POWER SYSTEM STABILIZER WITH SYNCHRONIZED PHASOR MEASUREMENTS

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Abstract – In many cases, it is a very challenging task to tune power system stabilizers to damp sufficiently well both local and inter-area modes based on local feedback signals only. However, it is possible in practice to equip the existing excitation systems with a global synchronizing clock and the functionality similar to phasor measurement units and design supplementary stabilizers for local and inter-area modes. Providing that multiple generator excitation systems can exchange information (perhaps, also with a regular wide-area system that integrates a number of phasor measurements) among each other, it gives new opportunities for tuning existing power system stabilizers to damp the inter-area modes as well. This idea will be discussed and evaluated on a realistic power system model in this work.

Keywords: Power system stabilizer, Phasor measurement unit, wide-area control, generator excitation system, power system oscillations, power system modeling.

1 INTRODUCTION

In the past years, continued load growth without a corresponding increase in transmission capacity has resulted in reduced operational margins for many power systems world-wide, and has led to operation of power systems closer to their stability limits [1]. Likewise, load transmission and wheeling of power from distant generators to local load consumers has become common practice. This has led to substantially increased amounts of power being transmitted through the existing networks, occasionally causing transmission bottlenecks and electromechanical oscillations of parts of the electric power systems [2]. These issues together with the on-going trend towards deregulation of the electric power systems on the one hand and the increased need for accurate and better network monitoring and control on the other hand, have created a demand for dynamic wide-area monitoring, protection and control that goes beyond the rather static view provided by SCADA/EMS [8].

The mechanism by which interconnected synchronous machines in large power systems maintain synchronism with one another is through restoring forces which act whenever there are forces tending to accelerate or decelerate one or more generators with respect to other generators in the system. In addition, Power System Stabilizers (PSS) are provided to add damping torque to the generator oscillations by modulation of the generator excitation signal [4]. PSS devices enhance small-signal stability and improve the damping of both plant mode oscillations and inter-area modes of power oscillation [7]. Conventional PSS devices operate locally, using exclusively local measurements for decisions on how to control generator excitation or damp power system oscillations. This is based primarily on variations of shaft speed, terminal frequency and electric power. Power oscillations in fact give rise to variations in these quantities but also other phenomena may affect them. The detection of relevant power system oscillations from these measurements is a very complex task [5]. The general problem is that the locally measured quantities often are insufficient for detection and control of power system oscillations [6], [9].

This paper describes a control scheme based on measurements of time-stamped signals in at least two locations of the power system that are evaluated in view of poorly damped power oscillations. Direct measurement of a node voltage angle difference between the two points provides an improved observability of the rotor angle oscillations compared to local measurements which are used by conventional Power System Stabilizers (PSS). In general, it is possible to equip the existing excitation systems easily with a global synchronizing clock and the functionality of a phasor measurement unit (PMU) [10]. Providing that multiple generator excitation systems can exchange this information (possibly with many other PMUs) among each other, it gives new opportunities for tuning power system stabilizers to damp also inter-area modes. This idea has been evaluated on a realistic power system model in the presented work.

2 UNITROL 6000 EXCITATION AND POWER SYSTEM STABILIZING SYSTEM

ABB's excitation system UNITROL 6000 is the latest generation of the UNITROL excitation system family. The technology is based on over a hundred years of know-how and experience. UNITROL 6000 is a modern, fully digital, highly modular, and flexible excitation system. The hardware concept of UNITROL 6000 is schematically presented in Figure 1, which depicts 3 control channels designed for redundancy reasons. In the figure, the acronyms can be explained as follows. CIO stands for the combined input-output device, CCM designates the control communication measurement module, AC PEC800 is the power electronic controller capable of performing 64-bit floating point operations.

The other abbreviations are: CCI for the converter control interface, GDI for the gate driver interface, and finally CSI denoting the converter signal interface module.

As most of other modern excitation systems UNITROL carries out a number of important regulating and limiting functions, e.g., control of the generator's terminal voltage or reactive power. Also, the excitation system is commonly used for stabilizing the generator and thus contributing to the overall power system stability.

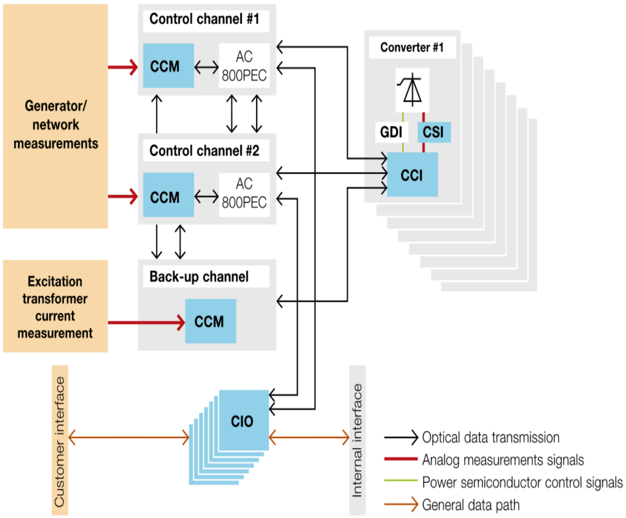

Figure 1: Hardware concept of UNITROL 6000 excitation system.

In UNITROL 6000 there are three built-in power system stabilizers, namely, IEEE PSS2A/B and IEEE PSS4B [7], and the adaptive PSS. To date, built-in PSS use local feedback signals, i.e., the rotor speed and the electrical power.

It has been repeatedly observed in practical applications that the PSS utilizing local signals can be very efficient in suppressing local oscillatory modes, that is, oscillations with frequencies above approximately 0.7Hz. However, it is a more complicated task to demonstrate the performance of the PSS in damping of inter-area oscillations approximately 0.1 – 0.7Hz.

Therefore, there have been research and development activities aiming to explore the use of global signals for more efficient stabilization of multi-modal oscillations. This work is based on the patent [10] which forms the foundation of the present paper.

3 TEST SYSTEM

To test and validate the use of synchronized phasor measurements for PSS and excitation system control, a 21-bus/20-generator test power system model has been used. It reflects some characteristics of the Nordic power system shown in Figure 2. The model contains the standard IEEE Type ST1A excitation systems, including PSS Type 2A power system stabilizers and governor controls. Loads are represented using static voltage and frequency dependent loads. In total the model includes 294 dynamic state variables.

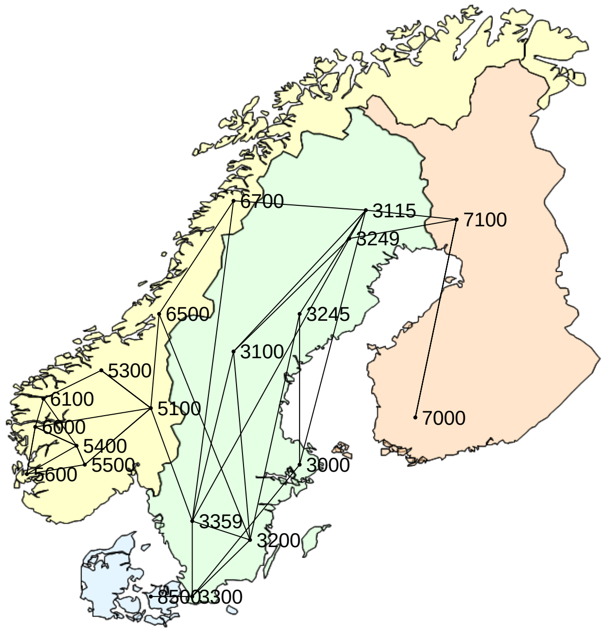

Figure 2 - The test network with generator locations and main tie-lines.

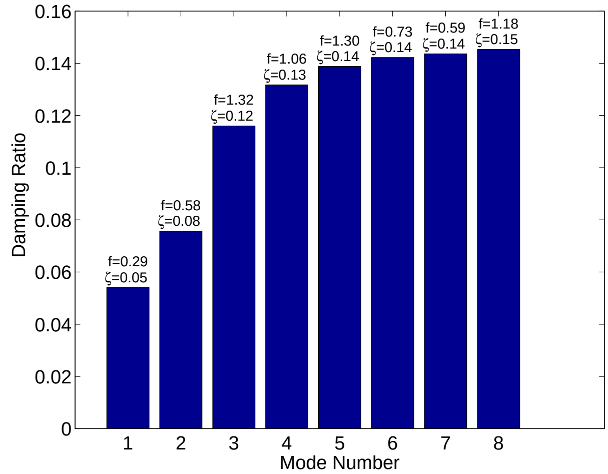

Figure 3 - Oscillation modes in the test power system identified by modal analysis of a linearized simulation model of the test network.

Because of its highly simplified nature, the model cannot fully reproduce the dynamics of the Nordic power system discussed e.g. in [1]. Nevertheless it shares some of its structural properties. Modal analysis performed on a linearization of a simulation model provided by ObjectStab [3] identifies 8 oscillatory modes with damping of less than 15% as shown in Figure 3.

The 0.29Hz mode between the far ends of the system that represents south Finland on one hand and south Sweden/Denmark on the other hand, and the 0.58 Hz mode (most visible in the Norwegian part of the grid) are well reproduced. These modes are labeled as Mode 1 and Mode 2, respectively, and will be the focus of the further investigation in this paper.

Modal analysis reveals that voltage angle measurements are particularly effective when it comes to the characterization and detection of inter-area oscillations. Figure 4 visualizes the modal observability [4] for voltage angle measurements taken at each of the generator location for the two dominant modes.

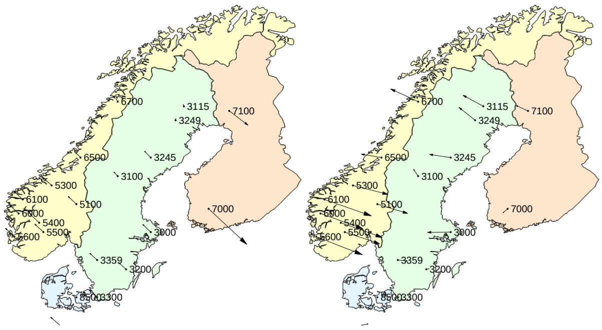

Figure 4 - Graphical representation of the modal observability of the 0.29 Hz (left) and 0.58 Hz modes (right) in the voltage angle measurements taken at the generator locations.

The 0.29Hz mode characterizes the coherent movement of the two measurements taken at the Finnish generator sites against the rest of the system. This mode is particularly visible in the measurements θ_{7000} and with the opposite phase in most other measurements. Voltage angle measurements θ_{3300} and θ_{5300} have been chosen to monitor the other end of this mode. The 0.58 Hz mode has a more complex nature and the split between the areas is less obvious. However, it mainly embodies coherent movement of generators in the northern part of the network which is visible well at θ_{5300} and with opposite phase in the Swedish part of the grid with good visibility in θ_{3000}. Based on the above observability analysis we choose the generators at buses 3300 and 5300 as candidates for the PSS tuning here since they are the largest generators located at the respective ends of each of the two critical oscillation modes. For improved observability of the 0.3 Hz mode, it is foreseen to use an additional PMU measurement θ_{7000} located at the generator bus 7000.

4 CONTROL DESIGN

4.1 Local PSS Tuning

It is known that the fast acting automatic voltage regulators (AVR) tend to increase the synchronizing torque component of the total electrical torque of the synchronous machine; however, this is done at the expense of the damping torque component. Thus, fast acting voltage regulators increase the attraction region of the post-fault equilibrium point of the generator at the same time reducing the small-signal stability margin of the generator.

To compensate for the decreased damping torque due to the AVR, a dedicated power system stabilizer is normally used. The PSS adds damping torque component to the electrical generator acting through the generator's automatic voltage regulator thus enhancing the small-signal stability properties of the generator and the power system in general.

There are several different types of power system stabilizers supported by the ABB's UNITROL excitation system family, namely, IEEE PSS2A/B, IEEE PSS4B, and the so-called Adaptive Power System Stabilizer (APSS). The first two PSS types are standardized and their implementation details can be found e.g. in [7].

The effectiveness of the PSS depends on the choice of its parameters. There is no unique way of tuning a power system stabilizer; however, in the industry there have been created appropriate tools for tuning the PSS. The PSS tuning procedure customarily used by engineers normally aims at fulfilling the following three goals:

1. The PSS should be tuned in such a way that the local mode oscillations, i.e., those with the frequencies above 0.7Hz, are well damped.
2. The tuning of the PSS should also provide adequate damping for inter-area mode oscillations. That is, the oscillations in the frequency range from 0.1 to 0.7Hz have to be properly damped.
3. The PSS should not over-modulate the terminal voltage of the generator when the generator is in steady-state operation.

There are some other requirements to be fulfilled by the PSS but those are of less importance for this paper.

The PSS tuning procedure in present case study was such as to respect the aforementioned three goals.

4.2 Wide-area PSS Tuning

The idea behind the wide-area approach to power system stabilizers is in principle very simple: Extend the number of signals which can be considered as a feedback for control (i.e. incl. the remote ones available through PMUs) and select between them carefully those with the highest observability of all critical oscillatory modes to be damped. Hence, the selection of the proper feedback signal is herewith the first and very important step in the stabilizing controller design. In theory, this is based on modal analysis of a linear (or linearized) model given by eq. (1).

$$\begin{aligned} \dot{x} &= Ax + Bu \\ y &= Cx + Du \end{aligned} \tag{1}$$

In practice, one can use as a starting point the measured signals collected from the installed PMUs and identify this model, see e.g. [5]. In either case, one shall evaluate the modal *controllability* and *observability* (or their product also known as *residues*) which correspond to the critical oscillatory modes in the available *i*-input and *j*-output channels:

$$G(s) = C(sI - A)^{-1} B + D = \begin{bmatrix} . & . & . \\ . & G_{ij}(s) & . \\ . & . & . \end{bmatrix} \quad (2)$$

where every single transfer function $G_{ij}(s)$ can be written in the following form

$$G_{ij}(s) = \sum_{k=1}^{n} \frac{R_k}{s - \lambda_k} = \prod_{k=1}^{n} \frac{s - z_k}{s - \lambda_k} \quad (3)$$

with all variables having a clear meaning well defined by means of linear algebra (z_k – transfer function zeros, $\lambda_k = \alpha_k + j\omega_k$ – transfer function poles with absolute damping α_k and eigen-frequency $\omega_k = 2\pi f_k$, R_k – residues, n – order of the dynamic system). One can show that the complete set of residues is given in terms of the state-space model (1) by the products of the modal controllability (products of the left eigenvector matrix of ***A*** with the input matrix ***B***) and observability (products of the right eigenvector matrix of ***A*** with the output matrix ***C***).

Applying the above concept to the reduced Nordic power system model for the input and output channels and the critical modes discussed in Section 3, one can get the following information with regard to the residues corresponding to mode 1 (f=0.29Hz) and mode 2 (f=0.58Hz) with regard to the voltage control input (Vs) of the generators at 3300 and 5300, see Figure 5 and Figure 6.

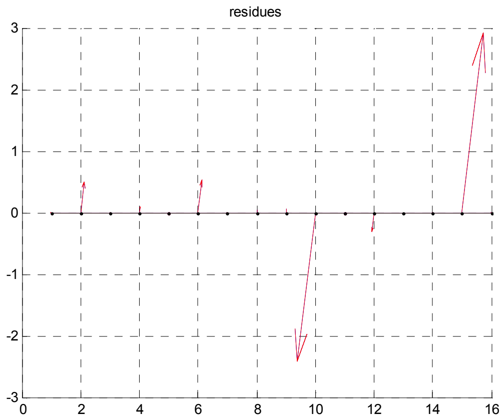

Figure 5: Residues for all considered output channels provided by installed PMUs and generator excitation systems equipped with the PMU functionality, for selected mode 1 and the control input 1 (i1 = excitation voltage of gen. 3300).

The largest residues (e.g. with the index 10 and 15) in Figure 5 correspond to the remote measurements provided by the PMU located at bus 7000 (namely, the voltage angle at bus 7000 and the angle difference between buses 3300 and 7000). The same type of analysis can be done for the second critical mode in the considered power system model, see Figure 6. The largest residues (e.g. with the index 6 and 13) in Figure 6 correspond to the remote measurements provided by the PMU located at bus 3300 (namely, the voltage angle at bus 3300 and the angle difference between buses 3300 and 5300).

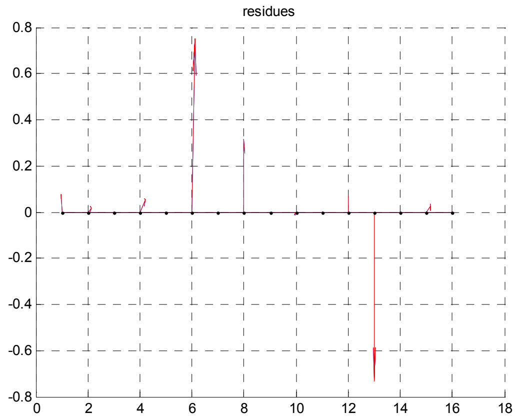

Figure 6: Residues for all considered output channels, a selected mode 2(f= 0.58Hz) and the control input 2 (i2 = excitation voltage of gen. 5300).

Applying the same approach (however, based only on the modal controllability) to both available input signals, one can show that the excitation system of the generator 3300 is more suitable to damp the mode 1 (very high modal controllability) than the mode 2 (low modal controllability). The opposite is true for mode 2 which can be better damped through the generator 5300.

The idea demonstrated here is not to deal with a design of a complex controller but to show the advantage of using remote signals. Therefore, exactly the same structure of the power system stabilizer will be used here as in case of the standard local control: lead-lag blocks with a low- and high pass filters given by eq. (4).

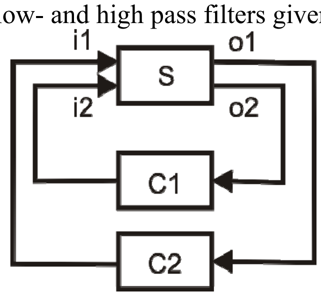

Figure 7: Considered closed loop control consisting of 2 PSS controllers C1 & C2, 2 input channels stand for the excitation of generators 3300 (i1) and 5300 (i2) and two feedback signals being available either remotely through PMUs (o1 = bus voltage angle difference 3300-7000 and o2 = bus voltage angle difference 3300-5300) or locally (o1, o2 = local electrical power and speed of generators 3300 and 5300).

The parameters of the controller can be for example calculated analytically for the two virtually decoupled (using tools of linear algebra) input-output channels (see Figure 7), known critical frequencies (imaginary parts of the dominant poles/eigenvalues) and the corresponding residues, for more details see e.g. [6]. It results in two damping controllers C1 and C2 with the following structure of each:

$$C(s) = KH_1(s) = K\frac{sT_H}{1+sT_H}\frac{1}{1+sT_L}\left(\frac{1+sT_1}{1+sT_2}\right)^{m_c} \quad (4)$$

where K is a positive constant gain given by (8) and $H_1(s)$ is a transfer function comprising a low-pass, high-pass and lead-lag blocks. The high-pass time constant T_H is usually set to 3s, the low-pass time T_L to 10s and the lead-lag parameters can be determined using the critical frequency ω_k and the corresponding residue R_k as follows:

$$\varphi = \pi - \angle R_k \quad (5)$$

$$x = \frac{T_1}{T_2} = \frac{1-\sin(\varphi / m_c)}{1+\sin(\varphi / m_c)} \quad (6)$$

$$T_2 = \frac{1}{\omega_k \sqrt{x}} \qquad T_1 = xT_1 \quad (7)$$

where $\angle R_k$ is the angle of the complex residue R_k, ω_k is the frequency of the critical oscillatory mode in rad/sec, m_c is the number of lead-lag compensation blocks (chosen usually so that each of them introduces max. 60° phase shift). The controller gain K is computed as a function of desired pole/eigenvalues location $\lambda_{k,\ des}$ and the controller gain at the complex frequency λ_k as:

$$K = \left|\frac{\lambda_{k,des} - \lambda_k}{R_k H_1(\lambda_k)}\right| \quad (8)$$

Note that in the presented work, four possible solutions – resulting merely in a simple modification of eq. (5) – to the controller design problem have been considered: leading and lagging, with a positive and negative feedbacks. Then, the solution providing the largest stability margins was selected using the Nyquist diagram.

5 RESULTS

Even with very simple controller design such as discussed above, very good control results with regard to damping of inter-area oscillations can be achieved with the wide-area approach. The achieved results can always be characterized in terms of well known diagrams in the frequency domain and few time-domain simulations, such as shown here in Figure 8-Figure 12. In general, any additional measurement (provided here by the remote PMUs) gives the possibility to optimize the selection of the feedback signal and to achieve better results than with the standard local approach. It is its very first step that seems to be more important than the method for the subsequent controller design. This selection has been done using modal analysis here applied to the set of same quantities captured by different PMUs.

Based on the collected experience, due to high modal observability of the critical oscillatory modes in the selected remote feedback signals one can observe the following tendencies:

- With wide-area controllers, the damping of all critical modes can be easier achieved and demonstrated in both frequency domain (for linear or linearized system model) as well as in non-linear simulations in the time domain, see e.g. Figure 8 and Figure 12.
- In addition, the wide-area controllers have small gain across all frequencies, and therefore, they are inherently more robust (than local requiring higher gains to achieve the same damping), see for example Figure 9.
- The overall small amplitude of the controller output in the time domain (as a logical consequence of both former facts) eases the entire design procedure as there are always some control limits one has to meet in practice – less control energy is required than in the local control case, see for example Figure 11.
- As a consequence of the fact above, the voltage disturbance (output of the stabilizing controller) during the transient period will be smaller for the wide-area control case.
- The price to be paid for the wide-area solution is in terms of higher investments into communication infrastructure to enable a reliable transfer of all required measurements from the remote place where they are captured to the generator excitation system. In general, the local measurements are still more reliable.
- Yet another advantage of the local approach is that only basic machine data and less information about the power system are needed for the proper tuning of the local stabilizer, whereas in the wide-area design a linear model of the power system (e.g. identified from field measurements according to [4]) is required a proper for controller tuning.

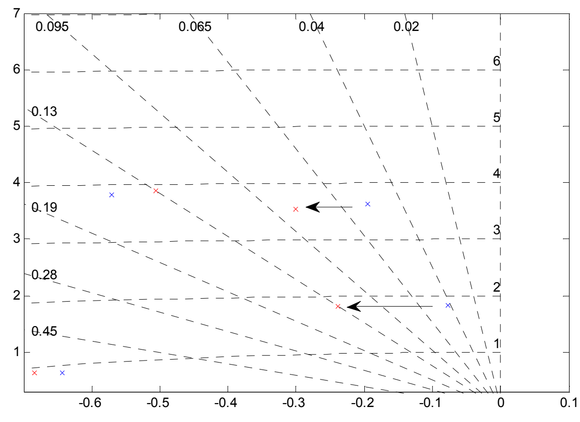

Figure 8: The main controller design requirement (relative damping at least 8%) gives the requested pole shift of the two dominant poles in the s-plane (diamantes = open-loop, crosses = closed-loop) for both cases the local and wide-area control subject to other constraints shown also in the figures below.

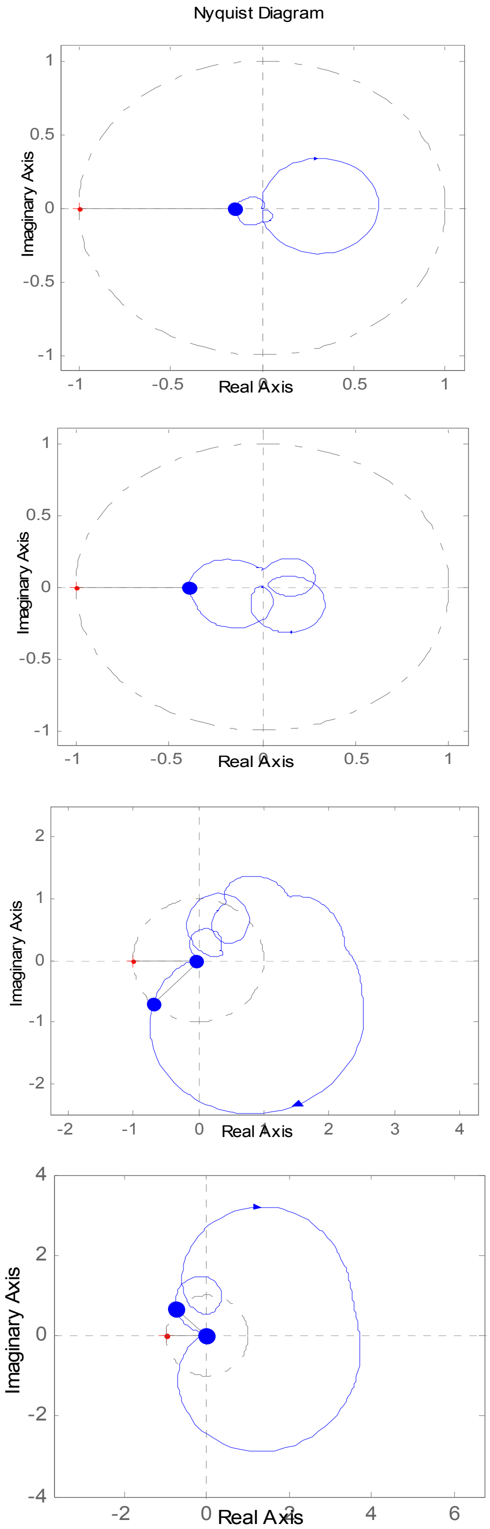

Figure 9: Nyquist plots of the system consisting of the power system model with wide-area controller 1(top most) and 2 (2nd from top), local controller 1 (3rd from top), and local controller 2 (bottom). High observability of the critical mode leads to a remarkably small gain of both wide-area controllers (fulfilling even the small gain theorem in this case). In all four cases, relative modal damping of at least 8% was required.

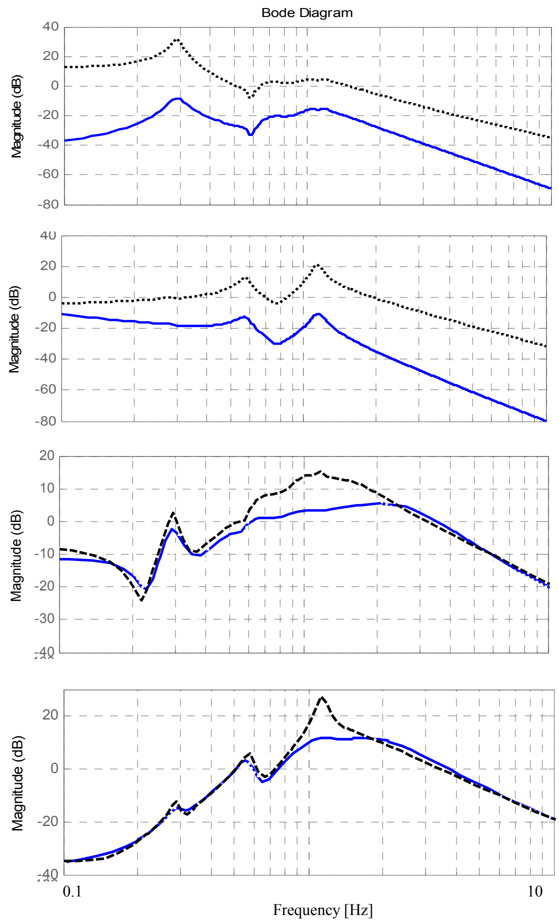

Figure 10: Bode diagram with (solid) and without (dashed) PSS achieved with both wide-area controllers (top and 2nd from top) and local controllers for gen.3300 (3rd from top) and gen.5300 (bottom).

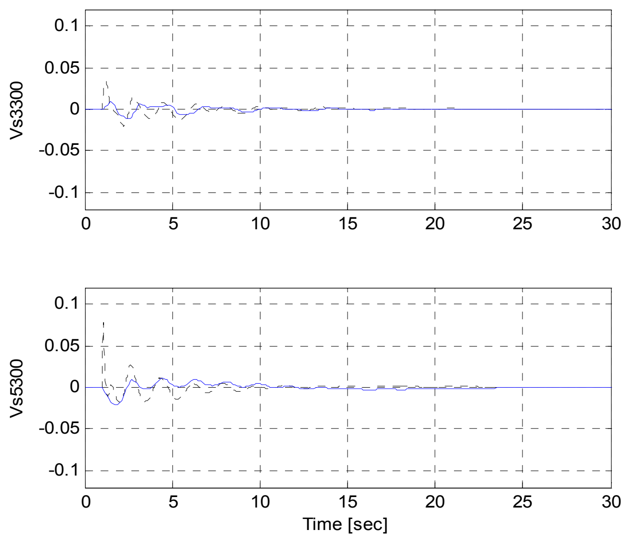

Figure 11: Output of PSS controllers for mode 1 (top) and mode 2 (bottom) using remote (solid line) and local (dashed) signals lies in all cases well within the permissible limits (0.1 pu.). However, less control energy is required for the wide-area control, and herewith, also the voltage profile (the controlled variable) is flatter and smoother.

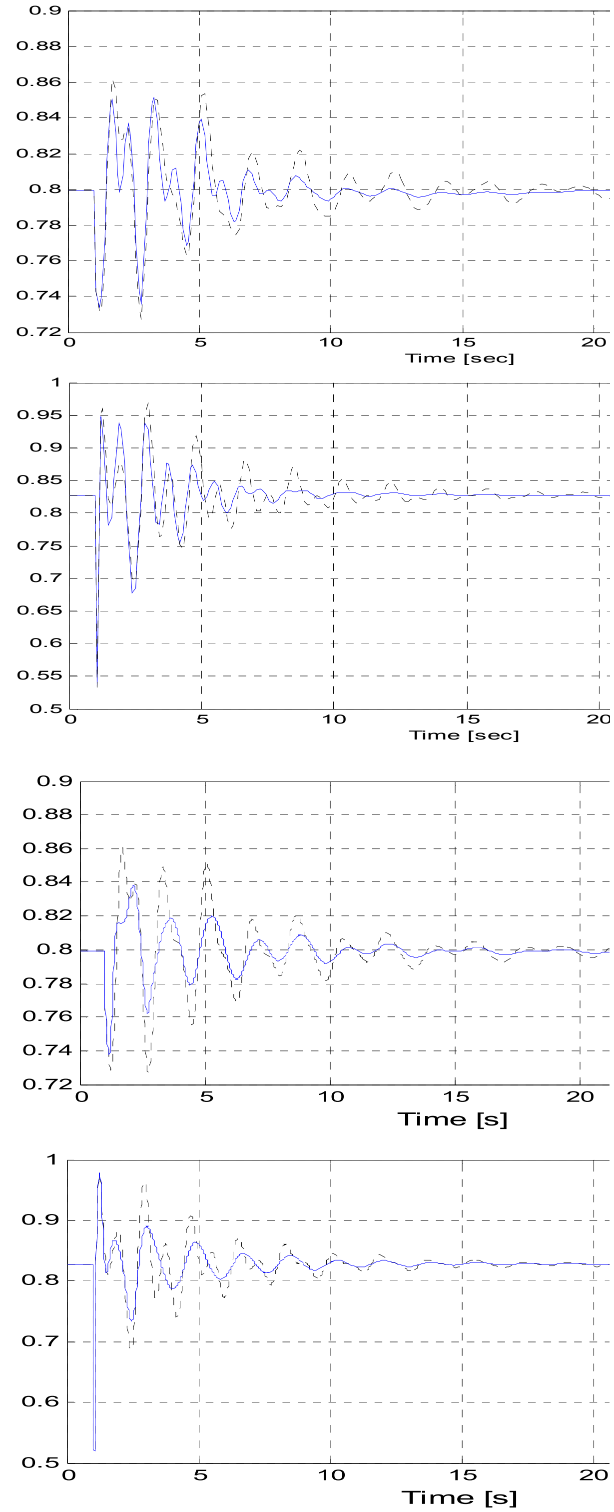

Figure 12: Active power of generators 3300 and 5300 in time domain. The disturbance was initiated at time t=1*s* by a bolted 100-ms ground fault at the terminals of generator 5500 with (solid) and without (dashed) stabilizing PSS controllers (top & 2nd from top wide-area and 3rd from top & bottom local).

6 CONCLUSION

Nowadays, it is a common practice to tune power system stabilizers based on local measurements only. However, the use of properly selected remote feedback signals yields a superior performance and robustness of the designed controller due to higher modal observability –and consequently, lower gains in the feedback control loop.

It is however, important to realize that the solution based on remote feedback has also a higher technical complexity and cost. Hence, the cost/benefit ratio will influence the decision on which solution will be applied in practice in the end.

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