Stability Investigation of a Longitudinal Power System and Its Stabilization by a Coordinated Application of Power System Stabilizers

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***Abstract*—This paper presents the results of a stability investigation of a power system with longitudinal structure and its stabilization by coordinated power system stabilizers (PSSs). The effects of the existing controllers on system stability are studied. If no PSSs are present, the damping of various swing modes in the system will be very poor and low frequency oscillations present. Eigenvalue analysis shows that the undamped modes are sensitive to excitation control while speed governors have little influence on damping. In order to enhance the overall system stability through excitation control, a coordinated design procedure for power system stabilizer has been developed based on generation coherency, total coupling factor and non-linear simulation. A PSS designed using this procedure is robust to different operating conditions and very effective for damping out oscillations. Comprehensive simulation studies were conducted and some results are presented.**

I. Introduction

Electromechanical oscillations of low frequency are inherent characteristics of power systems with either longitudinal structure or weak tie-lines. The presence of such oscillations has been reported all over the world [1,2,3,4]. Of interest is that the longitudinal type of power system seems to be more susceptive to poor damping.

Low frequency oscillations are also called system modes. Principally, there are two categories of modes: intertie mode associated with one group of generators or plants at one end of a tie-line oscillating against another group at the other end; and local mode associated with weakly connected power systems or remote generating units weakly connected to a large power system. Different system modes can occur simultaneously. This coupling among modes makes it difficult to define 'cause and effect' relationships in analyzing the dynamic behavior of a multimachine system, especially for intertie-line oscillations [5,6,7,8].

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Eigenvalue analysis is a fundamental technique to study the nature of system modes of a power system [9,10]. A positive real part of a swing mode indicates a negatively damped mode which needs controlling to ensure stable system operation.

The common remedy for inadequate damping is to utilize additional excitation control by means of power system stabilizers [6,11]. After more than two decades of research and practical applications, PSSs are now in wide use in power systems. In most PSS applications, only local feedback control is used. Multivariable and/or optimal stabilizers can be theoretically designed but may not be implemented because of the difficulties in accurately measuring most of the feedback variables. Coordination in PSS design has been considered by either eigenanalysis [12], or frequency domain methods [13] or a hybrid of the two [14]. No matter what algorithm is employed in tuning the settings of a PSS, the more information dependent on operating conditions is used, the less robust the PSS will be to system changes.

In this paper, a simple PSS design procedure is proposed and used in a practical power system of longitudinal structure. Usually, system modes must be known in PSS design. It is also generally true that the damping (real part) of a system mode is more sensitive to operating conditions than the frequency (imaginary part) of that mode. Reduction of these sensitivities of a mode increases the robustness of the PSS designed based on this mode. Instead of using a specific frequency for a particular PSS design, an average frequency is derived for each coherent group of generators that oscillate together. The coherent generation groups can be identified by available methods [15,16]. Another parameter needed in tuning a PSS is a lead/lag time constant spread [6,7]. Nonlinear simulation is utilized to determine the optimum gain of each PSS. Input signals to all the PSSs in each coherent generation group may be communicated with each other between the strongly coupled generators. The total coupling factors [17] computed from eigenanalysis can be employed to take into account these interactions among generators.

The rest of the paper is arranged as follows: First, a transient stability simulation package (TSSP) is briefly introduced. Secondly, an investigation of the steady state and transient stability of the system is performed. Then, a coordinated PSS design procedure and its application is presented. Finally, comprehensive simulation studies are conducted and conclusions drawn.

II. Simulation Tool

A transient stability simulation package (TSSP) is developed for the purpose of teaching and research in power system engineering at the University of Saskatchewan [18] and used to perform the studies reported in this paper. The package includes four main programs:

a) Fast decoupled load flow
b) Balanced and unbalanced fault studies
c) Steady state and transient stability simulation
d) Plotting in MS FORTRAN Graphic Environment

The simulation program is capable of modeling any linear, nonlinear, time-invariant and time-variant power components; balanced and unbalanced disturbances. The database used by the package is user-friendly.

III. System Description

The system studied in this paper is the Athabasca - Points North power system located in northern Saskatchewan, Canada, starting from the very northwest Charlot River plant to the far east Island Falls station along a 850 kilometers of overhead line operating at 110 kv and 138 kv. There are twelve hydro generators connected at both ends of the transmission line while loads are distributed along the line. At the east end, the system is connected to the Manitoba Hydro system through a rather weak tie-line. The connecting point to Manitoba Hydro system is modeled as an infinite bus. The Island Falls plant mainly feeds Flin Flon through a double circuit 95 kilometers long. At normal operation, the power transfer over the double circuit line is about 80% of the total generation of the plant. A single line diagram of the system showing the main generation and load buses is given in Fig. 1.

The generators are simulated by a fifth order model. It is justified that a fifth order model representation is adequate [21]. The generator model and typical values of its parameters for two generators are given in Appendix I. The block diagrams of models of the excitation systems as well as the values of their parameters are given in Appendix II. Appendix III lists the settings of the existing PSSs. Because of volume of modeling data and limitation of space, only pertinent and typical information is included in Appendices I, II and III. Complete information concerning models of various system components and the values of their parameters used in this research is available from [22] or from the authors of the paper. As the characteristics of the loads in the system are unavailable, constant impedance model is used, though the results may be optimistic.

IV. Stability Investigation

IV. 1 General

Because of the special arrangement of circuit breakers in the system as shown in Fig. 1, any fault that initiates trips on the transmission line from Island Falls to the northern end will separate the system into two or more parts. Therefore, our investigation will be focused on the following two situations: transient stability when there is a large disturbance on one of the double circuit lines and steady state stability when there is any small disturbance in the system.

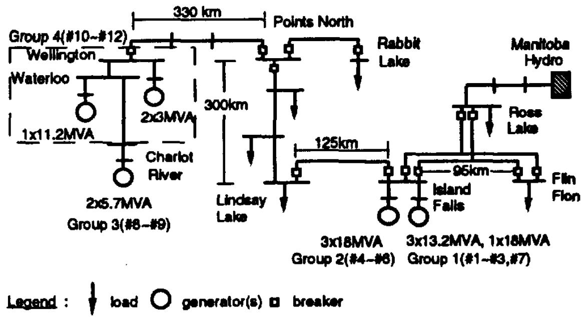

Fig. 1. Single line diagram of the Athabasca-Points North system.

IV. 2 Eigenvalue Analysis

The following analysis is conducted without PSSs in service. The purpose is to identify the best sites for PSS installation. Two operating conditions for eigenvalue analysis are considered; the normal operation and the operating condition when one of the double circuit lines is tripped. Table I shows the eigenvalues, frequencies of swing modes and their participating generators for both situations.

It is found that the participating generators in each swing mode under both cases are unchanged while swing mode λ_1 by which three remote generators oscillate, become more negatively damped under the system contingency. One of the most negatively damped modes, λ_2, and one of the second most negatively damped modes, λ_{10}, are intertie modes, by which all the seven generators at Island Falls oscillate together against the infinite bus.

It can also be observed from Table I that there are several unstable swing modes near the frequency of 2 Hz. This may be due to the longitudinal structure of the system, zero representation of the inherent damping of the generators and the fast static exciters. As the purpose of eigenanalysis was to determine the best PSS installation sites, this will not affect the analysis that follows.

TABLE I
EIGENVALUES WITHOUT PSSs

Mode	One Line Tripped		Normal Operation		Participating
No	σ, ω	f(Hz)	σ, ω	f(Hz)	Generators
1	0.216, 5.919	0.94	0.183, 6.102	0.97	8,9,10
2	0.246, 9.050	1.44	0.249, 9.710	1.55	1,2,3,4,5,6,7
3	0.010, 10.973	1.75	0.010, 10.895	1.73	8,9
4	-0.058, 11.298	1.8	-0.060, 11.219	1.79	12
5	-0.065, 11.840	1.88	-0.066, 11.759	1.87	11,12
6	0.157, 12.326	1.96	0.161, 12.225	1.95	7
7	-0.053, 12.380	1.97	-0.054, 12.300	1.96	10,11
8	0.094, 12.623	2.01	0.100, 12.535	2	1,2,3
9	0.105, 12.625	2.01	0.112, 12.536	2	2,3
10	0.104, 13.192	2.1	0.107, 13.106	2.09	1,2,3,4,5,6,7
11	0.079, 13.807	2.2	0.083, 13.684	2.18	4,5,6
12	0.094, 13.809	2.2	0.098, 13.687	2.18	5,6

IV. 3 Sensitivity Studies

It has been shown in the previous section that the damping of various swing modes without PSSs is quite poor or is negative. In order to achieve improvement in system stability by additional excitation control, the effects of the existing automatic voltage regulators (AVR) on damping are examined. Fig. 2 shows that the damping deteriorates when the excitation gains increase from 40% to 120%. Note that a mode that does not change with the AVR gains is not shown. Fig. 2 also shows that modes λ_3 and λ_4 are barely sensitive to the changes of AVR gains while modes $\lambda_1, \lambda_2, \lambda_6, \lambda_8$ to λ_{12} are sensitive. These sensitive modes involve generators #1 to #9 on which the existing PSSs are already in operation.

The effect of speed governor and turbine system on damping is negligible as shown in Fig. 3. This might be due to the large equivalent time constants (T_i>30s) as used in the general model for hydro speed governing systems [19] and small generator capacity (18 MVA at Island Falls).

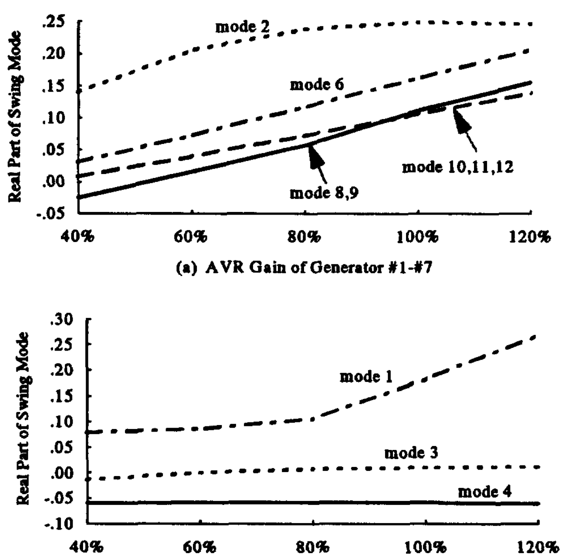

Fig. 2. Damping versus AVR gain.

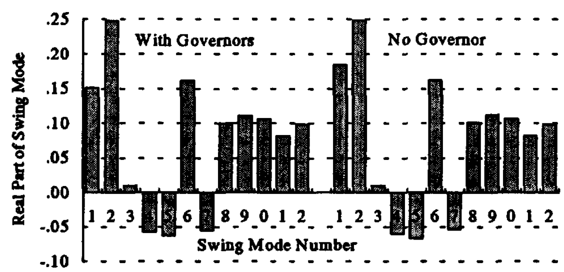

Fig. 3. Damping as affected by speed governor

Tables II and III list the functional sensitivities [20] of the swing modes with respect to AVR and PSS transfer functions (TF), respectively. These quantities are only valid near the vicinity of the current operating point and under the limitation that the changes of these transfer functions near the vicinity are not significantly large as compared to the changes of the system modes. However, they do provide quite accurate information for analyzing the effectiveness of existing controllers, such as AVRs, and for determining the most effective sites for PSSs installation. It can be concluded from Table II that only swing modes $\lambda_2, \lambda_6, \lambda_8$ to λ_{12} are sensitive to the AVR transfer function of generators #1 to #7. Swing mode λ_1 is much more sensitive than swing modes λ_3 and λ_4 to the AVR transfer function of generators #10 to #12. This conclusion is also supported by the results displayed in Fig. 2. Table III indicates how sensitive each swing mode is to various PSSs if they are installed at corresponding generators. Usually, each mode is coincident with more than one generator due to couplings among generators. It is based on these couplings that the coordinated PSS design procedure is proposed and its application presented in this paper. The best PSS installation sites as seen in the last row of Table III are decided based on the magnitude of the functional sensitivity.

It can be concluded that the obtained results in this section are in agreement with the fact that the actual system is equipped with PSSs on generators #1 to #9 to provide damping to the various swing modes.

TABLE II
SYSTEM MODE SENSITIVITY TO AVR TF

Gen	Swing Mode Number											
No	1	2	3	4	5	6	7	8	9	10	11	12
1	0	0	0	0	0	.02	0	.27	0	.06	0	0
2	0	0	0	0	0	.02	0	.09	.18	.06	0	0
3	0	0	0	0	0	.02	0	.05	.22	.06	0	0
4	0	0	0	0	0	0	0	0	0	.04	.18	0
5	0	0	0	0	0	0	0	0	0	.04	.04	.13
6	0	0	0	0	0	0	0	0	0	.04	.04	.13
7	0	.10	0	0	0	.36	0	0	0	.03	0	0
8	0	0	.10	.02	0	0	0	0	0	0	0	0
9	0	0	.10	.03	0	0	0	0	0	0	0	0
10	.60	0	0	0	.02	0	.08	0	0	0	0	0
11	.50	0	0	0	.12	0	.03	0	0	0	0	0
12	.40	0	0	.09	.02	0	0	0	0	0	0	0

TABLE III
SYSTEM MODE SENSITIVITY TO PSS TF

Gen	Swing Mode Number											
No	1	2	3	4	5	6	7	8	9	10	11	12
1	0	.03	0	0	0	0	.02	.15	0	.03	0	0
2	0	.03	0	0	0	0	.02	.05	.11	.03	0	0
3	0	.03	0	0	0	0	.02	.03	.13	.03	0	0
4	0	.02	0	0	0	0	0	0	0	.03	.08	0
5	0	.02	0	0	0	0	0	0	0	.03	.02	.07
6	0	.02	0	0	0	0	0	0	0	.03	.02	.07
7	0	0	0	0	0	0	.10	0	0	.01	0	0
8	.05	0	.15	.02	0	0	0	0	0	0	0	0
9	.05	0	.15	.02	0	0	0	0	0	0	0	0
10	.04	0	0	0	0	.03	0	0	0	0	0	0
11	.03	0	0	0	.05	.02	0	0	0	0	0	0
12	.03	0	0	.04	.02	0	0	0	0	0	0	0
PSS	10		8,9	12	11		7	1	2,3	0	4	5,6

IV. 4 Time Responses

Sustained low frequency oscillations are present and observed under either small disturbances or system contingencies. To illustrate these oscillations, two situations with all the existing controllers in service are investigated.

Small disturbance: It is assumed that a load increase of 1% of the system capacity takes place at Rabbit Lake. Fig. 4 shows typical rotor angle oscillations of the generators at both Island Falls and Charlot River plant.

It can be seen from Fig. 4 that generators #1 and #8 are oscillating in opposite direction. The reason is that the electrical distance from generator #8 to the location of the disturbance is twice of that from generator #1, the terminal voltage at Island Falls drops more and generator #1 begins to accelerate. On the other hand, generator #8 begins to generate more power to balance the sudden increase of load. All other generators at Island Falls behave similar to generator #1 and the generators at the northern end behave similar to generator #8.

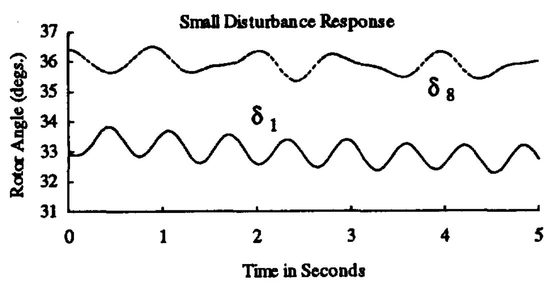

Fig. 4. Rotor angle responses. 1% load increase at Rabbit Lake.

System Contingency: It is assumed that there is a single phase to ground (SLG) fault on the double circuit line. The fault is cleared by opening the three phase circuit breakers in 6 cycles. Reclosure is initiated in 10 seconds and is assumed to be successful. Fig. 5 shows the speed difference swing of generator #1 that is close to the fault.

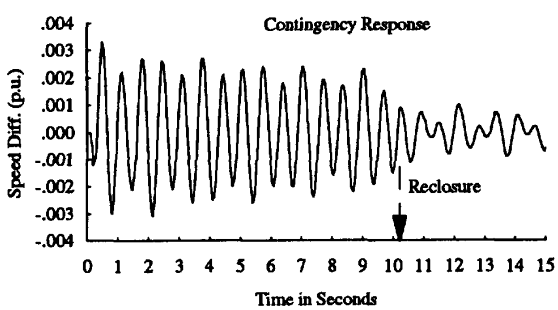

Fig. 5. Swing of machine speed difference (p.u.) for the SLG fault with existing PSSs in service

V. Coordinated PSS Design

V. 1 Design Procedure

According to the previous analysis, the negatively damped modes $\lambda_1, \lambda_2, \lambda_6, \lambda_8$ to λ_{12} mainly involve generators #1 to #10. In order to provide positive damping, these generators have been actually equipped with PSSs except generator #10. This paper attempts to utilize different but very effective PSSs to further enhance the overall system stability.

To design a PSS, it is essential to choose a proper input signal and then design a compensation circuit reasonably robust to different operating conditions. Because of the interactions among generators, there seems to be no way to correspond each and every swing mode with one specific machine. A new coordinated PSS design procedure was developed during the research, as outlined below:

- Determine the coherent generation groups by an available technique.
- Find the average center frequency for each group of generators participating in various swing modes together.
- Choose an input, say shaft speed.
- Let the system operate at full load and the strongest transmission for the tuning of speed input PSS.
- Set a washout time constant.
- Set a lead/lag time constant spread for the compensation circuit of the PSS.
- Determine the time constants according to the center frequency and the spread.
- Change the PSS gain from 0 to infinity and compute the root loci or perform non-linear time simulations. When instability is met, the best gain value is chosen to be one third of the gain at instability [6,7].
- Evaluate the effectiveness of the settings by either eigenvalue analysis or time domain simulation. Change the spread if necessary and repeat the last three steps.

V. 2 PSS Tuning

Extensive time simulations and calculations of coupling factors have shown that the following coherent generator groups can be identified: (#1,#2,#3,#7), (#4,#5,#6), (#8,#9) and (#10,#11,#12). The tuning of PSSs for generator group 1 is illustrated here. It can be shown from Table I that generator group 1 is participating in various swing modes at an average frequency of 1.9 Hz. The system is assumed to be operating at full load with the strongest transmission. The time constant spread is set to be 8:1 and the generator shaft speed is chosen as PSS input. The transfer function of a speed input PSS is given by (1):

$$G_{pss}(s) = K_s \left(\frac{T_w s}{1+T_w s} \right) \left(\frac{1+T_1 s}{1+T_2 s} \right) \left(\frac{1+T_3 s}{1+T_4 s} \right) \tag{1}$$

The initial lead/lag time constants, T_1, T_2, T_3 and T_4 are determined as follows [6]:

$$T_1 = T_3 = \sqrt{8} / 2\pi f_c = 0.237s \tag{2}$$

$$T_2 = T_4 = T_1 / 8 = 0.03s \tag{3}$$

where f_c is the average (or central) oscillation frequency of generation group 1. The gain K_s is set to be equal to 5 and the washout time constant, T_w, is 10s. The final settings after adjustments are listed in Table IV. PSSs for other generation groups were also designed and their settings are listed in Table IV.

TABLE IV
PSS SETTINGS OF THE 4 GENERATION GROUPS

Group No	Ks	T1/T2	T3/T4	Tw
1	5	.2465/.0342	.2465/.0342	10
2	5	.2350/.0290	.2350/.0290	10
3	10	.2000/.0100	.1000/.0300	6
4	10	.2000/.0100	.1000/.0300	6

V. 3 Communication of PSS Inputs

In order to increase the robustness of single input PSS and to reflect the coupling among generators, the stabilizer inputs in each group can be communicated among its PSSs. As all the generators in a coherent group behave in a very similar fashion, their speed deviations will be either positive or negative. These speed deviations can be summed up through the total coupling factors to feed each PSS in that group as illustrated in Fig. 6. Fortunately, the generators in each group of the first three groups are in the same plant and the last group involves two plants seven kilometers away. Therefore, only local communication of the PSS inputs is required. The input signal to the i-th PSS is given by

$$\Delta\tilde{y}_i = w_{ii}\,\Delta y_i + \sum_{j\neq i} w_{ij}\,\Delta y_j = \sum_j w_{ij}\,\Delta y_j \qquad (4)$$

where w_{ij} is the total coupling factor between generator i and generator j which reflects the extent of interaction between the two generators, and Δy_j is the output of generator j. For speed input PSS, Δy_j is the speed deviation of generator j. The calculated coupling factors are listed in Table V. Values less than 10^{-2} are neglected.

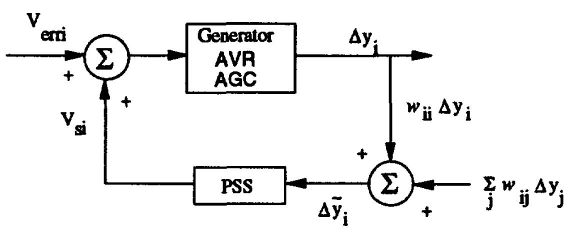

Fig. 6. Realization of the proposed PSS with communication.

VI. SIMULATION STUDIES

Considering the actual difficulties in implementation of power system stabilizers at generators #10 to #12 because of their rotating excitation systems and in provision of extra communication means between these two plants, the application of the proposed PSSs is divided into two stages. Stage I: only generators #1 to #9 are equipped with new PSSs. Stage II: the remaining three generators are also equipped with PSSs. In order to provide consistent comparison, the two disturbances covered in Section *V.4* are employed for simulation studies. Other simulation tests are also included.

TABLE V
TOTAL COUPLING FACTORS

Gen No	1	2	3	4	5	6	7	8	9	10	11	12
1	0.33	0.13	0.08	0.02	0.02	0.02	0.05	0	0	0	0	0
2	0.13	0.2	0.21	0.02	0.02	0.02	0.05	0	0	0	0	0
3	0.08	0.21	0.25	0.02	0.02	0.02	0.05	0	0	0	0	0
4	0.02	0.02	0.02	0.18	0.06	0.06	0.01	0	0	0	0	0
5	0.02	0.02	0.02	0.06	0.12	0.12	0.01	0	0	0	0	0
6	0.02	0.02	0.02	0.06	0.12	0.12	0.01	0	0	0	0	0
7	0.05	0.05	0.05	0.01	0.01	0.01	0.23	0	0	0	0	0
8	0	0	0	0	0	0	0	0.45	0.45	0.09	0.22	0.44
9	0	0	0	0	0	0	0	0.45	0.45	0.09	0.22	0.43
10	0	0	0	0	0	0	0	0.09	0.09	0.33	0.67	0.26
11	0	0	0	0	0	0	0	0.22	0.22	0.67	3.85	2.07
12	0	0	0	0	0	0	0	0.44	0.43	0.26	2.07	3.43

VI. 1 Existing PSSs

Simulations of the system under the single phase to ground (SLG) fault were performed with and without the existing PSSs in service, respectively. Fig. 7(a) shows that the system is unstable if no PSS is installed in the system. When the existing PSSs are put into service, the system stability is improved significantly (compare Figs. 7(a) and 7(b)). Fig. 7(c) displays the outputs of the existing PSSs.

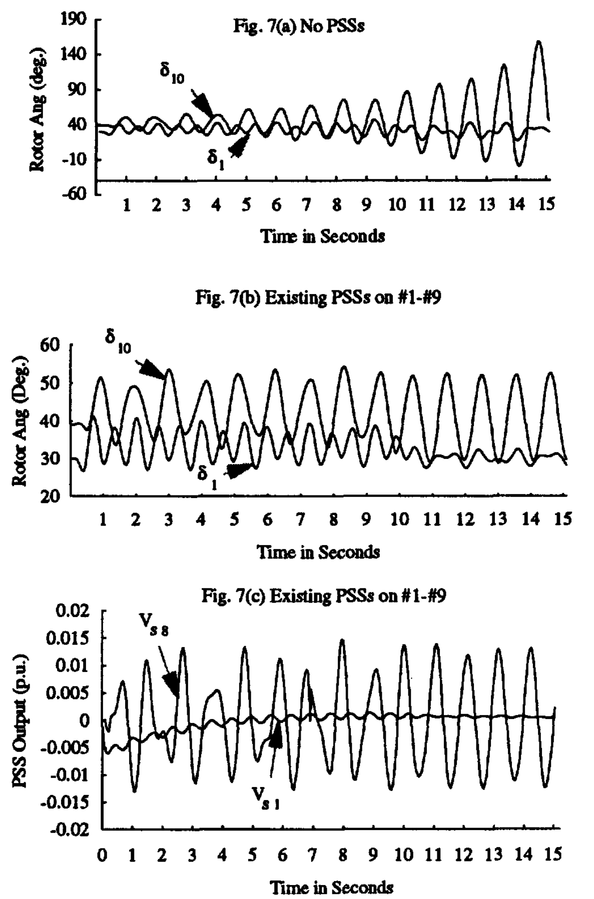

Fig. 7. Time domain simulation of the SLG fault with and without the existing PSSs in service.

VI. 2 Proposed PSSs on #1-#9

When the proposed PSSs are installed on generators #1 to #9, the transient stability is further enhanced (compare Figs. 8(a) and 7(b)). Further improvement in damping is illustrated in Fig. 8(b) when communication of PSS inputs is incorporated as discussed in Section *V.3*. The outputs of the proposed PSSs on generators #1 and #8 are shown in Fig. 8(c).

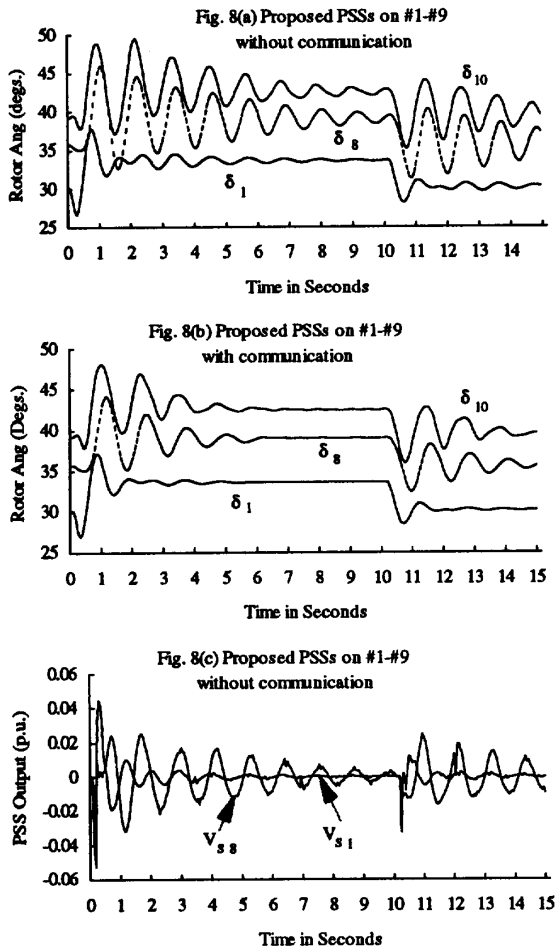

Fig. 8. Time domain simulation of the SLG fault with new PSSs on generators #1 - #9 in service.

VI. 3 Proposed PSSs on All Machines

If the three hydro generators of the last coherent generation group are also equipped with the proposed PSSs, further enhancement in overall system stability can be expected. This is illustrated in Figs. 9(a) and 9(b). The latter is with communication of PSS inputs.

It can be observed that (i) the oscillations with PSSs utilizing communication take much less time to settle down as compared to those in which communication is not present (compare Figs. 8(a) with 8(b), 9(a) with 9(b)), and (ii) proposed PSSs on generators #1 to #9 with communication are more efficient than the proposed PSSs on #1-#12 without communication (compare Figs. 8(b) with 9(a)).

VI. 4 Small Disturbance

The small disturbance studied in Section *IV.4* is simulated with proposed PSSs on generators #1 - #9. Fig. 10 illustrates the rotor angle swings of generators #1 and #8. The oscillations are damped out in 4 seconds, which is a further improvement as compared to those in Fig. 4 where the existing PSSs are in service.

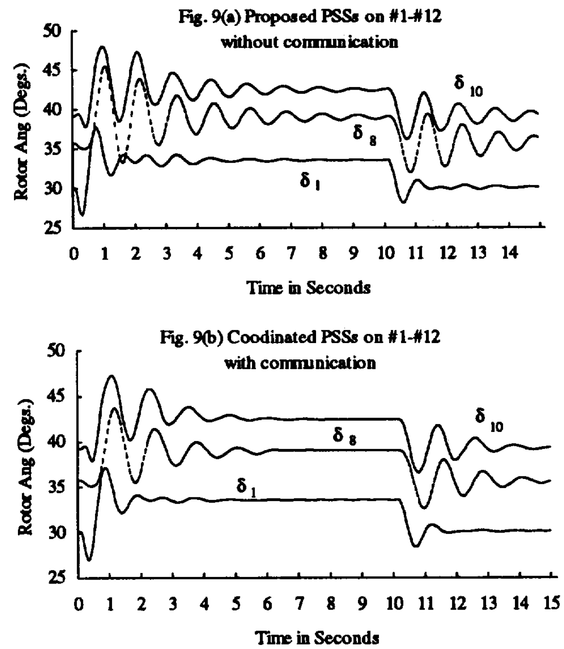

Fig. 9. Time domain simulations of the SLG fault with new PSSs on all machines are in service.

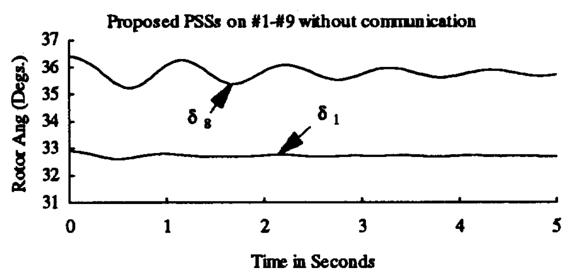

Fig. 10. Rotor angle swing responding to a load increase of 1% the system capacity at Rabbit Lake.

VI. 5 Other Tests

A number of other disturbances were simulated and a summary of the obtained results is presented in this section. All these tests were conducted with proposed PSSs only on generators #1 through #9. The objective was to further verify the effectiveness of the proposed PSSs while avoiding the installation of new PSSs on the last three hydro generators (#10-#12).

a) When there is one PSS failure in each of the three coherent groups, simulation of the SLG fault studied above shows that it took the system 12 seconds to completely settle down to a new equilibrium point if communication of PSS inputs is not present and about 7 seconds if communication is present.

b) A minimum of one proposed PSS for each of the three groups is needed to maintain stable operation of the system. This observation is in agreement with that of [14].

c) A three phase to ground (3LG) fault of the same duration as the SLG fault on the double circuit was simulated. It took the system 5 seconds more time than in the latter case to damp out the oscillations.

d) A 3LG fault for a duration of 6 cycles on the line from Island Falls to Lindsay Lake will separate the system into three parts. The stability of the northern part of the system depends on how much power is being transferred from Island Falls to Points North station at the time of disturbance. The objective of this simulation was to examine whether the Island Falls plant can be saved after the disturbance. Fig. 11 shows the swings of speed difference of generator #1 with the existing and the proposed PSSs with communication, respectively.

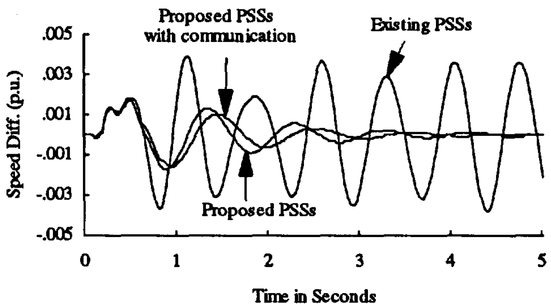

Fig. 11. Response of speed difference of generator #1 following 3LG fault for 6 cycles on the line from Island Falls to Lindsay Lake.

e) Simulations of the SLG fault under 50%, 75% and 100% loading were also performed. Fig. 12 displays the rotor angle swings of generator #1 under different loading. It can be concluded that though the proposed PSSs were tuned under full system loading, they work very well under other system loading.

VII. Conclusions

This paper reports an investigation of the steady state and transient stability of a realistic power system with longitudinal structure as well as its stabilization by coordinated application of power system stabilizers. Eigenanalysis has revealed that all the seven generators at Island Falls plant would be participating in the two negatively damped intertie mode oscillations collectively and five negatively damped local mode oscillations individually, if no PSSs were in service at all. This suggests that they will be the primary contributors to the instability of the system under disturbances.

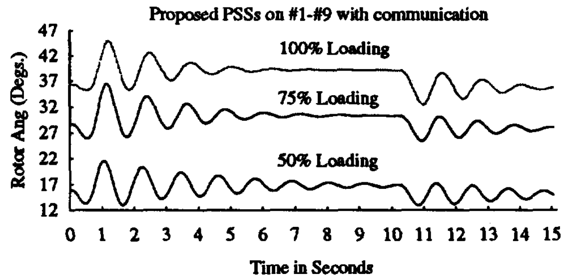

Fig. 12. Rotor angle swing of generator #1. SLG fault for a duration of 6 cycles under different system loading.

A coordinated PSS design procedure is then developed based on the concept that it is desirable to use less information that is operating condition dependent and more inherent properties of the system in tuning PSS settings. This idea is realized by utilizing the average natural oscillation frequency of a coherent generation group and a lead/lag time constant spread reflecting the strength of the system and the type of stabilizer input for PSS tuning. The total coupling factors among strongly coupled generators are also used as weighting factors in communication of PSS inputs.

A number of disturbances were applied to the system and some of the results are presented. The following general conclusions can be drawn from the studies reported in this paper:

- The system with the existing PSSs in service is stable under common outages.
- It is beneficial to the system if more positive damping can be provided through excitation control.
- Application of the proposed PSSs has exhibited promising results in terms of their effectiveness to damp out oscillations and their robustness to different operating conditions, small and large disturbances.
- A minimum of one proposed PSS must be installed in each coherent generation group of the first three groups to maintain stable operation and reasonably good damping.

The possibility and requirements for implementing the proposed PSSs are under study and progress will be reported in a future paper.

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Appendix I
Generator Model and Its Parameters

The differential equations of the fifth order generator model are given by [22]:

$$\frac{dE_q'}{dt} = \frac{1}{\tau_{do}'}\left\{kE_{fd} - E_q' - \left(x_d - x_d'\right)i_d\right\}$$

$$\frac{d}{dt}\left(E_q'' - E_q'\right) = \frac{1}{\tau_{do}''}\left\{-\left(E_q'' - E_q'\right) - \left(x_d' - x_d''\right)i_d\right\}$$

$$\frac{dE_d''}{dt} = \frac{1}{\tau_{qo}''}\left\{-E_d'' + \left(x_q - x_q''\right)i_q\right\}$$

$$\Delta\ddot{\delta} = \left(P_m - P_e - P_l - D\Delta\omega\right)/2H$$

$$\Delta\dot{\delta} = \omega_o\ (\Delta\omega)$$

The values of the parameters of the above equations for generators #5 and #10 are given in Table A.1.

Appendix II
Models of Excitation Systems and Their Parameters

The block diagram of the bus-fed static exciter is shown in Fig. A.1. The values of the parameters for the exciter of generator #5 are given as follows:

$$T_A = 1.0 \qquad T_E = .035$$
$$T_B = 1.0 \qquad E_{MAX} = 3.94$$
$$K_E = 54 \qquad E_{MIN} = -3.94$$

Table A.I Values of Generator Parameters

Gen No.	Cap. (MVA)	H	R	x_ℓ	x_d	x_{do}'	x_{do}''	x_q	x_{qo}''	τ_{do}'	τ_{do}''	τ_{qo}''	D	$s_{1.0}$	$s_{1.2}$
5	18	2.31	0.0	.239	.600	.280	.252	.424	.252	2.82	.050	.060	0.0	.173	.555
10	11.2	2.60	0.0	.093	.624	.218	.156	.470	.156	4.07	.038	.038	0.0	.171	.546

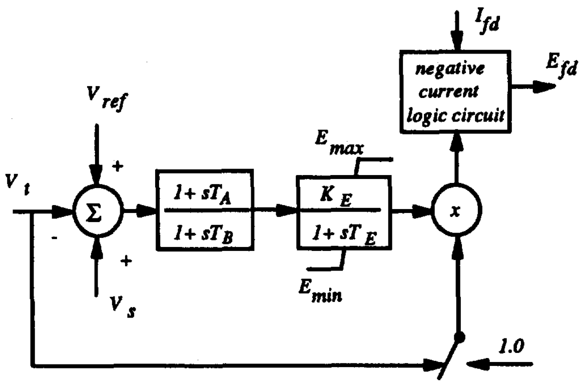

Fig. A.1 Block diagram of a bus-fed static exciter.

The block diagram of the modified IEEE DC Type 2 exciter [23] is given in Fig. A.2. The values of the parameters for the exciter of generator #10 are given as follows:

$T_R = 0.0$	$T_F = 1.0$	$V_{RMIN} = -3.97$
$T_C = 1.0$	$K_A = 369$	$E_1 = 1.83$
$T_B = .226$	$K_E = 1.0$	$S_1 = .108$
$T_A = 0.0$	$K_F = .022$	$E_2 = 2.357$
$T_E = 2.0$	$V_{RMAX} = 4.96$	$S_2 = .506$

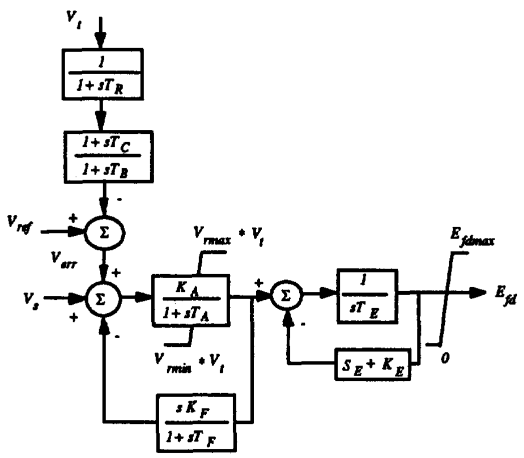

Fig. A. 2 Modified IEEE DC Type 2 excitation system

Appendix III
PSS Transfer Functions

The transfer function of the existing PSSs using electrical power as the input signal is given by Equation (A.1). Its output is limited at ± 0.1 per unit. The transfer function of the existing PSSs using accelerating power as the input signal is given by Equation (A.2). Its output is limited at ± 0.2 per unit.

$$G_{ep}(s) = -0.05\left(\frac{1}{1+.025s}\right)\left(\frac{4.4s}{1+4.4s}\right)\left(\frac{5s}{1+5s}\right)\left(\frac{1}{1+.014s}\right) \quad \text{(A.1)}$$

$$G_{ap}(s) = 10\left(\frac{1+.4s}{1+s}\right)\left(\frac{1+.08s}{1+.5s}\right)\left(\frac{2s}{1+2s}\right) \quad \text{(A.2)}$$

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