IMPACT OF WIND POWER INTEGRATION ON BELGIAN POWER RESERVE REQUIREMENTS

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Abstract - *As part of the European energy policy goals of sustainability, security of supply and improved competitiveness, the share of Renewable Energy Sources for Electricity (RES-E) is rapidly increasing. The two main technologies driving this development in Europe are wind and solar PV, which are both characterised by variable energy output with limited controllability and predictability. The unexpected power output variations challenge the power system, as additional generation reserves are expected to be necessary in order to balance demand and generation. This study suggests a probabilistic approach to assess the impact of wind power integration on upward and downward generation reserves required in order to reach a predefined reliability level. Focus of the study is put on a specific methodology enabling to distinct different categories of reserves as currently defined in most European power systems: this contribution suggests to dimension secondary reserves based on short-term wind power fluctuations and tertiary reserves based on the forecast error. This methodology is particularly useful in case of expensive secondary reserves as it minimises the required capacity and activation of secondary reserves. Results for a scenario towards 2020 for Belgium show a proportional increase of reserve requirements with installed wind capacity. The required secondary and tertiary reserves amount respectively up to 7% and 36-41% of the installed wind power capacity.*

1 Introduction

Wind power integration faces an electricity system requiring a continuous balance between demand and generation. Deviations from this equilibrium results in frequency deviations which may cause the disconnection of generation and even cause black-outs. As the main responsibility of the Transmission System Operators (TSOs) is to ensure the overall power system security, they are the final responsible for balancing their control area. This is executed by contracting balancing services from grid users, mainly from generators, under the form of power reserves. This reserve capacity can be activated upward or downward in order to restore the system balance (Tractebel Engineering and Katholieke Universiteit Leuven, 2009).

A part of this balancing responsibility is transferred to the market: average injections and off-takes are to be balanced by the market parties (Balancing Responsible Parties, BRPs) over a certain settlement period. In general, conventional generators adapt their positions according to the demand and the variable RES-E output. Technical and economic constraints require the scheduling of the generators well in advance (days up to hours). In real-time, the scheduled generators are dispatched according to the real-time demand and variable RES-E generation. Consequently, a well in advance predicted variation in demand or generation can be covered by rescheduling generators.

On the other hand, flexibility of the generation park decrease with shorter horizons. Starting generators may take hours up to days depending on the technology. Additionally, market regulations limit the ability of generators to adapt positions continuously as these are to be fixed and nominated to the TSO one day in advance. Today, intraday mechanisms allow rescheduling under certain circumstances, but this possibility also has its limitations in most power systems (De Vos and Driesen, 2009; De Vos et al., 2011). Either way, each imbalance is to be covered, or by the market (generation or demand side participation), or by the system operator (reserve capacity). In general, unexpected fluctuations are balanced by reserve capacity (TSO) while well in advance predicted fluctuations can be dealt with by the market. Additionally, the TSO remains responsible for fluctuations inside the settlement period.

As different studies show, variable RES-E integration such as wind is expected to increase system imbalances, resulting in increasing balancing costs (UKERC, 2006; VTT Technical Research Centre of Finland, 2009; ENTSO-E, 2010). The variability of these resources, leading to a limited controllability and predictability, is expected to require additional reserves when integrated in large scale in a power system. This impact is to be studied in combination with variability of demand and unexpected power plant outages.

Main objective of this document is to quantify and allocate increasing reserve requirements due to wind power integration in Belgium. When focussing on quantifying reserve requirements, the probabilistic method is usually presented as the most efficient approach, trading off complexity and accuracy. This methodology is based on a statistical analysis of system imbalance drivers, determining reserve requirements by means of a predefined reliability level (Maurer et al., 2009; Holttinen et al., 2008). In a second step, an approach is implemented to subdivide total reserve requirements over fast (secondary reserves, R2) and slow responsive reserves (tertiary reserves, R3) in a way that the overall system reliability level is maintained.

Section 2 presents an overview of the Belgium market for reserves, taken as a representative example for the ENTSO-E control zone. Section 3 discusses different methodologies to determine the impact of wind on the different groups of reserves. Focus is put on a probabilistic methodology to distinct R2 and R3 and which is applied in Section 4 on a case study for Belgium in 2020. Section 5 ends this contribution with some conclusions and recommendations for further research.

2 Reserve requirements for real-time imbalances

TSOs dimension the required reserve capacity based on their expectations of the system imbalance over a certain period. This is driven by two components: firstly, the imbalance volumes falling under the responsibility of the market by means of 'imbalance settlement' (Tractebel Engineering and Katholieke Universiteit Leuven, 2009). This concerns the averaged imbalances of generation and demand over the settlement period. Secondly, demand and generation fluctuations inside the settlement period which do not fall under the settlement period. Reserve requirements are generally allocated towards different groups of reserves characterised by specific response times and characteristics. As shown in Table 1, three groups are currently defined in the ENTSO-e zone: primary (R1), secondary (R2) and tertiary (R3) reserves. This classification, nomenclature and specific characteristics varies over different power systems. This is not further discussed in this work and focus remains on the current ENTSO-E zone and Belgium in specific.

Figure 1 shows the features and relations of the different groups of reserves for the Belgian control zone. Primary reserves (± 100 MW) are used to stabilise the system frequency at a stationary value after a disturbance or incident in the time frame of seconds (Elia, 2011). They are dimensioned on ENTSO-E level (3000 MW) and the total capacity is distributed over its members according to their weight in the interconnected power system. Activation occurs automatically where the service provider monitors the grid frequency and react accordingly. R1 has to provide half of the contracted capacity within 15'' and full capacity within 30''. It should be able to maintain this power output level for at least 15'.

In contrast to R1, secondary reserves restore the frequency in the synchronous zone and the balance in the control zone. R2 reacts after R1 (as can be seen in Figure 1) and ensures the balance between injections and off-takes in a control zone. R2 is activated automatically by the TSOs' dispatching centre and contracted capacity should be available after 30"-15' for as long as the service is required. According to the Belgian TSO, an average of 137 MW of R2 is currently contracted for the Belgian control zone. Tertiary reserves are generally scheduled or activated manually to free or assist the activated R2. In the Belgian control zone, R3 contracts require full delivery within 15' (Elia, 2011). 400 MW is currently contracted from the generators and additionally, 261 MW through load shedding large consumers.

Balancing Service Providers (BSPs) receive a reservation and a capped activation fee. Additional reserves can be contracted day-ahead (D-1) through biddings which only receive their bid price (activation fee) upon activation.

Table 1: Classification of active power reserves in the ENTSO-e zone (source: Tractebel Engineering and Katholieke Universiteit Leuven, 2009)

Frequency Control	Minimal Response Time	Control	Objective
Primary Frequency Control (R1)	≤ 30''	local automatic control	frequency stabilisation
Secondary Frequency Control (R2)	30'' - 15'	centralised automatic generation	restore overall frequency
Tertiary Control (R3)	≤ 15'	automatic or manual changes in load and generation	assist and relief for R2 & economic redispatch

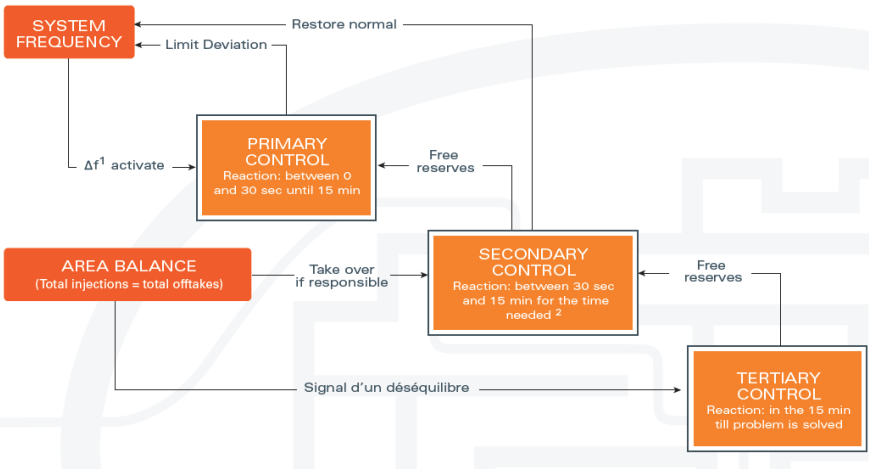


Figure 1: Activation of reserves in Belgian control zone (source: Elia, 2011)

3 Quantification and allocation of reserve requirements

3.1 Total reserve requirements

As reserve requirements are determined at system level, additional reserve requirements due to wind power integration may be determined by analysing the impact of wind power variability and predictability on the total system imbalance (Figure 2). The total system imbalance is an aggregation of three important drivers: demand variations, unexpected power plant outages and RES-E variability. Consequently, it is not only important to take into account smoothing effects between different wind farms, but also correlations between the different imbalance drivers, e.g. demand and wind, solar and wind or demand and solar are an important factor to take into account. This contribution focuses only on the variability and predictability of wind as an imbalance driver. When determining the impact of wind on the total system imbalance, it is assumed that there are no correlations between wind power and other imbalance drivers. This is not necessarily true as wind and demand imbalances or wind and solar PV imbalances are expected to smooth the system imbalance. The reserves estimates following the proposed methodology are therefore conservative.

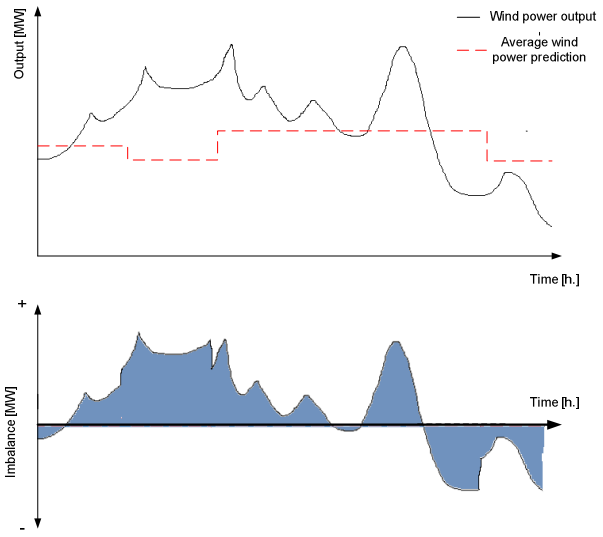


Figure 2: Representation of the aggregated wind power imbalance in a control zone

Literature presents three main methodologies to determine the impact of wind power on reserve requirements: heuristic, probabilistic and system simulation approaches. Current heuristic approaches, generally based on contingency analysis e.g. N-1, may not be adequate to tackle the increasing complexity of uncertainty which modern power systems are coping with. On the other hand, system simulations based on unit commitment economic dispatch or dynamic system models are generally used to determine system operation cost or check system reliability issues. They generally suffer from a restricted representation of wind power variability and limited predictability due to their high computational complexity. When specifically focussing on dimensioning reserve requirements, the probabilistic method is usually presented as the most efficient approach, trading off complexity and accuracy (Maurer et al., 2009; Holttinen et al., 2008).

The probabilistic methodology is based on combining the probability density curves of all three imbalance drivers. The aggregated cumulative probability density curve of the total system imbalance allows to determine up- and downward reserve requirements by means of a predefined reliability level. This is done by fitting a probability density curve on the imbalances and defining a reliability level. With a reliability of 99%, they are dimensioned to cover 99% of the power system imbalances while the remaining 1% may be resolved by load shedding. The reliability level is set as an assessment of the cost and benefits of security of supply. By means of this probabilistic methodology, reserve requirements are determined by extreme events.

3.2 Allocation of reserve requirements

Wind power system imbalances can be decomposed into two main components, namely the prediction error over the settlement period and the fluctuations inside the settlement period (Figure 3). The prediction error over the settlement period is the difference between the prediction and the averaged output over the same period (Figure 3, left). The aggregated generation deviations over the control zone are balanced by the TSO and charged to the responsible BRPs by means of the imbalance settlement. The fluctuations inside the settlement period remain the responsibility of the TSO (Figure 3, right). In view of the total imbalance, both components may reinforce (positive fluctuation together with positive prediction error) or may compensate (positive fluctuation together with negative prediction error) each other.

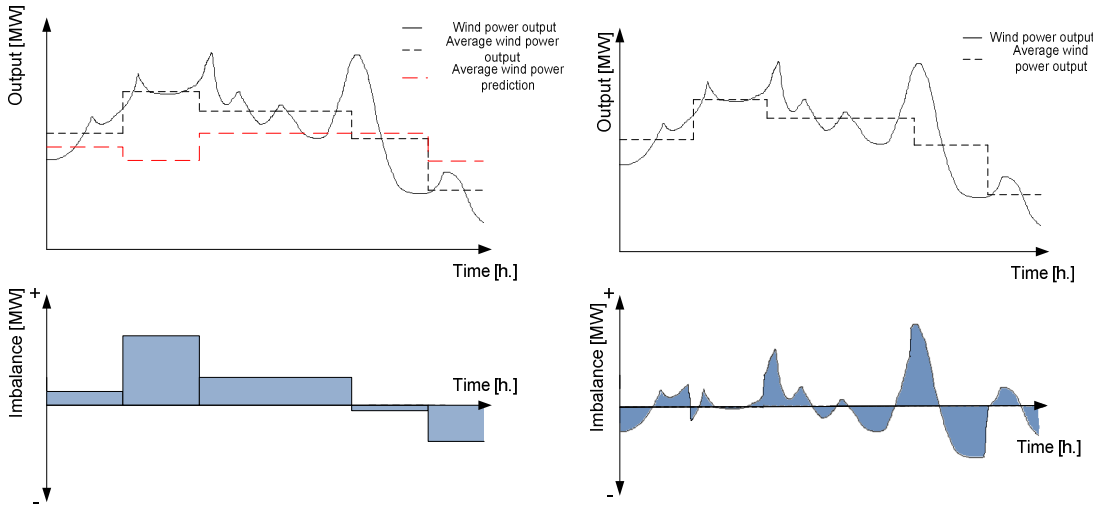


Figure 3: Representation of the aggregated prediction error over the settlement period (left) and the aggregated fluctuations inside the settlement period (right)

In order to ensure reliability, system imbalances are to be allocated towards flexible generators which meet the maximal ramping rates of the imbalances. A possible approach is to cover total reserve requirements with the most flexible reserves. This approach may result in high integration costs when assuming expensive R2 compared to R3. Therefore, the focus of this study is on dimensioning R2 and R3 by minimising R2 in a way that wind imbalances are still addressed adequately. In this contribution, a methodology is presented which dimensions R3 on the prediction error over the settlement period and the R2 on the fluctuations inside the settlement period.

In this approach, the amount of R2 is minimised in terms of capacity and activation, using them only when absolutely necessary, namely for short-term fluctuations. This may require oversized R3 and total reserves which may be justified if the activation costs of R2 exceed these of R3. Alternatively, assuming lower activation costs, a better methodology would be to determine the R3 by subtracting the R2 from the total reserves. Alternative methodologies to calculate R3 as the result of subtracting R2 from the total reserve requirements may be more expensive as R2 is also required to cover part of the imbalances that could have been covered by cheaper and slower R3.

4 Wind power reserve requirements for Belgium towards 2020

Based on the methodology discussed in Section 3, a numerical model is developed to quantify the impact of distributed wind power on system imbalances and R2, R3 requirements. The model is based on location specific wind speed measurements and predictions. Main inputs for the model are the installed wind power capacities distributed over these locations.

As Dutch wind data is used from locations distributed over an area of 160x100km², the model can be seen as representative for a small North Sea country. In this section, data, methodology and results are discussed in different subsections. Results are obtained for a case study for Belgium representing wind power integration towards 2020. The focus on the North Sea area was directed by the availability of relevant wind data. If data is available, this model can be transferred to other control zones.

4.1 Data

This model is based on measurements and predictions of wind speeds acquired from the Royal Dutch Metrologic Institute, KNMI (KNMI, 2010) and the Energy Research Centre of the Netherlands, ECN (Brand & Kok, 2003) respectively. In total, five locations were studied among which two offshore (Vlakte van de Raan, Lichteiland Goeree), two coastal (Stavenisse, Woensdrecht) and one inland (Eindhoven). These five locations cover a geographical area of 160x100 km² in the North Sea area which can represent a small North Sea control zone, e.g. Belgium. The distribution of the locations over zones with different wind characteristics allows to capture a large part of the aggregation effects which occur in a control zone.

One year of measurement data (2004) is processed towards a complete time-series of 8784 entries representing the hourly wind speed at the relevant hub height. As discussed in Section 2, the methodology requires a study of the wind power output fluctuations inside the settlement period. Consequently, wind speed measurement data with a resolution of one hour is not be sufficient to apply the proposed methodology. As higher resolutions are not available for the KNMI measurements, time series of measurement data with a resolution of 10’ are constructed synthetically by means of putting intra-hourly fluctuations on the hourly KNMI data. This is based on the statistic description of 10’ resolution data acquired from an offshore wind mast in the North Sea. There are two drawbacks resulting from the use of one reference measurement: first, it is assumed that the fluctuations for each location behave like offshore fluctuations. Second, the fluctuations of the different locations are assumed to be uncorrelated.

Forecast data for the same locations is acquired from the ECN Nederland. Like many other forecast tools, it is based on a combined physical and statistical approach. This data is processed towards 7 prediction horizons capturing hourly wind speed predictions. Three groups of time series of wind speeds are defined above and relevant for further calculations: KNMI 1h, KNMI 10' and ECN 1h.

The power curve represents the output characteristics of a wind turbine, farm or park and can be used to convert wind speeds in active power output. For this study, normalised, regional aggregated power curves from the TradeWind project are used representing current technology (Mc Lean, 2008). When evaluating the output of a farm or park, these curves are more realistic than the use of individual power curves as they take into account wind park effects (wake, electrical losses, unavailability). This results in smoother curves (not all turbines start generating power at the same time), lower active power output (aerodynamical and electrical losses, unavailability,...) and a smoothly decrease in power output in case of high wind speeds (not all wind turbines shut down at the same time during a storm).

4.2 Methodology

In this contribution, a settlement period is assumed of 60'. This choice is motivated by the limited resolution of the available data and avoids complex methodologies to increase resolution while losing on accuracy. This assumption is however not so unrealistic: power systems with 60' settlement periods do exist (e.g. Nordic countries), power exchanges quote hourly products which can make it difficult for inflexible BRPs to adapt to intra-hourly fluctuations. Additionally, it is shown that the forecast tool used in this study, predictions do not fluctuate that much inside the hour. The changes are much smaller compared to intra-hour wind speed fluctuations indicating that this forecast tool is not fully able to predict intra-hourly wind speed fluctuations. Today, forecast tools are generally based on hourly predictions interpolated over the settlement period to achieve higher resolutions.

By aggregating wind generation of five locations, a large part of the smoothing effects are captured by the model. However, further increasing the distribution of the installed capacity is not possible due the unavailability of wind data. As a consequence, the assumption of using five instead of multiple locations slightly overestimates the power reserves needed. Smoothing due to wind farm effects (wake effects, unavailability, electrical losses, ...) are however incorporated by using the Tradewind power curves. Secondly, correlations with other imbalance drivers such as load or solar PV are assumed to be zero. This is not necessarily true but the incorporation of possible correlations depends on the availability of data which was not the case in the framework of this study.

As discussed in Section 3, total system imbalance, prediction error and short-term fluctuations are the main input for determining total, tertiary and secondary reserves. In order to perform the probabilistic approach, historic time series of these parameters are constructed:

System Imbalances: *Imbalance = RT 10' - PRED 1h*

Tertiary Reserves: *Prediction error = RT 1h - PRED 1h*

Secondary Reserves: *Fluctuations = RT 10' - RT 1h*

In a second stage, the correct probability density curve is fitted on the aggregated system imbalance, prediction error and fluctuations. Combined with the relevant reliability level (99.9, 99, 95, 90%), the resulting reserve requirements can be determined. These reliability levels are determined separately for upward and downward reserves.

4.3 Results

In this section, the numerical model is applied to the Belgian control zone. This country is chosen for a case study as it is well represented by the simulation model developed in the framework of this research. The Belgian control zone is a small North Sea country with a surface of 30.500 km². Additionally, the Dutch wind speed data may be assumed representative for the Belgian territory (and certainly for Flanders) due to geographical proximity. Last but not least, the Belgian control zone has a balancing market design which is relatively similar, or at least comparable, with other ENTSO-E members.

The increasing share of wind power capacity is an important issue for the Belgian control zone. Similar to the EU-27 in general, wind power is seen as one of the main drivers for renewable developments in the electricity sector. This is certainly the case when taking into account its offshore potential. The issue of balancing may be even more important for Belgium when integrating large shares of variable RES-E in a small geographical area limiting potential smoothing effects. Data concerning the current Belgian wind power park is shown in Table 2. These numbers are published and regularly updated by the TSO and the regional regulators according to their authority. Taking into account the latest numbers available in October 2010, the total installed capacity adds up to 534 MW. Offshore capacities are still limited but are expected to grow significantly in the near future. In the rest of this section, new reserve requirement calculations are made which represent the current installed wind power capacity in Belgium. In order to take into account expected wind power developments, two development scenarios are presented focussing on the uncertainty of offshore developments by 2020 (Table 3). In this way, the impact of increasing shares of wind power on reserve power requirements can be evaluated.

Table 2: Installed wind power capacity in Belgium in 2010

2010	Offshore	Flanders	Wallonia	Brussels
Source	Elia	Vreg	CWaPE	BRUGEL
Data	23/09/2010	31/08/2010	18/03/2010	04/02/2009
Inst.cap. [MW]	30	243	261	0
TOTAL [MW]				534

Total installed capacity is derived from a baseline and reference scenario presented in a European Commission using the PRIMES model (Capros et al., 2010). As the EC document only describes national energy projections, other available scenarios are used to distinct the offshore from the onshore developments (Van der Toorn, 2007; Tambke and Michalowska, 2010). The baseline and reference scenario for 2020 are inserted in the model by distributing the installed capacity over the five wind data locations (Table 4). Only one offshore location is integrated as the expected offshore developments are to be installed in a rather concentrated way (ref. current domain concessions). The onshore capacities are distributed equally over the three onshore locations. Two third of the onshore capacity is consequently allocated to coastal areas which represent the expectation of higher installed capacities in the western part of the country.

Results are shown in Table 5 and Figure 4 for a 99% reliability level. This corresponds to the 3σ-approach applied in different case studies which can be found in literature (Holttinen et al., 2008). This factor is used as reference level for the rest of this study although reliability levels may vary over different power systems.

Table 3: Wind power development scenarios for Belgium towards 2020 (PRIMES1, TradeWind2, Offshore Grid3)

[MW]	Offshore		Onshore		Total[1]	
	base	Ref	base	ref	base	ref
2010	30		504		534	
P 2010	216[2]	337[2]	823	725	1039	1062
P 2020	1251	1994[3]	1236	1575	2487	3569

Table 4: Representation of installed wind capacity in simulation model

[MW]	Offshore1	Offshore2	Coastal1	Coastal2	Inland
2010	30	0	168	168	168
P 2020 base	1251	0	412	412	412
P 2020 ref	1994	0	525	525	525

Table 5: Additional reserve requirements (expressed in MW) for a fixed reliability level of 99

99%	TOTAL		R3		R2	
	up	down	up	down	Up	down
2010	204	186	203	184	31	32
P 2020 base	892	966	882	954	167	170
P 2020 ref	1307	1443	1290	1423	252	256

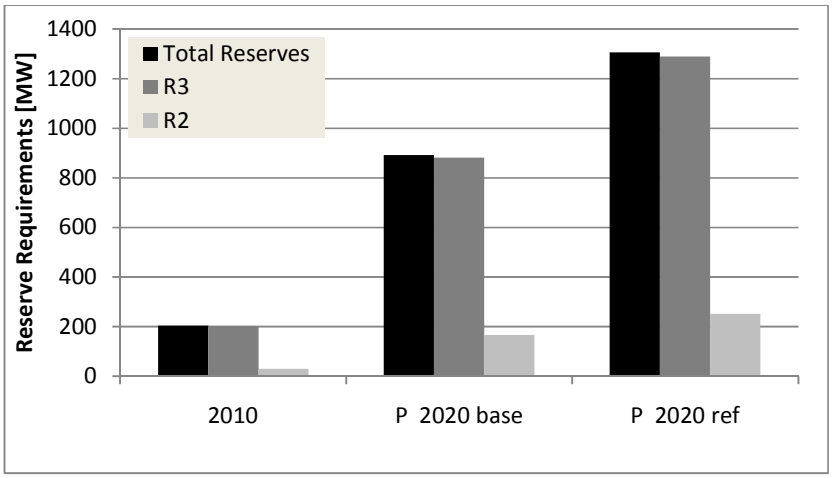


Figure 4: Additional upward reserve requirements (expressed in MW) for a fixed reliability level of 99%

Results show an increase of the reserve requirements with the installed wind power capacity. In the reference scenario, 99% of the total wind power imbalance is smaller than 1307 MW (shortage) and 1443 MW (surplus) in the reference scenario. This number rises with 6.5-7.5 times the current wind power imbalance volumes. As expected, the imbalance increases proportionally with installed wind power capacity. The asymmetric behavior can again be explained by the asymmetric wind power output predictions (characteristic of the prediction tool) which are now reinforced with the offshore concentration. When expressed in percentage of installed capacity, the maximal imbalances in the 99% range fall between 37-40%.

The required R2 and R3 amount respectively up to 7% and 36-40% of the installed capacity. These numbers can be seen as conservative as they do not take into account any correlation effects with other imbalance drivers. On the other hand, this may be partially compensated by assuming intraday predictions liquid intraday trading possibilities. Compared to the current contracted R2, R3 reserves (137 MW, 661 MW), which show a ratio of 1/5 the wind power projections show an increase of reserve requirements with 85% for R2 and 97-119% for R3.

5 Conclusions and recommendations for further research

This study puts forward a methodology to determine additional reserve requirements due to increasing wind power integration. The methodology is based on a probabilistic approach which is already applied in different case studies. However, this approach is further refined in the study by integrating real historic time series of wind speed measurements and predictions. This enables to take into account geographical smoothing effects and prediction errors which have a significant impact on the total wind power imbalance faced by the system.

Specific focus is put on the allocation of reserve requirements towards fast and slow response reserves. This issue is highly relevant for power systems from the viewpoint of system reliability and costs. This contribution is performed in a context of ENTSO-E, and Belgium in specific, characterised by primary (R1), secondary (R2) and tertiary (R3) reserves. In the suggested methodology, the impact of wind on R2 is dimensioned based on the short-term wind power output fluctuations. On the other hand, the impact on R3 is dimensioned by the wind power prediction error. This approach minimises the required R2 capacity (MW) which is generally expensive compared to R3. Additionally, the activation in terms of energy (MWh) is also minimised which is an advantage in case of high activations costs. R1 are not dealt with in this contribution as its impact is expected to be very small due to smoothing effects and inertia of wind power generators. In case that lower activation costs can be attached to R2 compared to R3, an alternative approach would be to determine the tertiary reserves as the difference between the total reserves and the secondary reserves. In this case, total reserve requirements are minimised in terms of capacity while R2 can also be activated to balance prediction errors which could also be balanced by R3. This case, together with activation costs of reserves, is therefore an interesting topic for further research.

In a final section, the constructed model is applied to a specific case study of the Belgian control zone. Projections for 2020 estimate the installed wind power capacity at 2.5-3.6 GW. This capacity is distributed over the offshore, coastal and onshore locations in the model allowing to assess the expected impact on reserve requirements. For a 99% reliability factor, the R3 may increase with 36-40% of the installed wind power capacity. The increase in R2 amounts to 7% of the total installed capacity.

In order to improve the accuracy of these results, correlations between wind power imbalances and other imbalance drivers are to be researched (solar PV, demand) and incorporated in the model. Similarly for the aggregation effects of short term wind power output fluctuations.

6 Acknowledgement

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