Load Frequency Control of a Multi-area Power System Incorporating Variable-speed Wind Turbines ⋆

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Abstract: The increasing use of renewable technologies in power generation may require its participation on ancillary services like frequency regulation. For the specific case of wind sources, this may lead to participation in frequency control loops. This paper focuses on the simulation of the performance of the LFC scheme for a multi-area power system, with participation of DFIG turbines in the frequency control loops, through the *synthetic inertia method*.

Keywords: Power systems, load frequency control, wind turbine, pitch angle, multi-area system.

1. INTRODUCTION

The behavior of generation systems based on unconventional energy sources like wind and solar energies may impact several aspects related with the operation and control of power systems; one of the ongoing research topics is related with understanding the impact of these new sources on the system frequency ((Bevrani, 2009; Valencia et al., 2012; Rahmann and Castillo, 2014; Horta et al., 2015)). As wind constitutes the most extensively used renewable energy source in the world, there are many studies about control strategies for the inclusion of wind turbines in the load frequency control loops of power systems (a complete rewiew of grid requirements and control methodologies can be seen in (Daz-Gonzlez et al., 2014)). In (de Almeida et al., 2006), an optimization is proposed in order to schedule the active and reactive power that wind turbines must deliver to meet the grid requirements. Additionally, a controller for the pitch angle in the turbine was also presented, forcing the turbine to operate over a de-load curve.

In (Ramtharan et al., 2007b) and (Moore and Ekanayake, 2009), the synthetic inertia method is used, where an additional control loop is proposed to emulate the behavior of conventional units in the frequency response of wind-turbines. Also, in (Camblong et al., 2014), the dynamic model of a DFIG (Doubly-fed Induction Generator) wind turbine is proposed in order to design an LQR controller to provide frequency support using reference torque and reference pitch angle as inputs. In (Bernard et al., 2013), a MPC (Model Predictive Controller) is developed through a simplified model of the DFIG, having the quadrature-axis rotor voltage of the wind-turbine dynamic system as an input.

In spite of the considerable efforts of the previously mentioned studies, those works did not consider the application over multi-area power systems, which are increasingly common representations as power grids continue to grow in size and complexity. Additionally, it is necessary to perform a comparison between the conventional control methods used for the load frequency control as PI (Proportional-Integral) and other more complex control strategies such as as the LQR controllers or MPCs in multi-area power systems.

Based on these requirements, this paper presents the simulation of the performance of the LFC (Load Frequency Control) scheme for a multi-area power system, having into account the participation of DFIG turbines in the frequency control loops, through the *synthetic inertia method*, with PI controllers for the AGC (Automatic Generation Control), the quadrature rotor voltage and the pitch angle and employing the simplified wind turbine model proposed in (Moore and Ekanayake, 2009) and (Bernard et al., 2013). The performance of these models and its contribution are illustrated by simulation using the IEEE nine bus system benchmark.

The paper is organized as follows: in section 2, a short description about the load frequency control is presented, and next the models and control loops required for wind modeling contribution are described in section 3. Section 4.1 shows the selected benchmark. The results of including wind-turbines in the LFC control loop are presented in section 4.2. At the end, some concluding remarks can be found.

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2. LOAD FREQUENCY CONTROL

In an electric power system, the frequency of the voltage wave must rely between rigorous limit values in order to keep the quality of the electric service inside an acceptable operational margin. This is a difficult task since the frequency is related to the load-generation balance and both variables are changing during the daily operation. This difficulty increases even more if the penetration of renewable energy sources is considered. Therefore, generating units require a control system able to respond to the generation or load changes, which is known as the load frequency control (LFC), (Saadat, 1999). This control system is organized in three levels: primary, secondary an tertiary frequency control. These levels are explained in (Bevrani, 2009), as follows:

- **Primary control (LFC).** Primary control is the fastest. It operates in a time band between 2-20 seconds and acts at the local level over each generation unit.
- **Secondary control (AGC).** Secondary control operates in a time band between 2 secondsand 2 minutes. It allows the correction of the steady-state errors in system frequency. For multi-area systems, it also regulates the power exchanged between areas.
- **Tertiary control.** Tertiary control is used in large power systems. It operates in a time margin above 10 minutes and specifies the set-points to the generation units by optimizing some cost function. Because the time and the tasks involved, this control stage is often considered as part of dispatch operations, and not fully mentioned as a frequency control loop.

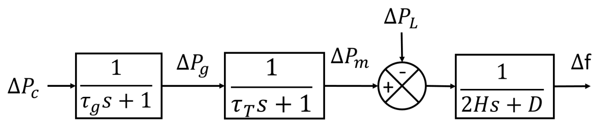

Fig. 1. Model of the set: speed-governor, turbine, generator and load (based on (Saadat, 1999)).

With the aim of designing these control systems, power system elements are modeled. For this, an equivalent model of an isolated power system is presented, where the response of all loads and generators are represented by a single damping and an equivalent inertia (see (Saadat, 1999) for a deeper description of these models). Also the dynamics of the speed-governor and the turbine are represented by first order transfer functions as illustrated in Figure 1, where:

- ΔP_m is the change in mechanical power of the generator.
- ΔP_g is the change in the governor output.
- ΔP_l is the load perturbation.
- Δf is the frequency change.
- D is the damping coefficient, due to the frequency sensitive loads.
- H is the equivalent inertia, the sum of the inertia of all generators in the system.
- ΔP_c is the control action of the LFC.

In an isolated power system, the function of the LFC is to restore frequency to its nominal value after a perturbation,

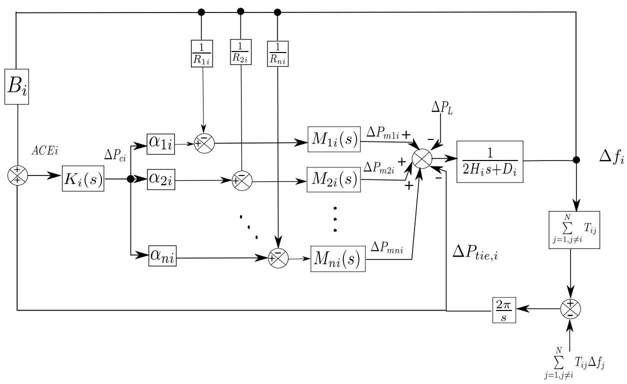

Fig. 2. Load frequency control scheme for a multi-area power system (based on Bevrani (2009)).

without taking into account power exchange. On the other hand, for interconnected systems, the control area concept has to be used, which is a group of generators and loads where the generators respond to load changes uniformly.

2.1 Load frequency control in multi-area power systems

A multi-area power system is composed by single area power systems that are interconnected by transmission lines or tie-lines. There is a LFC system on each of these single-area systems, which have the function of regulating, not only the frequency in the local area, but the power exchange with other areas (Saadat, 1999). Therefore, in the LFC dynamics, the tie-line power signal must be added in order to guarantee that the frequency deviation produced by load fluctuations in one area is controlled locally and does not propagate to other areas. Thus, each local area must be able to control its own load-generation perturbations.

Figure 2 depicts the load frequency control scheme for an N-area system, where (based on (Bevrani, 2009)):

- $M_{ni}(s)$ is the transfer function corresponding to the set of speed-governor, turbine, generator and load in area i.
- T_{ij} is the initial power exchange factor between area i and area j.
- ΔP_{tiei} is the change in the power exchange between the area i with other areas.
- Δf_j is the change in the frequency of the areas connected to area i.
- B_i is known as the *bias factor*, which allows minimize the power exchange with other areas through the input error signal in the AGC controller.
- $K_i(s)$ is the transfer function of the AGC controller.
- α_i is the participation factor of each generator in the AGC (these values are assumed equal to one for each generator if not established otherwise).

3. INCLUDING VARIABLE SPEED WIND-TURBINES IN LOAD FREQUENCY CONTROL

In order to include variable speed wind-turbines in the LFC, it is required to represent the power production of these generation units. For this, the model proposed in (Ramtharan et al., 2007a) is taken into account. There, the authors propose that the wind-turbine performs at an

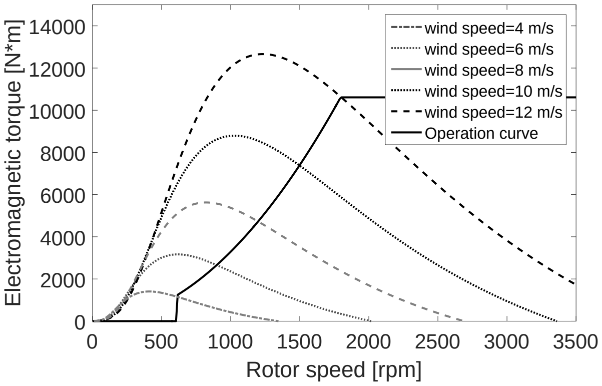

Fig. 3. Wind-turbine operation curve for different wind speeds (Thomsen, 2006)

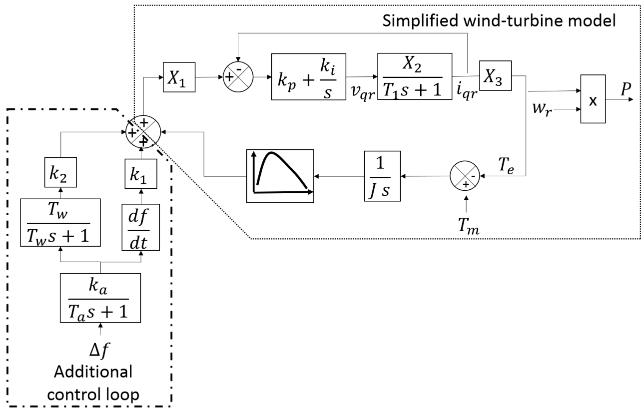

Fig. 4. Wind-turbine simplified model with additional control loop for LFC contribution (based on (Ramtharan et al., 2007a)).

operating point below its maximum power. As seen from figure 3, this results in the operating point of the wind-turbine being moved to the right regarding to its point of maximum power extraction.

The mechanical torque in each of the curves shown in Figure 3 is given by the equation (Thomsen, 2006):

$$T_m = \frac{Pm}{w_{shaft}G_b p}. \tag{1}$$

In equation (1), ω_{shaft} is the rotational speed of the wind-turbine shaft, G_b is the gearbox ratio, p denotes the number of pole pairs in the generator and P_m is the mechanical power, which is defined as:

$$P_m = \frac{1}{2}\rho\pi R^2 v^3 C_p. \tag{2}$$

There, $\rho = 1.225\ kg/m^3$ is the air density, $R = 45\ m$ is the blade's length, v is the wind speed and C_p is the efficiency coefficient described below:

$$C_p = 0.22((\frac{116}{\lambda_t}) - 0.4\beta - 5)e^{\frac{-12.5}{\lambda_t}}, \tag{3}$$

with λ_t a parameter given by Thomsen (2006):

$$\lambda_t = \frac{1}{\frac{1}{\frac{R\omega_{shaft}}{v}+0.08\beta} - \frac{0.035}{1+\beta^3}} \tag{4}$$

In this way, the value of the coefficient C_p will be depending on the pitch angle β, the wind speed v and the rotational speed ω_{shaft}. Thus, for each wind speed value an operating point slightly moved to the right is taken. At this operating point, the torque is given by equation (5), where the value of $K_{op} = 0.3$ is a constant.

$$T_{op} = K_{op}v^2 \tag{5}$$

Besides the simplified model previously described, is is also necessary to use a fraction of the power generated by the wind turbine in order to contribute to the LFC. Using the so-called *synthetic inertia model* (see (Ramtharan et al., 2007a) and Moore and Ekanayake (2009), a couple of additional loops are aggregated to the LFC: one containing a transfer function offering an output proportional (multiplying by K_1) to the frequency change rate (corresponding to the primary response of the wind turbine); and the other loop having the task of restoring the power delivered by the wind turbine after its participation in the load frequency control. The deviation frequency signal is pre-filtered, previously, by a filter with gain K_a.

Both the simplified model and the synthetic inertia model are depicted in figure 4, where:

and

- ω_r is the rotor angular speed,
- n is the number of wind-turbines,
- iq_r is the quadrature rotor current,
- vq_r is the quadrature rotor voltage, and
- X_1, X_2, X_3 and T_1 are constant values representing relationships between the internal wind generator parameters (see (Ramtharan et al., 2007a) for a detailed description of them).

A $2MW$ wind-turbine, is selected to perform the simulations, the parameters of this turbine are presented in table A.2 in section 5.

Moreover, for wind speeds equal or over the rated wind speed of the wind-turbine, a pitch angle control should be performed to maintain the angular speed of the wind-turbine at its nominal value. Additionally, when a frequency event occurs, and the turbine is operating under the action of pitch control, it is proposed to add a loop of additional control where the pitch angle is increased by a value proportional to the frequency deviation (this value is denoted by the constant R_β). This pitch control scheme is illustrated in Figure 5 with a PI controller.

The whole wind turbine model with the inclusion of control loops described above is presented in figure 6, where the variable n indicates the number of generating units, and the variable v_w indicates the wind speed. This model has an additional element compared with the models of (Ramtharan et al., 2007a) and (Moore and Ekanayake, 2009), the variable P_{ref}, which constitutes the power that the wind-turbine would deliver if it would not be contributing to system frequency control.

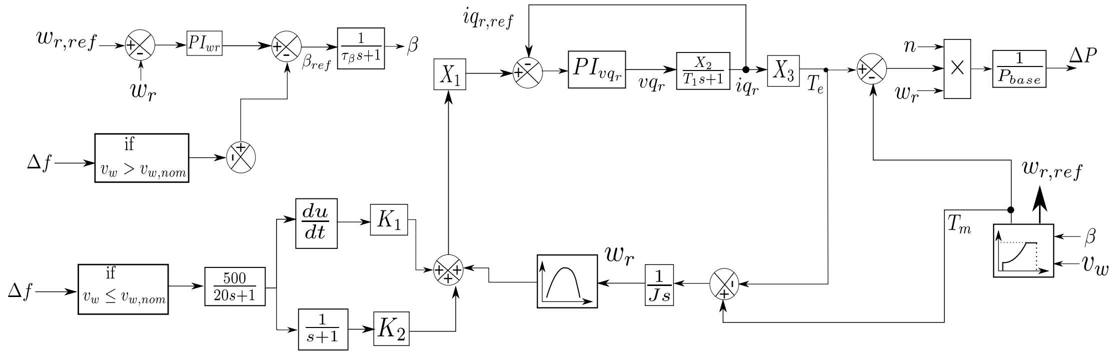

Fig. 6. Schematic diagram for wind-turbine integration in the LFC for a single area system (Moore and Ekanayake, 2009).

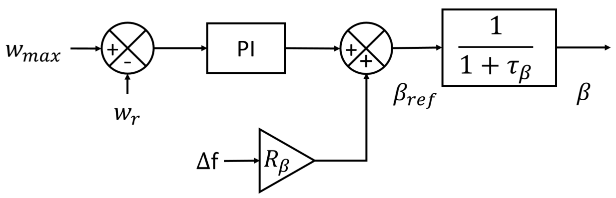

Fig. 5. Pitch control scheme for participation of wind-turbines in the LFC (based on (Ramtharan et al., 2007a)).

4. SIMULATION RESULTS

4.1 Benchmark Description

To perform the simulation of the LFC in a multi-area power system, the IEEE nine bus system is used (see (Anderson and Fouad, 2002)). This system is arbitrarily divided into in three areas, as illustrated figure 7. Each area has a generation unit and an associated load. Saturation blocks represent the operational limits of the units.

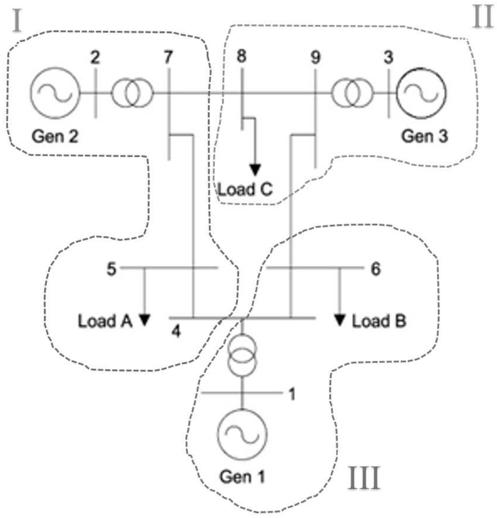

Fig. 7. IEEE 9 bus system with an arbitrary multi-area partition.

Simulations were performed using the parameters presented in table A.1 (see Appendix), taken from (Anderson and Fouad, 2002) and using 100 MVA as base power. The work is performed under the assumption of area 1 having a hydraulic turbine and generators 2 and 3 being gas turbines. Thus, each area could be represented by the scheme shown in Figure 2. Saturation blocks represent the generation units operational margins.

However, in area 3 the 50% of the conventional generation is replaced by wind-turbines with an equivalent power. A wind farm composed of 32 total turbines with a power of 2 MW for each unit. Figure 8 shows the modification of the LFC scheme to include wind turbines in the frequency regulation system.

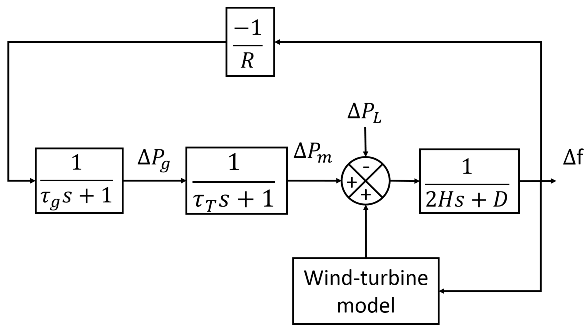

Fig. 8. LFC scheme including wind turbines for primary frequency regulation.

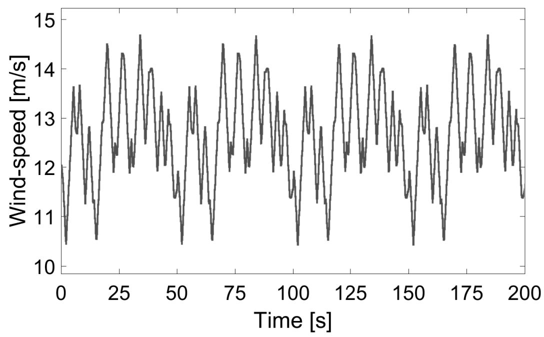

Fig. 9. Wind speed profile (from (Bernard et al., 2013)).

For simulation purposes, load disturbances are applied in each area as follows: In area 1 a perturbation of 0.01 p.u. is made at 90 seconds, in area 2 a perturbation of 0.08 p.u. is performed at 60 seconds, and in area 3 a load disturbance of 0.06 p.u. is applied at 30 seconds. Also, the wind speed profile employed to feed the wind units is shown in figure 9 as considered in in (Bernard et al., 2013).

4.2 Results

PI controllers are used in in the secondary control (AGC) of each area , and also for the regulation of the quadrature rotor current iq_r, and the pitch angle β in wind turbines. The parameters for these controllers were calculated with the Gradient Descent method, in Matlab Design Optimization-Based PID Controller toolbox (see table 1).

Table 1. Parameters for different PI controllers

Parameter	Area 1	Area 2	Area 3	iq_r	Pitch
P	0	0	0	0	7.19
I	-0.05	-0.05	-0.028	2.70	0.53

Figures 10 - 12 present the frequency deviations for each area with and without contribution of wind turbines in the LFC system of area 3. As the AGC, by design, leads to the local control of disturbances minimizing the effects in the other areas, the expected consequence is no sensible operational difference between the frequency deviations of each area. However, for each area, the inclusion of the wind farm in LFC of area 3 actually helps to compensate frequency deviations in the LFC, but only when there is enough wind to produce the required power. During the periods of low wind, disturbance effects are harder to compensate than the conventional case, due to the lack of renewable power in the system. Besides this, it is important to highlight that the presence of hydro generation in area 1 implies a greater inertia, diminishing even more the effects of frequency disturbances. The effects over areas 2 and 3 are pretty similar, because these areas have similar conditions.

The power exchanged between area 3 and the other areas is shown in figure 12. As it was said before, both frequency and power deviations are low when there is enough wind speed to sustain the power contribution of the wind farm. Once wind speed is low, area 3 needs to increase the power absorbed from the order areas in order to reduce the effects of local disturbances in the local area frequency.

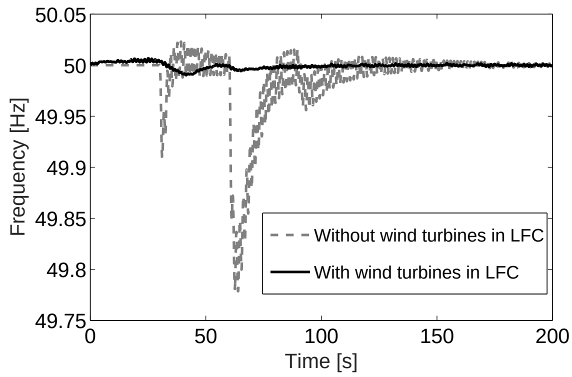

Fig. 10. Frequency deviation in area 1.

The responses of the rotor voltage vq_r and the pitch angle β_{ref} are depicted in figures 14 and 15, respectively. These figures show how the participation of wind turbines in LFC can be more stressful for them. However, a less aggressive performance could be obtained with a better tuning of the involved PI controller, or by the implementation of another kind of controllers.

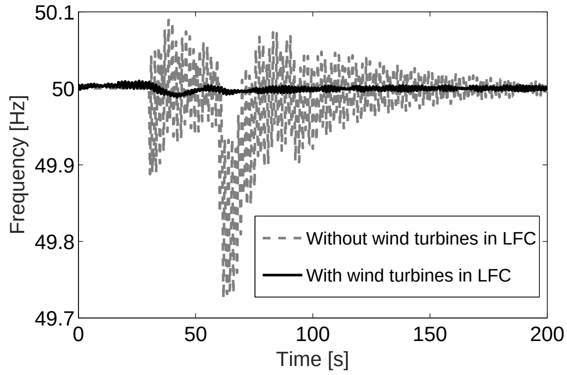

Fig. 11. Frequency deviation in area 2.

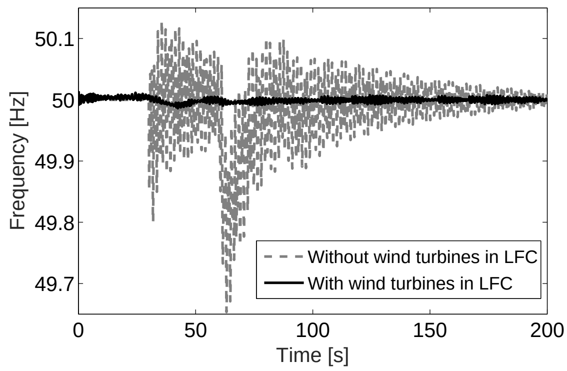

Fig. 12. Frequency deviation in area 3.

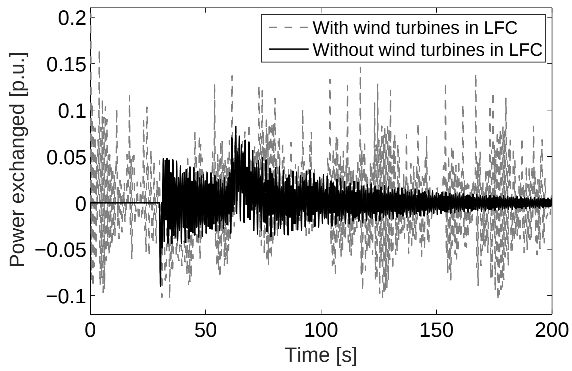

Fig. 13. Power exchange for area 3.

5. CONCLUSION

The simulation of the performance of the LFC scheme for a multi-area power system, with participation of DFIG turbines in the frequency control loops, through the *synthetic inertia method*, with PI controllers for the AGC control was presented. The results show that wind turbines are useful for frequency regulations tasks in primary control. However, the variability of wind and the effects of the decreasing inertia from conventional units can be dangerous for frequency performance. Additionally, it is also shown that the participation of wind turbines in LFC introduces more stress in the operation of these units, requiring the exploration of control techniques that help to reduce these efforts for the wind units.

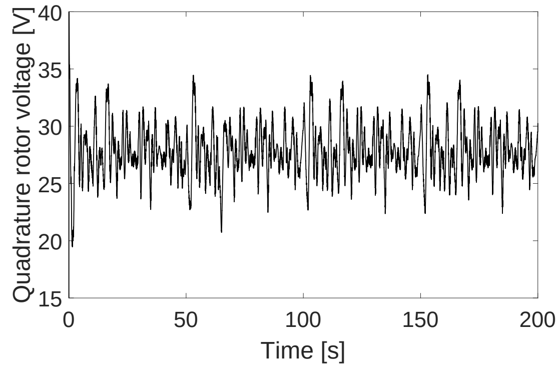

Fig. 14. Control action for the variable vq_r.

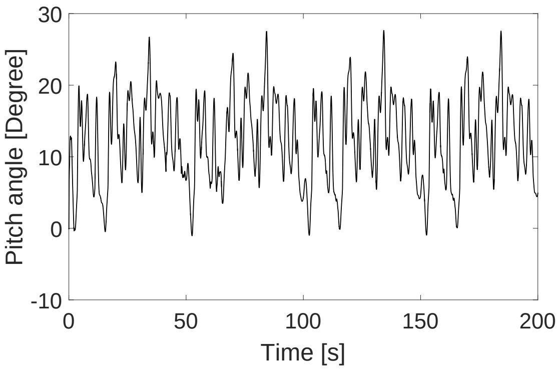

Fig. 15. Control action for the variable β_{ref}.

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Appendix A. SIMULATION PARAMETERS

Table A.1. IEEE nine bus system parameters (from Anderson and Fouad (2002))

Parameter	Value
H_1	23.64 s
H_2	6.4 s
H_3	1.505 s
MVA_{nom1}	247.5
MVA_{nom2}	192
MVA_{nom3}	128
$D1, D2, D3$	0.8
$Tg1, Tg2, Tg3$	0.2
$T_{\tau 1}, T\tau 2, T\tau 3$	0.3
T_{12}	2.064 p.u.
T_{13}	6.1191 p.u.
T_{23}	14.4353 p.u.
R_1	2 p.u.
R_2	10 p.u.
R_3	7.5019 p.u.
B_1	2.8 s
B_2	10.8 s
B_3	8.3 s

Table A.2. Wind-turbine model parameters (Ramtharan et al. (2007a) and Moore and Ekanayake (2009)).

Parameter	Value
P_{nom}	2 MW
V_{nom}	966 V
K_1	5000 Nm
K_2	2000 Nm
T_w	1
K_a	500
T_a	20
R_s(Stator resistance)	0.00491 p.u.
X_{ls}(Stator reactance)	0.09273 p.u..
X_m(Magnetization reactance)	3.96545 p.u.
R_r(Rotor resistance)	0.00552 p.u
X_{lr}(Rotor reactance)	0.1 p.u.
$H = \frac{1}{2}J\frac{w_{nom}{}^2}{VA_{nom}}$	4.5 s
J (Inertia moment)	506.6059 Kgm^2.
P_{base} (Power base)	128 Mw.