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Risk-based bidding of large electric utilities using Information Gap Decision Theory considering demand response

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ABSTRACT

The present study presents a new risk-constrained bidding strategy formulation of large electric utilities in, presence of demand response programs. The considered electric utility consists of generation facilities, along with a retailer part, which is responsible for supplying associated demands. The total profit of utility comes from participating in day-ahead energy markets and selling energy to corresponding consumers via retailer part. Different uncertainties, such as market price, affect the profit of the utility. Therefore, here, attempts are made to make use of Information Gap Decision Theory (IGDT) to obtain a robust scheduling method against the unfavorable deviations of the market prices. Implementing demand response programs sounds attractive for the consumers through providing some incentives in one hand, and it improves the risk hedging capability of the utility on the other hand. The proposed method is applied to a test system and effect of demand response programs is investigated on the total profit of the utility.

1. Introduction

The electricity market is performed as an oligopoly market rather than a perfect one, due to some reasons, such as transmission constraints, effect of loss on electricity price, and limited number of Generation Companies (GenCos). Participants of such markets are able to increase their profit by choosing a proper bidding strategy. Finding this strategy in day-ahead market has attracted attention of the power system researchers in recent years. Moreover, the structure of the market and its operating rules might affect such procedure, to a great extent [1].

The bidding strategy methods have structural differences for price-taker and price-maker GenCos. Since the price-maker GenCo's bid influences the market price, analyzing the behavior of other competitors seems necessary for this process. The game-based method has been widely used for the bidding strategy of price-maker GenCos. According to the level of competition, these methods could be categorized into Bertrand, Cournot, and supply function equilibrium (SFE). In Bertrand method, which models competitive markets, price is the strategic variable with no capacity constraints [2]. In the Cournot model, quantity setting equilibrium is used which is more practical [3]. The competition in SFE model is a combination of Bertrand and Cournot methods, in which the price and quantity are chosen simultaneously to set supply function of competitors [4,5]. The problem for price-taker GenCos is simpler because the market price is approximately independent of their bidding strategy. In this method, other participant's behaviors are modeled via market price forecasting [6–10]. Economic effect of price forecasting inaccuracies on short-term operation scheduling of GenCos is studied in [11]. In this sense, uncertainty modeling methods need to be implemented since the generation dispatches and the profit of the companies are very sensitive with respect to the forecasted day-ahead price. These methods can be classified into stochastic and interval-based methods. In the probabilistic methods, probability density function of the uncertain parameter is used in maximization of the expected profit of GenCo [7].

The simplification assumptions of stochastic methods make them capable of handling large problems. The interval-based and scenario-based optimization methods are the two important uncertainty modeling categories, which are employed in the context of bidding strategy. The scenario generation methods simulate the day-ahead price with various numbers of scenarios and try to cover the most probable states [8,12,13]. The risk of uncertain parameters is required to be taken into account for deviation from their forecasted value. Various criteria are proposed in the realm of

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risk management for this purpose. In [14], portfolio optimization is employed for risk modeling in self-scheduling of thermal units. Value at Risk (VaR) and Conditional Value at Risk (CVaR) are the other criteria used, respectively, in [15,16] as measures of risk for self-scheduling problem. Variance of profit, which is more suitable for probabilistic methods, is incorporated in objective function of self-scheduling problem of a price-taker GenCo in [17].

The interval-based optimization methods model the uncertain parameters by assuming a horizon around the predicted values. Information Gap Decision Theory (IGDT) [18] and Robust Optimization (RO) [19] are two kinds of interval-based optimization methods for modeling the uncertain parameters, which are used in power system problems. Interval-based optimization methods model the uncertainties and manage the risk of decision simultaneously. Unlike the scenario-based methods, these methods have no assumption on the density function of uncertain parameters and instead of introducing the probabilistic measure of risk, they guarantee a specified level of profit, which is more user friendly. The IGDT is proposed in [20] for bidding strategy of GenCos and in [21] for self-scheduling of thermal units and in [22] for demand-side scheduling. The RO is implemented for self-scheduling of hydrothermal GenCo in smart grids [23] and hedge the risk of price uncertainty in offering strategy problem [24].

In addition to the mentioned aspects of bidding strategy problem, there could be other options that could also affect this problem significantly. For example, participating in hybrid markets of energy and reserve is investigated in [25,26]. Moreover, the effect of bilateral contracts on competition strategy of GenCos is investigated in [27,28]. The bidding strategy of electric utilities that have generation units and retailer part would be affected by the schedule of the retail part. Two examples of such companies that are assumed to manage retail part beside the generation units are Georgia Power and Alabama Power [29,30]. In this kind of trading, the effect of retail side contracts should be included in day-ahead offering strategy. The day-ahead bidding strategy will be more complicated in the presence of demand response programs (DRP) in retail side contracts. In this situation, the day-ahead bidding curve and selling prices of retail side need to be determined simultaneously. In this paper, a new method is proposed for bidding strategy of companies that manage the generation and retailer sides, at the same time. Pool-based market with Market Clearing Price (MCP) is assumed as the market structure of the present survey. Risk management of this paper is based on IGDT modeling. The proposed IGDT-based method of this paper is formulated as a min–max problem; Genetic Algorithm (GA) and classic optimization are used for solution of the minimization layer and maximization, respectively. Finally, the bidding curve is constructed to guarantee specified profit level in each step.

This paper is organized as follows. Risk neutral formulation of bidding strategy and demand response is presented in Section 2. IGDT-based formulation of the problem and the method of bidding curve construction are presented in Section 3. Numerical studies and discussions using an illustrative seven unit GenCo are provided in Section 4. Finally, concluding remarks are presented in Section 5.

2. Risk neutral formulation

In this section the formulation of generation units and retail side of company is presented. The risk neutral formulation is introduced and the next section discusses the formulation considering risk of price uncertainty. Participation in two markets, day-ahead and retail market, can divide company's profit into two different parts. Therefore, objective of the bidding strategy problem can be written as follows.

$$\max R = \sum_{t=1}^{24}\{R_t^{DA} + R_T^{RTP}\} \tag{1}$$

where R is a total profit of company. R_t^{DA} and R_T^{RTP} represent profit obtained in day-ahead and retail market, respectively.

2.1. Day-ahead market profit

This part of profit comes from selling energy in day-ahead market. In this investigation, it is assumed that the energy price of day-ahead market is forecasted. Assuming no error for the estimated prices, the maximization of GenCo's profit is equivalent to a self-scheduling problem. The formulation of this part is presented in the following.

$$R_t^{DA} = \sum_{t=1}^{24}\{\rho_t P_t^{DA} - C_t\} \tag{2}$$

$$C_t = \sum_{u=1}^{U_g}\{a_u(P_{t,u}^G)^2 + b_u P_{t,u}^G + c_u B_{t,u} + B_{t,u}[1 - B_{t-1,u}]SU_u + B_{t-1,u}[1 - B_{t,u}]SD_u\} \tag{3}$$

$$P_{t,u}^G \le P_u^{\max} B_{t,u} \quad u = 1, 2, \ldots, U_g, \quad t = 1, 2, \ldots, 24 \tag{4}$$

$$P_{t,u}^G \ge P_u^{\min} B_{t,u} \quad u = 1, 2, \ldots, U_g, \quad t = 1, 2, \ldots, 24 \tag{5}$$

$$P_{t,u}^G - P_{t-1,u}^G \le R_u^{up} B_{t,u} \quad u = 1, 2, \ldots, U_g, \quad t = 1, 2, \ldots, 24 \tag{6}$$

$$P_{t-1,u}^G - P_{t,u}^G \le R_u^{dw} B_{t,u} \quad u = 1, 2, \ldots, U_g, \quad t = 1, 2, \ldots, 24 \tag{7}$$

$$B_{t,u} - B_{t-1,u} \le B_{(t+T_{u,j}^{up}),u} \quad u = 1, 2, \ldots, U_g, \quad t = 1, 2, \ldots, 24, \quad j = 1, 2, \ldots, 24 \tag{8}$$

$$T_{u,j}^{up} = \left\{ \begin{matrix} j & j \le Min_u^{up} \\ 0 & j > Min_u^{up} \end{matrix} \right\}, \quad u = 1, 2, \ldots, U_g, \quad j = 1, 2, \ldots, 24 \tag{9}$$

$$B_{t-1,u} - B_{t,u} \le 1 - B_{(t+T_{u,j}^{dw}),u}, \quad u = 1, 2, \ldots, U_g, \quad t = 1, 2, \ldots, 24, \quad j = 1, 2, \ldots, 24 \tag{10}$$

$$T_{u,j}^{dw} = \left\{ \begin{matrix} j & j \le Min_u^{dw} \\ 0 & j > Min_u^{dw} \end{matrix} \right\}, \quad u = 1, 2, \ldots, U_g, \quad j = 1, 2, \ldots, 24 \tag{11}$$

In which, ρ_t is the forecasted price for hour t, P_t^{DA} is the traded power in day-ahead market, $P_{t,u}^G$ is the generated power of unit u in hour t, U_g is the number of generation units, and C_t is an hourly cost of generation. The generation cost of thermal units is modeled as a quadratic function with a_u, b_u and c_u coefficients in (3), which can be generalized to the other types of generation units. $B_{t,u}$ is a binary variable that indicates the ON/Off state of the unit u at time t. As can be interpreted from (3), the star-tup (SU_u) and shut-down (SD_u) cost are added to the cost equation, too. In (4) and (5), the maximum and minimum constraints are modeled, respectively. In these equations, $P_u^{\max}$ and $P_u^{\min}$ represent the upper and lower limits of generation of unit u, respectively. Moreover, the ramp rate constraints are modeled in this formulation by (6) and (7). In these