Combining hydro-generation and wind energy Biddings and operation on electricity spot markets

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Abstract

Wind generation is growing rapidly in all the world, especially in Europe. The power produced by this kind of generation is difficult to predict and the predictions are not very accurate. In most systems these imbalances are costly. These penalties reduce the revenue for the wind generation company (WGENCOs). An option to solve this problem would be to work together with another agent. In this paper, a combined strategy for bidding and operating in a power exchange is presented. It considers the combination of a WGENCO and a hydro-generation company (HGENCO). The mathematical formulation for the optimal bids and for the optimal operation is presented, as well as results from realistic cases.

Keywords: Wind energy; Combined operation; Combined bids; Power exchange

1. Introduction

The great amount of non-dispatchable wind energy connected to the grid has led the regulatory authorities in Spain to promote the integration of this kind of energy in the electricity market. The rules that these producers must follow are the same of any other generator. This means that a wind generation company must make a schedule for the day ahead market, and that penalties must be paid if this schedule is not followed.

This paper presents two methods to minimize these penalties, taking into account the stochastic nature of the primary source of this energy, the wind. The first method is based on a statistical analysis of the expected production probability, in order to minimize the risk of the prediction for the day ahead.

The second one employs a hydro-plant (HGENCO), in order to minimize the penalty for incurring in imbalance.

In both cases, it is assumed that the company (WGENCO and HGENCO) is a price-taker.

1.1. Participation in the pool

The study presented here has been designed for a pool market, where bids must be made once a day and corrected in intraday markets. Bilateral contracts are not considered.

Two different hypotheses are studied. The first one considers a single daily auction, i.e., bids can be presented only once a day (1A). The second one considers several daily auctions (SA). An illustration of both cases is presented in Figs. 1 and 2.

In the example the following values will be used: $tdi = 14$ h, $tdf = 38$ h for single daily auction (1A) and $tdi = 4$ h and $tdf = 8$ h for several auctions (SA, 6 auctions per day in this case).

1.2. Penalties for imbalance

According to the Spanish regulation [1], those agents incurring in imbalances must pay the cost of this imbalance. This value is going to be expressed in this paper as a penalty proportional to the market price of energy. This approach is valid if this percentage is estimated somehow in advance.

In order to calculate the expected penalty it is necessary to forecast the day ahead energy prices [2–4]. In this paper a perfect price forecasting will be assumed.

1.3. Wind power prediction

In order to decrease the amount of the penalty for imbalance it is necessary to use a short term wind power prediction tool [5,6]. The simplest prediction tool is persistence. This method

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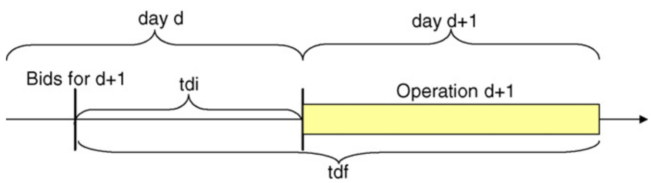

Fig. 1. Single daily auction session (1A).

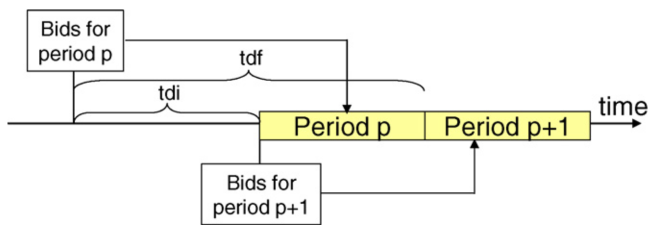

Fig. 2. Several day auction sessions (SA).

assumes that the production in the future is the same as the present one. Persistence is usually used as a reference that must be improved by any practical prediction tool.

In this paper, predictions will be made with higher accuracy, following the results obtained by the program SIPREÓLICO [7]. This program takes wind speed and direction predictions from the Numerical Weather Prediction program HIRLAM, as well as real time power measurements, and provides hourly predictions up to 42 h in advance. SIPREÓLICO has been developed by Universidad Carlos III de Madrid for Red Eléctrica de España, the Spanish TSO, where it has been running since 2002. The accuracy of SIPREÓLICO has been checked with other prediction tools, and it is similar to the present state-of-the-art [8].

In the following section, the equations for minimizing the imbalance cost of the WGENCO and maximizing the revenue of a HGENCO are presented. Section 3 presents the equations for the combined operation optimization problem. The results for a realistic case are shown in Section 4. Finally the conclusions are exposed.

2. Independent scheduling

In this section, the optimal power to be declared in the bid will be found. The WGENCO will try to find the minimum expected power imbalance cost and the HGENCO will try to find the maximum expected revenue.

2.1. Wind optimization problem

The revenue of a WGENCO is the difference between the revenues for the energy sold and the penalty paid for the incurred imbalance [9]. For the sake of simplicity, the operational costs of the wind generation are supposed to be negligible, although this is not realistic. The penalties paid are a fraction of the daily marginal prices. The formulation of the problem consists in minimizing the expected penalty for deviations (WEP), by choosing the best value of wind power to bid in each period t, pws_t.

Min WEP

$$\text{WEP}=\sum_{t=1}^{t=T}\left\{\sum_{i=1}^{i=N}\{\lambda_t\cdot\psi\cdot|\text{pwr}_i-\text{pws}_t|\cdot\rho(\text{pwr}_i|\text{pwr}_0,t\text{di}+t)\}\right\} \tag{1}$$

$$\text{if } \text{pwr}_i>\text{pws}_t,\quad \psi=\psi_{\text{up}}$$
$$\text{if } \text{pwr}_i<\text{pws}_t,\quad \psi=\psi_{\text{down}}$$

The probability density function ρ of Eq. (1) must be known. There are different methods to estimate it and in this paper it has been found from historical records of wind farm power production. The solution of this problem provides the optimum amount of power to be presented as a bid to the day ahead market for every hour $\{\text{pws}_1, \text{pws}_2, \ldots, \text{pws}_T\}$. Only a wind farm is considered, but this farm might also be a combination of wind farms that present a joint bid, as in the example shown later.

2.2. Hydro-optimization problem

This model is based on [10,11], but instead of limiting the water volume at the end of the period, the future price of water is used. The unit performance curve (UPC) is a highly nonlinear function, and it is approximated by a non-concave piecewise linear approximation. The effect of the head variation of the reservoir is neglected. This approximation is valid for large reservoirs and short term hydro-scheduling.

The problem consists in the choice of the scheduled hydro-power for each hour t and hydro-unit i $\text{phs}_{i,t}$ for the maximization of the revenue of the hydro-GENCO, but taking into account the expected price of the water.

Max HEP

$$\text{HEP}=\sum_{t=1}^{t=T}\left\{\sum_{i=1}^{i=I}\{\lambda_t\cdot\text{phs}_{i,t}-\text{su}_i\cdot y_{i,t}+x_{i,\text{TF}}\cdot Q_i\}\right\} \tag{2}$$

$$\text{phs}_{i,t}=p_{0,i}+\sum_{l=1}^{l=L}\rho_{i,l}\cdot u_{i,t,l},\quad \forall i\in I,\ \forall t\in T \tag{3}$$

$$x_{i,t}=x_{i,t-1}+W_{i,t}+M\sum_{j=1}^{j=I}\{u_{t-\tau ij,j}+s_{t-\tau ij,j}\}$$
$$-M\{u_{i,t}+s_{i,t}\},\quad \forall i\in I,\ \forall t\in T,\ \forall j\in R \tag{4}$$

$$x_{i,t}\geq X_{\min,i},\quad \forall i\in I,\ \forall t\in T$$
$$x_{i,t}\leq X_{\max,i},\quad \forall i\in I,\ \forall t\in T \tag{5}$$

$$u_{i,t,l}\leq U_{i,l},\quad \forall i\in I,\ \forall t\in T,\ \forall l\in L \tag{6}$$

The solution of this problem gives the power generated by each unit in the river basin. The data for this system have been taken from [10].

In this problem, Eq. (3) gives the hydro-generation characteristic which is a non-concave piecewise linear approximation. The output power of each hydro-plant has been divided into L blocks. The characteristic in each block is linear.

Eq. (4) gives the water continuity relation. Eq. (5) gives the limits of the water in the reservoir, while Eq. (6) sets the limits of the water discharged for every block.

This problem is a mixed real integer problem and the solution is obtained using GAMS/Cplex 7.5 [12,13].

The solution of the system gives the optimal set $\{\text{phs}_1, \text{phs}_2, \ldots, \text{pws}_T\}$ of the bids for the following period.

3. Optimal combined operation

Combined operation of hydro- and wind units has been proposed in [14–16]. A different approach is proposed in this paper, using actual wind power prediction results and with a market oriented strategy.

In the operation activity, the phs_i and pws_i from the auction process and the actual wind production, pwr_t, are known. The aim is to choose the optimal value of the actual hydro-production, $\text{phr}_{i,t}$, in order to find the maximum revenue for the joint operation (WHOP).

The proposed method may be applied in practice a few hours before the operation time. At that time, the accuracy of the wind power prediction is almost perfect, and the operation may be corrected accordingly.

The optimization problem of the combined operation can be expressed as follows:

Max WHOP

$$\text{WHOP} = \sum_{t=1}^{t=T} \{\text{Hr}_t + \text{Wr}_t - \text{Dr}\} \tag{7}$$

$$\text{Hr}_t = \sum_{i=1}^{i=I} \{\lambda_t \cdot \text{phr}_{i,t} - \text{su}_i \cdot y_{i,k} + x_{i,\text{TF}} \cdot Q_i\}$$

$$\text{Wr}_t = \text{pwr}_t \cdot \lambda_t$$

$$\text{Dr}_t = |R_t\} \cdot \lambda_t \cdot \psi$$

$$R_t = \sum_{i=1}^{i=I} \{\text{phr}_{i,t}\} + \text{pwr}_t - \sum_{i=1}^{i=I} \{\text{phs}_{i,t}\} - \text{pws}_t$$

if $R_t \geq 0, \quad \psi = \psi_{\text{up}}$
if $R_t < 0, \quad \psi = \psi_{\text{down}}$

In Eq. (7) Hr_t is the revenue coming from the hydro-generation in the hour t, Wr_t the revenue coming from the wind generation at hour t and Dr_t is the revenue reduction in hour t due to the imbalances. The penalty is proportional to the absolute value of the imbalance R_t.

Eqs. (3)–(6) should also be included. This problem has been solved using GAMS/Cplex 7.5.

4. Example

For running an example, realistic data have been used. They were obtained from real production of an aggregation of 13 Spanish wind farms, with a total rated power of 796.42 MW.

Wind power predictions have been generated using persistence, and for different accuracies within the range of SIPREÓLICO operation throughout Spain. For this reason, the simulations have been run for a maximum, minimum and average accuracy. These predictions are shown in Table 1. In this table the production of this aggregation is shown together with the predictions for the maximum, minimum and average accuracies, for a time horizon between 14 and 38 h ahead (single daily auction, 1A), and with 4 and 8 h ahead (6 auctions per day, SA). The last column shows the market price, and the column 'per SA' shows the predictions obtained using persistence, with several auctions. Some of the data of Table 1 are shown in Fig. 3.

The simulation shown here has been run for the prices of a single day (2002/01/02). However, it has been tested that the method behaves well for other days, and the day has been chosen as representative of the general trends in the Spanish market.

4.1. Revenue of the wind farm aggregation operating separately

In order to obtain the highest revenue, to bid the most probable value or the expected value of the prediction is not always the best choice. It depends on the difference between the penalties for over or under production ($\psi_{\text{up}}/\psi_{\text{down}}$). In the performed study, different relations of the ratio $\psi_{\text{up}}/\psi_{\text{down}}$ have been assumed. The probability that the production of the wind farm is pwr_N, when t hours before it was pwr_0, $\rho(\text{pwr}_N|\text{pwr}_0, tdi + t)$, has been obtained from historical records of production in the wind farm through 8 months. As an example, the probability density function of the production of the wind farm 14 h (the first period of the relevant operation time) after a moment when the production was 0.19 p.u. is given in Fig. 4. The values of these probability functions for the 20 first hours of the operation time, and for the value of $\text{pwr}_0 = 0.19$ p.u. are given in Table 2. The most probable values are marked in bold letters.

Once this probability density function is known, the best bid (that with the smallest penalty) for each hour is calculated for the day ahead. Fig. 5 shows the penalties expected for different values for the first hour of the next day (i.e., for an anticipation of 14 h). The penalty values in the Fig. 5 are in per unit (p.u.) of the

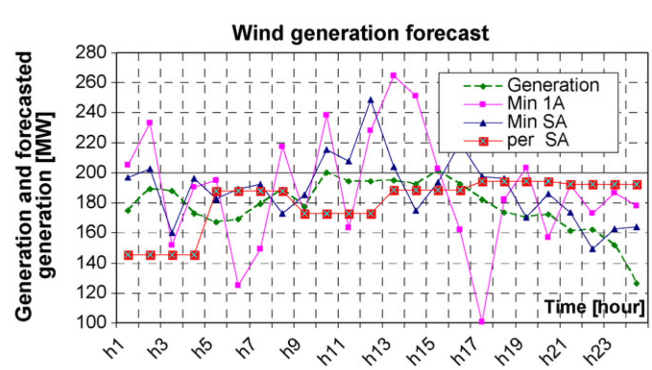

Fig. 3. Power generated and forecasted with different accuracies, date 2002/01/02.

Table 1
WGENCO forecasting for different markets

Time [h]	Generation [MWh]	Forecast [MWh]							λ [€/MWh]
		1A, $tdi=14$, $tdf=38$			SA, $tdi=4$, $tdf=8$				
		Minimum 1A	Average 1A	Maximum 1A	Minimum SA	Average SA	Maximum SA	Per SA	
1	174.7	204.8	177.6	187.1	196.7	173.3	189.5	145.2	15
2	189.0	233.4	206.9	210.0	202.5	187.6	198.4	145.2	14
3	187.5	151.9	194.0	173.4	160.4	171.7	170.2	145.2	14
4	172.9	190.2	183.7	181.7	195.9	181.8	185.4	145.2	14
5	167.6	194.8	174.9	182.2	182.8	180.3	177.5	187.8	14
6	169.0	125.2	170.2	151.5	189.3	185.5	181.5	187.8	14
7	179.3	149.2	155.9	166.6	192.5	169.4	186.7	187.8	15
8	188.6	217.1	246.1	201.2	173.1	181.4	179.1	187.8	15
9	177.8	172.5	181.5	179.7	181.1	200.5	182.1	172.9	15
10	199.9	238.2	204.7	223.9	215.6	208.7	209.2	172.9	22
11	193.9	163.6	194.8	183.4	207.4	218.0	201.1	172.9	24
12	194.3	228.4	244.6	209.8	248.6	209.4	229.1	172.9	24
13	194.8	264.7	155.9	226.0	203.6	182.9	202.0	188.6	24
14	192.3	251.3	192.8	223.0	174.9	186.7	182.2	188.6	21
15	201.1	202.5	225.3	204.5	193.2	221.6	195.0	188.6	15
16	192.4	162.3	182.5	178.3	219.7	173.3	210.1	188.6	14
17	182.1	100.7	201.2	146.7	197.6	195.8	192.2	194.3	14
18	173.8	181.8	203.2	179.9	195.9	156.0	187.4	194.3	14
19	170.2	203.2	192.7	189.3	170.2	173.9	169.1	194.3	15
20	172.7	157.2	184.4	164.4	185.9	181.0	179.3	194.3	27
21	161.7	191.8	138.5	178.0	173.8	180.4	169.5	192.4	33
22	162.0	173.3	185.1	165.5	149.2	170.9	152.6	192.4	25
23	151.9	186.5	158.8	169.3	162.8	150.6	160.1	192.4	15
24	126.1	177.8	111.0	158.4	164.1	134.0	149.7	192.4	17
Total up deviation		272.1	110.5	112.7	80.7	91.4	53.4	244.5	
Total down deviation		−519.1	−301.3	−271.1	−346.1	−190.7	−217.0	−294.2	

Table 2
Probability density function for different time horizons

Generation (p.u.)	Probability of generation ($pwr_0=0.19$ p.u.)											
	$t=1$	$t=2$	$t=3$	$t=4$	$t=9$	$t=10$	$t=11$	$t=12$	$t=17$	$t=18$	$t=19$	$t=20$
0.05	0.055	0.055	0.055	0.060	0.080	0.090	0.090	0.085	0.071	0.062	0.060	0.056
0.10	0.197	0.203	**0.209**	**0.212**	0.201	0.193	0.196	0.202	**0.214**	**0.207**	0.187	0.185
0.15	**0.237**	**0.223**	0.208	0.202	**0.219**	**0.226**	**0.231**	**0.227**	0.195	0.195	**0.202**	**0.195**
0.20	0.142	0.142	0.150	0.146	0.133	0.123	0.114	0.114	0.097	0.106	0.111	0.116
0.25	0.091	0.107	0.106	0.109	0.099	0.105	0.112	0.114	0.124	0.113	0.117	0.109
0.30	0.077	0.074	0.083	0.074	0.074	0.075	0.069	0.068	0.073	0.084	0.075	0.083
0.35	0.045	0.046	0.044	0.050	0.049	0.045	0.052	0.056	0.066	0.073	0.079	0.078
0.40	0.043	0.032	0.027	0.029	0.034	0.035	0.034	0.032	0.043	0.044	0.050	0.051
0.45	0.043	0.040	0.035	0.035	0.043	0.039	0.038	0.035	0.041	0.035	0.039	0.043
0.50	0.034	0.038	0.044	0.041	0.035	0.029	0.022	0.022	0.018	0.022	0.018	0.022
0.55	0.022	0.024	0.023	0.026	0.012	0.016	0.013	0.015	0.015	0.013	0.016	0.016
0.60	0.010	0.009	0.010	0.007	0.006	0.004	0.010	0.009	0.013	0.012	0.011	0.017
0.65	0.002	0.002	0.000	0.000	0.004	0.007	0.005	0.007	0.010	0.013	0.016	0.013
0.70	0.001	0.002	0.004	0.002	0.001	0.000	0.001	0.000	0.009	0.009	0.009	0.006
0.75	0.000	0.001	0.001	0.002	0.000	0.001	0.000	0.001	0.004	0.006	0.004	0.007
0.80	0.001	0.001	0.002	0.002	0.007	0.006	0.007	0.007	0.007	0.005	0.007	0.004
0.85	0.000	0.000	0.000	0.001	0.004	0.005	0.005	0.005	0.001	0.001	0.000	0.000
0.90	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
0.95	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1.00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Expected value	0.2226	0.2234	0.2238	0.2239	0.2203	0.2187	0.2175	0.2439	0.2322	0.2363	0.2403	0.2439

$pwr_0=0.19$ p.u.

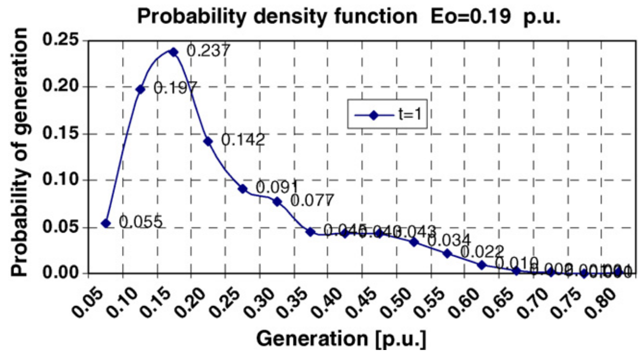

Fig. 4. Probability density function for $t = 1$.

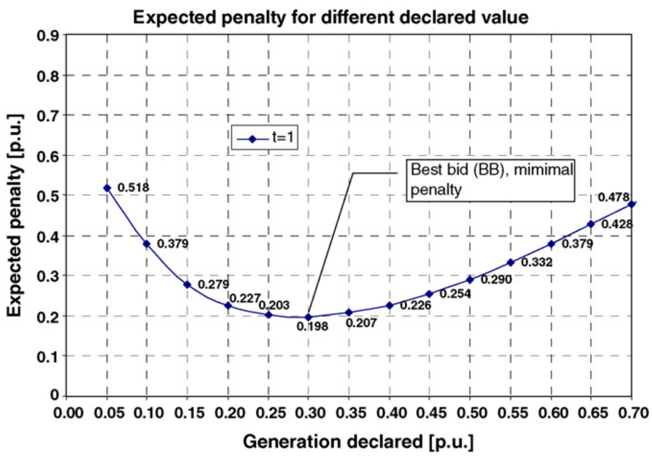

Fig. 5. Penalty according to the declared value.

penalty price and power base (S_b). It means that it is necessary to multiply the values by the penalty price and the Base Power of the particular system considered. From the figure, it can be deduced that the minimum expected penalty will be obtained for declaring a production of 0.3 p.u., while the most probable value is 0.237 p.u. and the expected value is 0.2226 p.u. (see Table 2). The values in the Table 2 are in per unit and the Base Power $S_b = 796$ MVA.

Table 3 shows a comparison – for a particular day – between the bids made following three strategies: maximum probability, expected value and minimum penalty. The results show that, for the day considered, the data and hypothesis considered, the real penalties are 7.84, 4.12 and 5.18 for HP, BB and EV, respectively.

In order to get a more general result the optimization process has been executed for 44 days which follows the condition $\mathrm{pwr}_0 = 0.19$ p.u. For a relation $\psi_{\mathrm{up}}/\psi_{\mathrm{down}} = 3$, the real penalties for the 44 days are 315.14, 202.22 and 226.52 p.u. for HP, BB and EV, respectively.

In Fig. 6 the results for the 44 days considered and under different penalty conditions are shown.

These results depend mostly on the relation $\psi_{\mathrm{up}}/\psi_{\mathrm{down}}$ and on the probability density function of the prediction.

4.2. *Combined versus separated operation*

The agents WGENCO and HGENCO may operate together or separately. The first case would happen if both generators have the same owner, who tries to maximize the joint revenue. In the paper both situations have been analyzed.

Table 3
Optimal bids according to three different strategies, only 1 bid per day, $\psi_{\mathrm{up}}/\psi_{\mathrm{down}} = 3$

Time [h]	Highest probability (HP)		Best bid (BB)		Expected value (EV)	
	Bid [p.u.]	Real penalty [p.u.]	Bid [p.u.]	Real penalty [p.u.]	Bid [p.u.]	Real penalty [p.u.]
1	0.15	0.1191	0.30	0.1103	0.20	0.0103
2	0.15	0.0447	0.30	0.1351	0.20	0.0351
3	0.10	0.26019	0.30	0.11327	0.20	0.01327
4	0.10	0.35517	0.30	0.08161	0.20	0.05517
5	0.10	0.23178	0.30	0.12274	0.20	0.02274
6	0.10	0.16437	0.30	0.14521	0.20	0.04521
7	0.15	0.00669	0.30	0.15669	0.20	0.05669
8	0.15	0.02535	0.30	0.17535	0.20	0.07535
9	0.15	0.04796	0.30	0.19796	0.20	0.09796
10	0.15	0.064103	0.30	0.214103	0.20	0.114103
11	0.15	0.050942	0.30	0.200942	0.20	0.100942
12	0.15	0.03961	0.30	0.18961	0.20	0.08961
13	0.15	0.05608	0.30	0.20608	0.20	0.10608
14	0.15	0.03019	0.30	0.18019	0.20	0.08019
15	0.10	0.08313	0.30	0.17229	0.20	0.07229
16	0.10	0.14949	0.30	0.15017	0.20	0.05017
17	0.10	0.30399	0.30	0.09867	0.20	0.00399
18	0.10	0.4737	0.30	0.0421	0.20	0.1737
19	0.10	0.77883	0.30	0.17883	0.20	0.47883
20	0.15	0.80244	0.35	0.20244	0.20	0.65244
21	0.15	0.85107	0.35	0.25107	0.20	0.70107
22	0.15	0.80736	0.35	0.20736	0.20	0.65736
23	0.10	0.97656	0.35	0.22656	0.20	0.67656
24	0.10	1.12047	0.35	0.37047	0.20	0.82047
Total day		7.843275		4.129115		5.189595

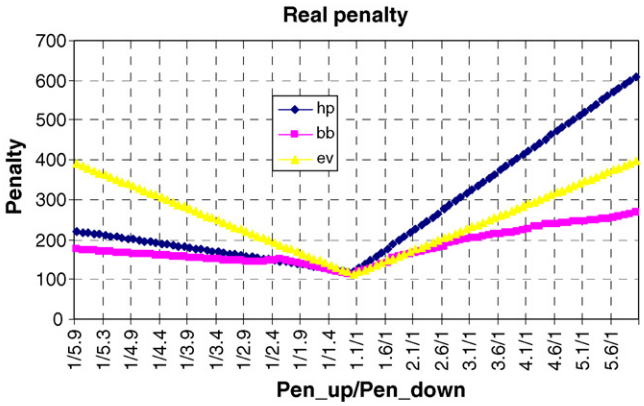

Fig. 6. Real penalty for different penalties conditions.

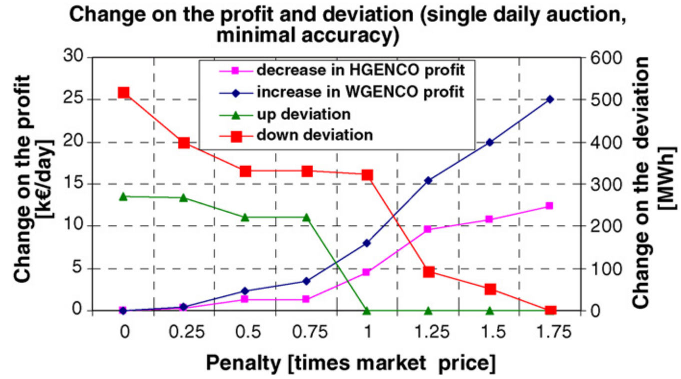

Fig. 8. Deviation and loss of revenue for different penalty values.

4.2.1. *Wind farm operating alone*

If the WGENCO operates separately, it must pay all the deviation between the scheduled and the actual generation. The amount paid depends on the accuracy of the prediction. In order to quantify the losses due to imbalance with a given prediction tool the *relative revenue* is defined as in Eq. (8).

$$\text{Relative revenue} = \frac{\text{revenue with actual forecast}}{\text{revenue with perfect forecast}} \tag{8}$$

In Fig. 7 the relative revenue is given for different prediction hypothesis. From this figure, the following conclusions could be extracted:

- The use of persistence as a forecasting tool caries a greater lost revenue. For instance, in a market with six auctions and a penalty of the imbalance of 1.75 times the market price, the relative revenues are 0.89 and 0.82 for maximal and minimal forecasting accuracies, respectively, while for persistence is 0.77.
- In a market with a single auction the time ahead for the forecast is larger than in a market with several auctions and it carries larger losses. For instance, with a penalty of 1.75 times the market price, and minimal accuracy, the lost revenue is 0.67 for a single daily auction and 0.825 for six daily auctions.

4.2.2. *GENCOs combined operation*

In the combined operation, the hydro-plant would cover the WGENCOs deviations from the joint schedule, in order to maximize the total revenue. Fig. 8 shows the change in the revenue of both HGENCO and WGENCO against the penalty paid as times the market price. Obviously, the increase of WGENCO revenue must be greater than the losses of the HGENCO for this combined operation. It also shows the imbalance that the joint system presents as a function of the penalty paid. When the penalty is zero, the imbalances are not compensated at all, and they are 272.1 and 519.1 MWh by up and down deviations, respectively, as is this case. In this figure, the amount of imbalances that are allowed to the wind farm to incur is also shown. When the penalty is low, it is better to allow imbalances than to modify the water scheduling. Since in this example the price of water is high, imbalances are totally compensated only when the penalties are also very high.

High penalties encourage the hydro-generator to cover the wind deviations. This covering also depends on the water future price. In the example, for a future price of water of €60 MWh^{-1}, the hydro-plant will only cover completely the under production of the wind farm if the penalty is very high (1.75 times the marginal price).

Fig. 9 shows the total (WGENCO and HGENCO together) increase in revenue for different market hypothesis and forecasting accuracies. Comparing the several auctions using maximal accuracy and persistence "SA max" and "SA per", respectively, the highest improvement is against persistence. Comparing single auction and several auctions (both with maximal accuracy) the highest improvement is for the single auction.

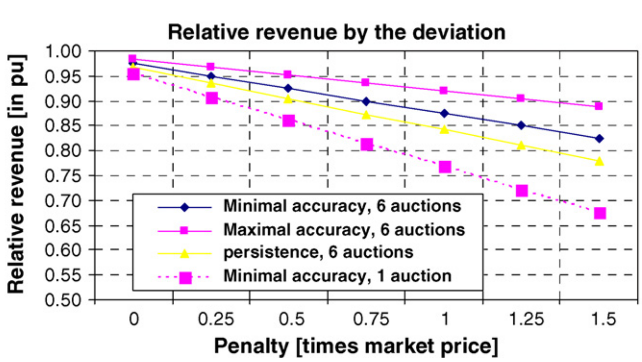

Fig. 7. Relative revenue for different forecasting techniques and operating alone.

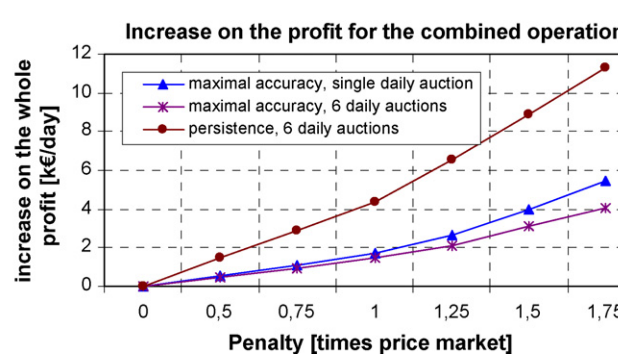

Fig. 9. Change in the revenue for different schedule markets.

Table 4
Percentage of wind penalties save with the combined operation

	Penalty						
	0.25	0.5	0.75	1	1.25	1.5	1.75
Difference between separated operation and combined							
1A							
Minimum	212.15	1079.01	2247.08	3437.30	5851.91	9141.15	12686.09
Medium	137.37	981.80	2071.35	3242.14	4865.31	6623.88	8395.35
Maximum	147.26	577.30	1126.49	1695.78	2657.24	3968.05	5491.74
SA							
Minimum	177.04	725.91	1457.66	2246.42	3542.45	5355.90	7285.96
Maximum	124.05	478.56	956.29	1466.33	2139.77	3086.40	4068.55
Per	287.32	1488.85	2892.90	4357.39	6534.61	8871.55	11318.99
Penalty for the WGENCO operating alone							
1A							
Minimum	3588.66	7177.33	10765.99	14354.65	17943.31	21531.98	25120.64
Medium	1935.78	3871.56	5807.33	7743.11	9678.89	11614.67	13550.45
Maximum	1746.33	3492.66	5238.99	6985.31	8731.64	10477.97	12224.30
SA							
Minimum	1930.06	3860.13	5790.20	7720.26	9650.33	11580.39	13510.46
Maximum	1220.44	2440.88	3661.33	4881.77	6102.21	7322.66	8543.10
Per	2447.44	4894.88	7342.33	9789.77	12237.21	14684.66	17132.10
Percentage of wind penalty recovered by combined operation							
1A							
Minimum	5.91	15.03	20.87	23.95	32.61	42.45	50.50
Medium	7.10	25.36	35.67	41.87	50.27	57.03	61.96
Maximum	8.43	16.53	21.50	24.28	30.43	37.87	44.92
SA							
Minimum	9.17	18.81	25.17	29.10	36.71	46.25	53.93
Maximum	10.16	19.61	26.12	30.04	35.07	42.15	47.62
Per	11.74	30.42	39.40	44.51	53.40	60.41	66.07

The numerical values of this benefit under different assumptions are given in Table 4 for values of $\psi = \psi_{\text{up}} = \psi_{\text{down}}$. For instance, for $\psi = 1.5$, with minimum accuracy of the wind poser prediction, and with several auctions (SA), the deviations paid by the WGENCO are €11,580.39. The savings with combined operation are €5355.90, which is 46.25%.

5. Conclusion

In this paper, two different strategies for maximizing the revenue of a WGENCO have been presented: (a) the short term wind power prediction tool SIPREOLICO has been used to get the optimal WGENCO bid and (b) a hydro-system was used to make the optimal joint operation maximizing the whole revenue by trying to minimize penalties. Both models have been successfully tested on realistic case studies.

The benefits of a short term wind power prediction tool such as SIPREÓLICO have been made apparent under different hypotheses. The convenience of using such a tool when a wind farm is in an electricity market is quantified.

Acknowledgement

This work has been made for the research project RENOMER (DI2003-00862), supported by the Spanish Ministry of Education.

Appendix A

List of symbols

Dr_t	penalties due to power imbalances in period t (€)
HEP	hydro-expected revenue (€)
Hr_t	real HGENCO revenue in period t (€)
I	set of indices of the plants belonging to the same river basin and the same company
L	set of indices of blocks of piecewise linearization of the unit performance curve
M	conversion factor, from water discharged to volume (Hm^3 s/m^3)
$phr_{i,t}$	actual hydro-power of unit i in period t (MW)
$phs_{i,t}$	scheduled hydro-power of unit i in period t (MW)
pwr_0	wind power output in initial period 0 (MW)
pwr_N	discrete generation states (p.u.) $\{0; 0.1; 0.2; \ldots; 1\}$
pwr_t	wind power in period t (MW)
pws_t	wind power scheduled in period t (MW)
$P_{0,i}$	minimum power output of plant i (MW)
Q_i	future value of the stored water in the reservoirs associated with the plant i (€/Hm^3)
R	set of the plants up-stream of the plant considerate; it depends on the topological river basin
R_t	power imbalance; difference between the powers scheduled and generated (MW)

$s_{i,t}$ spillage of the reservoir associated to plant i in period t (m^3/s)
su_i start-up cost of hydro-plant i (€)
T set of indices of the periods of the market time horizon
$u_{i,t}$ water discharge of plant i in period t (m^3/s)
$u_{i,t,l}$ water discharge of plant i in period t in block l (^{3}/s)
$U_{i,l}$ maximum water discharge of plant i of block l (m^3/s)
$W_{i,t}$ forecasted natural water inflow of the reservoir associated to plant i in period t (Hm^3/h)
Wr_t real WGENCO revenue in period t (€)
WEP expected penalty for WGENCO (€)
WHOP total revenue of WGENCO and HGENCO together (€)
$x_{i,t}$ water content of the reservoir associated to plant i at period t (Hm^3)
$x_{i,\mathrm{TF}}$ water content of the reservoir of plant i at the end of scheduled period (Hm^3)
$X_{\max,i}$ maximum content of the reservoir associated to plant i (Hm^3)
$X_{\min,j}$ minimum content of the reservoir associated to plant i (Hm^3)
$y_{i,t}$ binary variable which is equal to 1 if plant i started at the beginning of period t

Greek letters

λ_t forecasted price of energy in period t (€/MWh)
$\rho_{i,l}$ slope of the block l of plant i in the hydro-unit performance curve, UPC (MW/m^3/s)
$\rho(pwr_N|pwr_0, tdi+t)$ probability of generating pwr_N in $tdi+t$ when the power was pwr_0 in tdi
τ_{ij} time delay between reservoir of plant j and reservoir of plant i (h)
ψ_{down} penalty for down deviation, as a percentage of market price
ψ_{up} penalty for up deviation, as a percentage of market price

The $phs_{i,t}$ and $pws_{i,t}$ are variables in the planning process but they are constant in the operation process.

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