DISTRIBUTED GENERATION CONTROL FOR FREQUENCY SUPPORT

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ABSTRACT

This paper investigates a new technique that could be applied to control distributed generation units in an islanded distribution network to support frequency. The frequency control technique relies on slow communication in order to establish the units that are in operation. The magnitude of the disturbance is determined using the swing equation, thus obtaining this way a more efficient system operation during emergency conditions. Through optimisation, using the generators with spinning reserve the frequency could be maintained at acceptable limits.

INTRODUCTION

Much emphasis has been given on the promotion of economic incentives to support actions to cut down emissions and a possible solution is the use of renewable technologies and low-carbon distributed generation [1-3]. Defence plans for distribution power networks should therefore be applied and a basic defence may involve the primary frequency response which must be available within a small amount of time in the event of a major system disturbance isolating part of the distribution network [3-5]. This paper proposes a new frequency control method for the safe operation of an islanded distribution network. Conventional control methods of distributed generators connected to the network focus on maintaining constant power generation or constant power flow at the point of common coupling [6,7]. The proposed method introduces an approach to distributed generation management in which the scheme is online and based on the estimated magnitude of the disturbance.

FREQUENCY CONTROL SCHEME

The frequency control is presented in figure 1. The controller manages the downstream DG units depending on the area and can be used to accomplish frequency stability in case of network islanding. The scheme design considers the following problems:

1) Estimation of the magnitude of the disturbance
2) Location of disconnection
3) Control action taken by individual DG units

The first two problems are related and will be solved using the generator swing equation.

$$2H\dot{\omega} = P_m - P_e \tag{1}$$

where H is the generator's inertia constant in seconds, P_m and P_e are respectively mechanical and electrical power normalised to that same VA base, and ω is the electrical angular velocity or frequency in per unit values. For a system having N machines in operation we have:

$$2H_{system}\dot{\omega}_{system} = P_{m\_system} - P_{e\_system} = P_a$$

$$2H_{system}\frac{df_{system}/dt}{f_n} = P_a \tag{2}$$

where H_{system}, P_{mi} and P_{ei} are based on system base VA $S_{Bsystem}$. We define the system inertia constant H_{system} in relation to system angular frequency ω_{system}, system mechanical power P_{m_system}, and system electrical power P_{e_system}.

$$H_{system} = \sum_{i=1}^{N} H_i = \sum_{i=1}^{N} H_{machine}\left(\frac{S_{Bmachine}}{S_{Bsystem}}\right) \tag{3}$$

$$\omega_{system} = \frac{\sum_{i=1}^{N}(H_i\omega_i)}{\sum_{i=1}^{N} H_i} \tag{4}$$

$$P_{m\_system} = \sum_{i=1}^{N} P_{mi} \tag{5}$$

$$P_{e\_system} = \sum_{i=1}^{N} P_{ei} \tag{6}$$

In the first instant following a disturbance in the network, the accelerating power P_a consists of the disturbance P_D and the change in electrical power demand due to variation of the voltage and frequency.

$$P_a = P_D - \Delta P_e \tag{7}$$

To find the required amount of additional active power (P_a) to ensure that the system's steady frequency will stay above a preset value, the power is calculated using equation (2) and based on communication the distributed generation units that are participating in the production of power and

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contribute to the systems inertia (e.g synchronous generator and FSIG) will be enabled in the calculation. This information is transmitted to the central control unit prior to the disturbance using slow communication and immediately after the disturbance the additional power is calculated.
The algorithm is based on the generation costs of each DG unit and for this purpose is approximated using the quadratic equation. The optimisation is based on standard linear optimisation techniques and can generally be expressed as mathematical programs; involving a vector ***x*** depending of which DGs will participate in the optimisation, whose elements are required to be defined such that they minimise a cost function ***f(x)*** (8), the cost required for the additional power required.
The function is also subject to equality constrains, which include the required power to be equal to the power generated by all DGs participating and the inequality constraints which are the minimum and maximum power generated by the DGs.

$$\min f(x) = [A][c][x] \qquad (8)$$

$$\text{Subject to } \sum_{1}^{n} x = P_a \qquad (9)$$

$$[x] \geq [a]$$
$$[x] \leq [b] \qquad (10)$$

A is a vector of multipliers the enable the selection of the DGs that will participate in the optimisation
c is a vector of the cost functions of all DGs
x is a vector of generation set points to be evaluated
a is a vector of the minimum generation of each DG
b is a vector of the maximum generation of each DG

This optimisation when enabled is performed every ***Ts*** seconds and will provide the new setpoints required by each DG. The new set points will be sent to each DG and the distribution network will try to increase its power to that set point through the turbine system for the CHP, the deregulated power for the DFIG and pulse width modulation for the photovoltaic system. If the system frequency response for any reason does not operate as expected load shedding could be performed.

DISTRIBUTION NETWORK MODELLING

The test system used in this study is shown in figure 2. The network has long lines, including a sub-sea cable. The system is supplied by two 132 / 33 kV 30 MVA, Dy11 on load tap changing transformers which have 25% impedance. They regulate the voltage at the 33 kV side with 1.25% tap step over tapping range of 0.9-1.1 pu of nominal voltage. The system is modelled using the electromagnetic transient simulation program PSCAD.

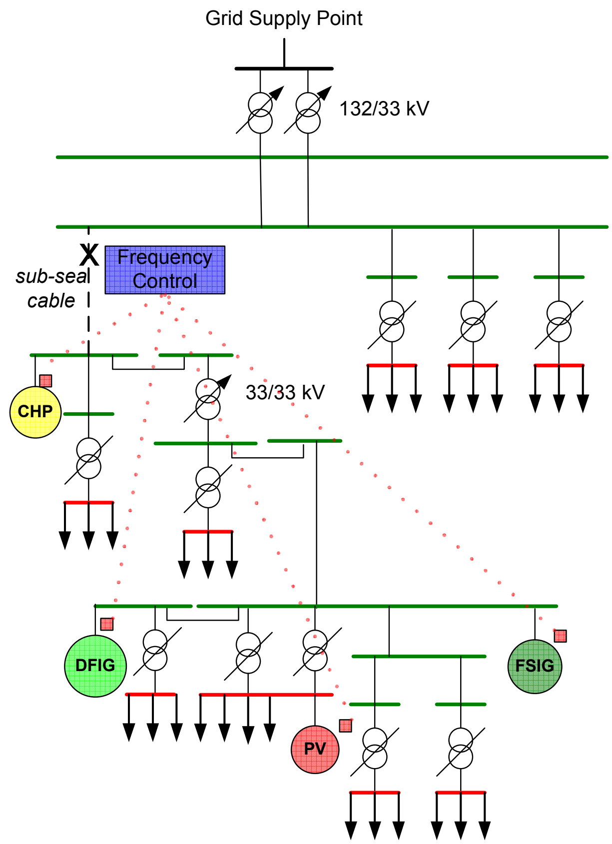

Figure 1. Frequency control architecture.

Synchronous Generator

The synchronous generator is simulated by the standard 5th order *d* and *q* dynamic model, already available in the library of PSCAD. The generator, 0.398 kV / 50 Hz, is driven by gas turbine unit modelled and equipped with automatic voltage regulator (AVR) represented by the IEEE

DFIG Based Wind Farm

The model is based on the steady-state power characteristics of the turbine. The DFIG model also includes the aerodynamic representation pitch control. Additional reactive power is provided by a fixed capacitor connected at the wind farm's terminals.

Converter Connected Generation

The photovoltaic complete system consists of modules together with a dc/dc converter, a dc/ac converter and a coupling inductance. Several PV modules are connected in a series and parallel in an array to obtain a suitable power rating.

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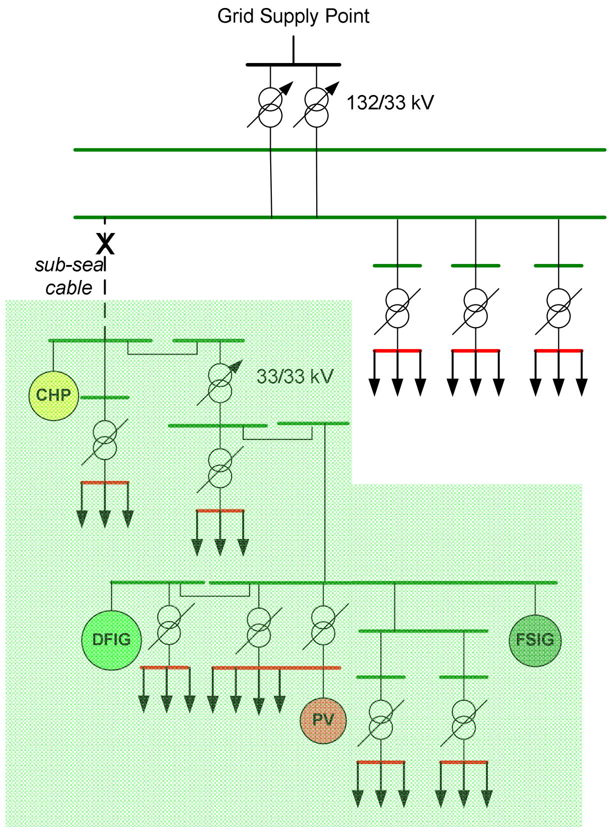

Figure 2. Single-line diagram of the 33 kV distribution network with different types of distributed generation.

COMPUTER SIMULATION RESULTS

The test case analysed shows a situation where the islanded network, shaded region in figure 2 containing the DGs is importing approximately 3 MW of active power from the upstream distribution network, in order to be able to supply the total load. Starting from this point, in steady-state, the subsea cable is disconnected at t = 50 s and the network will become islanded.

The system's frequency is continuously monitored by the frequency controller, every time interval T_s (sample time), and triggered by significant changes in frequency, the calculation in equation (2) will estimate the required active power.

$$\frac{df}{dt} = \frac{f_t - f_{t+T_s}}{T_s} \tag{8}$$

The rate of change of frequency based on "instantaneous" measurement of "df/dt" use a 3 cycles, filtered, "rolling" average technique. Using the average rate of change of frequency, when the measured frequency crosses the supervising frequency threshold a timer is initiated. At the end of this time period, T_s the frequency difference, $f_t - f_{t+Ts}$, is evaluated.

The results obtained show how the DG units contribute to the system stability following islanding. The system frequency responses to this scenario can be seen from the figure 3, 4, which also compares the response with and without the frequency controller. Right after the disconnection of the sub-sea cable, the frequency decreases abruptly and then recovers, although it has a steady state error of about 2 Hz and gradually decreases when the main DG unit has no governor action and when there is available governor action (enabled by the frequency controller) the frequency error is eliminated.

The frequency evolution with the central controller demonstrates the potential benefit of the algorithm in maintaining the frequency and voltage stability.

The maximum frequency reached in the simulations depends on the gains and time constant of the governor control of the synchronous machine connected to the distribution network. The minimum frequency reached in the simulation is affected by the following factors: inertia of islanded network, real power imported, the load type being supported by the DG's and the type of DG's supporting the load.

When the control is activated, figures 5-7, setpoints are being sent to the DG units being controlled. The CHP unit increases its power through the turbine action, the DFIG will increase its power through the reserve action employed by the pitch controller and the photovoltaic will also increase its power generation through its own control.

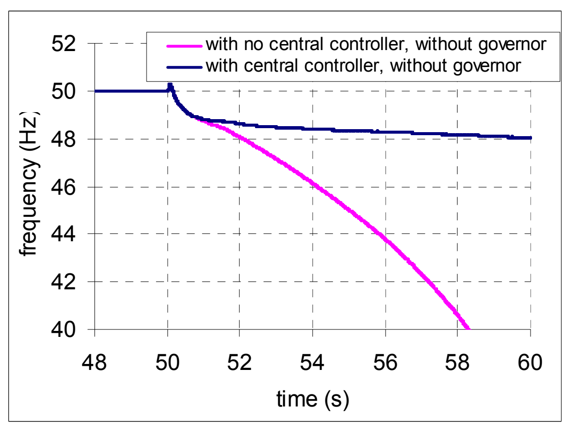

Figure 3. Frequency response with and without frequency controller (no governor on main unit).

CONCLUSIONS

In the event of an islanded distribution network; the frequency control scheme will be employed to reduce the impact of the imbalance in active power between connected load and generation. The frequency controller is initiated by

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frequency relays designed to measure the frequency against a threshold and then estimate the magnitude of the disturbance. Commands in the form of setpoints are sent by the central frequency controller depending on the DG units spinning reserve.
Through dynamic simulations of power systems, the sensitivity of the power system frequency and voltage response to the disturbance is investigated and discussed. The proposed load shedding scheme is designed to be optimal, however a backup plan also needs to be employed with load shedding in case of the scheme or of measuring elements within devices malfunction or the disturbance is larger than the spinning reserve of the DG units.

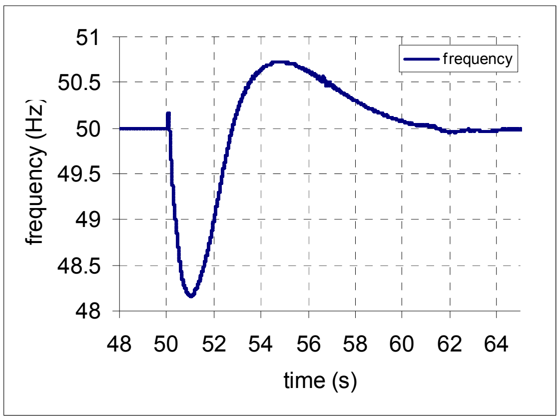

Figure 4. Frequency response with frequency controller (with governor on main unit).

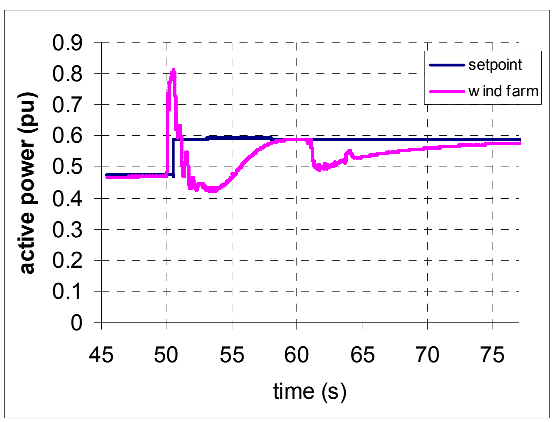

Figure 5. Setpoint and output power of windfarm unit.

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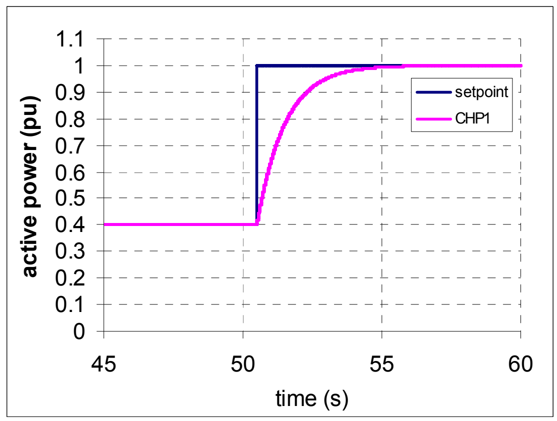

Figure 6. Setpoint and output power of CHP1 unit.

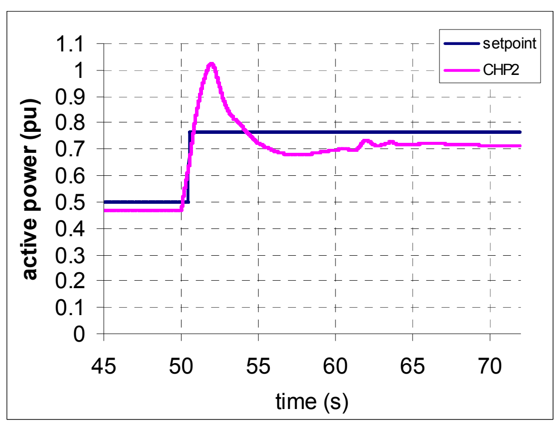

Figure 7. Setpoint and output power of CHP2 unit.

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