(c) power factor of the generator (leading power factor operation is more problematic than lagging power factor operation)

(d) AVR gain.

A cost efficient and satisfactory solution to the problem of oscillatory instability is to provide damping for generator rotor oscillations. This is conveniently done by providing Power System Stabilizers (PSS) which are supplementary controllers in the excitation systems. The signal V_s in Fig. 8.1 is the output from PSS which has input signal derived from rotor velocity, frequency, electrical power or a combination of these variables. The objective of designing PSS is to provide additional damping torque without affecting the synchronizing torque at critical oscillation frequencies [3].

PSS have been used for over 20 years in Western systems of United States of America and in Ontario Hydro. In United Kingdom, PSS have been used in Scotland to damp oscillations in tie lines connecting Scotland and England [8]. It can be generally said that need for PSS will be felt in situations when power has to be transmitted over long distances with weak AC ties. Even when PSS may not be required under normal operating conditions, they allow satisfactory operation under unusual or abnormal conditions which may be encountered at times. Thus, PSS has become a standard option with modern static exciters and it is essential for power engineers to use these effectively. Retrofitting of existing excitation systems with PSS may also be required to improve system stability.

This chapter presents the various aspects for the application of PSS with emphasis on the tuning procedures. The coverage includes not only on the current practices but also on recent developments and future trends. The stabilization through SVC and HVDC controllers are also discussed.

8.2 Basic concepts in applying PSS

A brief review of the basic concepts of stabilization is undertaken here. The power system, in general, is described by a set of nonlinear differential and algebraic equations. These can be expressed as

$$pX = F(X,\ Z), \quad p = \frac{d}{dt} \tag{8.1}$$

$$Y = H(X,\ Z) \tag{8.2}$$

$$0 = G(Y,\ Z) \tag{8.3}$$

The oscillatory instability can be viewed as stability of the operating point, subjected to small, random perturbations which are always present. The analysis can be performed by linearizing the system equations around the operating point ($X = X_o$, $Y = Y_o$, $Z = Z_o$). Here X are the state variables, Y represent active and reactive power injections (at buses), Z represent voltage magnitudes and angles at various buses.

Expressing

$$X = X_o + \Delta X, \quad Y = Y_o + \Delta Y, \quad Z = Z_o + \Delta Z \tag{8.4}$$

it is possible to obtain the following equation

$$p\Delta X = [A]\Delta X \tag{8.5}$$

where

$$[A] = \left[\frac{\partial F}{\partial X} - \frac{\partial F}{\partial Z}\left(\frac{\partial G}{\partial Y}\frac{\partial H}{\partial Z} + \frac{\partial G}{\partial Z}\right)^{-1}\frac{\partial G}{\partial Y}\frac{\partial H}{\partial X}\right] \tag{8.6}$$

It is to be noted that the elements of A are functions of the operating point.

The stability of the operating point can be judged by the location of the eigenvalues of the matrix A. If all the real parts of the eigenvalues are negative, the system is stable. If one or more has positive real part, then the system is unstable. While this criterion of stability is valid for very small perturbations (which may not be true in practice), it is interesting to note that several analytical studies [5, 6, 7] show excellent correlation between theory and field tests. The criterion indicates problem areas but cannot provide estimates for amplitudes of the oscillation observed.

To give more insight into the problem, we can take up a multi-machine system where generators are modelled by the 'classical' model, neglecting flux decay, saliency, damper windings and governor effects. In this case, the linearized system equations can be written as

$$[M]p^2\Delta\delta = -[K]\Delta\delta \tag{8.7}$$

where $[M]$ is diagonal matrix with $M_{jj} = \frac{2H_j}{\omega_B}$ (H_j is the inertia constant of j^{th} synchronous machine). $K_{ij} = \partial P_{ei}/\partial\delta_j$, where P_{ei} is the power output of i^{th} machine, δ_j is the rotor angle of j^{th} machine referred to a rotating reference frame (with the operating speed ω_o). If the network can be reduced by retaining only the internal buses of the generators and the losses in the reduced network can be neglected,

$$K_{ij} = \frac{E_iE_j}{X_{ij}}\cos(\delta_i - \delta_j) \simeq \frac{1}{X_{ij}} \tag{8.8}$$

where X_{ij} is the reactance of the element connecting the generator buses i and j. E_i and E_j are the generator voltages. The approximation assumes that the voltages are around 1.0 pu. and the bus angle difference (in steady-state) are small. The matrix $[K]$ is singular and has rank $\leq (m-1)$ where m is the size of K (also equal to the number of generators). This enables the reduction of the number of angle variables by one by treating relative angles (with respect to a reference machine which can be chosen as the first machine) as state variables.

The solution of equation (8.7) can, in general, be expressed as

$$\Delta\delta^R = \sum_{j=1}^{m-1} V_j(c_j \cos\omega_j t + d_j \sin\omega_j t) \tag{8.9}$$

where $\Delta\delta^R = [\Delta\delta_{21} \quad \Delta\delta_{31}.....\Delta\delta_{m1}]^t$ is the vector of relative angles ($\Delta\delta_{i1} = \Delta\delta_i - \Delta\delta_1$), $c_1, \ldots, c_{m-1}, d_1, d_2, \ldots, d_{m-1}$ are scalars depending on the initial conditions, V_1, V_{m-1} are vectors. The structure of a vector V_j depicts the participation of various machines in the oscillation mode whose frequency is ω_j. It is to be noted that for a 'm' machine system, there are $(m-1)$ oscillatory modes whose frequency varies in the range of (0.2 to 3 Hz). The frequencies are obtained as square roots of the non-zero and real eigenvalues of the matrix $[M]^{-1}[K]$.

In a practical system, the various modes (of oscillation) can be grouped into 3 broad categories [9].

A. Intra-plant modes in which only the generators in a power plant participate. The oscillation frequencies are generally high in the range of 1.5 to 3.0 Hz.

B. Local modes in which several generators in an area participate. The frequencies of oscillations are in the range of 0.8 to 1.8 Hz.

C. 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.

The above categorization can be illustrated with the help of a system consisting of two areas connected by a weak AC tie (see Fig. 8.3). Area 2 is represented by a single generator G_4. The area 1 contains 3 generators G_1, G_2, and G_3. The generators G_1 and G_2 are connected in parallel and participate in the intra-plant oscillations which have higher frequency due to the lower reactance between the two machines and also smaller inertias. In local mode oscillation, G_1 and G_2 swing together and against G_3. In oscillations due to inter area mode, all generators G_1 to G_4 participate and have the lowest frequency.

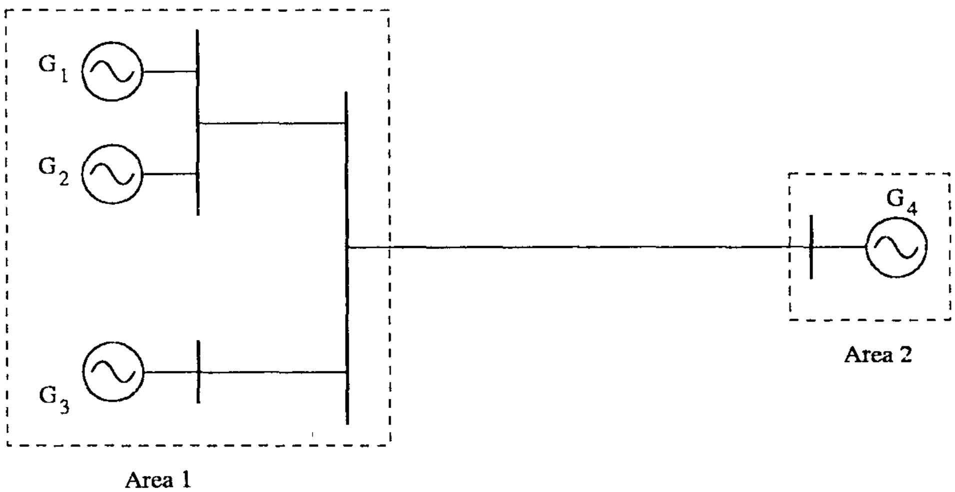


Figure 8.3: A sample power system

It is to be noted that the distinction between local modes and inter area modes applies mainly for those systems which can be divided into distinct areas which are separated by long distances. For systems in which the generating stations are distributed uniformly over a geographic area, it would be difficult to distinguish between local and inter area modes from physical considerations. However, a common observation is that the inter area modes have the lowest frequency and highest participation from the generators in the system spread over a wide geographic area.

The PSS are designed mainly to stabilize local and inter area modes. However, care must be taken to avoid unfavourable interaction with intra-plant modes [10] or introduce new modes which can become unstable.

Depending on the system configuration, the objective of PSS can differ. In Western U.S.A, PSS are mainly used to damp inter area modes without jeopardizing the stability of local modes. In other systems such as Ontario Hydro, the local modes were the major concern. In general, however, PSS must be designed to damp both types of modes. The procedures for tuning of PSS depend on the type of applications.

If the local mode of oscillation is of major concern (particularly for the case of a generating station transmitting power over long distances to a load centre) the analysis of the problem can be simplified by considering the model of a single machine (the generating station is represented by an equivalent machine) connected to an infinite bus (SMIB). With a simplified machine model (1.0), and the excitation system, the analysis can be carried out using the block diagram representation given in Chapter 7. The instability arises due to the negative damping torque caused by fast acting exciter under operating conditions that lead to $K_5 < 0$. The objective of PSS is to introduce additional damping torque without affecting the synchronizing torque.

8.3 Control Signals

The obvious control signal (to be used as input to the PSS) is the deviation in the rotor velocity. However, for practical implementation, other signals such as bus frequency [11], electrical power [9], accelerating power [12, 13] are also used. The latter signal is actually synthesized by a combination of electrical and mechanical power signals. The mechanical power signal can be obtained from the gate position in a hydraulic turbine or steam pressures in steam turbine. Nevertheless, it is difficult to measure mechanical power. It can be argued that if mechanical power variations are slow, then a signal derived from the electrical power approximates accelerating power. However, this can pose problem during rapid increases of generation for which PSS action leads to depression in the voltage, endangering security.

A recent development is to synthesize accelerating power signal from speed and electrical power signals. This is shown in Fig. 8.4 [13]. A similar approach is used at Ontario Hydro and the PSS utilizing these signals are termed as Delta-P-Omega stabilizers [14]. It is claimed that the new control signal has eliminated the problem of torsional interactions and improved reliability.

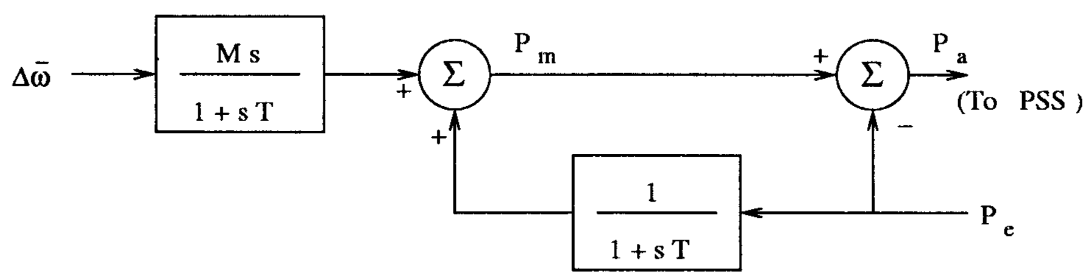


Figure 8.4: Synthesis of accelerating power signal

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. Alternately it can be obtained from the angle of the internal voltage which can be synthesized. The bus frequency signal can be obtained by measuring the period using zero crossing detection. The power signal can be derived from a Hall effect transducer.

The speed signal is inherently sensitive to the presence of torsional oscillations at frequencies in the range of 8 to 20 Hz. This can lead to negative damping of the torsional mode [15]. An initial solution to this problem was ingenious - to relocate the speed pick up at the node of the first torsional frequency. However, this was not a general solution (for example in 4 pole nuclear units in Ontario Hydro, the node of the first torsional mode of oscillation is located inside the turbine casing and hence inaccessible). A practical solution is to provide a torsional filter tuned to the frequency of the critical mode. However, this filter introduces another mode of oscillation, the damping of which reduces with increasing stabilizer gain [16].

Speed signal can also lead to negative damping of intra-plant modes if the PSS is not properly designed. In reference [10], the average speed instead of individual speed is suggested as a suitable control signal in a plant whenever more than one unit operate.

The frequency signal is insensitive to intra-plant modes and hence there is no danger of destabilising intra-plant modes. The frequency signal is also less sensitive to torsional frequency components. However, the frequency signal is prone to noise caused by nearby loads such as arc furnaces [6, 10].

The acceleration signal (based on accelerating power) results in minimum lead compensation requirements. The signal is also insensitive to torsional modes. Both these factors imply that torsional filters may be dispensed with completely or their design simplified.

8.4 Structure and tuning of PSS

The block diagram of the PSS used in industry is shown in Fig. 8.5. It consists of a washout circuit, dynamic compensator, torsional filter and limiter. The function of each of the components of PSS with guidelines for the selection of parameters (tuning) are given next.

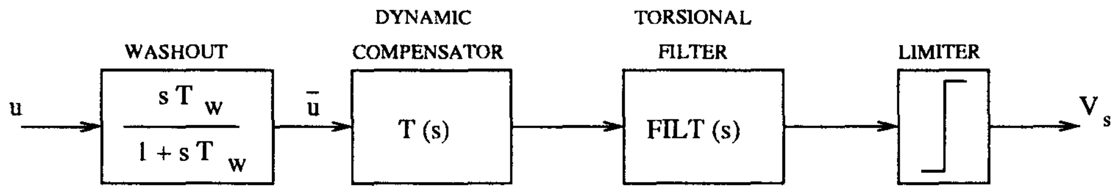


Figure 8.5: Block diagram of PSS

It is to be noted that the major objective of providing PSS is to increase the power transfer in the network, which would otherwise be limited by oscillatory instability. The PSS must also function properly when the system is subjected to large disturbances.

8.4.1 Washout Circuit

The washout circuit is provided to eliminate steady-state bias in the output of PSS which will modify the generator terminal voltage. The PSS is expected to respond only to transient variations in the input signal (say rotor speed) and not to the dc offsets in the signal. This is achieved by subtracting from it the low frequency components of the signal obtained by passing the signal through a low pass filter (see Fig. 8.6).

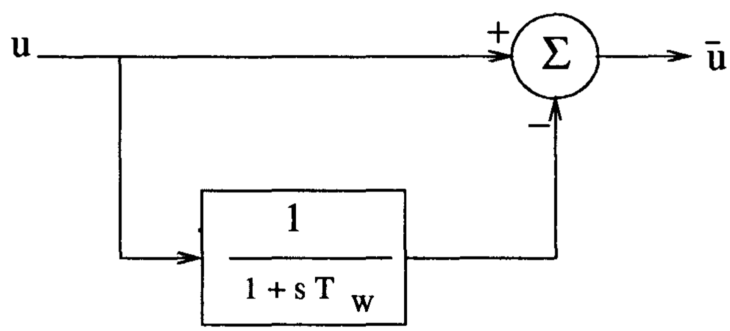


Figure 8.6: Washout circuit

The washout circuit acts essentially as a high pass filter and it must pass all frequencies that are of interest. If only the local modes are of interest, the time constant T_W can be chosen in the range of 1 to 2. However, if inter area modes are also to be damped, then T_W must be chosen in the range of 10 to 20. A recent study [1] has shown that a value of $T_W = 10$ is necessary to improve damping of the inter area modes. There is also a noticeable improvement in the first swing stability when T_W is increased from 1.5 to 10. The higher value of T_W also improved the overall terminal voltage response during system islanding conditions.

8.4.2 Dynamic Compensator

The dynamic compensator used in industry is made up to two lead-lag stages and has the following transfer function

$$T(s) = \frac{K_s(1 + sT_1)(1 + sT_3)}{(1 + sT_2)(1 + sT_4)} \tag{8.10}$$

where K_s is the gain of PSS and the time constants, T_1 to T_4 are chosen to provide a phase lead for the input signal in the range of frequencies that are of interest (0.1 to 3.0 Hz). With static exciters, only one lead-lag stage may be adequate. In general, the dynamic compensator can be chosen with the following transfer function

$$T(s) = \frac{K_s N(s)}{D(s)} \tag{8.11}$$

where

$$\begin{aligned} N(s) &= 1 + a_1 s + a_2 s^2 + ...a_p s^p \\ D(s) &= 1 + b_1 s + b_2 s^2 + ...b_p s^p \end{aligned}$$

The zeros of $D(s)$ should lie in the left half plane. They can be complex or real. Some of the zeros of $N(s)$ can lie in the right half plane making it a non-minimum phase.

For design purposes, the PSS transfer function is approximated to $T(s)$, the transfer function of the dynamic compensator. The effect of the washout circuit and torsional filter may be neglected in the design but must be considered in evaluating performance of PSS under various operating conditions.

There are two design criteria.

1. The time constants, T_1 to T_4 in equation (8.10) are to be chosen from the requirements of the phase compensation to achieve damping torque
2. The gain of PSS is to be chosen to provide adequate damping of all critical modes under various operating conditions. It is to be noted that PSS is tuned at a particular operating condition (full load conditions with strong or weak AC system) which is most critical. Although PSS may be tuned to give optimum damping under such condition, the performance will not be optimal under other conditions. The critical modes include not only local and inter area modes, but other modes (termed as control or exciter modes) introduced by exciter and/or torsional filter.

The basis for the choice of the time constants of the dynamic compensator can be explained with reference to the block diagram of the single machine

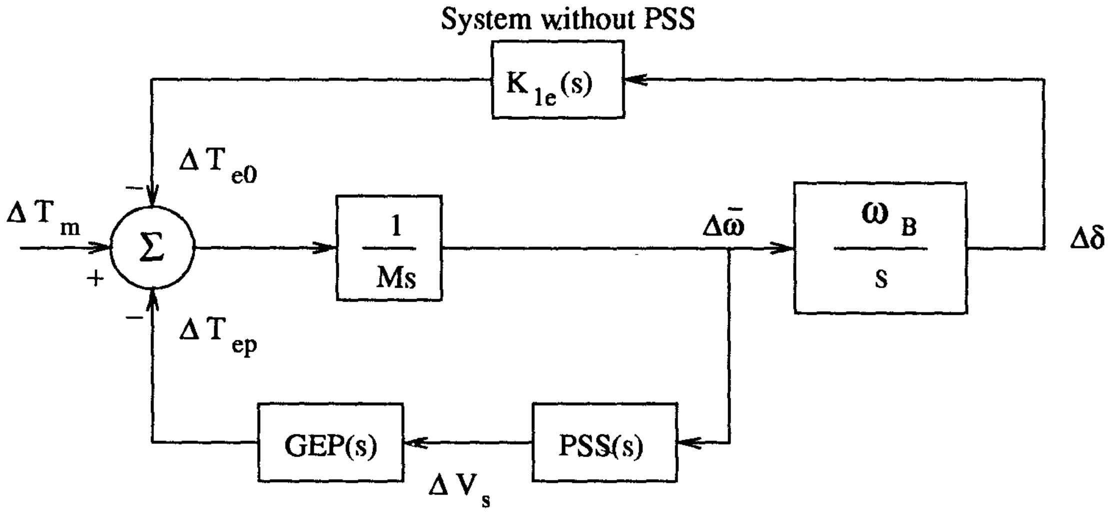


Figure 8.7: Stabilizer with speed input: system block diagram

system when PSS is included (see Fig. 8.7). If PSS is to provide pure damping torque at all frequencies, ideally the phase characteristics of PSS must balance the phase characteristics of GEP at all frequencies. As this is not practical, the following criteria are chosen to design the phase compensation for PSS.

(a) The compensated phase lag (phase of P(s) = GEP(s) PSS(s)) should pass through 90^o at frequency around 3.5 Hz (For frequency input signal this can be reduced to 2.0 Hz).

(b) The compensated phase lag at local mode frequency should be below 45^o, preferably near 20^o

(c) The gain of the compensator at high frequencies (this is proportional to T_1T_3/T_2T_4) should be minimized.

The first criterion is important to avoid destabilization of intra-plant modes with higher frequencies. It is also preferable to have the compensated phase to be lagging at inter area modes so that PSS provides some synchronizing torque at these frequencies. The time constant of the washout circuit can also affect the compensated phase lag. The third criterion is required to minimize the noise amplification through PSS.

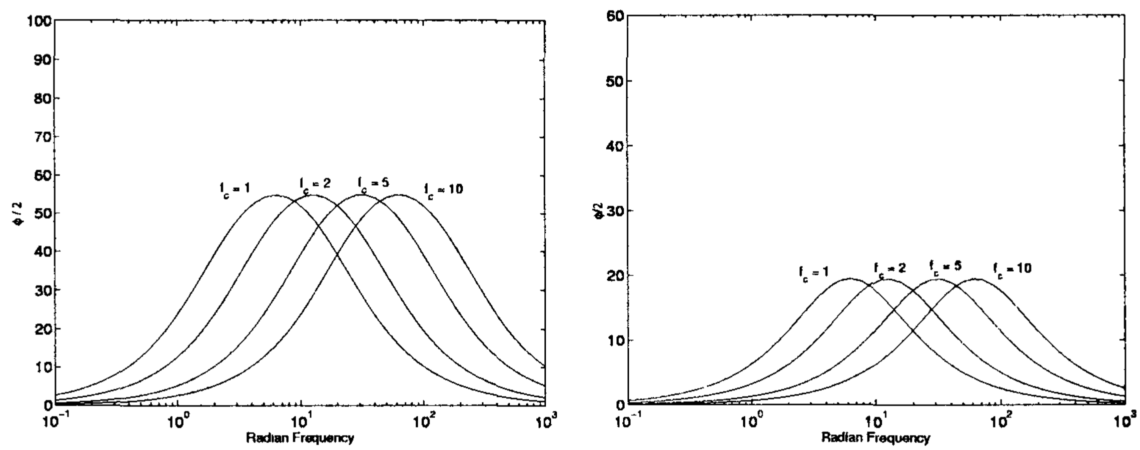
The plots of the phase angle ϕ of the compensator of Eq. (8.10), with variation in frequency are shown in Fig. 8.8 for different values of the centre frequency f_c defined by

$$f_c = \frac{1}{2\pi}\frac{1}{\sqrt{T_1T_2}} \tag{8.12}$$

It is assumed that

$$\frac{T_1}{T_2} = \frac{T_3}{T_4} = n$$

The plots of Fig. 8.8 (a) are obtained for $n = 10$. Fig. 8.8 (b) shows similar plots, but for $n = 2$. Since the two lead-lag stages are assumed to be identical, the phase angle ϕ is twice that for a single stage. The figure 8.8 shows the phase angle $(\frac{\phi}{2})$ corresponding to a single stage.



(a) $n = 10$ (b) $n = 2$

Figure 8.8: Variation of phase angle of compensator

The results given in Fig. 8.8 show that the peak value of the phase lead provided by the compensator occurs at the centre frequency (f_c). Also, increasing n increases the phase lead. Depending on the phase compensation required, f_c and n can be selected. A single stage of lead-lag network is adequate whenever the requirements of the phase lead are moderate.

The determination of the 'plant' transfer function can be done analytically or experimentally from field tests. In the former case, GEP(s) can be obtained from the fact that

$$GEP(s) = \left.\frac{\Delta T_e}{\Delta V_s}\right|_{\Delta\bar{\omega} = 0} \tag{8.13}$$

where V_s is the output of the PSS. The condition $\Delta\bar{\omega} = 0$, can be enforced by selecting arbitrarily very high values of inertias and calculating the frequency response over a range of frequencies. There are computer programs to compute eigenvalues or frequency response for a large system [17-19].

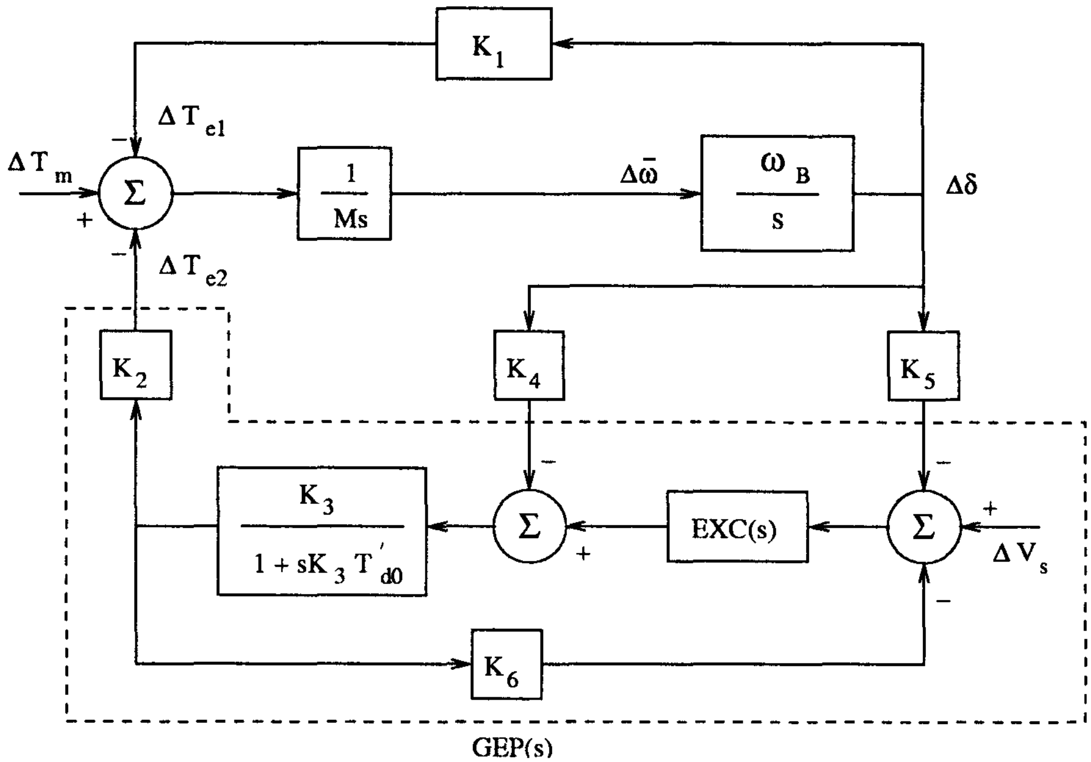


Figure 8.9: Simplified model of SMIB system

For a SMIB system with machine model (1.0), GEP(s) can be determined from the block diagram shown in Fig. 8.9. From this, GEP(s) is obtained as

$$GEP(s) = \frac{K_2 K_3 EXC(s)}{(1 + sT'_{do}K_3) + K_3 K_6 EXC(s)} \tag{8.14}$$

where $EXC(s)$ is the transfer function of the excitation system.

The transfer function GEP(s) cannot be determined exactly from the field tests as the rotor velocity variations can never be avoided in practice. However, it is shown below that GEP(s) can be determined from the following approximate relationship

$$GEP(s) \simeq \frac{K_2}{K_6} \frac{\Delta V_t(s)}{\Delta V_s(s)} \tag{8.15}$$

By measuring the transfer function between the terminal voltage and stabilizer output (V_s) it is possible to experimentally determine the phase characteristics of the plant.

Derivation of Eq. 8.15
The simplified model of the SMIB (single machine infinite bus) without PSS can

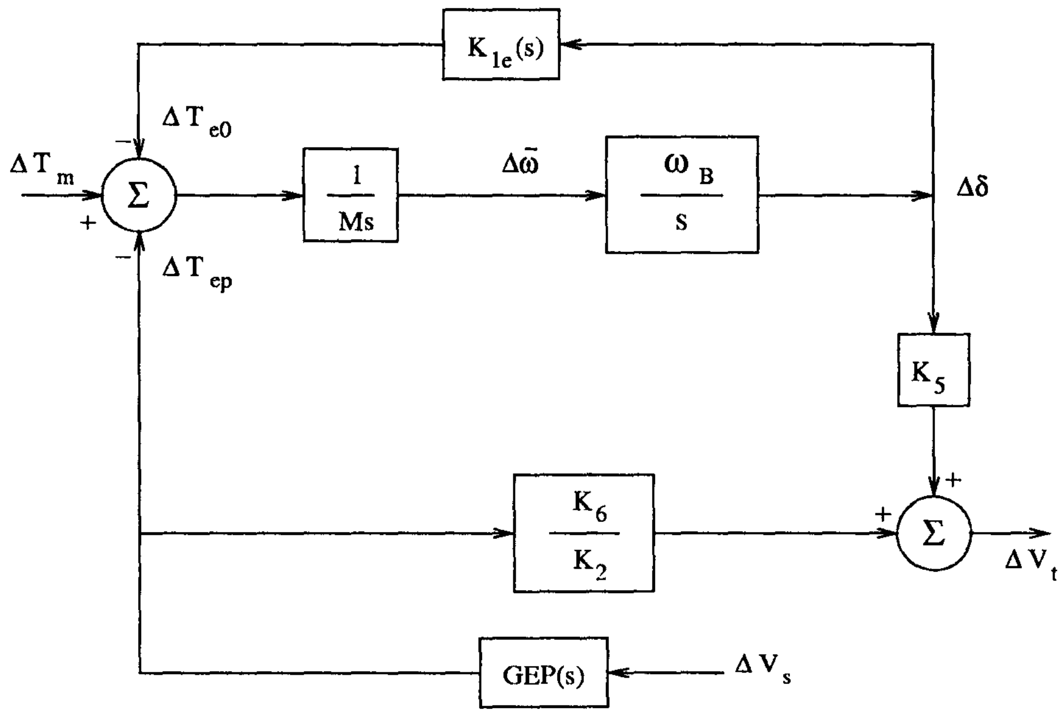


Figure 8.10: Simplified model of SMIB system without PSS

be obtained as shown in Fig. 8.10. From this figure, the transfer function from V_s to V_t can be obtained as

$$\frac{\Delta V_t}{\Delta V_s}(s) = GEP(s)\left[\frac{K_6}{K_2} - \frac{K_5\omega_B}{Ms^2 + \omega_B K_{1e}(s)}\right] \tag{8.16}$$

where $M = 2H$

K_{1e} is the effective complex synchronizing torque

If K_5 is zero, then

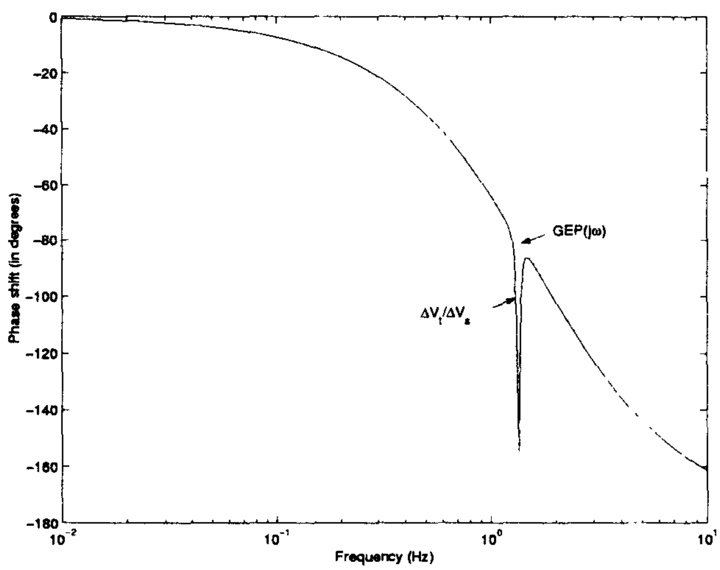
$$GEP(s) = \frac{K_2}{K_6}\frac{\Delta V_t(s)}{\Delta V_s(s)}$$

K_5 represents the effect of the rotor angle changes in terminal voltage which has he following characteristics.

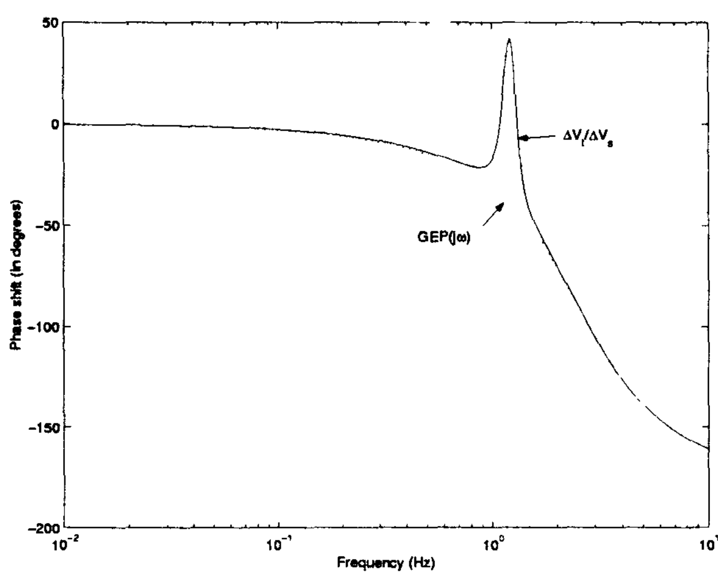
1. With no load on the generator, K_5 is positive and approaches zero as the transmission system becomes weaker.
2. Under load, K_5 is positive for strong systems but passes through zero and becomes negative as the system becomes weak.

Hence K_5 can be assumed to be zero and the approximation of GEP(s) by R.H.S. of equation (8.15) is valid.

The comparison between the exact and the approximate computation of GEP(s) is shown in Fig. 8.11 for a representative system.



(a) Strong System



(b) Weak System

Figure 8.11: Phase characteristics of measurable and ideal plant transfer functions

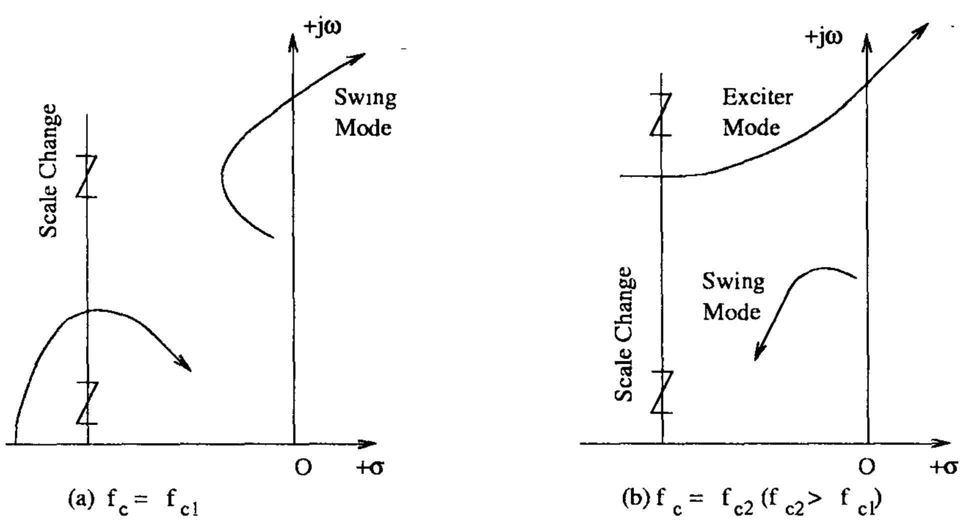


Figure 8.12: Root loci with variation in stabiliser gain

Once GEP(s) is determined, the PSS time constants are adjusted (by trial and error) such that the criteria given earlier are satisfied. The performance of the PSS can also be checked by root locus plots. See Fig. 8.12 for an example. The root loci with variation in stabilizer gain are drawn for two different values of f_c and for a fixed value of the ratio n. In addition to f_c, it is possible to vary the ratio of T_1/T_2 and T_3/T_4 independently to get a better performance. It is observed that either the local mode or the other mode (called the exciter mode irrespective of its source) gets destabilized as the PSS gain K_s is increased.

The studies carried out by Larsen and Swann [9] indicate that depending upon the input signal used, PSS is to be tuned for a particular system condition which has the highest stabilizer loop gain and greatest phase lag. Full load on the generator yields the highest loop gain. For speed and power input stabilizers, the strongest AC system results in the highest loop gain and greatest phase lag. For frequency input stabilizers, the highest loop gain occurs with weakest AC transmission system.

To set the gain of the PSS, root locus analysis is performed. The optimal PSS gain is chosen for the particular tuning condition as the gain that results in the maximum damping of the least damped mode. From studies carried out in [9], the optimum gain (K_{opt}) is related to the value of the gain (K_I) that results in instability. For speed input stabilizers $K_{opt} = 1/3K_I$, for frequency input stabilizers $K_{opt} = 2/3K_I$. For power input stabilizers $K_{opt} = 1/8K_I$. These thumb rules are useful while implementing PSS in the field without having to do root locus studies.

It is to be noted that for input signals other than rotor speed, the block diagram shown in Fig. 8.7 is not valid. In such cases, the diagram is as given in Fig. 8.13, where X is an arbitrarily chosen control (input) signal. $S_X(s)$ is defined as the input signal sensitivity factor and $FB_X(s)$ is defined as the input signal feedback factor. For power input stabilizer,

$$S_p(s) \simeq \frac{\omega_B K_{1e}(s)}{s} \tag{8.17}$$

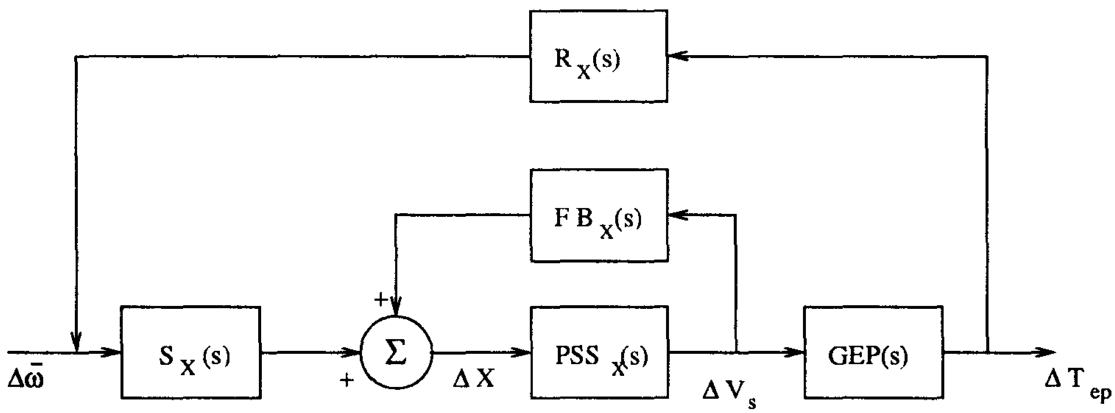


Figure 8.13: Stabilizer loop with arbitrary input X

$$FB_p(s) = GEP(s) \tag{8.18}$$

For the general case, the plant transfer function in the stabilizer path is given by

$$P_X(s) = \frac{\Delta T_{ep}}{\Delta \bar{\omega}}(s) = \frac{S_X(s) PSS_X(s) GEP(s)}{1 - FB_X(s) PSS_X(s)} \tag{8.19}$$

For speed input stabilizer, $S_X = 1.0$, $FB_X = 0$. Hence

$$P_\omega(s) = PSS_\omega(s) GEP(s) \tag{8.20}$$

To summarize, the tuning procedure for the dynamic compensator, the following steps are carried out.

1. Identify the plant GEP(s)
2. Choose the time constants from the phase compensation technique described earlier and from the knowledge of GEP(s).
3. Select the PSS gain such that it is a fraction of the gain corresponding to instability. This can be determined from root loci to maximize the damping of the critical (least damped) mode.