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The Merit Order Effect of Wind and Photovoltaic Electricity Generation in Germany 2008-2016

Estimation and Distributional Implications

Johanna Cludius[a,b] (j.cludius@unsw.edu.au)

Hauke Hermann[b]

Felix Chr. Matthes[b]

Verena Graichen[b]

[a] The University of New South Wales: School of Economics & Centre for Energy and Environmental Markets (CEEM), Sydney, NSW 2052, Australia

[b] Öko-Institut e.V. (Institute for Applied Ecology), Schicklerstraße 5, 10179 Berlin, Germany

Abstract

Generation from renewable energy sources in Germany has experienced a considerable uptake in recent years. Mainly responsible for this development is the German Renewable Energy Sources Act (Erneuerbare Energien Gesetz, EEG). This paper considers redistributive implications of the EEG for different electricity consumers. Using time-series regression analysis, we show that electricity generation by wind and PV has reduced spot market prices considerably by 6 €/MW h in 2010 rising to 10 €/MW h in 2012. We use these results to build a near-term forecasting tool for merit order effects, projected to reach 14-16 €/MW h in 2016. On the other hand, the costs of the EEG are passed forward to consumers in the form of a surcharge. Our findings highlight significant redistributive transfers under the current design of the EEG. In particular, some energy-intensive industries are benefiting from lower wholesale electricity prices whilst being largely exempted from contributing to the costs of the scheme. We also highlight implications of our results for other areas for reform of the EEG, such as adequate remuneration mechanisms that ensure efficient operation and investment decisions are made under the scheme. More generally, these findings suggest that policy makers need to integrate distributional assessments into policy design and implementation.

Keywords: Renewable electricity; Merit order effect; Industry exemptions; Distributional implications

JEL classifications: C22, H23, Q41, Q42, Q48, Q52

1 Introduction

Electricity generation from renewable energy sources in Germany has expanded rapidly over the past decades, rising from 20 TWh in 1990 to 142 TWh in 2012, of which wind provided 51 TWh and photovoltaics (PV) 26 TWh. Biomass was responsible for 39 TWh ((AG Energiebilanzen 2013). The main reason for this expansion is the key support instrument for renewables in Germany, the German Renewable Energy Sources Act (Erneuerbare Energien Gesetz, EEG). The EEG consists of priority feed-in, a purchase guarantee and a fixed feed-in tariff for electricity generated by renewable energy sources. The electricity from renewables fed into the grid via the EEG is mainly sold by network operators on the day-ahead (spot) market. The differential between the guaranteed price and the revenues achieved by renewables on the electricity market are paid for by power consumers.

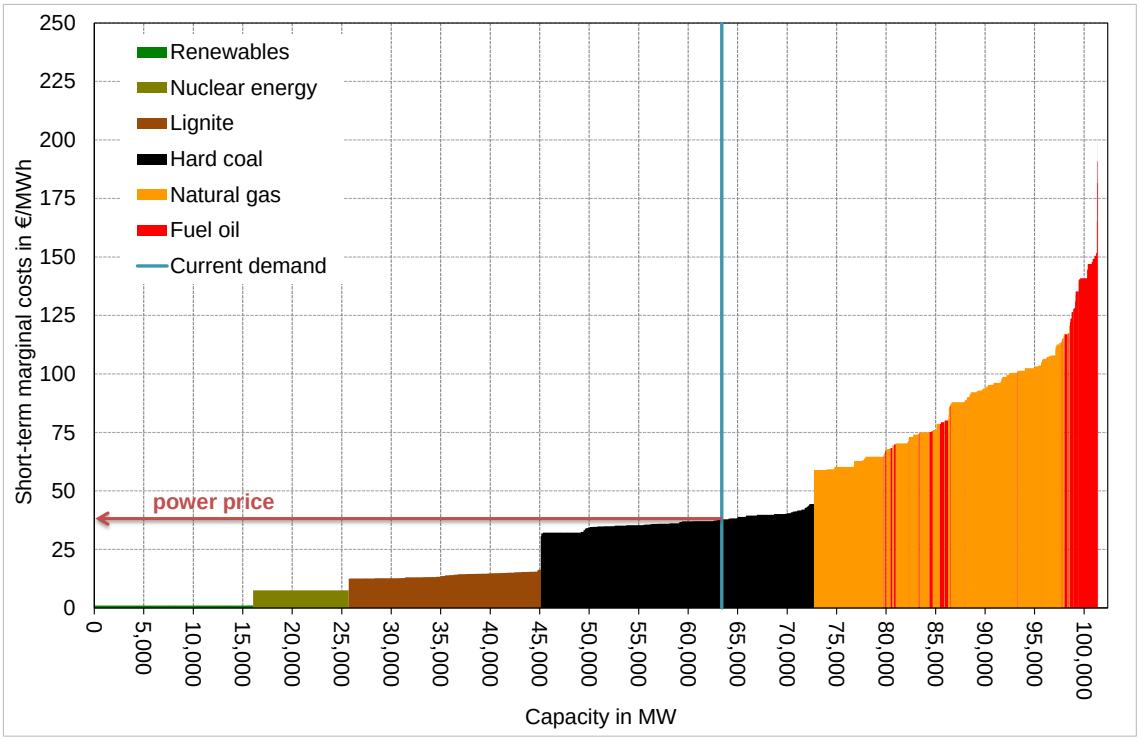
To this end, power consumers are divided into a privileged and a non-privileged group. The privileged consumers mainly consist of energy-intensive companies, who pay 0.05 ct/kWh for the EEG surcharge, whilst for non-privileged consumers (mainly households), the surcharge is calculated on a yearly basis based on the quantities of renewables fed into the grid, but also other parameters, such as revenues attainable on the spot market, the level of total final consumption, the scope of privileged consumers and forecasting errors of earlier years (see Öko-Institut 2012a for an analysis of the different components).

In October 2013 the transmission network operators published the surcharge for non-privileged consumers for 2014 at 6.24 ct/kWh rising from 5.28 ct/kWh in 2013 and 3.59 ct/kWh in 2012. The surcharge for non-privileged consumers is considerably (100 times) higher than the surcharge for the privileged consumers at 0.05 ct/kWh. This led to discussions about the appropriateness of the privilege rules. In their coalition agreement signed in December 2013, the coalition parties of the German government announced their plan to check the viability of the basis for the reduced surcharge (CDU/CSU and SPD 2013). A paper by the Federal Ministry for Economic Affairs and Energy (BMWi 2014) laying out reform options for the EEG further states the need for the privilege rules to conform to EU law, in light of infringement procedures opened against Germany by the European Union in December 2013.

A review of the scope and extent of the surcharge seems reasonable, not least because renewables have a depressing effect on the wholesale price of electricity through the so-called merit order effect. On a competitive electricity market, the higher the feed-in of renewables, the lower the wholesale price (at least in the short run). Therefore, companies that buy electricity on the wholesale market and are privileged under the EEG enjoy lower prices. This likely overcompensates for the amount they pay for the surcharge. As the International Energy Agency notes in their report on energy policies in Germany: “Recent increases in electricity costs have placed low-income households under pressure, while large consumers who buy power on the wholesale market have been shielded from the surcharge whilst benefitting from the renewables-induced reduction of wholesale prices” (IEA 2013 p.131).

On liberalised power markets electricity prices and the deployment of power plants on the day-ahead (spot) market are determined on an exchange. The EPEX Spot, a merger of the German EEX and the French Powernext, is responsible for the electricity spot markets in Germany, Austria, France and Switzerland. At 12 noon each day an auction for each of the 24 hours of the following day takes place. Power producers offer their electricity at short-term marginal costs, which consist mainly of fuel costs and CO_2–costs. The offers are then lined up from lowest to highest resulting in the merit order curve. Figure 1 shows a stylized merit order curve for Germany. Renewables have close to zero marginal costs, followed by nuclear energy, lignite, hard coal, gas and fuel oil plants. The spot market price for each hour is then determined by the marginal plant that is needed to satisfy electricity demand in the respective hour.

Figure 1 Stylized German merit order curve



Source: Own illustration

As more renewable energy sources are added to the generation mix, the merit order curve is shifted to the right and lower prices on the day-ahead market result. In their first monitoring report on the EEG, the Federal Environment Ministry gives an overview of the results of studies carried out on the merit order effect in Germany to date (BMWi / BMU 2012, p.40). The results range from 2 to 13 €/MWh and are generally higher in recent years, as more energy generated by renewable sources is fed into the grid. Previous research has shown that the merit order effect of renewables is greater on the spot market than on the forward market (Öko-Institut 2012b). However, a close interaction between the spot and the forward market exists. If this was not the case, arbitrage between the two markets would be possible (cf. Sensfuß 2011).

Two broad methods to analyse the merit order effect of renewables have been employed. First, regression analysis of historical time-series data and second, electricity market modelling. The former analyses historical price and generation data, whilst the latter compares different scenarios within an electricity market model. There are merits and challenges concerning either of the methods. Using an electricity market model requires careful calibration and especially the definition of a reasonable counterfactual scenario. Regression analysis, on the other hand, can employ actual historical data and does not have to make assumptions about alternative developments. At the same time, only rather short-term merit order effects, based on not only the current electricity market and power generation structure are calculated. Moreover, issues such as the costs for new power plants or network development are not considered (Würzburg, Labandeira and Linares 2013).

Regressing the German spot market price of electricity on the residual load, von Roon and Huck (2010) conclude that an extra GW of renewables or cogeneration decreases the spot price by 2.4 €/MWh (on average) and that the total merit order effect of renewables is 11 €/MWh in 2008. Since day-ahead wind forecasts are used as a basis by bidders in the spot market auctions, Neubarth, Woll, and Weber (2006) use those forecasts to determine the impact of an additional GW of wind on the hourly spot market price in Germany and conclude that it is equal to 1.9 €/MWh. This is equivalent to an average total merit order effect of 7.6 €/MWh in 2004-2005. Würzburg, Labandeira and Linares (2013, p.3) note the “very limited empirical evidence” on merit order effects in Germany and carry out an analysis of the merit order effect on the joint German and Austrian market using daily averaged data on electricity prices, renewable feed-in, load, the price of gas and import and export flows. They estimate an overall reduction in the electricity spot price of 7.6 €/MWh between mid-2010 and mid-2012.

Time-series regression analysis has also been used to determine the impact of renewables and cogeneration on electricity prices in other countries. Gelabert, Labandeira and Linares (2011) conclude that between 2005 and 2010 an additional GW of energy from renewables or cogeneration in Spain led to a decrease in the spot electricity price of 1.9 €/MWh on average. Jónsson, Pinson, and Madsen (2010) employ non-parametric parameter estimates to model the spot price dynamics on the Danish electricity market. They also find a significant price effect of wind, especially on the high demand end. Studies also exist for the Australian (Cludius, Forrest and MacGill 2014; Forrest and MacGill 2013) and Texan (Woo et al. 2011) markets, which both model the electricity price using an AR(1) process. Additionally, Forrest and MacGill (2013) employ a logarithmic transformation to account for specific impacts at the very low and high demand end.

Although electricity market models take a different approach, researchers have generated results in the same range. Using an agent-based electricity market model, Sensfuß (2011) and Sensfuß, Ragwitz and Genoese (2008) calculate average merit order effects for Germany of 1.7€/MWh in 2001, rising to 7.83 €/MWh in 2006 and between 5.82 €/MWh in 2007 and 6.09 €/MWh in 2009. Weigt (2009) uses a market equilibrium model to estimate cost savings and price effects due to wind generation. Aver-

age effects range from 6.26 €/MWh in 2006 to 13.13 €/MWh in 2008. Estimated price reductions exhibit large fluctuations and are particularly high at peak load times. In their model for Spain, Sáenz de Miera, del Río González and Vizcaíno (2008) determine a merit order effect between 5 and 12 €/MWh in 2005-2007.

Electricity market models are also employed to forecast merit order effects. Fürsch, Malischek and Lindenberger (2012) use a model that takes account of investment decisions to forecast merit order effects of 2 €/MWh in 2015, rising to 10 €/MWh in 2030. Traber and Kemfert (2011) and Traber, Kemfert and Diekmann (2011) use an electricity market model to estimate effects out to 2020. They conclude that renewables lower the electricity price by 3.7 and 3.2 €/MWh respectively. In their study of the effect of distributed photovoltaic generation on the Australian electricity market, McConnell et al. (2013) build a model based on historical bids in 2009 and 2010 and model the installation of distributed photovoltaic generation between 0 GW and 5 GW of capacity. They estimate considerable merit order effects of up to 12% of the total value traded on the Australian pool market.

Our contribution to the existing literature is the discussion of results on merit order effects in the context of the distribution of costs and benefits of Germany's Renewable Energy Sources Act (EEG) and the implications for equity issues. Furthermore we forecast merit order effects out to 2016. This forecasting exercise is somewhat similar to McConnell et al. (2013) in that we use historical data and results from our regression analysis to extrapolate results under different assumptions on development of generation by PV and wind and total load. This forecasting method is therefore distinct from the ones carried out to date using numerical electricity market models and we explain why we believe it is a viable method to forecast effects on the German electricity market in the near term. Our forecasting exercise enables us to give an indication of the implications of the merit order effect for a long-term reform of the EEG, both in the context of distributional aspects and other design issues of the EEG.

The remainder of the paper is structured as follows. In the following chapter, we present the data employed, conduct a first descriptive analysis and perform tests needed for the specification of our regression model. Chapter 3 presents estimation method and assumptions needed for our historical regression analysis and forecasting tool. Chapter 4 presents results. We show estimation results for historical merit order effects, forecasts to 2016 for different scenarios and discuss redistributive impacts in detail. We also derive implications for the immediate and near- and long-term reform of the EEG. In the final chapter we sum up and conclude.

2 Data

We use hourly time series data published by the European Power Exchange (EPEX), the European Energy Exchange (EEX) and the European Network of Transmission System Operators for Electricity (entso-e) for our analysis. We analyse hourly data for EPEX day-ahead (spot) prices using information on the total load, and the generation of wind and PV during the respective hours. Numbers for PV are available from July

2010 onwards, since they started to be reported after the installed capacity of PV reached 10 GW. Unlike conventional technologies, hourly generation from wind and PV is fully reported at the EEX. Biomass, on the other hand, which is also supported by the EEG does not report at the EEX. Since biomass acts as a baseload technology, we do not expect merit order effects varying each hour, but rather a general reduction of the price level. The same is the case for existing run of river hydro power plants that are not supported by the EEG. Generation by wind and PV as published by the exchange is scaled linearly in order to meet officially reported annual generation (AG Energiebilanzen 2013).

Whilst our dataset includes 100% of generation by wind and PV, demand published by entso-e only covers about 87% of total demand in the German market (cf Bundesnetzagentur 2012, p 72 ff, for a detailed discussion). One central reason why the demand published by entso-e does not cover 100% of the demand is (industrial) own consumption. Due to the privileges of own consumption (no EEG surcharge, no network fees), the power stations supplying for own consumption are often not shut down, when electricity prices at exchanges are low.[1] No correction is applied to the entso-e demand. Therefore, in the context of regression analysis, we might slightly overestimate the specific merit order effect of demand reduction. However, the approach taken (no correction) better reflects the real world situation, where power supply for own consumption is often not optimised against the exchange. This should not affect estimation of the coefficients for wind and PV.

Table 1 Summary statistics of sample variables (hourly data)

	2008		2009		2010		2011		2012	
	Mean [Min;Max]	**SD**	**Mean** [Min;Max]	**SD**	**Mean** [Min;Max]	**SD**	**Mean** [Min;Max]	**SD**	**Mean** [Min;Max]	**SD**
Spot (€/MWh)	**65.76** [-102;494]	28.66	**38.86** [-500;182]	19.42	**44.49** [-20;132]	13.98	**51.12** [-36.82;117.49]	13.60	**42.59** [-221.99;210]	18.69
Wind (GW)	**4.62** [0.14;19.23]	3.88	**4.41** [0.13;20.63]	3.53	**4.31** [0.12;22.75]	3.87	**5.58** [0.10;25.21]	4.86	**5.77** [0.14;24.09]	4.91
PV (GW)					**1.10** [0;9.04]	1.90	**2.20** [0;13.62]	3.39	**3.01** [0;22.20]	4.60
Load (GW)	**56.42** [34.31;76.76]	9.34	**52.48** [29.98;72.97]	9.83	**55.77** [34.61;79.88]	9.31	**55.35** [32.39;76.43]	10.33	**53.46** [29.20;74.48]	10.37
Obs.	8,784		8,760		8;760 [3;983 for PV]		8,760		8,784	

Source: EPEX, EEX, entso-e, AG Energiebilanzen (2013)

One can observe that both the load and especially mean prices fell sharply between 2008 and 2009 as a result of the financial and economic crisis (Table 1). The most negative prices were observed in 2009 at -500 €/MWh. This can be attributed to special effects - among others - related to regulatory provisions phased out at the end of the year. This phase-out led to negative power prices that occurred in hours with high renewable feed-in and low demand (for an analysis of the special situation in 2009 refer

[1] When electricity from the grid is consumed, the EEG surcharge and network fees have to be paid. At present, the level of the EEG surcharge is higher than the average spot price. Thus the incentive to reduce own consumption and consume electricity from the gird is eliminated even at zero spot prices, since the EEG surcharge would have to be paid.

to EWI 2010). In 2012, prices fell to below -200 €/MWh in hours with low demand and high renewable generation. This can be attributed to the considerable and growing penetration by renewables of the German market for electricity in combination with the way in which renewables are bid into the market on the EPEX (see below).

This build-up of generation by wind and especially PV can be observed looking at the mean values of GW produced in any given hour across the years, which follow an upward trend. Looking at the minimum and maximum values, the volatile nature of these technologies becomes visible.

Since transmission lines exist between countries in Europe, the power demand on the German market is not only influenced by German demand, but also through imports and exports to and from neighbouring countries. Germany's electricity market forms one market zone with Austria and is linked automatically via market coupling organised by the power exchanges to France, the Netherlands, Denmark and Sweden. With the introduction of the Central Western European market coupling (including France) at the end of 2010, price convergence between the German and the French spot market increased significantly. As a general trend it can be observed that price convergence is not yet as high with countries that have not yet introduced automatic market coupling with Germany (e.g. Poland and Switzerland).

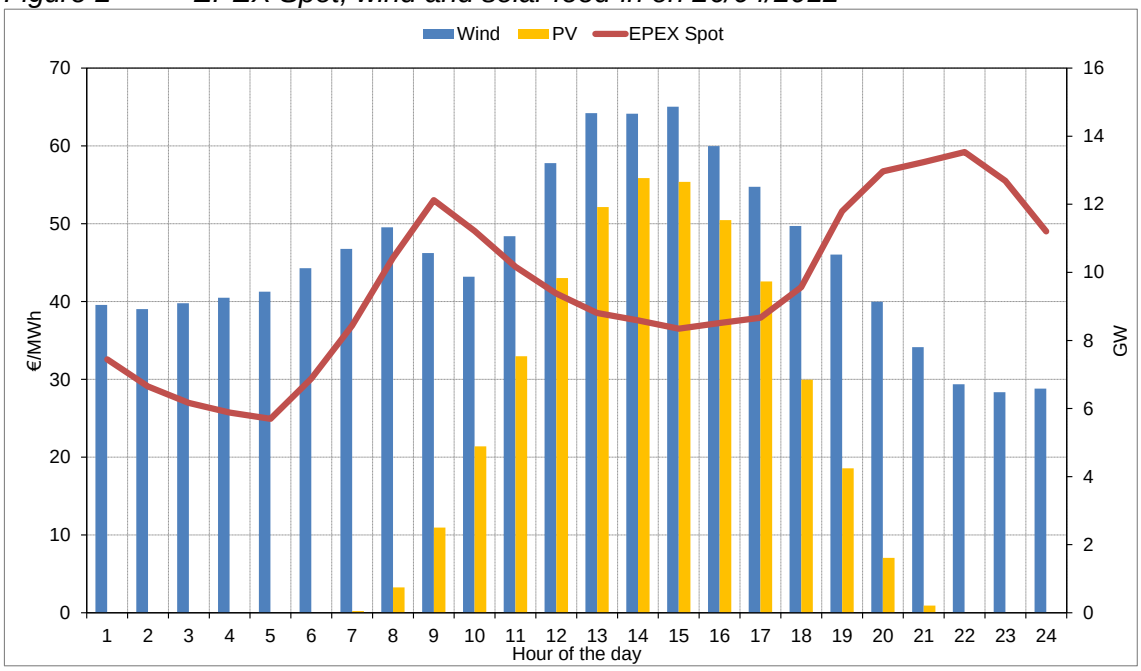
In essence, a common merit order curve for the linked markets exists, as long as prices are identical, i.e. enough transmission capacity is available. Since the electricity prices we use in this analysis already embody the effects of electricity imports and exports, we cannot isolate this effect. It could be expected that merit order effects were larger if the German market was taken in isolation. Würzburg, Labandeira and Linares (2013) include the German export-import balance in their regression equation, but find that this variable is insignificant. It would be an interesting endeavour to analyse if the merit order effect changes when import and export flows and transmission capacities are accounted for in more detail or whether this relationship will change in years to come.

We tested for unit roots in the hourly time-series using the augmented Dickey-Fuller (ADF) test (Dickey and Fuller 1979) with automatic lag selection based on the Schwarz information criterion (SIC) as well as the Phillips-Perron test. The null hypothesis of a unit root could be rejected for all of the hourly series used in the analysis.

2.1 Descriptive Analysis

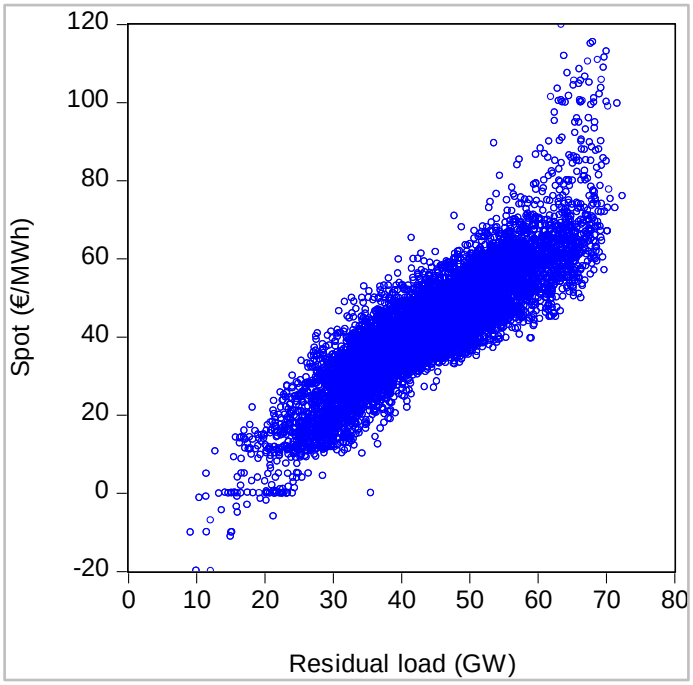
Looking at the conditions on an individual day with high generation levels of both wind and PV (26/04/2012), Figure 2 displays the hourly EPEX spot price and the feed-in of wind and PV in each hour of that day. Clearly, the spot price rises with demand in the early hours of the day, but during the middle of the day is reduced by high wind and photovoltaics feed-in. This is the merit order effect of renewable energy sources during those hours. Our goal is to estimate by how much on average the spot price is reduced through additional wind and PV feed-in.

Figure 2 EPEX Spot, wind and solar feed-in on 26/04/2012



Source: EPEX, EEX

Figure 3 Residual load (GW) and the spot price of electricity (€/MWh) 2012



Source: EPEX, EEX, entso-e

Figure 3 plots the relationship between the residual load (load – fluctuating renewables) and the spot market prices in 2012. It shows that the more electricity is generated using conventional technologies, the higher the EPEX spot price becomes. At very low levels of conventional generation, the price of electricity can fall below €0, as was the case on 25 December 2012, where low demand coupled with a lot of wind, depressed

prices to below -200€/MWh. At residual loads below 40 GW renewables start to substitute baseload power plants such as lignite and nuclear. If low residual loads occur for a few hours only, these plants are generally not shut down completely but are operated with partial load. This has different reasons such as ramp rates, start-up costs and the provision of system services.

The fact that negative prices occur in these situations also has do with the way in which renewable plants bid into the EPEX. Under the EEG, sellers of eligible power have an incentive to place negative bids even though the short-term marginal costs of EEG plants are positive.[2] As a result, the spot market has produced negative power prices at low residual loads. On the other hand, prices can climb to above 100 €/MWh, during times of high demand and low renewable feed-in, as generators with very high marginal cost (gas turbines, oil generators) set the price. Generally, the plot confirms that higher prices are usually associated with a higher residual load, a combination of high demand and a large percentage of this demand being met by conventional technologies.

2.2 EPEX Spot Price

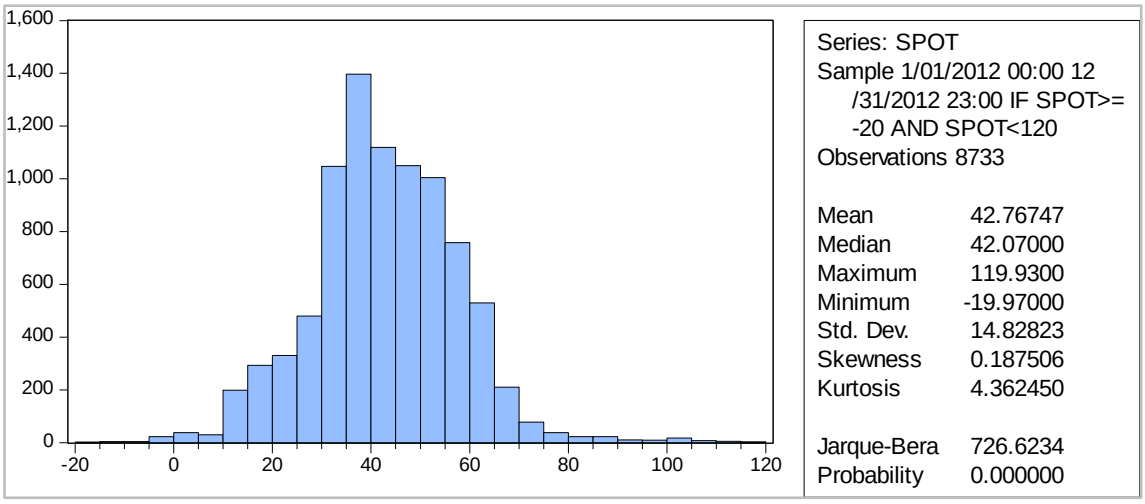
The distribution of the EPEX spot price is highly leptokurtic (Figure 4). The outliers in the tails are very few in number and did not significantly influence analysis of the whole sample or individual years. When modeling the relationship between the residual load and the spot price for 2012, however, these outliers proved influential at the high and the low load end. That is why we decided to use a censored sample between [-20,120] (using standardized Student residuals to determine the outliers) for the analysis of the relationship between the residual load and the spot price in 2012. 23 values below -20 were set to -20 and 25 values above 120 were set to 120. This censoring therefore affected 0.55% of the sample.

To mitigate the impact of hours with exceptional circumstances, daily averaged data can also be used (cf. Gelabert, Labandeira and Linares 2011). Another argument for the use of daily averages is that the prices for all 24 hours of the following day are determined at the same point in time on the day before and hence with the same information set. Usually, a time-series is characterised by updating, which means that information is updated from one observation to the next (cf. Huisman, Huurman and Mahieu 2007; Härdle and Trück 2010). This means that real updating on the electricity market only takes place every 24 hours. The information used to determine day-ahead prices, however, is different for each hour of the following day, even though this information is available at the same point in time on the day before. An advantage of using hourly data is that especially the feed-in of photovoltaic energy is very volatile during

[2] For EEG plants that generate under the fixed feed-in Tariff, price-independent bids are submitted, meaning the amount offered is sold at any price. In case of the market premium model, EEG plants have an incentive to bid up to the negative value of the expected market premium. Since the market premiums are adjusted periodically, this can bring about a downward spiral of bids for plants under the market premium model (EEX and EPEX SPOT 2014).

the day and that hourly effects are to be expected. If we averaged the data over the day, the PV effects might be less visible. A calculation using daily averages is provided in the Appendix as a sensitivity check. For the daily averages, the presence of unit roots could not be rejected. Therefore, the analysis was conducted in first differences, in which no unit roots could be detected.

Figure 4 Histogram of EPEX spot price 2012 (values between -20 €/MWh and 120 €/MWh)



Source: EPEX

3 Estimation Method

3.1 Merit Order Effects 2008-2012

We model the electricity spot (day-ahead) price as dependent on the feed-in of *wind* and photovolatics *pv* and total *load* as an indicator for total demand. As well as hourly, daily, monthly and yearly dummies to control for systematic changes in demand. A constant was omitted and, instead, seven dummies for days of the week introduced.

Equation 1

$$Spot_t = \beta_1 wind_t + \beta_2 pv_t + \beta_3 load_t + \sum_{k=1}^{23} \beta_{k+3} dh_{kt} + \sum_{l=1}^{7} \beta_{l+26} dd_{lt} + \sum_{m=1}^{11} \beta_{m+33} dm_{mt} + \sum_{n=1}^{4} \beta_{n+44} dy_{nt} + u_t$$

We use OLS and estimate this model for individual years 2008-2012, as well as for the three years 2010-2012 for which we have data on both wind and PV.[3] In order to run

[3] Non-parametric models were also applied and led to very similar results. Results for these regressions as well as the unit root tests are available from the authors upon request.

this regression, we have to assume that all of the explanatory variables are determined exogenously. This should be a valid assumption for wind and PV, since those sources generate electricity according to the occurrence of natural phenomena, and are fully brought to the market because of priority feed-in. In the case of demand, this means that we have to assume that demand is perfectly inelastic (in the short-run). As we do not expect that consumers base their day-to-day consumption decisions on hourly spot market prices for electricity, we believe that this assumption holds. There might be other factors, such as prices for coal and gas, as well as carbon prices that have an influence on electricity prices. However, whilst they influence the spot price of electricity, they are likely to be uncorrelated with the explanatory variables used in our analysis. Whilst this should be the case for wind and PV, we have to again assume that demand is perfectly inelastic. Looking at estimates for different years will allow us to disentangle some of those effects, as they can capture systematic differences in prices for coal, gas and carbon between different years.

The coefficients β_1 and β_2 are estimates of specific merit order effects, i.e. the average reduction in the spot market price per additional GW of wind or PV in a given hour. In order to estimate the total average merit order effect, those specific effects are multiplied with the load-weighted average wind or PV feed-in per hour in the respective year.[4]

Equation 2

$$Total\ average\ MO\ effect_{\ y} = \beta_{\ 1y} \times load - weighted\ av(wind)_y + \beta_{\ 2y} \times load - weighted\ av(PV)_y$$

3.2 Projection of Merit Order Effects 2013-2016

In order to determine the impact of increasing wind and PV penetration on the spot electricity price and forecast the revenue factors of wind and PV (average spot price earned by wind and PV relative to overall average spot prices), we first estimate the relationship between the spot price and the residual load (defined as total load – fluctuating renewables). This permits us to construct an electricity price curve for different residual loads. We run a regression of the 2012 EPEX spot price on the residual load and the hourly, daily and monthly dummies.

We want to account for the special shape of the electricity price curve, i.e. steep at the left side, flat in the middle and steep at the right end (cf. Figure 3). Therefore, we estimate the equation for the following brackets of residual load: below 30, 30-40, 40-50, 50-60 and over 60 GW.

[4] Load-weighted averages are calculated by multiplying the renewables feed-in in each hour with the respective load in this hour, summing up over all hours of the year, and then dividing by total load of the respective year.

Equation 3

$$Spot_t = b_1 res\_load_t + \sum_{k=1}^{23} b_{k+1} dh_{kt} + \sum_{l=1}^{7} b_{l+24} dd_{lt} + \sum_{m=1}^{11} b_{m+31} dm_{mt} + u_t$$

As discussed in the previous chapter, in 2012, electricity spot prices have exhibited a considerable level of volatility and fallen below -20 €/MWh on 23 occasions, whilst they climbed above 120 €/MWh on 25 occasions. Since those extreme values are likely to drive results in the very low and very high deciles of residual load (below 30 GW and over 60 GW) and are likely to reflect extreme and rare operating conditions, we estimate two different specifications: One where the whole sample is included, another one where spot prices are censored at [-20;120], i.e. all spot prices below and above the censoring limit are set to the limit values. The full sample is estimated using OLS, whilst Tobit estimation is used for the censored sample.

In order to forecast merit order effects for wind and PV between 2013 and 2016, we build a forecasting tool which models the build-up of these two technologies. We consider four different scenarios to account for changes in installed capacity of renewables and total load as follows:

- Reference scenario
- Sensitivity scenario 1: Wind and load held constant, but higher generation by PV
- Sensitivity scenario 2: PV and load held constant, but higher generation by wind
- Sensitivity scenario 3: Wind and PV held constant, but lower total load

We chose to estimate a conservative reference scenario. The reference values for PV are based on the current trend of capacity additions taken from the trend scenario as published by the German transmission network operators (ÜNB 2013). Installed PV capacity in the reference scenario reaches 46 GW at the end of 2016. The cap of 52 GW installed capacity (Bundestag 2012) at which the German feed-in tariffs for PV are set to be reduced to 0 is reached in 2018 in this scenario. The reference scenario for wind is based on the trend scenario of the German transmission network operators from 2012 (ÜNB 2012), which assumed a more conservative expansion of wind than the current scenario.

The reference scenario is contrasted with a high PV scenario, in which an installed capacity of 52 GW is already reached in 2015. This was the development still assumed in the 2012 trend scenario (ÜNB 2012). The difference in generation by PV for each year between the reference PV scenario and the high PV scenario ranges from 1 TWh in 2013 to 10 TWh in 2016. This difference in total generation is used to construct the two remaining sensitivity scenarios.

Table 2 Parameters used in the reference and sensitivity scenarios

	2013	2014	2015	2016
Reference scenario				
PV capacity at end of year (GW)	36.3	40.2	43.4	46.0
PV (TWh)	33.3	36.6	40.0	42.8
Wind (TWh)	55.8	58.8	61.4	64.9
Parameters changed in sensitivity scenarios				
Sensitivity 1: High PV (TWh)	34.7	41.0	49.5	52.5
PV capacity at end of year (GW)	39.0	45.5	53.8	54.3
Sensitivity 2: High Wind (TWh)	57.3	63.2	70.9	74.7
Sensitivity 3: High Efficiency (TWh)	-1.4	-4.4	-9.5	-9.7
Difference in generation between reference scenario and sensitivity scenarios				
Difference (TWh)	1.4	4.4	9.5	9.7

Source: ÜNB 2012, ÜNB 2013, own calculations

Whilst PV and load are the same as in the reference scenario, in the high wind scenario, wind generation is scaled up by exactly this difference in the respective years. The high wind scenario is in line with the fact that wind generation is forecast to be slightly higher in the updated trend scenario than in our reference scenario (ÜNB 2013). Furthermore, this expansion of wind generation also acts as a proxy for additional offshore capacity which we cannot model separately in our framework due to missing time-series data. Similarly, in the high efficiency scenario, total load is scaled down by exactly this difference in generation between the reference scenario and the high PV scenario, whilst PV and wind are held constant. Thus, it is possible to compare results across the sensitivity scenarios (Table 2).

Using these predictions regarding generation by wind and PV, as well as total load, we scale 2012 data on generation patterns of wind, PV and load to meet total output. Scaling is done for wind and load on a yearly basis, whilst numbers of PV a scaled with monthly accuracy. We then use these numbers to generate expected residual load in 2013 to 2016. All of the scenarios have the same effect in terms of total residual load. However, the load profiles differ and the changes will affect different hours of the day, giving an indication in what way electricity prices are impacted depending on which component is affected by an expansion (wind, PV) or reduction (load).

The forecast prices correspond to 2012 prices, adjusted for the predicted changes in renewable penetration and the resulting impact of lower residual load on prices. Therefore, we implicitly assume that the fleet of conventional power plants and prices for inputs to electricity such as fuels or carbon in 2013-2016 will be identical or at least similar to 2012. Furthermore, we assume that load, except in the high efficiency scenario, will remain constant and that the solar and wind profiles will be identical to the ones observed in 2012.

Looking at the total revenues earned by wind and PV in a given year and dividing them by the total amount of electricity produced by those two sources gives us the average revenues wind and PV can earn in any given hour. Relating those average revenues to overall average spot prices permits us to calculate revenue factors. These give an indication as to how profitable renewable energy is compared to an “average technology”.

4 Results

4.1 Specific and Total Merit Order Effects 2008-2012

Results of the regression determining specific merit order effects of wind and PV are displayed in Table 3. All coefficients are significant at the 99% confidence level (coefficients on the dummies are mostly individually and always jointly significant). The coefficients on wind and PV are negative, as expected, in all specifications. The estimated merit order effects range from -0.97 to -2.27 €/MWh for wind and from -0.84 to -1.37 €/MWh for PV.

Table 3 OLS regression: Specific merit order effect of wind and PV

	2008	2009	2010 (2nd half)	2011	2012	2010-12
Wind	**-2.27*** **	**-1.72*** **	**-1.15*** **	**-0.97*** **	**-0.97*** **	**-1.07*** **
	(0.09)	(0.18)	(0.07)	(0.05)	(0.06)	(0.04)
PV			**-0.84*** **	**-0.90*** **	**-1.37*** **	**-1.14*** **
			(0.16)	(0.07)	(0.11)	(0.06)
Load	2.58***	1.36***	1.27***	1.13***	1.65***	1.42***
	(0.07)	(0.06)	(0.06)	(0.05)	(0.15)	(0.09)
Hourly, daily, monthly and yearly dummies included						
Adjusted R2	0.80	0.66	0.81	0.81	0.69	0.73
DW-Statistic	0.54	0.64	0.42	0.42	0.33	0.32
Observations	8,784	8,760	3,983	8,760	8,784	21,527
Time frame	01/01/2008 - 31/12/2008	01/01/2009 - 31/12/2009	19/07/2010 - 31/21/2010	01/01/2011 - 31/21/2011	01/01/2012 - 31/21/2012	19/07/2010 - 31/12/2012
Newey-West standard errors in parentheses, robust to heteroskedasticity and autocorrelation *** significant at the 99% confidence level						

Source: EPEX, EEX, entso-e, own calculations

Würzburg et al. (2013) note that they expect differing impacts of PV and wind using data of such high frequency, especially that the specific effect of PV would be higher, because it coincides with demand peaks. The difference between the wind and PV coefficient estimates is only statistically significant in 2012. The very similar effects in 2010 and 2011 are probably due to the fact that we control for hour of the day, day of the week, month and year, as well as for total load, thus capturing the effect of high demand on the electricity price. The significantly higher effect for PV in 2012 could be associated with the fact that at higher levels of PV penetration, limits of export transmission capacity on sunny summer days are reached faster (cf. Öko-Institut 2013). Therefore, we expect that there were more hours in 2012 in which PV generated electricity could no longer be exported to neighbouring countries and therefore the effect of PV on German spot market prices was not mitigated through exports. This cannot be explored further in the current paper, but as noted above, the relationship between the merit order effect and imports and exports is an interesting topic for further research.

The remaining differences between individual years can be attributed to the changing circumstances. Higher specific effects occur in times of expensive fuel and high CO_2 prices (2008), because this means that the marginal cost of electricity generation is higher and therefore the merit order curve steeper. In 2009 high specific effects were also observed, despite low demand as a result of the financial and economic crisis. As noted above, in 2009 regulatory provisions were phased out at the end of the year leading to negative power prices that occurred in hours with high renewable feed-in and low demand. In those hours the merit order curve was extremely steep at the left end (EWI 2010).[5] In 2010, 2011 and 2012 the specific effect of renewables is smaller, since the price is determined in the middle of the merit order curve in more hours during those years, where the slope is less steep. The positive coefficient on load, which is of the same order of magnitude, also reflects the average slope of the merit order curve of conventional fuels. As noted above, the fact that it is slightly higher than the coefficients on wind and PV may reflect that we are capturing only about 87% of demand.

Since the Durbin-Watson test statistic (Durbin and Watson 1950) and the correlogram of squared residuals point to autocorrelation in the residuals, we estimate the model using Newey-West standard errors (Newey and West 1987) that are robust to heteroskedasticity and serial correlation. Autocorrelation in the residuals could pick up forecasting errors for wind, PV and load. Bids on the spot electricity market are placed at 12 noon for all 24 hours of the following day on the basis of forecasts of wind and PV generation and demand (cf. Neubarth, Woll and Weber 2006, who model merit order effects based on wind forecasts). Forecasting errors would therefore likely affect a number or all of the observations for an individual day, causing serial correlation in the residuals.

Table 4 Specific and total merit order effect of wind and PV

	2008	2009	2010 (2nd half)	2011	2012
Wind specific effect (€/MWh)	-2.27***	-1.72***	-1.15***	-0.97***	-0.97***
Load-weighted average wind in-feed per hour (GW)	4.76	4.51	4.41	5.63	5.73
Wind total effect (€/MWh)	-10.80	-7.76	-5.06	-5.49	-5.58
PV specific effect (€/MWh)			-0.84***	-0.90***	-1.37***
Load-weighted average PV in-feed per hour (GW)			1.17	2.41	3.32
PV total effect (€/MWh)			-0.98	-2.17	-4.56
Total average merit order effect of wind and PV (€/MWh)	**-10.80**	**-7.76**	**-6.04**	**-7.67**	**-10.13**

Source: EPEX, EEX, own calculations

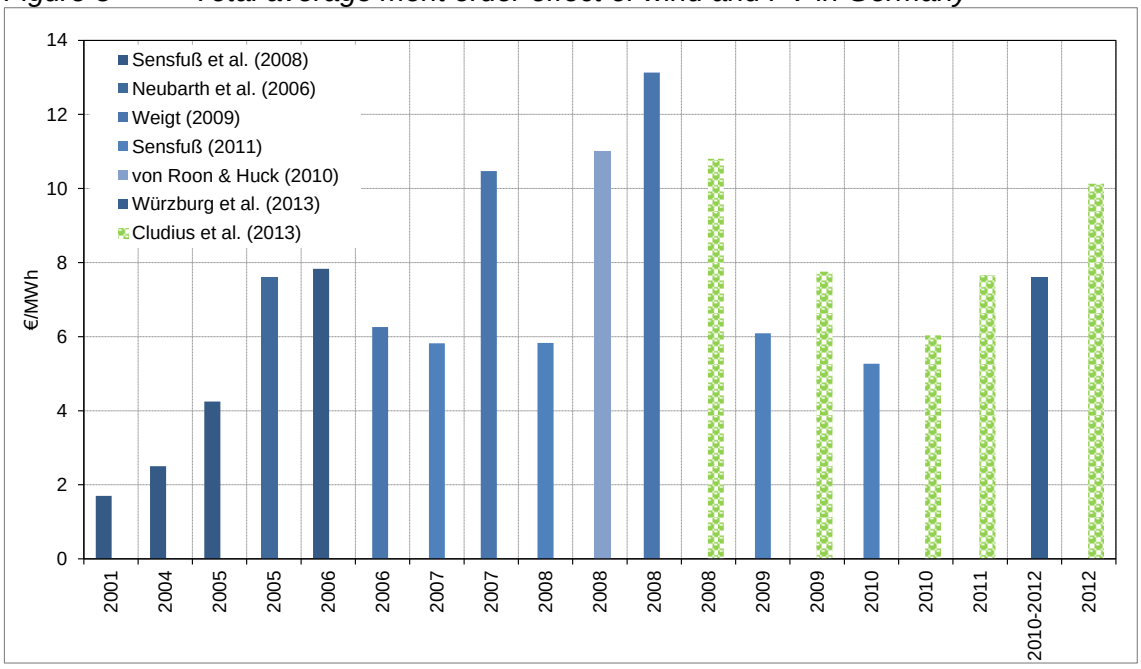
Up until now, we have estimated the specific merit order effects of renewables, i.e. what happens (on average) if an additional GW of renewable energy is fed into the grid. This is equal to the regression coefficients in Table 3. In a next step, we estimate the total average effect in the respective years, by multiplying the specific effects with

[5] Using censored data [-20,120] to account for these special circumstances and estimating a Tobit model of the same specification only slightly reduces the wind coefficient to -1.51.

the load-weighted average renewable energy that was fed into the grid in the respective year in each hour. Results are displayed in Table 4.

The size of the total average effect depends both on the specific effect, which reflects conditions in individual years (i.e. overall level of demand, fuel and carbon prices, and regulatory circumstances) and the (load-weighted) average amount of renewable energy fed into the grid in a given hour during the respective year. The total average effects in 2008 and 2009 are likely to be underestimated, as we cannot account for the PV that would have already played a role in those years. The total average effect in 2008 and 2009 is fairly high despite this limitation and can mostly be attributed to the high specific effect of wind reflecting high fuel prices (in 2008) and special regulatory conditions (in 2009), whilst the growth of the total average effect from 6.04 €/MWh in 2010 to 10.13 €/MWh in 2012 is mainly dependent on the growing feed-in of renewables and a higher coefficient on PV in 2012.[6] Figure 5 compares our results of the average total merit order effect with those of previous studies for Germany. Results are in the same range with an upward trend in recent years.

Figure 5 Total average merit order effect of wind and PV in Germany



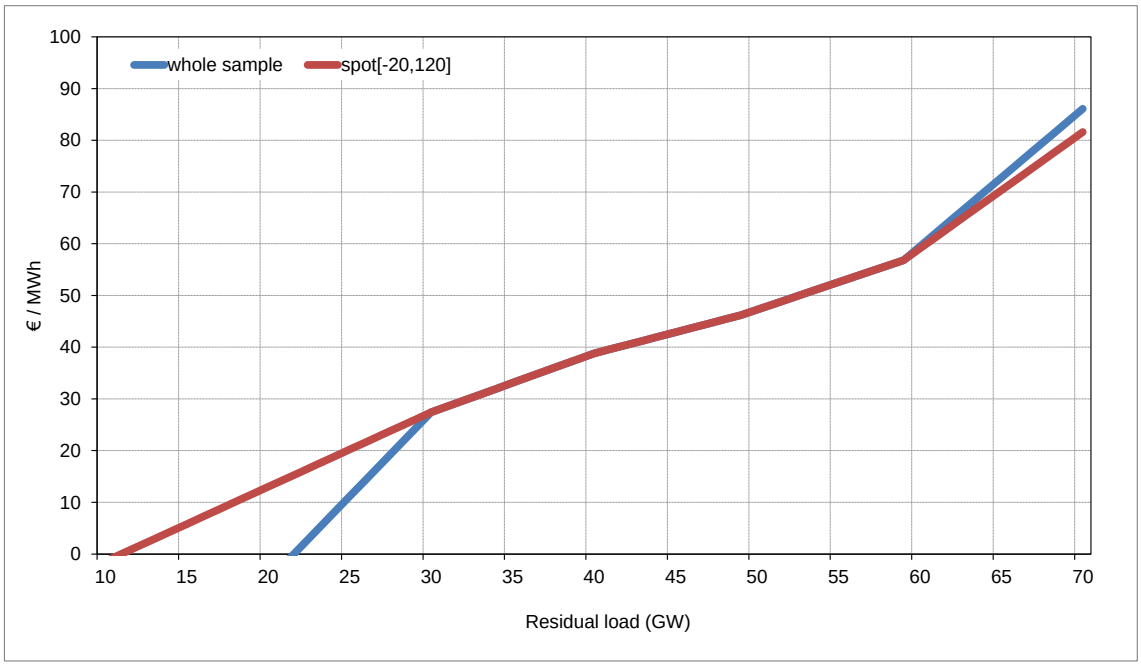
Source: EPEX, EEX, own calculations

[6] One could additionally consider the production of biomass, equal to about 30 39 TWh in 2012 (AG Energiebilanzen 2013), amounting to an average hourly feed-in of 4.5 GW. An additional merit order effect of around 4.5 €/MWh in 2012 can be estimated, using a proxy specific factor of renewables of -1 €/MWh per GW of renewables.

4.2 Projection of Merit Order Effects 2013-2016

The following part of our analysis is concerned with the near- and long-term implications of the merit order effect. First, we approximate the (spot) electricity price curve at different levels of residual load (to be met by conventional power plants). Should the installation of renewables continue to expand, the level of residual load is likely to be reduced in those hours in which renewables produce electricity (for example at noon for PV). Assuming conditions on the electricity market (conventional plant fleet, fuel and carbon prices, wind and solar profiles) will stay roughly constant over the next three years, allows us to forecast hourly spot market prices out to 2016 and calculate revenue factors for wind and PV (average spot prices earned by those technologies divided by overall average spot prices).

Figure 6 Approximation of the (spot) electricity price curve at different levels of residual load in 2012



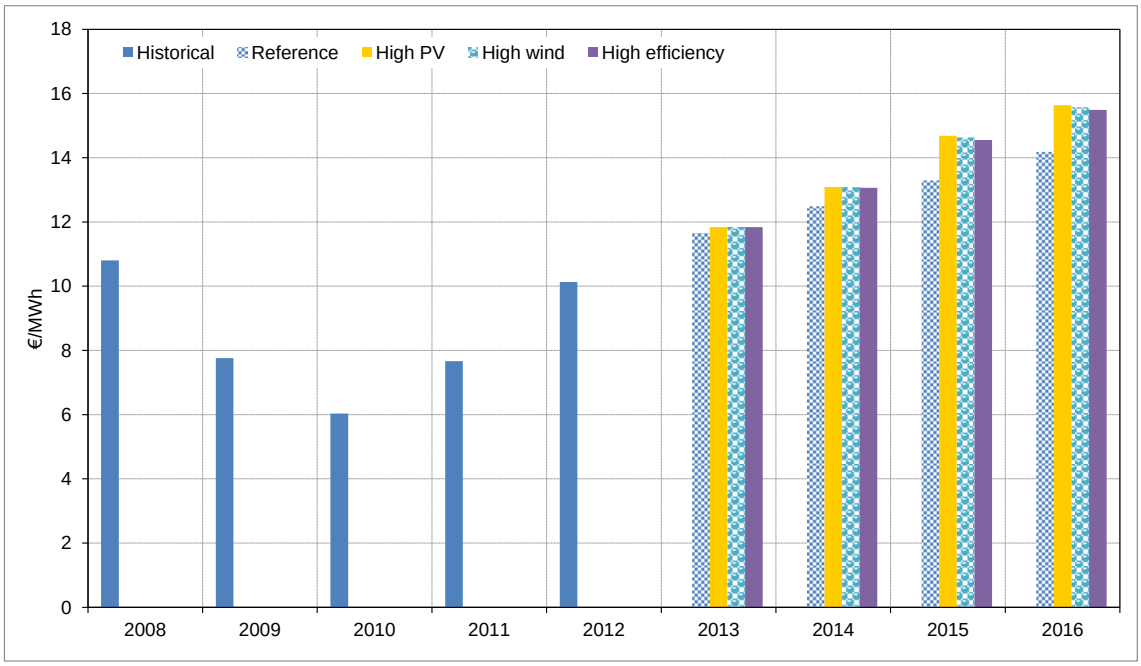
Source: EPEX, EEX, entso-e, own calculations

Figure 6 visualises the results of the regression of spot prices on different levels of residual load (Equation 3) in 2012. Two different specifications are estimated, i.e. prices censored at [-20;120] and using the whole sample. All coefficients are estimated highly precisely (Newey-West standard errors are again used in the OLS specification). Coefficients are used to plot the approximated price curve starting from mean values of 44 GW/ 42 €/MWh. Figure 6 confirms the expectation that the price curve is relatively steep at the left end (slope of 1.14 to 1.44 for the censored sample), then reaches a plateau between 40 to 60 GW (slope of 0.82 to 1.06) and becomes steeper again at 60 GW (slope of 2.25 for the censored sample).

Compared to the stylized merit order curve shown in Figure 1, the analysis based on actual historical data is different at the left hand side of the curve, where the slope is much steeper than in the stylized model. This is the case, because the stylized curve does not take into account the factors discussed above, which can lead to negative prices. Our results indicate that the more renewables come to the market the lower will be overall prices and therefore revenues that can be achieved on this market. This means that the value of renewable energy decreases exactly in those hours in which a large share of total demand can be met by renewable energy sources (cf. McConnell et al. 2013).

We use these results on the relationship between spot prices and the residual load to forecast merit order effects out to 2016 and to calculate revenue factors. We decided to use coefficients estimated using the censored data. The reason is that a small number of extreme values drive results in the very low and high residual demand deciles otherwise. These extreme events are likely to not reflect average market conditions. Furthermore, additional flexibility through higher trading activity (dependent on transmission capacity) can be expected, especially at negative prices and prices above 120 €/MWh, which would act as an additional adjustment mechanism in the future.

Figure 7 Projection of merit order effects 2013-2016



Source: EPEX, EEX, entso-e, own calculations

Using the estimated coefficients and forecast load, wind and solar feed-in for each hour in 2013-2016, we project merit order effects to 2016, scaling 2012 prices to account for lower residual load, due to higher renewable generation or increased demand efficiency. Figure 7 shows projected effects until 2016 for the four different scenarios. Effects in the high PV and high wind scenarios are about 2 €/MWh higher than in the reference scenario in 2016. The high PV scenario corresponds to a situation where the capacity

expansion of PV would have continued as it has up until mid-2012, while the high wind scenario accounts for additional capacity additions as recently observed and further capacity from offshore installations. The high efficiency scenario lies between the high PV and high wind scenario in 2013 and then produces slightly lower merit order effects until 2016. Differences between the reference and sensitivity scenarios expand over the years, as the differences in generation by PV and wind and total load become more pronounced.

In the context of our model that assumes a constant structure of the electricity industry and (conventional) merit order curve in any given hour, we cannot model the impact of fuel prices. In general, higher fuel prices would lead to higher merit order effects because the marginal generator that is displaced by wind or PV has higher variable cost. The same holds for higher CO_2 costs as illustrated by the high specific effects estimated for 2008 (Table 3).

Our forecasts are larger than those obtained using electricity market models (Fürsch, Malischek and Lindenberger 2012; Traber and Kemfert 2011; Traber, Kemfert and Diekmann 2011) which is probably due to the fact that we cannot take into account dynamic effects such as a reduction of capacities of fossil power plants (Wissen and Nicolosi 2008; Fürsch, Malischek and Lindenberger 2012). If conventional power plants with low marginal costs were mothballed, the short-term merit order effect (per GW additional renewables) may actually be higher as plants with higher marginal cost are displaced in a given hour. However, the effects estimated within electricity market models by comparing prices in a scenario with and without additional renewables may well be smaller in the medium term, as the overall price level is elevated if baseload plants with low marginal costs are shut down.

We still believe that our forecasting tool delivers viable results for the near term as outlined in the following. Currently a number of fossil power plants in Germany are closing (Bundesnetzagentur 2013a). One reason for these closures are merit order effects of renewables. However, it is important to acknowledge that until the end of 2012 the free allocation to electricity in the EU ETS worked like a capacity payment and avoided plant closures for many years (Öko-Institut et al. 2012). Therefore, current plant closures are not only triggered by the current merit order effect, but are also related to the phase out of free allocation in the EU ETS. Furthermore, most plants that are to be closed in Germany are fired with natural gas and have high marginal costs. This indicates that this lost capacity might only impact prices in very few hours of the year with high residual load. Therefore, in Germany, the closure of plants will only have a small impact on merit order effects in the near term. We therefore expect our forecasting tool to provide a reasonable forecast for the chosen forecasting horizon. However, the longer term impact of conventional plant closures on merit order effects needs to be addressed by further research.

The generated price forecasts are further used to estimate the revenues earned by wind and PV in each hour in a given year. Aggregating those revenues and dividing them by total electricity produced by those sources, allows us to calculate average revenue and revenue factors (average spot prices earned by wind and PV compared to

overall average spot prices). Revenue factors for wind and PV fall from close to 90% for wind in 2012 and more than 100% for PV to 83% for wind and 91% for PV in 2016 in the reference scenario. In the high wind scenario, the revenue factor for wind drops to 79% in 2016, while in the high PV scenario the revenue factor for PV drops to 81%.

Although estimated price effects in the high PV and high wind scenarios are fairly similar, revenue factors for PV decline much faster than those of wind. This is due to the fact that generation by PV is concentrated in a few hours only. The more electricity generated by PV in those hours, the lower the revenues in exactly those hours, leading to lower revenue factors. Generation by wind, on the other hand, is more spread out across the day (see Twomey and Neuhoff 2010 who show that the higher the variability of output by renewables, the lower the revenues earned by these technologies in a particular hour).

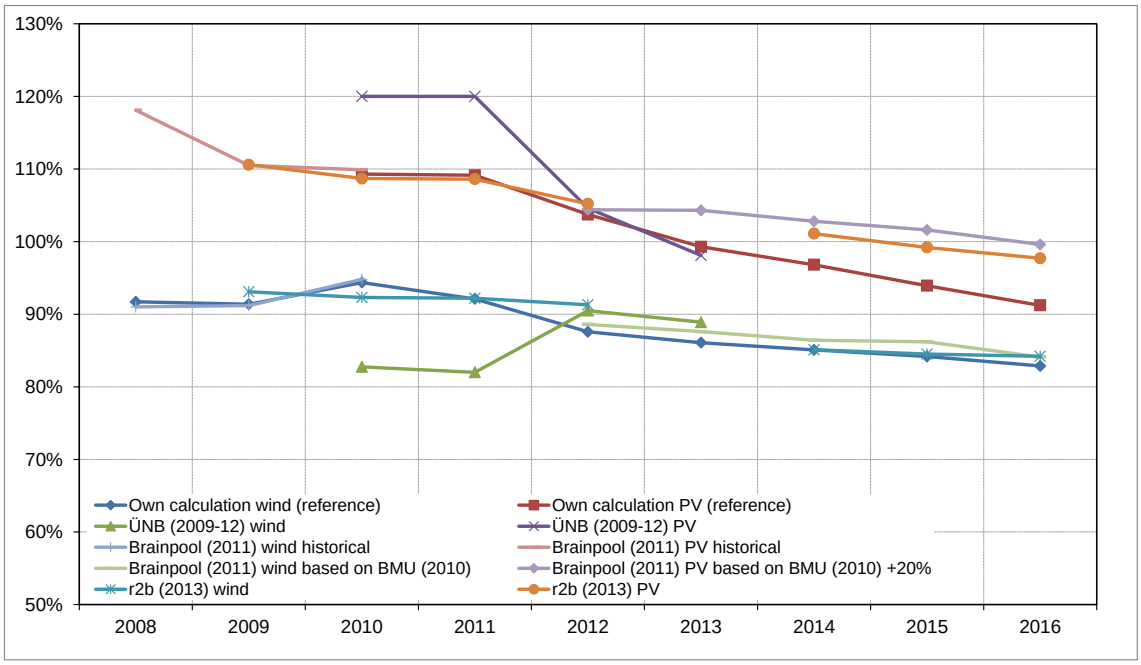
Table 5 Revenue factors for wind and PV 2008-2016

		Spot (€/MWh)			Revenue factor wind		Revenue factor PV	
		Ref	High PV	High wind	Ref	High wind	Ref	High PV
historical	2008	65.8	65.8	65.8	92%	92%		
historical	2009	38.9	38.9	38.9	91%	91%		
historical	2010	44.5	44.5	44.5	94%	94%	109%	109%
historical	2011	51.1	51.1	51.1	92%	92%	109%	109%
historical	2012	42.6	42.6	42.6	88%	88%	104%	104%
modelled	2013	41.1	40.9	40.9	86%	86%	99%	98%
modelled	2014	40.2	39.6	39.6	85%	84%	97%	93%
modelled	2015	39.4	38.0	38.1	84%	81%	94%	84%
modelled	2016	38.5	37.1	37.2	83%	79%	91%	81%

Source: EPEX, EEX, entso-e, own calculations

This development of revenue factors for PV shows a significant and quite rapid decline over only a short amount of time, which is, even in the reference scenario, more pronounced than the forecasts by the distribution network operators (Figure 8). This is partly due to the fact that some of these studies used somewhat dated assumptions on the build-up of PV (BMU 2010), which have already been surpassed. On the other hand, revenue factors of more recent studies are also generally higher than our estimates (r2b 2013), which might be due to the fact that those revenue factors are modelled using an electricity market model, which allows for flexibility through imports and exports by way of additional transmission capacity (ÜNB 2011; Brainpool 2011), while our model assumes transmission capacity and therefore import and export flows as in 2012. This could mean that we are underestimating the amount of renewable energy exported by Germany. More of these exports would lead to higher prices during hours with renewable generation and consequently, to higher revenue factors.

Figure 8 Revenue factors for wind and PV 2008-2016



Source: EPEX, EEX, entso-e, own calculations, Brainpool (2011), ÜNB (2011), r2b (2013)

The near- and long-term reform of the EEG needs to take into account the fact that revenues attainable by wind and PV on the spot market for electricity will continue to fall, thereby increasing the cost of the EEG to non-privileged consumers under its current design. Considering that Germany has a goal to produce at least 80 % of its electricity using renewable sources by 2050, a reform of the EEG has to be integrated with a reform of the overall electricity market design (cf. Matthes et al. 2012) and pursue two main goals: (i) ensure a coordination of the operation of renewable plants that is beneficial for the stability and affordability of the whole electricity system, (ii) ensure efficient investment decisions are made, which mainly concerns the question what kind of renewable plants should be constructed where using which layout.

Efficient operation of renewable plants can be achieved through adequate remuneration, at least in part linked to market prices, thus avoiding negative price events and limiting the costs to consumers. Efficient investment decisions will depend on the incentives to invest in plant layout that has the potential to stabilise the system and ensure efficient operation in the long run. To achieve these goals, a reform of the EEG has to deal with a complex set of issues, including the development of merit order effects and revenue factors and also taking into account future uncertainties and risk management options in a more volatile system. In their forthcoming study, Öko-Institut (2014) explore the challenges facing the EEG in-depth and specify a reform path for the law out to 2050.

4.3 Redistributive Effects

As the International Energy Agency notes, ”[t]he costs, but also the benefits, of renewables need to be allocated in a fair and transparent way. Exemptions for the industry have been mounting in the past years […], while the cost on small consumers has risen sharply” (IEA 2013, p.131). The estimated merit order effect for 2012 of 1 ct/kWh (10 €/MWh) has likely overcompensated the group of privileged consumers (mainly energy-intensive companies) for their contribution to the cost of the EEG at 0.05 ct/kWh. If the surcharge for privileged consumers took into account the merit order effect of renewables, the cost to non-privileged consumers could be reduced. Our results point to a potential contribution by privileged consumers of around 1 ct/kWh. Taking the estimated merit order effect into account this would mean that privileged consumers would have been neither better nor worse off after the introduction of the policy. At around 150 TWh exempt consumption in 2012 (85 TWh of industry and 65 TWh of own consumption), this change would mean a decrease in the EEG surcharge for the non-privileged consumption of roughly 0.4 ct/kWh. Our forecast of rising merit order effects out to 2016 further justifies this modification of the surcharge for privileged consumers. These results are especially relevant in light of the fact that the EEG surcharge has risen substantially from 2012 levels to 5.28 ct/kWh in 2013 and 6.24 ct/kWh in 2014.

Furthermore, when evaluating the impact of the EEG on electricity prices, both its costs, but also its benefits should be taken into account. At the moment the focus is on EEG costs expressed by the surcharge. If the reductions in the wholesale price caused by the merit order effect were adequately passed through to non-privileged electricity consumers, this could alleviate some of the extra cost caused by the EEG. The extent to which the pass through of merit order effects happens depends on the relationship between prices on the spot and forward markets, as prices on the forward market are an important input in the determination of retail electricity prices. In Germany, a competitive retail market exists with consumers being able to choose between more than 50 suppliers in three quarters of the network. However not all consumers use the opportunity to opt-out of the basic tariff that is usually more expensive than offers by competitors. At the end of 2011 60 % had opted out of the basic tariff (17 % had changed to a different supplier and a further 43 % opted into a different tariff with their original supplier) (Bundesnetzagentur 2013b). Some barriers to changing the electricity supplier still exist, including the need to provide financial references, which may be a challenge for low-income households.

There exist other dimensions of distributional issues in relation to renewable energy policies, which have not been addressed here, such as between producers and consumers of electricity (Hirth and Ueckerdt 2013), as well as between households of different income groups (Neuhoff et al. 2013).

5 Conclusion

We have estimated the merit order effect of wind and photovoltaic electricity generation in Germany between 2008 and 2012. The average specific effect (reduction of the spot

market price per additional GW of renewable energy) lies between 0.8 and 2.3 €/MWh. These effects vary across years, as they depend on fossil fuel prices, the overall level of demand and other factors. The average total effect of wind and PV (specific effect times average renewable energy feed-in) was estimated to lie between 6 €/MWh in 2010 and 10 €/MWh in 2012.

These findings are especially interesting in the context of the German Renewable Energy Sources Act (EEG) which levies a surcharge on electricity consumers for the support of renewable energy sources. It seems that the merit order effect overcompensates the group of privileged consumers for their contribution to the surcharge. The burden on non-privileged consumers could be reduced if the surcharge for the privileged consumers took into account the merit order effect of renewables. Our results point to a potential contribution by privileged consumers of around 1 ct/kWh (rather than 0.05 ct/kWh they are charged at the time of writing). Furthermore, if merit order effects were adequately passed through to all electricity consumers, the costs to households and small business could be reduced significantly.

Forecasting merit order effects out to 2016 shows that, depending on the assumptions made about capacity extensions of wind and PV and load development out to 2016, merit order effects are likely to rise to around 14-16 €/MWh, further justifying a reform of the arrangements for exemptions in the context of the EEG. At the same time spot market revenues attainable by renewables fall significantly as the merit order effect reduces revenues exactly in those hours electricity generated by wind and PV is fed into the grid. We estimate that revenue factors (average spot prices earned by wind and PV compared to overall average spot prices) fall by around 5-10 % for wind and by 12-22 % for PV between 2012 and 2016.

Besides a review of the scope and extent of exemptions, the near- and long-term reform of the EEG needs to take into account the fact that revenues attainable by wind and especially PV on the spot market for electricity will continue to fall. Thus, the surcharge for non-privileged consumers will rise further if no changes to the current design of the EEG are made. These reforms have to address operation decisions by renewable plants leading to negative market prices and inefficiencies regarding the layout of renewable plants in the context of investment decisions.

There exist many avenues for future research. As highlighted in our paper, it would be interesting to explore further the relationship between merit order effects, revenue factors and import and export flows, as well as the extent to which lower electricity prices due to merit order effects are passed forward to different types of electricity consumers.

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Appendix

As a sensitivity analysis, we present results for daily averages in first differences (cf. Gelabert, Labandeira and Linares 2011). The estimated merit order effects differ only slightly from the ones estimated in levels on an hourly basis. As expected, PV effects are both smaller and not estimated as precisely (in 2010), as averaging mutes effects that occur during different hours of the day.

Table A-1 OLS regression: Merit order effect of wind and PV (daily averages)

	2008	2009	2010 (2nd half)	2011	2012	2010-12
Wind	**-2.21*** **	**-1.53*** **	**-1.13*** **	**-0.94*** **	**-1.09*** **	**-1.05*** **
	(0.21)	(0.23)	(0.12)	(0.10)	(0.08)	(0.06)
PV			**-0.001**	**-0.96*** **	**-0.96*** **	**-0.91*** **
			(0.65)	(0.28)	(0.27)	(0.19)
Load	2.07***	0.73***	0.94***	0.75***	1.45***	1.08***
	(0.18)	(0.21)	(0.22)	(0.15)	(0.27)	(0.17)
Hourly, daily, monthly and yearly dummies included						
Adjusted R2	0.78	0.51	0.77	0.74	0.66	0.69
DW-Statistic	2.56	2.68	2.54	2.64	2.33	2.40
Observations	366	365	165	365	366	897
Time frame	01/01/2008 - 31/12/2008	01/01/2009 - 31/12/2009	19/07/2010 - 31/21/2010	01/01/2011 - 31/21/2011	01/01/2012 - 31/21/2012	19/07/2010 - 31/12/2012
Newey-West standard errors in parentheses, robust to heteroskedasticity and autocorrelation *** significant at the 99% confidence level						

Source: EPEX, EEX, entso-e, own calculations

Table A-2 Specific and total merit order effect of wind and PV (daily averages)

	2008	2009	2010 (2nd half)	2011	2012
Wind specific effect (€/MWh)	-2.21***	-1.53***	-1.13***	-0.94***	-1.09***
Load-weighted average wind in-feed per hour (GW)	4.76	4.51	4.41	5.63	5.73
Wind total effect (€/MWh)	-10.52	-6.87	-5.00	-5.27	-6.22
PV specific effect (€/MWh)			-0.001	-0.96***	-0.96***
Load-weighted average PV in-feed per hour (GW)			1.17	2.41	3.32
PV total effect (€/MWh)			0.00	-2.32	-3.19
Total average merit order effect of wind and PV (€/MWh)	**-10.52**	**-6.87**	**-5.01**	**-7.59**	**-9.41**

Source: EPEX, EEX, entso-e, own calculations