Primary frequency control by wind turbines

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Abstract: **The speed of modern converter controlled wind turbines is almost completely decoupled from the grid frequency. Accordingly, wind turbines do not possess a natural response to frequency excursions. In this paper three different control concepts that enable wind turbines to participate on grid frequency control are introduced. The first uses pitch control together with the provision of reserve capacity by operating the wind turbine in part load mode. The second and third strategies utilize the kinetic energy of wind turbines to provide frequency support for a limited time following a disturbance. One involves a control scheme which initiates the partial release of the kinetic energy immediately after the frequency drop is detected. Replenishing the stored energy and thus accelerating the wind turbine then follows during the frequency recovery phase. The third option calls for the wind turbine to accelerate first, and then decelerate by discharging energy during the phase of the disturbance in which the frequency is approaching its minimum, thus limiting the frequency drop more effectively. For all three concepts the control structures are presented, and the effectiveness of the suggested methods is demonstrated using simulation results.**

Index Term: **Wind Energy, Primary Control, Frequency Response, Pitch Control**

I. INTRODUCTION

THE next few years will see the installation of a number of large offshore wind farms in Germany. According to a study by the German Energy Agency [1], there will be up to 52.3 GW total installed wind power capacity in the German grid by 2020, of which 20.4 GW is projected to be offshore. To put this value into perspective, the overall generation capacity in Germany today stands at 86.2 GW [2]. The electromechanical behaviour of doubly-fed induction generator (DFIG) based wind turbines, which feature prominently in modern wind turbines, differs fundamentally from that of conventional synchronous generators. The immediate response of conventional synchronous generators to a change in system frequency caused by any disturbance is an increase or decrease in the inertial energy of the rotating masses until the rate of change of frequency (df/dt) induced by the disturbance becomes zero. The change in output power at individual generators resulting from the frequency deviation can be controlled via governor droop set points. The secondary control will then reset the frequency to the scheduled value by restoring the inertial energy to its pre-disturbance value. DFIG based wind turbines possess no or limited (due to limited band width of the current controller) inertia [3] since the machine is decoupled from the grid by a voltage source converter. In the absence of the inertia as a medium of energy storage, the DFIG is not capable of inherent frequency response. The steadily increasing number of wind turbines in the grid is bound to lead to the retirement of more and more conventional plants and thus to the reduction of overall system inertia. Without countermeasures, this would have wide ranging repercussions on the operational indices of the system including system security, cost of operation and protection system setting. This problem is well-known and extensively discussed over the last few years. The emerging consensus view points to the conclusion that large wind farms have to be operated like conventional power plants. In Germany and other European countries TSOs have published in the recent past special requirements which all newly installed wind farms have to fulfill. Regarding frequency support, the E.on Grid Code [4] in Germany, for example, stipulates a linear reduction of active power output by wind turbines at the rate of 40% for every Hz frequency increase over and above 50.2 Hz.

To offset the effect of the reduction in system inertia, one possible option is to equip variable-speed wind turbines with frequency support schemes using active power control. In [5-7] it was proposed to run wind turbines in a part load mode during normal operation and then use the reserve margin for providing frequency support by means of pitch angle control. This option necessitates foregoing some energy (the operating point lies slightly outside the maximum power point). In [8-12] results of investigations indicating the possibility of providing frequency support by using the rotating mass of the generator are reported and [13] reports verification of simulation results on test benches. Building on these suggestions, this paper introduces three different frequency support strategies. The first option involves frequency support by pitch control along the lines proposed by publications mentioned above. Simulations based on real world values are presented here to substantiate the feasibility of this approach. To use the energy stored in the rotating masses of the turbine, a control scheme utilising kinetic energy is introduced, which employs an additional, continuous control to provide frequency support. Another approach to support the frequency using rotating masses of the turbines is also introduced and both strategies based on kinetic energy control are compared. Simulations have been carried out on a test grid and the results compared.

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II. Modeling Approach

A. Test Power System and Methodology

The test network given in Fig. 1 has been used for this study. All the relevant data for the network can be found in [14]. For frequency studies, a primary power reserve of 15% (200 MW) at the hydro power plant has been assumed. To test frequency response of the test grid, a load of (143+j50) MVA has been switched on to the grid at the node indicated in Fig. 1. This results in a frequency drop to nearly 49.0 Hz (in a 50 Hz-system) without any controlled influence by the wind turbines, which is the lowest allowable frequency before load shedding is triggered.

The loads L1 and L2 each has a value of $(1000+j100)$ MVA, while L3 is a larger load of approximately (1900 + 150) MVA. The frequency-dependency of the loads has been considered in the models. The turbine controller of the primary controlled hydro power plant is modelled according to [15], whereas the thermal power plants are not participating in grid frequency control.

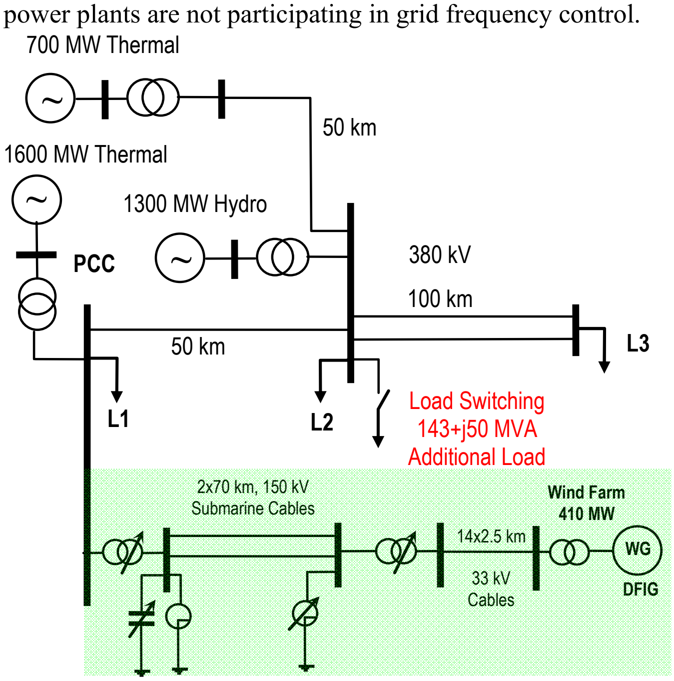

Fig. 1. Two-area, weakly coupled test network

The thermal plants therefore only respond to frequency changes in accordance with their inherent grid coupling property. The total generated power of conventional power plants adds up to 3.6 GW, in addition to the wind power share of roughly 400 MW. That means wind power supplies about 10% of the grid's load. Wind speed has been assumed constant for the duration of the simulation time. Considering the length of the simulation time (tens of seconds), this assumption seems to be reasonable. A typical arrangement for incorporating offshore wind farms to the grid that was used in this study is depicted in the lower part of Fig. 1, and aggregated models have been used for the wind farm. The submarine cable linking up the wind farm to the PCC at an onshore location comprises of two parallel cables. The charging reactive power of the cables is compensated using shunt reactors connected directly to the four cable terminations. To avoid any unintended de-energization of the cables without the compensating reactors (to avoid problems arising from the interruption of a capacitive current), both the cables and reactors are switched concurrently using the same switch. The reactor on the onshore side is continuously adjustable in the range of 40 – 100% (the onshore side is chosen for control in practice on grounds of ease of operation). The wind turbines themselves are assumed to be producing no reactive power at the grid side of their machine transformer during normal operation, the reactive power reference is set zero. To meet the reactive power requirements as specified by the grid code additional capacitances are installed, which are also variable.

B. Wind Turbines

Variable speed wind turbines are equipped with voltage source converters. Focusing on the converter, two types of turbines have to be distinguished: fully converted machines and doubly-fed induction machines. For the first one, the converter must be designed for the full rated power of the machine. For the latter one, the converter has to provide only one third of the rated power. In this paper, the focus is set to the doubly-fed induction machine (DFIM), as these machines are the concept with the highest market share. However, the presented frequency response schemes are suitable for every machine with a decoupled control of active and reactive power.

Speed and pitch control

The simplified model for speed and pitch control used in this study is shown in Fig. 2. The mechanical power extracted from the wind can be calculated as:

$$p_m = \frac{1}{2}\rho\, A_{rot} C_P(\lambda,\beta) v_w^3 \qquad (1)$$

where

- ρ air density
- A_{rot} cross-section through which the air mass is streaming
- Cp power coefficient
- v_W wind speed

WT manufacturers usually specify values of Cp of a turbine model as a function of the pitch-angle β and tip-speed ratio λ. The tip-speed ratio is defined as:

$$\lambda = \omega_T R / v_w \qquad (2)$$

R is the radius and ω_T is the speed of the turbine. There is a fixed relationship between ω_T and ω_R given by the gear transmission ratio.

The power calculated using (1) is based on a single wind speed. However, in reality, wind speed and direction differs over the area swept by the rotor of the wind turbine. To account for this behavior, the wind speed has to pass through a lag block before being passed on to the wind power conversion model.

The control schema shown in Fig. 2 has two outputs: the WT reference power to be passed on to the converter control and the pitch reference value. Both control channels have speed deviations as inputs. The speed through power controller tries to keep the speed at the optimum level corresponding to the actual WT power.

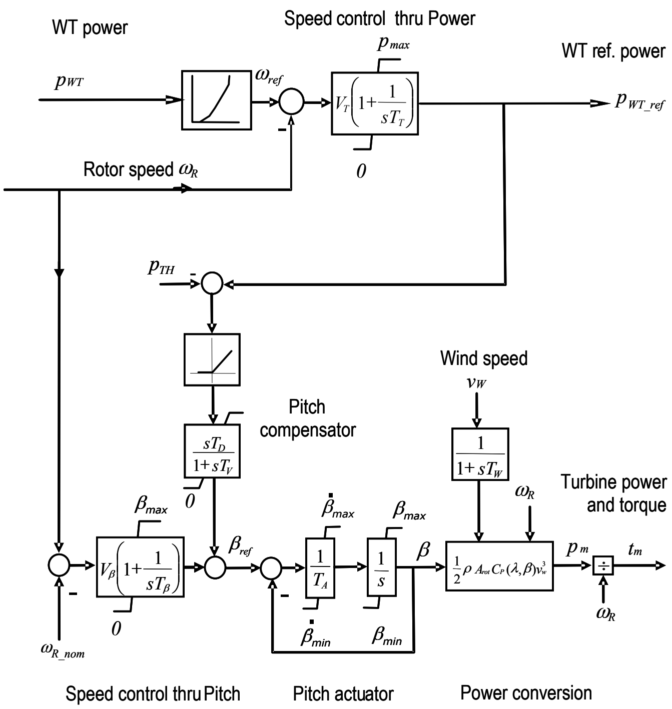

Fig. 2: Rotor speed and pitch angle control as well as power conversion model

The optimum speed is stored in a look-up table. When the speed exceeds the nominal speed the pitch controller initiates pitching of the blades. Thus the mechanical power generated by the wind will be reduced and subsequently also the shaft speed. The wind speed is not utilized for control in this schema due to the difficulties with the accuracy of wind speed measurements. Both controllers are permanently active so that switching between different structures is not necessary.

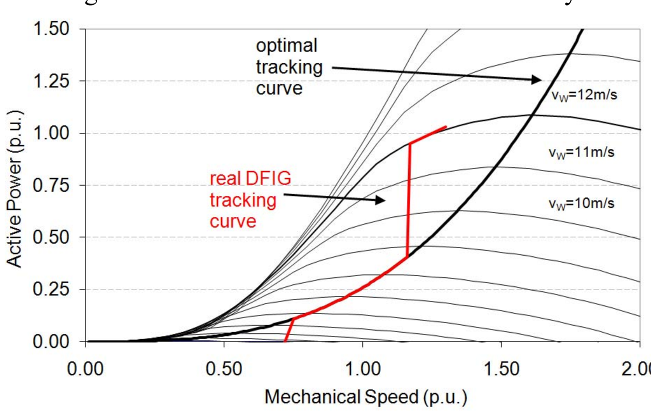

Fig. 3: Exemplary speed control characteristic (related to nominal active power)

An exemplary characteristic curve depicting turbine output power over mechanical speed is shown in Fig. 3. For limiting mechanical stress on rotor blades and to make sure rotor current is controllable over the whole operating range, rotor speed is usually restricted.

The derivation of the DFIG-model used here is explained in detail in [16]. For reasons of simplification, transient components in the stator voltage equations have been neglected. The resulting complex algebraic equations can be incorporated into the grid equations. Fig. 4 shows the model of the machine including the state equations.

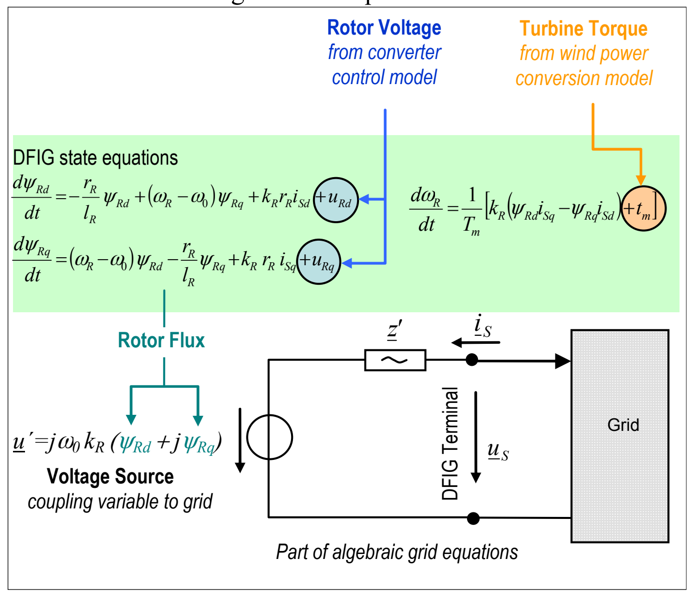

Fig. 4: DFIG model

Rotor side converter

The rotor side converter model is depicted in Fig. 5. Details are given in [16]. The reference of active and reactive rotor currents are given as:

$$i_{Rd\_ref}^{\angle u_S} = -\frac{p_{S\_ref}}{|\underline{u}_S|}\frac{x_S}{x_h} \tag{3}$$

$$i_{Rq\_ref}^{\angle u_S} = \frac{q_{S\_ref}}{|\underline{u}_S|}\frac{x_S}{x_h} - \frac{|\underline{u}_S|}{x_h} \tag{4}$$

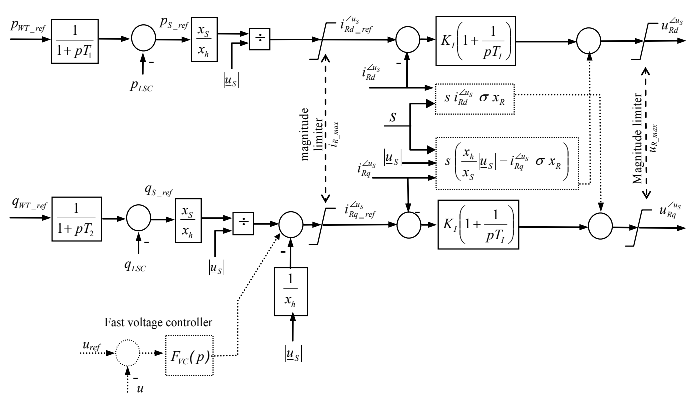

Fig. 5: DFIG rotor side converter model

The term $|\underline{u}_S|/x_h$ represents the magnetization current of the induction machine. This current has to be provided by the rotor side. Fig. 5 gives a overview of the control structure which corresponds with eq. (3) and (4). The magnitude limiter considers the maximum permissible rotor current magnitude. A fast acting local voltage controller can be included for transient situations. Rotor currents are fed to the machine's rotor via slip rings.

$p_{WT,\,ref}$ as input of the control structure in Fig. 5 is given by the rotor speed and pitch angle control shown in Fig. 2. It is worth mentioning that electric power control by the converter is much faster than power control via the mechanical pitch angle control.

III. Frequency Control Strategies

A. Frequency support by pitch control

Pitch angle control (FSPC) is an obvious way to enable wind turbines to maintain reserve capacity for use in frequency support, as already discussed in detail in several publications [5-7]. To realize such a control scheme, wind turbines have to be operated at a considerably lower power output than otherwise possible for a given wind speed. Therefore, the set point of output power has to be reduced actively for every operating point to allow for higher output power in response to any frequency event. This obviously results in lower energy yield, which may require monetary compensation for the plant owner and can also result (in a mixed-resources power grid) in higher CO_2-output by thermal power plants. EirGrid, the transmission system operator of the Republic of Ireland, for example, already stipulates an operating scheme with FSPC [17]. The machines connected to the Irish grid have to be capable of operating at a reduced output level, if the active power output has been restricted by the TSO. To make such a control possible, wind turbine manufacturers have to ensure that the pitch control and the associated mechanical system act fast enough to provide a frequency response in adequate time and the wind turbine control scheme given in Fig. 2 has to be modified for incorporating this additional feature (as shown in Fig. 6).

To create the necessary control margin for frequency support, a steady state offset of the pitch angle β has to be generated and introduced into the pitch controller. This needs extensive knowledge of the behavior of the wind turbine's mechanical system, since this offset has to be calculated and changed for nearly every new operating point.

The simulations shown here were carried out using only a proportional controller for the additional frequency support. Its advantage is easy adaptability to the existing primary controller of the hydro power plant in the grid, which also uses a proportional speed controller.

Fig. 7 shows simulation results obtained with the proposed frequency support by pitch control with proportional gain. Depending on the value of the gain (and the respective offset in output power) wind turbines are able to raise their output power continuously. They have thus the potential not only to smooth the frequency dip but also to raise the frequency until secondary control steps in. After the disturbance is over wind turbines are able to lower their output again and thus attain a new offset for smoothing future frequency disturbances.

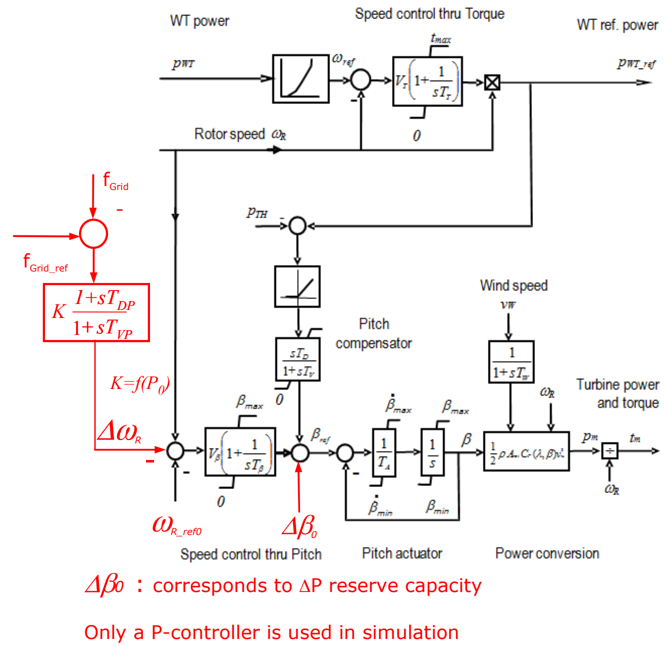

Fig. 6: Power control and conversion with added FSPC

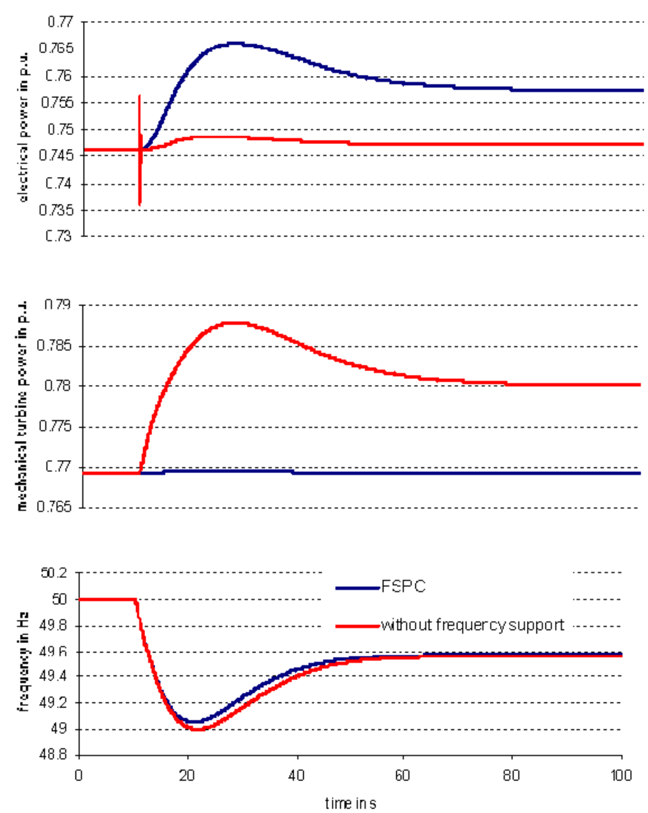

Fig. 7: Simulation results for frequency support by pitch control (FSPC)

B. Frequency support by utilizing kinetic energy

To supply additional active power to the grid in case of a power imbalance, it is also possible to use the energy stored in the rotating masses of the generator. Compared to frequency support by pitch control, the main advantage of this strategy is that it does not entail foregoing any energy from the wind turbine during normal operation. As already shown in [8-11], the lack of intrinsic property of wind turbines supporting grid frequency can be overcome by utilizing the stored energy of the rotating masses (kinetic energy control, KEC). Many of these publications consider only proportional frequency control by using kinetic energy. However, a lead/lag-compensator as controller can also be used, which will provide a better response to disturbances, but have to be parameterized carefully. With both control strategies, there is a risk of reducing the rotating speed of the machine too far, which would force the machine out of the stable operating range. Frequency support is thus only possible for a short period and also the available energy in-feed is strongly limited by the rotor inertia and the rotor speed immediately before the control starts to act. After discharging, the energy has to be replenished to bring the rotor back to the desired speed. The energy necessary for bringing the rotor up to speed is drawn in turn from the grid.

In this paper, two alternative control strategies for utilizing the energy of the rotating masses have been tested. The first (KEC I) represents a common, intuitive approach, while a second, less intuitive approach (KEC II) is newly introduced and provides surprising results.

Fig. 8 shows the adapted control structure including the parts needed for frequency support by utilizing kinetic energy (KEC I). The new elements are directly embedded into the turbine's control and are in operation at all times, i.e. there is no switching necessary between different operating modes.

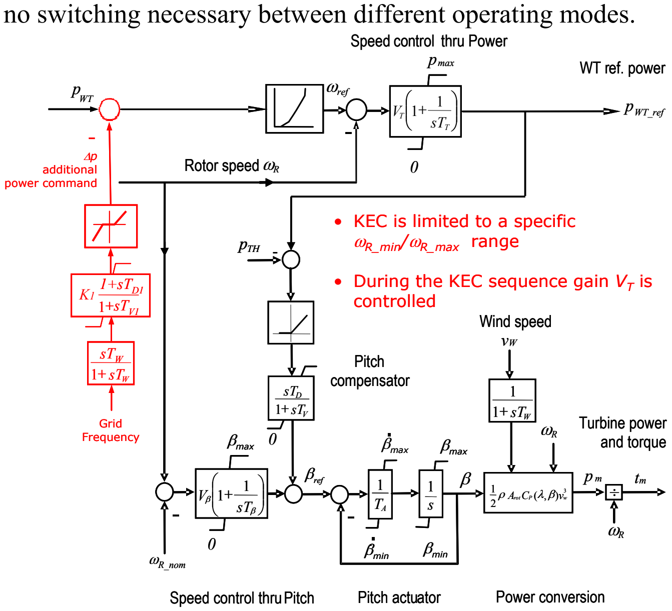

Fig. 8: Control structure for KEC I

KEC I utilizes a wash-out filter for measured grid frequency to avoid acting on slow frequency changes. The actual controller is realized by a lead/lag-compensator. Before adding the resulting value to the power set-point, a dead band is applied. KEC I is limited to a specific rotor speed range to ensure stable operation for all operating points. When KEC is active (i.e. the grid frequency has left the acceptable bandwidth) the gain of the speed control through power is controlled in such a way that it does not counteract the desired deceleration of the wind turbine rotor.

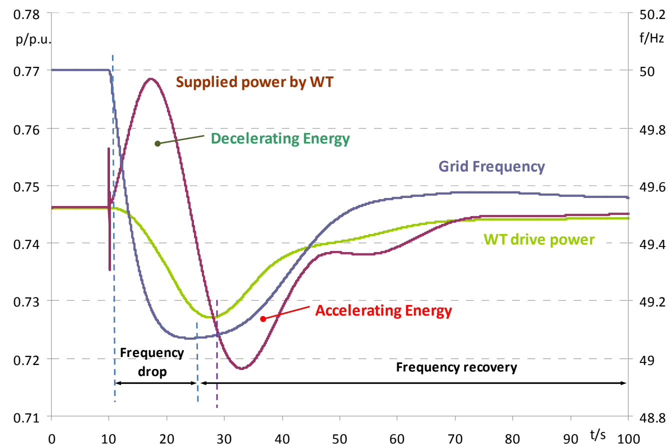

Fig. 9: Response of KEC I to a disturbance

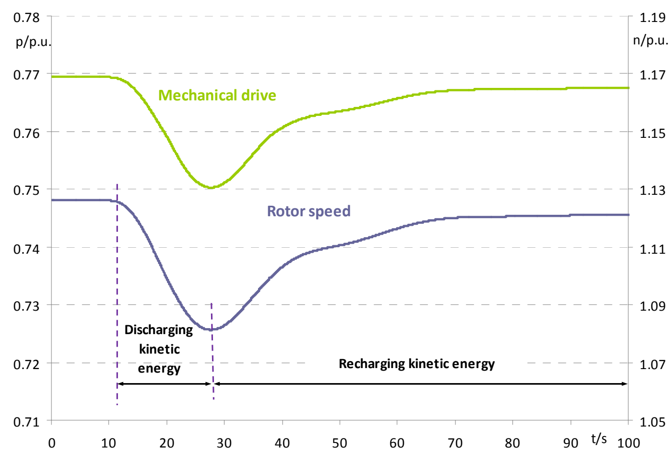

Fig. 10: Mechanical drive and rotor speed for the case shown in Fig. 9

Rotor speed and kinetic energy control have to be closely coordinated with one another to gain maximum response to frequency dips. In particular, the proper resetting of the speed control to its pre-disturbance set point is critical. Since the rotor speed control incorporates a comparatively large gain, a second incursion might occur with a badly tuned parameter set, since the wind turbine will rapidly change its output power when the controller is reset. Such a behavior can be precluded by limiting the gain of the speed controller or implementing the reset as a ramp function.

As can be seen from Fig. 9 and Fig. 10, the kinetic energy control responds as desired to the simulated disturbance, increasing the electrical output power of the wind turbines, which causes the rotor to decelerate. The green area in Fig. 9 shows the difference between mechanical power supplied by the drive train and electrical power fed into the grid. It correlates with the decelerating energy supplied to the grid.

The red area corresponds to the accelerating energy which is recovered afterwards by decreasing the electrical output power, or alternatively the energy drawn from the grid after the frequency reached its minimum. As can be seen in Fig. 10, as long as mechanical power is smaller than electrical power (up to around 30 s), the rotor speed drops. This means that the operating point of the turbine on the p-ω-characteristic (Fig. 3) is moved to a less favorable region in terms of aero dynamical efficiency since the (nearly optimal) nominal tracking curve of the machine is abandoned. Following this, the turbine cannot extract as much power from the wind as would be possible at higher rotational speed. Following the drop in rotational speed, the speed control through power lowers the active power set-point of the turbine to keep the turbine on the designated tracking curve and regain speed. The mechanical drive supplies more energy to the machine than fed into the grid and rotor speed recovers. Compared to the progression of the frequency curve for the case without any additional primary control by wind turbines (see Fig. 7), the minimum frequency is boosted by KEC I (compare also Fig. 15). The re-accelerating of the wind turbines however slightly broadens the lower part of the frequency slump by limiting energy fed into the grid immediately after the disturbance.

C. New approach to kinetic energy control

The kinetic energy stored in the rotating masses of a machine changes as the square of its rotational speed. If a provision of stored energy to be released at a later stage of a disturbance is desired, it therefore makes sense to increase the speed of the machine before discharging it.

For some operating points another advantage can be derived from controlled accelerating of the rotor. For the machine depicted in Fig. 3, the operating range between nearly 40% to 100% active power the tracking curve of the machine lies left of the optimal tracking curve. If the rotor is accelerated in this operational range, the overall efficiency of the system will be raised and thus the turbine will be able to generate more power for a short moment.

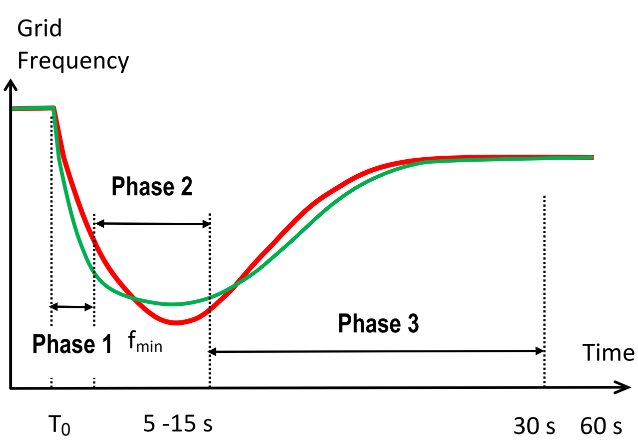

Fig. 11: Basic layout of new kinetic energy control

The proposed kinetic energy control (KEC II) can be divided into three major phases (see also Fig. 11):

I. WT controlled to deliver less power → rotor accelerates

II. WT controlled to deliver more power → rotor decelerates and frequency is supported

III. WT controlled to operate at optimal speed → rotor re-accelerates

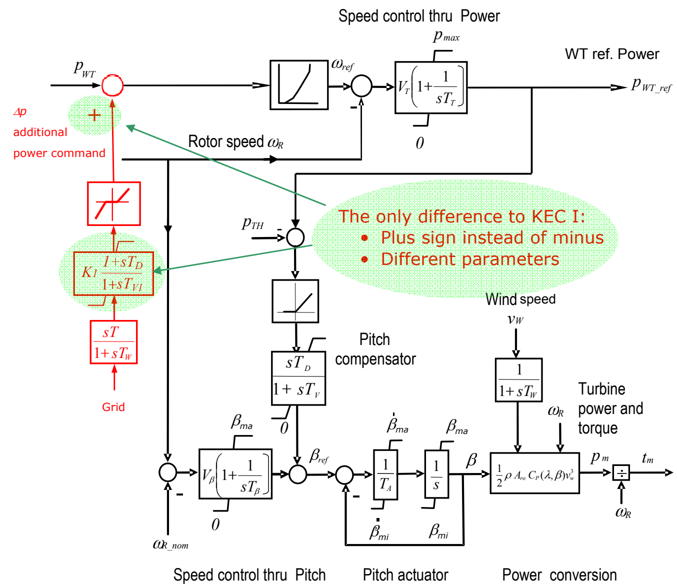

Fig. 12: Controller layout for KEC II

Fig. 12 shows a possible controller layout to realise the behaviors described in Fig. 11. The main difference to KEC I is the change of sign at the summation point of the power set point and the parameters of the lead/lag controller, which have to be adapted to the new control scheme. In contrast to KEC I it is not necessary to tune the rotor speed control through power during the kinetic energy control applied.

If a frequency drop occurs, caused by the changed sign at the summing point, the KEC will not generate an excess of electrical power but a reduction. This will lead to a rising rotor speed. The rotor control through power will react on the rising rotor speed by increasing the output power. As a result the turbine will feed in more power and thus support the frequency. KEC II induces therefore only indirectly rising output power.

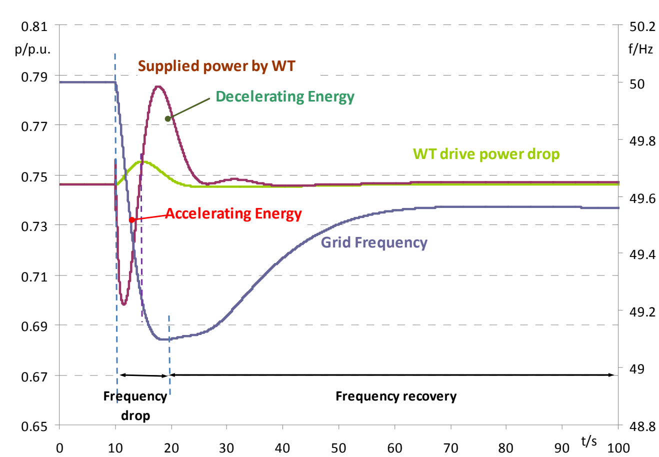

Fig. 13: Response of KEC II to a disturbance

Fig. 13 shows the response of a KEC II-controller to a frequency disturbance. Again, the same fault as with FSPC and KEC I has been simulated. Compared to the case without any frequency support by wind energy (Fig. 7), the minimum frequency is boosted. Fig. 15 illustrates this further by comparing all primary control strategies for the same fault.

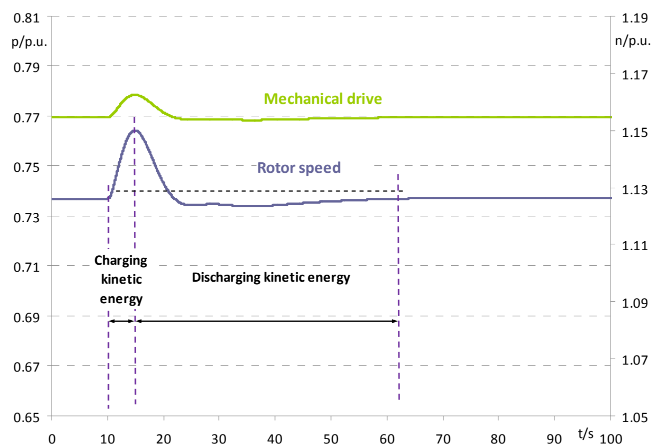

Fig. 14: Mechanical torque and rotor speed for the case shown in Fig. 13

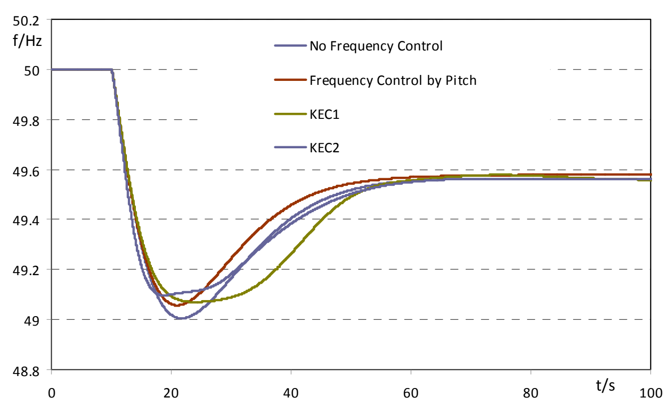

Fig. 15: Comparison of different frequency support strategies

As a result of the reduction in output power at the start of the frequency drop, the frequency drops faster when KEC II is used. In the case depicted in Fig. 13 the controller is parameterized in such a way that it needs almost no additional re-acceleration at the end of the frequency drop. Hence, the frequency characteristic after the disturbance does not differ from the scenario without primary control of wind turbines. Usually, a slight second drop of frequency could be expected for KEC II. Fig. 14 shows mechanical torque and rotor speed of the wind turbine equipped with KEC II. It shows that rotor speed does not need any further recovery at the end of phase 2 of the kinetic energy control. As opposed to KEC I, mechanical torque does not drop but rise at the beginning of the disturbance in which the rotational energy is raised. When releasing additional energy from the rotating masses to the grid, the turbine never undershoots the set-point for output energy of normal operation. That means the operating point in terms of efficiency is always the same or even better than during normal operation mode.

IV. Conclusion

In this paper, three different primary control strategies that enable wind turbines to support grid frequency following a disturbance have been introduced and their performance have been compared with one another. Frequency support by pitch control proves to be a straight-forward and easy way for wind turbines to take part in frequency support. For the investigated scenario and with the real world values used here it was able to improve frequency response on a continuous basis. The measure is in a way comparable to increasing primary reserve in conventional generation plants. Its main drawback is the loss of renewable based electrical energy by deliberately reducing the power output of wind turbines during normal operation.

Kinetic energy control, which momentarily increases the set point of power output of wind turbines, proves to be capable of improving the frequency response of the system following a disturbance. However, it realizes small power losses by leaving the tracking curve of the wind turbine to the range of lower rotational speeds, followed by, depending on the boost of the speed controller, a move to a working point of lower output power.

By contrast, an alternative scheme proposed in this paper (KEC II) acts in the reverse direction by first moving to an operating point with higher rotational speed by de-loading the turbine in the very first moment of the disturbance. Thereby it is possible to gain small advantages in terms of operating efficiency compared not only to KEC I but also to normal operating mode by leaving the tracking curve to working points with higher rotational speed. It also means that when the machine decelerates, more kinetic energy can be released from the rotor before reaching critical rotor speed. If the controller is properly parameterized and if the output power does not drop below the nominal output power for the actual wind speed, adverse impact on the grid observed in KEC I can be avoided. Comparing both kinetic energy control approaches, the new control strategy (KEC II) seems to perform better than the intuitive control which raises output power directly.

V. Biographies

Michael Wilch received his Dipl.-Ing. degree in electrical engineering with emphasis on Power Generation and Transmission from the University of Duisburg-Essen in 2006. He is currently a PhD student at the Institute of Electrical Power Systems of University Duisburg-Essen. His research interests include integration of large amounts of wind power into existing power systems.

Istvan Erlich received his Dipl.-Ing. degree in electrical engineering from the University of Dresden/Germany in 1976. After his studies, he worked in Hungary in the field of electrical distribution networks. From 1979 to 1991, he joined the Department of Electrical Power Systems of the University of Dresden again, where he received his PhD degree in 1983. In the period of 1991 to 1998, he worked with the consulting company EAB in Berlin and the Fraunhofer Institute IITB Dresden respectively. During this time, he also had a teaching assignment at the University of Dresden. Since 1998, he is Professor and head of the Institute of Electrical Power Systems at the University of Duisburg-Essen/Germany. His major scientific interest is focused on power system stability and control, modelling and simulation of power system dynamics including intelligent system applications. He is a member of VDE and senior member of IEEE.

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