UNDERSTANDING POWER SYSTEM STABILITY

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***Abstract* – This paper discusses power system instability and the importance of fast fault clearing performance to aid in reliable production of power. Explanation is provided regarding small signal stability, high impedance transmission lines, line loading, and high gain, fast acting excitation systems. Transient stability is discussed, including synchronizing and damping torques. The power angle curve is used to illustrate how fault clearing time and high initial response excitation systems can affect transient stability.**

The term, "power system stability" has become increasingly popular in generation and transmission. The sudden requirement for power system stabilizers has created confusion about their applicability, purpose, and benefit to the system. This paper discusses the fundamentals of the power system stabilizer and its effectiveness. In today's paper industry, power system stabilizers are being applied on larger machines in the Northwest United States and Canada.

Index Terms—Stability, voltage regulator, pole slip, excitation, synchronous machine, transient stability

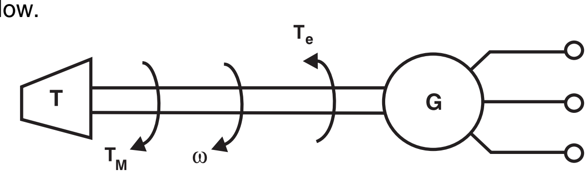
I. INTRODUCTION

In the 1950s and into the 1960s, many power generating plants were equipped with continuously acting automatic voltage regulators. As the number of power plants with automatic voltage regulators grew, it became apparent that the high performance of these voltage regulators had a destabilizing effect on the power system. Power oscillations of small magnitude and low frequency often persisted for long periods of time. In some cases, this presented a limitation on the amount of power able to be transmitted within the system. Power system stabilizers were developed to aid in damping of these power oscillations by modulating the excitation supplied to the synchronous machine.

This paper will discuss the various types of power system instability. It will cover the effects of system impedance and excitation on stability. Synchronizing torque and damping torque will be discussed and a justification will be made for the need for supplemental stabilization.

II. BASIS FOR STEADY-STATE STABILITY

In an interconnected power system, the rotors of each synchronous machine in the system rotate at the same average electrical speed. The power delivered by the generator to the power system is equal to the mechanical power applied by the prime mover, neglecting losses. During steady state operation, the electrical power out balances the mechanical power in. The mechanical power input to the shaft from the prime mover is the product of torque and speed, $P_M = T_M\omega$. The mechanical torque is in the direction of rotation. An electrical torque is applied to the shaft by the generator and is in a direction opposite of rotation as seen in Figure 1 below.



where P_M = Mechanical power
ω = speed
Te = Electrical torque

Fig. 1. Mechanical and Electrical Torque Applied to the Shaft

When the system is disturbed due to a fault or the load is changed quickly, the electrical power out of the machine changes. The electrical power out of the machine can change rapidly, but the mechanical power into the machine is relatively slow to change. Because of this difference in speed of response, there exists a temporary difference in the balance of power. This power unbalance causes a difference in torque applied to the shaft, which causes it to accelerate or decelerate, depending on the direction of the unbalance. As the rotor changes speed, the relative rotor angle changes.

Figure 2 shows the relationship between the rotor (torque) angle, δ, the stator magnetomotive force (MMF), F_1, and the rotor MMF, F_2. The torque angle, δ, is the angle between the rotor MMF, F_2, and the resultant of the vector addition of the rotor and stator MMFs, R, as seen in Figure 2 below.

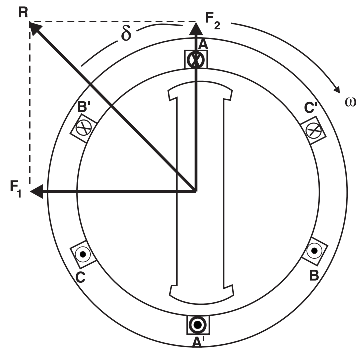
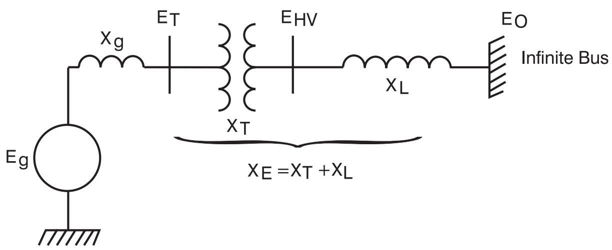


Fig. 2. Stator, Rotor, and Resultant MMFs and Torque Angle

Figure 3 is a circuit representation of a synchronous generator connected through a transmission system to an infinite bus.



where E_T *= Generator terminal voltage*
Xg = Generator internal reactance
E_g *= Internal generator voltage*
E_{HV} *= High side voltage of generator step transformer*
E_O *= System voltage*
X_E *= External impedance*

Fig. 3. Synchronous machine tied to infinite bus

The synchronous machine is modeled by an ideal voltage source, Eg, in series with an impedance, Xg. The terminal voltage of the machine, ET is increased to transmission system levels through a Generator Step-Up (GSU) transformer, which is represented by an impedance, XT. The high voltage side of the GSU is connected to the infinite bus via a transmission line represented by reactance, XL. The real (MW) power output from the generator on a steady state basis is governed by equation:

$$P_e = \frac{E_g E_T}{X_g} \sin \delta \qquad (1)$$

where δ is the angle between the generator terminal voltage and the internal voltage of the machine. As the power transfer increases, the angle δ increases. A fault in the system can result in a change in electrical power flow, resulting in a change in the power angle, δ. This can be seen graphically in Figure 4.

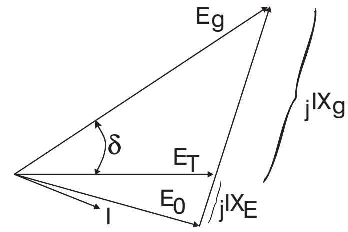


Fig. 4. Phasor Diagram, Generator tied to infinite bus

If a fault causes the current, I, to increase and the terminal voltage to decrease, the electrical power out of the machine will decrease, since the impedance seen by the generator is now mainly inductive. This disturbance causes the rotor angle to increase, perhaps beyond the limits of generator synchronous operation. The resulting variations in power flow as the rotor accelerates will cause a well-designed loss of synchronism protective relaying (78 function) to isolate that generator from the rest of the system. The disturbance on the remaining system, due to the loss of generation may result in additional units tripping off line, and potentially a cascading outage.

III. TRANSIENT STABILITY

Generators are connected to each other by a network that behaves much like weights interconnected by rubber bands (see Figure 5). The weights represent the rotating inertia of the turbine generators and the rubber bands are analogous to the inductance of the transmission lines. By pulling on a weight and letting go, an oscillation is setup with several of the weights that are interconnected by the rubber bands. The result of disturbing just one weight will result in all the weights oscillating. Eventually the system will come to rest, based on its damping characteristics. The frequency of oscillation depends on the mass of the weights and the springiness of the rubber bands. Likewise, a transient disturbance to the generator/network can be expected to cause some oscillations due to the inability of the mechanical torque to instantaneously balance out the transient variation in electrical torque.

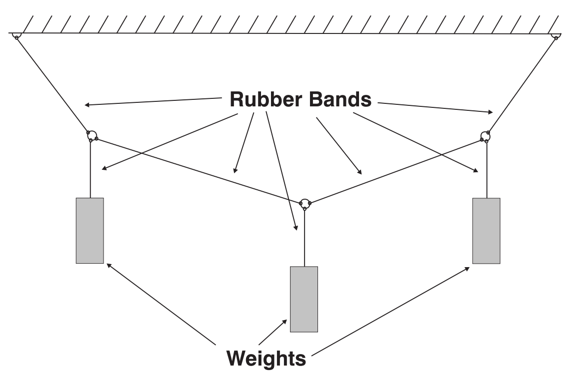


Fig. 5. Rubber Band Analogy

The synchronous machine's electrical power output can be resolved into an electrical torque, T_e multiplied by the speed , ω. Following a disturbance, the change in electrical torque can further resolved into two components:

$$\Delta T_e = K_s \Delta\delta + K_D \Delta\omega \qquad (2)$$

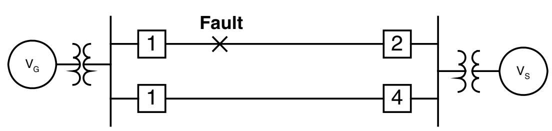
Where:

$K_S\ \Delta\delta$ = the component of torque that is in phase with the rotor angle change. This is known as the "synchronizing torque".

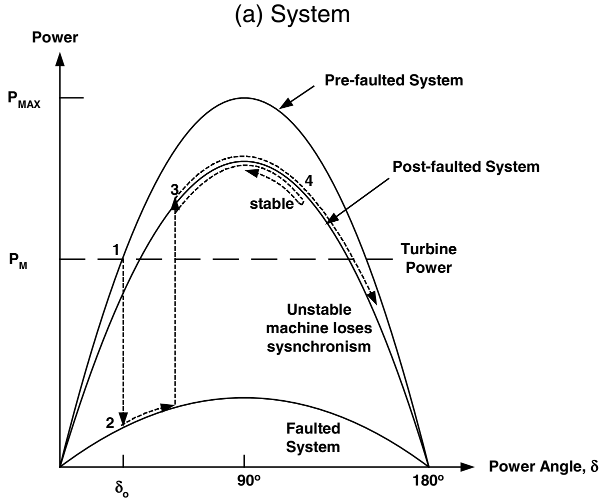
$K_D\ \Delta\omega$ = the component of torque that is in phase with the speed change. This is known as the "damping torque".

Both components of torque act on each generator in the system. A lack of sufficient synchronizing torque will result in loss of synchronism. Such loss of synchronism can only be prevented if sufficient magnetic flux can be developed when a transient change in electrical torque occurs. This is facilitated by a high initial response excitation system (an excitation system that will cause a change from the input to output within .1 seconds) having sufficient field forcing capability and sufficiently fast response to resist the accelerating or decelerating rotor. In order to be effective for both accelerating and decelerating rotor response, the excitation system must be capable of field forcing both positively and negatively, particularly on generators with rotating exciters. When the rotor is accelerating with respect to the stator flux, the rotor angle is increasing due to mechanical torque higher than electrical torque. The exciter system must increase excitation by applying a high positive voltage to the alternator field as quickly as possible. Conversely, when the rotor angle is decreasing due to mechanical torque less than electrical torque, the exciter system must decrease excitation by applying a high negative voltage to the alternator field as quickly as possible.

Transient stability is primarily concerned with the immediate effects of a transmission line fault on generator synchronism. Figure 6 illustrates the typical behavior of a generator in response to a fault condition.



(a) System

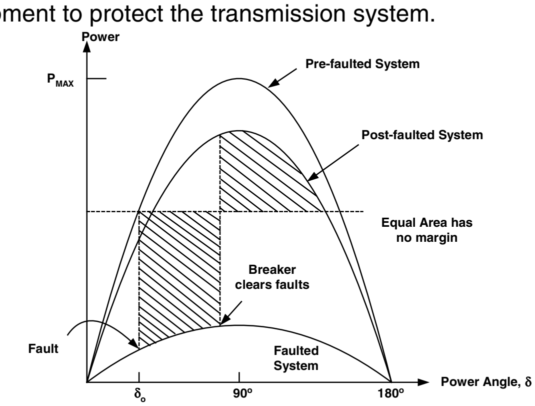


(b)Power-angle Curve

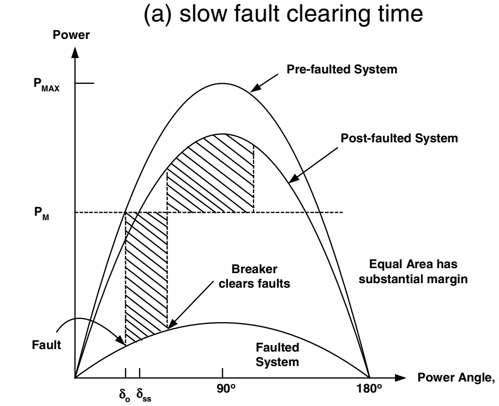
Fig. 6. Transient Stability Illustration

Starting from the initial operating condition (point 1), a close-in transmission fault causes the generator electrical output power Pe to be drastically reduced. The resultant difference between electrical power and the mechanical turbine power causes the generator rotor to accelerate with respect to the system, increasing the power angle (point 2). When the fault is cleared, the electrical power is restored to a level corresponding to the appropriate point on the power angle curve (point 3). Clearing the fault necessarily removes one or more transmission elements from service and at least temporarily weakens the transmission system. After clearing the fault, the electrical power out of the generator becomes greater than the turbine power. This causes the unit to decelerate (point 4), reducing the momentum the rotor gained during the fault. If there is enough retarding torque after fault clearing to make up for the acceleration during the fault, the generator will be transiently stable on the first swing and will move back toward its operating point. If the retarding torque is insufficient, the power angle will continue to increase until synchronism with the power system is lost.

Power system stability depends on the clearing time for a fault on the transmission system. Comparing the two examples in Figure 7 illustrates this point. In the example of slower fault clearing (a), the time duration of the fault allows the rotor to accelerate so far along the curve of PE, that the decelerating torque comes right to the limit of maintaining the rotor in synchronism. The shorter fault clearing time (b) stops the acceleration of the rotor much sooner, assuring that sufficient synchronizing torque is available to recover with a large safety margin. This effect is the demand placed on protection engineers to install the fastest available relaying equipment to protect the transmission system.



(a) slow fault clearing time



(b) fast fault clearing time

Fig. 7. Effect of Fault Clearing Time

IV. EFFECT OF THE EXCITATION SYSTEM ON STABILITY

Maintaining power system stability depends on speed of fault clearing, excitation system speed of response and forcing capacity. Increasing forcing capability and decreasing response time increases the margin of stability. This effect is illustrated in Figure 8, where the lower curve, A, represents the power angle curve of a lower forcing, slower response excitation system. Comparing the area under the curve for acceleration when the electrical load is less than the mechanical load to the area under curve A for deceleration clearly shows that a machine under the example condition will lose synchronism. For curve B representing a faster, higher forcing exciter, the area under the curve where electrical power exceeds mechanical power is much greater, sufficient to allow the generator to recover from this swing. This effect is the source of the demand placed on generation engineers to install the fastest available excitation equipment with very high levels of positive and negative forcing to secure the highest level of immunity to transient loss of synchronism.

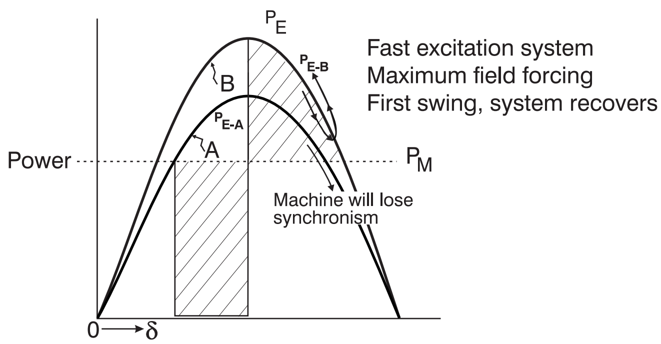


Fig. 8. Effect of High Initial Response Excitation System

While fast excitation systems help improve the transient stability following large impact disturbances to the system, the benefit may be outweighed by the impact of the excitation system on damping the oscillations that follow the first swing after the disturbance. In fact, the fast responding excitation system can contribute a significant amount of negative damping to oscillations because it can reduce damping torque. Thus an excitation system has the potential to contribute to small signal instability of power systems. With the very old electromechanical excitation systems, the transient response was relatively slow compared to systems introduced today. This slow response has minimal effect in reducing the damping torque.

V. SMALL-SIGNAL STABILITY

Small signal stability is defined as the ability of the power system to remain stable in the presence of small disturbances. These disturbances could be minor variations in load or generation on the system. If sufficient damping torque doesn't exist, the result can be rotor angle oscillations of increasing amplitude. Generators connected to the grid utilizing high gain automatic voltage regulators can experience insufficient damping to system oscillations.

To further understand the difference between the good effect of high performance excitation systems and the side-effect of reduced damping torque, recalling the equation (1) we discussed earlier that breaks down the change in electrical torque, ΔTe, into the two components of synchronizing torque and damping torque. The synchronizing torque increases the pull between rotor and stator flux, decreasing the angle δ, and reducing the risk of pulling out of step. The damping torque, on the other hand, results from the phase lag or lead of the excitation current. Like the timing of pushes to a swing, the excitation current acting to improve synchronizing torque normally is time delayed by the characteristics of the excitation system, the time delay of the alternator field, and the time delay of the exciter field (if used). These time delays cause the effect of a high initial response excitation system to cause negative damping, resulting in loss of small-signal stability. Loss of small-signal stability results in one or more of the types of oscillations listed below, involving rotor swings that may grow without bound or may take a long time to dampen.

Three types of oscillations that have been experienced with interconnected generators and transmission networks (shown in Figures 9 through 11) include:

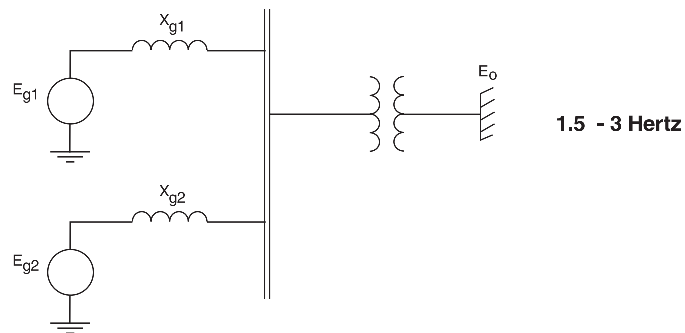


Fig. 9. Inter-unit Oscillations

A. Inter-Unit Oscillations

These oscillations involve typically two or more synchronous machines at a power plant or nearby power plants. The machines swing against each other, with the frequency of the power oscillation ranging between 1.5 to 3 Hertz.

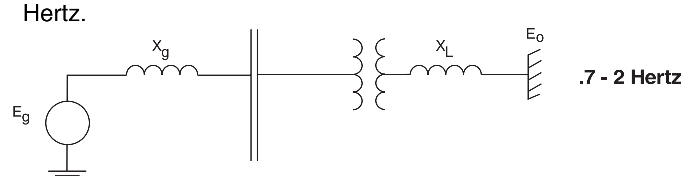


Fig. 10. Local Mode Oscillations

B. Local Mode Oscillations

These oscillations generally involve one or more synchronous machines at a power station swinging together against a comparatively large power system or load center. The frequency of oscillation is in the range of 0.7 Hertz to 2 Hertz. These oscillations become troublesome when the plant is at high load with a high reactance transmission system.

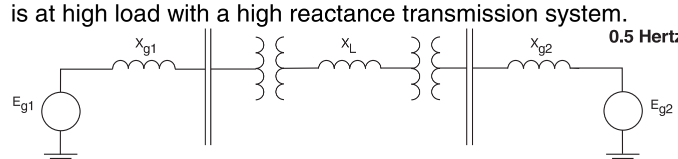


Fig. 11. Inter-area Oscillations

C. Inter-Area Oscillations

These oscillations usually involve combinations of many machines on one part of a power system swinging against machines on another part of the power system. Inter-area oscillations are normally in the frequency range of less than 0.5 Hertz.

New fast excitation systems that are installed to aid in improving transient stability can be a source of these types of oscillations. These systems recognize a change in voltage due to load change up to 10 times faster than older excitation systems. Thus, small oscillations of the unit cause the excitation system to correct immediately. Because of the high inductance in the generator field winding however, the field current rate of change is limited. This introduces considerable "lag" in the control function. Thus from the time of recognition of a desired excitation change to its partial fulfillment, there is an unavoidable time delay. During this delay time, the state of the oscillating system will change, causing a new excitation adjustment to be started. The net result is the excitation system tends to lag behind the need for a change, aiding the inherent oscillatory behavior of the generators interconnected by transmission lines. The excitation system acts to introduce energy into the oscillatory cycle at the wrong time.

Positive synchronizing torque can be provided to restore the rotor back to the steady state operating point if the excitation system can be made to appropriately accelerate or decelerate the rotor. Positive damping torque damps out the rotor oscillations of the torque angle loop to return the system back to normal. For most power systems, the configuration of the network and the generator control systems maintains stable damping forces that restore equilibrium to the power system. In some system configurations however, unstable oscillations can result from the introduction of negative damping torques caused by a fast responding excitation system. This can occur when the system is connected to a high impedance transmission system as compared to one connected to a low impedance transmission system.

One solution to improve the dynamic performance of this system and large scale systems in general would be to add more parallel transmission lines to reduce the reactance between the generator and load center. This solution is well known, but usually it is not acceptable due to the high cost of building transmission lines. An alternative solution adds a power system stabilizer (PSS) acting through the voltage regulator. Working together, the excitation output is modulated to provide positive damping torque to the system.

VI. POWER SYSTEM STABILIZERS

The Power System Stabilizer (PSS) is a device that improves the damping of generator electromechanical oscillations. Stabilizers have been employed on large generators for several decades, permitting utilities to improve stability-constrained operating limits. In order to describe the application of the PSS, it is necessary to introduce general concepts of power system stability and synchronous generator operation.

When disturbed by a sudden change in operating conditions, the generator speed and electrical power will vary around their steady-state operating points. The relationship between these quantities can be expressed in a simplified form of the "swing equation":

$$\frac{2H}{\omega_o}\frac{d^2\delta}{dt^2} = T_m - T_e \qquad (3)$$

where:

- δ *=rotor angle, in radians*
- ω_O *= angular speed of rotor (the base or rated value ω_O = 377 rad/s)*
- T_m *= mechanical torque in per-unit*
- T_e *= electrical torque in per-unit*
- H *= combined turbogenerator inertia constant expressed in MW-s/MVA*

For small deviations in rotor speed, the mechanical and electrical torques are approximately equal to the respective per unit power values. The base value of power is selected to be equal to the generator nameplate MVA. The "swing equation" dictates that, when disturbed from equilibrium, the rotor accelerates at a rate that is proportional to the net torque acting on the rotor divided by the machine's inertia constant.

Equation 3 can be rewritten in terms of small changes about an operating point:

$$\Delta T_e = K_s \Delta\delta + K_D \Delta\omega \qquad (4)$$

where the expression for electrical-torque-deviation has been expanded into its synchronizing and damping components:

- K_S = synchronizing coefficient
- K_D = damping coefficient
- $\Delta\delta$ *= rotor angle change*
- ω *= angular speed of rotor*
- Δ *= change*

From Equation 4, it can be seen that for positive values of K_S, the synchronizing torque component opposes changes in the rotor angle from the equilibrium point (i.e. an increase in rotor angle will lead to a net decelerating torque, causing the unit to slow down relative to the power system, until the rotor angle is restored to its equilibrium point, $\Delta\delta = 0$). Similarly, for positive values of K_D, the damping torque component opposes changes in the rotor speed from the steady-state operating point. A generator will remain stable as long as there are sufficient positive synchronizing and damping torques acting on its rotor for all operating conditions.

A. Damping of Electromechanical Oscillations

For positive values of the damping coefficient, and constant input power, the rotor angle's response to small disturbances (i.e. the solution of Equation 3) will take the form of a damped sinusoid. The relationship between rotor speed and electrical power following small disturbances is illustrated in Figure 12.

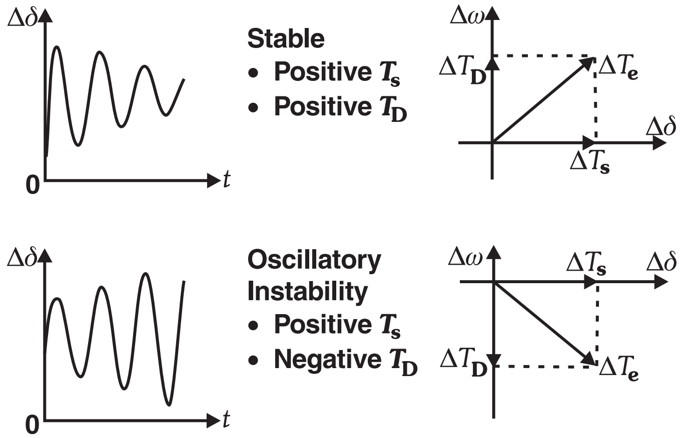


Fig. 12. Response of Speed and Angle to Small Disturbances

A number of factors can influence the damping coefficient of a synchronous generator, including the generator's design, the strength of the machine's interconnection to the grid, and the setting of the excitation system. While many units have adequate damping coefficients for normal operating conditions, they may experience a significant reduction in the value of K_D following transmission outages, leading to unacceptably low damping ratios. In extreme situations, the damping coefficient may become negative, causing the electromechanical oscillations to grow, and eventually causing loss of synchronism. This form of instability is normally referred to as dynamic, small-signal or oscillatory instability to differentiate it from the steady-state stability and transient stability.

By adding a power system stabilizer to a high initial response excitation system, the benefit of higher synchronizing torque is available and the possibility of decreased damping torque can be corrected. The function of the power system stabilizer is to counter any oscillations by signaling to change excitation at just the right time to dampen the oscillations. The source of reduced damping is the phase lags due to the field time constants and the lags in the normal voltage regulation loop. Thus, the pss (power system stabilizer) uses phase compensation to adjust the timing of its correction signal to oppose the oscillations it detects in the generator rotor.

A power system stabilizer can increase a generator's damping coefficient, thus allowing a unit to operate under conditions where there is insufficient natural damping.

VII. PSS THEORY OF OPERATION

Modulation of generator excitation can produce transient changes in the generator's electrical output power. Fast-responding exciters equipped with high-gain automatic voltage regulators (AVRs) use their speed and forcing to increase a generator's synchronizing torque coefficient (K_S), resulting in improved steady-state and transient stability limits. Unfortunately improvements in synchronizing torque are often achieved at the expense of damping torque, resulting in reduced levels of oscillatory or small-signal stability. To counteract this effect, many units that utilize high-gain AVRs are also equipped with power system stabilizers to increase the damping coefficient (K_D) and improve oscillatory stability. See Figure 13.

VIII. SPEED BASED STABILIZERS

To supplement the unit's natural damping after a disturbance, the power system stabilizer must produce a component of electrical torque that opposes changes in rotor speed. One method of accomplishing this is to introduce a signal proportional to measured rotor speed deviation into the voltage regulator input, as depicted in Figure 15.

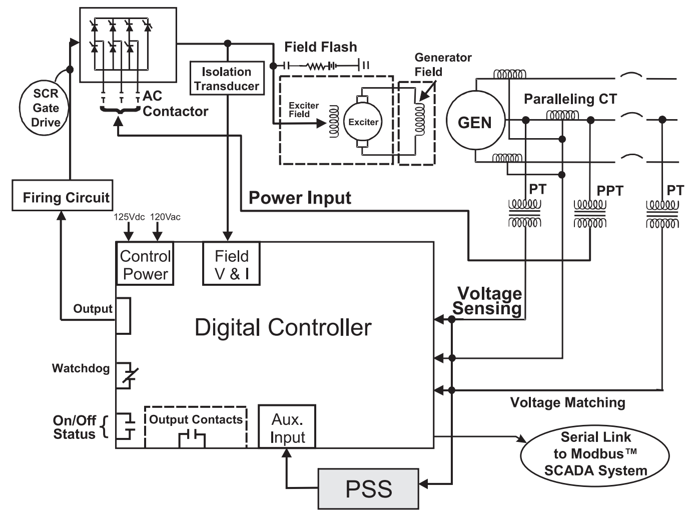


Fig. 13. Block Diagram of Excitation System and PSS

Figure 14 illustrates the steps used within the speed-based stabilizer to generate the output signal. These steps are summarized below:

- Measure shaft speed using a magnetic-probe and gear-wheel arrangement.
- Convert the measured speed signal into a dc voltage proportional to the speed.
- High-pass filter the resulting signal to remove the average speed level, producing a "change-in-speed" signal; this ensures that the stabilizer reacts only to changes in speed and does not permanently alter the generator terminal voltage reference.
- Apply phase lead to the resulting signal to compensate for the phase lag in the closed-loop voltage regulator.
- Adjust the gain of the final signal applied to the AVR input.

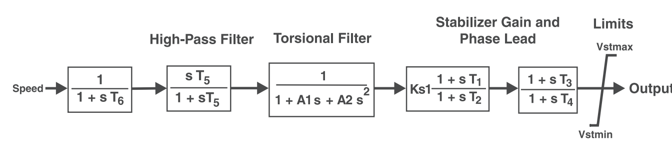


Fig. 14. Speed-based Stabilizer

With some minor variations, many of the early power system stabilizers were constructed using this basic structure.

IX. DUAL INPUT STABILIZERS

While speed-based stabilizers have proven to be extremely effective, it is frequently difficult to produce a noise-free speed signal that does not contain other components of shaft motion such as lateral shaft run-out (hydroelectric units) or torsional oscillations (steam-driven turbogenerators). The presence of these components in the input of a speed-based stabilizer can result in excessive modulation of the generator's excitation and, for the case of torsional components, in the production of potentially damaging electrical torque variations. These electrical torque variations led to the investigation of stabilizer designs based upon measured power.

Figure 15 illustrates a 2% voltage step change introduced into the voltage regulator summing point that causes the generator voltage to change by 2%. Here, a speed type power system stabilizer provides damping after the small signal disturbance to resolve the momentary MW oscillation after the disturbance. Note that the "PSS Out" changes abruptly during the disturbance to provide damping, but a constant modulation that is being applied into the excitation system even during normal operation is also observed.

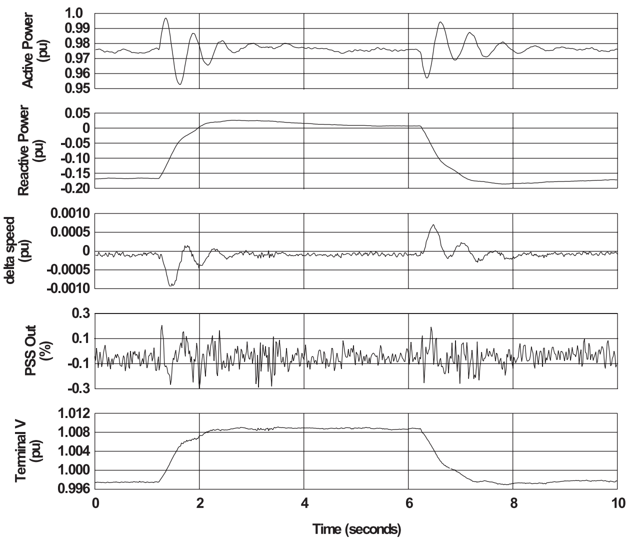


Fig. 15. On-line Step Response, Frequency Type PSS Ks=6, 92MW Hydro Turbine Generator

Although field voltage has not been recorded, one can conclude that the field voltage is also moving aggressively in response to the "PSS Out" driving the voltage regulator. The reason for the constant changing is the high noise content at the input of the speed type stabilizer. For years, the constant changes in the field voltage have alarmed operators using this type of power system stabilizer. Notice in the example that, while the generator active power is oscillatory for a few cycles after the disturbance, the terminal voltage and reactive power are very constant.

Incremental improvements were made to the power system stabilizer by manipulating the swing equation shown in Equation 4 to derive a better method of improving the damping signal input.

$$\frac{d}{dt}\Delta\omega = \frac{1}{2H}\left(T_m - T_e\right) = \frac{1}{2H}T_{acc} \qquad (5)$$

The simplified swing equation can be rearranged to reveal the principle of operation of early power-based stabilizers. Based on Equation 5, it is apparent that a speed deviation signal can be derived from the net accelerating power acting on the rotor; i.e., the difference between applied mechanical power and generated electrical power. Early attempts at constructing power-based stabilizers used the above relationship to substitute measured electrical and mechanical power signals for the input speed. The electrical power signal was measured directly using an instantaneous watt transducer. The mechanical power could not be measured directly, and instead was estimated based on the measurement of valve or gate positions. The relationship between these physical measurements and the actual mechanical power varies based on the turbine design and other factors, resulting in a high degree of customization and complexity.

This approach was abandoned in favor of an indirect method that employed the two available signals, electrical power and speed. The goal was to eliminate the undesirable components from the speed signal while avoiding a reliance on the difficult to measure mechanical power signal. To accomplish this, the relationship of Equation 2 was rearranged to obtain a derived integral-of-mechanical power signal from electrical power and speed:

$$\Delta\omega = \frac{1}{2H}\left[\int \Delta T_m dt - \int \Delta T_e dt\right] \qquad (6)$$

Since mechanical power normally changes slowly relative to the electromechanical oscillation frequencies, the derived mechanical power signal can be band-limited using a low-pass filter. The low-pass filter attenuates high-frequency components (e.g. torsional components, measurement noise) from the incoming signal while maintaining a reasonable representation of mechanical power changes. The resulting band-limited derived signal is then used in place of the real mechanical power in The Swing Equation to derive a change-in-speed signal with special properties.

The Swing Equation has been written in the frequency domain using the Laplace operator "s", to represent complex frequency. The final derived speed signal is derived from both a band-limited, measured speed signal and a high-pass filtered integral-of-electrical power signal. At lower frequencies the measured speed signal dominates this expression while at higher frequencies the output is determined primarily by the electrical power input.

The integral-of-accelerating-power arrangement is illustrated in the block diagram of Figure 16.

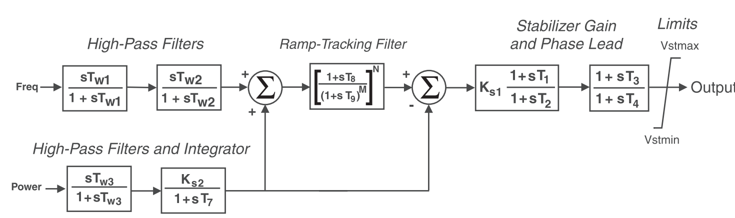


Fig.16. Block Diagram of Dual-Input Power System Stabilizer

X. SPEED SIGNAL

For the frequency or speed stabilizer, shaft speed was measured either directly or derived from the frequency of a compensated voltage signal obtained from the generator terminal VT and CT secondary voltages and currents. If directly measured, shaft speed is normally obtained from a magnetic-probe and gear-wheel arrangement. On horizontal turbo-generators, operating at 1800 RPM or 3600 RPM, there are normally several gear wheels already provided for the purpose of speed measurement or governing. The shaft location is not critical as long as it is directly coupled to the main turbo-generator shaft. On vertical turbogenerators (hydraulic) the direct measurement of shaft speed is considerably more difficult, particularly when the shaft is subjected to large amounts of lateral movement (shaft run-out) during normal operation. On these units, speed is almost always derived from a compensated frequency signal. In either type of generator, the speed signal is plagued by noise, masking the desired speed change information.

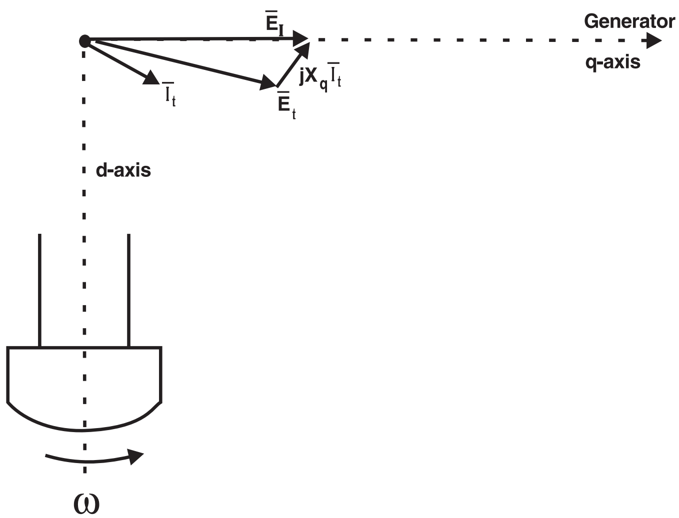


Fig. 17. Speed derived from VT and CT signals

The derivation of shaft speed from the frequency of a voltage phasor and a current phasor is depicted graphically in Figure 18. The internal voltage phasor is obtained by adding the voltage drop associated with a q-axis impedance (Note: For salient pole machines, the synchronous impedance provides the required compensation.) to the generator terminal voltage phasor. The magnitude of the internal phasor is proportional to field excitation and its position is tied to the quadrature axis. Therefore, shifts in the internal voltage phasor position correspond with shifts in the generator rotor position. The frequency derived from the compensated phasor corresponds to shaft speed and can be used in place of a physical measurement. On round-rotor machines, the selection of the correct compensating impedance is somewhat more complicated; simulations and site tests are normally performed to confirm this setting.

In either case, the resulting signal must be converted to a constant level, proportional to speed (frequency). Two high-pass filter stages are applied to the resulting signal to remove the average speed level, producing a speed deviation signal; this ensures that the stabilizer reacts only to changes in speed and does not permanently alter the generator terminal voltage reference.

Figure 18 shows the high-pass filter transfer function blocks in frequency domain form (the letter "s" is used to represent the complex frequency or Laplace operator).

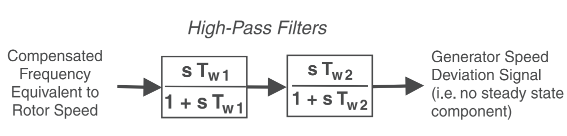


Fig. 18. Accelerating-Power Design (Speed Input)

XI. GENERATOR ELECTRICAL POWER SIGNAL

The generator electrical power output is derived from the generator VT secondary voltages and CT secondary currents. The power output is high-pass filtered to produce the required power deviation signal. This signal then is integrated and scaled, using the generator inertia constant (2H) for combination with the speed signal. Figure 19 depicts the operations performed on the power input signal to produce the integral-of-electrical power deviation signal.

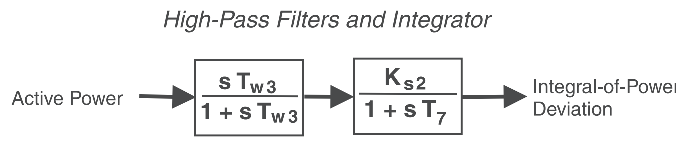


Fig. 19. Integral of Electrical Power Block Diagram

XII. DERIVED MECHANICAL POWER SIGNAL

As previously described, the speed deviation and integral-of-electrical power deviation signals are combined to produce a derived integral-of-mechanical power signal. This signal is then low-pass filtered, as depicted in the block diagram of Figure 20.

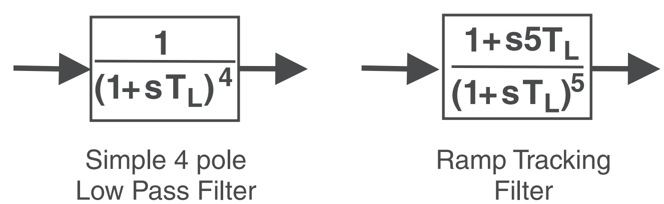


Fig. 20. Filter Configurations for Derived Mechanical Power Signal

A low-pass filter can be configured to take on one of the following two forms:

- The first filter, a simple four-pole low-pass filter, was used to provide attenuation of torsional components appearing in the speed. For thermal units, a time constant can be selected to provide attenuation at the lowest torsional frequency of the turbogenerator set. Unfortunately, this design requirement conflicts with the production of a reasonable derived mechanical power signal, which can follow changes in the actual prime mover output. This is particularly problematic on hydroelectric units where rates of mechanical power change can easily exceed 10 percent per second. Excessive band-limiting of the mechanical power signal can lead to excessive stabilizer output signal variations during loading and unloading of the unit.
- The second low-pass filter configuration deals with this problem. This filter, referred to as a "ramp-tracking" filter, produces a zero steady-state error to ramp changes in the input integral-of-electrical power signal. This limits the stabilizer output variation to very low levels for the rates-of-change of mechanical power that are normally encountered during operation of utility-scale generators.

XIII. STABILIZING SIGNAL SELECTION AND PHASE COMPENSATION

As depicted in the simplified block diagram of Figure 16, the derived speed signal is modified before it is applied to the voltage regulator input. The signal is filtered to provide phase lead at the electromechanical frequencies of interest i.e., 0.1 Hz to 5.0 Hz. The phase lead requirement is site-specific, and is required to compensate for phase lag introduced by the closed-loop voltage regulator.

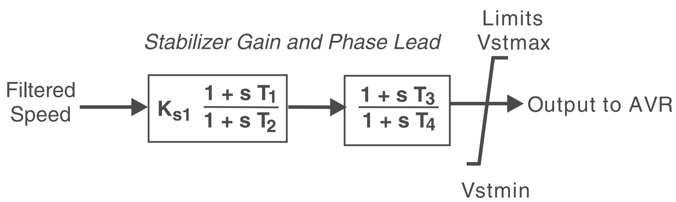


Fig. 21. Output stage of PSS to AVR

The diagram of Figure 21 depicts the phase compensation portion of the digital stabilizer. The transfer function for each stage of phase compensation is a simple pole-zero combination where the lead and lag time constants are adjustable.

Tests are performed to determine the amount of compensation required for the generator/excitation system by applying a low frequency signal into the voltage regulator auxiliary summing point input and then by comparing to the generator output for phase shift and gain over the frequency range applied. These tests are normally performed with the generator at 10% MW load. Figure 22 illustrates the results of a typical test performed to determine the phase lag of the voltage regulator/generator interconnected to the system without the power system stabilizer. Compensation is then provided through the lead and lag of the power system stabilizer to ensure that the voltage regulator will be responsive to the frequency range desired. Here, phase lead is needed above 1 Hertz as shown by the solid line in Figure 22.

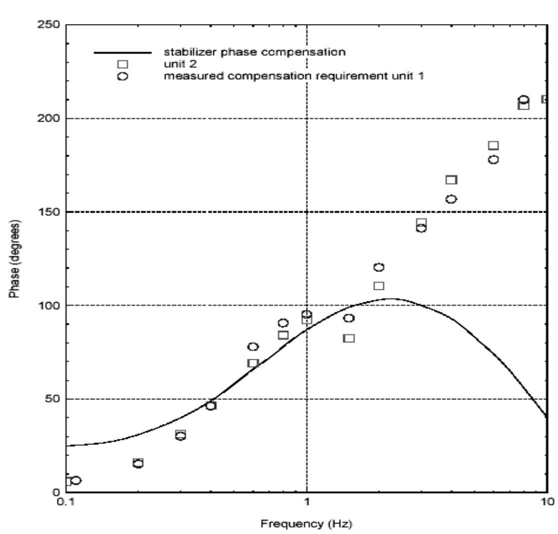


Fig.22. Phase Compensation denoted with and without the Power System Stabilizer

XIV. TERMINAL VOLTAGE LIMITER

Since the Power System Stabilizer operates by modulating the excitation, it may counteract the voltage regulator's attempts to maintain terminal voltage within a tolerance band. To avoid producing an overvoltage condition, the PSS may be equipped with a terminal voltage limiter that reduces the upper output limit to zero when the generator terminal voltage exceeds the set point.

The level is normally selected such that the limiter will operate to eliminate any contribution from the PSS before the generator's time delayed overvoltage or V/Hz protection operates.

The limiter will reduce the stabilizer's upper limit at a fixed rate until zero is reached, or the overvoltage is no longer present. The limiter does not reduce the AVR reference below its normal level; it will not interfere with system voltage control during disturbance conditions. The error signal (terminal voltage minus limit start point) is processed through a conventional low-pass filter to reduce the effect of measurement noise.

XV. CASE STUDIES

A small turbine generator was experiencing potentially damaging power oscillations when the unit load was increased to more than 0.5 pu, with oscillations triggered by small changes in load or terminal voltage. The oscillations could be triggered by a step change in unit terminal voltage. The waveforms in Figure 23 illustrate the test results indicating that the oscillations under the test condition were damped, but with significant duration. This condition occurred after the unit was upgraded from manual control to a modern static exciter system with high initial response characteristic.

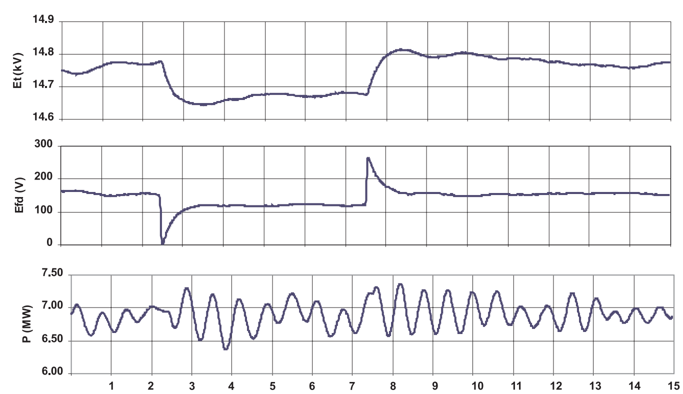


Fig. 23. Hydro Generator without PSS

When the PSS, a dual input type power system stabilizer, was implemented, the response of the turbine generator was substantially improved, showing much greater damping capability compared to the performance in Figure 23. In operation, with the settings of the PSS set as indicated in Figure 24, the unit was able to deliver rated load once again, with no danger from power oscillations threatening to damage the machine. This is an example of a local area oscillation. The combination of high performance excitation and the compensation of the PSS provides the best combination of performance benefits for this hydro turbine installation.

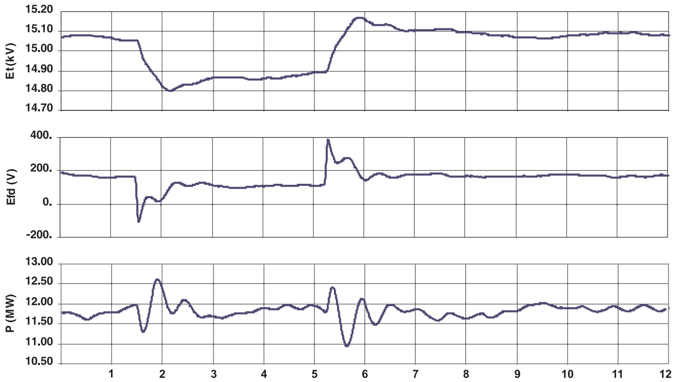


Fig. 24. Hydro Generator with PSS

The benefits of a newly installed dual-input type power system stabilizer (Figure 25) versus those of the existing single input power system stabilizer (Figure 15) for the same machine can be seen in the on-line step response of a 92MW turbine generator to system oscillations. The speed-based stabilizer produces a significant amount of noise in the stabilizing signal. This noise limits the maximum Ks gain to 6.2. With the dual-input type, the noise is considerably less, allowing higher gain, Ks=7.5s and more effective damping as illustrated in Figure 25.

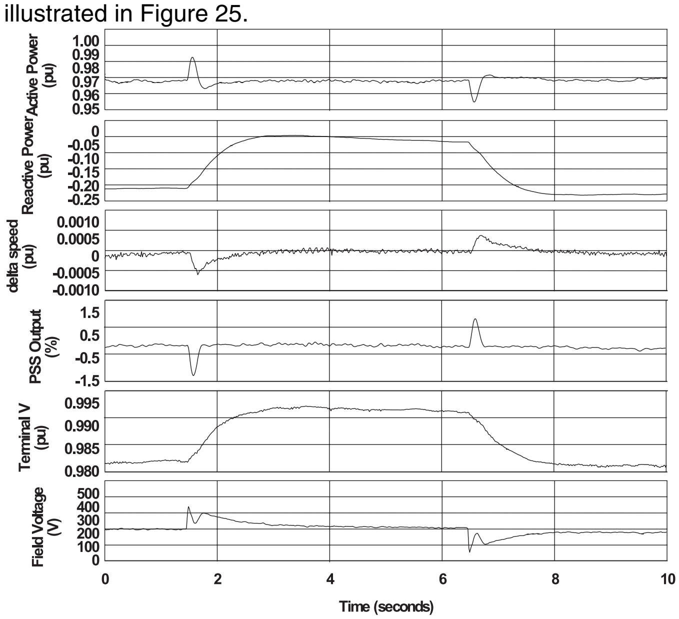


Fig. 25. On-line Step Response, Basler PSS-100 Ks=7.5, 92MW Hydro Turbine Generator

XVI. CHANGING TIMES FOR POWER SYSTEM STABILIZER IMPLEMENTATION

Since the blackouts in the Northwest in the late 90s and the more recent blackout in the Northeast, the frailty of the transmission system has become apparent. NERC (North American Reliability Council) has issued guidelines mandating testing to verify hardware to improve the reliability of the transmission system. These tests include verification of excitation models with excitation system performance and verification of excitation limiters and protective relays to ensure coordination. Today, use of power system stabilizers is being mandated in the Western portion of the country for all machines 35 MVA and above or groups of machines in a plant that total 75 MVA. To help improve the reliability of the transmission system, power system stabilizers have proven to dampen oscillations, and new innovations in power system stabilizer technology continue to make them more user-friendly in regard to commissioning and implementation. Old potentiometer-type stabilizer adjustments are obsolete with new commissioning software to reduce time for commissioning. See Figure 26.

Additional features provided in stabilizers, such as multiple setting groups, have made them more flexible to speed commissioning and accommodate a wide range of application needs. Here, reduced PSS gains may be required as the turbine generator is moving through its rough zones during machine loading. Without another set of gains in the power system stabilizer, the voltage regulator could become excessively aggressive and result in poor power system performance.

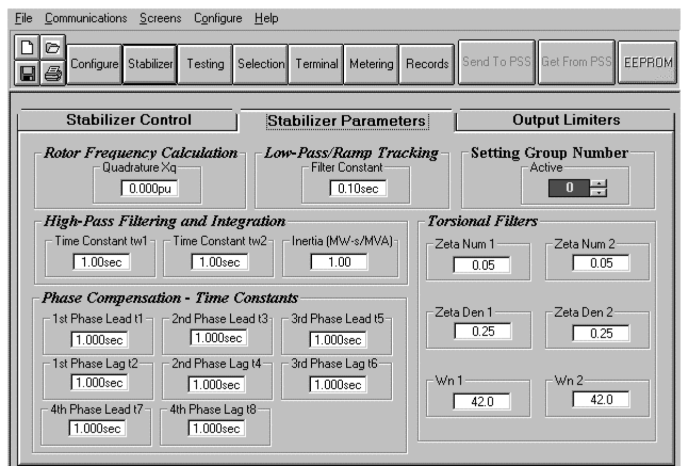


Fig. 26. Setup Screen for Power System Stabilizer Tuning

XVII. CONCLUSION

In 2006, the Energy Act was passed with legislation that requires conformance to performance audits by the American Electric Reliability Council that are specifically defined by the regional council. In the Northwest, WECC requires all generators, 35MVA, or group of machines totaling 75MVA to include a power system stabilizer. Many paper mills in the Northwest and Canada meet these guidelines and, therefore, may require power system stabilizers in the future if they do not already have them.

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