Modeling Spot Market Pricing with the Residual Load

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Abstract

The determining variable in investment decisions is the expected future revenue. In the electricity sector, this revenue is determined to a high degree by the electricity prices and the fuel costs. The spot market price is widely accepted as the reference price for electricity. The main determinants for the spot market prices are the power plant fleet, the fuel prices and the load. The paper aims to calculate the spot market price development as a function of the residual load.

The authors have identified the residual load as significant factor on spot market pricing through an analysis of the years from 2007 to 2009. The residual load represents the demand side on the electricity market. It is calculated as the load profile minus the feed-in from renewable energy sources (RES). The supply side is constituted through the conventional power plant fleet. In each hour the highest marginal costs of all committed power plants are decisive for pricing. In the model, a change of the power plant fleet is not regarded.

Applying a simple linear trend line for the years 2007 to 2009 establishes coefficients of determination R^2 ranging from 0.54 (2009) to 0.77 (2008). Prices generated by the model are compared to real prices. The mean prices of both datasets are nearly the same. The simulated prices tends to underestimate the very high prices and to overestimate the very low prices. Projections for spot market prices in 2020 are calculated on the basis of the residual load in 2020. The projections for the prices are based on a ceterus paribus analysis. The isolated analysis of the change of the residual load from 2008 to 2020 shows a higher deviation in prices and a decrease of the medial price of 15 €/MWh. A possible change in the conventional power plant fleet is not regarded in the paper but can be included into the model within further research work.

Keywords: Pricing, Spot Market, Residual Load, Wind, Merit Order Effect

Motivation

The spot market price is widely accepted as a reference price for electricity. Thus, it is a determining variable in power plant investment decisions. The pricing at the European Energy Exchange (EEX) is based on the market clearing price methodology. Therefore, prices are determined by three main factors:

- the composition of the power plant fleet,
- the electricity demand and
- the fuel prices.

The paper aims to assess the spot market price as a function of the residual load. This function enables to describe the influence of an increasing feed-in RES on the prices. Thereby, a possible adjustment of the conventional power plant fleet is not taken into account. This approach not only allows to appraise future electricity price levels but also to estimate the chronological order of these prices.

Historical Prices and Prices for Futures

Figure 1 shows the spot market baseload prices from to 2003 to 2009. These prices show a high deviation and it is not possible to define a clear trend.

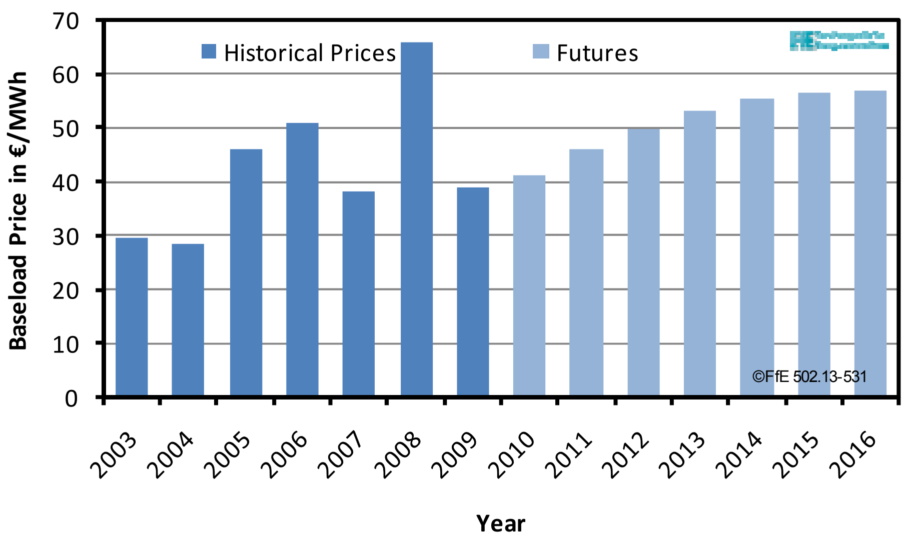

Figure 1: *Historical and estimated Baseload Prices at the EEX* /EEX-01 10/

The minimum price was at 28.6 €/MWh in 2004, the maximum was at 65.8 €/MWh in 2008. A brief analysis of the prices of the traded futures at the EEX gives a rough impression of the development of the next few years. They show a steady increase up to 57 €/MWh in 2016. **Table 1** shows further values of significance: the minimum, the maximum and the deviation of the annual prices. A higher deviation indicates more frequent extreme prices, which means a steeper annual price duration curve.

Table 1: *Key data of the day-ahead Spot-Market Prices from 2002-2009*

in €/MWh	2002	2003	2004	2005	2006	2007	2008	2009
medial	22.6	29.6	28.6	46.1	50.9	38.1	65.9	38.8
min	0.0	0.0	0.0	0.0	0.0	0.0	-101.5	-500.0
max	500.0	1719.7	150.0	500.0	2436.6	821.9	494.3	182.1
standard deviation	15.9	26.5	10.8	27.2	49.4	30.4	28.7	19.4

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Negative price bids are allowed with the beginning of 2008, which explains a minimum price of 0 €/MWh until 2007.

Pricing at the European Energy Exchange

For every single hour of the following day there is an auction at the EEX. The offers (supply) are sorted by price by ascending order and the bids (demand) are sorted by descending order. At the point of the cumulated load where the prices are equal the market clearing price is settled. Every successful offer gets this price and every successful bid has to pay this price (**Figure 2**).

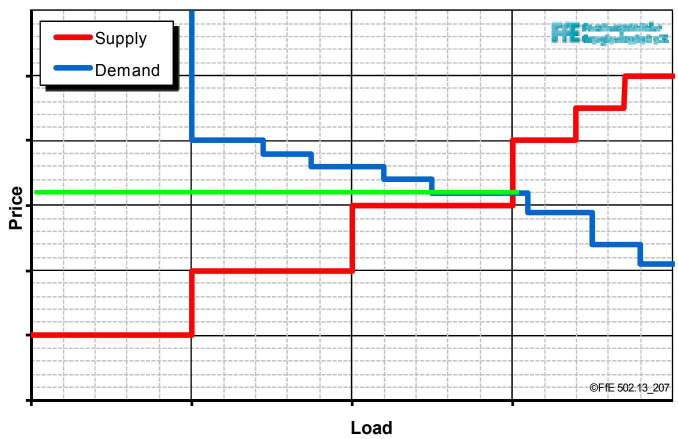


Figure 2: *Pricing at the EEX*

The demand for electricity is quite inelastic and storage is limited and expensive /UNIKA-01 05 /. Therefore, the overall consumption load has mostly to be supplied by the selection of the power plants with the lowest marginal costs. Even there are many long-term contracts, the possibility of domestic production and over-the-counter (OTC) deals, the price at the spot market can be considered as the overall market clearing price when assuming absence of arbitrage. **Figure 3** shows an example of bid and offer curves for one selected hour.

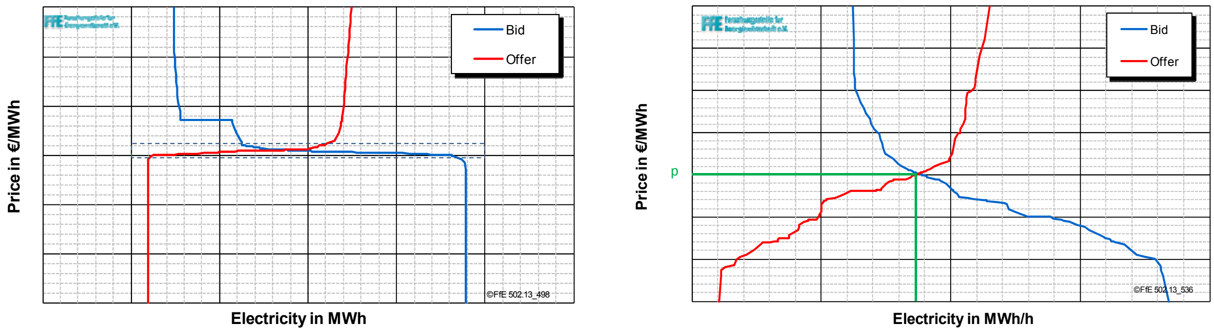


Figure 3: *Example of bid and offer curve of a selected hour; the right graph shows the dashed fraction of the same hour*

The "Erneuerbaren Energien Gesetz" /EEG-01 08/ allows to feed-in power from RES prior to conventional power at any time. Therefore, the offers for RES should be made without a price, despite the fact that the marginal costs of RES can be assumed with 0 €/MWh. According to the rules of the EEX an offer without a price means -3.000 €/MWh. For their impact on the market clearing price it is irrelevant whether the feed-in of RES is modeled as a surplus of supply without marginal costs or as a shortage of the demand. **Figure 4** shows this effect. The load that has to be covered by the conventional power plant fleet determines the price. This load is called the residual load (consumer load minus the feed-in of all must run power plants).

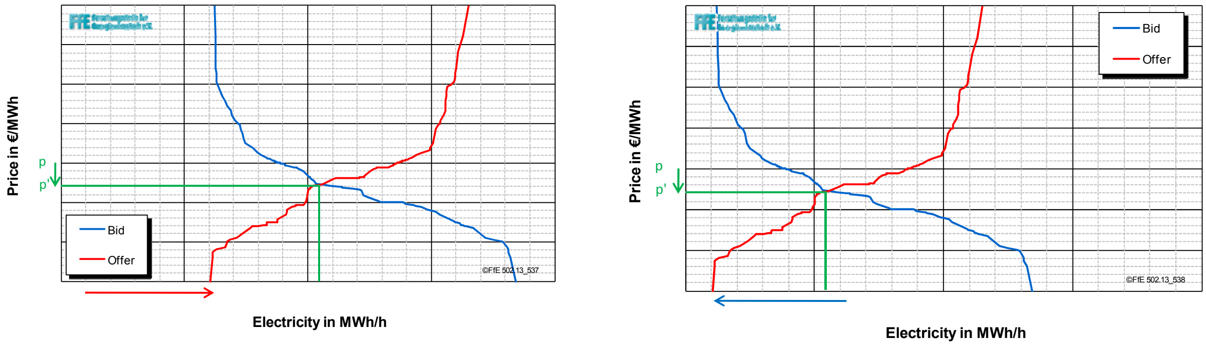


Figure 4: *Price effect of the feed-in of must-run power plants (left: modeled as surplus of supply; right: modeled as shortage of demand)*

Load Profiles

To assess the impact of an increasing feed-in of RES on electricity prices, it is essential to model their load profile. Therefore, public data were used and models for synthetic load profiles were developed. Moreover, the future development of the particular load curves has been assessed.

Consumer Load: The European Network of Transmission System Operators for Electricity (ENTSOE-E) publishes the consumption load for each country on an hourly basis for the last years /ENTSOE-01 09/. It is not possible to make reliable assumptions about the change in consumer load until 2020. Thus, it was assumed to be constant in characteristic as well as in total consumption.

Wind Power: For the analysis of the historical prices, the forecasted wind power published by the four German Transmission System Operators (TSO) is used /TSO-01 09/. As the analysis focuses on the day-ahead prices and market participants can only underlay their bids and offers on forecasted and planned values. In order to estimate the wind power expansion until 2020, the scenario in “Leitstudie 2008” is used /DLR-01 08/. This scenario predicts an installed capacity of 28 GW onshore and 10 GW offshore in the year 2020. For future wind feed-in load profiles a wind power model for Germany has been developed /FFE-04 08/. It is based on a physical approach with datasets of the atmospheric conditions contributed by the “Deutschen Wetterdienst” (DWD). The chosen 49 stations of the MIRIAM-station-net of the DWD are geographically corresponding with the installed wind power capacity. A year with either strong, medium or weak wind conditions in a temporal resolution of 10 minutes can be chosen. In Germany a multitude of different wind power plants are installed. In the model 20 different types are built in order to consider this aspect.

Photovoltaic: Despite the enormous growth of installed capacity of PV in Germany from 76 MW_p (2000) to 8.877 MW_p (2009), the corresponding energy production reaches only 6.2 TWh in 2009 which is about 1 % of the overall consumption /BMU-01 10/. Furthermore no public data of the hourly feed-in of PV are available. Up to 2009 the feed-in of PV is regarded as load reduction by the TSO. These were the reasons why PV was not considered in the price correlation analysis throughout the years 2007 - 2009. The situation seems to change in 2020. The “Leitstudie 2008” /DLR-01 08/ sees 17.9 GW installed capacity for the year 2020. The recent development (+1.9 GW in 2008 and +3.0 GW in 2009) appears to make this scenario quite conservative. An updated version of the “Leitstudie 2008” sees already 23.2 GW in 2020. This high capacity means a relevant contribution to the load at sunny days, hence the PV load has been considered in 2020. In a PV potential study at the FfE the overall roof surface in Germany has been determined, considering the inclination, what is appropriate for PV. For the load curve each rural district is related to a TRY region /DWD-01 04/ and to the global radiation /DWD-01 06/. This is the required data basis for establishing 117 reference regions and for simulating the hourly PV load with the method DIN 5034. The model approach is described in /FFE-02 09/. The resulting load curve has been upscaled to an installed capacity of 2020.

CHP Load: At the FfE a CHP load model for Germany was developed. The data basis were the load curves of the district heating from five big German municipal utilities, the ambient temperature of three gauging stations in the geographical centre of Germany, the annual power and heat output of the CHP plants of the German Heat & Power Association (AGFW) /AGFW-02 07/ and the monthly power and heat output of CHP registered at the Federal Statistical Office /STBA-01 08/. The result is the hourly load of CHP heat and power. On the assumption that the future characteristic of the CHP load is similar to the present load, it is possible to synthesize the hourly CHP load in 2020 with the FfE model only with the input data of annual CHP output and the ambient temperature. The method is described in /BVR-01 08/.

The Load of further RES: The load of hydropower (only run-off-river plants) is approximately constant over the day but shows high seasonal differences. This was proven by the Wednesday balances of the Federal Statistical Office /STBA-01 08/. The seasonal profile has been derived from the seasonal profile of the years 2005 to 2007. For the analysis of the residual load in 2020 there is no need to model the load of biomass/gas on its own, because biomass and -gas are mostly combusted regularly in a CHP process. The power out of geothermal with 1.3 TWh/a will be negligible in 2020. Hence, the load is not modeled and it could be expected that the load will follow a base load characteristic.

Residual Load in 2008 and 2020

On basis of the loads for 2008 and 2020 respective residual loads can be generated. **Figure 5** shows a typical summer and winter day of the modeled and calculated load curves and the resulting residual load in 2008.

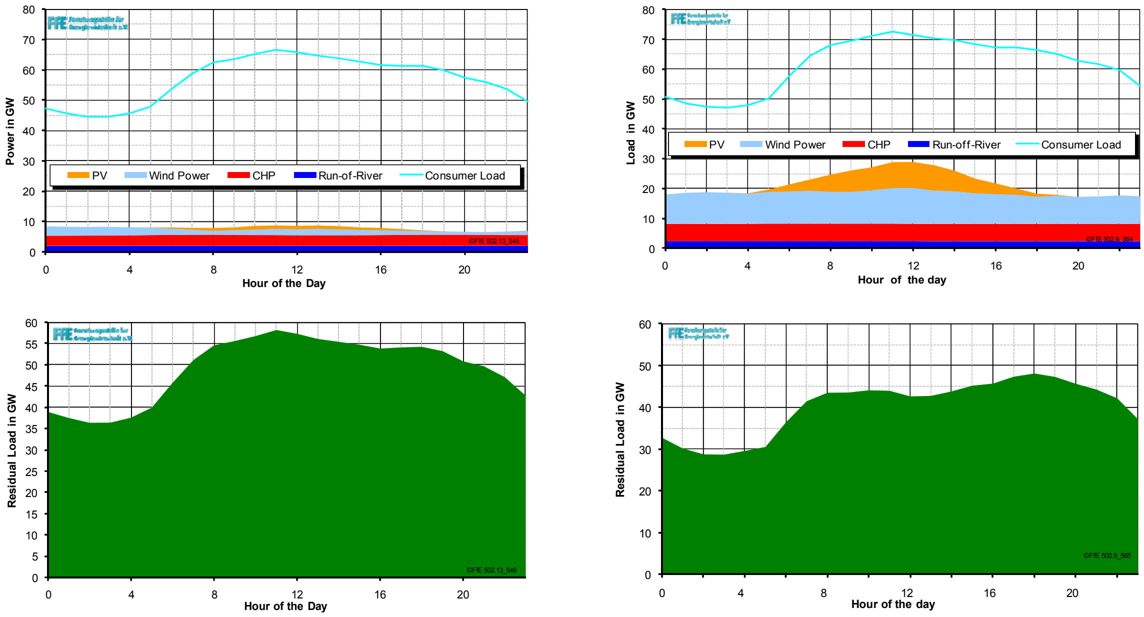


Figure 5: *Load curves on a summer day (selected at random) in 2008 (left) and in 2020 (right) and the resulting residual load (bottom)*

The scenario for the residual load in 2020 is based on the "BMU Leitszenario" for the development of installed capacity of RES:

- 38.05 GW installed wind power capacity in 2020 (23.90 GW in 2008)
- 17.90 GW installed PV capacity in 2020 (5.31 GW in 2008).

Hourly values of the feed-in were generated by the FFE tool with weather data from 1998 (wind) and from the test reference year (PV). Different data bases for the weather seems not to be problematic as no relevant correlation between feed-in of wind and PV is assumed. The consumer load is not changed, neither in level nor in characteristics as some studies predict an increasing and others a decreasing consumer load until 2020. Data base for the analysis in this paper is the consumer load from 2006 which is the newest data source with complete data. The data was made public by ENTSO-E.

Figure 6 compares the annual duration curves for the residual load in 2008 and 2020. A trend towards smaller residual load is observed. The maximal residual load is constant but the number of lower values increases with a higher share of RES. Regarding CHP as additional must run power plant shifts both curves significantly down.

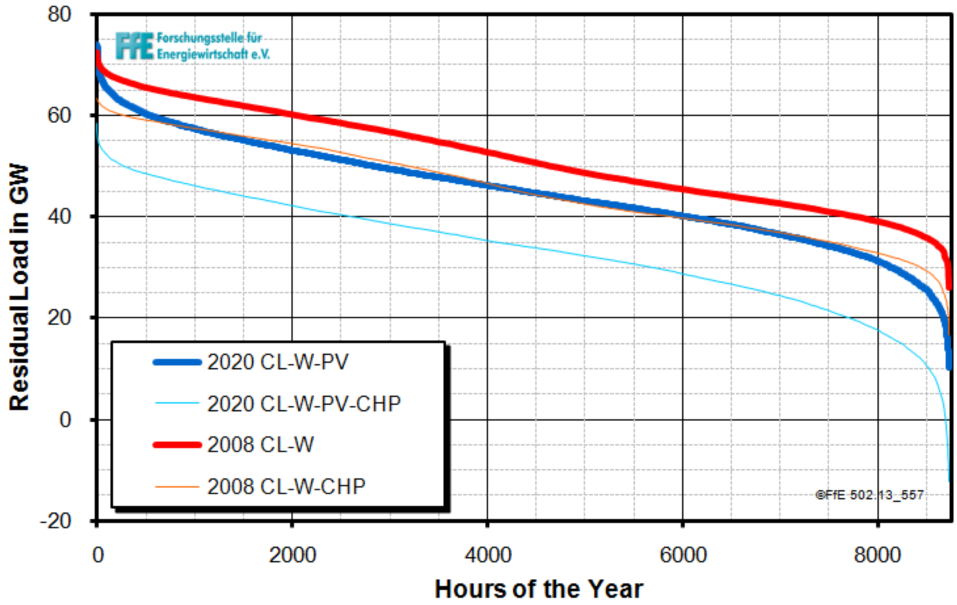


Figure 6: *Annual Duration Curve of Residual Load in 2008 and 2020*

Normalizing the Electricity Prices

In order to filter the effect of the residual load on the spot market price, the spot market price was normalized by dividing it through the natural gas price (incl. emission allowances). This allows forecasting future spot market prices independently from the development of gas prices. The gas price was used for the normalization because in many hours of the years, marginal costs of gas and coal power plants determine the spot market price. **Figure 7 left** shows the merit order of a typical conventional power plant fleet. As the load is higher than 40 GW in more than 8000 hours per year (see Figure 6), gas and coal power plants determine the spot market price most of the time. To simplify the analysis the spot market prices were normalized only by the natural gas prices, because the coal and gas prices showed a similar price development over the last years (**Figure 7 right**).

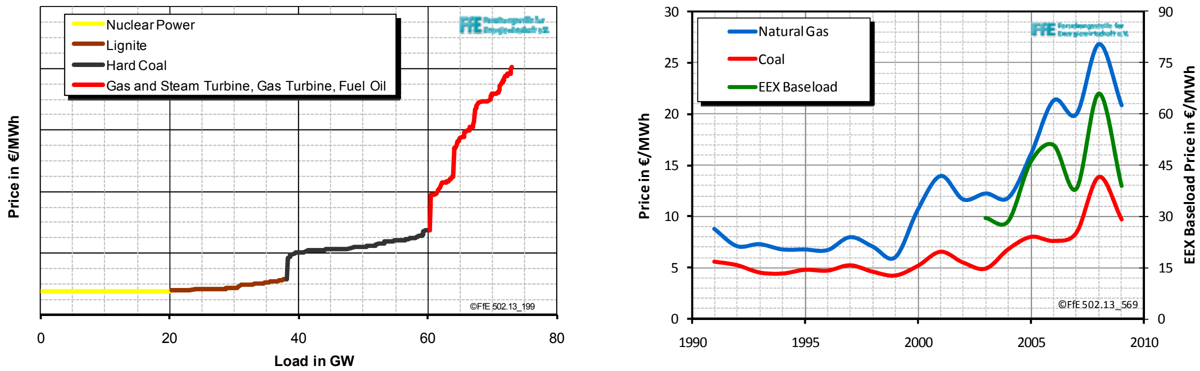


Figure 7: *Merit Order of a typical Conventional Power Plant Fleet (left) and the price development of natural gas, coal and electricity (right)* /BMWI-01 10/, /EEX-01 10/

Modeling the Electricity Prices as a Function of the Residual Load

This chapter presents the results of the statistical analysis made. **Figure 8 - Figure 10** show the normalized spot market prices /EEX-01 10/over the respective residual load in the years from 2007 to 2009. In each dataset 1 % of the highest and 1 % of the lowest spot market prices were ignored as the goal of this paper is to determine regular dependences of the spot market price but not extreme values. A linear regression line with its formula is illustrated in the diagrams. The quality of approximation with this regression line varies throughout the years. Especially in 2008 the regression line is a quite good estimator with a R^2 of 0.77. The slope of the regression line is quite similar in all diagrams. Thus, it seems to be a reliable measure for the impact of a change in residual load to the normalized spot market price.

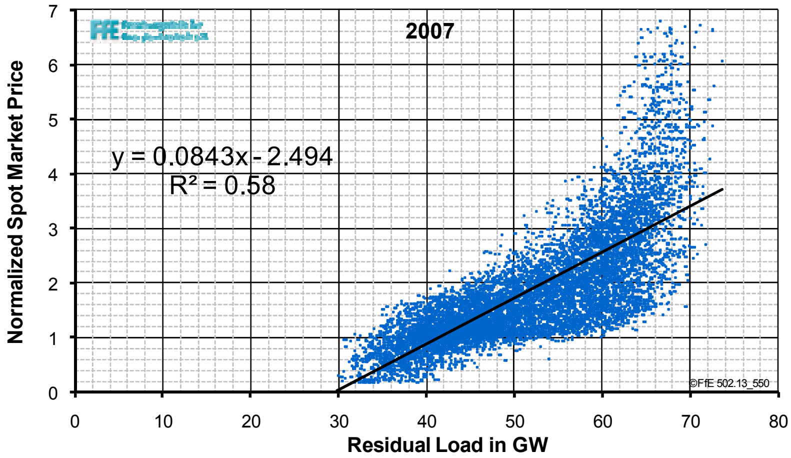


Figure 8: *Normalized Spot Market Price over Residual Load 2007*

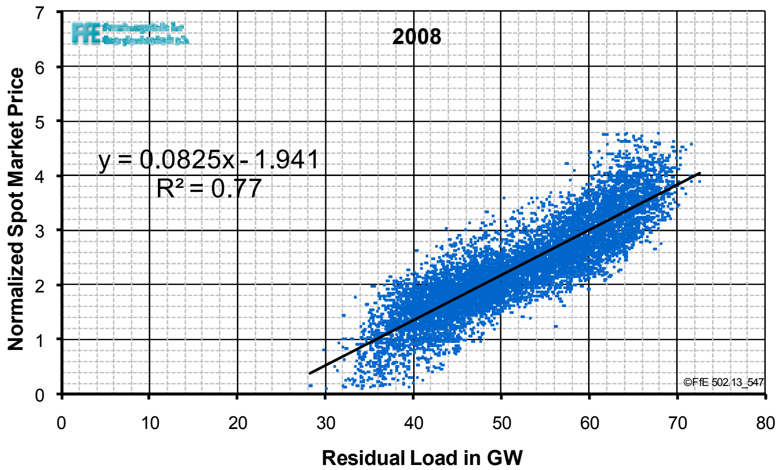


Figure 9: *Normalized Spot Market Price over Residual Load 2008*

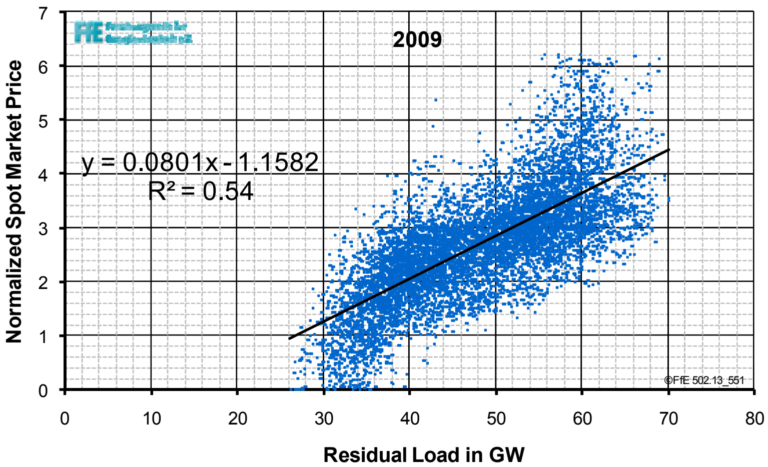


Figure 10: *Normalized Spot Market Price over Residual Load 2009*

In **Figure 11** the data from 2008 is separated into summer and winter values. A seasonal difference can be observed in the slope of the regression line and the R^2. In summer, another regression line (e.g. a polynomial) might fit better. The merit order in the conventional power plant fleet seems to change within a year. Possible reasons for this effect could be power plant maintenance work or different CHP operations in summer months. Further research could focus on these effects but it is not a subject of this paper.

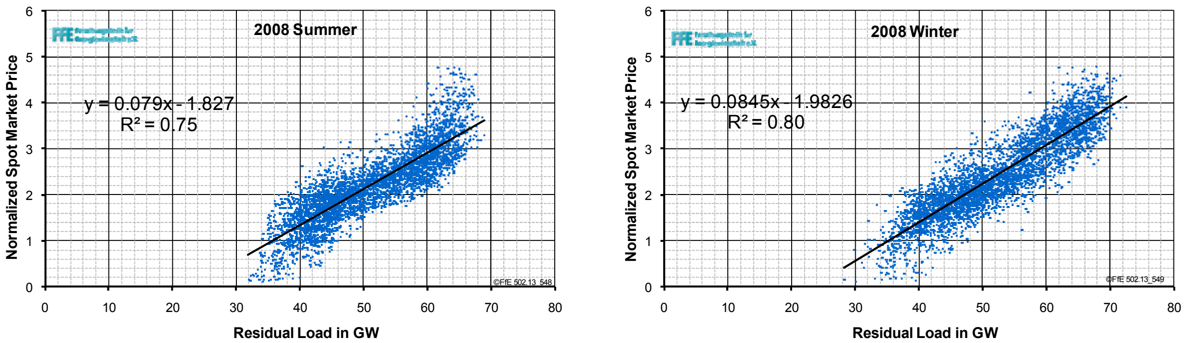


Figure 11: *Seasonal Influence on the Merit Order of the Conventional Power Plant Fleet*

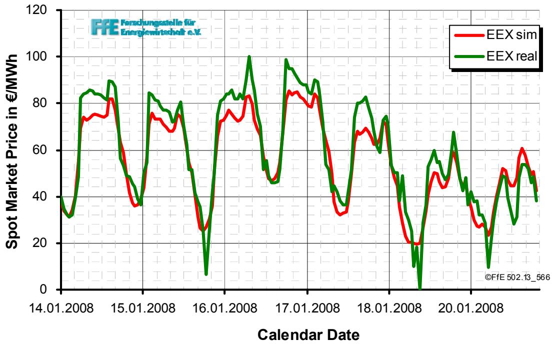
In **Table 2** the R^2 and slopes of the linear regressions in the different years are summarized. Moreover, summer and winter values are displayed. Spot market prices are plotted over two variants of residual load, one with regarding CHP (Consumer Load – Wind - CHP: CL-W-CHP) as must run power plant and one without (CL-W). Since no clear difference in the regression quality can be observed between those two versions, we recommend using “Load-Wind” for predictions in the near future. Referring to the BMU Leitstudie 2008, the installed capacity of PV will increase from 5.3 GW in 2008 up to 17.9 GW in 2020. Thus, the feed-in of electricity from PV has to be taken into account when analyzing future residual loads.

Table 2: *Overview of R^2 and Slopes of Regression Analysis*

	R²			Slope (linear regression)		
	2007	2008	2009	2007	2008	2009
CL-W-CHP	0.57	0.71	0.65	0.084	0.079	0.093
Summer	0.73	0.75	0.70	0.082	0.081	0.098
Winter	0.51	0.79	0.63	0.092	0.083	0.086
CL-W	0.58	0.77	0.54	0.084	0.083	0.080
Summer	0.73	0.75	0.69	0.082	0.079	0.098
Winter	0.55	0.80	0.56	0.095	0.085	0.080
W	0.04	0.00	0.01	-0.053	-0.012	-0.035
Summer	0.00	0.00	0.00	-0.021	-0.001	-0.028
Winter	0.09	0.04	0.04	-0.079	-0.035	-0.050

The exclusive effect on the spot market prices by the feed-in of wind was investigated by Neubarth et al. /ET-15 06/ for the period of 2004/09 – 2005/09. The calculated coefficients of determination are lower than 0.05. Thus, a prediction of spot market prices by forecasting wind power is not reliable. It is possible to quantify price reduction effects through wind power feed-in throughout a year.

Although the R^2 of regressions varies throughout the years, the slope is nearly constant in the CL-W regression. It varies from 0.080 – 0.084 with normalized spot market prices. The slope in 2008 is about the mean of these values, and thus is taken for further calculations. In order to validate this model, the spot market prices for 2008 were simulated on basis of the residual load and compared to the real values in 2008 (see **Figure 12).** The annual duration curves of both datasets show as well, that high prices are underestimated and low prices are overestimated by using the regression function for calculating the prices. The reasons therefore could be the approximation with a linear equation instead of a more complex functional correlation and other factors that are not explained within the model like speculation or blackouts. The most important range for decisions about power plant operations is the range of marginal costs of the plants. Most power plants have net efficiencies of $\eta_{el} = 0.3 – 0.58$ /FFE-25 09 /. Regarding only fuel costs for estimating marginal costs, these efficiencies correspond to normalized marginal costs/spot market prices of 85 – 48 €/MWh as respective limit for operation. In this range the simulated spot market prices fit the real values very well.



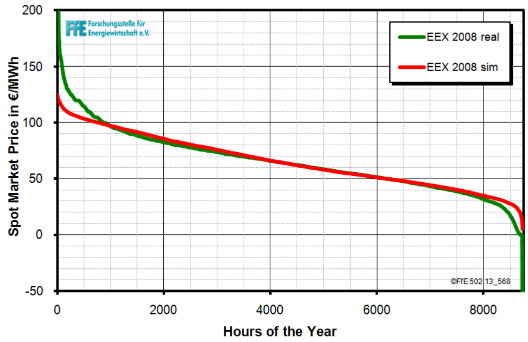


Figure 12: *Comparison of simulated and real spot market prices in 2008. Illustrated are a summer week (left) and the annual price duration curve (right).*

Merit Order Effects of RES Feed-in

In Germany, a scientific discussion about price reducing effects of feed-in of RES is taking place. This effect is called the merit order effect, because feed-in of RES leads to have a power plant with lower marginal costs as a price determining power plant. The statistics above allow to quantify and to compare this effect with other values from literature. Taking the average natural gas price of 28 € in 2008, the slope of the regression trend line is 2.3 (€/MWh)/$GWh_{\text{Residual Load}}$. Multiplying the slope from 2008 with the mean wind feed-in of 4.6 GW of wind in 2008, an average spot market price reducing effect of Ø 10.8 €/MWh results. With an overall consumption of 492 TWh, the merit order effect is calculated to 5.3 bn € in sum. In the literature, two other studies investigating this topic can be found. Sensfuß calculated 4.9 bn € in sum for the year 2006 with an agent based computational economics (ACE) model /ISI-03 07/. Neubarth et al. calculated a price reducing effect of 1.9 (€/MWh)/GWh_{RES} with statistical methods regarding only feed in of wind /ET-15 06/. A summary merit order effect of 4.3 bn € can be calculated for 2008 with this factor. Both values are in the same range as calculated with the model using the residual load as price determined However, the statistics with using the residual load are more reliable throughout different years and have much higher R^2 than regarding wind power feed-in only.

Residual Load in 2020 and its Impacts on the Electricity Prices

With the assumption of no change in the conventional power plant fleet, the spot market prices for 2020 can be calculated according to:

$$EEX_{2020} = (RL*0.0825-1.941)*Natural\ Gas\ Price.$$

The annual duration curves for the spot market prices with a natural gas price of 20 €/MWh and 40 €/MWh are displayed in **Figure 13**. Besides, simulated spot market prices for 2008 are illustrated, one with a natural gas price of 20 €/MWh and one with real gas prices of 2008 which were at Ø 28 €/MWh. It is important to mention that changes in the power plant fleet are not considered within this model. Nicolosi et al. showed that a change is likely with or without nuclear power phase out /EWI-02 09/.

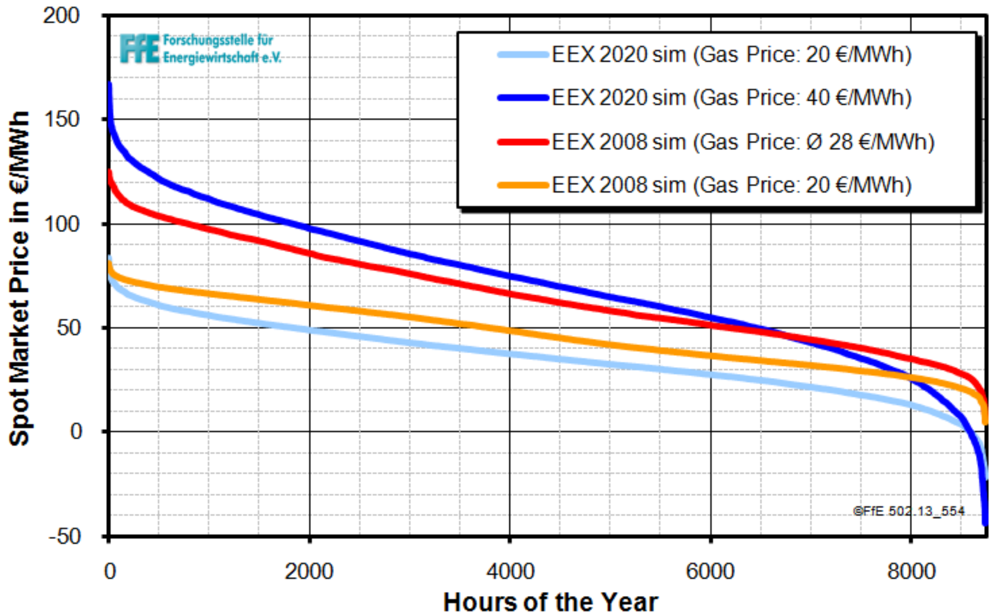


Figure 13: *Calculated price duration curves*

This analysis of the impact of changing the residual load from 2008 to 2020 shows a higher deviation in prices and a mean price reduction of 15 €/MWh by an assumed natural gas price of 28 €/MWh. The higher the fuel price, the steeper the price duration curve will be.

The regarded prices are spot market prices. However, consumer prices will be higher because of costs for transmission, costs for RES feed-in within the EEG and others.

Conclusions

The electricity prices are mainly determined by the consumer load (demand) and the respective marginal cost of the power plant fleet (supply). The efficiency and the fuel prices (including the costs for emission allowances) are the main factor for the marginal costs of power plants. Therefore, normalizing the electricity prices by natural gas prices is a solution for scenario calculations.

It does not matter whether the feed-in of RES is modeled as supply without marginal cost or is subtracted from the consumer load. Decisive for the price is the load that has to be covered by conventional power plants, the so defined residual load.

An observable correlation with coefficients of determination from 0.54 to 0.77 between the residual load and the spot market prices was shown in a linear regression in the years from 2007 - 2009. Applying a more complex regression function could lead to higher values for the R^2. Besides, other prices determining factors like blackouts or speculations are not regarded in the regression. Interestingly, taking into account more data than consumer load and wind power feed-in for calculating the residual load does not lead to higher coefficients of determination in the years from 2007 to 2009. Hence, for price correlation analysis it is sufficient to model the residual load by the consumer load minus the feed-in of wind in the near future. However, for scenario calculations, we recommend considering the load of PV as well. Moreover, it is important to be aware that a change in power plant fleet is not regarded.

The slope of the normalized spot market price over residual load is about 0.082 per $GW_{Residual\ Load}$. That means that the feed-in of 1 GWh must-run power, e.g. wind, leads to a spot market price reduction of 2.33 €/MWh (assuming the mean natural gas price in 2008 of 28 €/MWh).

The isolated analysis of the impact of changing the residual load from 2008 to 2020 shows a higher deviation in prices and a mean price reduction of 15 €/MWh. Changes in fuel prices and in the power plant fleet are not considered in this estimation.

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