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Photovoltaic and wind power feed-in impact on electricity prices: The case of Germany☆

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ABSTRACT

The aim of the paper is to quantify the impact of increasing renewable energy sources (RES), especially wind generation and photovoltaic feed-in, on electricity prices in Germany, with a view to investigating the well-known merit order effect.

To explore the dynamics of the merit order effect at an hourly resolution, we use the SURE methodology for carrying out an empirical analysis based on hourly historical data for the Germany electricity market between 2012 and 2015.

Our main empirical findings confirm that increasing the share of wind generation and photovoltaic feed-in induces a sharp fall in electricity spot prices. Moreover, this impact varies throughout the 24 h of the day due to the dynamics of electricity demand and the intermittency of wind and solar photovoltaic feed-in.

1. Introduction

Renewable energy is a key component of the EU energy strategy. Starting with the adoption of the 1997 White Paper, the strategy has been driven by the need to decarbonise the energy sector and address growing dependency on fossil fuel imports from politically unstable regions outside the EU. To achieve this goal, in 2009 the EU released the First Climate and Energy Package, with 2020 targets (compared to 1990 levels) of 20% GHG emissions reduction, 20% renewable energy share in the primary energy mix, and 20% energy efficiency improvement. Moreover, the European Commission's Energy 2020 strategy highlights how EU policies are supporting the development of the renewable energy sector. The Second Climate and Energy Package, with targets for 2030, was released in 2014. Its objectives submitted to COP21 in 2015 are (compared to 1990 levels) 40% GHG emissions reductions, 27% renewable energy share in the primary energy mix, and 27% energy efficiency improvement (European Commission, 2015).

Various support schemes for renewable energy sources (RES) are operating in Europe, mainly feed-in tariffs, fixed premiums, and green certificate systems. The German Renewable Energy Act, "Erneuerbare-Energien-Gesetz" (EEG), a well-known support scheme, has provided a favourable feed-in tariff (FIT) for a variety of renewable energy sources (RES) since the year 2000. It also gives priority to electric power feed-in from RES over power feed-in from conventional power plants, i.e. fossil-fuel and nuclear-fuel thermal and already existing hydro-based power plants. Thus combined generation from wind power and photovoltaic RES accounted for 25 per cent of gross electricity production in 2015 and is Germany's second largest source of electricity after lignite (BDEW, 2015).

Fig. 1 (see Appendix) summarizes the recent evolution of the electricity mix. Carbon-intensive technologies clearly prevail in Germany, even though the share of renewables has grown significantly in recent years.

In this paper, we address a central question of the research agenda on renewable energy sources by exploring the impact of RES on electricity prices (the merit order effect). One of the central empirical findings in the literature on renewable energy is that an increase in RES generation puts downward pressure on the spot electricity market price by displacing conventional power plants with higher marginal cost.

The aim of the paper is to quantify the impact of increasing renewable energy sources (RES) in particular (wind generation and the photovoltaic feed-in) on electricity prices in Germany, in order to investigate the merit order effect.

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The study makes two main contributions to the literature. Firstly, we take into account the joint impact of wind and solar photovoltaic feed-in on electricity prices, using a recent dataset that allows us to assess the learning curve of new technology integration in Germany's energy mix. Secondly, a multivariate regression: the seemingly unrelated regression (SUR) model is used to explore the joint impact of intermittent renewable electricity generation on the electricity spot price throughout the 24 h of the day over the 1461 days of our data sample. The dynamics of the merit order effect is then assessed at an hourly resolution.

Our main empirical findings confirm that increasing the share of wind generation and photovoltaic feed-in induces a fall in electricity spot prices. Moreover, this impact varies during the 24 h of the day due to the dynamics of daily electricity demand and to the intermittency of wind and solar photovoltaic feed-in.

Furthermore, the dynamics of the two impacts are quite different, as the wind impact, although more pronounced at the early hours of the day due to low demand, has approximately the same mean level throughout the day, whereas the PV impact reaches its maximum level between 12 a.m. and 1 p.m., having a bell-shaped curve, with no sunshine in the early morning, during the evening and at night. The generation of solar power over the day exactly follows the daily course of demand for electricity. The typical daily shape of the merit order effect for PV is due to the fact that PV electricity is predominantly generated during the middle of the day when power consumption is at its midday peak. During the middle of the day demand is high, and so the electricity price should be at its highest. However, as solar PV power mainly displaces electricity from expensive power plants (especially gas-fired power plants and pumped-storage), it thus lowers the equilibrium electricity price.

The growth of installed PV capacity has allowed the midday peak load to be covered even on less sunny days, while on sunny days the electricity production during the middle of the day will even cover part of the base load, especially during the weekend and holidays.

The paper is organized as follows. Section 2 provides the background on the merit order effect and the corresponding literature review. In Section 3, we present our empirical methodology based upon the SURE model. Section 4 presents the results and discusses the main findings. In Section 5, we conclude and explore the policy implications of our findings.

2. Background and literature review

2.1. Background: The merit order effect

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 such as hydroelectric generators, wind and solar energy).

The electricity market operates on the basis of day-ahead bidding. Transmission system operators receive bids from all power producers for the quantity and cost for each hour of the next day and then assign dispatch based on the lowest cost producer until demand is met. All dispatching producers get the marginal price of the last producer that dispatched. As a result, even if the last producer theoretically produced only one kWh then that is the price within the system. This standard approach involves ranking the power plants of the system in ascending order of their marginal cost of generation. This approach is called the merit order.

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

Although power plants with oil-fired gas turbines have the highest marginal cost, gas plants are usually marginal producers and consequently the cost of gas is very relevant to the setting of wholesale electricity prices. But due to price weaknesses in the EU ETS, carbon prices have plunged to record lows, making it more costly to burn gas than coal. Moreover, export of U.S. coal surpluses as a result of the shale gas revolution has lowered coal prices in 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 gas turbine plants and make them the key to electricity pricing.

The principle behind the functioning of the electricity market is that producers recover the fixed costs of base load power plants (e.g. hydroelectric and nuclear) during full and peak periods, when nuclear (or hydroelectric) generated electricity is sold on the market at the price per KWh of thermal energy. The mark-up thus recouped allows investment costs to be covered.

In a competitive market, when the power-generation fleet is optimal, the selling price permits all costs (fixed and variable) to be recovered if the pricing for each period is based on marginal costs, as follows:

1. variable cost of the base load plant
2. variable cost of the semi-base load plant
3. variable cost + fixed cost (access tariff) of the peaking plants.

In the third case, the fixed cost of the marginal plant must be taken into account if all the costs are to be covered. This is the “missing money‟ problem raised by Stoft (2007). Indeed, the fact that at peak periods the market electricity price in the spot market is often too low to cover the fixed costs of the peaking plants does not give operators sufficient incentive to invest in these facilities, which in addition suffer from random dispatching to the grid. Electricity producers with low variable costs (nuclear or hydroelectric) recover their fixed costs during the peak period, when the spot price corresponds to the variable cost + fixed cost of the peaking plant (combustion turbines running on diesel fuel, hereafter DCT). Here, it is useful to look at one example without taking into account transmission-distribution costs or taxes and levies. Let us assume that the power-generation fleet is composed exclusively of two kinds of plants: nuclear for the base load and DCT for the peak.

Let (0,H) represent peak hours and (H,T) the off-peak period (T = 8760 h). 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 $h = H = (a - b)/(g\text{-}f)$ (the 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 off-peak times and the DCT is the plant that 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 shown 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, not all the fixed costs would be recovered. The fact of selling the nuclear KWh at a price allowing the recovery of $b + gH$ per nuclear KWh does not constitute unjustified income because it allows coverage of the fixed costs of the nuclear plant. On the other hand, if for one reason or another the market price leads to returns higher than $b + gH$ during peak times, there is either a scarcity rent (if the available capacity is inadequate to satisfy all the demand) or a monopoly or oligopoly rent (if the price is