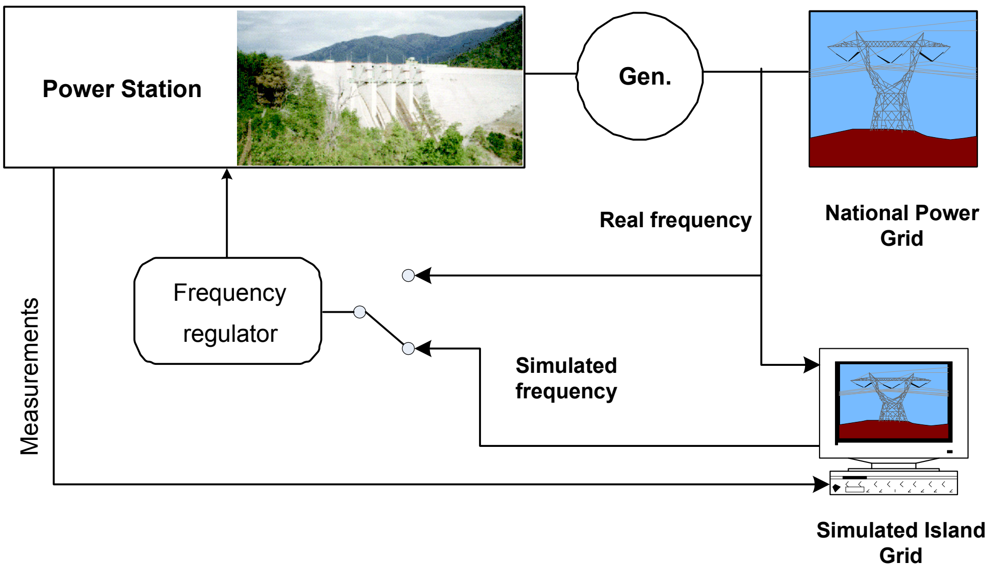

SolvSim Power Station tests in a grid with highly variable frequency

Master's Thesis in Electric Power Engineering

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Göteborg, Sweden 2014

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Göteborg, Sweden 2014

Abstract

SolvSim Power Station (SSPS) is a hard-ware-in-the-loop simulator that can be utilized to test and prepare power stations for island operation. SSPS has been successfully used in Sweden over the past decade. During the test, the power station remains connected to the grid without the need to establish an actual island system. SSPS requires the tested power station to be synchronized to a strong grid. The principle of SSPS is to replace the normal frequency feedback of the governor with a simulated frequency.
This thesis investigates the influence of grid frequency variation on the test. Two scenarios of frequency variation is considered; 1) spontaneous frequency variation in large grid 2) grid frequency variations as a consequence of the test.
In this thesis, a model of a power station connected to a grid with a variable frequency is implemented. SSPS tests are performed on the power station using a model of SSPS. The results of this thesis demonstrates that SSPS is dependent on the rate of change of frequency (RoCoF) of the grid rather active power output of the generating is used as an input during the test. The results also show that the influence of grid frequency variation on SSPS tests is insignificant for both scenarios.

Index terms: SolvSim Power Station, Island operation, Network simulator, Synchronous generator.

Acknowledgements

This thesis has been carried out at Solvina AB and Department of Energy & Environment at Chalmers University of Technology. I would like to thank everybody at Solvina AB especially Bengt Johansson for his valuable comments and advice. I'm also thankful toward my supervisor at Solvina, Sven Granfors, for his indispensable help and interesting discussions.

A special thanks to my examiner at Chalmers, Tuan Le, for his feedback on the work and the report. I would also like to thank everyone at the department of electric power for their interesting courses and always being available for help.

Finally, I would like to thank my family and friends for their support and encouragement throughout the years.

Rebaz Ahmed, Göteborg - 2014

Contents

List of abbreviations and symbols

ΔP	Mismatch between mechanical and electrical power [MW]
ω	Angular velocity [rad/s]
ω_{FL}	Angular velocity at no load [rad/s]
ω_{NL}	Angular velocity at full load [rad/s]
E_{rot}	Rotational energy [MWs]
f	Frequency [Hz]
f_0	Nominal frequency [Hz]
H	Inertia constant [s]
i_f	Field current [A]
i_s	Stator current [A]
J	Moment of inertia [kgm^2]
L_m	Mutual inductance [H]
L_s	Stator inductance [H]
P_C	Consumed active power [MW]
P_e	Electric power [MW]
P_G	Generated active power [MW]
P_m	Mechanical power [MW]
U_f	Field voltage [V]
U_s	Stator voltage [V]

X_s	Synchronous inductance [pu]
AGC	Automatic Generation Control
HVDC	High-voltage direct current
PID	Proportional Integrating Derivative
RoCoF	Rate of change of frequency [Hz/s]

1

Introduction

1.1 Background

The modern power system is designed to withstand multiple contingencies. However, in extreme situations establishing electrical islands throughout the power system might be necessary. The initiating event is usually a contingency not covered by normal design criteria such as tripping of several transmission lines, loss of synchronism between areas in the network etc. In such a situation the power quality, in terms of frequency and voltage, will depend entirely on the power stations in the electrical islands. Normally, all power stations are connected to the power system and many power stations are operated with governor deadband making them insensitive to small frequency deviation that occurs during normal operation. This leaves the task of frequency regulation to other power stations in the power system. In an event of dividing the system into electrical islands the frequency controller of the power stations inside the electrical island will have to activate their governor and assume responsibility for the network frequency.

Computer simulation has been available for many years to analyze the behavior of the system. Relying solely on simulation to understand the behavior of the system in island operation is not sufficient since simulation is often based on the theoretical behaviour of the system. The limitation of computer simulation is that the theoretical behaviour of the system might not accurately represent the actual system due to ageing or operation settings.

For the reasons mentioned above, field tests are required. Previously the only way to perform these tests was to establish electrical islands. Dividing the system in electrical islands to perform field tests is costly and involves taking risks with the systems which in worst case could lead to a complete blackout. As these tests are risky and costly they are often not performed.

For this purpose Solvina AB has developed SolvSim Power Station (SSPS). SSPS is a hardware-in-the-loop simulator which combines real-time simulation with actual tests. SSPS allows power stations to be tested for island operation without being disconnected from the grid. SSPS utilizes simulation to simulate the electrical island and the simulated frequency of the electrical island is sensed by the governor the power station under the test. The operating principle of SSPS is described in Chapter 3.

1.2 Problem description

When performing tests on power stations using SSPS, the power station remains synchronized to the grid and the test is performed during the normal operation. SSPS has been successfully used in Sweden for many years [1]. SSPS tests can only be performed on power stations that are synchronized to a large power system. The Nordic power system is strong enough to keep the system frequency at a relatively constant level even though the power output of the tested power station changes during these tests performed for their power station. Other countries with high penetration of wind power, such as Ireland, have shown interest in having these tests. This raises the question whether SSPS will be able perform these tests if the frequency of the grid to which was to change to a large extent during the test.

1.3 Aim

It has been demonstrated that SSPS is applicable on power stations that are synchronized to a strong grid [1]. The aim of this thesis is to investigate the influence of large frequency variations on SSPS tests. The grid frequency variations may be due to poorly regulated power system or a consequence of the performed test.

1.4 Simulation tool and scope

To achieve the aim of this thesis, a model of a power station connected to a grid is implemented in SIMULINK®. The next step is to perform SSPS tests on the power station under different scenarios. Finally, concluding remarks are made based on the results of the simulations.

Only the frequency variation of the grid will be considered for this thesis, all voltage magnitudes are assumed to remain constant at all times.

2

Technical background

2.1 Power system stability

One of the problems of stability is concerning with the loss of synchronism since power systems rely on synchronous machines for generation of electric power. A condition for stable operation is that all machines should remain in synchronism. Instability may also occur due to load voltage collapse, this form of instability occurs mainly due to loads that are consuming substantial amounts of reactive power such as induction machines.

The stability of the system is related to the behavior of the synchronous machines in the system. The rotor winding of a synchronous machine is excited by direct current [2]. Synchronous generators are driven by prime movers at the synchronous speed, and thus a balanced three-phase voltage and currents are induced in the stator windings with the same frequency as the rotor windings [3]. In power systems, with many machines interconnected, the stator voltages and currents of all the machines must be synchronized. To achieve this, the rotor of all synchronous machines in an interconnected system must be driven at the synchronous speed.

For purpose of analysis, stability problems are generally classified into two categories - *small-signal stability* and *transient stability* [2]. Small-signal stability is concerned with small and slow disturbances lasting for a long time. Such disturbances occur on regular basis in a power system due to variation in loads and generation. In this context, small disturbance is defined as a disturbance that can described by linearized equations. The swing equation is non-linear function of the power angle. For small changes in the rotor angle, the swing equation can be linearized with very little loss of accuracy [3]. Transient stability deals with the power system ability to maintain synchronism after being subjected to a severe and sudden disturbance such as load rejection, islanding or outage of a line [2].

2.2 Synchronous generator

Synchronous generators are dominating type of generators in power systems [2]-[3]. Synchronous generators can produce active power and reactive power independently from one another; they are sometimes used to solely produce reactive power for voltage controlling purposes. The rotor of a generator may be driven by hydro turbines, steam turbines or gas turbines at the synchronous speed. The armature windings are designed for high voltages and currents which require mechanical strength and insulation. For this reason, armature windings are placed in the stationary part of the generator known as *stator*. The armature winding are placed 120° apart on the stator to produce a balanced three-phase voltage and to develop the same number of magnetic poles as the field winding [3]. The field winding is placed on the rotor and is excited by direct current. A balanced three-phase current in the armature will produce a magnetic field in the air-gap rotating at the synchronous speed. To produce a steady torque [2], the rotor must rotate at precisely the synchronous speed. The rotor shape is usually round or salient depending on the speed. Round rotors are used for high speed generator; these generators are driven by steam or gas turbines. Generators with salient poles are used in hydro stations where the speed of prime movers is low. These generators have high number of poles since hydro turbines rotate at low speeds. The required number of poles is determined by the speed of the prime mover and the synchronous frequency.

To develop mathematical model of a synchronous generator, the following assumption are made [2]-[4]:

- The stator windings are symmetrically distributed.
- There are no zero-sequence currents in balanced operations.
- Magnetic hysteresis is neglected.
- The inductances do not depend on the current i.e. no saturation.
- The change in the stator inductance with the rotor position is sinusoidal.

The electrical circuit for a synchronous machine used for power system analysis is shown in Figure 2.1. By using *dq0*-transformation [4], the three-phases can be simplified into new variables that rotate with the same speed as the rotor. The transformation used in this is Power Invariant Transformation [2]. The equations for three-phase transformation is presented in Appendix A. The transformed variables are called direct- and quadrature axis. The angle θ in Figure 2.1 is the transformation angle. The electrical model is sixth-order state-space model which accounts for stator, rotor and damper windings.

The electrical dynamic performance of a synchronous machine shown in Figure 2.1 [2] can be described by equations from (2.1) to (2.5). The model assumes that the current flows out of the stator windings.

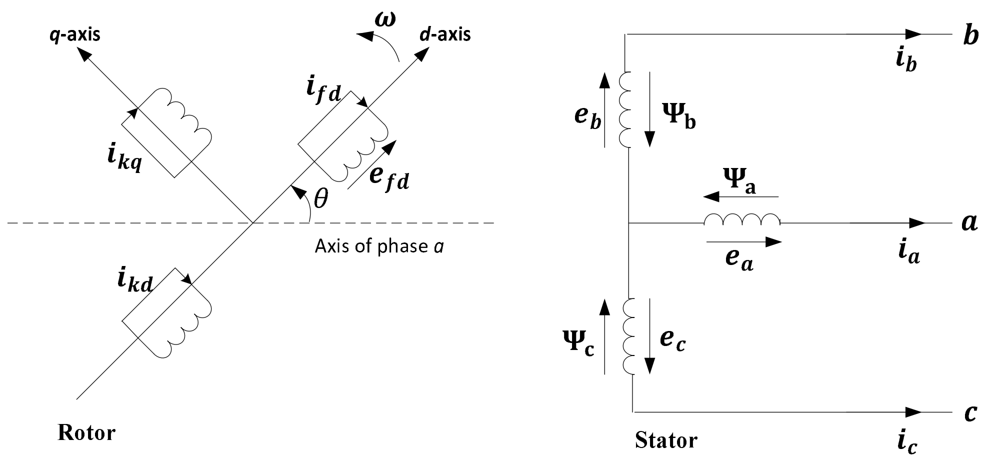

Figure 2.1: Electrical model for synchronous generator.

Per unit stator voltage equations

$$
\begin{aligned}
U_{sd} &= \frac{1}{\omega_{base}} \frac{d\psi_{sd}}{dt} - \omega_r \psi_q - R_s i_d \\
U_{sq} &= \frac{1}{\omega_{base}} \frac{d\psi_{sq}}{dt} - \omega_r \psi_{sd} - R_s i_q
\end{aligned}
\tag{2.1}
$$

U_d, U_q, i_{sq}, i_{sq}, ψ_d and ψ_q are the dq-components of the stator voltage, current and flux linkage. R_s is the stator resistance and ω_r is the rotor speed.

Per unit rotor voltage equations

$$
\begin{aligned}
U_{fd} &= \frac{1}{\omega_{base}} \frac{d\psi_{fd}}{dt} + R_{fd} i_{fd} \\
0 &= \frac{1}{\omega_{base}} \frac{d\psi_{1d}}{dt} + R_{1d} i_{1d} \\
0 &= \frac{1}{\omega_{base}} \frac{d\psi_{1q}}{dt} + R_{1q} i_{1q} \\
0 &= \frac{1}{\omega_{base}} \frac{d\psi_{2q}}{dt} + R_{2q} i_{2q}
\end{aligned}
\tag{2.2}
$$

The first equation in the rotor voltage equations represents the voltage of the field circuit. The rest are for the short-circuited damper windings in the rotor. The equations are valid when two q-axis damper winding are considered.

Per unit stator flux linkage equations

$$
\begin{aligned}
\psi_d &= -L_{sd} i_d + L_{md} i_{fd} + L_{md} i_{1d} \\
\psi_q &= -L_{sq} i_q + L_{mq} i_{1q} + L_{mq} i_{2d}
\end{aligned}
\tag{2.3}
$$

The subscript m of inductances is used for mutual inductance in the above equations.

Per unit rotor flux linkage

$$\begin{aligned}\psi_{fd} &= -L_{md}i_d + L_{fd}i_{fd} + L_{md}i_{1d}\\ \psi_{1d} &= -L_{md}i_q + L_{md}i_{fd} + L_{1d}i_{1d}\\ \psi_{1q} &= -L_{mq}i_q + L_{1q}i_{1q} + L_{mq}i_{2q}\\ \psi_{2q} &= -L_{mq}i_q + L_{mq}i_{1q} + L_{2q}i_{2q}\end{aligned} \tag{2.4}$$

Per unit electrical air-gap torque

$$T_e = \psi_{sd}i_{sq} - \psi sqi_{sd} \tag{2.5}$$

For stability studies, equations (2.1) to (2.5) are simplified to minimize computational efforts. For stability analysis in large connected system, the following assumptions are made [2][4]:

- The flux linkages in equation (2.1) to (2.4) are assumed to be constant in time.
- The effect of speed variation on voltages is neglected.
- The effect of saliency is neglected i.e. $X_s = X_d^{'} = X_q^{'}$.
- The effect of resistances is neglected.

Under steady state, the generator is represented by a constant voltage source behind a reactance. The reactance X_s in this model is known as the synchronous reactance. The model assumes constant field current. This model is known as the *Classical model* and it is only applicable under steady state conditions. A schematic overview of this model is shown in Figure 2.2 [2].

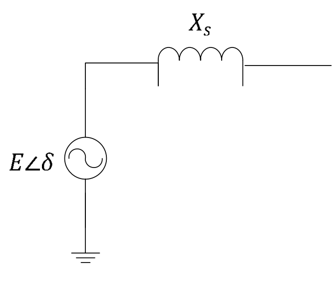

Figure 2.2: Electrical model for a synchronous generator.

For system stability analysis, it is of particular importance to describe the relation between electrical and mechanical power of individual generators. Under stable operation, the position of the rotor axis relative to the synchronously revolving field is fixed.

The angle between the rotor axis and revolving field is known as *power angle* [3], denoted δ. After being subjected to a disturbance, the power angle will decrease or decrease and an oscillatory motion begins. In order to maintain stability, the rotor has to lock back into synchronous speed after being subjected to such disturbance. This motion is described by equation (2.6) [3]. Equation (2.6) describes the behavior of a synchronous generator after being subjected to a disturbance, commonly known as the *swing equation* because it describes the swing of the rotor angle.

$$\frac{2H}{\omega_0}\frac{d^2\delta}{dt^2} = P_m - P_e \tag{2.6}$$

2.3 Energy balance

The frequency of a power system is the relation between the generated and consumed active power. To keep the frequency constant, the total active power generation and consumption should be in balance at any time. A change in active power balance is reflected instantaneously as a change in the electric power which in turn results in a mismatch in the active power balance. A mismatch in active power is reflected in the entire system by change in the system frequency since the frequency is a global factor.

For a power system, under steady-state operation with losses neglected

$$P_G = P_C \tag{2.7}$$

The rotating energy in all generators and motors in the power system is given by the law for rotation

$$E_{rot} = \frac{1}{2}J\omega^2 \tag{2.8}$$

J in equation (2.8) is the total inertia of all motors and generator in the system. An unbalance in active power causes change in the rotational energy [5], the changes can be described by

$$\frac{d}{dt}(\frac{1}{2}J\omega^2) = P_G - P_C \tag{2.9}$$

The total inertia J is normally quantified to a quantity known as the *inertia constant*, H, according to

$$H = \frac{1}{2}\frac{J\omega_0^2}{S_b} \tag{2.10}$$

The unit for H is MWs/MVA, but it is common practice to list it as s, which is valid for power factor of 1.

2.4 Power system control

Control of active and reactive power is required to sustain the power quality in the system. The main purpose of power system control is to maintain constant voltage and frequency in the power system. The frequency control is realized by controlling the active power flow while voltage control is by realized by controlling the reactive power. The flow of active and reactive power are fairly independent [2]-[3], therefor, active and reactive power are controlled separately.

Since the frequency in a power system is dependent on the active power balance, controlling the active power is vital. The active power control is realized by the speed governor. Figure 2.3 illustrates the concept of a speed governor for a generating unit supplying an isolated load [2].

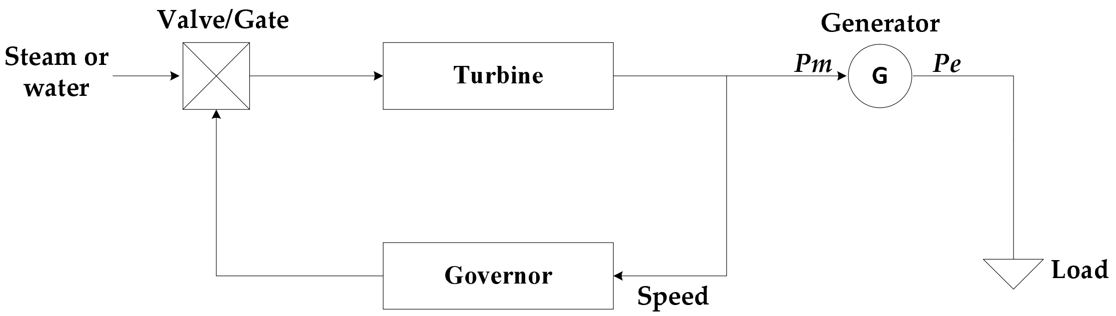

Figure 2.3: Generator supplying an isolated load.

In a power system, each generating unit is equipped with a speed governor which acts as the primary speed controller. An isochronous speed controller cannot be used when there is two or more generating units in the same system. Using isochronous governor when there is more than one generating unit would cause conflict between the governors since both would try to control the speed on its own setting. The governors are often provided with droop characteristic to allow small speed deviation as the load is increased. The value of droop characteristic, R, determines the steady-state speed with increasing output power. Figure 2.4 shows the characteristic of a governor equipped with speed droop[2].

In an interconnected system, the primary controllers are equipped with droop characteristic which results in a steady-state speed deviation. To restore the system frequency to the nominal value, an integrator is added which monitors the average error to overcome this offset. This scheme is known as *Automatic Generation Control* (AGC) and will automatically adjust the power active output with the continually changing loads in the system. The role of the AGC is to divide the loads to minimize the costs and also to maintain scheduled tie-line power interchange.

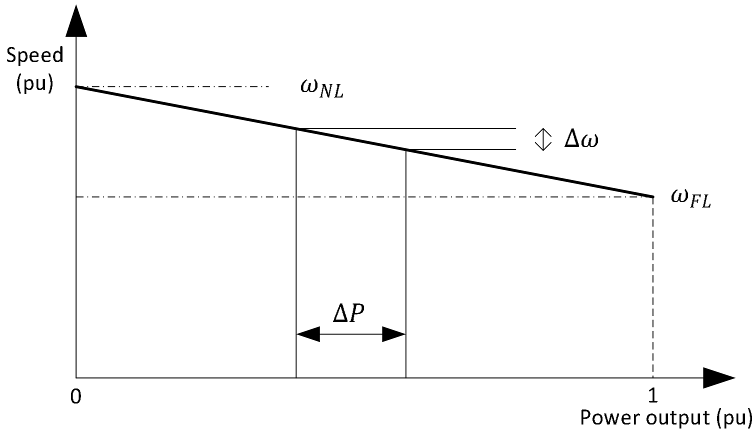

Figure 2.4: Characteristic of a governor with speed droop.

2.5 Island operation

Island operation is a mode of operation where a power system is divided to smaller networks. The term ”island operation” is normally not used to refer to physical islands where the power system is specifically designed for this type of operation. Dividing an interconnected power system to electrical islands is possible if the power system is designed and tuned for this purpose.

There are a number of challenges related to network frequency and voltage that need to be dealt with when a power system is divided into smaller electrical islands. Maintaining an acceptable frequency is the most challenging task as the total island system inertia is considerably smaller compared to normal operation. Lower inertia in a system results in much faster frequency deviation when there is an imbalance in active power according to equation (2.9).

After establishing electrical islands, the new system frequency will depend on the active power balance in the electrical islands. In *under-generated islands*, where the initial generation is less than the total loads, the frequency will decline. The frequency can be restored provided that there is sufficient spinning reserve and the generated power can be increased rapidly. For *over-generated islands*, where the initial of generation exceeds the loads, the frequency will increase. The speed governor should respond by reducing the generator input mechanical power to reduce the produced active power.

The frequency in an electrical island system can be illustrated by considering a generating unit supplying an isolated load as shown in Figure 2.5.

With losses neglected, the frequency response of Figure 2.5 is given by 2.11 [3].

$$f\frac{df}{dt} = \frac{f_0^2}{2H}(P_m - P_e) \tag{2.11}$$

For this type of operation, the primary speed control should act to stabilize the network frequency. The action of the supplementary control does not contribute to stabilizing the frequency since it is much slower than the primary speed controller. The

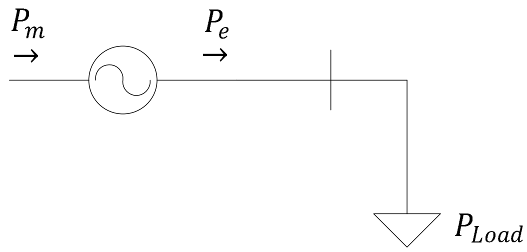

Figure 2.5: Generating unit supplying an isolated load.

function of the AGC in an electrical island is to restore the frequency to the nominal value since there is no need for maintaining power interchange [2].

3

SolvSim Power Station

SSPS is a test equipment that can be used to test all types of power station for island operation without being disconnected from the grid. The simulation technique is based on worked performed in [6]. Previously these types of tests have not been possible without establishing actual island systems which involves taking calculated risks. To minimize the risks when performing tests with SSPS, SSPS is equipped with safety mechanisms which are automatically activated and can also be manually activated by the operator.

The basic principle of SSPS is to replace the normal frequency feedback of the frequency controller by a real-time simulated frequency. An island network is simulated in SSPS and the frequency of the simulated island replaces the normal frequency feedback. A schematic overview on this is illustrated in Figure 3.1.

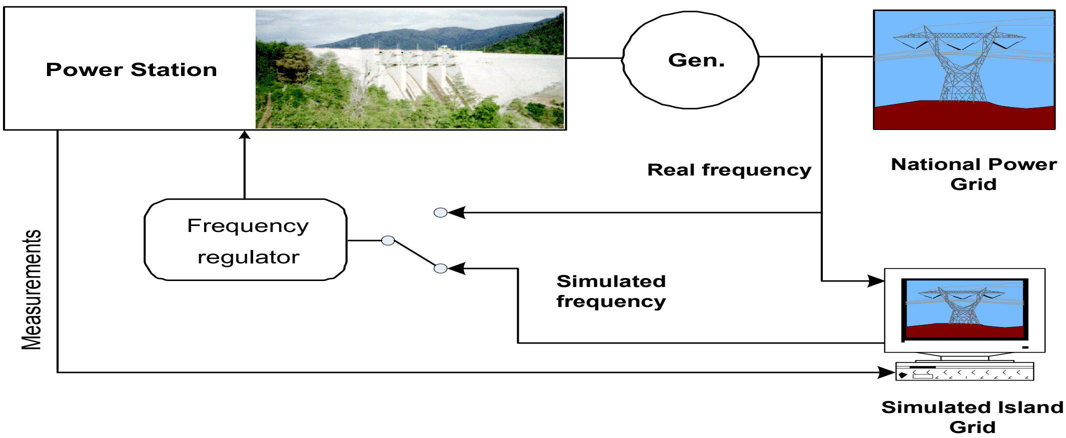

Figure 3.1: Operating principle of SSPS

3.1 Simulated island network

The simulated frequency can be arbitrarily varied by changing the simulated loads or the simulated power production sources in the simulated island. The response of the tested power station is observed mainly by the measuring the active power output of the power station being tested. The power station remains synchronized to the power system during and the influence of the change in the active power output of the power station is depending on the size of unit being tested compared to the power system.

The simulated island system in SSPS can include several generating units with speed governors, turbines, boilers or water conduits depending on the type of the power station. There is also possibility to include HVDC links with frequency control capability in the simulation. Loads with frequency dependency and load shedding schemes can also be included in the simulation. The frequency in the island system is principally calculated according Figure 3.2 [7].

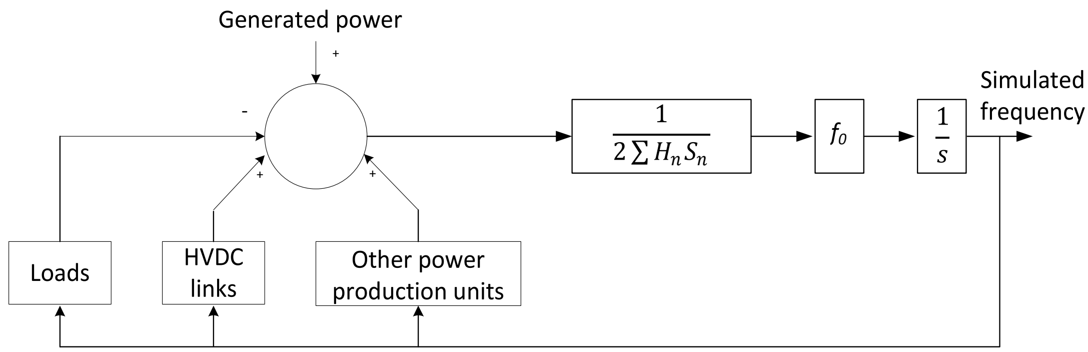

Figure 3.2: Simulated island network.

According to equation (2.11), the mechanical power is needed to calculate the frequency in an isolated system but since the mechanical power is usually not measured, its assumed to be equal to the active power output. This assumption is valid since the power station remains synchronized to the power system during the test. When a generating unit is synchronized to a power system; frequency controller action only changes the power output[2], it has only minor effect on the system frequency.

During the test many critical parameters are monitored including output power, temperatures, grid frequency and voltages. The purpose of monitoring these parameters is to minimize the risk of tripping the tested unit or damage the power station. The test is aborted if the grid frequency below a certain value to make sure that the test does not cause havoc in the network.

3.2 Results from an actual test

A small section from a field test performed by SSPS on a power station in Sweden is illustrated in Figure 3.4 and 3.3. At time = 356 s a step of 10 MW is made in the simulated load which is reflected in the simulated frequency. The simulated frequency is sensed by the governor which responds by increasing the mechanical power. The mechanical power is converted to electrical power by the generator in the tested unit as shown in Figure 3.3. When the active power output is equal to the simulated load, the simulated frequency stabilizes. The variations in the simulated load are due to the frequency dependency of the simulated load. During this test, as shown in Figure 3.4, the influence of the active power output of the tested on the grid frequency is marginal.

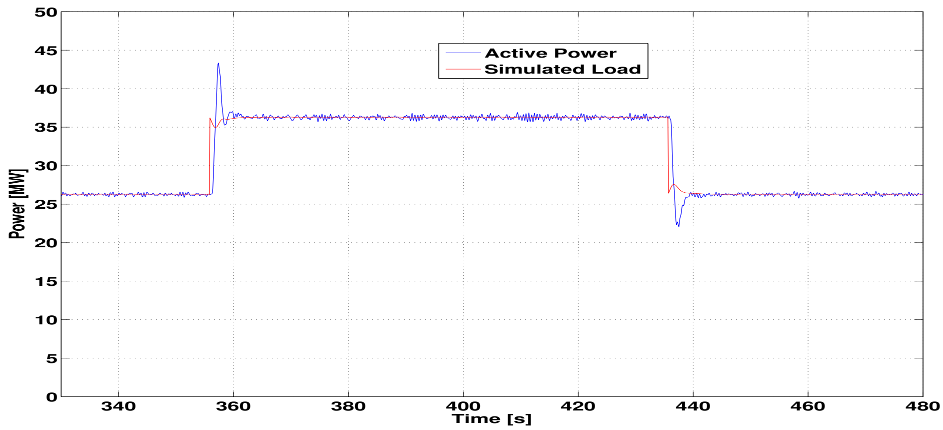

Figure 3.3: Active power output and simulated load.

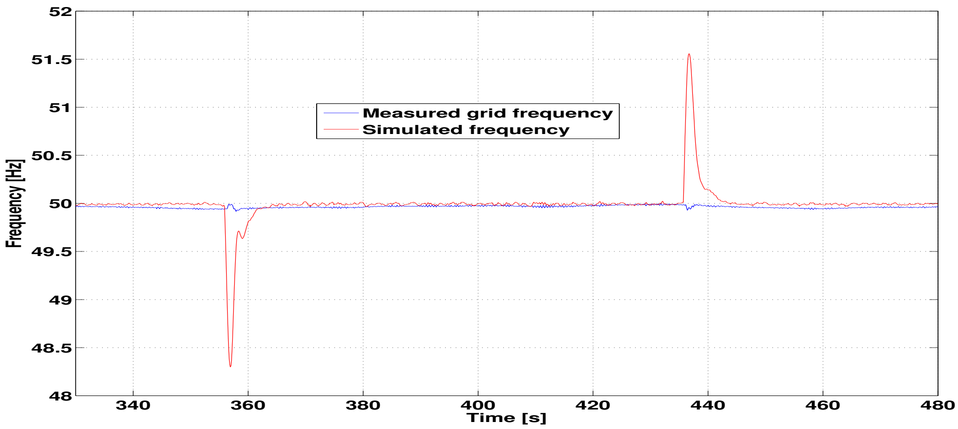

Figure 3.4: Real network frequency and simulated frequency

4

Simulink implementation of the simulation model

Tests performed with SolvSim Power Station are made on power stations operating at steady state while being synchronized to a grid. For a generating unit connected to a grid, the only information exchange between a power station and the grid is given by the electric coupling in terms of voltage and frequency of the grid at the point of delivery. In effect, the simulated model can be simplified to a small-signal stability model since during normal operation it is reasonable to assume that the grid frequency deviation is small and slow. Grid frequency deviations are slow due to presence of electrical machines which contribute to the total system inertia.

A general configuration of a generating unit connected through transmission lines to a large system is shown in Figure 4.1 [2].

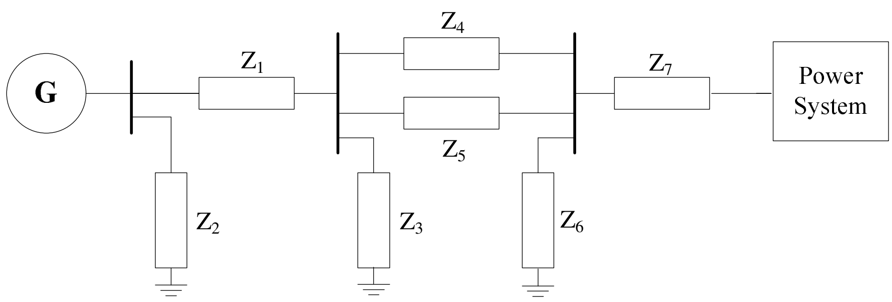

Figure 4.1: Generating unit connected to a power grid.

For analysis it is convenient to reduce the system shown in Figure 4.1 by applying Thévenin's theorem, the Thévenin equivalent is shown in Figure 4.2.

Since the frequency oscillation within the grid is not of interest for the test, it is ac-

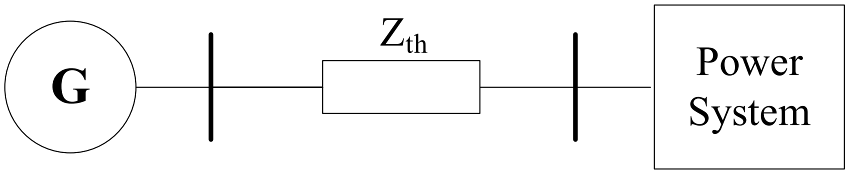

Figure 4.2: Thévenin equivalent of the system shown in Figure 4.1.

ceptable to model the grid as a voltage source behind a reactance [2]-[3]. The generators within the grid are assumed to be swinging in unison.

4.1 Generator model

For a generator represented by the *classical model* with all resistances neglected, the system representation is shown in Figure 4.3. All voltages magnitudes are assumed to remain constant and δ_1 is the power angle of the generator. E_B is the grid voltage with the angle δ_2. As the grid frequency changes, it is reflected in changes in δ_2.

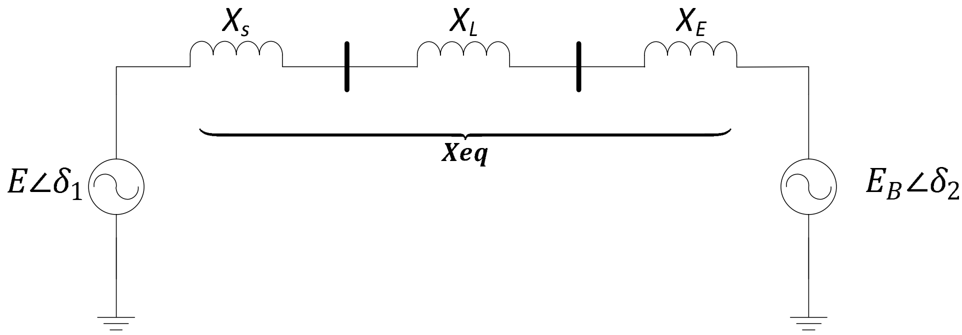

Figure 4.3: Electrical equivalent of Figure 4.2

With the resistances neglected, the active power exchanged with the grid is given by

$$P_e = \frac{EE_B}{X_{eq}} \sin(\delta_1 - \delta_2) \tag{4.1}$$

Applying the swing equation of a synchronous machine for small perturbations gives [3]

$$\frac{d\Delta\omega_r}{dt} = \frac{1}{2H}(\Delta P_m - \Delta P_e - K_D \Delta\omega_r) \tag{4.2}$$

$$\frac{d\delta}{dt} = \omega_0 \Delta\omega_r \tag{4.3}$$

Where $\Delta\omega_r$ is the per unit speed deviation, H is the inertia constant expressed in s, K_D is the damping torque component and δ in equation (4.3) is $\delta_1 - \delta_2$ which is measured in electrical radians.

It is common practice in power system to consider the combined inertia of the generator and turbine as one rigid mass. The inertia constant H is the total combined inertia of the generator and turbine. Typical values for H are listed below[2].

Type of power station	H
Thermal	4.0 to 10.0
Hydraulic	2.0 to 4.0

Block diagram representation of equations (4.2) and (4.3) is shown in Figure 4.4. In Figure 4.4, s is the Laplace operator which replaces d/dt.

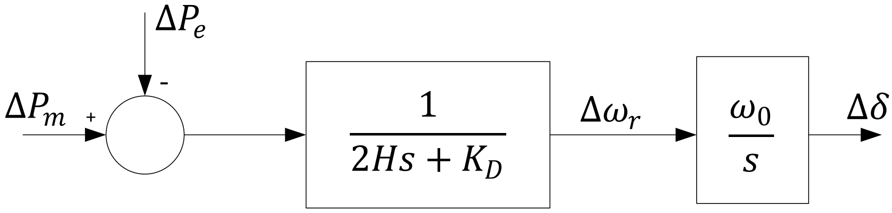

Figure 4.4: Block diagram of a synchronous generator.

4.2 Prime mover model

Prime movers are used to convert kinetic energy to mechanical energy which is converted to electric energy by synchronous generators. In a hydro-power station, the energy from falling or running water is converted into mechanical energy by means of turbines. Thermal energy is usually derived from fossil fuels or nuclear reactors are in turn converted into mechanical energy by turbines. Turbines can exhibit highly nonlinear behavior depending on the type and construction. Models of turbines are usually classified into different categories depending on their complexity. The linear models are used for small signal disturbances and are considered not sufficient for large-signal time-domain simulations involving large power and frequency variation [2],[8].

Since SSPS can be used on all types of power station and because the behavior of the turbine is not of interest for this project, the simplest possible representation of a turbine is used. The simplest representation for a turbine is the non-reheat steam turbine which can be represented by a low-pass filter [2]-[3] according to equation (4.4). This turbine model relates the changes in the steam valve position, ΔP_V, to changes in the mechanical power ΔP_m.

$$\frac{\Delta P_m}{\Delta P_V} = \frac{1}{1 + \tau s} \tag{4.4}$$

The value for the time constant τ is in the range 0.2 to 2.0 [3] seconds depending on the size and construction of the turbine. The block diagram for equation (4.4) is shown in Figure 4.5.

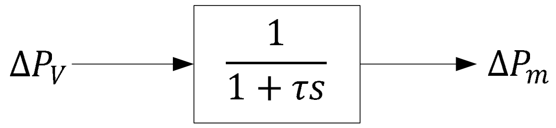

Figure 4.5: Block diagram of a simple non-reheat steam turbine.

4.3 Governor model

The main function of the governor is to regulate the generator speed which is the same as the frequency. When the load is increased, the electrical power exceeds the mechanical input power. This is supplied by the kinetic energy in the rotating mass which causes the speed to decay. The change in speed is sensed by the governor which acts to restore the speed to its nominal value.

Modern power stations use PID controllers to regulate speed or electric power output. Figure 4.6 illustrates a PID governor with a permanent droop R_p [2]. The proportional gain produces a control action proportional to the error. The integrating term contribution is determined by the size and duration of the error. The contribution of the derivative term is determined by the slope of the error. The permanent droop R_p in Figure 4.6 may also be obtained using the generator power output.

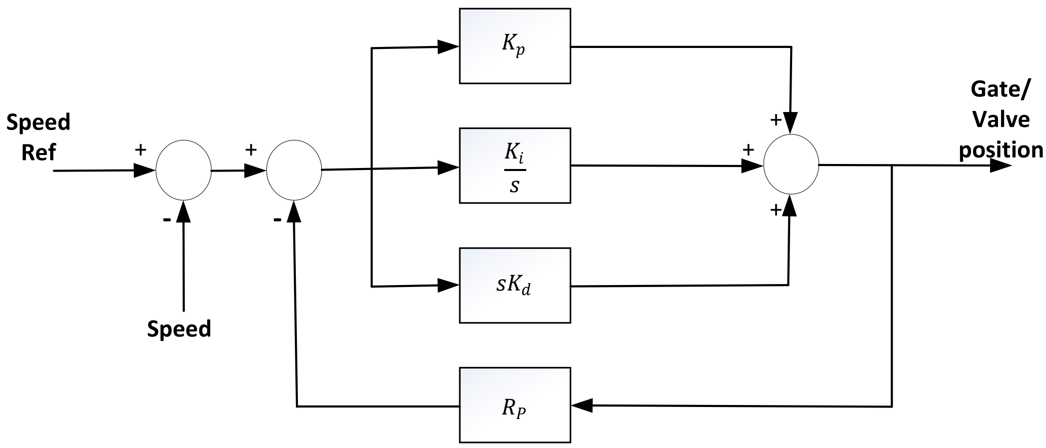

Figure 4.6: Block diagram of a PID governor with a permanent droop.

The transfer function of the PID governor is given by

$$\frac{y}{\omega_{ref} - \omega} = \frac{1}{R_p}\left(\frac{K_d s^2 + K_p s + K_i}{K_d s^2 + (K_p + \frac{1}{R_p})s + K_i}\right) \tag{4.5}$$

The parameter y in equation (4.5) is the gate/valve position.

For power stations connected to a large interconnected system, the use of derivative term will result in excessive oscillation and possibly instability[2]. The derivative gain is usually set to zero for this type of operation. Setting the derivative term to zero results in a controller with only a proportional and integrating action. The transfer function of a PI governor is

$$\frac{y}{\omega_{ref} - \omega} = \frac{1}{R_p} \frac{K_p s + K_i}{(K_p + \frac{1}{Rp})s + K_i} \tag{4.6}$$

4.4 SolvSim Power Station model

As described Chapter 3, SSPS relies on equation (4.7) to simulate an electrical island.

$$f \frac{df}{dt} = \frac{f_0^2}{2H}(P_m - P_e) \tag{4.7}$$

Equation (4.7) is implemented in SIMULINK. A block diagram of the model is shown in Figure 4.7.

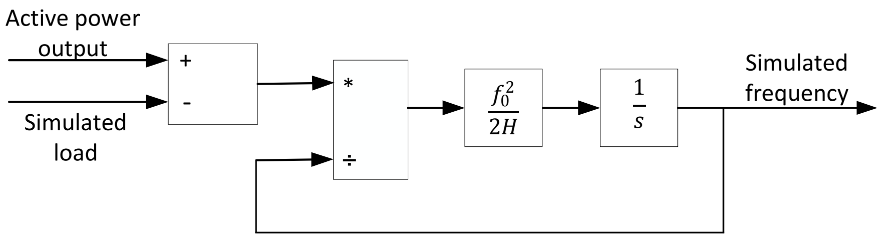

Figure 4.7: Electrical island frequency simulation.

Figure 4.8 shows a block diagram of the simulation model implemented in SIMULINK.

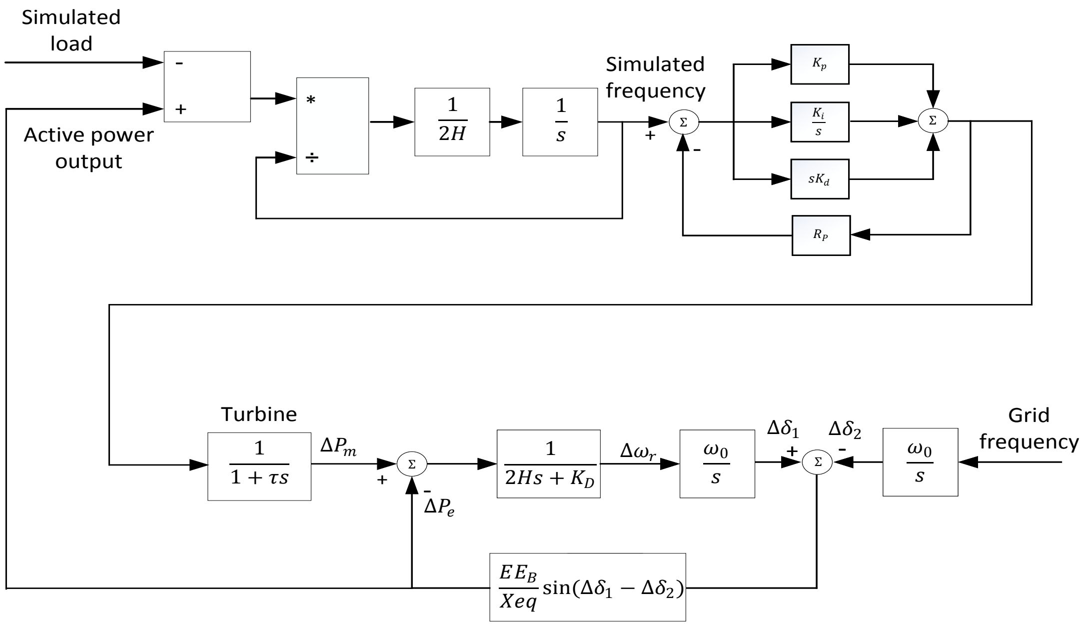

Figure 4.8: Block diagram of the simulation model implemented in SIMULINK.

The parameters used for the model are found Table 4.1.

K_P	20
K_i	9
K_d	0
R_p	0.02
τ	0.7 [s]
E	1 [pu]
E_B	1 [pu]
X_{eq}	1 [pu]
H	4 [s]
K_D	0 [pu]

Table 4.1: Parameters used for the model.

5

Results and discussion

SolvSim Power Station is built on the assumption that the electrical power output of a synchronous generator is equal to the input mechanical power. This relation is true for synchronous generators running a constant speed. between mechanical and electrical power for a synchronous generator is given by the swing equation. The swing equation for a synchronous generator, with losses neglected is

In the Nordic power system, the system frequency is well regulated. The same cannot be said for all power systems around the world. Figure 5.1 illustrates a measured utility frequency of a real system. The frequency is measured at 10 samples per second with a 0.002 Hz resolution. The frequency is measured during normal operation and the power system is not subjected to any major disturbance during this measurement.

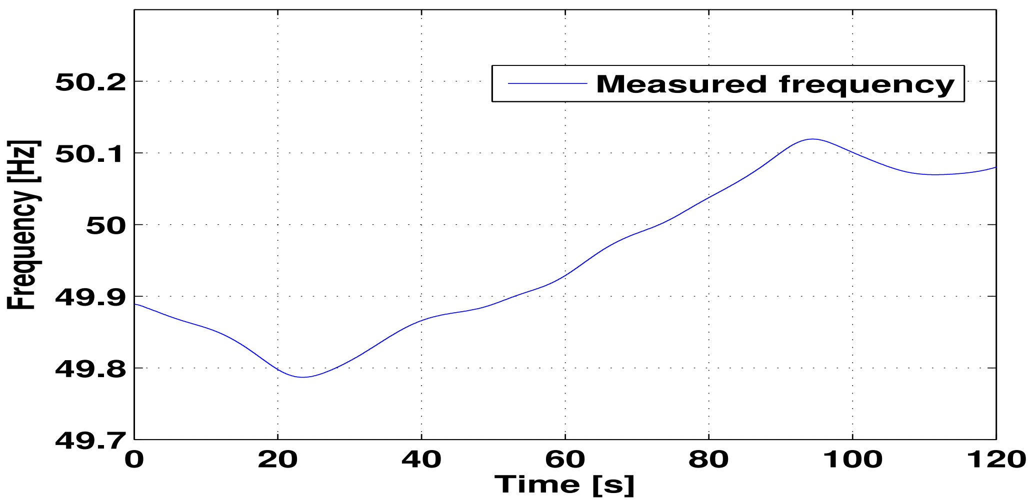

Figure 5.1: Measured frequency.

5.1 Power station connected to grid with highly variable frequency

The power station in this case is connected to an *infinite* grid. An infinite grid in this context is a grid where the voltage and frequency is imposed. Dynamics associated with the power station on which the analysis is being made is assumed to have no influence on the grid.

Figure 5.2 shows the change active power output of a synchronous generator synchronized to a grid with the frequency shown in Figure 5.1. The input mechanical power is constant during this time.

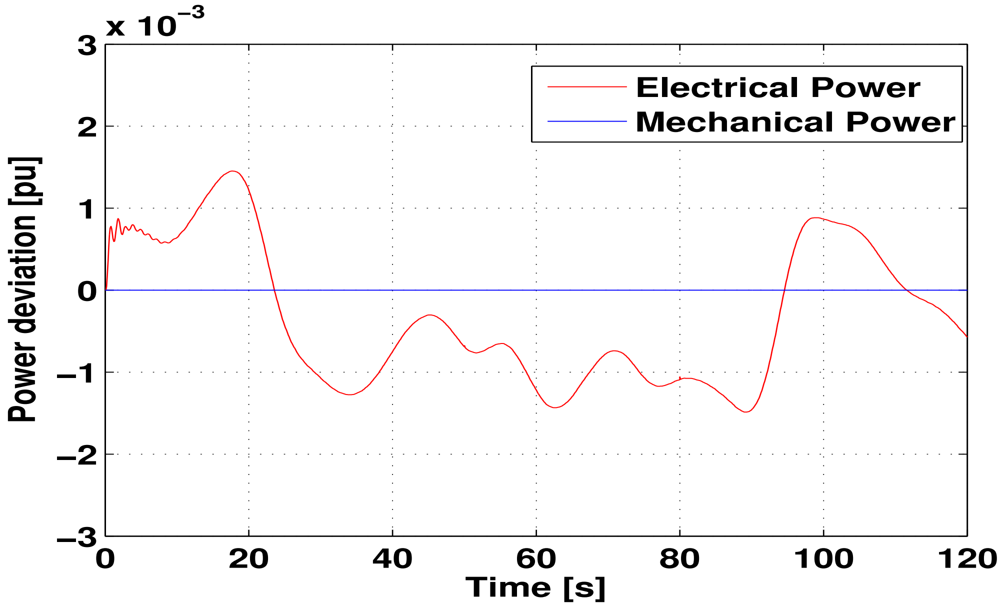

Figure 5.2: Change in input mechanical and active power output.

The variation in active power output, with losses neglected, is given by

$$\Delta P_e = \Delta P_m - 2H\frac{d\Delta\omega_r}{dt} \tag{5.1}$$

The speed of the machine is illustrated in Figure 5.3. The speed of the generator is almost identical to the grid to the frequency.

From equation (5.1), it is clear that the variation in the electric power output is only dependent on the rate of change in the generator speed and the inertia constant. The inertia constant in this case is the combined inertia constant of the generator and the turbine. The value of inertia constant differs for different types of power stations [2].

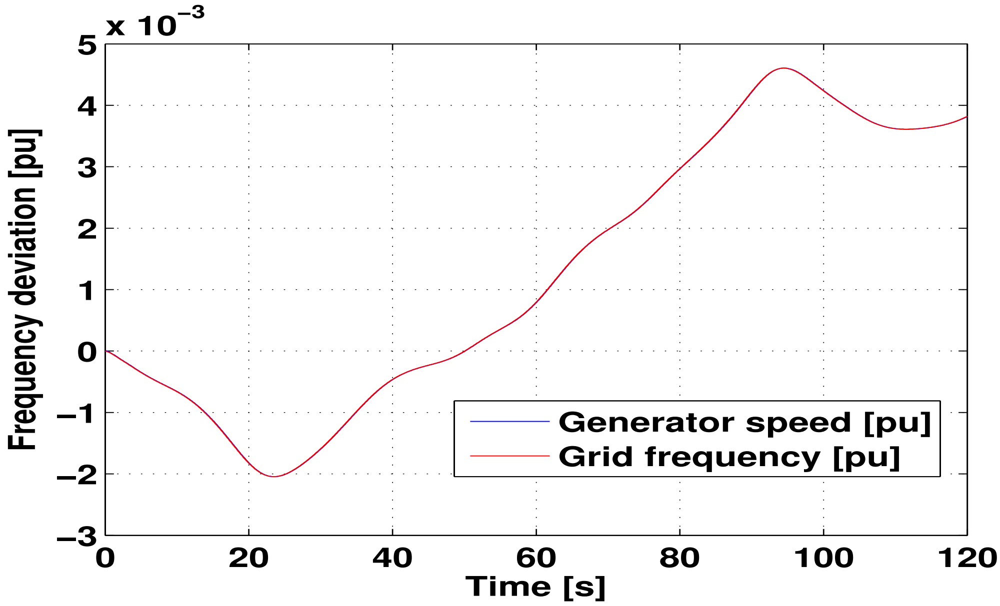

Figure 5.3: Generator speed and grid frequency.

Because the variation in active power output is related to the change in the kinetic energy stored in the rotating mass, the magnitude of the change in the active power output will differ for different types of power stations. The change in kinetic energy stored is proportional to the inertia constant and rate of speed change according to equation (5.1). The variation in the active power is illustrated in Figure 5.4 for power stations with different inertia constants. The input mechanical power remains unchanged and the frequency shown in Figure 5.1 is used as the grid frequency.

From Figure 5.4, it can be concluded that the imbalance caused between input mechanical power and electrical power output due to variation in the grid frequency is negligible. The maximum imbalance, for a generator connected to a power system with a frequency as shown in Figure 5.1, is 0.003 pu. The imbalance is 0.003 pu for a generator that has an inertia constant H of 10 s. However, the frequency shown in Figure 5.1 is not the worst case scenario. A power system subjected to a disturbance can experience even higher rate of change of frequency (RoCoF). For instance, according to the Irish transmission system operators (TSO), RoCoF values greater than 0.5 Hz/s but no greater than 1 Hz/s can be be experienced. These values of RoCoF are only experienced when the system is subjected severe disturbances during high wind generation [9]. When the generator experience high values of RoCoF, the rate of change of the kinetic energy in the rotating mass will also be high which causes imbalance between the input mechanical power and the active electric power output in accordance with the swing equation. The RoCoF in an interconnected power system is given by [5]

$$\frac{df}{dt} = \frac{f_0}{2H}(P_G - P_C) \tag{5.2}$$

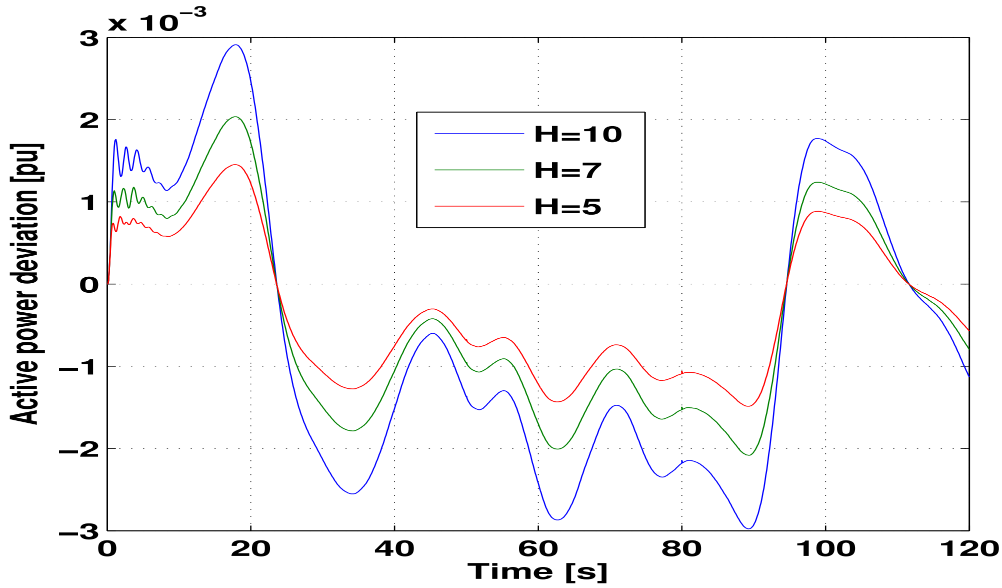

Figure 5.4: Generator speed and grid frequency.

Where H is the combined inertia constant of the power system. Equation 5.2 shows that high values RoCoF only occurs when there is a large imbalance between the active power production and active power consumption. For instance, in a power system with an inertia constant of 6 s and the loss of 1% of the total generation would result in RoCoF of 0.042 Hz/s. Based on this, it is safe to assume that high values of RoCoF is not experienced during normal operation.

High values of RoCoF are not considered since tests performed by SSPS are made under normal operation. During the test, the grid frequency is monitored. If large frequency deviation is observed, the test is safely aborted either automatically or by the operator [1].

The model of SSPS is used to perform test on the model of the power station that is synchronized to a grid with a frequency as shown in Figure 5.1. In the simulation, at time = 50 s a simulated load step increase of 0.1 pu is made. The simulated load step is then removed at time = 60 s. The test procedure is similar to the real test shown in Figures 3.3 and 3.4.

Figure 5.5 shows that the active power output follows the simulated load with some imbalance between the input mechanical power and active power output. In order for the electric power to follow the simulated load, the mechanical power is continuously adjusted by the governor. There are small adjustments in the input mechanical power even before the step in the simulated load is made. This is due to the fact that, the governor input is replaced with the simulated frequency which is calculated according to

The variation that occurs in the active power output due the variation in grid frequency results in variation in the simulated frequency which is sensed by the governor.

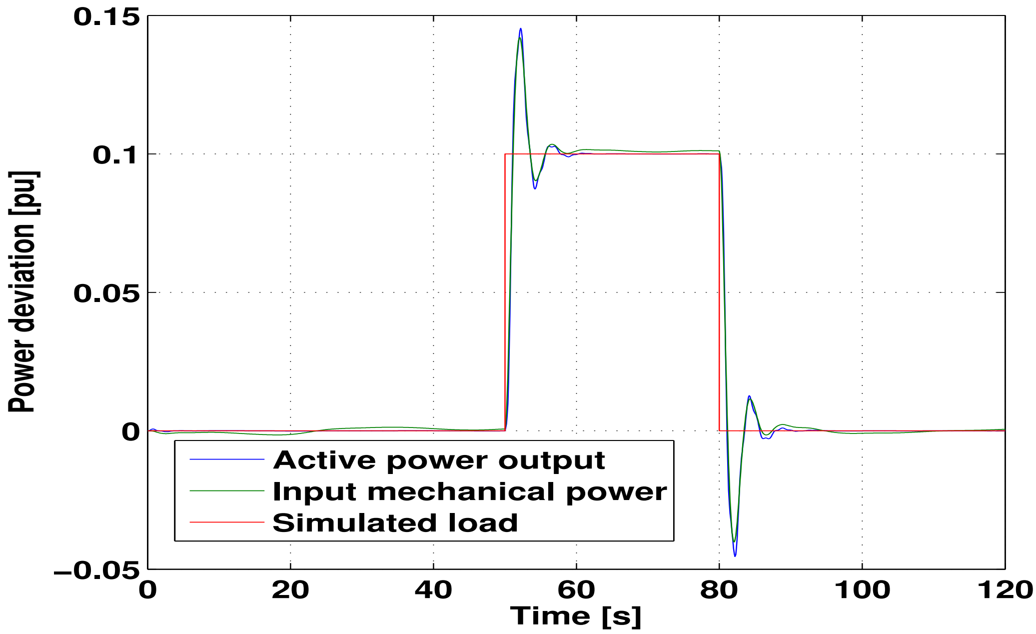

Figure 5.5: Generator speed and grid frequency.

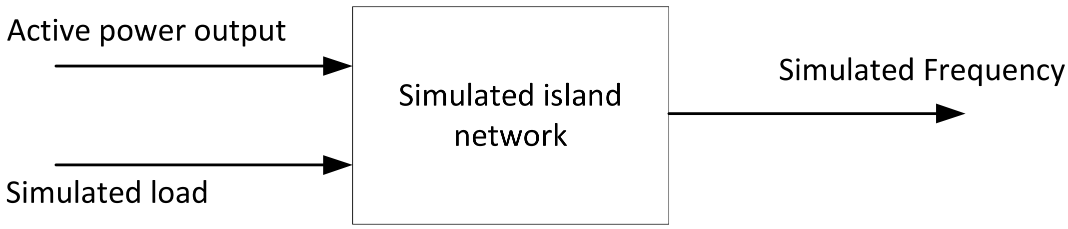

Figure 5.6: Island network frequency simulation.

The governor responds by altering the mechanical power based on the simulated frequency. Continuously adjusting the input mechanical power could result in wearing out the equipment in the long run. However, according to Solvina, SSPS tests lasts at most only for a few hours. Considering that such test only lasts for a few hours, it should not lead to any damage on the power station. This type of variation in the network frequency is also to be expected when operating in a real island operation since the frequency will inevitability vary more due the lower inertia in the system.

The simulated frequency is shown in Figure 5.7. Initially, there are only small variations caused by the variation in the active power output of the generating unit. As the simulated load step is made, the frequency drops and eventually recovers to the expected value of 49.9 Hz. The simulated frequency does not recover to nominal frequency of 50

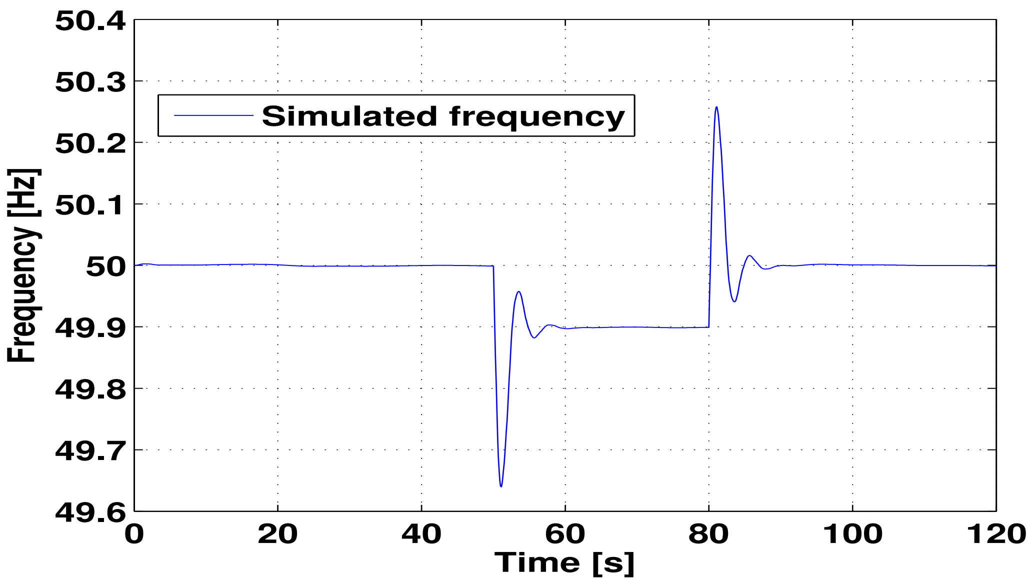

Figure 5.7: Simulated frequency.

Hz since the governor is provided with a droop characteristic of 2%. When the simulated load step is removed, the simulated frequency is increases and eventually recovers to the nominal value since the active power output is adjusted by the governor to match the simulated.

The generator speed and the grid frequency is shown in Figure 5.8. The generating unit remains synchronized to the grid during the test. At time = 50 s when the simulated load is increased, the speed of the generating unit deviates momentarily from the grid frequency. When the simulated load step is made, the generator active power output increases to match the simulated load. To increase the active power output, the power angle must increase. The active power output for a generating unit is given by

$$P_e = \frac{EE_B}{X_{eq}} \sin(\delta) \tag{5.3}$$

In order for the power angle to increase, the generator must run faster for a short period of time. Similarly, when the simulated load is decreased the generator runs slower for a short period of time to decrease the power angle.

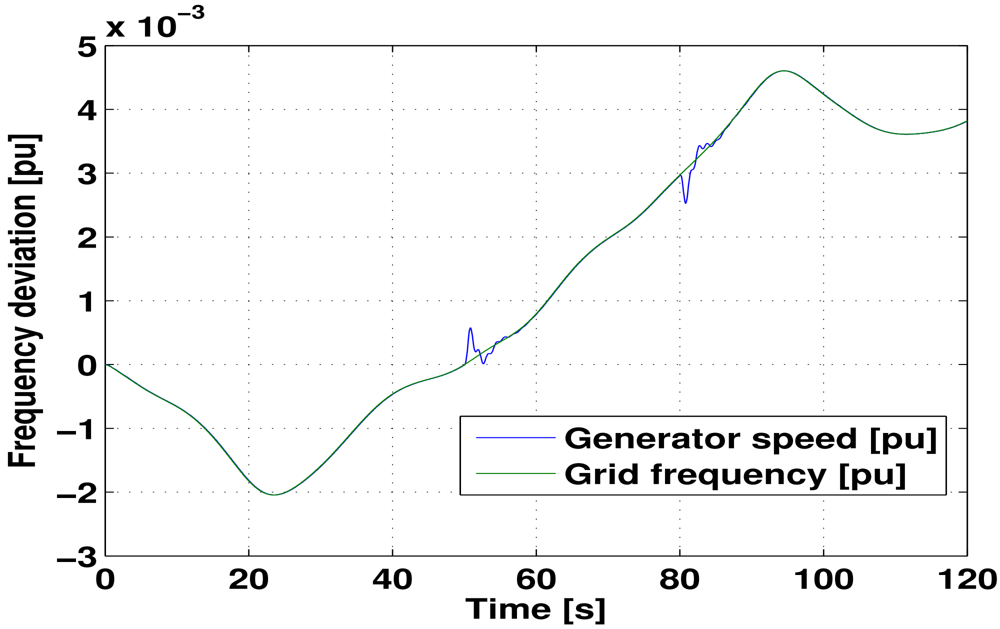

Figure 5.8: Generator speed and grid frequency.

Figure 5.9 shows the comparison for the test above if there are no variation in the grid frequency. As shown in the figure the difference between the two is marginal.

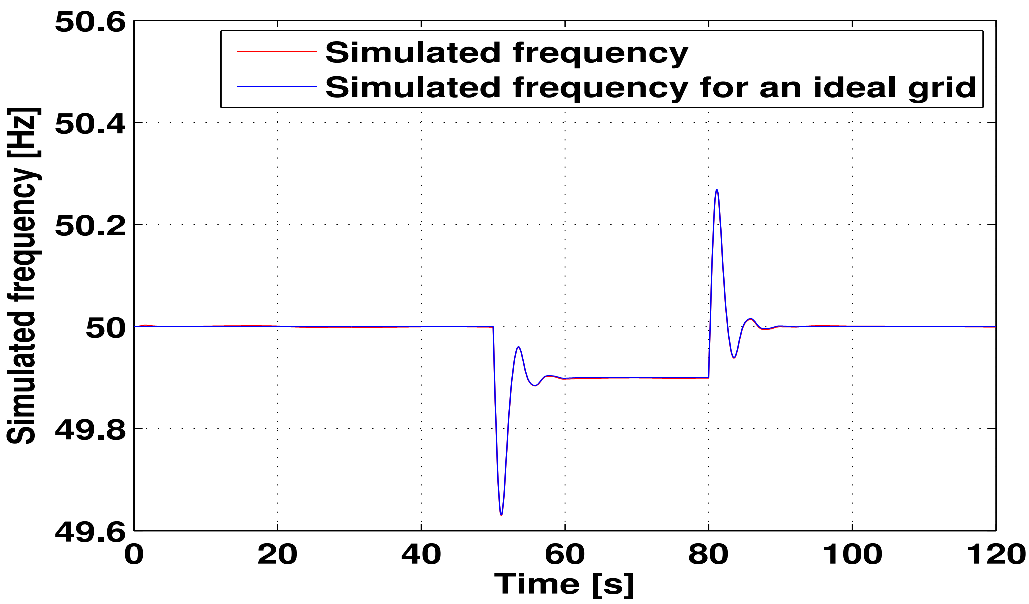

Figure 5.9: Simulated frequency.

5.2 Power station connected to a small grid

To safely perform SSPS tests, it is important to take into consideration the consequences of the test on the grid on which the test unit is connected. When performing tests with SSPS, usually several steps are made in the simulated load which cause changes in the active power output of the tested unit. Changing the active power output of a generating unit leads to imbalance between the produced active power and the consumed active power in the system. This imbalance is reflected in the network frequency. The frequency response in the grid is dependent mainly on four factors:

- The magnitude of the imbalance in active power.
- The combined moment of inertia in the power system when the imbalance occurs.
- The power/frequency characteristic of the power system.
- The response of the frequency control systems in the power system.

The variation in the frequency with no governor action is given by[2]:

$$\Delta f = \frac{\Delta P}{D}(1 - e^{\frac{-tD}{2H}})f_0 \tag{5.4}$$

The combined moment of inertia in a power system differs depending on the present type of generating units in the power system. For a power system with high penetration of wind power, the moment of inertia is lower as compared to a power system relying other conventional power generating units such as thermal units. The initial frequency response of a power due to an imbalance is almost exclusively determined by the total moment of inertia in the power system [10].

The magnitude of the imbalance caused by SSPS tests is dependent on the size of the variation made relative to the total generation in the power system. Variation of some tens of MWs in active power output of a single generating unit in Sweden has been considered negligible. Figure 3.3 and 3.4 show that a variation of 10 MW has only marginal influence on the grid frequency in Sweden. For a smaller power system where the combined inertia constant is smaller, a separate analysis is required to insure the security of the power system.

The simulations below show results of an SSPS tests performed on a generic grid with an inertia constant of 4 s and load damping constant of 1. The frequency response of the grid for a variation of 0.01 pu is shown in Figure 5.10.

Using the assumed parameter for the generic grid and equation 5.4, the highest RoCoF that can be experienced is 0.0625 Hz/s which is equivalent to 0.00125 pu/s. The generic power system used in this case is tuned in such a way that when increasing the total generation is equivalent of 0.01 pu of the total generation the frequency increases to 50.18 Hz before it recovers to the nominal value.

Simulation results from an SSPS test performed on a power station with the inertia constant of 4 s is shown below. The rated power of the power station in this case is 10% of the total rated power of the power plants in the grid.

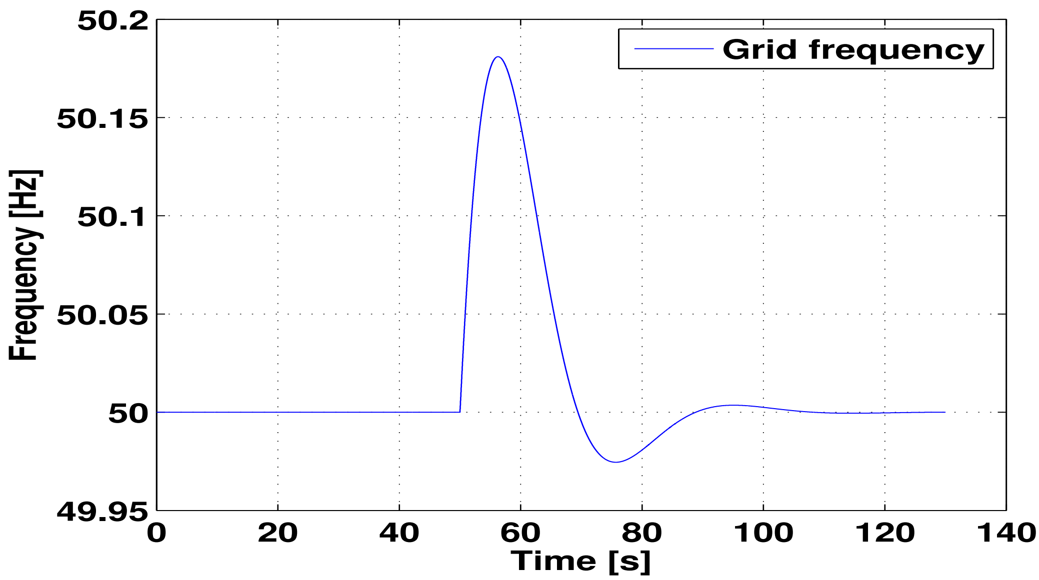

Figure 5.10: Grid frequency response.

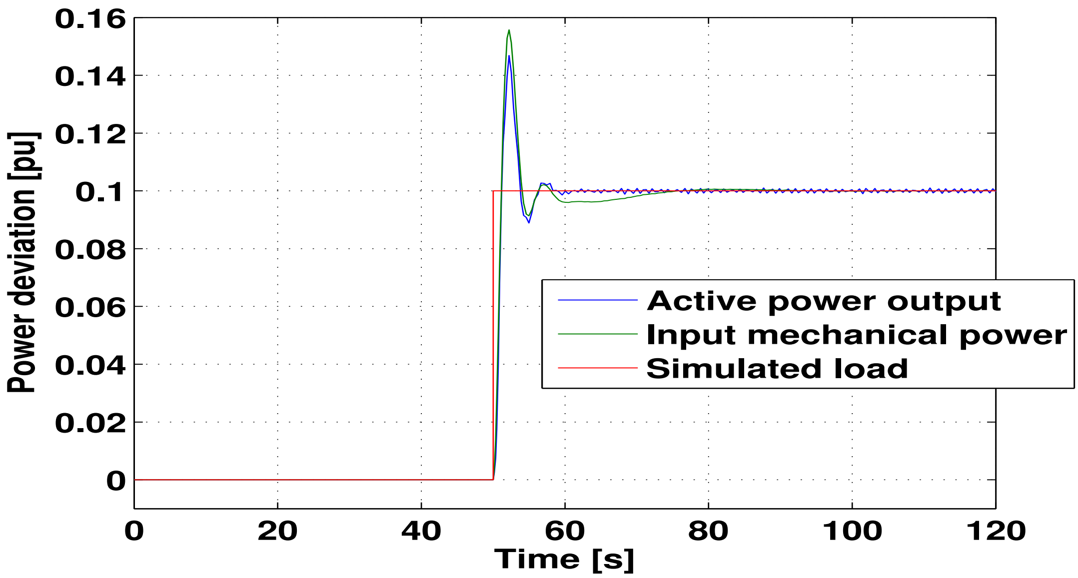

Figure 5.11: Change in input mechanical and active power output.

Figures 5.11 and 5.12 shows that for a test performed under such circumstances it is still sufficient to use the active power output to approximate the mechanical input mechanical power. This can be explained by the fact that the generator does not experience large variation in its speed during this test. The RoCoF is shown in Figure 5.14.

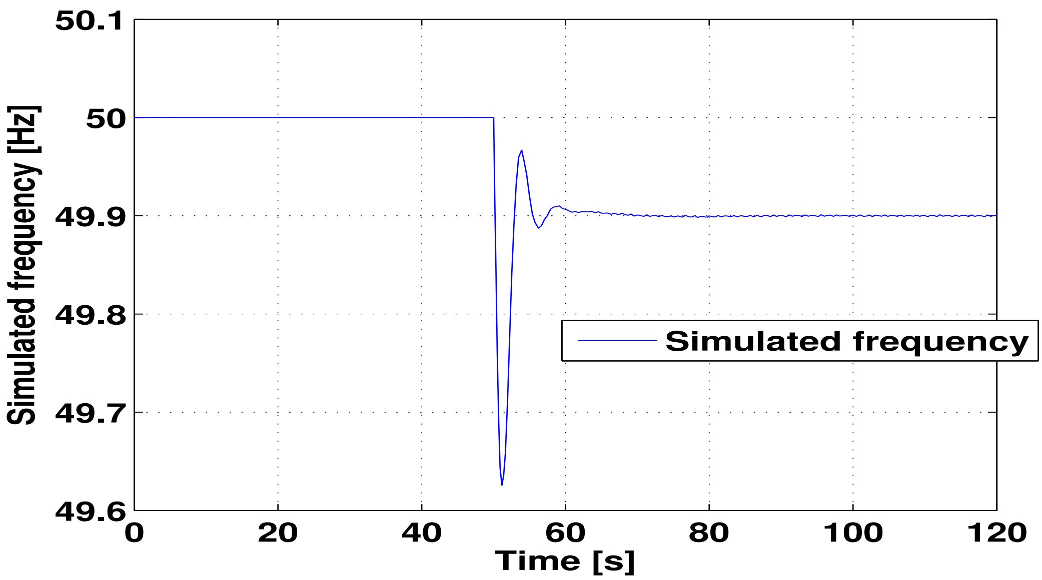

Figure 5.12: Simulated frequency.

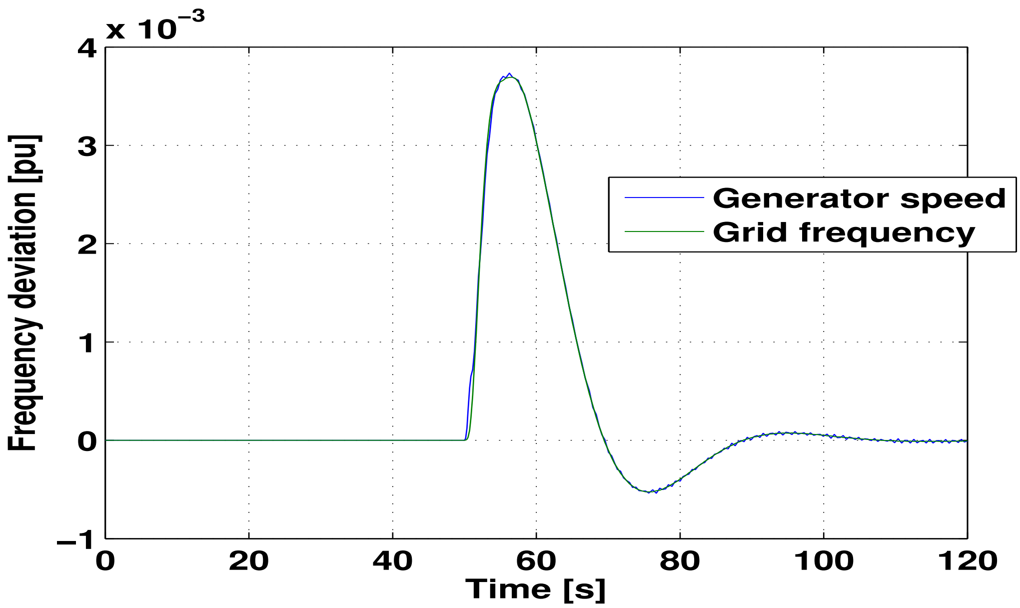

Figure 5.13: Generator speed and grid frequency.

The highest RoCoF experienced by the generator is 0.00125 pu. The highest variation in active power output caused by the rotating mass is $0.00125 * 2H$ which is equal to 0.0125 pu. The value 0.0125 pu is small compared to the simulated load step which is 0.1 pu.

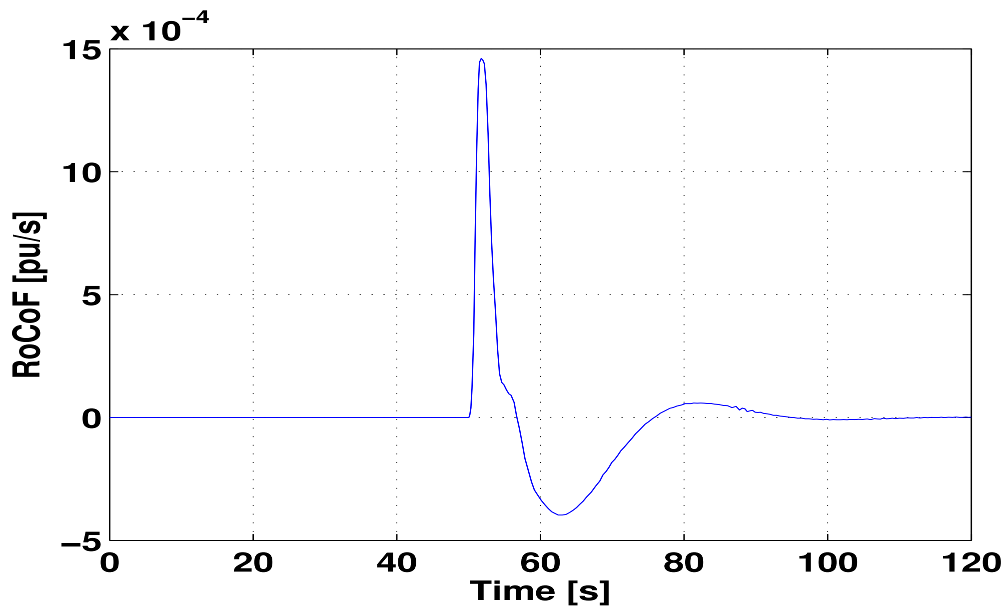

Figure 5.14: Rate of change of frequency.

The simulated frequency above along with a simulated frequency for a grid where no variation in the grid frequency occurs is shown in Figure 5.15.

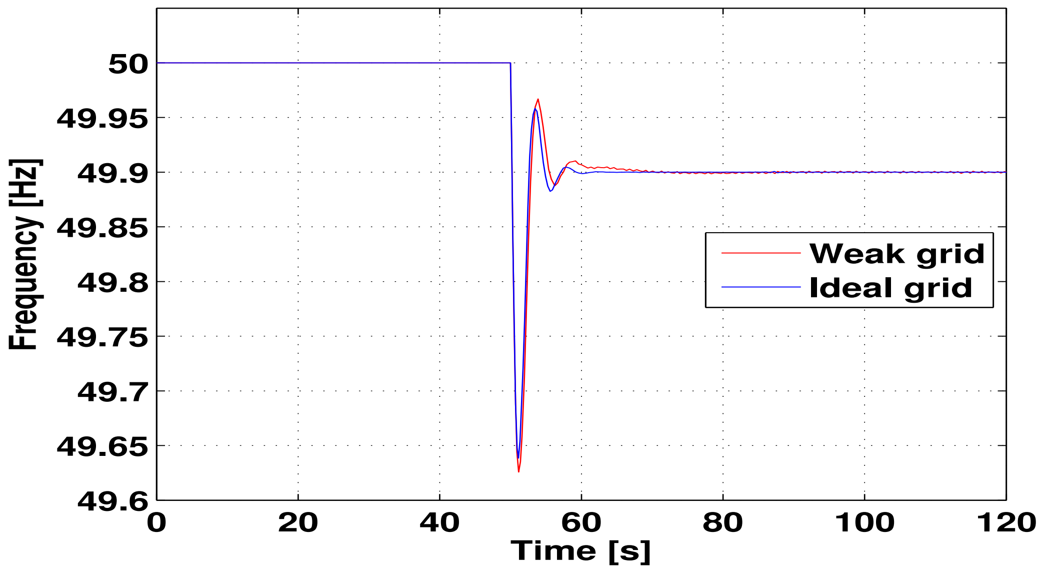

Figure 5.15: Simulated frequency.

The simulation above shows that SSPS tests can be performed on power stations with rated power at least 10% of the power stations in the grid. The conclusion made above regarding the test is not valid for all power stations. A power station with higher value of inertia constant will inevitability experience higher variation in its active power output. In order to make sure that the test is valid for a certain power station similar analysis has to be made. The analysis must take into account the highest RoCoF that will occur as a consequence of the performed test. If the variation in the active power output due the change in speed of the generator is found to be small enough then the test can be performed.

When using SSPS to perform tests it is also important to maintain the network security. As shown in Figure 5.10, SSPS tests could lead to large frequency deviation. Therefore, it is very important to carefully analyze the grid where the test is performed. If the grid, is found to be of sufficient strength based on its inertia, frequency control systems and spinning reserve to handle the variations in the active power output of the tested unit then the test can be performed.

The situation shown above is for simulating *under-generated* island where the initial active power generation is less than the total loads in the island. Simulation of an *over-generated* island will result in reduction of the active power output of the tested unit. In such case, the frequency control systems in the power system should increase the total active power to maintain the network frequency. To maintain the network security, there must be enough spinning reserve in the network to cover for this loss of active power.

6

Conclusions and future work

6.1 Conclusions

The objective of this project was to determine the applicability of SolvSim Power Station in a grid where frequency variation occurs. During this project, two different scenarios have been considered: 1) a grid where the frequency is varying due a poorly regulated power system 2) variation in the grid frequency as a consequence of the performed test.

For a power station connected to a grid with a frequency as shown in Figure 5.1, it has been demonstrated that these tests are still possible. The simulated frequency in SSPS is only dependent on the active power of the tested unit. The active power output of a synchronous generator varies in accordance with swing equation. Based on analytical review and the simulation made it can be concluded that large variation in active power output occurs when the generator experiences accelerations. For variation in grid frequency that occurs under normal operation, the RoCoF is not large enough to cause large variation in the active power output.

If large RoCoF were to occur during such test then the test should be aborted since large RoCoF only occur when the grid a subjected a severe disturbance. Aborting the test in such a situation is necessary because the normal frequency feedback of the governor is replaced with the simulated frequency. Replacing the normal frequency feedback of the governor excludes the tested unit from contributing to stabilize the network frequency.

For the second scenario, a thorough analysis is needed to successfully perform the test while maintaining the network frequency. To determine if the network security can be maintained while performing SSPS depends on the type of simulated island network.

To conclude the possibility of conducting an SSPS test on a power station, the variation in active power output due to change in the rotor speed has to be examined. The variation in active is proportional to the rate of speed change of the generator in accordance with the swing equation. If these variation are considered to be small in relation to the change in the simulated load then such test can be performed.

When testing the network for an *over-generated* island, the active power output of the tested unit is increased during the test. In this case, the frequency control systems in the network should respond by reducing the net active power output to balance the system. If the network is deemed to be of sufficient strength based on the total inertia and frequency control capability then there is no problem. For testing a unit for *under-generated* island, the active power output of the testes unit is reduced. In this case, the frequency control system should increase active power output to balance the system. In order of fulfill the active power balance in this case, there must enough spinning reserve in the network.

There are several ways to determine if the network meets requirements above. The easiest way for this is to consult the transmission system operators. If however, such information is not available then the analysis needed can be performed using methods suggested in [10] and [11].

6.2 Future work

In this project, the grid voltage is assumed to be constant at all time. For a future work investigating the limitation of SSPS in terms of voltage stability can performed. Variation of voltage is of concern especially for power station in the distance connected through long transmission lines.

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Appendix A

Power invariant 3-phase to $\alpha\beta$ transformation

$$\begin{bmatrix} s_\alpha \\ s_\beta \end{bmatrix} = \sqrt{\frac{2}{3}} \begin{bmatrix} 1 & -\frac{1}{2} & -\frac{1}{2} \\ 0 & \frac{\sqrt{3}}{2} & -\frac{\sqrt{3}}{2} \end{bmatrix} \begin{bmatrix} s_1 \\ s_2 \\ s_3 \end{bmatrix}$$

Power invariant $\alpha\beta$ to 3-phase transformation

$$\begin{bmatrix} s_1 \\ s_2 \\ s_3 \end{bmatrix} = \sqrt{\frac{2}{3}} \begin{bmatrix} 1 & 0 \\ -\frac{1}{2} & \frac{\sqrt{3}}{2} \\ -\frac{1}{2} & -\frac{\sqrt{3}}{2} \end{bmatrix} \begin{bmatrix} s_\alpha \\ s_\beta \end{bmatrix}$$

$\alpha\beta$ to dq transformation

$$\begin{bmatrix} v_d(t) \\ v_q(t) \end{bmatrix} = \begin{bmatrix} cos(\theta) & sin(\theta) \\ -sin(\theta) & cos(\theta) \end{bmatrix} \begin{bmatrix} v_\alpha(t) \\ v_\beta(t) \end{bmatrix}$$

dq to $\alpha\beta$ transformation

$$\begin{bmatrix} v_\alpha(t) \\ v_\beta(t) \end{bmatrix} = \begin{bmatrix} cos(\theta) & sin(\theta) \\ -sin(\theta) & cos(\theta) \end{bmatrix} \begin{bmatrix} v_d(t) \\ v_q(t) \end{bmatrix}$$