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Stochastic Price-Based Coordination of Intrahour Wind Energy and Storage in a Generation Company

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***Abstract*—This paper develops a day-ahead price-based scheduling strategy for the coordination of wind and storage units in a generating company (GENCO). The proposed strategy is based on the stochastic price-based unit commitment (PBUC) for the scheduling of wind energy and storage units, which considers volatilities in day-ahead intrahour market prices and wind power generation. The proposed approach firms up the hourly sum of wind and storage unit generation, and mitigates potential wind energy imbalance charges for participating GENCOs in electricity markets. Although the proposed approach would apply to any kind of storage, we consider the pumped-storage (PS) hydro unit as an example in this study. Numerical examples illustrate a GENCO's day-ahead coordinated scheduling results for wind and PS units.**

***Index Terms*—Day-ahead market, generating companies (GENCOs), pumped-storage (PS) hydro units, stochastic price-based unit commitment (PBUC), variable wind power generation.**

NOMENCLATURE

Indices:

h	Index for pumped-storage (PS) units.
k	Index for intrahour intervals.
s	Index for scenarios.
t	Index for hourly scheduling periods.
w	Index for wind energy units.

Functions:

$F_{g,h}$	Water to power conversion function of PS unit h in generation mode.
$F_{p,h}$	Water to power conversion function of PS unit h in pump mode.

Variables:

$I_{g,h,t}$	Commitment status of PS unit h in generation mode at hour t (binary variable; 0: not in generation mode; 1: in generation mode).
$I_{i,h,t}$	Commitment status of PS unit h in idle mode at hour t (binary variable; 0: not in idle mode; 1: in idle mode).
$I_{p,h,t}$	Commitment status of PS unit h in pump mode at hour t (binary variable; 0: not in pump mode; 1: in pump mode).
$P_{h,t}$	Generation dispatch of PS unit h at hour t (MW).
$P_{C,h,t}$	Coordinated generation dispatch of PS unit h and its coordinated wind energy units at hour t (MW).
$P^s_{(\cdot),t,k}$	Generation dispatch of unit at hour t and intrahour k in scenario s (MW).
$P^s_{g,h,t,k}$	Generation dispatch of PS unit h in generation mode at hour t and intrahour k in scenario s (MW).
$P^s_{p,h,t,k}$	Output power of PS unit h in pump mode at hour t and intrahour k in scenario s (MW).
$P_{w,t}$	Generation dispatch of wind energy unit w at hour t (MW).
$P^s_{\Delta,(\cdot),t,k}$	Power imbalance of unit at hour t and intrahour k in scenario s (MW).
$P^s_{\Delta,C,h,t,k}$	Deviation of coordinated dispatch of wind-PS at hour t and intrahour k in scenario s (MW).
$P^{c,s}_{w,t,k}$	Wind power curtailment of wind energy unit w at hour t and intrahour k in scenario s (MW).
$q^s_{h,t,k}$	Net water flow rate of PS unit h at hour t and intrahour k in scenario s (Hm^3/h).
$q^s_{g,h,t,k}$	Water flow rate of PS unit h in generation mode at hour t and intrahour k in scenario s (Hm^3/h).
$q^s_{p,h,t,k}$	Water flow rate of PS unit h in pump mode at hour t and intrahour k in scenario s (Hm^3/h).
$V^s_{h,t,k}$	Reservoir volume of PS unit h at hour t intrahour k in scenario s (Hm^3).
$y_{g,h,t}$	Generation startup indicator of PS unit h at hour t.
$z_{g,h,t}$	Generation shutdown indicator of PS unit h at hour t.
$y_{p,h,t}$	Pumping startup indicator of PS unit h at hour t.
$z_{p,h,t}$	Pumping shutdown indicator of PS unit h at hour t.

Constants:

NH	Number of PS units.
NK	Number of intrahour intervals in one hour.
NS	Number of scenarios.
NT	Number of hours.

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NW	Number of wind energy units.
p^s	Probability of scenario s.
$P^{f,s}_{w,t,k}$	Forecasted generation of wind energy unit w at hour t and intrahour k in scenario s (MW).
$q^{\max}_{g,h}, q^{\min}_{g,h}$	Max/min water flow rates of PS unit h in generation mode (Hm^3/h).
$q^{\max}_{p,h}, q^{\min}_{p,h}$	Max/min water flow rates of PS unit h in pump mode (Hm^3/h).
$RU_{g,h}, RD_{g,h}$	Ramp up/down rate limits of PS unit h in generation mode (MW/h).
$RU_{p,h}, RD_{p,h}$	Ramp up/down rate limits of PS unit h in pump mode (MW/h).
$S_{C,h}$	Set of wind energy units coordinated with PS unit h.
$V^{\max}_h, V^{\min}_h$	Max/min reservoir volume of PS unit h (Hm^3).
ρ_{BP}	Energy balancing price (\$/MWh).
$\rho^s_{\mathrm{DA},t}$	Day-ahead energy price at hour t in scenario s (\$/MWh).
$\rho^s_{\mathrm{DA},t,k}$	Day-ahead energy price at hour t and intrahour k in scenario s (\$/MWh).

I. Introduction

GENERATING companies (GENCOs) with wind energy units could incur imbalance energy charges in real-time markets due to uninstructed deviations of wind power generation from the day-ahead schedule. In practice, wind energy units participate in day-ahead markets as price takers by offering hourly generation quantities that are based on wind speed forecasts [1].

State-of-the-art forecasting models are able to predict the hourly wind power generation with a mean absolute error in the range of 15%–20% of the installed capacity of a wind farm [2]. Such errors may considerably lower the payoff of GENCOs when the scheduled wind power generation cannot be delivered in real-time. Furthermore, the intermittency of wind power generation could make it difficult for wind energy units to take advantage of differences in daily locational marginal prices (LMPs) [3]–[5]. The coordination of energy storage with wind energy is a promising strategy since it not only reduces imbalance energy charges but also improves the dispatchability of wind power generation [6]–[13].

An optimal PS bidding strategy is proposed in [14] which is based on the forecasted market clearing price (MCP) in a competitive electricity market. However, the coordination of energy storage and intermittent wind energy would need to be further addressed. An optimization approach to procure the hourly operation strategy of wind farms located near a small PS generation in a day-ahead energy market is proposed in [15]. In [16], the optimal operation of wind energy unit and PS is investigated from a GENCO's viewpoint considering the volatility of hourly wind power generation and electricity prices in a day-ahead electricity market. The proposed optimization model includes a stochastic analysis of PS and wind power generation in coordinated and uncoordinated schemes. However, the market price volatility and intrahour fluctuations of wind energy would need to be further addressed [17].

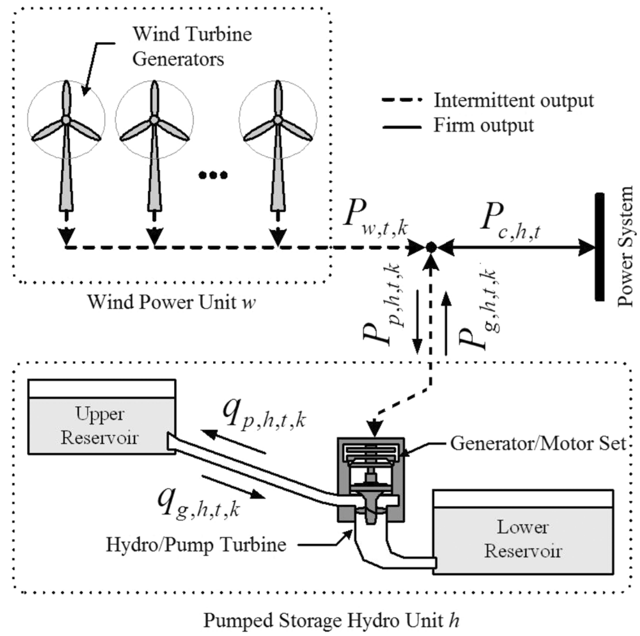

Fig. 1. Coordination of wind energy and PS units.

Hourly or intrahourly variations of load and wind power generation will impose load following and regulation charges on power systems [18]. Imbalance energy charges imposed on wind energy units would compensate the corresponding load following and regulation charges borne by the power system.

In this paper, we apply the stochastic price-based unit commitment (PBUC) to the day-ahead coordinated scheduling of PS and wind energy units in a GENCO [19], [20]. The coordination, depicted in Fig. 1, would firm-up the hourly wind power generation and increase the payoff of wind energy units by mitigating imbalance energy charges. The stochastic PBUC considers day-ahead market price and wind power generation forecast errors in Monte Carlo scenarios. We divide the hourly scheduling period into k intrahour intervals. The auto-regressive moving average (ARMA) time series is used to simulate the intrahour wind speed variations [21]. Artificial neural network (ANN) is used to represent the intrahour price forecasts [22].

The rest of this paper is organized as follows. The stochastic PBUC formulation with wind-PS unit coordination is presented in Section II. Illustrative examples and conclusions are provided in Sections III and IV, respectively.

II. Stochastic PBUC for Wind-PS Unit Coordination

The PBUC formulation with wind-PS unit coordination is presented in this section as a stochastic optimization problem. In this paper, we assume the forecasts for day-ahead hourly energy

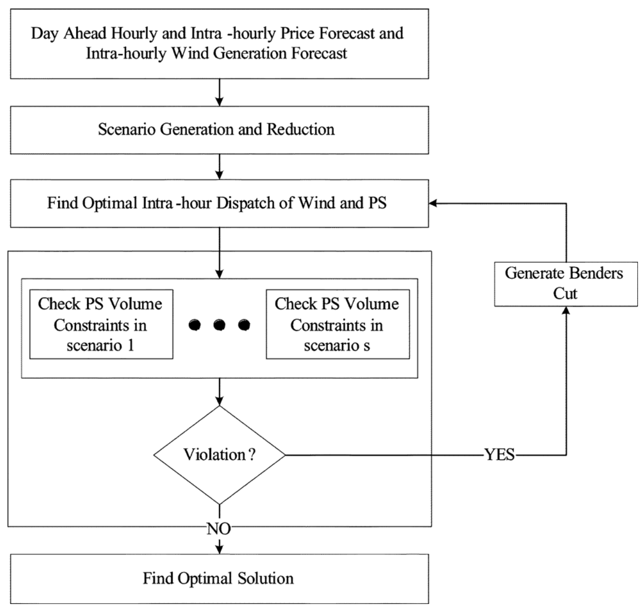

Fig. 2. Proposed GENCO's Stochastic PBUC solution.

prices as well as intrahourly energy price and wind power generation are available. The wind power generation forecast is procured by incorporating power curve of wind turbine and wind speed time series. The wind speed time series is procured by a Markov chain with the probability transition matrix. The probability transition matrix is a square matrix which defines probabilities of transiting from one wind speed category to others. Each wind speed category defines a wind speed range represented by its respective mean value. The probability transition matrix is either constructed by using historical data or by incorporating the characteristics of the probability distribution of the wind speed. Considering the Weibull distribution function and the autocorrelation factor for the wind speed time series, the probability transition matrix is procured by incorporating an initial probability vector, a weighting matrix, and a normalizing vector [23]. Once the probability transition matrix is acquired, Markov chain simulation is used to procure the wind speed time series. In the next step, the diurnal pattern strength is applied to the acquired time series. The diurnal pattern strength which has a sinusoidal form signifies the daily pattern of wind speed. The peak value indicates the ratio of the maximum wind speed to the average wind speed. The wind speed forecast error is further represented by ARMA which is applied to the procured time series [24], [25].

The time series for the market price forecast is procured by using the historical data and ANN. In this paper, the intrahour (5-min) historical data of the ISO New England is used [26]. The Monte Carlo simulation method is applied for generating scenarios. The computation burden in the scenario-based optimization is highly dependent on the number of scenarios. The basic idea of scenario reduction is to eliminate low-probability and bundle similar scenarios [27]–[30]. After scenario reduction, each scenario s is associated with a probability p^s. The scenario input to the stochastic PBUC includes the day-ahead hourly energy price, day-ahead intrahour energy price, and intrahour wind power generation.

The stochastic optimization is decomposed into a master MIP problem and several linear programming (LP) subproblems. Once a solution for the master problem is procured, the subproblems check the volume constraints of PS hydro units in the scenarios. In case of any violation in the scenarios, benders cuts are generated and fed back to the master problem. The decomposition methodology is shown in Fig. 2.

The stochastic PBUC formulation with wind-PS unit coordination is represented by (1)–(28). The objective function (1) maximizes the expected payoff of the coordinated wind-PS schedule which is represented in (2) and (3). The rest of the constraints include wind energy unit constraints (4)–(6) and PS unit constraints (7)–(28). The expected day-ahead payoff (1) represents the weighted revenue from day-ahead energy sales based on day-ahead hourly energy prices, day-ahead intrahourly prices, and coordinated wind-PS hourly and intrahourly schedules:

$$\begin{aligned}\max \sum_{s=1}^{NS} p^s \cdot &\left[\sum_{h=1}^{NH}\sum_{t=1}^{NT}\left(\rho^s_{DA,t}\cdot P_{C,h,t}\right)\right]\\ + p^s \cdot &\left[\frac{1}{NK}\sum_{h=1}^{NH}\sum_{t=1}^{NT}\sum_{k=1}^{NK}\left(\rho^s_{DA,t,k}\cdot P^s_{\Delta,C,h,t,k}\right)\right]\\ - p^s \cdot &\left[\frac{1}{NK}\sum_{h=1}^{NH}\sum_{t=1}^{NT}\sum_{k=1}^{NK}\rho_{\mathrm{BP}}\cdot\left|P^s_{\Delta,C,h,t,k}\right|\right] \end{aligned} \tag{1}$$

s.t.

$$P_{C,h,t} = \sum_{w\in S_{C,h}} P_{w,t} + P_{h,t} \quad \forall h,\forall t \tag{2}$$

$$P^s_{\Delta,C,h,t,k} = P^s_{\Delta,w,t,k} + P^s_{\Delta,h,t,k} \quad \forall h,\forall t,\forall k,\forall s,\forall w\in S_{C,h} \tag{3}$$

$$P^s_{\Delta,w,t,k} = P^s_{w,t,k} - P_{w,t} \quad \forall w,\forall t,\forall k,\forall s \tag{4}$$

$$P^s_{w,t,k} = P^{f,s}_{w,t,k} - P^{c,s}_{w,t,k} \quad \forall w,\forall t,\forall k,\forall s \tag{5}$$

$$P_{w,t} \le \sum_{s=1}^{NS} p^s\cdot\frac{1}{NK}\sum_{k=1}^{NK} P^{f,s}_{w,t,k} \quad \forall w,\forall t,\forall k,\forall s \tag{6}$$

$$P^s_{h,t,k} = P^s_{g,h,t,k} - P^s_{p,h,t,k} \quad \forall h,\forall t,\forall k,\forall s \tag{7}$$

$$P^s_{\Delta,h,t,k} = P^s_{h,t,k} - P_{h,t} \quad \forall h,\forall t,\forall k,\forall s \tag{8}$$

$$P^s_{g,h,t,k} = F_{g,h}\left(q^s_{g,h,t,k}\right) \quad \forall h,\forall t,\forall k,\forall s \tag{9}$$

$$P^s_{p,h,t,k} = F_{p,h}\left(q^s_{p,h,t,k}\right) \quad \forall h,\forall t,\forall k,\forall s \tag{10}$$

$$\begin{aligned}-RD_{g,h}/NK \le P^s_{g,h,t,(k+1)} - P^s_{g,h,t,k} \le RU_{g,h}/NK\\ \forall h,\forall t,\forall k\in[1,NK-1]\end{aligned} \tag{11}$$

$$\begin{aligned}&P^s_{g,h,t+1,1} - P^s_{g,h,t,NK} \le (RU_{g,h}/NK)(1-y_{g,h,t+1})\\ &+F\left(q^{\min}_{g,h}\right)\cdot y_{g,h,t+1}\forall h,\forall t,\forall s\end{aligned} \tag{12}$$

$$\begin{aligned}&(-RD_{g,h}/NK)(1-z_{g,h,t+1}) - F\left(q^{\min}_{g,h}\right)\cdot z_{g,h,t+1}\\ &\le P^s_{g,h,t+1,1} - P^s_{g,h,t,NK} \quad \forall h,\forall t,\forall s\end{aligned} \tag{13}$$

$$\begin{aligned}-RD_{p,h}/NK \le P^s_{p,h,t,(k+1)} - P^s_{p,h,t,k} \le RU_{p,h}/NK\\ \forall h,\forall t,\forall k\in[1,NK-1]\end{aligned} \tag{14}$$

$$\begin{aligned}&P^s_{p,h,t+1,1} - P^s_{p,h,t,NK} \le (RU_{p,h}/NK)(1-y_{p,h,t+1})\\ &+F\left(q^{\min}_{p,h}\right)\cdot y_{p,h,t+1}\forall h,\forall t,\forall s\end{aligned} \tag{15}$$

$$\begin{aligned}&(-RD_{p,h}/NK)(1-z_{p,h,t+1}) - F\left(q^{\min}_{p,h}\right) z_{p,h,t+1}\\ &\le P^s_{p,h,t+1,1} - P^s_{p,h,t,NK} \quad \forall h,\forall t,\forall s\end{aligned} \tag{16}$$

$$z_{g,h,t} + y_{g,h,t} \leq 1 \tag{17}$$
$$y_{g,h,t} - z_{g,h,t} = I_{g,h,t} - I_{g,h,t-1} \tag{18}$$
$$z_{p,h,t} + y_{p,h,t} \leq 1 \tag{19}$$
$$y_{p,h,t} - z_{p,h,t} = I_{p,h,t} - I_{p,h,t-1} \tag{20}$$
$$q^s_{h,t,k} = q^s_{g,h,t,k} - q^s_{p,h,t,k} \quad \forall h, \forall t, \forall k, \forall s \tag{21}$$
$$q^{\min}_{g,h} \cdot I_{g,h,t} \leq q^s_{g,h,t,k} \leq q^{\max}_{g,h} \cdot I_{g,h,t} \quad \forall h, \forall t, \forall k, \forall s \tag{22}$$
$$q^{\min}_{p,h} \cdot I_{p,h,t} \leq q^s_{p,h,t,k} \leq q^{\max}_{p,h} \cdot I_{p,h,t} \quad \forall h, \forall t, \forall k, \forall s \tag{23}$$
$$I_{g,h,t} + I_{p,h,t} + I_{i,h,t} = 1 \quad \forall h, \forall t \tag{24}$$
$$V^s_{h,t,k} = V^s_{h,t,k-1} - \frac{1}{NK} q^s_{h,t,k} \quad \forall h, \forall t, \forall k \in [2, NK], \forall s \tag{25}$$
$$V^s_{h,t,1} = V^s_{h,(t-1),NK} - \frac{1}{NK} q^s_{h,t,1} \quad \forall h, \forall t, \forall s \tag{26}$$
$$V^{\min}_h \leq V^s_{h,t,k} \leq V^{\max}_h \quad \forall h, \forall t, \forall k, \forall s \tag{27}$$
$$V^s_{h,0,NK} = V^s_{h,NT,NK} \quad \forall h, \forall s. \tag{28}$$

The first part in (1) represents the expected day-ahead revenue for the coordinated wind-PS dispatch. The second part represents the incurred expected cost in the day-ahead market, based on the day-ahead intrahour energy price and the deviation of intrahour wind-PS dispatch from the day-ahead hourly schedule. As shown in (2), the coordinated dispatch is the cumulative dispatch of wind energy and PS units. Here, $P_{C,h,t}$ is the hourly PBUC schedule that a GENCO would submit to the ISO in the day-ahead market. The wind-PS power imbalance is the difference between the day-ahead hourly schedule and the intrahour output. The GENCO gets paid extra if the intrahour energy delivery is higher than the hourly day-ahead schedule, and pays to the ISO otherwise. The third term in (1) represents imbalance energy charges for the uninstructed deviation of the coordinated wind-PS power from the hourly day-ahead schedule caused by the intrahour volatility of wind and PS power generation [31], [32].

As shown in (1), the GENCO pays balancing charges based on the energy balancing price and the absolute value of deviation. Once the energy balancing price is high enough, there would be no deviation from the hourly coordinated schedule of wind-PS units and no imbalance energy charge would incur in the day-ahead market. As shown in the numerical cases, the energy balancing price could play a major role in the GENCO's scheduling decision. Note that, the energy balancing price can be different for excesses and shortages of the scheduled coordinated power. For the sake of simplicity, we assume in this paper that the two prices are the same.

In this paper, only the hourly schedule for energy is considered; however, ancillary services could also be included. Moreover, the operation cost of PS units, which include startup and shutdown costs caused by the wear and tear of turbines, are ignored. Note that a PS unit can be coordinated with several wind energy units as shown in (2), where $S_{C,h}$ contains wind energy units coordinated with a PS unit h. Equation (3) represents the deviation of intrahour coordinated dispatch of wind-PS from the day-ahead hourly schedule.

Equation (4) represents the deviation of day-ahead intrahour wind power generation from the hourly generation schedule. The intrahourly wind curtailment is represented in (5) where the wind power forecast is a function of forecasted wind speed. The wind power generation is zero when the wind speed is below the cut-in and above the cut-out levels and it is procured by incorporating the wind turbine power curve as the wind speed is between the cut-in and cut-out limits. The actual wind power that is delivered to the power system in scenario s is equal to the Monte Carlo simulated wind power generation minus the nonnegative curtailed wind power. In order to maintain the generation/load balance, the wind power generation may also be curtailed at the ISO's request. The hourly wind power dispatch in (6) is limited by the expected hourly wind power forecast.

Equations (7)–(28) represent the PS unit constraints at intrahour levels. A PS unit has multiple operating modes including generation, pump, and idle. Each mode is modeled as a pseudo-unit with ramping up/down rate limits, water balance equations, and reservoir limits. Pseudo-units corresponding to the same PS unit are mutually exclusive [20].

Equation (7) shows that the net intrahour dispatch of a PS unit is either the power output in the generation mode or the negative of the consumed power in the pump mode. The deviation of intrahour dispatch from the hourly dispatch is shown in (8). The water-to-power conversion functions are presented in (9)–(10) for the generation mode and the pump mode, respectively. The ramp up/down constraints for the intrahour operation are shown in (11)–(20). The net intrahour water flow rate is defined in (21) as the difference between intrahour generation and pump flow rates, which are constrained by respective lower and upper flow rates in (22)–(23).

Since the switching between operation modes (i.e., generation, pump, idle) would take time, we assume that a PS unit cannot change its operation mode within the same hour. The intrahour generation dispatch of a PS unit can vary every 10 min but its operation mode must be retained for the entire hour. Equation (24) shows that the pump, generation, and idle modes are mutually exclusive.

The intrahour water volume in the PS reservoir shown in (25) is dependent on its previous intrahour value and the net water flow in the present intrahour. In particular, the volume in the first intrahour of each hour shown in (26) is dependent on the volume in the last intrahour of the previous hour and the present net water flow rate. Here, (25)–(26) represent PS reservoirs with no external flows. This implies that the sum of upstream and downstream reservoir volumes is constant; thus, only one reservoir volume (either the upstream or the downstream) is considered. The volume at each intrahour is bound to be between min/max values, as shown in (27). Equation (28) imposes volume limits at the beginning and the end of the period. For the sake of simplicity, the initial and the terminal volumes of reservoirs are assumed to be the same in this paper so that the simulation can be performed using the same assumptions for the next day. The hourly constraints for PS unit are included in the formulation by representing the same set of constraints (9), (10), and (21)–(28) and changing the intrahour indices with the hourly ones.

Equations (1)–(28) represent the coordinated wind-PS formulation, which is converted into a master problem with several subproblems, as shown in Fig. 2. The master problem is a mixed-integer linear programming (MILP) optimization problem and the subproblems are LP problems which are solved by the CPLEX MILP/LP solver. The optimization result is the coordinated wind-PS unit schedule that a GENCO would submit to the ISO. For comparison, we calculate the dispatch of wind and PS units independently (without wind-PS unit coordination). In this case, a GENCO would submit to the ISO a separate schedule for wind energy and PS units. The stochastic PBUC formulation for PS and wind energy units without wind-PS unit coordination is presented in (29), which maximizes the expected payoff of PS and wind energy units separately subjected to the respective unit constraints:

$$\begin{aligned}\max\sum_{s=1}^{NS} p^s \cdot \Bigg[&\sum_{w=1}^{NW}\sum_{t=1}^{NT}\left(\rho_{DA,t}^s \cdot P_{w,t}\right)\\&+\frac{1}{NK}\sum_{w=1}^{NW}\sum_{t=1}^{NT}\sum_{k=1}^{NK}\left(\rho_{DA,t,k}^s \cdot P_{\Delta,w,t,k}^s\right)\\&-\frac{1}{NK}\sum_{w=1}^{NW}\sum_{t=1}^{NT}\sum_{k=1}^{NK}\rho_{BP}\cdot\left|P_{\Delta,w,t,k}^s\right|\\&+\sum_{h=1}^{NH}\sum_{t=1}^{NT}\left(\rho_{DA,t}^s \cdot P_{h,t}\right)\\&+\frac{1}{NK}\sum_{h=1}^{NH}\sum_{t=1}^{NT}\sum_{k=1}^{NK}\left(\rho_{DA,t,k}^s \cdot P_{\Delta,h,t,k}^s\right)\\&-\frac{1}{NK}\sum_{h=1}^{NH}\sum_{t=1}^{NT}\sum_{k=1}^{NK}\rho_{BP}\cdot\left|P_{\Delta,h,t,k}^s\right|\Bigg]. \quad (29)\end{aligned}$$

In this formulation, the payoff of wind and PS units are presented as autonomous terms in the objective function. The first part in (29) represents the day-ahead revenue for wind energy unit w. The second part represents the incurred cost in the day-ahead market based on the intrahour energy price and the deviation of intrahour wind power from the day-ahead hourly schedule. As shown in (4), the wind power imbalance is the difference between the hourly day-ahead schedule and the actual intrahour output. Hence, the GENCO gets paid if the intrahourly energy delivery is higher than the hourly day-ahead schedule, and pays to the ISO otherwise. The third part in (29) represents imbalance energy charges for the uninstructed deviation of delivered wind power from the day-ahead schedule caused by wind power generation variations. As shown, GENCO pays balancing charges based on the energy balancing price and the absolute value of deviation. Similar terms for the PS generation are presented in (29). The objective function is maximized subjected to the constraints (4)–(28) which were presented before.

III. Numerical Examples

To illustrate the proposed PBUC model, we consider a GENCO that has a single wind energy unit and a single PS unit and participates in the day-ahead energy market. The capacity of the wind energy unit is 150 MW and the operating characteristics of the PS unit are provided in Table I. The input to the proposed model includes the day-ahead hourly and intrahourly forecasted market price and wind power. The output is the GENCO's coordinated and uncoordinated generation dispatch schedule for wind and PS units.

TABLE I
Operating Characteristics of the PS Unit

Generation Mode	Minimum Discharge Rate	0.1 Hm³/h
	Maximum Discharge Rate	1.5 Hm³/h
	Maximum Power Output	240 MW
	Minimum Power Output	16 MW
	Ramp Up/Down Rate	250 MW/h
Pump Mode	Minimum Discharge Rate	0.1 Hm³/h
	Maximum Discharge Rate	1.5 Hm³/h
	Maximum Power Output	300 MW
	Minimum Power Output	20 MW
	Ramp Up/Down Rate	250 MW/h
Reservoir Volume	Maximum Volume	20 Hm³
	Minimum Volume	3 Hm³

To consider forecast errors in electricity market prices, we generate 10 000 scenarios using ANN based on the hourly and intrahourly historical data of energy price in the market [26]. The forecasted wind power is procured by synthesizing wind speed time series and adding the wind speed forecast error using the ARMA method. The forecasted wind power generation is procured by applying the power curve of wind turbine. The 10 000 scenarios are then reduced to 13 scenarios using scenario reduction techniques [29], [30]. The 13 scenarios in 10-min intrahour intervals for the forecasted energy price and wind power are depicted in Figs. 3 and 4, respectively. The day-ahead hourly energy price is procured by using the historical data of day-ahead energy prices. The day-ahead hourly forecasted wind power generation is calculated as the expected average intrahourly wind power generation as indicated on the right-hand side of (6).

Four cases are studied in this section. In deterministic Cases 1 and 3, the scenario with highest probability represents the forecasted hourly and intrahourly energy price and wind power. In stochastic Cases 2 and 4, 13 scenarios are considered for energy price and wind power generation. The considered cases are as follows:

Case 1) Deterministic solution without any unit coordination.
Case 2) Stochastic solution without any unit coordination.
Case 3) Deterministic solution with wind-PS unit coordination.
Case 4) Stochastic solution with wind-PS unit coordination.

The four cases are analyzed with respect to the GENCO's payoff, unit commitment, and generation dispatch as follows.

1) Payoff Analysis: Table II shows the total payoff, the wind energy unit payoff, and the PS unit payoff for Cases 1 and 3, and expected payoffs for Cases 2 and 4 once the energy balancing prices is 30 \$/MWh. In this table, the imbalance charges incurred in Cases 3 and 4 were divided equally between the wind energy and PS units. Tables III and IV show the impact of energy balancing price in Cases 1–4 on the total payoff. Based on the results given in Tables II–IV, we offer the following observations.

The first observation is that a stochastic model in comparison with the deterministic solution would result in a lower total payoff and wind energy and PS unit payoffs. For the wind energy unit, if there is no wind-PS coordination and 30 \$/MWh energy balancing price is incurred, the payoff in Case 1 is \$113 580.42 and the expected payoff in the Case

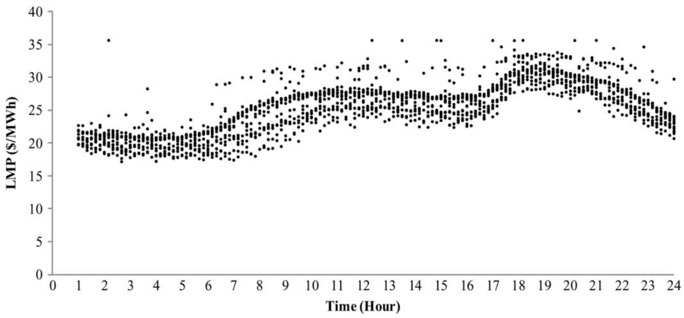

Fig. 3. Forecasted intrahourly energy price in 13 scenarios.

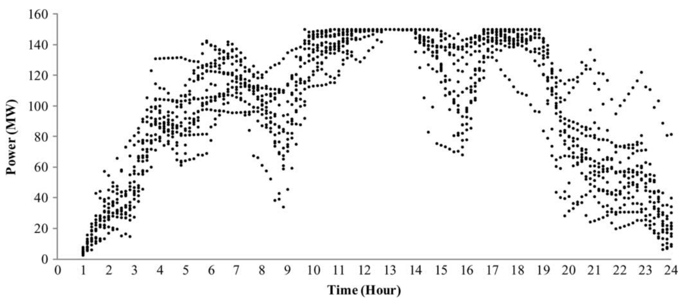

Fig. 4. Forecasted intrahour wind power generation in 13 scenarios.

TABLE II
EXPECTED PAYOFFS ($)

Case	Total	Wind Unit	PS Unit
1	139,563.5	113,580.42	25,983.11
2	110,770.8	92,482.10	18,288.68
3	142,568.9	115,192.74	27,376.16
4	115,556.5	97,233.78	18,322.75

TABLE III
IMPACT OF ENERGY BALANCING PRICE ON PAYOFFS IN CASE 1

Balancing Price ($/MWh)	Day Ahead Energy Sale Revenue ($)	Day Ahead Revenue Adjustment ($)	DA Imbalance Charge ($)	Payoff ($)
0	149,598.75	4,934.05	0	154,532.8
40	145,317.83	-1,781.29	-5,493.97	138,042.6
80	141,718.44	-1,300.58	-6,710.33	133,707.5
120	138,554.00	-890.29	-6,621.07	131,042.6
160	136,701.14	-562.10	-6,974.67	129,164.4

TABLE IV
IMPACT OF ENERGY BALANCING PRICE ON PAYOFFS IN CASE 3

Balancing Price ($/MWh)	DA Energy Sale Revenue ($)	DA Revenue Adjustment ($)	DA Imbalance Charge ($)	Payoff ($)
0	149,598.75	4,934.04	0	154,532.8
40	145,417.30	-1,395.75	-2,005.83	142,015.7
80	143,853.97	-889.10	-2,494.40	140,470.5
120	141,823.83	-402.11	-1,669.13	139,752.6
160	139,546.51	0	0	139,546.5

2 is $92 482.09. The difference between the two payoffs is $21 098.33. The same comparison is applied to Cases 3 and 4 in which the difference between the stochastic and deterministic payoffs is $17 958.96.

For the uncoordinated wind energy and PS units, the differences in total payoff are $28 792.75 and $27 012.37 in Cases 1–2 and Cases 3–4, which show a 20.6% and 18.9% reduction in the total payoff, respectively. In Table II, The deterministic case represents a perfect forecast (i.e., zero forecast error) which indicates that a more accurate forecast would result in higher payoffs. If the deterministic solution of Case 1 is applied to Case 2, the wind, PS, and total payoff are $91 102.651, $17 485.763, and $97 798.822, respectively. The payoffs are higher in Case 2 which indicate the value of stochastic solution. The same applies to Cases 3–4 in which the total payoff in stochastic solution is higher by $1702.813.

The second observation is that the payoffs for wind energy and PS units and the wind-PS coordination are higher than those in the noncoordinated strategy. Table II shows the payoffs for wind energy and PS units and wind-PS are increased from Case 1 to Case 3 by 1.4%, 5.3%, and 2.1%, respectively. In the stochastic solution, the payoffs for wind energy and PS units and wind-PS coordination are increased from Case 2 to Case 4 by 5.1%, 0.2%, and 4.3%, respectively. Here, the coordination can increase the payoff by reducing the intrahour imbalance charges in the day-ahead market.

The third observation is that, as the energy balancing price increases, imbalance energy charges become more expensive and wind power generation curtailment becomes preferable to avoid higher imbalance energy charges. Wind power generation curtailments reduce the day-ahead generation dispatch and decrease the day-ahead energy revenue. Figs. 5 and 6 show the total payoff and day-ahead total sales revenue in Cases 1–4 with respect to energy imbalance charges. The increase in energy balancing price would decrease the day-ahead energy sale revenues when more conservative day-ahead generation schedules are submitted and the total payoff would decrease accordingly.

The fourth observation is that, as energy balancing prices increase, the wind-PS coordination would result in lower imbalance charges. Comparing Tables III and IV, the difference in day-ahead energy imbalance charges is increased between Cases 1 and 3 as the balancing price increases.

In Fig. 7, for energy balancing prices that are less than 20 $/MWh, the energy imbalance charges in coordinated cases will increase with the energy balancing price. In this case, imbalance charges will be compensated by intrahour energy sales. For energy balancing prices that are higher than 30 $/MWh, the wind-PS coordination will decrease the energy imbalance charges.

In Fig. 7, the energy imbalance charge in Case 3 is zero if the energy balancing price reaches 150 $/MWh; however, the imbalance charges are higher in uncoordinated cases and will reach zero when the energy balancing price is 230 $/MWh. Hence the wind-PS coordination is less susceptible to high energy balancing prices and would decrease the imbalance charges more rapidly than the uncoordinated operation schemes.

The balancing price plays an important role in determining the day-ahead payoff of a GENCO. The monthly average energy balancing price may become higher than the spot price in certain cases [32], [33]. As energy balancing prices increase, the difference in day-ahead energy sales and intrahour imbalance charges will increase from Case 1 to Case 3. Once the balancing price

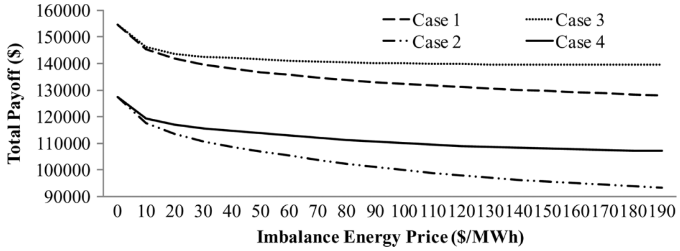

Fig. 5. Total payoff with respect to balancing price.

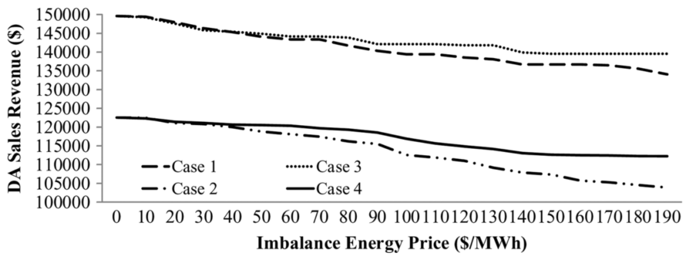

Fig. 6. Day ahead sales revenue with respect to balancing price.

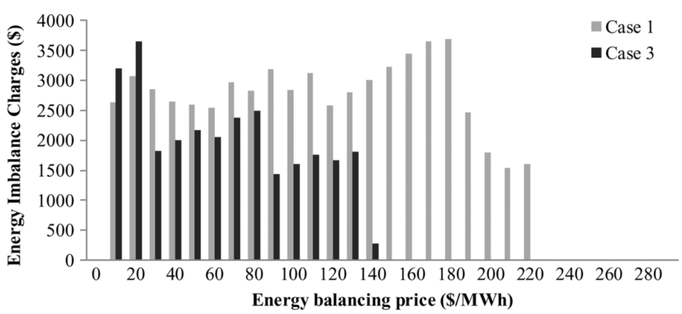

Fig. 7. Energy imbalance charges with respect to energy balancing price.

is zero, the payoffs in Cases 1 and 3 would become the same; however, the payoff in Case 3 is more resilient as energy balancing prices increase.

2) Unit Commitment and Generation Dispatch: The hourly unit commitment for PS is given in Table V. In Cases 1 and 3, the PS unit pumps at hours 1–8 and 23–24 when the energy price is relatively low (see Fig. 3), and generates between hours 9–22 when the energy price is relatively high. Comparing Cases 4 and 2 in which the forecast error is considered, the wind-PS unit coordination would change the unit commitment at hour 22 as shown in Table V. The inclusion of forecast errors may alter the PS unit schedule as shown by comparing Case 3 with Case 4.

In Table V, there is a difference between Cases 3 and 4 at low and high price hours of 9 and 22. In Case 3, the PS unit will generate at those hours while it would switch to pumping in Case 4 to increase the expected payoff.

We offer the following observations which are based on the results presented in Fig. 8 and Table VI.

The first observation is that additional curtailments may be necessary when considering market price and wind speed forecast errors. The wind energy curtailments in Cases 1–4 are 60.554, 140.737, 58.261, and 90.099 MWh, respectively. The stochastic case has a higher wind energy curtailment because a

TABLE V
HOURLY COMMITMENT SCHEDULE OF THE PS UNIT

PS	Hours (1-24)																							
Case 1	-1	-1	-1	-1	-1	-1	-1	-1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-1	-1
Case 2	-1	-1	-1	-1	-1	-1	-1	-1	-1	1	1	1	1	1	1	1	1	1	1	1	1	**1**	-1	-1
Case 3	-1	-1	-1	-1	-1	-1	-1	-1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-1	-1
Case 4	-1	-1	-1	-1	-1	-1	-1	-1	-1	1	1	1	1	1	1	1	1	1	1	1	1	**-1**	-1	-1

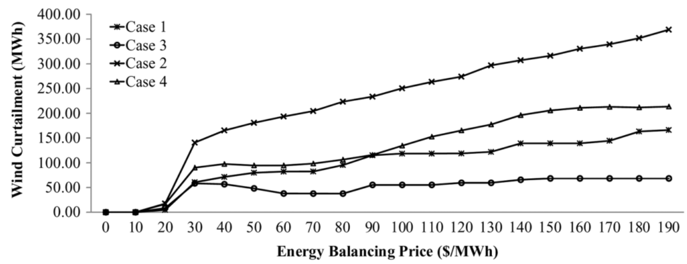

Fig. 8. Wind curtailment with respect to energy balancing price.

GENCO would be more conservative in submitting the generation schedule as it considers the outcome of different scenarios. Comparing Cases 1 and 3 and Cases 2 and 4 in Fig. 8, it is clear that the coordination will help reduce the wind curtailment once the energy balancing price is increased.

The second observation is that according to Table VI, the scheduled PS dispatch is reduced by 4.47 MWh from Case 1 to Case 3 which indicates the effect of wind-PS coordination and the efficiency of PS units in reducing the total dispatched energy. The same notion is applied to the stochastic solution as the PS energy dispatch is reduced by 22.85 MWh from Case 2 to Case 4. The coordination tends to reduce the total generation dispatch. In the deterministic solution, the hourly coordinated dispatch is reduced slightly from 1870 MWh in Case 1 to 1865 MWh in Case 3. The net reduction is caused by a frequent use of the PS unit to compensate the intrahour variations of wind power generation. The effect is a lower generation because of the difference in water-to-power conversion curves of pumping and generation. Also, the coordinated dispatched energy was decreased from 1923.25 MWh in Case 2 to 1902.36 MWh in Case 4. However, the payoff was increased by 4.32%.

The third observation is that the scheduled wind power generation is increased in coordinated cases. The total dispatched wind energy in Cases 1–4 are 2262.53, 2346.92, 2262.53, and 2348.81 MWh, respectively. The reduction in the uncoordinated operation is caused by imposing energy balancing price and intrahour energy price. Note that the energy balancing price is 30 $/MWh in all four cases. The curtailment of wind power generation in Cases 1–4 would increase as the energy balancing price was increased, which would lead to lower payoffs.

IV. CONCLUSION

We proposed a stochastic PBUC solution strategy for the intrahour coordination of wind-PS units when considering the intrahour wind energy and market price forecast errors in a GENCO. The numerical example shows the effect of coordination in deterministic and stochastic case studies. The results show that PS units can be coordinated with wind energy units in order to firm up the wind power generation and to

TABLE VI
DAY-AHEAD HOURLY WIND AND PS UNIT DISPATCH (MWh)

Hour	Case 1			Case 3		
	Total	Wind	PS	Total	Wind	PS
1	-280.00	20.01	-300	-276.1	20.01	-296.10
2	-259.80	40.20	-300	-257.36	40.2	-297.56
3	-223.65	76.36	-300	-222.57	76.36	-298.92
4	-212.83	87.17	-300	-212.83	87.172	-300
5	-206.32	93.68	-300	-203.41	93.68	-297.09
6	-150.94	107.39	-258.3	-155.22	107.39	-262.61
7	37.310	98.98	-61.67	13.99	98.98	-84.98
8	60.420	80.42	-20	52.57	80.42	-27.85
9	117.46	101.46	16	130.94	101.46	29.48
10	189.81	132.14	57.67	180.26	132.14	48.115
11	262.21	146.17	116	255.13	146.17	108.97
12	349.38	150.00	199.4	338.47	150	188.47
13	307.40	149.69	157.7	296.72	149.69	147.03
14	254.85	138.81	11.04	253.08	138.81	114.27
15	182.11	107.73	74.38	203.35	107.73	95.61
16	152.88	120.17	32.71	171.55	120.17	51.38
17	217.15	142.77	74.38	213.14	142.77	70.37
18	259.90	143.86	116.0	255.12	143.86	111.26
19	341.76	101.76	240	341.76	101.76	240
20	306.43	66.43	240	306.42	66.43	240
21	166.11	51.11	115	175.22	51.11	124.11
22	63.68	47.68	16	67.71	47.68	20.03
23	-31.41	30.26	-61.67	-21.03	30.26	-51.29
24	-34.21	28.29	-62.50	-41.66	28.29	-69.95
Total	1,869.70	2,262.53	-392.8	1,865.26	2,262.53	-397.27

Hour	Case 2			Case 4		
	Total	Wind	PS	Total	Wind	PS
1	-283.47	16.53	-300	-274.828	16.53	-291.36
2	-263.09	36.911	-300	-256.23	36.91	-293.14
3	-223.67	76.327	-300	-218.63	76.33	-294.95
4	-208.14	91.86	-300	-206.24	93.75	-300
5	-198.72	101.28	-300	-198.72	101.28	-300
6	-181.74	118.26	-300	-168.92	118.26	-287.17
7	-63.420	111.58	-175	-54.09	111.58	-165.66
8	29.500	91.17	-61.67	21.68	91.17	-69.49
9	91.910	111.91	-20	84.89	111.91	-27.018
10	152.53	136.53	16	162.19	136.53	25.659
11	202.43	144.77	57.67	248.87	144.77	104.12
12	249.04	149.71	99.33	332.22	149.71	182.51
13	290.95	149.95	141	373.81	149.95	223.85
14	309.8	139.13	170.67	330.17	139.13	191.04
15	243.26	114.26	129	279.96	114.26	165.70
16	241.33	126.33	115	246.74	126.33	120.40
17	298.60	141.94	156.67	254.61	141.94	112.67
18	338.90	140.57	198.33	296.27	140.57	155.7
19	339.1	99.1	240	331.76	99.10	232.66
20	308.2	68.2	240	296.17	68.20	227.97
21	172.77	57.77	115	101.30	57.77	43.52
22	70.595	54.59	16	15.56	54.595	-39.035
23	16.875	36.87	-20	-70.14	36.875	-107.02
24	-10.305	31.36	-41.67	-26.05	31.362	-57.408
Total	1,923.25	2,346.92	-423.6	1,902.36	2,348.81	-446.45

take advantage of electricity price volatilities. The imbalance energy charges can reduce a GENCO's expected payoffs which can be fixed by the wind-PS unit coordination. The merits of coordination are more significant as energy balancing price are increased. Thus, the proposed wind-PS unit coordination provides a hedging mechanism to protect GENCOs against wind speed variations. The major contributions of the paper are listed as follows:

1) The intrahour variation of wind power generation is modeled and the PS coordination is proposed to firm the total hourly wind-PS generation.
2) The intrahour variation of energy price is considered for maximizing the GENCO's expected payoff which includes imbalance energy charges and additional intrahour costs.
3) The forecast errors for energy price and wind power are modeled and their impacts on the hourly commitment, generation dispatch, and payoffs are considered.

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