Increasing the Competition on Reserve for Balancing Wind Power with the help of Ensemble Forecasts

Jess U. Jørgensen and Corinna Möhrlen

Abstract-- **The experience from Denmark shows that the use of inter-connectors increases the competition and therefore lower the price of balancing wind power. This paper investigates how large scale integration of wind power can help to reduce the total costs for balancing wind power and other Renewables by coupling the German and Danish area to an extended Grid Correction Corporation (eGCC). The primary goal has been to make use of inter-connectors for balancing and to formulate a "reduced counter balancing" strategy for TSO's in a cross border scenario. We have used a 32GW wind power subsystem of Europe and our analysis showed that an average balancing power saving of 25% is achieved from a combination of balancing via inter-connectors, increasing the area and amount of wind turbines, consideration of forecast uncertainty and deployment of two types of balancing power.**

Index Terms—Balancing Wind Power, Energy Market Bidding, Reserve prediction, **Ensemble Forecasts, Wind Power Prediction.**

Introduction

The goal of this study is to show how a drop in efficiency of wind power can be prevented and the balancing requirements significantly reduced independent of whether the type of responsible balancing party is a TSO or private party. In 2009 and 2010, the German regulator Bundesnetzagentur (BNA) introduced a grid correction corporation for the TSO's to prevent counter balancing and thereby reduce balancing costs ([1,2]). In 2011, the BNA has started a new consultation together with the German power exchange (EPEX), stakeholders from the industry, research institutions and associations to investigate if costs for balancing wind power and other Renewables can be lowered further ([3]). One of the discussed suggestions is to no longer let the bulk of the trading of wind power and solar power be carried out by the German TSO's but instead by one or multiple third parties. Additionally, the EPEX is suggesting the introduction of a "green" spot market, which could be introduced in a 2nd step auction, where the first step is the traditional energy auction and the second step is a green proof auction ([7]). In the following we have been investigating and designing an alternative trading mechanism that could be carried out on the same basis as this green energy trading in a second step scenario by the market operator. In our study, the balancing area is extended to a Danish-German grid but intended to be sliced between different forecast providers for maximum competition and minimal risk. Although the equations and balancing technique that will be introduced in this paper could be applied to smaller pools, we will show that the benefit of a large pool lies in the inertia and internal cancellation of errors. Therefore, all wind power is included, regardless of ownership and incentive scheme. We also justify this strategy by claiming that only offshore wind farms in a windy January may be competitive to such a trading approach. Another issue is that the work-overhead per MW to manage many small pools is much higher than centralized balancing. What is proposed in this study can be formulated as an attempt to start the balancing process 2 hours in advance and avoid excessive balancing through use of uncertainty forecasts with a minimal of counter balancing and maximized utilization of inter-connectors.

The proposed balancing technique is not limited to wind power, but it has to be limited to non-scheduled generation. In fact, it should be seen as a compensation for the fact that such generation is by nature forced to live with publications of its expected output either for transparency reasons or because anybody has the possibility to predict its output by purchase of predictions from forecast suppliers. The opposite is true for scheduled generators that can decide and operate more strategic. Therefore, it can be argued that the non-scheduled generators have a disadvantage not only because they are price takers, but also because they cannot choose when to produce. From a fairness and non-discriminating perspective, it is therefore necessary to allow for different rules for price takers and price makers. A possible and especially cost efficient solution to compensate the price takers could be to offer free balancing over inter-connectors. This would not impose a cost to anybody, but would be a large saving for the non-scheduled generators and hence make them more competitive.

Without strategic long-term actions to integrate more wind power efficiently, it is expected that balance costs will increase and wind power and other Renewables become less cost effective, which may postpone projects until energy prices have increased further and meanwhile make the non-scheduled generators less competitive.

Methodology and Approach

As discussed above, we suggest a second step scenario, where the balancing process of the wind power generation starts shortly after gate closure by using a combination of:

- a day-ahead summation of contracted wind power (DFC)
- a short-term forecast for the wind power pool (SFC)
- an aggregated Pool Forecast Uncertainty (PFU)

From this information we will compute how much energy can be balanced by the inter-connectors, how much should be traded in the intra-day market and how much should be

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balanced by shared balancing power. This is done by a sign evaluation of the expected balance:

$$EB = SFC - DFC \quad (1)$$

and the absolute balance

$$AB = |SFC - DFC| - PFU \quad (2)$$

where (2) expresses, whether we trust the sign of equation (1). From (1) and (2) we can derive a decision table (see Table I) for the forecast update process (FUP). The column "a,b,c" will be used to generated a FUP increment later.

TABLE I
DECICION TABLE FOR THE FORECAST UPDATE PROCESS (FUP).

EB	AB	FUP	a,b,c
<0	<0	DFC	0,0,0
<0	>0	SFC+PFU	1,1,1
>=0	>0	SFC-PFU	1,-1,1
>=0	<0	DFC	0,0,0

When EB < 0 we are in a risk state, because a large power plant can suddenly fail and wind power is charged for expensive balancing power. Thus, we prefer keeping the error small. For EB >=0 the risk of a very high price is low with the suggested correction.

In real-time operation, intra-day trading is likely to be competitive, if the error remains the same over several hours (i.e. start-up once). Thus, for EB < 0 we can often choose SFC and benefit, if we look ahead. When AB < 0 we have small DFC errors, which could be balanced by primary and secondary reserve.

The need of the PFU term has been identified by studying the intra-day sales and corresponding costs of the German EEG-based wind power [5,6]. It was found that so far there is a significant loss on trading wind power on the intra-day market. This loss is due to the fact that it is more expensive to buy additional power than selling excess wind power in the intra-day market combined with an unbiased DFC. When studying this pattern it becomes obvious that an efficient trading scheme has to ensure to not re-trade the imbalance nor be charged balancing costs for the same MW multiple times. This is in fact what is achieved by acting in accordance with FUP given in Table 1 and by limiting the trading with the PFU uncertainty band.

A. The Short-term Forecast

It is not very important for the approach how the short-term forecast is generated. The forecast could be a meta forecast put together from a number of deterministic forecasts for all generation or come from an ensemble forecasting system. However, the forecast must cover the entire area and be based on consistent weather forecasts valid for the full area. There is a risk of inconsistency and volatility in error, if one weather forecast provider's forecast is used in one country and another weather forecast provider in another country. In other words, the "meta" forecast has to be a sum of consistent forecasts for the entire pool.

For our study we used the SFC forecast generated by the iEnKF algorithm [8] and published online estimates of each TSO region. This meant that 6 regional measurements were used per time stamp to produce one forecast for the entire area. This does not provide an ideal SFC compared to using all online data instead. In such a system there would be more feed back across borders than what can be achieved with 6 regional online numbers. The Forecast Uncertainty

The aggregated pool forecast uncertainty (PFU) is quite crucial for the scheme that computes, which action to take.

B. The Forecast Uncertainty

The PFU is independent DFC and SFC in the sense that they can be generated by anybody and by any method.

The PFU needs to be calibrated with live historical data. This means forecast data from a real-time system or historical data produced in real-time like conditions. Thus, if SFC is a meta forecast, then hourly forecast values need to be generated with the same meta forecast combination scheme.

The first step to determine the PFU is to compute the average error (EA) of the uncorrected short-term forecast for the total pool over 1 year with live data:

$$EA = \int (SFC - OBS)\,dt \quad (3)$$

A fraction of this error cannot be explained by weather uncertainty. This is represented as a constant base uncertainty. The remainder of the uncertainty varies with the weather. Various tests have shown that the weather related uncertainty is best modelled via the ensemble spread in wind power (ESP) using its correlation with the forecast error (ERR). The PFU can then be expressed as a sum of the weather dependent uncertainty and a random uncertainty

$$PFU = C \cdot ESP\left(\frac{EA}{ESPM}\right) + (1.0 - C) \cdot EA \quad (4)$$

where ESPM is the time integral of ESP and C is the correlation of forecast error and ensemble spread (ESP,ERR).

There is some freedom to choose ESP, but experience has shown that the distance between two percentiles centred around P50 works well. The percentile pair with the highest correlation (C value) is therefore chosen. An example could be to represent ESP as P75 – P25.

The magnitude of C, ESPM and EA depend on each other, but they are constants for a given pool and a fixed look ahead time. All variability lies in the ESP term. Generally, the C, EA and ESPM terms increase with forecast horizon, which means that the PFU will improve with forecast horizon for almost any pool.

C. The Refinement Process

Spatial smoothing over regions is commonly used to lower the error and improve the value of wind power. What is special in our study is that we extend the spatial smoothing over 6 areas with very different levels of installed capacity.

Spatial smoothing has often been applied, but it is often forgotten that there is an implicit assumption of congestionless conditions. This assumption is critical when discussing large scale wind integration using DC inter-connectors between different price areas, which are likely to be congested every so often. Thus, it is not sufficient to look at the apparently low forecast error of the big dispersed pool. We will therefore formulate an extension to the aggregated forecast approach, which will provide overview and control of the internal imbalances in a large area.

In order to explain the value of the enlarged problem and also to illustrate the hidden error in the system better, we decompose generation into

- Foreground generation (FG) as the mean of all areas
- Background generation (BG) for each specific area

The total generation is then:

$$TG = FG + \sum_{area} (BG) \qquad (5)$$

where the second term is zero for the total area.
The BG term for a single region is:

$$BG = \sum_{region} (P_{turbine}) - FG \qquad (6)$$

where we remove the mean generation from each turbine's generation $P_{turbine}$. This results in non-zero region BG summation, representing the excess or missing generation in each area. Thus, it is exactly that part of the generation that needs to be exchanged over the inter-connectors to maintain balance everywhere. A constant value of zero for the 2nd term of (5) expresses that no external balancing is required. Thus, the BG integral is balanced by inter-connector flow and is not visible in the market, because it is valueless. Trading or balancing with third parties is only relevant for the FG Generation. What is traded in the intra-day market is then the difference between the FUP and DFC according to Table I. We can formulate the FG Correction Forecast (FGCF) with the help of the 3 constants from Table I:

$$FGCF = a \cdot SFC + b \cdot PFU - c \cdot DFC \qquad (7)$$

The magnitude of FGCF changes smoothly compared to the BG elements on region basis of (6), because all 3 terms in (7) have a rather slow variation due to the inertia of the large pool. The smoothing of generation and therefore also the trading expresses exactly that we have conducted a refinement of the wind power. We have separated the valueless part from the valuable part and hide the valueless part from the market with pure inter-connector balancing.

D. *The Verification Technique*

In wind power forecast quality studies it is normally not taken into account that there is a price asymmetry, that a fraction of the small errors do not result in costs nor that some errors count double when forecasts have been applied to trade multiple times. We therefore need to consider new error measures to reach a fair comparison on different trading and balancing strategies.

We have defined a quantity named "Total Balancing Volume" (TBV) as the sum of balancing in the intra-day, secondary and primary reserve. The TBV is similar to the MAE measure, but contains a discount and a penalty term.

The discount is activated with 50% whenever the error is under 2%. That is, whenever wind power causes less error than 2% of the installed wind power capacity, then it is random, whether or not this costs on the balancing.

The penalty lies in that the absolute value of the intra-day trade volume is added to the absolute value of the primary+secondary balance volume, because each volume represents a cost, also if the sign would cancel out.

We have tested 5 different balancing scenarios each with two different accuracy levels of the online estimates. The different scenarios are targeted to show with objective criteria how much intra-day trading should be activated to bring the pool in near balance. The scenarios differ essentially in their trust of the correctness of the online estimate and the accuracy of the SFC, which is done with an objective uncertainty estimate. They can either be fully trusted, partially trusted or ignored.

The purpose of this type of validation is to test how much double trading a given methodology leads to.

The Experiment

The forecast update process (FUP) has been applied over one year (07/2010 – 06/2011). This was possible by using public online estimates of the total generation in each of the 6 zones (2 in Denmark and 4 in Germany) with a combined system capacity of 32GW distributed over 1200x600km (see Fig. 1). The raw online data covers close to 5GW of installed capacity in a rather inhomogeneous distribution. It is only the published estimated generation for each of the 6 zones, which is used for all computations.

It is assumed that the difference between measured and estimated values varies rather random, fast and unstructured when 6 different results are combined into the one final measure, which is used for verification.

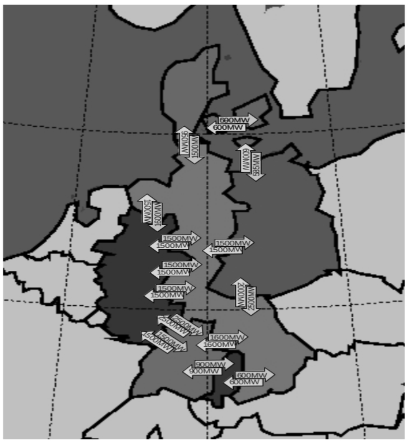

Fig. 1. Area and inter-connectors between the 6 tso areas.

For the one year study (07/2010-06/2011) we used the following datasets and assumptions in our simulation:

1) The capacity of the forecast was kept constant over the year and set as per January 2011. The offshore wind farm Hornsrev2 was included at 1st October 2010.
2) Published measurements for the 6 regions were scaled to January 2011 capacities with some approximations on Denmark West.
3) 75 member weather forecasts from WEPROG's MSEPS low resolution system were used to generate the DFC power forecast in each sub area. This step also produces the so-called raw forecast input (rSFC) which is input to the iEnKF forecast
4) WEPROG's iEnKF short-term forecast algorithm [8] was used to generate 2 hour short-term forecasts (SFC)
5) The pool forecast uncertainty (PFU) was computed for each hour

Results

Table (II) shows the errors in different regions and for different forecast types as well as different traditional statistical parameters. It was found that there was an improvement in RMSE for all regions on the 2H forecast horizon. For total Germany, the error improved 0.34% of installed capacity in this specific test compared to the scenario, where Denmark is not present.

However, the gain in accuracy is very different from region to region. In particular the SFC forecast improvement is very high compared to persistence on the total pool. Although the SFC can easily outperform persistence, we noted that the uncertainty is so high that the SFC+PFU cannot match persistence in raw error measures for DK-DE.
Table (III) shows the TBV measures for a number of trading scenarios representing different options. The effective TBV shows the double trading, which is expected to occur with and without PFU consideration and Fig. 2. shows the frequency distribution of errors for the various forecasts. This shows that DFC has some large errors, which would mean high costs for secondary reserve. The forecasts using PFU are hybrids between SFC and DFC in the frequency distribution.

TABLE II

RMSE ERRORS IN DIFFERENT REGIONS AND FOR DIFFERENT FORECAST TYPES. ALL VALUES ARE IN % OF INSTALLED CAPACITY.

area	DFC	rSFC	SFC	persistence	SFC + PFU	DFC BG
DK1	7.98	5.74	5.39	5.35	-	7.19
DK2	10.75	7.87	7.73	7.23	-	9.59
DE_50H	6.51	4.89	3.91	4.32	-	3.57
DE_TTG	5.97	4.49	3.69	4.00	-	3.13
DE_AMP	5.54	4.33	3.98	4.35	-	4.77
DE_ENBW	5.14	4.60	4.67	3.81	-	6.29
DE	4.96	3.54	2.53	3.28	-	0.95
DK-DE	4.79	3.39	2.29	3.13	3.69	0

TABLE III

TOTAL BALANCING VOLUME FOR 2 TRADING SCENARIOS.

Forecast Type	Trading	% of time with Small errors	Balance 1	Volume 1	Balance 2	Volume 2	Effective Volume	Double Trading
Scenario	1+2	100	1	1	2	2	1+2	1+2
Online error	0.00	100	0.77	0.77	0.50	0.50	-	-
SFC	2.56	91	1.85	4.41	1.73	4.29	3.51	0.82
SFC+PFU	0.61	77	2.84	3.45	2.74	3.35	2.69	0.00
DFC	0.00	71	3.41	3.41	3.31	3.31	2.70	0.00
rSFC	2.20	81	2.60	4.80	2.47	4.67	3.99	1.30

In order to compare our results with the 600MW improvement estimated from 8 EU countries with the Netherlands as centre of the grid [9], we have scaled the improvements achieved in this study from 32GW to 43GW and obtained a permanent saving of 704MW with DFC, 622MW using intra-day forecast without online data (rSFC) and 787 MW with SFC. The new results with 6 areas in two countries hence confirm that an enlarged area reduces the error, where Germany contributed in both studies with the largest portion of the capacity.
The region results of SFC indicate that there are many hours where the sign of the error is random and that the amplitude of the error must be significant. Another way to express this is that a considerable part of the error lies in the online estimation, otherwise SFC could not show the highest improvement of all measures from the enlarged problem. This gives a partial cancellation of error when multiple regions are added together.
Table II shows explicitly the BG error of the DFC, which is less than the total error for each region, because part of the error lies in the FG error. Other important results to summarise are the correlation of the 2 hour forecast error with ensemble spread. We have two relevant correlations. One is the DFC's ESP correlation of 0.43 and the other is rSFC's ESP correlation of 0.53.

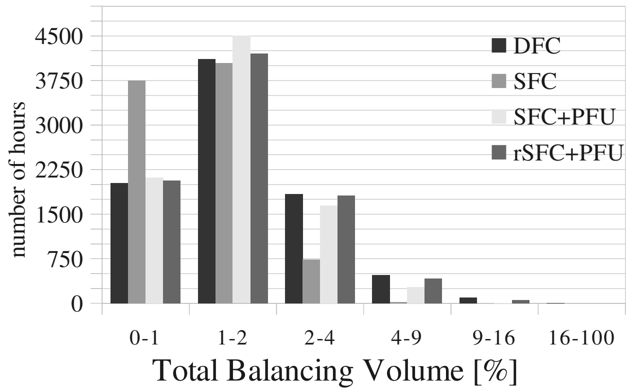

Fig. 2. Frequency distribution of the Total Balancing Volume (TBV) for the different forecast types.

DISCUSSION

E. Qualitative analysis of Pool Forecast Uncertainty (PFU)

A 2-hour RMSE error of 2.29% of inst. capacity sounds like a high error, but the persistence forecast error is 36% higher (3.13%). This is the most relevant comparison for this horizon. The correlation between ensemble spread and forecast error gives insight of the source of the error, which is otherwise very difficult to access, because the frequency distribution indicates that there exist very few large errors. The 0-2% error gives a RMSE of 1.07% and represent 92% of all hours. Errors above 4% take place only 0.6% of the year. The predictability of a high error on the day-ahead horizon is a useful parameter, because a major fraction of the secondary reserve is allocated day-ahead.
For this reason it is worthwhile to note that the SFC error has a 0.43 correlation to the ensemble spread and is available before the spot market closure. This means that the planing of the amount of reserve can be predicted with a reasonable good approximation on the day-ahead horizon, also before the spot market gate closure. This is a major saving of costs when the amount of wind power increases to a level, where the secondary reserve could be fully utilised by wind power, but very rarely is (maybe 0.6%). The correlation between SFC error and ensemble spread increases only 10% from the spot market gate closure (0.43) to the 2 hour horizon (0.53). The improvement in correlation suggests an allocation scheme where secondary reserve is 10% underestimated in the day-ahead and the 10% improvement on the 2 hour horizon is essentially bought in the intra-day market.
This two step process seems to deploy the knowledge of the uncertainty best and limits the balancing costs to a minimum, while it prevents allocation of excessive secondary reserve for intermittent generation. The correlation numbers and forecast error ranges achieved in this test are most likely not the final ranges, as they are influenced by:

1. inconsistency in capacity and MW
2. errors in the measurement handling
3. insufficient accuracy of online estimation approach
4. a moderate resolution of the MSEPS ensemble data
5. a better predictor than percentiles may exist

An operational setup would not need to be limited by using only 6 online estimates, but could use all available measurements. This would most likely increase the correlation by 0.1-0.2, which would mean a day-ahead correlation of more than 0.5 for allocation of secondary reserve. The tested system is influenced by temporary high errors in the individual 6 areas. Those errors are most likely the most important to solve as they are responsible for part of the double trading in the intra-day market.

In the tested system, PFU is probably not only predicting the forecast uncertainty, but also some uncertainty on the measurement side, because the online estimation process is more uncertain whenever the forecast process is most uncertain. This is when there are strong horizontal gradients in the wind speed in regions of strong gradients in the installed capacity. This is what generates most uncertainty on both the forecast and online estimation process. This kind of uncertainty source is also why PFU works well regardless of how the SFC is generated. The uncertainty does not depend on the type of SFC. The uncertainty of a given forecast is a function of PFU at initial time and PFU at 2 hours ahead. There can be an increase or reduction in uncertainty depending on how the ensemble spread changes over the 2 hours relative to the starting point.

The forecast uncertainty measure is a result of an evaluation of many ensemble forecasts on the complete generation and there is no disturbance from few recent measurements with random errors. The ensemble forecasts are not influenced by inherent errors in the SFC input and the difference between the ensemble forecasts describes how difficult it is to forecast the present moment. This difficulty applies to SFC regardless of how it is generated. It is the uncertainty in the physical conditions of the weather and the installed capacity with which every forecast technology has to deal.

Although the difference between the DFC and SFC on RMSE is 2.5%, we have found a RMSE on (DFC-SFC) of 3.79%. This means that there are large wasted corrections applied when using SFC without considering uncertainty and corresponds to a waste percentage of 51.6% in terms of RMSE. The wasted correction is also a considerable fraction of the produced power of 19.6% of the capacity. It is subjective what considerable is, but considering that we have measured on a 32GW problem, this amount of wasted trading calls for attention. It is difficult to prove the origin of so much wasted trading, but it appears like more emphasis needs to put into online estimation to at least eliminate initial noise in the forecast.

F. Cost profile comparison

If DFC is unbiased then there is no possibility to trade on the intra-day market with a real gain measured over time as a non-scheduled weather driven generator. The trading has to be seen as a pre-balancing process, which has a MWh price and where the rule applies that the more MWh there is traded, the higher the loss per MW error. The cost in the intra-day market is expected to follow the secondary reserve costs for the same amount of MW or moderately cheaper. Otherwise there would not be made contracts. Thus, an offer of 1GW will cost approximately the same in intra-day and secondary reserve. The scheduled generators know that the wind generator will pay that price. This is because another party could have a correlated error and cause the balancing costs to go even higher. Thus, in a competitive market, intra-day prices are expected to lie at the same level as the pre-allocated reserve price for the same amount of MW.

The wind generator would have no reason to not pay the cost profile of the secondary reserve, if the sign of the balance is certain, which is the case for a large error over 2% of the installed capacity. We can assume reserve prices go with a power of 2, because large amounts of secondary reserve is less often activated than small amounts and the marginal costs are higher for doing work. With a simple 50% split of the error between intra-day and secondary reserve it is therefore possible to balance half the amount twice and each at 25% of the cost and thereby save 50% compared to using one market. Reality is however more complicated, because of two factors. The uncertainty forecast may suggest that it is not even clever to trade 50% in the intra-day market.

Moreover, we must consider that every action in the intra-day market gives a certain loss per MW, while nearly 50% of the small imbalances are free of charge, because they help the system to balance. Nobody knows 2 hours in advance whether a small imbalance is for free or not. Therefore, there is an incentive to not trade uncertain imbalances that may be counted twice and rather add than reduce the costs. From this analysis and by not considering uncertainties, we could conclude that small imbalances should not be traded in the intra-day market and larger imbalances should be shared between intra-day market and secondary reserve. In the next section we will therefore discuss the results of uncertainty considerations by computing total balancing volume (TBV).

G. Quantitative analysis of PFU

The TBV value is very similar for the different scenarios. It is obvious that the two scenarios, where the short-term forecasts are fully trusted result in significantly more TBV. This is a result of trading power in the intra-day market first and thereafter balancing a portion of the same energy with secondary reserve. That is, the poorer the short-term forecast, the more double trading is carried out. However, because the error can be predicted with a reasonable success rate we achieve a considerable saving in TBV by using the PFU correction defensively. For two similar TBV values it is the frequency distribution of the large errors that make the difference. The SFC with PFU has the least large errors and seems therefore to be the best combination in terms of volume. The weak point of this analysis is that the frequency distribution of the SFC error seems much better than with PFU included. The final choice of strategy therefore depends on the competitiveness of the involved markets.

H. Impact of Congestion

The study has been carried out without Norway and Sweden. This means Denmark and Germany is one price area and we assume the inter-connectors are available for balancing forecast errors. Therefore, inter-connector flow was simulated without competing generation in all hours. It turned out that the DFC error did not trigger any congested hour. Thus, the inter-connectors could maintain BG balance in every hour of the year. It was therefore decided to only simulate the impact of full import and export in the 100 most extreme hours of the year. The inter-connector balancing for the BG generation requires free capacity, which is not permanently available in real life, because the capacity is used to level out price differences.

Asymmetry in error space needs to be built into the bidding process to pre-allocate inter-connector capacity, which would imply an increase in TBV and also higher costs, unless limited to special events.

A Conditional Bidding Scheme (CBS) was suggested in the SuperGrid study [9] to hold sufficient capacity available, also in the event of full export from or import to a region. The proposed CBS allows for one price per participant. In addition to the normal bid, a lower band for import conditions and upper band for export conditions are allowed. Connected neighbours cannot both be full exporters nor importers. Thus, the CBS requires only a rerun of the auction with modified volume from CBS bands. A CBS is a fair solution, because it helps the price taker to deliver more energy to the consumer at a lower system price and it is simple to use, because it is automatic. Therefore, it is a feature that fits into an efficient market system design for a high level of competition. The lower and upper band can be chosen more or less extreme and will at the end of the day be a MW consideration on how much cost efficient balancing is available in the local price area. A typical choice would be percentiles P10 and P90 as the lower and upper bands, respectively. We calculated the annual increase in TBV by such a scheme to 0.02% of the capacity for 50 hours full import and 50 hours of full export. This appears to be a rather cheap warranty against side effects of congestion in a system with more than one inter-connection possibility, also because 100 hours of full import/export in a year is likely to be an upper limit for a well interconnected system.

Conclusions

We have studied the impacts of an extended grid correction corporation between Denmark and Germany with a capacity of 32GW wind power. A previous study [9] indicated a sustained reduced balancing requirement of 600MW by pooling 43GW in 8 countries, which we are now able to confirm on different forecast horizons down to 2 hours with a fully independent data set. In fact, we have found a significant value increase of wind power and increased predictability with more constant generation. In addition, we found a methodology, where uncertainty forecasts are an extremely useful tool, even on the 2 hour forecast horizon and in a system with a considerable inherent uncertainty due to the geographical scale of the area and a rather inhomogeneous concentration of generation capacity.

The core approach is the application of a 300 member multi-scheme ensemble (MSEPS) and an iEnKF short-term forecast [8] applied using public data from 6 regions. This approach in combination with an objective uncertainty forecast provides an intra-day trading scheme suitable for automation. The scheme assumes that all wind power is going in as one pool at a gate closure of 2 hours, regardless of how the power is sold and by whom. In that way, the suggested trading scheme could eliminate all of the 0.79% (in MAE) double trading, which would be the effect of not considering uncertainty. This was achieved by not correcting the day-ahead forecast more than to the boundary of a uncertainty band around the short-term forecast. The frequency distribution of the error did also confirm that the large errors were reduced to smaller errors. The proposed scheme can function on a European pool, if required, but the analysis in [9] suggest that not all countries fit equally well together.

Our analysis also showed that the saving of the enlarged area is achieved from a combination of balancing via inter-connectors, an increased area and more wind turbines, consideration of forecast uncertainty and deployment of two types of balancing power.

Altogether we found a 25% (DFC) and 44% (SFC) reduction of the balancing power for a 32GW pool of wind power distributed over Denmark and Germany. This can be regarded a technology shift that enables the handling of significantly more wind power, because such a system will be safer to operate and will ensure that wind power rather gains that looses market value at higher penetration levels.

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Biographies

Jess U. Jørgensen holds a MSc degree in Geophysics with specialisation in Dynamic Meteorology from Copenhagen University (1989). He started his career in the Danish Meteorological Institute in 1988. From 1992 to 2002 he was responsible for the operational forecasting system in DMI. Jess was involved in research on wind power forecasting since the 1990'ies and coordinated the EU 5thFramework project HONEYMOON (www.honeymoon-windpower.net). Jess is co-founder of WEPROG (2003) and concentrates since 2004 on the operation and development of WEPROG's MSEPS that today contains 75 ensemble members and is forecasting world wide up to 6 days ahead**.**

Corinna Möhrlen holds a MEngSc degree in Civil Engineering from Ruhr-University of Bochum, Germany (1997) and University College Cork (UCC), Ireland (1998) and a Ph.D. from UCC (2004). Corinna started her career in the wind energy area in 2000, being responsible for the development of wind energy forecasting in Ireland at UCC. In 2001 she began intense studies on ensemble forecasting and co-founded WEPROG in 2003. She concentrates on the operation and further development of the Multi-Scheme Ensemble prediction System (MSEPS) that today contains 75 ensemble members and is forecasting world wide up to 6 days ahead.