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Wind power integration and power system flexibility–An empirical analysis of extreme events in Germany under the new negative price regime

Marco Nicolosi *

Institute of Energy Economics at the University of Cologne (EWI), Alte Wagenfabrik, Vogelsanger Str. 321, 50827 Köln, Germany

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ABSTRACT

In this article, the flexibility of the German power market with respect to the integration of an increasing share of electricity from renewable energy sources was analysed. Flexibility limiting system components, which cause negative prices, are explained and illustrated for the German market. The decision of the European Energy Exchange in Leipzig to allow negative price bids is then explained. The empirical data illustrate the flexibility of conventional generating capacities in Germany from October 2008 to December 2009. Of the 86 h of negative spot prices, 19 h were significantly negative, with prices of at least −100 €/MWh. These extreme hours were analysed in greater detail by the examination of different system components. Thereby, load, wind power infeed and conventional generation by fuel type were observed, as well as the market for negative tertiary reserve, as indicators for market tightness. Although the market situations were found to be severe, under the current conditions, it could have been much worse. In order to enable the market to clear at all times, policy recommendations are provided and long-run implications of an increasing RES-E share on the conventional generation capacity are discussed. The article concludes with an outlook on additional power system flexibility options.

1. Introduction

The promotion of electricity from renewable energy sources (RES-E) in Germany began in the early 1990s. Since 2000, the deployment of RES-E capacities has grown considerably. In 2008, 6.3% of the gross electricity production stemmed from wind power alone (BMU, 2009a). With a total installed capacity of 25.8 GW at the end of 2009, Germany is the largest wind power market in Europe, in absolute terms (EWEA, 2010). Since wind is an intermitting energy source, the power markets react strongly to the stochastic wind power infeed. In times of high wind power infeed, the spot price at the wholesale market tends to be lower, compared to times without wind power in the system. This phenomenon became popular under the term merit-order effect (see Bode and Groscurth, 2006; Moesgaard and Morthorst, 2008; Sensfus et al., 2008; Wissen and Nicolosi, 2008). As wind power already covers a certain share of the load, the conventional power market only needs to cover the so-called residual load. This leads to a lower interception of the merit-order curve with the demand function, and thus, to lower power prices.

In times of low demand and high wind power infeed, the market reacts with bids below variable costs to avoid ramping-down base load power plants. Until the September of 2008, the consequences included situations with a potential oversupply that needed to be cut on an inefficient pro-rata basis. The European Energy Exchange in Leipzig reacted to this inefficiency by allowing for the possibility of negative price bids. In October 2008, the EEX closed with a negative power price for the first time. Until December 2009, 86 h with negative prices were observed at the EEX. Among those, 19 h had significantly negative prices under −100 €/MWh. The occurrence of negative prices is not problematic per se. However, they are an indicator for a tight market situation, which could lead to situations in which the market does not clear at all and consequently illustrates flaws in the market design. Therefore, in this article, these 19 h were examined in detail by analysing the factors limiting market flexibility.

The rest of this article is structured as follows. In Section 2, the demand for market flexibility is explained and examples for its limiting factors are provided. Section 3 introduces the German power market, with a focus on the particular flexibility characteristics. An empirical analysis of the hours with negative prices is presented in the fourth section. Section 5 discusses the long-term effects of the empirical market observations and provides some policy recommendations. Section 6 concludes this article.

2. Power system flexibility and negative wholesale power prices

The flexibility of power markets is characterised by their ability to efficiently cover fluctuating demand. This flexibility is

* Tel.: +49 221 27729 320.
E-mail address: nicolosi.energy@gmail.com

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influenced by the installed power plant mix and the interaction with other markets. A power system, consisting of supply, grid infrastructure and demand, is adequately designed if it is able to cope with its challenges (see, e.g. Batlle and Pérez-Arriaga (2008) and Roques (2008) for a more detailed discussion on system adequacy). The reserve power markets are responsible for system security in the real-time period. Since they require additional capacity, they also influence the flexibility of the power system. Flexibility becomes an issue in times with either very high or very low demand. In both cases, the market shows wholesale power prices, which deviate from the usual pattern (Cramton, 2004; Ockenfels et al., 2008). In times with very high demand, the market occasionally shows prices above variable cost, while in hours with very low demand, the market shows prices below variable costs of the power plants. This article analyses the flexibility restrictions concerning low demand cases by showing how different markets and market participants behave during these hours.

The system components supply, grid and demand have their own flexibility restrictions. This article abstracts from the grid infrastructure, since the price settlement at the market under consideration (the German power market) does not take grid bottlenecks into account for the price settlement. In case internal grid bottlenecks occur, the transmission system operators (TSOs) redispatch power plants on both sides of the bottlenecks after the market settling of the wholesale market. In this case, the operation of power plants is based not only on economic principles but also on post-market system security measures.

2.1. The demand side

The most obvious flexibility requiring factor on the demand side is the fluctuating, but almost inflexible, demand itself (Strbac, 2008). Depending on the load structure throughout the day and the year, either a flexible power supply system is required if the load structure is very volatile or a rather inflexible supply system is required in the case of low volatility. The second factor is the amount of must-run generation, which is subtracted from the total load. Since must-run generation is independent of the level of demand, the offset of both factors defines the residual demand, which needs to be covered by the conventional supply system. In general, the more the must-run installations, the more the flexibility required by the remaining generation capacity. Furthermore, the must-run generation can be subdivided: the most important differentiation is the renewable and the conventional side, such as combined heat and power (chp). The focus of this article is the intermitting RES-E infeed from wind power. The more the load covered by wind power infeed, the less the needs to be covered by the conventional power market. The fluctuation of the demand, in addition to the fluctuation of the wind power, forms a challenging requirement for the supply system (Nicolosi and Fürsch, 2009).

2.2. The supply side

The flexibility of the supply side is determined by the mix of its installed capacities and the design of its interrelated markets (see, e.g. Stoft, 2002). Base load power plants have high investment costs and low variable costs. Therefore, they require a high utilisation throughout the year to cover investment costs. In addition, these plants are not designed for ramping-up and down regularly since this reduces the lifetime of the parts that are exposed to high levels of pressure and heat. Consequently, a high share of base load plants limits the flexibility of the power system. Furthermore, all thermal power plants have a minimum load. Due to the steam stream they are not able to produce electricity below a particular share. If they are willing to lower the generation below this threshold, they need to shut-off the plant. This minimum-load restriction limits the flexibility considerably, especially when big power blocks are required to stay online.

The integrated design with the interrelated markets can limit market flexibility in several ways. First, the national market for reserve power strongly influences the power system, since it reduces the flexibility by the amount of reserve power, which needs to be held back for system security. If the auctions for the reserve power markets are not efficiently aligned with the wholesale power market, inefficient capacity commitment could be a result (Weber (2009) analyses the intraday market design to integrate wind power). Second, the interaction with international markets through interconnectors influences the power market. Again, if the auction of interconnector capacities is not well aligned with the gate-closure of the spot markets, the auctioned flow direction of the interconnector could deviate from the price delta between the two power markets. This reduces the efficiency of the market results, and therefore, the market flexibility. In this case, inefficient market results are the consequence (for a more detailed analysis of market splitting, see e.g. Brunekreeft et al., 2005; Wawer, 2009).

2.3. Tight market situation

As explained previously, a market situation sometimes becomes critical due to a lack of flexibility. Since this article focuses on negative prices, the situations under consideration have a potential oversupply. In the case of a low load and high wind power infeed, the residual load is consequently quite low. The supply system needs to react to this situation by ramping down, or shutting off, power plants. Until a certain threshold this is not uncommon. However, at a certain point, this "negative flexibility" becomes tight. This means that there is a lack of opportunities to further reduce conventional generation.

A tight market situation occurs when the plants that are online are not allowed to reduce their generation, because they are obligated to supply system services, e.g. through commitments on the reserve power market. In reality, base load plants are also likely to generate, because they are not willing to shut-off the plant due to very high start-up costs and opportunity costs, which arise when prices above variable costs occur in the following hours and the plants cannot start-up in time. The base load induced market tightness varies by season. Since power plants need to be in revision once a year, they usually choose to revise during the season with the lowest demand. During this season, a lower base load share is available meaning that the market becomes more flexible.

2.4. Negative wholesale power prices

Although the possibility of negative prices seems to be counter intuitive for an "ordinary" good, the particular attributes of electricity, primarily the non-economic storage possibilities of large amounts and unit commitment, in combination with the very limited flexibility of demand, lead to the occurrence of bids below variable costs, even negative ones. Before negative price bids were allowed in Germany, oversupply was cut on a pro-rata basis, which led to inefficiency (see the left side of Fig. 1). This oversupply was due to the fact that opportunity costs are marginal cost relevant (Cramton, 2004), e.g. if a power plant needs to ramp-down, additional costs occur for the later ramp-up (e.g. Hofer (2008) quantifies a ramp-up of a combined cycle gas turbine with 2500–5000 €). Therefore, it is efficient to integrate