Energy Policy 87 (2015) 199–215

Contents lists available at ScienceDirect

Energy Policy

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

Market splitting in Germany – New evidence from a three-stage numerical model of Europe

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HIGHLIGHTS

- A three-stage approach to model redispatch and zonal pricing is proposed.
- Energy transition will lead to a tripling of congestion in Germany until 2020.
- Market splitting in Germany substantially reduces redispatch measures.
- Overall welfare gain is negligible, but considerable distributional effects occur.
- The beneficial effects of market splitting depend strongly on its design.

ARTICLE INFO

Article history:
Received 27 February 2015
Received in revised form
4 July 2015
Accepted 12 August 2015
Available online 22 September 2015

Keywords:
Congestion management
Market splitting
Zonal pricing
Redispatch
Market design

ABSTRACT

With the sharp increase in redispatch measures seen during recent years, the importance of an efficient congestion management has increased, particularly in Germany. As the current market design, with a single bidding area, ignores the physical constraints of the transmission grid, there is an ongoing discussion about introducing price zones. Against this background, we develop a three-stage approach to model redispatch and market splitting for Germany while considering interactions with interconnected countries. We identify an increasing spatial imbalance between generation and load and delays in grid extension as being the main drivers for the increase of modeled redispatch volumes from 2012 to 2020. We show that market splitting reduces imminent congestion although results are sensitive to the zonal delimitation and corresponding net transfer capacities. The overall welfare effect is negligible, but price differences between the bidding areas investigated, i.e. one Northern and Southern price zone, result in considerable distributional effects. While consumers in Northern Germany would benefit – producer rents and in particular the value of wind energy would decrease – the opposite is true for Southern Germany. We conclude that market splitting constitutes a solution to reduce redispatch measures as long as transmission grid expansion is further delayed.

1. Introduction

Germany's accelerated nuclear phase out, increasing intermittent electricity production from renewable energy sources (RES) and a grid not keeping pace with these developments, as well as increasing international trading activities, are challenging the European electricity transmission grids and cause increasing difficulties for transmission system operators (TSOs) in daily grid operation. While redispatch[1] in Germany was exceptional in the past, curative congestion management, and especially redispatch, are now more and more necessary to secure grid stability. Since 2011 the number of redispatch measures has substantially increased, albeit from a low level of 1589 redispatch events in 2010.[2] In 2013 the single price zone induced technically infeasible market results of 7965 h[3] forcing the four German TSOs to adjust the market-based generation. The corresponding total redispatch volume covered 4390 GWh while the total redispatch costs amount to 132.6 M€ (cf. BNetzA and BKartA, 2014).

To counter this, provision is made for network expansion as suggested by the German grid development plan (cf. 50Hertz

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[1] ENTSO-E (2012b, p. 9) defines redispatch as follows: “Redispatching means a measure activated by one or several System Operators by altering the generation and/or load pattern, in order to change physical flows in the Transmission System and relieve a Physical Congestion”.

[2] The main reason for the increase seen in 2011 was the moratorium on nuclear power and the corresponding shut-down of Germany's eight oldest nuclear power plants.

[3] Refers to redispatch event hours, not to the total number of hours of a year (cf. Section 2.5 for the definition applied).

http://dx.doi.org/10.1016/j.enpol.2015.08.016
0301-4215/

Transmission GmbH, 2014b) which is based on the legal requirements as stipulated by the German Energy Management Act. Besides grid investments the allocation of the use of scarce transmission capacity provides an alternative solution to manage congestion. Several congestion management schemes such as nodal, zonal and uniform pricing, combined with redispatch but also market coupling, are currently being discussed in academic literature and policy making (cf. for instance Egerer et al., 2015; Kunz, 2013; Neuhoff et al., 2013; Oggioni and Smeers, 2013).

According to textbook economic theory, the first-best answer for an efficient congestion management is nodal pricing as nodal prices not only reflect marginal generation costs but also take the costs of grid constraints into account (cf. Green, 2007; Hogan, 1992; Schweppe et al., 1988). Harvey and Hogan (2000) underline the benefits of nodal pricing, compared to zonal market designs, with particular regard to competition and local market power. While a nodal representation provides transparent market results, zonal pricing systems include (1) a hypothetical intra-zonal unconstrained dispatch step and (2) a redispatch step (in order to deal with technical infeasibilities arising from the previous intra-zonal unconstrained dispatch) and thus require more complex market rules. Consequently, in these steps market power could arise that would not exist in a nodal market. That is what happened in California from 2000 where new resources entered the market and intra-zonal congestion became very frequent and significant. Strategic bidding behavior, through the withholding of capacity in the dispatch market, together with inefficient forward and redispatch markets, lead to a high increase of electricity prices and congestion costs and finally to a blackout (cf. e.g. Alaywan et al., 2004; Joskow and Kahn, 2002).

However, a timely implementation of nodal pricing in Germany or Europe seems unrealistic for several reasons – notably due to the need for a German or Europe-wide Independent System Operator (ISO) and corresponding political obstacles. The implementation of additional bidding zones with regard to physical transmission constraints, or in other words zonal pricing, as for example implemented in the Scandinavian market Nordpool (cf. Bjørndal and Jörnsten, 2001; 2007), could be a preferable interim solution to deal with increasing congestion in Germany (cf. Breuer et al., 2013). In this case no ISO is needed and a faster implementation of the mechanism can be expected. On a national and European level the topic of an alternative bidding zone configuration is currently intensively discussed and investigated (cf. e.g. BMWi, 2014; ACER, 2014; ENTSO-E, 2014a; Breuer et al., 2013). The draft regulatory framework foresees a periodical review of national bidding zones (cf. European Commission, 2015). In this regard an ENTSO-E initiative is currently examining the adequacy of the present bidding zone configuration in Europe (cf. ENTSO-E, 2014a).

In order to be able to evaluate different congestion management schemes for Germany, the development of the congestion situation and the corresponding redispatch volumes in Germany first have to be adequately modeled. This involves two main challenges. First, resulting load flows and congestion as well as available generation capacity for redispatch are particularly affected by the modeling of operating states (on-/off-mode) of generation units. Hence, the modeling of unit-wise redispatch requires an hourly mixed-integer unit commitment model. Second, the stand-alone modeling of Germany is insufficient as intermittent RES generation, changes in market design (such as the implementation of zonal pricing in Germany), and grid expansion, substantially influence electricity flows within the entire European transmission grid. To deal with these conflicting requirements, we develop a three-stage modeling approach for evaluating congestion and redispatch in Germany while considering interactions with interconnected countries. In a first step, a load flow model is used to compute power flow sensitivities and transfer capacities. Subsequently, the dispatch and resulting cross-border flows for the European power system are modeled using a large scale linear dispatch model. Finally, we use a mixed integer dispatch model for the detailed modeling of generation constraints and to compute congestion and redispatch measures.

The focus of our case study is on Germany in 2020. This time horizon is chosen due to its critical nature. While urgent network measures are scheduled for completion by 2020 according to the national grid development plan (50Hertz Transmission GmbH, 2014b), grid expansion is currently delayed by about three years (cf. BNetzA, 2012). Moreover, the institutional implementation of additional bidding zones in Germany is expected to take about three years (cf. Consentec and Frontier Economics, 2011). Besides the evaluation of the congestion situation from a system operation and an economic point of view, we analyze potential benefits from market splitting and highlight the main issues posing challenges to the successful design and implementation of zonal pricing in Germany. Furthermore, distributional effects of market splitting and implications for the integration of RES are discussed.

The paper is organized as follows. After a short review of the relevant literature focusing on the modeling of redispatch and congestion management, in Section 2 we describe our model framework including the applied load flow and dispatch models. Furthermore, we discuss measures chosen to analyze the impact of market splitting and describe the analyzed scenarios. Our model results are shown in Section 3 where we evaluate changes in the congestion situation in Germany from 2012 to 2020 and assess the impacts of market splitting. Section 4 draws the main conclusions for policy makers.

2. Methodology

2.1. Relevant literature

Future congestion management is one of the major market design issues in the European electricity market. The network code and framework guidelines on capacity allocation and congestion management for electricity (CACM) as proposed by ENTSO-E (2012b) and adopted by the European Commission (2015) are a major step in paving the way for efficient congestion management for the whole of Europe. Due to the increased spatial imbalance between generation and load in combination with insufficient grid expansion, congestion management in Germany is of particular interest. In the future, regional imbalances will continue to increase as wind capacity in Northern Germany is added and the accelerated nuclear phase out combined with imminent shutdowns of gas fired plants being out of the money increases scarcity in Southern Germany. So far it has not been possible to investigate a full European power system with a high (hourly) temporal resolution – due to the high dimensionality of the resulting optimization problem (cf. Breuer et al., 2013). Hence, the modeling of redispatch volumes and costs involves necessary but appropriate simplifications.

For instance, Burstedde (2012) uses the cost-minimizing European linear investment and DC grid model NEULING to quantify the difference in total system costs between a first-best nodal and a zonal electricity market design for Europe. Redispatch costs are also calculated within this context. The high temporal resolution of 8760 h a year and the geographical representation of the core European model regions seem to be adequate simplifications with regard to the European focus of the study. However, the linear programming approach allows no detailed modeling of unit-specific constraints such as on-/off-status, minimum run times or minimum generation. Furthermore, the applied partial