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Prosumer bidding and scheduling in electricity markets

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ABSTRACT

We propose short-term decision-support models for aggregators that sell electricity to prosumers and buy back surplus electricity. The key element is that the aggregator can control flexible energy units at the prosumers. Our objective is total cost minimization by trading in an electricity spot market also taking into consideration costs from grid tariffs, use of fuels and imbalance penalization. We explicitly model the flexibility properties of the underlying energy systems in the prosumers' buildings. In addition, we include the bidding rules and handle the interrelations between hours. Finally, we capture the information structure of uncertain parameters through scenario trees. This results in a two-stage stochastic mixed integer linear program where the bidding decision is made in the first stage and the scheduling in the second. We illustrate the approach in a case study with a diverse portfolio of prosumers. By simulating over a two-month period, we calculate the value of flexibility and the value of stochastic planning.

1. Introduction

Due to technology developments and policy measures intended to combat climate change, electricity markets all over the world are undergoing dramatic changes [1]. One change driver is the integration of non-dispatchable renewable electricity generation from solar photovoltaic and wind power systems. New types of electricity loads for electric vehicles and heating are other such drivers. Some of the consequences are that there is less predictability and faster changes in the generation and loads. Since these changes are taking place in the distribution grid, demand side flexibility is a key resource in order to balance supply and demand, so as to be able to operate the electricity grid within safe limits and to avoid massive investments [2]. According to ENTSO-E [3], the demand side should participate as much as possible in all markets and contribute to overcome system scarcities.

Applicable decision-support models are needed to let the demand side participate actively in the electricity markets and reduce problems with market failure. In Ref. [4] we developed a modelling concept for a single building participating in the end-user market. We split the demand side units according to their flexibility properties: Inflexible loads, shiftable and curtailable loads, dispatchable converters/generators and energy storages. In order to handle multiple energy carriers, we based our approach on the energy hub concept [5].

In this paper, we extend our scope to cover several buildings participating in the wholesale electricity market. We are inspired by the concept of aggregation of smaller consumers [6], but our work is also relevant for single larger consumers. Since we want to cover local generation, we use the term prosumer, defined as a consumer who produces electricity [1].

Many articles focus on optimal integration of local generation, storage and flexible loads in the context of a microgrid or virtual power plant, see for instance [7–15]. We contribute by taking the bidding process and market rules explicitly into account and model the information revelation process for the uncertain parameters.

A comprehensive list of reference work is available regarding generation scheduling, see for instance [16]. However, much of the work focuses only on the scheduling part, without taking the bidding process into consideration. De Laduranetaye et al. [17] empirically demonstrate that models that integrate the bidding process outperform those where the bidding process is disregarded.

Fleten and Kristoffersen [18] determine optimal bidding strategies for a hydropower producer with two power stations in series and with one storage (reservoir) for each station. They assume uncertain market prices and model the decision process as a two-stage stochastic program. Here the bidding decision belongs to

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stage one, while the scheduling decision belongs to stage two, when prices are revealed. They define bidding constraints for piecewise linear hourly bids and for block-bids valid for a number of consecutive hours. In addition, they define the technical constraints for the power stations, the reservoirs and the watercourses. Due to the start-up costs for the power stations, the decision problem becomes a mixed integer linear stochastic program.

Aasgård et al. [19] take this one step further as they also take uncertain inflow into account as well as the fact that in real life the data realizations will not follow any of the predefined scenarios. They also compare a deterministic approach with a stochastic one and report that the mean price earned per produced MWh is higher by explicitly modelling uncertainty.

In current electricity markets, a normal bidding procedure for retailers and large consumers is to bid the expected load independent of the price. There are different reasons for this “flat bid” strategy: small end-users are currently not exposed to time-varying prices, the technical infrastructure for direct control of load is not in place and the price variations during the day and the imbalance penalties are small. We expect this to change in the near future, which increases the value of more advanced bidding procedures.

Compared to the literature covering production side bidding and scheduling, there is little literature focussing on demand side bidding. Among the few publications, the work often simplifies the problem by disregarding the bidding process and only considers the decision for a single hour or avoids the proper representation of the physical properties of the underlying energy system.

The work presented in Ref. [20] covers the bidding process for a retailer in the Norwegian electricity market. A piecewise linear bid curve is constructed for a single hour, taking into consideration uncertain prices and potential penalization from the imbalance market. The load is represented as an inverse demand-function.

In the work by Zare et al. [21] optimal bid curve construction is presented for a large consumer with the possibility for self-generation. They assume uncertain and normally distributed market prices and no auto correlation. No interrelation between hours is treated.

Garnier and Madlener [22] explore the economic benefits that wind and photovoltaic power plant operators can extract from demand-side flexibility. They compare two alternatives: 1) To maximize relative day-ahead market value in view of price developments and 2) intraday operations to minimize costs incurred when balancing forecast errors. Furthermore, in Ref. [23] they optimize volume and timing decisions in the intraday market to balance forecast errors.

In this paper we use the scheduling model outlined in Ref. [4] as our starting point regarding energy systems in buildings with special focus on flexibility properties. Next, we use the concepts from Refs. [18] and [19] to handle the bidding process. However, we use this for a different type of market participant, an aggregator representing a portfolio of prosumers. The aggregator delivers electricity to the prosumers, receives surplus electricity and trades the net demand in a wholesale market, which we denote the electricity spot market. Imbalances between commitments in the spot market and real purchase/sales are settled according to prices and rules from a balancing market. Depending on the regulation in each country, the prosumers may have entered a grid contract with the local grid company. Finally, the prosumers with thermal generators or converters buy fuel from a fuel provider (Fig. 1).

We assume that the aggregator's task is to minimize the costs for the prosumers in total. We leave to further research how the benefits should be distributed between the aggregator and each of the prosumers. Furthermore, we assume that the aggregator is risk neutral and is a price-taker. Risk averse aggregators can still use this approach. Risk can be mitigated by hedging and insurance programs. Reducing risk through changing operating decisions can be costly compared to financial operations [24].

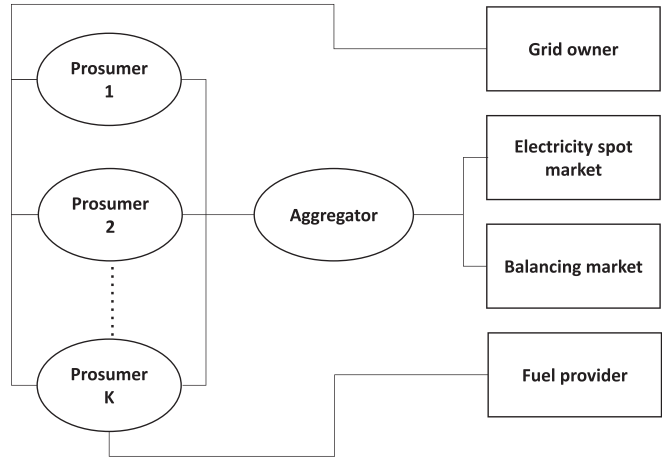

Fig. 1. Overview of the involved entities.

Since we expect market design changes in the future, we keep the model as general as possible. Such changes can be market clearing closer to operation, shorter than one day trading horizons or shorter than 1 h trading periods [25].

The main contribution from this article is the representation of the bidding process seen from demand side taking into consideration the interrelation between hours and the connection to the underlying physical energy system in the portfolio of prosumers. We model the bidding and scheduling process as a two-stage stochastic program, where uncertain parameters are represented in scenario trees. We illustrate this by including a case study where we also calculate the value of flexibility and the value of stochastic planning for a specific Norwegian case simulated over a two-month period.

The remainder of the paper is organized as follows: Section 2 outlines the bidding and scheduling process. The mathematical formulations are presented in Section 3, while Section 4 contains the case study.

2. The bidding and scheduling process

The aggregator has two decisions to make: First, before market gate closure, he needs to decide the optimal bid to send to the spot market for all periods within the trading horizon. Second, he needs to decide the optimal schedules for every flexible unit in the portfolio. Fig. 2 describes this process.

The bid decision must be made under uncertainty, since we do not know what values the prices, loads and generation will have for the periods in the trading horizon. We model the uncertainty explicitly in a two-stage stochastic recourse program [26]. The uncertain parameters are represented by discrete probability distributions in a two-stage scenario tree, as illustrated in Fig. 3. Each path through the tree from the root node (to the left) to one of the leaf nodes (to the right) is called a scenario and represents a possible realization of all the uncertain parameters, see the right hand side of Fig. 7 and Appendix B for examples of scenarios. We assign a probability to each scenario. For more information about scenarios and scenario generation methods, see for instance [26] or [27]. When making the bid decisions (stage one decisions), we take into account the different possible outcomes of the uncertain parameters in the operations phase (stage two). Because the two stages are optimized simultaneously, the bid decisions are made recognizing the expected cost of the operational scenarios.