°C outside air)
NWD	- Non-working days (i.e. either a weekend or public holiday) (0/1)
T	- A set of seasonal, month-and year variables

We are primarily interested in the supply equation (1) and, in particular, the effects of access to adequate cooling water. Electricity supply in this instance is defined by the daily electricity price (*P*), which is a function of quantity demanded (*Q*) and several other supply-related variables. In turn, the price of electricity is formed by the supply of thermal-based power stations that are critically dependent on cooling water (e.g. coal and nuclear), together with the production costs associated with for instance heating the steam circuits in these power stations. Furthermore, monthly and year dummies are included to account for seasonality and trend. Most important to this study, however, are the two variables related to water scarcity: river levels (*RiverLevel*) and river temperatures (*RiverTemp*). These variables are expected to measure the extent to which electricity supply is constrained by diminished cooling water availability. This may arise in either absolute terms (i.e. falling river levels), or in a regulated sense (i.e. electricity producers will be forced to power down once river temperatures breach an environmentally sensitive threshold).

The demand equation (2) includes two terms that capture the nonlinear effect of changing temperatures on electricity demand; heating degree days *(HDDs)* and cooling degree days *(CDDs)*. These variables measure the extent to which air temperatures fall outside a given "comfort zone", which we define as 18°C – 22°C.[9] *HDDs* measure how far the temperature drops below 18°C on any given "cold" day (thus requiring heating), while *CDD*s measure the extent to which temperatures exceed 22°C on any given "hot" day (thus requiring cooling).[10] The dummy variable *NonWorkingDay* reflects the fact the electricity demand is expected to fall on non-working days, such as weekends and public holidays. As with the supply equation, monthly and yearly dummies are included to account for seasonal variations and trend in demand.

It is important to note that *P* and *Q* are jointly determined within the set of above equations. Given this simultaneity of supply and demand, simply regressing electricity prices on volumes with OLS estimators would generate inconsistent parameter estimates because of endogeneity. To resolve this issue, instrumental variables and the application of two-stage least squares (2SLS) is used. As per the order condition, we can see that both equations (1) and (2) are overidentified. The null hypothesis of instrument exogeneity is therefore tested using the Sargan-Hansen test. The standard Hausman specification test is used to test for endogeneity. Furthermore, the Anderson identification test is used to test for instrument validity.[11]

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[9] This is a fairly standard range in the literature, although some studies (c.f. Bessec and Fouquau, 2008) contend that the turning point for temperate European countries occurs at slightly low intervals, from roughly 16°C. Nevertheless, having tested this formally, there is no significant difference in using 16°C or 18°C as the threshold for *HDD*s for our data set.

[10] To illustrate, an aggregate daily temperature of 17°C would correspond to one *HDD*, while a temperature of 15°C would equate to three *HDDs*. Similarly, a temperature of 27°C would correspond to five *CDDs*, and so forth.

[11] See Baum *et al*. 2007.

3. Data description

The data for this paper are collected from several different sources. The data for each series consist of daily values over the period 2002 to 2009. Data on German spot *electricity prices* and *volumes* are obtained from the European Energy Exchange AG (EEX).[12] It is important to note that electricity prices in Germany are uniform geographically and that there is no zonal differentiation. It is also worth mentioning that the spot market comprises approximately 30% of the German electricity consumption. Daily electricity data are available for both base (24-hour continuous) and peak (12 hours from 8am to 8pm) periods. However, we focus exclusively on the base series in this paper. The primary reason for this is the fact that those power plants most vulnerable to water-related factors – such as nuclear and coal-fired plants – are all baseload electricity operators. Consequently, one would expect that the impact of any supply constraints to these plants will already be visible within the base price. Our rationale for concentrating on the spot market is simply due to the fact that it constitutes the optimisation part of the electricity market. We would thus only expect marginal (and unforeseen) changes in river levels or temperatures to be reflected in spot prices, since you cannot readily account for specific variations in river data in the futures market. Both electricity prices and volumes are log-transformed for the regression analysis.

Air temperature data are obtained from Deutscher Wetterdienst (DWD). To compute aggregate temperature data, daily values are first collected for each capital city of the 16 German federal states. In the minority of cases where data limitations mean that a state cannot be represented by its capital, a significant counterpart city is used instead.[13] The mean temperature recording in all of these cities (computed from 24 hourly observations) is then

[12] EEX acts as Germany's energy exchange and is the largest energy trading market in central Europe.

[13] For instance, data for Wiesbaden, the capital of Hesse, was not available so this was substituted with data from the much bigger Frankfurt.

aggregated into a single daily mean temperature series for the entire country. Next, we create a series of heating degree days, *HDDs*, and cooling degree days, *CDDs*. These variables capture the extent to which temperatures fall outside the 18°C – 22°C interval, given that the temperature actually *is* outside this interval. Both the *HDD* and *CDD* series are adjusted so as to reflect logged values, i.e. $D^{temp>22^{o}} \cdot \log(temp - 22^{o})$, and $D^{temp<18^{o}} \cdot \log(18^{o} - temp)$.

Hydrological data, in the form of river levels and temperatures, are obtained through the Bundesanstalt für Gewässerkunde (BfG). Data from various points along four major German rivers; the Elbe, the Rhine, and two of its major tributaries, the Main and Neckar, are used. The mean daily values for each river is calculated, and then aggregated into single metrics, *River Temperatures* (measured in °C) and *River Levels* (measured in cm). It is worth noting that a number of Germany's nuclear plants, which were active during the period of interest (2002-2009), drew cooling water from one of the represented rivers. [14] Moreover, these rivers also acted as the primary cooling source for several coal-fired plants, which also suffered from reduced capacity as a result of restrictions on thermal pollution during the heat waves of 2003 and 2006. These hydrological variables should therefore act as good proxies for the point at which German environmental authorities would begin to close down plants due to excessive thermal pollution.

Two variables are derived from the *River Temperatures* series so as to measure the negative effects that thermal pollution has on electricity prices. The first is a standard dummy variable that simply tests for a difference in price intercept when river temperatures exceed 25°C. The second variable measures the continued rise in temperature above this 25°C threshold, i.e. $D^{Riv.Temp>25^{o}} \cdot \log(Riv.Temp - 25^{o})$. This formulation ensures some flexibility

[14] This includes the following plants: Biblis and Phillipsburg (Rhine River); Brunsbüttel and Krümmel (Elbe River); Grafenrheinfeld (River Main); and Neckarwestheim and Obrigheim (Neckar River). The Obrigheim Plant was decommissioned in 2005, but was among those temporarily switched off during the 2003 heat wave due to thermal pollution.

and allows for some non-linear effects of an increasing temperature around the exogenous threshold.[15] It should also be noted that this type of specification is consistent with the theoretical model described in Section 2; a shadow price is comes into play when the river temperature is greater than some regulatory limit, with a positive marginal effect of increasing temperature above that threshold. The formulation is depicted in Figure 1.

[Figure 1 about here]

We use the *River Levels* to construct variables that reflect the scarcity of water. In particular, we want to control for the possibility that changes in water availability might matter at different stages of relative abundance. Thus, the river level series is log-transformed and then partitioned into separate splines. After experimenting with different groupings, three river level splines are generated according to the following percentile distributions: i) "Very low" (0%-15%); ii) "low" (16%-33%); and iii) "mid to high" (34% and greater).

To control for the effect of input prices we use the log-transformed 90-day moving average (MA) of daily Brent crude oil prices, which are obtained from Bloomberg. Although oil is not a significant input fuel for Germany's electricity sector, it is widely held as a good proxy for natural gas (and even the general price movements of coal). The availability of daily spot prices also makes oil more amenable to our analysis here.

A dummy variable measuring weekends and public holidays is included in the regressions. Two approaches are taken to control for seasonal effects. The first is simply to include monthly dummies, while the second incorporates a wave function using the

[15] This aggregate 25°C threshold does gloss over some site-specific issues, since the permitted mixing temperature measured downstream from the thermal discharge in Germany varies between 23°C and 28°C; depending on river-specific ecological characteristics (Müller *et al.*, 2007). Still, given that we use aggregate data in this study, and not site- or river-specific data, this form is hopefully flexible enough to capture the river-specific deviation from this aggregate threshold.

trigonometric predictors, sine and cosine.[16] The set of variables aimed at controlling for trend and seasonal effects is completed by a group of year dummies, which were included to account for annual changes over the review period. Besides standard calendar and seasonal effects, these variables are thus expected to control for unaccounted variations in demand – for example, stemming from changes in the aggregate income level of electricity consumers.

4. Empirical Results

The regression outputs for two contemporaneous models are summarised in Table 1. Model (1) in the left-hand column uses month dummies to account for seasonality, while model (2) in the right-hand column does so by incorporating a wave function using the trigonometric predictors, sine and cosine. These contemporaneous specifications include no predetermined (i.e. lagged electricity price or volume) variables in estimating the base electricity price. The rationale underpinning this specification is that – given its role as an optimising market – the spot power exchange should effectively constitute a new market each day. All results are calculated using heteroskedasticity- and autocorrelation-consistent (HAC) estimators (Newey and West 1987).

[Table 1 "Static models" about here]

Focusing on model (1), which controls for seasonality using monthly dummies, the regression results suggest that a one percent increase in the quantity of electricity will induce a six percent increase in the base price. This implies that the daily power supply in Germany

[16] The formulas used are $F(t) = \sin(2.\pi.t/365)$ and $G(t) = \cos(2.\pi.t/365)$, respectively, where t denotes time in days, and reflect the fact that a full seasonal cycle would complete each year.

is highly inelastic – which we would expect given the very short-term nature of the (daily) data observations in this study.

We find the impact of water scarcity, measured by river levels, to be negative with statistically significant coefficients on the "mid-to-high" and "low" bands. This indicates that the electricity price is expected to fall as river levels rise and is consistent with the hypothesis that prices move in the opposite direction to the availability of cooling water, even after controlling for potential demand effects. In particular, model (1) implies that a one percent increase in aggregated river levels in the "mid-to-high" range (from the 34th percentile up) will result in a 1.2 percent decrease in the electricity price. Furthermore, when river levels are in the "low" band (16th to 33rd percentile), a one percent increase in river levels will yield a corresponding price drop of 1.3 percent. It is somewhat surprising to note that the coefficient on the "very low" river level band (15th percentile and less) is not statistically significant, since one might expect prices to drop more significantly during times when rivers are at their lowest levels. One potential explanation for this statistical insignificance is that those plants most reliant on water consumption – i.e. those most sensitive to water scarcity – may already have been forced to power down by the time that rivers reach their lowest levels.

Model (1) also indicates that there is a statistically significant (positive) relationship between the electricity price and an aggregate river temperature over 25°C. Once this threshold is breached, prices are expected to rise by 0.3 percent for every additional percentage increase in river temperature. In other words, a temperature rise from 25°C to 26°C (i.e. a four percent increase) will correspond to a 1.2 percent increase in the price of electricity. The mechanism underpinning this relationship is that power plants will be forced to throttle production for environmental reasons associated with thermal pollution. If one also takes the coefficient on the $D^{Riv.Temp>25°C}$ dummy in account, even though it is not statistically significant at the five percent level for model (1), passing the 25°C threshold would imply an additional [100 * ($e^{0.171}$ – 1) =] 18.7 percent. Thus, an increase in the river temperature from (just below) 25°C to 26°C has a quite substantial effect on the electricity price.[17]

Although fuel costs are included more for the sake of completeness than anything else, the coefficient on the 90-day MA for Brent crude is statistically significant and positive – as we would expect given its role as a fuel input for the production of electricity. In particular, the results suggest that the electricity price will rise by half a percent for every one percent increase in the price of oil.[18]

The results for model (2), which attempts to control for seasonality using a trigonometric wave function instead of monthly dummies, are not much different from the model (1) specification. One interesting distinction, however, is that the coefficient on the $D^{Riv.Temp>25°C}$ dummy variable is now statistically significant at the five percent level. Slightly adapting our earlier example, if river temperatures rise from just under 25°C to 26°C, then the electricity price is predicted to increase by approximately [100 * ($e^{0.216}$ – 1) + 4 * 0.344 =] 25.5 percent. Thus, an increase in river temperatures above the 25°C threshold produces an increase of roughly the same magnitude as found in model (1).

For both model (1) and model (2), the Hausman test shows that endogeneity/simultaneity *is* a problem, and thus, OLS must be discarded in favour of 2SLS. The Anderson canonical correlation tests state that the instruments – *HDDs*, *CDDs* and *NonWorkingDay* – are relevant, while the Hansen's *J* test of overidentifying restrictions shows that the instruments are valid.[19]

[17] The $D^{Riv.Temp>25°C}$ dummy is significant at the 10 percent level, returning a *p*-value of 0.08.

[18] While neither the monthly dummies nor the year dummies are reported individually, they are all jointly significant. There is an increasingly negative coefficient on the year dummy coefficients until 2009, demonstrating that electricity prices have been increasing slowly relative to volumes over the years. Furthermore, the coefficients on the month dummies indicate that German electricity prices are typically higher in the summer months.

[19] Anderson's canonical correlations test is way of testing the rank condition of the (system of equations) matrix, where the null hypothesis is that the system is unidentified and the instruments are not relevant. The test statistic follows a chi-squared ($\chi 2$) distribution with (L − K + 1) degrees of freedom. The Hansen *J* statistic is in principle similar to the Sargan test of overidentifying restrictions,

Looking at the series of estimated residuals for models (1) and (2), using an augmented Dickey-Fuller test (ADF) shows that non-stationarity in the residuals does not appear to be a problem.[20] However, testing shows that there is positive autocorrelation in the residuals of both models. One potential explanation could be misspecified dynamics. In particular, the fact that we have relied on a static model formulation so far. Such a formulation implicitly assumes that the daily spot electricity price is market-clearing, yet it could be argued that today's electricity price is correlated with the previous day's price or even that of the week before. This idea is given credence by the fact that electricity supply is comprised of quasi-fixed proportions of baseload and variable power. In general, baseload facilities like nuclear and coal-fired plants are not readily able to alter electricity production and one could say that there is some "memory" in the power market system.[21] In this case, our modelling efforts would be improved by incorporating dynamic aspects.

The key results from two such dynamic models, which include one- and seven-day lags for both electricity price and volumes, are shown in Table 2. Consistent with the contemporaneous models described earlier, model (3) in the first column incorporates month dummies to account for seasonality, while model (4) in the second column does so by using trigonometric predictors.

[Table 2 "Dynamic models" about here]

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except that it has been adjusted to be consistent with HAC standard errors used in the robust regression estimation. See Baum *et al.* 2007 for further discussion.

[20] Although not reported, it is also tested whether non-stationarity is a problem for the log-transformed electricity prices- and volumes using an ADF test. These results indicate that, having accounted for trends in the form of year and monthly dummies (as well as trigonometric seasonal predictors), we are able to reject the null hypothesis of non-stationarity for these series.

[21] The load-following capacity of baseload power is an important concept here. In particular, certain baseload generating facilities such as nuclear and coal-fired plants are typically run continuously. This is both a result of economic efficiency (since they have low variable costs in comparison with the high fixed costs that must be recouped), and technical efficiency (since these plants cannot readily alter power output in the same way that gas or hydro plants can). See, for instance, WNA (2011).

It can be seen that the coefficients on the lagged endogenous variables in both models are all statistically significant. Thus, we appear to have vindicated our suspicions that the German electricity spot exchange does not constitute a "new" market every day. Looking first at model (3), the coefficient on the contemporaneous volumes of electricity (i.e. 8.244) denotes the short-run, instantaneous impact of a change in volumes on prices. We calculate the corresponding long-run multiplier to be 9.559 and statistically significant (p-value = 0.0002). Thus, the dynamic specification of our model shows that a one percent increase in electricity volumes will lead to a 9.6 percent increase in price in the long-run. Similar to our previous results, this is clearly indicative of a very inelastic supply curve, but it is representative of the inertia present within the system.

At first glance, the dynamic model presents somewhat puzzling results in terms of the relationship between electricity prices on one hand, and river levels and river temperatures on the other. For example, contrary to the static models (1) and (2), the coefficient on "low" river levels is no longer significant; neither for model (3) nor model (4).[22] In fact, only changes within the "mid to high" river level band are now estimated to be statistically significant. The immediate short-run effects of a one percent fall in river levels in the "mid to high" category is to bring about a 0.4 percent rise in prices. In the long-run, this effect is calculated to be 1.8 percent (p-value = 0.004). The slope coefficient on river temperatures above 25°C (i.e. D_{Riv25}) is both statistically significant and positive. In particular, a one percent increase in river temperatures above this threshold is expected to yield a slightly bigger than 0.2 percent immediate increase in prices. The equivalent long-run effect is 0.9 percent with a corresponding p-value of 0.004. In other words, a temperature rise from 25°C

[22] Similarly, the corresponding long-run multipliers are 1.1 percent and -2.0 percent for river levels defined by the 15th and 33rd percentiles, respectively. Again, neither of these coefficients is statistically significant at the five percent level.

to 26°C would cause an immediate price increase of approximately 0.9 percent, and an increase of 3.8 percent over the course of a week.

While of lesser importance to this study, we also note that the coefficient on fuel costs is no longer significant under the dynamic specification. It would thus appear that accounting for lagged values of prices and volumes renders the variation in fuel costs insignificant in terms of being able to explain daily electricity price fluctuations.

As with the static model specification, the dynamic model results are not significantly altered when using a trigonometric wave function to control for seasonality; the output from model (4) is broadly equivalent to that of model (3). In short, the primary results remain that electricity supply is highly inelastic, while prices are expected to increase as river levels fall, or river temperatures rise above 25°C.

Running through the same set of statistical tests described previously, we are able to confirm the validity of our instruments (as well as the presence of endogeneity that necessitates 2SLS in the first place). A more pertinent question surrounding the extension towards a dynamic specification, however, is whether it removes the autocorrelation that was present in the contemporaneous models. Indeed, no significant sign of autocorrelation is found when one now tests for the presence of autocorrelation in the predicted residuals.

In addition to the primary models described above, we also run a number of alternate specifications to confirm the robustness of our findings. First, we test whether there are any significant differences between the slope coefficients of the river level splines. Using model 3 to illustrate, the null hypothesis, H_0: $\beta_{\text{Low}} = \beta_{\text{MidtoHigh}}$ cannot be rejected, owing to the high *p*-value of 0.9151. Thus, we infer that the coefficients on the "low" and "mid to high" river level splines are the same. For the sake of completeness, we conduct a similar test incorporating the "very low" spline coefficient. While this may seem a strange test at face value (i.e. given the disparity in the coefficient magnitudes), it is plausible that equivalence is still possible and may simply be hidden by large standard errors of the smaller sample group.[23] Indeed, these suspicions appear to be confirmed, since we are unable to reject the null hypothesis of equality when comparing the "very low" coefficient to both the "low" and "mid to high" coefficients; the relevant chi-squared test statistics (and *p*-values) being 0.98 (and 0.3213) and 2.38 (and 0.1231), respectively. As a consequence of these tests, it makes sense to do away with the separate splines and simply include river levels as a single, continuous series in the model. The results of these exercises are reported in Table 3.

[Table 3 "Dynamic models; no splines" about here]

We only comment on the river variables in the above models. Most importantly – given the nature of this particular specification – the coefficient on the now continuous river level series is both negative and statistically significant. Both models (5) and (6) suggest that a one percent drop in river levels will be associated with a contemporaneous 0.3-0.4 percent rise in electricity prices. The relevant long-run multipliers are approximately -1.6 percent for each model and highly significant.

With regards to river temperatures, we again see a positive relationship between electricity prices and river temperatures above 25°C. Prices will be expected to rise by approximately 0.2 percent for every one percent that temperatures increase above this level in the short-run. In other words, if aggregate river temperatures rise from 25°C to 26°C then the electricity price would be expected to immediately rise in the range of 0.8-0.9 percent.

In an additional robustness check, we have replaced the river level splines with river level dummies. Thus, rather than measuring the potential difference in slope coefficients, we aim to assess whether there are any statistically significant differences in the intercepts of the

[23] Recall that only 15 percent of the sample observations fall into the "very low" river level band (as per definition).

various river level bands. These dummies are defined so as to correspond to the same percentile distribution that we have used for river levels throughout this study – i.e. the 15th percentile is the cut-off point for the "very low" band, the 33rd percentile for the "low" band, while the "mid-to-high" base group is everything above this. Again, we find that electricity prices will be driven higher as river levels fall.[24]

Finally, we have included a log-transformed 90-day moving average of CO_2 future contracts in the dynamic model where seasonal effects are modelled using monthly dummies. This variable is meant to act as a proxy for the costs of inputs for substitutes of thermal-based electricity production. Again, and while we only have available data for the period 2006-2009, the basic results of our regression analysis are not altered by the inclusion of emission permits.[25]

5. Concluding remarks

In this paper, we have tried to quantify the empirical relationship between electricity prices and water scarcity and quality (as measured by river levels and temperatures, respectively). The link between water and thermal plants stems from the critical role that it plays in the cooling process. In cases where thermal facilities are located inland, tremendous quantities of water must be drawn from rivers, lakes and other freshwater reservoirs. These sources may be subject to incidents of scarcity, environmental regulations, and competing economic concerns.

[24] These results are not reported, but are available from the authors on request.

[25] These results are not reported, but available from the authors on request. Please note that, when we compare the results of this particular dynamic model with one for the same period (2006-2009) without the additional CO_2 variable, we find no difference in most of the coefficients. More importantly, the coefficient of the CO_2 permit variable has a *p*-value of 0.068. Thus, our specification presented in Table 3 is robust also to including emission permits.

Having successfully controlled for various demand and seasonal effects within a simultaneous equation framework, our results indicate that (German) electricity prices are significantly affected by both falling river levels and higher river temperatures. The magnitude of these relationships varies according to the exact specification of the model, where we have used both contemporaneous and dynamic iterations to model electricity prices. Under a fully contemporaneous setting, the electricity price is expected to rise by around one percent for every one percent that river levels fall. Conversely, the dynamic specification suggests that price will rise at about half that rate in the short-run, before increasing to approximately one and a half percent in the long-run. With regards to river temperatures, the models imply that the price of electricity will increase by roughly 1-1.5 percent for every degree that temperatures rise above a 25°C threshold in the short-run. Incorporating the long-run effects implied by a dynamic model shows that prices will rise by nearly four percent over the course of a week. In addition to this slope effect, the contemporaneous model actually shows a price discontinuity on either side of this 25°C threshold. Incorporating this intercept effect would suggest that prices can be expected to increase significantly during very hot periods.

One implication of our findings is that future climate change will impact electricity prices not only through changes in demand, but also as a result of increased cooling water scarcity. We believe that this type of analysis would lend itself to application in a number of regions and countries, which have a marked dependency on thermal-based power at the same time as being prone to drought and high temperature events.

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Figure 1: The effect of river temperature on electricity price

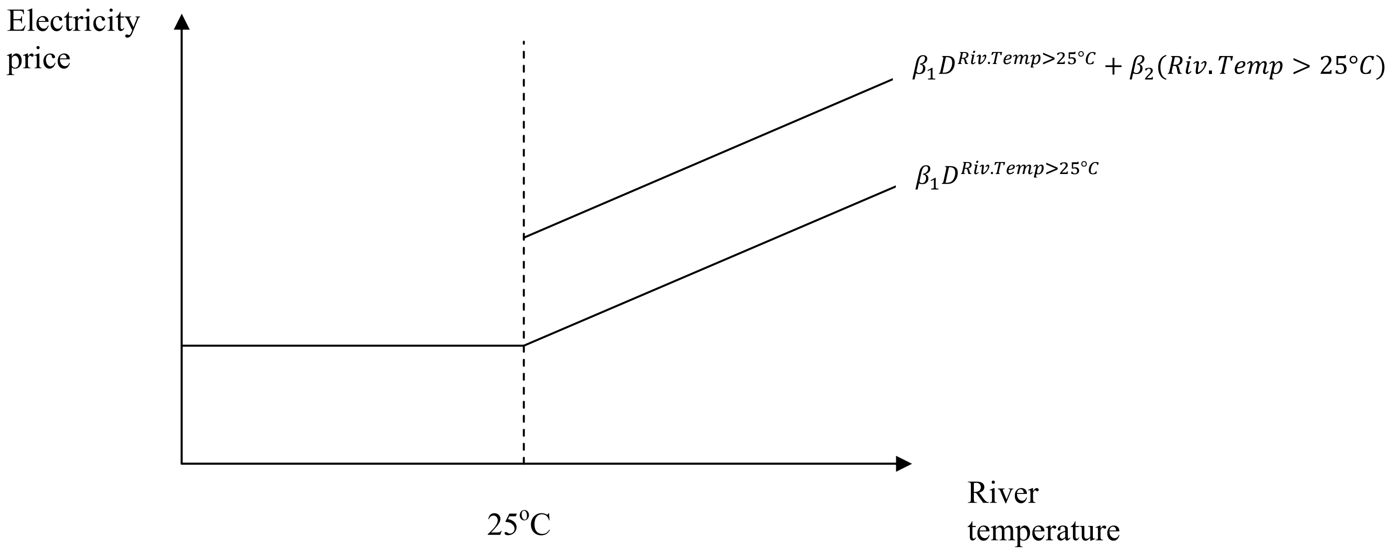

Table 1: Contemporaneous Models

	Model 1 (Month Dummies)	Model 2 (Trig Variables)
Dep. Var. = Base Price		
COEFFICIENTS		
Base Volume	5.983**	6.065**
	(0.397)	(0.421)
River Level Splines (by percentiles)		
"Very Low" (0-15%)	0.389	0.187
	(0.470)	(0.469)
"Low" (16-33%)	-1.267**	-1.099*
	(0.457)	(0.468)
"Mid to high" (34+%)	-1.118**	-0.993**
	(0.142)	(0.145)
River Temperature		
$D^{Riv.Temp>25°C}$	0.171	0.216*
	(0.097)	(0.098)
$D^{Riv.Temp>25°C}.\log(Riv.Temp - 25°C)$	0.310**	0.344**
	(0.093)	(0.098)
Brent (90-day MA)	0.460**	0.141
	(0.153)	(0.170)
TESTS (p-values)		
Endogeneity test[a]	0.000	0.000
Instrumental variable test[b]	0.000	0.000
Overidentifying restrictions test[c]	0.122	0.100
Joint significance tests		
Month Dummies	0.000	N/A
Trigonometric Predictors	N/A	0.000
Year Dummies	0.000	0.000
N	2922	2922

$^{*}\ p < 0.05$, $^{**}\ p < 0.01$

Notes: For the coefficients, standard errors are reported in parentheses. For the tests, p-values are reported rather than test statistics. A constant term, year dummies, and seasonal variables are also included as regressors in the price equation, but the estimated coefficients attached to these variables are not reported in the table. Heating degree days (*HDDs*), cooling degree days (*CDDs*), and a *NonWorkingDay* dummy are used as instruments.

[a] Hausman test includes the saved residuals from the first-stage regression in the second stage of the 2SLS estimation. H_0: System is exogenous.

[b] Anderson's canonical correlations test of the rank condition of the (system of equations) matrix. H_0: System is unidentified and the instruments are not relevant.

[c] The Hansen *J* statistic for overidentifying restrictions is computed using HAC estimators. H_0: Instruments are exogenous.

Table 2: Dynamic Models

	Model 3 (Month Dummies)	Model 4 (Trig Variables)
Dep. Var. = Base Price		
COEFFICIENTS		
Base Volume	8.244***	8.337***
	(0.918)	(0.928)
Predetermined Variables		
L1.Base Price	0.624***	0.646***
	(0.074)	(0.075)
L7.Base Price	0.138*	0.146**
	(0.057)	(0.056)
L1.Base Volume	-3.705***	-3.875***
	(0.418)	(0.438)
L7.Base Volume	-2.264***	-2.316***
	(0.362)	(0.369)
River Level Splines (by percentiles)		
"Very Low" (0-15%)	0.260	0.083
	(0.449)	(0.426)
"Low" (16-33%)	-0.485	-0.376
	(0.427)	(0.412)
"Mid to high" (34+%)	-0.434***	-0.357***
	(0.112)	(0.107)
River Temperature		
$D^{Riv.Temp>25^\circ C}$	-0.018	-0.016
	(0.084)	(0.082)
$D^{Riv.Temp>25^\circ C}.\log(Riv.Temp - 25^\circ\mathrm{C})$	0.225***	0.237***
	(0.060)	(0.059)
Brent (90-day MA)	0.131	0.092
	(0.127)	(0.130)
TESTS		
Endogeneity test[a]	0.000	0.000
Instrumental variable test[b]	0.000	0.000
Overidentifying restrictions test[c]	0.078	0.115
Joint significance tests		
Month Dummies	0.000	N/A
Trigonometric Predictors	N/A	0.000
Year Dummies	0.000	0.000
N	2915	2915

* $p < 0.05$, ** $p < 0.01$
See Notes to Table 1.
[a b c] See Table 1 for explanation.

Table 3: Dynamic Models with a continuous river level series

	Model 5 (Month Dummies)	Model 6 (Trig Variables)
Dep. Var. = Base Price		
COEFFICIENTS		
Base Volume	8.267***	8.349***
	(0.925)	(0.931)
Predetermined Variables		
L1.Base Price	0.624***	0.646***
	(0.073)	(0.074)
L7.Base Price	0.138*	0.145**
	(0.057)	(0.056)
L1.Base Volume	-3.729***	-3.887***
	(0.421)	(0.440)
L7.Base Volume	-2.280***	-2.325***
	(0.365)	(0.371)
River Levels	-0.389***	-0.329***
	(0.092)	(0.090)
River Temperature		
$D^{Riv.Temp>25°C}.\log(Riv.Temp - 25°C)$	-0.053	-0.037
	(0.087)	(0.083)
$D^{Riv.Temp>25°C}$	0.210***	0.227***
	(0.062)	(0.060)
Brent (90-day MA)	0.163	0.114
	(0.125)	(0.128)
TESTS		
Endogeneity test[a]	0.000	0.000
Instrumental variable test[b]	0.000	0.000
Overidentifying restrictions test[c]	0.079	0.113
Joint significance tests		
Month Dummies	0.000	N/A
Trigonometric Predictors	N/A	0.000
Year Dummies	0.000	0.000
N	2915	2915

* $p < 0.05$, ** $p < 0.01$

See Notes to Table 1.

[a b c] See Table 1 for explanation.

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12/11 July, Karin Monstad, Carol Propper, and **Kjell G. Salvanes**, "Is teenage motherhood contagious? Evidence from a Natural Experiment".

13/11 August, **Kurt R. Brekke**, Rosella Levaggi, Luigi Siciliani, and Odd Rune Straume, "Patient Mobility, Health Care Quality and Welfare".

14/11 July, **Sigbjørn Birkeland d.y**., "Fairness motivation in bargaining".

15/11 September, **Sigbjørn Birkeland d.y**, **Alexander Cappelen**, **Erik Ø. Sørensen**, and **Bertil Tungodden**, "Immoral criminals? An experimental study of social preferences among prisoners".

16/11 September, **Hans Jarle Kind**, Guttorm Schjelderup, and Frank Stähler, "Newspaper Differentiation and Investments in Journalism: The Role of Tax Policy".

17/11 **Gregory Corcos**, Massimo Del Gatto, Giordano Mion, and Gianmarco I.P. Ottaviano, "Productivity and Firm Selection: Quantifying the "New" Gains from Trade".

18/11 **Grant R. McDermott** and **Øivind Anti Nilsen**, "Electricity Prices, River Temperatures and Cooling Water Scarcity".

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