Price based Unit Commitment with Wind Generation and Market Clearing Price Variations

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Abstract: Bidding plays an important role for Gencos (Generation Companies) participating in competitive electricity markets with the objective of maximizing profit. The characteristics of generators and price uncertainty need to be considered while formulating bidding strategies as they have a direct impact on expected profit. The rapid development of wind technology leads to an increasing share of wind power in the market and should be considered for calculating the Market Clearing Price (MCP). In this paper, the effects of wind intermittency on MCP variations of the wind farm generators are considered for the price based unit commitment strategy of the Genco. Simulations are performed on an IEEE 30-bus test system with wind farm that indicate significant corrections in day ahead forecasted PBUC (Price Based Unit Commitment) schedule and real time dispatch schedule of the Genco for optimal bidding.

1 INTRODUCTION

The electric industry throughout the world is undergoing a significant transformation from a vertically integrated framework to a distributed, deregulated and competitive structure consisting of independent generation, transmission and distribution entities. In doing so, the net cost of electricity has been reduced due to increased competition between the market entities. The reliable and efficient operation of this new grid structure is ensured by an independent body known as the ISO (Independent System Operator). The ISO establishes rules for energy and ancillary services markets, manages the system in a fair and non-discriminatory manner and shields the markets from risks and accumulation of market power with a single entity. In order to achieve these goals, the ISO supports different market models namely the PoolCo, Bilateral contracts and Hybrid models. The PoolCo market model is defined as a centralized marketplace that clears the market for power buyers and sellers. Electric power sellers/buyers submit bids to the pool and each bid contains information on how much power, at which prices, in which area, at what time, a market participant is willing to buy or sell. The PoolCo market model is achieved by the Power Exchange (PX) that is integral to the ISO's operation. The PX functions as an independent, non-government and non-profit entity that conducts the auction for electricity trades in the market. The PX calculates the Market-Clearing Price (MCP) based on the highest price bid in the market.

In such a competitive market, Genco (Generation Company) sells electricity to the PX from which large customers such as Discos (Distribution Company) and aggregators may purchase electricity to meet their needs. Along with real power, Gencos also trade reactive power and operating reserves. For successful bidding in the market, Gencos need innovative strategies to determine their optimal bid to maximize revenue and profit targets. Generation schedules covering a range of 24 hours to 1 week ahead achieved through unit commitment, help in formulating optimal bids for a competitive Genco.

In the deregulated power market, a particular type of unit commitment is used by the Genco to optimize generation resources in order to maximize its profit, called the Price Based Unit Commitment (PBUC). In PBUC, satisfying load is no longer an obligation and the objective is of maximizing the profit from trading energy and Ancillary Services (AS) in the market. The distinct feature of PBUC is that the market price

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reflects on all market transactions indicating market price as the only signal that enforces a unit's ON/OFF status and generation dispatch. In day-ahead market Genco runs PBUC based on forecasted energy and ancillary services price, and price uncertainty needs to be considered as it has a direct impact on the expected profit. Several approaches have been used to solve the PBUC problem *viz*. Linear/Non-Linear/Dynamic Programming and other meta-heuristic techniques (Senjyu, 2003- Mantawy, 1997). The PBUC problem has been approached using Lagrangian Relaxation (LR) and Dynamic Programming in (Pokharel, 2005). A tradeoff between LR and Mixed Integer Programming to solve the PBUC is presented in (Li, 2005). A hybrid technique involving LR and evolutionary programming has been used in (Attaviriyanupap, 2003). Intelligent techniques like multi-agent and particle swarm optimization for solving PBUC are presented in (Xiaohui, 2005-Yu, 2004).

Apart from innovative bidding strategies, Gencos have adopted distributed generation resources such as wind farms to their portfolio; to supplement coal/natural gas fired generation and meet green generation mandates thereby maximizing profits. Wind farms present an innovative and clean technology, but their output is intermittent. Wind farms are capital-intensive but have lower operating costs than fossil-fuel plants. Although wind power offers many possible benefits, it has many potential challenges to participate competitively in the current restructured electric industry (Fabbri, 2005-Milligan, 2005). These challenges can be broadly classified into four categories.

- *Network*: The network constraints include geographical locations of wind farms and the capacity of the line/cable infrastructure to extract power at medium and high voltages from remote wind farms.

- *Availability:* For a Genco with wind generation, wind power availability forecast is very essential as it has direct impact on the system performance and stability. A combination of simulation statistical and weather based techniques to predict the quantity of intermittent wind power are presented in (Sideratos, 2007) and (Kariniotakis, 2006). The impacts of wind power variability on system operating costs are not negligible (DeMeo, 2005).

- *Operation:* Large penetration of wind farms introduce significant operational difficulties like reverse power flow, voltage fluctuations and harmonics depending on size and voltage.

- *Pricing:* The uncertainty in wind availability has a direct impact on its pricing which depends on the nature of wind intermittency. Under this scenario, the MCP varies and some approaches to calculate MCP are presented in (Zeineldin, 2009- Singh, 2008). There are different approaches to handle the wind uncertainties in competitive electricity market: probabilistic, stochastic and fuzzy systems. Fuzzy sets have been successfully applied to power system operation and planning to simulate uncertainties (Martin, 2015, Sharma, 2014 and Ting, 2013).

Earlier works have focused on the formulation of the PBUC problem and different optimization techniques to solve it. Several other works have addressed the challenges faced by Gencos owning intermittent energy resources. However, there is not much contribution made towards investigating the effects of wind intermittency on the PBUC schedules of a Genco.

A novel approach to PBUC has been presented in this paper by calculating MCP under varying wind conditions. The relationship between wind intermittency and MCP is used to determine a revised PBUC strategy for a Genco owning wind farms, so as to maximize profits. The paper is organized as follows: Section II proposes the MCP formulation with wind integration. The existing methods for calculating MCP (pay-as-bid market clearing rules, single price market clearing rules and single auction market) and the proposed method (optimal power flow based) for MCP calculations with wind integration are described. Section III presents the PBUC problem formulation and dynamic programming for obtaining the optimal unit commitment schedule. LR method with dynamic programming is used to solve the PBUC problem in this paper. Section IV provides the test system information and results. The IEEE 30 bus system comprising of two Gencos consisting of six generating units G1-G6 and two additional windfarm units is used as the test system. A 24-hour varying output from the two windfarms simulates the intermittency and volatility of wind power. PBUC strategies are developed for the six generating units under different conditions such as a) No wind power b) With rated wind power c) Low wind volatility d) High wind volatility and e) Brief wind intermittency. The resulting effects of wind intermittency on MCP and the PBUC strategies of Gencos are discussed. Section V concludes the discussion.

NOMENCLATURE

p	Price of electricity in \$/kWh.
m_{1j}	Slope of the linear supply curve.
m_{2j}	Slope of the linear demand curve.
N	Number of generating units.
D	Total demand of the system.
j	Index for unit.
p_j	Price Axis Intercept of the Demand curve.
C	Total Generation Cost
F	Total profit of the Genco
P_i	Power output of generator *i*.
$C_i(P_i)$	Cost function of generator *i*.
λ_i	Incremental cost at bus *i*.
ρ	Uniform electricity market price.
P (*j*, *i*)	Generation of unit *j* at time *i*.
R (*j*, *i*)	Spinning reserve of unit *j* at time *i*.
N (*j*, *i*)	Non-spinning reserve of unit *j* at time *i*.
RP (*j*, *i*)	Energy price at the instant *i*.
RR (*j*, *i*)	Spin price at the instant *i*.
RN (*j*, *i*)	Non-Spin price at the instant *i*.
$T^{on}(j)$	Minimum ON time of unit *j*.
$T^{off}(j)$	Minimum OFF time of unit *j*.
$X^{on}(j,i)$	Time duration for which unit *j* has been ON at time *i*.
$X^{off}(j,i)$	Time duration for which unit *j* has been OFF at time *i*.
UR (*j*)	Ramp up limit of unit *j*.
DR (*j*)	Ramp down limit of unit *j*.
L (t, ON)	Lagrangian function at time *i* for ON status.
CL^* (t, ON)	Optimal cumulative Lagrangian at hour *i* for the ON status.
CL^* (t, OFF)	Optimal cumulative Lagrangian at hour *i* for the OFF status.
$SU_{i,t}$	Start-up cost for unit *j* at time *i*.
$SD_{i,t}$	Shutdown cost for unit *j* at time *i*.

2 MARKET CLEARING PRICE FORMULATION

The most common method for MCP formulation for PBUC is based on electricity auction. Most of the earlier works treat wind farms as conventional generators that are paid according to the hourly market price. However, this method is not valid for a Genco with wind resources to bid into the market as the wind intermittency and price variation are not taken into effect while formulating MCP. Existing and proposed methods for MCP formulation are described in detail and the corresponding changes in PBUC schedules of the GENCO are analyzed.

2.1 Existing MCP Formulation based on Electricity Auction

The important aspects of pricing for electricity auction, which are generally used in real-time markets, are listed below:

- *Discriminatory/ pay-as-bid market clearing rules*: Under this rule, every participant pays or is paid at the price of winning bid. In this system, the bidding is made by predicting the cut-off price and not on marginal cost. It may happen such that some of the Gencos having lower energy cost may bid above the cut-off price and some high cost firms would win the bid and the customers have to pay more to obtain the high cost energy. The cost of generation would, therefore, be above the market clearing cost. Pay-as-bid system can increase the total cost of generating electricity and will therefore be less efficient.
- *Uniform/ single price market clearing rules*: This rule is more efficient and commonly used. After receiving bids, ISO aggregates the supply bids into a supply curve (S) and aggregates the demand bids into a demand curve (D) and clears the market by determining the clearing price. The sellers and buyers receive the same clearing price, even if they bid less than this clearing price. The theory behind such a bidding system is that all bids to sell electricity would be priced at the marginal cost of that electricity. In an electricity auction, market clearing price is formulated as the lowest price obtained at the point of intersection of aggregated supply and demand curves. At this price, both the winning generation and demand bids are satisfied and would provide enough electricity to satisfy all purchase bids.
- *For single auction market*, demand bid is not available, the load is assumed to be fixed and only Gencos are participating in the bidding. This auction formulation starts with the energy generated by bidder j, represented as

$$\mathrm{E_j(p)} = {}^{\mathrm{p}}/_{\mathrm{m_{1j}}} \tag{1}$$

The total combined generation can be calculated by,

$$E(p) = \sum E_j(p) = p\sum_{j=1}^{N} {}^{1}/_{m_{ij}} \tag{2}$$

The MCP, p^* can be calculated from,

$$\mathrm{E}(p^*) = D \tag{3}$$

$$p^* = {}^{D}\Big/_{\sum_{j=1}^{N} {}^{1}/_{m_{ij}}} \tag{4}$$

If the capacity limits are considered, then the combined supply curve can be represented as,

$$E(p) = \begin{cases} p\sum_{j=1}^{N} {}^{1}/_{m_{ij}}, & E_{min} \le E \le E_{max} \\ 0, & E \le E_{min} \\ E_{max}, & E_{max} \le E \end{cases} \tag{5}$$

2.2. Developed MCP Formulation with Wind based on Optimal Power Flow

With proper pricing mechanism for MCP determination, the efficiency of the market can be improved. In this paper an MCP formulation is developed to handle the uncertainty in wind availability. The basic concept used for this formulation is that the MCP with and without the wind availability is different. A time series based Optimal Power Flow (OPF) which considers fluctuating wind farm output as and when available is developed. The solution of the optimal power flow determines the new MCP for each instant, which reflects the wind availability for the corresponding instant.

The objective of the standard OPF for an ISO is to maximize social welfare. For a 24-hour period, load and wind generation are varying in each time interval, and the optimization problem can be formulated as

$$min\ C = \sum_{i=1}^{N} C_i(P_i) + C_i(P_{wind}) \tag{6}$$

$$C_i(P_i) = aP_i^2 + bP_i + c \tag{7}$$

Solving this OPF yields the highest value of the bus incremental cost which is now set as the new MCP. Thus,

$$\rho \geq \lambda_i \quad \forall \in 1,2 \dots, N \tag{8}$$

The new MCP, defined by ρ, incorporates the wind generators in the market clearing process. This takes into effect the nature of wind intermittency and its impacts.

3 PRICE BASED UNIT COMMITMENT

3.1 Problem Formulation

The objective of PBUC is to maximize the profit (i.e. revenue minus cost) subject to all prevailing constraints. For unit j at time i, the objective function is given as:

$$\sum_{i=1}^{nhrs} \{(-RP_i^j * P_i^j - RR_i^j * R_i^j - RN_i^j * N_i^j) + C(P_i^j + R_i^j + N_i^j)\} * I_i^j + \{(-RN_i^j * N_i^j) + C(N_i^j)\} * (1 - I_i^j) \tag{9}$$

The first part of the equation represents the profit when the unit is ON and the second part represents the profit when the unit is OFF. Here, profit represents revenue from the non-spinning reserve sales minus production costs and the cost of any energy purchases. Similarly, profit from bilateral contracts would also be included. The objective function for the total time period is

$$max\ F = \sum_j \sum_i F(j,i) \tag{10}$$

The system constraints can be expressed by (11)-(17).

Unit ON

$$N^j - \min(R_{max}^j, P_{max}^j - P^j - R^j) \leq 0 \tag{11}$$

$$P_{min}^j \leq P^j \leq P_{max}^j \tag{12}$$

$$R_{min}^{-j} \leq R^j \leq R_{max}^j \tag{13}$$

$$P_{min}^j \leq P^j + R^j + N^j \leq P_{max}^j \tag{14}$$

Unit OFF

$$P^j = 0 \tag{15}$$

$$R^j = 0 \tag{16}$$

$$N_{min}^j \leq N^j \leq N_{max}^j \tag{17}$$

These constraints represent the special requirements of the Genco like the minimum and maximum generation, ramp rates, quick start and minimum ON–OFF time constraints. The minimum ON time and OFF time constraints are to be implemented in the dynamic programming routine. They can be represented as

$$[X^{on}(j,i) - T^{on}(j)] * [I_{i-1}^j - I_i^j] \geq 0 \tag{18}$$

$$[X^{off}(j,i) - T^{off}(j,i)] * [I_{i-1}^j - I_i^j] \geq 0 \tag{19}$$

The minimum ON–OFF time constraints result in an expanded state transition diagram for the dynamic programming problem. The ramp up and ramp down constraints of the system can be represented as

$$P_i^j - P_{i-1}^j \leq UR(j) \tag{20}$$

$$P_{i-1}^j - P_i^j \leq DR(j) \tag{21}$$

The forward stage of dynamic programming is used to find the optimal cumulative value at every hour for each state described by (22) and (23) while the backward search is used to find out the optimal commitment trajectory.

$$CL^*(t,ON) = min\{CL^*(t-1,ON), CL^*(t-1,OFF) + SU(i,t)\} + L(t,ON) \tag{22}$$

$$CL^*(t,OFF) = min\{CL^*(t-1,ON) + SD(i,t), CL^*(t-1,OFF)\} + L(t,OFF) \tag{23}$$

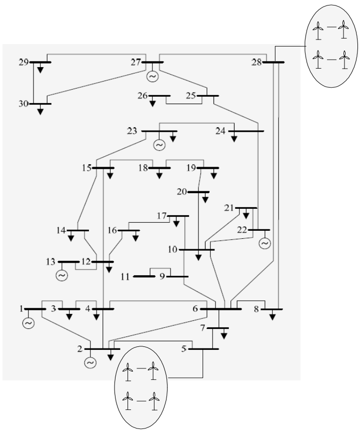

Figure 1: IEEE 30 bus Test System with Wind Farm.

Table 1 (B): Genco II - Generator Data and Constraints.

Parameter	Genco II		
	G4	G5	G6
Unit Type	Coal	Coal	Oil
Pmin (MW)	10	5	10
Pmax(MW)	50	30	55
Ramp Rate(MW/h)	30	15	30
Quick Start (MW)	5	5	1
Minimum ON time (h)	2	2	2
Minimum OFF time	1	1	1
Initial State	OFF	OFF	OFF
Initial Hour (h)	2	2	2
Fuel Price ($/MBtu)	2	2	2
Startup (MBtu)	10	10	10
Cost Coeff. a ($/MWh^2)	0	0	0
Cost Coeff. b ($/MWh)	24	26	25.25
Cost Coeff. c ($/h)	0.0625	0.025	0.0083

4 SIMULATION AND RESULTS

The IEEE 30 bus test system is used to simulate power market operation and the system configuration is shown in Figure 1. The system consists of two Gencos- Genco I and Genco II respectively. Genco I consists of three non-wind generators –units G1, G2 and G3 connected at buses 1, 2 and 13 respectively. Genco II also consists of three non-wind generators – units G4, G5 and G6 connected at buses 22, 23 and 27 respectively. Genco I consists of a wind farm unit G7 with capacity of 59.4 MW at bus 5 and Genco II consists of a wind farm with capacity of 35.6 MW at bus 28. Generator data is listed in Tables I (A) and I (B). The intermittency and volatility of the wind power and time varying loads for a 24 hour period were considered in this study. Figure 2 shows forecasted wind farm output for 24 hours for both the wind farms considered in this paper.

Table 1 (A): Genco I - Generator Data and Constraints.

Parameter	Genco I		
	G1	G2	G3
Unit Type	Coal	Coal	Oil
Pmin (MW)	15	15	10
Pmax(MW)	80	80	50
Ramp Rate(MW/h)	40	40	30
Quick Start (MW)	10	10	1
Minimum ON time (h)	2	2	2
Minimum OFF time	2	2	2
Initial State	ON	ON	ON
Initial Hour (h)	4	4	4
Fuel Price ($/MBtu)	2	2	2
Startup (MBtu)	60	60	30
Cost Coeff. a ($/MWh^2)	0	0	0
Cost Coeff. b ($/MWh)	25	24.75	26
Cost Coeff. c ($/h)	0.02	0.0175	0.0250

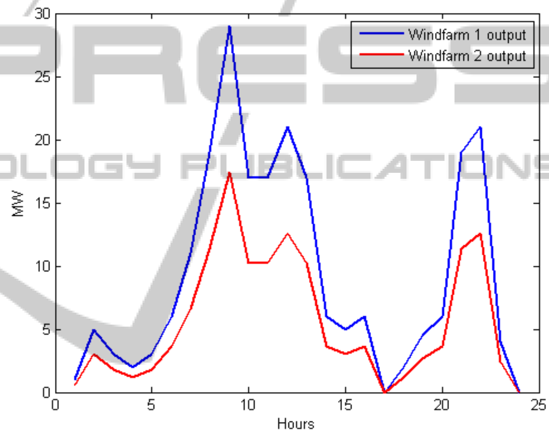

Figure 2: Forecasted Wind farm output.

4.1 MCP Determination using OPF

A 24 hour optimal power flow solution is run for the system with the forecasted wind farm output. In the event of wind power availability, dispatching generators should reduce their outputs to accommodate the wind power in the energy market. Figure 3 shows that the presence of wind generation decreases the incremental cost of the online generators and thereby decreases the MCP. Wind energy, thus has a positive impact on customer benefit. With the new MCP, the PBUC program determines the optimal commitment schedule of the generators. To integrate the effects of uncertainty in wind availability, three wind scenarios were considered. Scenario I assumes low volatility in wind power for the forecasted wind output shown in Figure 3.

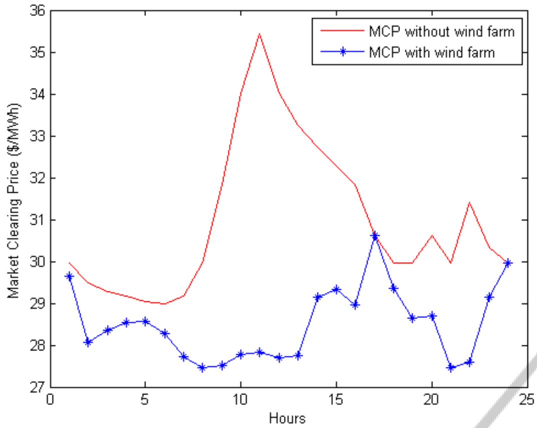

Figure 3: Variation of Market Clearing Price with Wind Integration.

Table 2: 24 HOUR Wind Farm Data.

Wind Power Wind Farm1 MW	Wind Power S-1 MW	Wind Power S-2 MW	Wind Power S-3 MW	Wind Power Wind Farm2 MW	Wind Power S-1 MW	Wind Power S-2 MW	Wind Power S-3 MW
1	0.886	0.85	1	0.6	0.531	0.51	0.6
5	4.55	4.25	5	3	2.73	2.55	3
3	2.67	2.55	3	1.8	1.602	1.53	1.8
2	2	1.7	2	1.2	1.2	1.02	1.2
3	3.07	2.55	3	1.8	1.842	1.53	1.8
6	6.082	5.1	6	3.6	3.649	3.06	3.6
11	10.12	9.35	11	6.6	6.077	5.61	6.6
19	18.97	16.15	19	11.4	11.38	9.69	11.4
29	27.50	24.65	29	17.4	16.50	14.79	17.4
17	17.60	14.45	17	10.2	10.56	8.67	10.2
17	16.23	14.45	17	10.2	9.738	8.67	10.2
21	20.33	17.85	21	12.6	12.20	10.71	12.6
17	17.21	14.45	17	10.2	10.33	8.67	10.2
6	5.565	5.1	6	3.6	3.339	3.06	3.6
5	5.385	4.25	5	3	3.231	2.55	3
6	5.97	5.1	0	3.6	3.582	3.06	0
0	0	0	0	0	0	0	0
2	0	0	0	1.2	0	0	0
4.5	4.2	3.825	0	2.7	2.52	2.295	0
6	6.72	5.1	6	3.6	4.032	3.06	3.6
19	22.16	16.15	19	11.4	13.29	9.69	11.4
21	21.97	17.85	21	12.6	13.18	10.71	12.6
4	3.91	3.4	4	2.4	2.34	2.04	2.4
0	0	0	0	0	0	0	0

Scenario II represents high volatility which follows a normal distribution with a standard deviation of 15%. In Scenario III, the intermittency of wind power is considered during hours 17-20, when the wind power drops to zero. The simulated scenarios for both the wind farms are in Table 2.

4.2 Dispatch with Forecasted Wind Power

With forecasted wind power in Table 2, PBUC determines the dispatch of the non-wind units as detailed in Table 3. For Genco I, PBUC determines units G1, G2 and G3 to be "ON" for hours 1-24 for all scenarios to maximize profit with the initial state of all units being "ON".

Table 3: PBUC Plans For Generators.

Scenario			Hours (0-24)
Forecasted Schedule without Wind	Genco I	Unit G1	1111111111111111111111111
		Unit G2	1111111111111111111111111
		Unit G3	1111111111111111111111111
	Genco II	Unit G4	0111111111111111111111111
		Unit G5	0111111111111111111111111
		Unit G6	0111111111111111111111111
Forecasted Schedule with Wind	Genco I	Unit G1	1111111111111111111111111
		Unit G2	1111111111111111111111111
		Unit G3	1111111111111111111111111
	Genco II	Unit G4	0111111111111111111111111
		Unit G5	0111111111111111111111111
		Unit G6	0111111111111111111111111
Scenario 1 Low Wind Volatility	Genco I	Unit G1	1111111111111111111111111
		Unit G2	1111111111111111111111111
		Unit G3	1111111111111111111111111
	Genco II	Unit G4	0111111111111111111111111
		Unit G5	0111111000000000000000000
		Unit G6	0111111111111111111111111
Scenario 2 High Wind Volatility	Genco I	Unit G1	1111111111111111111111111
		Unit G2	1111111111111111111111111
		Unit G3	1111111111111111111111111
	Genco II	Unit G4	0111111111111111111111111
		Unit G5	0111111000000000000000000
		Unit G6	0111111111111111111111111
Scenario 3 Brief Wind Intermittency	Genco I	Unit G1	1111111111111111111111111
		Unit G2	1111111111111111111111111
		Unit G3	1111111111111111111111111
	Genco II	Unit G4	0111111111111111111111111
		Unit G5	0111111111111111111111111
		Unit G6	0111111111111111111111111

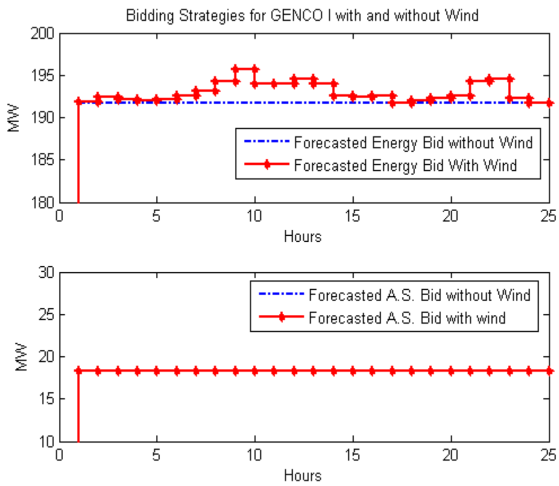

Figure 4(a): Bidding Strategy of the Genco I with and without wind.

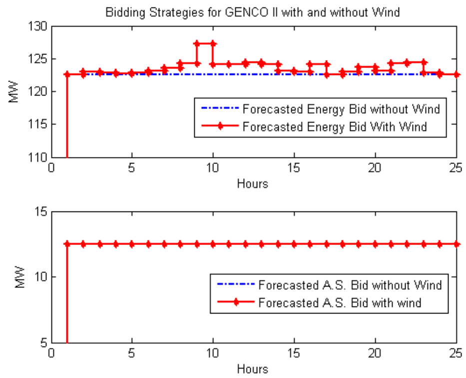

Figure 4(b): Bidding Strategy of the Genco II with and without wind.

For Genco II, the initial state of all units is “OFF” and PBUC determines the units G4 and G6 to be “ON” for hours 1-24 for all scenarios to maximize profit. Unit G5 turns off from hours 7-24 for scenarios I and II. With the availability of wind power, both Genco I and Genco II bid more in the market as shown in Figures 4(a) and 4(b). The ancillary services bid for both the cases remains same because all the units of Genco I and Genco II remain “ON” for hours 1-24, therefore not capable of providing non-spinning reserve. These energy bids with wind are assumed to be contracted by the Genco to the power pool in the day ahead market.

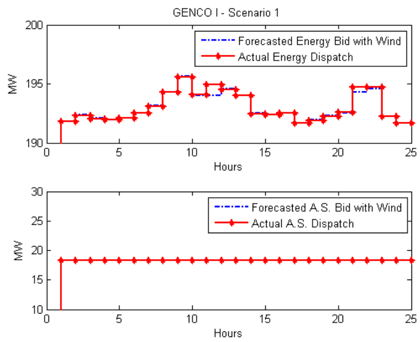

Figure 5(a): Bidding Strategy for Genco I in Scenario I.

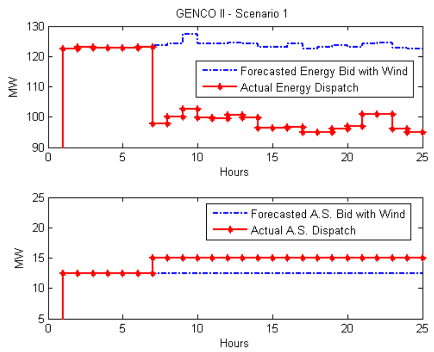

Figure 5(b): Bidding Strategy for Genco II in Scenario I.

4.3 Scenario I: Dispatch with Low Wind Volatility

Scenario I, considers low volatility in forecasted wind power. This challenges the Gencos as changes in the expected wind power may require a re-dispatch from the non-wind generators. The PBUC solution for this scenario in Table 3 shows the commitments of units G1, G2 and G3, G4 and G6 are same as the forecast while unit G5 turns off for hours 7-24 to maximize profits.

Figures 5(a) and 5(b) show the committed dispatch and the actual dispatch for Genco I and Genco II in Scenario I. It is noticed that, due to low wind volatility, the Genco I is able to satisfy its contract for hours 1-24. For Genco II, there is decrease in the dispatch from committed value for hours 7-24 as unit G5 turns “OFF”. The other units, namely G4 and G6 do not have enough ramping and quick start capabilities to increase the dispatch to committed value. The units with faster ramp rate G4 and G6 have a quick start of only 5 MW and 1 MW respectively. For hours 1-24, the ancillary services contract is satisfied by the Genco I. For Genco II there is an increase in the ancillary services dispatch from hours 7-24 as the “OFF” unit G5 provides non-spinning reserve.

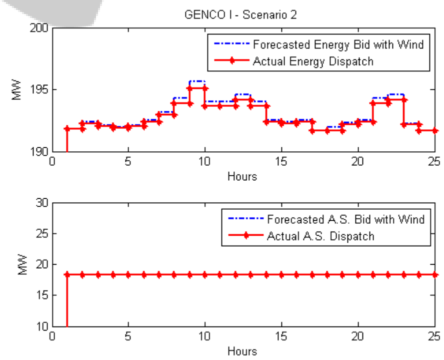

Figure 6(a): Bidding Strategy for Genco I in Scenario II.

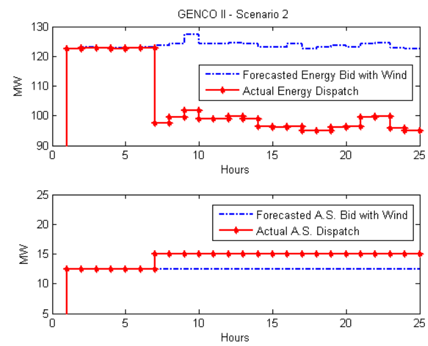

Figure 6(b): Bidding Strategy for Genco II in Scenario II.

4.4 Scenario II: Dispatch with High Wind Volatility

Scenario II, considers high volatility in forecasted wind power. The PBUC solution for this scenario in Table 3 shows the commitments of units G1, G2 and G3, G4 and G6 are same as the forecast while the PBUC schedule turns the unit G5 "OFF" for hours 7-24. Figures 6(a) and 6(b) show the committed dispatch and the actual dispatch for Genco I and Genco II in Scenario II. From hours 1-6 Genco I is still able to maintain the committed value because the higher capacity units G1 and G2 are able to ramp up to meet the volatility. It is noticed that, due to the high volatility of the wind, Genco I violates its contract for hours 6-23.

Similarly, highly volatile wind generation results in Genco II violating its contract with the power pool for hours 7-24 as shown in Figure 6(b) due to insufficient ramping and quick start capabilities of units G4 and G6, with the unit G5 turned "OFF". For hours 1-24, the ancillary services contract is satisfied by Genco I. For Genco II there is an increase in the ancillary services dispatch from hours 7-24 as the "OFF" unit G5 provides non-spinning reserve.

4.5 Scenario III: Dispatch with Wind Intermittency

Scenario III, considers a brief intermittency in forecasted wind power. The PBUC solution for this scenario in Table 3 determines the commitments of all the units to be same as the forecasted commitment to maximize profit.

Figures 7(a) and 7(b) show that the Genco I satisfies the contract during wind intermittency in hours 17-20 by ramping up units G1 and G2. It is evident that in this scenario, the ramp and quick start constraints of G1 and G2 are such that brief wind intermittency can be met by Genco I and satisfy the contracted value. For Genco II, it is evident that the ramp up and quick start capabilities of units G4, G5 and G6 are insufficient to meet the wind intermittency in hours 17-20 thereby resulting in the violation of contract. Ancillary services like spinning and non-spinning reserve can be met by both Gencos, without violation of this contract due to brief periods of wind intermittency. From the three scenarios, it is evident that, Genco I with units having higher ramping and quick start capabilities is able to meet the contract to the power pool during periods of low volatility and brief wind intermittency. Genco II is observed to violate its contract during these scenarios. For highly volatile wind conditions, both the Gencos fail to satisfy the contract in the hours with high wind volatility.

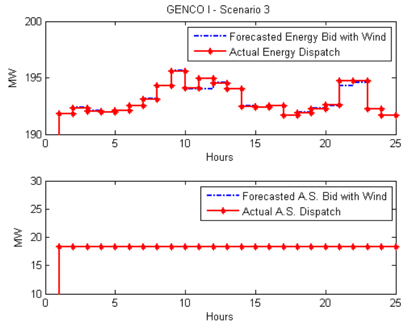

Figure 7(a): Bidding Strategy for Genco I in Scenario III.

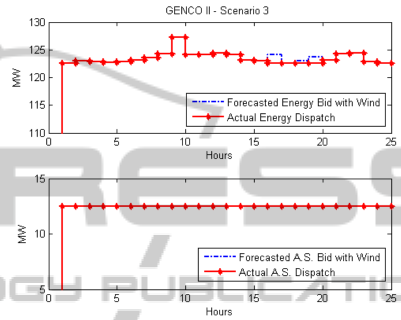

Figure 7(b): Bidding Strategy for Genco II in Scenario III.

The results obtained in this paper compare well with existing literature and provides avenues for future research in the area of PBUC strategies for Gencos owning wind farms. In this paper, it has been shown that the presence of wind generation has a positive impact on the electricity prices and leads to reduction of MCP and incremental cost of generators. This confirms with the detailed MCP studies conducted in in (Sinha, 2008), which state that the accurate wind power prediction and the resulting MCP calculations can result in greater savings for customers and additional revenue for Gencos. It is also demonstrated in this paper that under conditions of low wind volatility and brief wind intermittency, the Gencos will be able to meet their contracts to the power pool if they have sufficient quick start generating units. Under highly volatile wind conditions, the Gencos may fail to meet their power contracts. Wind power can also play a vital role in satisfying the ancillary services contracts to the power market. These results reinforces the studies conducted in (Sinha, 2008) and (Ting, 2013), which prove that uncertainty in wind production is the major factor for Gencos to compete with conventional power producers in the market. In case of non-availability of wind power, Gencos must be ready to supply complete load to be sustainable and recover costs.

5 CONCLUSIONS

A novel approach to PBUC by considering the effects of wind intermittency and market price variations is presented in this paper. The results indicate that the profit of the Genco is largely dependent on the wind intermittency and volatility. The results for the 30 bus system show that the physical limitations of the units such as ramping and quick start are crucial for accommodating the volatility of the wind power. In a wind based power system a tradeoff between security and economy must be achieved such that the security of the system is maintained while the operational cost is minimized. Another option for accommodating wind power volatility is to allocate additional hourly reserves or utilize battery storage. The problem with this option is that the security of the power system may not be guaranteed since the system may not have enough ramping capabilities in real time and the battery may be bound by physical constraints.

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