



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

Solomon Feleke, Mihret Fetene, Atinkut Bay

Electrical and Computer Engineering Department, Debre Berhan University, Debre Berhan, Ethiopia.

Abstract

This research investigates strategies to enhance damping capabilities in hydropower plants during inter-area oscillations by incorporating advanced management techniques. It begins by addressing key managerial challenges, such as the water hammer effect, and evaluates the integration of a Power System Stabilizer (PSS) to regulate generator excitation and governor control within a single-machine infinite bus system (SMIBS). The PSS is designed to generate additional control signals to mitigate low-frequency oscillations, which can impact the dynamic stability of power systems. Through appropriate PSS configuration, these oscillations are effectively reduced, improving overall system stability. The study highlights the importance of introducing a stabilizing signal to counteract voltage error oscillations during dynamic conditions and to provide a damping factor in synchronization with rotor speed, electromagnetic torque, and mechanical torque. A customized PSS is shown to provide supplementary damping torque across various operating states, enhancing dynamic stability. The Heffron-Phillips model, which incorporates the hydro turbine, excitation system, and integrated design of the PSS and model-based controller, is used to assess damping performance. Time-domain analysis using a three-machine model demonstrates that the combined PSS-G and PSS-EG controllers deliver optimal performance, ensuring stability across all operational states in hydropower plants.

Keywords: Inter-area oscillations control; Power system stabilizer tuning; Optimal power system control; Power system stability enhancement; Damping capability improvement techniques.

1. Introduction

Electric power transmission networks are complex systems consisting of generators, transmission lines, transformers, and loads. The increasing demand for electricity, coupled with the need for improved reliability, has a significant impact on the performance of the system. Therefore, it is crucial to utilize appropriate tools for analyzing system stability. Engineers depend on computer-based simulation tools to assess the dynamic stability and efficiency of power systems, ensuring safe and reliable operation. In these systems, generators are powered by mechanical energy from turbines, each of which is equipped with a turbine governor. This speed control mechanism regulates the turbine's speed to maintain the desired power output[1]. Turbine governors play a crucial role as the primary frequency controllers for synchronous machines in the event of system disturbances. Their function is essential in

maintaining the stability and reliability of the power system during unexpected events [2]. Synchronous generators in stability studies include both inertial and rotor flux dynamics. Modern power plants use static excitation systems for faster response, replacing older DC exciters. However, their high initial response can impact oscillatory damping, requiring power system stabilizers. Additional controls include current, voltage, and flux limiters for protection. [3]. Management strategies for men and women are assessed within the single-machine infinite bus system (SMIBS). Figure 1 shows a synchronous generator connected to an infinite bus via a transmission line, regulated by a hydraulic turbine and excitation system, implementing PSS-E in the AVR and PSS-G in the governor control[4].

*Corresponding author: sole12@dbu.edu.et/solomonfelek1888@gmail.com.

Received: Mar 15/2023, **Revised Sep 25/2023**, **Accepted:** Oct 10/2023, **Published:** Feb 1/2024.

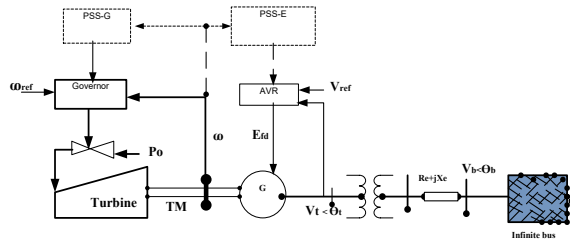


Figure 1: SMIBS with hydro governor and PSS-E and PSS-G

2. Mathematical modeling of the system

The Single Machine Infinite Bus System (SMIBS) connects a synchronous generator to the grid, with excitation on the d-axis which is shown in figure 1 [5]. As outlined in reference [5], characterizes generator dynamics using differential (1-4) and algebraic equations (5-6).

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

$$\frac{dE'_q}{dt} = \frac{1}{T'_{d0}} (-E'_q - (X_d - X'_d)I_d + E_{fd}) \text{ and } \frac{dE'_d}{dt} = \frac{1}{T'_{q0}} (-E'_d - (X_q - X'_q)I_q) \quad (2)$$

Equations (3) and (4) provide the generator's torque and excitation dynamics.

$$T_E = (E'_d I_d + E'_q I_q + (X_q - X'_d)I_d I_q) \quad (3)$$

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

Equations (5) and (6) represent generator currents and stator voltage in polar and dq-model.

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

$$V_d = R_e I_d - X_e I_q + V_b \sin(\delta - \theta_b) \text{ and}$$

$$V_q = R_e I_q - X_e I_d + V_b \cos(\delta - \theta_b) \quad (6)$$

The generator terminal voltage, denoted as V_t , also needs to be considered. $V_t = \sqrt{V_d^2 + V_q^2}$.

Power system stabilizer (PSS)

The state space controller and PSS reduce rotor oscillations, targeting 0.2 to 2.0 Hz [6]. Excessive AVR gain may compromise damping; PSS output should be zero in steady state[7]. The control signal for PSS should satisfy specific criteria: it should be derived from local measurements and easily

synthesized, have minimal noise content to avoid the need for complex filters and be robust and capable of rejecting noise. Local availability of rotor speed, frequency, and electric power signals is essential, with the speed signal obtainable from a transducer using a tooth wheel mounted on the shaft.

An automatic voltage regulator (AVR): is employed to maintain a stable voltage by converting fluctuating voltage into a consistent level [8]. Voltage fluctuations commonly occur as a result of changes in the load on the supply system. The PSS signals are incorporated as additional feedback to implement a damping torque control component. Among these, the speed signal is most frequently utilized. Shaft speed, frequency, and power stabilize rotor oscillations [9]. In the present day, interconnected power systems are susceptible to low-frequency oscillations, which can endure for extended periods and potentially lead to system separation if not adequately dampened. Insufficient damping torque in the synchronous generator unit, often caused by factors such as high speed and gain of the AVR exciter and system loading, can exacerbate this issue. To mitigate these challenges, Power System Stabilizers (PSSs) have been effectively tested and deployed to counteract low-frequency oscillations. PSSs function by introducing supplementary stabilizing signals into the excitation system, thereby dampening electromechanical oscillations [10]. The excitation system provides DC to the synchronous generator's field winding, ensuring voltage regulation and stability. It includes components like the exciter, regulator, and amplification methods (digital or magnetic). Key functions include voltage regulation, load compensation, and integrating stabilizers and protective circuits for reliable operation [11].

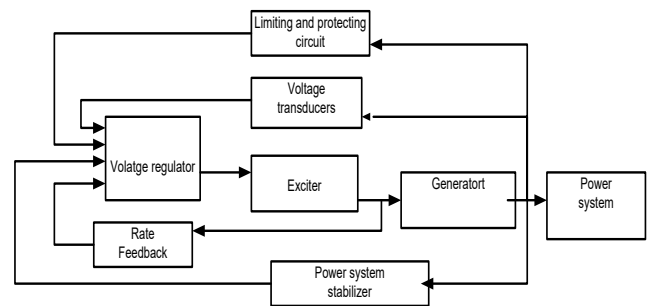


Figure 2. Basic blocks of excitation system

Inter-area modes involve the participation of generators across different regions, resulting in low oscillation frequencies typically ranging from 0.2 to 0.5 Hz [2]. Stabilizers regulate generator excitation to mitigate oscillations in the 0.2 to 2.5 Hz range.

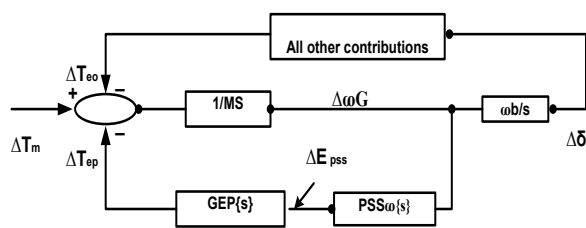


Figure 3. generator, excitation system, and power system (GEP(s)). From Larsen, [12]

The objective is to address the section lag within the GEP. Typically, the stabilizer input is derived from the shaft speed, and T_6 denotes the measurement delay, which is generally negligible (close to zero). Recommendations suggest less than ten seconds for swift low-frequency component elimination with two washout filters [13].

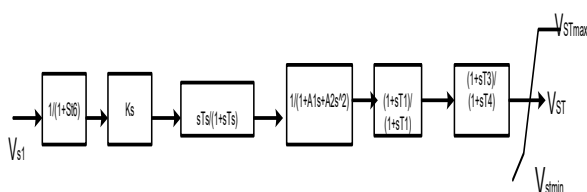


Figure 4. Single input PSS

Stabilizer Design Values: The design values for stabilizer design with a washout filter value of $T_5 = 10$ at 0.1 Hz ($s = j0.2\pi = j0.63$) result in a gain of 0.987, while with $T_5 = 1$ at 0.1 Hz, the gain is 0.53. Ignoring the second-order block, parameters to be tuned include the gain (K_s) and time constants of the lead-lag blocks, assuming ($T_1 = T_3$) and ($T_2 = T_4$), for phase compensation. A damping torque component can be introduced using the speed to control generator excitation. Due to frequency-dependent gain and phase characteristics in both the generator and exciter, the PSS transfer function needs phase compensation to address the phase lag between the exciter input and electrical torque. Electromechanical oscillations can be influenced by the electric air gap torque or turbine mechanical torque in equation (7).

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

The voltage regulator behavior is described by transfer function (s) in equation (8)

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

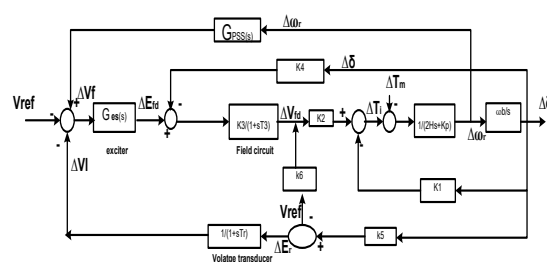


Figure. 5. AVR and PSS

Transfer function for PSS-E is given by [8] which is illustrated in equation (9).

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

Where $K \left(\frac{stp}{1+stp} \right)$ are high pass-filter and $\left(\frac{1+st1}{1+st2} \right)^n$ are phase shift.

Controlling System Modeling

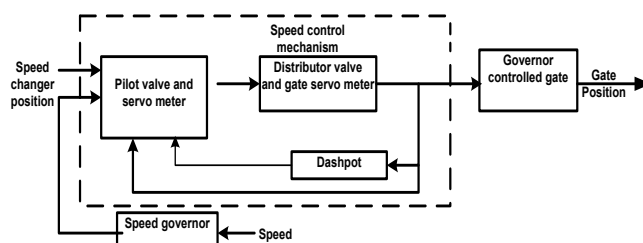


Figure 8. Speed governing system for hydro turbines-functional block diagram

When hydro turbine modeling, a slight variation in water velocity can be described as the cumulative effect of linear adjustments in gate position and hydraulic head. The water velocity within the penstock is quantifiable by the equation: $U = K_u * G * H$, where U represents the water velocity, K_u denotes constant, G signifies the gate position, and H indicates the hydraulic head at the gate.

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

The acceleration of the water column can be determined by computing the partial derivatives in the equation under the initial operating condition. This initial condition should accurately reflect a minor alteration in the water speed. The initial water speed, corresponding to a specific initial gate position (G_0) and head (H_0), can be expressed using equation (10) with a slight deviation of normalized water velocity, or it can be normalized by dividing it by another equation, equation (11).

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

Turbine mechanical power can be obtained from the product of pressure and flow as illustrated in equation (12);

$$P_m = K_p H U \quad (12)$$

The partial derivative of equation (12) which mechanical power changed by a small amount as:

$P_{mo} = K_p H_o U_o$, and $\Delta P_m = K_p U_o \Delta H + K_p H_o \Delta U$; This equation can be normalized by dividing it with the initial value

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

$$\begin{aligned} \text{Substituting } \Delta U: \Delta P_m &= 3/2 \Delta H + \Delta G, \text{ and} \\ \text{Substituting } \Delta H: \Delta P_m &= 3/2 \Delta U - 2 \Delta G \end{aligned} \quad (14)$$

Water column acceleration due to turbine head change.

$$[2]: \quad \rho L A d \Delta U / dt = -(\rho a g) \Delta H \quad (15)$$

If this equation is converted in to Laplace domain, then $T_w s \Delta U$, $s = -\Delta(s)$. Substituting ΔU from $\Delta P_m = 3 \Delta U - 2 \Delta G$ and rearranging;

$$\begin{aligned} T_w s \Delta(s) &= -2(\Delta U - \Delta G)(s), T_w s \Delta(s) + 2 \Delta U(s) = \\ 2 \Delta G(s), \Delta U(s) (T_w s + 2) &= 2 \Delta(s), \Delta U(s) = \frac{2 \Delta G(s)}{T_w s + 2}, \frac{\Delta P_m}{\Delta G} = \\ \frac{1 - T_w s}{1 + 0.5 T_w s} \end{aligned} \quad (16)$$

$$\begin{aligned} \text{OR, } \Delta U(s) &= \frac{\Delta G(s)}{1 + 0.5 T_w s}, \text{ In the previous equation,} \\ \Delta \bar{P} m &= 3 \Delta \bar{U} - 2 \Delta \bar{G} \end{aligned} \quad (17)$$

$$\begin{aligned} \text{Substituting equation (14) in equation (13) and} \\ \text{eliminating } \Delta U \text{ led to: } \Delta \bar{P} m(s) &= \frac{1 - T_w s}{1 + 0.5 T_w s} \Delta G(s) \text{ OR} \\ \frac{\Delta \bar{P} m}{\Delta \bar{G}} &= \frac{1 - T_w s}{1 + 0.5 T_w s} \end{aligned}$$

This is the equation representing the transfer function of a hydraulic turbine. The mathematical equation of synchronous generator (transfer function) is given by;

$$\frac{\Delta \omega}{\Delta P_m} = \frac{1}{2 H S} = \frac{1}{T_m S + 1}$$

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

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

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

$$\text{Partial derivatives of flow: } a_{11} = \frac{\partial u}{\partial}, a_{12} = \frac{\partial u}{\partial n}, a_{13} = \frac{\partial u}{\partial g},$$

Partial derivatives of output 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, the transfer function between $\Delta \bar{P}$ and $\Delta \bar{G}$ becomes:

$$\frac{\Delta \bar{P} m}{\Delta \bar{G}} = a_{23} \frac{1 + (a_{11} - a_{13} a_{21} / a_{23}) T_w s}{1 + a_{11} T_w s} \quad (18)$$

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

Hydraulic turbines increase generator oscillations; typical governor bandwidth is 0.03-1 Hz, with rise times 1-25 s.[14].

Load Model: Load changes with frequency variations are shown in equation (19);

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

Prime-mover models for generators, like steam or hydro turbines, must account for steam or penstock characteristics. Speed measurement creates an error signal that adjusts the steam valve, impacting generator output. The feedback loop with gain R regulates output changes to maintain frequency, often expressed as a percentage of valve change.

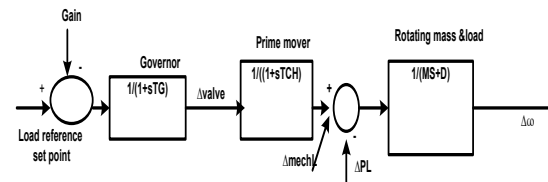


Figure 9: Governor, Prime mover, and load

Transfer function relating load changes, D_{PL} , to $D\omega$, is express in equation (20).

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

Point movements relate through constants; turbine model uses transfer functions.

Modeling of Governor

The governor's speed control uses relays, servomotors, and linkages. The transfer function of transient droop compensation is as described as follow in paper [5]. To achieve optimal performance, the overall hydro governor and hydraulic turbine governing system should be combined. This integration will ensure seamless coordination and control of the hydropower generation process, resulting in improved efficiency and stability.

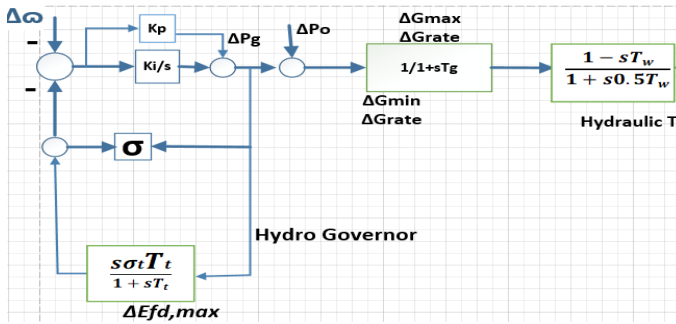


Figure 10: Governing scheme

PSS-G design matches PSS-E, compensates phase shifts.

3. Matlab modeling the system

The process of modeling and simulating a system in Matlab involves the utilization of parameters that are applicable to the entire system [4]. These parameters are derived from mathematical analysis and are crucial for accurately representing the system in the simulation. The Matlab model created using these parameters enables system-wide modeling and simulation, providing a comprehensive understanding of the system's behavior and performance.

Table 1: Parameters used for system modeling

For governor	Value s (p.u)	For Exci ter	Val ue (p.u)	For Synchro nous machine	Value (p.u)
Water starting time(T_w)	3	V ref	1.1	KP,f, Tj	3,50,0.33
$\omega; \omega_{ref}$	50	Td	0.7	KI, Kd	0.1, 3.522
Ta, Kp	0.1,3	Tj	0.3 33	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,	1.5, 0.3	K3, k4, k5, k6,	0.333; 1.8; -0.12; 0.3;

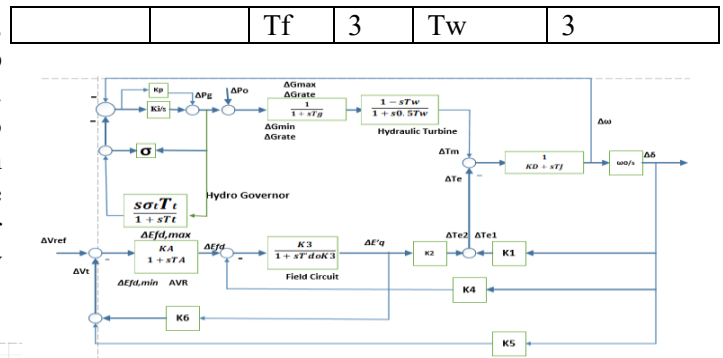


Figure 11 Modeling in Matlab/SIMULINK Heffron-Phillips model incorporating a hydro governor.

4. Results Discussions

The study utilized a simulation model based on the SMIBS, incorporating the hydro governor with the hydraulic turbine. Simulation parameters were determined from the mathematical analysis detailed in Table 1. Examination of the simulations in Figures 12 to 18 revealed several significant conclusions. Figure 12 shows hydro governor causes more generator speed oscillation. Additionally, Figure 13 demonstrated the speed deviation response under normal load conditions with PSS-PID and PSS-E. Moreover, Figures 14 and 15 showcased the speed deviation response under normal load conditions with PSSE-PID, PSS-G, and an electric air gap torque response under normal load conditions with PSS-G and PSS-E & PID, respectively. Furthermore, Figures 16 and 17 displayed the mechanical torque response under normal load conditions with PSS-E, PID, and PSS-G, as well as the voltage at V, causing an oscillation with 0.52 Hz, and the generator voltage Vt, respectively. Figure 18 shows voltage oscillation and hydro governor outputs ΔP_g .

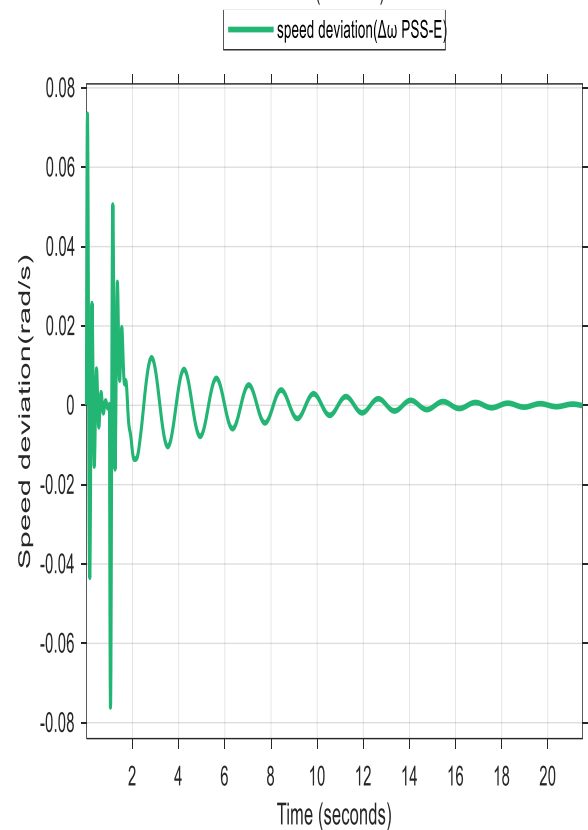
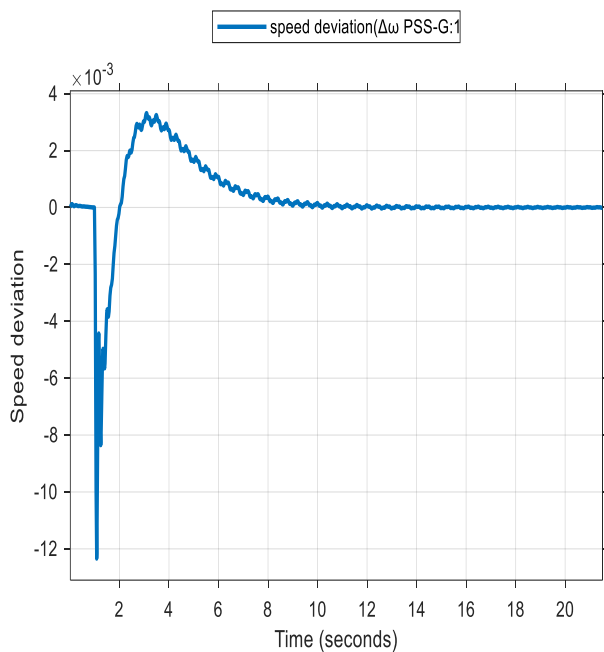
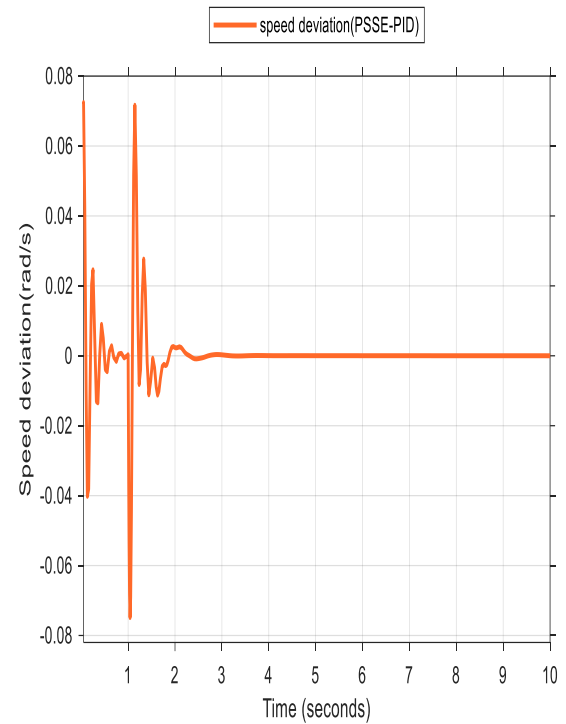
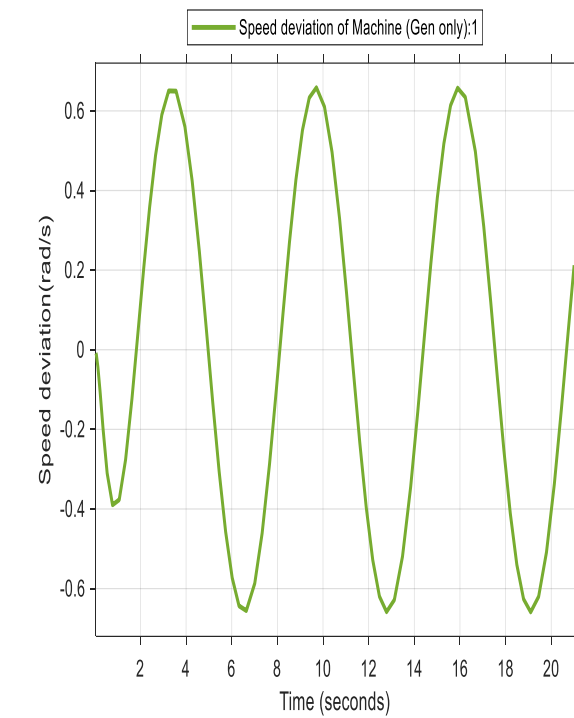


Figure 12: Speed variation response in case of normal load with Gen only and PSS-G

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

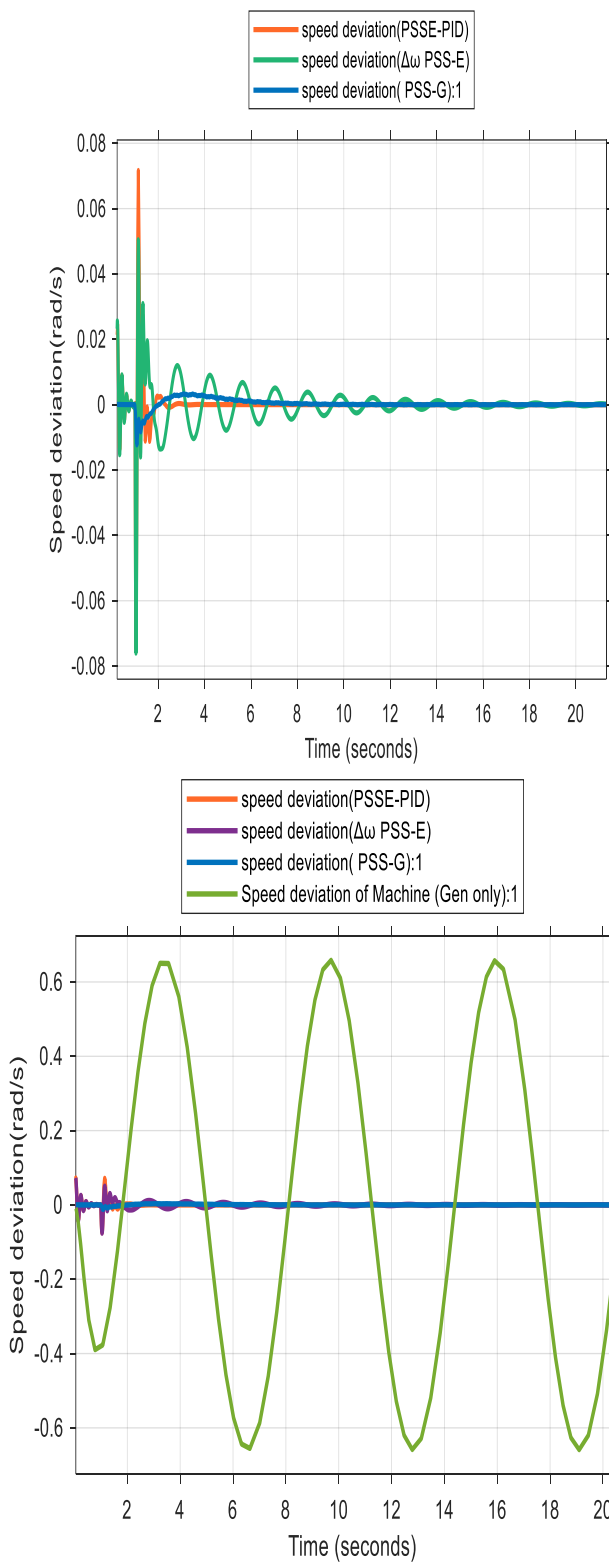


Figure 14. Speed variation response in case of normal load with PSSE-PID, PSS-G and both

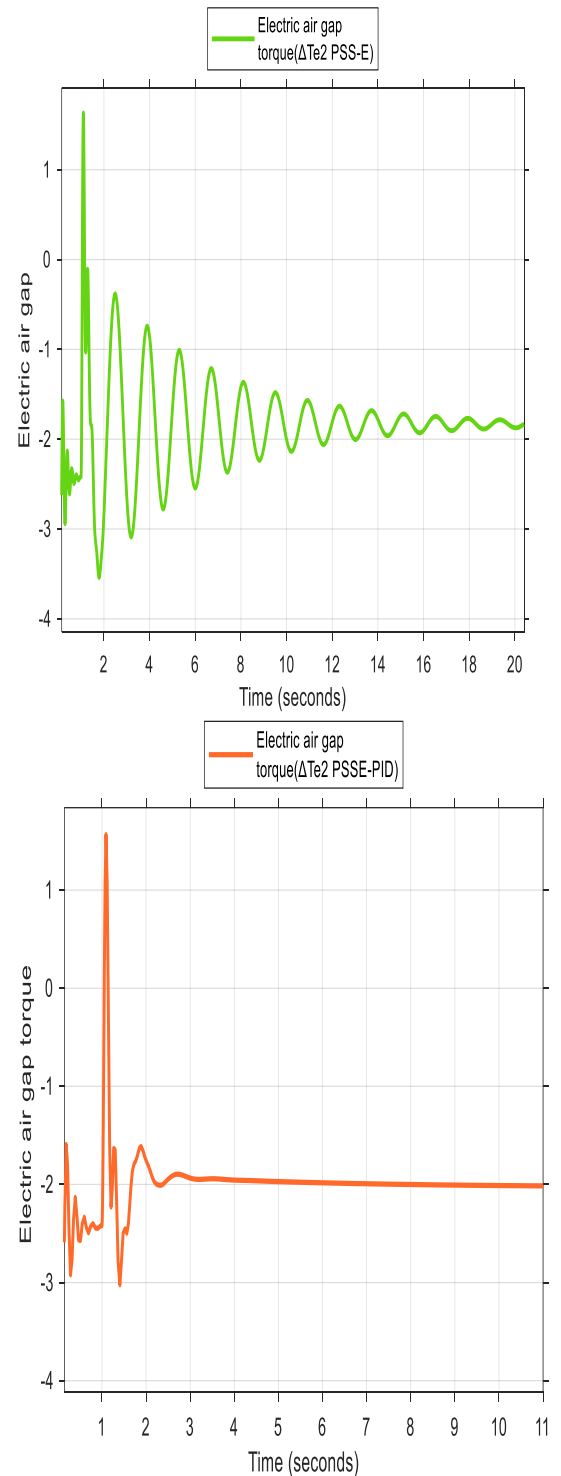


Figure 15 a: Electric air gap torque response in case of normal load with PSS-G and PSS-E & PID

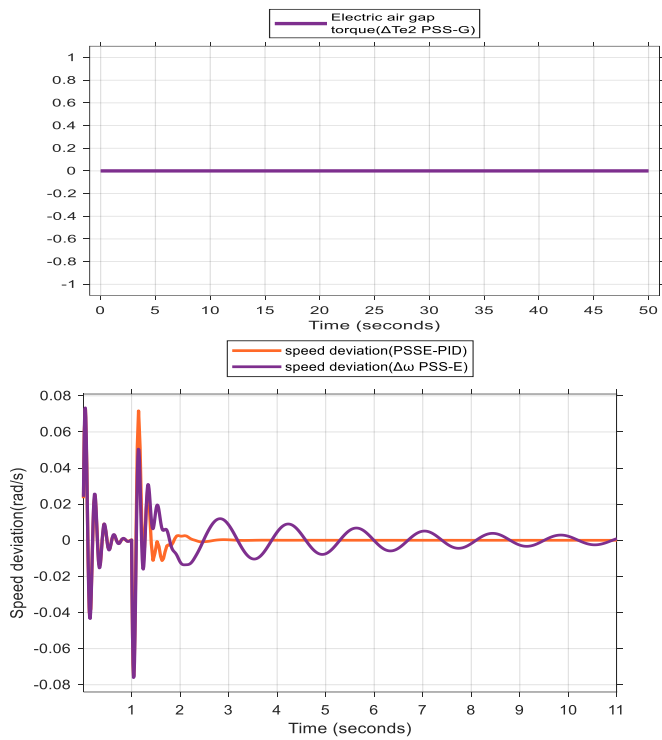


Figure 15 b: Electric air gap torque response in case of normal load with PSS-G and PSS-E & PID

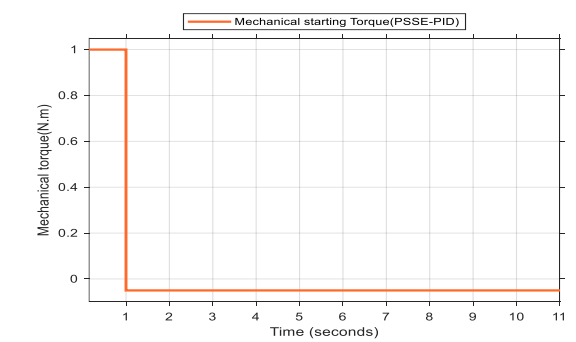
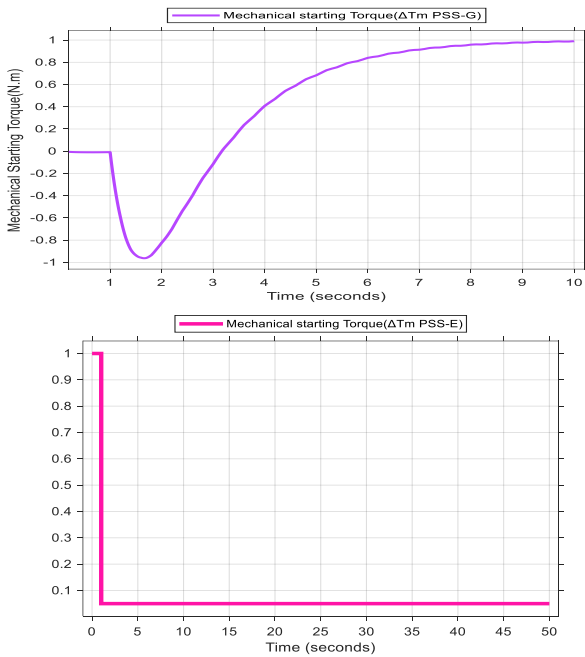


Figure 16: Mechanical torque response in case of normal load with PSS-E, PID and PSS-G

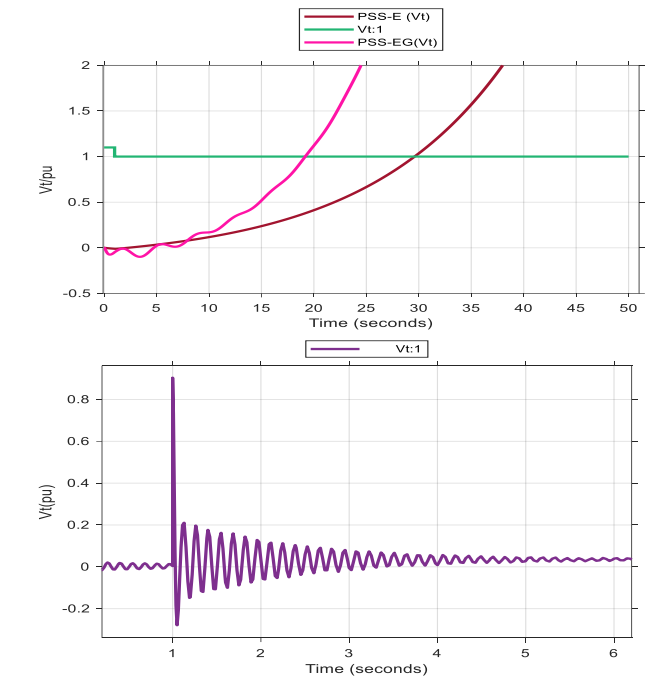


Figure.17. With triggering an oscillation with 0.52 Hz. generator voltage V_t

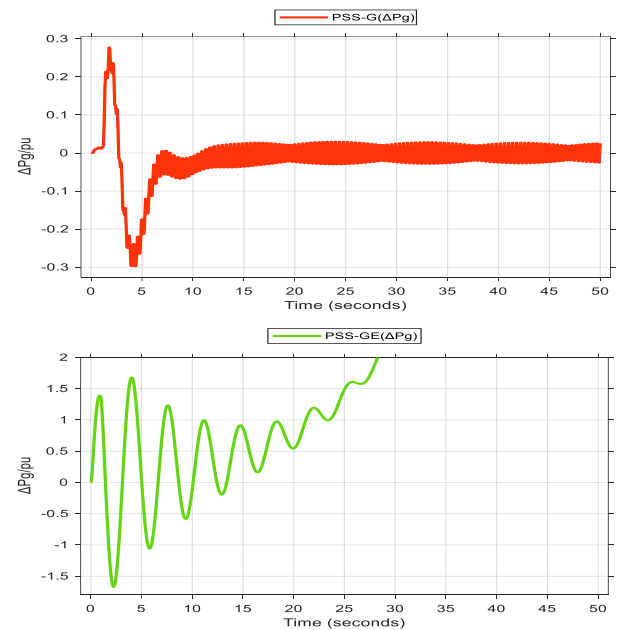


Figure. 18. Voltage output

The frequency signal in Figure 12 reveals that the generator regulated by a hydro governor shows a higher tendency for oscillation compared to a generator operated independently. This behavior is attributed to a reduction in the damping ratio of the electromechanical mode, influenced by the negative effects of hydraulic strain surges. Implementing PSS-E in the generator's excitation path improves the damping ratio of the dominant mode, as shown by the enhanced damping in the frequency signal. However, adding PSS-E increases the dynamics in the generator's excitation, leading to more pronounced oscillations in the voltage. Introducing a power system stabilizer in the hydro governor control path (PSS-G) further improves the damping ratio, particularly during decaying oscillations, without affecting the generator's excitation or voltage. Still, frequency oscillations with PSS-G may cause the maximum actuating valve speed to be reached, limiting the control gradient at the hydro governor output. The combined use of PSS-E and PSS-G offers enhanced damping for low-frequency oscillations without negative interference. Additionally, an optimal controller (PSS-E-PID) provides the highest damping for single machines, while PSS-EG controllers are more effective for multi-machine inter-area oscillations. For single-machine infinite bus systems, a combination of PSS-E-PID controllers is most effective for damping.

Conclusion

This study demonstrates the effectiveness of using both PSS-E and PSS-PID in hydropower plant control systems to enhance the damping of inter-area oscillations. PSS-G, when applied through the hydro governor, provides superior damping for low-frequency oscillations compared to PSS-E, which uses generator excitation. The simultaneous application of PSS-E and PSS-G does not cause detrimental interference. However, the effective implementation of PSS-G and PSS-E-PID requires a dynamic hydro governor and significant valve velocity gradients in the turbine. Additionally, careful consideration must be given to the increased mechanical stress on the generator shaft and actuator when employing combined control strategies.

The optimal controller, such as the PSS-E-PID, demonstrates the highest damping performance in a single-machine model, making it ideal for maximizing damping capability. This underscores the need for a comprehensive approach to optimizing damping methods in power systems. The PSS-E-PID is a robust solution across a wide frequency range, providing a simpler design that can be more precisely applied to the generator, significantly impacting grid oscillation

behavior. However, the mutual influence of voltage regulators from nearby plants must be carefully considered when using PSS-E.

The strong performance of PSS-E-PID highlights its potential to enhance damping in hydropower plants, contributing to overall power system stability. Simulation results confirm that an improved PID controller, based on SMES, enhances inter-area damping in single-machine systems. As a result, the PSS-E-PID plays a vital role in stabilizing power systems with high penetration of renewable energy sources, requiring advanced control techniques to mitigate interactions and maintain stable operations under optimal conditions.

5. References

1. Kundur P, et al: Power system stability and control, New York, 1994.
2. Machowski J, et al: Power system dynamics: Stability and control, John Wiley and Sons 8, 2020.
3. Wood AJ, Wollenberg BF: Power generation, operation, and control, John Wiley and Sons , 2013.
4. Tsegaye S, a Fante K: Hydro governor control of synchronous machines. MATLAB/SIMULINK based analysis., December 2018.
5. Demello F P, Concordia C: Concepts of Synchronous Machine Stability as affected by Excitation Control, *IEEE Trans. on Power Apparatus System* , 1969.
6. El-Saied Othman MI, Maneef Abd Alla FB: : Dynamic Stability Improvement of Multi machine Power Systems By Using Avr. Power System Stabilizer and Turbine Generator, *Journal of Al-Azhar University Engineering Sector* , vol. 15, no. 54, pp. 162-177, 2020.
7. .Nayini S, Raghutu R: Coordinated PSS and STATCOM Controller for Damping Low Frequency Oscillations in Power Systems," *IJERT-Int. J. Eng. Res. Technol*, 2014, 3: 609-614,.
8. Angu R, Mehta RK: Effect of extended state observer and automatic voltage regulator on synchronous machine connected to infinite bus power system, *Journal of the Institution of Engineers (India): Series B* 2018: 147-156,.
9. Koritarov V, et al: Review of existing hydroelectric turbine-governor simulation models,," Decision and Information services, Argonne National Laboratory , 2013.
10. Choo YC, Muttaqi KM, Negnevitsky M: Modelling of hydraulic governor-turbine for control stabilization, *ANZIAM Journal* , 2007, 49: 681-691.

11. L. D, " An introduction to observers," *IEEE Transactions on automatic control* 1971, 16(6): 596-602,.
12. Larsen EV, Swann DA: Applying power system stabilizers part I: general concepts, *IEEE Transactions on Power Apparatus and systems* 1981, ,6: 3017-24,.
13. JJ G: Power system analysis, McGraw-Hill, 199.
14. LW: Hydro turbine and governor modeling and scripting for small-signal and transient stability analysis of power systems., Stockholm, Sweden , Sweden 2011.