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Impact of the wind forecast error on the French balancing system

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***Abstract*—The aim of this paper is to quantify the possible increase of the balance system's cost due to the wind forecast error in a system with large amounts of wind power. We created a model of the wind forecast error and of the balancing system offers to simulate these costs.**

***Index Terms*— balancing, forecast error, merit order, wind power.**

I. Introduction

It is the European Union's ambition to increase the part of renewable energy sources in the electricity production mix. In the last years, wind power growth has been exponential, reaching up to unprecedented levels. The installed capacity in Europe was 5 GW in 1995, and is now 74 GW. In France, the current installed capacity is only 2.5 GW, but the goals are ambitious: 13.5 GW in 2010 and 17 GW in 2015.

This promising technology has some characteristics that impact the system operation, both in positive and negative ways. In particular, wind is a non-controllable variable power source. This raises new questions about the integration of large amounts of wind energy in the existing system. The aim of this paper is to analyze particular aspect of this integration: the impact of the forecast error on the balancing system.

The Transmission System Operator (TSO) is responsible for maintaining the system balance between production and consumption in its area. In most countries, a market mechanism based on a merit order system is used to compensate for the imbalances. Because the impact of wind forecast error is proportional to the installed wind capacity, the total system imbalance will rise with the integration of large amounts of wind power. This will lead to an increase in the balancing costs. In the French system, these costs are at present supported by the historical producer, Electricité De France, EDF. EDF buys the wind power at a feed-in tariff and adds this production to its own balance perimeter.

The aim of this paper is to quantify the possible increase of the balancing cost. Part II briefly sums up the main characteristics of wind uncertainties. Part III describes how a balancing mechanism works. Part IV assesses the impact of wind forecast error on a balancing mechanism from a theoretical point of view. Lastly, Part V studies the French system in detail allowing us to form conclusion on the studied impact.

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II. Characteristics of wind uncertainties and their financial impact

Production from wind turbines is proportional to the cube of the wind speed [1]. Unfortunately, wind speed varies over time on a scale of minutes, hours and days, and is quite difficult to accurately predict.

Therefore, an uncertainty exists on the prediction of wind production. This difference between planned production and actual production is the *wind forecast error*. This error depends on three factors.

The first factor is the method used to predict the wind production. Forecast methods are constantly improving and becoming more complex. Nevertheless, for short-time prediction (the next four hours or less), simple approaches such as the persistence method brings a good accuracy. The persistence method simply consists of assuming that the wind production for the next hour is equal to the production of the current hour. Fig. 1 shows that at these time scales, the persistence method gives results similar to those obtained using much more complex methods. Our study focuses only on errors seen from less than two hours ahead so the simpler persistence method was used in this paper.

The second factor is the number of wind turbines on which the prediction is made, and their geographical position. The forecast for a large amount of wind farms located over a large territory will have a more reliable output than one wind farm considered individually. Farms distributed in a region will not see the same wind speed, thus their forecast errors will be uncorrelated. According to [2], the mean forecasting error for eight wind farms is roughly 12% of the installed capacity when viewed from one day ahead whereas the mean forecasting error for one single wind farm is roughly 30% when viewed from one day ahead.

The third factor, and most relevant to this article, is how far ahead the wind production is anticipated. For example, the mean forecasting error for eight wind turbines is roughly 12% of the installed capacity when viewed from one day ahead but only 3.5% when viewed from one hour ahead. (Fig. 1)

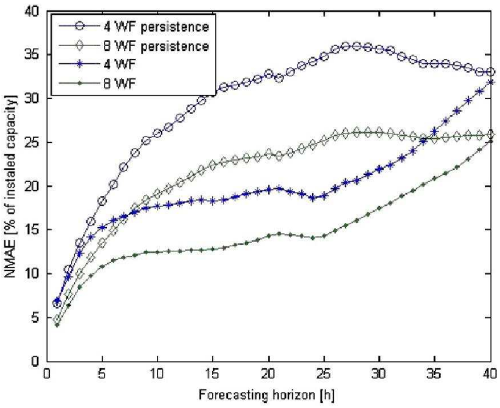

Fig. 1. Wind Forecast Error as a function of methodology, number of wind farms and forecast horizon [2]

Even when anticipated from just one hour ahead, the uncertainty could have an impact on the system balance. Therefore, additional balancing capacity could be required.

III. Balancing mechanism

Most UCTE countries have developed in the recent years a day-ahead electricity market and in most cases an intraday market as well. Nonetheless, the real time balance between production and consumption is the responsibility of the Transmission System Operator (TSO).

This is usually done using a market-based balancing mechanism. The actual implementation differs from one country to another, but this mechanism can always be broken down into two basic steps. The first step occurs in real time and is a permanent tenure used by the TSO to buy or sell the energy it needs. It is described in section III.B. The second step is the "imbalance settlement". It happens later, between two days and two years after a given imbalance and consists of passing the various costs implied by the first step on those who created the imbalance. It is described in section III.C

A. Definition of an imbalance

Every day, all producers must tell the TSO their planned production for every half-hour of the next day. In real time, it is possible that the actual production does not match the planned production due to the loss of a production unit or errors on the load level. If a producer produces more than planned, then he has a *positive imbalance*: too much energy is injected in the system. If he produces less than planned, he has a *negative imbalance*: not enough energy is injected into the system. For the TSO, the *system imbalance* is the sum of all the producers' imbalances and is the amount of energy that must be adjusted.

For example, if one actor produces 105 MW while his planned production was 100 MW and another produces 80 MW while his planned production was 100 MW then the system has a negative imbalance of 15 MW.

The system position is sometimes referred as being *long* (positive imbalance) or *short* (negative imbalance).

B. Bid selection

When an imbalance occurs, the first step is the selection of bids in real time by the TSO to deal with it. Two types of offers are submitted to the TSO: *upward offers*, where a Balancing Service Provider (BSP) offers to sell energy to the TSO and are therefore used in cases of *negative system imbalances*, and *downward offers* where a Balancing Service Provider offers to buy some energy and is used when there is a *positive system imbalance*. An upward offer submitted to the TSO consists of three things: how much energy the BSP is willing to sell, at what price it is willing to sell it, and its technical constraints. Similarly, a downward offer consists of how much energy the BSP is willing to buy, at what price, and what its constraints are. A single BSP can offer both upward and downward offers at the same time.

The TSO then selects the most interesting offers financially (lowest priced first when buying energy, highest priced first when selling energy) taking into account the technical constraints of the BSPs. In this study, the most important technical constraint to take into account is how quickly a BSP can deliver his offer once it is selected. If a producer is willing to sell energy at a low price but needs eight hour to start the unit, the offer cannot be used for an imbalance planned in two hours time.

The accepted upward offers are paid as bid by the TSO to the BSP while an accepted downward offer is paid as bid by the BSP to the TSO.

C. The Imbalance Settlement

Once the system imbalance has been resolved, the second step of the balancing mechanism is to pass the cost of these operations on those who did not respect their program. This step is fundamental as it discourages actors to rely on the balancing mechanism.

1) The Balance Responsible Party

In most UCTE countries, the producers are not directly responsible for their imbalances towards the TSO. An intermediary level exists which is called the *Balance Responsible Party* (BRP). Each actor must be attached to one and only one BRP. He is a purely financial player that has contracts with producers and consumers to be responsible for their imbalances towards the TSO. The BRP benefits from a smoothing effect: the more actors are attached to its perimeter the more likely the small imbalances will be smoothed out. In our example, the two producers have a 15 MW imbalance if they are attached to the same BRP but a total of 25 MW of imbalance if they are attached to two different BRPs. The cost of imbalances is paid by the BRP which then passes it on the actors attached to its balancing perimeter.

2) *Imbalance calculation and charges*

During the Imbalance settlement, BRPs that were negatively imbalanced will pay for the energy the TSO had to supply for them. The BRPs that were positively imbalanced will receive money for their excess energy. It should be noted that this excess energy will most likely be bought by the TSO at a low price, making it a loss for the BRP. These financial settlements are also impacted by the total system position. If a BRP is long while the system is short, he is somehow helping the system, and therefore will not be penalized as much as a BRP that was short. In a two-price system, the long BRP will be paid the spot price, while the BRP with a negative imbalance will have to pay the average price of upward regulation plus a penalty. (Fig. 2, left column). This penalty compensates the TSO for the cases where he looses some money in the balancing process due to the simultaneous activation of upward and downward regulation. The same logic applies when the system is long (Fig. 2, right column)

To avoid the temptation for a producer to be voluntarily unbalanced in the hope that his excess energy will be bought at a high price or his lacking energy sold to him at a low price, balancing mechanisms often use the day-ahead spot market price as a cap/ceiling.

		SYSTEM IMBALANCE	
		NEGATIVE (short) • Σ injections < Σ off-takes • TSO requests more generation • NRV > 0	POSITIVE (long) • Σ injections > Σ off-takes • TSO requests less generation • NRV < 0
BRP IMBALANCE	NEGATIVE (short) Injections < off-takes	+ AP_u*(1+ $penalty_u$)	+ P_{DA}
	POSITIVE (long) Injections > off-takes	- P_{DA}	- AP_d/(1+ $penalty_d$)

AP_u = average price of upward regulation; AP_d = average price of downward regulation; NRV = net regulation volume; P_{DA} = day-ahead power exchange price

Fig. 2. Imbalance Settlement in a Two-Price System[3]

IV. Theoretical Impact

With the increase of wind energy, the wind forecast error brings an additional source of uncertainty. This new uncertainty has to be balanced and represents a new balancing cost.

The wind forecast error has two effects on the balancing mechanism: one on required energy volumes and one on price.

A. *Impact on Balancing needs*

The wind forecast error follows a centered Gaussian repartition [4], meaning than *on average* and over a long enough period of time, positive and negative errors compensate.

However on an hourly basis, wind power introduces a new source of possible imbalance, leading to an increase of the amount of required energy for balancing the system. Fortunately, wind error predictions are not correlated to consumption or generation forecast errors [4][5]. Therefore, these individual fluctuations are smoothed out, meaning the needs in balancing energy does not increase as much as the wind forecast error. This is illustrated in Fig. 3: the wind forecast error can increase the system imbalance (Fig. 3-A) as it can reduce it (Fig. 3-B). Nonetheless, this leads to situations where bigger imbalances must be dealt with.

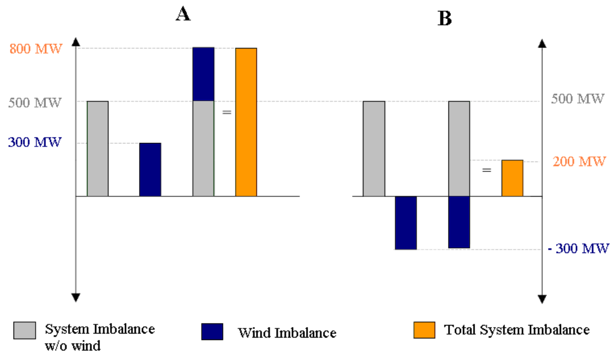

Fig. 3. Wind and System Imbalance

B. *Impact on Prices*

As balancing volumes increase, the TSO needs to use balancing offers that are further away in the merit order. Therefore, the average cost of balancing for one MWh increases.

Because the price versus quantity offer curve is rising, the additional cost introduced by wind forecast error when it aggravates a given imbalance (Fig. 4 top left) is bigger than the economy made when the wind error compensates the same imbalance (Fig. 4 top right).

Therefore, although the wind forecast error is symmetrical and centered, the total cost of the balancing mechanism will increase (Fig. 4 bottom).

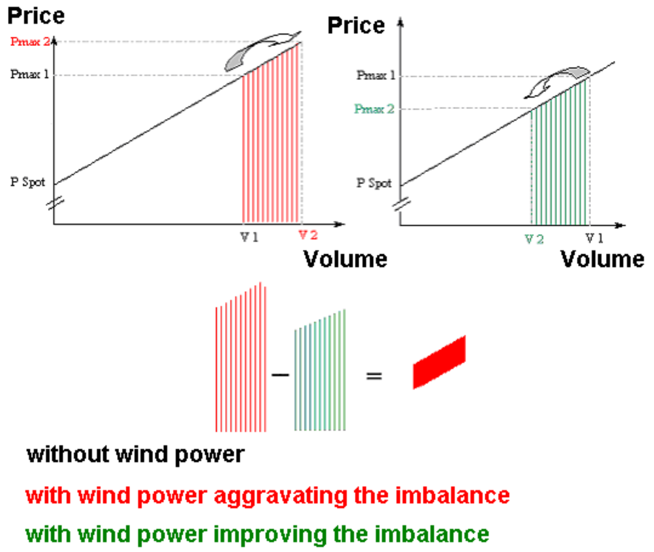

Fig. 4. Theoretical financial impact of the wind forecast error

V. Modeling of the French case

Simulations were made on the French balancing mechanism in order to quantify the expected increase in balancing costs.

Although this type of study has been made for other European countries [5][6], the results cannot directly be used for France as they depend on the number of wind regions, the cost of other units, and the legal framework of the electric system.

Several studies use probabilistic methodologies combining the variability of wind and the load to quantify the increase in reserve requirement [5] [7].

Kleinschmidt [8] estimates this cost using time series of wind forecast error without taking into account the statistical compensation between both imbalances.

In this study we combined both methodologies, combining a normal distribution for the wind imbalance with time series of system imbalance.

The only other study on this subject [9] does not use public data so the results cannot be duplicated.

We evaluate here the cost of wind forecast error on balancing using only public data.

A. Impact on balancing needs

To study the impact on volumes, we used half hourly time series of the French system imbalance for the year 2007 [10] and we simulated wind forecast error for a given wind generation capacity, using the persistence approach. These data were randomly generated to follow a symmetric and centered Gaussian curve whose dispersion is the wind forecast error viewed from two hours ahead.

Fig. 5, shows the actual distribution of the French system imbalance for the year 2007 (in white). On average, there are 150 MW in excess in the system. The positive imbalance never exceeds 3000 MW while the negative imbalance never exceeds 2500 MW.

From the actual system imbalance and the simulated wind imbalance, we can tell what the total system imbalance for each half hour of 2007 would have been like if a larger wind park was installed in France, taking into account the smoothing effect. The results for a two-hour ahead prediction can be seen in Fig. . With 10 GW of installed capacity in wind power, the values of the extreme imbalances are not modified, but they tend to appear more frequently. (Fig. 5, light grey)

With 20 GW of installed capacity, we now see the appearance of imbalances of 3500 MW in both directions.(Fig. 5, heavy grey)

With 30 GW, the single most extreme imbalance could rise up to 5500 MW.(Fig. 5, black)

We observe that as the installed wind capacity increases, two effects occur: small imbalances happen less frequently, and extreme imbalances tend to appear. Because the price curve of balancing offers is not linear but convex, it is possible that this second consequence is the most likely to increase the total balancing cost.

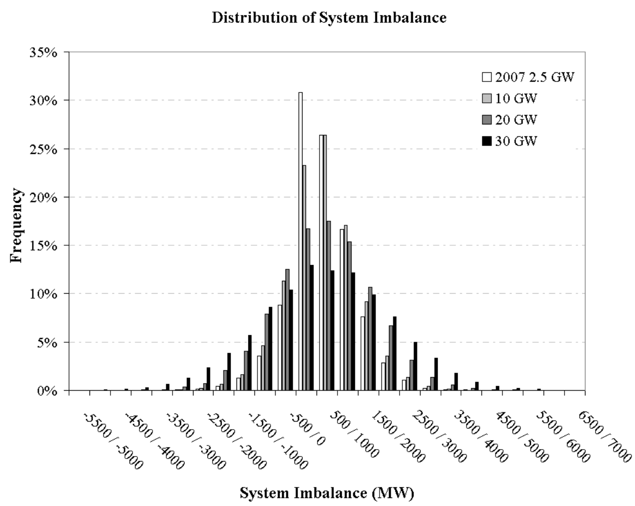

Fig. 5. Evolution of balancing volume needs with installed wind power

B. Impact on Prices

To study the financial impact, data on balancing offers were necessary. Unfortunately, the offer curves for the French balancing mechanism are not public. The only available data are the average price of activated offers and the price of the most expensive activated offer for each half hour. Offers beyond the last accepted one are not published.

We made the assumption that the offer curve is in two parts: a first part where the energy is bought or sold at the day-ahead market price and a linear section in order to simulate offers beyond the most expensive known one. (Fig. 6).

It is more likely that the offer curve is not linear but convex:

suboptimal offers tend to be more and more expensive because they imply less frequently used production units.

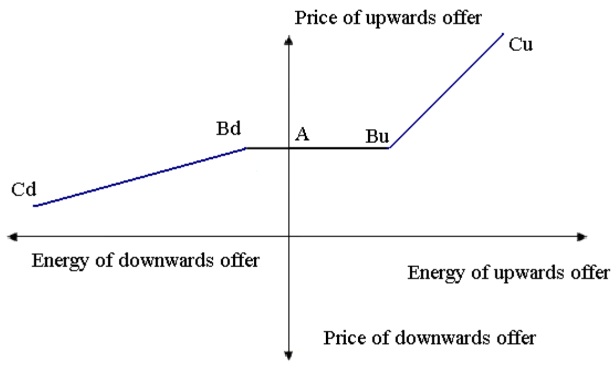

Fig. 6. Model of downward offers and off-peak upward offers curve using public data

Fortunately the French TSO, RTE, gives for each day an aggregated curve for all upward offers whether they were selected or not, for the peak hours of the day [11]. We analyzed the 639 available curves of the year 2007, (morning and evening peaks in all seasons except for summer where there are no evening demand peaks) and were able, using linear regressions, to successfully correlate these curves to three publicly available data: the day-ahead market price, the system margin and the load.

The modeling of a daily peak hour offer curve can be seen in Fig. 7. Our model consists of three straight lines. The first section always represents offers for energy sold at the day-ahead spot price of the concerned period [12]. This means that the balancing offers always comply with economical theory and are sold above market price. The volume of energy offered at the day-ahead spot price is roughly constant throughout the year. This volume and the spot price allow us to position point A correctly.

At the other end of the curve, point C represents the last offer made. In the French system rules, all capacity that is not running must be offered on the Balancing Mechanism. The total volume of upward offers is therefore the system margin, minus the energy assigned for the primary and secondary reserves. The system margin is a public data, the primary reserve is roughly constant and the secondary reserve depends mostly on the anticipated load, which is also a public data, allowing us to know the volume of submitted offers to the balancing mechanism. We observed that these curves always showed an inflection point, noted B here. We found out that the volume of the offers beyond that point was constant (Fig. 7, L_{bc}) and that their price always followed the same curve. The difference between the price of B and A was also constant, (Fig. 7, K_{ab}). Therefore, the position of point B can be deducted from the position of point C and A.

Finally, the price C is deducted from the price B by another parameter (Fig. 7, K_{bc}) which is constant over a season.

This allows us to simulate an offer curve for any peak hour of 2007, using only the day-ahead market price and the system margin.

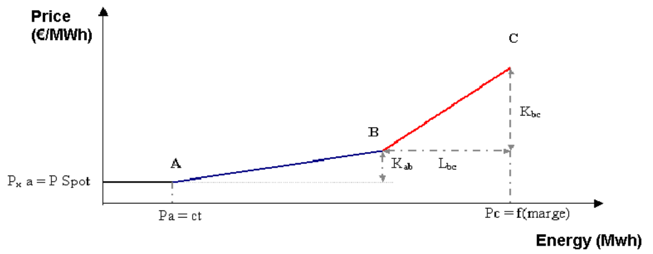

Fig. 7. Model of a peak upward offers curve using public data

Using the simulated imbalance volumes for a given wind park and the offer curves both for peak hours and for off-peak hours, we evaluated the yearly additional cost of wind forecast error.

These simulations were made considering both a two-hour and a one-hour ahead prediction to match the evolution of the gate closure in France. The results can be seen in Fig. 9 and are detailed in the following section.

VI. Results

We ran our simulations taking into account the 2007 system imbalances without any additional wind capacity to validate our model. We found an estimated annual cost of 181M€, while in reality the balancing cost was 187M€. This indicates that our model for the offers is relatively accurate but tends to slightly underestimate the cost of balancing. This is most likely due to our linear approximation of block offers (Fig. 8: linear approximation in light grey, real price in black)

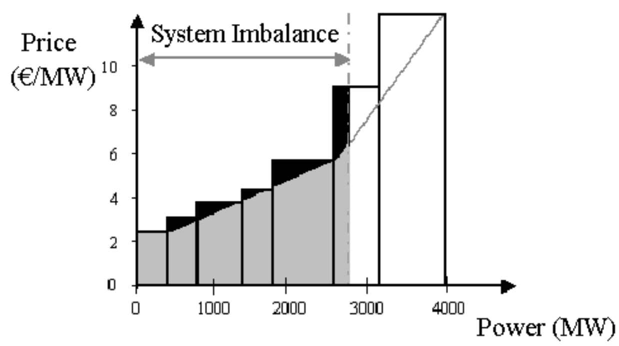

Fig. 8. Cost underestimation of our model

We then ran our model with installed wind capacity of 5 GW and 10 GW considering both a two-hour and a one-hour ahead prediction.

For both wind park sizes, making predictions one hour ahead of real time divides by two the total cost of wind imbalance. It is therefore highly beneficial for balance responsible parties to communicate to the TSO the latest production prediction. But the legal framework of the system must allow for such short notice notification. In France, it is possible to redeclare the production programme two hours before real time. The rules are evolving, and a one-hour delay between gates can be expected in the near future.

If wind producers can update their program two hours ahead¸ the total additional cost of balancing a 5 GW wind park is roughly 12 million euros. If we consider that the wind turbines run at nominal capacity an equivalent of 2500 hours per year, the average additional balancing cost is a little less than one euro per MWh of wind-energy.

For 10 GW of installed capacity, which is targeted to happen in France in 2010, the total yearly balancing cost for the system is of 50 M€. Compared to the 187 M€ cost without wind, these specific balancing costs can no longer be neglected.

The forward prices for the year 2010 are already known and could have been used as an indicator of what the day-ahead market prices will be at this date. We decided to use market prices from 2007 to stay consistent with our analysis of the system imbalance. In doing so, we also made the implicit assumption that an increase in wind capacity had no measurable impact on the spot market prices.

Beyond 10 GW of installed capacity, we consider our results to be much less accurate: 20 GW of installed wind power capacity in France will not occur before 2015 and will most likely have a measurable impact on market prices.

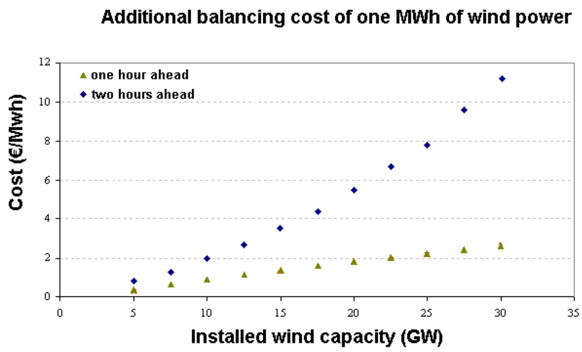

Fig. 9. Additional balancing cost of one MWh of wind power by installed wind capacity

Although it is fairly reasonable to consider the specific cost of balancing wind power negligible today, where the installed capacity is only 2.5 GW, these costs will rapidly increase beyond that point and should be taken into account when evaluating the impact of wind energy in power systems. This will likely raise the question of whether these costs should be passed on the wind producers or paid by all actors in the system.

If these costs were to be paid by the wind producers, the imbalances could cost up to 2€/MWh. Although quite small, this cost should be considered when assessing the profitability of a new wind project.

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