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The impact of heat waves on electricity spot markets

Anna Pechan *, Klaus Eisenack

Department of Economics, University of Oldenburg, Germany

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ABSTRACT

Thermoelectric power plants depend on cooling water drawn from water bodies. Low river run-off and/or high water temperatures limit a plant's production capacity. This problem may intensify with climate change. Our study quantifies the impact of forced capacity reductions on market prices, production costs, consumer and producer surplus, as well as emissions by means of a bottom-up power generation system model. First, we simulate the German electricity spot market during the heat wave of 2006. Then we conduct a sensitivity study that accounts for future climatic and technological conditions.

We find an average price increase of 11% during the heat wave 2006, which is even more pronounced during times of peak demand. Production costs accumulate to an additional but moderate 16 m. Due to the price increase, producers gain from the heat wave, whereas consumers disproportionately bear the costs. Carbon emissions in the German electricity sector increase during the heat wave. The price and cost effects are more pronounced and increase significantly if assumptions on heat-sensitive demand, hydropower capacity, net exports, and capacity reductions are tightened. These are potential additional effects of climate change. Hence, if mitigation fails or is postponed globally, the impacts on the current energy system are very likely to rise. Increases in feed-in from renewable resources and demand-side management can counter the effects to a considerable degree. Countries with a shift toward a renewable energy supply can be expected to be much less susceptible to cooling water scarcity than those with a high share of nuclear and coal-fired power plants.

1. Introduction

The role of fossil-fuel power plants in causing climate change has been investigated and discussed in-depth. The repercussions of a changing climate on electricity production and markets have, however, received less attention in the research to date. Owing to the dependency of steam power plants on cooling water, an increasing frequency or intensity of heat waves can have significant effects on the electricity sector. During hot periods, not only does the cooling water drawn from freshwater reservoirs become physically scarce; the discharge and temperature of effluent water also fall under legal restrictions protecting aquatic ecosystems (e.g., EU Freshwater Fish Directive, 78/659/EEC). Under heat wave conditions, many of these legal standards mandate a reduction in power generation. This was the case during the European heat waves of 2003 and 2006 (Strauch, 2011). The forced capacity reductions affect a range of key variables, from electricity prices to production costs, and may have different impacts on consumers and producers. During the 2006 heat wave, electricity spot market prices reached € 2000 per megawatt hour (MWh) at the European Energy Exchange (EEX), compared to their usual price of € 50 per MWh (EEX, 2012). Past heat wave impacts have not been quantified in the literature to date, except in studies of the European agricultural sector (Eisenreich et al., 2005). Yet evaluation of the impacts and resulting costs is crucial for informed decision-making in both industry and politics, especially against the backdrop of accelerating climate change.

The impact of increasing river temperatures and of decreasing water flows on electricity production has been analyzed in numerous studies of recent years (Koch and Vögele, 2009; Linnerud et al., 2011; Mideksa and Kallbekken, 2010; Pechan et al., 2011; Rübbelke and Vögele, 2011; van Vliet et al., 2012). Efforts to quantify the economic effects of forced capacity reductions on individual power plants have produced wide-ranging estimates: Förster and Lilliestam (2010) found annual income losses between 5.2 m and 81 m for a (nuclear) power plant; Koch et al. (2012) reported cumulative losses of between 15 m and approximately 60 m for all power plants in Berlin between 2010 and 2050. Most of the existing studies do not endogenize electricity market prices. Exceptions are Golombek et al. (2012), van Vliet et al. (2013) and Rübbelke and Vögele (2013), who simulated climate change impacts based on energy system scenarios, finding only minor price effects for Germany. These studies, however, focused on future average temperatures and not on weather extremes. To our knowledge, the relation between river temperatures and base load prices has only been investigated in one econometric analysis up to now (McDermott and Nilsen, 2011). A reference case based on historic data that also provides insights into the cost incidence of heat waves for producers and consumers is therefore missing. Furthermore, with the exception of Golombek et al.

* Corresponding author at: University of Oldenburg, Ammerlaender Heerstr. 114-118, 26129 Oldenburg, Germany. Tel.: +49 441 7984523.
E-mail address: anna.pechan@uni-oldenburg.de (A. Pechan).

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(2012), additional heat wave impacts on the electricity sector such as reduced hydropower availability or effect on imports and exports have not been tested for or analyzed separately. Finally, to our knowledge the effect of forced capacity reductions due to heat waves on carbon dioxide emissions has not been examined in the literature so far.

In this paper, we try to fill these gaps. We apply a bottom-up simulation model of the German electricity wholesale market to examine the effect of forced capacity reductions. We start from historic data on the German heat wave of July 2006, and perform an extensive sensitivity study (i) to validate the robustness of the results and (ii) to determine how market impacts may depend on climate change and on a transformation of the energy system.

Our simulation results show that forced capacity reductions have a substantial impact on prices, which rose on average by 11% during the heat wave. As a consequence, total producer surplus increased, whereas consumer surplus decreased notedly. Production costs and carbon dioxide emissions in the German electricity sector increased moderately during the heat wave. The sensitivity analyses show that if further heat-induced effects are taken into account, e.g., increased electricity demand, or if heat waves become more intense in the future due to climate change, these impacts are more pronounced. Rising feed-in from renewable resources and improved demand-side management can counter the effects to a considerable degree.

In Section 2, we introduce the model and give an overview of the data used and scenarios applied. In Section 3, we show the results of the 2006 heat wave. The results of the sensitivity analyses are presented in Section 4. In Section 5, we discuss the results and conclude.

2. The model and data

2.1. Theoretical model

In the following, we present a theoretical model illustrating the main effects of reduced thermal capacity on the electricity market. We assume a market with perfect competition where producers bid at variable production costs. Each producer operates only one power plant. The market price is determined by the marginal costs of the most expensive power plant necessary to cover demand. Producers are able to make profits when the market price exceeds their variable costs. Profits are used to cover capacity costs.[1] Fig. 1 gives a stylized overview of the effects.

The inverse demand for electricity is denoted by $D(q)$, where q is the quantity of power. Demand is assumed to be price-inelastic in the short term. $S_{nhw}(q)$ is the domestic electricity supply without capacity reductions, $S_{hw}(q)$ is the supply with capacity reductions. The suffix *hw* denotes the heat wave situation, while *nhw* signifies the undisrupted situation without a heat wave. The market price is represented by p. Power plants are denoted $i = 1,\ldots,N$ and produce a power output q_i each, subject to a capacity constraint, $q_i \leq q_i^{max}$, with variable production costs c_i. The sum of generation costs is represented by C. All these variables are positive.

Under undisturbed conditions, the market equilibrium leads to the electricity price p_{nhw}. Due to the scarcity of cooling water, the capacity of several plants is temporarily reduced, causing a supply gap of Δq. This gap has to be closed by power plants located further to the right in the supply curve, i.e., plants with higher production costs.[2]

Power plant operators maximize profits, regarding fixed costs as sunk. The sum of producer surplus, PS, is given by

$$PS = \sum_{i=1,\ldots,N} (p - c_i) q_i. \tag{1}$$

[1] Capacity costs are not considered here.

[2] These considerations also hold if multiple power plants are curtailed, no matter whether they are adjacent in the merit order.

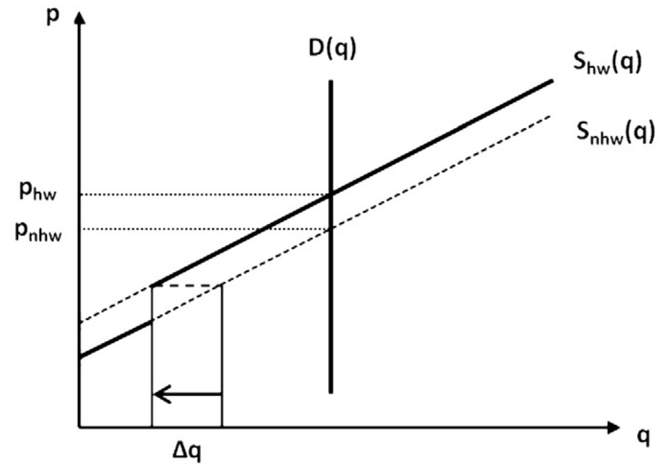

Fig. 1. Effects of capacity reductions on market equilibrium and prices.

The sum of generation costs, C, is

$$C = \sum_{i=1,\ldots,N} c_i q_i \tag{2}$$

The total of consumer surplus, CS, is defined as the difference between willingness to pay, represented in the demand curve, and the market price. Since demand is inelastic, CS changes during the heat wave by

$$\Delta CS = p_{nhw} \sum_{i=1,\ldots,N} q_{i,nhw} - p_{hw} \sum_{i=1,\ldots,N} q_{i,hw} \tag{3}$$

It is evident from the partial equilibrium analysis that the electricity price increases due to the capacity reductions. With increasing prices, consumer surplus decreases, since $\sum_i q_{i,nhw} = D = \sum_i q_{i,hw}$. Since the supply gap is closed by plants that have higher variable production costs c_i, the sum of generation costs C unambiguously increases by

$$\Delta C = \sum_{i=1,\ldots,N} c_i q_{i,hw} - \sum_{i=1,\ldots,N} c_i q_{i,nhw}. \tag{4}$$

The effect on the surplus of a single power plant is generally ambiguous. It changes during the heat wave by

$$\Delta PS_i = (p_{hw} - c_i) q_{i,hw} - (p_{nhw} - c_i) q_{i,nhw}. \tag{5}$$

If production q_i were identical in both situations, then ΔPS_i would be positive: the producer can sell the same quantity at higher prices. Yet in cases where $0 < q_{i,hw} < q_{i,nhw}$, the effect on the producer surplus earned by a single power plant could be either positive or negative. The direction of the overall effect depends on the magnitude of the price and the quantity effect. The smaller the difference in production and the higher the price increase, the more likely it is that ΔPS_i is positive. Two extreme cases have straightforward effects on a single power plant's producer: if $q_{i,hw}$ is zero (positive) and $q_{i,nhw}$ positive (zero), then ΔPS_i is negative (positive).

The effect on total producer surplus PS does not depend on the quantity effect since the total amount of energy remains unchanged when demand is price inelastic. Given a linear supply curve as depicted in Fig. 1, total producer surplus increases or at least remains unchanged in any case. However, the real supply curve or merit order is not a linear but a step function with a roughly convex shape at medium to high demand. Therefore, the total effect on PS can be either positive or negative. Total producer surplus clearly increases when only the marginal power plant has to reduce production and is replaced by a plant with substantially higher costs, e.g. in times of high demand. Then the price increases significantly whereas total generation costs rise only marginally. In this case, the protection of the freshwater ecosystems would be realized almost exclusively at consumers' expense. On the other hand, the change in *PS* can be negative, when the replacement does not result in a higher market price, e.g. in times of low demand. Then plants with low cost may be replaced by plants that do not have (significantly) greater production costs than the formerly price-setting power plant. Hence, the question of whether producers gain or lose remains open at this point. Also the magnitude of the effect on consumer surplus and production costs cannot be determined per se theoretically. To resolve these open questions, we develop a numerical energy system model that also considers effects not included in the theoretical analysis of this subsection.

2.2. Model implementation

Beyond the theoretical setting, several characteristics of electricity markets have a significant influence on prices. Besides the real shape of the supply curve, inter-temporal aspects such as start-up times play a decisive role, too. In the following we outline the amendments made to the theoretical model, which closely follows the approach of Schwarz and Lang (2006), Weigt and Hirschhausen (2008), and Leuthold et al. (2012) (see Annex for a more technical description).

The model is based on real data on all German thermal power plant units exceeding 20 MW net capacity.[3] The calculations for the 2006 heat wave are based on historic demand and historic feed-in from renewable energies (excluding hydropower, see below). One component that determines the supply curve is the marginal production costs c_i of each plant resulting from fuel costs and certificate prices for carbon in the European Union's Emission Trading System (EU ETS). In addition, start-up and abrasion costs, sc_i, influence supply and hence prices. They occur only during the time when the plant unit is started up and comprise technology-specific fuel and abrasion costs. The model is implemented in GAMS with a successive run of a mixed integer (MIP) and a nonlinear program (NLP). The commitment of the single power plant units is determined in the first run and the hourly market price is computed in the second run. With the results from the first stage day-specific start-up and abrasion costs can be computed, which can hence be converted into variable cost components in the second step. We find that the model explains variation in real market prices better when start-up costs are not neglected.[4] The time resolution is 1 month (744 h).

The objective of the unit commitment problem in the first step is to minimize the production costs over an entire month

$$minC = \sum_{i,t} c_{i,t}q_{i,t} + sc_{i,t}, \tag{6}$$

subject to the technical constraints of electricity generation[5] and demand. Here $c_{i,t}$ are the variable generation costs of power plant unit i in hour t. The start-up costs $sc_{i,t}$ occur if the plant unit is started up in hour t. The production of the plant unit is restricted upwards by its installed net capacity, q_i^{max} and downwards by a minimum necessary amount of production, q_i^{min}:

$$on_{i,t}q_i^{min} \le q_{i,t} \le on_{i,t}q_i^{max}, \tag{7}$$

where $on_{i,t}$ is the binary variable that states whether plant i is producing in hour t (1) or not (0).

The model is further adjusted by considering start-up constraints. When a power plant unit is switched off, it has to remain off for a certain period of time before it can be restarted (Takriti et al., 2000). Likewise, some units have a minimum operation period. If a plant unit is started up in one period, it cannot be shut off before the minimum "on" period has passed (ibid.).

Additionally, the optimal operation of pumped-storage power plants (PSPs) is simulated. They are included as an aggregate in the model. Again, technical restrictions apply: The sum of the energy withdrawn from the grid, psp_t^{up}, and of the energy fed in to the grid, psp_t^{down}, cannot exceed the bottleneck capacity of the PSPs. In addition, the power generated by PSPs cannot exceed the capacity stored.

To balance energy, supply has to match demand at every point in time:

$$\sum_i q_{i,t} = D_t + psp_t^{up} - psp_t^{down}. \tag{8}$$

The residual load, D_t, is constructed as the sum of hourly load and net exports to neighboring countries net of feed in from renewable energy sources (RES-E; excluding hydropower), run-off river power plants, heat-lead combined heat production (CHP), and from industrial power plants, which are all given exogenously. In the second step, fixed binary plant commitments and hourly production from PSPs are included in the optimization problem. By means of the deduced number of start-ups and production of each plant per day in the first stage, the start-up and abrasion costs are converted into mark-ups per MW on the former variable costs of that day. The hourly price is then computed by minimizing the production costs in each time step t:

$$min\,C_t = \sum_t \left(scm_{i,t} + c_i\right)\tilde{q}_{i,t} \tag{9}$$

where $scm_{i,t}$ is the day-specific mark-up per MW produced.

In a specific sensitivity study below, we also consider elastic demand. This requires a modified model specification as a welfare maximizing problem in the second step. The unit commitment problem of the first step is solved as before by fixing demand values to the reference values. The maximization problem is:

$$max\,W_t = \int_0^{\tilde{D}_t} p_t\left(\tilde{D}_t\right)d\tilde{D}_t - \sum_i \left(scm_{i,t} + c_i\right)\tilde{q}_{i,t} \tag{10}$$

for every hour, subject to energy balance and technical constraints as introduced above. A linear inverse demand function $p_t\left(\tilde{D}_t\right)$ is assumed (see Annex).

It is assumed that all electricity is traded on one (day-ahead) wholesale market. Although only about 20 to 30% of the power is traded via the EEX, the day-ahead spot market price still plays a significant role, also for other ways of trading. Due to arbitrage opportunities, it serves as point of reference for forward markets and over-the-counter trade (Judith et al., 2011; Ockenfels et al., 2008).[6] This modeling assumption is common to numerous other studies (e.g., Rübbelke and Vögele, 2013; Sensfuß et al., 2008). Note that the changes in the model concern wholesale market prices and are not to be confused with end user prices.

2.3. Data

In Germany, gross electricity production in 2006 was dominated by nuclear power (26.2%), lignite (23.6%), hard coal (21.6%) and gas (11.8%) (BMWi, 2013). Power from renewable energy sources (excluding hydropower) covered 7.5%, hydropower plants 4.2%, and oil-fired plants 1.7% of gross electricity production (ibid.). The hourly load

[3] The model has been developed for this purpose and has not been applied before.

[4] Without start-up cost, the model explains 82% of the variation in the real price data, whereas with start-up costs it explains 86%. In addition, model mean price and price volatility deviate more from those of the real data (−19% and −39% respectively) in the first case than in the latter (−16% and −31%).

[5] Constraints due to transmission are not considered in this approach.

[6] Prices in forward markets or in long-term bilateral contracts, which are based on expected exchange prices, may vary from the exchange price but not in a systematic way (Ockenfels et al., 2008).

ranged between approximately 68,700 MW and 78,600 MW during daytime and between 43,500 MW and 59,000 MW during nighttime (ENTSO-E, 2012).

For the model, the supply curve (merit order) was estimated based on data from the German Federal Network Agency (Bundesnetzagentur) containing information on all conventional and renewable power units with an installed capacity greater than 20 MW by unit (Bundesnetzagentur, 2012), adjusted for changes since 2006. Data on RES-E feed-in (excluding hydropower) were retrieved from the transmission system operators (50Hertz, 2013; Amprion, 2013; Tennet, 2013; TransnetBW, 2013). Feed-in from run-off river power plants are assumed to be 100% of net installed capacity (ENTSO-E, 2012). Since the production of heat-led CHP mainly covers space heat demand, which is insignificant in summer, we assume that in this period, production is 20% of the net installed capacity (cf. Weigt and Hirschhausen, 2008). Operators of power-led CHP plants can offer electricity below marginal costs, because part of the costs is recovered through the sale of heat. The amount of this effect is calculated with the net realizable value method (Cornehl, 2008; Frank, 2003). The annual load factor of industrial power plants ranges between 80 and 91% (Konstantin, 2006). Due to summer holidays and weekends, we assume that industrial power plants produce at 80% of their net installed capacity, provided by Bundesnetzagentur (2012). Net electricity exports that reduce or increase domestic production are provided by the European Network of Transmission System Operators for Electricity (ENTSO-E).[7] The availability of the conventional power plants is reduced by planned revisions and unplanned non-availability. Revision times differ for each technology and occur mostly in summertime (Roth, 2008). We therefore assume higher planned non-availabilities in summer based on Roth (2008). In addition, unplanned non-availability occurs in case of e.g. technical problems, which are different for each technology and are taken from DEWI et al. (2005).

To estimate the marginal cost curve, the following cost components are taken into account: efficiency factor, fuel price, emission factor, certificate price for carbon, variable operating expenses (e.g., taxes, charges, fuel transportation), and start-up costs. An overview of the data sources is given in Table 1. The emission factor is taken into account not only to integrate carbon dioxide costs but also to be able to compare CO_2 emissions in the situations with and without a heat wave. Emissions of electricity production may decrease during a heat wave when carbon-intensive power plants have to reduce production and are replaced by power plants with lower emissions and vice versa.

The demand data for 2006 were obtained from ENTSO-E, (2012).[8] We fit the model to historic EEX prices. Through the appropriate choice of available PSP capacity and input of real data, the model explains 86% of the variation in the real electricity price data.[9] The model mean price is 16% lower than the mean of real price. The model produces lower electricity price volatility (−31%) than seen in the real prices. Real prices at night especially on the weekends are below model prices. In addition, some price peaks in the model do not match the real data. These occur particularly where plants with high start-up costs are run for a very short time (e.g., 1 h). These deviations may be explained by market power that might result in higher prices especially during times of peak demand, incomplete data, and/or an underestimation of start-up costs. Furthermore, the model is based on perfect foresight of the plant operators. The deviation from the EEX price could hence also be due to asymmetric information (cf. Weigt and Hirschhausen, 2008). In sum, the results of the model are satisfactory and reliable.[10]

We now describe the use of heat wave data and a counterfactual without a heat wave. The cases with and without heat wave are to be compared. In the *heat wave scenario* ('hw'), the maximum capacity of thermoelectric power plants that experienced problems during the heat wave of 2006 is restricted. The information on the forced capacity restrictions in Germany is based on Strauch (2011). Strauch collected data from several sources including interviews, literature, and the mass media. In total, thirteen coal-fired and seven nuclear power plants had to reduce their production (most of these at the end of July). Of these 20 power units, a share of 40% was equipped with a cooling tower. With regard to the capacity reductions of nuclear power plants, we cross-checked with monthly data from the International Atomic Energy Agency (IAEA, 2007). Based on this information, the highest reductions found by Strauch, which are applied here, can be assumed to be a conservative approximation. For those coal-fired power plants where the capacity reduction was only specified as small, we assume 10% reductions. The reductions in the model all occurred during the last fortnight (18th–31st) of July, 2006, yet not all constantly and simultaneously. On average, the concurrent reductions amount to 1946 MW, which corresponds to the capacity of approximately two nuclear power stations. At a minimum 338 MW and at a maximum 2830 MW were simultaneously not available.

The main difference in the *counterfactual scenario* ('nhw') is the assumption of absent capacity reductions. Hence, the upper limit of production is the net installed capacity of all power plant units. We assume that the residual load data used remains unaffected. Potential additional heat wave impacts such as an effect on electricity demand – due, e.g., to cooling needs – and on imports and exports will be discussed in the sensitivity analysis.

3. Results

We first compare the heat wave scenario with the counterfactual scenario to identify the impacts of capacity reductions on market prices, production costs, consumer and producer surplus, as well as emissions. Table 2 reports the results of the two scenarios for the 2-week period and shows the difference between the two.

The wholesale electricity price increased on average by 11%. In times of peak demand (weekdays from 8 a.m. to 8 p.m.) the increase was even more pronounced (17%) than during off-peak times (7%) (see Fig. 2). The rise in production costs was not as distinct: On average, production costs increased by about 6% (€ 1.04/MWh). The increase was only slightly higher during peak times than off-peak times.

The price increase is relatively high and therefore relevant for our analysis. The difference in impact between peak and off-peak times can be explained by the shape of the merit order. Reduced capacity has greater effects for higher demand levels (see Fig. 2).

Most of the costs of the heat wave are borne by the consumers. Production costs moderately increased in total by € 16 m during the fortnight. Producer surplus rose simultaneously by approximately € 55 m. To put this into perspective, the producer surplus increase corresponds to approximately 1% of the annual external sales of one of the largest power producer in Germany in 2006, i.e. RWE Power (RWE, 2007). At the same time, the consumer surplus decreased by € 71 m. More than 70% of these gains or losses were realized in times of peak demand.

[7] ENTSO-E only provides the data for the past 2 years. For 2006, data were kindly provided by Hannes Weigt, who had obtained the data from ENTSO-E in previous years.

[8] Load is not identical to consumption data. The former is given in MW for a single point in time, while the latter is given in MWh for a certain period. The load data are provided as average values for every hour and are therefore less precise than consumption values. ENTSO-E only provides load data on an hourly basis, while consumption data are given as a monthly aggregate only. We take hourly load data as an approximation for the power demand. The data represents only 91% of the total demand since they lack, e.g., demand from industry and railway companies. The values are scaled up to represent 100% of the hourly electricity load in Germany.

[9] Due to their ability to produce and consume power, pump-storage power plants play a great role in balancing and reserve energy provision: in 2007 about 33% of the installed capacity was withheld for positive balancing energy and about 6% for reserve energy (Judith et al., 2011). Data on the withholding for negative balancing capacity is not available. In addition, the production from PSPs depends on inflow of water and storage level (Judith et al., 2011). We hence varied the maximum PSP capacity, psp^{max}, from 0 up to 40% of the net installed capacity. A maximum PSP capacity of 20% gives the best representation of the real prices.

[10] See Annex B for a graphical comparison between model and EEX prices.

Table 1
Variable cost components.

Component	Source
Efficiency factor	Nuclear: (Förster and Lilliestam, 2010) Hard coal, lignite, gas/ oil-fired, gas-steam (age dependent): (BMWi (Bundesministerium für Wirtschaft und Technologie), 2006) Pump-storage: (Weigt and Hirschhausen, 2008)
Fuel price (monthly prices)	Crude oil (UK Brent): (Mineraloelwirtschaftsverband, 2012) Hard coal (cif-NW Europe): (EURACOAL, 2012) Uranium: (IndexMundi, 2012) Fuel oil: (StatistischesBundesamt, 2011) Natural gas: (BAFA, 2013) Lignite: (Jansen et al., 2005)
Emission factor	(BMU, 2003)
Emission certificate price	(EEX, 2012)
Additional variable costs	(Ellersdorfer et al., 2008)
Start-up costs	(Jansen et al., 2005)
Start-up and minimum down times	(Steck and Mauch, 2008)

This shows that a substantial shift of wealth from consumers to producers was indeed caused by the capacity reductions.

The large decrease in consumer surplus and the large increase in producer surplus are in part due to the assumed inelasticity of demand. Still, it is interesting to see that the overall effect on producer surplus is positive even in off-peak times with lower price effects.

Another effect that has not been examined before in the literature is the change in carbon dioxide emissions during a heat wave. It can be observed that emissions in the German electricity sector increase by about 5% per MWh. During the heat wave, this adds up to additional emissions of approximately 150,000 tons of CO_2. This is due to the fact that in our case, mainly carbon-neutral nuclear plants were temporarily replaced by carbon-intensive plants. Clearly, the direction of the effect depends on the respective generation mix, i.e. emissions in the electricity sector could also decrease if carbon-intensive plants were replaced by plants that emit less.

Since obviously not all plants gain from the price increase, it is useful to take a closer look at the situation of single power plants to identify where losses are made. For an illustration, we select two nuclear power units from our generation system, called A and B hereafter. They have similar net installed capacities but experienced different forced reduction with regard to degree and time. Power unit A has 1345 MW net installed capacity. During the heat wave, the plant had to reduce the maximum capacity by 65% during a period of 9 days and hence produced approximately 180 GWh less in sum. At the same time, power is sold at higher prices. As a consequence, the plant lost € 4.9 m of surplus during these 9 days. In addition, it was able to profit slightly from the price increase in the remaining 3 days of normal operation. During these days, the loss of surplus was compensated by about € 172,000 additional income (see Table 3). In contrast, if prices had remained unaffected, the power plant would have lost even more surplus (−€ 5.5 m) during the heat wave. This shows that the price effect is not negligible and can lead to positive effects on producer surplus, despite capacity reductions.

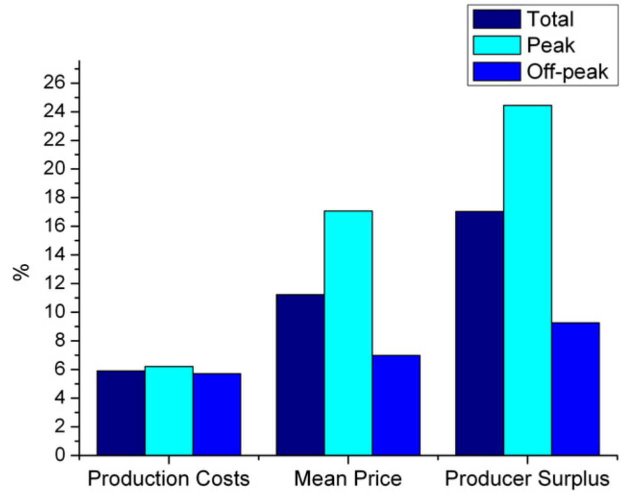

Fig. 2. Effect of capacity reductions on production costs, price and producer surplus (mean values per MWh).

This effect is even more evident for the second power plant B (1167 MW net installed capacity). It had to reduce maximum capacity by only 10% and for a shorter period of time (4 days) during the heat wave. In total, only 7.8 GWh less were produced in this case. During the period of reduced capacity, the effect on producer surplus was indeed negative but moderate (−€ 93,000). In sum, the plant profited from the heat wave price increase: Net of the losses, it gained approximately € 1.4 m (see Table 3). The results thus confirm the previous considerations: The smaller the capacity reductions, the more likely it is that the price effect will outweigh the quantity effect.

4. Sensitivity analyses

To infer the implications of climate change, changes in the generation mix and of selected modeling assumptions, we conduct a series of sensitivity analyses. First, we test for additional climate change impacts such as more severe capacity reductions. Second, additional heat wave impacts (e.g. higher demand for cooling) are considered. Third, we allow for elastic demand. Fourth, a change in the generation mix is taken into account. We determine for all modifications the difference between the heat wave and the counterfactual scenario. In a second step, these differences are compared with the reference case as computed in Section 3 above. Table 4 gives an overview of this section's results.

4.1. Additional climate change impacts

Projections for Germany show that the frequency and intensity of temperature anomalies in the summer months are likely to increase drastically up to the end of the current century, especially in the south (Deutschländer and Dalelane, 2012). This can have different consequences.

Table 2
Overview of results in the heat wave (hw) and counterfactual (nhw) scenarios and the differences between them.

	Scenario		Change	
	nhw	hw	hw vs. nhw	
Average price [€/MWh]	37.41	41.61	+4.21	(+11.2%)
Total production costs [€]	270 m	286 m	+16 m	(+5.9%)
Total producer surplus [€]	323 m	378 m	+55 m	(+17%)
Total consumer surplus [€]			−71 m	
Total CO_2 emissions [t]	2.97 m	3.12 m	+0.15 m	(+4.9%)

Table 3
Impact on producer surplus of power plant units A and B during hours with capacity reductions, hours of normal operation and the sum of both (A produces 180 GWh; B produces 7.8 GWh less). Changes are given relative to the counterfactual scenario.

Δ PS (hw vs. nhw)	Power unit	
	A	B
- During capacity reductions	−€4.9 m	−€0.1 m
- During normal operation	+€0.2 m	+€1.5 m
- Total	−€4.7 m	+€1.4 m

Table 4
Overview of sensitivity analyses. Changes in costs (ΔC), mean price ($\Delta \text{Ø}p$) and producer surplus (ΔPS) are all given relative to the counterfactual scenario (without a heat wave). Costs and surplus (in brackets) refer to million €. Heat wave conditions are denoted by 'hw', and 'nhw' refers to the counterfactual scenario.

Case	Modification	ΔC	$\Delta \text{Ø}p$	ΔPS
Reference (Section 3)	–	+5.9% (+16 m)	+11.2%	+17% (+55 m)
Additional climate change impacts				
More capacity red.	Ø +2.1 GW red. in hw	+13.1% (+35.3 m)	+23.2%	+33.8% (+109 m)
Strong capacity red.	Ø +4.9 GW red. in hw	+26.3% (+71.1 m)	+48.8%	+72.3% (+233.3 m)
Less hydropower	+0.4% res. load in hw	+6.9% (+18.6 m)	+12.3%	+19.1% (+62 m)
Additional heat wave impacts				
More demand	−2.5% res. load in nhw	+11.2% (+29.7 m)	+19%	+31.3% (+96.4 m)
Less import	−0.7% res. load in nhw	+7.5% (+19.9 m)	+13.1%	+21.2% (+65.4 m)
Elastic demand				
Low elasticity	−0.10 (hw and nhw)	+4.7% (+12.7 m)	+4.4%	+3.4% (+11 m)
Medium elasticity	−0.25 (hw and nhw)	+4.3% (+11.5 m)	+2.6%	−0.1% (−0.2 m)
High elasticity	−0.40 (hw and nhw)	+4.0% (+10.8 m)	+1.9%	−1.3% (−4.2 m)
Change in the energy generation system				
Slightly more RES-E	−1% res. load (hw and nhw)	+5.8% (+15.3 m)	+9.9%	+14.5% (+44.8 m)
Much more RES-E	−34% res. load (hw and nhw)	+6.51% (+7.8 m)	+4.5%	+1.8% (+2.2 m)

A more severe heat wave might result in greater capacity reductions (if there are no long-term changes in the capacity structure). In two additional model runs, we further constrain the capacities of those power plants that reduce capacity in the 2006 heat wave scenario (for the same time periods as in 2006) (i) to their minimum necessary amount of production q_i^{min} (*min capacity* model run), and (ii) to zero capacity (*off* model run). On average, reductions are 2090 MW(min capacity) and 4890 MW (off) greater than before. As a result, the average price increases by 23% in the min capacity run and by almost 50% in the off model run during the heat wave. The price effect is hence substantially greater than in the reference case (11%). With the additional contraints, production costs increase by € 35 m and € 71 m, respectively, and producer surplus even rises by € 109 m and € 233 m during the heat wave. Consumer surplus decreases by € 144 m and € 304 m, respectively. Compared to the effects in the reference case, it shows that the results are very sensitive to the extent of capacity reductions (see Table 4). The risk of blackouts also rises with higher capacity reductions, which is not considered here.

In addition to cooling water scarcity, reduced river-run off (expected up to 10% during summers in 2020 (Zebisch et al., 2005)), can lead to a reduced capacity of run-off river power plants. As this renewable electricity source has to be substituted by other generators, a 10% capacity reduction converts to an average residual load increase by 180 MW (0.4%) during the heat wave. This leads to an increase of the average price by 12.3% during the heat wave, which is only slightly higher than in the reference case (see Table 4). The gain in producer surplus increases by € 62.4 m during the heat wave, which is also slightly greater than in the reference case.

We have computed the latter effect via increasing residual load in the heat wave scenario, i.e. more load has to be covered by the unaffected power plants. This can generally be depicted as in Fig. 3, where we vary the residual load during the heat wave scenario between 0 and 6% of the historical data. It can be seen that costs and prices can substantially increase with more intensive heat waves. On the other hand, there seem to be no thresholds where the effects abruptly intensify. Qualitatively, the disproportionate producers' gain from the heat wave holds for the whole simulated range.

4.2. Additional heat wave impacts

In the reference case, we have only accounted for the capacity reductions due to cooling water scarcity in Germany. This assumes that all other conditions remain the same. Yet in a situation without a heat wave, demand and net exports could differ from the historic heat wave data.

It can be expected that electricity demand is higher than usual during a heat wave due to an increased need for cooling energy. In the hot summer of 2003, for instance, demand rose by 2% in Germany (VDEW, 2003). Thus it can be assumed that the historical load values of 2006 that we apply already contain such a demand increase. To compute this effect we hence need to adjust the residual load in the counterfactual (case without heat wave) to lower values. If the electricity demand is on average 2% lower in the counterfactual scenario[11] than in the heat wave scenario, the average electricity price increases by 19% during the heat wave. Producer surplus rises by € 96 m and production costs by almost € 30 m, which is considerably greater than in the reference case (see Table 4). Hence even very small differences in demand exacerbate the effect on prices and costs.

The heat wave impacts also depend on net exports to neighboring countries. These can, in turn, depend on whether those countries are affected by a heat wave as well. If we assume, e.g., a simultaneous heat wave in France, the power imports would have been greater in the counterfactual than in the heat wave scenario.[12] Based on the calculations of Rübbelke and Vögele (2011) for the effect of greater water scarcity on cross-border flows, we decrease the net exports by 30% in the counterfactual. This corresponds to a decrease in residual load of 327 MW (0.7%) on average. As a consequence, the average price would increase by 13% during the heat wave. Since more demand has to be covered by domestic power plants, domestic producers profit: Producer surplus rises by approximately € 65 m during the heat wave and thus by more than in the reference case (see Table 4).

Both these additional impacts of heat waves are determined by reducing the counterfactual residual load. In Fig. 4 we varied the residual load of the counterfactual between 0 and −6% of the historical data to cover the plausible changes. By giving consideration to more heat wave impacts, the costs of heat waves considerably increase, which is quite intuitive. Again, there is no threshold in the behavior, and the additional producer surplus due to heat waves is a robust result.

4.3. Demand elasticity

The above calculations assume an inelastic demand which is a quite reasonable and common approximation. Estimates of short-term

[11] This corresponds to an increase of residual load by 2.5%.

[12] If the electricity production in neighboring countries was not affected during a heat wave, the effect on imports and exports depends on the price differences. It might become more profitable to export to Germany in case of increasing power prices, and hence Germany's net exports might decrease during a heat wave (effect not covered here). We are grateful to Rolf Golombek for suggesting this relationship.

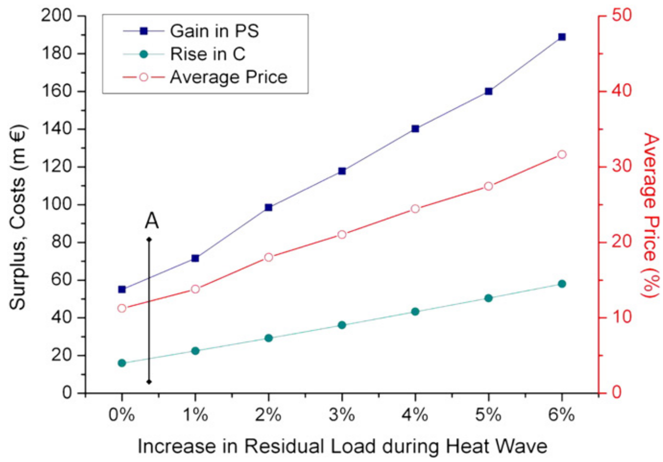

Fig. 3. Effect of changes in residual load during the heat wave on mean price, producer surplus (PS), and production costs (C). Line A represents an increase of residual load due decreasing hydropower availability by 0.4%.

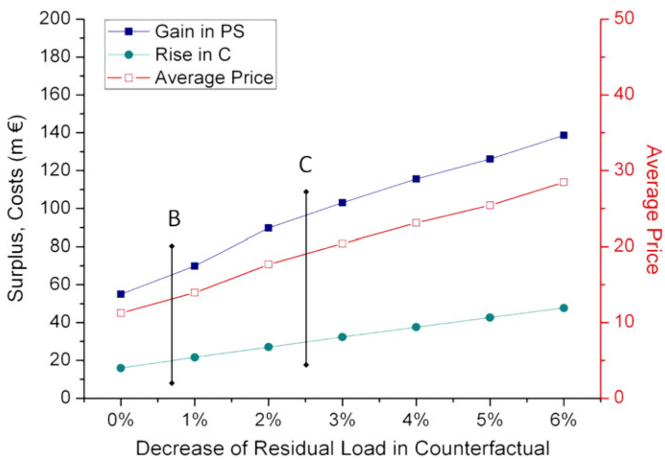

Fig. 4. Effect of changes in residual load during counterfactual on mean price, producer surplus (PS), and production costs (C). Line B represents impacts of less imports during a heat wave, and line C the impacts of increasing electricity demand.

elasticities range mostly between −0.04 and −0.3 (see Lijesen (2007) for an overview).[13] To show how the elasticity of demand affects the results, we apply values of −0.1, −0.25, and −0.4. It can be seen that the results are very sensitive (see Table 4): In the first case, the average price only increases by 4.4%, in the second by 2.6%, and in the third by 1.9% on average during the heat wave. In the first case, producer surplus increases again during the heat wave, but decreases by 0.1% and 1.3% respectively in the second and third case. The heat wave leads to an increase in production costs by 4.7%, 4.3%, and 4%, respectively. The results, in particular for the third case (where the demand elasticity is out of the usual range) show, that current technological developments as the introduction of smart metering and demand response programs could be very effective in reducing the impacts of heat waves. A further (technological) option is a change in the energy mix. This is analyzed in the next section.

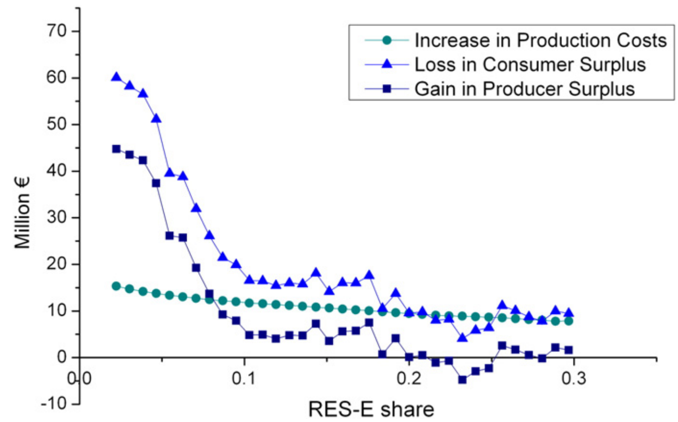

Fig. 5. Effect of changes in RES-E share of domestic power production (excluding hydropower) on production costs, producer and consumer surplus.

4.4. Change in the energy generation system

In Germany, the energy generation system has undergone some substantial changes in the past, e.g., with regard to the energy mix, and plans are to transform this system even more significantly in the future. To make some tentative statements about the impacts on heat waves in a future power generation system, we determine the sensitivity of the results to an increase in the share of RES-E.

In the 2006 reference case, the RES-E share of domestic production (excluding hydropower) was 2.2%. If we slightly increase this share to 3.0%, the sum of additional generation costs due to the heat wave increases by € 15.3 m,[14] which is less than in the reference case (see Table 4). To get a broader picture, we compute the effects of the heat wave for an interval for the RES-E share between the initial 2.2% and 30%, i.e., the amount in 2006 and the amount projected for 2030 (Schlesinger et al., 2011). As can be seen in Fig. 5, the sensitivity of the results is not negligible.

In the case of a 30% coverage of domestic production by wind, solar, and biomass, the additional generation costs during the heat wave amount to € 7.8 m, which is substantially lower than in the reference case. Producer surplus increases during the heat wave by approximately € 2.2 m. The precipitous drop in the loss of consumer and the gain of producer surplus from heat waves under conditions of a higher RES-E share can be explained by the shape of the merit order curve. Its step course as well as varying start-up costs and constraints account for the fluctuations in consumer and producer surplus (which can even become negative).

The variation of RES-E share does not account for the planned fade-out of nuclear energy in Germany. Variations of the nuclear energy share would add another dimension to the sensitivity analysis. As nuclear power plants particularly suffer from cooling water scarcity, their fading out would likely further reduce the heat wave impacts.[15]

5. Discussion and conclusion

Most thermoelectric power plants depend on nearby freshwater for cooling. Due to water scarcity and/or legal restrictions, several power plants had to reduce production during the July 2006 heat wave in Germany. We quantify the electricity price changes and the costs of this heat wave. We also investigate whether electricity producers might have gained additional profits, as the theory is indecisive about this effect in partial equilibrium. The electricity market impact of heat waves might change considerably in the future, not only due to global warming, but

[13] Alberini and Filippini (2011) find a short-term price elasticity of −0.08 to −0.15 in the residential sector in the United States; Kopsakangas Savolainen and Svento (2012) vary between −0.025 and −0.30 for the Nordic power market; Leuthold et al. (2012) apply a price elasticity of −0.25.

[14] Decreases of net exports, which have to be considered due to the sensitive data situation, would affect the results in the same direction.

[15] Except if nuclear is substituted by large scale coal power plants at German rivers. This is not very likely with an increasing RES-E share.

also due to the transformation of the German energy system. This paper addresses both questions with an extensive sensitivity study.

Capacity reductions due to the 2006 heat wave show the following main pattern: electricity spot market prices increase more than generation costs, leading to an additional producer surplus. Consumers bear a disproportionate burden of heat wave costs. Note that, in our setting, consumers do not coincide with the end users, but with retail companies and large customers. The generation costs rise substantially. We further find that the heat wave led to increasing carbon emissions in the German electricity sector, since CO_2 neutral nuclear power plants were substituted by emission-intensive plants.

The sensitivity analyses underscore the robustness of our results. The main pattern remains mostly unaltered for additional heat wave impacts, such as increased electricity demand, reduced hydropower capacity, reduced net exports, and also for more strict capacity reductions that are likely under climate change. The quantitative effects on prices, costs, and surplus yet become considerably more pronounced under increasing heat wave stress. The disproportionate relation between additional generation costs and additional producer surplus increases slightly. This picture yet changes if options as demand-side management (increasing the price elasticity of demand) or an increasing RES-E share of domestic production are introduced. Production costs increase less, and producers may lose surplus during a heat wave.

It is not straightforward to extrapolate our findings to a dynamic setting with both climate change and an energy system transformation. Our current study investigates these effects independently and does not draw on detailed climate projections. For future research, investing the interactions of climate impacts, climate policy and capacity investment could be a rewarding task. One avenue could be the development of consistent scenarios for the energy system and climate change. Those scenarios could be evaluated in terms of their heat wave and investment costs. The current analysis, however, already leads to expected results of such work. Our sensitivity analysis shows that a transformation of the energy system away from large-scale thermoelectric power plants would likely dominate the effect of more severe heat waves.

There are also further issues on the medium time scale. Our paper models spot-market prices, but in fact producers are also bound to long-term contracts. Thus, when forced to reduce production, they may have to cover additional costs themselves. But still, over-the-counter (OTC) trading and futures are based on expected prices on the spot market. If heat-wave-induced capacity reductions become more frequent, this will be reflected in other electricity markets, e.g., in forward markets. With more price-elastic demand, the price would increase significantly less, as seen in the sensitivity analysis, and producer surplus changes would be attenuated. On the other hand, a rise in electricity demand for air conditioning during heat waves might counterbalance or even outweigh this effect.

Also for spot-markets, simulation models have their limits. We can only partially explain the historic record prices of up to € 2000 per MWh during the 2006 heat wave. Market power might be one reason for prices exceeding marginal costs on average by more than 55%. On the other hand, the study by McDermott and Nilsen (2011) associates the price increase of 11% found here with river water temperatures of up to 32–35 °C, whereas temperatures of only 29 °C were measured in the Rhine River (the most important cooling water body in Germany) during the 2006 heat wave (IKSR, 2006). McDermott and Nilsen (2011) might hence underestimate the heat wave price effect since they focus on base load prices.

The works of Golombek et al. (2012) and Rübbelke and Vögele (2013) calculated climate change costs and price effects for the electricity sector by assuming scenarios for 2030. Rübbelke and Vögele (2013) found a 9% increase of producer surplus during peak load in summer. Even with a comparable increase of net exports to that in Rübbelke and Vögele (2013), our model shows a much lower effect on domestic producer surplus (2.8%). This difference is mainly due to the absence of heat-sensitive nuclear power plants in the generation system of Rübbelke and Vögele (2013). It may also be due to the difference in temperature extremes, since Rübbelke and Vögele (2013) assumed average temperatures rather than a heat wave situation. The effect on prices found by Golombek et al. (2012) is comparable to our model when there is a RES-E share of 30% of inland electricity production.

Compared to the range of losses for a single power plant found by Förster and Lilliestam (2010), our results are at the lower end, even for plants with great capacity reductions. There are two possible reasons: First, Förster and Lilliestam (2010) assumed a relatively high average EEX price compared to our simulation, and second, they did not take the effect on equilibrium market prices into account. Neither do Koch et al. (2012), who found relatively low economic losses for all power plants in Berlin up to 2050.[16]

In this respect, we contribute to the literature with a quantification of the effects of the 2006 heat wave from an energy system perspective using endogenous prices. Our detailed model allows us to compute variations of many parameters that are indicative of both the impacts of climate change and the consequences of a restructured energy system: While the former effects increase costs, the latter lead to cost reductions. In any case, surpluses react more sensitively than prices, consumers disproportionately bear the costs, and producers gain.

The model results demonstrate two new relations between climate change adaptation and mitigation in the energy sector: (i) Carbon emissions in the affected electricity sector increase during heat waves when nuclear power production has to be reduced. (ii) Climate change mitigation policies that shift the energy mix away from large-scale thermoelectric power plants can lead to a reduction in water withdrawal and thus render the power generation system less sensitive to heat waves.

Climate change impacts in an industry that provides basic public services can have major political repercussions. First, the cost incidence found in the model points to distributional conflicts that should be considered carefully by policy makers. It could lead to situations where the protection of freshwater ecosystems under climate change comes at substantial expense to power consumers. This cost incidence depends crucially on the elasticity of demand and the institutional settings of electricity trading. Second, current political and technological developments such as the transformation of the German energy system towards renewable energies and an increase of demand flexibility can counter the impact of water scarcity on the energy markets. Without a shift towards carbon-neutral and water-independent power plants, the resource use conflict between ecosystem protection and energy security will intensify.

Our results thus emphasize the interrelation between mitigation and adaptation to climate change. If mitigation fails or is postponed, the impacts of heat waves on the energy system and the associated costs will rise.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at http://dx.doi.org/10.1016/j.eneco.2014.02.006.

[16] The comparability of our results with the work of Koch et al. is limited, since they published cumulative losses only.

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