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WIND POWER FEED-IN IMPACTS ON ELECTRICITY SYSTEM

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Wind Power Feed-in Impacts on Electricity system

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Abstract

Until quite recently no electricity system had faced the challenges associated with high penetrations of renewable energy sources (RES)-namely the need for greater flexibility, storability and reserve due to their intermittency, along with the potential conflict of interest between suppliers and consumers of electricity. These challenges may introduce controversy in the assessment of the cost-effectiveness of RES promoting policies.

In this paper, we explore the economic impacts of the challenges of wind power feed-in on electricity prices (the merit order effect), on investments in back-up capacities and storage facilities, on grid transmission, and finally on end consumers (the households).

Our main findings suggest that the increasing share of RES induces a lowering of electricity prices, an increase in back-up and transmission grids costs and huge over costs for power end consumers.

Keywords: RES, Electricity system, Challenges,impacts

JEL classification : Q41, Q42, Q48

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Introduction

The European Climate and Energy Strategy stretches out to 2020 with a set of policy goals to encourage sustainable, secure and affordable energy supply. They include a target to increase the use of renewable energy sources (RES) in covering at least 20% of the final energy consumption, cut greenhouse emissions by 20 percent and increase energy savings to 20 percent of projected levels.

It started in 1997 with the adoption of the White paper and has been driven by the need to tackle climate change by decarbonising the energy sector and address growing dependency on fossil fuel imports from politically unstable regions outside the EU.

To achieve the 2020 RES target, various supporting schemes are operating in EU member states, mainly feed-in-tariffs, fixed premiums, and green certificates.

Indeed, countries that have succeeded to increase significantly their RES capacities have done so by implementing mostly feed-in-tariffs (FIT). The German FIT system constitutes the most ambitious European experience in the field

However, this success has led to many challenges to energy system, thus raising doubts on RES future economic viability.

In this paper, we adress a central question of research agenda on renewable energy sources by exploring the economic impacts of the RES challenges on electricity prices (the merit order effect), on investments in back-up plants and storage facilities, on grid transmission, and finally on end consumers (the households).

Indeed, until quite recently no electricity system had faced the challenges associated with high penetrations of RES-namely the need for greater flexibility, storability and reserve due to their intermittency, along with the potential conflict of interest between suppliers and consumers of electricity. These challenges may introduce controversy in the calculation of the benefits and costs of renewable energy to assess cost-effectiveness of future policies.

Our main findings suggest that energy power systems faces several market distortions due to increasing production share of renewables. These distortions are mainly due to the intermittent, unpredictable and unevenly geographically distributed nature of RES, and have significant and far-reaching effects on both the electricity market (lower and /or negative prices, back-up costs), on transmission and distribution grids (grid upgrades and interconnections) and distributional (over costs for power end consumers).

While Germany's plan to shift to renewable energy enjoys overwhelming public support, there is also growing concern about its cost. Indeed, beyond a certain share of the energy mix, intermittent RES require additional components of the energy system to be put in place: grid extensions, storage facilities, and reserve capacities. If these components are not made available, it will lead to an inefficient use of the installed facilities, as well as threats to the security of energy supply and to a viable European energy market. Moreover, these components may induce extra costs for electricity end users both industrial and domestic that risk leading to market fragmentation, inefficiencies and acceptance problems by citizens. Therefore, the cost issue with its opportunities and problems must become more transparent.

The remainder of this paper is outlined as follows. Section 2 provides an overview of the Renewable Energy Act in Germany. Section 3 deals with the challenges of integrating renewable energy into electricity system. Finally, Section 4 concludes and presents the key results and policy implications.

2. Renewable Energy Act:

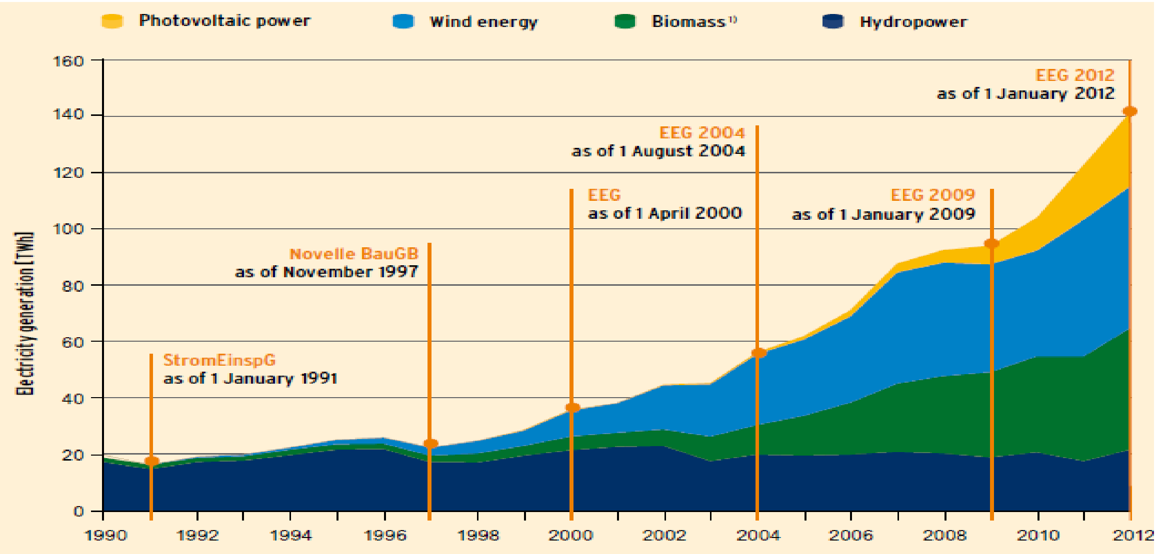
Germany has the largest electricity market in Europe. Its generation system is based mostly on coal and lignite inducing a high carbonization rate and therefore high environmental concerns. That is the main reason which explains the FIT system introduction since 1991. This support scheme for renewable energy sources gave grid access to all renewable producers. However, its limited success in increasing investments in renewable capacities has led to the 2000 reform through the Renewable Energy Act (Erneuerbare Energien Gesetz, EEG).

The EEG, as a support scheme, has provided a favorable feed-in tariff (FIT) for a variety of renewable energy sources (RES). It also gives priority to electric power in-feed from RES over power in-feed from conventional power plants, i.e., fossil- and nuclear-fuel thermal and hydro-based power plants. It allows producers of renewable energy to be paid a fixed rate over 20 years for electricity they fed into the public grid. The rates paid to renewable energy producers varied depending on the energy source, plant capacity and construction type.

This favorable environment has helped investment in renewable energy to become profitable and many households and farmers to become electricity producers on a small scale.

This has led to a massive build-up notably of wind and photovoltaic (PV) power capacities. The total nominal power of wind farms climbed from 6.06 gigawatt (GW) in 2000 up to 33 GW by 2013 making Germany the third place in the international rankings behind China and the USA. Over the same period, the nominal solar power had experienced a tremendous growth rising from 0.07 GW in 2000 up to 39 GW. With the total nominal power for solar facilities worldwide estimated at 100 GW, Germany now accounts for almost one-third of nominal solar electricity across the planet. With a combined installed power capacity of RES units of more than 70 GW, and significant annual RES energy shares, about 15% combined, wind and PV units. The following Figure1 shows the development of electricity generation from renewable energy sources in Germany since 1990.

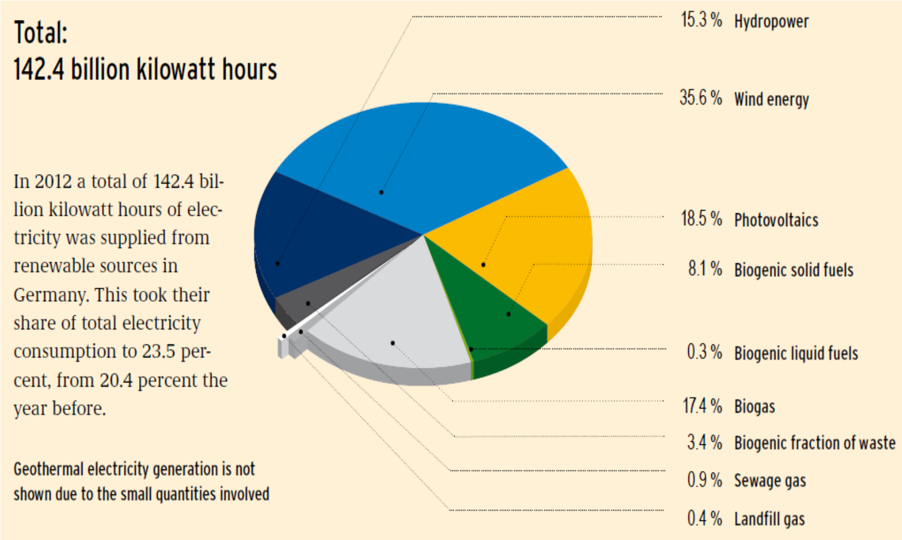
Figure1. Development of electricity generation from renewable energy sources in Germany since 1990 (Source : BMU)



Thus, the EEG converted Germany into a world leader in photovoltaic and wind installed capacity (Bode and Groscurth, 2006).

The structure of German renewables-based electricity supply in 2012 is reported in Figure 2. The wind energy and photovoltaics are the most important sources.

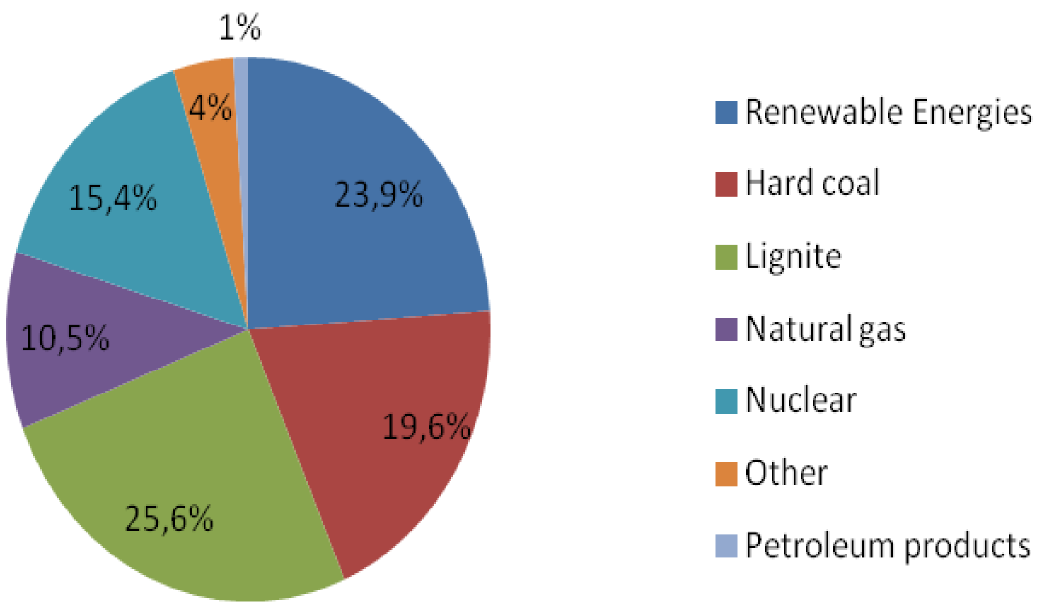
Figure 2. Structure of renewables-based electricity supply in Germany,2012(Source:BMU).



All renewable sources combined made up 24 per cent of gross electricity production in 2013 and are Germany's second most important source of electricity generation after lignite (BDEW, 2013).

Figures 3 summarizes the recent evolution of the electricity mix. Carbon-intensive technologies clearly prevail in Germany, even though the system participation of renewables has grown significantly in the last few years (renewable production tripled from 40 TWh per year in 2001 to more than 150 TWh in 2013).

Figure 3. Share of gross electricity generation,%2013.



Author, source AG Energie bilanzen

The fact that a market of this size, located in the core of Europe, may strongly influence other closely integrated energy areas adds interest to the results of our analysis of German experience.

3.Challenges of integrating renewable energy into electricity system:

<u>3.1.The merit order effect:</u>

3.1.1. The merit order curve:

In order to supply electricity, different power generation technologies compete with each other according to their availability of supply and their marginal cost of production (fossil fuels such as coal or natural gas, nuclear power, renewable energy sources like hydroelectric generators, wind or solar energy).

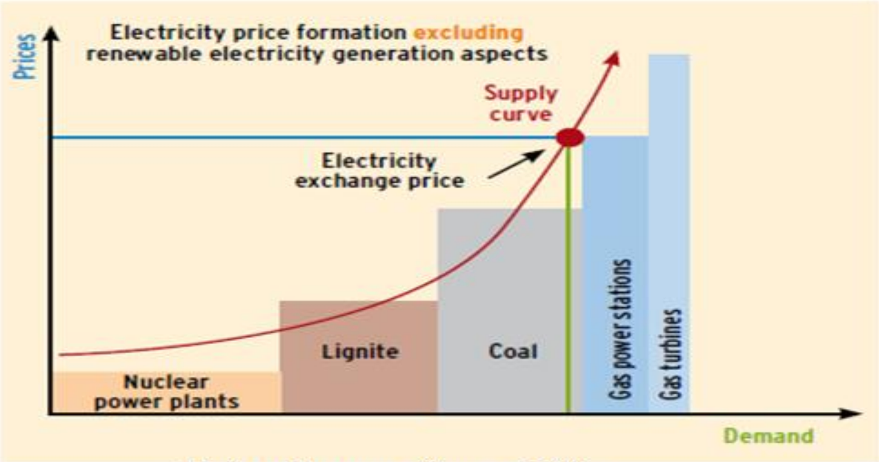
The electricity market operates according to day ahead bidding. Indeed, the transmission system operators basically receive the bids from all power producers for the quantity and cost for each hour of the next day and then assigns the dispatch based on the lowest cost producer until demand is met. All producers who dispatch get the marginal price of the last producer that dispatched. As a result even if the last producer only produced theoretically one kWh then that is the price of the system.

This conventional approach consists on ranking the power plants of the system in ascending order of their marginal cost of generation. This approach is called the merit order

Traditionally, the hydroelectric power plants are the first to be dispatched on the grid. They are followed respectively by nuclear plants, coal-fired and/or combined-cycle gas turbines (CCGT), and then open cycle gas turbine (OCGT) plants and oil-fired units with the highest fuel costs.

Although power plants with the highest marginal cost correspond to the oil-fired gas turbines, gas plants are usually the marginal producers and as a result the cost of gas is very relevant to the wholesale pricing setting of electricity. But, due to EU ETS price weaknesses, carbon prices have plunged to record low prices making it more expensive to burn gas than coal. Moreover, The US coal surpluses export due to shale gas revolution has lowered coal prices Europe whereas oil indexation of gas contracts and geopolitical concerns have made natural gas more expensive. Therefore, the price competitiveness of more polluting coal-fired plants, allow them to be dispatched before the gas turbine and to be the key of electricity price setting.

<u>Figure 4: The merit order curve w/o renewables</u>



Merit order curve (*Source*: **ZSW**)

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3.1.2 The merit order effect:

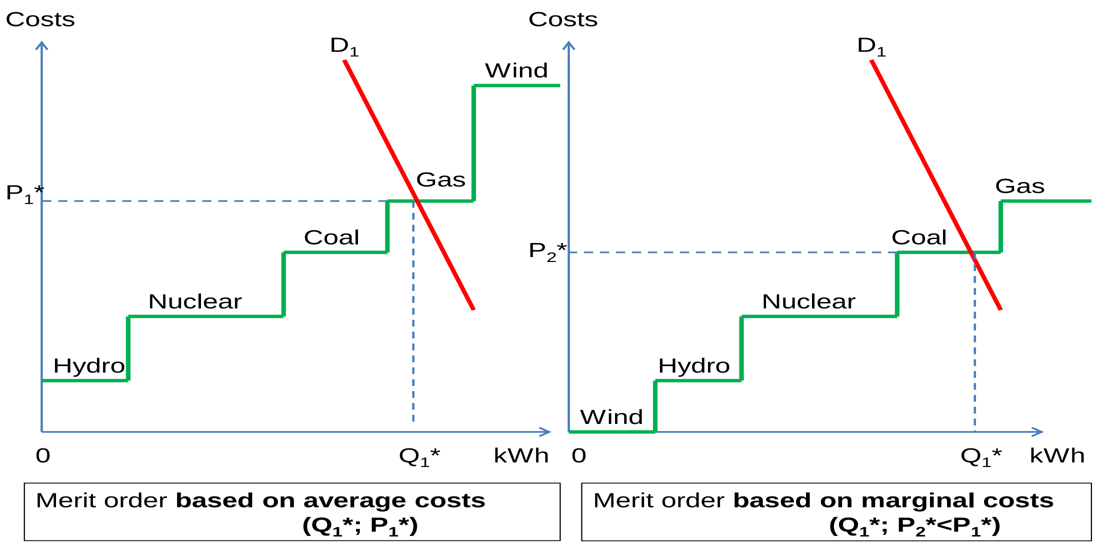
In the economic theory of competitive markets, the price of electricity should equal its marginal cost. However, a pricing based on marginal costs could never allow RES to recover their fixed costs. Indeed, the photovoltaic (PV) and wind power plants have a high average cost and their load factor is too low due to intermittency. Therefore, subsidising renewable energy sources by feed-in tariff scheme allowing their average costs to be recovered corresponds to a support mechanism outside the market. By granting an economic return above the market price, these supporting schemes have promoted RES development in several European electricity markets.

As the renewable energy sources (RES) have priority for grid access at zero marginal cost, i.e, have the privilege of priority dispatch, electricity from RES participating to the auction process at zero marginal cost replaces every other energy source with higher marginal cost. The decoupling of spot market prices and RES in-feed due to FIT support scheme results in lower average equilibrium price level on the spot market. This downward pressure on wholesale electricity prices is the so-called *merit order effect* (Sioshansi,2013).

Indeed, during full and peak times, the marginal power plant is logically a combined-cycle gas-fired plant. However, as they have no fuel costs, RES have a zero marginal cost. Thus, electricity from RES makes the coal-fired plant becoming the marginal plant. The electricity market price is thus lower than it would be if there is no RES power in-feed. Lowering electricity spot prices causes a serious distortion to the electricity market. Indeed, if the wind or solar power plants were not remunerated according to feed-in tariffs scheme they could never be profitable because the spot market price at full and peak periods would not allow them to recovery their fixed costs. Furthermore, the insufficient dispatching of the flexible gas-fired plants jeopardises their profitability as they cannot be operated profitably because peak spot prices are too often below their marginal operation costs. Thus, the RES, by lowering equilibrium spot price level, will squeeze peak load power plants out of the market due to their comparatively higher variable costs.

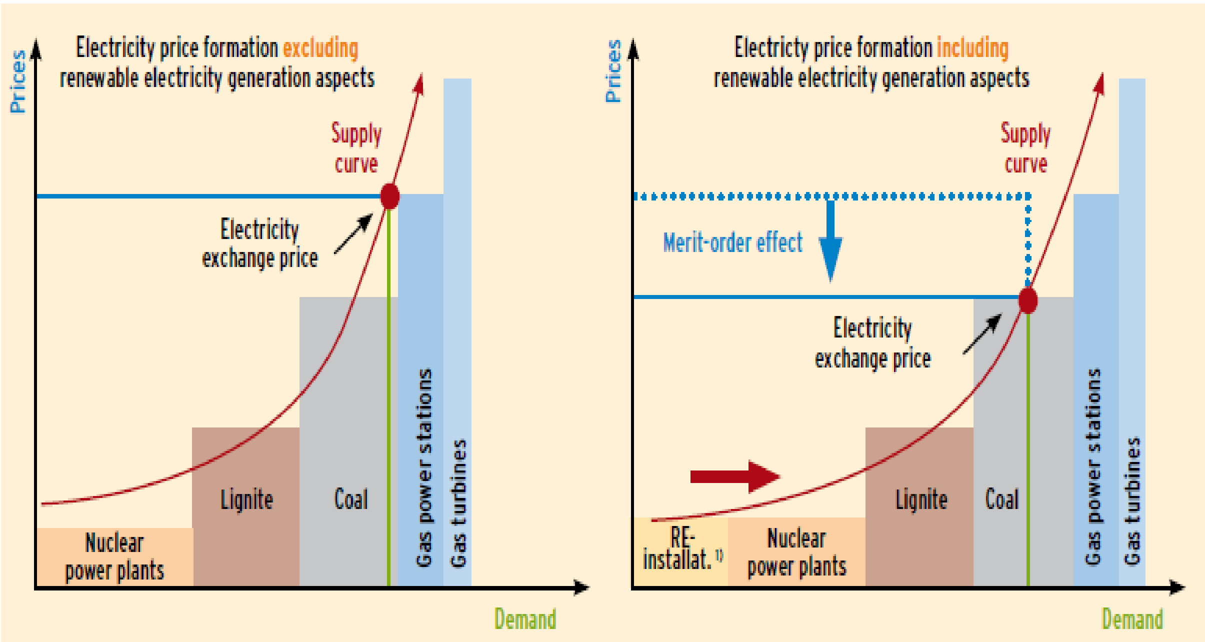
The following Figure5 shows the merit order curve based respectively on average and on marginal costs.

Figure5. Merit order based on average and marginal costs (*Source:* CREDEN)



Thus, the RES, for instance the wind power feed-in when included in the electricity price formation will lead to a shift of the merit order curve. The following figure 6 reveals this shift.

Figure 6. Merit order curve shift due to RES



The so-called merit order effect has gained increasing attention in the literature both on a theoretical basis and a empirical one. Indeed, Jensen and Skytte (2002) point out that RES generation enters at the base of the merit order function, thus shifting the supply curve to the right and crowding the most expensive marginal plants out from the market, with a reduction of the wholesale clearing electricity price.

Several papers have carried out empirical analysis on the impact of RES in electricity markets, finding evidence of the merit-order effect. Indeed, one of the central empirical findings in the literature on renewable energy (RE) is that an increase in intermittent sources generation would put a downward pressure on the spot electricity market price by displacing high fuel-cost marginal generation. RE installations, although they are very capital-intensive, have almost zero marginal generation cost and thus are certainly dispatched to meet demand. More expensive conventional power plants are crowded out, and the electricity price declines.

It is worth noting that several authors have explored this topic. For Germany, Bode and Groscurth (2006) find that renewable power generation lowers the electricity price. Neubarth et al. (2006) show that the daily average value of the market spot price decreases by 1 €/MWh per additional 1,000 MW wind capacity. Sensfuss et al. (2008) show that in 2006 renewables reduced the average market price by 7.83 €/MWh. Weigt (2008) concludes that the price was on average 10 €/MWh lower. Nicolosi and Fürsch (2009) confirm that in the short run, wind power feed-in reduces prices whereas in the long run, wind power affects conventional capacity, which could eventually be substituted. For Denmark, Munksgaard and Morthorst (2008) conclude that if there is little or no wind (<400MW), prices can increase up to around 80 €/MWh (600 DKK/MWh), whilst with strong wind (>1500MW) spot prices can be brought down to around 34 €/MWh (250 DKK/MWh). Jonsson et al. (2010) show that the average spot price is considerably lower at times where wind power production has been predicted to be large. Sáenz de Miera et al., (2008) found that wind power generation in Spain would have led to a drop in the wholesale price amounting to 7.08 €/MWh in 2005, 4.75 €/MWh in 2006, and 12.44 €/MWh during the first half of 2007.

Gelabert el al. (2011) find that an increase of renewable electricity production by 1 GWh reduces the daily average of the Spanish electricity price by 2 €/MWh. Wurzburg et al. (2013) find that additional RES generation by 1 GWh reduces the daily average price by roughly 1 €/MWh in German and Austrian integrated markets.Woo et al. (2011) use a regression analysis for the Texas electricity price market to examine the effect of wind power generation. Huisman et al. (2013) obtained equivalent results for the Nord Pool market by modeling energy supply and demand. Benhmad et Percebois(2014) examined wind power in German electricity markets and found a similar result,i.e an additional RES generation by 1GWh led to a reduction of daily spot price by approximatively 1€/MWh. Ketterer (2014) also obtained equivalent results.

In this paper, we carry out a new empirical analysis for Germany in order to explore this most evidenced stylized fact of RES impact on spot electricity prices.

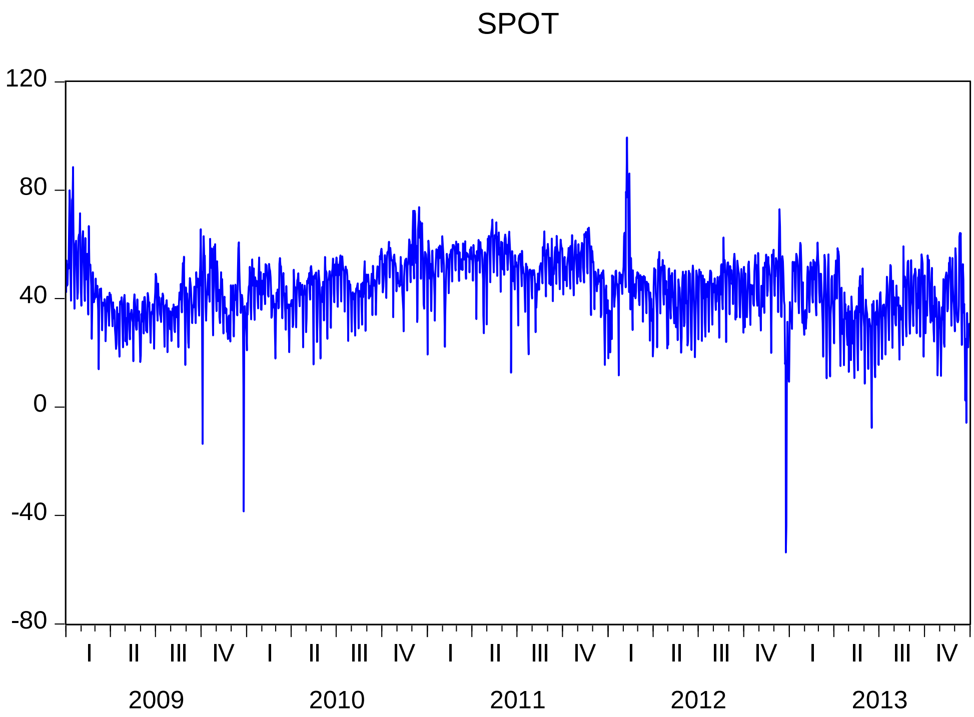
3. 1.3 Testing the merit order effect:

3.1.3.1 Data:

Phelix daily baseload

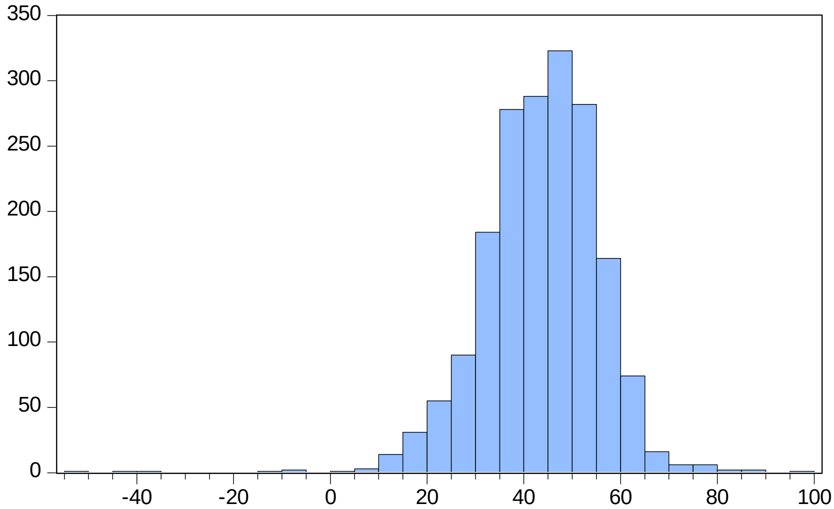
The analysis is based on time-series data of the German power system as provided by platform of the European Energy Exchange (EEX) . The data is daily Phelix baseload. The spot market is a day-ahead market and the spot price is an hourly contract with physical delivery on the next day. The daily Phelix baseload is then calculated as the average, weighted price over these hourly contracts. The sample data covers the period going from the 1th January 2009 to the 31th December 2013 from to, summing up to 1826 observations. Figure 7 provides a plot of the data for the whole period. It is easy to see that the data exhibits the typical features of electricity prices and contains several periods of extreme volatility, price spikes and shows a mean-reverting behavior.

Figure7. The Phelix daily electricity spot price Base (2009-2013)



The descriptive statistics of German electricity spot prices summarized in Table 1 show that values of sample mean are close to 44.26 and a standard deviation of 11.51.

Table 1 Descriptive statistics of German electricity spot prices.



Series: SPOT
Sample 1/01/2009 12/31/2013
Observations 1826

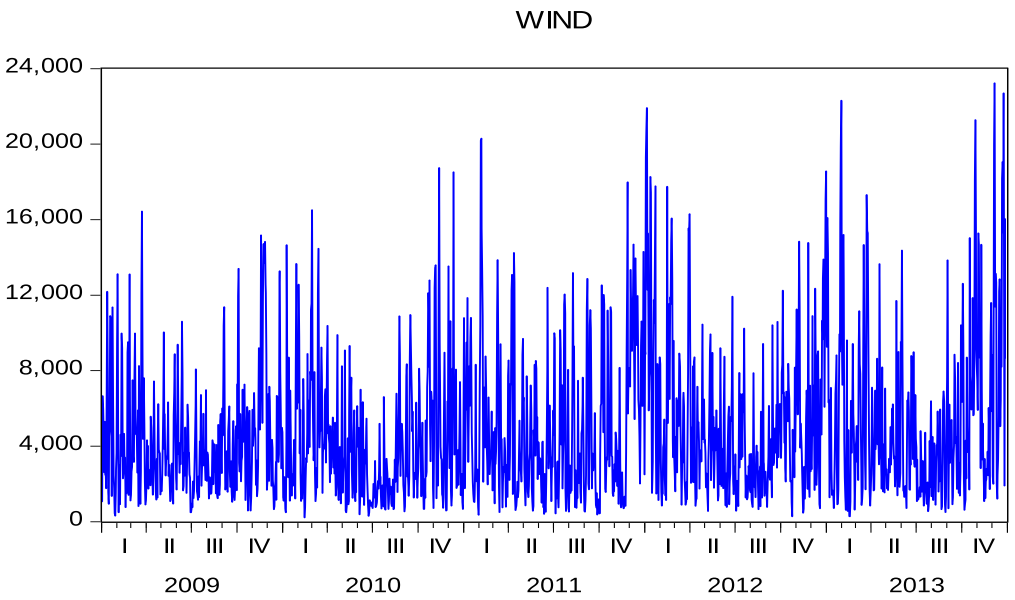
Mean	43.57047
Median	44.50500
Maximum	99.49000
Minimum	-53.63000
Std. Dev.	12.10965
Skewness	-0.849886
Kurtosis	8.345953
Jarque-Bera	2394.224
Probability	0.000000

The sample kurtosis (11.50) is higher than 3, the kurtosis of a normal distribution, implying that price distribution exhibit fat tails. Furthermore, negative skewness indicates a greater probability of large falls in electricity price than large increase. By the Jarque- Bera statistic, the null hypothesis of normal distributions is also rejected.

Wind power in-feed

We use forecasts for daily wind power fed-into the grid from 1th January 2009 to 31th December 2013 as illustrated in Figure 8.

Figure8 .Wind power feed-in (2009-2013)



These forecasts are made by the four German transmission system operators (TSO) [1]. The descriptive statistics of wind feed-in reported in Table 2 (see Appendix) show that the Wind power forecasts fed into the grid has a mean of 4787 MWh per day but a high variability.

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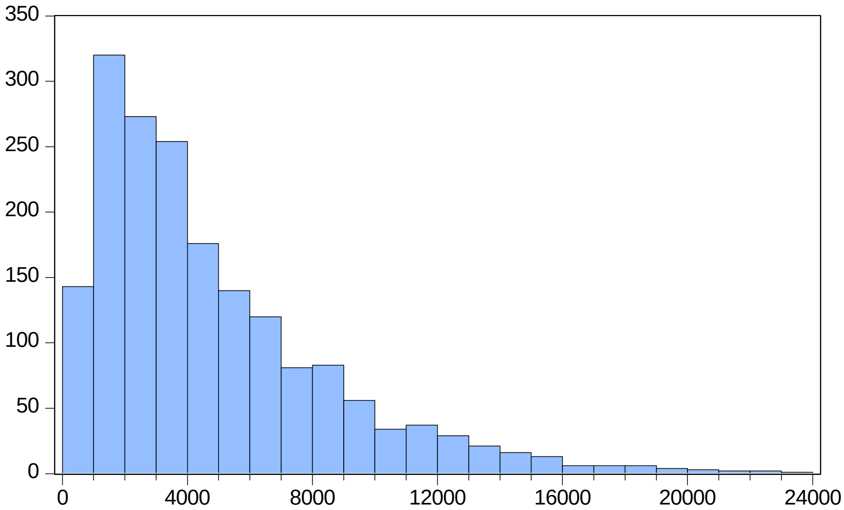
[1] The data are available in 15-minute format. For this study, 15-minute MW data are averaged for each hour and again averaged to MWh per day.There is four transmission system operators (TSO) in Germany and one TSO in Austria: *Amprion GmbH*, *TenneT TSO GmbH*, *50hertz Transmission GmbH*, *EnBW Transportnetze*, and *APG-Austrian Power Grid AG*.

The wind feed-in descriptive statistics are reported in Table 2

Table2. Descriptive statistics of wind feed-in



Series: WIND
Sample 1/01/2009 12/31/2013
Observations 1826

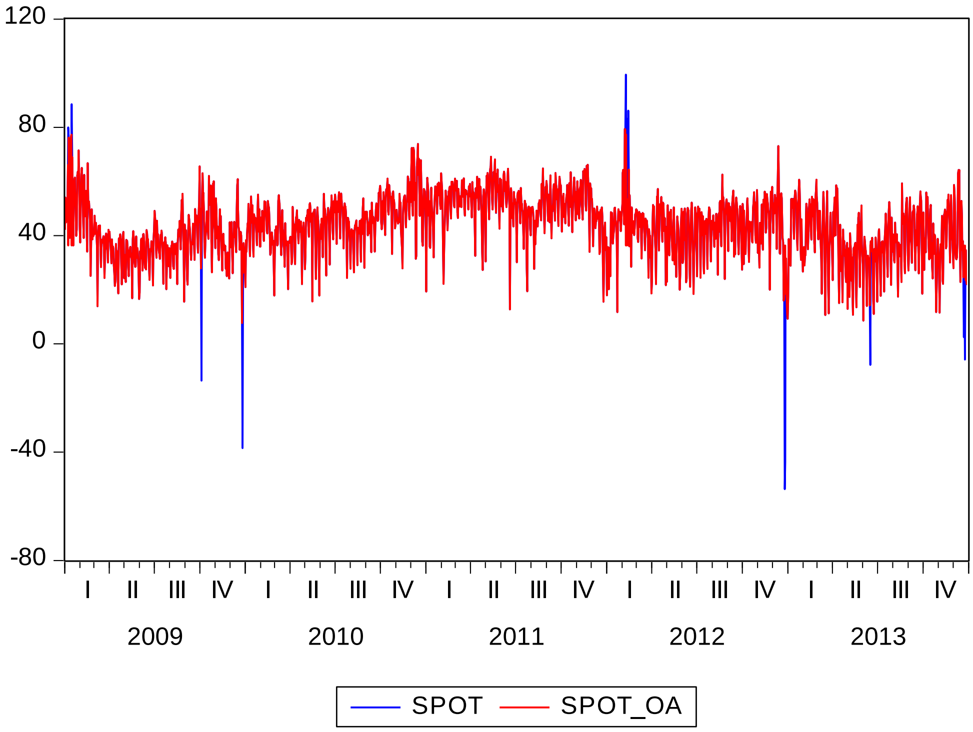
Mean	4787.288
Median	3656.438
Maximum	23220.79
Minimum	216.1667
Std. Dev.	3795.482
Skewness	1.500937
Kurtosis	5.527047
Jarque-Bera	1171.471
Probability	0.000000

The price distribution exhibit fat tails (excess kurtosis); the null hypothesis of normal distribution is rejected according to Jarque-Bera statistic.

3.1.3.2 Empirical methodology: ARMA-X-GARCH-X model

In order to explore the link between daily electricity spot price and wind in-feed, we should carry out a linear regression using least squares method. As electricity spot prices deviates from the normal distribution due to more frequent large outliers, outliers should first be removed before conducting the regression analysis. In line with the literature, I filter values that exceed three times the standard deviation of the original price series should be filtered out. The outliers are then replaced with the value of three times the standard deviation.

Figure 9. Outliers adjustment of spot electricity prices



Then, we use a logarithmic transformation to the outlier adjusted data in order stabilize the variance and reduce data excess volatility. Furthermore, as electricity demand varies throughout the day and during the week, as well as across the year, seasonality should be incorporated in modeling of electricity prices (Knittel and Roberts,2005) by using daily and monthly dummy variables.

After seasonal adjustment, outliers removal, and logarithmic data, testing for the stationarity of the electricity adjusted spot price and adjusted wind-feed in according to Augmented Dickey-Fuller test (Dickey and Fuller,1981) is the ultimate stage before carrying out the linear regression estimates.

However, the least squares estimator is based upon a strong hypothesis of no autocorrelation nor heteroskedasticity of linear regression estimates residuals. Even after filtering out seasonality, outliers, electricity spot prices could still present high order serial correlation in its structure. Thus, an ARMA (autoregressive moving average) modeling (Box and Jenkins, 1976) should be carried out in order to filter out this evidenced autocorrelation.

The assumed linear relationship between electricity prices and wind in-feed could then be explored according to the following equation where wind in-feed is considered as an exogenous explanatory variable (ARMA-X model):

$$(spot\_sa)_t = \alpha_0 + \sum_{i=1}^{p} \alpha_1 (spot\_sa)_{t-i} + \sum_{j=1}^{q} \beta_j \varepsilon_{t-j} + \delta wind\_sa_t + \upsilon_t$$

The residuals of linear regression should then be homoskedastic according to least squares estimator hypothesis.

Therefore, an ARCH-effect test following the procedure of Engle (1982) should be carried out on residuals. An ARCH effect in the residuals data indicates a time varying volatility dynamics. The parsimonious specification GARCH(1,1) [2] (Bolleslev,1986) should be used to take into account the volatility of spot electricity prices.

Many authors have used a similar modeling for forecasting electricity prices (Mugele et al. (2005), Keles et al. (2011)). Furthermore, Woo et al.(2011) used an AR-GARCH model to assess the impact of wind generation on the electricity spot-market price level and variance in Texas.

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[2] The GARCH (p,q) model was introduced by Bollerslev (1986). The conditional variance is expressed as $\sigma_t^2 = w + \sum_{i=1}^{p} \alpha_i \varepsilon_{t-i}^2 + \sum_{j=1}^{q} \beta_j \sigma_{t-j}^2$ where $w > 0$; $\alpha_i \geq 0; i = 1,2,......p$; $\beta_j \geq 0, j = 1,2,.....q$ and $[\ \sum_{i=1}^{p} \alpha_i + \sum_{j=1}^{q} \beta_j\ ] < 1$).The most used model in empirical litterature is GARCH (1,1) model where p=q =1 ; $\sigma_t^2 = w + \alpha \varepsilon_{t-1}^2 + \beta \sigma_{t-1}^2$.

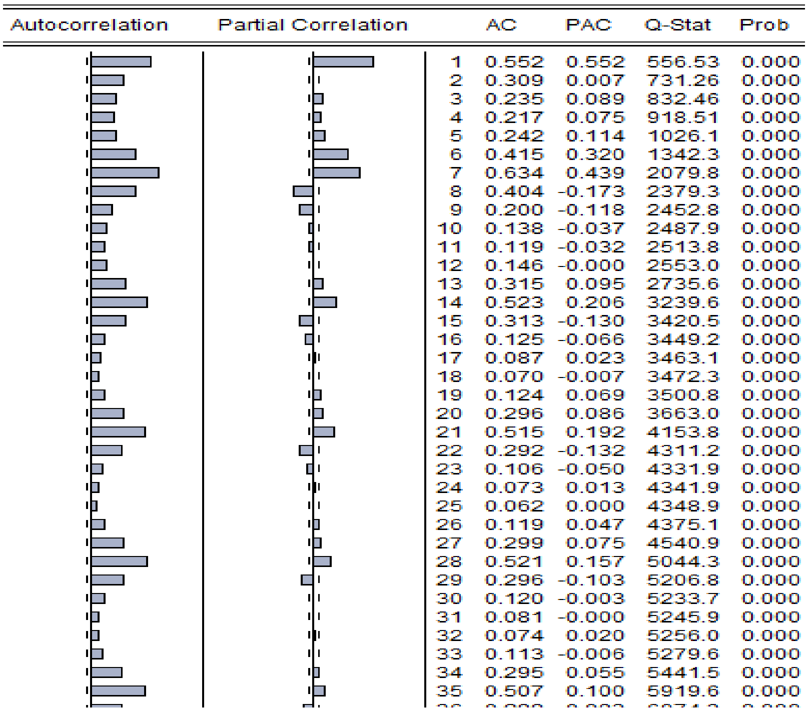
As our goal consists on exploring the joint impact of wind in-feed on spot electricity price level and also on price volatility dynamics, the wind feed-in should be taken into account as an exogenous variable in the mean equation as well as in the variance one. Therefore, our empirical analysis is based on ARMA(p,q)-X-GARCH(1,1)-X modeling.

The exogenous variable X represents the Wind-in feed. In conclusion, the parameters estimates of ARMA(p,q)-X-GARCH(1,1)-X model will allow us an empirical assessment of the merit order effect (lowering electricity prices), but also the impact of RES on electricity prices volatility.

3.1.3.3 Results:

Before showing the parameters estimates of ARMA(p,q)-X-GARCH(1,1)-X model, we adjust electricity spot prices from outliers according to 3 sigma rule as shown in figure 9.We then use a logarithmic transformation of the outlier adjusted data in order to stabilize the variance et reduce the excess volatility. Correlogram figure 10) analysis of electricity prices show a strong autocorrelation in lags 7, 14, 21, 28 which imply a weekly seasonality.

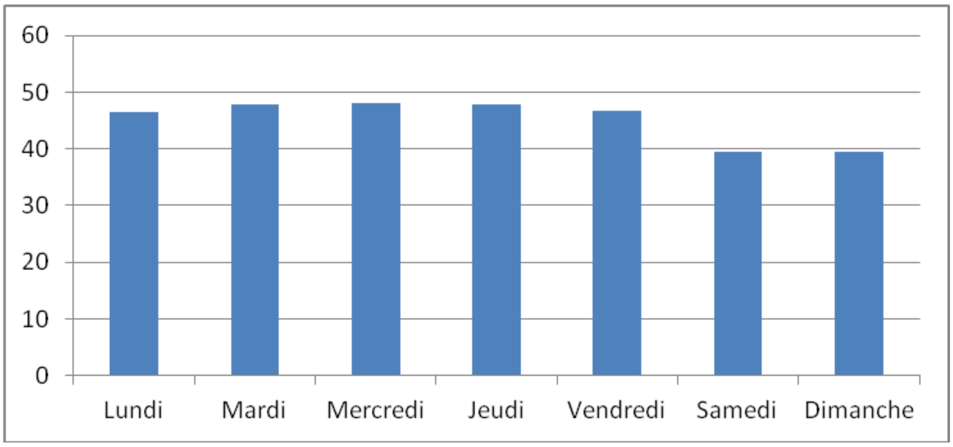
Figure 10. Electricity prices correlogram



Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob
		1	0.552	0.552	556.53	0.000
		2	0.309	0.007	731.26	0.000
		3	0.235	0.089	832.46	0.000
		4	0.217	0.075	918.51	0.000
		5	0.242	0.114	1026.1	0.000
		6	0.415	0.320	1342.3	0.000
		7	0.634	0.439	2079.8	0.000
		8	0.404	-0.173	2379.3	0.000
		9	0.200	-0.118	2452.8	0.000
		10	0.138	-0.037	2487.9	0.000
		11	0.119	-0.032	2513.8	0.000
		12	0.146	-0.000	2553.0	0.000
		13	0.315	0.095	2735.6	0.000
		14	0.523	0.206	3239.6	0.000
		15	0.313	-0.130	3420.5	0.000
		16	0.125	-0.066	3449.2	0.000
		17	0.087	0.023	3463.1	0.000
		18	0.070	-0.007	3472.3	0.000
		19	0.124	0.069	3500.8	0.000
		20	0.296	0.086	3663.0	0.000
		21	0.515	0.192	4153.8	0.000
		22	0.292	-0.132	4311.2	0.000
		23	0.106	-0.050	4331.9	0.000
		24	0.073	0.013	4341.9	0.000
		25	0.062	0.000	4348.9	0.000
		26	0.119	0.047	4375.1	0.000
		27	0.299	0.075	4540.9	0.000
		28	0.521	0.157	5044.3	0.000
		29	0.296	-0.103	5206.8	0.000
		30	0.120	-0.003	5233.7	0.000
		31	0.081	-0.000	5245.9	0.000
		32	0.074	0.020	5256.0	0.000
		33	0.113	-0.006	5279.6	0.000
		34	0.295	0.055	5441.5	0.000
		35	0.507	0.100	5919.6	0.000

As shown by figure 11, the daily electricity spot prices decrease progressively from Monday to the week-end and are lowest on Saturday.

Figure 11 . Average electricity spot prices during during 7 days of the week



For the monthly data, electricity spot prices decrease during March, April, Mai, June, July and August.

After seasonal adjustment, we carry out an Augmented Dickey-Fuller test (Dickey and Fuller,1981) to test for the stationary electricity spot prices.

Table 3. ADF unit root test on sa_electricity spot prices

		t-Statistic	Prob.*
Augmented Dickey-Fuller test statistic		-6.831103	0.0000
Test critical values:	1% level	-2.566234	
	5% level	-1.940998	
	10% level	-1.616582	

The ADF t-statistic is -6.8311 whereas the 5% critical value is -1.9410. The null hypothesis of a unit root is rejected, spot electricity prices are then stationary. As electricity is not storable, the price tends to spike and then revert (mean-reverting behavior) as soon as the divergence of supply and demand is resolved (Escribano et al., 2011).

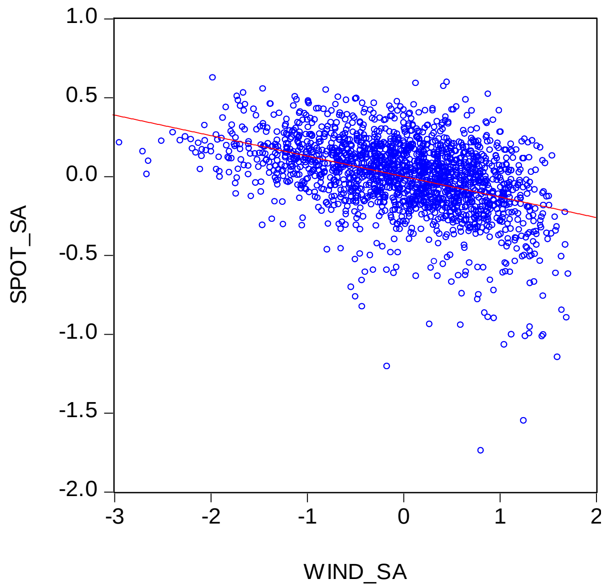
For the Wind power, its forecasts show seasonal dynamics which could be adjusted by using dummy variables after logarithmically transforming the data. The deseasonnalized time series called (wind_sa) is then tested by Augmented Dickey Fuller test which reveals their stationary behavior(The ADF t-statistic is -23.6438 whereas the 5% critical value is -1.9410).

Table 4 . ADF unit root test on WIND_SA

		t-Statistic	Prob.*
Augmented Dickey-Fuller test statistic		-23.64385	0.0000
Test critical values:	1% level	-2.566230	
	5% level	-1.940997	
	10% level	-1.616583	

The following figure 12 shows the negative impact of wind power on electricity spot price, the so- called merit order effect.

Figure12. The merit order effect



After all these adjustments and tests, we can now carry out a linear regression in order to explore the impact of wind-in feed on spot electricity prices according to an ARMA-X model:

$$(spot\_sa)_t = \alpha_0 + \sum_{i=1}^{p} \alpha_1 (spot\_sa)_{t-i} + \sum_{j=1}^{q} \beta_j \varepsilon_{t-j} + \delta wind\_sa_t + \upsilon_t$$

The selection of autoregressive lag p could depend on AIC minimization, and q is assumed to be 0. According to Akaike info criterion, the best choice was lag p=7 which corresponds to a weekly seasonality.

The estimation results a reported in Table 5 reveal a negative impact of wind power on the electricity price in Germany. A 10 percent increase of wind electricity in feed (MWh per day) increases by 10 decreases spot prices by 1 per cent. Indeed, for each additional GWh of wind-feed-in, the electricity price decreases by 1cts/MWh at the spot market.

Table5. Linear regression of wind feed-in on electricity price

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-0.006308	0.028348	-0.222512	0.8239
WIND_SA	-0.108446	0.005202	-20.84529	0.0000
AR(1)	0.339332	0.023200	14.62612	0.0000
AR(2)	0.122441	0.024460	5.005736	0.0000
AR(3)	0.086467	0.024659	3.506514	0.0005
AR(4)	0.056929	0.024681	2.306547	0.0212
AR(5)	0.034658	0.024654	1.405821	0.1599
AR(6)	0.062264	0.024501	2.541228	0.0111
AR(7)	0.165326	0.023199	7.126333	0.0000

Then, an ARCH-effect test following the procedure of Engle (1982). was conducted for the residuals time series (See Table 6).

Table6. ARCH heteroskedasticity test on regression residuals

F-statistic	13.61856	Prob. F(7,1804)	0.0000
Obs*R-squared	90.94673	Prob. Chi-Square(7)	0.0000

We can conclude that residuals time series is heteroskedastic. Therefore, a GARCH(1,1) model should be used to take into account the volatility of spot electricity prices.

Moreover, the wind in-feed is taken into account as an exogenous variable in the mean equation as well as in the variance one. The empirical results based on AR(7)-X-GARCH(1,1)-X model are reported in Table 7 .

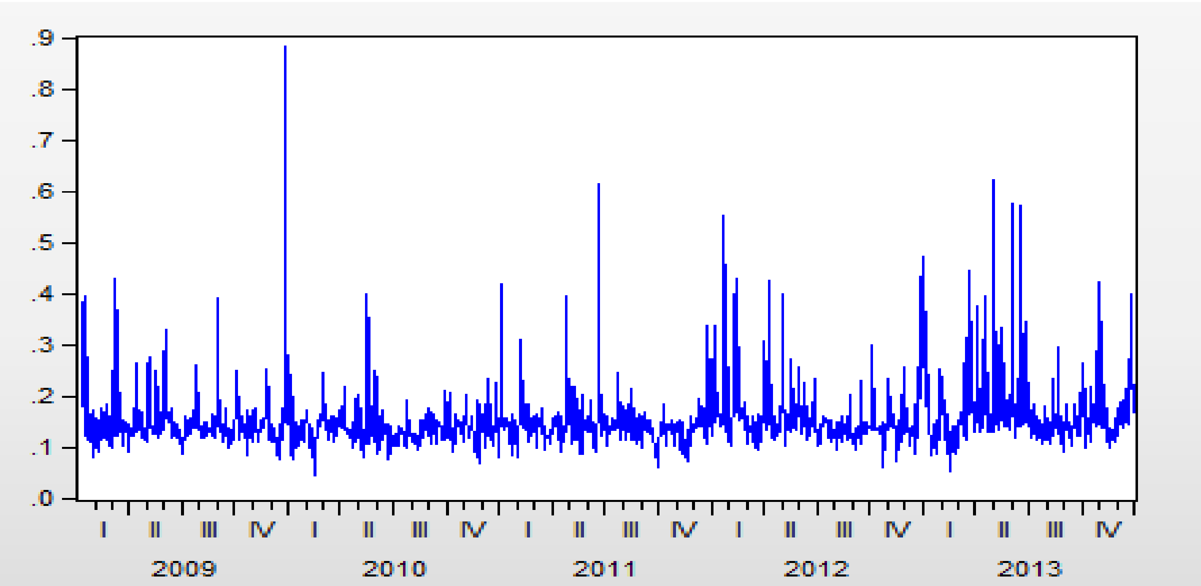
Table7.AR(7)-X-GARCH(1,1)-X model estimation

Variable	Coefficient	Std. Error	z-Statistic	Prob.
C	-0.007790	0.027124	-0.287197	0.7740
WIND_SA	-0.092284	0.004027	-22.91491	0.0000
AR(1)	0.494964	0.029007	17.06348	0.0000
AR(2)	0.051656	0.032074	1.610552	0.1073
AR(3)	0.064715	0.030151	2.146342	0.0318
AR(4)	0.066381	0.021237	3.125636	0.0018
AR(5)	0.015081	0.021617	0.697655	0.4854
AR(6)	0.034208	0.015567	2.197415	0.0280
AR(7)	0.152187	0.012254	12.41922	0.0000
Variance Equation				
C	0.011395	0.000610	18.67749	0.0000
RESID(-1)^2	0.341558	0.028055	12.17436	0.0000
GARCH(-1)	0.242328	0.029782	8.136720	0.0000
WIND_SA	0.004430	0.000239	18.54617	0.0000

The model parameters are positive and statistically significant at the 1% level. The sum of $\alpha + \beta$ was less than one. We can conclude that introducing of wind electricity in Germany has not only reduced the electricity spot prices (-0.092), but also induced an increase of their volatility (positive sign +0.0044 at the conditional variance equation). Indeed, wind in-feed integration at the power system, by the well-known merit order effect, reduces the electricity spot price level making them sometimes negative. At the same time, it has the impact of increasing the electricity price volatility, exacerbating risks in electricity markets.

The following figure 13 shows the volatility dynamics of electricity spot prices in Germany from 2009 to 2013.

Figure 13.Volatility dynamics of electricity spot prices in Germany from 2009 to 2013.



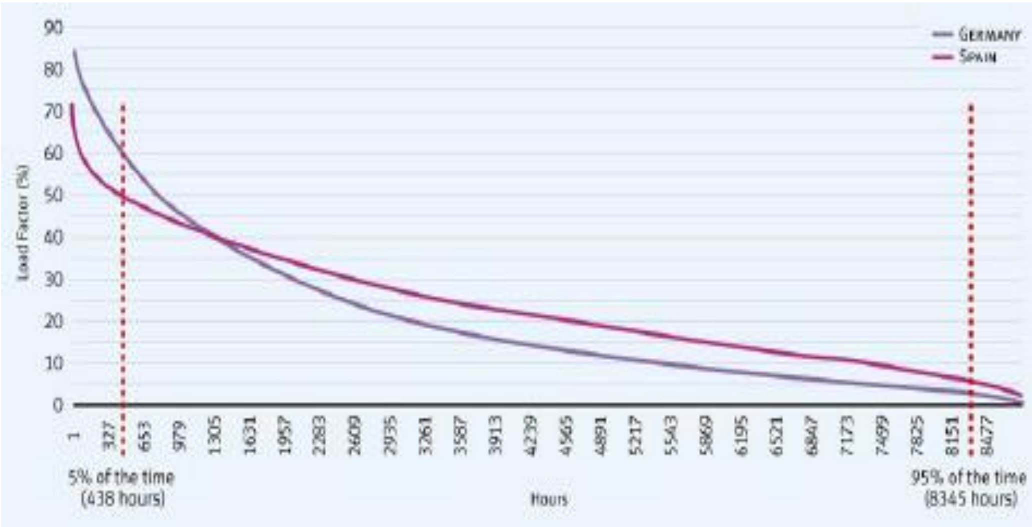
3.2 Intermittency and back-up costs:

The power from renewable energy sources such as wind and solar varies from hour to hour due to environmental conditions. This fluctuation nature of the RES power injection into an electric grid is called intermittency. For example, in Germany the production of the wind farms (in MWh) divided by the installed capacity (in MW) equals the number of 'equivalent full-time' hours of production. In 2009, for example, 37,809.10*3/25.877 = 1,461 hours. Given that there are 365*24 = 8,760 hours in the year, the German wind farms can only produce an average of 17 % of their installed capacity. Which means that even in the best-case scenario, wind-generated energy would only be available an average of 20 % of the time. Likewise, a solar panel only operates at full capacity one out of every eight days.

In order to illustrate this phenomenon, the following figure 6 (see the appendix) shows the load factor duration curve (being the ratio of produced wind energy to installed wind capacity) on an hourly basis for the Spanish and German electricity system during 2008. Installed capacity in Spain reached 16,4 GW and 23,46 GW in Germany in 2008.

reached 16,4 GW and 23,46 GW in Germany in 2008.

Figure 14 : Load factor duration curve of wind generation
(Germany and Spain,2008)Source: EURELECTRIC (2010)



The analysis of figure 14 allow us to draw some conclusions about the wind injection:

− On average, only 4% (2,5% in Spain, 5,5 in Germany) of the total wind installed capacity has a level of firmness of 95%, which is a similar level of availability to conventional power plants. So, wind’s firm capacity contribution to the system is 4% of its total installed capacity.

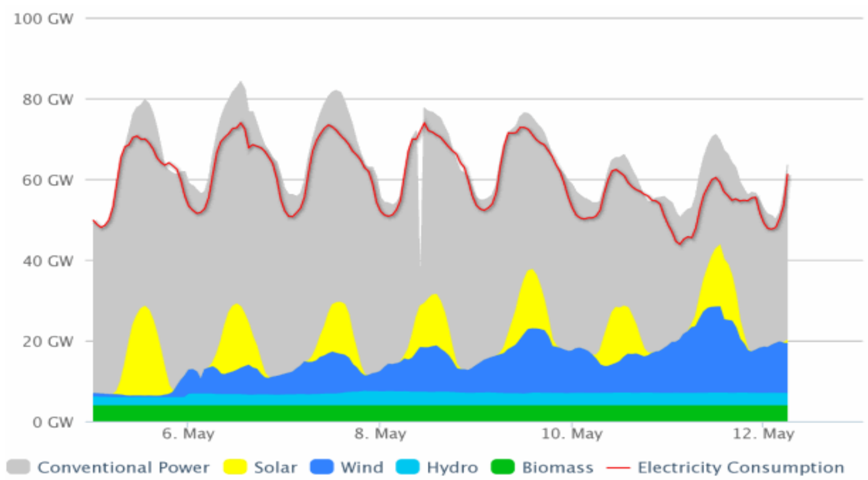
− Around 55% of wind installed capacity (50% in Spain, 60% in Germany) has a level of firmness of less than 5%. In fact, the level of injection of wind generation never reaches a percentage higher than 77% (this limit is higher in Germany but lower in Spain), so 23% of wind installed capacity can be considered as fully unavailable.

− On average, the expected working rate of wind capacity has a 90% probability of oscillating between 4% and 55% with an average load factor of 22%.

Thus, with a 90% probability, wind generated electricity as a function of total electricity consumption for 2008 year have oscillated between a minimum contribution of 4% and a maximum contribution of 55%.The mean contribution over the full year 2008 is therefore 22%. In 2012 and 2013, all RES generated electricity have contributed less than a fifth of Germany's and Austria's total load demand (respectively 19.2% in 2012, and 20% in 2013).

We can conclude that the feed-in of renewable energy sources, mostly wind and solar, are intermittent and have a low load factor. Therefore, RES are primarily an energy resource and not a capacity resource. Thus, the electricity system needs backup capacity to bridge periods with high and low electricity generation from renewables. In order to cope with increasing levels of intermittent RES, some baseload plants will be forced out of the markets, but flexible plants (like hydro, pump storage, OCGT and CCGT) will be more required. This need for flexibility allowing for a quicker response (faster ramping speed) requires investments to be made in flexible back-up generation plants (thermal or hydro) is order to compensate for more frequent imbalances between supply and demand and thus to ensure the security of supply. As an evidence for the RES intermittency, figure 15 shows us an overview of the German power sector during the week running from Monday 5 May to Monday 12 May 2014.

Figure15. German power sector during May 2014 second week. (Source: Agora Energiewende)



The week was quite unusual in terms of the high level of combined wind and solar output. Indeed, at 1 PM on Sunday 11 May, wind and solar alone made up around 62% of German power domestic demand excluding exports. Add on power from biomass and hydro, and renewables covered 73% of demand during the midday peak – albeit on a Sunday, when demand is low. However, there was a quite small share of renewables at 5 AM on the first day of the week. Hydro was at 2.0 GW, biomass at 3.7 GW – and wind and solar collectively only at around 0.7 GW. Yet, domestic demand was 53.1 GW. Renewable power only covered 12% of demand that hour, when the residual load came in at 46.7 GW (Morris, 2014).

However, this growing RES penetration- renewables made 25 percent for 2013 power demand, and increased up 27 percent over the first quarter of 2014- will undoubtedly result in a significantly reduced load factor for conventional generation. Therefore, the ability of existing back-up plants to recover their fixed costs may be weakened and may lead to earlier decommissioning decisions. It can also create uncertainty and reduce appetite for investors and thus discourage new investment in new plants.

As an illustration, we assume a competitive electricity market where the pricing is based on fleet's marginal costs, the power price would allow the full recovery of fixed and variable costs of production. Indeed, variable and fixed costs of peaking plants, such as gas turbines, must be covered during peak hours. Therefore, baseload power plants (e.g., hydroelectric and nuclear) can recover their fixed costs of electricity production during peak hours. Indeed, nuclear plants are typically price takers in a power market where marginal prices are set by more expensive peaking units. Selling a nuclear KWh based on the gas plant's marginal cost at peak hours allow them to cover their fixed costs. However, during off-peak hours, the marginal plants variable costs are the only costs to be recovered. The marginal plant could be a coal-fired one, or sometimes a nuclear plant.

*Here, it is useful to look at one example (Percebois and Hansen,2010). Let us assume that the power-generation fleet is composed exclusively of two kinds of plants: nuclear for the base load and diesel combustion turbinr(DCT) for the peak; let (0,H) represent peak hours and (H,T) the off-peak period (T = 8,760 hours)***.** *Let a represent the unit fixed cost of the nuclear KWh and b the unit fixed cost of the DCT KWh; f is the variable cost per operating hour of the nuclear KWh and g the variable cost per hour of operation of the DCT KWh.*

The cost price of the nuclear KWh is expressed as y = a + fh, and that of the DCT KWh,
z = b + gh, where h equals the number of operating hours. We show that y = z for
h = H = (a – b)/(g-f) (difference between fixed costs over difference between variable costs). The period (0,H) corresponds here to the peak. The nuclear power station is the marginal facility during the off-peak times and the DCT, the plant which determines the price at peak times (0,H) because it is then the marginal facility. The optimum pricing system consists of recovering a revenue equal to f(T – H) per KWh during off-peak times and equal to b + gH per KWh during peak times. It is clear in this case that the total revenue recovered for 1 nuclear KW dispatched throughout the year (0,T) is equal to: fT – H) + b + gH, or, if H is replaced by the value indicated below, a + fT, which covers both the fixed costs and the variable costs of the nuclear power plant.

If, during peak times, the price were fixed in such a way that the returns only covered the variable cost of the DCT, or gH, the whole of the fixed costs would not be recovered. The fact of selling the nuclear KWh at a price permitting the recovery of b + gH per nuclear KWh does not constitute unjustified income because it offers the means of covering the fixed costs of the nuclear plant. On the other hand, if, for one reason or another, the market price leads toreturns higher than b + gH during peak times, there is either a scarcity rent (if the available capacity is inadequate for satisfying all the demand) or a monopoly or oligopoly rent (if the price is manipulated and results from the "market power" of the operators present on the market).

However, at peak times, the market power price is often too low to cover the fixed costs of the peaking plants. This fact would not create enough profits to incentivize to investments in peak plants. Consequently, there would be the 'missing money' problem raised by Stoft (2002).

The decrease of average electricity prices due to the merit order effect leads to market crowding-out of flexible peak-load power plants with comparatively high variable costs.

However, focusing solely on variable costs of flexible power plants at energy-only markets cannot ensure that power supply will be available when it is needed most and that the increasing intermittent electricity generation from renewable will be balanced in the long run.

Therefore, power plants have to receive compensation for capacity, or the power that they will provide at some point in the future. This is the basic idea of capacity markets. It consists on recovering the 'missing money' needed to incentivize new investments through capacity payments outside the energy market. This mechanism is based on a two-part price, with one set of revenues paying for energy on a €/MWh basis and another rewarding capacity needed on a €/MW-period basis. It thus will allow sufficient revenues to be recovered to support needed investment in peak-load plants or to keep existing capacity operational.

The capacity market will consequently lead to a more flexible power plants opposing the results of the merit order effect observed on energy-only markets. Thus, a capacity market creates the right answer to more intermittent electricity generation from renewable energy with respect to flexibility issues as it can ensure reliability by continuous and sufficient investment incentives.

On Oct 11, 2013 Brussels meeting, the CEOs from 10 utilities representing half of Europe's power-generating capacity urged the European Union to adopt reforms to prevent black-outs. Yet, the utilities have been forced to mothball gas-fired power plants because they cannot compete. They have closed 51 gigawatts of modern gas-fired generation assets - the equivalent of the combined capacity of Belgium, the Czech Republic and Portugal - and the risk is more will be shut.

To help maintain the gas-fired capacity as vital back-up to intermittent renewable power, the CEOs want a Europe-wide mechanism to pay utilities for keeping capacity on stand-by.

3.3 Negatives prices

Due to increasing injection of RES, the power markets may observe more frequently situations where there is more supply than demand, even at negatives wholesale prices . This is due to the non-storability of electricity.

During the night of 24 December 2012, the price of electricity was at its lowest on the EEX electricity market : -50.056 euros/MWh in France and -221.99 euros/MWh in Germany.

The phenomenon of negative prices had already occurred in Germany twenty-five times in 2009, seventeen times in 2010 and fifteen times in 2011. Negative prices were also observed on the spot market in France on Sunday 16 June 2013.

On Sunday, May 11, 2014, Germany set a new record by getting nearly three quarters of its electricity from renewable sources during a midday peak resulting negative prices as shown by the following Figure 16.

Figure16. Power prices in Germany, 2014, May,5. (Source: EPEX)

Wind power peaked at around 21.3 GW at 1 PM, with solar simultaneously coming in at 15.2 GW. Add in the roughly 3.1 GW of hydropower and 3.7 GW of electricity from biomass that Germany usually has, and the output of conventional power plants was pushed down to 26 GW at 1 PM on Sunday. Power demand, however, was only at 59.2 GW, meaning that only 15.9 GW of conventional power was needed to serve domestic demand.

During Sunday 11 May 2014, Germany has a must-run capacity of around 20 GW, meaning that 16 GW (the residual load from domestic demand on Sunday at 1 PM) is simply too little for the German power sector to serve. As the residual load approaches the mid-20s GW, power firms therefore begin paying customers to take electricity off their hands. Electricity prices went negative for the entire Sunday afternoon (Morris,2014).

In Germany, generally the occurrences of negative prices may be explained by the combination of two phenomena:

- low demand during holiday periods (3 October national holiday, Christmas, school holidays) or during week-ends and especially during night.
- high renewable feed-in mainly strong winds (which set the offshore wind turbines in the Baltic Sea running at full capacity) which induce a power oversupply to the market.

Based on the priority dispatch, TSOs are not allowed to curtail wind farms. Conventional plants will thus have to reduce their production. However, an output reduction below a certain technical minimum would be to shut them down. Moreover, ramping rates of conventional plants for up and downwards regulation may increase maintenance and operation costs.

In addition, most nuclear plants cannot be regulated downwards for a short period of time for safety reasons and have only a limited ability for a fast start-up and specific requirements to stop them.

Consequently, due to these constraints, these power generators prefer to keep their plants running by bidding in negative prices. They make the choice to pay somebody to take the electricity they produce avoiding to stop their plants and start them again shortly afterwards.

Therefore, the occurrence of negative prices could be a real loss of social welfare, that the energy system has to prevent. Indeed, negative prices should incentivize investments in storage facilities (pumping plants, compressed air storage, or electric vehicles), which consume electricity at times when prices are low and deliver it back to the grid when prices are high. They should also stimulate investments in power plants with a lower minimal technical production, and a lower start/stop costs.

The energy system should also introduce a market mechanism to cope with the negative prices. Indeed, if electricity end users can receive the right signals, they will respond to it by adapting their consumption behavior. This goal can be reached if there is a huge development of smart grids and smart metering providing greater flexibility to the system.

Thus, while the negative prices due to the increased intermittent RES penetration induce an increase of electricity price volatility, the energy system can overcome it by huge investments in storability and flexibility.

3.4 Reinforcing the transmission grid

The mostly highest wind energy potential is concentrated the northern Europe, rather “far” away from the consumption location. Therefore, grid reinforcements will be necessary to accommodate the growing energy fluxes from large volumes of intermittent RES through the grids. Indeed, the wind power generation in one European state constitutes a constraint for neighbouring countries grids. When offshore wind power from the Baltic Sea cannot be transferred towards the south of Germany for technical reasons- the lack of adequate high-tension lines-it is exported via Poland and the Czech Republic to provide power for Bavarian industry. The wind energy feed-in has also a significant impact on the French grid. Consequently, the Germany neighbouring are at risk of having a congested grid.

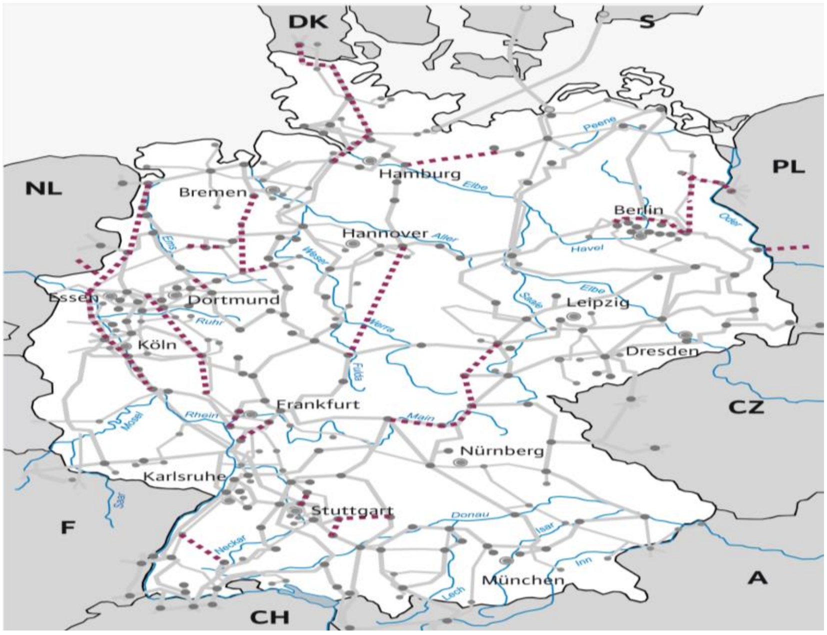
Therefore, the wind power generation constitutes a constraint for neighbouring countries grids that should be overcome. This goal could be reached if the necessary grid investments are undertaken. Indeed, the introduction of large volumes of RES will not only considerably affect both distribution and national transmission networks, but also transmission networks in adjacent and further away countries. Hence the focus on grid investments should be shifted from a national to an European perspective. This is further emphasized, by the fact that large scale transmission investments are also needed in order to achieve the ultimate goal of the creation of an “internal market in electricity” (IEM) in Europe. The objective sought by the IEM, is the integration all of today’s existing markets within the European Union into one unique market. Germany have coupled its electricity markets respectively with Denmark in 2009, with Sweden 2010). On November 2010, the countries of the CWE region (Belgium, France, Germany, Luxembourg and the Netherlands) and the Northern region (Denmark, Sweden and Norway) coupled also their electricity markets allowing flows of electricity toward and from neighboring countries.

To achieve the internal market, the market integration tools-market coupling, cross-border intraday and cross-border balancing - are indispensable. The market coupling is the best tool to allocate cross-border capacity as it facilitates the necessary coordination of the European electrical system. There could then be a common merit-order for the whole Europe.

Moreover, the market coupling could be a real solution to avoid negative prices. Indeed, European countries with abundant RES generation (like Germany) and thus low electricity price (in particular negative) should be provided with sufficient grid capacity to “export” their

low prices to other European areas. Therefore, the interconnections increase the efficiency of the interconnected systems. Indeed, electricity exchanges are established taking advantage of the price spreads between electricity systems, allowing energy to be transported from where it is cheaper to where it is more expensive. The grid capacity will then allow the transport for the energy generated at low marginal cost to places where it is less efficient to build similar RES plants. However, these interconnections require costly investments which would have to be added to all the higher costs for society from renewable energy sources. It thus remains to be seen who would bear this additional network-related cost. From an economic perspective, the relevant question is: who will pay for the grid? If we consider that the benefits would be shared among customers from different European states, costs should then theoretically also be borne by several countries states. The Figure 18 shows the grid extension projects up to 2015 in Germany.

Figure 18. Grid extension projects up to 2015 in Germany(Source:BDEW).



3.5 Rising electricity costs for end consumers

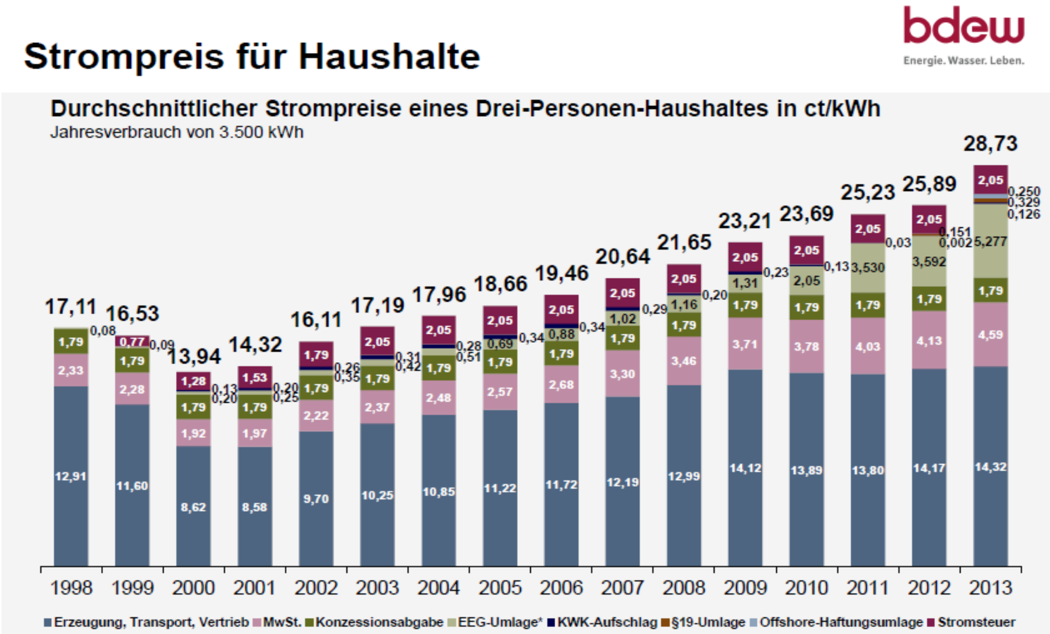
The goals of “Energiewende” consist not only on greater energy efficiency, the development of renewable energy sources, and the reduction of carbon emissions but are also coupled with an exit from nuclear energy by 2022. The question that one need to address is who exactly should pay for reaching these goals?

Indeed, the rapid expansion in renewable energy has occurred with a negative impact on the households especially the low-income ones : electricity prices have increased sharply. Back in 2000 an average household in Germany consuming 3,500 kWh/year paid €40.67 per month for electricity. By 2011 the same amount of electricity cost €72.78 per month, and in the coming years, the price of electricity is on track to climb still further. Therefore, households do not benefit from ant lowering of electricity prices that could be realized at the European Energy Exchange AG (*EEX*) in Leipzig due to the merit-order effect.

The rising cost of power is partly due to the introduction of feed in tariffs: growth in the amount generated by renewable sources leads to a higher amount paid to the renewable producers. Consumers have to pay a surcharge on energy consumption, that is, a tax on energy bills known as the *EEG Umlage*. This surcharge pays for the difference between the market price and the guaranteed price for renewable energy that producers receive. *EEG Umlage* had level of 5.27ct/kWh in 2013, and has increased to 6,4 ct/kWh in 2014. The German energy ministry expects the EEG surcharge to rise to 7.7 euro cents by 2020, with the Centre for European Economic Research pegging it at 8.3 euro cents.

Figure 19 shows the evolution of EEG Umlage as a cost component of electricity paid by for german households.

Figure 19. Cost components for one kWh of electricity for household consumers (Source: BDEW).



The EEG-surchage accounts for approximatively 18% of the price for 1 kWh in 2013. Germany has the highest consumer electricity price levels in Europe even though the average electricity spot price is currently one of the lowest in Europe. The total paid “EEG-Umlage” in Germany alone was almost 17 billion euros in 2012 and 2013 and estimated almost 20 billion in 2014.

As EEG Umlage has to cover the wholesale electricity price/FIT spread, the more the electricity prices are low at the spot market, the more the gap between market prices and feed in tariffs is large, making EEG Umlage more higher.

Moreover, the EEG-surcharge is affected by the increasing number of exempt companies. Indeed, in 2010 approximately 650 companies were not required to pay the whole EEG-surcharge. Their electricity consumption represented one-third of Germany’s total industrial electricity consumption. The exemption was introduced to prevent the international competitiveness of German companies not be damaged. Overall, half of the electricity used for industrial production in Germany was either exempt or partially exempt from the surcharge.

The EEG surcharge, being passed through to electricity price paid by households, imply a transfer from energy consumers to energy producers, raising a wide redistributive concern for the current electricity system.

Indeed, the price of industrial electricity has dropped from 9.46 euro cents in 2007 to 8.6c in 2013 and will be even lower in 2014. Germany industry is now paying less than the EU27 average of 9.4cts whereas Germany has the highest consumer electricity price levels in Europe.

By lowering the wholesale electricity price, RES development affects the **consumer**s' welfare as the feed-in tariffs represent an excessive cost to end users. The rising costs of renewable are driving low income households to fuel poverty.
It seems unfair that smaller electricity consumers should be effectively subsidizing larger consumers. This raises questions about equity of the current electricity system.

In fact, a recent DIW Report estimates that the poor pay more than double their proportion of income for the *EEG Umlage* than the rich (Neuhoff et. al 2012). The energy costs can then affect households's welfare.

Furthermore, the goal of EEG Ulmage paid by german households is the greening of their own electricity. However, when there is a substantial wind in Germany, the oversupply of power from RES pushes prices down in France or Netherlands due to the increased level of interconnection. It then corresponds to a cross-border power flow from Germany to neighbouring markets consumers who receive a cheap power without paying for its generation.

4.Policy implications:

The Germany's attempts to green its energy mix is interesting to watch, especially for other countries that are building up RES capacities.

However, The EEG developments in Germany teach us that a policy has always unwanted consequences, and hard conclusions have to be drawn.

Indeed,the merit order effect, lowering the equilibrium power price, may hurt the conventional power firms. Negative prices make such backup capacity unprofitable. So, the power system is in need of considerable backup capacity on a regular basis. Moreover, a capacity market have to avoid missing money problem of back-up power plants. The stability of the electricity system asks for huge investments in storage.and in grid reinforcements. Furthermore, the rising bills for households due EEG umlage showed that the affordability of electricity is the issue which most concerns the public especially low-income households in Germany which are at risk to suffer from a fuel poverty. The reforms recently (August 2014) implemented in Germany (a switch from the FIT system towards a FIP system) will be also implemented in France in the near future (January 2016, as mentioned in the recent law about energy transition).

If we assume that a sustainable energy system – comprised largely of renewables – is the only long-term solution to our energy future, the RES expansion may incur higher costs for electricity system and society.

Therefore, the central issue that politics have to address is the increasing surcharges due to RES integration into the power system and the "distorting" effect of subsidies on electricity system. A more open debate on these subsidies costs' related issues are essential for paving the way, maintaining the strong support of citizens and preparing the required policy decisions about a rethink of the entire Energiewende.

The Energiewende as a renewable revolution at national level will be even successful in a single European market although it is the biggest one? After all, Europeans live so close to each other that a national energy policy makes little sense.

The nuclear phase-out decision is not credible as a reactor-free Germany can non longer be safe when nuclear power plants go are runnig next door in France.

The energy policy should be shifted from a national to an European perspective. The objective sought by creation of an "internal market in electricity" in Europe can no longer be a reality without co-operation between German renewable, French atomic power, and the Scandinavian hydro reservoirs.

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