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Evaluating the impacts of priority dispatch in the European electricity market

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ABSTRACT

This paper compares the impact of the Nodal Pricing and European Market Coupling organizations on different economic agents of the power system under two main wind policies. Under the "priority dispatch" policy, Transmission System Operators (TSOs) must accommodate all wind energy produced, which thus has the priority over energy produced by conventional plants; in the "no priority dispatch" policy, TSOs can decide not to inject all potential wind power in the grid in order to limit congestion problems. The effects of these two wind policies are measured by developing simple stochastic programming models that consider cases with different wind penetration levels, existing capacities and endogenous investments, as well as assumptions on the EU-ETS.

Our computational experiments show that, when there is "priority dispatch", Nodal Pricing and Market Coupling evolve in a similar way as long as wind penetration is not too high. In contrast, a significant increase of wind penetration causes the collapse of the Market Coupling organization while Nodal Pricing continues to perform well. On the other hand, "no priority dispatch" removes most of the problems resulting from Market Coupling, which still exhibits a slightly lower efficiency than Nodal Pricing. These outcomes do not depend on the contextual assumptions (fixed capacities vs. investment; EU-ETS vs. non EU-ETS) that characterize the several cases analyzed. This suggests that our policy conclusions are robust. Furthermore, our models overestimate the flexibility of conventional plants, which means that these conclusions would likely be reinforced with a more detailed model.

1. Introduction

The development of renewable energy is a key element of European climate policy. A first objective is a 20% penetration of renewable energy by the year 2020 (European Commission, 2009a). A follow up target is an almost full decarbonization of the power system in 2050 (European Commission, 2011a, 2011b). This development takes place in a complex set of policies that involve the restructuring of the gas and power sectors (European Commission, 2009b, 2009c), the Emissions Trading System (EU-ETS) (European Commission, 2009d) and energy conservation (European Commission, 2011c). It is now well accepted that a high penetration of wind generation poses long and short-term problems for the restructured power sector (IEC, 2012). This paper deals with a short-term question at the intersection of the renewable and restructuring policies: we concentrate on some of the grid problems raised by the introduction of intermittent sources in a restructured electricity market organized using the Market Coupling regime that is now emerging as the reference mechanism for managing transmission among European countries.

The problem can be stated as follows. Wind speed and hence wind generation cannot be forecast more than a few hours before actual generation (four hours) (see Foley et al., 2012 for a recent survey). The wholesale electricity market clears a day ahead, that is, much before wind speed is known with any degree of certainty.[1] Real time electricity injections in the grid can drastically differ from those forecasted a day ahead. This may pose grid management difficulties: even though the estimated flows resulting from the clearing of the day-ahead market are normally feasible for the grid,[2] real-time flows can violate grid constraints with extreme deviations from forecasted wind generation. The Transmission System

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[1] An intraday market would mitigate this problem. One is currently in the design phase as stated in ENTSO-E/Europex (2012) and Gence-Creux (2012) contributions on intraday. This market will be built on the new "Flow Based Market Coupling" that has been delayed for several years (see also Gence-Creux's contribution on the matter). It is thus difficult to foresee what the efficiency of that system will be, since experience of the EU power restructuring has in general encountered unexpected difficulties. We accordingly do not include the intraday market in this work.

[2] We explain in Oggioni and Smeers (2013) that TSOs restrict announced "Available Transmission Capacities (or ATCs)" in order to avoid as much as possible countertrading. This policy, which is sustainable in a system with few countries and little wind, becomes more complicated with the multiplication of large zones and wind penetration.

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Operators (TSOs) must then restore feasibility by re-dispatching operations (known as counter-trading). Past experiences with the discontinued zonal system in the US, even with comparatively lower wind penetration (e.g. ERCOT), have shown that counter-trading may be very expensive and even sometimes impossible when discrepancies between day-ahead and real-time injections are too large. Needless to say, larger wind penetration increases the possibility of greater discrepancies between the day-ahead and real-time injections; this in turn requires more counter-trading operations and increases costs. We study the impact of these possible discrepancies in this paper.

Real-time injections result from the dispatch of power generators, including wind generation. Which plants operate depends on the extent to which wind potential exists and is turned into energy. Because wind power is essentially free after the installation of the generation capacity, it may seem natural to use whatever wind energy is available at any moment of time, even if this implies counter-trading. Alternatively, one can allow TSOs to curtail wind generation to decrease expensive counter-trading. We refer to the policy that requires TSOs to accommodate all potential wind generated power as the “priority dispatch” policy. Alternatively, allowing TSOs to reduce wind generation (and hence to spill some potential wind energy) is referred to as the “no priority dispatch” policy. The literature contains many papers modeling the possibility of wind spillage (see, e.g., Morales et al., 2011, 2012) but to the best of our knowledge none of these analyze its impacts on the efficiency of different market organizations. Our paper addresses the question of the viability of “priority dispatch” and “no priority dispatch” policies in Market Coupling and, if viable, which one is preferable from an economic point of view.

We study this question by simulating these two wind priority policies on a stylized representation of part of the European power system. In order to emphasize the role of the market architecture (here Market Coupling), we compare the outcomes of the “priority dispatch” and of “no priority dispatch” policies in Market Coupling with a Nodal Pricing regime. Our models of these systems are highly stylized but they capture two of the essential differences in these market designs. First, the definition of the spot market is different: it takes place in real time in the nodal system but in the day ahead in Market Coupling. The second difference is in the spatial granularity of the grid: the market is cleared at each physical node in the nodal system, using a full description of the grid. It is cleared in virtual nodes or zones in Market Coupling, using a simplified representation of the grid that results from clustering nodes into zones.

Nodal Pricing and Market Coupling thus have different capabilities for accommodating unpredictable wind energy. The objective of the comparison of the “priority dispatch” and “no priority dispatch” policies through numerical experiments is twofold: on one side, we numerically quantify the gain achieved by the switch from the “priority dispatch” to the “no priority dispatch” policy in Nodal Pricing; on the other side, we explore whether the same switch also benefits Market Coupling. In order to assess these potential gains, we analyze different cases using these two market designs. Specifically, we consider four different levels of wind penetration. Because model results always depend on assumptions, we verify the robustness of our results by examining different “contextual cases”. We first consider the alternatives of keeping conventional generation capacities fixed versus allowing for new investment. Because of the importance of carbon policy and the questions that it raises today in European policy, we also consider the alternative system with and without EU-ETS. We conclude that the results of our analysis of the “priority dispatch” and “no priority dispatch” policies on “Nodal Pricing” and “Market Coupling” are robust with respect to these assumptions.

The paper is organized as follows. Section 2 gives a brief introduction to the model and explains major simplifications made with respect to real systems. Sections 3 and 4 respectively present the Nodal Pricing and Market Coupling models developed under the assumptions indicated above. Section 5 contains the case study and the corresponding results for Nodal Pricing and Market Coupling are explained respectively in Sections 6 and 7. Section 8 provides further insight into our analysis. Finally, Section 9 is devoted to conclusions and final comments. Additional model information and results are reported in Appendices.

2. Assumptions and modeling principles

Our analysis compares the performance of two market designs in the presence of wind penetration. The models make important simplifications with respect to reality but retain some of the main differences between the Nodal and Market Coupling organizations. The full set of notation and equations are given in Sections 3 and 4.

We consider a spatial power grid consisting of generation and demand nodes connected by transmission lines. Electricity can be generated using different technologies characterized by capacity and operating costs and CO_2 emissions. The price of emission allowances is exogenous. Capacities can be exogenous or endogenous depending on the case; when endogenous, the model includes the investment costs associated with the amount and type of capacity. We do not model investment in wind generation beyond specifying the wind capacity. Wind injections are exogenous in every case but depend on the installed capacity and wind availability. The models are static and cover a period of one day decomposed into twenty-four hourly segments on which we build different wind scenarios (see Appendix D) and run dispatch models. Investment costs, when relevant, are converted to daily values (annualized costs divided by 365).

This neglects important phenomena related to unit commitment and equipment dynamics (conventional and wind), which become crucial with wind penetration. We return later to the unit-commitment issue and briefly discuss how our simplification can be overcome at the cost of additional and sometimes non-standard computations.

The dispatch models are formulated as welfare maximization problems (computed over twenty-four successive hours) using exogenously given inverted demand and cost functions. The grid is modeled using standard Power Transfer Distribution Factor (PTDF) coefficients (DC approximation of Kirchhoff's laws[3]). Real systems contain security criteria such as N-k reliability, where the system with N components can operate with k contingencies occurring. We neglect these security issues throughout and simply assume a single configuration of the network in all our computations.

Two representations of the grid affect the equilibria. The clearing of the nodal market and counter-trading operations are performed on the (assumed) true representation of the grid. The clearing of the day-ahead market in Market Coupling is conducted on a zonal representation of the grid that is based on an aggregation of nodes and lines. We use expected wind injection in the day-ahead market cleared by Power Exchanges (PXs) with Market Coupling. The nodal-pricing market clears in real time using actual wind injections. Counter-trading is also conducted by TSOs in real time using actual wind injections.

Our models contain considerable simplifications with respect to real systems as we discuss in the next subsections. Specifically, we overestimate the flexibility of conventional plants by not including start-up and shut-down costs, which makes it easier to accommodate wind fluctuation. A more realistic representation of the system would reinforce our conclusions.

2.1. Implications for the Nodal Pricing system

2.1.1. Two settlement system

In contrast with our single, real-time model, nodal markets are organized as two settlement systems (see Stoft, 2002 for a textbook discussion and ISO web sites, e.g. PJM, 2013). The day-ahead market is an auction that commits the units and clears a forward energy market. The real-time market is also organized as an auction but clears energy

[3] See Appendices A.1 and A.2 respectively for Kirchhoff's laws and PTDF functioning.