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Government of India
केंद्रीय विद्युत् प्राधिकरण
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No.:WRPC/Comm1-I/NPC/2023/

दिनांक: 30.06.2023

To,
The Member Secretary, NPC
Central Electricity Authority
New Delhi – 110066

विषय: "पावर-सिस्टम स्टेबलाइजर (PSS) ट्यूनिंग के संबंध में सामान्य प्रक्रिया को अंतिम रूप देने के लिए उप-समूह" की रिपोर्ट - के संबंध में।

Subject: Report of the "of Sub-Group to finalize common procedure for Power System Stabilizer (PSS) Tuning – regarding

Ref: NPC Division letter no. 4/MTGS/NPC/CEA/2021/71-81 dated 08.02.2021

Please find enclosed herewith the final report of the Sub-Group constituted to finalize common procedure for Power System Stabilizer (PSS) Tuning, constituted by NPC vide letter under reference.
Submitted for needful please.

भवदीय /Yours faithfully

Enclosed: As above.

(P. D. Lone)
(सदस्य संयोजक/Member Convener)

Copy to: All members as per list.

PROCEDURE FOR PSS TUNING IN INDIAN POWER SYSTEM

Detailed Guide for PSS Tuning in Indian Power Sector

The Report at a Glance

NPC in the 9th Meeting formed the following group to standardize the PSS Tuning procedure. Meetings of the group were held on 15.04.2021 (involving experts from IIT Bombay) and 30.03.2023 (involving experts from OEM BHEL) and the report was finalized.

It is a well-known fact that slow moving oscillations are observed in power systems occasionally affecting power and voltage. Such oscillations appear spontaneously under some operating conditions and are experienced by power utilities worldwide. Research literature as well as standard textbooks have analyzed this phenomenon. The PSS (or the slip-stabilizer as it was known in older machines) is a controller which when set properly provides adequate damping to mitigate the problem and is a very elegant and economical solution, instead of restricting power transfer.

The literature on PSS Tuning is however very vast over the years and amongst the standard textbooks the ones by K.R Padiyar or Prabha Kundur discusses these problems. While this report briefly touches on the various aspects of the literature as well shares our experiences of PSS Tuning, a serious reader is encouraged to go through the above textbooks to have a clearer understanding on the subject.

In case one feels overwhelmed we present a quick but limited glance of the objectives and approaches to PSS tuning.

Objectives of PSS Tuning

The PSS should be tuned in such a way that the following objectives are achieved:

Objective 1. The PSS shall not interfere with the primary function of the AVR which is to maintain the excitation especially under stressed conditions.

Objective 2. The PSS shall not worsen the synchronizing Torque (T_s) at any rotor swing frequency.

Objective 3. The intra-plant modes of generator are stable to begin with (by design). The PSS shall not destabilize such intra-plant modes.

Objective 4. Subject to objective (1), (2) and (3) compulsorily satisfied, the PSS may add a moderate phase lead so as to improve the Damping torque (T_d). By adding such a phase lead particularly during inter-area and local-area swing frequencies the small signal stability is enhanced. The PSS compensates for the lag introduced by AVR during small

signal stability conditions. This is the primary scope and duty of PSS. A well tuned PSS also enhances transient stability to some extent.

Approach and Testing for achieving the Objectives

Objective-1:-

1. In order to achieve objective (1), the output limits of the PSS signal shall be restricted to maximum $\pm 10\%$ of AVR reference.

Some literature papers recommended these limits should be $+10\%$ & -5% as the limits of PSS influenced on AVR due to first swing stability consideration. So we feel that $+10\%$ and -5% limits are desirable but in any case do not exceed beyond the $\pm 10\%$ guideline without strong justifications.

Objective-2 :-

2. In order to achieve objective (2), the frequency response of PSS and other transfer function such as $GEP(j\omega)$ must be available prior to field trials.

A software taking inputs from load flow and dynamic data was developed by IIT-B in MATLAB which gave frequency response and was used in WR during PSS tuning exercise. It is strongly recommended that at bare minimum this information must be available to the PSS tuner, and same information may be obtained through this platform or similar platforms.

3. Due to advancement in technology, better ways of estimating the transfer function of the generator using very low input test signal are currently available. It is encouraged to explore them.
4. Attempting to set PSS by only the step response of AVR (without frequency response information available from 2 above) has the hidden danger of possibly destabilizing synchronizing Torque (T_s).

For some excitation system such as brushless excitation, the step responses of AVR with & without PSS are nearly identical and that is alright. Because step change excites only intra-plant modes, the field step test may not show an appreciable improvement in damping.

But, when inter-area or local area frequencies are induced by the power system, the same settings of PSS will indicate much better response in simulation. Because of this,

we recommended the PSS should be tuned keeping the theoretical frequency response from software and test step response of AVR in field. In short, do not set the PSS only on the basis of step response of AVR.

Objective-3:-

5. In order to achieve objective (3), the step response with and without PSS is the proof. This response should clearly show that the PSS tuning has not spoilt the damping. For a few cases as mentioned earlier, it may appear that there is no improvement in damping. But, it is alright if the PSS tuning is done in alignment with the frequency response and simulation confirms the same. In most cases appreciable damping improvement is seen.

6. Summary: -

Objective	Tests
Objective 1	PSS output limits set to $\pm 10\%$ (preferably +10% and -5%)
Objective 2	Tuning as guided by the theoretical frequency response 0 Hz to 3 Hz.
Objective 3	Step test of AVR with and without PSS.

7. Keeping the above approaches as a guideline and suitably blending it with other advances in technology and literature, PSS tuning in field may be adopted. If any doubts on interpretation of settings arises in field, enable the PSS only after removal of such doubts.
8. PSS Tuning done by a group of engineers from the excitation areas of Owner, OEM, RPC/RLDC/CTU and preferably with an academic expertise along with the required software generally blends well. Data of observed oscillations if any, can be shared with the group for better PSS Tuning experience.

Procedure For PSS Tuning in Indian Power System

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1. Regulatory Provision on PSS and its Tuning

1.1 CEA (Technical standards for connectivity to the Grid) Regulation, 2007¹:

- Power System stabilizer means controlling equipment which receives input signal of speed, frequency and power to control the excitation via the voltage regulator for damping power oscillation of a synchronous machine”.

The PSS need to be Multi-Input PSS (input signal from speed, frequency, and power of generating unit) rather than single input for better performance and stability.

- For New generating Units (part II. 1. C): The AVR of generator of 100 MW and above shall include Power system stabilizer (PSS)

For Old Units: (part II. 2. 2): For thermal generating units of having rated capacity of 200 MW and above and Hydro Units having rated capacity of 100 MW and above, following facility should be provided at the time of renovation and modernization: Every generating unit of capacity having rated capacity higher than 100 MW shall have PSS.

- **6.g:** The requester and user shall cooperate with RPC and appropriate Load dispatch center in respect of matter listed below, but not limited to: Cooperate with RPC for tuning of PSS provided in the excitation system of generating Unit.

1.2 CEA Technical Standard for Construction of Electrical Plants and Electric Lines (Published in 2010)²:

- For Coal or lignite based Thermal Generating Stations (10.2. g.i:), Gas turbine based Thermal generating stations (18), Internal Combustion(IC) engine based Thermal generating station (27) : Suitable Excitation System, as well as Automatic voltage regulator (AVR), shall be provided with the generator as per CEA (Technical standards for connectivity to the Grid) Regulation, 2007. Power System Stabilizer (PSS) shall be provided in AVR for generator of 100 MW and above rating.

¹ https://cea.nic.in/wp-content/uploads/2020/02/grid_connect_reg.pdf

² https://cea.nic.in/wp-content/uploads/2020/02/tech_std_reg.pdf

- For Hydro power Plan (37.3.e): All the performance requirements of AVR, PSS shall be in accordance shall be in accordance with CEA (Technical standards for connectivity to the Grid) Regulation, 2007 and CEA (Grid standard) regulation as and when they come into force.

1.3 Standard technical features of BTG system for supercritical 660/800 MW thermal units, CEA, July 2013³

1. (16.2.4.iii.d.5) Power system stabilizer (PSS): The excitation system shall be provided with power system stabilizer for achieving the dynamic stability of the system under most stringent conditions of operation in the phase of disturbance created by short circuits conditions, load rejections, switching on/ off of transmission lines as per manufacturer's practice
2. (16.2.5) Stability studies: The detailed computer studies shall be carried out by the supplier considering single machine with infinite bus to confirm the suitability of the turbine generator and its excitation system in the grid for maintaining the power system stability under dynamic and transient conditions and tune the PSS parameters at site for all the machines. The details of simulation technique and method proposed to be used for this purpose shall be furnished.

1.4 Standard technical specification for main plant package of sub-critical thermal power project 2 X (500 MW or above), CEA, Sept 2008:⁴

3. (5.2.4.iv) Power system stabilizer (PSS):
 - a) The excitation system shall be provided with power system stabilizer for achieving the dynamic stability of the system under most stringent conditions of operation in the phase of disturbance created by short circuits conditions, load rejections, switching on/ off of transmission lines.
 - b) The power system stabilizer should have adoptable settings, which should automatically adjust to system reactance. In other words, the system should

³ <https://cea.nic.in/wp-content/uploads/2020/04/supercritical.pdf>

⁴ https://cea.nic.in/wp-content/uploads/2020/04/standard_tech_spec.pdf

provide automatic and continuous measurement of system reactance and power system stabilizer setting must continually adjust itself for any changes in the system reactance to provide required dynamic stability margins.

4. (5.2.4.i.b) Stability studies, both dynamic (long duration, transient) and steady state, shall be carried out to evaluate various parameters of the excitation system, e.g., response time, response ratio, ceiling voltage, loop gains, power system stabilizer (PSS) parameters etc., so as to meet the operational requirements of the grid particularly on loading side as the power station is connected to the grid by long transmission lines. The purchaser will furnish all information/ data necessary to carry out the stability studies to the contractor at detail engineering stage.

1.5 IEGC 5.2.k⁵: All generating units shall normally have their automatic voltage regulators (AVRs) in operation. In particular, if a generating unit of over fifty (50) MW size is required to be operated without its AVR in service, the RLDC shall be immediately intimated about the reason and duration, and its permission obtained. Power System Stabilizers (PSS) in AVRs of generating units (wherever provided), shall be got properly tuned by the respective generating unit owner as per a plan prepared for the purpose by the CTU/RPC from time to time. CTU /RPC will be allowed to carry out checking of PSS and further tuning it, wherever considered necessary.

1.6 Report of the Task Force on Power System Analysis under Contingencies⁶: Power System Stabilizers (PSS) as part of the generators installed in the network are also critical for damping the local area oscillations and imparting stability to the networks. Optimal tuning of PSS also enhances effectiveness of other HVDC and FACTS controllers in supporting overall/ inter-area stability. Necessary exercise to retune PSS should be undertaken at interval of 3-4 years or even earlier depending on network additions in vicinity of specific generators.

⁵ <https://cercind.gov.in/2016/regulation/9.pdf>

⁶ http://erpc.gov.in/wp-content/uploads/2016/10/Ramkrishna-report_power_system_analysis.pdf q

1.7 Report of the Expert Group: Review of Indian Electricity Grid Code⁷

All generating units shall have their automatic voltage regulators (AVRs) in operation and tuned. In particular, if a generating unit of over fifty (50) MW size is required to be operated without its AVR in service, the RLDC shall be immediately intimated about the reason and duration, and its permission obtained. AVR, Power System Stabilizers (PSS) of synchronous generating units, voltage or reactive power controller of wind, solar generating unit or ESS shall be properly tuned by the respective owner. The above tuning, including for low and high voltage ride through capability of wind and solar generators shall be carried out – at least once every five (5) years, – based on operational feedback provided by the RLDC after analysis of a grid event or disturbance and in case of a major change in excitation system or major network changes/fault level changes near to generating plant as reported by NLDC, RLDC. In order to provide basic requirement of PSS tuning for system security, the PSS tuning procedure shall be prepared by NLDC. The generating stations shall submit the detailed list of proposed tuning of AVR/PSS or reactive power controllers to RPC prior to 31st December for the next financial year. RPC shall compile a list before 31st March and share with all users and RLDC. After completing the PSS tuning, the report shall be submitted by the generating station. The report shall comprise of requisite power system mapping, simulation study and field testing, and report shall be submitted to RPC. RPC may carry out field checking of AVR, Power System Stabilizers (PSS) or voltage or reactive power controller of wind, solar generating unit or ESS, whenever considered necessary. Behaviour of the generating station during actual system event would also be recorded and retuning advised by RPC, if necessary.

⁷ <https://cercind.gov.in/2020/reports/Final%20Report%20dated%2014.1.2020.pdf>

2. PSS Tuning: Sharing of the experience of WR by Sh. S.

Satyanarayan

2.1 Introduction and Motivation:

PSS Tuning exercise was attempted in the Western Region of India and 23 generating units were taken up for tuning. While the individual testing and reports were made available to the concerned generating stations immediately, a combined report of the full exercise after completion could not be produced. This was partly because of the fact that as the project moved into the next phase, newer situations were emerging and took the focus.

At present an attempt is made to compile all the information from memory about the testing and sharing of the experience gained by the PSS Tuning exercise. So, this report is more like sharing of the experiences of PSS Tuning exercise in WR, from an **individual perspective**.

PSS field tuning began in WR in 2003. During the field trials of PSS Tuning exercise in WR, Dr A.M. Kulkarni, IIT-B (consultant) and Shri Parthasarathy, Manager, BHEL and Shri Satyanarayan S., S.E., WRPC were associated in the PSS tuning field trials at all the station in WR. The generation station excitation team gave all the support and made the tuning a great success. In the initial stages, all utility engineers would participate in the tuning exercise. Two training sessions were organized in IIT-B, Electrical Engg. Dept, by Dr A.M. Kulkarni and their team, for familiarization with all the issues involved. The progress of PSS Tuning exercise was regularly reported in the WREB/WRPC meetings.

After the grid disturbance of 2012, the role and importance of tuning PSS on generators, tuning TCSC damping controllers, HVDC damping controllers has been increasingly felt. While these controllers can positively influence the stability **when done correctly** they can, equally harm, if not correctly tuned or be not efficacious if they are ill-tuned. Hence the tuning of these complex controllers, should be done systematically and properly and with a scientific approach.

- a) **Scope of PSS Tuning:** PSS Tuning can be done to improve the poor damping observed in the inter-area modes of oscillations or local mode oscillations without destabilizing the synchronous torque or interfering into the scope of the functions of the AVR. Further PSS comes into action only when there are changes that originate from the grid side. Manual changes

in generation *usually* bypass the PSS controller by design for power input PSS. Similarly, PSS can be set to be bypassed for very low load levels of generation. Such a well-tuned PSS can stabilize the oscillations and also improve the power transfer accordingly.

- b) **Benefits of PSS Tuning:** The PSS is a standard circuitry that is found invariably shipped even in the early machines (late 60s –early 70s). it is also known as the slip stabilizer. And therefore, would be certainly available in newer machines. By properly tuning it, damping of poorly observed modes can be done. The cost of tuning is negligible compared to other modes of enhancing stability, and so the PSS Tuning is a very cost-effective solution to the oscillatory stability issue. The PSS Tuning exercise in WR also enhanced the academic-industry interaction. It also improved the general understanding of the stability issues of the operation of the grid.
- c) **Wrongly tuned PSS:** If the PSS is set keeping the above scope in mind, it usually results in a smooth operation. However, if set randomly or erroneously (not as per the scope), it *does have* the potential to destabilize a stable operation. In the past, prior to the PSS Tuning exercise, PSS were enabled at some generating units to enhance stability. The PSS Tuning exercise undertaken in WR is the first one to study the tuning problem from a regional perspective. It is also known that individual attempts in the past, to switch on the PSS has been partly successful and partly failure and if unstable operation is observed in the generator, usually such a PSS would be switched off in the field. Such a sorry situation can occur, if either the gains or limits are set incorrectly. Ambitiously trying to improve the step response with the PSS in field trials, can also lead to problems, as one can lose sight of the inter-area oscillatory problems in field testing. Hence the frequency response approach helps in the tuning. It is also known that PSS requires retuning when there are major changes in the grid.
- d) **Approach of PSS Tuning in WR:** In the present approach, initially two worst case grid scenarios of high MW and high MVAR dispatches were initially given. Linear analysis of the same was done by IIT-B and analytically modes of oscillations and their damping were quantized. The frequency response of the generators was simulated. Then during field trials, an apt value of the gains was chosen such that the conditions

mentioned in the scope are satisfied. By plotting the frequency response curves as a function of the gains, the possible behaviour of the machine during such oscillations was predictable. Finally transient response was done to check that the settings were indeed acceptable. The theory of the method is given in K.R. Padiyar's book in details and the interested reader can pursue the same.

We conclude the introduction and motivation with a brief outline of the exercise.

2.2 A brief outline of the exercise of PSS Tuning in WR:

- a) The Vijoy Kumar Committee in April and May 1994 twin grid disturbances in WR had then recommended that the possibility of tuning of PSS on generating machines to enhance stability should be explored.
- b) WREB (now WRPC) then handed over the studies to CPRI to examine this aspect. CPRI completed the exercise of carrying out system studies and in 1998-99 had recommended that by tuning PSS on all 210 MW and 500 MW units the stability is enhanced, as seen for the cases of the grid disturbances of April and May 1995 (under the Vijoy Kumar Committee).
- c) It has to be remembered that in those days (around 1997-98), the Windows version of power system stability studies packages were not available. CPRI had performed the studies on SIMPOW package of ABB. Since at that time the simulation had modelled all distance relays for the grid, this was probably the first attempt then to simulate the situation and see what the distance relays were seeing and was novel in that aspect.
- d) So as per the recommendations of CPRI studies, the task of tuning the PSS on 210 MW and 500 MW units were decided to be undertaken. A search for vendors who could do that task was then explored. There were many discussions and foreign vendors was sought for PSS Tuning work. However, it could not materialize. At about the same time (around 1999-2000) Northern Region had undertaken PSS Tuning of 4 machines with the help of PTI, USA. But before WR could finalize some sort of agreement the same could go through to the final stage. It was also clear that involving a foreign consultant would be expensive from the project cost point of view. The confidence from the discussions that was emerging in WR at that time, was WR could attempt the PSS Tuning exercise using our own engineers and taking academic support from IIT-B.

- e) In WR, it was finally decided in the 114th WREB meeting in November 2000, that this exercise can be undertaken with academic support from IIT-B and so the exercise of doing the PSS Tuning was entrusted to IIT-B.
- f) Almost two years went in getting data from the generating units. This led to a large gestation period during which the data had to be literally mined and checked. System studies were done again as per the revised grid conditions, and the pilot project to tune 4 generating stations was proposed by IIT-B. It was then decided by WREB to carry out the pilot project at twelve units in the first phase involving two generating units from Gujarat, MP, Maharashtra, Chhattisgarh, RPL and NTPC.
- g) In the first phase, the two units chosen were from Wanakbori (Gujarat), Nasik (Maharashtra), Satpura (MP), Korba-W (Chhattisgarh), Dahanu (RPL) and Korba (NTPC). All these units incidentally had BHEL as the manufacturer and all were 200/210/250 MW units.
- h) In the initial stage of field exercise itself it became clear that the manufacturer's representative is needed while doing the field test. So BHEL was involved during the field PSS Tuning.
- i) The first phase of field testing was completed at all the stations successfully as shown in the table below:

Table 2.2.1

Station	Units	Dates	Excitation	Remarks
NTPC Korba	2,3 (200 MW)	28.06.03-30.06.03	Static DVR	Testing done for fixed gain PSS successfully. But since the DVR had adaptive PSS, the fixed PSS settings could not be used. The DVR's adaptive PSS was however enabled.
Wanakbori Gujarat	4, 5 (210 MW)	14.06.04-16.06.04	Static AVR	Successfully tested and PSS enabled.
Nasik Maharashtra	3, 5 (210 MW)	18.06.04-20.06.04	Static AVR	Successfully tested and PSS enabled.
Dahanu –RPL	1,2 (250 MW)	09.12.04	Static AVR	Successfully tested and PSS enabled.
Korba West – Chhattisgarh	1, 3 (210 MW)	21.07.05-22.07.05	Static AVR	Successfully tested and PSS enabled.

Satpura-MP	8.9 (210 MW)	12.09.06-13.09.06)	Static AVR	Successfully tested and PSS enabled.
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*** Please note that the PSS were enabled and continued for some time. Since these were analog old units, at most places, they were also planning retrofitting with Digital version of AVRs.**

- j) The success of the first phase led to the second phase of PSS Tuning in WR. The second phase planned for PSS Tuning at 29 units. In addition, with new DVRs coming and DVRs usually (depending on the manufacturer) provide for a default PSS enabled and at that time 11 units were proposed for status checking. This meant to study whether the PSS settings were optimal. The PSS Testing exercise was also extended to 500 MW tuning in this phase. The units planned were divided in two parts.

Table 2.2.2

Station	Units	Dates	Excitation	Remarks
NTPC Korba	4,5, 6 (500 MW)	Sept 06 22.08.08	Static DVR	Cards Checked. PSS Tuned.
MSEB Parli	3 units (210 MW)	12.12.06	Static AVR	Successfully tested and PSS enabled.
SGTPS-MP	4 units (210 MW)		Static AVR	Successfully tested and PSS enabled.
Korba West – Chhattisgarh	4 (210 MW)		Static AVR	Successfully tested and PSS enabled.
Gandhinagar–Gujarat	3 units			Could not undertake this PSS Tuning.

Thus 11 units were tuned in the second phase. A total of 23 units were tuned in this project.

- k) Eastern region also adopted the same methodology and IIT-B was associated. It is understood that ER had completed at least 8 units at that time.
- l) The exercise finished at Part-I of the Second Phase. The status verification proposed earlier could not be done.
- m) So, to conclude the brief history, the PSS Tuning exercise in WR was largely successful. It had given excellent academic-industry interaction. Both sides

benefitted from the exercise. During the first phase the testing / excitation group of generators were involved from all states in each PSS Tuning. One or two training sessions were also arranged at IIT-B. The approach followed in the PSS Tuning is what is already explained in papers and today is also available in standard post-graduate textbook levels.

2.3 Knowing the PSS and AVR – its role and scope

2.3.1 AVR:

The modern generators have high performance excitation systems. This is essential for steady state operation and also for transient stability. It provides fast control of terminal voltage. However, the fast-acting exciters with high gain AVR can contribute to oscillatory instability. This type of instability is low frequency oscillations (0.2 Hz to 2 Hz) which can appear / persist for no apparent reason. By tuning a PSS, we can get a good stable response.

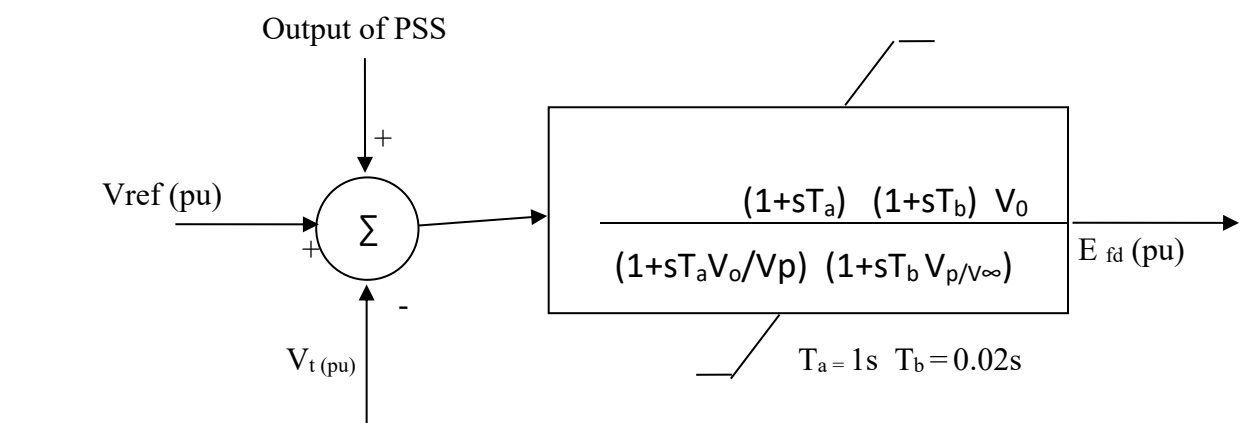
2.3.2 What is the PSS?

PSS or Power System Stabilizer is a controller in the Voltage Regulator (AVR or DVR). Its input signals are either

- (a) Power
- (b) Frequency or speed
- (c) A combination of both
- (d) A combination of other signals (newer delta-P omega type)

Its output is a voltage signal. This signal is added into the AVR reference voltage.

Thus, a PSS modulates the AVR reference voltage. Fig 2.1 gives the AVR block diagram at a 210 MW plant.



$$V_o = 200 \quad V_p = 5.5 \quad V_\infty = 80$$

Fig 2.3.1 AVR Block Diagram

The structure of the PSS is shown in Fig 2.3.2. This is the transfer function version.

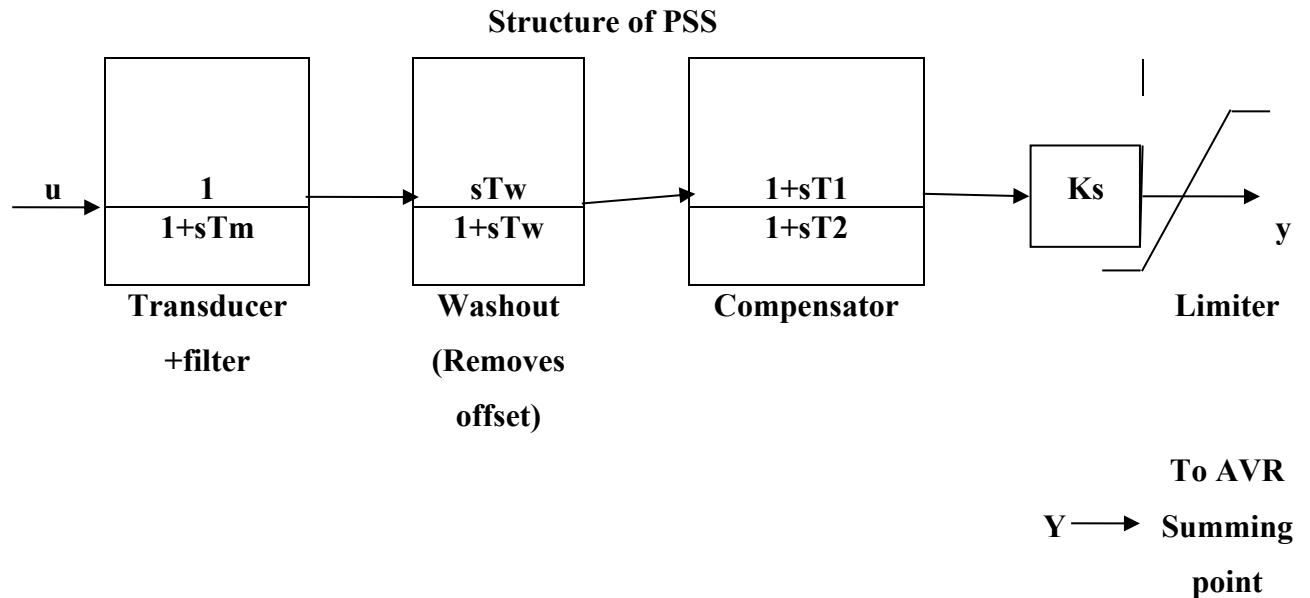


Fig 2.3.2 Structure of PSS

It contains

- Transducer or filter:** The input transducer or filter. The input signal u is applied to the PSS.
- Washout:** The block removes any dc offset. In other words, it allows changes to be passed. It is because of this the PSS does not respond to steady state. For example, if the input signal is Power, and if the value of P is constant, the output is zero. It is mathematically a practical differentiator.
- The main compensator:** At the heart of it, the PSS is a lead compensator. It lifts the lag or compensates for the AVR lag response. This improves the stability in small signal stability conditions. The above controller with one input shown say P .

Let us look at the PSS card (Fig 2.3.3)

Prop. Amplifier

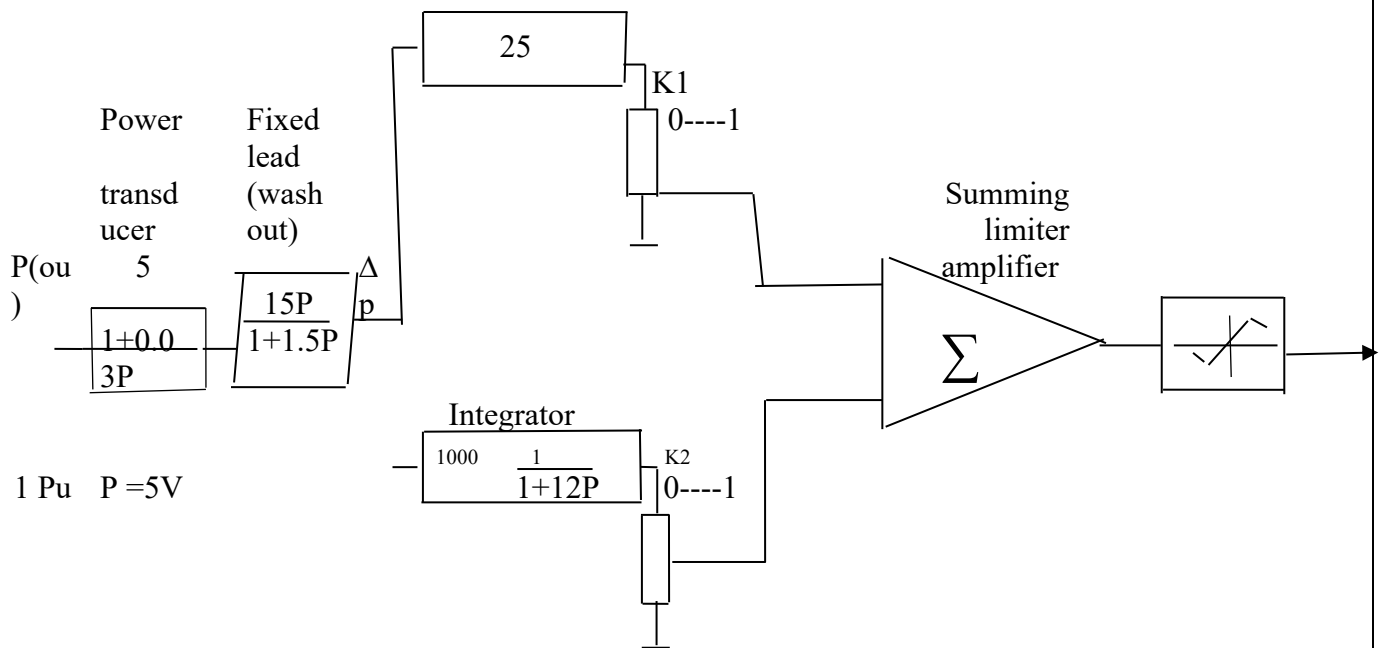


Fig 2.3.3 PSS Card transfer function

We can reduce the same as

$$\frac{\Delta V_{PSS}(s)}{\Delta P(s)} = -25_{k1} - \frac{1000_{k2}}{1+12s}$$

$$= - \frac{(25_{k1} + 1000_{k2}) + 300_{k1}s}{1+12s} = -K \frac{(1+sT)}{1+12s}$$

$$T = \frac{300_{k1}}{25_{k1} - 1000_{k2}}$$

$$K = 25_{k1} + 1000_{k2}$$

By changing the ratio of K1/K2 we can change the response of $\Delta V_{PSS} / \Delta P$.

4. **Limiter:** The output of ΔV_{PSS} can be limited V_{REF} of AVR. Typically, this is set to +0.1 or -0.05 of V_{REF} . **This is done to prevent / control the PSS excessively modulating V_{REF} .**

2.4 Will the PSS act always?

The PSS is supposed to act only when there are changes in the input signal.

However, the PSS is deliberately made ineffective under the following conditions:

- a) Manual changes made by operator. For e.g., a power input PSS will not respond to changes in power done from the operator's desk through say the speeder gear. As the changes were done manually, design control logic exists to pass these changes to PSS.

b) PSS can also be disabled if power of the machine is below a certain percentage of the unit rating. This is settable. Usually, 40% or below Power setting. Refer manual for details.

Except such restrictions, PSS will always act if the changes of power are passed to the PSS controller.

2.5 Logic of PSS Tuning:

The Fig 2.3 shows the logic of PSS Tuning. The ratio of $K1/K2$ controls the phase of the voltage injected into the AVR. As we can see the PSS is some form of a lead compensation that if added to the pure AVR frequency response, will lift the AVR response upwards.

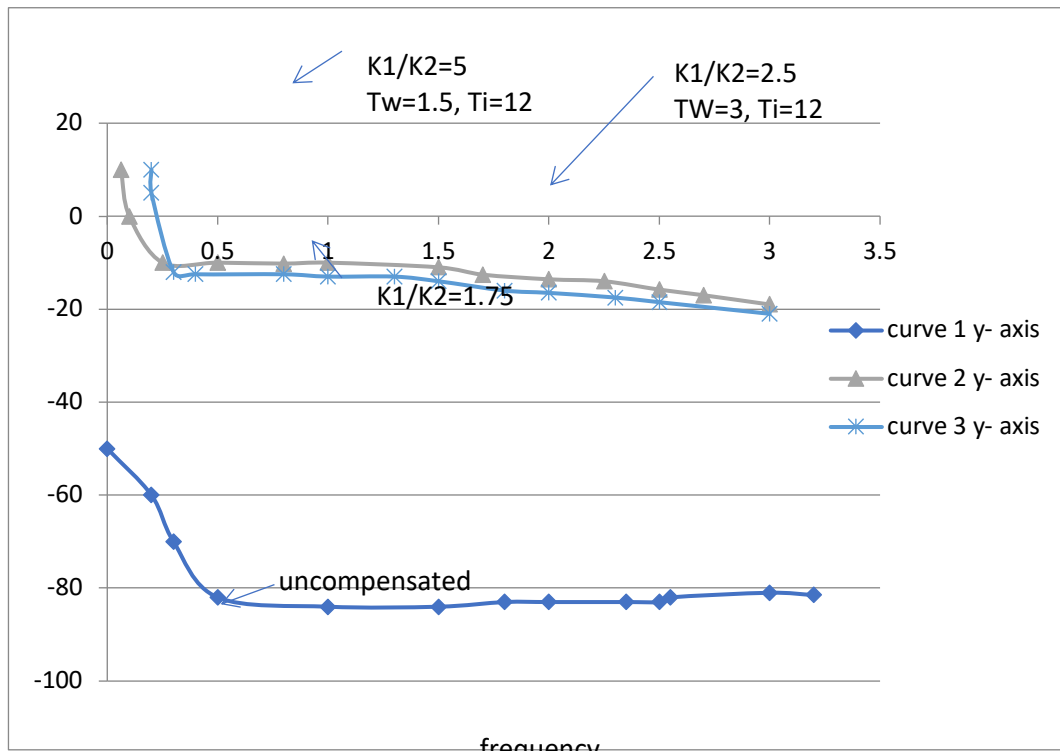


Fig 2.5 Logic of PSS Tuning

The compensated final curve will be above the AVR response which is shown for various values of $K1/K2$. Settings around 1.75 nicely lifts the curve **and more importantly keeps the compensated curve in first quadrant only**. This ensures T_s (synchronizing torque) is not made negative which is another important factor. For example the light blue coloured curve for $k1/k2 = 5$ is to be avoided, as for frequencies below 1 Hz, it makes T_s negative. At frequencies around 2 to 2.5 Hz this is very nice. The step response of AVR may show a very good damping. But

This is bad for inter-area modes as T_s is negative. Hence the plotting of frequency response curve helps in choosing PSS gains.

Fixed Gain vs Adaptive PSS: Fixed gain PSS are equally adequate in their role for providing damping requirements. If we have an adaptive PSS then the mechanism of adaptation must be known to comment on the same. Excepting one machine, all PSS tuned in this project were fixed gain PSS.

DVR vs AVR: DVR is the digital version of the AVR. It is easy to know the parameters easily. In AVR the parameters have to be read from the link positions on the card. Apart from that there is no major difference.

Getting Frequency response curves:

This is achieved by a proprietary program developed by IIT-B on the lines of theory given in Padiyar's book. It is beyond the scope of this little report to explain the logic of the same.

3. Effect of Excitation System on Power System Behavior

3.1 Introduction

Instability in Power system crop up due to the fundamental nature of oscillations of the machines. We can understand the basics of excitation system effect through a Single Machine Infinite Bus (SMIB) System. The generator is modelled as a voltage source behind transient reactance - this model is known as the classical model. The internal voltage angle is related to the position of the rotor and described by following equation.

$$M \frac{d^2 \delta}{dt^2} = T_m - T_e$$

Where M is the combined moment of Inertia of generator rotor and turbine in kg.m^2

δ is the angular position of the rotor with respect to a stationary axis in (rad)

T_m is the mechanical torque supplied by the prime mover in N-m

T_e is the electrical torque output of the alternator in N-m

The SMIB System is as given below:

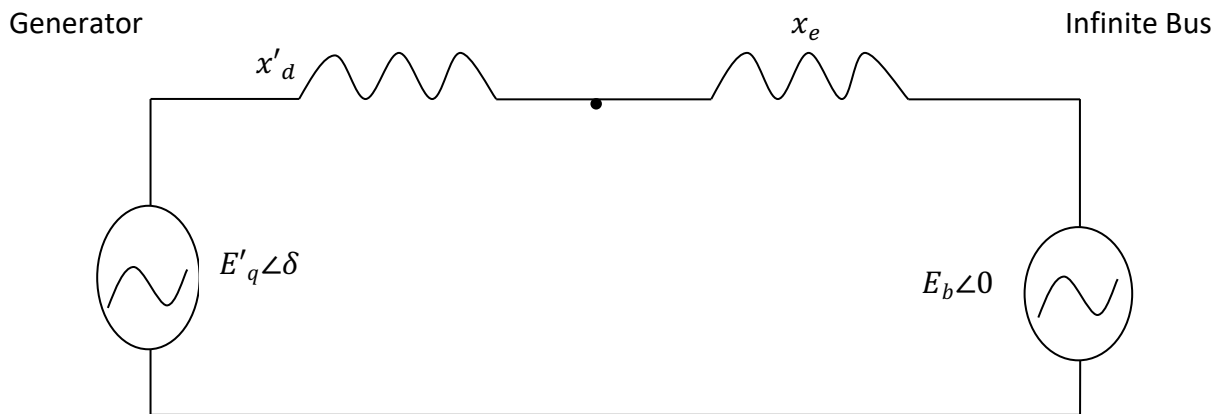


Fig. 3.1.1

When a disturbance is applied to the above system, the deviation is a monotonic increasing deviation from the point of equilibrium. This is because the torque is no longer restoring in nature, but it enhances the deviation. The equilibrium point is called as monotonically unstable and is not a viable operating point. Further to help

understand the dynamic behavior of the system, the qualitative behavior is inferred by a familiar dynamic system analogy – the spring mass system.

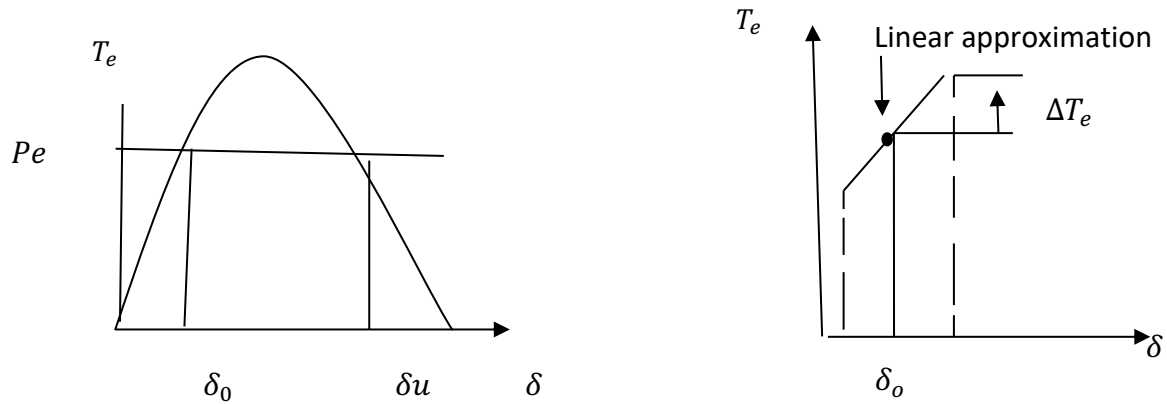


Fig. 3.1.2

The response of the spring mass system is well known as an oscillatory behavior to a disturbance. The SMIB system also has oscillatory behavior of rotor (swings). The frequency of oscillations of the system will depend on the M in the swing equation. If M is larger, the frequency of oscillations will lower and vice-versa. In such situations if there is no damping present, there is a sustained oscillation of the rotor following the disturbance. However, if the friction is present, then the oscillations will eventually die down. Friction usually implies that there is some kind of a retarding torque proportional to the angular speed.

3.2 SMIB model with field winding equationⁱ

For the classical model, it is assumed that field flux remains constant during a disturbance. This is equivalent to say that “ E_q ” which is proportional to field flux is constant. Following a disturbance, flux seen by the winding does not change immediately, but responds according to Faradays law of Electromagnetism.

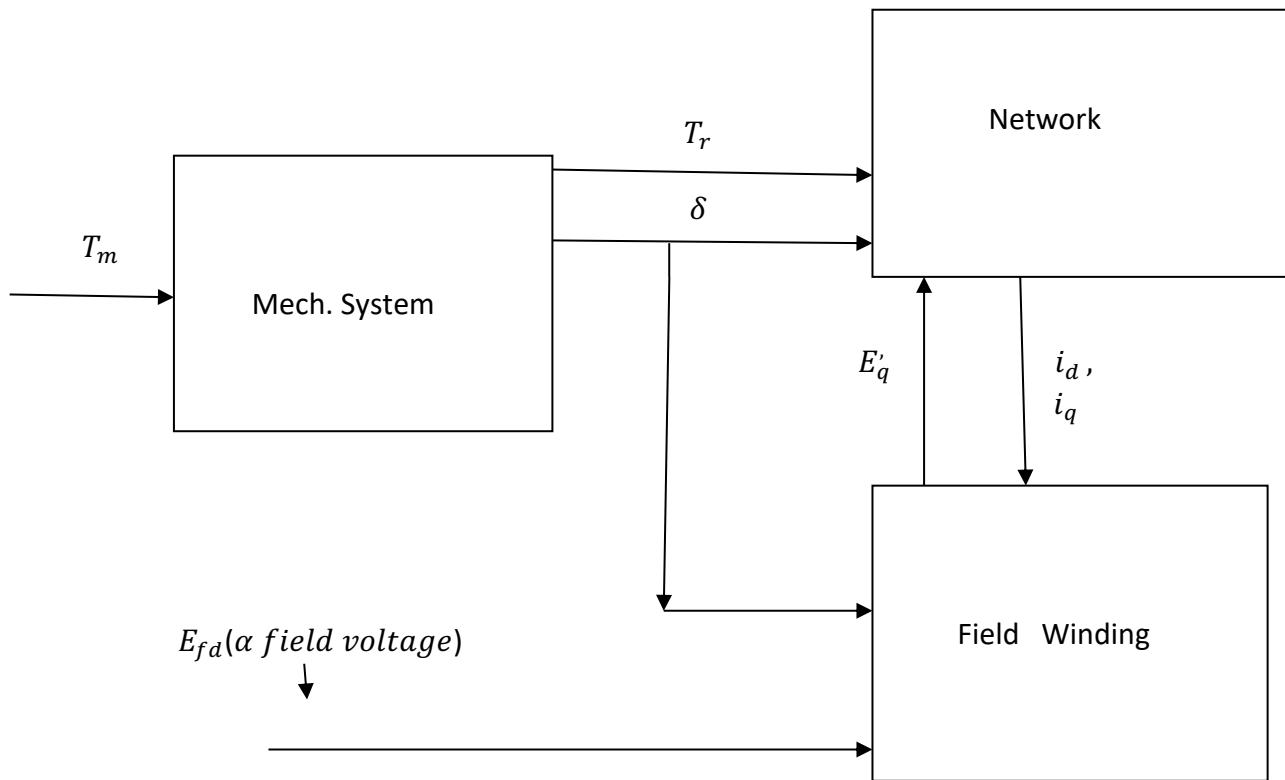


Fig. 3.2.1

The above figure shows a system with field winding. The electrical torque is dependent on both Angle and E_q (the state proportional to field flux). If the angle is oscillating sinusoidally, the response of the field winding flux state is also of oscillatory nature. However, the phase and magnitude of the oscillation is determined by the transfer function. E_{fd} is zero for manual excitation control.

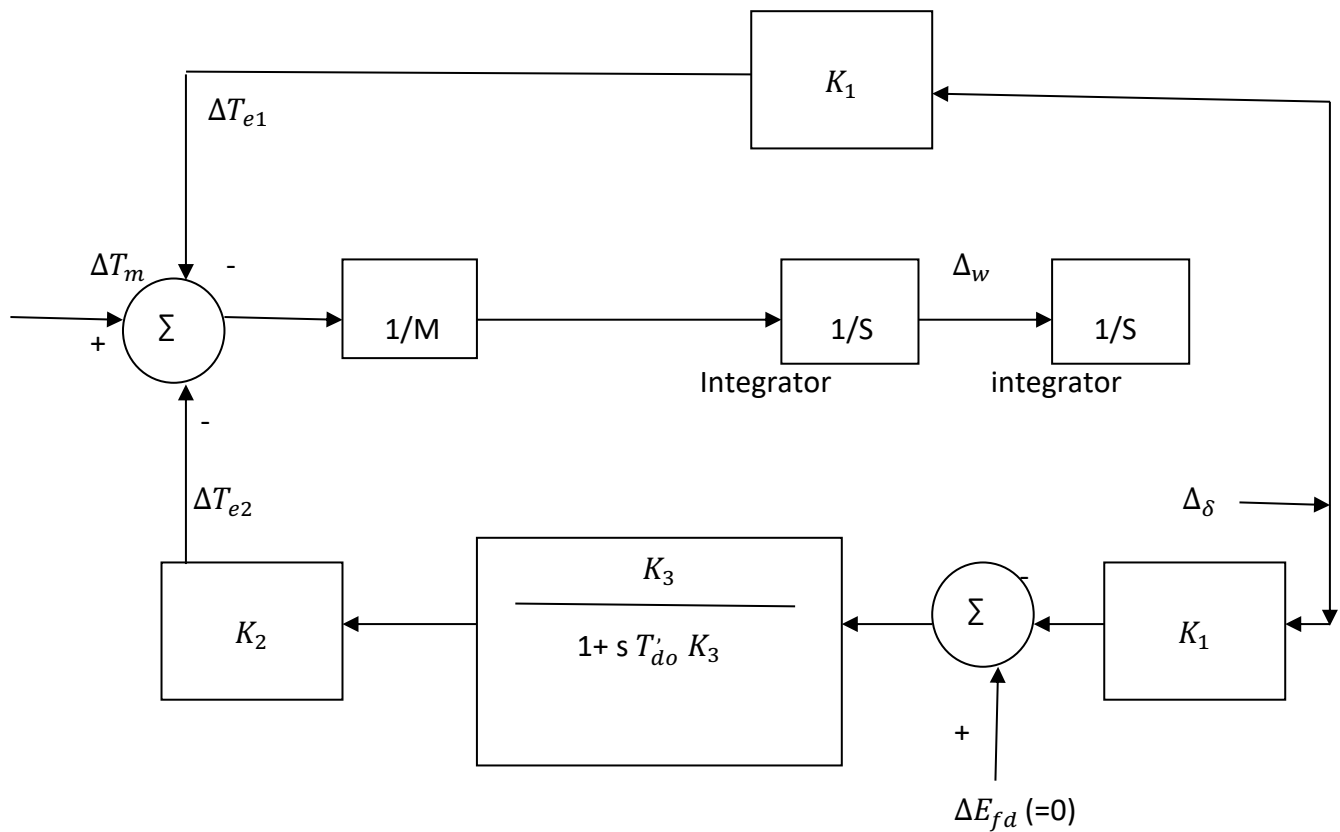


Fig. 3.2.2

The above block diagram represents the transfer function Block Diagram (with effect of field winding). For normal system operation the constant K_1 to K_4 are positive. Thus, if the angle is oscillating sinusoidally, the total electrical torque (forced response) at this oscillation frequency is such that it has a positive component in phase and also a positive component 90° leading the angular oscillations (i.e., in phase with speed oscillations). Consequently, the system is stable because the damping and synchronizing torques are positive.

3.3 Effect of Automatic Voltage Regulator

An AVR is used to regulate the generator terminal voltage by controlling the field current of the excitor. Without AVRs modern turbogenerators cannot operate at full rated power, as their synchronous reactance's are around 2.0pu. Also, the transient stability is improved by fast acting exciters with high gain AVR. V_g is the machine terminal voltage and V_s is output from PSS.

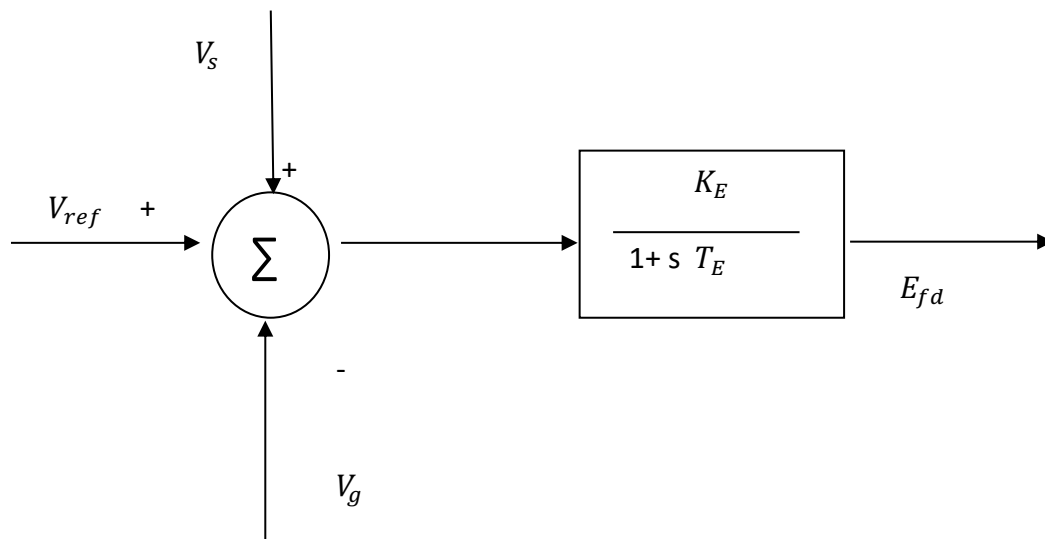


Fig 3.3.1 - Schematic diagram of Static Excitation System

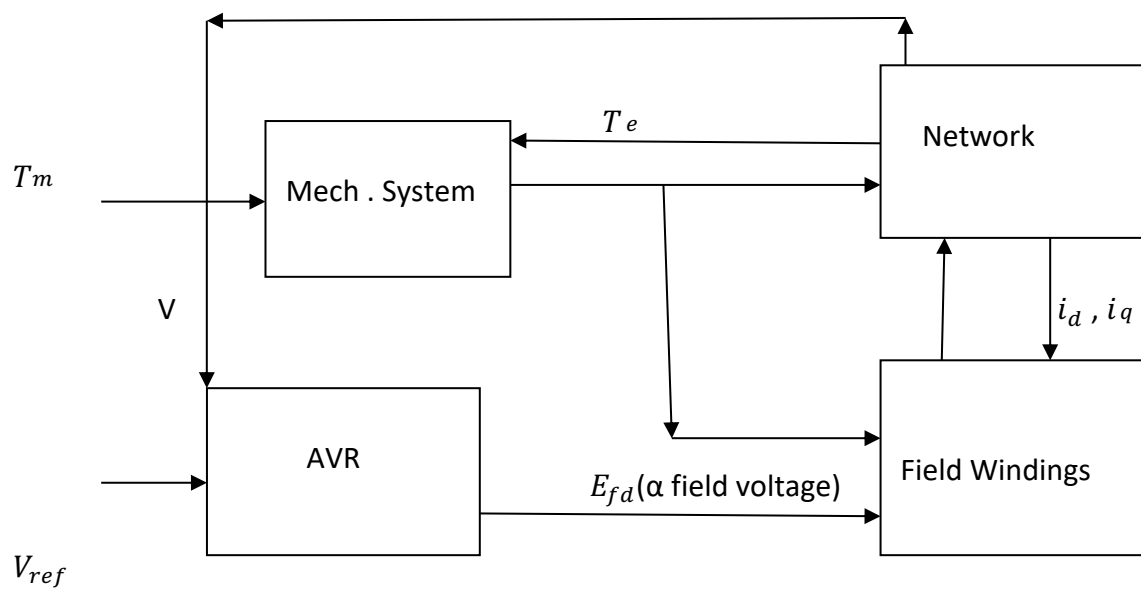


Fig. 3.3.2 - Block Diagram including the static excitation system

4. Power System Stabilizer & Power System Dynamics

4.1 Introduction

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

Depending on the system configuration, the objective of PSS can differ. In general, the PSS is used to damp inter-area modes without jeopardizing the stability of local modes. Many a times local area modes are of major concern. In general, however PSS must be designed to damp both types of modes.

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 center) the analysis of the problem, can be simplified by considering the model of a single machine (the generating stations is represented by an equivalent machine) connected to an infinite bus (SMIB).

Typically, only a few of the oscillatory swing modes are unstable. The procedure then is to identify the critical mode and the machines which have significant participation in these critical modes. PSS can be tuned on the participating machines.

4.2 Controlling Oscillations

One of the essential of controlling the oscillations and providing the damping is to modulate some controllable quantities which will directly or indirectly cause damping.

The necessary conditions for doing this are

- a) The oscillation should be seen in the quantity which is used as the modulation signal. Some obvious quantities which can be used are speed of the generator and power output from the generator.
- b) Variation of the controllable quantity should be able to cause an adequate variation in the torque. One possibility is to control the input mechanical torque itself. However, this is not practically feasible due to slow response of the turbine control system. Another option is to control the voltage reference of the AVR or references of the HVDC and SVC controllers in the system.

- c) The controller should modulate the controllable quantity appropriately using the modulating signal, so that damping torque is produced at the rotor oscillation frequency.

The most widely accepted and inexpensive way of achieving a stabilizer is to modulate the voltage reference of the AVR using speed/power/bus frequency signals. Note that the controller in each case will be different since these oscillations are not in phase with each other. The feedback signal can be synthesized using a combination of several signals.

4.3 Control Signals for the AVR Voltage Reference:

The following signals have been in use and the controller in each case will be different.

- a) **Speed:** This is the most natural choice for the feedback signal. However, the speed signal can aggravate (Sub-Synchronous Resonance) SSR problems and therefore a torsional filter is necessary.
- b) **Frequency:** Frequency signal is similar to a speed signal. If frequency at a common (HV) bus for a plant with identical generators is taken, then intra-plant oscillations may be absent in the signal. However, frequency signal is susceptible to noise from nearby loads like arc-furnaces.
- c) **Power:** Speed is proportional to the integral of the difference between mechanical and electrical power. Sometimes electrical power alone is used as a signal. However, during power ramping or load changes, the PSS using power signal causes transient variations in the terminal voltage.
- d) **Acceleration power:** The acceleration power signal is obtained from the difference of filtered mechanical power (which is synthesized from the speed and electrical power signals) and the electrical power.
- e) **Synthesized speed (Delta P - Omega):** This signal is derived from power and speed signals and is almost like the speed signal in the frequency range of interest but is not prone to causing problems at SSR frequencies.

4.4 Power System Stabilizer

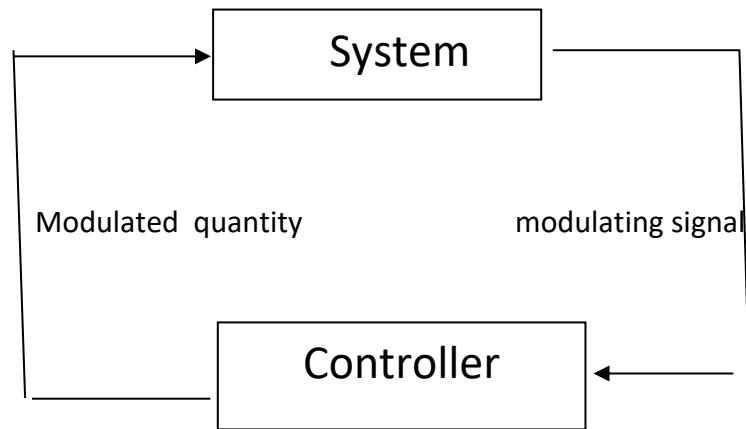


Fig. 4.4.1

4.4.1 Structure of PSS

The structure of PSS and its blocks is discussed in the subsequent sections. It consists of a washout circuit, dynamic compensator, torsional filter, and limiter. The main objective of providing PSS is to increase the power transfer in the network, which would otherwise be limited by oscillatory instability as discussed above.

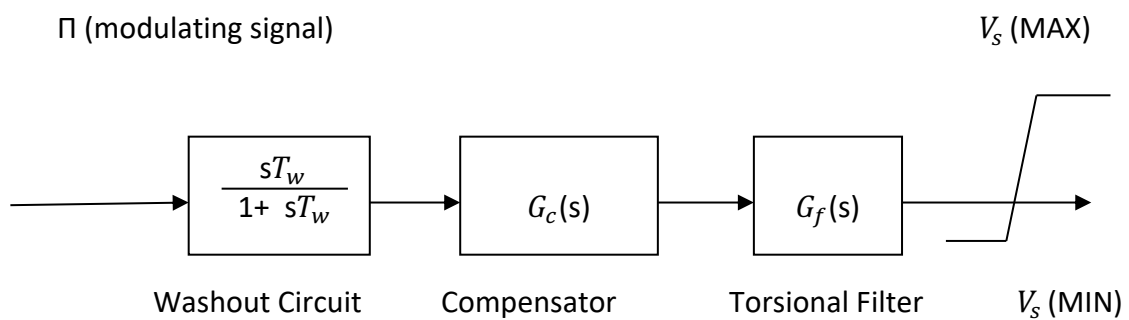


Fig. 4.4.2

4.4.2 Washout Circuit

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 and not to the dc offsets in the signal. This is achieved by subtracting the low frequency components of the signal obtained by passing the signal through a low pass filter.

$$G_w(s) = \frac{sT_w}{1 + sT_w} = 1 - \frac{1}{1 + sT_w} = 1 - G_{ip}(s)$$

4.4.3 Dynamic Compensator

Compensator modulates the controllable quantity appropriately using the modulating signal, so that damping torque is produced at the rotor oscillation frequency. The dynamic compensator used in industry is made up of two lead-lag stages. With static exciters, only one lead-lag stage may be adequate. For design purposes the PSS transfer function is approximated to $T(s)$, the transfer function of the dynamic compensator.

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

where,

$$N(s) = 1 + a_1 s + a_2 s^2 + \dots + a_p s^p$$

$$D(s) = 1 + b_1 s + b_2 s^2 + \dots + b_p s^p$$

4.4.4 Torsional Filter

Torsional filter is essentially a band reject filter to attenuate the first torsional mode frequency. For stabilizers derived from accelerating power, torsional filter can have a simple configuration of a low pass filter independent of the frequency of the torsional mode to be filtered out. Torsional filter is necessitated by the adverse interaction of PSS with the torsional oscillations. This can lead to shaft damage, particularly at light generated loads when the inherent mechanical damping is small. Even if shaft damage does not occur, stabilizer output can go into saturation making it ineffective.

4.4.5 Limiter

The output of PSS must be limited to prevent the PSS acting to counter the action of AVR. For example, when load rejection takes place, the AVR acts to reduce

the terminal voltage when PSS action calls for higher value of the terminal voltage. It may be even desirable to trip PSS in case of load rejection.

The negative limit of PSS output is of importance during the back swing of the rotor (after initial acceleration is over). The AVR action is required to maintain the voltage (and prevent loss of synchronism) after the angular separation has increased. PSS action in the negative direction must be curtailed more than in the positive direction. On the other hand, a Higher negative limit can impair first swing stability.

4.5 Uncompensated PSS Open Loop Transfer Function ($GEP(s)$):

The Uncompensated PSS Open Loop Transfer Function ($GEP(s)$) is a system representing the characteristics of a generator, exciter, and power system.

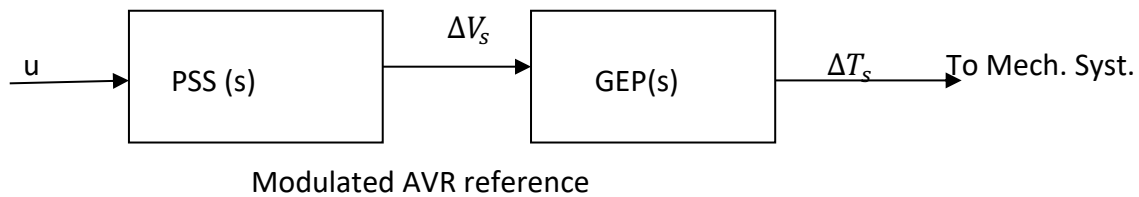


Fig. 4.5.1

The transfer function of the whole assembly is given as where GEP is the

$$\frac{\Delta T_{ep}}{\Delta \omega_G} = -PSS_{\omega}(s)GEP(s) \underline{\Delta P}(s)$$

$\Delta \omega_G$

During the system study, the aim is to find the suitable Gain and time constant for the PSS. This is to ensure that how much gain the system can be supplied with before it touches instability. The above process is subdivided into three parts as described below:

- a. Checking how much phase lag is there with the help of frequency domain analysis between the generator speed and its electrical torque under various operating condition. Basically, it yields uncompensated PSS open loop transfer function ($GEP(s)$).

- b. Checking the AVR response with PSS under operating various scenarios and comparing with a. above, to find the best suitable PSS parameters for suitable phase compensation.
- c. Checking the PSS gain Margin to obtain suitable PSS gain having no adverse impact under various operating scenarios. Also, check the PSS gain with root locus method to obtain suitable gain constant so that system is stable even if the gain is increased to three times.

The steps a and b, as described during PSS parameters tuning can be described by the frequency domain analysis of the transfer function generator, exciter, and power system (GEP(s)) and Power system stabilizer compensation (PSS(s)).

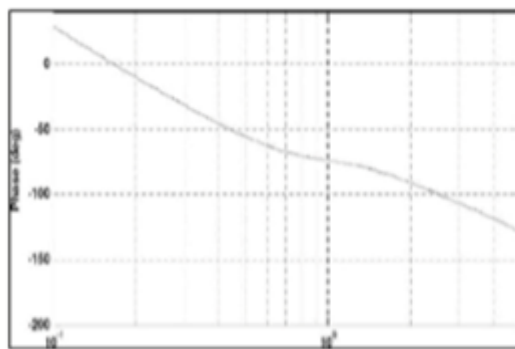


Figure (a) Phase of function GEP(s)

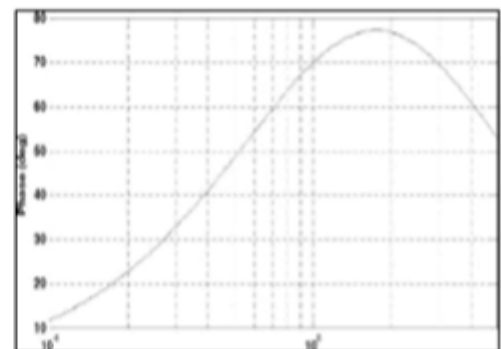


Figure (b) Phase introduced by the PSS lead-lag filters

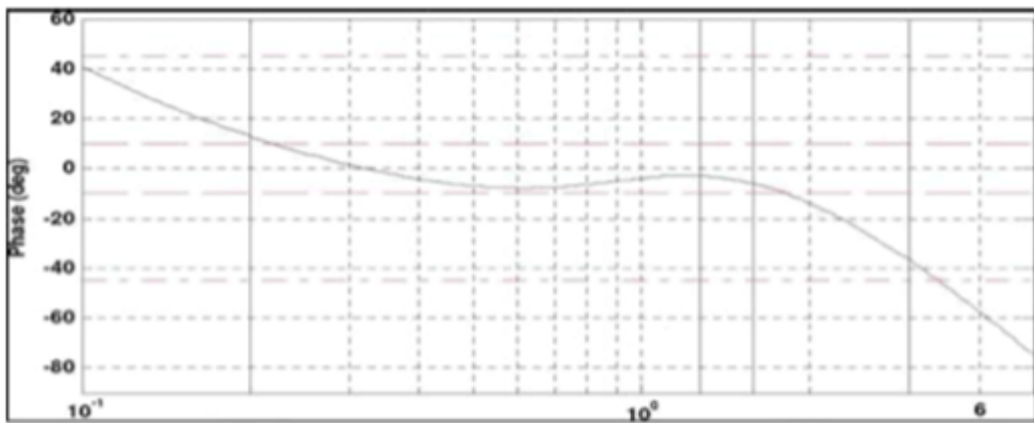


Figure (c) Global phase compensation (After Tuning of PSS with Phase compensation)

Fig. 4.5.2

The PSS transfer function should compensate the phase characteristics of the generator, exciter, and power (GEP) system transfer function so the compensated transfer function ((PSS(s) * GEP(s))) has a phase characteristic of ± 30 degrees in the frequency range of 0.1 Hz to 3 Hz. This is illustrated with the help of figure (a), (b) and (c). The GEP(s) transfer function is a theoretical transfer function, and its

phase characteristic cannot be directly measured during field tests (only via simulation). Thus, the Requirement recognizes the practical approach of measuring the frequency response between voltage reference set point and terminal voltage ($E_{\text{term}}/V_{\text{ref}}$) and using the phase characteristic of such frequency response as being the phase characteristic of GEP(s). The phase characteristic of $E_{\text{term}}/V_{\text{ref}}$ is a better approximation to the phase characteristic of GEP(s) when the frequency response $E_{\text{term}}/V_{\text{ref}}$ is obtained with the generator synchronized to the grid at its minimum stable power output.

In order find the suitable PSS time constants, the above parameter estimation must be done for a wide range of external network reactance i.e., from 0.15 p.u. to 0.5 p.u.

After determining the suitable phase margin, the step c., is to find a suitable gain constant for the PSS. Based on literature available, the gain margin can be best computed using frequency domain analysis with the help of root locus method (Eigenvalue analysis/small signal stability studies). As the simulated model can be either a two-area system (Machine with infinite bus) or small area system with nearby buses, so the small signal stability analysis of the system will yield the Eigenvalue and the respective local and control modes. The gain value must be selected such that it is significantly away from the instability. This must be calculated again for a wide range of external network reactance varying from 0.15 p.u. to 0.5 p.u.

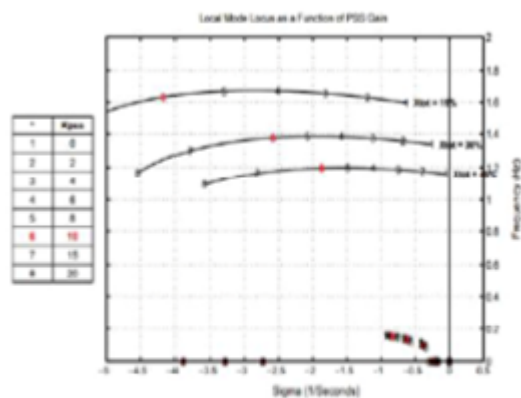


Figure (d) Root Locus of Local mode for different system strength [Ref]

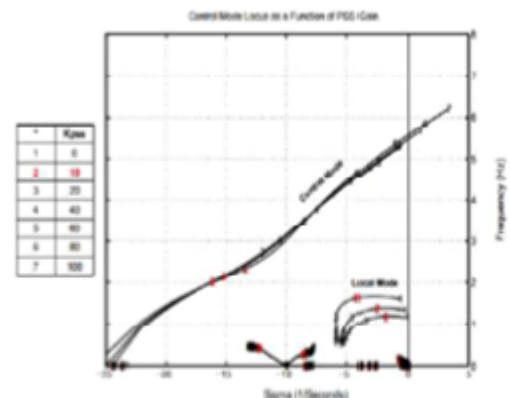


Figure (e) Root Locus of Control Mode for different system strength [Ref]

Fig. 4.5.3

Figure (d) and (e) shows the local and control mode oscillation root locus plot with a variation of gain constant at three different system impedances. During selection of gain margin, it should be verified that the selected gain margin when multiplied by three times then also system should be stable. With this, one gain value can be chosen for one set of external system reactance and similarly for others.

During the selection of gain margin, it is highly desirable to compute the local mode of oscillation for the generators. This local mode of oscillation frequency helps in validating the parameters of the generator during the testing to be done at the field. This oscillation frequency is obtained during gain constant determination from root locus method when the external network impedance used is in proximity of actual system. The obtained gain constant at this frequency is more suitable during actual implementation at site however it may vary depending on the testing carried out at the site.

4.6 Eigen value analysis of a SMIB System:

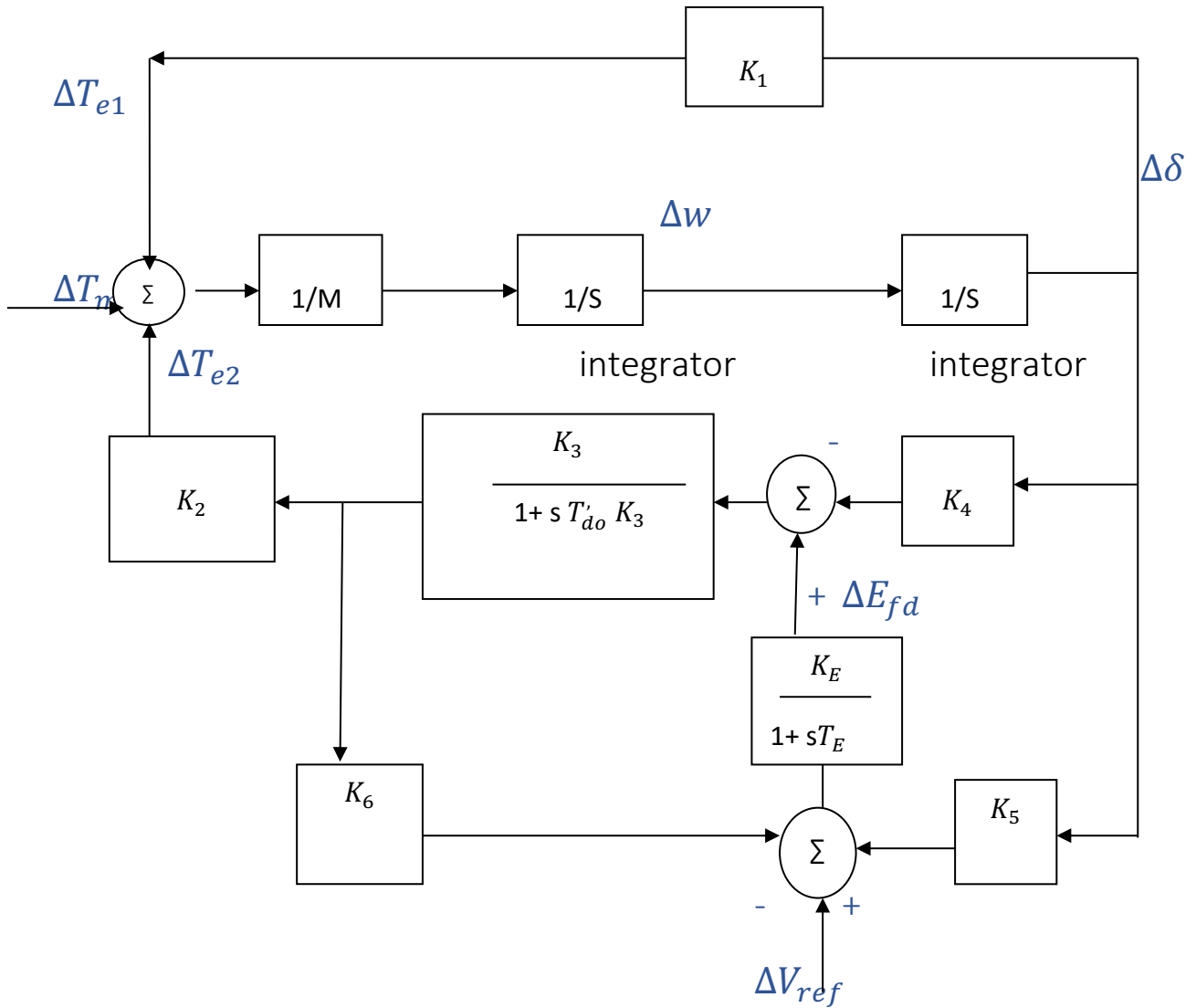


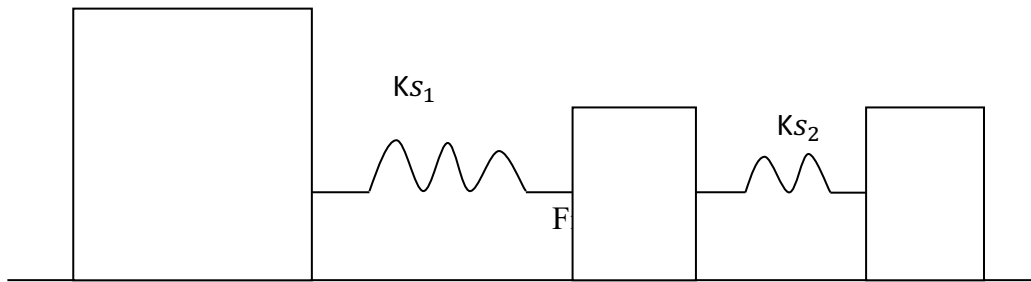
Fig. 4.6.1 - Transfer function Block Diagram including Excitation System.

The mathematical derivation of Eigen value Analysis of a SMIB system and the extent to which a mode is excited (depends on the initial disturbance) is placed at Annexure C.

4.7 Multimachine System

In realistic situation there is no infinite bus, moreover there are many machines connected to each other and the loads by transmission lines. Therefore, a systematic analysis of multimachine systems is required. Let us consider a multi mass, multi spring system.

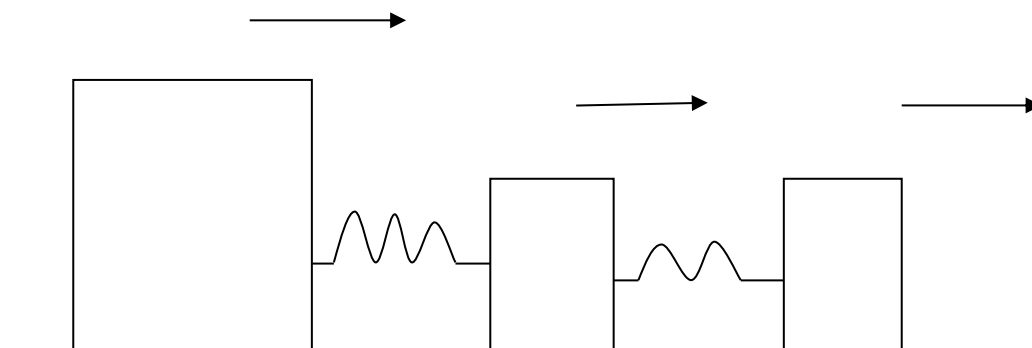
$$Ks_1 \ll Ks_2$$



4.7.1 Two Masses connected together analogy:

There are 2 small masses connected by a very stiff spring which in turn are connected to a relatively larger mass via much less stiff spring. Without explicitly solving the equations of motions, we can easily imagine that their response is a combination of several modes. Out of the three modes of which 2 are oscillatory and one which is associated with all the masses moving together. This oscillatory mode of lower frequency involves the two smaller masses moving together against the larger mass. The higher frequency mode involves the two smaller masses oscillating against each other with lesser involvement of the larger mass.

Another point which needs to be addressed is the extent to which each mode is excited. This is determined by initial conditions & disturbances. If a disturbance results in a common initial velocity and displacement for all the masses, then only the non-oscillatory mode is excited.



All masses move together

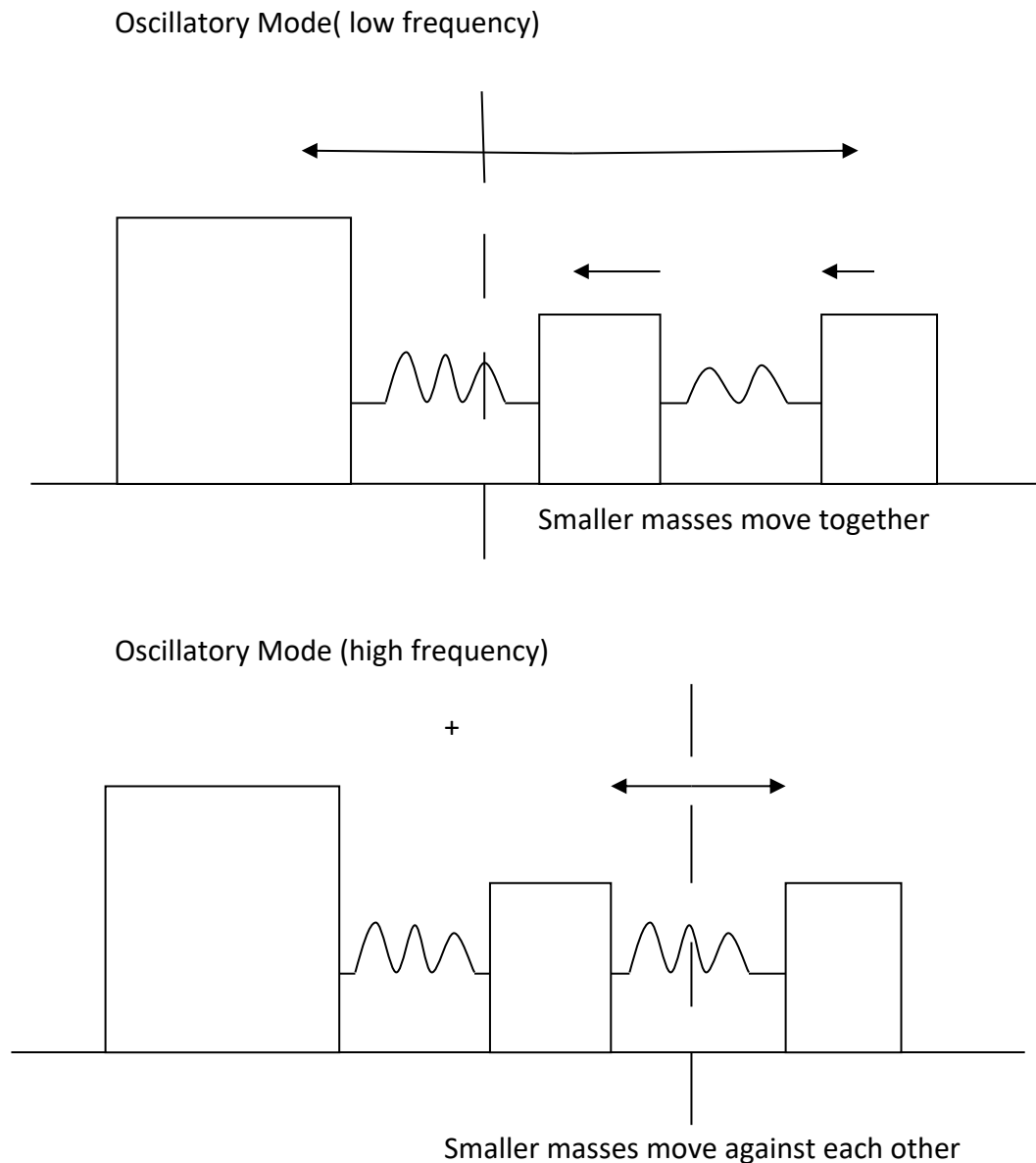


Fig. 4.7.2

4.7.2 Characterization of Swing Modes

For a generator system, there are $n - 1$ swing (oscillatory) modes associated with the rotor swings. Each of these modes is characterized by a frequency of oscillation. The frequencies are obtained as square root of the non-zero and real eigenvalues of the matrix $[M]^{-1}[K]$.

Not all the generators are 'involved' in all the modes. Typically, each mode is associated with a group of generators swinging against another group. This information can be obtained by doing eigenvalue analysis. There is also a mode

associated with the movement of the 'center of inertia' which corresponds to the dynamics of the average frequency. If there is no mechanical damping present and loads are of constant power type, this is manifested as a pair of zero eigenvalues. In a practical system, the various modes (of oscillation) can be grouped into 3 broad categories

- 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.

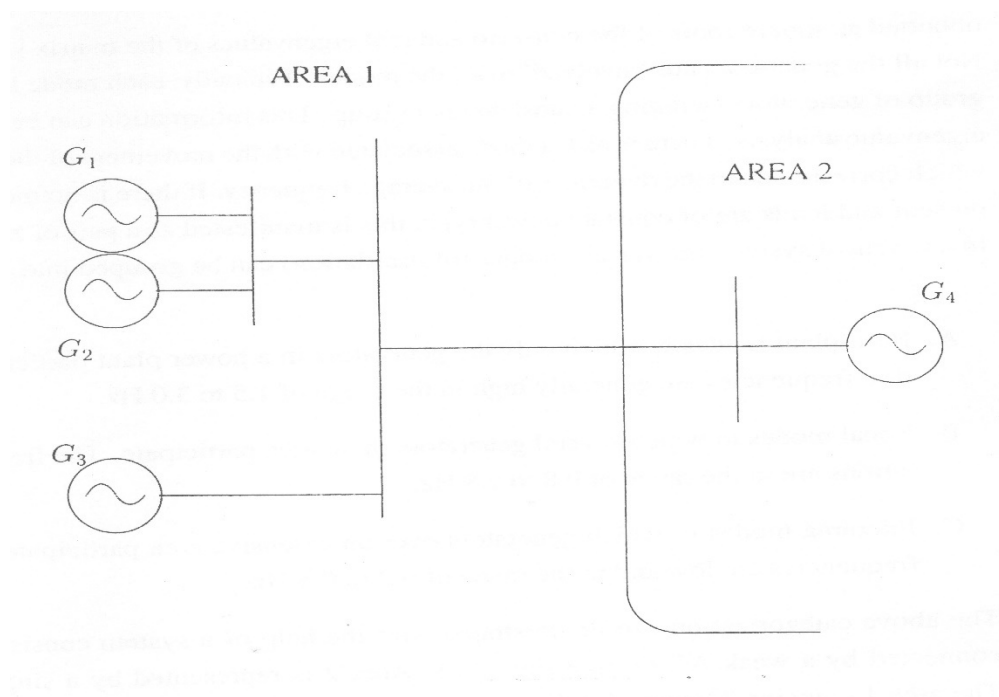


Fig. 4.7.3

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 smaller inertias. During the local mode oscillation, G_1 & G_2 swing together against G_3 . During oscillations due to inter-area mode, all generators G_1 to G_4 participate and have the lowest frequency.

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.

4.7.3 Participation of Machine to oscillation mode

The participation of the machines to a particular oscillation mode can be estimated and the mathematical derivation is placed at Annexure D.

5. PSS Tuning Approach

The basic intent of adding a Power System Stabilizer (PSS) is to enhance damping to extend power transfer limits. The very nature of a PSS limits its effectiveness to small excursions about a steady state operating point. The small excursions about an operating point are typically the result of an electrical system that is lightly damped which can cause spontaneous growing oscillations, known as system modes of oscillation. Enhanced damping is required when a weak transmission condition exists along with a heavy transfer of load. A PSS works in conjunction with the excitation system of a synchronous machine to modify the torque angle of the shaft to increase damping. The performance of the excitation system is critical in the overall capability of a PSS. Tuning of a PSS shall only be accomplished after the excitation system has been tuned and calibrated. On new equipment, PSS may be software incorporated in digital automatic voltage regulators. AVR terminal voltage and current measurements are used to compute accelerating power and synthetic speed (integral of accelerating power). PSS cost can be low if PSS is required in competitive power plant procurement specifications. Procurement specifications should include requirement for tuning during commissioning and a requirement for stability program model and data.

5.1 PSS Tuning points to be considered

PSS typically utilizes phase compensation and adjusting phase compensation is the main task in PSS tuning. Phase compensation is accomplished by adjusting the PSS to compensate for phase lags through the generator, excitation system, and power system such that PSS provides torque changes in phase with speed changes. Tuning should be performed when system configurations and operating conditions result in the least damping

Some areas of concern of PSS are:

- a) PSSs are manufactured as both analog and digital types. Testing methods may not be identical with both types of PSSs.
- b) PSS modification of torque angles by varying excitation can excite turbine generator shaft torsional where shaft torsional are less than 20 hertz. This is especially true for PSSs that utilize speed as input. Typically, torsional filters are used to remove the torsional contribution to the input to the PSS.

- c) PSS output can interfere with transient response of excitation systems. Therefore, output limits are usually incorporated in the PSS scheme.
- d) PSS can interact with under excitation limiters. Thus, the limiters must be tuned to work in conjunction with the PSS.
- e) Rapid load changes can result in large VAR swings from PSS response that utilize electric power. Upgrading to type 2 PSS input (integral of accelerating power) may solve this problem.
- f) Another major concern is that PSS response should be checked with UEL limits as many times UEL can result in PSS to be made off which can result in negative damping in the system with a high load angle scenario. In one plant when the UEL limit got hit has led to PSS being switched off causing LFO.

5.2 Experience of PSS tuning in Indian Power System

Some of the experiences of PSS tuning in Indian Power sector has showed following observations

5.2.1 Model validation

Model validation is one important aspect that needs to be carried out during the PSS tuning exercise as the first step. This ensures the study results and actual site tests are matching and the calculated PSS setting can be directly implemented for further PSS testing and fine- tuning. This can be done by validation of the local mode of frequency during the step test. Among all vendors referred in table 1, only vendor V1 performs the model validation during actual PSS tuning.

5.2.2 Measurement devices

One of the major issues observed during the field testing is the lack of a high sample rate (>10 Hz) and high-resolution recording (up to 2 decimal places) devices for important parameters. In the absence of good data, validating the response and deciding whether the system is adequately damped becomes difficult. One such example is shown in figure 1 corresponding to vendor V2 where accessing the damping is not quite visible due to low- resolution data.

5.2.3 Reference voltage step change

During tuning it was observed that a voltage step of 5 % is good for analyzing the PSS response on active power damping. In many cases, vendors have utilized smaller voltage steps of 1%-3% which were found to be inadequate for analyzing the response.

5.2.4 Disturbance test:

Overall plant response can only be determined by a disturbance test. It is one of the most effective tests to ensure the actual performance of PSS during an actual event. The disturbance test is done by either switching of transmission lines/ shunt compensation or creating any artificial fault on any of the transmission lines evacuating from the generating plant. The precursor to this test is that first the PSS in all units for the plant is tuned with step response. While performing this test, first the PSS of all units is made off and then disturbance is applied. Again, the same sequence is performed by keeping PSS on for all units. In case there are different capacity units, then the first PSS of the same capacity units to be tested one by one and then overall plant testing can be completed and compared in the sequence as described above.

5.2.5 Generation level for PSS tuning

PSS damping effect is more pronounced when the unit is generating on the higher side. Therefore, PSS tuning is recommended to be conducted at the generation level of 80-100 % of the rated capacity. During field testing, it was observed that PSS has cutoff criteria due to which below a certain constrained generation level, it gets bypassed. It was observed that in the thermal power plant that it is bypassed below the technical minimum level and for hydro its generally 0-10 % of the unit capacity. So, while performing step test on one unit, the generation level of other unit is also to be known so that its PSS on/off status is known. In addition to this, all the PSS tuning test at the generators must be done at the same generation level so that results/output can be easily compared.

5.2.6 Governor status

In India, restricted governor mode of operation (RGMO) has been implemented on governor control in line with IEGC. To get appropriate results by creating an ideal condition for PSS tuning, generator primary frequency response control must be switched off as due to frequency variation the generation point keeps on varying, and thus comparison among various test results becomes difficult.

5.2.7 PSS gain

During testing, it was observed that utilities are conservative on increasing PSS gain even though sufficient margin is available for better PSS performance. Thus, to resolve this issue, PSS study was carried out to provide them with sufficient input on how higher gain improves PSS performance on damping without compromising on the security aspects. One example of a PSS response with higher PSS gain is shown in figure 2.

5.3 Simulation Studies to be carried out before PSS Tuning

1. Inputs from plant to be taken as per the data format at Annexure E and preparation of the Base Case
2. List of Assumptions and the Details of different local/inter-area modes from PMU data to be taken for the base case.
3. Damping Indices such as Damping Ratio, Gain Margin, Phase Margin and Settling Time. There are two ways for damping calculation. One is based on successive peak reduction methods while the other is measurement techniques like Prony, Matrix pencil, etc. which utilizes exponential decaying sinusoidal representation of the power system signal. Practical indices are given below. Range is in line with IEEE 421.2 Standard.

Table 5.3

Damping Index	Range
Gain margin	2-20 dB
Phase margin	20 to 80 degrees
Mp	1 to 4 (0-12 dB)
Bandwidth	0.3-5 Hz

Overshoot	0% to 40%
Rise Time	0.025s-2.5s
Settling Time	0.2s-10s
Damping Ratio ($\cos \phi$)	0.25-1

4. Constructing GEP(s) and the Procedure for finding Local Mode and the standard software for root locus as per 3.3 in the previous chapter. The tuning of GEP to be done as per the requirement.
5. Selecting Parameters and Tuning PSS(s), using standard software for bode plots, such that compensated phase = ± 30 degrees at 0.1Hz - 4Hz Preferably achieve low gain and phase lag at noted modes
6. Gain test (3x) using root locus, Running the model for different simulated tests using standard transient stability program, Step test & Disturbance Test
7. Simulation Report Template for handing over to Plant

5.4 Modeling of Power Plant during Study⁸

Any Generating power plant where PSS tuning is to be carried out may not have the details of complete Indian power system for dynamic study. However, they have the details of the transmission system evacuating from their substation. So, a detailed modeling of the generator with adjacent nodes needs to be done during PSS tuning. Further in a large integrated system like all India Grid, it is difficult to carry out simulation studies. It is therefore desirable to have following approaches

1. Single Machine Infinite Bus (SMIB) System – In this approach an equivalent infinite bus to be represented by the rest of the grid is required to made available to the generator company, based on which generator can carry out simulation studies adopting the optimal PSS & Settings (for more details see chapter 1)
2. Plant bus with Incidental Buses are modeled in detail & rest of the grid with equivalent generators at remote buses – in this approach, up to 3rd buses from the plant are modeled in detail and at the 3rd bus equivalent generator representing the rest of the system is required to be modeled. All the details are required to made available to the Generator for carrying out simulation studies

⁸ Designing a stabilizer for satisfactory operation with an external system reactance ranging from 20% to 80% on the unit rating will ensure robust performance (Ref: Vitthal Bandal, Student Member, IEEE, B. Bandyopadhyay, Member, IEEE, and A. M. Kulkarni "Design of Power System Stabilizer using Power Rate Reaching Law based Sliding Mode Control Technique"

for adopting the optimal PSS settings (for more details see Multi Machine model in Chapter 2)

Out of the above two choices the first choice seems to be a simplistic approach and easily implementable.

During the Study, the generating power station is connected to Infinite Bus such as the system becomes a SMIB system which means constant voltage and constant frequency at the Infinite Bus (as already discussed in Chapter 1). An estimated total external grid reactance varying from (including main transformer reactance) 0.2 to 0.8 pu (on Generator MVA base) connecting the generator to the infinite grid need to be used for simulation. This will enable to check the AVR response and PSS output during varying network topologies ranging from strong to weak system.

To validate the models, the AVR step test, which is implemented to give the small step voltage into the summing junction of the AVR reference, is simulated in terms of both armature voltage, V_t , and generator field voltage, E_{fd} . The response of the excitation system to a 5% step change of AVR needs to be plotted.

5.4.1 Phase Compensator tuning

Following points should be considered while identifying phase compensations

- a) Identify inter-area modes of oscillation. Measure generator and excitation system response without PSS.
- b) Time constants of two lead-lag blocks should be optimally determine for this purpose. Normally, in the range of low frequency oscillations ranging from 0.1 to 2 Hz, time constants of the PSS should be selected to compensate for the phase lags of the system by linear analysis. The time constants for the phase compensation for T1, T2, T3 & T4 can be 0.25, 0.025, 0.25 & 0.025 respectively.
- c) PSS should be tuned to provide as close to 0 degrees of phase shift as possible at the inter-area frequency or frequencies. The destabilization of intra-plant modes with higher frequencies should be avoided.
- d) If local stability concerns require PSS settings resulting in an inter-area phase shift other than zero, the setting shall in no case result in a phase

shift more than 40 degrees at inter-area modes. The compensated phase lag at local mode frequency should be below 100° , preferable near 2Hz.

- e) The PSS provides substantial phase shift so that the electrical torque provided by the generator is approximately in phase with speed. The goal is to eliminate phase lag as best as possible throughout a wide range of frequencies of interest, then adjust gain.

5.4.2 Washout

To eliminate the steady state bias output of PSS, washout is required. There is an interrelationship between the phase compensation and the washout time constant as already discussed in chapter 2. Short washout time constants provide additional phase compensation in frequency-based PSS at the lower frequencies while dramatically reducing the gain. A washout time constant of 10 seconds or less is recommended to quickly remove low frequency components (below 0.1 Hz) from the PSS output. The smaller time constant will reduce the influence on the system voltage from the PSS during any sustained/extended frequency deviation (i.e., loss of generation), especially if the PSS has a high gain setting.

5.4.3 Gain Selection

Gain Selection has already been discussed in detail in Chapter 2 GEP section. For the gain tuning of PSS, eigenvalue analysis is used to determine a range of the gain instead of a single gain value. It had to be determined, not only from analytical methods, but also from field testing, to obtain the gain that could provide the best possible damping of the selected modes while keeping the noises from the PSS at an acceptable level. The control mode of the system became unstable while the local mode of oscillations is stabilized as the system gain, K_s , increased. At approximately 25 p.u. of the system gain, the control mode became un-stabilized. Therefore, the tentative range of the gain can be selected near a third of the un-stabilized gain value at which the local mode has been stabilized. The maximum gain is supposed to be in the range of 7 to 8 p.u.

5.4.4 Time – Domain Simulation

After tuning of the PSS parameters, the effect of the tuned PSS should be simulated in the time-domain by transient stability programs, such as PSS/E or TSAT, among others. A 2% AVR step response and a three-phase fault test simulated in the time-domain for this purpose will show a greater degree of damping to the oscillations compared to a system without the PSS.

5.4.5 Commissioning Tests:

- a. Perform an impulse response by injecting a large signal into the AVR (5-10%) and identify local mode damping. Verify local mode oscillation damping has improved, or, at a minimum, has not been degraded.
- b. Additionally, non-take over type under excitation limiters (UEL) must be coordinated with the PSS to ensure stable performance during limiter operation. After the gain is set, under excite the machine until the UEL becomes active and perform a step and/or an impulse response test while monitoring the output power (MW). Ensure that the UEL is not interacting with the PSS in such a way that the damping level is reduced, or instability is observed (since the PSS reduces the gain margin in the UEL control and vice versa).
- c. If instability is observed, retuning of the UEL or PSS is required. Coordination should be performed with all appropriate limiters in the AVR.

5.5 The varying operating conditions are:

- a) External Network Reactance: By Varying External Network reactance from 0.15 p.u. to 0.5 p.u. in step of 0.05- and 0.1 p.u.
- b) Generator Reactive Power: keeping reactive power to Maximum, Minimum and Zero with maximum real power output.

5.6 The various perturbations applied are:

- a) Step Response: The perturbation consists in voltage reference steps increase as well as a decrease of 2 % and 5 % magnitude.

- b) 3 phase Fault on Transmission line connecting the generator and its tripping: 100 ms three phase fault on the mid-way of the line with connecting the generator with the grid followed by its tripping. This is to be done for all the lines if the generator is connected to multiple substations (Only if detailed modeling is done)
- c) 3 phase faults on the HV side of main generating transformer: 100 ms three phase fault on the generating transformer.

5.7 Performance Verification in Field tests

5.7.1 AVR Step response test with open circuited Generator

This test is carried out to establish the internal DC voltage of the AVR and to get the behavior of the excitation system of the generator. It also confirms the validation of the excitation models used in offline simulation of PSS tuning. A 3% AVR step signal may be injected into the summing point of the AVR at 3600 turbine speeds (rpm), with the main circuit breaker open. The results obtained are to be matched with the models used in the simulation to establish that the excitation models are validated.

5.7.2 AVR Step response test with Full Load (Before Tuning)

In this test, the validation of the existing PSS parameters set by the manufacturer can be checked by a 2% AVR step test (e.g., If the time constant for phase compensation is set at 0.5 sec. and the gain is set approximately 7 p.u., a high-frequency oscillation appears in the outputs. This should be ascertained through off-line simulation, the control mode of the system seems unstable because of the inappropriate parameters of the PSS, including time constants for phase compensation and system gain).

5.7.3 PSS Gain Margin Test

After setting the tuned parameters in the PSS, the gain margin test should be performed by increasing the gain step-by- step, without applying step signal until one of the output signals was hunted. (e.g., for a typical system suppose at approximately 20 p.u. of the gain, the MW and field voltage is found to be hunting then, the maximum gain should tentatively be considered as 7 p.u.). The final value of gain should be selected after checking the response in the next test.

5.7.4 AVR Step Response Test with Full Load (After Tuning)

In this test, the damping effects at each gain are observed in accordance with an increase in the gain, up to the tentative value set in the previous gain margin test. (e.g., the final value of PSS gain is set at 7 p.u. after an analysis of the damping of power oscillations, number and amplitude of swings, and field voltage variation. Compared with the results without PSS (gain=0), the damping of low-frequency oscillation is significantly enhanced for the tuned PSS (gain=7)). This establishes that the parameters of PSS were successfully tuned so that the performance of PSS was finally verified in the field test.

5.7.5 Impulse test

As the actual disturbance cannot be applied to units during PSS tuning at the site, so to check unit the response for the various disturbance, an impulse test can be carried out. That's why it is a complimentary test to the disturbance test. As demonstrated like the frequency response test, random noises as done for frequency response test, low magnitude Impulse type signal can be superimposed over the generator terminal voltage reference for a step-change in impulse input, the response of generator and exciter parameters can be checked with and without PSS.

5.7.6 OEL/UEL test

After the PSS gain is set, it is important to ensure that under excitation limiter (UEL) & over excitation limiter (OEL) is not interacting with the PSS in such a way that the damping level is reduced or instability is observed. For this, the machine is under and overexcited until the UEL/OEL becomes active and then step/impulse response test is performed. If any instability is observed in active power, then retuning of the UEL/OEL or PSS is required.

5.7.7 Frequency response test

Frequency response testing consists of applying a known driving signal to the system (or a portion of the system) and measuring the output (or an intermediate point) concerning to the input. Several methods are used to measure frequency response, including methods that apply either sinusoidal or noise signals. Frequency response testing has the advantage that the transfer function of the element under test is often immediately evident. For

this reason, the frequency response method is recommended for determining the small-signal transfer functions of excitation system components.

5.7.8 Disturbance test

This is the most effective way to check PSS performance by creating an actual disturbance like the opening of transmission lines/switching of reactors after consultation with the system operator. This ensures the conformance of the PSS tuning impact in real-time. During this test, all units at the plant should have their PSS out service followed by all units with their PSS in service.

5.7.9 Governor test

The interaction of the PSS with changes in Active Power should also need to be tested by application of a +0.5 Hz frequency injection to the governor while the Generating Unit is selected to Frequency Sensitive Mode. This ensures PSS performance during frequency events.

5.8 Additional test which can also be performed by the generator to ascertain the PSS response under other varying condition.

5.8.1 Active Power Response Test:

The interaction of the PSS with changes in Active Power should also be tested by application of a +0.5 Hz frequency injection to the governor while the Generating Unit is selected to Frequency Sensitive Mode.

5.8.2 Actual Disturbance Test (if Possible)

The PSS performance also to be tested with creating actual disturbance like the opening of transmission lines/Switching of Reactors/Other after consultation with RPC and RLDC. This ensures the conformance of PSS tuning impact in real time.

5.9 Care to be taken while performing the PSS tuning.

- a) The test should be stopped when the large deviation is observed in simulated and actual response.
- b) Any Test should be immediately stopped when growing/sustained oscillation is observed in the parameters of the generator.

- c) When performing a frequency response test on a generator connected to the grid, caution should be exercised when injecting frequencies that are close to the resonant frequencies of the machine (e.g., local mode, inter-area mode, intra-plant mode) or neighboring machines.
- d) Extreme care should be taken when injecting frequencies higher than 3 Hz, as these may correspond to the lowest shaft torsional frequencies of turbogenerator sets. The turbine manufacturer should be consulted to obtain a torsional profile of the rotor turbine shaft prior to proceeding with testing.

5.10 PSS Tuning Report

The PSS Tuning Report should be able to demonstrate the following and should include:

- A. Improved damping following a step change in voltage from 1% -5%.
- B. Improved damping of frequencies in the band 0.02 Hz – 4 Hz.
- C. Any oscillations getting damp out within 2 cycles.
- D. No appreciable instability at 3 times proposed gain.
- E. Improved Damping under variable system operating condition (Real and Reactive Power and Terminal voltage) and network topologies by varying the system impedance ($15\% < X \text{ system impedance} < 50\%$).
- F. Improved Damping after the short circuit as for a duration defined in CEA transmission planning Criteria 2013 on the directly connected lines from the generating station.
- G. Should not have negative interaction or any adverse impact on the torsional mode of the generator (Applicable for Large Steam Turbine generating unit on single shaft units)
- H. Procedure adopted for simulation model validation after PSS Tuning.
- I. Changes made on file during the PSS tuning Activity.
- J. Proposed changes / suggestions for the simulation model.
- K. Proposed changes / suggestions for the PSS

5.11 Frequency of PSS field testing

- A. Regular Interval of five years.
- B. After large network change near to the generating station.

- C. As per operational feedback by system operator.
- D. Use simulation outputs.
- E. Preferable loading of 80-100% MCR.
- F. Before tuning of PSS, the AVR needs to be properly tuned using standard tests as per IEEE Std 421.2-2014.
- G. After any abnormal PMU signatures / less-damped oscillations observed.

5.12 Timelines for PSS Tuning Activity

Table 5.12

S. No.	Activity	Nodal Agency	Format No.	Due date
1	Advance intimation and simulation data submission by plant to RPC, CTU, RLDC	Power Plant	PSS-F1 (Coal, Gas, Hydro)	31 st Dec before the start of due FY.
2	Annual PSS Testing/Tuning plan	RPC	List	31 st Mar
3	Share SMIB grid data to plants	RLDC/NLDC	Format PSS-F2	30 th Apr
4	Conduct SMIB simulations and provide report with findings to RPC, CTU and RLDC. Submit the PSS tuning planned date for concurrence in OCCM.	Power Plant (with OEM)	Report and model (raw, dyr) along with test date.	30 days before test
5	Feedback from RLDC to plant	RLDC / NLDC	Report	15 days before test
6	Field Testing, PSS tuning, model validation and submission of report to RPC, CTU and RLDC	Power Plant (with OEM)	Report and validated model (raw, dyr)	60 days after test
7	Acceptance and feedback to plant/RPC/CTU	RPC	Report	45 days after report submission
8	Initiate retesting/re-tuning, if needed within 5 years	RPC	List	As required

5.13 Keeping PSS ON during real-time

Sometimes the operators at generating plant forget to put ON the PSS after synchronizing of unit (no automatic switching of PSS in/out is available at many plants due to which the plants are manually maintaining the PSS ON/OFF, whenever there is low generation/start-up of unit). As a result, oscillations were observed for longer time with high peak to peak amplitude during N-1 contingency from generating plant. So, compliance monitoring must be there (Ref: WECC Standard VAR-STD-2b-1 – Power System Stabilizer) and suitable actions must be taken for compliance by the generating plant. Code must be taken from RLDC/SLDC to make PSS ON/OFF like RGMO/FGMO.

6. Conclusions

6.1 Block design criteria and choice of parameters:

The tuning of the PSS shall be carried out once in two years or whenever there is significant change in the network nearby the generator. The choice of various parameters of the PSS each of the component block in short is as given below:

6.1.1 Washout Circuit

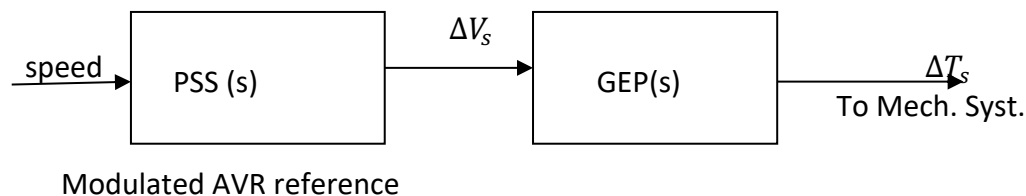
If only the oscillations of frequency around 2 Hz are of interest, the time constant T_w can be chosen in the range of 1 to 2. However, if low frequency modes are also to be damped, then T_w must be chosen in the range of 10 to 20 Sec.

6.1.2 Dynamic Compensator

PSS settings would be set to dampen mode with oscillations within the range of 0.2 Hz to 2 Hz.

The time constants, T_1 to T_4 are to be chosen from the requirements of the phase compensation to achieve damping torque.

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. 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.



System Block Diagram showing the effect of PSS on Electric Torque

Fig. 6.1.1

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

system when PSS is included as shown in the above block diagram. Note that ΔV_s is the modulated AVR reference, while T_{e3} is the component of electrical torque caused by modulating the AVR reference.

The transfer function $PSS(s)$ is obtained from the above figure for speed as the input u . If u is not speed, but some other signal like electrical power, then $PSS(s)$ should also include the effect of the transfer function between speed and the input. 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.

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

The compensated phase lag at local mode frequency should be below 45° , preferably near 20°

The gain of the compensator at high frequencies (this is proportional to $T_1 T_3/T_2 T_4$) 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.

To set the gain of the PSS, root locus analysis is performed. The optimal PSS gain is chosen for the tuning condition as the gain that results in the maximum damping of the least damped mode. The optimum gain (K_{opt}) is related to the value of the gain (K_I) that results in instability. For speed input stabilizers $K_{opt} = 1/3 K_I$ for frequency input stabilizers $K_{opt} = 2/3 K_I$. For power input stabilizers $K_{opt} = 1/8 K_I$.

These thumb rules are useful while implementing PSS in the field without having to do root locus studies.

To summarize, the tuning procedure for the dynamic compensator is as follows:

Identify the plant GEP(s)

Choose the time constants from the phase compensation technique described earlier and from the knowledge of GEP(s).

Select the PSS gain such that it is a fraction of the gain corresponding to instability. This can be determined from root loci.

6.1.3 Torsional Filter

The torsional filter in the PSS is essentially a band reject filter to attenuate the first torsional mode frequency. The transfer function of the filter can be expressed as

$$FILT(s) = \frac{w_n^2}{w_n^2 + 2\xi w_n s + w_n^2}$$

For stabilizers derived from accelerating power, torsional filter can have a simple configuration of a low pass filter independent of the frequency of the torsional mode to be filtered out. Torsional oscillations are a concern mainly for speed input stabilizers. In PSSs which use power, Delta P- Omega, or acceleration power input torsional filters may not be used.

6.1.4 Limiter

Ontario Hydro (in the WECC report) uses a -0.05 p.u as the lower limit and 0.1 to 0.2 as the higher limit. Recent studies have shown that higher negative limit can impair first swing stability.

6.2 Data for carrying out PSS tuning studies and responsibilities of utilities

The Generating Power Plant where the PSS tuning has to be carried out will submit the Generating Unit Data for PSS tuning Study along with the PSS tuning Study Report to CEA/POSOCO/CTU/STU. These details need to be provided prior to the actual tuning of the generating plant in advance (at least 2 months) for validation by CEA/POSOCO/CTU/STU.

6.2.1 The details of Generator Data Submission

- A. Generator Dynamic and Short Circuit Data (Standard IEEE Dynamic Model as per PSS/E Software being used by CEA/POSOCO/SLDC/CTU/STU)
- B. Combined Generator-Turbine inertia of the Unit (in Sec)
- C. Generator Transformer Details (R, X, R0, X0, Voltage Ratio, Rating)
- D. Generator Excitation Characteristic Details (Type, Make etc.)
- E. Curves to be submitted: Generator PQ Capability Curve, VEE Curve, Open and short circuit saturation curve.
- F. IEEE Standard Model/ Transfer Function Block Diagram of AVR and PSS and their variation range (As per the PSS/E Software being used by CEA/POSOCO/SLDC/CTU/STU)
- G. IEEE Standard Model/Transfer Function Block Diagram of Generator Governor and their parameter (As per the PSS/E Software being used by CEA/POSOCO/SLDC/CTU/STU)
- h. Rotor and Stator Current limits.
- H. Over excitation and Under Excitation Limit of AVR.
- I. Any other details required for Studies.
- J. Whenever the Generator Components Models (Generator / AVR / PSS / Governor/ Limiters) are not as per standard IEEE models, the onus will be on generating station to submit a verified generic model in PSS/E format to CEA/ POSOCO/ SLDC/ CTU/STU. The new model submitted should capture the input/output relationship appropriately in the simulation. Further, the Curves submitted should be easily readable. In case it is not readable, then the generator plant should submit at least a set of suitably spaced 10-20 data points to enable reconstruction of the manufacturer curves
- K. Formats for RLDC data sharing to Plants is enclosed as Annexure E.
- L. Detailed formats for the First time Charging (FTC) may be as per available on the GRID-INDIA website as amended from time to time.

6.2.2 Data from POSOCO

- A. Low frequency Oscillation Range for Inter-Area observed in the grid based on analysis of Oscillation monitoring system history of last six months.
- B. Inter plant oscillations captured during small perturbations and during faults near the generating units through WAMS system should be periodically shared in the Protection sub-Committee of RPCs to decide the review of PSS Tuning of the nearby Generators.
- C. Minimum and Maximum Fault level of the Generator Bus and Adjacent Bus without the contribution of generating unit where PSS has to be commissioned and tuned.

6.3 Operational Planning for PSS testing/tuning of units under commercial operation

Generating units shall submit the testing plan to OCCM. In the test plan, the following details must necessarily be shared.

- Indicated date and test duration
- Generation level at which the test has to be done.
- Transmission switching if required
- Unit synchronization / de-synchronization

On the day of the test, code shall be exchanged with the RLDCs for conducting the test. After concurrence from OCCM, the final plan shall be confirmed to RLDC on D-3 basis (D is the date of scheduled PSS testing).

In case of unit tripping during PSS tuning, the DC of the generators shall be revised by the power plant from the 7th time blocks. Schedules of the beneficiaries would be revised accordingly. Beneficiaries shall treat the unit under PSS tuning as a credible contingency and should be ready with matching reserve within the state control area to avoid deviations. As PSS tuning is a compliance requirement by the power plant, tripping of the unit during testing shall be treated only as a business risk.

During PSS tuning field-test, the desired injection schedule for conducting the test shall be ensured by the beneficiaries. Power plant shall coordinate with the

beneficiaries for the same. It is observed that PSS of thermal plant is bypassed (many times automatically) when the generation is below technical minimum.

6.4 Field Tuning Procedure & steps to be followed

1. Briefing to power plant personnel about the PSS tuning activity.
2. Confirm AVR/PSS block diagram and PSS parameter ranges.
3. Actual values of AVR parameter settings to be confirmed (from documentation or visual inspection of settings)
4. If values are different from those used in analytical studies, the design is redone
5. Excitation System Engineer (Manufacturer's representative) shall check the AVR and PSS hardware.
6. To confirm the machine parameters used for design, check whether for a step change in AVR reference, the reactive power response is a good approximation of the simulated response.
7. For step response of AVR reference (2%), obtain the response of generator output power (without PSS)
8. Now include the PSS as follows:
 - Keep output limits at a small range (+/- 0.01).
 - Set the time constants as per analytical studies as follows: Increase the gains in small steps according to a proportion dictated by analytical studies. The values may be increased to slightly more than this value (just to ensure that adequate stability margin exists) and then reverted. If spontaneous instability is detected in field voltage during this process, reduce the gains.
 - Increase limits range to about +/- 0.1 pu.
9. Carry out tests at 4.3 to establish/ensure that the PSS is tuned properly. Tests at 4.4 and Active Power Response Test & Actual Disturbance Test may be carried out if feasible.
10. A report on the tuning activity shall be prepared with all details at 4.9.
11. Monitor PSS and generator as the operating conditions change. The response for close in line faults and tripping be recorded for future analysis.

6.5 PSS Typical Testing Procedure

The following procedure may be followed by generators for the PSS tuning tests and its performance

Table 6.5

Test	Method	Remarks
A	Frequency Response Test, Step Response Test, Impulse Test without PSS	
	Synchronous Generator Switched running rated MW, unity pf, PSS OFF	
	1. Record steady state for 10 seconds 2. Inject +1% step to AVR Voltage Reference and hold for at least 10 seconds until stabilised 3. Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	
	1. Record steady state for 10 seconds 2. Inject 3% step to AVR Voltage Reference and hold for at least 10 seconds until stabilised 3. Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	
	1. Inject band limited (0.2- 4Hz) random noise signal into voltage reference and measure frequency spectrum of Real Power. 2. Remove noise injection.	
	1. Inject Limited Magnitude Impulse signal (Recommendation of OEM) into voltage reference and measure frequency spectrum of Real Power. In between change the magnitude of Impulse to inject the disturbance. 2. Remove Impulse Injection.	

B	Gain Margin Test, Frequency Response Test, Step Response Test, Impulse Test without PSS, Active power response test.	
	Synchronous Generator running rated MW, unity pf, PSS Switched ON	
	1. Increase PSS gain at 30 second intervals. i.e. x1 – x1.5 – x2 – x2.5 – x3 – x4 2. Return PSS gain to initial setting	
	1. Record steady state for 10 seconds 2. Inject +1% step to AVR Voltage Reference and hold for at least 10 seconds until stabilised 3. Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	
	1. Record steady state for 10 seconds 2. Inject +3% step to AVR Voltage Reference and hold for at least 10 seconds until stabilised 3. Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	
	1. Inject band limited (0.2-3Hz) random noise signal into voltage reference and measure frequency spectrum of Real Power. 2. Remove noise injection.	
	1. Select the governor for Frequency Sensitive Mode (FSM) 2. Inject +0.5 Hz step into the governor. 3. Hold until generator MW output is stabilised 4. Remove step	
C	Under-excitation limiter Interaction test	

	Synchronous generator running rated MW at unity power factor. Under-excitation limit temporarily moved close to the operating point of the generator	
	1. PSS on. 2. Inject -2% voltage step into AVR voltage reference and hold at least for 10 seconds until stabilised 3. Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	
	Under-excitation limit moved to the normal position. Synchronous generator running at rated MW and at leading MVar close to Under-excitation limit.	
	1. PSS on. 2. Inject -2% voltage step into AVR voltage reference and hold at least for 10 seconds until stabilised 3. Remove step returning AVR Voltage Reference to nominal and hold for at least 10 seconds	
D	Over-excitation limiter Interaction test	
	Synchronous Generator running rated MW and maximum lagging MVar. Over-excitation Limit temporarily set close to this operating point. PSS on	
	1. Inject positive voltage step into AVR voltage reference and hold. 2. Wait till Over-excitation Limiter operates after sufficient time delay to bring back the excitation back to the limit. 3. Remove step returning AVR Voltage Reference to nominal	
	Over-excitation Limit restored to its normal operating value. PSS on	

References

1. CEA (Technical standards for connectivity to the Grid) Regulation, 2007 and CEA Technical Standard for Construction of Electrical Plants and Electric Lines.
2. CEA Technical Standard for Construction of Electrical Plants and Electric Lines (Published in 2010)
3. Standard technical features of BTG system for supercritical 660/ 800 mw thermal units, CEA, July 2013
4. Standard technical specification for main plant package of sub- critical thermal power project 2 x (500 MW or above), CEA, Sept 2008.
5. CERC, Indian Electricity Grid Code 2010
6. CEA Transmission Planning Criteria 2013
7. Report of the Task Force on Power System Analysis under Contingencies, August 2013, New Delhi.
8. PSS Tuning Study and Implementation finalized by ERLDC & ERPC in 171st OCC.

(Extracts from WECC Report)ⁱⁱ

Simplified Power System Stabilizer Tuning Procedure for Hydro Units with Static Exciters

This procedure assumes that the unit in test will remain stable when the Power System Stabilizer is removed from service.

1. Attach equipment. Disconnect the Power System Stabilizer (PSS) from the Automatic Voltage Regulator (AVR) summing junction. Perform a frequency response of the terminal voltage (V_t) vs. V signal with the unit at full load.
2. From the V - t frequency plot, establish the phase delay of the exciter and generator (for example 154° at 0.4Hz).
3. Tune the Washout and PSS to provide phase lead in the frequency range of 0.1Hz to 1.0Hz equal the phase lag of V_t . The phase lead angle is equal to $90 + 180 - 26 = 296$ or -64 . 90 is derived from P_e lagging the terminal voltage by 90. The 180 is to be compensated for the -1 of the PSS.
4. Turn the gain of the PSS to near 0. Synchronize the unit. Ensure that the PSS output is not connected to the AVR summing junction (test switch 2 is open).
5. Perform a frequency response of P_e vs. V -signal. This will indicate the frequency of the local mode oscillation. However, this will not indicate the inter-area oscillations, as they are very difficult to excite with a single machine connected to a very strong bus.
6. Now that the local mode phase and frequency are known with the help of pole-zero placement techniques, the PSS settings can be calculated.
7. Use a modeling program or equivalent mathematical program to verify PSS settings are going to result in the proper phase in the inter-area (0.1Hz to 1.0Hz) and provide indication of the local mode damping.
8. Apply settings to PSS with gain turned down. Ensuring test switch 2 is open. Connect test equipment to the PSS, replacing the Watt Transducer output (PSS input) with V -signal.
9. Compare the frequency response of the model and actual equipment to ensure correct operation of the PSS.
10. Reconnect the watt transducer to the PSS. With the machine on-line at a reasonable loading, connect the PSS (test switch 2).

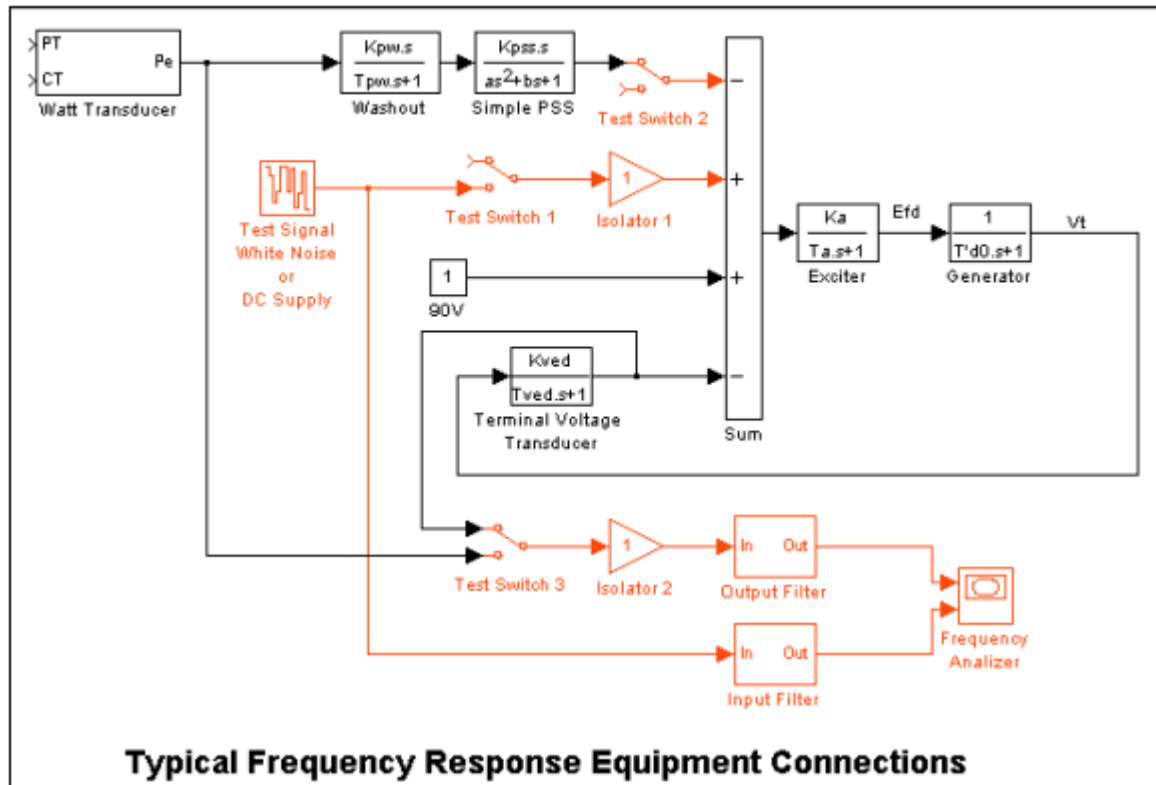


Figure 1

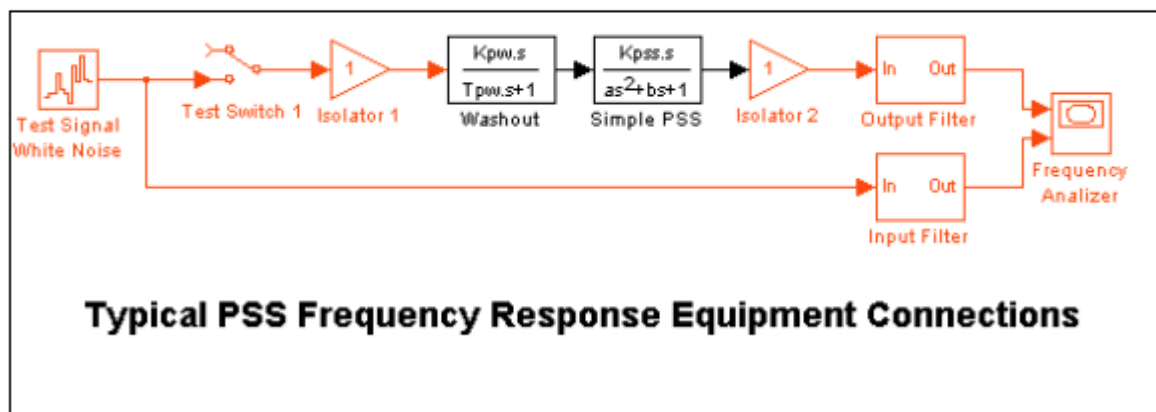


Figure 2

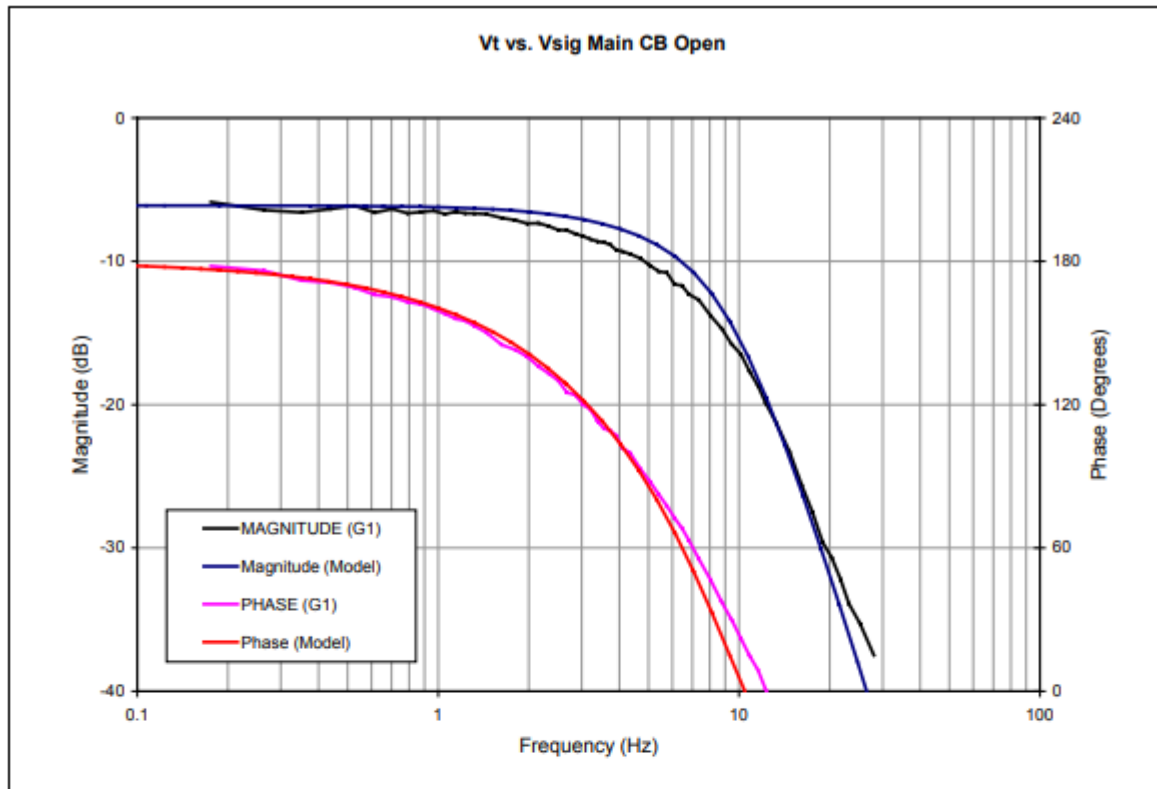


Figure 3

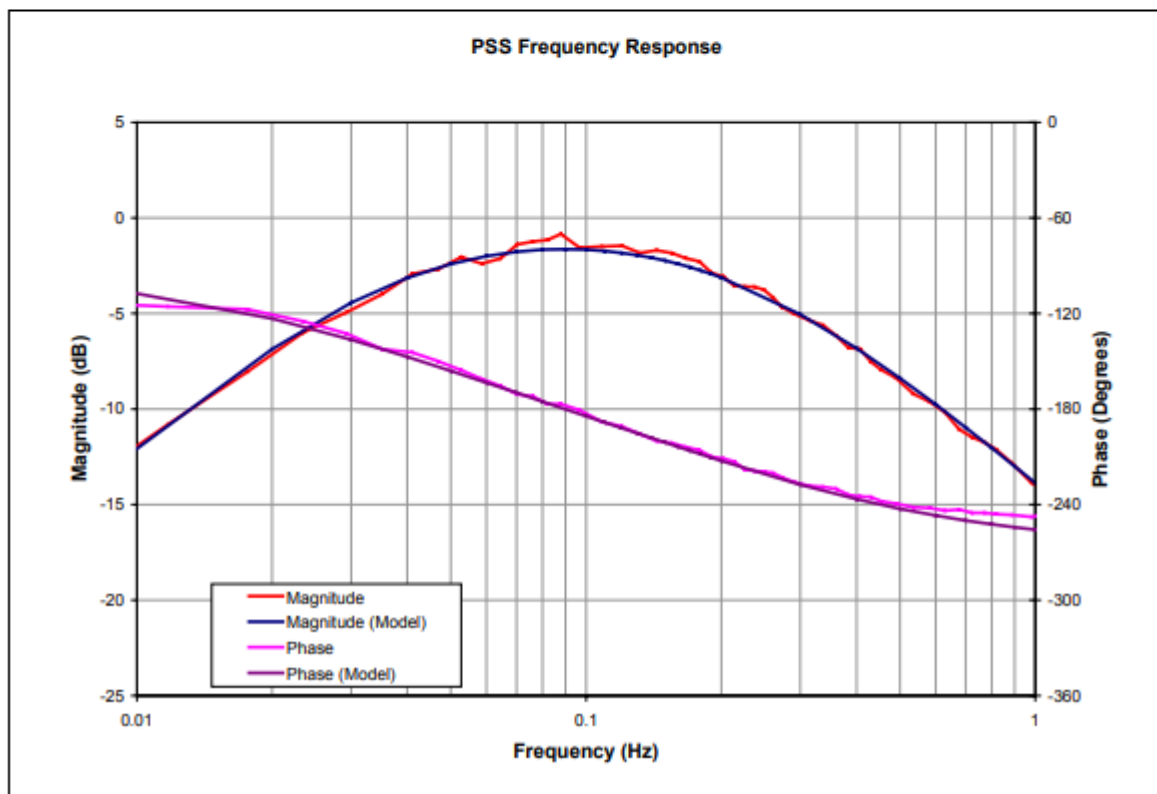


Figure 4

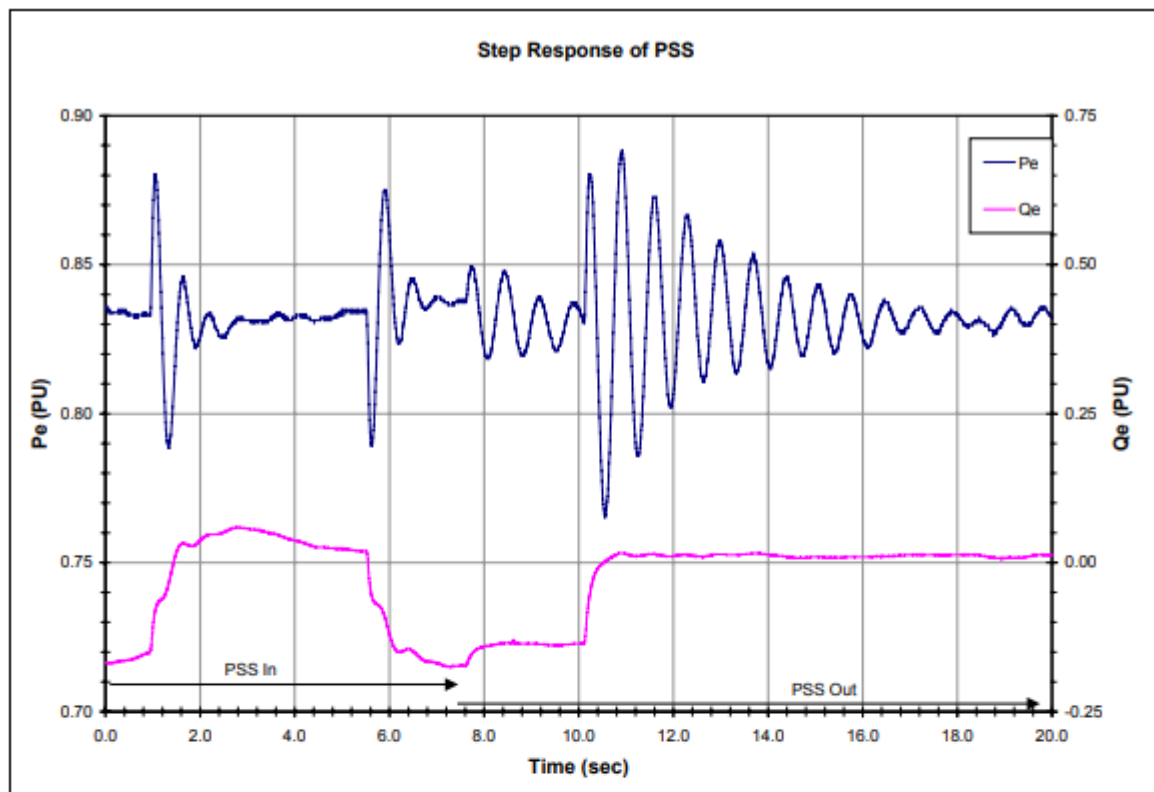


Figure 5

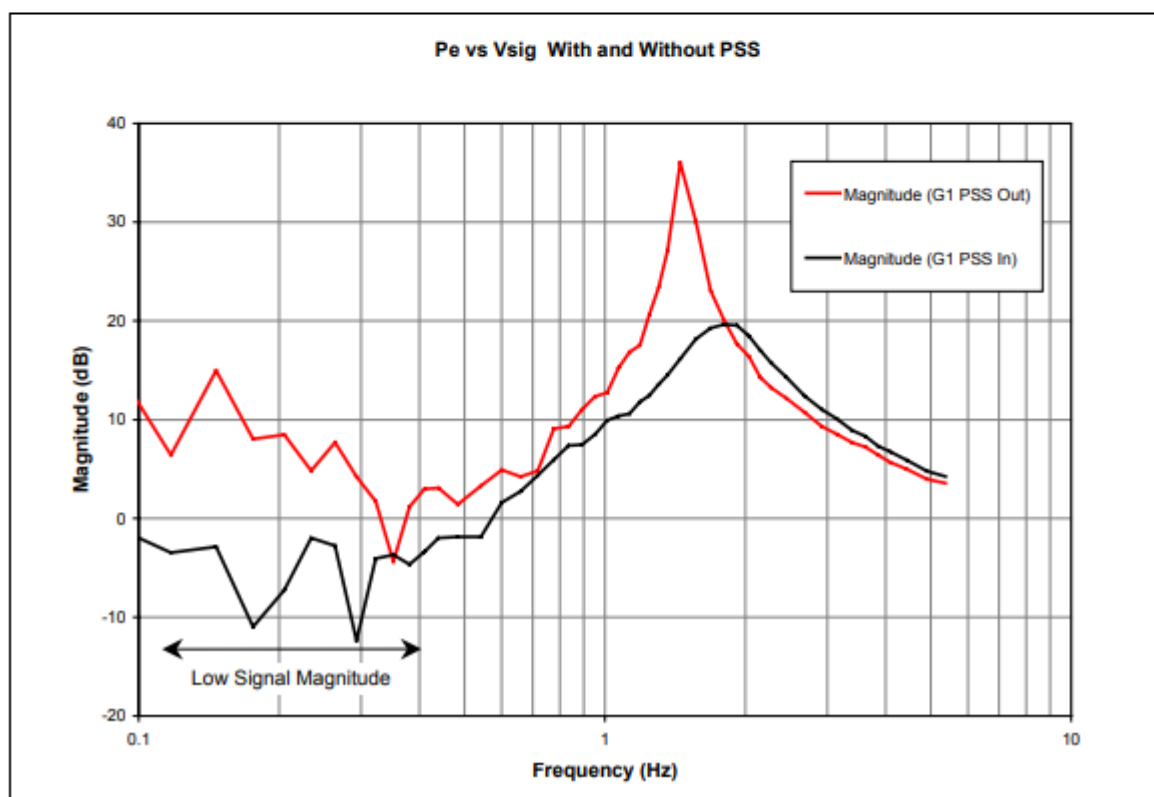


Figure 6

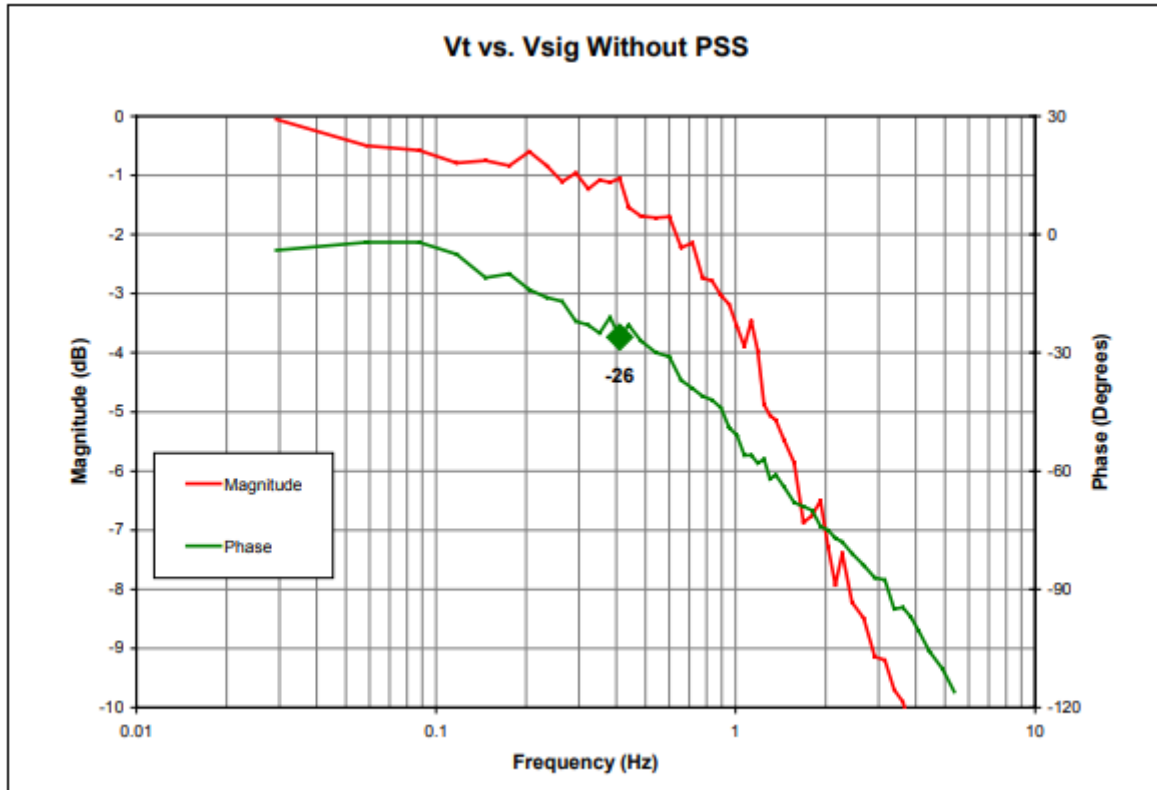


Figure 7

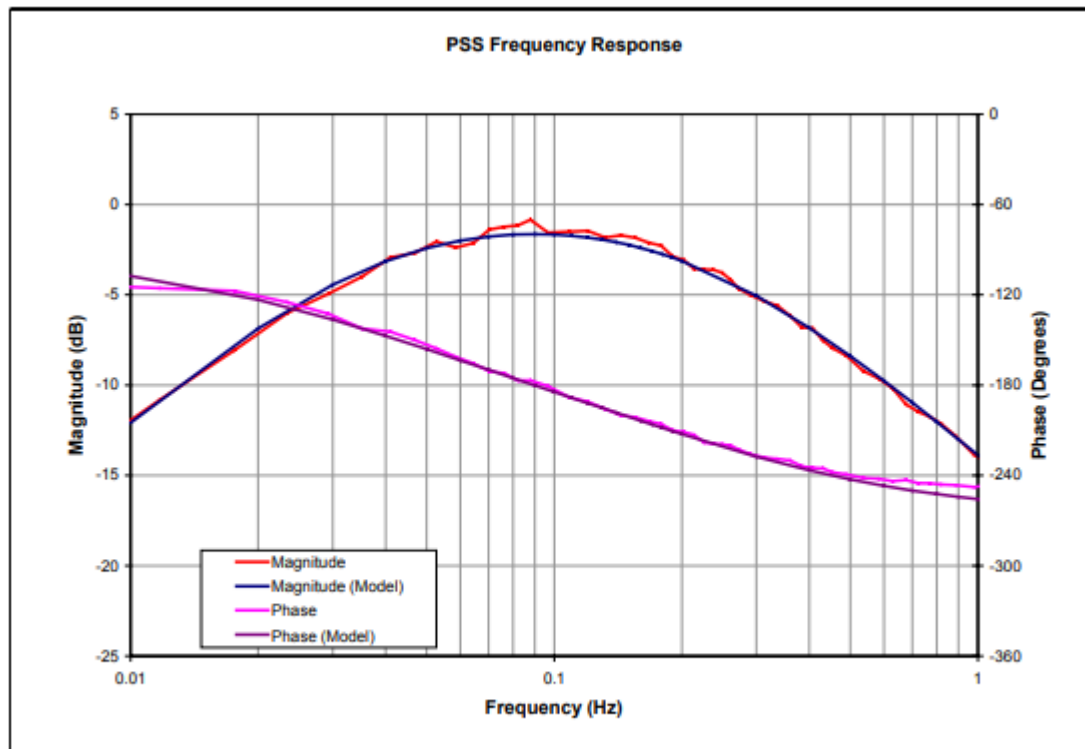


Figure 8 Model Verification

IEEEEST Model

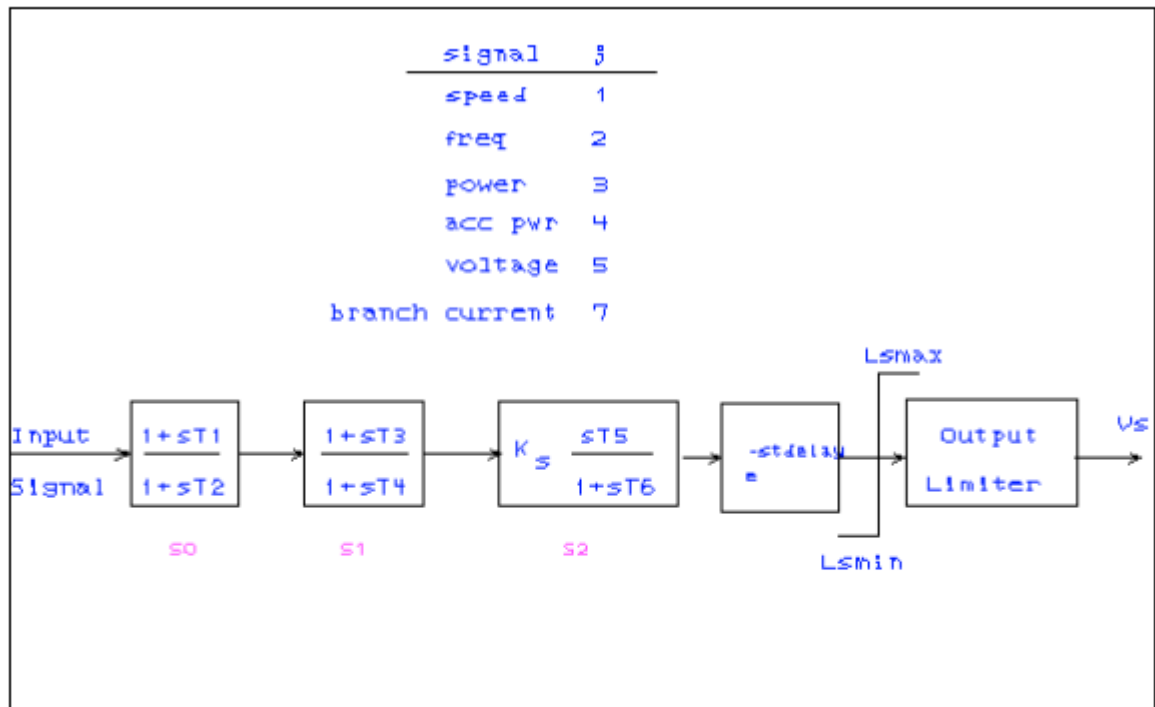


Figure 9 IEEEEST Model

Bus No.	Bus Name	PSS/E MODEL	ID	T1	T2	T3	T4	T5	T6	Ks	Lsmax	Lsmin	Tdelay
6021	KCL G1 13.8	IEEEEST	1	0.00	0.00	0.00	0.75	1.00	4.20	-4.10	0.10	-0.10	0.00
6022	KCL G2 13.8	IEEEEST	1	0.00	0.00	0.00	0.75	1.00	4.20	-4.10	0.10	-0.10	0.00
6023	KCL G3 13.8	IEEEEST	1	0.00	0.00	0.00	0.75	1.00	4.20	-4.10	0.10	-0.10	0.00
6024	KCL G4 13.8	IEEEEST	1	0.00	0.00	0.00	0.75	1.00	4.20	-4.10	0.10	-0.10	0.00

Figure 10 Model Parameters

Commonly Used PSS as Per IEEE Standard

1. PSS1 A: Generalized form of a PSS with a single input. Some common stabilizer input signals are speed, frequency, and power. Typical design parameter for power system stabilizers with frequency or speed input is given in the table 1 and 2 respectively.

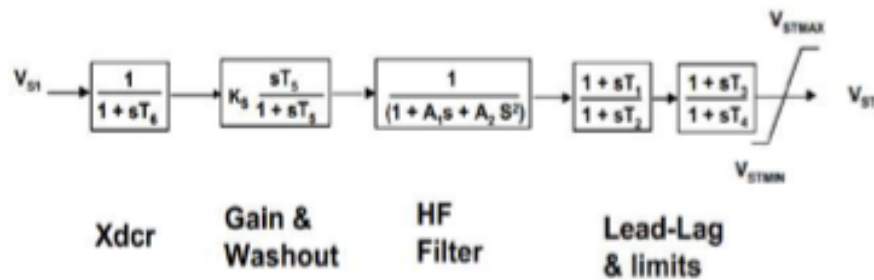


Figure.1

PSS1A Table 1: Range of typical design parameters for power system stabilizers with frequency or speed input

Symbol	Typical range	Definition
T_6	0 s to 0.04 s	Transducer time constant
T_3	0.5 s to 50 s	Washout (reset) time constant
T_1, T_3	0.03 s to 2.0 s	Lead (zero) time constant
T_2, T_4	0.01 s to 10 s	Lag (pole) time constant
K_S	0.10 pu to 10 pu	Stabilizer gain
V_{STMIN}, V_{STMAX}	± 0.02 pu to ± 0.10 pu	Stabilizer output signal limits

Table 2: Range of typical design parameters for power system stabilizers with power input

Symbol	Typical range	Definition
T_6	0 s to 0.04 s	Transducer time constant
T_3	0.5 s to 50 s	Washout (reset) time constant
T_1, T_3	0.1 s to 2.0 s	Lead (zero) time constant
T_2, T_4	0.01 s to 0.20 s or 10 s to 20 s	Lag (pole) time constant
K_S	± 0.10 pu to 10 pu	Stabilizer gain (sign depends upon choice of input signal)
V_{STMIN}, V_{STMAX}	± 0.02 pu to ± 0.10 pu	Stabilizer output signal limits

2. PSS2A/2B: This stabilizer model is designed to represent a variety of dual-input stabilizers, which normally use combinations of power and speed or frequency to the stabilizing signal.

This model can be used to represent two distinct types of dual-input stabilizer implementations as described as follows:

A. Stabilizers that, in the frequency range of system oscillations, act as electrical power input stabilizers. These use the speed or frequency input for the generation of an equivalent mechanical power signal, to make the total signal insensitive to mechanical power change.

B. Stabilizers that use a combination of speed (or frequency) and electrical power. These systems usually use the speed directly (i.e., without phase-lead compensation) and add a signal proportional to electrical power to achieve the desired stabilizing signal shaping.

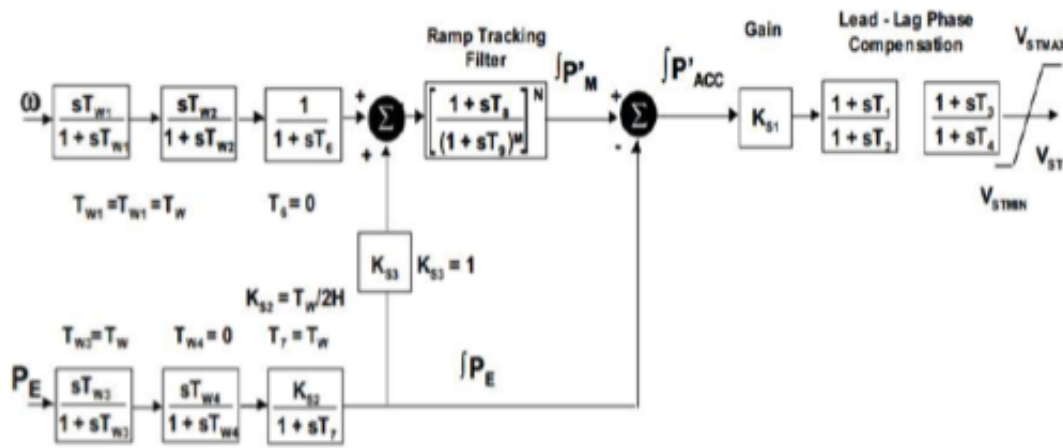


Figure 2: PSS2A

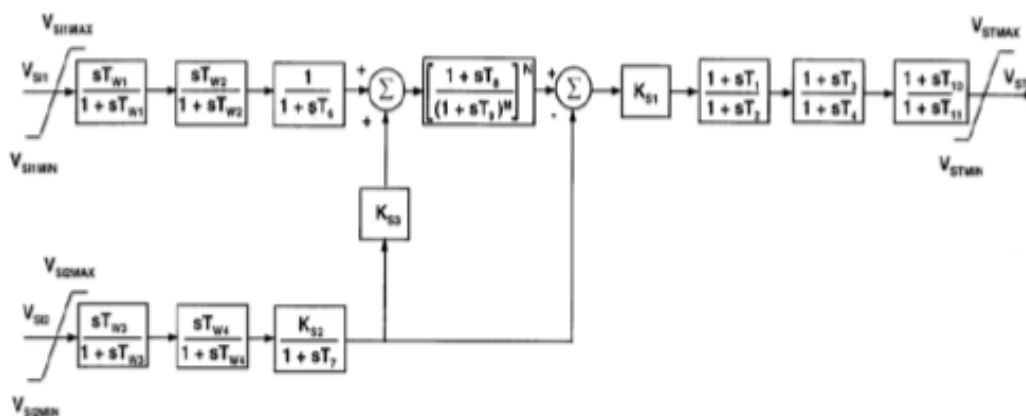


Figure 3: PSS2B

Table 3 : Range of typical design parameters for dual input power system stabilizers (PSS2A/2B)

Symbol	Typical range	Definition
T_6	0 s to 0.04 s	Transducer time constant
T_{w1} through T_{w4}	0 s to 20 s	Washout (reset) time constants ^a
K_{S2}	0 pu to 10 pu	Mixing gain
K_{S3}	1	Mixing gain ^b
T_8, T_9, N, M	$T_8 = 0.5$ s; $T_9 = 0.1$ s; $N = 1$; $M = 5$ or $T_8 = 0.3$; $T_9 = 0.15$; $N = 4$; $M = 2$	Selected to minimize voltage change during mechanical power changes ^c
T_7	0 s to 20 s	Low pass filter time constant ^b
T_1, T_3, T_{10}	0.01 s to 6.0 s	Lead (zero) time constant
T_2, T_4, T_{11}	0.01 s to 6.0 s	Lag (pole) time constant
K_{S1}	0.10 pu to 50 pu	Stabilizer gain ^d
V_{STMIN}, V_{STMAX}	± 0.02 pu to ± 0.10 pu	Stabilizer output signal limits ^d

^a A value of 0 indicates a bypassed block.

^b When the PSS2A or PSS2B structure is used to represent integral-of-accelerating-power-based PSS units $K_{S3} = 1$, $T_7 = T_{w2}$, $T_{w4} = 0$, $K_{S2} = T_9/(2 \times \text{inertia})$.

^c Some special circumstances may require alternative selection of T_8 , T_9 , N , and M .

^d V_{STMAX} and K_{S1} typical values assume V_{REF} summation point PSS.

3. PSS 3B: The PSS model PSS3B has dual inputs of electrical power (V_{SI1}) and rotor angular frequency deviation (V_{SI2}). The signals are used to derive an equivalent mechanical power signal. By combining this signal with electrical power, a signal proportional to accelerating power is produced. The time constants T_1 and T_2 represent the transducer time constants, and the time constants T_{W1} to T_{W3} represent the washout time constants for electric power, rotor angular speed, and derived mechanical power, respectively. In this model, the stabilizing signal V_{ST} results from the vector summation of processed signals for electrical power and angular frequency deviation.

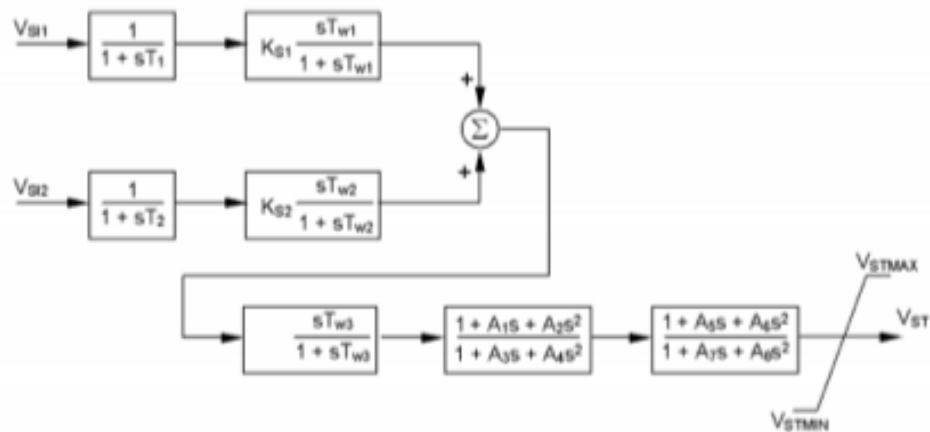


Figure 4: PSS3B

4. PSS4B: The PSS4B model represents a structure based on multiple working frequency bands. Three separate bands, respectively dedicated to the low-, intermediate- and high-frequency modes of oscillations, are used in this delta-omega (speed input) PSS. The low band is typically associated with the power system global mode, the intermediate with the inter-area modes, and the high with the local modes. Each of the three bands is composed of a differential

filter, a gain, and a limiter. Their outputs are summed and passed through a final limiter V_{STMIN} / V_{STMAX} resulting in PSS output V_{ST}

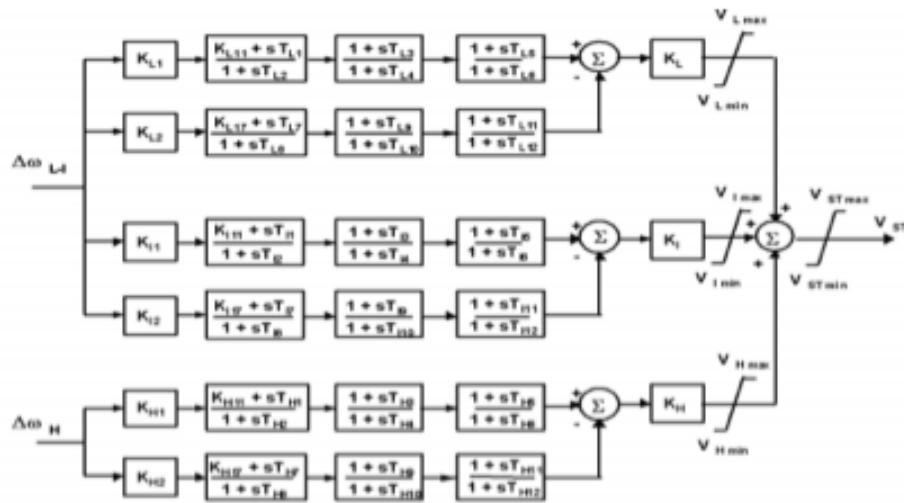


Figure 5: PSS4B

Table 4 Range of typical design parameters for multi-band power system stabilizers

Symbol	Typical range	Definition
F_L	0 Hz to 0.3 Hz	Low band central frequency
F_I	0.3 Hz to 2 Hz	Intermediate central frequency
F_H	2 Hz to 10 Hz	High band central frequency
K_L	0 pu to 10 pu	Low band gain
K_I	0 pu to 50 pu	Intermediate band gain
K_H	0 pu to 100 pu	High band gain
V_{LMIN}, V_{LMAX}	0 pu to 1.0 pu	Low band output signal limits
V_{IMIN}, V_{IMAX}	0 to 1.0 pu	Intermediate band output signal limits
V_{HMIN}, V_{HMAX}	0 to 1.0 pu	High band output signal limits
V_{STMIN}, V_{STMAX}	0 to 0.1 pu	Stabilizer output signal limits

Eigen Value Analysis of SMIB System

Consider the system:

$$\dot{x} = f(x, u)$$

The stability of an equilibrium point can be judged by the solution of the linearized system at the equilibrium point x_o . Letting

$$x = x_o + \Delta x$$

and $\Delta u = 0$, we obtain:

$$\dot{x} = \dot{x}_o + \Delta \dot{x} = f(x_o, u) + \left[\frac{\partial f(x, u)}{\partial x} \right] \Delta x \Big|_{x=x_o}$$

Therefore

$$\Delta \dot{x} = [A(x_o, u)] \Delta x$$

where A is a nxn matrix whose elements are functions of x_o and u . The ij^{th} element of [A] is given by

$$A_{ij}(x_o, u) = \frac{\partial f_i}{\partial x_j}(x_o, u)$$

For a given x_o , and u , the matrix A is constant. The solution of the linearized state equation is given by

$$\begin{aligned} \Delta x(t) &= e^{A(t-t_o)} \Delta x(t_o) \\ &= C_1 e^{\lambda_1 t} v_1 + C_2 e^{\lambda_2 t} v_2 + \dots + C_n e^{\lambda_n t} v_n \end{aligned}$$

where $C_1, C_2, \dots, C_n$ are constants depending on the initial conditions. λ_i and v_i are the i^{th} eigenvalue and the corresponding eigenvector of matrix [A]. It is assumed that all eigenvalues are distinct. If the number of first order differential equations is n , then there are n eigenvalues. It can be seen that if $\text{Re}[\lambda_i] < 0$ for all λ_i , then for all sufficiently small perturbations from the equilibrium point x_o , the trajectories tend to x_o as $t \rightarrow \infty$. Hence, x_o is asymptotically stable. If $\text{Re}[\lambda_i] > 0$ for all λ_i then any perturbation leads to the trajectory leaving the neighborhood of x_o . Hence x_o is unstable. If there exists i and j such that $\text{Re}[\lambda_i] < 0$ and $\text{Re}[\lambda_j] > 0$ then x_o is called a saddle point and the system is unstable.

Complex eigenvalues are associated with oscillatory behavior. In this context it is useful to note that:

$$\begin{aligned} \cos(\omega t) + j \sin(\omega t) &= e^{j\omega t} \\ \cos(\omega t) - j \sin(\omega t) &= e^{-j\omega t} \end{aligned}$$

The extent of a particular mode in the response is dependent on the nature of the disturbance. Some mode (λ_i) may be 'visible' in some states in greater proportion compared to other states. This is determined by the individual components of the 'eigenvector' (v_i) corresponding to that mode. Also, the extent to which a mode is excited depends on the initial disturbance ($\Delta x(0)$).

The swing equation for SMIB system is

$$M \frac{d^2\delta}{dt^2} + D \frac{d\delta}{dt} = T_m - T_{max} \sin \delta$$

Where,

$$T_{max} = \frac{E_g E_b}{(x_g + x_o)}$$

The state space form is given by

$$\begin{aligned} \frac{dx_1}{dt} &= x_2 \\ \frac{dx_2}{dt} &= -\frac{D}{M} x_2 - \frac{T_{max}}{M} \sin x_1 + \frac{T_m}{M} \end{aligned}$$

Where,

$$x_1 = \delta, x_2 = \frac{d\delta}{dt}$$

The equilibrium points are given by

$$\begin{aligned} x_2 &= 0 \\ x_1 &= \sin^{-1} \frac{T_m}{T_{max}} \end{aligned}$$

From the power angle curve shown in Fig. 1.2, it can be seen that there are two values of δ corresponding to a specified value of T_m , (when $T_m < T_{max}$) when the range of δ is confined to $-180^\circ < \delta < 180^\circ$.

$$\begin{aligned} x_o^1 &= x_s = (\delta_s, 0) \\ x_o^2 &= x_u = (\delta_u, 0) \end{aligned}$$

Let $y_1 = \Delta x_1, y_2 = \Delta x_2$,

Then,

$$\begin{bmatrix} \dot{y}_1 \\ \dot{y}_2 \end{bmatrix} = \begin{bmatrix} 0 & 1 \\ -\frac{K}{M} & -\frac{D}{M} \end{bmatrix} \begin{bmatrix} y_1 \\ y_2 \end{bmatrix}$$

Where,

$$K = T_{max} \cos \delta_e$$

δ_e is the angle at equilibrium δ_s or δ_u

The eigenvalues of the linearized system are given by

$$\lambda = \frac{-D \pm \sqrt{D^2 - 4KM}}{4M^2}$$

If K is positive, then eigen values have negative real parts. If K is negative one of the eigenvalues is positive real. This is true when $\delta_e = \delta_u$. Hence the system is small signal unstable at δ_u . For small D, and $K > 0$ eigenvalues are complex given by

$$\lambda = -\sigma \pm jw$$

Where,

$$\sigma = \frac{D}{2M}, \quad w = \sqrt{\frac{K}{M} - \frac{D^2}{4M^2}}$$

Participation factors

In SMIB system it was determined that the response of various states of the system was a combination of several patterns or modes:

$$\begin{aligned}\Delta x(t) &= e^{A(t-t_0)} \Delta x(t_0) \\ &= C_1 e^{\lambda_1 t} v_1 + C_2 e^{\lambda_2 t} v_2 + \dots + C_n e^{\lambda_n t} v_n\end{aligned}$$

where $C_1, C_2, \dots, C_n$, are constants depending on the initial conditions. λ_i and v_i are the eigenvalue and the corresponding right eigenvector of matrix $[A]$. It is assumed that all eigenvalues are distinct.

The extent of a mode being excited is determined by the vector product $c_i = u_i^T \Delta x(0)$ where $\Delta x(0)$ is the initial deviation from the equilibrium point. The vector u_i is called the left eigen vector corresponding to eigenvalue λ_i and is related to the right eigenvectors v_i as follows:

$$\begin{aligned}u_i^T v_j &= 0 \quad i \neq j \\ &= 1 \quad i = j\end{aligned}$$

To characterize the involvement of individual states in the various modes (eigenvalues), we use a measure called 'participation factor': The participation of a particular state j in a mode i is given by,

$$p_i(j) = v_i(j) u_i(j)$$

For certain class of systems, magnitude of $v_i(j)$ and $u_i(j)$ are identical. Then $v_i(j)$ itself is a measure of the participation. The multi-mass multi-spring system is an example of such a system.

The multi-mass multi-spring system is analogous to a multimachine system with 1) the machines represented by the classical model, 2) loads being constant power 3) Transmission system being lossless.

In this case, the linearized system equations can be written as

$$[M] p^2 \Delta \delta = -[K] \Delta \delta$$

where $[M]$ is diagonal matrix with $M_{ij} = \frac{2H_j}{w_B}$ (H_j is the inertia constant of j^{th} synchronous machine). $K_{ij} = \frac{\partial P_{ei}}{\partial \delta_j}$ 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 w_0). 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,

$$K_{ij} = -\frac{E_i E_j}{X_{ij}} \cos(\delta_i - \delta_j) \approx \frac{1}{X_{ij}}$$

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. Assume that the voltages are around 1.0 p.u. 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 can, in general, be expressed as

$$\Delta \delta^R = \sum_{j=1}^{m-1} v_j (c_i \cos w_i t + d_j \sin w_j t)$$

where $\Delta \delta^R [\Delta \delta_{21} \ \Delta \delta_{31} \ \dots \ \Delta \delta_{m1}]^t$ is the vector of relative angles ($\Delta \delta_{i1} = \Delta \delta_i - \Delta \delta_1$) $c_i, \dots, c_{m-1}, d_1, d_2, \dots, d_{m-1}$ are scalars depending on the initial conditions, v_i, 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 w_j .

Details to Plant for PSS Tuning

1. Lowest possible oscillation frequency: Hz
2. Inter-area oscillation frequency: Hz (Range is 0.2-0.8 Hz)
3. Local area oscillation frequency: Hz (Range is 1 - 3 Hz)
4. Highest possible Oscillation. Frequency: Hz
5. Three Phase Short Circuit Level (Fault Level) at step-up transformer HV side (minimum value): [MVA]
6. Three Phase Short Circuit Level (Fault Level) at step-up transformer HV side (maximum value): [MVA]
7. Assumptions made for calculating short circuit level:

ⁱ Power System Stabilizers a short course under Continuing Education Program – Department of Electrical Engineering, IIT Bombay, Powai Mumbai

ⁱⁱ WECC Power System stabilizer Tuning Guidelines.



भारत सरकार/Government of India

विद्युत मंत्रालय/Ministry of Power

केन्द्रीय विद्युत प्राधिकरण/Central Electricity Authority

एन.पी.सी. प्रभाग/National Power Committee Division

Ist Floor, Wing-5 ,West Block-II, RK Puram, New Delhi-66, e-mail:rishika@nic.in

No. 4/MTGS/NPC/CEA/2020/ 71-81

Date: 8th February, 2020

To,
(As per distribution list)

Subject: Constitution of “Sub-group to finalize a common procedure for Power System Stabilizers (PSS) Tuning”-reg.

In the 9th meeting of NPC, it was decided that a Sub-group may be constituted comprising of representatives of Protection Sub-Committee (PSC) of respective RPCs, NPC, NLDC, CTU, NTPC and NHPC, to finalize a common procedure for Power System Stabilizers (PSS) Tuning. NPC Secretariat vide letter No. 4/MTGS/NPC/CEA/2020/07-14 dated 01.01.2021 had asked for nominations from all the RPCs, NLDC, CTU, NTPC and NHPC. Based on the receipt of nominations, the composition of the Sub-group has been formed as follow:

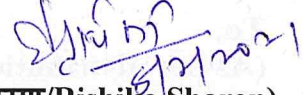
S. No.	Designation	Organisation	Name	Constitution of the Committee
1	Member Secretary	WRPC	Sh. Satyanarayan S.	Chairman
2	Member Secretary	NPC	Smt. Rishika Sharan	Member
3	Superintending Engineer	WRPC	Sh. P. D.Lone	Member Convener
4	Executive Engineer	NERPC	Sh. S. Mukherjee	Member
5	Executive Engineer	NRPC	Sh. Ratnesh Kumar,	Member
7	Executive Engineer	ERPC	Sh. Pranaya Piyusha Jena	Member
6	Assistant Executive Engineer	SRPC	Sh. Sriharsha Mundluri	Member
8	Sr. General Manager	CTU	Sh. Partha Sarathi Das	Member
9	General Manager	NHPC	Sh. Umesh Kumar Nand	Member
10	General Manager	NLDC	Sh. Vivek Pandey	Member
11	Chief Manager	NLDC	Sh Phanishankar	Member
11	AGM (OS-SIIS)	NTPC	Sh. Sanjeev Kumar Singh	Member

Term of Reference (TOR) of the Sub-group:

1. To examine the present procedure of Power System Stabilizer (PSS) tuning of generating units in all the five regions of Indian Power System.
2. To study the PSS tuning exercise in the past and to finalize a common procedure for PSS Tuning at all India Level.

Sub-Group may Co-opt/associate any other expert in the field, as they feel necessary.

Yours faithfully,



(ऋषिका शरण/Rishika Sharan)

मुख्य अभियन्ता एवं सदस्य सचिव, रा.वि.स /
Chief Engineer & Member Secretary, NPC

Distribution list:

1. Member secretary, WRPC
2. Member secretary, NRPC
3. Member secretary, ERPC
4. Member secretary, SRPC
5. Member secretary, NERPC
6. PGCIL, CTU-Planning (1st Floor-A Wing), Saudamini, Plot No.- 2, Sector-29, Near IFFCO Chowk Metro Station, Gurgaon – 122 001, Haryana
7. CMD, NHPC, NHPC Office Complex, Sector-33, Faridabad – 121003 (Haryana)
8. CMD, NTPC, NTPC Bhawan, SCOPE Complex, Institutional Area, Lodhi Road, New Delhi – 110003
9. CMD – POSOCO, B-9, Qutab Institutional Area, Katwaria Sarai, New Delhi-110016

Copy for kind information to:

1. Chairperson, CEA
2. Member (GO&D), CEA