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Electricity market-clearing prices and investment incentives: The role of pricing rules

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ABSTRACT

Pricing rules in wholesale electricity markets are usually classified around two major groups, namely linear (aka non-discriminatory) and non-linear (aka discriminatory). As well known, the major difference lies on the way non-convexities are considered in the computation of market prices.

According to the classical marginal pricing theories, the resulting market prices are supposed to serve as the key signals around which capacity expansion revolves. Thus, the implementation of one or the other pricing rule can have a different effect on the investment incentives perceived by generation technologies, affecting the long-term efficiency of the whole market scheme.

The objective of this paper is to assess to what extent long-term investment incentives can be affected by the pricing rule implemented. To do so, we propose a long-term capacity expansion model where investment decisions are taken based on the market remuneration. We use the model to determine the optimal mix in a real-size thermal system with high penetration of renewable energy sources (since its intermittency enhances the relevance of non-convexities), when alternatively considering the aforementioned pricing schemes.

1. Introduction

Wholesale electricity market restructuring has been ongoing since the original liberalization processes of electric power sectors started back in early eighties in Chile. Yet, the unavoidable complexities of electricity generation have led to many different market designs and many associated regulatory questions (many of which remain open). In general, each design includes various markets to represent different time-scales in which energy and ancillary services are traded (Batlle, 2013). This sequence of markets could be classified into long-term markets, day-ahead markets (DAM) and intraday plus balancing markets (in the EU) or real-time markets (in the US).

The core of wholesale markets is commonly the DAM, whose purpose is to match generators' offers and consumers' bids to determine electricity prices for each time interval of the following day. However, this can be achieved in a number of different ways and, as mentioned, DAMs evolved very differently in each system. An essential difference lies in the way generators can submit their offers. As explained in detail in Batlle (2013), in the majority of European Power Exchanges, market clearing is built upon simple bids (i.e. generators submit quantity-price pairs per time interval). Although some additional semi-complex conditions can be added to the bids (as for instance block bids linking bids in consecutive time intervals), this approach does not reflect either the real generation cost structure (e.g. the start-up costs) or many of the plant operation constraints (e.g. the start-up trajectory). These features can be explicitly declared in the markets run by US ISOs, where generation agents submit offers representing the parameters and costs that define their generating units' characteristics.

In principle, auctions based on simple bids have the advantage of applying a more straightforward and transparent clearing process to compute prices, but this is obtained at the expense of the efficiency of the economic dispatch.[1] In contrast, complex auctions resort to a traditional centralized unit commitment (UC) algorithm (security constrained

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[1] However, while it is true that the schedule resulting from the clearing of the simple bids in the DAM is often not close to the one that in principle would result from solving a unit commitment problem with perfect information, intraday markets provide market agents with an opportunity to partly correct these potential inefficiencies.

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economic dispatch optimization), with the only difference from the traditional UC problem solved in the non-liberalized context being that the data considered are market agents' bids instead of costs. The downside of complex auctions is that finding a way to compute short-term prices has no obvious solution.

In a complex auction, a uniform[2] price computed as the marginal cost of the economic dispatch solution cannot guarantee total production cost recovery for all generation agents. The marginal cost reflects the variable costs components of the offers but not the fixed cost components that introduce non-convexities in the optimization problem (start-up, no-load cost). This led to different approaches to calculate market-clearing prices that can sufficiently compensate generators for the entirety of their costs; these approaches can be classified into two large groups: non-linear and linear pricing rules.

Non-linear pricing rules (also known as discriminatory) obtain a uniform marginal price (marginal cost) from the unit commitment model and, on top of it, additional side-payments are provided on a differentiated per generation unit basis. Side-payments account for the costs produced by fixed operation costs that generation units could not recover solely through uniform prices.[3]

On the other hand, linear pricing rules (or non-discriminatory) produce a uniform price that includes in it the effect of non-convexities. In the short term, the most important reasons given in favor of linear pricing rules are based on efficiency implications. In particular, linear prices should bring generators' short-term offers closer to their real costs. See for example Hogan and Ring (2003) for further details.

Both of these two pricing approaches support the optimal short-term operation of DAMs but prices also have to serve as the key signal for new investments. Prices do not only compensate for operation costs, in the long run, prices resulting from a well-designed and well-functioning market should allow generators to recover the investment costs. For all inframarginal units, the difference between market prices and their operation costs should be considered a payment to finance their capital costs. Given that the uniform price perceived by all units differs from one pricing rule to the other, so does the remuneration aimed at compensating investment costs and therefore, different investment decisions should in principle be expected under each pricing rule. This long-term consideration should help to discern which of the pricing approaches is more appropriate (Vázquez, 2003). Nonetheless, it has been profusely pointed out by some of the most reputed academic experts in the field that the full long-run incentive effects of these pricing rules are not well understood (Hogan and Ring, 2003; Ring, 1995).

This paper further analyses the long-term impact of different pricing rules in an energy mix if investment is driven by short-term market prices. In particular, we follow the evidence presented by Vázquez (2003) who compared various pricing rules and stated the following: "Although, when exclusively studying operation decisions, it seems that only variable costs need to be considered (in the price formation); when the impact of the price on investment decisions is considered it is observed that it also has to partially include fixed operation costs that produce non-convexities. When including in the price the corresponding part of start-up and no-load cost of the marginal unit, a larger remuneration is given to inframarginal units. These inframarginal units will find a greater long-term incentive to invest, and as a consequence will partially substitute the marginal technology."

Moreover, intermittent renewable energy sources (RES-E) which are expected to reach larger penetration levels in the next decades, can make this discussion more relevant. We build on the foundations of Veiga et al. (2013), who already exposed how RES-E penetration increases conventional thermal plants cycling -augmenting the share of start-up costs in total operation costs- and therefore increases the differences in remuneration perceived under each of the pricing rules, especially for the case of base-load plants. This article, in the light of the increasing share of RES-E in generation mixes, considers a system with a large deployment of intermittent generation and analyses the impact of pricing rules on investments through the application of a very detailed capacity expansion optimization model.

The paper is organized as follows. The general methodology is described in Section 2. A brief revision of necessary background and a mathematical formulation are included in Section 3 in order to complement the description of the method and to detail some calculations. Section 4 presents the results obtained, which are discussed in Section 5, and Section 6 summarizes the outcomes of this research.

2. Material and methods

The approach developed in this paper aims at calculating the perfectly adapted generation mix to be installed in a market context under different pricing rules. We base our analysis on a very detailed long-term greenfield capacity expansion optimization of a real-size case example. Three different thermal generation technologies (Nuclear, CCGT and OCGT) and their detailed costs and operation constraints are considered in the simulation (overnight costs, fuel variable costs, start-up costs, minimum stable load, ramps, etc.). These three technologies are chosen to represent base-load, mid-load, and peak-load plants. The mix is optimized to supply the chronological hourly demand of Spain for 2012 (assumed to be perfectly inelastic). This mix includes a fixed level of RES-E penetration assuming its remuneration is not provided by the DAM but through some additional payment mechanism. The effect of renewable energy sources is represented by means of a high penetration of solar photovoltaic (PV). The exogenous PV production profile has been scaled from the 2012 hourly production profile in Spain and in the short-term simulation the PV power output can be curtailed when needed for optimized operation.

Fig. 1 aims at illustrating the different stages of the implemented methodology, while the following sections detail the operation of each element of the model.

2.1. Module 1: reference generation mix

Module 1 calculates the least-cost energy mix using a traditional capacity expansion model as in a centralized planning case.[4] This energy mix is used only as initial reference for the subsequent search of the perfectly adapted mix corresponding to each of the pricing rules. Since in principle market prices are believed to drive investment towards the least cost generation mix, we assume that the market-based mixes to be obtained later will not deviate substantially from this reference, although as will be described next, we explore up to around 4000 different alternatives.

We build a set of possible mixes by considering all combinations of the three thermal generation technologies which amount to n^3 possibilities (where n is the maximum number of units considered for each technology). In a real size example this produces a number of possibilities in the order of 10^6. We reduce the search by excluding those mixes that significantly deviate from the initial reference to handle some thousand combinations only. This way, the computation time[5] in following modules is minimized while maintaining an extensive set of possible solutions, so that an optimum can be found.

[2] "Uniform" indicates that all generating agents at a given bus are compensated using the same price regardless of their offer.

[3] Note that side-payments resemble a "pay-as-bid" system for non-convex costs, bringing along all its inefficiency issues (Baldick et al., 2005).

[4] The model used in this step includes a detailed representation of both expansion and operation. The formulation is similar to that of presented later in Section 3.1, but the number of units available of each technology is in this case variables to be determined by the problem itself. To do so, obviously associated investment costs are included in the objective function.

[5] It took 2 h and 37 min to analyze the real-size case example presented in this paper. The model was run using CPLEX on GAMS on an Intel Core i7@ 2.8 GHz, 3.5 GB RAM.