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The Effect of High Penetration of Wind Power on Primary Frequency Control of Power Systems

Master of Science Thesis

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Department of Energy and Environment
Division of Electric Power Engineering
CHALMERS UNIVERSITY OF TECHNOLOGY
Göteborg, Sweden 2013

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Cover:
Wind turbine which is located in Germany. The photo has been taken by Bardia Motamed.

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Abstract

In this work, a power system with wind power units and hydro power units are considered. The hydro power unit and variable speed wind turbine are modeled in Matlab/Simulink. The wind turbine has a pitch controller to be used during high wind speed range. The behavior of grid frequency and hydro power are analyzed when there is a power imbalance. Also the effect of increasing wind power penetration on frequency is investigated.
Short-term extra active power, inertia emulation and direct pitch angle regulation as a primary frequency control are added to the wind turbine to improve frequency behavior and temporary minimum frequency when there is a mismatch between load and generator. In addition, the combination of these three primary frequency control methods are evaluated. Simulation results show that using primary frequency control methods could be useful to improve the grid frequency behavior when there is a power imbalance in case of high wind power penetration level. The temporary minimum frequency of Inertia emulation method is higher than two other methods. Also the combination of temporary extra active power method and inertia emulation method has the highest value of temporary minimum frequency, although it is slower than other proposed methods.

Index Terms: Hydro turbine, inertia emulation, pitch controller, primary frequency control, wind turbine modeling.

Acknowledgements

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Even though only my name appears on the cover of this thesis report, great many people have contributed to its production. I owe my gratitude to all those people who have made this dissertation possible. It gives me great pleasure in acknowledging the support and help of Doctor Peiyuan Chen for his supervision, patience and giving me the opportunity to work on this project.
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I wish to express my love and gratitude to my beloved parents, for their understanding, support and endless love.

Bardia Motamed
Gothenborg, Sweden, 2013

List of symbols

A	Area swept by blades	[m]
C_p	Power coefficient	-
D	Load damping	-
E	Kinetic energy	[J]
$E_{down-regulation}$	Kinetic energy is used for down regulating	[J]
$E_{up-regulation}$	Kinetic energy is used for up regulating	[J]
f	Frequency	[Hz]
g	Gravity constant	[m/s^2]
H	Inertia constant	[s]
H_0	Inertia constant of each generator	[s]
H_{eq}	System inertia constant	[s]
H_{wt}	Inertia constant of wind turbine	[s]
J	Moment of inertia of the rotating masses	[Kgm^2]
L_p	Wind energy penetration level	-
P_o	Standard sea level atmospheric density	[Kgm^3]
P_a	Accelerating power	[W]
P_e	Electric power	[W]
P_{ef}	Measured electric power	[W]
P_{in}	Inertial power	[W]
P_L	Load power	[W]
P_m	Mechanical power	[W]
P_{mo}	Input mechanical power	[W]
R	Rotor radius	[m]
R_0	droop of each generator	-
$R_{p,eq}$	Permanent droop	-
R_T	Temporary droop	-
S_0	Power rating of each generator	[MVA]
T	Temperature	[K]
T_a	Accelerating torque	[Nm]
t_{acc}	Accelerating time	[s]
t_{dcc}	Decelerating time	[s]
T_e	Electrical torque	[Nm]
T_G	Governor time constant	[s]
T_m	Mechanical torque	[Nm]

T_R	Reset time	[s]
T_W	Water starting time	[s]
U_H	Upper voltage limit	[V]
U_{HF}	Upper voltage limit for full load range	[V]
U_L	Lower voltage limit	[V]
U_{LF}	Lower voltage limit for full load range	[V]
U_N	Nominal voltage	[V]
v_ω	Wind speed	[m/s]
z	Altitude above sea level	[m]
α	Values of the coefficient	-
β	Pitch angle	[°]
λ	Tip speed ratio	-
ρ	Air density	$[\mathrm{kg/m^3}]$
ω_m	Angular velocity of the rotor	[Mech.rad/s]
ω_{m0}	Angular velocity of the rotor at rated speed	[Mech.rad/s]
ω_{max}	Maximum limitation for rotor speed	[rad/s]
ω_{min}	Minimum limitation for rotor speed	[rad/s]
ω_r	Angular velocity in electrical	[rad/s]
ω_{ref}	Reference speed	[rad/s]
ω_{wt}	Rotor speed	[rad/s]

Abbreviations

AESO	Alberta electric system operation
DFIG	Doubly-fed induction generator
ENE	E. ON Netz GmbH
EWEA	European wind association
WPF	Wind power facility
FRC-WT	Fully-rated converter wind turbine
FSWT	Fixed-speed wind turbine
SFD	Second frequency drop
TMF	Temporary minimum frequency
VSWT	Variable-speed wind turbine

Contents

Chapter 1

Introduction

Wind power generation is one of the most important sources of electricity from renewable energy and the expansion of it has been rapidly increased during the past decade. Wind energy is a green renewable energy and governments would prefer to use it due to the environmental and economic goals. For example, Germany, as one of the precursors in terms of installing wind capacity, has a plan to increase installed wind turbine capacity to at least 20 % by 2020 [1]. The Danish Parliament reached a political consensus during 2008 that in 2025, 50 % of Denmark's electricity demand must be produced by renewable resources, mostly wind power [2]. It is forecasted by the European Wind Association (EWEA) that the generation of electricity by using wind turbine will become 12 % and 20 % in 2020 and 2030, respectively [3].

1.1 Background and Motivation

As the power system's dependency on wind power increases, wind power generation is expected to contribute with services that are normally delivered by conventional power plants [4] e.g. hydro power. In a power system with high wind power penetration, certain conventional power plants are mothballed. This results in a reduction in system inertia and may lead to frequency control and operational issues [5]. In a network with conventional power plants, if the load is increased, the system frequency may decrease. By using droop controller, the system frequency may be stabilized and settled down but with a steady-state frequency deviation. The steady-state frequency deviation may increase as the wind power penetration level increases. Furthermore, as shown in Fig. 1.1, the temporary minimum frequency (TMF) of the system may also increase as wind power penetration level increases.

There are several publications related to the subject of frequency support using wind energy conversion systems (WECS). Most of the presented methods use the kinetic energy stored in the wind turbine rotating mass to provide additional power to the grid in case of frequency variation [6]. This kinetic energy could be utilized to provide temporary primary frequency support to the grid in the event of a load/generation mismatch. Variable speed wind turbines are designed to be able to vary their rotational speed in a wide range during normal operations. This gives the possibility to utilize the rotational energy in the

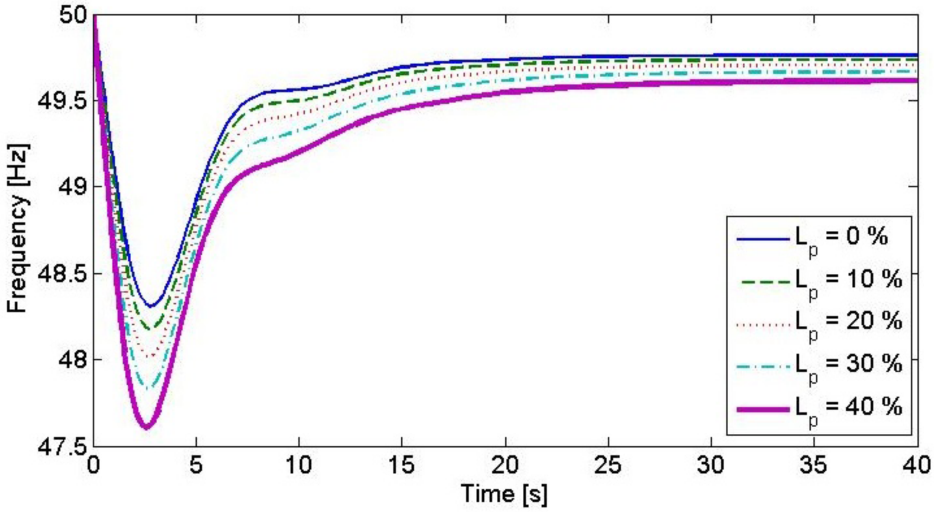


Fig. 1.1 Network frequency excursion after a 0.1 pu load step increase with different scenarios of wind power penetration level without frequency support.

turbines-generator to provide short term active power support in the event of network frequency excursions [7]. In some publications, it is proposed to control the WECS to maintain a reserve of active power ΔP_{ω}, e.g., regulating the pitch angle to avoid extracting the maximum power from the wind. Using this power reserve, the frequency regulation is performed by regulating the electrical torque of wind turbines [6].

1.2 Purpose

This thesis focuses on the effect of high penetration of wind power on primary frequency control under disturbance situations. Furthermore, it evaluates the percentage of penetration of wind power such that the system frequency can be controlled within the acceptable range. The effects of high penetration of wind turbine on primary frequency control during power unbalance are analyzed for the system which includes the following characteristics.

1. Review of grid code requirement for generators on frequency control and support.
2. Modeling of hydro turbine without any penetration of wind power.
3. Modeling of wind farms connected to the system with hydro power dominated.
4. Modeling of wind farms with pitch controller.
5. Evaluation of different frequency support strategies from wind farms (e.g., inertia emulation and droop control).
   (a) During low/medium wind speed operating range
   (b) During high wind speed operating range

Chapter 2

Theory

2.1 Aerodynamic Power

The mechanical power produced by a wind turbine can be expressed as [8]:

$$P_m = \frac{1}{2}\rho C_p(\lambda, \beta) A \omega_s^3 \quad (2.1)$$

where ρ is air density (kg m^{-3}); ω_s is wind speed (m s^{-1}); C_p is power coefficient and the tip speed ratio (λ) is defined as:

$$\lambda = R\frac{\omega_{\omega t}}{\omega_s} \quad (2.2)$$

In (2.2), R is the rotor radius in m, ω_{wt} is the rotor speed in pu. Also the air density is a function of air pressure and air temperature, which both are functions of the height above sea level [8].

$$\rho = (\frac{P_0}{RT}) \exp(\frac{-gz}{RT}) \quad (2.3)$$

Where P_0 is standard sea level atmospheric density (1.225 kg m^3); R is specific gas constant for air (287.05 J kg^{-1} K^{-1}); g is gravity constant (9.81 ms^{-2}); T is temperature (K) and z is altitude above sea level (m).
Equation (2.1) indicates that by increasing 10 % wind speed, the available energy will increase by around 30 %.The power curve of variable speed wind turbine is shown in Fig. 2.1. The turbine usually reaches its rated value at a wind speed between 12 - 17 m/s, depending on the design of the individual wind turbine [8–10].
The maximum power production will be limited at the high wind speed. The power output regulation can be done by pitch controller. The cut-out wind speed is the wind speed where the wind turbine stops producing and turns its blades out of the main wind direction. The cut-out wind speed is usually in the range of 20 to 25 m/s [8–10]. Fig. 2.1 also shows the cut-out of wind speed at 25 m/s wind speed.

2.2 Wind Turbine Topologies

2.2.1 Fixed-Speed Wind Turbine

Fixed speed wind turbines (FSWTs) is a kind of wind turbine that the rotor speed is almost constant for different wind speeds. The value of rotor speed is chosen by considering the gear ratio, the design of generator and the grid frequency. Normally the induction generator is used for FSWTs. This generator has different winding sets for different wind speed ranges, because of increasing power. It means that, the number of poles for low wind speed range is usually higher than the number of poles for high wind speed range [8]. Table 2.1 lists some advantages and disadvantages of FSWTs.

Table 2.1: Some advantages and disadvantages of FSWTs [8].

Advantages	Disadvantages
Simple	Mechanical stress
Robust	Uncontrollable reactive power consumption
Reliable	Limited power

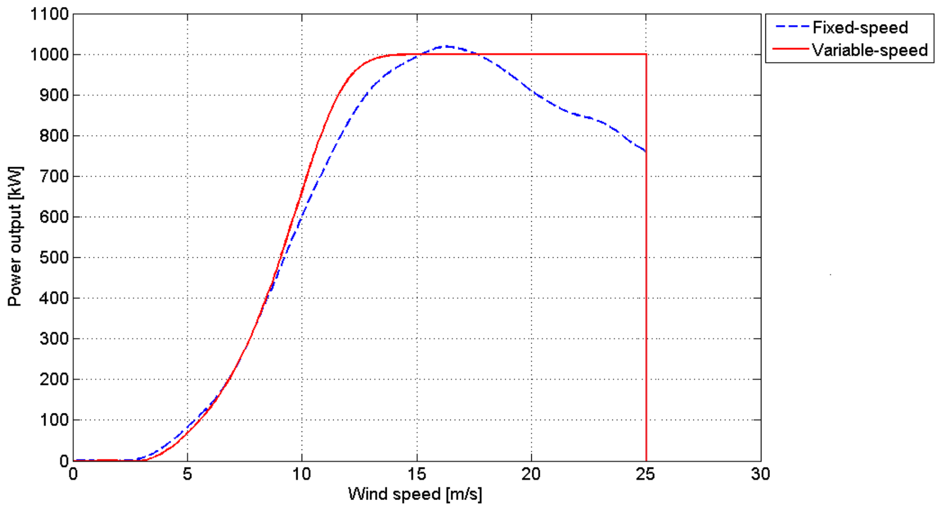


Fig. 2.1 Typical power curve versus wind speed related to variable speed wind turbine with a cut-out speed of 25 m/s.

2.2.2 Variable-Speed Wind Turbine

Variable-speed wind turbines (VSWTs) has different rotor speeds at different wind speeds. Thus, it is possible to have a maximum efficiency at different wind speed ranges. Typically synchronous or induction generator is used for VSWTs [8]. Table 2.2 lists some advantages and disadvantages of variable speed wind turbine in comparison with fixed speed wind turbine.

Table 2.2: Some advantages and disadvantages of VSWTs in comparison with FSWTs [8].

Advantages	Disadvantages
Reduced mechanical stress	More complicated electrical part
Increased energy captured	More losses in power electronics
Higher efficiency	Higher cost of equipment

Doubly-Fed Induction Generator

"Doubly fed" means that, there is a difference between sources of voltage for rotor (power converter) and stator (grid). The power converter includes two converters: one is the grid-side converter and the other one is the rotor-side converter [8].

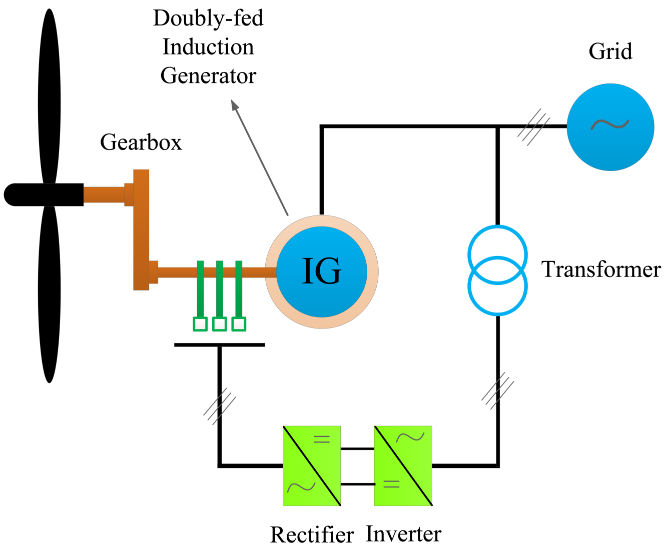


Fig. 2.2 Typical configuration of a DFIG wind turbine.

The rotor of Doubly-fed induction generator (DFIG) can deliver and absorb power. This characteristic depends on the operation point of generator. In other words, when the rotor speed is lower than the synchronous speed, the power is sent to the rotor from network and vice versa, when the rotor speed is higher than the synchronous speed, the power is sent to the grid from rotor [11]. One of the advantages of DFIG in comparison with full-power converter is that, more power can be delivered to the grid [12].

Fully Rated Converter Wind Turbines

Fully rated converter wind turbines (FRC-WTs) can be with or without gearbox. It is possible to use many kinds of generator such as induction generator and synchronous generator (wound rotor and permanent magnet) [11].

2.3 Grid Code Requirements on Frequency

Installing high penetration of wind power has an impact on the stability of the power system. Some countries, such as Germany, Denmark, Canada and Ireland, who are pioneer in installing wind power, have prepared specific grid codes for the connection of wind farms and wind turbines to the grid to maintain continuity and security of the electric supply [3].

2.3.1 Canada

The Alberta Electric System Operation (AESO) specifies a transmission system voltage operating range at the point of connection that the Wind Power Facilities (WPF) should be able to operate within. A WPF reactive capability is about to meet or exceed 0.9 lagging to 0.95 leading power factor [3]. Table 2.3 Shows under/over frequency limits in Alberta.

Table 2.3: Under/Over frequency limits in Alberta [3].

Frequency [Hz]	Minimum Time Delay
> 61.7	0 seconds
61.6 to 61.7	30 seconds
60.6 to 61.6	3 minutes
> 59.4 to 60.6	Continuous operation
> 58.4 to 61.7	3 minutes
> 57.8 to 58.4	30 seconds
> 57.3 to 57.8	7.5 seconds
> 57.0 to 57.3	45 cicles
57 or less	0 seconds

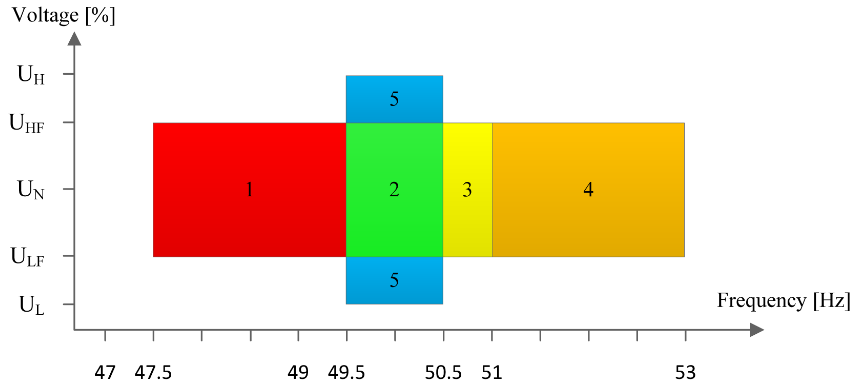
2.3.2 Denmark

The voltage-frequency operational window for the Danish grid code is graphically represented in Fig. 2.3.

Fig. 2.3 shows U_H is upper voltage limit, U_{HF} is upper voltage limit for full-load range, U_N is nominal voltage, U_{LF} is lower voltage limit for full-load range and U_L is lower voltage limit. Table 2.4 shows the values for different voltage ranges.

Table 2.4: Dimension voltage in the Danish grid code [3].

U_H [kV]	U_{HF} [kV]	U_N [kV]	U_{LF} [kV]	U_L [kV]
440	420	400	360	320
180	170	150	146	135
155	145	132	125	119



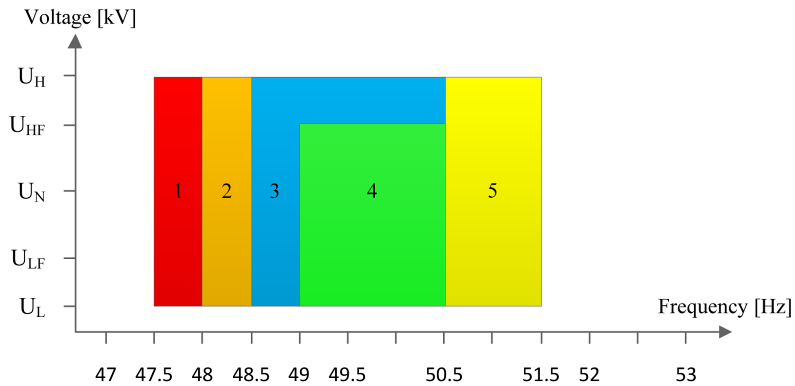
1	2	3	4	5
30 min	countinue	30 min	3 min	1 hour
Power reduction 0 % at 49 Hz 15 % at 47.5 Hz		10 h/year No power reduction	No requirement for active power production	10 % reduction

Fig. 2.3 The voltage-frequency operational window according to the Danish grid code [3].

2.3.3 Germany

German grid code describes the minimum organizational and technical requirements that must be achieved when operating grid connections on the E. ON Netz GmbH (ENE) high voltage or extra high voltage power system. The term connectee refers to those parties who operate a connection on the ENE grid, regardless of supplying or drawing electrical energy [13].

Connection of generation plants by the connectee is acceptable following approval by ENE. Each generator has to be able to operate when the output power reduces and also allow constant 1% power changes of the rated power per minute across the entire range between minimum and continuous power.



1	2	3	4	5
t ≤ 10min	t ≤ 20min	t ≤ 30min	Continuos	t ≤ 30min

Fig. 2.4 The voltage- frequency operational window according to E. ON grid code [13].

Fig. 2.4 shows U_H is upper voltage limit, U_{HF} is upper voltage limit for full-load range,

U_N is nominal voltage, U_{LF} is lower voltage limit for full-load range and U_L is lower voltage limit. Table 2.5 shows the Dimension voltage in e.on grid code.

Table 2.5: Dimension voltage in e.on grid code [13].

U_H [kV]	U_{HF} [kV]	U_N [kV]	U_{LF} [kV]	U_L [kV]
440	420	380	360	350
253	245	220	210	193
127	123	110	100	96

For offshore wind turbines, all generators must be disconnected from the grid upon reaching a frequency at the grid connection point of more than 53.5 Hz and less than 46.5 Hz and after a time delay of 300 ms. In the range of 51.5- 53.5 Hz or 46.5- 47.5 Hz, a subsequent disconnection is allowed only after 10 s [14].

2.3.4 Ireland

The voltage-frequency operational window according Irish grid code is shown in Fig. 2.5.

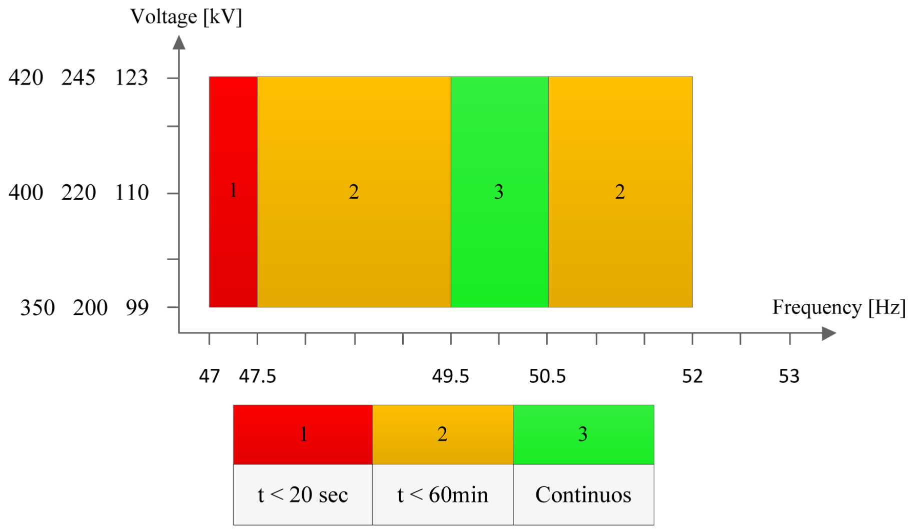


Fig. 2.5 The voltage-frequency operational window according Irish grid code [15].

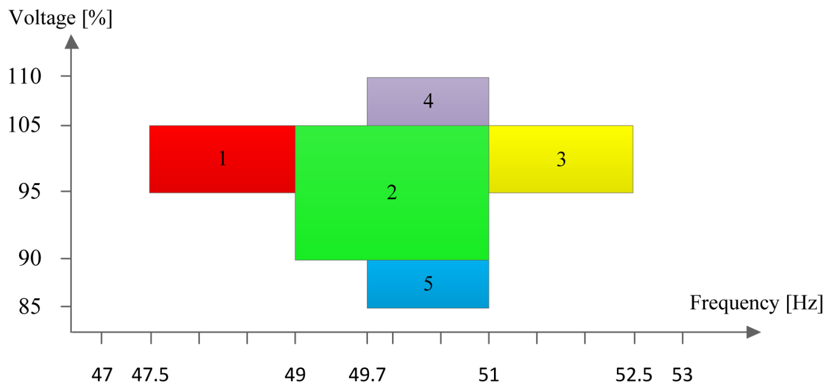
2.3.5 Sweden

Fig. 2.6 shows the interference tolerance for hydroelectric power stations, gas turbine units and wind power groups. Table 2.6 illustrates the size of production plants according to installed nominal active power output in the Swedish grid code.

Wind power group means that a wind power unit with associated equipment including network and any transformers. The network, including associated equipment and any transformer shall, at the time of its construction, be designed only to wind power units [16].

Table 2.6: Size of production plants according to installed nominal active power output in the Swedish grid code [16].

	Large plants	Medium plants	Small plants
Hydroelectric power stations	> 50 MW	25-50 MW	1.5-25 MW
Thermal power block	> 100 MW	25-50 MW	1.5-25 MW
Gas turbine unit	> 100 MW	25-50 MW	1.5-25 MW
Wind power group	> 100 MW	25-50 MW	1.5-25 MW



	1	2	3	4	5
Operation time	>30 min	Countinuos	>30 min	>1 hour	>1 hour
Other			Return to normal production within 1 min. When f<50.1 Hz in the case of wind power groups, a frequency range of 51-52 Hz applies		Does not apply to wind power

Fig. 2.6 The voltage-frequency operational window according Swedish grid code [16].

Chapter 3

Modeling of Hydro and Wind Turbine

First, the model of a hydro turbine will be simulated. Second, pitch regulated wind turbine models for different wind speed ranges will be implemented. Third, the effect of increased wind power penetration on the frequency nadir will be analyzed in a hydro dominated power system.

3.1 Hydrodynamic Model of Hydro Turbine

3.1.1 Fundamentals of Speed Governing

The basic concept of speed governing is the best illustrated by considering an isolated generating unit supplying a local load as shown in Fig. 3.1 [17]. T_m is the mechanical torque and T_e is the electrical torque. P_m, P_e and P_L are the mechanical, electrical and load power, respectively.

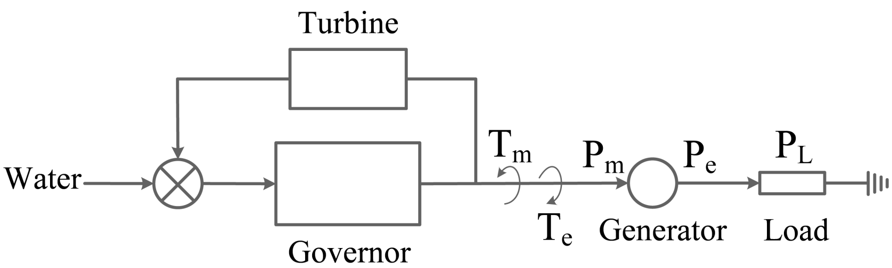


Fig. 3.1 Generator supplying isolated load [17].

In the case of a load change, it is reflected as a change in the mechanical torque T_m and the electrical torque T_e [17]. However in the case of load-frequency studies, it would be preferred to use mechanical power and electrical power instead of mechanical and electrical torque, respectively. The relationship between power and torque of a generator is given by:

$$P = \omega_r T \tag{3.1}$$

As illustrated in [17], the final transfer function which is related to the change in speed and the change in power is shown in Fig. 3.2. In this transfer function, H is the inertia constant, which is defined as the kinetic energy at rated speed divided by the VA_{base} according to (3.2)

$$H = \frac{1}{2}\frac{J\omega_{0m}^2}{VA_{base}} \tag{3.2}$$

Where J is moment of inertia of the rotating masses (generator + turbine) and ω_m is the angular velocity of the rotor.

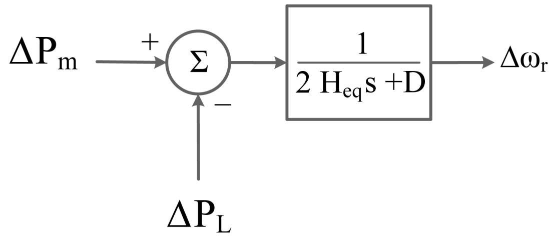


Fig. 3.2 Transfer function relating speed and power of the hydro system.

3.1.2 Equivalent Model of Hydro Turbine

The block diagram of a hydro turbine and governor with rotor/load is shown in Fig. 3.3. In this figure, ΔP_L, ΔG and ΔP_m are the change in the load demand, gate position and mechanical power, respectively. $\Delta\omega_r$ is the rotor speed deviation; H_{eq} is the inertia constant of the system and D is the load-damping constant. T_W, T_G and T_R are the water starting time, governor time constant and reset time, respectively. $R_{p,eq}$ is the permanent droop and R_T is the temporary droop. Hydro turbine due to the water inertia has a weird response. Changing in the gate position makes an initial turbine power change which is opposite to that sought. So a large temporary droop with a long reset time is needed to have stable control operation. Water starting time defines the time needed for a initial head to accelerate the water in the penstock from standstill to the initial velocity [17]. Values of different parameters are also chosen from [17] and are given in the Appendix.

It can be assumed that, this equivalent system is related to a system with n machines with equal ratings, where S_0, R_0 and H_0 represent the MVA rating of each generator, the droop of each generator speed governors and the inertia of each generator, respectively [7]. So the total MVA rating of the system is nS_0 (S_{sys} = nS_0). The equations of H_{eq} and $R_{p,eq}$ are

$$H_{eq} = \frac{nH_0S_0}{nS_0} \rightarrow H_{eq} = H_0 \tag{3.3}$$

$$\frac{1}{R_{p,eq}} = n\frac{1}{R_0} \rightarrow R_{p,eq} = \frac{R_0}{n} \tag{3.4}$$

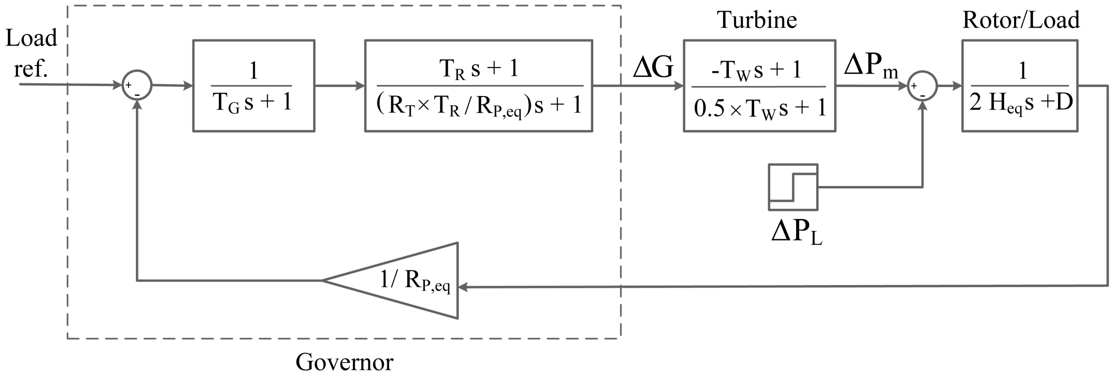


Fig. 3.3 Block diagram of hydro turbine with governor and rotor/load [17].

Fig. 3.4 shows the change in the gate position, mechanical power and speed deviation of the hydraulic unit (Fig. 3.3), when there is 0.1 pu increase in load (ΔP_L).

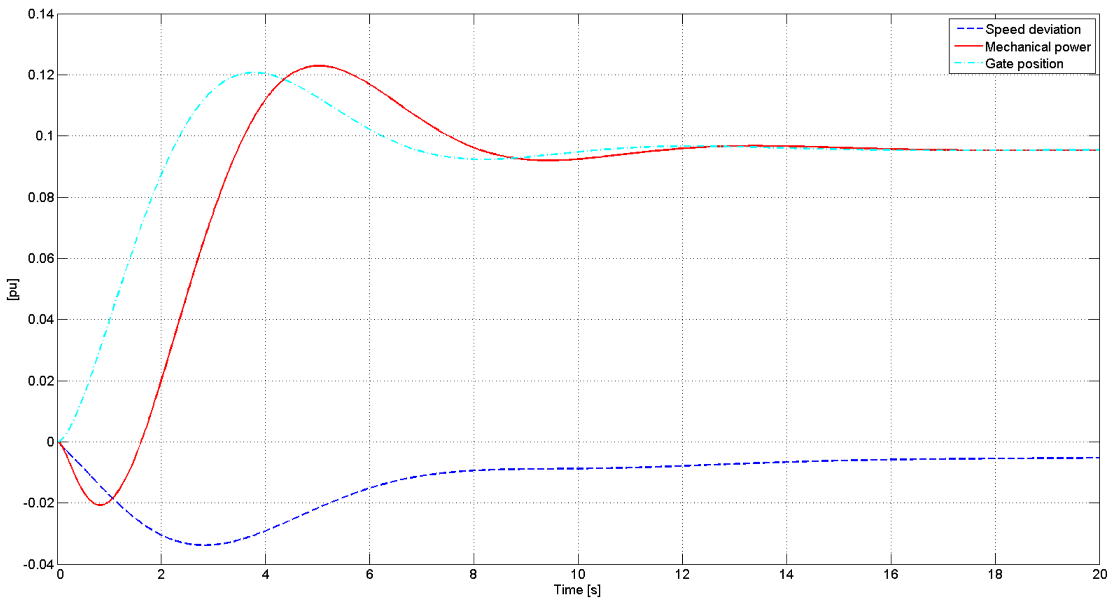


Fig. 3.4 Response of a hydraulic unit (shown in Fig. 3.3) to 0.1 pu load increasing.

Observe the initial opposite mechanical power change of the turbine which is about 20 % of the load step during 1.6 s. This is because the flow does not change as immediately as the gate is opened due to the water inertia; however, the pressure across the turbine is reduced, causing the power to reduce. This initial opposite mechanical power change depends on the water starting time (T_W). It has to be mentioned that T_W varies with load [17].

3.2 Aerodynamic Model of Wind Turbine

3.2.1 Low and Medium Wind Speed

A model of wind turbine is simulated in Matlab/Simulink (Fig. 3.5). In this thesis, variable speed wind turbine is considered which is a published model of a multi megawatt commercial VSWT (3.6 MW) and is adopted from [7] [18] [19]. At the low wind speed range, the value of pitch angle (β) is constant and is equal to $1°$. According to the tip-speed ratio (λ) versus power coefficient (C_p) curve, a higher power coefficient (C_p) corresponds to a lower pitch angle value (β=1°) as it is shown in Fig. 3.6. To achieve maximum mechanical power, when the wind speed is low, the power coefficient must be optimal in accordance with (2.1).

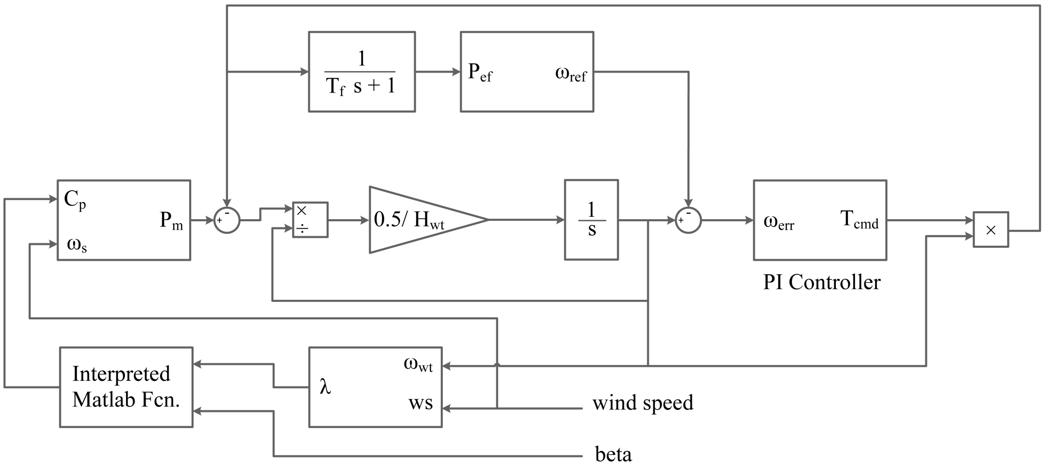


Fig. 3.5 Block diagram of the wind turbine model [17].

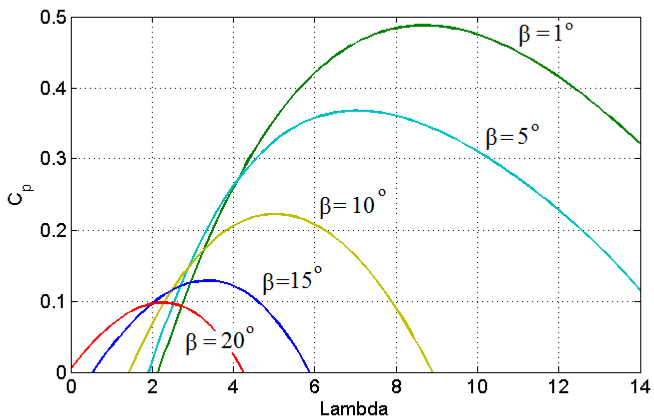


Fig. 3.6 Power coefficient curves versus tip speed ratio for different pitch angles.

In Fig. 3.5, the reference speed (ω_{ref}) is determined by the measured electrical power (P_{ef}) based on the maximum power tracking as the equation below

$$\omega_{ref} = -0.67P_{ef}^2 + 1.42P_{ef} + 0.51 \tag{3.5}$$

It has to be mentioned that (3.5) is only valid for the low wind speed range when the power is below 0.75 pu. The power coefficient (C_p) is calculated on the basis of pitch angle (β) and tip speed ratio (λ) according to the following equation [7].

$$C_p(\lambda, \beta) = \sum_{i=0}^{4} \sum_{j=0}^{4} \alpha_{i,j} \beta^i \lambda^j \tag{3.6}$$

The values of the coefficient $\alpha_{i,j}$, T_f and H_{wt} are given in the Appendix. The expression for λ was in (2.2). Table 3.1 shows the values of input mechanical power (P_{mo}) and rotor speed for different wind speeds.

Table 3.1: Input mechanical power and rotor speed for different low and medium wind speeds.

Wind speed [m/s]	Input mechanical power (P_{mo})	Rotor speed
6	0.1522	0.7106
6.5	0.1931	0.7593
7	0.241	0.8133
7.5	0.2964	0.872
8	0.36	0.9343
8.5	0.4321	0.9985
9	0.5133	1.062
9.5	0.6038	1.123
10	0.7039	1.178
10.5	0.8106	1.2
11	0.9207	1.2
11.5	1	1.2

3.2.2 High Wind Speed

Pitch Controller

Generally, using automatic control is one of the most important items for having efficient and reliable operation of wind power. Nowadays, VSWTs are used more than FSWTs. This has happened because of reduction in weight, cost of the main components and the reduction of stresses in the turbine [20]. Pitch controller is one of the most common control techniques to regulate the output power of the wind turbine generators [21]. Above the rated wind speed, pitch angle regulation is required. The purpose of the pitch angle control includes [22]:

1. Optimizing the power output of the wind turbine. Below rated wind speed, the pitch setting should be at its optimum value to give maximum power.

2. Keep the input mechanical power at the design limits.

3. Keeping minimum fatigue loads of the turbine. It is obvious that operation of the control system has an influence on the turbine's load.

During the high wind speed range, it is not possible to control rotor speed by increasing the generated power, because of overloading the generator. Consequently for limiting the aerodynamic efficiency of the rotor, the pitch angle of the blade is changed [8]. The pitch angle cannot change immediately because of mechanical limitations. The rate of change of the pitch angle, depending on the size of the wind turbine, is 3-10 degrees per second [8, 10, 23]. The advantage of using proportional (P) controller in pitch angle controller is that if the rotor speed goes up slightly more than its nominal value, it does not pose any problems to the wind turbine structure because that value can be tolerated. Although wind speed varies a lot and the system is almost never in steady state, using integral controller would be better than proportional controller because it can achieve zero steady state error [8].
Fig. 3.7 shows the pitch controller of a VSWT. As wind speed increases, pitch angle will increase to keep the electrical power constant to 1 pu.

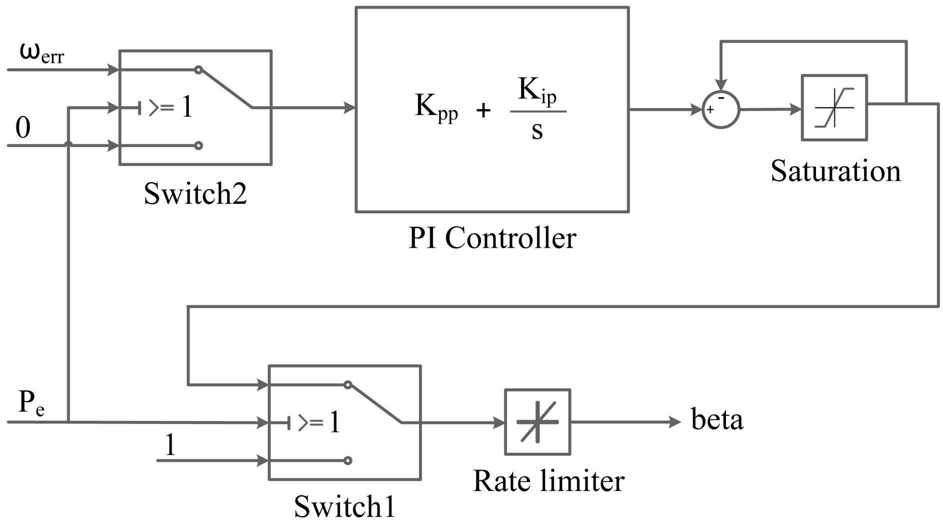


Fig. 3.7 Block diagram of pitch controller.

In this figure (Fig. 3.7) when the electrical power of the wind turbine is less than 1 pu, it means that the wind turbine is operating during low or medium wind speed range. Thus the pitch controller is not needed. In this situation the output of switch 1 (pitch angle) is 1 degree [7] and the pitch controller is out. In addition, to have a fast response of simulation, the output of switch 2 as a input of pitch controller becomes zero.
When the electrical power of the wind turbine reaches 1 pu, the wind turbine works during high wind speed range. So the wind turbine for reducing electrical power needs pitch controller. In this case, by switching switch 1, the pitch controller starts working and the output of switch 2 becomes ω_{err}. The values of $\mathrm{K_{pp}}$, $\mathrm{K_{ip}}$, saturation and rate limiter are given in the Appendix.

3.2.3 Simulation of Pitch Controller for Wind Turbine

This section shows the simulations of pitch controller of the wind turbine introduced in (3.2.2). $\mathrm{K_{pp}}$ and $\mathrm{K_{ip}}$ are chosen according to simulation to have a satisfied behavior of the pitch controller when the wind speed changes. Fig. 3.8 shows the wind speed changes. Wind speed increases from 7 m/s to 17 m/s and after that decrease to 7 m/s. The step of increasing wind speed is 1 m/s every 25 seconds and it starts from 75th second. So this figure includes 3 kinds of wind speeds; low, medium and high wind speed.

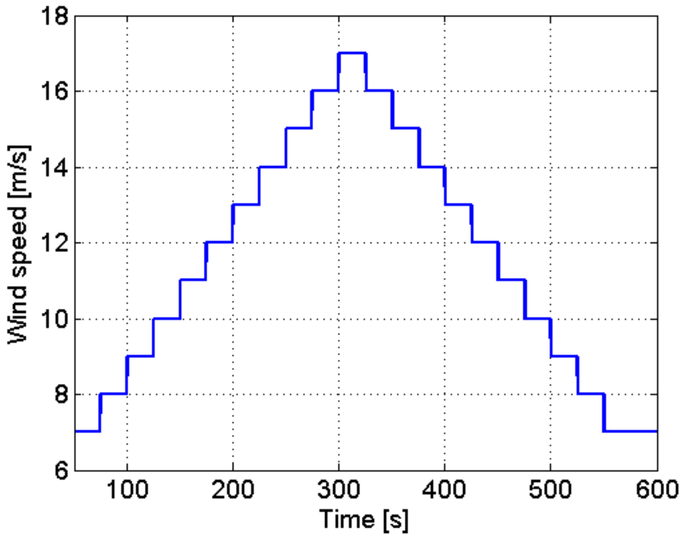


Fig. 3.8 Increasing wind speed from 7 m/s until 17 m/s.

Fig. 3.9 Shows the pitch angle changes according to change in wind speed as it is illustrated in Fig. 3.8.

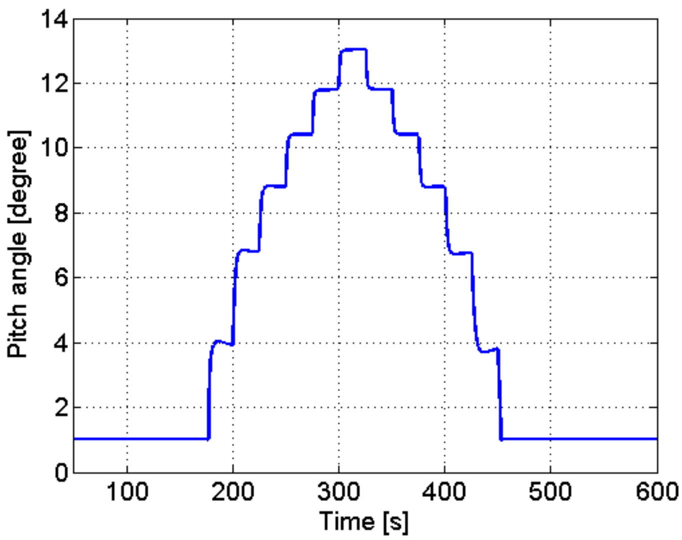


Fig. 3.9 Response of pitch angle to wind speed changes.

In Fig. 3.9 it can be observed that when the wind speed reaches 12 m/s at 175 s, the pitch controller starts to work and changes the pitch angle from 1 degree to approximately

4 degrees for 12 m/s wind speed. After that, by increasing wind speed each step, the pitch angle is increased. The maximum allowed value for the pitch angle is 27°.
Fig. 3.10 shows the mechanical and electrical power. By changing the wind speed according to (2.1), the mechanical power increases. The mechanical and electrical power reach 1 pu at 12 m/s (high wind speed range). Thus the pitch controller starts working at this speed and increases the pitch angle to decrease the power coefficient (C_p) and keep the mechanical and electrical power to 1 pu.

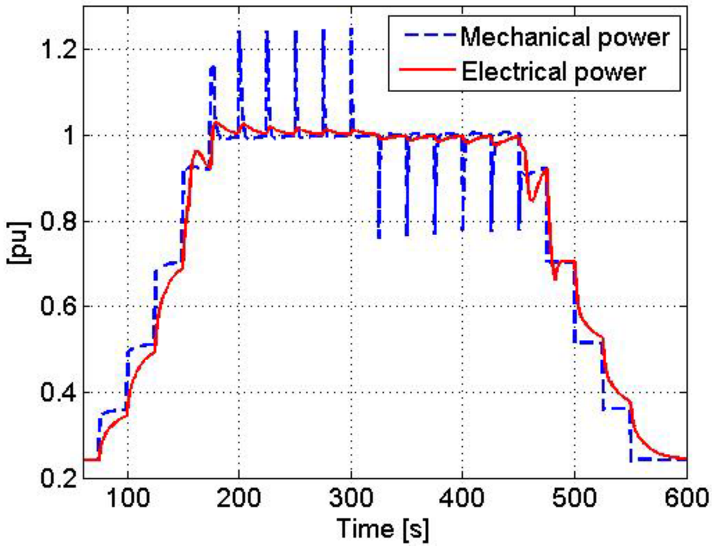


Fig. 3.10 Response of mechanical and electrical power to wind speed changes.

Fig. 3.11 shows the response of the rotor speed to wind speed changes. Between 150 s and 500 s the rotor speed is 1.2 pu. This is because, the wind turbine works during high wind speed range and the rotor speed has reached its maximum value. By changing the wind speed during this period the rotor speed varies due to the difference between the electrical and mechanical power.

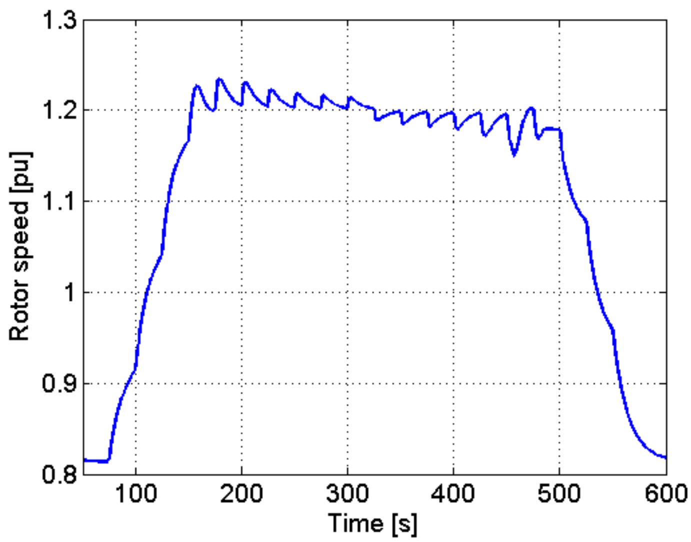


Fig. 3.11 Response of rotor speed to wind speed changes.

3.3 Modeling of a Hydro-Wind System

3.3.1 Without Support from WTs

The Effect of Wind Power on the Hydro System

Changing inertia energy of rotating masses (increase or decrease) is the immediate response of conventional generators when there is a change in the grid frequency due to the mismatch between load and generation. In the absence of the inertia, the wind turbine is not capable of frequency response [1]. In the case that a certain capacity of the hydro turbines is replaced by the wind turbines, the system characteristics may change. consequently, the resulting hydro-wind system can be modeled by changing H_{eq} and $R_{p,eq}$ of the original hydro system. In the hydro turbine model (Fig. 3.3), the penetration level of wind power can be increased by changing some parameters, such as system inertia constant (H_{eq}) and permanent droop ($R_{p,eq}$). This increment is done based on the following assumptions [7].

- In the system by increasing penetration of wind power, the total load remains constant.
- The wind turbines are not responsible for network frequency deviations.
- An x $\%$ wind penetration means that the existing generator units (hydro units in this thesis) are reduced by x $\%$, i.e. an x $\%$ reduction in inertia and increase in permanent droop.
- The existing generating units have enough spinning reserve to take up any generation deficit.

As a numerical example, when the penetration level of wind power increases by 30 $\%$, the inertia constant of the system becomes $H_{eq} = 3 \times (1 - 0.3)$ (the inertia constant for this model without any wind power is considered as 3 s) and the permanent droop becomes $R_{p,eq} = 0.05/(1 - 0.3)$ (the inertia constant and permanent droop for this model without any wind power are considered as 3 s and 0.05, respectively) [7].
However, wind turbines have a significant amount of stored kinetic energy in the rotating mass of their blades.

Simulation of increasing Penetration Level of Wind Power

Fig. 3.12 shows the TMF and frequency deviation for different wind power penetration when the load increases by 0.1 pu (ΔP_L in Fig. 3.15).

According to the Danish Grid code described in Section 2.3.2, the wind power penetration level can be increased to 40 $\%$ without any frequency support. It has to be mentioned that, by considering voltage variation, this percentage may be decreases. The TMF is 48.31 Hz when there is no wind power and the steady state frequency is 49.76 Hz. By increasing the penetration of wind power in a system with hydro dominated, the TMF drop and

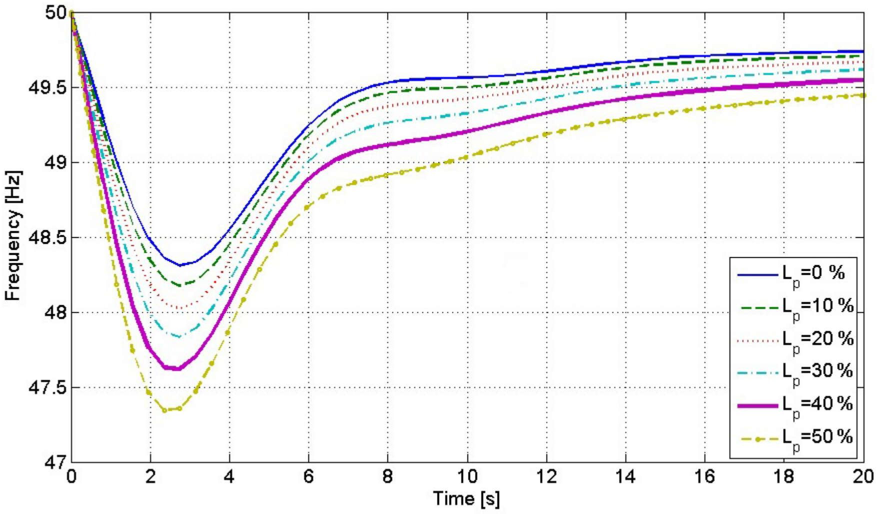


Fig. 3.12 Frequency behavior after a 0.1 pu load step increase with different scenarios of wind power penetration level without frequency support.

frequency deviation increase further in comparison with 0 % penetration of wind power. Table 3.2 shows the TMF and steady state frequency deviation for different penetration levels of wind power.

Table 3.2: TMF and steady state frequency deviation for different penetration levels of wind power.

	TMF [Hz]	Steady state deviation [Hz]
$L_p = 0$ %	48.31	49.76
$L_p = 10$ %	48.17	49.74
$L_p = 20$ %	48.02	49.71
$L_p = 30$ %	47.83	49.67
$L_p = 40$ %	47.61	49.62
$L_p = 50$ %	47.34	49.55

By increasing the penetration level of the wind power, the inertia constant and permanent droop change as explained in section (3.3.1). Thus according to (3.7) the steady state frequency for different penetration levels are not the same and it decreases by increasing penetration level.

$$\Delta f = \frac{-\Delta P_L}{\frac{1}{R}} \tag{3.7}$$

Fig. 3.13 and Fig. 3.14 show the mechanical power and gate position for hydro turbine respectively, for different penetration levels of wind power. By decreasing the inertia constant, gate position and mechanical power decrease according to Fig. 3.3. This is because, when the load share of wind power increases, the hydro power is decreased. Thus the mechanical power from hydro turbine decreases. Thus, the frequency deviation will increase as shown in Fig. 3.12.

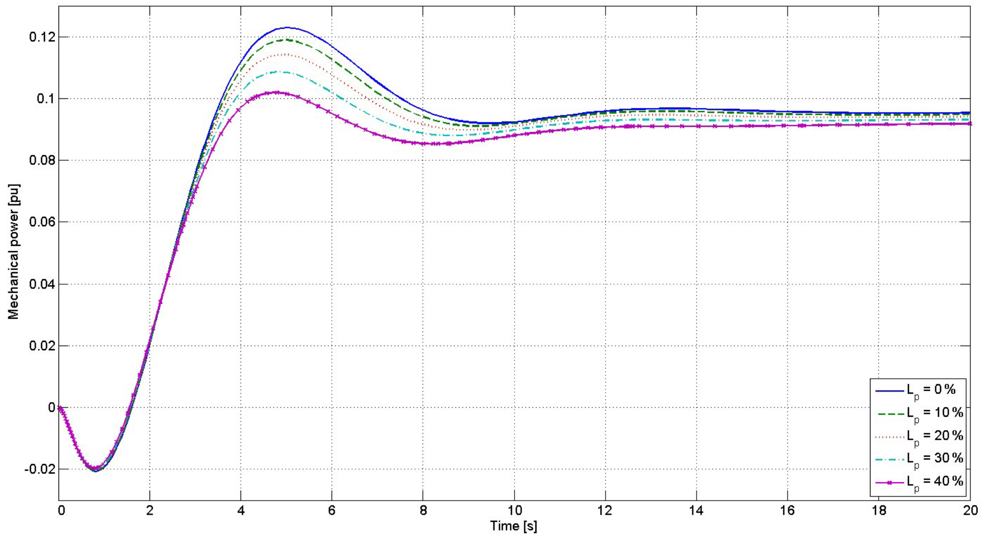


Fig. 3.13 Response of a mechanical power of hydraulic generation unit to step change in the load demand without frequency support.

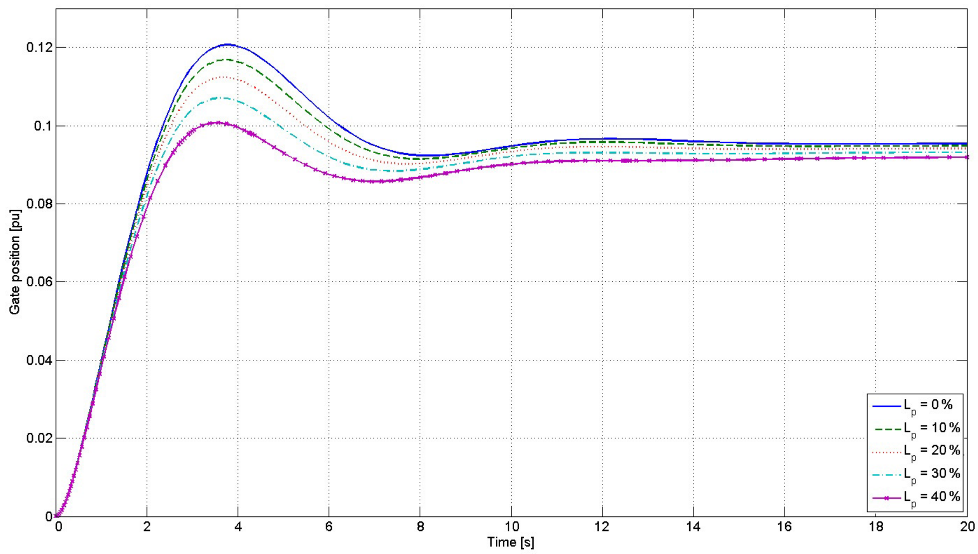


Fig. 3.14 Response of a gate position of hydraulic generation unit to step change in the load demand without frequency support.

3.3.2 With Support from WTs

For analyzing the effect of high penetration of wind power on the primary frequency control for a system with hydro power dominated, a block diagram shown in Fig. 3.15 is used. L_p in this block diagram is the wind power penetration level and $\Delta\omega_r$ is the rotor speed deviation of the hydro system. P_{e_o} is the electrical power output from the wind turbine and can be defined as:

$$P_e = P_{e_o} + \Delta P_e \tag{3.8}$$

The electrical power of wind turbine (P_e) is simulated according to Fig. 3.5 and ΔP_m from hydro turbine is simulated according to Fig. 3.3.

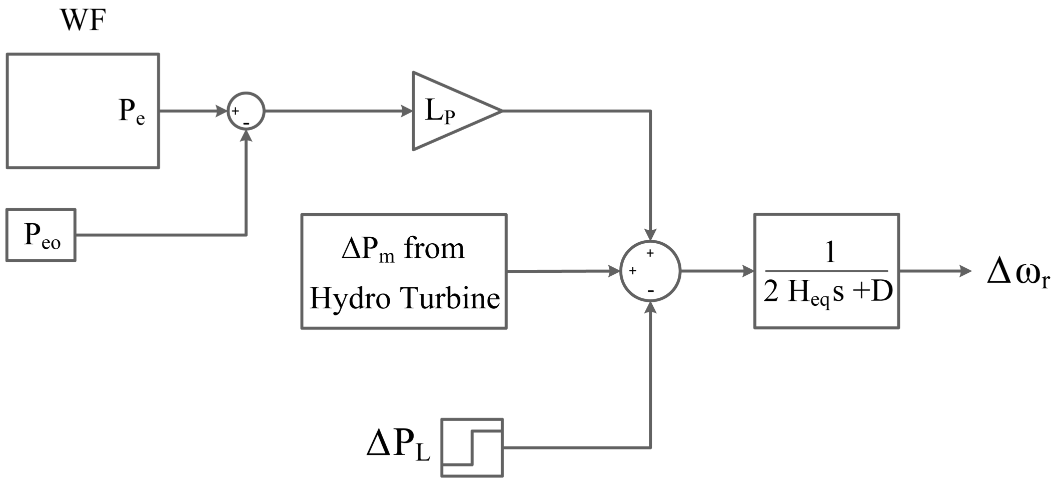


Fig. 3.15 Connection of WF to the existing hydro dominated system.

Chapter 4

Primary Frequency Control of VSWTs

Wind turbines similar to conventional generators, have a significant amount of kinetic energy stored in the rotating mass of their blades. This energy can not contribute to the inertia of the grid in case of VSWT as the rotational speed is decoupled from the grid frequency by power electronic converters. Additional control is proposed that makes the ”hidden inertia” available to the grid [24].

4.1 Temporary Extra Active Power Support by VSWTs

In this part the extra active power is added to the electrical power of the wind turbine for a specific time to improve frequency behavior when there is a mismatch between load and generation. Fig. 4.1 shows a control function adopted in this thesis. In normal operation, the switch is connected to ”position 1” which is related to normal wind turbine control. When there is a power imbalance, it is time to switch to ”position 2”. The extra active power ΔP_e could be added for a predefined time (t_{dcc} in Fig. 4.1) to improve TMF of the system within an acceptable level. During this period, the rotor will decelerate and the value of wind turbine mechanical power will decrease [7].

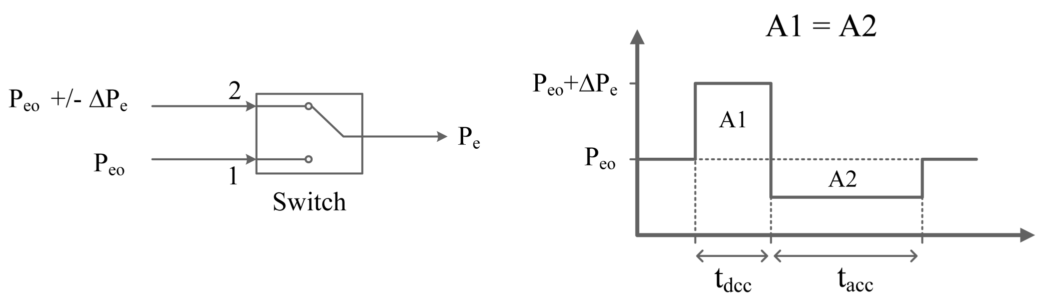


Fig. 4.1 Control function to provide the extra active power injection from wind turbine.

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After this time, the pre disturbance value can be made by decreasing power demand quickly for a certain predefined time (t_{acc} in Fig. 4.1). During this time period, the rotor will accelerate and the mechanical power starts to increase. After this accelerating time (t_{acc}) the control can be switched to the normal wind turbine control again (position 1). It has to be mentioned that the acceleration period of the turbine can be made longer than the deceleration period for reducing the pressure on the rest of the system ($t_{acc} > t_{dcc}$). During the low and medium wind speed range by applying temporary extra active power in t_{dcc} period, the mechanical power and the rotor speed decrease (this will be investigated more in the next chapter). Thus there is a limitation for increasing t_{dcc}. This time limitation depends on the rotor speed and the amount of extra active power and wind speed. In this model (GE 3.6 MW) t_{dcc} can be increased until the rotor speed reaches 0.7 pu [7]. After this time during accelerating period, the difference between mechanical and electrical power is still negative and the rotor speed and the mechanical power do not return to their initial values.

As illustrated before, there is a certain amount of kinetic energy in rotating masses in the blades of a wind turbine that is possible to be used for primary frequency support. The kinetic energy in the rotating mass for any speed can be defined as [11]:

$$E_{\mathrm{k}} = \frac{1}{2} J \omega_m^2 \tag{4.1}$$

Where ω_m is the rotational speed, J is the moment of inertia of the rotating mass and E_{k} is kinetic energy. Moment of inertia (J) can be defined as:

$$J = \frac{2H}{\omega_{m0}^2} VA_{base} \tag{4.2}$$

where H is the inertia constant,ω_{m0} is the rated value of angular velocity. This kinetic energy can be used for up or down regulating to increase and decrease frequency, respectively. The amount of energy used for providing up-regulation can be defined as:

$$E_{up-regulation} = \frac{1}{2} J(\omega^2 - \omega_{min}^2) \tag{4.3}$$

by replacing J with H, (4.3) becomes:

$$E_{up-regulation} = HS_{base}(\omega^2 - \omega_{min}^2) \tag{4.4}$$

and for down-regulating is:

$$E_{down-regulation} = \frac{1}{2} J(\omega_{max}^2 - \omega^2) \tag{4.5}$$

by replacing J with H, (4.5) becomes:

$$E_{down-regulation} = HS_{base}(\omega_{max}^2 - \omega^2) \tag{4.6}$$

where ω_{max} is the maximum limitation for rotor speed i.e. 1.2 pu in this model and ω_{min}

is minimum limitation for rotor speed i.e. 0.7 pu. Fig. 4.2 and Fig. 4.3 show the kinetic energy at different wind speeds for up and down regulation, respectively.

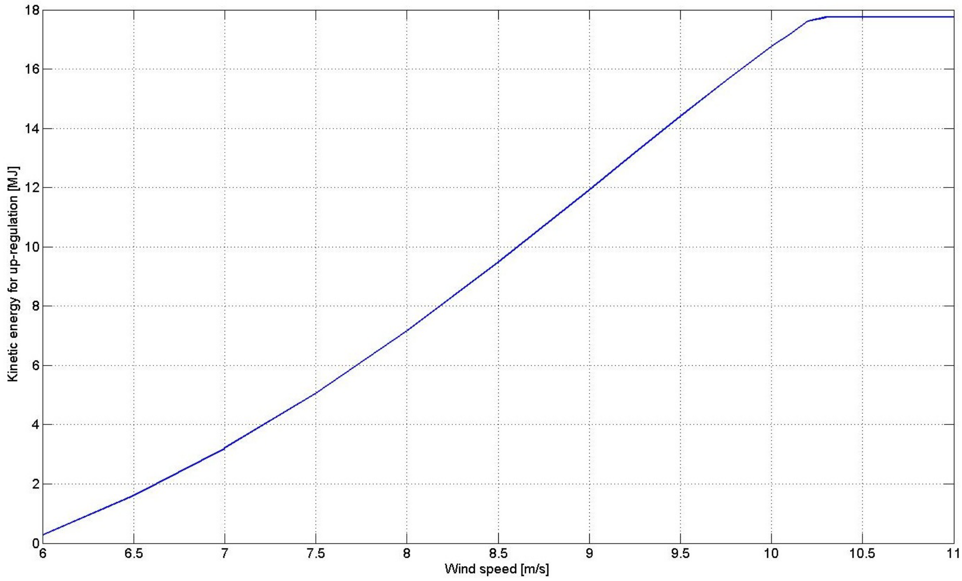

Fig. 4.2 Amount of kinetic energy available in different wind speed using for up-regulation.

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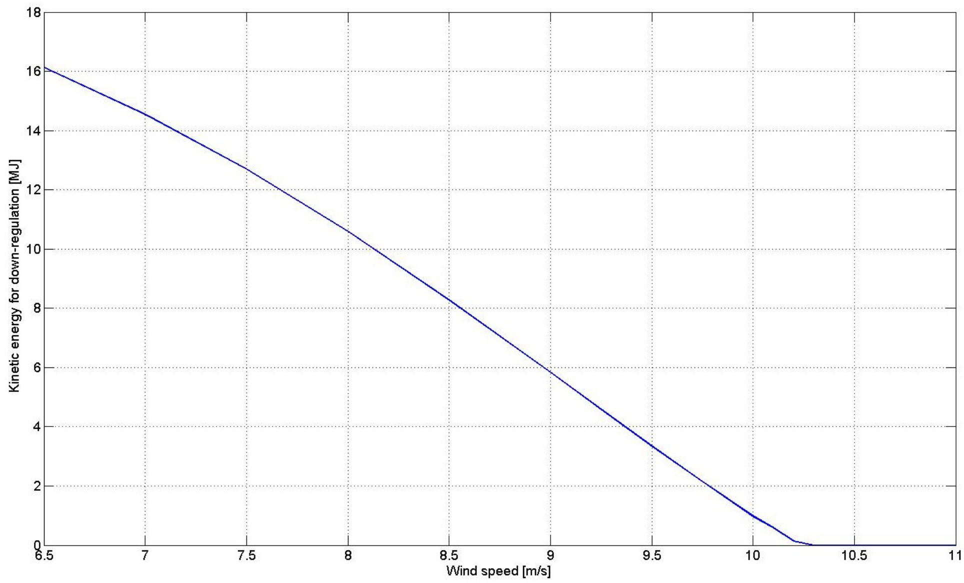

Fig. 4.3 Amount of kinetic energy available in different wind speed using for down-regulation.

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It seems that this total amount of kinetic energy for up and down regulation available in the rotating mass of wind turbine (which are calculated by (4.4) and (4.6)) can be fully utilized for grid support.

$$E = Pt \tag{4.7}$$

By using (4.7) the maximum value for t_{dcc} (in Fig. 4.1) for 0.05 pu and 0.1 pu extra active power can be calculated (in the case of up-regulation).
Fig. 4.4 shows the 0.05 pu and 0.1 pu temporary extra active power support capability of the wind turbine at different wind speeds.

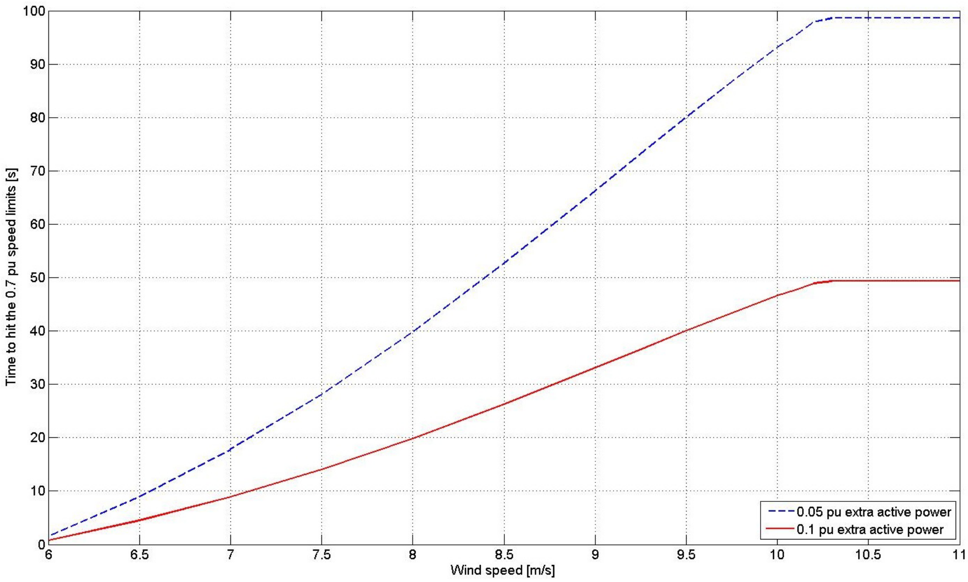

Fig. 4.4 The time for reaching rotor speed to its minimum limit speed (0.7 pu) for different wind speed.

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Fig. 4.5 shows the temporary extra active power support capability of the wind turbine at different wind speeds according to simulation (Fig. 3.5).

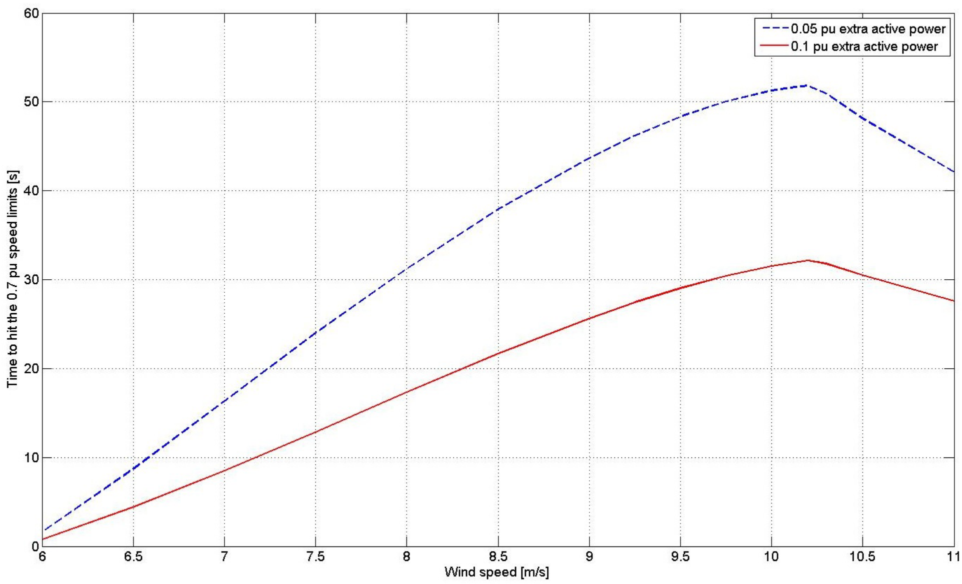

Fig. 4.5 Capability of the WT to provide a 0.05 and 0.1 pu of extra active power before hitting the 0.7 pu minimum speed limit of the turbine at low and medium wind speed range.

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During low wind speed by increasing wind speed, the time to hit the 0.7 minimum speed limit is increased. For example for 7.5 m/s wind speed, the wind power can provide 0.05 pu and 0.1 pu extra active power for 24 s and 13 s, respectively. However these times for 7.5 m/s in Fig. 4.4 are 28 s and 14.1 (for 0.05 pu and 0.1 pu, respectively).
During medium wind speed range, by increasing the wind speed, the time to reach the rotor speed limit is decreased. This is because, during this wind speed range, rotor speed reaches its limit speed and does not increase anymore. Thus, for compensating this energy, the mechanical power starts to decrease more. On the other hand, during the high wind speed range, the rotor speed is not a limitation for increasing t_{dcc}. This is because by changing pitch angle, more mechanical power is produced and after a while the mechanical power reaches the desired electrical power value. as a result, the rotor speed remains at 1.2 pu.
In down-regulation, by decreasing load, the grid frequency starts to increase. Thus the electrical power can be decreased for a while to improve frequency behavior. Fig. 4.6 shows the temporary extra active power support capability of the wind turbine at different wind speeds for down regulation. This figure shows, the time that the wind turbine can reduce the electrical power output before the rotor speed reaches the maximum value (1.2 pu).

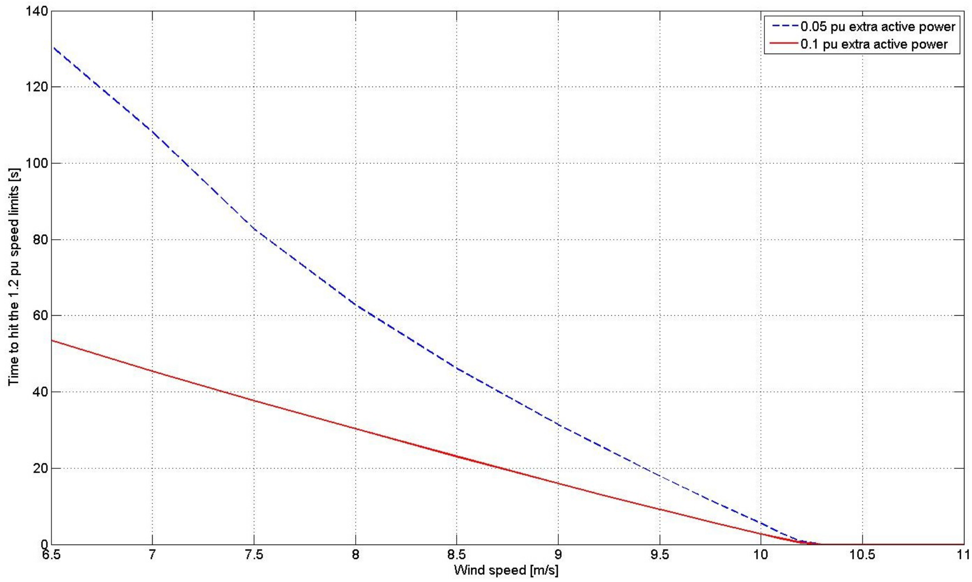

Fig. 4.6 Capability of the WT to decrease 0.05 pu and 0.1 pu electrical power output before the rotor speed reaches its maximum value (1.2 pu).

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Comparing Fig. 4.4 and Fig. 4.5 shows that the total amount of kinetic energy for up-regulation (and also for down-regulation) available in the rotating mass of wind turbine can not be fully utilized for grid support. The mechanical power input into this system is rotor speed dependent. During low and medium wind speed range, as the rotor speed varies (increase or decrease), the mechanical power will be reduced. In the other words, when WTs provides grid support can not be fully delivered for grid support. Fig. 4.7 shows the proportion of output energy to energy witch is produced by wind turbine for up regulation at different wind speeds.

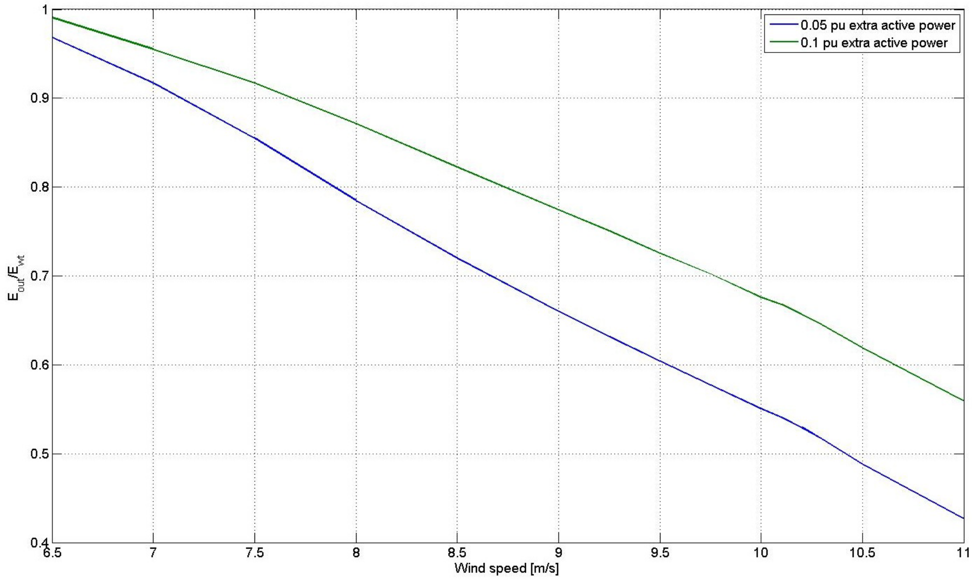

Fig. 4.7 The proportion of output energy to energy witch is produced by wind turbine for up and down regulation and different wind speed.

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According to Fig. 3.5, during up regulation, by increasing electrical power, the difference of mechanical and electrical power is decreased. Thus the rotor speed starts to decrease. After that according to (2.2), tip speed ratio (λ) decreases. During this wind speed range, the pitch angle is $1°$. Thus, by considering Fig. 3.6, as the tip speed ratio decreases, the power coefficient starts to decrease. This is because the power coefficient had its optimum value before it happened. finally the mechanical power decreases because of decreasing power coefficient.
Equation (4.8) shows that by decreasing the mechanical power, when the electrical power increases, the slop of decreasing rotor speed increases. Thus the time for reaching rotor speed of 0.7 pu speed limit is decreased.

$$P_m - P_e = J\frac{d\omega}{dt} \tag{4.8}$$

4.2 Inertia Emulation

Normally, VSWTs do not contribute to the power system inertia and do not participate in grid frequency control [4] [25]. Thus, to reduce the maximum frequency change rate, the "hidden" inertia has to be emulated [26] [27]. According to swing equation in [17], when there is an unbalance between the torques acting on the rotor, the net torque causing acceleration (or deceleration) with inertia of the generator is

$$T_m - T_e = J\frac{d\omega_m}{dt} \tag{4.9}$$

By combining (4.2) and (4.9), the above equation can be written as:

$$T_m - T_e = \frac{2H}{\omega_{m0}} VA_{base} \frac{d\omega_m}{dt} \tag{4.10}$$

Rearranging yields

$$\frac{T_m - T_e}{VA_{base}/\omega_{m0}} = 2H\frac{d}{dt}(\frac{\omega_m}{\omega_{m0}}) \tag{4.11}$$

The equation of motion in per unit form is

$$\bar{T_a} = 2H\bar{\omega}\frac{d\bar{\omega}}{dt} \tag{4.12}$$

Where $\bar{T_a}$ is accelerating torque in pu and $\bar{\omega}$ is rotor speed in pu. Noting that $P = \omega T$, the equation changes to

$$P_a = 2H\omega\frac{d\omega}{dt} \tag{4.13}$$

The values for the power and the rotor speed are in pu. Thus the rotor speed can be replaced by frequency. The active power control signal (inertial power) P_{in} of the inertial control is achieved by:

$$P_{in} = -2Hf\frac{df}{dt} \tag{4.14}$$

Where f is the grid frequency and the minus in the equation is because of reducing frequency. Thus the frequency deviation becomes negative [4]. By using (4.14), the electrical power output of the wind turbine can be increased to improve the frequency behavior when there is a mismatch between load and power generation. Fig. 4.8 shows block diagram of inertia emulation. When the difference of grid frequency and reference frequency (1 pu) becomes more than 4×10^{-4} pu (20 mHz) according to the grid code [28], the switch starts to conduct and P_{in} produced from inertia emulation, is added to the electrical power of the wind turbine.

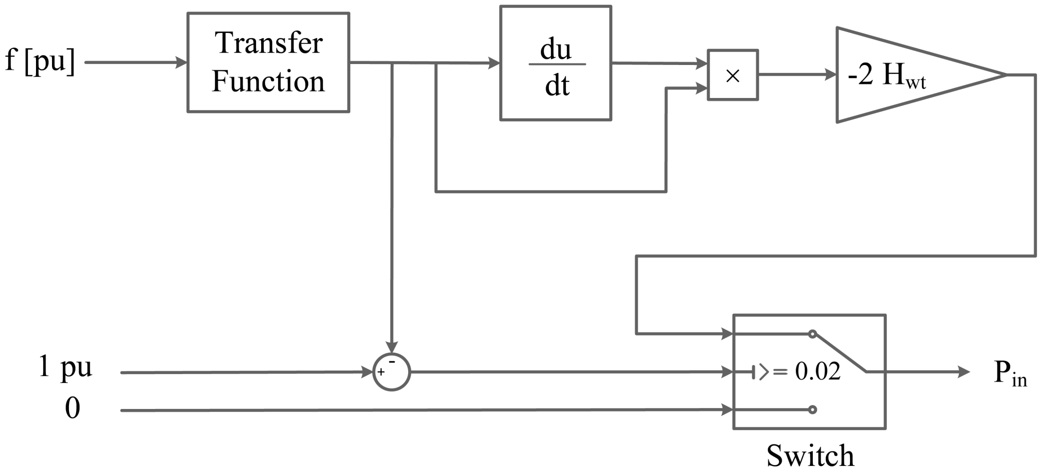

Fig. 4.8 Block diagram of inertia emulation to improve frequency behavior.

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Fig. 4.9 shows how P_{in} is added to the electrical power of the wind turbine to improve the frequency behavior of grid.

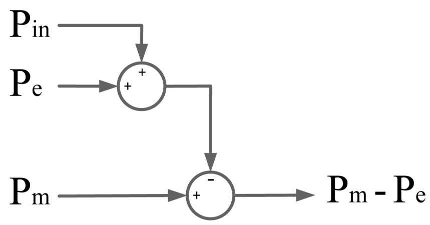

Fig. 4.9 Adding P_{in} (which is produced by inertia emulation) to the electrical power of wind turbine in Fig. 3.5.

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4.3 Direct Pitch Angle Regulation

When the wind turbine is working during the high wind speed range, using pitch controller to decrease the TMF will be evaluated. By decreasing the pitch angle the mechanical power goes up due to the change in the power coefficient (C_p) in accordance with (2.1) and Fig. 3.6. Then the rotor speed of the wind turbine accelerates and TMF increases. Fig. 4.10 shows the block diagram of direct pitch angle regulation which is added to the pitch controller. When the grid frequency changes due to the mismatch between load and generation and the frequency deviation becomes more than 0.02 Hz according to the grid code [28], the pitch angle starts to decrease. It has to be mentioned that this block diagram can be operated for up-regulation. The model for down-regulation can be investigated in the future.

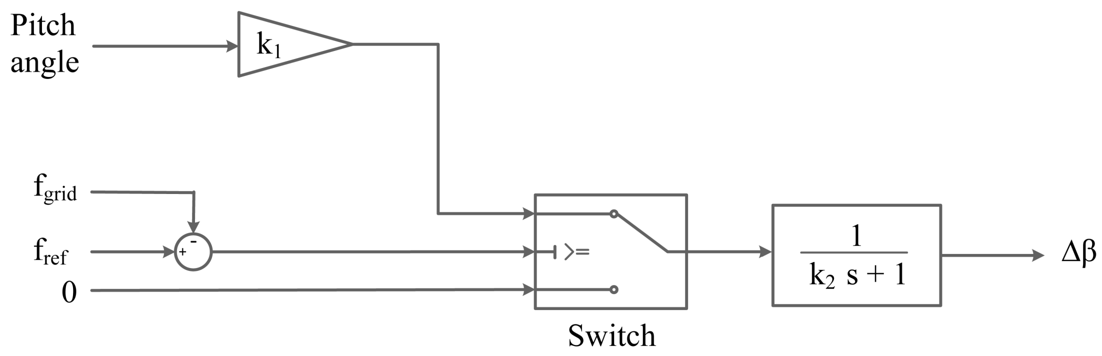

Fig. 4.10 Block diagram of direct pitch angle regulation to improve TMF.

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k_1 is a gain that introduces how many degrees the blades should pitch. When the load step increase is applied, the pitch angle can be reduced to provide more mechanical power. Thus increasing the amount of mechanical power maybe is a limitation factor for decreasing pitch angle (increase k_1). By using Table 4.1, the value for k_1 is determined. This table shows the maximum change in mechanical and electrical power and pitch angle for different wind speed and k_1.

Table 4.1: The maximum change in mechanical and electrical power and pitch angle for different wind speed and gain (k_1).

Wind speed $[\mathrm{m/s}]$	Gain (k_1)	Max change in β [degrees]	Max change in P_m [pu]	Max change in P_e [pu]
15	0.15	0.747	0.116	0.012
	0.2	0.976	0.15	0.016
	0.25	1.196	0.183	0.02
	0.3	1.41	0.215	0.024
	0.35	1.622	0.246	0.028
20	0.15	1	0.232	0.019
	0.2	1.32	0.305	0.026
	0.25	1.65	0.382	0.032
	0.3	2.01	0.467	0.038
	0.35	2.43	0.568	0.045
25	0.15	1.2	0.35	0.025
	0.2	1.62	0.474	0.033
	0.25	2.12	0.628	0.041

By increasing the gain for different wind speeds, the amount of change in pitch angle is not a lot and it is between 0.747 and 2.43 degrees. However the value for the mechanical power has to be considered. In this thesis, the gain is chosen as 0.25. This value is approximately suitable for different wind speeds by considering the value for maximum change in the mechanical power. However this value for 25 m/s wind speed is maybe high but

this wind speed is happened rarely. It has to be mentioned that this value for the gain can be changed in different places with different wind speed distribution.
Fig. 4.11 shows how the block diagram of direct pitch angle regulation in Fig. 4.10 connects to the pitch controller. It has to be mentioned that as shown in Fig. 4.10, the block diagram of direct pitch angle regulation method uses the pitch angle as input, which is produced by the pitch controller. Thus, there is a feedback of pitch angle.

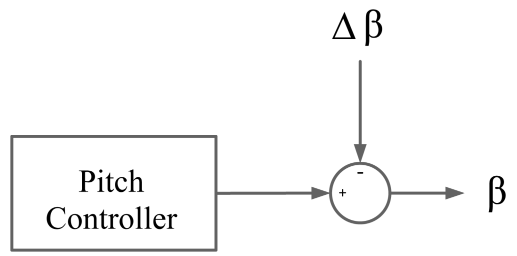

Fig. 4.11 Connection of block diagram of direct pitch angle regulation method and pitch controller.

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Chapter 5

Simulation Result of WT Primary Frequency Support

5.1 Case Studies

In this chapter, the system frequency and the load step increase are set to 50 Hz and 0.1 pu, respectively. 10 % load increases or generation lost is the maximum value which is considered in many papers such as [1] [7] [29]. Wind speed is considered 7.5 m/s for low wind speed and 20 m/s for high wind speed.

5.2 Temporary Extra Active Power Support

In this part, the simulations of the wind turbine parameters and the grid frequency are shown for the situation that the wind turbine uses temporary extra active power as a primary frequency support when there is a mismatch between load and generation. Decelerating time (t_{dcc}) and accelerating time (t_{acc}) are 10 s and 20 s, respectively and 0.05 pu is considered for temporary extra active power.

5.2.1 Low and Medium Wind Speed

Fig. 5.1 shows the mechanical and electrical power and the rotor speed of the wind turbine with and without 0.05 pu extra active power (ΔP_e) output. The wind speed in this case is 7.5 m/s.

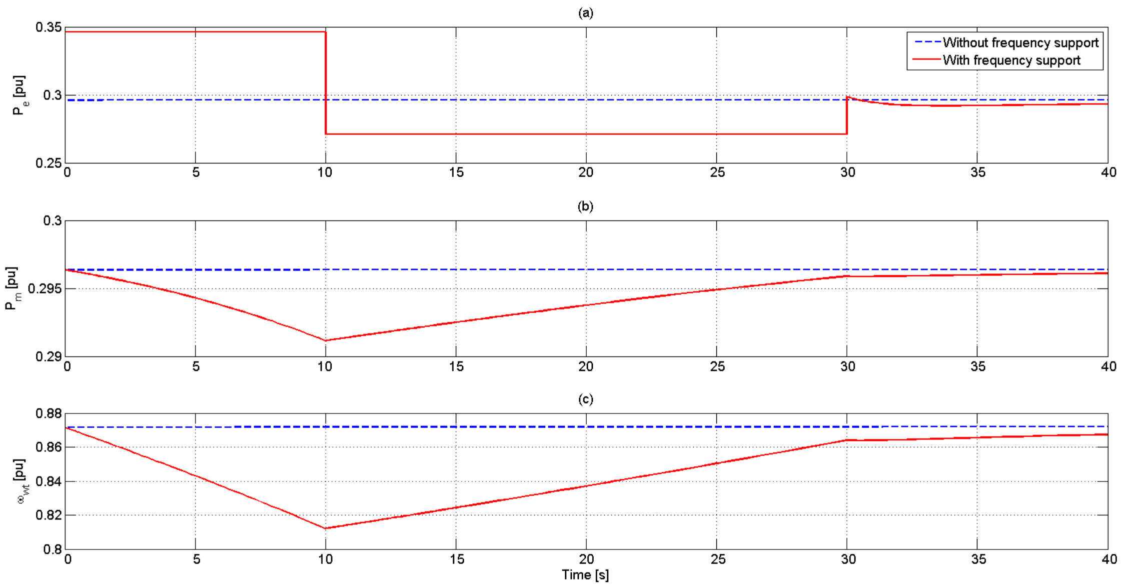

Fig. 5.1 a) Wind turbine electrical power, b) wind turbine mechanical power and c) rotor speed of wind turbine: with and without 0.05 extra active power support from WF.

The acceleration of the WF, in the simulation is done in 20 s (from 10-30 s). When the electrical power increases and becomes higher than the mechanical power, the rotor speed starts to decrease. As the rotor speed decreases, the mechanical power starts to decrease too, due to the reduction in the tip speed ratio (λ) and the power coefficient (C_p). During the accelerating period, the difference between the mechanical and electrical power ($P_m - P_e$) becomes positive, so the rotor speed starts to increase and therefore the mechanical power increases. Fig. 5.2 shows the frequency response of the WF to 0.1 pu load step increase for three different cases. The first case is when there is no penetration level of wind power in the system. The second and the third cases are when there is 20 % penetration of wind power with and without 0.05 pu extra active power, respectively.

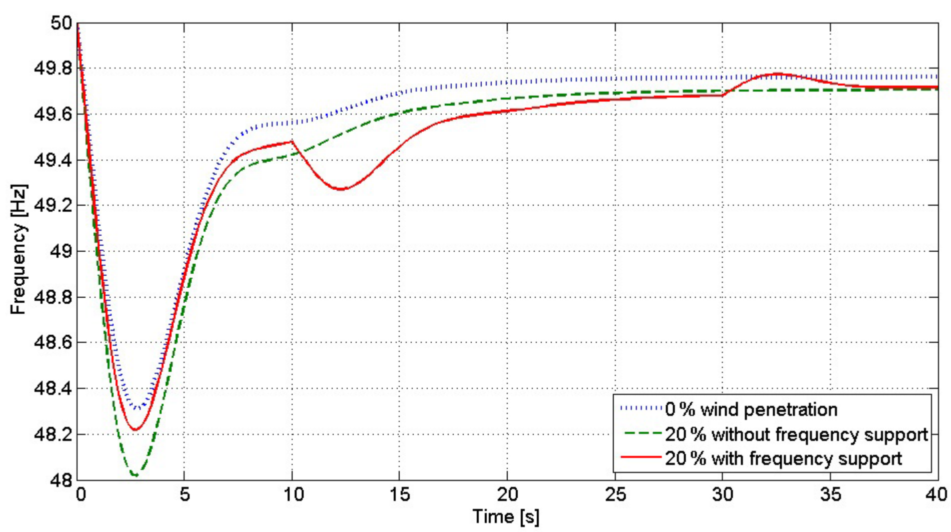

Fig. 5.2 Network frequency behavior after a 0.1 pu load step increase with and without 0.05 pu extra active power for 20 % wind power penetration.

After 10 s the frequency goes down again due to the negative active power injection (accelerating area) from the WT. After 30 seconds the switch (Fig. 3.7) is connected to ”position 1” again and the electrical power returns to the initial value. By reaching the electrical power to its initial value at 30 s, it goes a bit higher than the initial value for a moment. This is because the speed controller accumulating error during this period. Thus the frequency starts to increase at 30 s and return to the without frequency support situation again .

The drop of TMF increases as the wind penetration level increases as shown in Fig. 5.3. However each value of TMF for different penetration levels is higher than the TMF in the same penetration level without frequency support. By increasing the penetration of wind power, the electrical power in accelerating area decreases further more. Thus, the second frequency drop (SFD) becomes lorger.

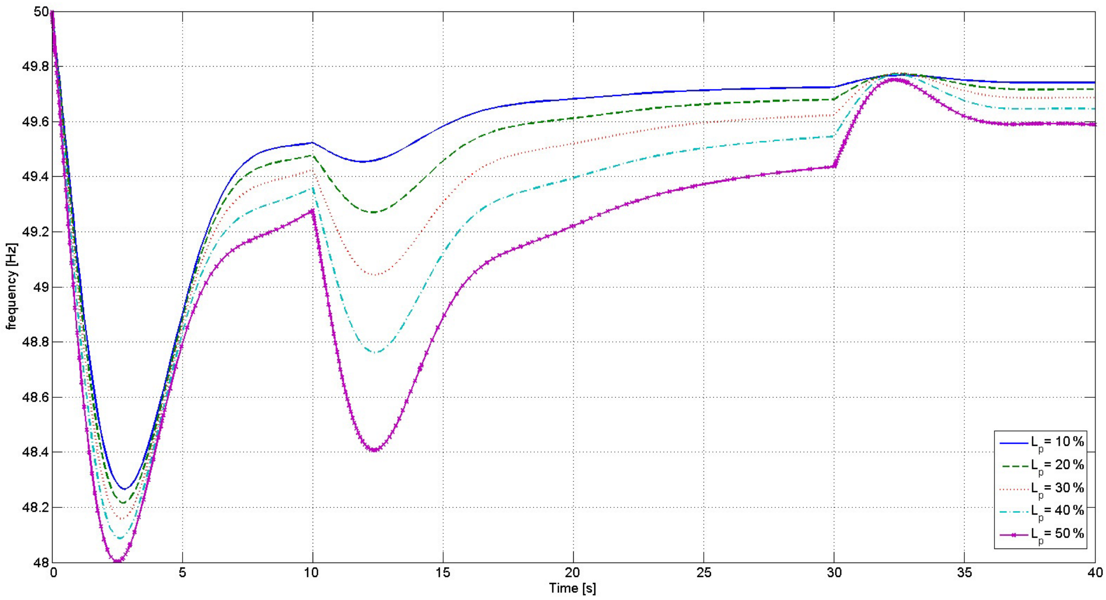

Fig. 5.3 Network frequency behavior after a 0.1 pu load step increase with 0.05 pu extra active power for different wind power penetration scenarios.

The TMF for 50 % wind penetration without frequency support as shown in Fig. 3.12 is 47.34 Hz and it is 48 Hz when there is 0.05 extra active power as a frequency support. The steady state frequency deviations for this level with and without frequency support are the same, which is 0.46 Hz (50 - 49.54 Hz).

In addition, it has to be mentioned that if 0.1 extra active power is used instead of 0.05; the TMF will increase, but the SFD will increase and it will be a critical problem during high penetration of wind power. Table 5.1 shows the comparison between TMF and SFD for different penetration levels for two cases. Case 1 is when there is 0.05 pu temporary extra active power and Case 2 is when there is 0.1 pu temporary extra active power.

As Table 5.1 shows, for 40 % of wind power penetration; the SFD is less than the TMF

Table 5.1: TMF and SFD for different penetration levels for two cases.

	TMF for case 1 [Hz]	SFD for case 1 [Hz]	TMF for case 2 [Hz]	SFD for case 2 [Hz]
L_p = 10 %	48.27	49.45	48.3	49.35
L_p = 20 %	48.22	49.27	48.41	49.03
L_p = 30 %	48.16	49.04	48.48	48.64
L_p = 40 %	48.09	48.76	48.57	48.17
L_p = 50 %	48	48.41	48.67	47.61

when there is 0.1 pu temporary extra active power. Thus, by increasing penetration level of wind power for higher value of temporary extra active power, the SFD must be monitored as well. For example for 60 % of wind power penetration the first and second minimum frequency are 47.76 and 47.33 Hz, respectively. In other words, it is not possible to increase the penetration of wind power until 60 % according to the Danish grid code because of the second drop frequency.

5.2.2 High Wind Speed

In this part, the wind turbine operates at high wind speed range. Thus, the wind turbine activates the pitch controller. Fig. 5.4 shows the mechanical and electrical power and the rotor speed of the wind turbine with and without 0.05 pu extra active power (ΔP_e). The wind speed in this case is 20 m/s.

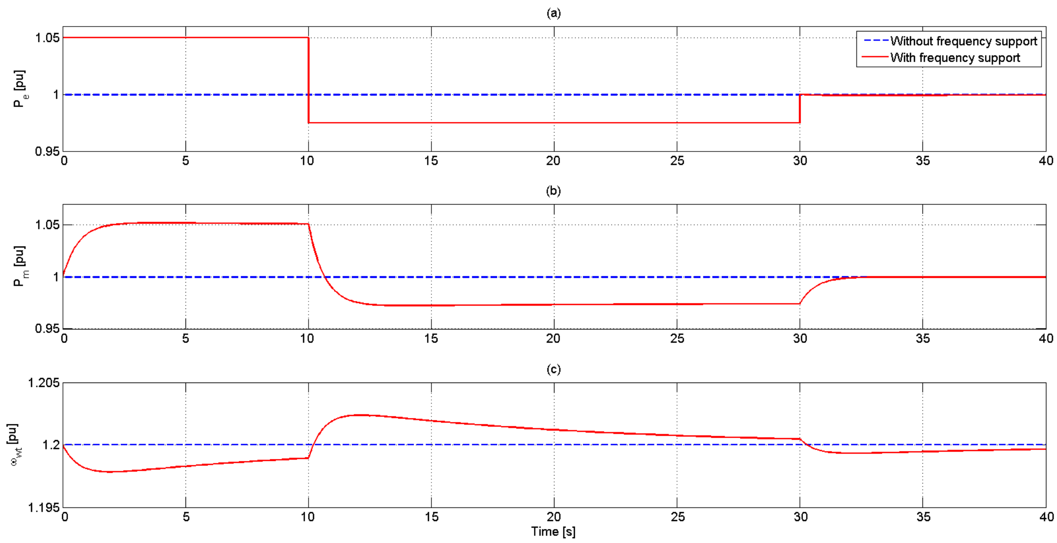

Fig. 5.4 a) Wind turbine electrical power , b) wind turbine mechanical power and c) rotor speed of wind turbine: with and without 0.05 extra active power support from WF during high wind speed range.

By applying a load step increase to the system, the primary frequency control of the WT starts to act, providing 0.05 pu extra active power to the grid for 10 s. The difference between mechanical and electrical power becomes negative and the rotor speed starts to decrease. However, unlike the mechanical power behavior in low wind speed (Fig. 5.1), the mechanical power starts to increase and track the electrical power due to the change in pitch angle. After 10 s, by decreasing the electrical power, the difference between mechanical and electrical power suddenly becomes positive, so rotor speed increases with high slope until the mechanical power reaches electrical power value. After that there is no difference between the electrical and mechanical power anymore and the rotor speed starts to decrease.

Fig. 5.5 shows the frequency response of the system to 0.1 pu load step increase with and without frequency support. In this case the wind speed is 20 m/s and the penetration level of wind power is 20 %. TMF increases approximately by 0.2 Hz when there is 0.05 pu temporary extra active power. The response is exactly the same as in Fig. 5.2. This is because wind speed does not have effect in this case. The change in the electrical power has effect on frequency and wind speed does not have effect on changing electrical power.

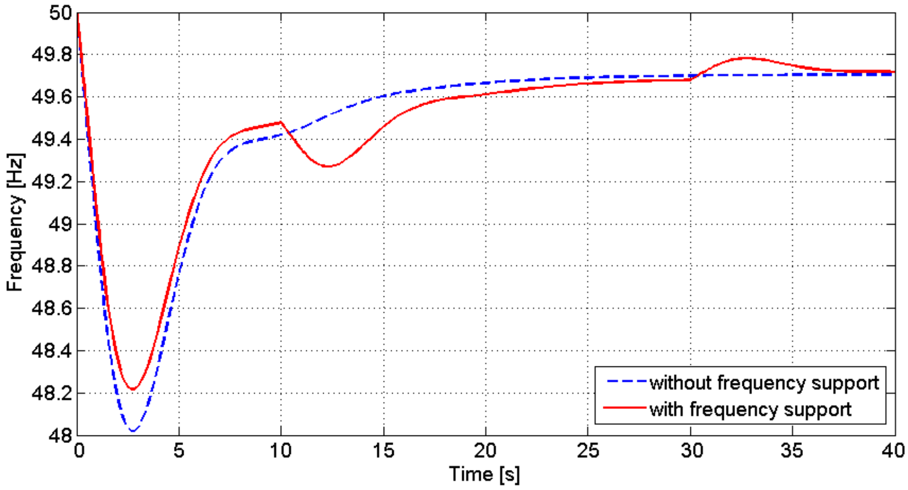

Fig. 5.5 Network frequency behavior after a 0.1 pu load step increase with and without 0.05 pu extra active power for 20 % wind penetration in 20 m/s wind speed.

Fig. 5.6 shows the pitch angle of the wind turbine blades. By injecting active power, the pitch controller decreases the pitch angle to keep the mechanical power equal to 1.05 pu. In accelerating area when the electrical power decreases, the pitch controller increases pitch angle to keep the mechanical power constant.

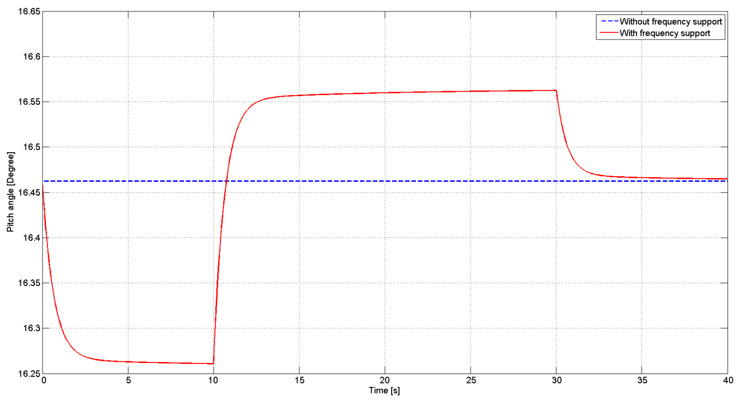

Fig. 5.6 Network frequency behavior after a 0.1 pu load step increase with and without 0.05 pu extra active power for 20 % wind penetration in 20 m/s wind speed.

During the high wind speed range, by increasing the electrical power of the wind turbine, the mechanical power follows the electrical power and increases. This is because, there is a pitch controller during this wind speed range. According to (3.6), the power coefficient (C_p) depends on the tip speed ratio (λ) and the pitch angle (β) and according to Fig. 3.6 by decreasing the pitch angle, the power coefficient increases. Thus, according to (2.1), the mechanical power increases.

5.3 Inertia Emulation

5.3.1 Low Wind Speed

In this case P_{in} is added to the electrical power of the wind turbine in accordance with (4.14). Fig. 5.7 shows the amount of power due to the inertia emulation which is added to the electrical power to improve the frequency behavior.

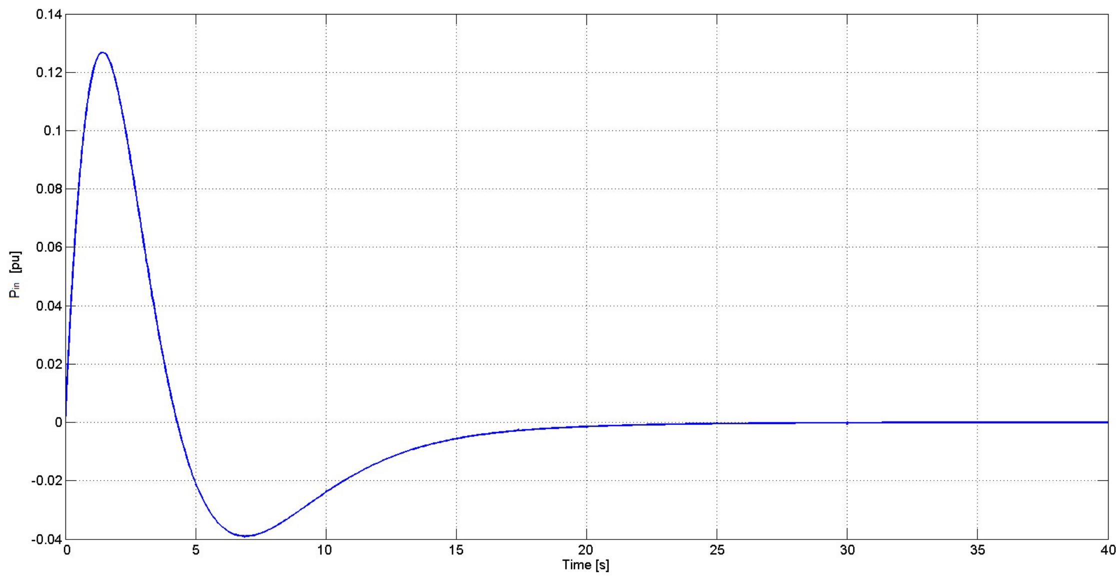

Fig. 5.7 Inertia response which is added to electrical power reference of wind turbine.

By applying the load step increase, the grid frequency starts to decrease (Fig. 3.12). Therefore df/dt becomes negative and P_{in} in (4.14) starts to increase. Fig. 5.8 part (a) shows the total electrical power of the wind turbine with P_{in} (extra electrical power produced by using the inertia emulation) shown in Fig. 5.7. Furthermore, the mechanical power and the rotor speed of the wind turbine during inertia emulation are shown in (b) and (c), respectively. The wind speed is 7.5 m/s.

By increasing the total electrical power, its value becomes higher than the mechanical power. Therefore the rotor speed starts to decrease. The mechanical power starts to decrease too, because of decreasing the tip speed ratio and the power coefficient (C_p). By increasing the total electrical power, the frequency behavior during the first 4 s is improved and TMF increases as it is shown in Fig. 5.9. This figure shows the frequency

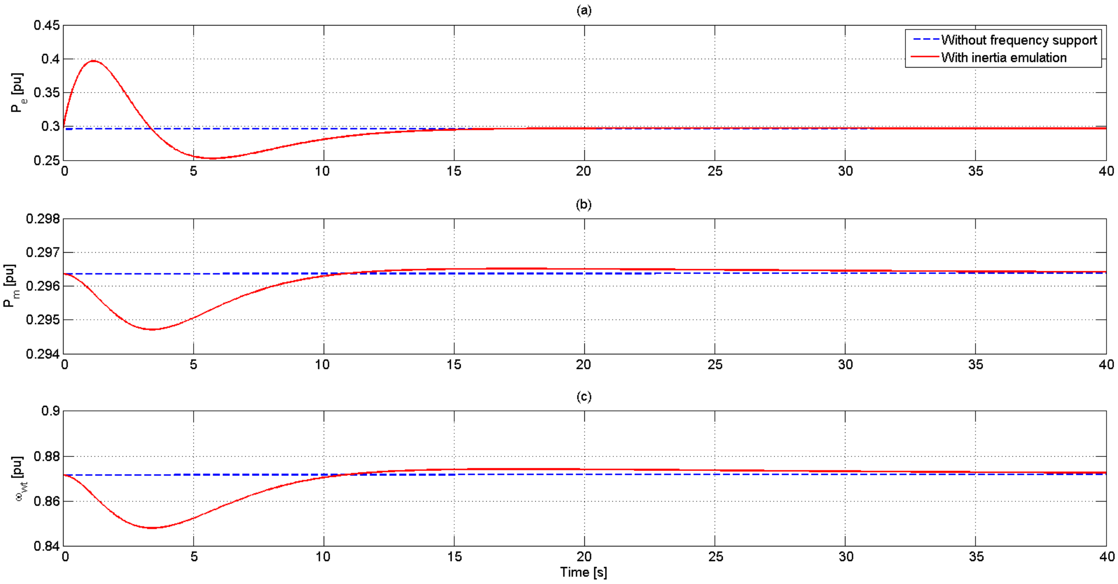

Fig. 5.8 a) Wind turbine electrical power, b) wind turbine mechanical power and c) rotor speed of wind turbine: with and without inertia emulation support from WF for 7.5 m/s wind speed.

response of the system to 0.1 pu load step increase with and without frequency support. In this case the wind speed is 7.5 m/s (low wind speed) and the penetration level of wind power is 20 %. After 3.4 s the value of total electrical power becomes lower than its initial value (before applying load step), so the rotor speed and the mechanical power start to increase. According to Fig. 5.9 the frequency in this case returns to its initial value with steady state deviation slower than the case without inertia emulation. This is because the electrical power is lower than its initial value. The maximum value of P_{in} injection in this case is approximately 0.127 pu.

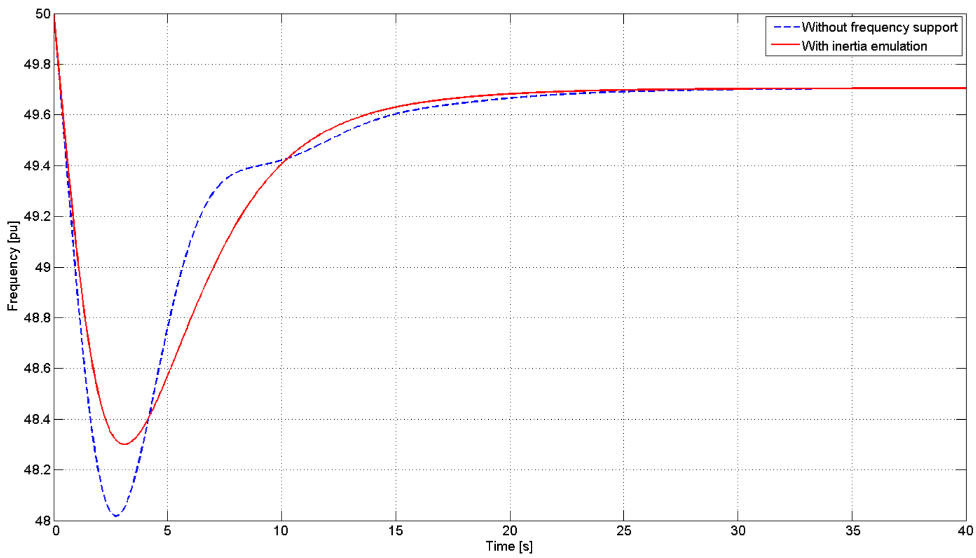

Fig. 5.9 Network frequency behavior after 0.1 pu load step increase with and without frequency support for 20 % wind power penetration in 7.5 m/s.

Fig. 5.10 shows the frequency response to 0.1 pu load step increase with frequency support of the wind power (inertia emulation) for different penetration of wind power. the wind speed is 7.5 m/s.

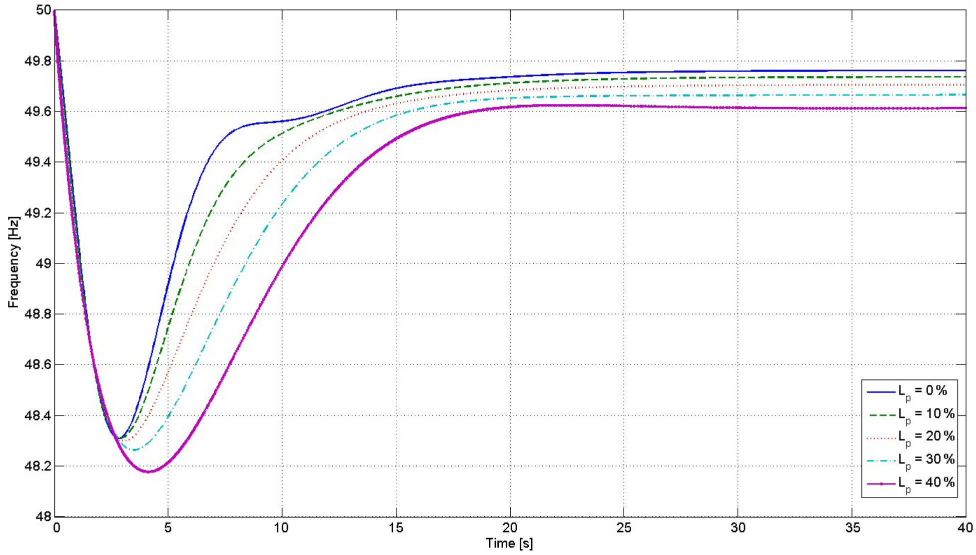

Fig. 5.10 Frequency response to 0.1 pu load step increase with frequency support of wind power (inertia emulation) for different penetration of wind power.

As expected, by increasing penetration of wind power, TMF is decreased. Furthermore the system becomes slow. In the other words, the grid frequency goes back to its initial value for a high penetration level of wind turbine slower than the frequency for a low level of penetration. The slope of increasing frequency is lower in comparison with Fig. 5.3. In a system with using temporary extra active power, increasing penetration of wind power only has effect on the electrical power among the wind turbine parameters as it is obvious in Fig. 3.15. However in the inertia emulation case, because the value of extra electrical power (produced by using inertia emulation) is related to the frequency in accordance with (4.14). Thus the parameters of the wind turbine (such as mechanical power, rotor speed, tip speed ratio) are changed by changing the frequency.

5.3.2 High Wind Speed

Fig. 5.11 shows the mechanical and electrical power of the wind turbine when there is inertia emulation as a primary frequency support for 20 m/s wind speed. In addition, Fig. 5.12 and Fig. 5.13 show the rotor speed of the wind turbine and the pitch angle (β), respectively.

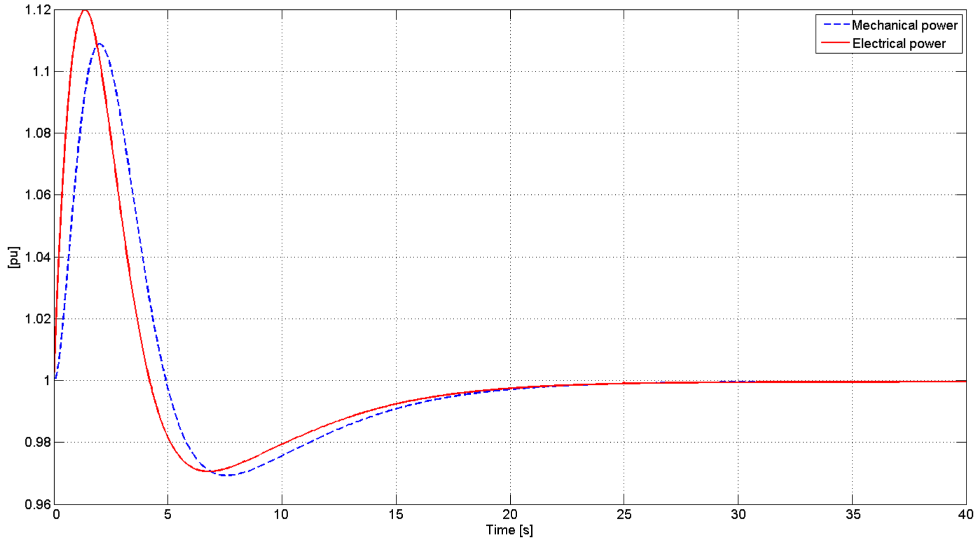

Fig. 5.11 Mechanical and electrical power of the wind turbine when there is inertia emulation as a primary frequency support in 20 m/s wind speed.

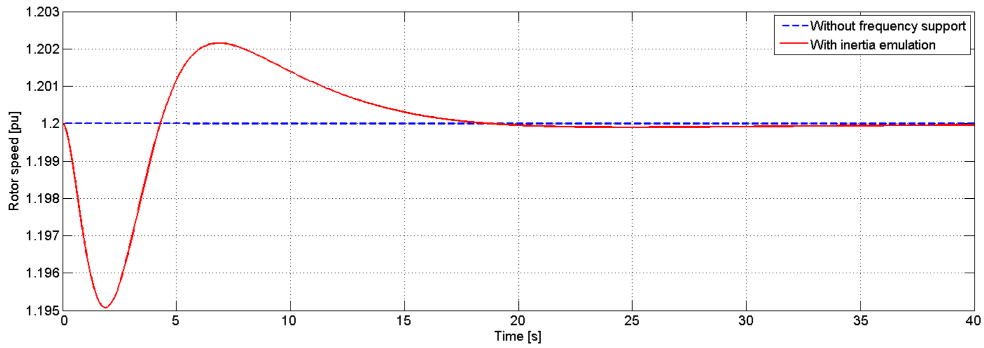

Fig. 5.12 Rotor speed of the wind turbine when there is inertia emulation as a primary frequency support in 20 m/s wind speed.

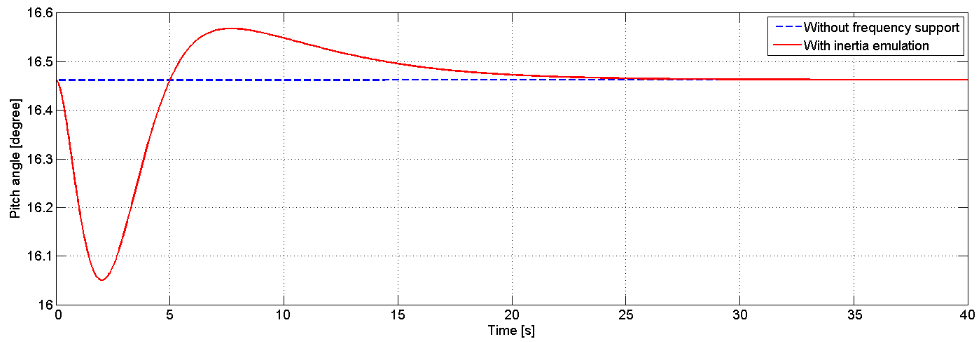

Fig. 5.13 Pitch angle of blades when there is inertia emulation as a primary frequency support in 20 m/s wind speed.

By applying inertia emulation, the electrical power starts to increase and the rotor speed starts to decrease. This is because the mechanical power is lower than the electrical power. After approximately 2 s the mechanical power becomes more than the electrical power,

thus the rotor speed starts to increase. The pitch angle also changes due to change in the rotor speed.
Fig. 5.14 shows the comparison between the frequency response of the system to 0.1 pu load step increase with and without frequency support. TMF increases approximately 0.3 Hz by using inertia emulation.

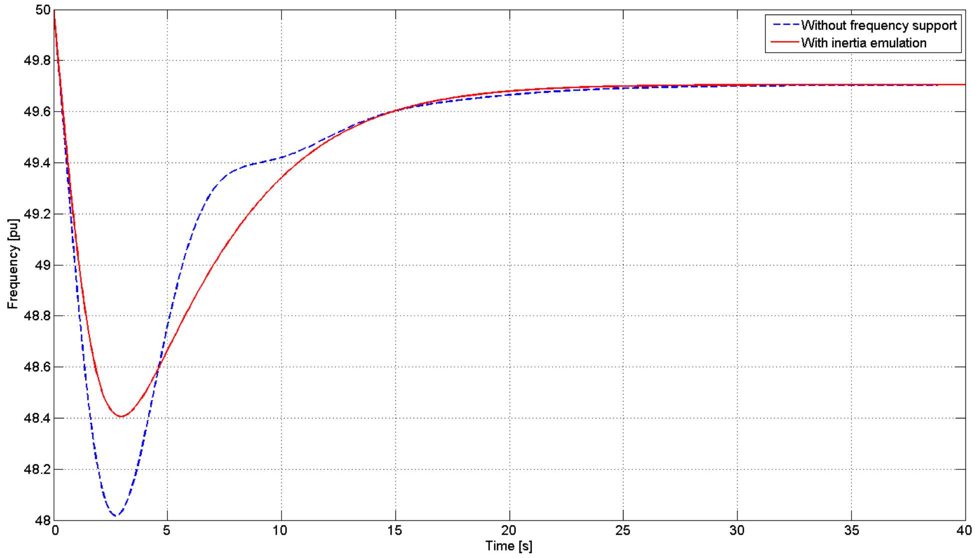

Fig. 5.14 Network frequency behavior after 0.1 pu load step increase with and without frequency support for 20% wind penetration in 20 m/s.

The TMF in this case is higher than the TMF in temporary extra active power (Fig. 5.5) due to the higher extra electrical power produced by the primary frequency control. However the slope of increasing frequency is lower than that in the extra active power method. This is because the accelerating time for the rotor speed is lower than the extra active power support (comparison between Fig. 5.4 and Fig. 5.12) and the electrical power is lower than the electrical power in the extra active power method (between approximately 4 s and 10 s).

5.4 Direct Pitch Angle Regulation

Direct pitch angle regulation can be used as a primary frequency control to improve frequency behavior in high wind speed range. In this part, the wind turbine controls the pitch angle as a primary frequency control when there is a power unbalance. Fig. 5.15 shows the mechanical power, electrical power and rotor speed response of the WF to 0.1 pu load step increase with and without frequency support. The wind speed is 20 m/s and the wind power penetration is 20 %. Fig. 5.16 shows the pitch angle of the wind turbine in this case.

In this method the mechanical power starts to increase due to the change in pitch angle. Thus, approximately in the first three seconds the mechanical power is more than the electrical power and the rotor speed increases. After that, the electrical power becomes

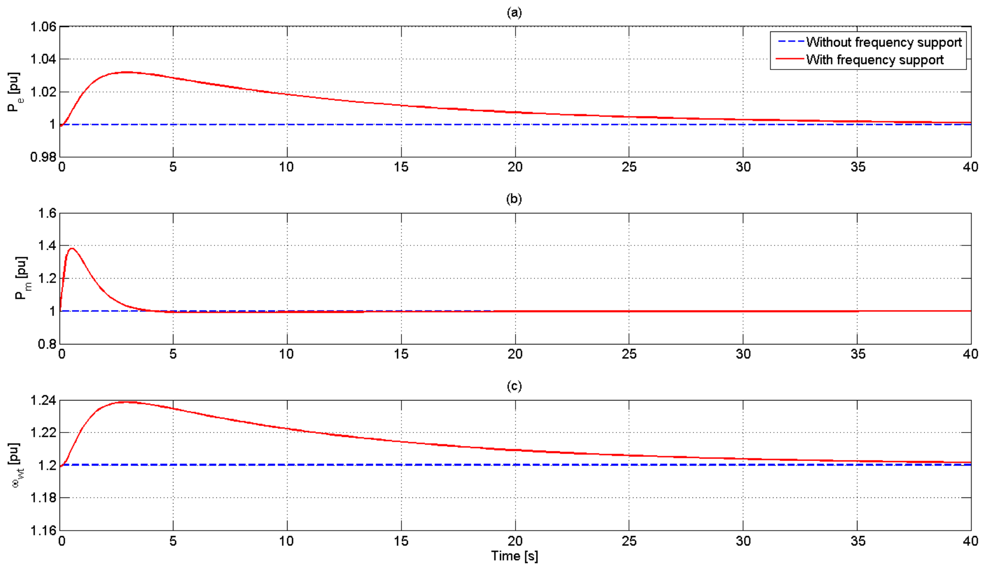

Fig. 5.15 Wind turbine electrical power (a), wind turbine mechanical power (b) and rotor speed of wind turbine (c) with and without primary frequency support from WF for 20 m/s wind speed.

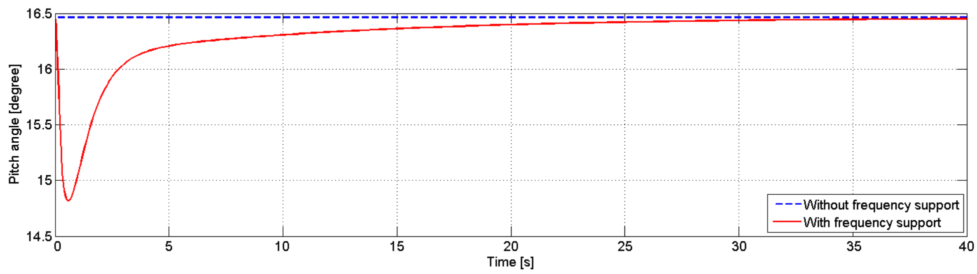

Fig. 5.16 Pitch angle behavior after 0.1 pu load step increase with and without frequency support for 20 % wind penetration in 20 m/s wind speed.

greater than the mechanical power and the rotor speed starts to decrease.
Fig. 5.17 shows the network frequency behavior after 0.1 pu load step increase with and without frequency support (direct pitch angle regulation) for 20 % wind penetration in 20 m/s. TMF increases approximately by 0.1 Hz.

The TMF is 48.12 Hz in this case by using pitch controller as a primary frequency control. This figure shows the TMF is improved and the frequency returns its initial value with steady state frequency deviation faster than when there is no primary frequency control.
the increase in TMF in this method is less than two others methods (temporary extra active power and inertia emulation) due to a smaller change in electrical power. The advantage of using this method is that the slope of increasing frequency is higher than two other methods.
Fig. 5.18 shows the response of frequency to 0.1 step load increase for those three methods of primary frequency control. The wind speed is 20 m/s and the penetration level of wind power is 20 %. The time that the frequency reaches 98.8 % of its initial value for direct pitch angle regulation method and temporary extra active power method are approx-

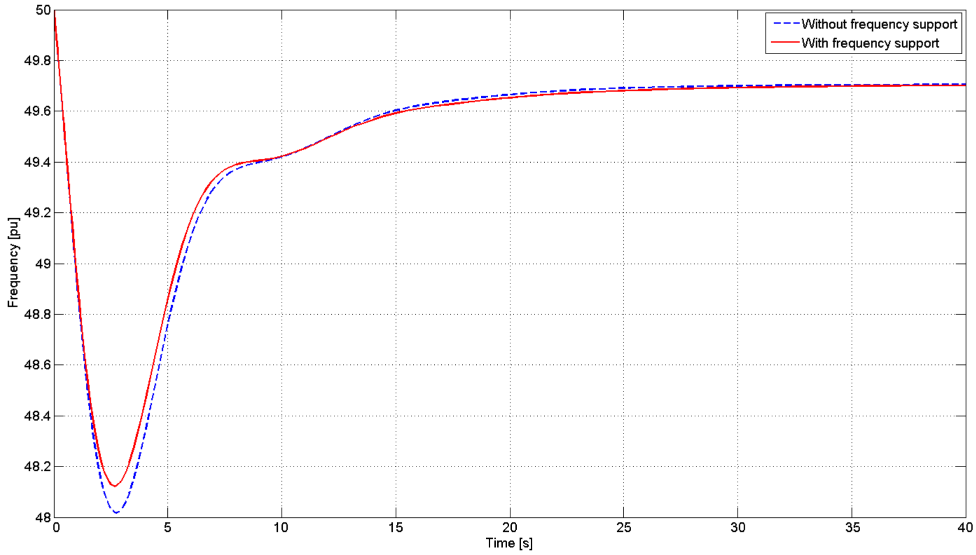

Fig. 5.17 Pitch angle behavior after 0.1 pu load step increase with and without frequency support for 20 % wind penetration in 20 m/s wind speed.

imately the same. However frequency behavior in direct pitch angle regulation method does not have SDF. Thus direct pitch angle regulation has the best frequency behavior after 5 s and Inertia emulation has the highest value for TMF.

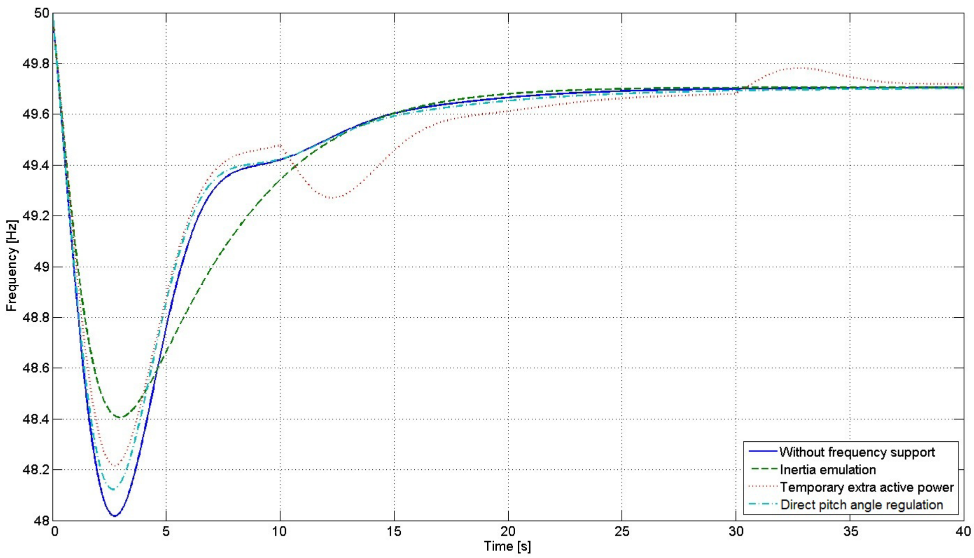

Fig. 5.18 Response of frequency to increase 0.1 pu load step for different methods of primary frequency control.

Chapter 6

Combination of Methods of Primary Frequency Control

6.1 Temporary Extra Active Power and Direct Pitch Angle Regulation

In this part temporary extra active power support by VSWTs and direct pitch angle regulation methods are combined. Also the combination is compared with each method. In the first case, the primary frequency control is direct pitch angle regulation. In the second case, the primary frequency control is temporary extra active power support by VSWTs and the third one is a combination of them. 20 % wind power penetration is set for all simulations in this chapter. Fig. 6.1 shows the response of the mechanical and electrical power of the wind turbine to 0.1 pu load step increase for these three cases.

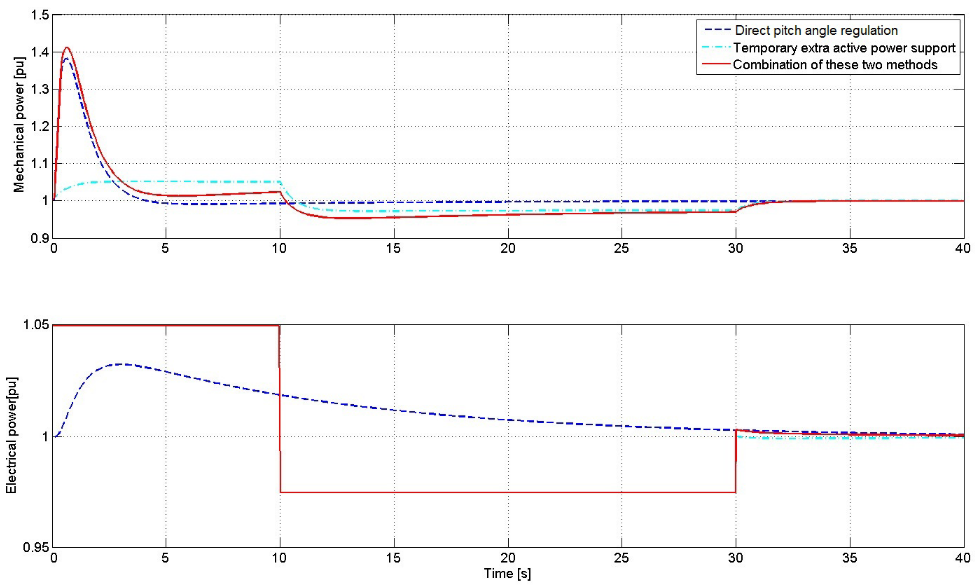

Fig. 6.1 Response of mechanical and electrical power of wind turbine to a 0.1 pu load step increase for these three cases during high wind speed.

The electrical power of the wind turbine for the third case is exactly the same as the electrical power in the second case in the first 30 s. This is because, the electrical power of the wind turbine is kept constant during this period. Fig. 6.2 shows the rotor speed of the wind turbine and the pitch angle of the blades for above scenarios.

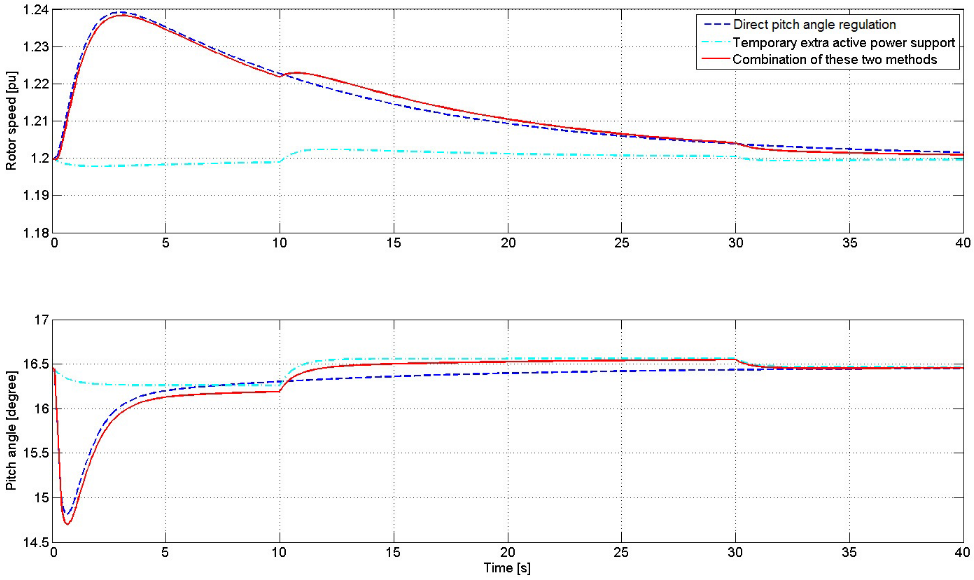

Fig. 6.2 Response of rotor speed of wind turbine and pitch angle of blades to increase 0.1 pu load step for these three cases.

Fig. 6.3 shows the response of grid frequency to increase 0.1 pu load step for three cases. The grid frequency of the second and third case are the same in the first 30 s, as the electrical power of the wind turbine are the same in this period. The TMF for the first and second case are 48.12 and 48.22 Hz, respectively.

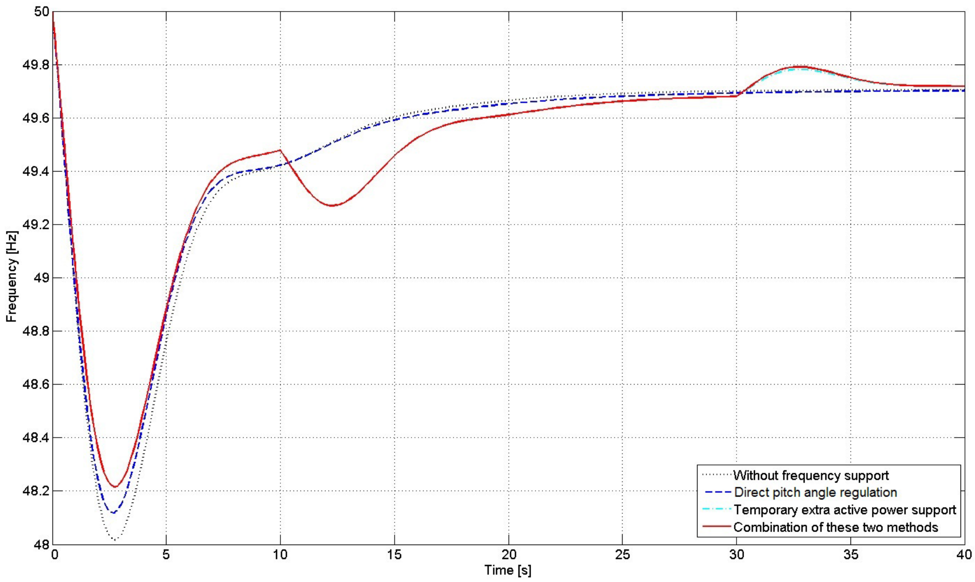

Fig. 6.3 Response of frequency to increase 0.1 pu load step for these three cases.

The grid frequency of the second and third case are the same in the first 30 s, as the electrical power of the wind turbine are the same in this period. The TMF for the first and

second case are 48.12 and 48.22 Hz, respectively.

As it is shown in Fig. 6.3, the frequency behavior for combination of two scenarios is similar to the frequency behavior for the second case. In addition the electrical power and the rotor speed for combination approximately look like the second case (Fig. 6.1 and Fig. 6.2). Furthermore, as Fig. 6.1 shows, the mechanical power for the combination of two cases increases even more than the mechanical power in the first case. Thus, the combination of direct pitch angle regulation and primary frequency control as primary frequency control is not a suitable method.

6.2 Inertia Emulation and Direct Pitch Angle Regulation

In this part, Inertia emulation and direct pitch angle regulation as a primary frequency control are combined. Also the combination is compared with each method. In the first case, the primary frequency control is direct pitch angle regulation. In the second case the primary frequency control is inertia emulation and the third one is a combination of them. Fig. 6.4 shows the response of the mechanical and electrical power of the wind turbine to 0.1 pu load step increase for these three cases.

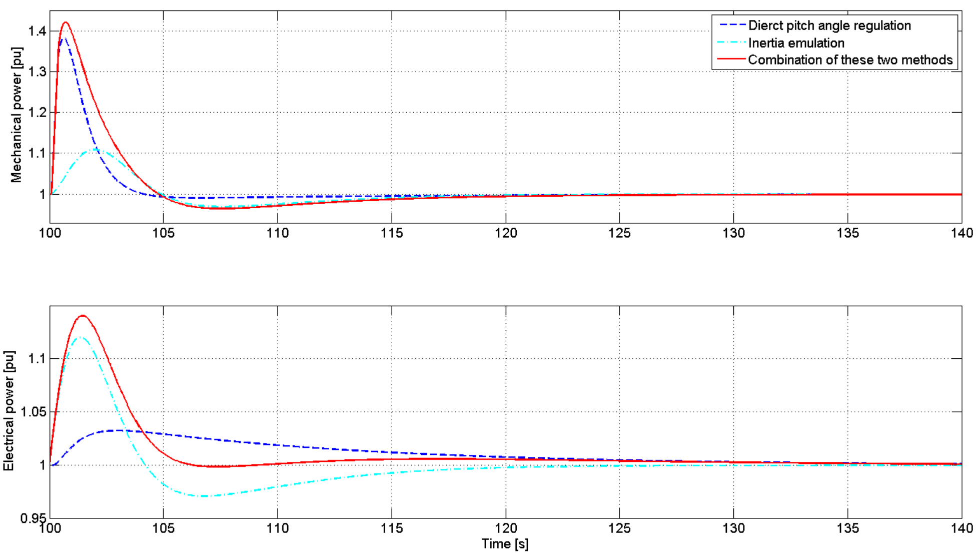

Fig. 6.4 Response of mechanical and electrical power of wind turbine to increase 0.1 pu load step for these three cases.

The mechanical power of the wind turbine for the third case is very close to the first case during the first 5 s due to the change in the pitch angle. The electrical power of the wind turbine for the third case is approximately between the electrical powers of other two cases in the first 20 s, approximately. Fig. 6.5 shows the rotor speed of the wind turbine and the pitch angle of the blades for above scenarios.

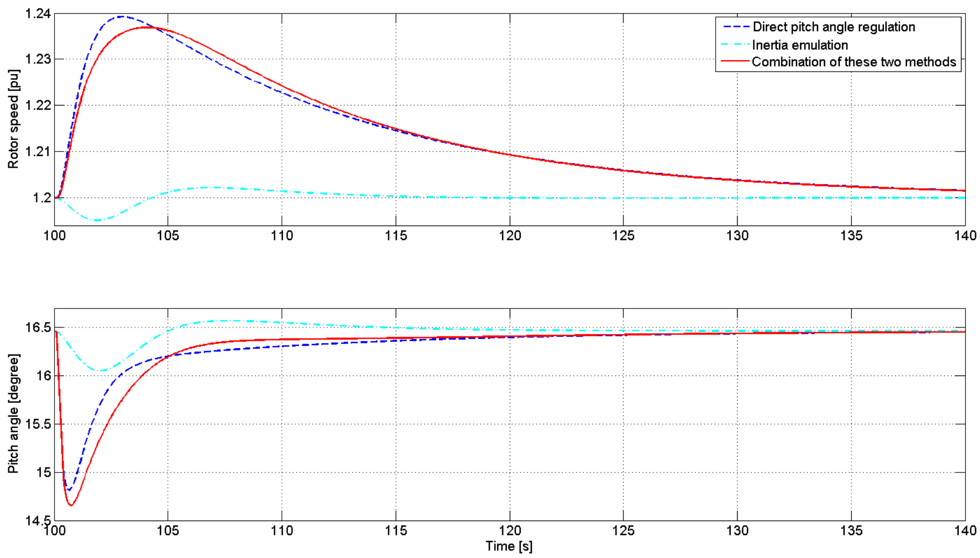

Fig. 6.5 Response of rotor speed of wind turbine and pitch angle of blades to increase 0.1 pu load step for these three cases.

Fig. 6.6 shows the response of the grid frequency to increase 0.1 pu load step for three cases.

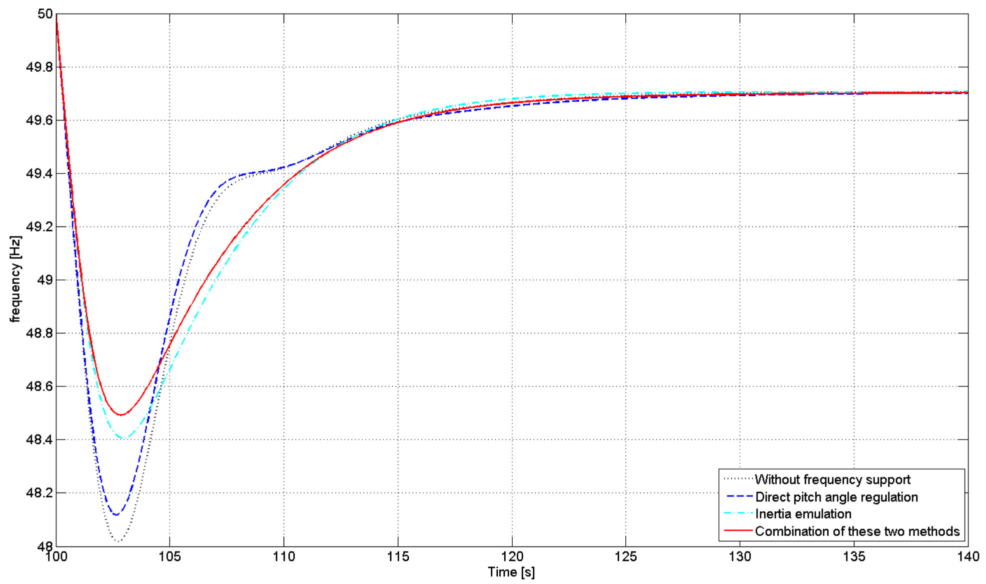

Fig. 6.6 Response of frequency to increase 0.1 pu load step for these three cases.

The grid frequency of the second case has a better behavior than two other cases in the first 3.7 s due to a higher value of the electrical power of the wind turbine. Between 3.7 s and 4.5 s the third case acts faster than other cases due to the higher value of the electrical power of the wind turbine in that case. Between 4.5 s and 10.6 s the first case acts faster than other two cases. TMF of the first, second and third cases are 48.12, 48.41 and 48.33 Hz, respectively.

6.3 Inertia Emulation and Temporary Extra Active Power Support

In this part, Inertia emulation and temporary extra active power methods are combined. Also the combination is compared with each method. In the first case, the primary frequency control is temporary extra active power support. In the second case the primary frequency control is inertia emulation and the third one is a combination of them. Fig. 6.7 shows the response of the mechanical and electrical power of the wind turbine to 0.1 pu load step increase for these three cases.

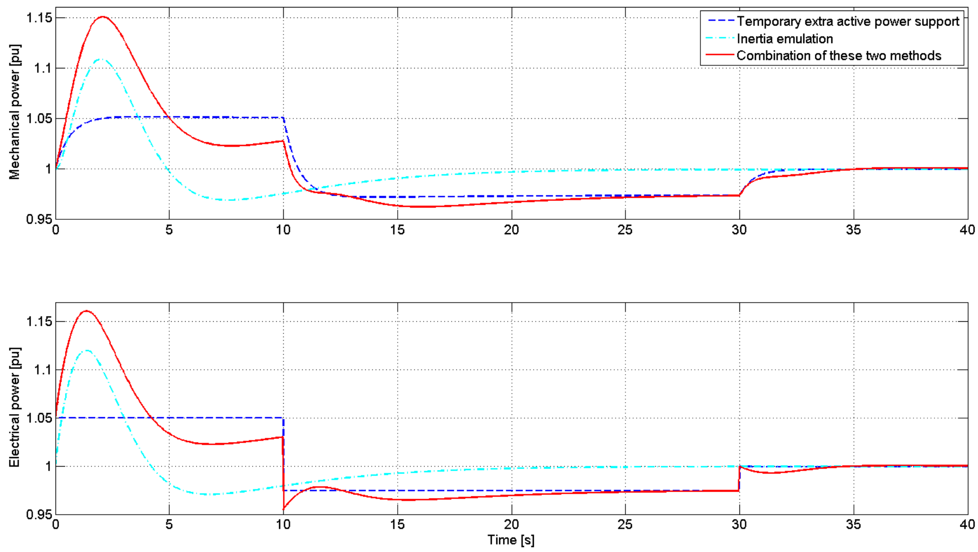

Fig. 6.7 Response of mechanical and electrical power of wind turbine to increase 0.1 pu load step for these three cases.

The electrical and mechanical power of the wind turbine for the third case increase more than two other cases. Thus, this method can improve TMF better than two other cases. Fig. 6.8 shows the rotor speed of the wind turbine and pitch angle of the blades for above scenarios.

The rotor speed of the wind turbine for the combination case decreases more than two other cases, because of higher electrical power. Fig. 6.9 shows the response of the grid frequency to 0.1 pu load step increase for three cases. TMF for the third case is higher in comparison with other cases. However the second case is faster than others and the electrical power in this case returns to its initial value so it can be more useful in case of having mismatch between load and generator frequently.

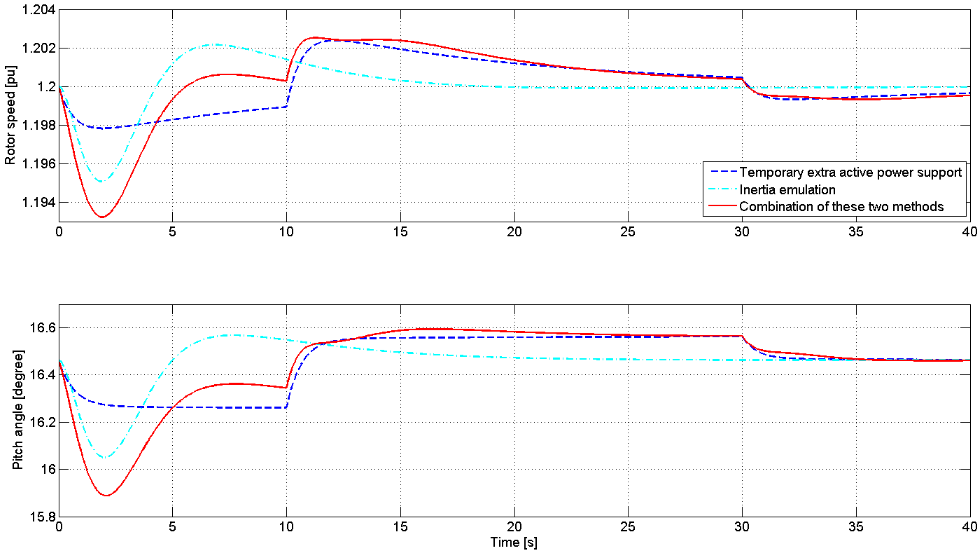

Fig. 6.8 Response of rotor speed of wind turbine and pitch angle of blades to increase 0.1 pu load step for these three cases.

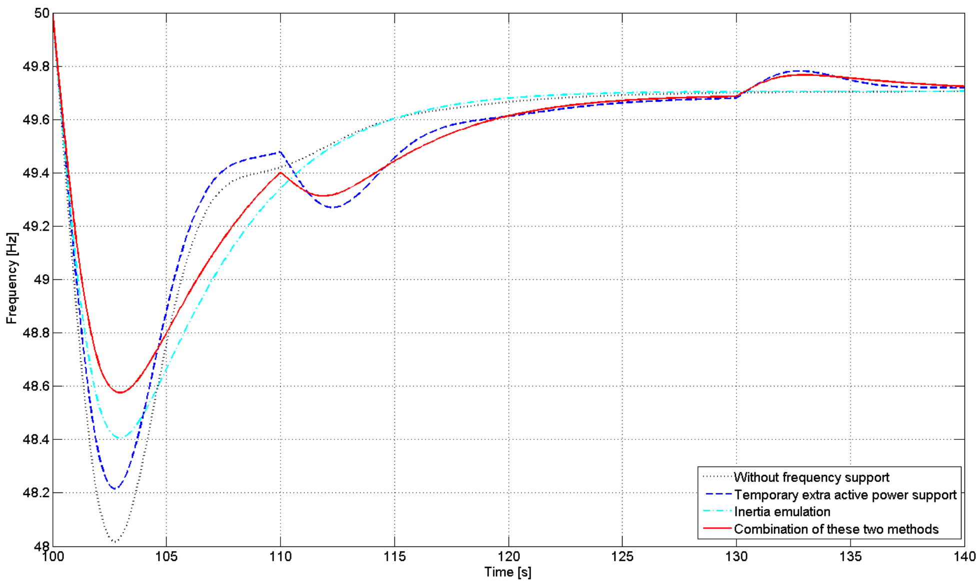

Fig. 6.9 Response of frequency to increase 0.1 pu load step for these three cases.

The TMF for the combination of inertia emulation and temporary extra active power is a higher than the TMF for the inertia emulation in accordance with Fig. 6.9. The slope of increasing the frequency of the combination method is also higher than the inertia emulation method. Thus, the grid frequency behavior of combination of inertia emulation and temporary extra active power methods is better than the frequency behavior of inertia emulation method. It has to be mentioned that the combination of inertia emulation and temporary extra active power has the highes value of TMF among other proposed methods.

Chapter 7

Conclusions and Future Work

7.1 Summery and Conclusions

In this thesis, the effect of high penetration of wind power on primary frequency control of a power system during mismatching between load and generation is studied. The wind turbine is working at three ranges of wind speed (low, medium and high). In addition, three methods of primary frequency control of WTs are tested and the effect of increasing the wind power penetration on the frequency in these cases are evaluated.

At first, a hydro turbine and a pitch regulated wind turbine are modeled in Matlab/Simulink. The pitch controller includes a switch, a rate limiter and a PI controller. The values for PI controller are tested by tries and error to have a satisfied operation of the pitch controller especially when the pitch controller starts or stops working (behavior of the mechanical power, electrical power, rotor speed and the pitch angle). Then, three scenarios for the primary frequency control (temporary extra active power supported by VSWTs, inertia emulation and direct pitch angle regulation) are analyzed and compared. At the end, the combination of these methods are compared and investigated.

When the temporary extra active power are used as primary frequency control, simulation results show that the total amount of kinetic energy can not be fully utilized for grid support. This is because, the mechanical power input into the system is rotor dependent. During low and medium wind speed range, as the rotor speed varies, the mechanical power will be reduced.
The direct pitch angle regulation method uses a gain that introduces how many degrees, the blades should pitch. Higher values of this gain cause higher reduction in pitch angle and better frequency behavior. However increasing the amount of mechanical power maybe is a limitation factor for decreasing pitch angle (increasing the gain). It has to be mentioned the gain value can be changed in different places with different wind speed distribution.

In the case of comparing primary frequency control methods, simulation results show that the inertia emulation method has the highes value for temporary minimum frequency. This is because, the electrical power which is produced and added to the electrical power of the wind turbine, in this method is higher than the two other methods. However the slope of increasing frequency for this method is slow in comparison with other proposed methods. The time that the frequency reaches 98.8 % of its initial value for direct pitch angle regulation method and temporary extra active power method are approximately the same. However frequency in temporary extra active power has the another frequency drop (SDF). The SDF in temporary extra active power can make a critical problem during high penetration of wind power. Thus direct pitch angle regulation has the best frequency behavior after approximately 3 s.

In the end, simulation results of combination methods show that the combination of extra active power and inertia emulation has the highest value for TMF. However the slope of increasing frequency in this scenario is slow. In addition this scenario has SDF like the combination of temporary extra active power and direct pitch angle regulation. It seems that combination of inertia emulation and direct pitch angle regulation has better performance of two other scenarios. Although it has to be mentioned that the slope of increasing frequency in this scenario is as slow as this slope in combination of extra active power and inertia emulation scenario.

7.2 Future Work

In this thesis, the analysis of effect of high penetration of wind turbine on primary frequency support is done without consideration of voltage variation. However the voltage variation may have effect on frequency response and extra active power in case of mismatch between load and generation due to the change in reactive power. Therefore, as a future research suggestion, these results with considering of voltage variation could be studied.
In addition, the load is considered as a active power load in this thesis. However the inductive load may have effect on frequency response and extra active power too. Thus the future studies could be studied with inductive load.

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Appendix A

A.1 Hydro Model Parameters

$R_{P,eq}$ = 0.05 , T_G = 0.2 s , H_{eq} = 3.0 s , D = 1.0 s , T_W = 1.0 s , R_T = 0.38 , T_R = 5.0 s

A.2 Wind Model Parameters

H_{WT}= 5.19 s, T_f= 5 s , K_2= 0.5

A.2.1 C_p Coefficient

$\alpha_{i,j}$: $\alpha_{0,0}$ = -4.1909e -1, $\alpha_{0,1}$ = 2.1808e -1, $\alpha_{0,2}$ = -1.2406e -2, $\alpha_{0,3}$ = -1.3365e -4, $\alpha_{0,4}$ = 1.1524e -5; $\alpha_{1,0}$ = -6.7606e -2, $\alpha_{1,1}$ = 6.0405e -2, $\alpha_{1,2}$ = -1.3934e -2, $\alpha_{1,3}$ = 1.0683e -3, $\alpha_{1,4}$ = -2.3895e -5; $\alpha_{2,0}$ =1.5727e -2, $\alpha_{2,1}$ = -1.0996e -2, $\alpha_{2,2}$ = 2.1495e -3, $\alpha_{2,3}$ = -1.4855e -4, $\alpha_{2,4}$ = 2.7937e -6; $\alpha_{3,0}$ = -8.6018e -4, $\alpha_{3,1}$ = 5.7051e -4, $\alpha_{3,2}$ = -1.0479e -4, $\alpha_{3,3}$ = 5.9924e -6, $\alpha_{3,4}$ = -8.9194e -8; $\alpha_{4,0}$ = 1.4787e -5, $\alpha_{4,1}$ = -9.4839e -6, $\alpha_{4,2}$ = 1.6167e -6, $\alpha_{4,3}$ = -7.1535e -8, $\alpha_{4,4}$ = 4.9686e -10;

A.2.2 Pitch Controller Parameters

K_{pp} = 150, $K_{ip} = 15$, Rate limiter = +/- 5° , Saturation = 27°