

Steinhäuser, J. Micha; Eisenack, Klaus

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Spatial incidence of large-scale power plant curtailment costs

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Oldenburg Discussion Papers in Economics

Spatial incidence of large-scale power plant
curtailment costs

J. Micha Steinhäuser

Klaus Eisenack

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Department of Economics

University of Oldenburg, D-26111 Oldenburg

Spatial incidence of large-scale power plant curtailment costs

J. Micha Steinhäuser and Klaus Eisenack*

July 3, 2015

Strongly correlated and spatially concentrated curtailment of power plants strongly affects the electricity market. Such curtailment is observed during heat waves in middle Europe, for example. First, curtailed power plants need to be substituted by more expensive ones. Second, additional congestion of the electricity grid may constrain substitution. These consequences and their spatial incidence have yet not been thoroughly assessed at the level of a national electricity system. Does congestion excessively amplify curtailment costs? Do costs remain localized? How does the cost incidence depend on the market design? We employ a calibrated DC load flow model of the German electricity system that simulates an energy-only market followed by redispatch, as well as nodal prices, for a representative week and renewable feed-in scenarios. We find that spatially concentrated curtailment by 10% of Germany's installed non-renewable generation capacity leads to a 3% welfare loss of the market value, but that loss is not driven by congestion. The electricity price rises by 14% in average, and up to 17% in peak load hours. Consumers bear the burden of curtailment, whereas producer gain in the aggregate. Effects considerably spill over to other regions. While consumers in Southern Germany always lose, consumers in Eastern and Western Germany may gain welfare. Nodal pricing reduces loss by up to 1.5%, and shifts a larger burden to consumers and to Southern Germany. The aggregated economic effects of curtailment are manageable in Germany, but its distributional effects are multiple times larger.

Keywords: climate change; distribution; energy-only market; Germany; heat wave; loop-flows; market design; nodal prices; renewables; surplus.

JEL classification: D39; D47; Q41; Q54.

*Both Department for Economics, Carl von Ossietzky University Oldenburg, Germany, Email {micha.steinhaeuser, klaus.eisenack}@uni-oldenburg.de

1 Introduction

What are the costs of a large-scale, temporally correlated and spatially concentrated curtailment of power plants? How is its burden distributed in space and between producers and consumers? How do the level and distribution of costs depend on the electricity market design? These questions are crucial, e.g. in the context of nuclear accidents (e.g. Fukushima et al. 2011), the German Atommoratorium¹ (e.g. Kemfert and Traber 2011), the California energy crisis (e.g. Reiss and White 2003), earthquakes, impacts of climate change (e.g. van Vliet et al. 2012), and severe accidents (Burgherr and Hirschberg 2014) or disruptions of primary energy supply chains (e.g. delivery of natural gas or coal). Existing economic studies yet pay little attention to the spatial constraints imposed by the electricity grid and focus little on distributional issues. The theoretical literature primarily considers uncorrelated disruptions of single power plants and disregards space (Crew et al. 1995, Chao 2011). The effects of alternative market designs on the costs of curtailment are not well-researched either.

We study these general questions, and quantify the effects for a real-world example, a large-scale correlated curtailment of power plants in the south-west of Germany. Such a curtailment happened during the heat waves in middle Europe in the years 2003, 2006 and 2011² (Strauch 2011, Pechan and Eisenack 2014). The generation of thermoelectric power is restricted by the availability of cooling systems, which is mainly based on water withdrawal in Europe. Heat emissions to water bodies are restricted by environmental regulation (e.g., EU Freshwater Fish Directive, 78/659/EEC) to prevent freshwater ecosystems from being harmed by high water temperature. Thus, decreasing water levels and increasing water temperature during heat waves require curtailment of power plants. When many power plants are using the same river for cooling (as Rhine and Neckar in the south-west of Germany), curtailment is spatially concentrated. Since power plants are affected by the heat wave during the same time, curtailment is also temporally correlated. This problem is relevant in many electricity systems all over the world (Spang et al. 2014). During the 2003 heat wave, electricity utilities expressed the concern that curtailment of power plants may lead to an instability of the electricity grid, or probably even blackouts. Due to climate change, it is expected that such curtailment becomes more frequent and intense in future (van Vliet et al. 2012). The costs of curtailment from heat waves have been addressed by some studies (e.g. Förster and Lilliestam 2010, Koch and Vögele 2010, Linnerud et al. 2011, van Vliet et al. 2012). To our knowledge, distributional effects are investigated only between producers and consumers (Pechan and Eisenack 2014), and between European countries with a model that considers net transfer capacities for electricity (Rübbelke and Vögele 2013). The effect of curtailment on the load flows of a transmission network, however, has not been analyzed yet. This is crucial, (i) since already existing congestion in a network (i.e. binding transmission capacity constraints) is likely amplified during curtailment, and thus raises costs. (ii) The spatial distribution of the burden of curtailment requires a spatially explicit model that considers physical loop-flows in the electricity grid. While (Kunz 2013) investigate what

¹After the Fukushima disaster in 2011, the German government pushed through a three months closure of all German nuclear power plants at short notice.

²And, similar, in 2003 and 2009 in France.

different market designs imply in the light of an increasing share of renewables, we are not aware of studies that investigate the implications for the costs of curtailment.

Our analysis exposes the German electricity system to a kind of stress test. It compares the cost incidence of curtailment during a hypothetical heat wave between two market designs. First, nodal pricing (NP, Schweppe et al. 1988) is known to lead to an efficient allocation of electricity production. It internalizes all costs from physical loop-flows and transmission capacity constraints, and is thus a crucial benchmark. Second, Germany and other European countries actually employ an energy-only-market (EOM) where electricity prices are settled disregarding transmission capacities. If this leads to congestion, grid operators are required to redispatch production in order to maintain the physical feasibility of the production plan. We examine whether curtailment in the south-west of Germany leads to excessive costs, in particular if the costs of redispatch are added to the bill, and we quantify the inefficiency of the EOM compared to NP. For both NP and EOM, it is analyzed how much costs remain localized in the net importing region of Southern Germany, and how much costs spill over to other regions.

We address these questions with a DC load flow model that is first explored theoretically, and then calibrated and georeferenced for the German electricity system, with import/export nodes to neighboring countries. The EOM is implemented by a merit order model, followed by a minimal cost redispatch. Redispatch costs are socialized. The model takes exogenous nodal demand curves, calibrated to real-world data for hours of a selected week. Different levels of curtailment are considered by imposing generation capacity constraints on selected nodes. We further extend the analysis by determining the sensitivity of the results to different scenarios for feed-in of wind and solar energy supply.

We find that, for both market designs, the German electricity system passes the stress test of the curtailment scenarios. Yet, curtailment leads to increasing costs and welfare loss in Germany. Due to a low elasticity of demand, consumers bear a disproportionate burden of the loss, while producers (in the aggregate) gain from curtailment. The situation becomes worse for large RES feed-in from wind power plants, located mainly in the net exporting region of Northern Germany, but it is ameliorated with large RES feed-in from photovoltaic power plants, that are located mainly in the net importing region of Southern Germany. With the EOM, Southern Germany bears most losses, while Western Germany gains from curtailment. Also consumer surplus in Eastern Germany rises, although the general effects in Northern and Eastern Germany are minor compared to that in Southern and Western Germany. If the market design would be shifted to efficient NP, total loss from curtailment would be reduced by about 1.5%. Also, more burden would be shifted to electricity consumers (in aggregate), while Eastern Germany would gain. There are only minor effects of the market design in Northern Germany. NP would shift a larger burden to Southern Germany, but also increase producer surplus (and thus investment incentives) in this region.

The next section introduces our model for both market designs. We start with a theoretical exposition of the main effects, and introduce the empirically calibrated simulation model. Section 3 reports the simulation results for the EOM and NP market design, followed by a comparison. The final section summarizes the results and puts them in context of the general questions.

2 The Model

In order to determine the consequences of spatially concentrated curtailment, we need a model that considers the electricity grid in a spatially explicit way. Two versions of the model are needed to compare different market designs: an energy-only-market (EOM) and nodal prices (NP). We start with a short theoretical exposition of these static DC-load flow models, and discuss the economic effects of a curtailment for a simplified two-region case without loop-flows. Subsequently, a fully calibrated simulation model for the German electricity market is introduced. In the last part of this section, we describe the curtailment scenarios.

2.1 Theoretical base

We first introduce the common assumptions to both market designs. Space is represented by a set of nodes $n \in N$, and demand at nodes d_n with inverse demand functions $p_n(d_n)$. Each power plant $k \in K$ (assigned to a node) generates the quantity g_k at its specific constant marginal generation cost C'_k within its capacity constraint G_k . Total demand and generation need to be balanced within production constraints

$$\sum_n d_n = \sum_k g_k, \quad \forall k \in K : g_k \leq G_k. \quad (1)$$

The electricity grid is represented by a set of power lines $l \in L$, where each line connects two nodes. The load flow y_l in each line might be positive or negative, depending on the direction of flow. Their absolute value must not exceed the physical transmission capacities Y_l (thermal limit). If lines are operated at their maximum transmission capacity, they are called to be congested. For each demand and generation vector, the load flow vector in the transmission grid is determined by the DC-load flow equation

$$y = H(g - d), \quad (2)$$

$$\forall l \in L : |y_l| \leq Y_l, \quad (3)$$

where the admittance matrix H is determined by the topology of power lines. The DC-load flow model is a good approximation of the real-world AC-network in case of stable conditions, in particular in case of only small differences of constant phase-angles at each node (Stigler and Todem 2005), and is commonly applied in the literature (e.g. Leuthold et al. 2012). An important characteristics of physical load-flows is that electricity is not transmitted through one selected connection (e.g. the shortest), but distributed over all available connections according to Kirchhoff's laws. This can cause so-called loop-flows that can lead to contra-intuitive effects. For example, adding a new power line to the grid can lead to more congestion.

In both market designs perfect competition is assumed, such that welfare

$$W = \sum_{n \in N} \left(\int_0^{d_n^*} p_n(d_n) dd_n \right) - \sum_{k \in K} g_k C'_k, \quad (4)$$

is maximized with respect to $d_n, n \in N$ and $g_k, k \in K$, subject to the specific physical constraints, and constraints following from the market design.

First consider an energy-only market (EOM) design. It features a unit price for electricity, and has the advantage that electricity transmission and generation can be unbundled more easily. It is yet not efficient in case of congestion. The assumption that unbundling is conducive to competition, and that this outweighs the inefficiency of an EOM, is one reason that an EOM is frequently adopted in practice.

With an EOM, the electricity market is settled in a first step by ignoring possible congestion. The same uniform price p^* is obtained at all nodes. However, the resulting load flows according to Eq. (2) may violate the load flow constraints Eq. (3). In this case, a redispatch becomes necessary in a second step. Generation is reallocated in a cost optimal way, such that the power line constraints become fulfilled. As this is done after market closure, it has no effect on the uniform market price. Formally, the first step determines

$$\max_{\substack{d_n, n \in N, \\ g_k^{EOM}, k \in K}} W, \quad \text{s.t.} \quad \forall k \in K : g_k^{EOM} \leq G_k, \quad (5)$$

subject to the balance of generation and demand (Eq. 1). The load flow constraints Eq. (3) are ignored, such that a uniform price $\forall n \in N : p_n(d_n) = p^*$ is obtained.

In the second step, the demand vector and the production vector g_k^{EOM} of the first step are taken as given and used to determine the resulting load flows according to Eq. (2). In case that these load flows violate capacity constraints, the redispatch is determined such that the costs of redispatch C_{RD} are minimized, i.e.

$$\min_{g_k^{RD}, k \in K} C_{RD} = \sum_{k \in K} (g_k^{RD} - g_k^{EOM}) C'_k, \quad (6)$$

$$\text{s.t.} \quad \forall l \in L : |y_l| \leq Y_l, \quad (7)$$

$$\forall k \in K : 0 \leq g_k^{RD} \leq G_k, \quad (8)$$

$$\sum_k (g_k^{RD} - g_k^{EOM}) = 0. \quad (9)$$

The resulting vector g^{RD} is the generation after redispatch. Redispatch cost arise by replacing cheaper generation in an exporting region in front of a congestion by more expensive one in the importing region at the back of congestion. We assume that the costs of redispatch are charged to the electricity customers in shares proportional to their demand. This charge adds to the market price ex-post. It thus does not affect demand, as the charge is collected after market closure. According to Eq.(4), total welfare in an EOM W^{EOM} can be decomposed into the final producer surplus PS_n^{EOM} and consumer surplus CS_n^{EOM}

$$W^{EOM} = \sum_n (PS_n^{EOM} + CS_n^{EOM}), \quad (10)$$

where consumer surplus is the surplus after closure of the EOM minus the redispatch cost C_{RD} .

Now turn to nodal prices (NP). This market design is well-known for its convenient theoretical properties. Nodal prices are efficient if the DC load flow approximation is valid (Schweppe et al. 1988). It is a good benchmark to estimate the cost and economic effects of changes in the electricity system. NP is also applied in real-world electricity markets, for example in the US or Australia (Holmberg and Lazarczyk 2012, e.g.). In a NP market, possible congestion of transmission lines is directly anticipated, such that the allocation solves the optimization problem

$$\max_{\substack{d_n, n \in N, \\ g_k^{NP}, k \in K}} W, \quad \text{s.t.} \quad \forall k \in K : g_k^{NP} \leq G_k; \quad \forall l \in L : |y_l| \leq Y_l, \quad (11)$$

subject to the balance equation (Eq. 1) and the load flow equations (Eq. 2). The result is a cost-efficient allocation with node-specific prices $p_n(d_n)$.

If there is no congestion in the optimum, all nodal prices are identical. If at least one transmission capacity constraint becomes binding, this congestion leads to price differentials. Nodal prices decrease for nodes where increasing feed-in would result in an increasing load flow of congested lines. Owing to this price signal, generation is reduced such that the transmission constraint is not exceeded. Nodes where increasing feed-in results in decreasing load flows of congested lines need to raise their generation and hence observe higher prices. Owing to the resulting difference of nodal prices (which is associated with the shadow price of the binding transmission constraint), a congestion rent is generated.

In an NP market, congestion rents can be used to refinance grid investment and set incentives for grid expansion in the long-term. In our context it is helpful to note that the congestion rent of a power-line is a good measure of how strong the congestion is. A high congestion rent expresses that a large effort is needed to prevent an overload of the concerned power-line. Stronger congestions results in an increasing spread of nodal prices, and therefore in higher congestion rents.

For a given allocation and a vector of nodal prices, the producer surplus PS_n^{NP} and the consumer surplus CS_n^{NP} can be determined for each node. Furthermore, each line's congestion rent CR_l can be computed, so that total welfare decomposes into

$$W^{NP} = \sum_n (PS_n^{NP} + CS_n^{NP}) + \sum_l CR_l. \quad (12)$$

The congestions rents add to welfare since they are part of the gains from trade, but are not captured by producers or consumers.

We now turn to a first theoretical analysis of curtailment. The is represented in the model by tightening the generation capacity constraints G_k to $\bar{G}_k < G_k$ at selected nodes. To get an intuition of the basic welfare effects of spatially concentrated and correlated curtailment, we compare EOM and NP for a stylized setting with just two regions, interconnected by only one line with limited transmission capacity. In this case, loop flows are not relevant to discuss

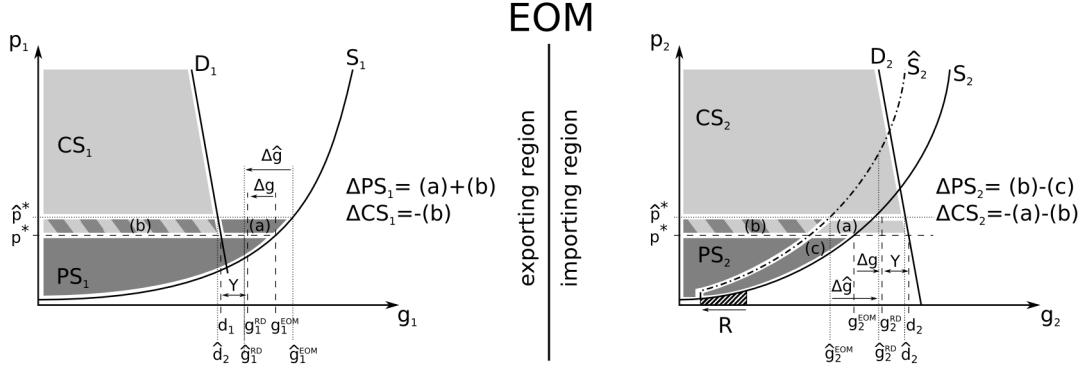


Figure 1: EOM example of two regions connected by a single line with limited transmission capacity Y . Values after curtailment R are labeled with hats. Shown are the change of producer surplus ΔPS_n and consumer surplus ΔCS_n , the market price p_n^* , regional demand d_n , allocated generation after market closure g_n^{EOM} , redispatched generation Δg and allocated generation after redispatch g_n^{RD} .

the economic effect of congestion.³ Assume that one region exports, while the other imports. First consider the case before curtailment. If transmissions capacities are sufficient, both EOM and NP lead to the same allocation and the same uniform price p^* . However, if transmission capacity is not sufficient, the two market designs lead to different results. Under NP, the price in the exporting region is lower than in the importing region. The price difference generates the congestion rent. Therefore, consumers react to the local scarcity caused by congestion. Under EOM, in contrast, the congestion has no effect on the uniform market price. The cost of redispatch are equally distributed to all consumers. Consumers receive no price signals from congested lines. This is why a NP setting results in an economic efficiency gain in case of congestion.

Now suppose that there is curtailment in the importing region. This is known to all market participants before prices are settled. Without congestion, the effect is the same for EOM and NP: the price is uniform and increases in both regions, as the curtailed power plants have to be replaced by more expensive ones. The load flow between the nodes increases, as the unavailable generation in the importing region is partly substituted by generators at the exporting node. Due to the increasing price, consumer surplus decreases at both nodes. Producer surplus in the importing region and in total increases or decreases, depending on whether the price effect or the quantity effect of curtailment dominates, while producer surplus rises unambiguously in the exporting region (cf. Pechan and Eisenack 2014). Total welfare decreases.

In the more interesting case, transmission capacity is binding after curtailment. It is intuitive that this becomes more likely if more power plants are curtailed in the importing region. In this case EOM and NP lead to different outcomes. As congestion is not accounted for by the EOM (see Fig 1) in the first step, the lost capacity from curtailment is substituted by the cheapest available power plants at any of the regions. The uniform price increases in both region, like discussed before. However, in the second step (redispatch) it turns out that lost capacities of power plants in the importing region cannot be substituted by power plants located in the

³As in this case there are no loop-flows around the congestion, the effects of a congestion are quite similar to that of a quota in common trade theory.

2.2 Model implementation and data

The model covers Germany and selected lines with neighboring countries. Substations, power plants and transmission lines are georeferenced. This high spatial resolution allows to model realistic load flow situations in the German transmission grid. The model is solved for a characteristic summer week, and fits well to empirical data. The load flow situation and the occurrence of congestion simulated with the model matches publicly available data BNetzA (2014). The simulated EOM prices are in a realistic range (p-value of 0.82) compared to historic prices.

The model is mainly based on publicly available data described by Egerer et al. (2014). The grid represents circuits with a nominal voltage of 220kV and 380kV (VDE 2012), supplemented with data of the TSO (50Hertz 2015, TenneT 2012b) and GIS data for georeferencing (OSM 2014). As conductor specific data on thermal limits and reactances of power lines is not public available for Germany, it is approximated, depending on the voltage level and the length of the line (with reference values from Kießling et al. 2001).

Generation data contains block specific data of generation capacities for conventional power plants and renewables (>10 MW BNetzA 2013). For RES feed-in, only aggregated generation data on the federal state level is given. These are assigned to ZIP codes according to the generation capacities published by the TSOs (50Hertz 2013, Amprion 2013, TenneT 2013, TransnetBW 2013) and then distributed to the substations according to their location. The marginal cost of renewable energy sources are set to zero. The marginal cost of conventional electricity generation is approximated by considering power plant efficiencies and calculating fuel-cost, cost of CO₂ emission and variable operation cost (Pechan and Eisenack 2014). International electricity trade is captured by exogenously setting the cross border load flows (as published by the ENTSO-E and TSOs: EntsoE 2012, Amprion 2012, 50Hertz 2012, TenneT 2012a, TransnetBW 2012).

Demand is calibrated to a reference price of 42.36 EUR/MWh, which is the average EEX Phelix Day Ahead price for the summer (June-September) of 2012 (EEX 2013). The price elasticity of demand is set to -0.25 . This low value is consistent with the literature (Shu and Hyndman 2011, Lee and Lee 2010, Labandeira et al. 2010, Leuthold et al. 2008). Nodal demand functions are determined by splitting up hourly load data on the national level (Entso-E 2014) to the single nodes proportional to the gross value added of the assigned regions. Gross value added is available at NUTS 3 level (Eurostat 2013) in the national accounts of the German federal states (VGRdL 2011).

2.3 Curtailment and renewable feed-in scenarios

The effects of correlated and concentrated curtailment are determined for an historic week in Summer 2012 (June 18 - 25). We chose this week, since it includes the hour with the highest national load in summer 2012. Starting from this baseline, different assumptions are made about curtailment and RES feed-in. A situation without curtailment is denoted by R0. Three levels of capacity curtailment are analyzed for the selected week. In the curtailment settings R3 / R6 / R9, curtailment at selected sites in Baden-Württemberg is increasing by steps of 3 GW⁵. This

⁵This is a quite strong curtailment of up to 90% of installed capacity in the Rhine-Neckar region, and up to 10% of non-renewable capacity in Germany.

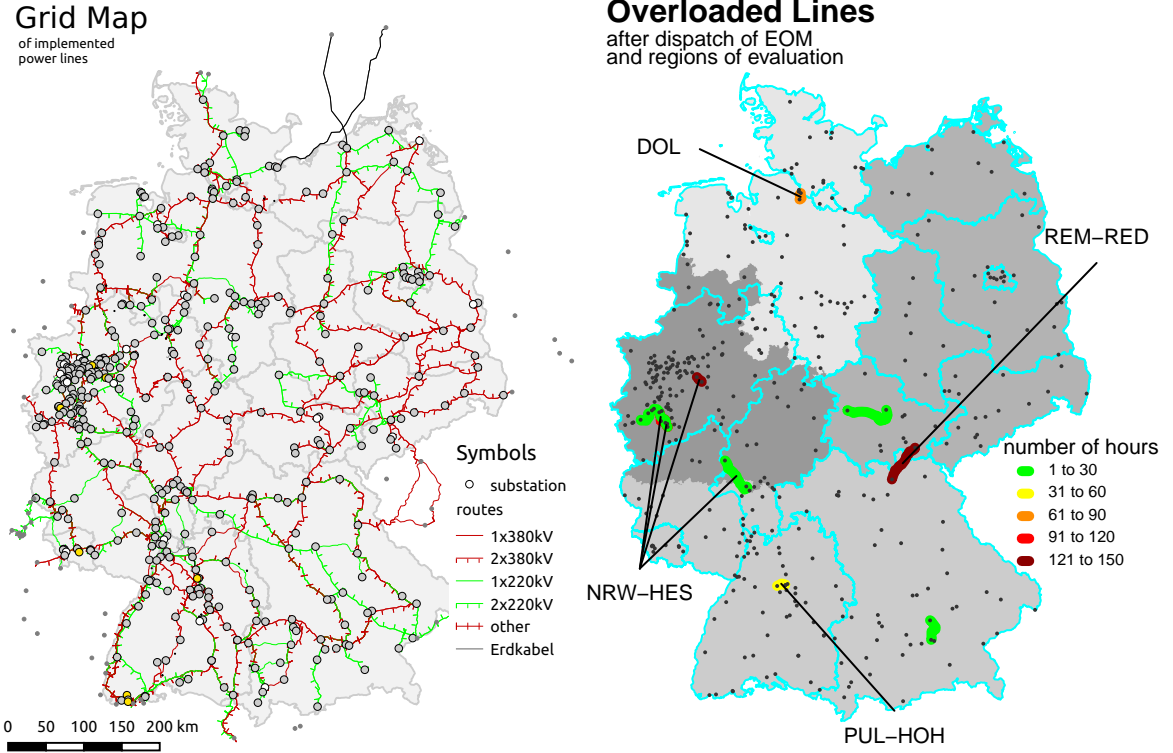


Figure 3: Left: Implemented infrastructure of model. Right: Map of overloaded power lines after closure of EOM (sum of hours where line is overloaded across all scenarios) and the regions of evaluation (grey scales).

mimicks a curtailment of hard-coal and nuclear power plants in the Rhine-Neckar region due to cooling-water scarcity as has been observed during past heat-waves (Strauch 2011, Pechan and Eisenack 2014). To study the sensitivity of our results, four different patterns of wind and photovoltaic feed-in are simulated. First with historic feed-in of photovoltaic and wind (W1-S1), then with photovoltaic only (W0-S1) and with wind only (W1-S0). Finally, we simulate the case without wind and solar (W0-S0). This allows us to identify the effect of wind and photovoltaic feed-in on congestion. The selection of these assumptions also reflects our purpose to expose the simulated electricity system to a kind of stress test. By combining the four curtailment situations with the four RES feed-in pattern, 16 scenarios can be computed for an energy only market (EOM) as well as for nodal pricing (NP).

3 Results

At first we concentrate on the EOM and analyze how concentrated and correlated curtailment enforces congestion in Germany. We analyze the level and distribution of curtailment costs, and how welfare effects depend on wind and photovoltaic feed-in. Subsequently, we turn to the effects if there were a NP market design in Germany. Finally, both market designs are compared.

3.1 Curtailment in the energy-only-market (EOM)

None of the computed scenarios, even those with 9 GW curtailment (R9), lead to a contradictory set of capacity constraints. Otherwise, the EOM would lead to an allocation that cannot be solved by a redispatch, i.e. there might be load shedding. Thus we can show that the existing generation and network capacities are sufficient to cope with spatially concentrated and correlated curtailment of power plants in the Rhine-Neckar Region of up to 9 GW.

Curtailment leads to an intensification of congestion between Northern and Southern Germany (Fig. 3), mainly caused by missing cheap generation in Southern Germany since the Atomkraft-BNetzA (2012). For scenarios with wind feed-in, the most pronounced congestion is observed between Thuringia and Bavaria (REM-RED Fig. 3). This bottleneck of the German transmission grid between Eastern and Southern Germany is well-known to the TSOs. Furthermore we observe for some scenarios congestion in Western Germany (at several lines, NRW-HES in Fig. 3). Another congestion lies in the Rhine-Neckar region itself (PUL-HOH on Fig. 3). Furthermore, we observe a congestion in Northern Germany caused by high wind feed-in in this region (DOL on Fig. 3).

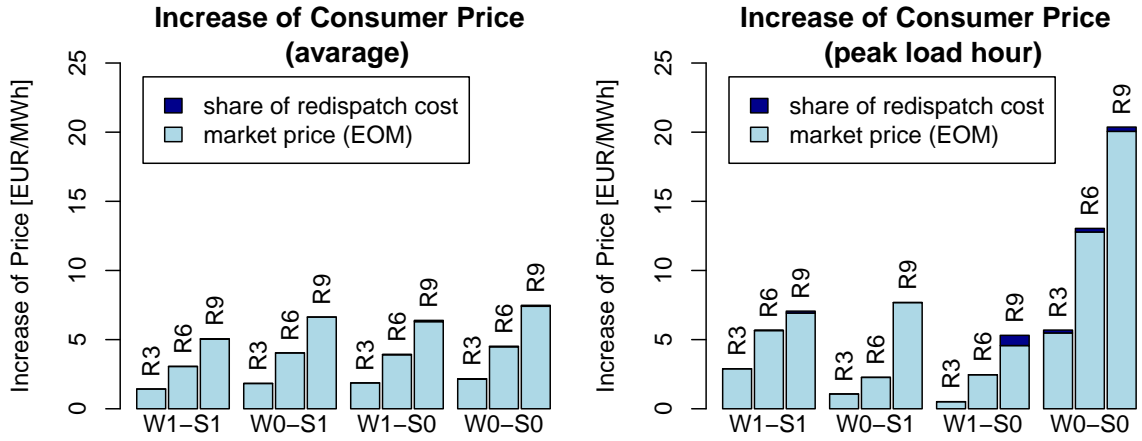


Figure 4: Average increase of consumer price relative to the scenario without curtailments (light) and redispatch costs (dark). Left: average values over week, right: values of peak load hour (18.6, 14:00).

Now turn to the price changes (Fig. 4). If averaged over the whole week, the electricity price increases by 4% (R3, W1-S1) up to 14.2% (R9, W1-S1). During peak load, however price increases more (7.2% for R3, 17.5% for R9). Comparing the different scenarios of RES feed-in, it is to see that prices rise less in scenarios with solar and/or wind feed-in. Furthermore, redispatch cost are higher with wind feed-in. However, the total cost from redispatch over the whole week are comparable low.

We now consider the welfare effects of curtailment for the historic feed-in scenario W1-S1. As stated in Eq. (10), it can be decomposed into the interim loss at market closure of the EOM, and the additional losses from redispatch, which is shown in Fig. 5, on the left. Welfare loss ranges from approximately 0.78% (R3) up to 2.96% (R9) of the market value of electricity⁶. As there is no congestion without curtailment (R0), there are no costs of redispatch in this scenario. If

⁶Defined as total demand, multiplied by the EOM price, plus redispatch costs.

curtailment rises, the welfare loss from curtailment reaches from 2.33 million EUR/week (R3) up to 8.79 million EUR/week (R9). The additional cost of redispatch only have a small share of the loss (R3: 0.11%, R6: 0.39%, R9: 2.77%). Yet, during peak load hours, the share can be considerably larger (R6: 0.9%, R9: 12.3%). Thus, giving consideration to limited transmission capacities is essential for assessing the economic impact of heat waves during peak load.

How are losses distributed? In most scenarios, consumers bear most of the curtailment costs. Additionally there is a reallocation of surplus to the producers, resulting from an increasing market price. Producers can offset their increasing cost of generation by increasing revenues.

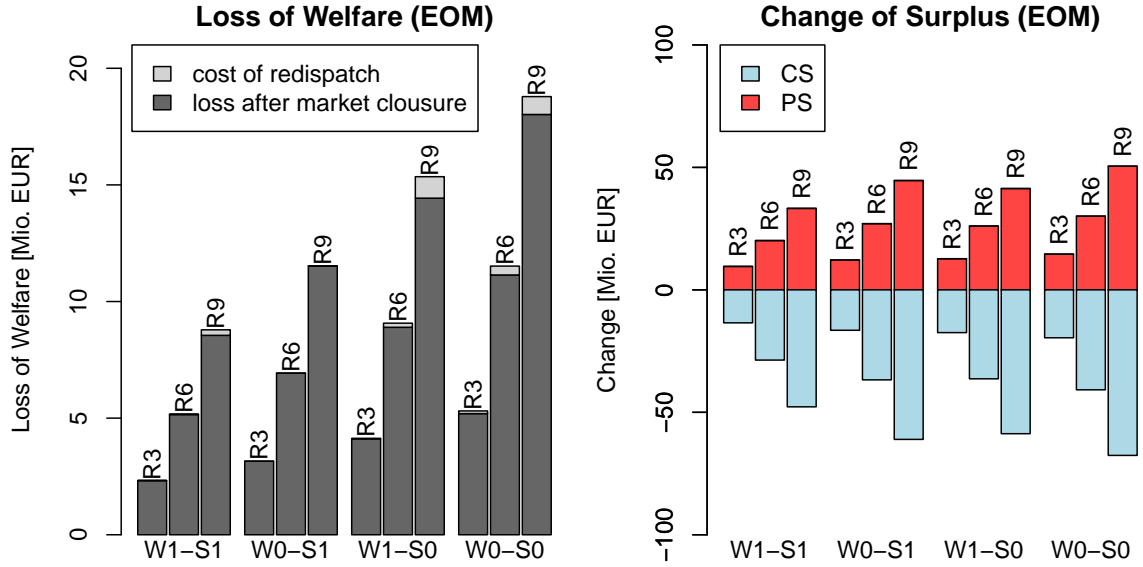


Figure 5: Left: Welfare loss (dark) and redispatch costs (light) per week. Right: Change of producer (PS) and consumer (CS) surplus due to curtailment for different scenarios (per week).

We finally assess the effects of the spatial pattern of RES feed-in. Owing to the merit order effect, RES feed-in displaces more expensive generation, which then becomes available to substitute curtailed capacity. Therefore, the cost increase from curtailment is lower for more RES feed-in (cf. Pechan and Eisenack 2014). In the scenario with photovoltaic feed-in only (W0-S1), the redispatch cost are nearly zero for all tested curtailments. As in Germany the majority of photovoltaic is located in Southern Germany, this provides cheap electricity in this region and thus reduces the congestion in Central Germany. However, there is a different picture for scenarios with wind feed-in only (W1-S0). Here the costs of redispatch are higher than for the setting with complete RES feed-in (W1-S1), as the majority of generation is located in Northern Germany. Thus, in contrast to photovoltaics, windy weather is not able to moderate the congestion, but enforces the problem, as it already causes congestion between Northern and Southern Germany.

3.2 Curtailment with nodal pricing (NP)

We now analyze the effects of curtailment in the presence of nodal pricing. With curtailment, congestion rents rise up to 2 million EUR/week (W1-S1, see Fig. 6). Nodal prices increasingly

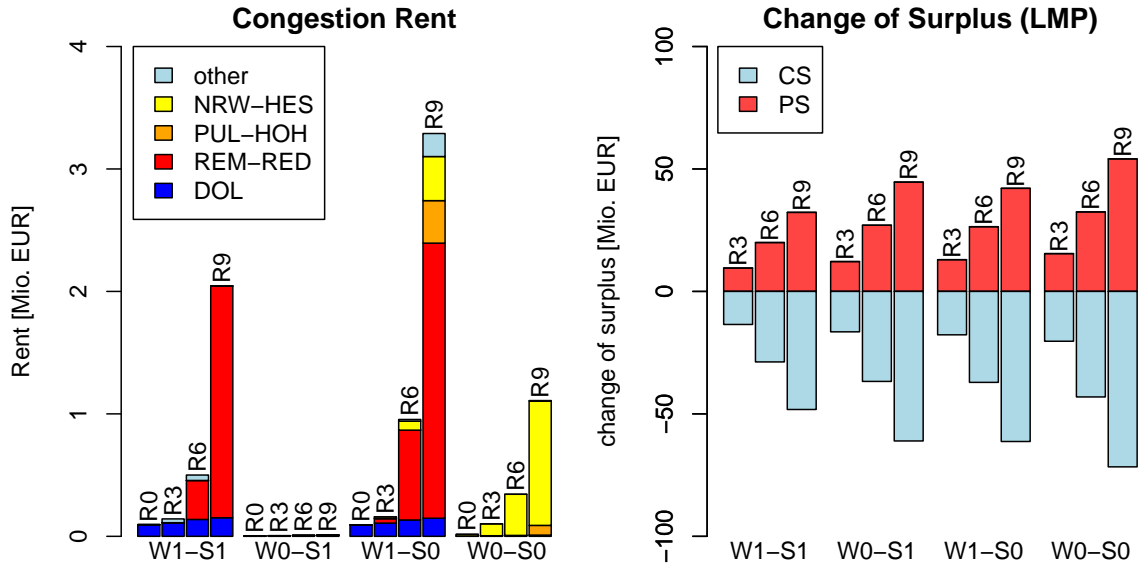


Figure 6: Congestion rents per week (left), producer surplus (PS) and consumer surplus (CS) for nodal pricing over one week (national aggregate, right).

spread with more curtailment, in particular between Eastern and Southern Germany (see Fig. 8 for a selected peak-load hour). This further indicates that congestion becomes more pressing with curtailment. Whereas prices in Southern Germany experience a sharp increase, prices in Northern and Western Germany increase only moderately. Nodes in Eastern Germany face slightly falling prices, such that producers reduce generation during curtailment. Thus, the price increase is mainly localized in Southern Germany. Here, prices increase much stronger than they do in the other regions, as there is sharp increase of marginal cost for activated generators in Southern Germany.

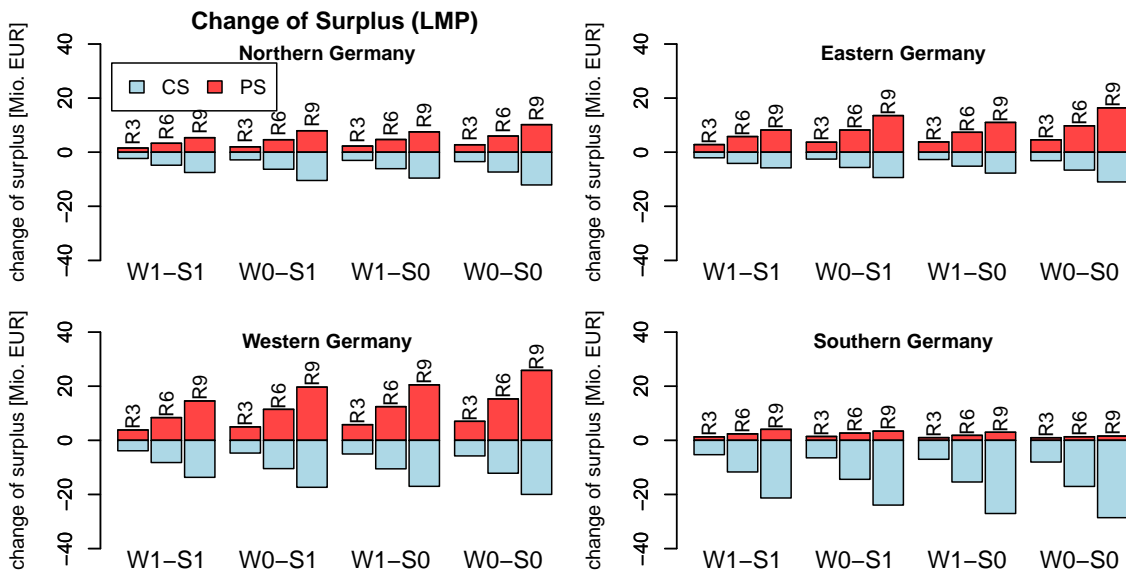


Figure 7: Producers surplus (PS) and consumer surplus (CS) for nodal pricing (regional aggregates).

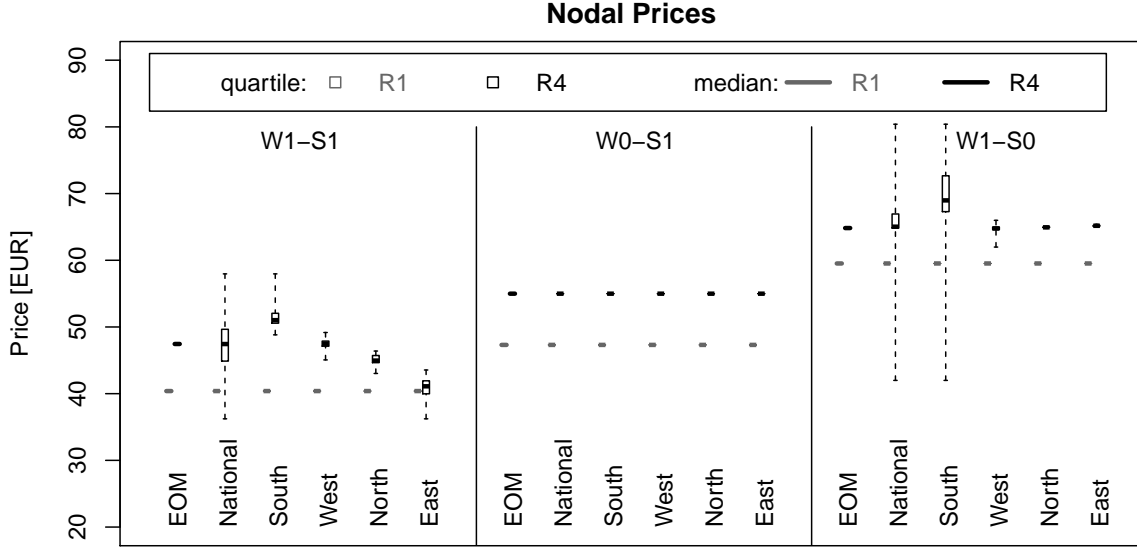


Figure 8: Boxplot of nodal prices of a selected peak-load hour (18.6, 14:00) in the national aggregate, and separated for Northern, Southern, Western and Eastern Germany (boxes 2nd-3rd quartile, dashed lines full range). EOM price is shown for comparison.

Welfare loss in the national aggregate ranges from 0.78% (R3) to 2.92% (R9) of market value⁷. According to Eq. (12) this welfare loss can be decomposed into change in surplus, plus the congestion rents. In the national aggregate, mostly increasing nodal prices reduce consumer surplus and raise producer surplus (Fig. 6, right). The regional aggregates (Fig. 7) show that decreasing CS is more concentrated in Southern Germany. At the same time, PS stays nearly constant in this region, whereas there is a clear benefit for producers in Western Germany. We observe an increasing total surplus in Eastern Germany in the weekly average. Interestingly, this is different during the peak load hours, where congestion is binding. Here, curtailment lets decrease total surplus and CS even increases in Eastern Germany, against the trend.

Less wind feed-in relieves the impact of curtailment as expected. We observe no spread of nodal prices with only photovoltaic feed-in W0-S1 (Fig. 8). Yet, there is a higher spread of nodal prices for the setting W1-S0. This reflects that the feed-in of wind energy in Northern and Eastern Germany enforces congestion. The congestion rent is even higher than without photovoltaic feed-in (W1-S1). Although congestion rents are significantly smaller in the case without wind and photovoltaic feed-in (W0-S0), the welfare loss is still 25% higher for the case of only wind feed-in (W1-S0), owing to the merit order effect. Solar energy, in contrast, is able to relief the impact of curtailment much better, such that for W0-S1 the welfare loss is only two third of that in W0-S0. As photovoltaic capacities are concentrated in Southern Germany, they effectively relief congestion in Central Germany. Therefore, it is possible to substitute curtailed capacity with reaching less capacity constraints, and thus with lower additional generation costs.

⁷Here defined as the product of demand and nodal prices, summed over all nodes.

3.3 Comparing curtailment for the different market designs

This subsection compares the above results. We know from theory that if congestion appears, the impacts of curtailment are more efficiently dealt with in the presence of an NP instead of an EOM. However, we want to estimate the size and relevance of this efficiency gain. We furthermore want to compare the distributional effects of both market designs, and want to obtain a clearer picture of how the impacts of correlated and concentrated curtailment can be attributed to rising production costs or to transmission capacity becoming more scarce.

In both market designs congestion occurs at the same lines. This is in particular the connection between Thuringia and Bavaria. In the case of congestion, the nodal prices are mostly higher than the uniform EOM price (Fig. 8). More expensive generators (mainly gas fired power plants) are setting prices in large parts of Germany with NP, whereas the regions with lower nodal prices (mostly Eastern Germany) are comparatively small. With increasing curtailment the price spread of nodal prices increases, whereas the price at the EOM reacts only weakly.

Now compare the welfare effects of both market designs. As expected, the EOM leads to larger welfare losses, but it is interesting to observe that losses are only about 0.05% - 1.46% smaller with NP. At the same time, NP is accompanied with a lower consumer surplus in the aggregate

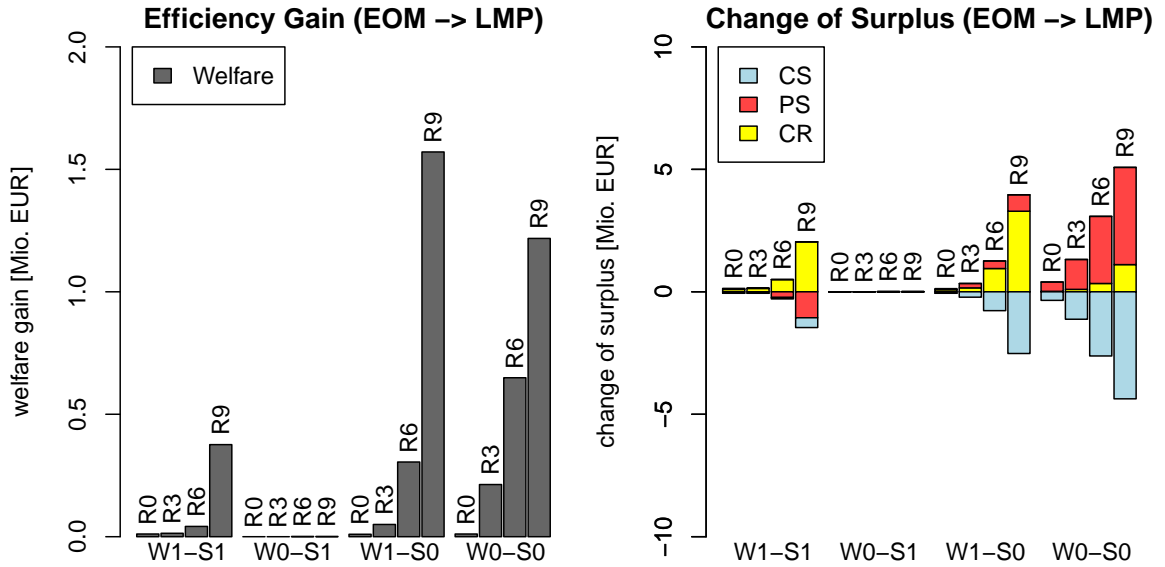


Figure 9: Difference of welfare loss (left) and change in consumer and producer surplus, and congestion rent between EOM and NP in the national aggregate over one week (right).

(Fig. 9). Although the cost of redispatch are fully carried by consumers in the EOM, they profit because congestion has no effect on the market price. The effect for producer surplus is indifferent across the simulated feed-in settings. For W1-S1 aggregated producer surplus is lower with NP than in an EOM setting. This is to explain by a combined effect of photovoltaic and wind feed-in in Germany. First, wind reinforces the congestion between Eastern and Southern Germany, such that producers in Eastern and Northern Germany suffer from nodal prices that are clearly below the EOM price (Fig. 8). Second, photovoltaic feed-in in Southern Germany prevents this region from a very strong increase of nodal prices, resulting in only moderately

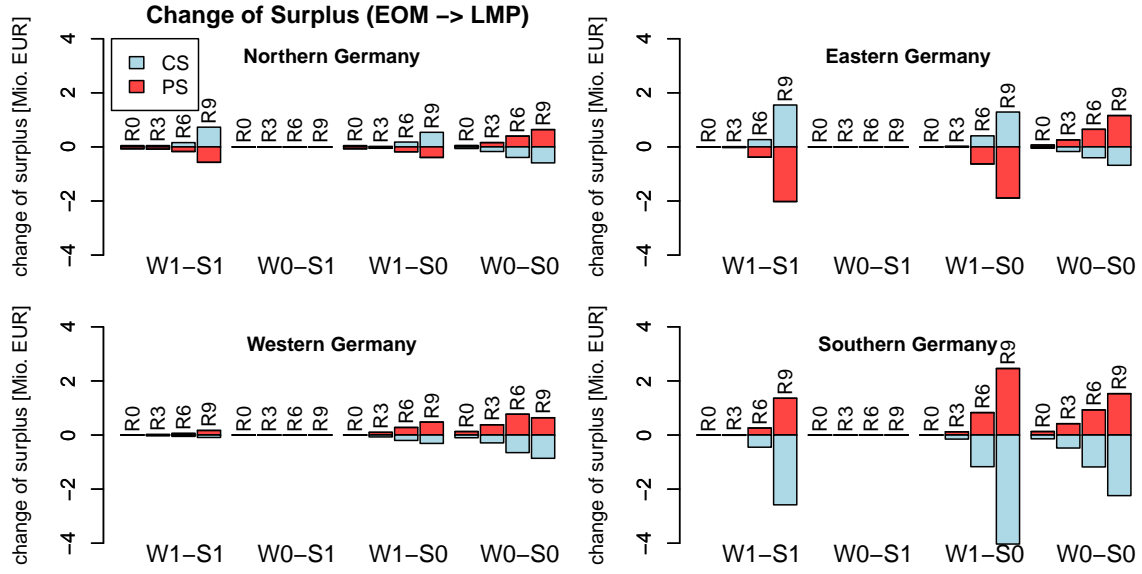


Figure 10: Change in consumer and producer surplus, and congestion rent between EOM and NP in the regional aggregates.

higher producer surplus in this region with NP. Considering the other feed-in settings it is to see that here producers would profit from a change to NP. This is particularly the case for the settings without wind and photovoltaic feed-in (W0-S0) where producer surplus is clearly higher, at the expense of consumer surplus. This difference widens for more curtailment and thus more congestion. It should be noted, that the order of magnitude of the distributional effect's volume is much larger than the efficiency gain of NP (e.g. five times for R9).

The previous results are clarified when looking at the regional distribution of the effects (Fig. 10). NP are more beneficial to producers in Western and Southern Germany due to increasing nodal prices. In these regions, consumers suffer more, whereas consumers in Eastern and Northern Germany profit from nodal prices below the EOM-price. The net effect from a hypothetical change from the EOM to NP would be negative for Eastern Germany, while Western Germany would have a positive net effect. In Northern Germany, differences between both market designs are comparatively small, whereas they are largest for Southern Germany. Here, consumer loss clearly outweighs producer gain if the market design would be changed to NP. Thus, compared to the EOM, with NP the consumers in Southern Germany, and to a smaller part the producers in Eastern Germany, would bear more curtailment costs.

4 Conclusions

The analysis has quantified the cost incidence of a large-scale, spatially concentrated and correlated curtailment of power plants. Since dealing with space in the analysis requires consideration of physical loop-flows in the electricity grid, and since the consequences of loop-flows and grid congestion cannot be solved analytically, results depend on a simulation model. Our simulated stress test focuses on curtailment in the south-west of Germany that might occur during a heat

wave due to cooling water scarcity.

We find that Germany has ample excess generation and transmission capacity to deal with correlated and concentrated curtailment. Curtailment yet results in an enforced congestion, increasing generation costs, and increasing need for redispatch. For the simulated energy-only market, curtailment of up to 10% of installed capacity leads to welfare losses of up to 3% of the market value of electricity, with a share of redispatch costs up to 12% during peak-load hours (where the electricity price rises by up to 17%). If efficient nodal prices are in place instead of the energy-only market, welfare loss would be reduced by 1.5%, and the incidence pattern of heat wave impacts amplifies. Consumers in Southern Germany would then bear a disproportionate burden of the costs, while consumers in Eastern Germany even benefit from a new market design. If weather is windy, such that there is much RES feed-in in Northern Germany (due to the spatial distribution of generating capacity), the situation is not relaxed as there is more congestion. This is different for high insolation, like it is to expect during heat waves, resulting in much RES feed-in in Southern Germany. On average, up to 2.8% of total welfare loss is due to transmission line congestion being considered in the analysis with the energy-only market (1.3% with nodal pricing).

These results need to be interpreted within the limitations of the model. First, it disregards intertemporal components like pump storage power plants and constraints on ramping up thermal power plants. The latter leads to the unit commitment problem, and might increase the impacts from curtailment. However, as heat waves have a typical duration of multiple days up to weeks, and since weather forecasts are available some days ahead, we do not expect that including the intertemporal components would change much of the results. Also, electricity imports/exports to neighboring countries are not represented endogenously. However, it is likely that curtailment from heat waves is correlated between countries (as during the 2003 heat wave in France and Germany)⁸. It is a further caveat that our model cannot address the issue of electricity grid stability by regional missing reactive power during phases of correlated curtailment. This is considered as a serious problem by grid operators and public authorities (BNetzA 2012), but requires integration of reactive power to the model. This would go far beyond the usual DC load flow approximation towards a more engineering type model. The DC load flow approximation, however, does not invalidate our economic results. The economic analysis yields some plausible results, for example investment incentives from rising producer surplus in regions with curtailment, and surprises, as gains for consumers in an adjacent region.

In comparison to other literature, our study confirms that impacts of climate change for the electricity sector due to more frequent or intense heat waves are important in Germany, but far from catastrophic. For a single heat wave, Koch et al. (2012) determine losses between 15m € and 60m € for curtailed power plants in the Berlin area, and Förster and Lilliestam (2010) between 5.2m € and 81m € for a single nuclear power plant. McDermott and Nilsen (2014) econometrically estimate a price increase of 11%. The simulation of Pechan and Eisenack (2014) likewise determines an average price increase of 11% during a heat wave in Germany. All these

⁸We also made some sensitivity analyses with respect to net flows, and found no qualitatively different pattern. Except, of course, an amplification of the effects for more scarce electricity).

studies do not consider the effects of physical loop-flows in the electricity grid. Thus, our result on a price increase up to 14% in average (and up to 17.5% during peak-load) is slightly higher. Also (Kunz 2013) compare the two markets designs in the presence of rising RES feed-in, but disregard curtailment. Similar to our study, they do not find large differences in the total costs (although they assume inelastic demand), and also observe that nodal pricing reduces consumer surplus in comparison to an energy-only market.

Comparison with other studies and our results leads to some cautious generalizations. Producer's aggregate gain from curtailment is in line with other studies (Rübbelke and Vögele 2013, Pechan and Eisenack 2014), and is plausible since demand for electricity tends to be quite inelastic. It is also plausibly sets investment incentives in a situation of scarcity. These incentives, although they may spill over, remain concentrated in the region where curtailment is expected to be more frequent or severe. With nodal pricing, the spatial distribution of impacts is more concentrated, while the existing energy-only market favors consumers. Yet, the welfare loss from the less efficient energy-only market seems to be of minor importance in comparison to its effects on the spatial cost incidence. One needs to expect surprises due to the electricity grid topology. We think that this shall be carefully considered by policy makers and in future studies.

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