TWO PRICE ZONES IN THE GERMAN ELECTRICITY MARKET – DISTRIBUTIONAL EFFECTS OF REGIONAL PRICE SIGNALS

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Overview

We discuss the implications of zonal pricing (i.e. a northern and southern price zone) on the German electricity spot market. In the northern zone, the additions in wind capacity combined with existing regional overcapacities of low variable cost power plants cause large regional supply surpluses in the day-ahead market dispatch. The current uniform pricing regime does not consider internal transmission capacity constraints and often results in technically infeasible market results. Ex-post adjustments of the market result by redispatch becomes necessary. Zonal or nodal pricing would enable a better market integration of scarce transmission capacities in a market with regional imbalances. Yet regional price differentiation comes at the cost of redistribution between stakeholders.

Using a line sharp electricity sector model, this paper analyzes the possible efficiency gains and the distributional effects of two price zones and nodal pricing, respectively, in the German electricity system in 2012 and for a 2015 scenario. Results show that zonal pricing can reduce system costs and prices in the southern price zone are higher than in the northern price zone, on average. However, the average price difference and thus distributional effects are rather low on annual level. Lower redispatch costs from two price zones in Germany can results in higher distributional effects for power plants and consumers. In summary, distributional effects of introducing two price zones are surprisingly small compared to the wholesale price or different network charges in Germany.

Methods

This paper applies two electricity sector models representing the two consecutive steps of market settling in the day-ahead market and redispatch by the TSO in the physical electricity system to determine the final power plant operation and related costs. First, the dispatch model determines the cost-minimizing market dispatch in the day-ahead market. Thereby, electricity generation and exchange flows have to settle load in all market zones. We examine two scenarios with aggregated price zones (uniform pricing and two price zones) and discuss the results in reference to nodal pricing. In the second step, the re-dispatch model calculates the cost-minimizing adjustments for the initial dispatch of the scenarios with aggregated market zones. This is necessary as the line sharp physical transmission system is not represented in the market. Thus, the zonal results might prove infeasible in the nodal system. The re-dispatch model adjusts the output of individual power plants until the transmission flows are within technical line parameters for every transmission line. The generation levels of the first model are used as exogenous default and the transmission system is modelled with the DC load flow approach (Schweppe et al., 1988).

The applied data set (Egerer et al., 2014) has a high spatial disaggregation (438 network nodes and 938 transmission lines) with individual power plant blocks, renewable capacity and electricity load aggregated to the network nodes. The hourly time series include load, cross-border flows, as well as seasonal availability factors for conventional and hourly factors for renewable power plants. The model runs are conducted for the 8,784 hours of 2012 in 53 weekly blocks. In addition we provide a 2015 sensitivity run with adjusted generation capacities. The scenario with two price zones is analyzed for different NTC values and results are provided for the cost-minimizing NTC on a weekly basis. For reasons of simplification import and export flows with neighboring countries are fixed to the hourly physical flows measured at the cross-border lines in 2012. The model is implemented in GAMS and solved with the commercial solver CPLEX.

Results

The model results indicate annual cost reductions of 19.3 mn EUR/year for nodal pricing and 8.1 mn EUR/year for two price zones. The costs of the initial market dispatch are 10.0 mn EUR/year higher for nodal pricing and 7.8 mn EUR/year for zonal pricing. This is due to the individual line constraints in the nodal DC load flow model and the NTC constraint between the northern and southern zone. While no redispatch is required for nodal pricing the modelled redispatch costs are 29.3 mn EUR/year for uniform pricing.[1] The higher costs of the initial dispatch in zonal pricing are more than compensated by lower redispatch costs in the two-zone scenario resulting in lower overall costs compared to uniform pricing. In the 2015 scenario, the model results indicate system costs for nodal pricing

[1] The national and cross-border re-dispatch costs have been 164.79 mn EUR for Germany in 2012 (BNetzA and Bundeskartellamt, 2013). The applied model only considers national re-dispatch measures and the DC load flow approximation only includes flow based constraints and no voltage limitations. Together with additional limitations (CHP, ramping costs, and uncertainty not included), results are likely to underestimate the costs of re-dispatch.

111.1 mn EUR/year lower than for uniform pricing. With two price zones 26.1 mn EUR/year of the cost saving can be realized. In addition, two price zones can limit the increase in redispatch costs to 154.0 mn EUR/year compared to 223.1 mn EUR/year.

The hourly trade flows between the north and south price zone in the day-ahead market (Figure 1) illustrate that the optimal NTC capacity varies over the weeks and is binding mostly in the winter time. On an average level, the annual price difference is rather low with only 0.7 EUR/MWh higher prices in the south in 2012. The zonal prices deviate in about 1,000 hours of the year with a maximum difference of 29 EUR/MWh. Most hours with significant price differences are in January and February, occur at average price levels of about 50 EUR/MWh, and wind power generation above 20 GW always results in deviating zonal prices. In the scenario for 2015 the annual price difference increases to 3 EUR/MWh. The zonal prices deviate in about 3,000 hours of the year with a maximum difference of 50 EUR/MWh and an average difference of 10 EUR/MWh. The increasing price differences cause higher reallocation of electricity costs for consumers but also affect the rents of power plant (Table 1).

Figure 1: Hourly trade flows north to south (-) and south to north (+) and weekly NTC

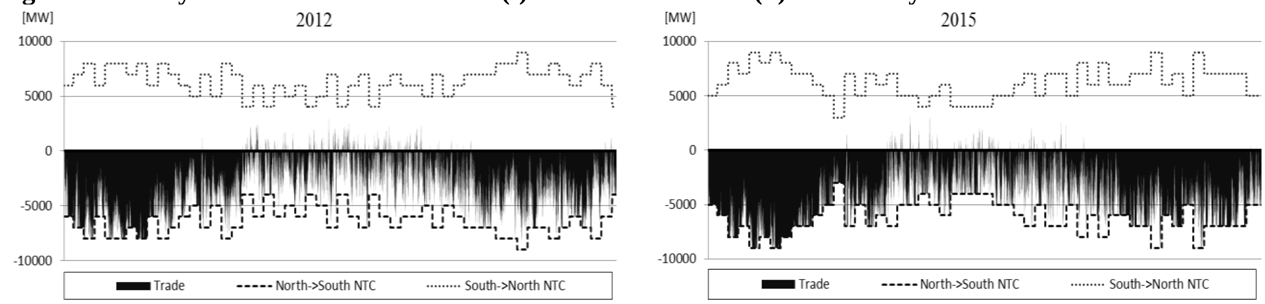

Table 1: Annual change in quantities and rents from uniform to zonal pricing

2012		Change in costs/revenues			
[mn EUR]	Demand	Lignite	Nuclear	Hard coal	Gas
North	-93	-35	-8	-22	-2
South	+105		+36	+24	+7

2015		Change in costs/revenues			
[mn EUR]	Demand	Lignite	Nuclear	Hard coal	Gas
North	-370	-136	-31	-69	-3
South	+427		+124	+92	+18

Conclusions

We analyze the cost saving potential and distributionary effects of zonal pricing in comarision to the current unifcorm pricing scheme and to the benchmark of nodal pricing for the German electricity sector in 2012 and 2015. The results show that a north and south price zone reduces re-dispatch costs and system costs but to a significantly lower extend than nodal pricing. This becomes the more important in 2015 as the new renewable capacity and additional coal power plants in the north result in market dispatchs which require increasing redispatch measures and result in higher related costs. The numeric of distributional effects are discussed and the annual regional price differences are rather low compared to the day-ahead market price in 2012, but increasing in 2015. Distributional effects can however be very high for indicidual hours with strong regional price spreads.

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