Ethiopian Journal of Indigenous Knowledge and Applied Sciences

Eth. J. Indig. Know. Appl. Sci.
Vol. 2, No. 1, 2024, 12-20

Damping of one-area oscillations in single machine infinite bus system of hydropower plants using PSS

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Abstract

This paper examined how the damping capability can be improved if inter-area oscillations occur by combining control strategies in hydropower plants. First, the control challenges of hydropower plants, such as the water hammer effect, are discussed. In a single machine infinite bus system (SMIBS), the use of a Power System Stabilizer (PSS) in the generator excitation and in the governor control path as well as the combination of both strategies were examined for their effectiveness in terms of their damping capability. Power system stabilizer was used to generate supplementary control signal for the excitation system in order to damp the low frequency oscillation. The traditional solution of this problem was application of conventional Power system stabilizer. The dynamic stability of power systems is also affected by these low frequency oscillations. With proper design of Power System Stabilizer (PSS), these oscillations can be well damped and hence the system stability is enhanced. It is required to add a stabilizing signal that compensates the oscillations of the voltage error of the excitation system during the dynamic/transient state, and to provide a damping component when it's on phase with rotor speed deviation, electric air gap torque and mechanical torque of machine. This study showed that PSS is designed to provide additional damping torque, for different operation point to improve power system dynamic stability. The Heffron-Phillips model combination of Hydro turbine, Excitation and combined design model for the PSS as well as for the model-based controller. The verification of the damping capability through the PSS variants was evaluated by using a three-machine model in the time domain analysis. Therefore, PSS-G and PSS-EG are very smart to control a hydropower plant as a combined controller that could present good performance in all operating points of electric power system.

Keywords: Excitation; inter-area oscillations; Power System Stabilizer; hydropower plant regulation; optimal control; power system stability; damping capability in the power system.

1. Introduction

Power transmission networks are inherently complex systems which mainly consist of generators, transmission lines, transformers and loads. An increase in electricity demand, together with a need for reliability enhancement, heavily affects overall system performance. As a consequence, system stability is of importance and must be analyzed by means of appropriate tools. To guarantee the secure and reliable operation of actual power systems, computer-based simulation tools are used by engineers to assess the stability dynamic and performance of the power system. In power systems, generators are commonly driven by mechanical power provided by turbines. Each turbine is equipped with a speed governing system called turbine governor to regulate its speed in order to meet a desired power output [1]. Turbine governors function as primary frequency controllers of synchronous machines when the system is subjected to disturbances [2]. Models for synchronous generators used for large and small signal stability studies include both inertial and rotor circuits flux dynamics. Excitation systems found in "old" hydro power plants were usually powered with DC rotating exciters. However, static excitation systems are often being used in upgrading old facilities and in modern power plants. Excitation systems of the static type do not use rotating exciters and thus have a much faster dynamic response and a larger field forcing capability to respond to large disturbances without exceeding generator field current limits. However, because of the high initial response, they require voltage regulators with high gains that may have an adverse impact on the damping of electromechanical oscillatory modes in power systems. Power system stabilizers are often used as supplementary controls to add positive damping to the affected oscillatory modes through the excitation system by adding an electric torque in phase with the generator rotor speed. Additional control and protection systems used in excitation systems include field current limiters, terminal voltage limiters, under excitation and over-excitation limiters (UELs and OELs), and flux (V/Hz) limiters and relays [3]. In order to be able to evaluate the individual control strategies, they are first examined in the so called single machine infinite bus system (SMIBS). Figure 1 represents such a model, in which a synchronous generator is connected via a transmission line to an infinite bus with $V_b\angle\theta_b$. Generator is coupled to a hydraulic turbine which is speed controlled by the hydro governor. By changing the excitation E_{fd} through the voltage regulator (AVR), the voltage of the generator V_t can be adjusted. In addition, in Figure 1, the principal way of implementing a PSS-E in the voltage regulator path and a PSS-G in the hydro governor control path is shown.

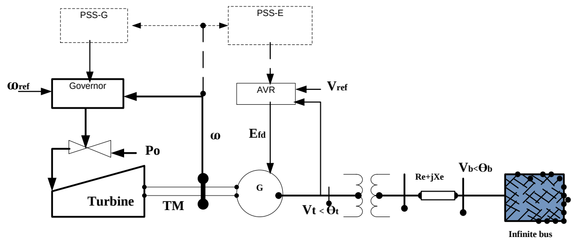


Figure 1: SMIBS with hydro governor and PSS-E as well as PSS-G

Mathematical Modeling of Components

Single machine infinite bus system(SMIBS): synchronous generator with stiff grid connection from Figure 1 is modeled as with a generator excitation in d-axis and an equivalent damper winding in q-axis [4]. According to [13], time behavior of generator can be described with differential equations (1) to (4) and algebraic equations (5) to (6).

$$\frac{d\delta}{dt}=\omega-\omega_s, \text{ and } \frac{d\omega}{dt}=\frac{\omega_s}{2H}\left(T_M-T_E-D(\omega-\omega_s)\right) \quad (1)$$

$$\frac{dE'_q}{dt}=\frac{1}{T'_{do}}\left(-E'_q-(X_d-X'_d)I_d+E_{fd}\right) \text{ and}$$

$$\frac{dE'_d}{dt}=\frac{1}{T'_{q0}}\left(-E'_d-\left(X_q-X'_q\right)I_q\right) \quad (2)$$

Electrical air gap torque of generator and dynamics of the generator excitation E_{fd} is given by in equation (3 & 4);

$$T_E=\left(E'_dI_d+E'_qI_q+\left(X_q-X'_d\right)I_dI_q\right) \quad (3)$$

$$\frac{dE_{fd}}{dt}=\frac{1}{T_A}\left(-E_{fd}+K_A\left(V_{ref}-V_t\right)\right) \quad (4)$$

From algebraic equations according to [13], generator currents in polar form and stator voltage in dq-model in equations (5 &6);

$$\begin{bmatrix} I_d \\ I_q \end{bmatrix}=\begin{bmatrix} -(R_s+R_e) & (X'_d+X_e) \\ -(X'_d+X_e) & -(R_s+R_e) \end{bmatrix}^{-1}\begin{bmatrix} V_b\sin(\delta-\theta_b)-E'_d \\ V_b\cos(\delta-\theta_b)-E'_q \end{bmatrix} \quad (5)$$

$$V_d=R_eI_d-X_eI_q+V_b\sin(\delta-\theta_b) \text{ and}$$

$$V_q=R_eI_q-X_eI_d+V_b\cos(\delta-\theta_b) \quad (6)$$

As well as the generator terminal voltage with $Vt=\sqrt{Vd^2+Vq^2}$ can be calculated.

Design of a power system stabilizer

For the design of the power system stabilizer as well as the state space controller as damping element (PSS), the nonlinear simulation model from (1) to (6) is linearized around a specified operating point. The objective of PSS is to provide damping of the rotor oscillations whenever there is a transient disturbance. The damping of these oscillations (whose frequency varies from 0.2 to 2.0 Hz) can be impaired by the provision of high gain AVR, particularly at high loading conditions when a generator is connected through a high external impedance (due to weak transmission network). In any case, the stabilizer is designed to have zero output in steady state.Besides the output is limited in order not to adversely affect the voltage control. The stabilizer output Vs is added to the terminal voltage error signal. Generally, the choice of control signal for PSS can be based on the following criteria;

(a) The signal must be obtained from local measurements and easily synthesized. (b) The noise content of the signal must be minimal. Otherwise, complicated filters are required which can introduce their own problems. (c) The PSS design based on a particular signal must be robust and reject noise. This implies that lead compensation must be kept to a minimum to avoid amplifying the noise. All the control signals considered- rotor speed, frequency, electrical power are locally available. The speed signal can be obtained from a transducer using a tooth wheel mounted on the shaft. [15]. Types of excitation control system for speed control of the generator are PSS and AVR.

(b) Automatic Voltage Regulator (AVR):

Automatic voltage regulator is used to regulate the voltage and takes fluctuate voltage and changes them into a constant voltage. The fluctuation in the voltage mainly occurs due to the variation in load on the supply system.

Power system stabilizer (PSS) is used as a supplementary controller to the AVR, this combined generator excitation control, could eliminate any negative effects on the damping of the post-fault oscillation [4]. The control signal for the power system stability (PSS) is either the speed deviation, or the electric power, or the system frequency as additional feedback signals for introducing a damping torque control component. Speed signal is the most commonly used. **A**uxiliary stabilizing signals are used (such as shaft speed, frequency, power) to modulate generator field voltage so as to damp rotor oscillations during transient disturbance [5]. Power systems nowadays are the low frequency oscillations arising from interconnected systems. Sometimes, oscillations sustain for minutes and grow to cause system separation that occurs no adequate damping is available to compensate for the insufficiency of the damping torque in the synchronous generator unit due to the AVR exciter's high speed and gain and the system's loading. In order to overcome problem, PSSs were successfully tested and implemented to damp low frequency oscillations. The PSS provides supplementary feedback stabilizing signal in the excitation system. The basic function of PSS is to damp electromechanical oscillations. [6] The functions of an excitation system are: to provide direct current to the synchronous generator field winding, and to perform control and protective functions essential to the satisfactory operation of power system, Control of voltage and reactive power flow Enhancement of system stability and ensures that capability limits of synchronous machine excitation system and other equipment are not exceeded. The basic blocks that are involved in the excitation system are:

Exciter provides dc power to generator field winding. Regulator helps for processes and amplifies input control signals to a level and form appropriate for control of exciter (can be magnetic amplification type or digital amplification type). At present digital amplification is widely used. Terminal voltage transducer and load compensator which senses generator terminal voltage, rectifies and filters it to dc quantity and compares with a reference and the error signal is used to control the main exciter field winding current through the exciter; load compensation may be provided if desired to hold voltage at a remote point. Power system stabilizer and Limiters and protective circuits.

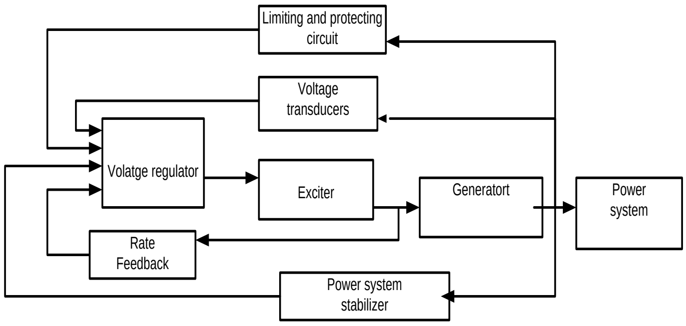


Figure 2. Basic blocks of excitation system

Inter area modes in which generators over an extensive area participate. The oscillation frequencies are low and in the range of 0.2 to 0.5 Hz [2]. As noted by Larsen, the basic function of stabilizers is to modulate the generator excitation to damp generator oscillations in frequency range of about 0.2 to 2.5 Hz. This requires adding a torque that is in phase with the speed variation and requires compensating for the gain and phase characteristics of the generator, excitation system, and power system (GEP(s)).

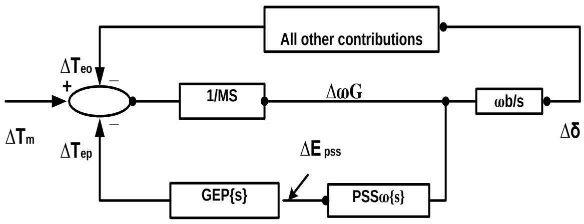


Figure 3. From Larsen, 1981

The aim is to compensate for the phase lag in the GEP. The stabilizer input is often the shaft speed and T6 is used to represent measurement delay; it is usually zero (ignoring the delay) or a small value (< 0.02 sec). The washout filter removes low frequencies; T5 is usually several seconds (with an average of say 5). Some guidelines say less than ten seconds to quickly remove the low frequency component and stabilizer inputs include two washout filters.

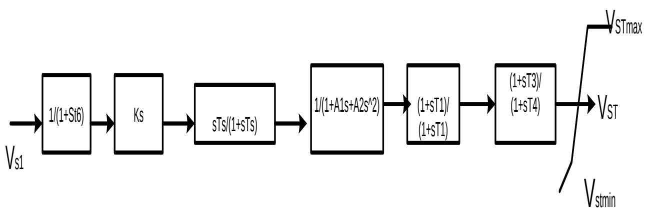


Figure 4. Single input PSS

Stabilizer Design Values: With a washout filter value of T5 = 10 at 0.1 Hz ($s = j0.2\pi = j0.63$) the gain is 0.987; with T5 = 1 at 0.1 Hz the gain is 0.53 by ignoring the second order block, the values to be tuned are the gain, Ks, and the time constants on the two lead-lag blocks to provide phase compensation we'll assume T1=T3 and T2=T4

Stabilizer Design Phase Compensation: Since the purpose of a PSS is to introduce a damping torque component, a logical signal to use for controlling generator excitation is the speed deviation $\Delta\omega_r$.If the exciter transfer function $G_{ex}(s)$ and the generator transfer function between ΔE_{fd} and ΔT_e were pure gains, a direct feedback of $\Delta\omega_r$ would result in a damping torque component. However, in practice both the generator and the exciter (depending on its type) exhibit frequency dependent gain and phase characteristics. Therefore, the PSS transfer function,$G_{PSS}(s)$, should have appropriate phase compensation circuits to compensate the phase lag between the exciter input and the electrical torque . Electromechanical oscillations can be influenced either via the electric air gap torque ΔTe or via the mechanical torque of turbine ΔTm. Electric-air gap torque ΔTe2 influenced via the PSS-E is given by

$\Delta T_{e2}(s)= G_{ex}(s)G_{PSSE}(s)\Delta\omega(s)$ (7)

The behavior of the voltage regulator with excitation according to [2] can be described by the transfer function $G_{ex}(s)$ with ΔVref (s) → $\Delta T_{e2}(s)$from Figure 1, neglecting the angle Δδ over K4 and K5, with

$$G_{ex}(s) = \frac{K2K3KA}{K3K6KA+(1+sK3T'_{d0})(1+sTA)} \quad (8)$$

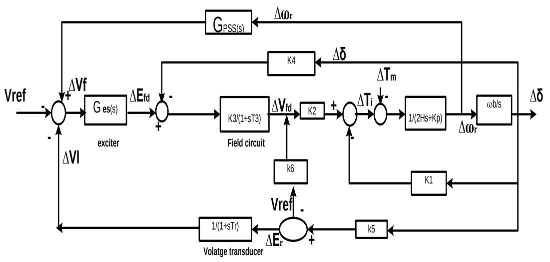


Figure. 5. Block diagram representation of AVR and PSS

The transfer function of the PSS-E is given by [10] through

$$G_{pssE}(s) = \frac{\Delta v_{pssE}(s)}{\Delta\omega(s)} = K\left(\frac{sTp}{1+sTp}\right)\left(\frac{1+sT1}{1+sT2}\right)^n \quad (9)$$

Where, $K\left(\frac{sTp}{1+sTp}\right)$ are high pass-filter and $\left(\frac{1+sT1}{1+sT2}\right)^n$ are phase shift.

In order to achieve a positive damping effect with the PSS-E, the lead element must have the phase shift of the generator excitation Gex (s). The high-pass filter allows the PSS-E to act on the voltage regulator only during speed changes, and this prevents voltage offset during steady-state operation. With the factor K the damping influence of the PSS-E can be defined.

Modelling of Controlling System

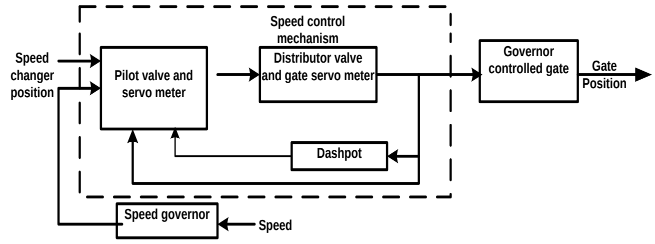


Figure 8. Speed governing system for hydro turbines- functional block diagram

Hydro turbine modeling**:** If there is a small change in the velocity of water, it can be expressed as a sum of linear changes in the gate position and head. Velocity of water that normalized values in the penstock is given by in the penstock. Where U-water velocity, Ku- constant, G-gate position and H-hydraulic head at gate

$U = KuG\sqrt{H}$ (10)

Acceleration of water column: The partial derivatives in the above equation should be evaluated at an initial operating condition from which speed of the water changed by a small amount. The initial speed of water, for a given initial gate position G_o and head H_o, and the equation (10) by a small deviation of normalized water velocity or can be normalized by dividing it with equation

$$U_o = K_u G_0\sqrt{H_0}: \Delta U = \frac{1}{2}\Delta H + \Delta G \quad (11)$$

Turbine mechanical power: Turbine mechanical power is proportional to the product of pressure and flow and hence, with proportionality constant

$Pm = KpHU$ (12)

Partial derivative of equation (12) should be evaluated at an initial operating condition from which mechanical power changed by a small amount as:

$P_{mo}= K_pH_oU_o$, and $\Delta P_m = K_pU_o\Delta H + K_pH_o\Delta U$; This equation can be normalized by dividing it with initial value

$$P_{mo} = K_pH_oU_o \text{ and } \Delta P_m = \Delta H+ \Delta U = 1.5\Delta H + \Delta G;\ \text{OR}= 3\Delta U - 2\Delta G;\ \Delta Pm = \Delta H + \Delta U \quad (13)$$

Substituting ΔU: $\Delta Pm = 3/2\ \Delta H + \Delta G$, and Substituting ΔH: $\Delta Pm = 3/2\ \Delta U - 2\Delta G$ (14)

Acceleration of water column due to a change in head at turbine motion can be expressed as [2]:

$\rho LAd\Delta U/ dt = -(\rho a g)\Delta H$ (15)

Where: L, A, ρ - are the length of the conduit, area of the pipe and the mass density of the water respectively. a_g - is the acceleration due to gravity. ρ LA - represents the mass of the water in conduit ρ $a_g\Delta H$ - represents the incremental force. The acceleration equation in normalized form. T_W*[seconds]* It is called as water starting time and it is the time required for a head H_o to accelerate the water to a velocity U_o. (at full load). If this equation is converted in to Laplace domain, then $T_w s\Delta U$, $s = -\Delta(s)$. Substituting ΔU from $\Delta Pm = 3\Delta U - 2\Delta G$ and rearranging; We can get:

$$T_w s\Delta(s) = -2(\Delta U - \Delta G)\,(s),\ T_w s\Delta(s) + 2\Delta U(s) = 2\Delta G(s),\ \Delta Us\,(T_w s + 2) = 2\Delta(s),\ \Delta Us = \frac{2\Delta G(s)}{Tws+2},$$

$$\frac{\Delta Pm}{\Delta G} = \frac{1 - TwS}{1 + 0.5TwS} \qquad (16)$$

OR, $\Delta U(s) = \frac{\Delta G(s)}{1+0.5TwS}$, In the previous equation,

$$\Delta\bar{P}m = 3\Delta\bar{U} - 2\Delta\bar{G} \qquad (17)$$

Substituting eqn. 14 in eqn. 13 and eliminating ΔU lead to: $\Delta\bar{P}m(s) = \frac{1-TwS}{1+0.5TwS}\Delta G(s)$ OR $\frac{\Delta\bar{P}m}{\Delta\bar{G}} = \frac{1-TwS}{1+0.5TwS}$

This is the equation representing the transfer function of a hydraulic turbine

Mathematical equation of synchronous generator (transfer function) is given by; $\frac{\Delta\omega}{\Delta Pm} = \frac{1}{2HS} = \frac{1}{TmS+1}$

For small perturbations about a steady state condition, the turbine is represented for system stability studies by linearized equations

$$\Delta\bar{U} = a_{11}\Delta\bar{H} + a_{12}\Delta\bar{\omega} + a_{13}\Delta\bar{G},\quad \Delta\bar{P}m = a_{21}\Delta\bar{H} + a_{22}\Delta\bar{\omega} + a_{23}\Delta\bar{G}$$

Using these equations and using dynamics of the water flow in the penstock, transfer function model for hydro turbine is obtained.

Partial derivatives of flow: $a_{11} = \frac{\partial u}{\partial}$, $a_{12} = \frac{\partial u}{\partial n}$, $a_{13} = \frac{\partial u}{\partial g}$, Partial derivatives ofoutput power; $a_{21} = \frac{\partial u}{\partial}$, $a_{22} = \frac{\partial u}{\partial n}$, $a_{23} = \frac{\partial u}{\partial g}$

The speed deviation being small is neglected and Substituting:

$$\Delta\bar{U} = \frac{1}{2}\Delta\bar{H} + \Delta\bar{G} \text{ and } \Delta\bar{P}m = 1.5\Delta\bar{H} + \Delta\bar{G}$$

In the above equation, transfer function between $\Delta\bar{P}$ and $\Delta\bar{G}$ becomes:

$$\frac{\Delta\bar{P}m}{\Delta\bar{G}} = a_{23}\frac{1 + \left(a_{11} - a_{13}a_{21/a_{23}}TwS\right)}{1 + a_{11}TwS} \qquad (18)$$

For ideal turbine at rated speed and head (Francis turbine), $a_{11} = 0.5, a_{13} = 1, a_{21} = 1.5, a_{23} = 1$.

Due to this behavior of the hydraulic turbine, the oscillation tendency of the speed-controlled generator is significantly increased. The typical bandwidth of a hydro governor according to [7] ranges from 0.03 Hz to 1 Hz and the step response exhibits rise times from 1 s to 25 s. This illustrates the low dynamics of speed control via a water turbine and due to the hydraulic and mechanical boundary conditions. Despite the low control dynamics, the hydraulic turbine controller for low-frequency oscillations can positively contribute to oscillation damping.

Load Model: Since motor loads are a dominant part of the electrical load, there is a need to model the effect of a change in frequency on the net load drawn by the system. Relationship between changes in load due to the change in frequency is given by;

$$\Delta P_{L(freq)} = D\Delta\omega \text{ or } D = \frac{\Delta P_{L(freq)}}{\Delta\omega} \qquad (19)$$

Where D is expressed as percent change in load divided by percent change in frequency. If load changed by 1.5% for a 1% change in frequency, then D would equal 1.5. However, the value of D used in solving for system dynamic response must be changed if the system base MVA is different from the nominal value of load. $\Delta P_{elec} = \Delta P_L + D\Delta\omega$, Where ΔP_L are non-frequency sensitive load change and $D\Delta\omega$ frequency sensitive load change.

Prime-Mover Model: Prime mover driving a generator unit may be a steam turbine or a hydro turbine. Models for prime mover must take account of steam supply and boiler control system characteristics in the case of a steam turbine, or penstock characteristics for a hydro turbine.

Governor Model: Speed-measurement device's output, w, is compared with a reference, ω_{ref}, to produce an error signal, D_ω. The error, D_ω, is negated and then amplified by a gain KG and integrated to produce a control signal, D_{Pvalve}, which causes the main steam supply valve to open (D_{Pvalve} position) when D_ω is negative. If, for example, the machine is running at reference speed and the electrical load increases, ω will fall below ω_{ref} and D_ω will be negative. Action of gain and integrator will be to open steam valve, causing turbine to increase its mechanical output, thereby increasing electrical output of generator and increasing speed w. When w exactly equals ω_{ref}, steam valve stays at new position (further opened) to allow turbine generator to meet increased electrical load. The result of adding the feedback loop with gain R is a governor characteristic as shown in Figure 9. The value of R determines the slope of the characteristic. That is, R determines the change on the unit's output for a given change in frequency. Common practice is to set R on each generating unit so that a change from 0 to 100%. By adjusting load reference set point. on each unit, a desired unit dispatch can be maintained while holding system frequency close to the desired nominal value. Boundary between response capability and economic allocation by economic dispatch. Note that a steady-state change in DP_{valve} of 1.0 pu requires a value of R pu change in frequency, Dω. One often hears unit regulation referred to in percent. For instance, a 3%

regulation for a unit would indicate that a 100% (1.0 pu) change in valve position (or equivalently a 100% change in unit output) requires a 3% change in frequency. R is equal to pu change in frequency divided by pu change in unit output.

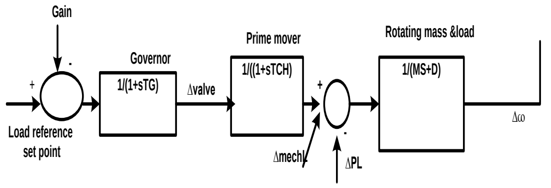


Figure 9: Block diagram of governor, prime mover, and rotating mass (load)

If this generator experiences a step increase in load, $\Delta P_L(s) = \frac{\Delta P_L}{s}$. Transfer function relating load changes, D_{PL}, to $D\omega$, is

$$\Delta\omega(s) = \Delta P_L(s)\left[\frac{\frac{-1}{Ms+D}}{1+\frac{1}{R}\left[\frac{1}{1+sT_G}\right]\left[\frac{1}{1+sT_{CH}}\right]\left[\frac{1}{Ms+D}\right]}\right] \qquad (20)$$

If the point b moves a distance Δy_b, then it is related to the change in point let **a** and **c** (Δy_a and Δy_c respectively), $\Delta y_{h=K_{ba}\Delta y_a+K_{bc}\Delta y_c}$, $\Delta y_{d=K_{dc}\Delta y_c+K_{de}\Delta y_e}$, $\Delta P_{ref} = K_a \Delta y_a$, Where K_{ba}, K_{bc}, K_{dc}, K_{de} are constants. The point **a** is related to the change in the reference power and if the reference power is P_{ref} then $\Delta\omega = \omega_{base} K_b \Delta y_b$, Point **d** effects point **e** through the high pressure oil servo mechanism. Point **e** moves according to the rate of change of oil flow in the main piston chamber. Note that points d and e move in opposite direction: $\frac{d\Delta y_e}{dt} = -K_e \Delta y_d$. The model shown in Figure 9. It consists of a typical hydro turbine governor model and a linearized hydro turbine model. The output of turbine governor is the gate position derivative (ΔG), while the input of the turbine is the gate position (G). Consequently, a position reference Gref , which is regarded as equal to Pref , is required between them. To implement models in computer software and determine its future behavior, normally, a set of state variables that consists of coupled first-order differential equations are necessary for a dynamic system. However, it is hard to figure out the state variables in the structural diagram. The solution is redrawing the models only by integrators and gain blocks. After few substitutions and mathematical analysis, we can develop a transfer function block diagram model of speed governor of hydro turbines. Where: P_o is the initial power PGV is the output of the governor, K is the reciprocal of *Permanant droop* R (steady state speed regulation expressed in per unit). For mechanical-hydraulic governor: T_1= 0.2 – 0.3, T_2= 0, T_3= 0.1. K depends on the permanent droop that indicates the amount by which the frequency falls from no load to full load without change in the input power. General model represents a compact block of transfer function where input is the speed deviation $\Delta\omega$ and the output is change in power ΔP.

Modeling of Governor: Speed control mechanism includes equipment such as relays, servomotors, pressure or power amplifying devices, levers and linkages between speed governor and governor-controlled gates. Speed governor normally actuates the governor-controlled gates that regulate water input to the turbine through the speed control mechanism. Additionally, temporary droop and three phase fault disturbances are utilized. [3] Temporary droop is used to limit overshoot of the turbine control servomotor during a transient condition. Temporary droop may be developed either by connecting a dashpot from the wicket gate position to governor error summing point, or adding a filtered derivative of wicket gate position to governor error summing point. Transfer function of transient droop compensation is given [4] by combining overall hydro governor, hydraulic turbine governing system.

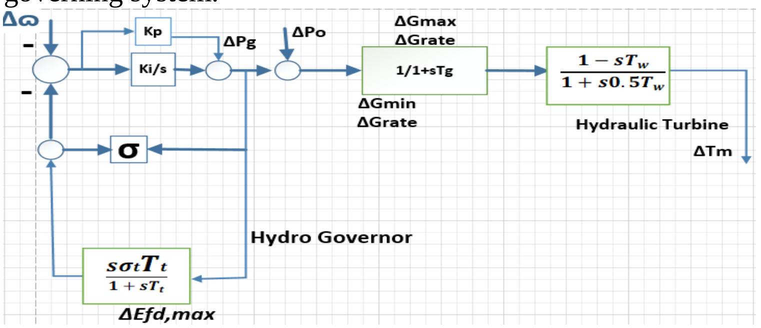


Figure 10: Schematic diagram of the Governing system

The design of the PSS-G is to be carried out in the same way as for the PSS-E and the transfer function for the PSS-G is used from (13). The mechanical torque ΔTm provided by the PSS-G is given by:

$$\Delta T_m(s) = \left(\frac{1}{1+sTg}\right)\left(\frac{1-T_w s}{1+0.5T_w s}\right) G_{PSSG}(s)\Delta\omega(s)$$

Where $\left(\frac{1}{1+sTg}\right)$ are servo and $\left(\frac{1-T_w s}{1+0.5T_w s}\right)$ are turbine. In order for the damping capability to be improved by the PSS-G via the path of governor control path, it must compensate the phase shift of the hydraulic turbine and the servo dynamics [19].

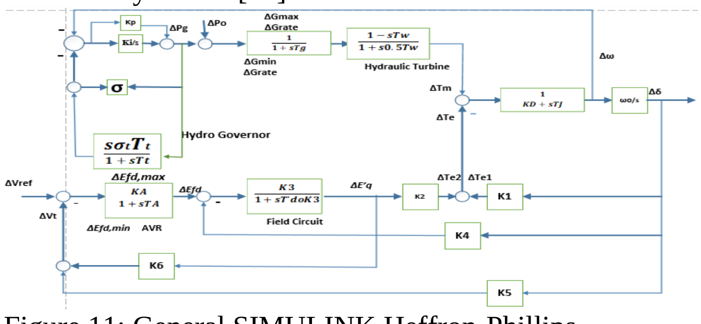


Figure 11: General SIMULINK Heffron-Phillips model with hydro governor

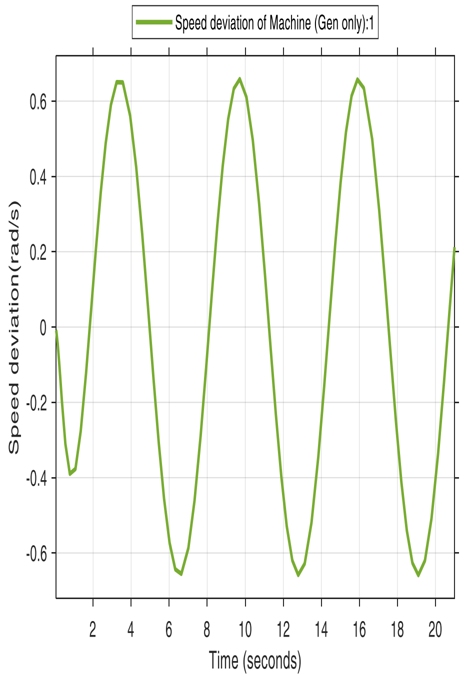
Parameters Used for entire system modeling and Simulation

Table 1: Parameters used for system modeling

For governor	Values (p.u)	For Exciter	Value (p.u)	For Synchronous machine	Value (p.u)
Water starting time(Tw)	3	V ref	1.1	KP,f , Tj	3,50,0.33
ω; ω_{ref}	50	Td	0.7	KI, Kd	0.1, 3.522
Ta, Kp	0.1,3	Tj	0.333	Tt, Td	5,0.7
Gains Kp, Ki, Kd	0.1,3.522	Ka, Ta	1.1, 0.1	Tg, K1, K2	0.5, 1.591, 1.5;
Td, Ka	0.7,1.1	K2, Kf, Tf	1.5, 0.33	K3, k4, k5, k6, Tw	0.333; 1.8; -0.12; 0.3; 3

2. Results and Discussion

The simulation model wss based on the SMIBS and used the hydro governor with hydraulic turbine. The simulation parameters were taken from the mathematical analysis from Table 1. The simulations shown in the figures 12 to 18 were analysised. It can be seen in the output signal in Figure 12 that the generator with speed control via the hydro governor (Gen+Hyd.-Gov.) has a higher tendency to oscillate than the one which is only operated with constant power (Gen only). The reason is the reduction of the damping ratio of the electromechanical mode due to the negative influence of the hydraulic pressure surge. In figure 13, speed deviation response in case of normal load with PSS-PID and PSS-E has been illustrated. In Figures 14 and 15, it has done on speed deviation response in case of normal load with PSSE-PID, PSS-G and both and electric air gap torque response in case of normal load with PSS-G and PSS-E &PID respectively. In figures 16 and 17, mechanical torque response in case of normal load with PSS-E, PID and PSS-G and Voltage at V, starting at t=0.5 s and lasting 1 s, triggering an oscillation with 0.52 Hz and generator voltage Vt are illustrated respectively. Figure 18 shows voltage at V, starting at t=0.5 s and lasting 1 s, triggering an oscillation with 0.52 Hz. Top: hydro governor output ΔPg with PSS-G, right side: ΔPg with PSSE-PID.



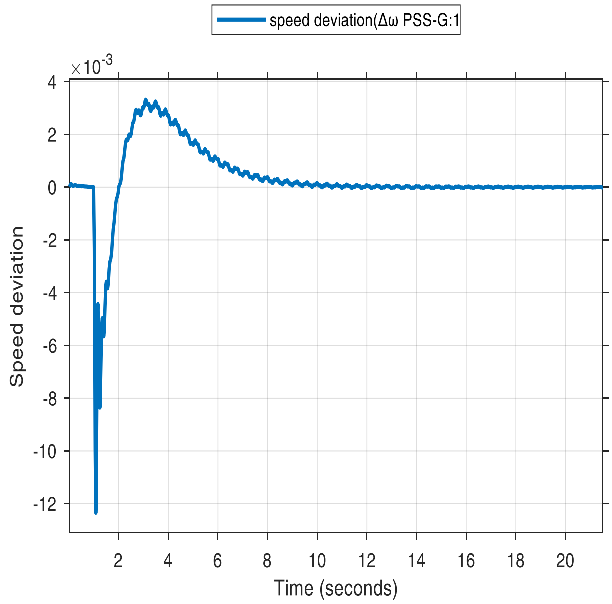


Figure 12: Speed deviation response in case of normal load with Gen only and PSS-G

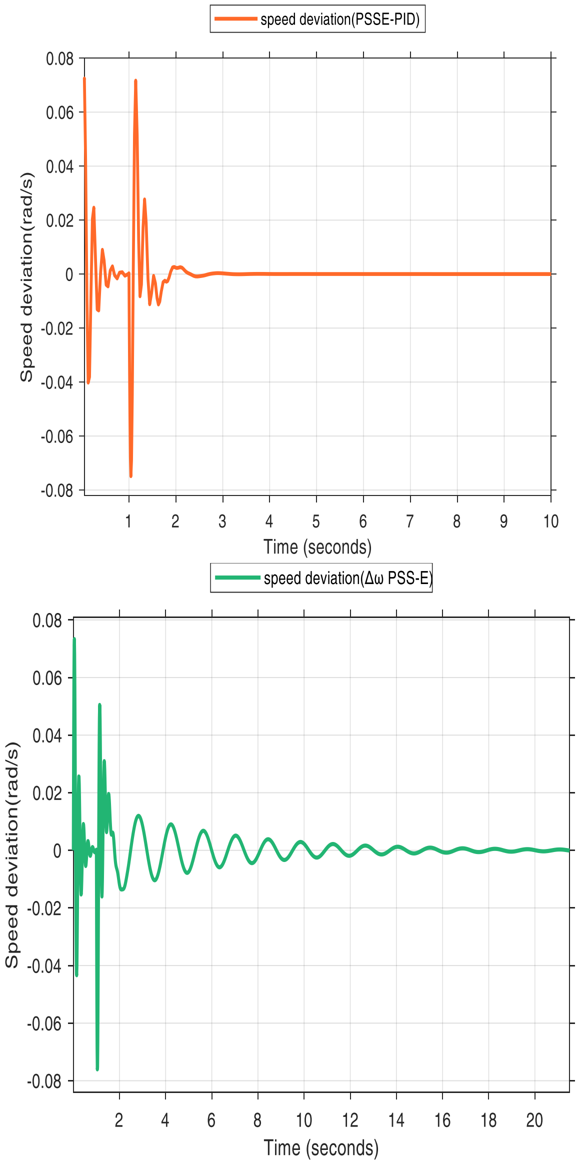


Figure 13: Speed deviation response in case of normal load with PSS-PID and PSS-E

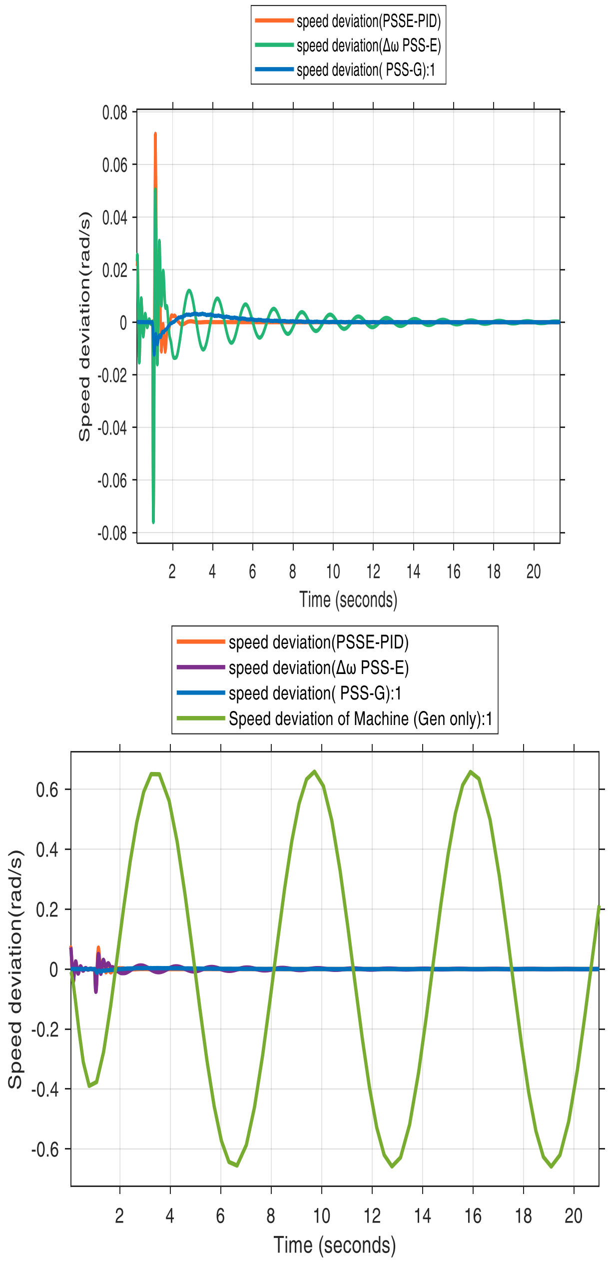
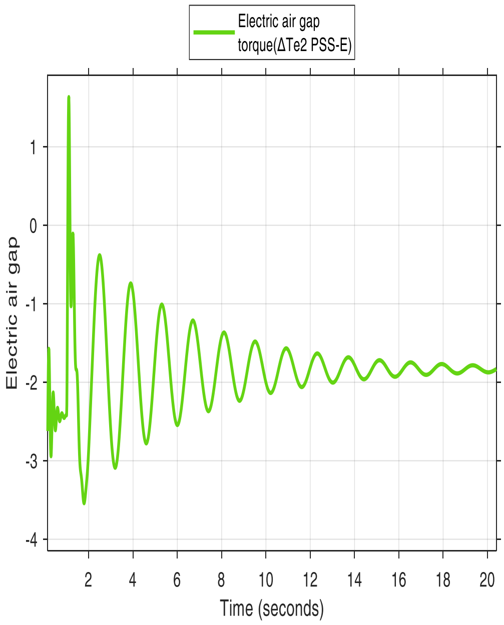
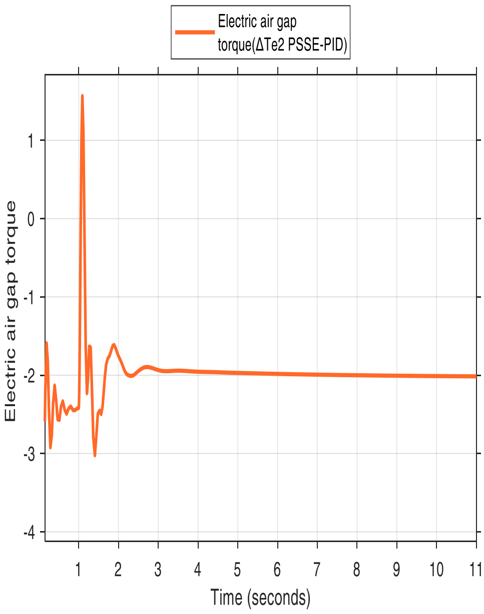
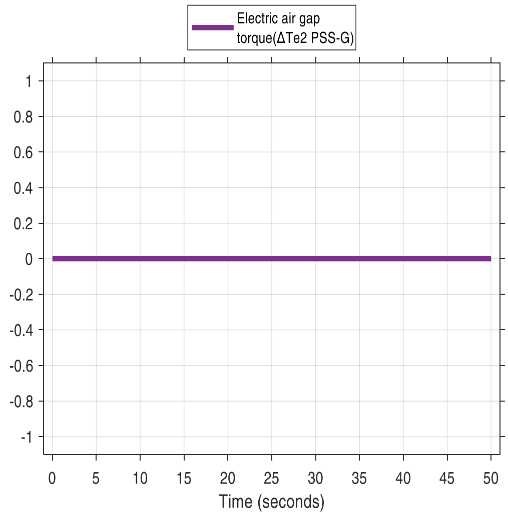


Figure 14. Speed deviation response in case of normal load with PSSE-PID, PSS-G and both







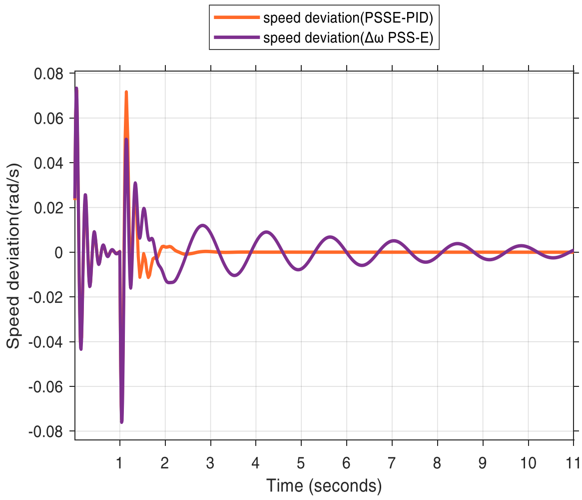
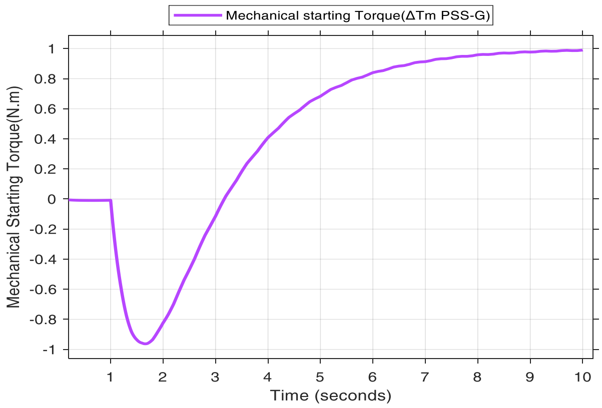
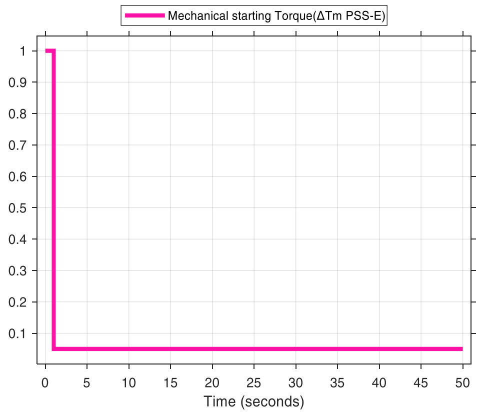


Figure 15: Electric air gap torque response in case of normal load with PSS-G and PSS-E &PID





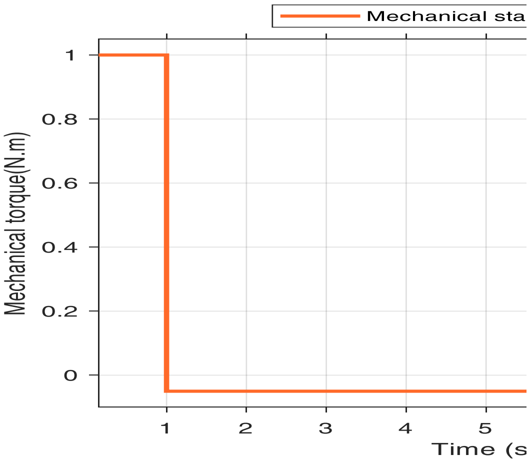


Figure 16: Mechanical torque response in case of normal load with PSS-E, PID and PSS-G

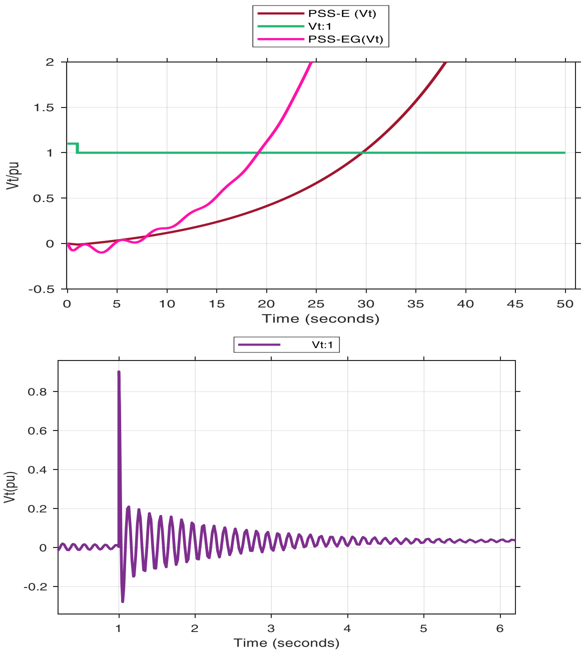


Figure.17. Voltage at V, starting at t=0.5 s and lasting 1 s, triggering an oscillation with 0.52 Hz. generator voltage Vt

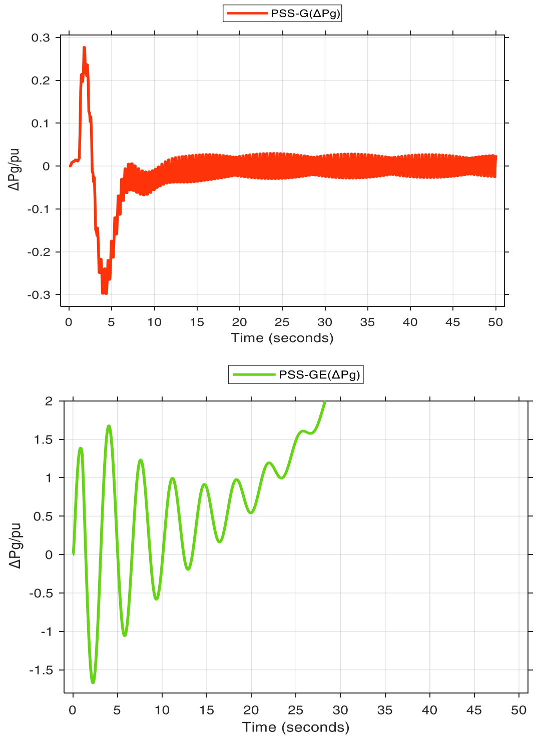


Figure. 18. Voltage at V, starting at t=0.5 s and lasting 1 s, triggering an oscillation with 0.52 Hz. Top: hydro governor output ΔPg with PSS-G, right side: ΔPg with PSSE-PID

It can be seen in the frequency signal in Figure 12 that the generator with speed control via the hydro governor (Gen+Hyd.-Gov.) has a higher tendency to oscillate than the one which is only operated with constant power (Gen only). The reason is the reduction of the damping ratio of the electromechanical mode due to the negative influence of the hydraulic pressure surge. By adding a power system stabilizer in the excitation path of the generator (PSS-E), the damping ratio of the dominant mode can be increased . In Figure 12, the improved damping behavior with the PSS-E can be seen in the frequency signal. At the same time, due to the PSS-E, the generator is excited with higher dynamics, which results in an increased oscillation behavior in the voltage characteristic Vt from Figure 12 as a result.

When a power system stabilizer in the hydro governor control path (PSS-G) is added, the damping ratio of the dominant mode can be significantly increased except at initial time shooting than PSS-E. In the frequency response from Figure 12, the decaying oscillation due to the PSS-G can be seen. Since the generator excitation is not influenced by the PSS-G, this does not affect the generator voltage Vt, compared to the basic version (Gen+Hyd.-Gov.). The occurring frequency oscillation has the consequence of the PSS-G that the maximum actuating valve speed of 0.05 pu/s has already been reached. From the results, the limitation of the control gradient at the hydro governor output Pg can be clearly seen. When using the PSS-G, it must be ensured that it is only used in the case of correspondingly low-frequency oscillations where the turbine valve is not operated permanently at the maximum velocity gradient. At the same time, when a power system stabilizer in the hydro governor control path (PSSE-PID) is added, the PSSE-PID again increases the oscillation behavior at the generator voltage because of the negative influence of the PSS-E.

PSS-G can provide significantly greater damping capability for low-frequency oscillations/single machine via the hydro governor than the PSS-E via the generator excitation. The combined use of PSS-E and PSS-G has not resulted in any negative mutual interference. The reasonable use of a PSS-G as well as a PSS-EG requires a high dynamic hydro governor and correspondingly large velocity gradients of the turbine valve. The combined control strategies require additional consideration of the increased mechanical load on the generator shaft and the actuator. With an optimal controller as damping element (PSSE-PID), the highest damping capability could be achieved in the single-machine model. The application of this method in the three-machine model used is not quite as effective as compared to the PSS-EG. This is because the PSSE-PID is only useful where the generator connection is similar to that of the SMIBS mode.Therefore,for multi-machine inter-area oscillation PSS-EG are more efficient than other controllers, but damping inter-area oscillation for single machine infinite bus, the combined PSSE-PID controllers are most effective.

3. Conclusion

In this work, it could be shown that the combined use of a PSS-E and PSS-PID in a hydropower plant control system can significantly improve the damping behavior with regard to inter-area oscillations. The PSS-G can provide significantly greater damping capability for low-frequency oscillations via the hydro governor than the PSS-E via the generator excitation. The combined use of PSS-E and PSS-G has not resulted in any negative mutual interference. The reasonable use of a PSS-G as well as a PSSE-PID requires a high dynamic hydro governor and correspondingly large velocity gradients of the turbine valve. The combined control strategies require additional consideration of the increased mechanical load on the generator shaft and the actuator. With an optimal controller as damping element (PSSE-PID), the highest damping capability could be achieved in the single-machine model. A generator with such a connection is automatically the optimal choice in terms of the best possible damping capability. This highlights the importance of the overall consideration of the power system with respect to the best possible use of damping methods. The PSSE-PID has been shown to be an extremely robust method in the single-machine model for a defined wide frequency band. The PSSE-PID is simpler in design and can be applied more precisely to the generator with the greatest influence on the oscillation behavior in the grid. However, the mutual influence of the voltage regulators of neighboring generators by the PSS-E must be taken into account. To increase robustness with the PSS,the promising results with the PSSE-PID make it clear that hydropower plants with appropriate control strategies can increase the damping capability with respect to inter-area oscillations in the power system and thus make an important contribution to increasing power system stability.

The PSS-E-PID method showed a high performance that contributed to effective damping of the oscillation that arises through the integration of hydropower energy sources. The simulation results confirm that the PID controller based on the SMES enhanced the damping inter-area in the single machine power system with a better PID controller. Thus, the PSSE-PID can play an important role in improving the stability of the power systems integrated with high penetration and require to utilize advanced and robust control methods to avoid potential interactions, avoid the unstable operating condition of power systems, and fast up to obtain optimal operating conditions for power systems.

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