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Price computation in electricity auctions with complex rules: An analysis of investment signals☆

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ABSTRACT

This paper discusses the problem of defining marginal costs when integer variables are present, in the context of short-term power auctions. Most of the proposals for price computation existing in the literature are concerned with short-term competitive equilibrium (generators should not be willing to change the dispatch assigned to them by the auctioneer), which implies operational-cost recovery for all of the generators accepted in the auction. However, this is in general not enough to choose between the different pricing schemes. We propose to include an additional criterion in order to discriminate among different pricing schemes: prices have to be also signals for generation expansion. Using this condition, we arrive to a single solution to the problem of defining prices, where they are computed as the shadow prices of the balance equations in a linear version of the unit commitment problem. Importantly, not every linearization of the unit commitment is valid; we develop the conditions for this linear model to provide adequate investment signals. Compared to other proposals in the literature, our results provide a strong motivation for the pricing scheme and a simple method for price computation.

1. Introduction

This paper is concerned with the study of mechanisms to coordinate long- and short-term decisions in power markets. Since often a very relevant part of this coordination happens through the price signal provided by short-run marginal costs, we will revisit the problem with the aim of showing that including start-up costs and other costs related to integer decisions in the definition of short-run marginal costs plays a relevant role in the coordination of system operation and investment.

Specifically, we will discuss the computation of marginal cost when cost functions include binary variables (those with only two possible values: 1 or 0). More precisely, we will focus on day-ahead electricity markets. Generators willing to sell in a day-ahead market face binary start-up and shut-down decisions, which are not yet fixed at the time of bidding and have to be included in the decision-making process. The existence of these binary variables makes cost functions non-convex, which in turn causes the cost derivative to be ill-defined (see Section 2 for details), so the direct application of the standard perfect competition concept of "price equal to marginal cost" is not obvious for this case. Therefore, when start-up variables are present additional criteria have to be used to define price. The existing literature shows a range of different alternatives to do so, each of them leading to different prices. This paper will try to gain insight into the reasons why marginal costs are not clearly defined, with the aim of contributing to the discussion on the choice of the criteria to be used to calculate prices.

The problem of ill-defined prices is especially apparent when the regulator has opted for a market design that is based on a complex auction. The pure complex auction is essentially a traditional unit commitment model, which is applied to clearing power markets (Hobbs, 2001). Therefore, the auctioneer receives bids from generators that include, not only their variable costs and their output capacities, but also their start-up costs, minimum stable loads, ramp rates, and other technical characteristics. The problem of the auctioneer becomes thus a non-convex optimization, so price is not anymore the cost derivative at the optimal solution point, and a number of different proposals arise for price computation.

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Most of the solutions presented in the literature are derived from the algorithms used to solve the mixed-integer optimization problem. Basically, the processes used to compute the optimal solution are translated into price-setting criteria. Since there are many alternative ways to reach the optimal solution (the values of the production for each plant), marginal costs may differ greatly between the different approaches. This paper is aimed to adding some additional criteria to help discriminating between these approaches. Kahn (1970) identified two goals required from prices when fixed costs are involved: i) ensuring efficient accounting-cost recovery, and ii) defining forward-looking opportunity cost and incentives. Almost all of the solutions proposed in the literature for the day-ahead pricing problem focus on the first of them: making sure that all of the generators that are accepted in the auction receive at least their operating costs, so they are willing to produce. We will focus on the second one: providing incentives for future decisions, both for consumers and for investment in new generation plants (Vazquez, 2003). This will allow us to discard some of the proposals already on the table, narrowing the range of mechanisms to be considered.

The problem of investing in power plants can be split into several separate topics. On the one hand, there is plenty of literature regarding the adequacy issue –see for instance Vazquez et al. (2002) or Finon and Pignon (2008)– which focus on how to make sure that there will be enough installed capacity in the system to provide a reasonable level of security of supply. This includes proposals such as capacity remuneration mechanisms, the Value of Lost Load (VOLL) mechanism that was used in the original England and Wales Pool, etc. Our numerical example in Section 3.4 includes a representation of that, showing that the problems associated with lost load are not necessary the same as the ones studied in this paper. We will not address those problems in this paper. Alternatively, we will concentrate on the problem of technology choice, trying to understand how the choices are made to decide which part of the installed capacity will be baseload generators, and which part will be mid-merit, or peaking units. Those decisions are mainly driven by the prices captured at the spot market, so different ways of calculating short-run marginal costs may lead to different technology mixes.

The problem of price computation is not restricted to complex auctions. Many electricity markets have opted for a simple auction in their market design. Under this scheme, bidders just submit to the auctioneer several pairs of price and quantity for each of the hours in the market horizon (typically, one day), and prices can be computed in a clear and unequivocal way just by crossing the aggregated supply and demand curves, for each hour independently. The auctioneer does not have to consider any start-up cost nor binary decision variables when computing prices, and the problem of concern to this paper is apparently not present in simple auctions. However, in a simple auction generators have to internalize into their bids all of the technical characteristics that are not directly taken into account by the auction; for instance, they have to bid above their variable cost in order to incorporate their start-up cost in the price. When preparing such bids, sellers would typically use an optimization model to, among other things, determine how to split their start-up cost among the different hours of the following day or days. And that problem will include start-up decisions, so it will have binary variables, and ill-defined prices. The price definition issue moves from the auctioneer's problem to the bidder's problem, but it is still in place. We will concentrate hereafter in the complex auction case, but the reasoning and conclusions that we will elaborate are of application to the bidder´s problem in a simple auction. Even in other less common designs for the day-ahead market, such as clock auctions (Wilson, 1998), the issue of prices still holds, either at the auctioneer's problem or at the bidder's one.

The increasing role of renewable energy tends to stress the opportunity of this discussion, see for instance (de Sisternes et al., 2015) for numerical simulations of the effects of different pricing rules. On the one hand, more renewable energy requires a larger amount of start-ups and cycling from marginal generators, so the impact of non-convexities on prices will tend to increase and the market will benefit from a refined approach to its computation. On the other hand, we can expect a shift in the investment in new merchant generators, moving from the predominance of near-marginal technologies that we have seen in the latter decades, which are more or less isolated from the pricing problem (see Section 3.1 for details), to a larger share of base-load renewable-based capacity, which bear a much larger impact of using one pricing mechanism or another.

In this paper we will not address the discussion of whether the regulator should adopt a complex or a simple auction, which we assume that depends on the conditions at each market. Also, we will restrict ourselves to a perfect competition situation, ignoring market power, in order to concentrate on the pricing issues linked to non-convexities.

The paper will first present the pricing problem in Section 2, using some simple examples to illustrate why price may not be defined when the only criterion considered is ensuring that generators agree with the centralized dispatch, while reviewing in light of this description the different proposals presented in the literature. Then, we will incorporate into the discussion the criterion of providing incentives for the investment decisions of other generators (Section 3), identifying some additional requirements for the prices. Section 4 will be devoted to discuss the implications of the results obtained, while Section 5 will sum up the conclusions.

2. Statement of the problem and literature review

2.1. A simple example with binary variables

Let us assume a single-hour problem, where demand is d and there are three generators $i=\{i_1, i_2, i_3\}$, with maximum output g_i^{max} and a cost function that only involves a start-up cost ca_i and a variable cost cv_i for each of the generators, being $ca_i < ca_{i+1}$ and $cv_i < cv_{i+1}$. This is a very simple example, but it keeps the essential feature of including binary variables, which are the source of the pricing problems under study. The optimization of the centralized problem is rather easy in this case: if demand is smaller than the capacity of the cheapest generator, then only this one should produce; if demand is higher than the maximum output of the cheapest generator, but smaller than the aggregate capacity of the first and second generators, then the first one should produce at its maximum and the rest of the demand should be provided by the second unit; if demand is larger than the capacity of the first two generators, then both of them should operate at their maximum and the rest of the demand should be produced by the third generator. It results in the curve, presented in Fig. 1, of total production cost as generation increases. The optimal solution is the point where generation is equal to demand.

In a perfect competition context, each generator decides its output by maximizing its income from market sales minus its operating cost. If

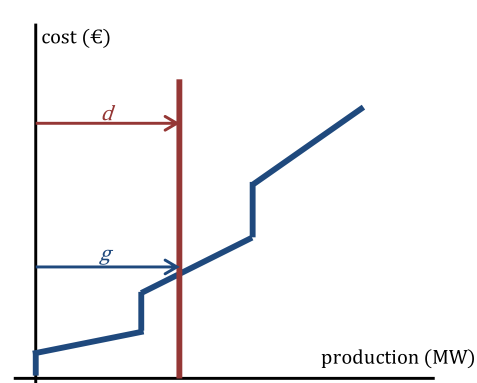

Fig. 1. Production costs as a function of production.