The Participation in Ancillary Services by High Capacity Wind Power Plants: Reserve Power

Kristof De Vos, Paula Souto Perez and Johan Driesen

***Abstract*—The Transmission System Operator (TSO) is responsible for a stable and secure exploitation of the electricity grid in its control zone. This is mainly achieved by contracting power generators delivering ancillary services in addition to their main commercial product, active power. Electricity from Renewable Energy Sources (RES-e) is today generally exempted from the participation in ancillary services. However, the increasing share integration of variable RES-e with a limited predictability has an impact on the demand and supply structure of these services.**

In this paper, the possibility of wind power participating in frequency control or delivering active power reserves as an ancillary service is investigated. Within this framework, technical, regulatory and economic aspects are examined and evaluated. As the specific details about the way ancillary services are contracted differ over Europe, a case-study is done for the Belgian control zone.

***Index Terms*—ancillary services, balancing, frequency control, reserve power, wind energy, wind power plants, wind power**

I. Introduction

Under the 'Climate Action and Renewable Energy Package', the European Union defined a binding target for the EU-27 to achieve 20% of total energy consumption from Renewable Energy Sources (RES) by 2020 [1]. This results in about 35% of total electricity production and a renewable electricity source that is expected to contribute largely to this target is wind power. In 2008, 8.484 MW of wind power capacity was installed in the EU-27 (36% of all new installed capacity) leading to a total wind power capacity of 65 GW (Fig. 1). This accounted for 8% of total cumulative installed generation capacity (791 GW) at the end of 2008 (Fig. 2.), producing 142 TWh of electricity that year. This was already 4,2% of EU-27 demand [2]. With the ambitious 20/20/20 targets the European Wind Energy Association (EWEA) expects the share of wind energy to increase further to 230 GW of installed capacity by 2020, with 40 GW of offshore capacity.

Concerning Belgium, in 2008, 104 MW was installed leading to a total capacity of 384 MW onshore at the end of 2008. The first offshore projects are being constructed by

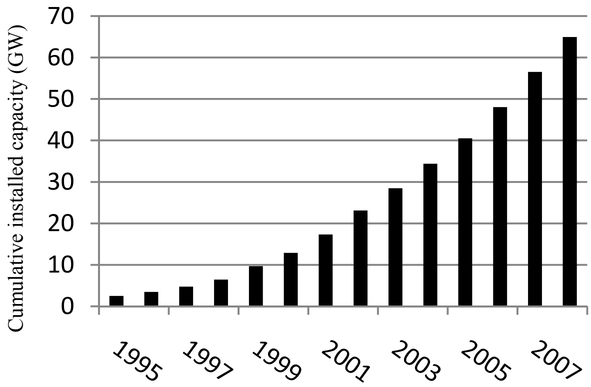

Fig. 1. Cumulative installed wind energy capacity in GW from 1995 until 2008 (source: EWEA)

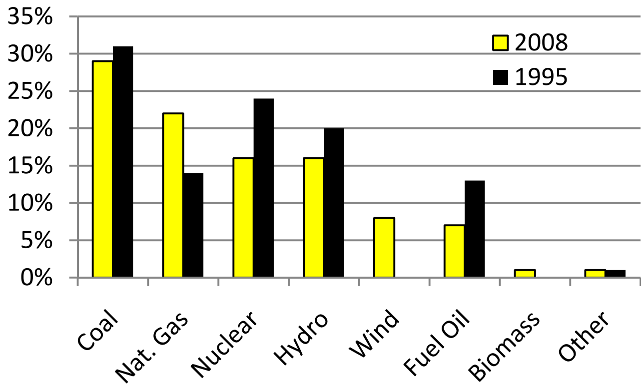

Fig. 2. Energy Mix EU for 2008 compared to 1995 (source: EWEA)

C-Power (Thornton bank) and Belwind (Bligh bank): C-Power plans to achieve 300 MW by 2013 and Belwind 330 MW by 2010, respectively on the two banks. If onshore growth is maintained at the same rate and these two offshore wind power plants are added to total wind power capacity, the frontier of 1 GW of wind capacity in Belgium is expected to be breached in 2010.

However, to assure a reliable and secure electricity provision, all network users benefit from system services such as stable voltage levels and a constant frequency. As in liberalized electricity markets the Transmission System Operator (TSO) is responsible (and accountable) for a safe and reliable exploitation of the transmission grid, management of these services belongs to its basic obligations. These are usually contracted from power generators delivering them in addition or ancillary to active power.

Today, ancillary services are generally contracted from conventional power plants. However, this may come under pressure as governments worldwide commit themselves to increase the share of RES-e. First, the share of conventional power plants delivering ancillary services decreases and

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second, as renewable sources are often variable, not controllable and not entirely predictable [3] they are likely to have an impact on the need of ancillary services of a power system.

State-of-the-art wind power plants are technically capable of delivering ancillary services such as voltage and frequency control (Horns Rev) [4], [5]. Main question is tough if availability and economic value of this participation by wind power is interesting enough under current market regulations. This paper deals only with frequency control and active power reserves. In a first section, ancillary services are defined focusing on the different kinds of active power reserves in the framework of Belgian regulation and market structure. The second section describes the technical and economic feasibility of participation by wind power plants in these services. The paper ends with a case-study for a virtual wind power plant and the impact of different parameters as localization and type of wind generator on the technical availability and the economic cost of keeping a certain bandwidth as reserve.

II. Frequency Control and Active Power Reserves

Ancillary services are defined by EURELECTRIC[1] (2003) as *"all services required by the transmission or distribution system operator to enable them to maintain the integrity and stability of the transmission or distribution system as well as the power quality [6]."* System operators procure them from grid users, such as consumers and generators, who deliver these services in addition or ancillary to their main product, namely active power. This explains the difference with system services that can be delivered by every system function, for instance the system operators themselves.

Different ancillary services are defined by different organizations but in this paper, the focus is on frequency control and the delivery of reserve power. To ensure performance of generators and motors, it is important to keep system frequency stable at 50 Hz in Europe. This is achieved by maintaining a balance of generation and consumption at each moment in time. Each deviation from this balance leads to an increase or decrease in frequency which has to be avoided by activating reserve power to counteract on these imbalances. Reserve capacity can come from changing the operation point of a power plant, storage (e.g. pumped hydro) or consumers (load shedding) but in practice, they are mainly delivered by the generators.

Before the liberalization of the electricity markets, with large national vertical integrated electric utility companies made frequency control relatively simple. The required reserve capacity was determined in order to operate within a certain safety margin and delivered by available generators. Costs of this service could easily be transferred to the final consumer. With the unbundling of generation, transmission, distribution and supply, this became more complex. All grid users benefit together from a reliable grid whether an individual grid user participate in grid support or not. This leads to the specific issues of public goods and free rider problems.

To ensure the presence of enough reserve capacity, the local TSO, responsible for the exploitation of the transmission grid, manages the provision of the necessary capacity. Generally, the system operator provides them by own means or contracts them from other system users. In most cases they are however contracted as most services are delivered by generators and system operators are not allowed to own production capacity in liberalized markets.

An important issue is how these ancillary services should be procured and remunerated. Different procurement methods are described in literature as for instance compulsory provision, bilateral contracts, tendering or the spot market [7]. This can happen without remuneration or with a regulated, a bid or a common clearing price [7]. To summarize the two extreme cases: power producers could be obligated (for instance every generator) to be able to deliver certain ancillary services, with or without remuneration. The other option is to establish an open market where remuneration prices should be high enough to stimulate investments and delivery of the demanded services.

The rest of this section deals with the different kinds of reserve power which are discussed in the framework of the Belgian market (Table 1). The classification corresponds generally to the ones in other countries of the UCTE-zone[2], though the specific requirements can be different per country [7], [8], [9].

A. Primary Reserves

Primary reserves are addressed automatically and the respond time is in a time frame of a few seconds. After 15 seconds reserves have to be at 50% of contracted capacity and at full capacity after 30 seconds. These reserves are to be delivered for maximal 15 minutes [10]. Since liberalization primary reserves are contracted in an annual tendering system in Belgium. Participants can submit bids to the Belgian TSO, Elia, for reserve blocks of 10 MW which contains 5 MW up and 5 MW downward regulation. On day-ahead basis, participants have to submit to the TSO which production units will provide the reserves.

This sort of fast acting primary reserve is regulated on European level by the UCTE. It defines that a certain amount of reserve capacity should be available for each country and this capacity has to be available 100% of the time [10]. Remuneration schemes for primary reserve may be different across Europe, but in Belgium these reserves are remunerated with a contracted fixed reservation price.

B. Secondary Reserves

Activation of secondary reserves are automatically activated by instruction of Elia and have to be at full contracted capacity after 30 seconds and this for at least 15 minutes. Secondary reserves have two components:

- Contracted secondary reserve

This component is assigned via an annual tendering procedure. If a bid is selected by the TSO, the producer has to provide continuously the reserve power specified in the contract. This is remunerated by a reservation price. Each day (15h00 D-1), this capacity is bid on the reserve market in blocks of 10 MW (similar to primary reserve). They are to be accepted by Elia in merit order [10]. The activation price of these bids are however capped in function of the market reference price and the fuel costs.

[1] Union of the Electricity Industry, EURELECTRIC is the sector association representing the common interests of the electricity sector on pan-European level.

[2] Union for the Co-ordination of Transmission of Electricity (UCTE) is the association of transmission system operators in continental Europe.

- Free bids of secondary control power

Additionally, bids can be freely submitted outside the annual tendering procedure if producers fulfil all technical requirements. These bids receive only the bid activation price.

C. Tertiary Reserves

Tertiary reserves serve to relief secondary and primary reserves and is thus in fact an economic dispatch. It is activated manually and response time has to be minimal 15 minutes and can be used until imbalance problems are disappeared limited to 8 hours. This kind of reserve can be contracted as well via production units as well as load shedding via consumers. We will focus on the tertiary reserve via production units which has two components:

- Contracted tertiary reserve

Similar to primary and secondary reserves, tertiary reserves can be assigned via an annual call for tender. Remuneration exists consequently also in a reservation and activation price. Reservation price is determined by Elia and should compensate costs made for keeping capacity available. Activation price is contractually determined with a formula accounting for fuel costs and starting costs [10]. This kind of reserve can only be activated upwards.

- Forced bids of tertiary control power

The Belgian grid code obliges each power plant with a nominal capacity larger than 75 MW to bid non-nominated power capacity on the reserve market [3]. This applies in theory also on wind power plants but the grid code allows exceptions for RES-e. The participant in the tertiary reserve market has to submit these bids before gate closure (14h00, D-1). It contains a list with production units participating, reserve power available for each unit per 15 minutes and the bidding price.

Reserve	**Remuneration fee**		
	Tender	**Free Bid**	**Forced Bid**
Primary	reservation	-	-
Secondary	reservation activation	activation	-
Tertiary	reservation + activation	activation	activation

Table 1. The different contracting and remuneration schemes of reserve power in the Belgian market.

III. Frequency Control By Wind Power Plants

As shown in Fig. 3, different control techniques make wind power plants able to participate in frequency control [11]. Even the fast ramp-up rates needed for primary reserves are not a technical threshold for wind power participating in frequency control. However as wind power output depends on a variable power source with a limited predictability, this means that injection or absorption of active power cannot be guaranteed. In practice, contracted reserves are never for 100% of the time available at 100% capacity. Introducing availability coefficients would make it possible to wind power plants to participate. As saying that x MW can be available at x % of the time.

Even if wind power is able to participate in frequency control, the second question to be asked is if this is also the

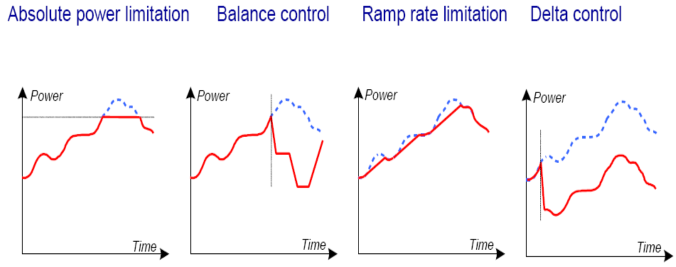


Fig. 3. Wind Power Plant Control in Horns Rev *(Source: P. Sørensen)*

most economic alternative to do so. Intuitively, the costs for wind power producers would be rather high in comparison with other technologies. A wind turbine, keeping reserves has no variable costs (in contrast with thermal power plants saving fuel costs) but a high opportunity cost due to the lost green certificates (or other forms of support) next to the electricity value. Especially the participation in upward reserves is expensive as the wind power plant has to produce continuously under maximal capacity.

A. Availability

For primary reserves, as mentioned in section two, there is the requirement of the UCTE to deliver this service at fulltime availability. This makes it however impossible for wind farms to participate as availability depend on a variable and not entirely predictable input. However, less tight standards may be defined in the future to have a certain capacity at a certain availability rate.

For secondary and tertiary reserves, 100% availability is not required in Belgium as long as a certain bandwidth is available on average basis. It should thus be technically possible for wind power plants to participate if sufficient high availability rates could be reached. An important issue herein is the impact of prediction errors and nomination deadline (gate closure). In reality, reservation bids have to be nominated before real time (generally one day ahead) meaning that there has to be relied on forecasts with a limited reliability. This has a negative impact on the availability.

B. Economic Feasibility

Reserving and activating a reserve bandwidth imposes a cost for the participant (Fig. 4). This cost can be referred to as the opportunity cost where the better alternative is not to contract the active power reserves. In case of a wind power plant, this cost depend on the lost revenues of electricity and green certificates that could have been sold. When analysing the total cost of delivering upward and downward reserves with wind power, four components can be defined (Fig. 4): upward reservation, upward activation, downward reservation and downward activation.

Concerning the reservation costs, wind power has a priority dispatch, zero marginal cost and receives production support. This means that the most profitable strategy of a wind power plant is to produce all the time at maximal capacity. Consequently, keeping an upward bandwidth (bandUP) reserved imposes a lost revenue determined by the price of electricity (E) and certificates (GC). On the other hand, keeping the downward bandwidth (bandDOWN) reserved has no opportunity cost at all as the wind power plant has as such an incentive to produce at maximal capacity. The hourly reservation costs of contracting a certain bandwidth of reserve power can be calculated as:

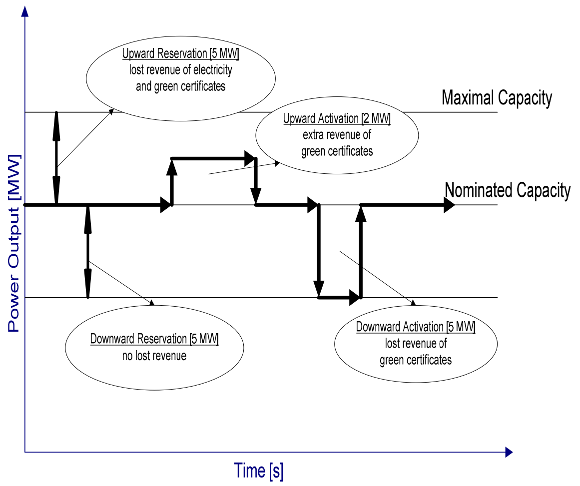


Fig. 4. Costs and revenues linked to reservation and activation of reserves by wind power plants

- reservation upward: (E + GC) x bandUP
- reservation downward: 0

When these hourly costs are aggregated over a whole year, the yearly reservation cost is found for a wind power plant holding reserves. This cost is only determined by the lost revenues of keeping the upward reserves. If this reserve bandwidth was available for 100% of the time, this cost becomes:

- (E + G) x bandUP x 8760 hours

If less than 100% availability of the contracted bandwidth is allowed, this influences the opportunity cost (if the reserve bandwidth cannot be activated as there is no wind available, there are also no lost revenues to be assigned). If for instance the contracted bandwidth can only be available for 70% of the time and in the other 30% of the time there is no wind the formula becomes:

- (E + GC) x bandUP x 8760 x 0.70

However, if in this remaining 30% the maximal wind power capacity (Pcap) was smaller than the contracted bandwidth but larger than zero, the opportunity cost becomes (Fig. 5):

- (E + GC) x Pcap

The hourly opportunity costs are thus also dependent of the wind power output (P) and the hourly cost can be modelled as:

- (E + GC) x bandUP x IF1 + (E + GC) * Pcap * IF2
- IF1 = 1 if $P \geq Pcap$, 0 if not
- IF2 = 1 if $P < Pcap$, 0 if not

Concerning the activation costs, they only depend on the green certificates. When reserves are activated, this is not submitted to the imbalance mechanism. The participant activating its reserves counteracts on an imbalance created in the system, and the TSO considers it as its normal nominated power was delivered. Result is that there is no

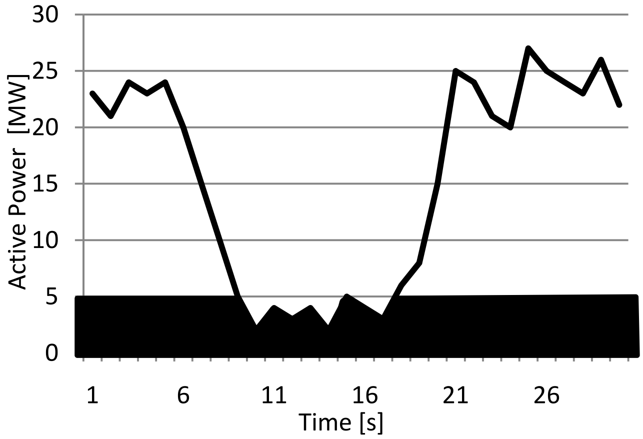


Fig. 5. Reservation cost of a 5 MW bandwidth in

impact on the revenues of electricity when activating upward or downward reserves. On the other hand, activation has an impact on the registered power production which determines the amount of green certificates to be received. The activation cost thus only depends on the certificates and the activation volume (Vol.Act) which can be expressed in MWh. The activation costs over a certain period are calculated as:

- activation upward: - GC x Vol.Act.UP
- activation downward: GC x Vol.Act.DOWN

Note that if upward and downward activation volumes are equal, these terms cancel each other out and the total activation cost becomes zero. This assumption is in reality only correct for primary reserves.

If the total cost of keeping reserves by wind power is modelled for a certain period, reservation costs have to be aggregated over this period and added to the total activation cost in this period:

- upward: $\sum[(\mathrm{E} + \mathrm{GC}) * \mathrm{bandUP}] - \mathrm{GC\ Vol.Act.UP}$
- downward: $\mathrm{GC\ Vol.Act.UP}$

When upward and downward reserves are activated in equal volumes, this becomes:

- $\sum[(\mathrm{E} + \mathrm{GC}) * \mathrm{bandUP}]$

This corresponds to the opportunity costs where the better alternative was to produce at maximal power. This opportunity cost is what is to be paid to the supplier of reserve power to make him to participate voluntary in this market. As total costs from keeping reserves by wind power come from the upward bandwidth, it might be interesting to contract this power source only for downward regulation. In this case the opportunity costs are limited to the lost green certificates during activation periods. A possible portfolio is for instance wind power for the downward and classic fuel driven thermal plants for the upward part. This is theoretically already possible in Belgium intra-BRP: a BRP contracts the reserves and it is allowed to use different units for the downward and upward regulation.

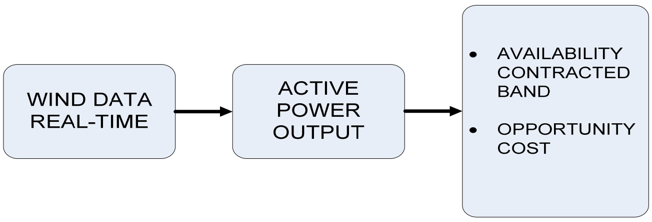
It has to be noted that although using wind power only for the downward regulation is economically more interesting, the cost when activating these reserves may still be higher than alternatives due to lost green certificates and saved fuel costs in case of thermal plants.

When constructing the model to calculate the opportunity costs of the supply of reserve power by wind power plants, no distinction has been made between the three different types of reserves. However, secondary and tertiary reserves are different from primary reserves. As it was fair to assume an equal activation volume of upward and downward reserves in the case of primary reserves, secondary and tertiary reserves are activated more in the downward direction. This is explained by the fact that more electricity is often nominated than consumed. A second difference is that creating asymmetric products becomes difficult as most participants prefer to deliver downward reserves.

Participating in secondary and tertiary control is normally not interesting for wind power due to the same reasons as primary control. Activation and reservation prices have to compensate opportunity costs of electricity and green certificates and as reserves are contracted and activated according to merit order, wind power is not able to compete with other capacity. Wind parks larger than 75 MW should in theory participate in the bidding process, though can be exempted by the TSO as RES-e. It is not interesting for a wind producer to submit incremental bids as they are too expensive. Decremental bids however can be more attractive as only the activation cost has to be remunerated. These costs are determined by the lost certificates.

IV. Case-Study: Reserve Power Delivery By a Wind Power Plant

To evaluate technical availability and economic value of the provision of active power reserves for frequency control by high capacity wind parks, a model is built converting real-time wind data into active power output for a fictive wind park. This enables us to evaluate the availability of a certain bandwidth for reserves together with the opportunity costs (lost revenues) compared to the alternative where the wind park does not participate in the delivery of this ancillary service.



For this case study, real-time wind data are taken from the Royal Netherlands Meteorological Institute for three different locations (Fig. 6): Eindhoven (inland), Vlissingen (coastal) and the plain of De Raan (offshore) for 2008 [12]. As measuring points are located in the same climate zone, they are also representative for Belgium. The data acquired are potential wind speeds meaning that they are wind speeds measured at location and recalculated as it was measured in open terrain at 10 meters height (roughness 0,03 onshore and 0,002 offshore). With these roughness coefficients, wind speeds are recalculated for hub height of the turbines according to the power law wind profile.

The model is built for two different kinds of wind turbines. In a first part, calculations are done for the Vestas V90 3MW turbines with a hub height of 80 meters and a power curve described in Fig. 7 [13]. This wind turbine was introduced in 2002 and has a relatively high rated wind speed (15 m/s) and cut-in speed (4 m/s). This model can be seen as representative for the technology installed a few years ago[3] [14]. It is interesting to take up this turbine in this study as these have a life expectancy of 20 years which means they are staying an important part of the wind park for a long time.

This turbine can still be found in the product line of Vestas but newer and better turbines are available today. They attain lower rated wind speed (12 m/s) and cut-in speed (3 m/s) which has a positive impact on the power output. Therefore, calculations are repeated in a second phase for a Vestas 112 3MW turbine with a power curve as shown in Fig. 7. This last turbine has a slightly higher hub height but due to the low roughness coefficients, this difference is neglected. Capacity factor and time at rated wind speed are calculated for the available wind data and is shown in Table 2.

As specific data about entire wind farm power curves is not available, the next step should be to construct these. This is difficult as multi-turbine power curve are not just the

Fig. 6. Geographical representation of the measurement locations

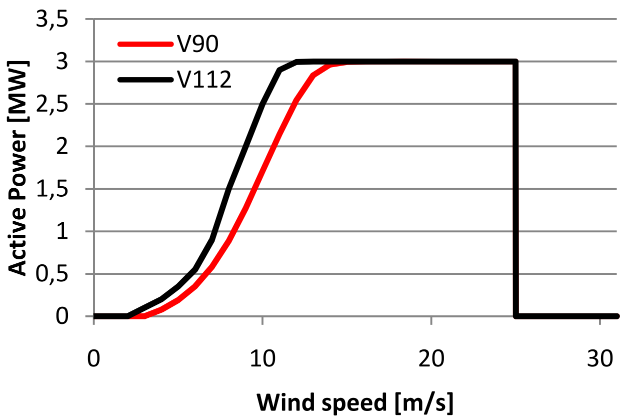


Fig. 7. Power curve of the V90 3MW and V112 3 MW (source: Vestas)

Table. 2. Characteristics of V90 and V112 Turbine

	Capacity Factor [%]		*% at Nominal Power*	
	V90	V112	V90	V112
Inland	10,03	16,52	0,02	0,75
Coastal	22,98	32,79	1,25	6,57
Offshore	34,08	45,99	1,47	10,88

[3] Vestas had a market share of about 30% between 2001 and 2007 with its flagship, the V90 3MW.

sum of the single turbines in the park due to wake effects amongst others. These effects will smooth the aggregated power curve: cut-in becomes lower, cut-out higher and a more curved path at rated wind speeds. In this case-study the power curve without smoothing effects is used as no specific data was available. This is justified as in a wind power plant not too large in surface, smoothing effects remain minimal and high rated wind speeds above cut-in rarely occur (6 times for the plain of De Raan in 2008).

A. Availability

Based on a power curve, hourly wind speeds are converted into active power capacities for a wind power plant. This means a theoretical availability can be calculated for a certain reserve bandwidth. In Fig. 8 (V90-turbine) and Fig. 9 (V112-turbine), the availability is evaluated for different bandwidth sizes (expressed in percentage of the rated power of the wind farm). First of all, a large difference can be seen between the three locations. This difference can intuitively be understood as average wind speeds are higher offshore than onshore as can be seen in Table 3. Second, there is a large difference between the V90-turbine and the V112-turbine. Much higher availability rates can be attained with the state-of-the-art turbines due to the lower cut-in speed. A third observation is that the availability rates converge as park size increases. This can be explained by the time frames where wind speeds are zero and no output can be delivered regardless of wind park size. The most important conclusion however is that a bandwidth of 10 MW (which is the minimal bandwidth that can be contracted in Belgium) can be delivered by reasonable park sizes with sufficient availability rates (Table 3). This certainly for offshore locations but even for coastal areas with state-of-the-art turbines.

In Fig. 9 and Fig. 10, decreasing paths of the availability can be observed if the reserved bandwidth becomes larger for a certain wind park. It can be concluded that a reserve bandwidth of 10% of the nominal power of the wind power plant can be attained with an availability of 31%, 55% and 70% for the older V90 turbine respectively for inland, coastal and offshore. For the newer turbines, these numbers increase even to 47%, 68% and 80% (Table 4).

As can be seen in Table 3 and Table 4, availability improves significantly if the bandwidth is reduced to 5 MW. The results of the 5 MW bandwidth can be interpreted as the availabilities when only the upward or the downward part is contracted by the wind park producer. As already explained, it may be interesting to contract only the downward part from wind generators.

An important simplification of the model is that in this case-study, nomination is assumed to happen real-time. In reality, this nomination of reserve power happens day-ahead, meaning a certain prediction error exists having a negative impact on the availability rates. On the other hand, with intra-day nominations possible, this negative impact will be damped.

B. Economic evaluation

In the previous section, the conclusion was that the availability of certain bandwidths may be high enough to be interesting for participation by wind power. For instance, as shown in Table 3, an availability of above 70% can be attained for reasonable park sizes . The main issue is now if this is also interesting from the economic point of view. A wind power producer will only participate voluntary in the

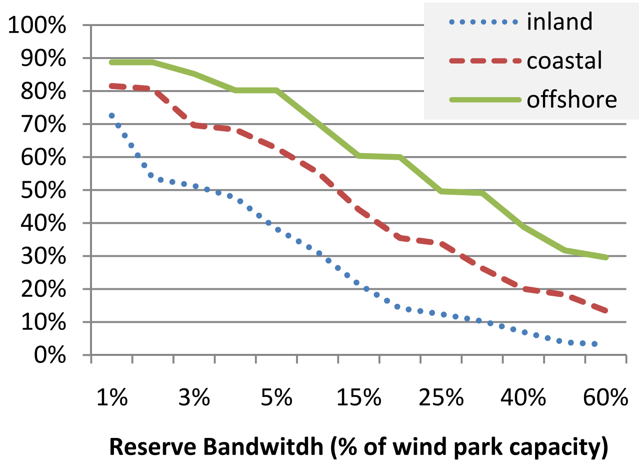


Fig. 8. Availability reserve bandwidth in function of size bandwidth expressed in percent of nominal power wind park with V90-turbines.

Table 3 Availabilities of reserve bandwidths of 5 MW and 10 MW

	Onshore		Coastal		Offshore	
Turbine	V90	V112	V90	V112	V90	V112
Average wind speed [m/s]	4,62		6,43		7,68	
Maximal availability [%]	72,6	90,0	85,8	95,1	92,5	98,4
Park size for 70% availability [5 MW]	480	108	180	69	60	27
Park size for 70% availability [10 MW]	960	216	336	132	96	60

Table 4 Availabilities of reserve bandwidths of 5 MW and 10 MW

%	**10 MW**		**5 MW**	
Turbine	V90	V112	V90	V112
Onshore	31,12	46,51	38,23	68,21
Coastal	55,38	68,34	62,69	81,50
Offshore	70,31	80,25	80,25	88,73

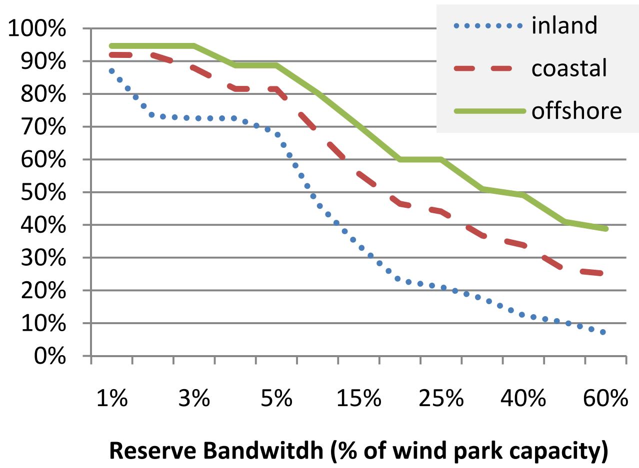


Fig. 9 Availability reserve bandwidth in function of size bandwidth expressed in percent of nominal power wind park with V112-turbines.

reserve market if the remuneration he may receive covers at least his extra costs. As already explained in section 3, these extra costs for wind power are the lost revenues of the active power he cannot sell. These costs depend on electricity price (plus support mechanism if present), availability and size of the bandwidth.

In this case-study, the Belgium market situation is used as reference. A Balancing Responsible Party (BRP) may contract reserve bandwidth with the system operator for blocks of 10MW, meaning 5 MW up- and 5 MW downward regulation. If this cost is to be modelled for wind power, the lost revenues are calculated per hour after which they are aggregated for a whole year. The lost revenues depend on electricity prices (data used form the Belpex Spot Market [15]), increased with the average price of green certificates for 2008 which was €88,22 for 2008 [16]. The hourly electricity price is taken into account as using the average electricity price would distort results due to higher prices in daytime than at night (when less wind is produced). The main problem with the Belpex data is however that in reality, electricity is sold with long term over-the-counter contracts being cheaper due to reduced risks. Average electricity price in 2008 was also rather high (€70,62) which may overestimate revenues. In Fig.10 and Fig. 11, the lost revenues of keeping reserves are visualised as a function of the size of the bandwidth. The results show that these opportunity costs rise with increasing size of the contracted bandwidth, newer turbines and localization closer to sea. This is explained by the fact that the lost revenues increase with higher availabilities.

Besides all technical requirements that can be fulfilled to facilitate the participation of wind parks in the delivery of reserve power (except demanding a 100% availability), costs to do so are relatively high (Table 5). This is due to a zero marginal cost and green certificates. A wind power producer receives the price of electricity plus a green certificate per MWh in comparison to the price of electricity minus the marginal production cost (fuel) in case of a classic thermal generator. Prices paid by the TSO to acquire this service on voluntary basis must be compared with other technologies and are surely too high to be competitive. In order to get wind power plants to participate, one option is to oblige them trough regulation to keep a certain percentage of their maximal output in reserve to assure grid stability.

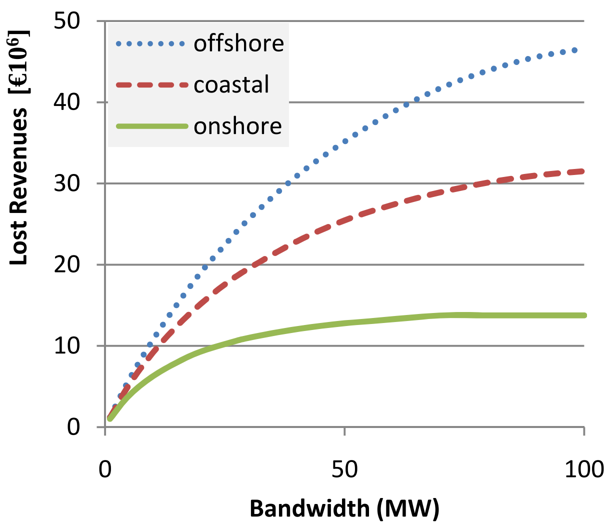


Fig. 10 Opportunity cost in function of bandwidth size for a wind power plant with a rated power of 100 MW (V90)

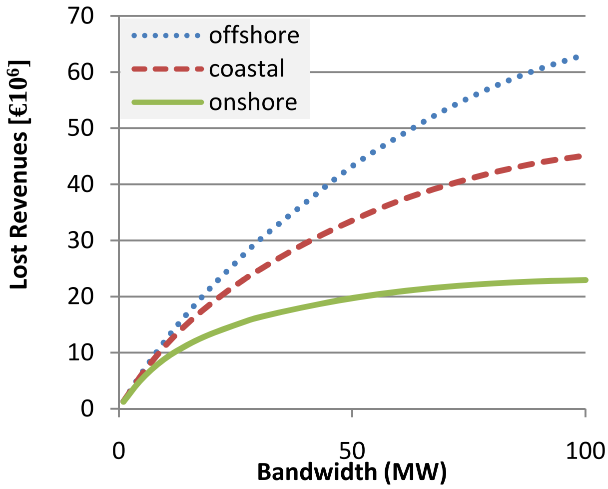


Fig. 11. Opportunity cost in function of bandwidth size for a wind power plant with a rated power of 100 MW (V112).

Table 5. Economic cost of keeping a reserve bandwidth of 5 MW from a wind park of 100 MW

Lost Revenue [€ 10^6]	5 MW		10 MW	
Turbine	**V90**	**V112**	**V90**	**V112**
Inland	3,90	5,37	6,3	9,0
Coastal	5,23	6,17	9,2	11,3
Offshore	5,87	6,45	10,8	12,2

A second solution is to adapt market rules in a way that it becomes allowed for wind producers to submit bids for only a certain amount of downward regulation. This means that the producer does not have to produce the whole year under maximal capacity. Reservation costs in this case become zero and the only cost is the activation cost depending on green certificates and activation volume. This is already possible in Belgium intra-BRP but this rule should be further extended that a BRP can contract its reserve capacity asymmetric.

V. Conclusions

Wind power plants are today technically able to participate in frequency control and the provision of reserve power capacity. This as well for the primary, secondary and tertiary type. Different case studies exist as for instance Horns Rev and undiscriminating grid requirements for wind power in Ireland. More and more, having the ability to deliver reserve power or disposing of frequency control capabilities becomes compulsory for wind power plants that want to be connected to the grid.

Concerning the theoretically availability of reserve power delivered by a wind power plant, the conclusion is that reasonable values can be attained, certainly for coastal and offshore locations. A bandwidth of 5%, 10% of the rated power of a wind farm can be kept reserve up to respectively 89% and 80% of the time for an offshore farm with state-of-the-art turbines. These turbines (with a lower cut-in wind speed) improve availability rates significantly in comparison with older models. A second variable is the localisation of the wind power plant: the availability of a bandwidth is higher offshore than onshore.

The economic costs of delivering a certain bandwidth as reserve capacity corresponds to the lost revenues of the electricity that could have been sold and the additionally production support (green certificates, feed-in tariffs, feed-in premiums). Main conclusion here is that keeping reserves by wind power plants is relatively expensive due to production support mechanisms and negligible marginal costs. A possible solution is to use wind power only for downward regulation and other production units (or load shedding) as upward regulation. This would eliminate the large opportunity costs for RES-e producing constantly under maximal power capacity. The only remaining cost is the activation cost of the downward reserves which is determined by the lost certificates and activation volume. Further research is therefore to be directed to the comparison of the costs of frequency control for different technologies and the optimal combinations for up- and downward regulation.

The assumption made in this study concerning the real-time nomination is also subject for further research. In reality, nominations have to be send to the TSO before a certain deadline which leads to prediction errors and has negative impact on the availability of the reserved bandwidth.

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