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QUANTIFICATION OF CAPACITY CREDIT AND RESERVE REQUIREMENTS FROM THE LARGE-SCALE INTEGRATION OF WIND ENERGY IN THE FRENCH POWER SYSTEM

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Abstract

The paper presents results of a detailed study carried out to simulate the integration of large amount of wind power in the French power system. The targets set for France are between 10 000 and 14 000 MW of installed wind capacity by year 2010. In order to simulate the projected wind production, hourly wind speed measurements from 40 sites spread over the country and covering a period of 3 years are used. The data reflect both temporal and spatial correlations that are proper to the climate conditions in France. Then, realistic scenarios are built for the installation of several levels of wind power based on appropriate assumptions. The simulation of each scenario provides a detailed profile of the wind production at a national level. The paper presents the level of guaranteed wind power that is provided for given probability for each scenario. The variability of the production is analyzed in order to define the reserve or storage requirements to achieve a secure integration of wind power. Finally, an analysis is presented on how wind generation can be integrated in the national power generation mix in France.

I. INTRODUCTION

In the frame of the European Union directive of September 2001 [1], 22% of the Union's electricity needs should be met by renewable energy sources by 2010. To meet this goal, each member state has been given a specific target [2]. France's target is to produce 21% of its electricity from renewable sources by 2010 (compared to 15% currently). Translated into wind power capacity, this means 10 000 to 14 000 MW of installed capacity by 2010. Moreover, to reach this objective, the French Ministry of Industry has defined an intermediate target ranging from 2 000 to 6 000 MW of installed capacity by 2007, of which 500 to 1 000 MW to be installed offshore. Successfully reaching the above targets, is critical for achieving the goals set at a European level.

Today, the development in France is slow (239 MW installed by the end of year 2003 [3]). Moreover, several questions are raised on how intermittent generation, and namely wind power of several GWs, will be integrated in the power system. Wind generators are often equipped with asynchronous generators and their production depends solely on the weather, thus, using a wind turbine to maintain frequency, to maintain voltage or to follow load is almost impossible.

The aim of this work is to evaluate the profile of the projected wind generation and its impact on the French power system. For this purpose, hourly measurements of wind speed from 40 sites spread over the country and covering a period of 3 years are considered. The data reflect both temporal and

spatial correlations of the specific climate conditions in France. Then, scenarios are built for the installation of several levels of wind power based on realistic assumptions (wind potential, existing proposals by independent producers for wind park projects, etc). The simulation of each scenario provides a detailed profile of the wind production at a national level.

The estimation of the likelihood of zero or near-zero output from all wind farms is of great importance [4]. This issue is related to the 'capacity credit' that can be credited to wind generation, i.e. how 'firm' this type of generation can be considered, from a system's operator or planner's point of view. The level of guaranteed power that is provided with a given probability is estimated for each scenario. The variability of the production is analyzed in order to define the reserve or storage requirements to achieve a secure integration of wind power. Finally, an analysis is presented on how wind generation can be integrated in the national power generation scheme in France.

II. STATE-OF-THE-ART

Several studies have been performed in the past to evaluate the impact of a large-scale integration of wind power in an interconnected system. Early studies (*i.e.* [5]) were performed in the frame of the EU ensemble of projects "Wind Power Penetration Study" for various countries.

The questions raised in this paper concern the capacity credit that wind farms may offer at a national level, as well as the reserve and storage

requirements to manage intermittence. At a single wind farm level, or even at a regional level, one would expect wind intermittence to be very high for any "capacity" to be credited. However, over the large geographical area of a country, one would expect some spatial smoothing effect able to reduce the variability of the total wind generation. Also, the likelihood of not having any wind generation at a certain moment of the year at any wind farm of the country becomes lower.

Regarding capacity credit the aim is to evaluate whether the installation of wind generators in an electric system permits to offset the use of generators with high production cost. In this way, capacity credit is defined as the amount of conventional power that can be replaced with wind power without decreasing the reliability of the power system [6]. At the level of system planning it is interesting to know the amount of investment in conventional capacity that can be avoided due to the installed wind capacity.

Typical criteria for system reliability evaluation are the system's Loss of Load Probability (*LOLP*) and Loss of Load Expectation (*LOLE*) [7]. *LOLP* is the probability that the load will exceed the available generation at a given time. This criterion gives an idea of the possibility of system malfunction but it lacks information on the importance and duration of the fault. *LOLE*, being currently the most mainstream criterion, is the number of hours, usually per year, during which the load will not be met over a defined time period. This criterion has more practical significance than *LOLP*, although both criteria are related. *LOLE* is given by:

$$LOLE = \sum_{i=1}^n P(C_i < L_i) \quad (1)$$

where $P(C_i < L_i)$ is the *LOLP* at time i , C_i the available capacity at time i and L_i the load at time i . Note that the available capacity is not always equal to the total installed capacity due to the generating unit's forced outage rates.

Based on *LOLP* and *LOLE*, several measures of capacity credit can be computed. Among these are: Equivalent Conventional Capacity (*ECC*), Equivalent Firm Capacity (*EFC*), Effective Load Carrying Capability (*ELCC*) and Capacity Savings (*CS*) [8].

ECC is the amount of conventional generation needed to obtain the same *LOLE* as that of the system with the added wind capacity. The *LOLE* of the system is given by:

$$LOLE' = \sum_{i=1}^n P(C_i + W_i < L_i) = \sum_{i=1}^n P(C_i + C_i^c < L_i) \quad (2)$$

where W_i is the available wind capacity at time i . To obtain the *ECC*, equation (2) must be solved for C_i^c , which is the added conventional capacity

available a time i . The added conventional capacity considered here has a non-zero forced outage rate.

The Equivalent Firm Capacity is obtained in the same way as the *ECC*. The difference resides in the fact that the added capacity is considered to be totally reliable (i.e it has a null forced-outage rate). This generally leads to values of *EFC* lower than those of *ECC*.

The *ELCC* is the amount of added load the system can meet with the same reliability due to the addition of wind capacity. To obtain this measure the following equation must be solved for E_i the extra load at time i .

$$\sum_{i=1}^n P(C_i < L_i) = \sum_{i=1}^n P(C_i + W_i < L_i + E_i) \quad (3)$$

Capacity saving is the amount of installed capacity no longer needed because of the addition of wind power. This value is calculated by solving:

$$\sum_{i=1}^n P(C_i < L_i) = \sum_{i=1}^n P(C_i^w + W_i < L_i) \quad (4)$$

In (4), C_i^w is the available capacity need in combination with available wind power to meet the load, which correspond to an installed conventional capacity C^w . The capacity saving is the difference between C , the actual installed capacity, and C^w .

As we have seen, calculating capacity credit values involves evaluating system's reliability. To do so, two main types of methods exist: analytical and simulation. Analytical approaches are based on mathematical descriptions of the system. They use mathematical tools to solve the above-mentioned equations. The main advantage of these methods is that, for a specific set of parameters, they provide a unique solution. Their main disadvantage is that, often, simplifying hypotheses have to be made.

In [8], an analytical method is presented. The system conventional available capacity and the load are modeled by Normal distribution functions, and wind power is based on a Rayleigh distribution of wind speed. The capacity credit values are given as a function of the parameters of these distributions. Although the assumptions made can be simplifying, these expressions can be useful as first approach indicators of the capacity credit of wind.

A simple approach described in [9] is based on the computation of a wind sources capacity factor based on the top 50% load hours. The wind sources power production is simulated using measured wind data and a power curve. The resulting power values are coupled with measured load data corresponding to the same time period. The coupled values are then sorted in decreasing order of load and the capacity factor is computed. Similar methods are presented in [10]. These simple methods provide a good estimation of capacity credit and do not require extensive modeling effort.

In [11], an algorithm is proposed to calculate capacity saving. Load and wind speed are modeled using generic two-parameter distributions (in the numerical example load is modeled with Normal distribution and wind speed with a two parameter Weibull distribution). The necessary generating capacity is computed so as to obtain a predefined LOLP. Two values of generating capacity are calculated: one to satisfy the load and a second one to satisfy the residual demand (i.e. the load minus the wind capacity). The difference between the two generating capacities determines the capacity saving.

More elaborate techniques involve the use of existing power system cost and reliability calculation models [12] in which simulated wind speed and load timeseries are used as input. Most of the time wind production is considered as negative load. These techniques, based on Monte Carlo simulation, differ from one another because of the cost reliability models used and the wind speed simulation procedures employed. For wind speed simulation, the use of an ARMA model is proposed in [15], where wind speed randomness is represented by the white noise component of the model. The model parameters are fitted using measured wind speed. Other methods use Markov chain models [12]. This approach calculates transition matrixes from measured wind speed time series. The simulated time series are then randomly drawn from the transition matrices.

In [16], a method that quantifies the level of reserve a system should carry to correspond to a certain reliability criterion is proposed. The technique considers generators' outage rates, load and wind power forecast errors in such a way as to directly relate the system reserve level to the security of the system. It is shown that as penetration of wind power increases the system will become less reliable unless reserve levels are increased.

In [17], a method is proposed to quantify the supplemental reserve needed to accommodate intermittent resources. The method mimics the hour-ahead scheduling process, real time dispatch and automatic generation control. This simulation provides a way to evaluate the added cost incurred because of the intermittent resource.

Finally, in [18] the impact of wind integration is studied at a European scale. The capacity credit is assessed with the National Grid scheduling Model, using input from one year meteorological data from 60 stations in Europe, and from reanalysis calculations for 34 years. Using a supply security of 95% for the definition of the capacity credit, a value of 19.3% of the installed capacity was estimated.

The present paper presents the first part of a study for aiming to quantify the capacity credit and reserve requirements for the French power system. Initially, it provides estimations for the variability of wind production. Then, the level of guaranteed wind

power with a certain probability is estimated. For the estimation of capacity credit and reserve requirements a simple model of the generation mix is considered. Complete estimation of the criteria presented in this Section requires a more elaborated reliability model for the power system and this is part of a second on-going phase of this work.

III. DESCRIPTION OF THE METHODOLOGY

A. Wind data and extrapolation

The data used to carry out the study consist in hourly wind speed measurements at 10 meters above ground level (a.g.l.), collected from 40 meteorological stations and covering a period of 3 years (1st April 2000 to the 31st March 2003). These stations belong to Meteo-France network and were chosen according to:

- the quality of the data,
- the probability that wind farms set up nearby in the medium term.

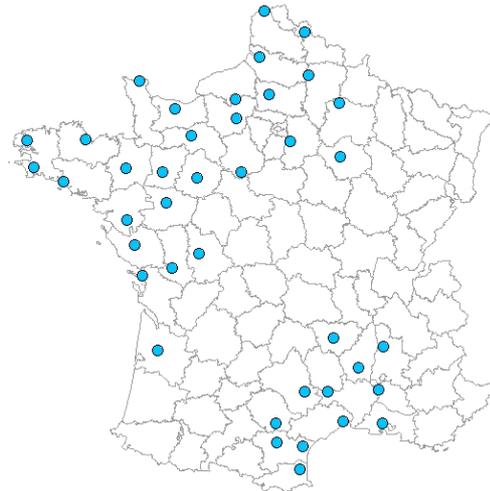


Figure 1 : Distribution of the 40 meteorological stations.

Often the meteorological stations are located to sites with moderate wind resource that cannot be considered in general as representative for sites where wind farms are installed. Using these measurements as such would lead to an underestimation of wind production. Horizontal extrapolation is needed to account for the differences in the characteristics (orography, roughness) of the terrain between the meteorological station and that of the potential wind farm. This extrapolation also involves conversion of wind speed from 10m ($V_{anemometer}$) to the hub height (V_{hub}), which can be done using the following logarithmic law:

$$V_{hub} = V_{anemometer} \times \frac{\ln\left(\frac{z_{hub}}{z_0}\right)}{\ln\left(\frac{z_{anemometer}}{z_0}\right)} \quad (5)$$

where z_0 is the roughness, z_{hub} the hub height of the wind turbine and $z_{anemometer}$ the height at which measurements are made.

For a specific projected wind farm site j , linked to the meteorological station i ; the above relation can be expressed as a linear one:

$$v_{hub}^j = C^{ji} * v_{anemometer}^i \quad (6)$$

Then, choices have to be made on the roughness but also on all the other factors that are important for the horizontal extrapolation. This is a very complex issue since wind resource is very sensitive to topology and wind farm settlement is exposed to various externalities that we can hardly foresee in the short term. Among these externalities we can mention public opposition, environmental constraints, political choices and connection to the grid.

For the above reasons, we make the hypothesis that parameter C^{ji} in (6) compensates not only height conversion but also horizontal extrapolation. This parameter, specific for each wind farm j , is the only unknown quantity that has to be assessed. It is linked to the capacity factor C_F^j of the wind farm by:

$$C_F^j = \frac{\sum_t P_N^j \bar{P}(C^{ji} \times v_{anemometer}^i(t)) \times 1hr}{P_N^j} \quad (7)$$

where $\bar{P}(\cdot)$ is the normalized wind turbine power curve presented below and P_N^j is the projected nominal power for wind farm site j . C_F^j is given in hours.

There are two arguments in favor of this methodology: firstly, if the model is simple, it can be checked easily; secondly, the above logarithmic law and some linearized models that we can find in the literature come to a similar linear relation (but with the factor C depending on wind direction).

B. Power Curves

Power curves differ from one wind turbine to another. Furthermore, there is no certainty either about the market share of the different technologies in the future or about the improvements that could be made. In order to build a realistic reference power curve, some common types of wind generators have been compared. After a normalization using nominal power, the study showed similarities between the curves (Figure 2). An average wind curve was considered as reference power curve $\bar{P}(\cdot)$ in this study.

C. Modeling the overall generation

Based on the above considerations, the overall generation can be modeled provided that hypotheses on installed power and mean capacity factors, for the wind farms linked to each

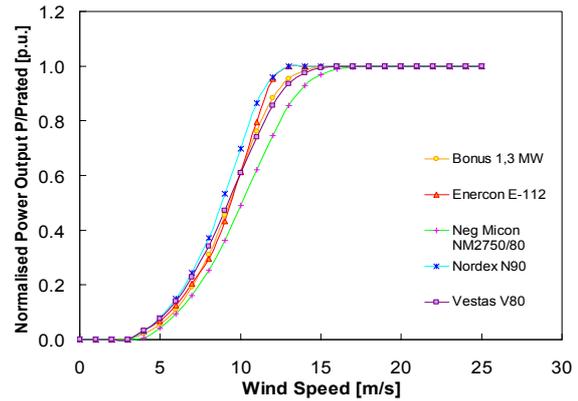
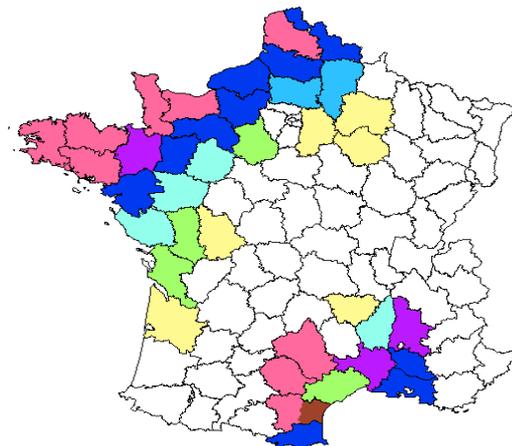


Figure 2: Normalized power curves for a sample of large turbines.

meteorological station, are made.

Capacity factors were assumed to be unique for all wind farms attached to the same meteorological station. To set the values of these factors, we proceed empirically by considering feedback from wind project developers. The three scenarios shown in Figure 3 were considered.



| | Low C_F | Medium C_F | High C_F |
|-------------|-----------|--------------|------------|
| Yellow | 1 800 h | 2 000 h | 2 100 h |
| Light Green | 2 000 h | 2 200 h | 2 300 h |
| Cyan | 2 100 h | 2 300 h | 2 400 h |
| Blue | 2 200 h | 2 400 h | 2 500 h |
| Dark Blue | 2 300 h | 2 500 h | 2 600 h |
| Purple | 2 400 h | 2 600 h | 2 700 h |
| Pink | 2 500 h | 2 700 h | 2 800 h |
| Brown | 2 700 h | 2 900 h | 3 000 h |

Figure 3: Estimation of the capacity factor for various areas.

The geographical dispersion is a problematic issue because of many uncertainties and externalities. In France, for instance, it appeared that due to residents opposition and administrative constraints, wind generation projects transferred from coastal areas to inland between 2001 and 2002. For this reason, two scenarios have been built for the deployment of the projected wind parks shown in Figure 4. The first one assumes low

dispersion and results from statistics on the requests of independent wind farm producers for grid connection in 2002. The data were provided by RTE, which is the Transmission System Operator (TSO) in France. The second scenario is derived from the first one by increasing the geographical dispersion.

The two scenarios do not necessarily agree with the present geographical dispersion of wind farms in France. This is due to former incentive programs that do not reflect the current trends.

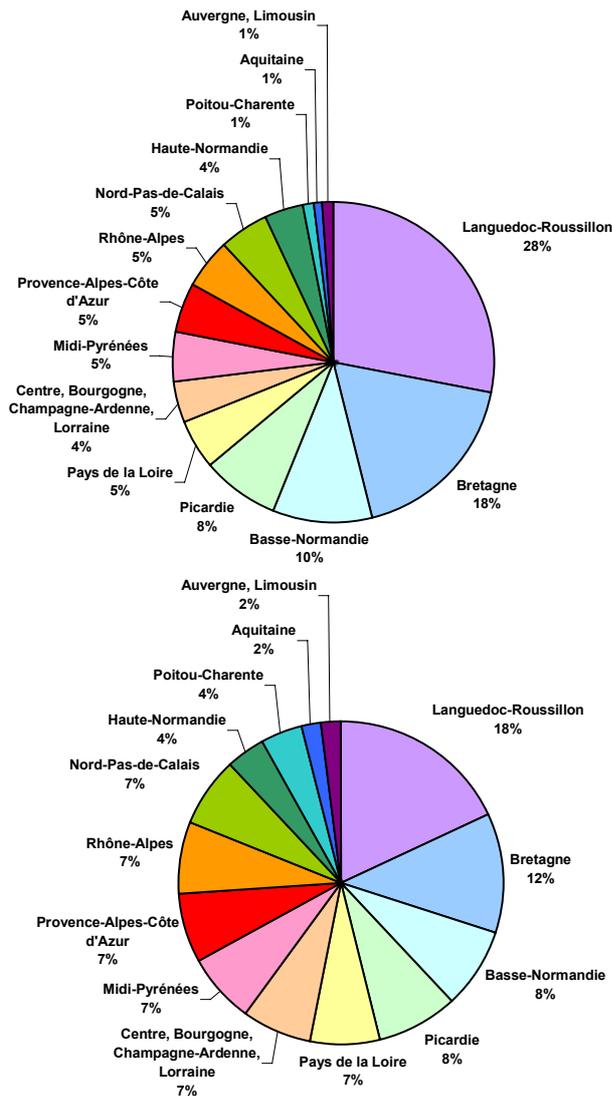


Figure 4: Geographical dispersion of wind capacity Upper: low dispersion hypothesis, Lower: high dispersion hypothesis.

IV. RESULTS

Results are presented here on the hypothesis of 6 000 MW installed wind capacity. The combination of the three choices for the capacity factor and the two for the geographical dispersion provides six scenarios named hereafter as «S1» to «S6». Three scenarios were added («S7» to «S9»)

representing extreme situations where the whole park is developed in the south (Languedoc-Roussillon) (S7), or shared between two regions, one in the south (Languedoc-Roussillon) and one in the north (Bretagne) (S8). A last scenario (S9) considers a uniform dispersion of the installed capacity among the 40 stations. The nine scenarios are summarized in Table I.

Table I: Overview of simulated scenarios (L-R: Languedoc-Roussillon, Br.: Bretagne)

| N° | Capacity factors | Geographical dispersion |
|----|------------------|-------------------------|
| S1 | option "low" | low |
| S2 | option "low" | high |
| S3 | option "medium" | low |
| S4 | option "medium" | high |
| S5 | option "high" | low |
| S6 | option "high" | high |
| S7 | option "medium" | 100% in L-R |
| S8 | option "medium" | 60% in L-R, 40% in Br. |
| S9 | option "medium" | Uniform |

Table II summarizes the statistics for each scenario. It can be noticed that the ratio between standard deviation and average production decreases as wind park dispersion increases (due to geographic smoothing effect) or as the capacity factor increases (due to the shape of the power curve).

Table II: Statistics of the simulations

| N° | Mean Production (P_m in MW) | Capacity Factor (C_F in hours) | Std Deviation (σ in MW) | σ / P_m |
|----|--------------------------------|-----------------------------------|---------------------------------|----------------|
| S1 | 1 608 | 2 348 | 1 063 | 0,66 |
| S2 | 1 569 | 2 291 | 1 044 | 0,67 |
| S3 | 1 746 | 2 549 | 1 110 | 0,64 |
| S4 | 1 707 | 2 492 | 1 093 | 0,64 |
| S5 | 1 814 | 2 648 | 1 131 | 0,62 |
| S6 | 1 775 | 2 591 | 1 114 | 0,63 |
| S7 | 1 796 | 2 622 | 1 543 | 0,86 |
| S8 | 1 811 | 2 644 | 1 204 | 0,67 |
| S9 | 1 671 | 2 440 | 1 135 | 0,68 |

A. Geographic smoothing effect and guaranteed power

In order to quantify the smoothing effect, the guaranteed power (i.e with an x% probability) for the different scenarios is shown in Table III. The guaranteed power increases significantly from S7 to S8, and slightly from S8 to the remaining scenarios. This increase stems from the very tenuous correlation of the wind regimes of northern and southern France. However, correlations are stronger within these zones, which explains for instance the small difference between S8 and S9. The ratio of the guaranteed power on the average power does not vary between the concentrated

scenarios (S1, S3 and S5) and the dispersed scenarios (S2, S4 and S6). A uniform distribution of the wind parks (S9) even leads to poorer performance.

According to these results, the power guaranteed with a 90 % probability is at the level of 24 % of the average power, or 7 % of the installed capacity, for a capacity factor of 2500 hours. These are average yearly values; the seasonality of the guaranteed power needs to be further investigated.

Table III: Guaranteed Power

| N° | P guaranteed at 95 % (P_{95} in MW) | P_{95} / P_m | P guaranteed at 90 % (P_{90} in MW) | P_{90} / P_m | P guaranteed at 80 % (P_{80} in MW) | P_{80} / P_m |
|----|--|----------------|--|----------------|--|----------------|
| S1 | 217 | 0,14 | 357 | 0,22 | 613 | 0,38 |
| S2 | 223 | 0,14 | 357 | 0,23 | 596 | 0,38 |
| S3 | 257 | 0,15 | 413 | 0,24 | 698 | 0,40 |
| S4 | 263 | 0,15 | 415 | 0,24 | 683 | 0,40 |
| S5 | 278 | 0,15 | 444 | 0,24 | 742 | 0,41 |
| S6 | 286 | 0,16 | 446 | 0,25 | 727 | 0,41 |
| S7 | 58 | 0,03 | 145 | 0,08 | 352 | 0,20 |
| S8 | 198 | 0,11 | 346 | 0,19 | 665 | 0,37 |
| S9 | 246 | 0,15 | 386 | 0,23 | 626 | 0,37 |

B. Characterization of wind power production

In this Section, the relation between wind production and demand and also the magnitude of wind power fluctuations are examined. Results based on the scenario "S4" are given.

1) Wind power production and electricity demand

The seasonality of wind production and load are examined here in order to study possible correlations between the two time series. Hourly timeseries of the total load of France covering the same period as the wind speed data are used.

Figure 5 depicts the power system load and the simulated wind power generation as well as the penetration level for a period of 2 weeks. The wind generation is as produced by scenario S4 for an installed capacity of 6 000 MW. The maximum penetration for the overall period of 3 years is found to be 13.48%.

The simulated wind power values were sorted into 20 bins corresponding to the levels of load observed at the corresponding times. *I.e.* the first bin contains the wind production values of the hours for which the 5% lowest loads were observed. The average and the guaranteed wind power for 90% and 95% probability were computed for each bin as shown in Figure 6.

The comparison of the simulated wind production and the load in this Figure shows that,

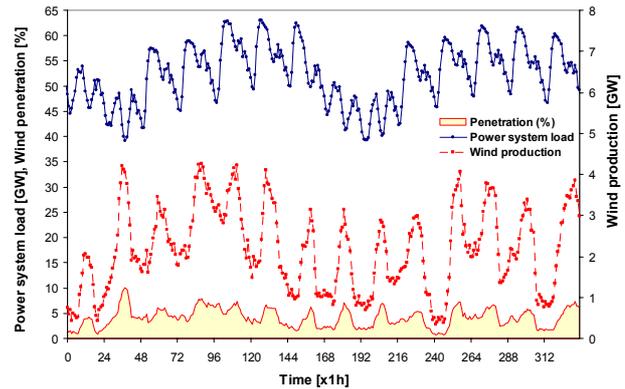


Figure 5: Power system load and simulated wind generation for a period of two weeks (1-14 April 2000). Penetration varies between 0.7 and 10.5%.

although these quantities are weakly correlated, the availability of wind power is statistically greater when load is high. For high loads, the guaranteed wind power with a 90% probability reaches 10% of the installed capacity (representing 30% of the 3 year average power). This result is higher than the average guaranteed power level (7% of the installed capacity with a 90% probability), but it should be cautiously interpreted. Certainly this result should be verified against extreme loads: particularly cold temperatures are often observed during anticyclonic conditions during which low wind speeds are to be expected.

In its provisional assessment for 2006-2015 RTE assumed an average wind power production of 15% of the installed capacity for very cold periods. This is 50% less than the value for the last bin. A climatologic study would be necessary to evaluate an accurate value.

Finally, the daily cycles of both hourly wind production and load time series were compared. These cycles were computed by averaging daily curves. To take into account daylight saving time two averages were computed: one for summer time and another for winter time. As shown in Figure 7 there is phase shift between wind production and

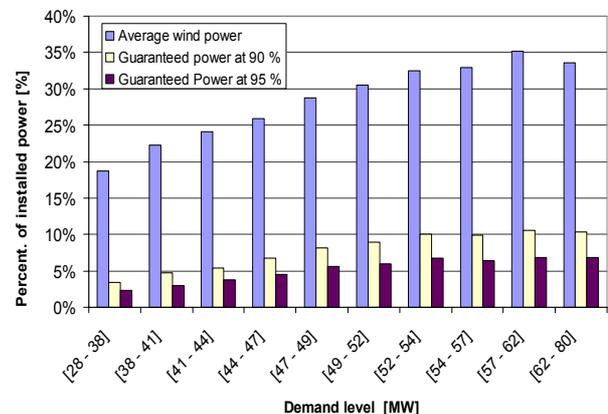


Figure 6: Wind production statistics computed as a function of load level.

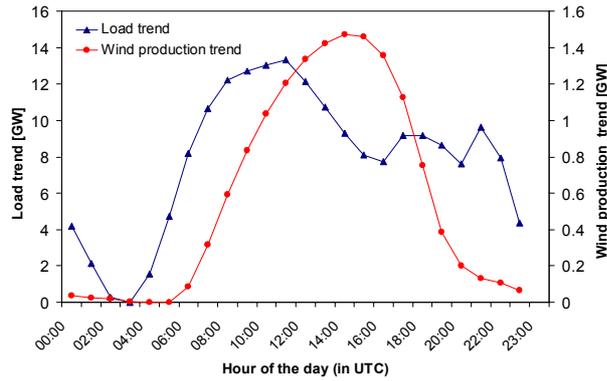


Figure 7: Daily trends of wind power production and load for summer months.

load. For summer time, the amplitude of wind production variations is quite high: 1400 MW (1000 MW in winter) with an average standard deviation of 1090 MW. The difference is more important in summer due to thermal breezes caused by important, sun induced, temperature gradients.

However, the amplitude of variation might have been overestimated by the wind speed extrapolation model. Indeed, the extrapolation model does not take into account atmospheric stability. Since the vertical component of wind speed is more important in stable atmospheric conditions than in unstable ones, for the same 10-meter wind speed measure, the wind speed at hub height will be greater at night.

2) Wind power fluctuations

This Paragraph deals with wind power production fluctuations. The daily trends (computed separately for summer months and winter months) have been subtracted from the time series.

Figure 8 shows the probability of witnessing a variation greater than the threshold noted on the horizontal axis within a given time window. For example, the percentage for the -1000 MW threshold indicates the probability of observing a decrease of at least 1000 MW between time t and time $t + T$. It is noted that the power variations from one hour to the next are within ± 680 MW, which is less than $\pm 11.5\%$ of the installed capacity, with a 99% probability.

C. Impact of wind power integration on the generation scheme.

The role of each type of generation in covering demand is illustrated in Figure 9. The order shown in the figure represents priorities followed in practice. The integration of the wind power into the generation mix can be envisaged from a static point of view as following. Since system operators are legally obliged to use all available wind energy, wind power will replace the most expensive

generating sources: first classic thermal and then nuclear. Contrary to what the order presented in Figure 9 might suggest, peak hydroelectric generation should not be offset by wind production. Indeed this type of generation is less expensive than thermal or nuclear generation. Pumped hydro storage is placed at the top of the production pile because of its limited size. It is more profitable to exploit the hydro storage when electricity prices are high (i.e. when load is high). Of course, offsetting hydro production instead of thermal or nuclear power can make economic sense if hydro storage can be sold later at a higher price.

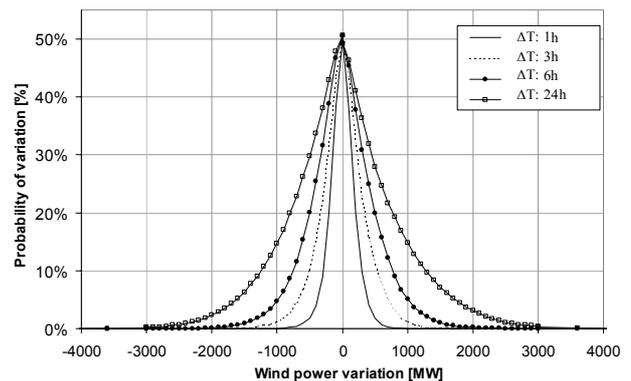


Figure 8: Variations of the hourly wind production corrected for daily trend.

The above approach was used to study the impact of the simulated wind production from scenario "S4" on the generating mix for a period between April and December 2000. The resulting generation mix was computed from production data on each generation type (thermal, nuclear, hydro etc). The results are summarized in Table IV.

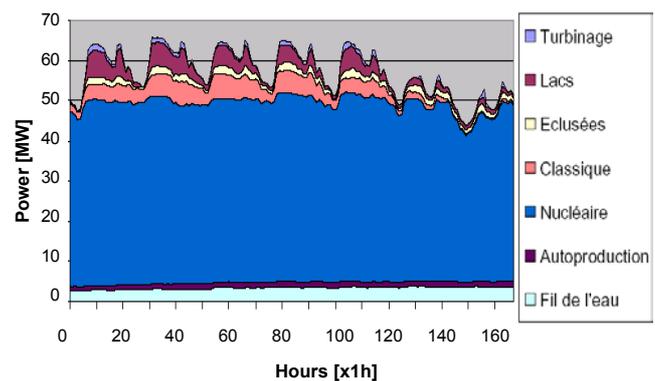


Figure 9 : Example of generation mix for covering the load of one week [13].

These results must be interpreted taking into account that the considered period does not cover the first three months of the year. Over the 9-month period considered, classic thermal generation was 17 TWh as opposed to 30 TWh over the whole year. Yet, with the 6 000 MW wind capacity hypothesis, wind power significantly replaces thermal generation and only marginally nuclear

production. With hypothetical installed wind capacity of 14 000 MW a very important part of thermal generation can be avoided. But, in this case, nuclear generation would be reduced by a similar amount, which can be a problem. Nuclear generation, for economic as well as for technical reasons, cannot be easily subject to power modulations. If it then becomes necessary to couple wind generation with a complementary type of generation to attenuate power variations, the actual replaced nuclear power would be greater than that given in Table IV.

Table IV: Production reduction for each generation type after the inclusion of wind generation.

| Installed wind capacity | 6 GW | 10 GW | 14 GW |
|---|-----------------|------------------|------------------|
| Wind energy production over the period | 10,81 TWh | 18,02 TWh | 25,22 TWh |
| Share of avoided classic thermal energy | 8,14 TWh (48 %) | 11,40 TWh (67 %) | 13,28 TWh (78 %) |
| Share of avoided nuclear energy avoided | 2,66 TWh (1 %) | 6,61 TWh (2 %) | 11,93 TWh (4 %) |

The approach used here relies on a simplified vision of the power system. It should be noted that:

- it does not take into account the problems linked to wind power volatility and system balance.
- interactions with peak hydro generation were not considered,
- demand at the time when installed wind capacity reaches 6, 10 and 14 GW will be higher than that of year 2000, whereas the installed conventional capacity will not increase in the same proportion,
- power exchanges with neighboring networks were not considered.

Nevertheless, the results obtained with the 6 000 MW scenario agree with the "EnR" scenario for 2006 developed by RTE [14] according to which wind power should primarily replace thermal power and only marginally offset nuclear power.

D. Uncertainty management and reserve needs

In electricity market deregulation policy, RTE is responsible for maintaining balance between generation and demand and managing deviations between these two. Deviations may result from uncertainty:

- on demand due to erroneous meteorological forecasts, especially concerning nebulosity and temperature. For example, a 1 °C drop in temperature in winter leads to an increase in power demand by 1300 MW while a cloudy sky over Paris can lead to a 400 MW increase,
- on demand due to customer behavior,
- on production due to generators reliability,
- on production due to intermittent energy sources like wind power.

In order to handle these uncertainties, the TSO uses an "Adjustment Mechanism" that permits to build up production reserves to face upward and downward load variations. The reserves can be of the following types:

- primary reserve: Roughly 700 MW available automatically in less than 30 seconds. This reserve contributes to maintaining frequency.
- secondary reserve: Between 700 MW and 1 000 MW (depending on the load) automatically available within a few minutes.
- fast tertiary reserve: manually started and available within 15 minutes, it must allow to compensate the loss of the largest operating generating plant.
- predefined horizon reserve: upward or downward reserve available at a given horizon (at the moment of peak load this reserve can reach 3 000 to 4 000 MW)

Figure 10 shows the distribution of reserves called by the "Adjustment Mechanism" during the period between 01/04/2003 and 26/08/2003. The histogram is based on all time slots considered by the mechanism each day (0h-3h, 3h-8h, 8h-11h, 11h-14h, 14h-17h, 17h-20h et 20h-24h).

1) Additional reserve needs resulting from wind power uncertainty

In this Paragraph we focus rather on wind predictability than on variability. It is assumed that predictions are available for the total wind power and that the balancing mechanism has to call for reserves to compensate errors in the prediction of this power. A typical performance is considered for predictions as this can be obtained by a state of the art prediction model [19]-[21]. Given that realistic errors are required, while a prediction model is not available for the case of total wind generation in France, we considered the errors provided by persistence for 3 hours ahead as representative of those that would be obtained by a prediction model for 24 hours ahead. The histogram of prediction errors was then considered to estimate the average reserves needed to cope with wind power uncertainty for different horizons. The resulting distribution for "S4" scenario is presented in Figure 10. From this figure it can be seen that, for 6 000 MW installed wind capacity, reserve needs are already significant.

These results however do not reveal a considerable increase of the amount of energy traded through the "Adjustment Mechanism".

V. CONCLUSIONS

The aim of this paper was to obtain representative results on the spatial and temporal characteristics of wind generation in France. A methodology has been developed to simulate the wind production based on a certain number of

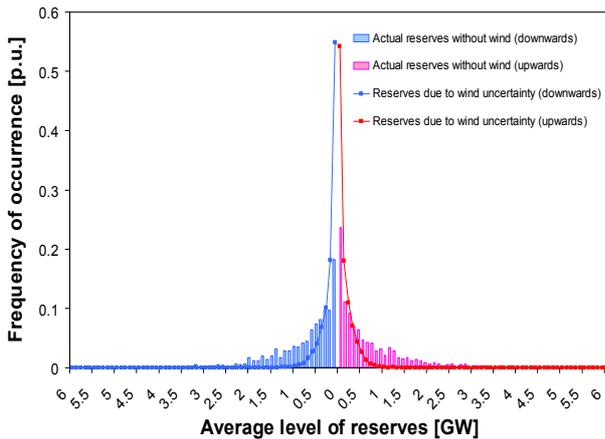


Figure 10: (Vertical bars) Distribution of the upwards and downwards average adjustment power used in the balancing mechanism between 01/04/2003 and 26/08/2003. (Dotted line) Distribution of the average power needed to balance wind power due to forecasting uncertainty.

assumptions. These assumptions are justified given the uncertainty on the development of wind generation in the country.

The variability of the wind generation was studied for several look ahead times. This variability is clearly reduced due to the smoothing effect compared to the variability of single wind farm production. The geographical dispersion of the wind parks is providing a guaranteed power at the level of 7% of the installed capacity with a 90% probability. The integration of wind power into the French generation scheme was studied. It was shown that wind power could replace a sizable portion of thermal generation. Finally, the reserves expected to be engaged by the balancing mechanism depend on the level of predictability of wind power. However, further analysis is ongoing on this point that combines uncertainty in both load and wind predictions to estimate the global reserves.

Further steps are planned to refine this work considering the uncertainty on the distribution of wind park installations, the adaptation of the extrapolation model for situation of complex terrains, the variability of characteristics of wind farms linked to a specific meteorological station, a higher amount of stations and more years of data. Finally, additional scenarios considering offshore wind generation are built.

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