Energy 117 (2016) 300–313

Contents lists available at ScienceDirect

Energy

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

How much is enough? Optimal support payments in a renewable-rich power system

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ARTICLE INFO

Article history:
Received 7 December 2015
Received in revised form
16 September 2016
Accepted 18 October 2016

Keywords:
Renewable energy
Support payments
Day-ahead market
Balancing market
Congestion management
Mathematical programming with equilibrium constraints

ABSTRACT

The large-scale deployment of intermittent renewable energy sources may cause substantial power imbalance. Together with the transmission grid congestion caused by the remoteness of these sources from load centers, this creates a need for fast-adjusting conventional capacity such as gas-fired plants. However, these plants have become unprofitable because of lower power prices due to the zero marginal costs of renewables. Consequently, policymakers are proposing new measures for mitigating balancing costs and securing supply. In this paper, we take the perspective of the regulator to assess the effectiveness of support payments to flexible generators. Using data on the German power system, we implement a bi-level programming model, which shows that such payments for gas-fired plants in southern Germany reduce balancing costs and can be used as part of policy to integrate renewable energy.

1. Introduction

In deregulated electricity industries, the expansion of wind and solar power has decreased power prices and, thus, eroded the viability of coal, lignite, and gas-fired conventional electricity generation units [38]. At the same time, the intermittency of renewables and insufficient transmission capacity has increased the need for grid congestion management and flexible conventional generation capacity [35]. Indeed, the lack of flexibility may risk grid stability under scenarios with high load or sudden changes in renewable energy generation.

As a potential solution to the threat to security of supply in the long term, capacity markets to entice conventional power plants have been proposed. In these schemes, an authority ensures a sufficient level of capacity through payments or obligations [18]. On the other hand, [15] envisages an energy-only "electricity market 2.0" scheme that permits high price peaks, develops intraday markets, and promotes new technologies such as demand response, for instance.

As a response to insufficient flexible generation capacity in southern Germany, a regional transmission system operator (TSO), TenneT, and the Federal Network Agency, Bundesnetzagentur, have agreed to compensate fixed costs of two flexible plants via support payments [33]. Therefore, in this paper, we develop a complementarity model to assess the increased dispatch of fast-adjusting conventional capacity through support payments, which, in effect, reduce the bid prices of these generators. Specifically, we cast the sequential model in Ref. [23] as a bi-level problem in which the day-ahead decisions are taken at the upper level and congestion management decisions at the lower level. The latter are guided by the upper-level support payment decisions that the regulator takes in order to minimize the total generation costs. We develop a novel set of constraints to enforce the merit order and cast the problem as a mixed-

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http://dx.doi.org/10.1016/j.energy.2016.10.058
0360-5442/

integer linear program (MILP) by using a linearization technique [13]. Hence, we assess the performance of a recently implemented regulation for a realistic test network via a rigorous mathematical programming approach.

We calibrate the model to the German power system using realistic data and identify the congested parts of the transmission network to provide insights about the geographical distribution of optimal support payments under different demand and renewable energy scenarios. We also test the performance of the optimal decisions by introducing spatially correlated imbalances in the balancing market. Moreover, we contribute to the ongoing debate by comparing the optimal support payments to the nodal pricing mechanism [24] and demonstrate that they lead to similar patterns of generation that reduce re-dispatching. In particular, we find that re-dispatch volumes are halved when support payments are introduced. We also extend the model to multiple time periods to show how support payments mitigate the intermittency of renewables by utilizing the fast-ramping capabilities of the flexible units. Thus, alternative market designs such as support payments and nodal pricing improve the flexibility of the power system and reduce the costs of integrating renewables.

The paper is organized as follows. In Section 2, we discuss complementarity models of electricity markets, the challenges posed by the higher penetration of renewables in the day-ahead and balancing markets, and the relevant policy alternatives. Section 3 presents the structure of our bi-level model, and Section 4 gives numerical results for a model calibrated to the German power system along with sensitivity analysis of the optimal decisions. We provide conclusions on the likely impacts of support payments in Germany and discuss directions for future research in Section 5.

2. Literature review

Complementarity models are often used to analyze electricity markets in which prices are formed endogenously and strategic interactions occur among players. [30] give an overview of these models, and a thorough treatise can be found in Ref. [12]. [25] develop a large-scale perfect competition model of the European electricity market that covers transmission, variable demand, wind power, and pumped storage, for example. In bi-level models, a group of players in the lead role make optimal decisions anticipating the reaction of a group of follower players, e.g., see Ref. [1].

[23] presents a sequential model for Germany with a high level of wind generation in which the production schedules determined by a day-ahead market model ignoring the physical transmission network are fed into a congestion management model, which minimizes the re-dispatch costs, i.e., the costs of relieving congestion. [23] uses data on realistic projections to 2020 of the increase in demand and renewable energy generation in Germany and finds that annual national congestion management costs increase from €40 million to €147 million without transmission grid extensions.

The need for fast-ramping units to balance generation from intermittent renewables is supported by recent empirical data, e.g. [29], show that the variability of wind and solar power increases the volatility of German hourly and daily electricity prices. [19] conclude that there is a dramatic increase in flexibility requirements when the share of renewables of annual electricity consumption exceeds 30%. However, renewable generation has a negative impact on power prices due to its zero marginal costs and prevents the deployment of high-cost flexible plants [39].

Also, [34] show that gas-fired plants are required when short-term variability of renewables is introduced into a long-term German power system model with an 80% emission reduction target. Indeed, gas-fired plants have lower CO_2 emissions and higher fuel efficiency than coal plants [16]. However, major utilities in the UK, France, Germany, and Italy, among others, have recently closed or mothballed gas-fired power plants in response to low profitability [6].

Apart from flexible gas-fired plants, there are several other mechanisms to integrate renewables into power systems. At specific sites, the variability of wind power can be reduced by coupling it with wave power [11]. [37] analyze the economic viability of high-voltage direct current (HVDC) transmission lines from windy northern Germany to load centers in the west and south assuming extensive wind power deployment. They conclude that the welfare gains resulting from full wind power utilization and lower price levels would quickly cover the lines' investment costs. In a similar vein, [20] postulate that the expansion of the cross-border HDVC network allows the hydro-dominant power systems in the Nordic countries to balance the variability of renewable generation in continental Europe by adjusting hydro production. On the demand side, more flexible pricing schemes could also integrate renewables [8]. Likewise, storage and power-to-gas technologies have been explored to increase flexibility [21,31].

Price-based policies, which directly grant the generating capacity a payment, have been implemented in Spain and Italy, for example [3]. In Italy, in particular, the policy aimed to keeping existing capacity in operation and compensates generators when prices are too low [4]. Conversely, quantity-based policies, e.g., as implemented in the UK, determine the capacity payment in an auction to cover a quantity considered to secure supply. Typically, they enforce the availability of the procured capacity by setting a strike price for the spot market price above which the generators need to compensate the regulator [36]. [17] show that capacity payments can reduce the impact of renewable energy generation on the profitability of gas-fired plants and, thus, prevent their mothballing.

By contrast, energy-only policies such as the “electricity market 2.0” concept have the virtue that they minimize interventions in the electricity market. Even under these policies, some kind of back-up reserves are maintained [2]. A BMWi white paper [5] outlines a reserve capacity based mainly on old lignite plants, which are started up when a market price cannot be formed. Moreover, the white paper describes a reserve to relieve congestion in southern Germany.

Conceptually, our model resembles [26] and [22] in using a bi-level approach for integrating renewables by comparing alternative market-clearing schemes. However, we seek to find the optimal trade-off between the least-cost day-ahead market dispatch and the support payments, which have the potential to reduce congestion management and balancing costs by enticing the dispatch of flexible but more expensive power plants.

3. Mathematical formulation

3.1. Notation