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Operation and Control of Wind Farms in Non-Interconnected Power Systems

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1. Introduction

Autonomous power systems are characterized by the absence of interconnections with neighbouring systems due to geographical, economic and political reasons. These systems face particular problems associated with safety and reliability during the design and operation procedure associated with safety and reliability. Typical problems include large variations in frequency because of the low inertia and the large fluctuations voltage due to the low short circuit ratio. The quality of the provided electricity to consumers is threatened. At the same time, special features of non interconnected systems, such as concentration of production in a limited number of power stations, the large size of the units in relation to the load, the need for larger spinning reserve due to the absence of interconnections, and the small stability margins raise the impact on safety and cost of operation.

Under these conditions, the effective handling of transient phenomena arising due to serious disorders is particularly critical. The systems should respond adequately to dynamic events and ensure static and dynamic safety. The most common faults that may cause undesired events are the loss of transmission lines, the sudden loss of load, and short circuits - especially three phase errors - and loss of production units. Based on collected operational data, incidents of loss of unit during operation are quite common and cause serious problems, therefore require special treatment. In several cases, such events have led in the past in smaller or even general black-outs.

These problems are becoming more intense due to the increasing penetration of wind power in the last decade. Since renewable energy sources and particularly wind energy have stochastic behaviour, the power output is not guaranteed. This is the main factor that imposes restrictions on the expansion because in general, distributed energy sources do not contribute to the control and regulation of the system in the same way as conventional units. Another important point, which differentiates the turbines compared with conventional synchronous generators used in electric systems, is associated with the technology of converting mechanical energy into electrical. The wind turbines are in large proportion

equipped with asynchronous generators (possibly in conjunction with electronic power converters) and therefore have substantial differences in the dynamic response over conventional units. For these reasons, limits are always imposed in the instantaneous penetration of wind power. These limits vary across the power systems, depending on the specific circumstances prevailing in each autonomous system, both in terms of conventional units (e.g. production technology, control capabilities, etc.) and wind farms (size and technology of the wind turbines, dispersion of wind turbines on the island, etc.). It is often the case that the limit set by the system operator for the instantaneous penetration of wind power is around 30% -40% of the load. In order to allow both the evaluation of the dynamic behaviour of autonomous systems after severe disturbances (e.g. ability of the system to restore frequency back to the desired limits after a major disturbance, such as loss of production and / or lines) as well as the definition of safe penetration limits, it is essential to conduct numerous studies. These include transient stability, load - frequency regulation, etc. The development of appropriate models for dynamic simulations in non interconnected systems is critical.

2. Power system model

2.1 Thermal power plant models

The conventional generating capacity comprises usually diesel, gas and steam plants with different ratings and control attributes. Each thermal plant contains several control blocks, which are essential for power system of dynamic simulations, e.g. voltage controller, primary controller (governor), primary mover unit and the synchronous generator. In many cases, due to lack of accurate data, simplified models for the conventional units are used in simulations. In this study, the exact models for each unit were used to ensure optimal representation of the interaction between wind farms and the power system.

The following three different models, already existing as built-in standard models in PowerFactory, (DIGSILENT, 2006), are used for the governors: GAST2A model for the gas turbines, DEGOV1 model for the diesel generators and IEEEG1 general model for the steam plants. A detailed description of the GAST2A built-in model in PSS/E for the governor used in the gas plant is described in (Mantzaris et al., 2008), while details on the corresponding standard IEEEG1 model for the governor in the steam plant can be found in (DIGSILENT, 2006). The parameters of these models, validated both in Matlab and PSS/E software packages, are presented in (Mantzaris et al., 2008). For the Automatic Voltage Regulators (AVR), the built-in SEXS model of PowerFactory is used with adjusted parameters for each unit.

2.2 Dynamic load models

The electrical loads of the systems include typically various kinds of electrical devices. An appropriate approach for the dynamic modeling of the loads connected to Medium Voltage (MV) feeders is to assume constant impedance of the loads during dynamic simulations, (Cutsem & Vournas, 1998):

$$P = P_0(V / V_0)^2 \quad (2.1)$$

$$Q = Q_0 (V / V_0)^2 \quad (2.2)$$

where P , P_0 and Q , Q_0 are the active and reactive power consumed by the load for voltage equal to reference voltage V , V_0 respectively.

2.3 Protection system

The protection system was also modeled in the simulation platform. The settings for both under/over voltage and under/over frequency protection system are crucial for the operation and dynamic response of the system during transient instances. As mentioned in the Introduction, non interconnected system, like the one used in this report as a study case, face the problem of significant variations in voltage and frequency. The relays, which act on either the production (protection of the conventional units or protection of the wind turbines), or the demand side (relays attached on the Medium Voltage feeders) decide the disconnection of equipment or loads, when the limits set by the system operator (or the production unit user) are violated. Regarding the loads, this leads to the so called load shedding, which often determines also the dynamic security margins for the system. It is often the case, in isolated systems, with low inertia, that during frequency variations, large proportion of the load is disconnected to avoid further frequency drop and possible frequency instability, i.e. due to sudden loss of a production unit.

The voltage and frequency protection system was modeled specifying the lower (or upper) limit of the value and the time duration, during which the variable measured, is out of the accepted range. One kind of under/over frequency protection operating in modern power systems is the so called ROCOF protection (Rate of Change of Frequency). The relays controlled by this system, open when the frequency changes at a rate faster than the specified one for a specific time. Thus, a part of the substation loads is disconnected. However, in many non-interconnected systems, especially those designed many decades ago, the under/over frequency protection system controlling the relays at substation loads measures the actual frequency and not the rate of change. Thus, if the frequency drops lower than a specified limit for specific time duration, the relay is ordered to open.

As a case study the small size island system of Rhodes is used. Rhodes power system for the reference year 2012 includes a 150 kV transmission system, two power plants, distributed in the north and in the south, as shown in Figure 1, and five wind farms. A significant proportion of the generation comes from wind turbines and diesel units. In 2012, the total installed wind power capacity and the maximum annual power demand are assumed to be about 48 MW and 233 MW, respectively (see Table 1).

The present Rhodes power system model is based on dynamic models of conventional generating units, loads and wind turbines. In order to be able to perform power system simulation studies for 2012, the present system model has to be modified with additional generating units and wind farms, which are expected to be online by the year of study, 2012, (Margaris et al. 2009). The protection system, mainly under/over frequency and voltage protection relay is also included in the dynamic power system model. In the reference year study 2012, five wind farms with different technologies will be connected online in Rhodes power system. Table 2 depicts the wind turbine technology and the size of each wind farm.

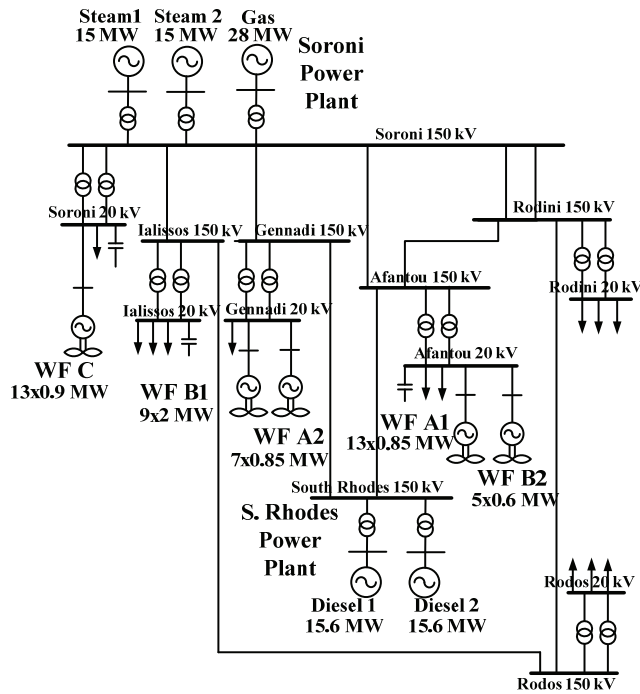


Fig. 1. Rhodes power system

The basic characteristics of Rhodes power system in 2012 are summarized in Table 1:

| Rhodes power system | |
|----------------------------------|-------|
| Max Power Demand (MW) | 233.1 |
| Rated Thermal Power (MW) | 322.9 |
| Rated Wind Power Generation (MW) | 48.8 |

Table 1. Basic Characteristics of Rhodes Power System (2012)

| | Wind Turbine Technology | Installed Capacity (MW) |
|--------------|-------------------------|-------------------------|
| Wind Farm A1 | DFIG | 11.05 |
| Wind Farm A2 | DFIG | 5.95 |
| Wind Farm B1 | PMSG | 18 |
| Wind Farm B2 | PMSG | 3 |
| Wind Farm C | ASIG | 11.7 |

Table 2. Wind Farms in Rhodes Power System (2012)

2.4 Load scenarios

Regarding the first step of the approach, the operating scenarios have to be carefully defined. These scenarios are based on collected operational data of the power system and correspond to the possible severe condition of operation. In this way, it is ensured that their analysis covers the intermediate modes of operation in terms of security. Three reference scenarios were defined as follows:

- The Peak Load Demand scenario – SCENa
- The Maximum Wind Power Production scenario (in absolute values of power) – SCENb
- The Maximum Wind Power Penetration scenario (in percentage of the load demand) – SCENc

The first scenario is the base case scenario and is used to evaluate the operational mode of the system in terms of security without significant wind power production, because annual peak load occurs in a hot summer day with typically very low wind. The second scenario is used to investigate security with large wind power production levels. In this case the levels of wind penetration are quite high going beyond 20% of the total load demand. The third scenario examines a penetration level above the 30% margin, which has been used until now for wind energy as a rule of thumb in autonomous island systems.

2.5 Static security analysis

Under the different scenarios, the secure operation of the system for steady operation has to be ensured, based on the N and N-1 criteria. Among the security requirements which have to be fulfilled by the power system are the following:

- The loading of the transmission lines should be within the accepted limits
- Bus voltages should be in the range of $\pm 5\%$ around the nominal voltage for normal operation (N)
- Bus voltages should be in the range of $\pm 10\%$ around the nominal voltage for emergency operation (N-1)

3. Wind power fluctuations

This part addresses different grid integration issues of large wind farms in non-interconnected power systems with respect to secure operation during variable wind and load profiles. Today, the power systems all over the world need a dramatic and continuous restructuring, as different renewable energy technologies are going to replace some of conventional units in the near future. This means, that there is urgent need for accurate modeling of various different generation technologies and novel wind turbine control strategies to fulfill requirements set by the TSOs, in order to ensure the dynamic security of such power systems.

Especially referring to wind power, the fluctuating nature of wind power imposes serious challenges to system operators. Power system inertia, protection relays settings, voltage and frequency stability in autonomous power systems have to be carefully and thoroughly analyzed before the penetration margin levels are expanded.

In most of the cases, operation experience defines the accepted penetration levels keeping the margin at 25-30% of peak annual load. However, higher or lower values can actually be accepted depending on the combination of power generator technologies online, (Margaris et al. 2009) – as it is the case of the specific power system under study here.

Modeling considerations of the power system under study are presented, especially speed governors and automatic voltage regulators of the conventional units. Defining accurate models of these system components is of vital importance for the overall system performance. Modeling and control issues for three different wind turbine technologies are described. The study case of Rhodes island is presented through simulations for various load and wind scenarios. The frequency fluctuations are calculated using wind time series based on measured and validated results, (Sørensen et al., 2007).

3.1 Wind farms modelling

Modern power systems include a variety of wind turbine technologies. The different response of each kind in dynamic phenomena requires separate and detailed modeling of each one. Three wind turbine technologies are considered here, namely Doubly Fed Induction Generator (DFIG), Permanent Magnet Synchronous Generator (PMSG) and Active Stall Induction Generator (ASIG) based wind turbines.

In order to investigate the interaction between these large wind farms and the power system, an aggregated method for modeling the wind farms is used, (Akhmatov et al., 2003; Poeller & Achilles, 2003). Such modeling approach is commonly used for power system studies, as it reduces substantially both the complexity of the system and the computation time, without compromising the accuracy of the simulation results.

Models for all these different wind turbine technologies are implemented, including the main components of each wind turbine configuration:

- Drive train and aerodynamics
- Pitch angle control system
- Control system
- Protection system

The system configuration, as well as some modeling and control issues for each wind turbine technology are described in the following section.

3.1.1 System configuration of variable speed DFIG wind turbine

The DFIG wind turbine configuration stands nowadays as the mainstream configuration for large wind turbines, (A.D. Hansen & L.H. Hansen, 2007). To ensure a realistic response of a DFIG wind turbine, the main electrical components as well as the mechanical parts and the controllers have to be considered in the model. The model used in this study for the wind farms with DFIG wind turbines is described in detail in (A.D. Hansen et al., 2006). The DFIG system is essentially a wound rotor induction generator with slip rings, with the stator directly connected to the grid and with the rotor interfaced through a back-to-back partial-scale power converter (A.D. Hansen & G. Michalke, 2007). The converter consists of two conventional voltage source converters (rotor-side converter RSC and grid-side converter GSC), and a DC-bus, as illustrated in Figure 2.

A two-mass model is used to represent the drive train to illustrate the dynamic impact of wind turbines on the grid properly. A large mass for the wind turbine rotor and a small mass for the generator are thus connected by a flexible shaft characterized by stiffness and damping for the low-speed shaft. A simplified aerodynamic model, based on a two-dimensional aerodynamic torque coefficient C_q table, (A.D. Hansen & G. Michalke, 2007), is typically sufficient for such studies.

The control system consists of a pitch control system and an electrical control system of the converters. The pitch control system is realized by a PI controller with antiwind-up, using a servomechanism model with limitation of both the pitch angle and its rate-of-change. As the pitch angle controls directly the generator speed to its reference signal, this control is able to prevent over-speeding both in normal operations and during grid faults, by limiting the mechanical power extracted from the wind and thus restoring the balance between electrical and mechanical power.

The efficiency of the pitch control system is crucial for studies like in this work, where the response of the wind farms under variable and extreme wind conditions is vital from the power system perspective.

The electrical control system, depicted in Figure 2, is essential for a good behavior of a DFIG wind turbine during both normal and grid fault operations. Decoupled control of active and reactive power is applied through vector control techniques, (A.D. Hansen & G. Michalke, 2007), allowing for changes in the active and reactive power in the range of milliseconds. The RSC controls mainly the active and reactive power delivered to the grid, while the GSC ensures nominal voltage at the common DC-bus at unity power factor operation of the converter. As illustrated in Figure 2 and described in details in (Gail et al., 2006; M.H. Hansen et al., 2005), the control of the converters is based on cascade control loops: a very fast inner current controller regulates the currents to the reference values that are specified by the outer slower power controller.

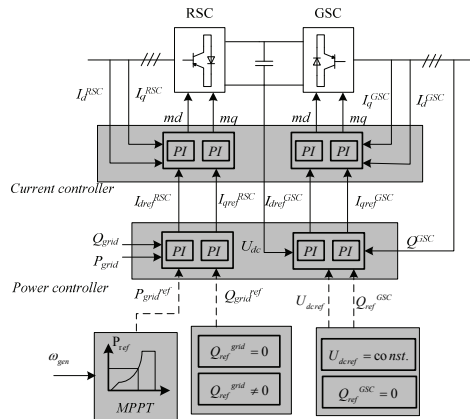


Fig. 2. Electrical control scheme for the DFIG wind turbine

3.1.2 System configuration of variable speed PMSG wind turbine

Similar to the DFIG wind turbine configuration, the PMSG model consists both of a wind turbine mechanical level (i.e. aerodynamics, gearless drive-train and pitch angle control) and a wind turbine electrical level (i.e. multi-pole PMSG with a full-scale frequency converter and its control).

The synchronous generator is connected to the grid through a full-scale frequency converter system that controls the speed of the generator and the power flow to the grid. The full-scale frequency converter system consists of a back-to-back voltage source converter (generator-side converter and the grid-side converter connected through a DC link), controlled by IGBT

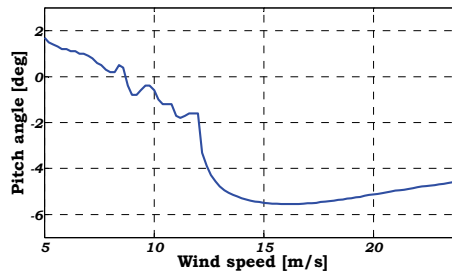


Fig. 4. Pitch angle as a function of the wind speed

Notice that all three wind turbine configurations are using a gain scheduling procedure, (Ackermann, 2005), in their pitch control system in order to compensate for the existing non-linear aerodynamic characteristics. The fundamental principle of the gain scheduling feature is that the proportional controller of the pitch angle controller is varied so that the total gain of the system remains unchanged for all the operating points of the wind turbine.

3.2 Simulation results

In the following, the emphasis is made on the secure operation of the system under variable load and wind profiles. The goal of these simulations is to illustrate and evaluate the interaction between the five wind farms with Rhodes power system during different load scenarios and winds. The first set of simulations focuses on the dynamic response of the three types of wind farms configurations, considered in this article and on the impact on the system during deterministic wind speed steps. The second set of simulations is carried out in order to illustrate and evaluate the fluctuations that occur in the generator speed and the power of wind turbines in the presence of a turbulent wind. The attention is also drawn to the impact of these fluctuations on the power system of Rhodes and to the wind farm controller capability to ensure safe operation of the wind farms during different variable load and wind profiles.

3.2.1 Turbulent wind speed in wind farms

In the following, simulations with turbulent wind speed time series are presented and discussed. The goal of these simulations is to evaluate the fluctuations in the system frequency due to wind speed fluctuations during different load scenarios. It is assumed that all five farms are running with turbulent wind speed.

The wind turbine time series, which are inputs to the wind farms, are generated based on the wind speed fluctuation model developed by Sorensen et. al., (Sørensen et al., 2007). This wind speed fluctuation model has been validated against wind speed measurements from large wind farms.

For each wind farm site and each wind and load scenario, different wind time series are generated for 10 minutes. The correlation between the wind speeds of the wind turbines in a wind farm is taken into account in the wind speed fluctuation model. The correlation aspect is even more important for such isolated power system as it is the case of Rhodes island. As the distances between the wind farms are quite small, the wind speeds seen by the wind farms can be highly correlated.

Figure illustrates the wind time series, which has been applied to the wind farms, during the load scenario with maximum load demand, i.e. SCENa. Notice, that all wind farms are running in power optimization mode, as their wind speeds are below the rated wind speed.

In this scenario, the wind farms produce in total 7.5 MW, accounting only for 3% of the total demand. The system frequency fluctuations due to the wind speed fluctuations are negligible, as illustrated in Figure 6, thus the wind power impact on the power system is in this case very small. As expected, although visible, the fluctuations are of quite small magnitude and they are therefore not leading to problems in the system security.

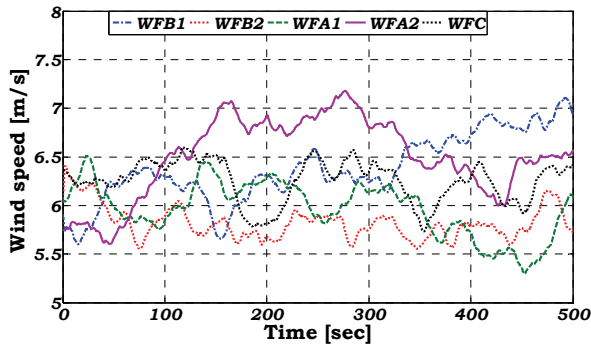


Fig. 5. Wind time series applied to the wind farms - SCENa

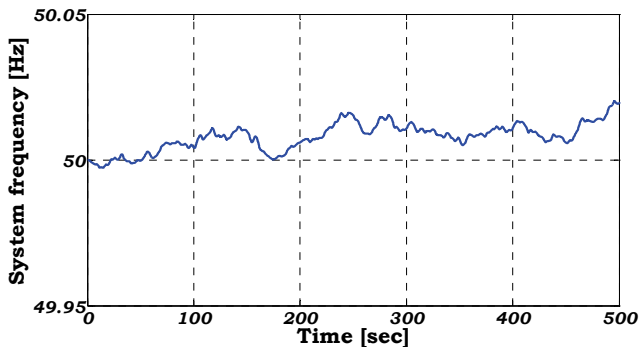


Fig. 6. System frequency for wind time series - SCENa

Figure 7 illustrates the wind time series, which has been applied to the wind farms, during the load scenario with maximum wind power production, i.e. SCENb.

Notice that in this SCENb, the wind turbines operate in a narrow range around their rated capacity and it can thus be presumed that the wind power fluctuations' impact on the Rhodes power system to be more significant compared to the SCENa.

Due to the highly correlated the wind speeds, the form that frequency fluctuations appear to have in Figure 8, is not directly related to a specific wind time series, but rather to the combination of the active power fluctuations delivered by all five wind farms.

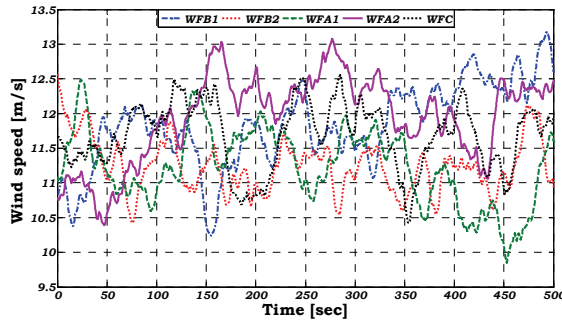


Fig. 7. Wind time series applied to the wind farms - SCENb

In this scenario, the wind farms produce in total 45.2 MW, which corresponds to 26% of the total demand. Notice that the system frequency, illustrated in Figure 8, has very fast dynamic deviations in the range 49.96 Hz - 50.1 Hz, which is considered safe from the power system security point.

Even though the wind power penetration is significant in SCENb, the frequency fluctuations are not considered large enough to impose security questions. The high correlation among the wind in all the wind farms is ensuring that the system frequency is not strongly dependent on a sudden drop or increase of the wind in only one wind farms. One of the most important factors influencing the frequency deviations - besides the parameters of the conventional units and their emergency rate of power undertake - is of course the size of each wind farm and the type of generator used.

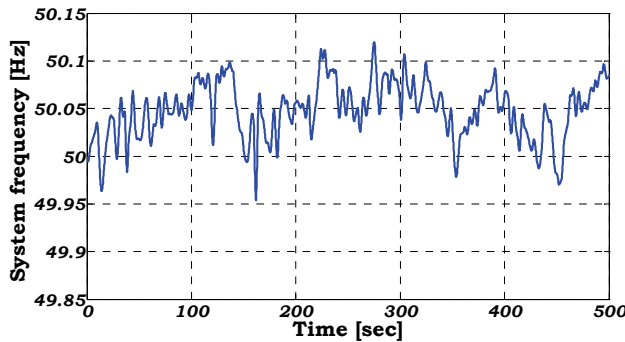


Fig. 8. System frequency for wind time series - SCENb

The following graphs show the performance during the scenario SCENb of two wind turbine technologies, i.e. ASIG wind turbine and PMSG wind turbine, which are picked-up to illustrate the behavior of a generic fixed and variable speed wind turbine, respectively. Beside the wind speed, typical quantities, as generated power to the grid, generator speed and the pitch angle are illustrated.

Figure 9 illustrates the wind speed time series applied as input to an ASIG wind turbine inside wind farm WFC. Notice that the wind turbine is simulated at an average wind speed

of about 11.5 m/s. This operational point corresponds to a transition operational regime for the wind turbine, between power optimization and power limitation regime.

The strong correlation between the wind speed fluctuations, active power output and generator speed is obvious in Figures 9 -11. As expected for a ASIG wind turbine, the 3p fluctuation in the wind is visible both in the active power output and the generator speed. It should be noticed that, in this scenario SCENb, the ASIG wind farm produces around 6 % of the total demand.

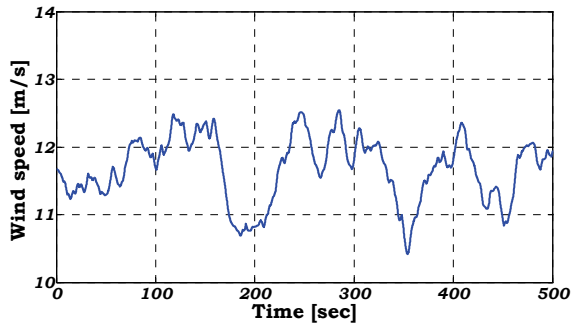


Fig. 9. Wind time series in ASIG wind farm WFC - SCENb

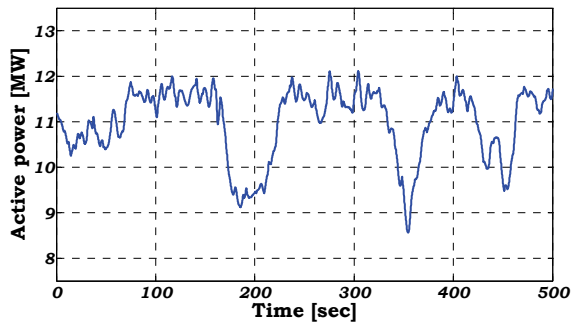


Fig. 10. Wind farm active power output for ASIG wind farm WFC - SCENb

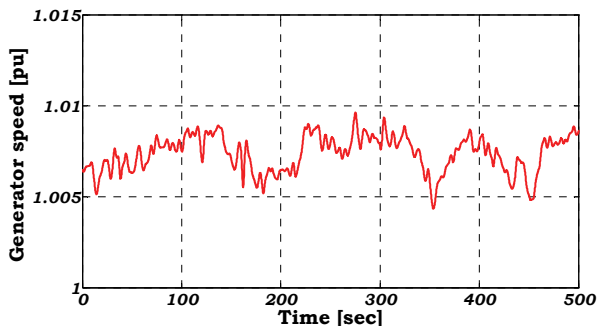


Fig. 11. Generator speed for ASIG wind turbine in wind farm WFC - SCENb

Figure 12 shows the pitch angle of ASIG wind turbine during SCENb. When the wind speed is less than the rated wind, the wind turbine produces maximum possible power. In this case, the pitch angle is equal with its optimal value, i.e. -1.7 deg. When the wind speed is above rated wind speed value, the pitch angle corresponds to the values which keep the turbine power to the rated power. Notice that the pitch system responds with delay due to the pitch rate limiter existing in the actuator. Despite the very fast wind speed deviations, the pitch control system manages to ensure smooth transition between the optimization and limitation range whenever the wind speed crosses the rated value.

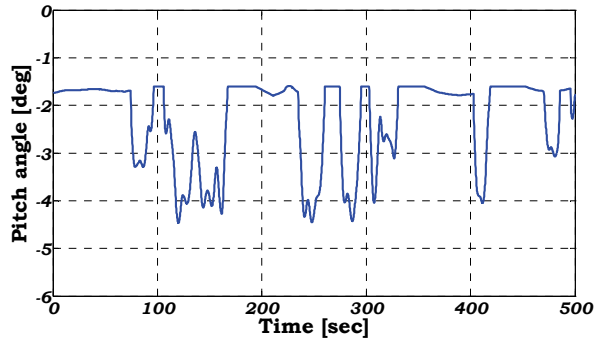


Fig. 12. Pitch angle for ASIG wind turbine in wind farm WFC - SCENb

Figures 13-16 illustrate how the wind farm WFB2 equipped with PMSG wind turbines behaves during the scenario SCENb. Figure shows the wind speed time series, which has been applied as input to a PMSG wind turbine inside wind farm WFB2.

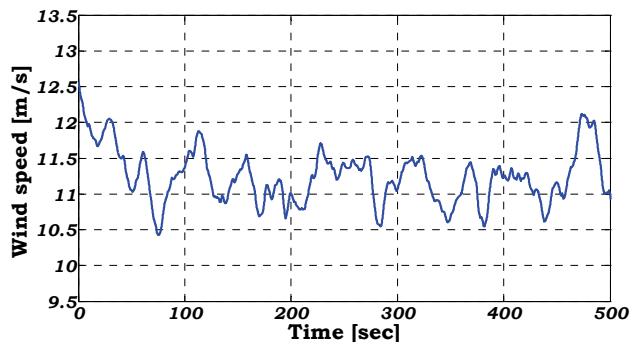


Fig. 13. Wind time series in PMSG wind farm WFB2 - SCENb

Similar to the ASIG wind turbine, discussed previously, the operation point of the PMSG wind turbine corresponds again to a transition operational regime for the wind turbine, between power optimization and power limitation regime.

This wind farm has rated capacity 3 MW, which stands for 1% of the total demand. As illustrated in Figure14, whenever the wind speed goes above the rated value, the pitch control manages to keep the active power output constant and equal to nominal power.

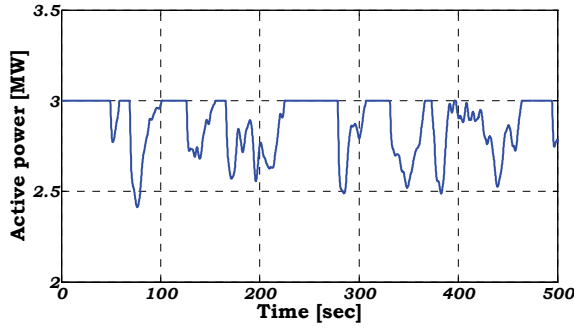


Fig. 14. Wind farm active power output for PMSG wind farm WFB2 - SCENb

Notice that the generator speed of the PMSG wind turbine is tracking the slow variation in the wind speed each time the turbine is running in the operation mode, while in power limitation mode, the speed controller tries to control the generator speed to its rated value.

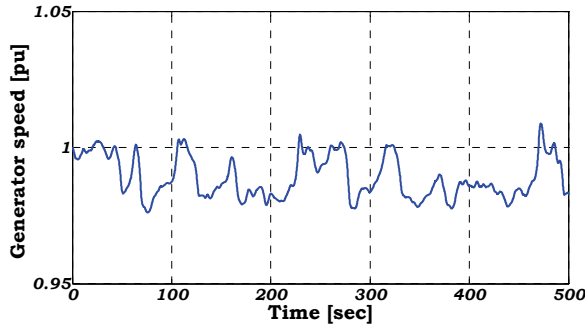


Fig. 15. Generator speed for PMSG wind turbine in wind farm WFB2 - SCENb

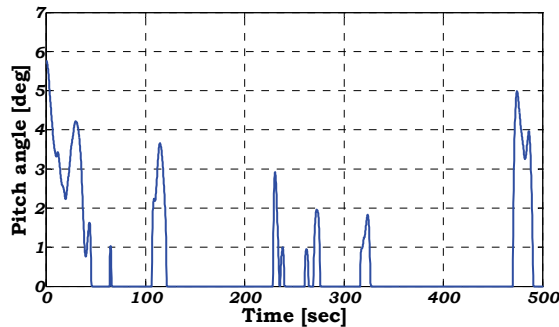


Fig. 16. Pitch angle for PMSG wind turbine in wind farm WFB2 - SCENb

The damping controller manages to damp the torsional oscillations in the drive train and ensures safe operation of the wind turbine. Compared to the results from the ASIG wind farm above, the fast deviations in the wind are filtered out from the electrical power. The

generator is decoupled from the grid through the converter at its terminal and any rapid fluctuations in the wind are not influencing the power delivered to the grid. Figure 16 gives the pitch angle, which is increased from its optimal value each time the turbine is running in power limitation mode.

In this scenario, the wind power penetration is maximum, reaching 32% of the total demand. The wind farms however are not producing as much as in SCENb. This scenario is considered the worst case scenario, as the fluctuations in the wind may have serious impact on the power system operation.

Figure 17 illustrates the wind time series, which has been applied to the wind farms, during the load scenario with maximum wind power penetration, i.e. SCENc.

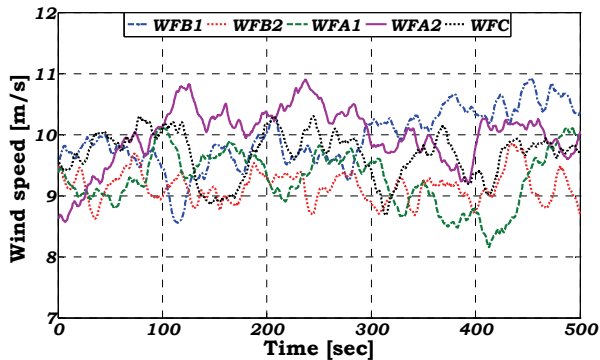


Fig. 17. Wind time series applied to the wind farms - SCENc

The range of operation for the wind turbines in this case covers the optimization area, where the control of the wind turbine has to ensure optimum power output.

As illustrated in Figure 18, due to the wind fluctuations, the system frequency varies between 50 Hz and 50.25 Hz, which is considered safe for the system operation. Although the wind speeds in each wind farm may have sudden changes, as it is illustrated in Figure 17, the overall response of the system is satisfactory, and the power outputs from the wind

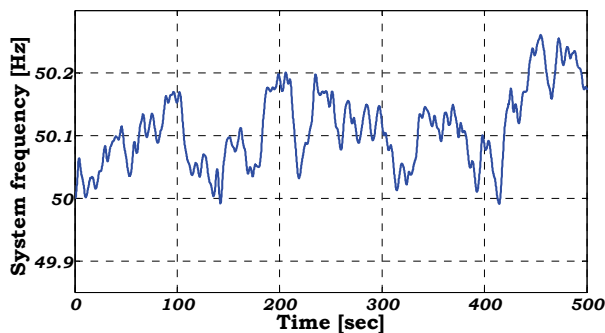


Fig. 18. System frequency for wind time series - SCENc

farms seem to counteract each other in the frequency impact. The system frequency deviates more in this case than in SCENb (see Figure 8), which is due to the increased wind power

penetration levels in this scenario. Nevertheless, the emergency rate of power undertaken by the conventional units is sufficient to overcome the rapid active power fluctuations produced by the wind farms on the island.

In the following, the attention is directed in details towards the performance of two wind turbine technologies during SCENc, this time on a ASIG wind turbine and a DFIG wind turbine. Again typical quantities, as generated power to the grid, generator speed and the pitch angle are illustrated.

Figure 19 illustrates the wind speed time series, which has been applied as input to the ASIG wind farm WFC. In scenario SCENc, this wind farm produces around 7 MW i.e. 8 % of the total demand.

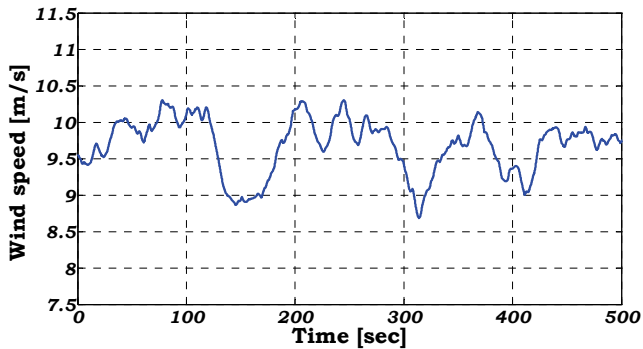


Fig. 19. Wind time series in ASIG wind farm WFC - SCENc

Notice in Figures 19-21 that the fluctuations in wind speed, active power output, generator speed are strongly correlated in this case, and the fast dynamic deviations are also here significant. Figure 22 shows the pitch angle, which is reduced accordingly although restricted by the pitch rate limiter when the wind speed changes at very high rate.

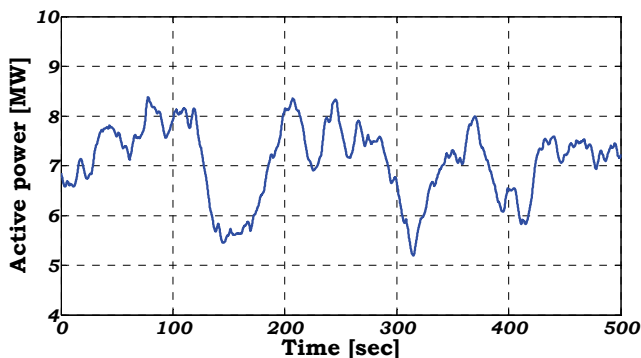


Fig. 20. Wind farm active power output for ASIG wind farm WFC - SCENc

The dynamic performance of the DFIG wind farm WFA1 during SCENc is in the following addressed in order to illustrate the efficiency of the designed models. This farm produces

almost 6.5 MW i.e. 7.5% of the total demand. Figure 23 shows the wind speed time series, which has been applied as input to the DFIG wind farm during SCENc.

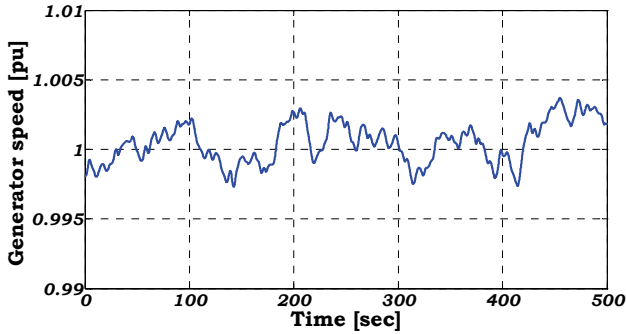


Fig. 21. Generator speed for ASIG wind turbine in wind farm WFC - SCENc

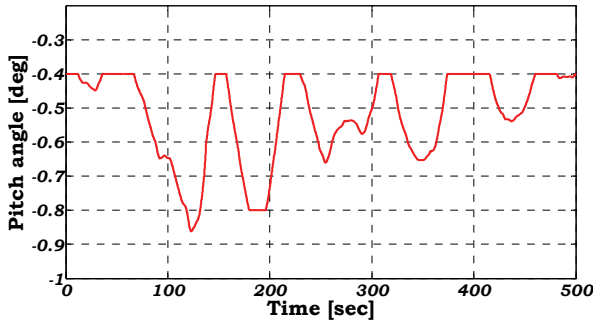


Fig. 22. Pitch angle for ASIG wind turbine in wind farm WFC - SCENc

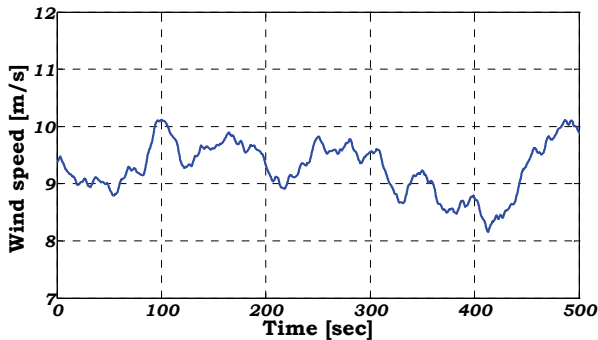


Fig. 23. Wind time series in DFIG wind farm WFA1 - SCENc

The Maximum Power Tracking (MPT) strategy, implemented in the RSC (rotor-side converter) of the DFIG system ensures optimum operation of the wind turbine maximizing the aerodynamic coefficient C_p in every wind speed. In this operational area for the DFIG

wind turbines, small changes in the rotor speed result in significant changes in the active power output of the system. This is due to the fact, that the designed MPT characteristic is very stiff in this area.

Notice that, contrary to an ASWT wind farm, where the correlation between the system frequency and the wind turbine response is very strong, in the case of DFIG configuration the generator is partially decoupled from the system frequency, as seen in Figure 18s 18, 21 and 25.

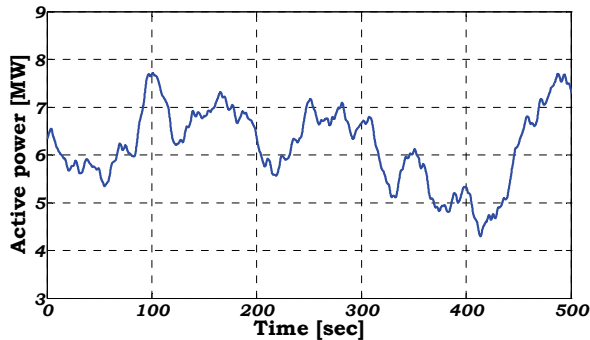


Fig. 24. Wind farm active power output for DFIG wind farm WFA1 - SCENc

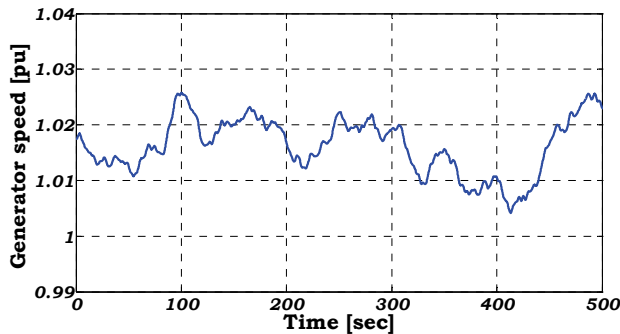


Fig. 25. Generator speed for DFIG wind turbine in wind farm WFA1 - SCENc

The generator speed is continuously adapted to the wind speed in order to extract maximum power out of wind. As wind farm is running in optimization mode, the pitch angle is passive, being kept constant to its optimal value.

4. Frequency control of wind power

Increasing wind power penetration especially in non-interconnected systems is changing gradually the way grid frequency control is achieved. The technical requirements set by the networks operators include various aspects, such as fault ride-through of wind turbines during faults, voltage-reactive power control and overall control of the wind farms as conventional power plants. A key aspect of the operation of wind farms in autonomous power systems is the frequency control. This session presents the results from a study on the

Rhodes power system already presented above, focusing on frequency control. The Rhodes power system has been used to address all the main issues related to system secure operation under different system conditions. The response of the wind farms in frequency disturbances is analyzed and the different characteristics of each wind turbine type related to frequency are described. Three different wind turbine configurations have been used – Active Stall Induction generator (ASIG), Doubly Fed Induction generator (DFIG) and Permanent Magnet Synchronous generator (PMSG). An auxiliary control has been designed for the DFIG type to enhance the capability to support the frequency control. The load shedding following severe frequency disturbances is calculated and the under/over-frequency protection relay settings are discussed under the novel system conditions. Results for different system conditions and control methods are presented and discussed focusing on the ability of modern wind turbine technologies to assist in frequency control in isolated power systems during severe disturbances in the production-consumption balance.

As wind power penetration increases in modern power systems, a variety of technical and regulatory issues regarding the interaction between large wind farms and power system is under constant discussion. The system operators are setting onerous requirements that that wind farms have to fulfill. Among these, voltage and frequency control play an important role. Frequency control has started to appear as emerging need under increasing wind power penetration conditions and due to the extended replacement of conventional generators by large wind farms in power supply. The impact of wind farms in frequency phenomena is even more vital in non-interconnected power systems, where the power system inertia is limited.

It is often the case, that when auxiliary services of wind turbines, like frequency control, are investigated, simple models are used for either the power system or the wind turbines. In this article, detailed model for all different components of the system were used to evaluate the system response in serious events with maximum accuracy. The dynamic security of power systems has to be carefully examined, before wind power penetration limits are expanded. The response of conventional units, the load dependency on frequency and voltage and the wind turbines' response during events that affect system frequency are some of the key aspects that have to be modeled in detail for this kind of investigations.

In this article the main issues of frequency control in isolated power systems, with high wind power penetration are investigated. Rhodes power system, includes three different types of conventional generators – namely gas, diesel and steam units – and three different types of wind turbines – Active Stall Induction generator (ASIG), Doubly Fed Induction generator (DFIG) and Permanent Magnet Synchronous generator (PMSG) wind turbines. This variety of components gives the chance for a wide range investigation of frequency issues for modern power systems.

Definitions regarding the frequency control in autonomous power systems are given and the protection relay system settings related to under/over frequency deviations are discussed. The response of different wind turbine technologies during frequency events is explained. Three different primary frequency control schemes implemented in the developed model are analyzed. Finally, the basic characteristics of the power system are given followed by a brief description of the available wind turbine technologies available on line in the system for the reference year 2012. Results from various simulations are discussed

and the capability of modern wind farms to provide auxiliary frequency control is demonstrated.

Frequency definitions and protection system

In this section, some basic definitions on frequency are given to introduce the main issues regarding frequency control with emphasis on isolated power systems.

In the power system, frequency is the variable indicating balance or imbalance between production and consumption. During normal operation, the frequency should be around the nominal value. The deadband which is considered as safe operation in most European grid codes is the zone 50 ± 0.1 Hz, although the limits vary between the different system operators in Europe, mainly due to the different characteristics of each grid. The range $49 \div 50.3$ Hz is in general the dynamic security zone that in most of the cases is not allowed to be violated at any means, (Lalor et al., 2005). However, these safety margins for frequency deviations are often expanded in autonomous power systems, where system inertia is low, to avoid constant load shedding whenever the balance between production and consumption is lost.

In case of sudden generation loss or large load connection, the frequency of the frequency starts to drop. The two main system functions that ensure return of an unbalanced system to nominal frequency are:

- **Primary Control:** During the first 30-40 sec after the event leading to frequency deviation, the rotational energy stored in large synchronous machines is utilized to keep the balance between production and consumption through deceleration of the rotors. The generation of these units (often referred to as primary control units) is thus increased until the power balance is restored and the frequency is stabilized.
- **Secondary control:** After the primary response of the generators, a slow supplementary control function is activated in order to bring frequency back to its nominal value. The generators connected to the system are ordered to change their production accordingly either through an Automatic Generation Control scheme, either through manual request by the system operator – which is often the case in isolated systems like Rhodes.

These two main frequency control functions are illustrated in Figure 26 for a sudden drop in system frequency.

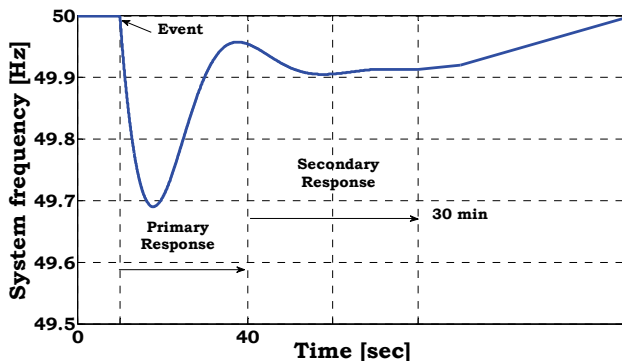


Fig. 26. Definitions of frequency control in power systems

The rate, at which the frequency changes following an event i.e. drops in Figure 34, is depending on the so called inertia of the system thus the total angular momentum of the system which is the sum of the angular momenta of the rotating masses in the system i.e. generators and spinning loads. The frequency control implemented in this study tries to improve the system response in terms of initial Rate of Change of Frequency and minimum frequency (frequency nadir). Therefore, the discussion and also the results will emphasize the capability of wind farms to provide with primary frequency support in the first seconds after the event which causes the frequency deviation.

4.1 Response of wind turbines to frequency events

The replacement of conventional synchronous generators by wind farms in modern power systems with increased wind power penetration, changes the way traditional frequency control was treated in power systems. Wind turbines connected to the grid, depending on their configuration, have a different response to frequency deviations. In this Session, the relation between each wind turbine configuration and its response during frequency deviations is discussed and explained.

4.1.1 Response of ASIG wind turbines in frequency events

One of the most common wind turbine configurations in modern power systems is the standard fixed speed wind turbine based on induction generator connected to the rotor through a transmission shaft and a gearbox. The Active Stall Induction Generator wind turbine model developed to simulate the fixed speed wind turbines in this study is described in previous sections.

As described in (Morren et al., 2006), the induction machine based wind turbine inertia response is slower and lower than the conventional synchronous generator's response. This difference is mainly because of the reduced coupling of the rotational speed of the WT and the system frequency and of the lower inertia constant of the WT compared to a standard conventional generator connected to the grid.

However, in the case of a frequency drop, like the one illustrated in Figure 34, the inertia response of the ASIG wind turbine is not negligible due to usual low nominal slips. The rotor of the ASIG is decelerating following the system frequency drop. The kinetic energy which was accumulated in the rotating mass is transformed into electrical energy delivered to the grid. The amount of the available kinetic energy is determined from the total angular momentum of the WT - thus the sum of the angular momenta of the electrical generator, the rotating blades and the gearbox - and the rotational speed. There are some studies estimating this available energy (Ullah et al., 2008; Ramtharan et al., 2007) through rough estimations.

A comparison between the inertia response provided by the three different wind turbine configurations studied in this article is given in Figure 27 for loss of the largest infeed in the system of Rhodes. When the frequency starts to drop, the ASIG provides with significant active power surge to the grid, thus, reducing the initial rate of change of frequency. The response of the DFIG and PMSG wind turbine types is explained further below. It is obvious that, fixed speed wind turbines have an intrinsic behavior that provides auxiliary service to the system during frequency imbalances, although they can not contribute to other services, i.e. voltage - reactive power control, in the same way the variable speed wind turbines can.

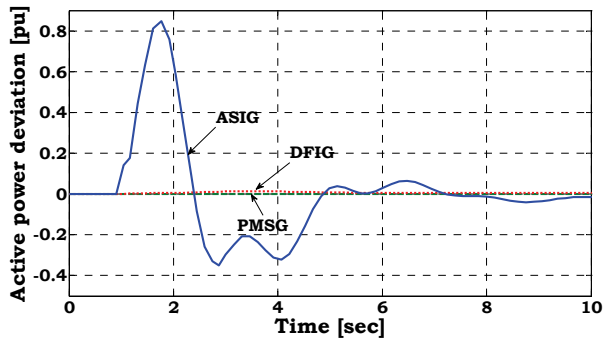


Fig. 27. Change in active power production during a frequency drop for the three main wind turbine configurations

4.1.2 Response of DFIG wind turbines in frequency events

The DFIG wind turbine configuration, which is the most common configuration for large wind turbines, is mainly based on an induction generator and a frequency converter connected to the rotor circuit via slip rings. Details on the model developed in this study, including control aspects, can be found in section 3.1.1.

As described in (Ullah et al., 2008), the response of a DFIG wind turbine is slightly different than the one described above for synchronous and induction generators. The inertial response of the DFIG type is mostly based on the applied control scheme acting on the converter connecting the rotor to the grid (Morren et al., 2006). The overall response can be explained as the result of two opposite torques acting on the rotor during a frequency change, i.e. a frequency drop: a decelerating torque, proportional to the rate of change of the rotor speed $\frac{d\omega}{dt}$ and therefore to the frequency $\frac{df}{dt}$, which makes the rotor speed follow

the frequency drop – an accelerating torque, which is produced by the difference in the electromagnetic torque, controlled by the speed controller of the machine, and the aerodynamic torque acting on the rotor of the turbine. This last component tends to cancel the decreasing effect that would eventually make the DFIG have a similar response to a simple induction generator connected to the grid, (Ekanayake et al., 2003).

4.1.3 Response of PMSG wind turbines in frequency events

A multi-pole PMSG wind turbine is connected via a full-scale frequency converter to the grid. The converter decouples the generator from the grid; the generator and the turbine system are not directly subjected to grid faults in contrast to the direct grid connected wind turbine generators. Therefore, the power output from the WTG does not change and no inertial response is obtained during a frequency event. The rotor speed of the multi-pole synchronous generator is not connected with system frequency at any means.

Large wind turbines nowadays substitute conventional generators in modern power systems under increasing wind power penetration conditions. The effect on the power system inertia and the availability of inertia response from wind turbines have become key issues for the secure integration of wind energy into the electrical grids, especially in autonomous power systems like Rhodes. In power systems, like the one studied in this

article, regular load shedding occurs due to large frequency deviations. Although sufficient spinning reserve is ensured to overcome any frequency problems, increasing wind power penetration is challenging the system security.

Supplementary control attributes have been proposed in the literature in order to achieve active frequency control by the wind turbines, (Morren et al., 2006; Ullah et al., 2008; Ekanayake et al., 2003; Ekanayake & Jenkins, 2004; Holdsworth et al., 2004; Suwannarat et al., 2007). In most of these publications, simple models for either the power system or the wind turbines are used based mainly on the assumption that the aerodynamic torque acting on the rotor during the frequency event does not vary significantly. In this section, the three different frequency control methods, which were applied in the DFIG wind turbine models used in the Rhodes power system model, are described:

- Inertia Control
- Droop Control
- Combined Control

Results from frequency events in the Rhodes power system when these control methods are used in the wind farms equipped with DFIG wind turbines are given in Section VI. The general control scheme is illustrated in Figure 28.

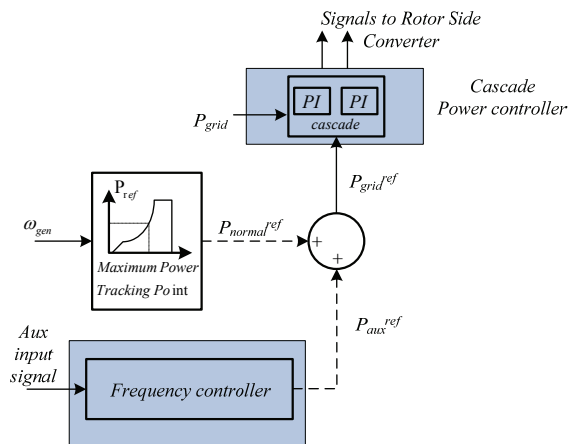


Fig. 28. General frequency control scheme for DFIG wind turbines

In the first method, the inertial response of the DFIG is restored through an additional loop in the power reference block providing the active power reference signal to the Rotor Side Converter. Details for the basic control structure of the DFIG model designed in this study for normal operation can be found in section 3.1.1. Figure29 shows the inertia control loop.

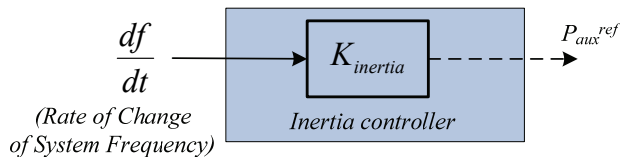


Fig. 29. Inertia controller for DFIG wind turbine

This feature is often referred to as “virtual inertia” effect, thus the control aim is to control the DFIG wind turbine to adjust its power output when subjected to frequency deviations. The rate of change of frequency defines the additional power reference signal, which is added to the normal power reference provided by the Maximum Power Tracking Controller. This auxiliary signal introduces a term proportional to $2H\frac{df}{dt}$, where H is the total inertia constant of the wind turbine, (Suwannarat et al., 2007). This inertia constant is expressed in seconds and represents the time that the wind turbine is able to provide with rated active power when decelerating the rotor from the nominal speed down to zero using only the available kinetic energy in the rotor mass, (Ullah et al., 2008). Thus, in physical terms the values of the proportional parameter $K_{inertia}$ shown in Figure 29 are restricted by this amount of energy. However, the wind turbine could be ordered to provide with even more active power, given that the stability of the system is ensured. The second control method applied in the DFIG models is the Droop control, illustrated in Figure 30.

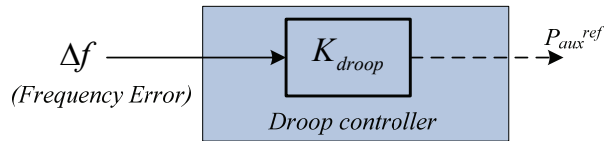


Fig. 30. Droop controller for DFIG wind turbine

In this case, the additional reference signal is equal to:

$$P_{aux}^{ref} = K_{droop} (f - f_0) \quad (6.1)$$

where f_0 is the nominal system frequency, 50 Hz for the Rhodes power system. This control method is based on the primary frequency control applied to conventional generators. Typical values for the droop parameter of large conventional units are 3%-5%, depending on the type of unit.

This control loop aims to decrease the accelerating torque acting on the generator rotor during a frequency drop, as described above for DFIG wind turbines, (Ekanayake et al., 2003). The droop control can be assumed to be implemented in the wind farm controller level instead of individual wind turbine controller. This means that the overall wind farm controller provides the auxiliary signal P_{aux}^{ref} which is distributed to the individual wind turbine controllers. In that case, the communication delays should be taken into consideration, as the rate at which the wind farm changes its output during the first milliseconds following the frequency event is crucial for the overall system response. Results from both control levels, thus Droop controller on individual wind turbine controller and Droop controller on wind farm controller, are shown and compared.

The last method tested in this study, is actually a combination of the two first control methods. Based on the analysis made in (Ekanayake et al., 2003) and referred in section 2.2 for DFIG wind turbines, the sum of Droop and Inertia control should manage to counteract

the opposite torques acting on the generator rotor during frequency phenomena. The Combined control scheme is given in Figure 31.

As a first approach, this last method of Combined Control seems to be optimum for the DFIG wind turbines. In most of the publications available, Droop Controller and Inertia controller have been treated independently. Discussion on the results from each control method proposed here is made in section 4.2.

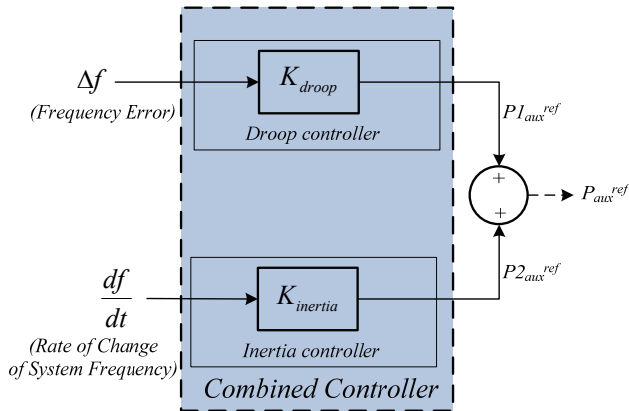


Fig. 31. Combined controller for DFIG wind turbine

4.2 Results

In this section, results from the Rhodes power system are presented. The frequency control capability of DFIG wind turbines is investigated for the load scenarios defined above. The standard event often used to check the dynamic security of power systems, thus the loss of the largest conventional generator, is simulated and the frequency response of the system under the different frequency control methods is illustrated. The emphasis on these results is given on the first seconds of the primary control operation of the system and the load shedding following the event is computed, based on the action of the under-frequency protection relay settings.

In SCENb, the wind farms online produce close or equal to their rated capacity. The total wind power production is 45.21 MW which stands for 27% of the total demand. The wind speeds in both wind farms equipped with auxiliary frequency control capability the wind is considered constant during the event studied, close to 11.5 m/s. The largest conventional unit produces 20.1 MW when ordered to trip, leading to loss of 11% of the total production. Figure 32 shows the response of three wind farms during this fault, when no auxiliary control is activated in the wind turbines. The wind farm with ASIG wind turbines increases its active power output during the first seconds following the frequency drop, contributing to the system inertia. On the other hand, the wind farm with DFIG wind turbines has almost negligible power contribution, while the PMSG wind farm does not change its active power output during the frequency drop. These results confirm the analysis made in Section III

regarding the natural response of each wind turbine type. The change in active power output for each wind farm in Figure 32 is given in p.u. of the rated capacity of each wind farm.

Figure 33 shows the frequency response for all different control methods for frequency control in the wind farms with DFIG wind turbines described in Section IV. In SCENb, these two wind farms produce in total 15 MW – 9% of the total demand. In the same figure, the results for Droop control implemented in the wind farm level or the wind turbine level are included.

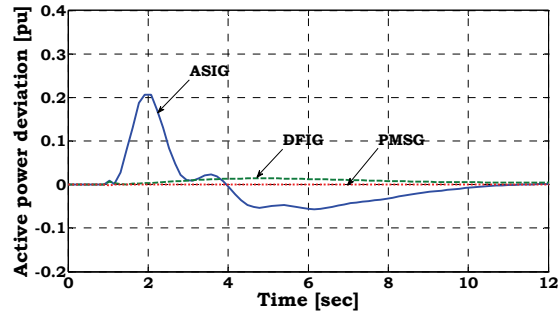


Fig. 32. Change in power in different wind turbine configurations during frequency drop - SCENb

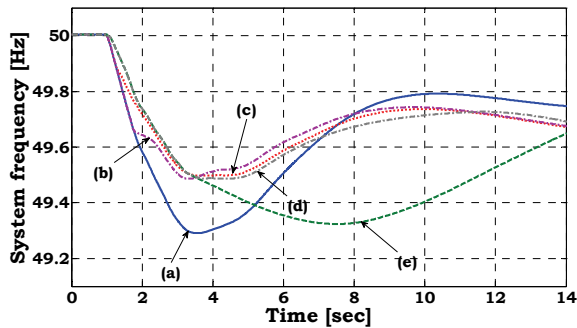


Fig. 33. System frequency for largest unit loss when frequency control is applied by DFIGs - (a) No auxiliary control, (b) Droop control on WF level, (c) Droop control on WT level, (d) Combined control, (e) Inertia control - SCENb

When no aux control (case (a)) is used in the DFIG wind farms, the frequency reaches its minimum (see also Table 2 below) with the highest initial rate of change of frequency. In this scenario, even in the case with no auxiliary control provided from wind farms there is no load shedding as the system inertia is high enough to ensure moderate frequency drops. The Droop control implemented in the wind farm control level (case (b)) does not manage to improve the maximum rate of change of frequency, although the minimum frequency is higher compared to the case (a). The best case, in terms of minimum frequency, is as expected case (c), where Droop control is implemented in the wind turbine control level. On the other hand, the Inertia control (case (e)) achieves the slowest rate of change of frequency

although the frequency minimum is the lowest among the different frequency control methods proposed here. The optimum performance seems to be achieved through the Combined control scheme (d) where both minimum frequency and maximum rate of change of frequency are improved. This last control method seems to combine the pos from the Droop and Inertia control schemes. The droop control implemented in the wind turbine control level (case (c)) has slightly higher minimum frequency but the difference is negligible (0.01 Hz).

Figure 34 shows frequency drop during the first 2 seconds after the loss of the conventional unit to clarify the effect of each control method on the initial rate of change of frequency.

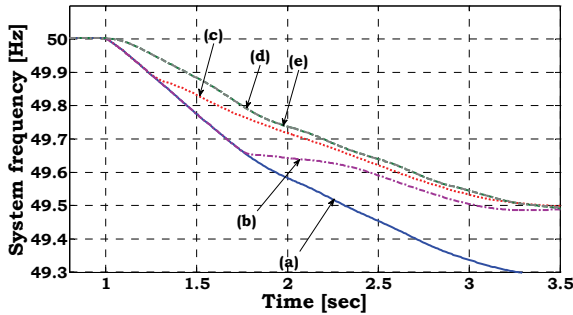


Fig. 34. System frequency for largest unit loss when frequency control is applied by DFIGs - Zoom in the first seconds after the event (a) No auxiliary control, (b) Droop control on WF level, (c) Droop control on WT level, (d) Combined control, (e) Inertia control - SCENb

The results for this scenario are summarized in Table 3, where the minimum frequency, the maximum rate of change of frequency and the load shedding are computed for all the cases demonstrated above.

| Frequency Control Scheme | | Minimum Frequency (Hz) | Maximum Rate of change of frequency (Hz/sec) | Load Shedding (MW) |
|--------------------------|---------------------------|------------------------|--|--------------------|
| (a) | No auxiliary control | 49.29 | -0.48 | 0 |
| (b) | Droop control on WF level | 49.49 | -0.48 | 0 |
| (c) | Droop control on WT level | 49.41 | -0.48 | 0 |
| (d) | Combined control | 49.49 | -0.36 | 0 |
| (e) | Inertia control | 49.32 | -0.36 | 0 |

Table 3. Results for SCENb- loss of largest infeed

The contribution of the wind farms during the frequency drop is obvious from the results presented above. From the wind turbine side now, the results for the rotor speed and the active power output of wind farm A1 (see Table 2) equipped with DFIG wind turbines are illustrated here for all the cases of frequency control.

As already discussed in section 2.2, the rotor speed of the DFIG wind turbines is not affected if no auxiliary frequency control is applied. Therefore, the inertia response of the DFIG is negligible (see Figure 35). In all the other cases, the rotor decelerates while the system frequency drops. Thus, the kinetic energy accumulated in the rotor mass is converted to electrical energy and delivered to the grid – giving the power surge during the primary frequency control period shown in Figure 36.

When Inertia control is used (case (e)), the rotor speed goes back to its pre fault value, as the auxiliary power reference signal is calculated based on the derivative of the frequency $\frac{df}{dt}$.

When the frequency stabilizes after the primary frequency control period, although not nominal yet as the secondary control has not been activated in this time frame, the derivative goes to zero and the auxiliary power reference signal goes also to zero. However, in the rest of the frequency control schemes, when droop control is used, the rotor speed is decreasing reaching another steady state value, as the difference from the nominal value remains even after the stabilization of the frequency. This means, that the wind turbine is no longer operating in the maximum power tracking curve as the normal control demands, (Ekanayake & Jenkins, 2004). The tertiary response which re-establishes the rotor speed of the wind turbine may take place several seconds after the event, when the power system has overcome the imbalance and the stress to stabilize the frequency. This procedure could also be implemented as part of an Automatic Generation controller operating in the whole power system, including the wind farms as active components, (Margaris et al., 2010).

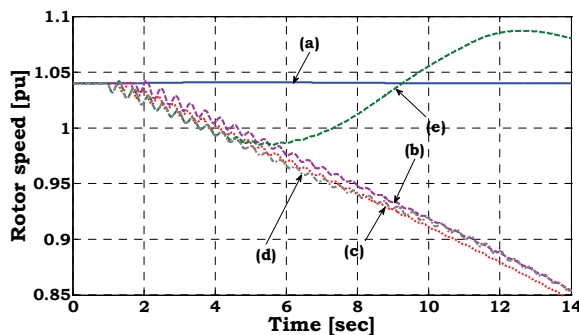


Fig. 35. Rotor speed deviations after largest unit loss for different frequency control methods applied in DFIGs - (a) No auxiliary control, (b) Droop control on WF level, (c) Droop control on WT level, (d) Combined control, (e) Inertia control - SCENb

The active power output of the wind farm A1 is given in Figure 36. In cases (d) and (e), where Inertia control and Combined control are used respectively, the wind farm increases its active power at a high rate, thus leading to lower rate of change of frequency as described in Table 3 above. In case (a) of course, when no auxiliary control is provided the active power change is negligible. In case (b), where the Droop controller is assumed to work in the wind farm control level, the power surge is delayed compared to case (a).

In SCENc, the wind power penetration is maximum. The total wind power production is 28.2 MW in total 83 MW of demand (34 %). Although, the wind farms produce less than in the Maximum Wind Power Production scenario (SCENb) studied above, the impact of wind power in the power system operation is considered far more significant. The system inertia is decreased in this case, making the frequency control task in the system more complex. The wind speeds in this scenario is almost 9.3 m/s for the wind farms A1 and A2 (see Table 2).

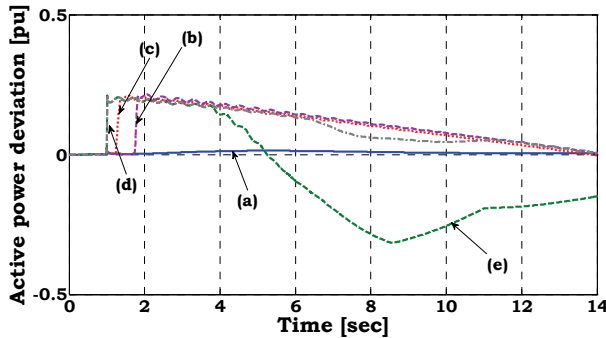


Fig. 36. Change in active power output after largest unit loss for different frequency control methods applied in DFIGs - (a) No auxiliary control, (b) Droop control on WF level, (c) Droop control on WT level, (d) Combined control, (e) Inertia control - SCENb

The largest conventional unit in the system produces 21 MW before the protection system acts to take it out of operation - this means production loss equal to 25 % of the total demand. The fault is severe and the power system stability is checked for all the frequency control schemes designed in this study.

Figure 37 illustrates the response of the three different wind turbine configurations available in the Rhodes power system, during the event, when no auxiliary control is activated in the DFIG wind farms. The comments made in section 2.2 are confirmed by the results (see also

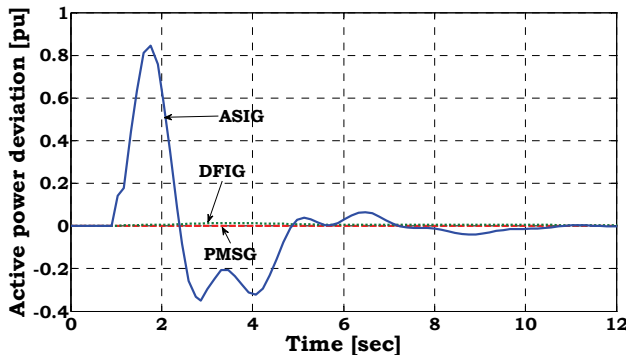


Fig. 37. Change in power in different wind turbine configurations during frequency drop - SCENc

Figure 32). Comparing to Figure 32, which demonstrates the response for SCENb, the contribution of the ASIG in SCENc is higher. The change in the active power production of the wind farm with ASIG wind turbines is higher than 0.8 pu compared to almost 0.2 p.u. in SCENb. This can be explained comparing the frequency response in both cases. In SCENb (see Figure 33 – case (a)), the frequency does not decrease as much as in SCENc (see Figure 38 – case (b)), therefore, the rotor of the ASIG wind turbines decelerates more in the first scenario, leading to higher active power contribution. In Figure 37 the response of wind farms equipped with DFIG or PMSG wind turbines is almost negligible, as explained in section 2.2.

In Figures 38 and 39 the system frequency for all the different frequency control schemes implemented in the wind farms A1 and A2 (see Table 2) is shown. In this scenario, the minimum frequency following the event is very low compared to SCENb, whereas the maximum rate of change of frequency is significantly higher.

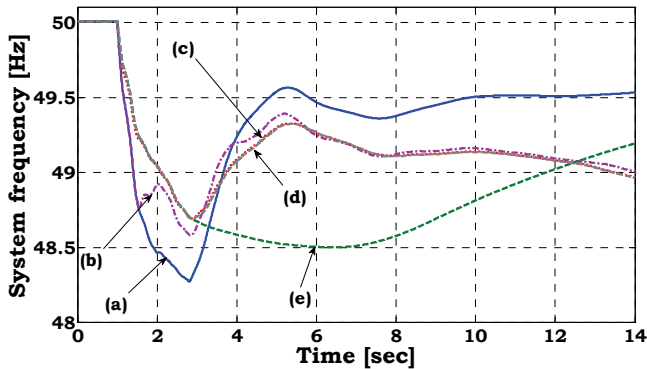


Fig. 38. System frequency for largest unit loss when frequency control is applied by DFIGs - (a) No auxiliary control, (b) Droop control on WF level, (c) Droop control on WT level, (d) Combined control, (e) Inertia control - SCENc

In case (a), when the wind farms do not have auxiliary frequency control, the frequency drops below 48.5 Hz which is the upper zone of the under-frequency protection relay settings acting on the loads. This drop leads to disconnection of 15.1 MW of load – 18 % of the total demand. This load shedding is not considered accepted in terms of dynamic security terms, (Margaris et al. 2009). However, in all the other cases, where the frequency control is activated in the DFIG wind farms, the load shedding is avoided totally. The maximum frequency drop appears in case (e), where the inertia controller is used. The optimum frequency drop in terms of minimum frequency is achieved in cases (c) and (d), thus when either Droop control is implemented on the wind turbine control level (case (c)) or when the Combined control is used (case (d)).

In this scenario, the effect of auxiliary frequency control on the maximum rate of change of frequency is very crucial. As illustrated in Figure 39, where the initial drop of the frequency for all cases is zoomed in, and as summarized also in Table 4, this rate is very high compared to SCENb (see also Table 3). The inertia of the system in this case is lower because the number of the conventional generators connected to the system in SCENc, and which are the ones determining the system inertia in large percentage, are reduced.

The rate of change of frequency is close to 2.8 Hz/sec (in absolute value) in cases (a) and (b), although in the last case the minimum frequency does not drop below 48.5 Hz. Inertia control manages to reduce the rate to less than 1.8 Hz/sec, which is the highest rate among all the cases. Here also, as explained for SCENb above, the Combined control seems to be the best compromise in terms of minimum frequency and maximum rate of change.

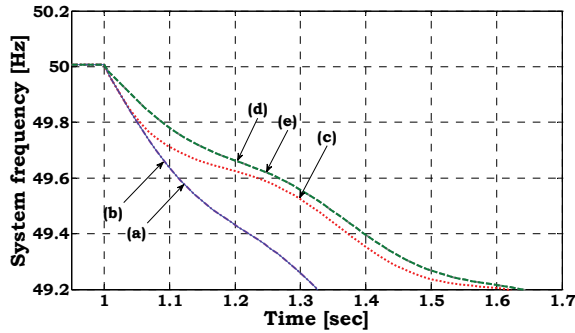


Fig. 39. System frequency for largest unit loss when frequency control is applied by DFIGs - Zoom in the first seconds after the event (a) No auxiliary control, (b) Droop control on WF level, (c) Droop control on WT level, (d) Combined control, (e) Inertia control - SCENc

| Frequency Control Scheme | | Minimum Frequency (Hz) | Maximum Rate of change of frequency (Hz/sec) | Load Shedding (MW) |
|--------------------------|---------------------------|------------------------|--|--------------------|
| (a) | No auxiliary control | 48.28 | -5 | 15.1 |
| (b) | Droop control on WF level | 48.58 | -5 | 0 |
| (c) | Droop control on WT level | 48.69 | -5 | 0 |
| (d) | Combined control | 48.69 | -3.8 | 0 |
| (e) | Inertia control | 48.50 | -3.8 | 0 |

Table 4. Results for SCENc - loss of largest infeed

Figure 40 and Figure 41 show respectively the rotor speed deviation and the change in active power output for wind farm A1, during the frequency drop. The comments made in SCENb are also valid here, regarding the differences among the various frequency control schemes. However, looking at the active power produced by the wind farm A1 in SCENc the contribution of the wind farms is more significant during the primary frequency response. The rotor deceleration is higher, thus more kinetic energy from the rotor mass is delivered to the grid as active power.

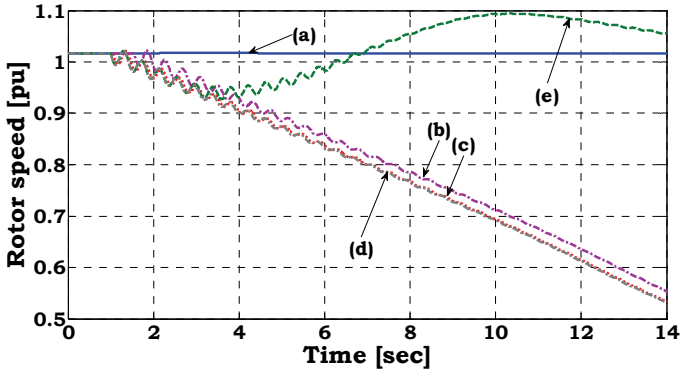


Fig. 40. Rotor speed deviations after largest unit loss for different frequency control methods applied in DFIGs - (a) No auxiliary control, (b) Droop control on WF level, (c) Droop control on WT level, (d) Combined control, (e) Inertia control - SCENc

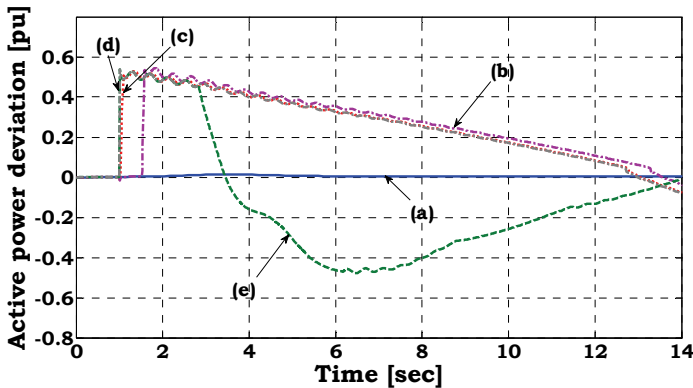


Fig. 41. Change in active power output after largest unit loss for different frequency control methods applied in DFIGs - (a) No auxiliary control, (b) Droop control on WF level, (c) Droop control on WT level, (d) Combined control, (e) Inertia control - SCENc

In the last part of the results section, comparative results will be shown for SCENb between the cases, where Combined frequency control is implemented only in one wind farm and the later, where the control is incorporated in both wind farms with DFIG wind turbines. All

the results presented previously are extracted when both wind farms A1 and A2 have this frequency control capability.

As shown in Figure 42 and also summarized in Table 5 below, in case (d1) only wind farm A1 provides auxiliary frequency control leading to bigger frequency drop and higher rate of

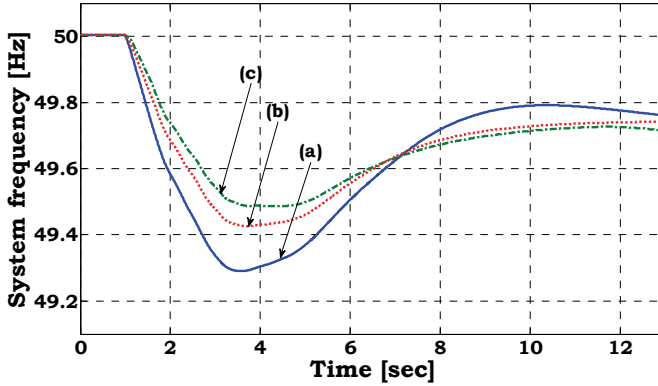


Fig. 42. System frequency for largest unit loss for different frequency control methods applied in DFIGs - (a) No auxiliary control, (b) Combined control provided by only one wind farm (c) Combined control provided by two wind farms

| Frequency Control Scheme | | Minimum Frequency (Hz) | Maximum Rate of change of frequency (Hz/sec) | Load Shedding (MW) |
|--------------------------|---|------------------------|--|--------------------|
| (a) | No auxiliary control | 49.29 | -0.48 | 0 |
| (b) | Combined control through one wind farm | 49.43 | -0.4 | 0 |
| (c) | Combined control through two wind farms | 49.49 | -0.36 | 0 |

Table 5. Results for SCENb – loss of largest infeed

change of frequency compared to case (d2) where also wind farm A2 is equipped with this control capability. Thus, the inertia of the system, including the “virtual” inertia provided by the DFIG wind turbines, is obviously reduced when the proportion of the wind turbines providing auxiliary control is smaller. It is noted here, that in this comparison the Combined control method was chosen, as it is concluded by the previous results that this scheme achieves the best performance among the other proposed ones.

The conclusions from all the results presented in this section will be summarized in the next session, where also discussion on the expansion of the maximum allowed penetration in autonomous systems, like Rhodes, is made.

5. Conclusions

This chapter presented a detailed investigation of Rhodes power system dynamic security in the case of reference year 2012, when large wind farms are expected to be connected to the island. The conventional units, including Automatic Voltage Regulators and Speed Governors, were modeled in detail. The response of the governors during dynamic phenomena in the system is essential for the overall response. Especially the emergency rate of power undertake by the all different kinds of units i.e. steam, gas and diesel plants, is a major factor defining the overall system operation. The presented models includes also the models of the five wind farms which are connected in the system, comprising detailed models for three different wind turbine technologies – namely Doubly Fed Induction Generator (DFIG), Permanent Magnet Synchronous Generator (PMSG) and Active Stall Induction Generator (ASIG) based wind turbines.

Different load scenarios, relevant for the island operation, are analyzed, such as maximum wind power penetration scenario, maximum wind power production scenario and maximum load demand scenario.

In many non-interconnected systems the penetration of wind power has started to reach the boundaries of 30%. Serious concerns are expressed by the operators of these systems and wind fluctuations are one of the aspects that has to be evaluated before expanding the penetration levels, (Margaris et al., 2011). From the results, it is concluded that even in the worst case scenario, the Maximum Wind Power Penetration, the frequency fluctuations resulting from the wind speed fluctuations are not considered to pose security questions for the power system. However, the impact of wind variations is obvious in the system frequency and the correlation between wind speeds and system frequency has to be always investigated before reviewing the penetration levels.

Increased wind power penetration does not only limit the ability of thermal plants to undertake power, but also limits inertia. Systems inertia in cases of increased wind penetration is crucial for system stability as it defines the rate of frequency drop. The designed models for the conventional units in Rhodes power system, were sufficient to undertake power despite the rapid wind changes and the resulting active power fluctuations delivered by the wind farms. This study has proven that, when it comes to wind power fluctuations, the penetration levels of wind power can be expanded beyond 30% of the load.

Another issue, which should be remarked, is that the increased wind power penetration does not only limit the ability of thermal plants to undertake power, but also the inertia of

the system. Systems inertia in cases with increased wind penetration is crucial for system stability, as it defines the rate of frequency drop.

The second part of the investigations provided a survey on frequency control issues of the autonomous power system with high wind power penetration, (Margaris et al., 2011). Frequency response during severe faults, i.e. the sudden loss of the biggest conventional generator, was simulated for two different load scenarios. These scenarios correspond to different system inertia but also to different operating points of the wind turbines. The wind turbines have different response when the system frequency varies, depending on the specific electrical configuration characteristics. Although the fixed speed ones contribute to the system inertia during frequency phenomena, this is not the case for DFIG and PMSG wind turbines, where the rotor is partially or totally detached from the system frequency respectively. The under-frequency protection system acting on the loads connected to MV substations can measure either the rate of change of frequency or the actual frequency to act on the relays. Modeling the protection system in the power system provides more accurate results regarding the load shedding, a variable that defines the dynamic security level of a system. As wind power penetration is increasing in modern power systems, the wind turbines have to contribute to the frequency stability of the system, acting similar to conventional power plants. In this article, three different frequency control schemes were investigated to enhance the primary frequency support of DFIG wind turbines. Simulation ended up to the following conclusions:

Non interconnected systems face the problem of decreased system inertia, especially when wind farms tend to substitute conventional units under increasing wind power penetration conditions. The DFIG wind turbines can be equipped with auxiliary Inertia control, providing with valuable inertia response during the first seconds following the frequency event. This control, reestablishes in the DFIG wind turbines the intrinsic characteristic of the fixed speed ASIG wind turbines, thus, using the kinetic energy accumulated in the rotor mass to support the grid during frequency variations.

Additional control methods can also be used in DFIG wind turbines, like Droop control used in conventional generators providing primary frequency support. The case, where the Droop control is implemented in the wind farm control level, instead of the turbine level, was also investigated to check the effect of communication delay in the response of the wind farm. Although when the Inertia control is used, the rate of change of frequency is significantly reduced, the Droop control seems to benefit more power system when looking at the minimum frequency after the event.

A Combined control, where both Inertia and Droop control schemes are used, was incorporated in the model. This last method manages to combine the positive effects of both methods, improving not only the initial rate of change of frequency after the fault but also ensuring lower frequency drop.

In some cases, when wind power production is higher than 30 % of the total demand, the auxiliary frequency control implemented in two wind farms in the Rhodes power system, manages to avoid load shedding totally. Therefore, the rule of thumb of 30 % penetration, which is often used in autonomous power systems, can be further expanded as long as auxiliary frequency control is provided by wind farms.

The benefits of the primary frequency support from modern wind turbines increase as the number of the turbines with this capability rises. This means that, if all new wind farms

installed in autonomous power systems are equipped with primary frequency control capability, the frequency stability can be ensured even for penetration levels that today are hard to consider.

From the wind turbine side, in some cases the turbine may be forced to operate away from the maximum power-tracking curve, which means economic cost for the wind farm. So, before the system operators set any requirements for frequency control, the economic costs of frequency control for the wind turbine owner should be addressed.

The review of the frequency protection system settings can be done, as long as the frequency stability of the system is ensured. In many cases, the protection settings are quite sensitive and large amounts of load are cut off. The review of the protection system in modern power systems has to follow the progress made in the wind farms' capability to support the grid during disturbances.

Although, technology such as flywheels can support system inertia in autonomous power systems, advanced frequency control implemented in wind turbines will make it possible to achieve the penetration levels for wind power that today seem hard to reach.

There are some measures that can further enhance the dynamic security of systems like Rhodes:

The review of the frequency protection system settings can be done, if the dynamic security is ensured through FRT capability of wind farms online. The protection settings are quite sensitive and large amounts of load can be cut off just after the fault incident.

Systems like SVC or STATCOM for fast voltage control systems can guaranty the uninterrupted operation of wind parks, especially those consisting of fixed speed wind turbines. For instance, the substation, where most of these wind parks are connected, could be considered as the most appropriate for this installation. Under these conditions, wind power penetration could increase beyond 30% of the load, keeping the dynamic security of the system in the acceptable levels.

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