Integrating power and reserve trade in electricity networks (Extended Abstract)

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ABSTRACT

In power markets, the trade of reserve energy will become more important as more intermittent generation is traded. In this work, we propose a novel bidding mechanism for the integration of power and reserve markets. It adds expressivity to reserve bids and facilitates planning[1].

Categories and Subject Descriptors

I.6 [**Computing Methodologies**]: Simulation And Modeling—*Applications, Distributed*

General Terms

Management, Design, Economics, Reliability

Keywords

Energy and Emissions, Simulation, Electronic Markets

1. INTRODUCTION

The currently most popular power market design is to conduct two separate ahead-markets for each hour of the following day, one market to trade binding commitments to transfer power (the *day-ahead market*), and one market to trade optional intervals of power (the *reserve market*). In a real-time balancing phase, the differences between the outcome of the day-ahead market and actual demand are settled by executing parts of the intervals sold in the reserve market. The System Operator (SO) most often functions as the market maker. Formally, during the day-ahead phase, a generator g, with a capacity $\in [P_g^L, P_g^U]$ and a cost function $c_g(P)$, sells a default amount of power P_g^{def} and offers an optional interval $[0, P_g^{opt}]$. During balancing, the SO can execute $P_g^{exe} \in [0, P_g^{opt}]$ per generator g. In both phases combined, g will sell at least P_g^{def} and at most $P_g^{max} = P_g^{def} + P_g^{opt} \leq P_g^U$.

Most research into the co-existence of both markets agrees to clear them simultaneously to avoid market power issues. However, the bids for fixed power and reserves are still made separately, although there is in fact only one product (power capacity) which can be offered in both markets. This causes several problems for bidders. First, as there is only one cost function for this product, then if bids are separated, at least one bid needs to be simplified as long as it is unclear how much capacity each bid will win. Current reserve market designs restrict bids for reserves to only a constant price for each activated unit in P_g^{exe} (sometimes also a fixed price for keeping up to P_g^{opt} available is asked). In addition, the decision which amounts to offer in each of the two markets such that all outcomes respect the upper capacity constraint P_g^U, as well as the resulting calculation of opportunity costs, are difficult issues for the bidding strategies of generators.

The trade volume of reserve power is expected to grow: We are faced with decreasing certainty of supply caused by the advent of intermittent generation, i.e. renewables like solar and wind, and hope to use technologies like storage systems and Demand Response to manage this problem. This paper explores this new research challenge, beginning with the standard use case of reserve capacity offered by supply.

Its main contribution is the proposal of a novel, bundled bid format and an associated clearing mechanism for an integrated power- and reserve market. The bid format allows generators to offer P_g^{opt} with non-constant price functions that can resemble actual costs of production and relieves them of the planning problem for P_g^U. In addition, the SO is enabled to include estimates of $\sum_g^G P_g^{exe}$ in its task to minimise generation and transmission costs. We formulate the two-stage clearing process of the SO as a Strictly Convex Quadratic Programming problem [2], which we have successfully implemented in the well-known electricity network simulation framework AMES [3] (thus incorporating transmission constraints into pricing). We close by introducing a strategy space to include opportunity costs within bids.

2. THE BID FORMAT

Generator g maps amounts of power to total prices via a quadratic bid function. Quadratic functions are widely used to model bids in power markets because they are sufficiently realistic and their derivatives are continuous, and thus marginal prices are well-defined. In traditional day-ahead power auctions, the amounts P_g^{def} for all g are allocated by the SO by announcing a marginal clearing price. To also express bidding for reserve capacity P_g^{opt} within these supply functions, we propose that g fixes the ratio $r = P_g^{opt}/P_g^{max}$ for each bid, such that knowing P_g^{def} determines $P_g^{opt} = P_g^{def}\frac{r}{1-r}$. For example, with $r = \frac{1}{3}$ we denote that

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P_g^{def} will certainly be sold and $[0, P_g^{opt}] = [0, \frac{1}{3} P_g^{def} / \frac{2}{3}]$ is the optional interval. Thus, the reserve interval $[P_g^{def}, P_g^{max}]$ is determined by the market clearing, allowing the SO to price P_g^{def} and P_g^{exe} on the same function and g to include opportunity costs in the bid.

At $r = 0$, no flexibility is offered and the generator has full certainty how much he sells ($P_g^{def} = P_g^{max}, P_g^{opt} = 0$). This resembles traditional bid functions with no reserve offer. At $r = 1$, everything is flexible and the SO will assume full flexibility over P_g^{exe} in the balancing phase ($P_g^{def} = 0, P_g^{opt} = P_g^{max}$). Generator g can place several bids $b_{g,r}$, each using a different $r \in [0, 1]$.

3. THE MARKET MECHANISM

3.1 Optimal dispatch in the day-ahead trade

We now formulate a Constraint Satisfaction Problem for the day-ahead phase. The SO conducts a one-shot auction. Demand is modelled by agents $l \in L$, where L stands for Load-serving-entities (LSE), who only submit the requested amounts for fixed power P_l^{def} and reserve power P_l^{opt}. The SO chooses one bid b_{g,r_g} per generator g and announces a marginal market clearing price γ_{def}, which defines how much each unit in $\sum_g^G P_g^{def}$ will be paid for. The marginal clearing price of the balancing phase γ_{exe} will be higher - its theoretical maximum is known as it will also be determined from the winning bids b_{g,r_g}. Via γ_{def}, each generator can look up on b_{g,r_g} how much power P_g^{def} he is committed to supply and this also tells him how much reserve capacity P_g^{opt} he needs to keep available. The optimisation goal of the SO is to minimise generation costs. One approach is to only minimise the costs which are known for sure in this phase ($\sum_g^G P_g^{def} \gamma_{def}$), another is to include an estimation of the costs of the balancing phase ($\sum_g^G P_g^{exe} \gamma_{exe}$). The first constraint to this optimisation requires that demand is satisfied: $\sum_g^G P_g^{def} = \sum_l^L P_l^{def}$. Secondly, the SO needs to make sure that each generator will stay within his generation limits: $P_g^L \le P_g^{def} \le P_g^U (1 - r_g)$. Each generator agrees to hold back reserve capacity $P_g^{opt} = P_g^{def} \frac{r}{1-r}$. The overall reserve capacity needs to match the demand for reserves. Hence, we add the third constraint $\sum_g^G P_g^{opt} \ge \sum_l^L P_l^{opt}$.

The number of functions each generator can bid is a parameter of the mechanism. This is a trade-off between the time complexity of finding a solution and the freedom of the generators to bid on as many different r as they want.

3.2 Optimal dispatch during balancing

During the real-time phase, LSEs announce their balancing requirements $P_l^{exe} \in [0, P_l^{opt}]$. In order to find γ_{exe} and thereby allocate each generator a value for $P_g^{exe} \in [0, P_g^{opt}]$, the SO translates the interval $[P_g^{def}, P_g^{max}]$ of each successful bid b_{g,r_g} from the day-ahead phase into a new bid function b_g^{bal} in the interval $[0, P_g^{opt}]$. These translated bids are then used to minimise $\sum_g^G P_g^{exe} \gamma_{exe}$.

4. OPPORTUNITY COST ASSESSMENT

Reserve markets should compensate generators for their (lost) opportunity costs of withholding reserve capacity, the computation of which is non-trivial [1]. We assume an approximation can be done via some function $\phi_g(P_g^{opt})$. To include opportunity costs in bids, most approaches (see [4]) either use general *availability costs*, where generators include a one-time fee for providing the reserve capacity interval (\$/MW), or *activation costs*, only adding costs to each unit of reserve capacity that is actually activated in real time (\$/MWh). While the former approach is easier to derive, the latter approach uses no constants which is a needed feature of many quadratic optimisers, like the one AMES uses. We show how the a pure activation strategy as well as mixed strategies can be computed, given the availability strategy.

Let $c_g(P) = aP + bP^2$ be the cost function of generator g. The availability strategy simply shifts the function upwards by $\phi_g(P_g^{opt})$ and thus uses $b_{g,r}^{Av}(P) = c_g(P) + \phi_g(P_g^{opt})$. The activation strategy instead increases the unit price a by some amount a', such that the expected total revenue equals $b_{g,r}^{Av}(P)$, when taking an expected probability distribution D over P_g^{exe} into account.

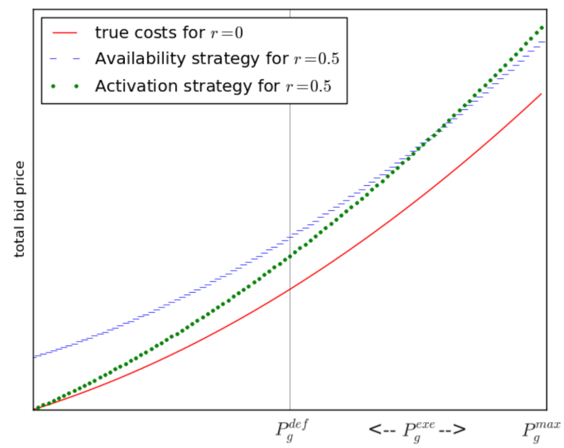

Figure 1: Pricing strategies for opportunity costs

With the availability strategy, the generator carries the risk of underestimating P_g^{exe}, and the demand side carries the risk of him overestimating it, while for the activation strategy it is the other way around. Mixed strategies increase a by a value $\in [0, a']$ and shift the cost function upwards by a value $\in [0, \phi_g(P_g^{opt})]$. As for the activation strategy, g can also use an expected probability distribution to find these values, such that over the interval of possible outcomes for P_g^{exe}, the expected total revenue equals $b_{g,r}^{Av}$.

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