Energy Policy 107 (2017) 323–336

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

An analysis of the decline of electricity spot prices in Europe: Who is to blame?

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ARTICLE INFO

Keywords:
Merit-order
Electricity markets
Agent-based simulation
Multiple regression analysis

ABSTRACT

The European electricity markets are going through a phase of agitating transition, which is shaped by different key factors, such as the expansion of renewable energies, the changes in the EU carbon trading scheme and the European market integration. In addition, markets are affected by the volatile prices of primary energy carriers, e.g. gas and coal. The development of these different factors led to a decline of German wholesale electricity prices of almost 40% — from about 51 €/MWh in 2011 to 31 €/MWh in 2015.

The goal of this study is to analyze the contribution of different price drivers to this decline. Thus, an agent-based modeling and a regression approach are applied to investigate the effect of price drivers and to verify model results by comparing both approaches. Our results show that, against the public perception, the impact of carbon and coal prices on German electricity prices has been twice as high as the renewable expansion between 2011 and 2015. Furthermore, if carbon and coal prices do not recover to at least the level of 2011, electricity prices will remain on the current low level complicating the economic operation of gas power plants.

1. Introduction

European electricity markets are currently going through a phase of transition, which is shaped by three key factors: The expansion of renewable energies, especially wind power and photovoltaics, the phase-out of nuclear energy and the European market integration.

Different promotion schemes were installed in European countries to support the expansion of renewable energies. Germany as a leading country in the promotion of renewable energy already introduced its first renewable energy law ("Stromeinspeisegesetz", (Bundesregierung, 1990)) in 1991. This law is regarded as the first feed-in law worldwide and marked the start of a tremendous rise of renewable energies. In 2000, technology-specific feed-in tariffs were established, as most renewable energies have not been able to undercut the costs of conventional fossil-fueled power plants. These tariffs guaranteed a fixed price for all electricity generated in a predetermined period that is paid by the transmission system operators who pass on the costs to the end consumers (German Renewable Energy Sources Act, (Bundesregierung, 2000)). In 2015, renewable energies contributed with 195.9 TWh (about 30%) to electricity generation, which compared to 2005 corresponds to an increase of 213% (Federal Ministry for Economic Affairs and Energy, 2016). Among the different renewable energy sources, wind is currently the most important source of energy production with a share of 44.9% followed by biomass (22.6%) and photovoltaic (19.6%). However, considering entire Europe, hydropower still has the largest share with 45.4% mainly due to the electricity production in the Alpine and Scandinavian countries (European Commission, 2015).

A major advance for the integration of the European electricity markets represents the market coupling in Central Western Europe (Benelux, France and Germany) at the European power exchange (EPEX SPOT), which started on November 9, 2010 (European Power Exchange, 2016). About three years later, market coupling was extended to also include North-Western Europe (NWE). Through market coupling, generation capacities can be used more efficiently across borders and market participants profit from welfare gains (Weber et al., 2010). As long as sufficient interconnecting capacities between neighboring countries are available, wholesale prices in coupled markets converge, leading for instance to identical day-ahead market prices in Germany and France in about 27% of the time in 2015.

In the last years, the transition of the German electricity market was accompanied by a substantial price decline in the base as well as peak wholesale prices (see Fig. 1). In 2011, the yearly base price corresponded equal to 51.12 €/MWh but dropped to 31.63 €/MWh in 2015, a decrease of roughly 38%. Electricity generators have been profoundly affected by these developments, even more so as no capacity remuneration market is currently implemented in Germany. Many power

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http://dx.doi.org/10.1016/j.enpol.2017.04.034
Received 28 July 2016; Received in revised form 13 April 2017; Accepted 18 April 2017
0301-4215/

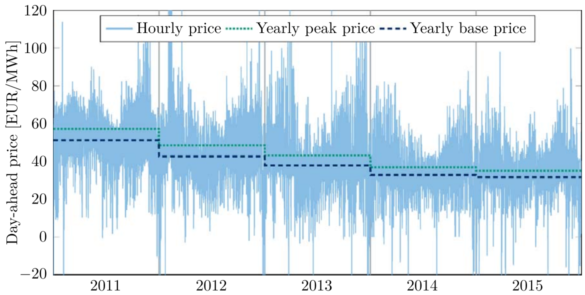

Fig. 1. The day-ahead market prices for the German/Austrian market zone.
Source: Own illustration based on data from European Power Exchange (2016).

plants are facing diminishing return. Currently, the decommissioning of 9 GW of thermal capacities within the next years is expected (Federal Network Agency, 2016a), stirring up concerns about generation adequacy.[1] In order to safeguard the transition phase of the electricity market and to guarantee the security of supply, the German government decided to implement a capacity reserve that will be procured in December 2016 (Federal Ministry for Economic Affairs and Energy, 2015). Investment decisions in a changing market with major uncertainties are challenging and certainly not all market participants expected the ongoing price decline. E.ON SE, for example, decided in 2008 to build a state-of-art gas-fired power plant (Irsching 5) with an efficiency of 59.7% and in 2010, Irsching 5 was commissioned. However, on 1 April 2016, the power plant was scheduled to be decommissioned due to economic reasons (Uniper, 2016).[2]

In the public perception and many political discussions, the blame for the current price slide and the related developments is shifted to the expansion of renewable energies, which have been strongly fostered by financial subsidies. Additionally, in the recent academic discourse, there is a broad spectrum of research that focuses on the impact of the promotion of renewable energies, but only few studies have been undertaken to analyze the impact of other factors on wholesale electricity prices. Therefore, this paper contributes to the academic discussion by providing a quantitative analysis of the fundamental price drivers and their impact on the recent decline in the German wholesale electricity prices, which also can be observed in other European markets such as France, Italy or Spain. To understand also the future effect of these price drivers on electricity prices and power plant investments, different scenarios for the development of price drivers until 2020 are generated and applied. These scenarios allow on the one hand to understand, how strongly electricity prices can vary in 2020, and on the other hand to assess the economic feasibility of power plant investments, especially that of gas power plants. For this reason, in the final step, an economic evaluation is carried out based on a net present value (NPV) approach for a state of the art technology, a combined gas power plant (CCGT) like the Irsching plant.

The remainder of the paper is structured as follows. In Section 2, selected studies on price drivers in electricity markets are discussed. In the next section, our methodology is described, and three different models are presented. Section 4 then shows an analysis of the main price drivers in the German electricity market. Finally, in Section 5 we summarize the results and conclude.

2. Literature review

In this section, we present an overview of previous studies that analyze the influence of fundamental factors on electricity prices. In these studies, a wide range of models[3] is utilized. According to Aggarwal et al. (2009), electricity market models can be classified into game theory, simulation and time series models. Game theory models often focus on the strategies of the market players, simulation models create a detailed representation of the electricity system and time series models use historical data of the dependent variable. Since there does not exist a study in the subject scope of this study that utilizes a game theory model, in the following, we only distinguish between simulation and time series models.

In line with the rise of renewable energies, many of the recent studies focus on the effect of wind and photovoltaic on the electricity price, the so-called merit-order effect (Sensfuß et al., 2008), and do not discuss the impact of fuel price changes or changing import/export flows. Furthermore, as Würzburg et al. (2013) point out, it must be kept in mind that the comparability of studies regarding the merit-order effect is limited due to the heterogeneous approaches, e.g. different sets of included fundamental variables (e.g. fuel prices, market scarcity), alternate scope (inclusion of neighboring countries or emission trading systems) and varying scenarios (no changes or alternative capacity expansion paths). An overview on the selected literature can be found in Table 1.

2.1. Simulation models

One of the first studies of the merit-order effect is carried out by Sensfuß et al. (2008), who use an agent-based model of the German electricity market to analyze the effect of electricity production from wind power and photovoltaic on the day-ahead electricity price. They determine an average price reduction for the year 2001 of 1.70 €/MWh and for the years from 2004 to 2006 a reduction of 2.50–7.83 €/MWh. In another study, Sensfuß (2013) applies the same model and calculates a price reduction of 8.72 and 8.91 €/MWh for 2011 and 2012 respectively. In this analysis, the electricity production of biogas and biomass is considered as well as additional capacities of coal and gas-fired power plants in the scenario with no renewable production. Bode and Groscurth (2006) take a rather simplistic approach by calculating the intersection of the electricity demand and supply curve under the assumption of perfect competition and static daily demand profiles for each month. They show that the price reduction depends on the level of the installed renewable capacity and quantify the effect in the case of an elastic demand at 0.55 €/MWh per GW and in the case of a nearly inelastic demand at 0.61 €/MWh per GW.

Using a fundamental merit-order model of the German electricity system that separates between 34 different power plant types, Weber and Woll (2007) find that in 2006 the feed-in of wind leads to a short-term price reduction of 4.04 €/MWh when compared to a scenario with no wind feed-in. However, if the wind capacity is replaced by alternative hypothetical power plants, they expect a medium-term price effect of −0.4 €/MWh and long-term effect of −1.00 €/MWh.

In another study, Weigt (2009) carries out an analysis of the effects of wind energy by applying a model of the Germany electricity market that minimizes unit commitment, start-up and marginal costs without taking into account cross-border flows. While the results show that the installed capacity cannot significantly reduce fossil capacities, it, however, does reduce the average wholesale market price.

Based on the work of Traber and Kemfert (2009), Traber and Kemfert (2011) apply an optimization model (ESYMMETRY) to analyze the impact of wind energy in Germany. Compared to the prices of a counterfactual scenario with no wind feed-in, the historical wholesale electricity prices from winter 2007 to autumn 2008 are on average 3.7 €/MWh higher. In a subsequent study, Traber et al. (2011)

[1] As power plant owners are not obliged to explain the reasons for a decommissioning, it not clear to which extent the decisions are based on economical or technical reasons.

[2] Already in 2012, Irsching 5 achieved only half of the expected yearly operating hours (Reuters, 2013) and became part of a reserve for redispatch measurements until 2016. Afterward, the power plant was supposed to be decommissioned. However, this decision is currently facing a ban from the regional TSO due to security and reliability of supply concerns.

[3] A recent discussion and outlook on electricity price modeling can be found e.g. in Weron (2014).