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WECC Guideline:

WECC Test Guidelines for Synchronous Unit Dynamic Testing and Model Validation
Date: 2/1997

Introduction

This guideline provides instructions regarding validation of dynamics models for generating units. It was written to provide guidance on how to perform model validation to comply with a recommendation resulting from the 1996 WECC disturbance

Approved By:

Approving Committee, Entity or Person	Date
WECC Modeling and Validation Work Group	February 1997
WECC Control Work Group	February 1997

Western Systems Coordinating Council

DENNIS E. EYRE
EXECUTIVE DIRECTOR
WESTERN SYSTEMS COORDINATING COUNCIL
UNIVERSITY OF UTAH RESEARCH PARK
540 ARAPEEN DRIVE, SUITE 203
SALT LAKE CITY, UTAH 84108-1288
TEL.: (801) 582-0353
FAX: (801) 582-3918

March 21, 1997

PLANNING COORDINATION COMMITTEE
OPERATIONS COMMITTEE
NON-WSCC MEMBER GENERATION OWNERS

Subject: Testing of Synchronous Unit Reactive Limits and Dynamic Testing/Model Validation

The disturbances on July 2 and August 10 have had a considerable impact on the Western Interconnection as well as the electric industry as a whole. Detailed system disturbance reports were prepared following these incidents to comply with WSCC's policies and to address questions raised by The President of the United States, the Department of Energy, and the North American Electric Reliability Council (NERC). Over 140 recommendations were adopted to address specific problem areas identified in the analysis of these events.

The testing of generating units is an extremely important issue which is addressed by the disturbance report recommendations. The reports call for the testing of all generating units in the Western Interconnection which have a generating capacity of 10 MW or greater. The PCC/OC Joint Guidance Committee has agreed that the most critical or largest units should be tested by June 1997 and all remaining units (10 MW or larger) should be tested by December 1997. Your cooperation as a generation owner in seeing that this testing is completed on schedule is vitally important to maintaining the reliability of electric service in the Western Interconnection.

The purpose of this letter is to inform you of the need to conduct the tests, provide you with test procedures that have been developed by technical experts from Western Systems Coordinating Council (WSCC) and the electric industry, and to provide information on who to contact if you have questions regarding the testing. Please submit your test results, in accordance with the enclosed procedures and requested timetable, to:

Western Systems Coordinating Council
540 Arapeen Drive, Suite 203
Salt Lake City, UT 84108-1288

BACKGROUND

Following the disturbances of July 2 and August 10, 1996, the WSCC Control Work Group (CWG) and the Modeling and Validation Work Group (M&VWG) were tasked with developing guidelines for testing generators, excitation systems, power system stabilizers (PSS) and turbine governors for all units greater than 10 MW for:

- verification of reactive limits,
- proper performance of the dynamic control systems, and
- validation of the computer models used for stability analysis.

The data obtained from the field testing of the generator exciters, governors and power system stabilizers are to be validated for use in the models of these devices by conducting dynamic simulations of the tests. A good match between the test results and the dynamic simulation of the tests should be established.

TEST GUIDELINES

The attached steady-state synchronous machine reactive limits verification guidelines have been modified slightly since the original was released on November 25, 1996. If you have already performed the steady-state testing using the original guidelines you need not repeat the testing.

A testing workshop sponsored by the CWG and M&VWG was held in January 1997. Presentations were made by manufacturers, consultants and WSCC members experienced in dynamic testing of units and their control systems, and a panel discussion was held. Information from this workshop has been factored into the enclosed testing guidelines.

It is recognized that the generating units to be tested vary in sizes over a wide range from the smaller ratings to greater than 1,000 MW, with speeds ranging from about 90 to 3,600 rpm. Unit types include large high speed thermal and nuclear units, slow speed hydroelectric units up to 700 MW and combustion turbine units ranging from 25 to 120 MW and larger. Furthermore, excitation systems are of the rotating (DC or AC) type or static type with brushes, or rotating brushless type. Governors are of the mechanical dashpot needle type or electrohydraulic PID type. The newer control systems for excitation systems, PSS and governors are of the digital type.

It is evident therefore that test guidelines to cover such a wide range of unit types and ratings cannot incorporate in detail what is ideally required for testing each particular unit. Consequently, the enclosed guidelines for dynamic testing are general in scope and content. Typical test methods and guidelines are suggested, but the final selection of the tests to be performed should be made by the test engineer after discussing with the plant test personnel and the analytical modeling engineer the most appropriate tests for the particular type and rating of the unit to be tested.

SCHEDULING OF TESTS

Scheduling of the tests should be performed with care. Scheduling tests of the larger units or plants equal to or greater than 500 MW should be coordinated over the WSCCNet so that there is no danger of near simultaneous trips or disturbances arising from these tests, or of more than one large plant or unit being tested at the same time by different owners. Generators should be tested in order of importance to system reliability. The larger units/plants critical to system reliability should have testing completed by June, 1997 as required by the August 10 disturbance report. If it is impossible to complete critical unit testing by this date, it is imperative that you complete the steady-state tests by June, 1997, with dynamic testing of these units completed as soon as possible thereafter.

In order to complete validation of WSCC models in a timely manner, all testing of critical units must be completed by June 1997 and testing of non-critical units must be completed by December 1997. These are important dates which we urge you to meet. If you are not able to meet these dates for any reason, please provide a test plan, timeline of expected completion, and reasons for the delay in testing to the WSCC office by April 18, 1997.

If you have any questions, please call either Bart McManus, Chairman, WSCC Control Work Group, at 360-418-2309 or Les Pereira, Chairman, WSCC Modeling & Validation Work Group, at 916-781-4218.

Sincerely,

Dennis E. Eyre

DEE:aml
enclosure

cc: Technical Studies Subcommittee Members
Committee on Regional Electric Power Cooperation
w/enclosure

Western Systems Coordinating Council

TEST GUIDELINES FOR SYNCHRONOUS UNIT DYNAMIC TESTING AND MODEL VALIDATION

Prepared by:

WSCC
Control Work Group and
Modeling & Validation Work Group

February 1997

TABLE OF CONTENTS

NOTICE

These test guidelines were prepared by the WSCC Control Work Group and the Modeling & Validation Work Group to provide general information to WSCC Members for performance testing and model validation of generating units' dynamic control and protection systems. This general information has been obtained from practices in the industry and also in published technical literature. Neither WSCC or members of the work groups mentioned above, nor any person acting on behalf of any of them, makes any warranty, express or implied, with respect to the use of any information, method of process or instrument/device disclosed in this document, or assumes any liabilities with respect to the use of, or for damages resulting from the use of any information, method or process, or instrument/device disclosed in this document.

TEST GUIDELINES FOR SYNCHRONOUS UNIT DYNAMIC TESTING AND MODEL VALIDATION

1. OBJECTIVES

These guidelines apply to the testing of generator excitation systems, power system stabilizers (PSS) and turbine governors for:

- proper performance of the dynamic control systems, and
- validation of the computer models used for stability analysis.

The task for testing the generator excitation systems, power system stabilizers (PSS) came from the August 10, 1996 Disturbance Report. Governor testing and validation was also added following studies and recommendations by the Operating Capability Study Group (OCSG). The guidelines also include the validation of key modeling data for the synchronous machine that are required for correct stability model simulation.

2. GENERAL

It is recognized that generating units to be tested vary in sizes over a wide range with speeds ranging from about 90 to 3,600 rpm. Guidelines to cover such a wide range of unit types and ratings cannot incorporate in detail what is ideally required for each particular unit.

These guidelines are therefore necessarily general in scope and content. Typical test methods and guidelines are suggested, but the final selection of the tests to be performed will be made by the test engineer after discussing with the plant test personnel and the analytical modeling engineer what are the most appropriate tests for the particular type and rating of the unit to be tested.

It is recognized that plants with multiple identical units will not require repetition of all of the work for every unit. Model validation work may be executed in full for one unit and need be repeated only as required by variations in the units. Performance verification work, however, must be carried out in full for every unit. Where performance tests reveal a unit whose performance is significantly different than the others even though it is nominally of the same design, data for that unit shall be validated and submitted in full.

It must be noted that this guideline pertains to the testing for performance and model validation of units and not to plant design, protection, or maintenance philosophies or practices. Nevertheless, where testing for performance reveals deficiencies in unit dynamic control systems performance, or miscoordination of protection and these control systems, these should be corrected and the validated data should describe the plant as corrected.

3. PREVIOUS TESTING OF UNITS

If a unit has had detailed testing performed on it in the past five years and has not been modified and parts of this data validation were achieved by this work that work need not be repeated.

4. DATA REQUIRED FOR MODEL VALIDATION AND SUBMISSION METHOD

- Plant parameters in Table 1 as related to Levels of Validation (described in Section 6 below).
- Technical data and block diagrams of selected models from Appendix A.
- Submission method for data as described in Appendix C.

5. APPROACH TO PERFORMANCE AND VALIDATION TESTS

In considering their approach to data validation and scheduling the test, the owners should consider the following:

- The type and rating of the unit
- The availability and currency of standard technical data including manufacturers' capability curves, control transfer function diagrams, control and protection schematic drawings and documentation of settings
- The service cycle of the unit and daily/weekly/seasonal availability for testing
- The availability and currency of commissioning and other test results.
- The availability of operating and test staff in owner's organization
- The availability of reserve capacity in owners system during test periods.

The integrity and security of both the plant being tested and the external power system are paramount at all times and in all circumstances are overriding.

6. LEVELS OF VALIDATION

Table 1 lists the most significant parameters of a plant which need to be validated and classifies them in three levels below. These assignments are not related to the requirement of verification for performance.

Level A parameters:

These parameters are essential. Validated parameter values MUST be provided.

Level B parameters:

The accuracy of values of these parameters has a clear effect on the accuracy of interconnected system studies. It is highly desirable that the values of these parameters should be validated.

Values of these parameters MUST be provided. If they have not been validated, the reason therefore should be stated. (e.g. - test session was curtailed because of overheating of transformers or detailed tests on similar units have established confidence in design data.)

Level C parameters:

These parameters are useful but not essential. Values should be provided as available. If values are not provided, standard default values may be used in interconnected system studies

7. *SUGGESTED METHODS RELATING TO PARAMETER VALIDATION FOR DYNAMIC MODELING*

Because limits and mode changes are of prime importance, large displacement/perturbation tests are required. Tests using small perturbations, such as frequency response measurements, may be applied where appropriate to characterize linear transfer function elements of the models.

Large displacement tests can be executed, for example, by injecting a voltage step into the voltage regulator reference, by tripping the generator circuit breaker with the unit running at an appropriate moderate load, or by judicious switching of a nearby transmission line.

All tests procedures and instrumentation must be applicable for both steady state and over the bandwidth that the equipment can respond, typically 0.01Hz to 10Hz.

Examples of validation of parameters from test recordings are:

a. The inertia constant of a unit is given by the initial acceleration when the generator main circuit breaker is tripped from a moderate initial MW loading. (Refer to Figure A).

b. Voltage regulator maximum output or maximum field voltage can be identified by applying a positive step to the voltage regulator reference. The magnitude and duration of the step, and the initial condition must be chosen to ensure that the generator stator voltage remains within acceptable limits. (Refer to Figure B).

c. Generator d-axis reactances and time constants can be measured directly from the recording of stator voltage following tripping of the main circuit breaker when the generator is running at an initial output of 0 MW, moderate leading MVAR and fixed field voltage. (Refer to Figure C.)

d. Generator saturation factors are given directly by the generator open circuit magnetization curve at rated voltage of 1.0 pu and 1.2 times rated voltage. This curve is measured by manually adjusting field current upward from minimum with the generator at rated speed disconnected from the system. The owner must determine the allowable maximum voltage for test and extrapolate test results as necessary to extend the curve to 1.2 times rated voltage. (Refer to Figure D.)

e. Power system stabilizer linear characteristics can be identified by frequency response tests relating stabilizer input (or inputs) to stabilizer output. (Refer to Figure E.) See also WSCC Test Procedure for Power System Stabilizers.

f. Voltage regulator series current compensating impedance can be identified by measuring the change in generator terminal voltage when a zero power factor stator current is interrupted by opening the main circuit breaker with the voltage regulator in automatic mode. (Refer to Figure F.) Polarity of series current compensation is critical. The data submission must state whether the polarity of the compensation produces a drooping or rising voltage-current characteristic. A drooping characteristic is used to give a proportional reactive power sharing in units that are bussed at their terminals. A rising characteristic is used on plants with unit-connected transformers to improve control of high side voltage bus.

g. Governor droop can be measured by noting the initial and final turbine speed in a test where the generator is tripped from a moderate real power load. The droop shall be identified as being obtained by valve position feedback or electrical power feedback. The MW power rejected shall be the largest value allowed by plant and system operating considerations. Alternatively, governor droop can be measured by plotting a graph of generator electrical output or gate position versus speed reference position. Where accurate system performance monitoring recorders exist, governor droop can be measured directly from response to a significant system disturbance. (Refer to Figure G.)

h. Intentional governor dead-band can be measured by running the unit synchronized to the bus and injecting a small but progressively increasing signal at the governor reference. The level of this signal when a change is seen in the governor output indicates the magnitude of the dead band. The tests should be run in both directions. (Refer to Figure H.)

8. *SAMPLE TEST PLANS*

Three sample test plans are attached as appendices: Appendix D is a test plan for the measurement of generator-excitation system and governor characteristics, Appendix E is a generator excitation system and power system stabilizer test procedure, and Appendix F is a test plan for testing and model validation of hydro governors. These test plans are provided for general information. As stated in the Notice in the front of this document, WSCC makes no warranty, or assumes any liabilities, express or implied, with respect to the use of any information, method of process or instrument/device disclosed in this document.

9. *SAMPLE MODEL VALIDATION PROCESS*

Before any testing for validation is performed, the owner should be satisfied that the dynamic behavior of the unit is satisfactory. If not, the unit's controls should be tuned for proper performance before testing for data validation is commenced.

The following is a sample model validation process for the generator excitation system and turbine-governor that could be utilized. The modeling engineer will no doubt have other preferred ways of verifying that the model parameters give an accurate simulation of the test results. In the end, the model data when used in the stability program of choice should give an accurate simulation of the test results.

a. Collect all technical data for the unit. Set up simulation models for the equipment in the stability program of choice.

b. Specify the tests to be performed.

c. Simulate the planned tests to obtain a set of expected response data.

d. Perform the tests. (Example, load rejection or step response, with PSS off.)

e. Compare the pre-test simulations to the corresponding tests. (Note: Verify that the stability simulations have the same initial values as the field tests for all voltage, current, and power quantities.)

f. If the stability program time simulation plots for key variables show a reasonable fit to the test results, the existing model data is validated. Submit the data to WSCC in the appropriate model sheets in Appendix A for the GE stability program and in the forms in Appendix C.

g. If the stability program time simulation plots for key variables do not show a reasonable fit to the test results, it is necessary to repeat the simulations with refined estimates of parameter values until an adequate match is reached. Also verify all limiter values in the model are correct. Additional tests may have to be performed for model validation including load rejection, step response tests and frequency response tests. Obtaining the model parameters to obtain the best fit for the model to test results requires the use of dynamic control system theory, Bode plots and data reduction methods.

h. Submit the validated data to WSCC in the appropriate model sheets in Appendix A for the GE stability program and in the forms in Appendix C.

10. SUGGESTED METHODS RELATING TO CONTROL AND PROTECTION VERIFICATION

a. Limits and trips related to overexcited and underexcited operation should be field checked by tests in which step changes are applied to the voltage regulator to drive it to a high or low output within prudence. The high or low output should be allowed to remain in effect until corrected by limiters or trips. The time delays and levels at which the limiters or trips operate should be recorded. Limiter and/or trip settings may need to be temporarily changed during testing in order to avoid excessive currents and/or voltages. Alternatively, calibrate the limiter while the unit is shut down using conventional relay test techniques. Where practical, limits and trip settings should be determined by challenging the limits in loaded operation. Where appropriate, the limiter and trip elements can be described by graphs and/or tables. (Refer to Figure I.)

b. Correct operation of Volts/Hz trip and limiter devices can be verified for example by observing the response of the excitation system as the machine speed is reduced. (Refer to Figure J.)

c. Owners should verify that the limiters are properly coordinated with protection to prevent unwanted trips and specify whether these are limiters or protection devices. Most limiters leave the excitation system in automatic with the limiter or terminal voltage controlling the excitation level. Protection devices trip the excitation to manual (a preset value) or trip the unit circuit breaker.

11. MEMO ITEMS

Memo items are defined as those additional descriptive items to be submitted by the owner for which there are no specific data entry locations in the Submission Forms. Memo items include the following.

a. Power factor controller status should be reported.

b. There are a wide variety of specific special-purpose limiters in particular plants and particular manufacturers' equipment. These should be described in a memo item and noted in the Submission Forms in Appendix C.

12. BIBLIOGRAPHY

The bibliography is given in Appendix G.

13. APPENDICES

A Model Block Diagrams and Data
B Definitions
C. Submission Forms
D. Example of Test Plan for Measurement of Generator-Excitation System Turbine-Governor Characteristics.
E. Example of Generator Excitation System and Power System Stabilizer Test Procedure.
F. Example of Hydro Turbine Governor Modeling.
G. Bibliography

TABLE 1

Plant Parameters and Levels of Validation

Levels of Validation	Generator	Exciter	PSS	Governor	Excitation Control & Protection		Governor Limiters	
					Limits	Trips	Hydro	Steam
A	X_d X_q H T do' S1.0 S1.2	Max Efd. Ka Static/Rotating Power Source Vrmax Time Constant Xcomp $K_a, T_f, T_b T_c$ etc/ Se (DC exc)	Kpss Type of Input Dominant Time Constant	R (droop) gml Gain At $K_1 \rightarrow K6$ Pmax Intentional Deadband Vel max	Overexcitation OEL- Type/Setting Underexcitation - UEL, Type/Setting V/HZ Power Factor Control Status Stator Current limit	Loss of Field IPP Interface Over/Under Freq. Over/Under Volt Over current Excitation Overcurrent V/HZ	Tunnels/Tanks Motoring/ Water Depressed	Boiler Modes BF, TF, CC Load Limiters
B	X_d" X_q" X'_d X_q' T do" T_{qo}" X_l	K_p K_I (SCPT parameters) (Generex) Se (Brushless) Efd Max (Brushless)		Tw Kp r Ki Tr $T_1 \rightarrow T_4$ Steam//Turbine Model				
C	R_a X_2 X_o R_o			D (turbine damping)				

NOTE: For symbol definitions and typical models, see also Appendices A and B.

Nomenclature for Table 1

Exciter

Ka	Voltage regulator gain
Ta	Voltage regulator time constant, sec
Tb	Lag time constant, sec
Tc	Lead time constant, sec
Vrmax	Maximum control element output, pu
Kf	Rate feedback gain, pu
Tf	Rate feedback time constant, sec
Se	Saturation factor

Generator

T'do	D-axis transient rotor time constant
T"do	D-axis subtransient rotor time constant
T'qo	Q-axis transient rotor time constant
T"qo	Q-axis subtransient rotor time constant
H	Inertia constant, MW-sec/MVA
D	Damping factor, pu
Xd	D-axis synchronous reactance
Xq	Q-axis synchronous reactance
X'd	D-axis transient reactance
X'q	Q-axis transient reactance
X"d	D-axis subtransient reactance
X"q	Q-axis subtransient reactance
Xl	Stator leakage reactance, pu
Se (1.0)	Saturation factor at 1 pu flux
Se (1.2)	Saturation factor at 1.2 pu flux
Ra	Stator resistance, pu
Rcomp	Compounding resistance for voltage control, pu
Xcomp	Compounding reactance for voltage control, pu

Turbine - Governor (Hydro)

Tg	Gate serve time constant, sec
Tp	Pilot serve valve time constant, sec
Uo	Maximum gate opening velocity, p.u./sec
Uc	Maximum gate closing velocity, p.u./sec
Pmax	Maximum gate opening, p.u.
Pmin	Minimum gate opening, p.u.
Rperm	Permanent droop, p.u.
Rtemp	Temporary droop, p.u.
Tr	Dashpot (Relaxation or reset) time constant, sec
Tw	Water inertia time constant, sec

Turbine -Governor (Steam)

K	Governor gain, p.u. (reciprocal of droop)
T1	Governor lead time constant, sec
T2	Governor lag time constant, sec
T3	Valve positioner time constant, sec
Uo	Maximum valve opening velocity, p.u./sec
Uc	Maximum value closing velociy, p.u./sec (<o)
Pmax	Maximum valve opening, p.u.
Pmin	Minimum valve opening, p.u.
T4	Inlet piping/steam bowl time constant, sec
K1	Fraction of hp turbine power developed after first boiler pass
K2	Fraction of lp turbine power developed after first boiler pass
T5	Time constant of second boiler pass (*i.e., reheater), sec
K3	Fraction of hp turbine power developed after second boiler pass
K4	Fraction of lp turbine power developed after second boiler pass
T6	Time constant of third boiler pass, sec
K5	Fraction of hp turbine power developed after third boiler pass
K6	Fraction of lp turbine power developed after third boiler pass
T7	Time constant of fourth boiler pass
K7	Fraction of hp turbine power developed after fourth boiler pass
K8	Fraction of lp turbine power developed after fourth boiler pass

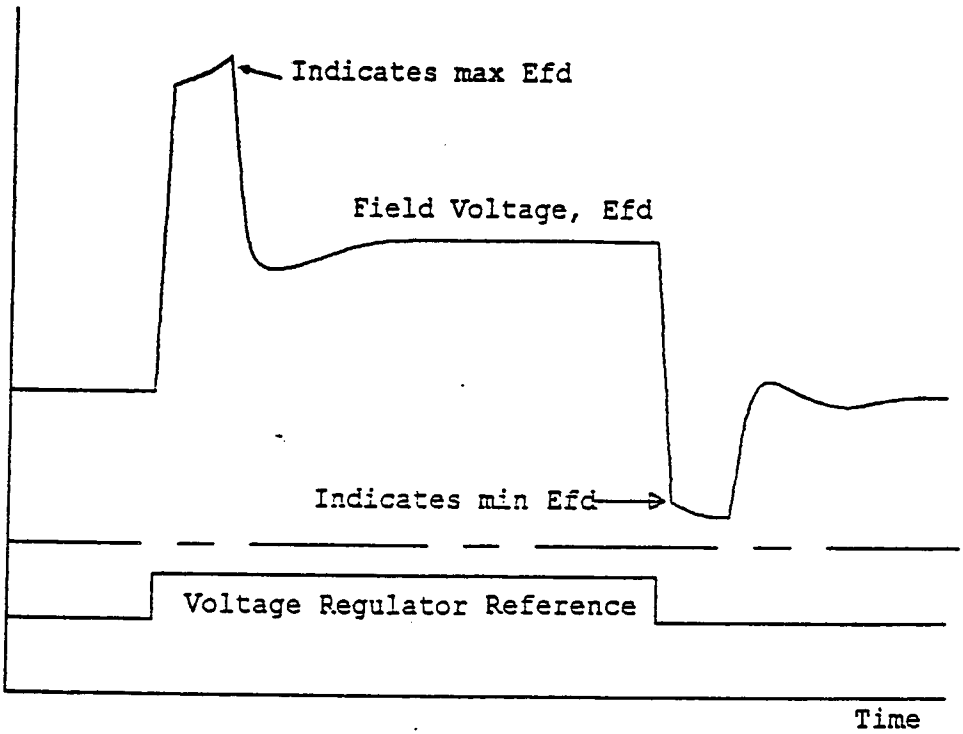


Figure B Estimation of maximum and minimum field voltages from response to step changes in voltage regulator reference setting

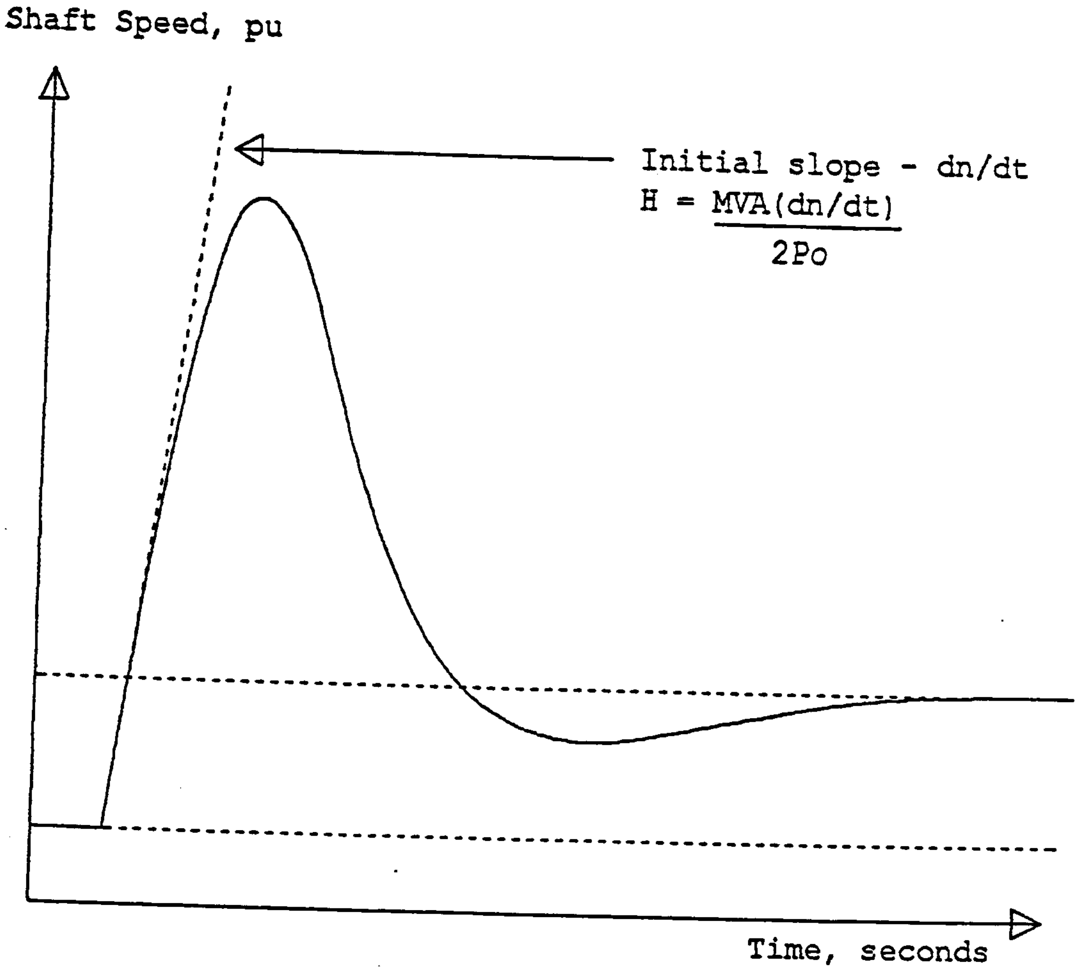


Figure A   Derivation of Machine Inertia Constant, H, and governor droop, R, from trip of Po MW

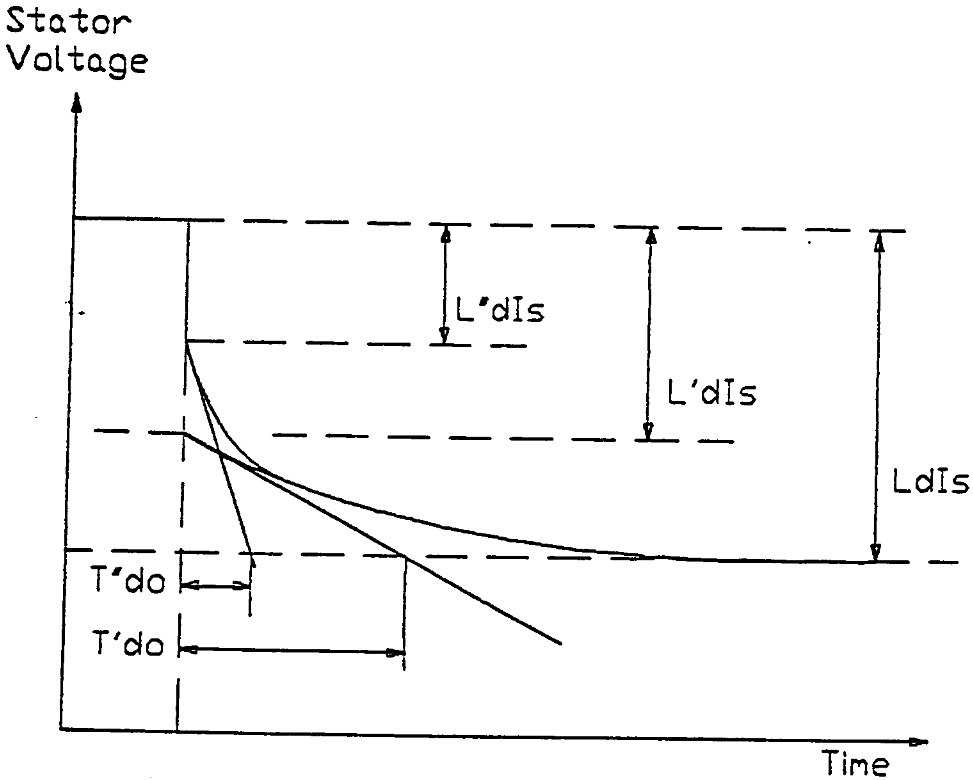
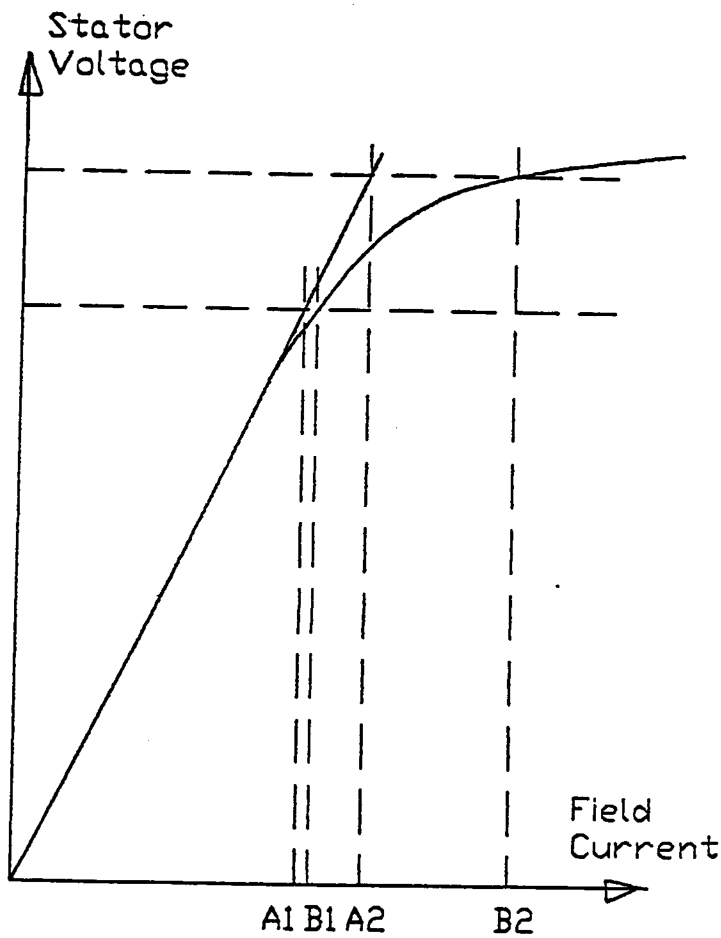


Figure C   Estimation of generator reactances and time constants from response to tripping of zero power factor leading current, Is



$$S = \frac{B - A}{A} \qquad Ifdbase = A1$$

Figure D Estimation of Field Current Base Value and generator saturation parameters from open circuit magnetization curve

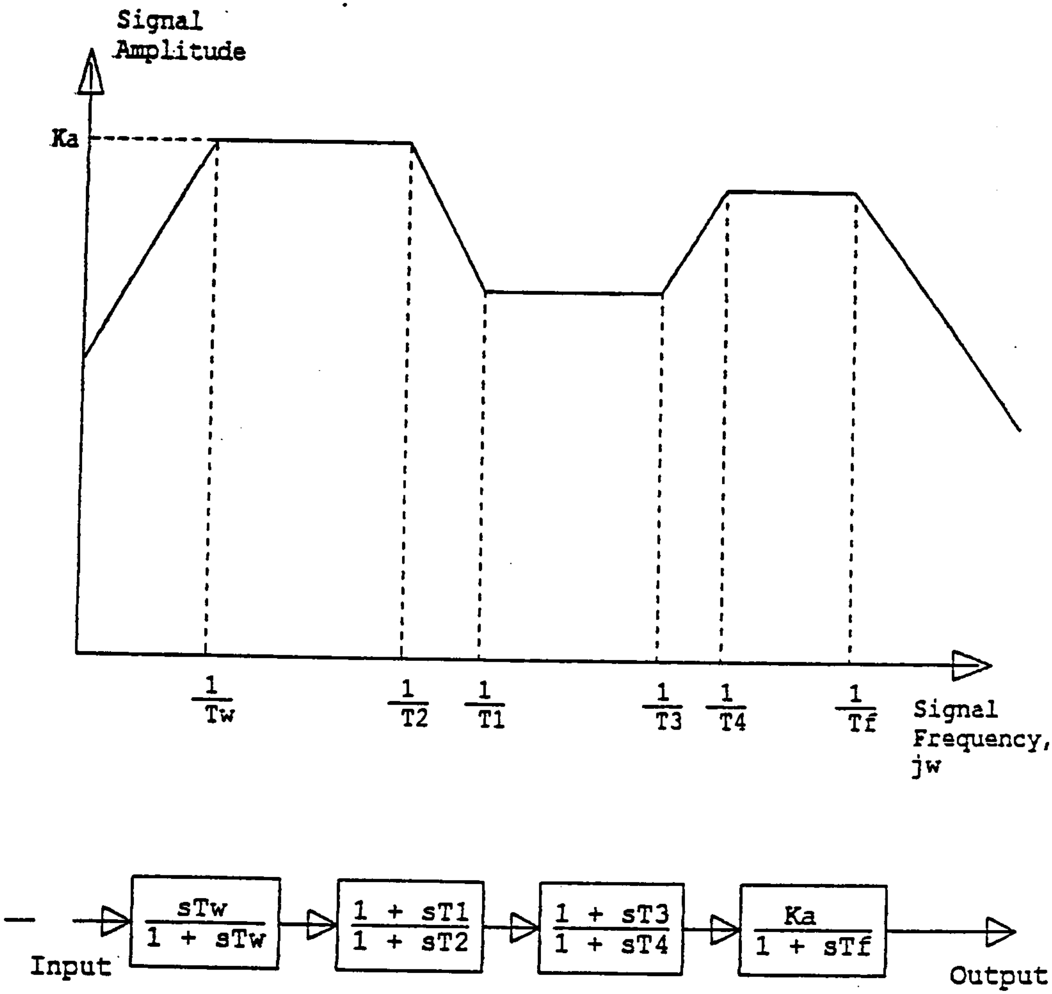


Figure E   Estimation of Voltage Regulator Linear Transfer Function Parameters from Frequency Response Test

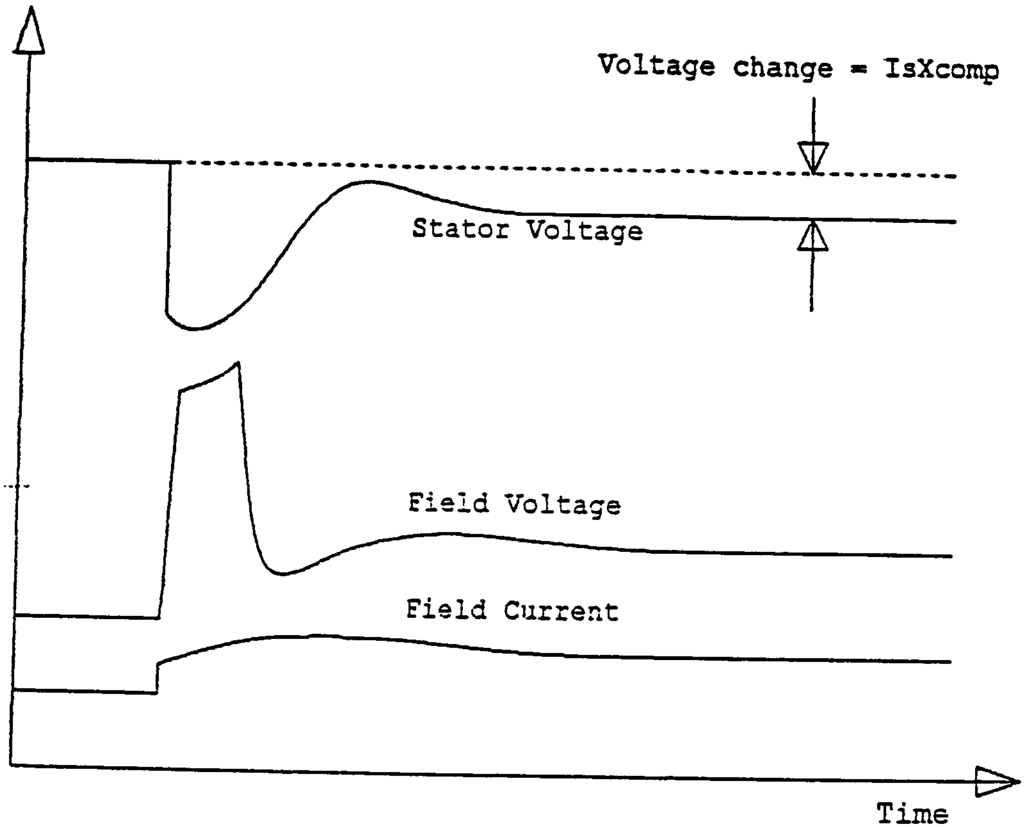


Figure F Estimation of Voltage Regulator Series Current Compensating Reactance from Response to Tripping Zero Power Factor Leading Current, Is

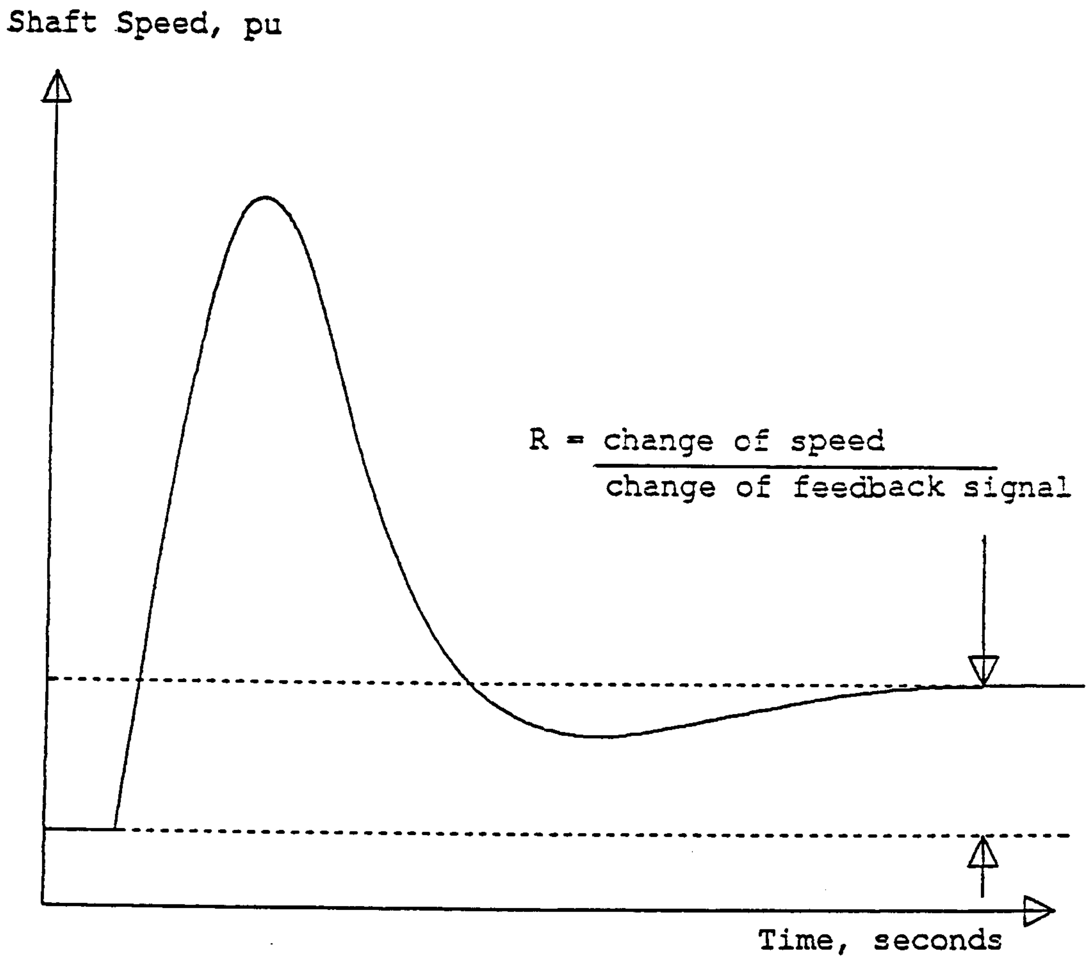


Figure G Estimation of Governor Permanent Droop from response to tripping of moderate real power load

Feedback signal may be valve or gate opening, electrical power, or governor output signal

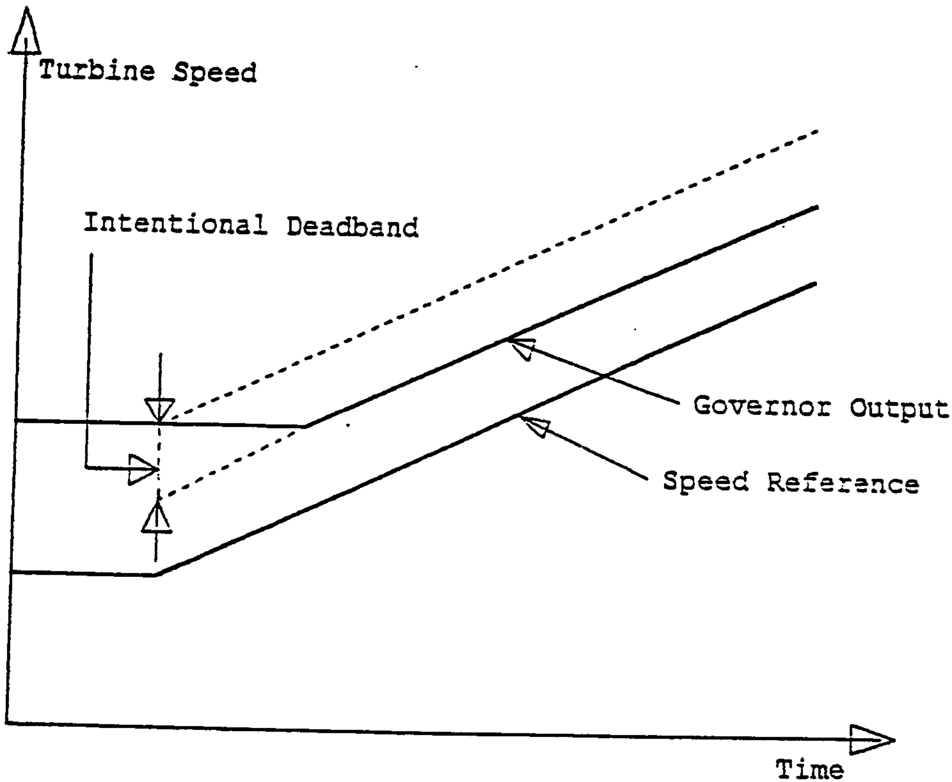


Figure H Estimation of Intentional Dead Band from response to Ramp change of Governor Speed Reference

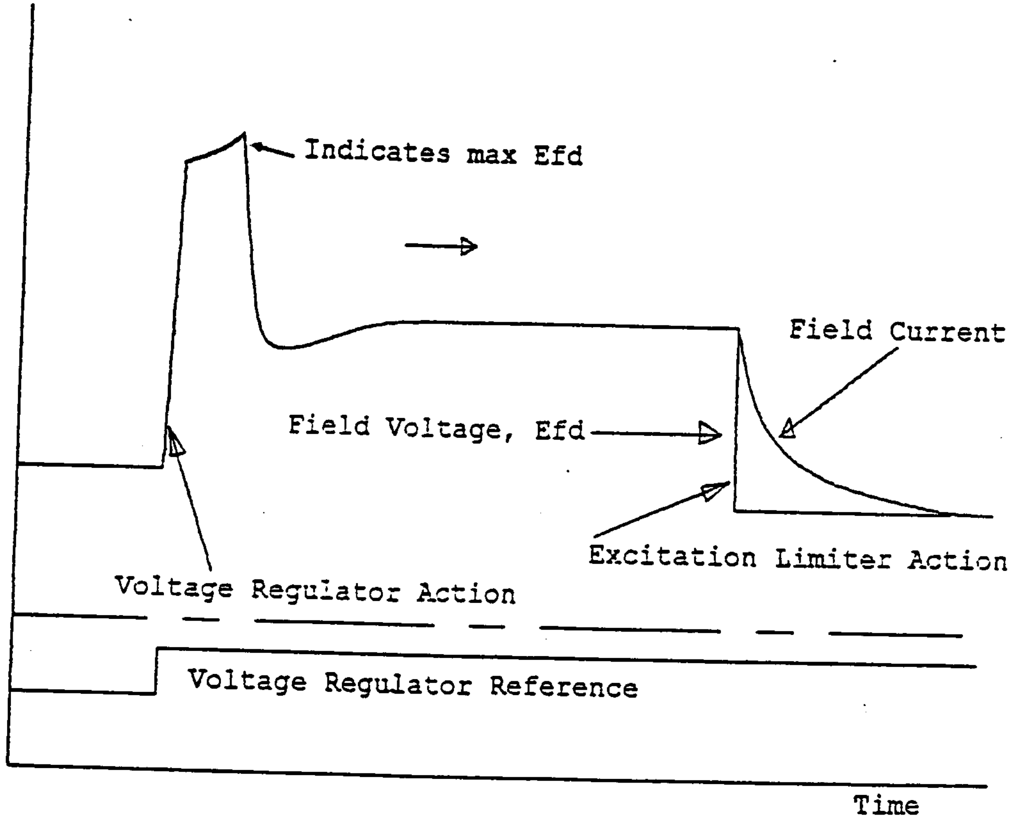


Figure I Estimation of Overexcitation limiter Characteristics from response to step changes of voltage regulator reference

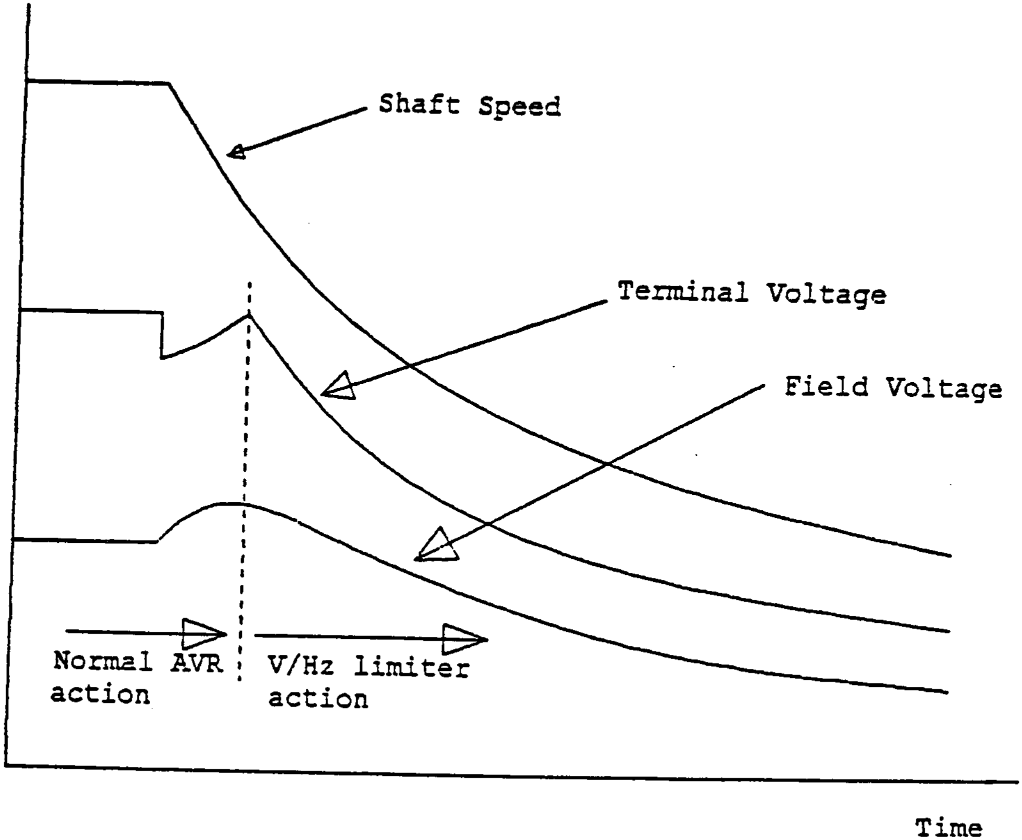


Figure J Response of shaft speed and voltages following trip from moderate real power load reveals volts/Hz limiter characteristics

APPENDIX A

MODEL BLOCK DIAGRAMS AND DATA

TECHNICAL DATA, MODELS AND BLOCK DIAGRAMS

Typical block diagrams from stability programs based on IEEE and WSCC models have been included to assist the test and modeling engineers. The appropriate models should be selected and copied for each unit. Model data should be entered in each model block diagram sheet after validation.

If other models are used, these should be adequately described by a block diagram and corresponding data tables.

It is recognized that for some of the older units such data may be incomplete or unavailable. After model validation, all assumptions made in the derivation of the model should be clearly stated in the documentation.

Correspondence Between WSCC Models and PSDS Models

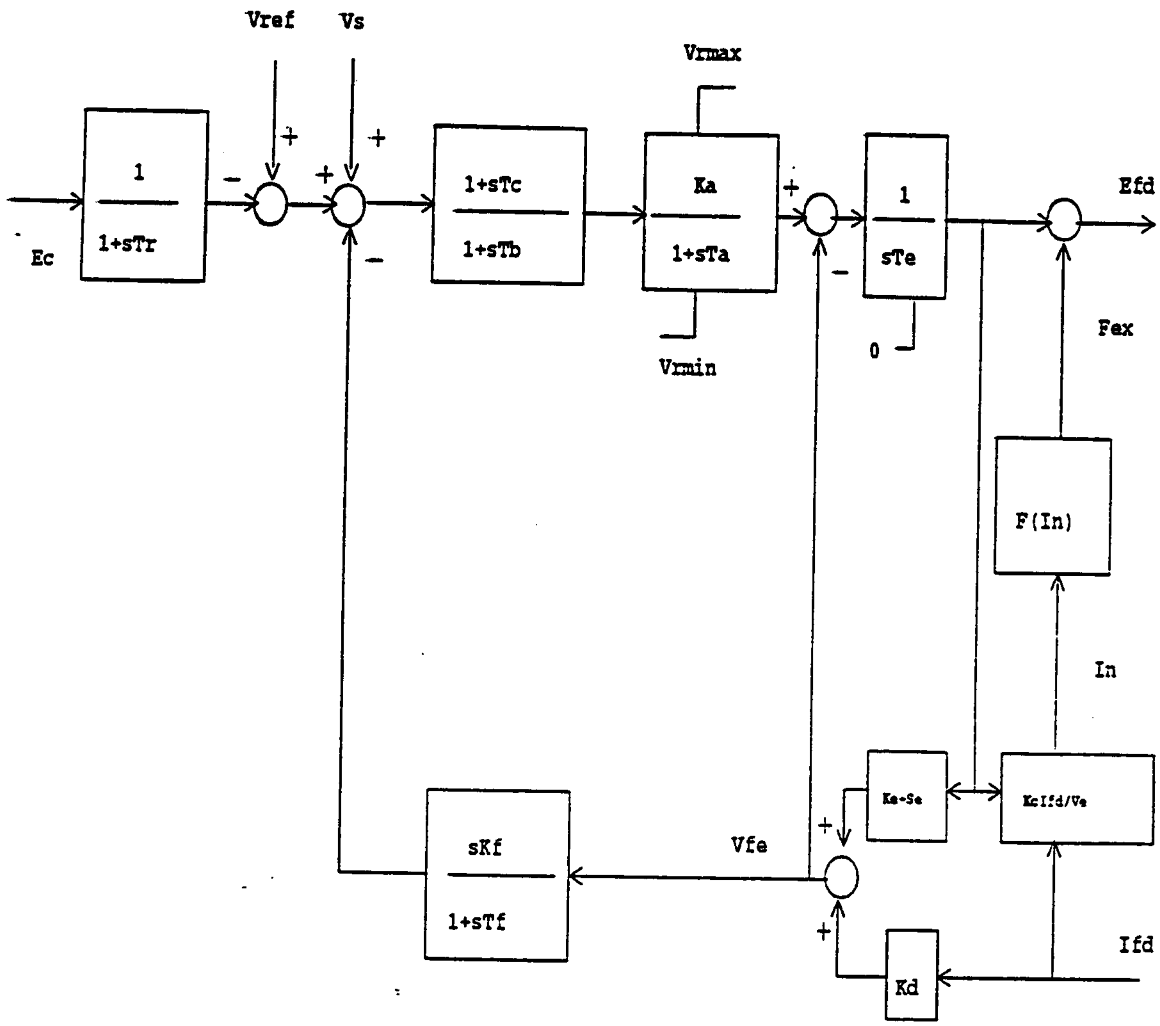
Type of Model	Description	Model Name EPC	Model Name WSCC
MACHINE	* Detailed generator	gentpf	MF
	* Classical generator	gencls	MC
	* Induction motor	motor1	MI
EXCITATION	* Amplidyne/Magamp controlled dc exciter	exdc1	FA
	* Amplidyne/Magamp controlled dc exciter bus voltage regulator supply	exdc2	FB
	* Alternator exciter with non-controlled rectifiers	exac1	FC
	* Compound source static exciter	exst2	FD
	* DC exciter with motor-driven rheostat contactor control	exdc4	FE
	* Alternator exciter with non-controlled rectifiers - high initial response	exac2	FF
	* Alternator exciter with controlled rectifiers	exac4	FG
	* Alternator exciter with non-controlled rectifiers - output dependent control	exac3	FH
	* WSCC Transition Excitation System Model	exstj	FJ
	* Bus-fed static exciter	exst1	FK
	* Series current-potential transformer or internal winding exciter	exst3	FL
GOVERNOR	* Steam	tgov1	GS
	* Hydro	hygov	GW
STABILIZER	* Power system stabilizer	wsccst	ST
STATIC VAR	* Thyristor controlled reactor	vwscc	V
RELAY	* Under frequency relay	lsdt1	UF
	* Under voltage relay	lsdt2	UV
DC	* DC line model	cdc6	D
LOAD	* Algebraic voltage frequency dependence	alwscc	LA
		blwscc	LB
		zlwscc	

REPRESENTATIVE LIST OF GE MODELS

Model Name:	Description:
exac1	IEEE type AC1 excitation system
exac1a	Modified IEEE type AC1 excitation system
exac2	IEEE type AC2 excitation system
exac3	IEEE type AC3 excitation system
exac3a	IEEE type AC3 excitation system
exac4	IEEE type AC4 excitation system
exac6a	IEEE type AC6a excitation system
exbas	Basler static voltage regulator feeding dc or ac rotating exciter
exbbb	ABB Unitrol Voltage Regulator with stator current compounded rotating exciter
exbbc	Transformer fed static excitation system
exdc1	IEEE type 1 excitation system model. Represents systems with d.c. exciters and continuously acting voltage regulators, such as amplidyne-based excitation systems
exdc2	IEEE type 2 excitation system model.

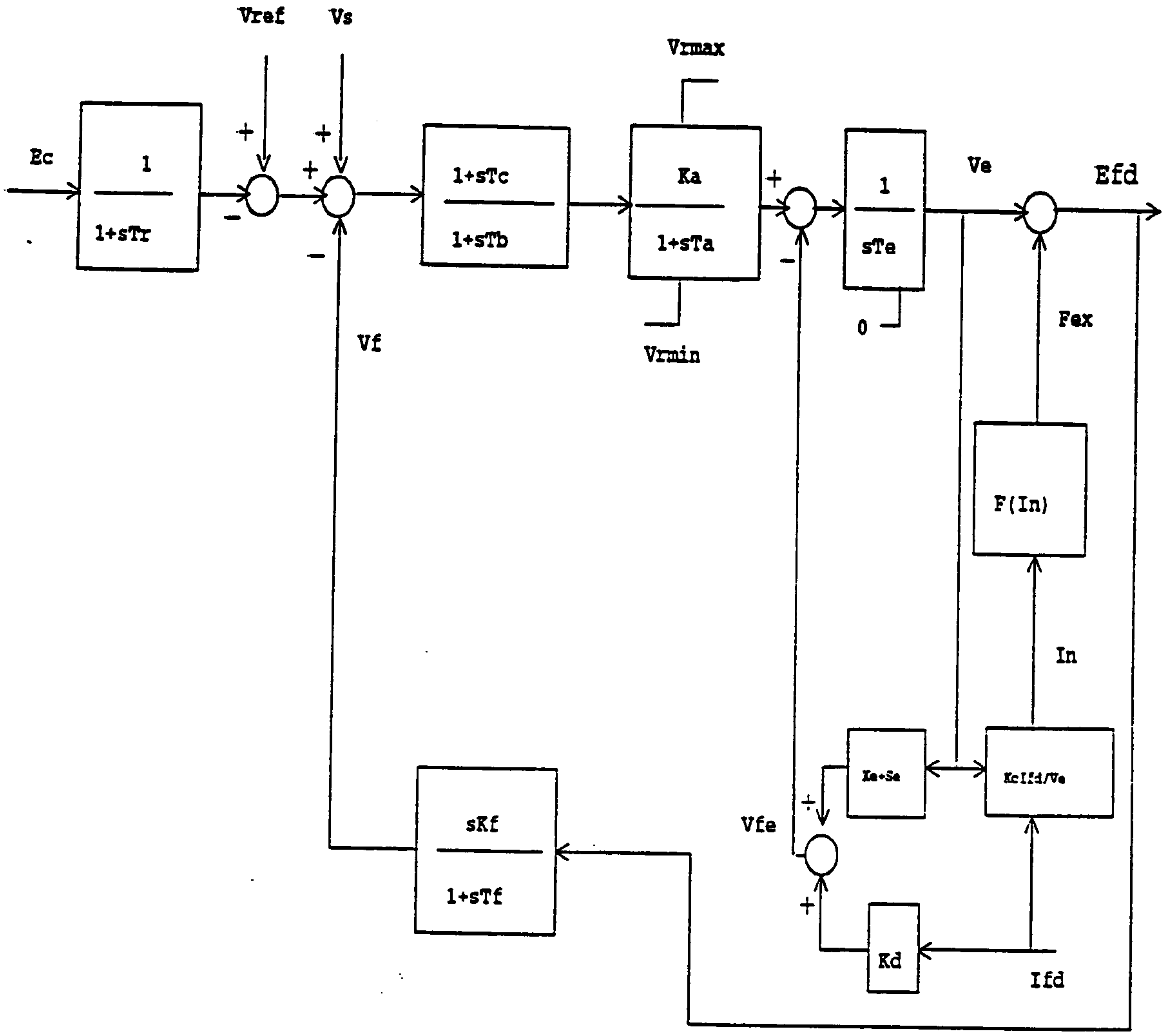
exdc2a	IEEE type dc2a excitation system model.. Represents systems with d.c. exciters and continuously acting voltage regulators, such as amplidyne-based excitation systems
exdc4	"Old" IEEE type 4 excitation system model. Represents systems with d.c. exciters and non- continuously acting voltage regulators.
exeli	Static PI transformer fed excitation system
exst1	IEEE type ST1 excitation system
exst2	IEEE type ST2 excitation system
exst3	IEEE type ST3 excitation system
exst3a	IEEE type ST3a excitation system
exst4b	IEEE type ST4b excitation system
g2wscc	Double derivative hydro governor and turbine Represents WSCC G2 model
gast	Single shaft gas turbine
gpwscc	PID governor and turbine Represents WSCC GP model
gentpf	Generator represented by uniform inductance ratios rotor modeling to match WSCC type F model; shaft speed effects are neglected
hygov	Hydro turbine and governor. Represents plants with straight forward penstock configurations and hydraulic-dashpot governors or electro-hydraulic governors that mimic dashpot governors (i.e. Woodward

	hydraulic; ASEA electrohydraulic)
hyst1	Hydro turbine with Woodward Electro-hydraulic PID Governor, Penstock, Surge Tank, and Inlet Tunnel
ieeeg1	IEEE turbine/governor model
ieeeg3	IEEE hydro turbine/governor model.
mexs	Manual excitation control with field circuit resistance
motor1	Induction machine modeled with rotor flux transients
motorw	Motor model
pfqrg	Power factor / Reactive power regulator
pss2a	Dual input PSS (IEEE type PSS 2A)
pss2b	Dual input PSS (IEEE type PSS 2A) + voltage boost signal
silco5	Canadian GE Silco5 excitation system model
svcwsc	Static var device model
vwscc	WSCC Static var device model
w2301	Woodward 2301 governor and basic turbine model
wsccst	WSCC Power System Stabilizer



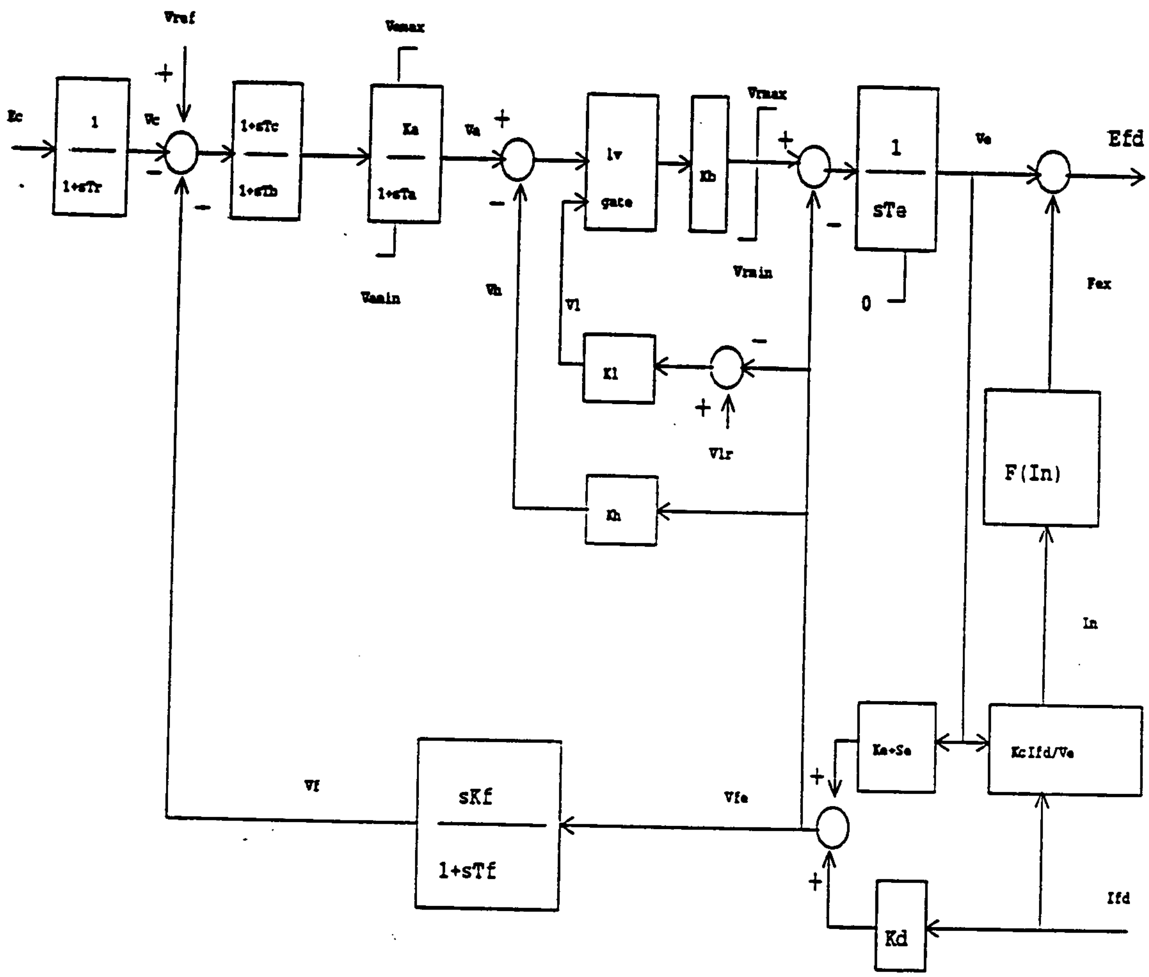
tr	Filter time constant, sec
tb	Time constant, sec
tc	Time constant, sec
ka	Voltage regulator gain
ta	Time constant, sec
vrmax	Maximum control element output, p.u.
vrmin	Minimum control element output, p.u.
te	Exciter time constant, sec
kf	Rate feedback gain, p.u.
tf	Rate feedback time constant, sec
kc	Rectifier regulation factor, p.u.
kd	Exciter internal reactance, p.u.
ke	Exciter field resistance constant, p.u.
e1	Field voltage value, 1
se1	Saturation factor at E1
e2	Field voltage value, 2
se2	Saturation factor at E2

exac1 IEEE type AC1 excitation system



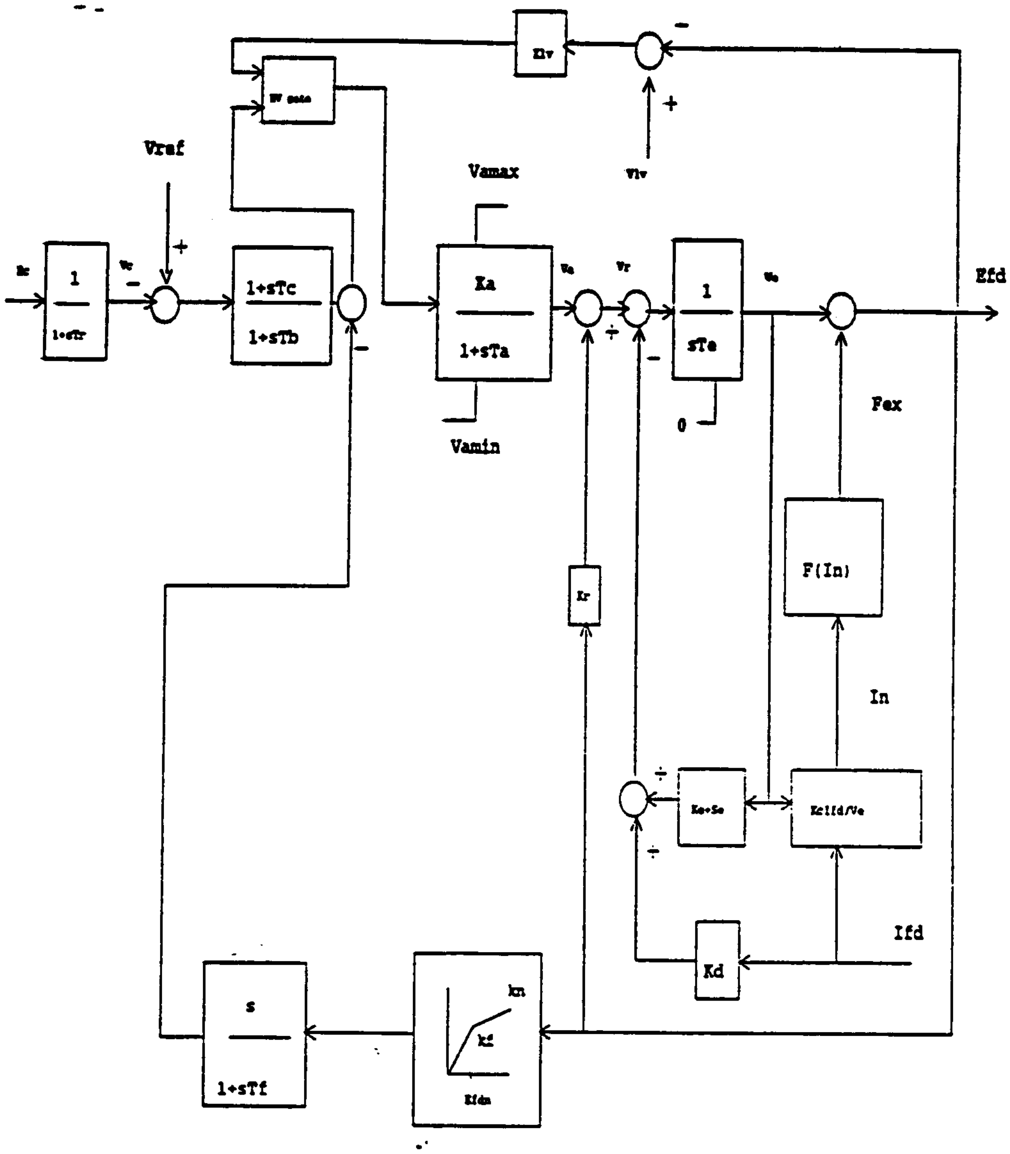
tr	Filter time constant, sec
tb	Lag time constant, sec
tc	Lead time constant, seca
ka	Voltage regulator gain
ta	Time constant, sec
vrmax	Maximum control element output, p.u.
vrmin	Minimum control element output, p.u.
te	Exciter time constant, sec
kf	Rate feedback gain, p.u.
tf	Rate feedback time constant, sec
kc	Exciter regulation factor, p.u.
kd	Exciter internal reactance, p.u.
ke	Exciter field resistance constant, p.u
e1	Field voltage value, 1
se1	Saturation factor at E1
e2	Field voltage value, 2
se2	Saturation factor at E2

exac1a   Modified IEEE type AC1 excitation system



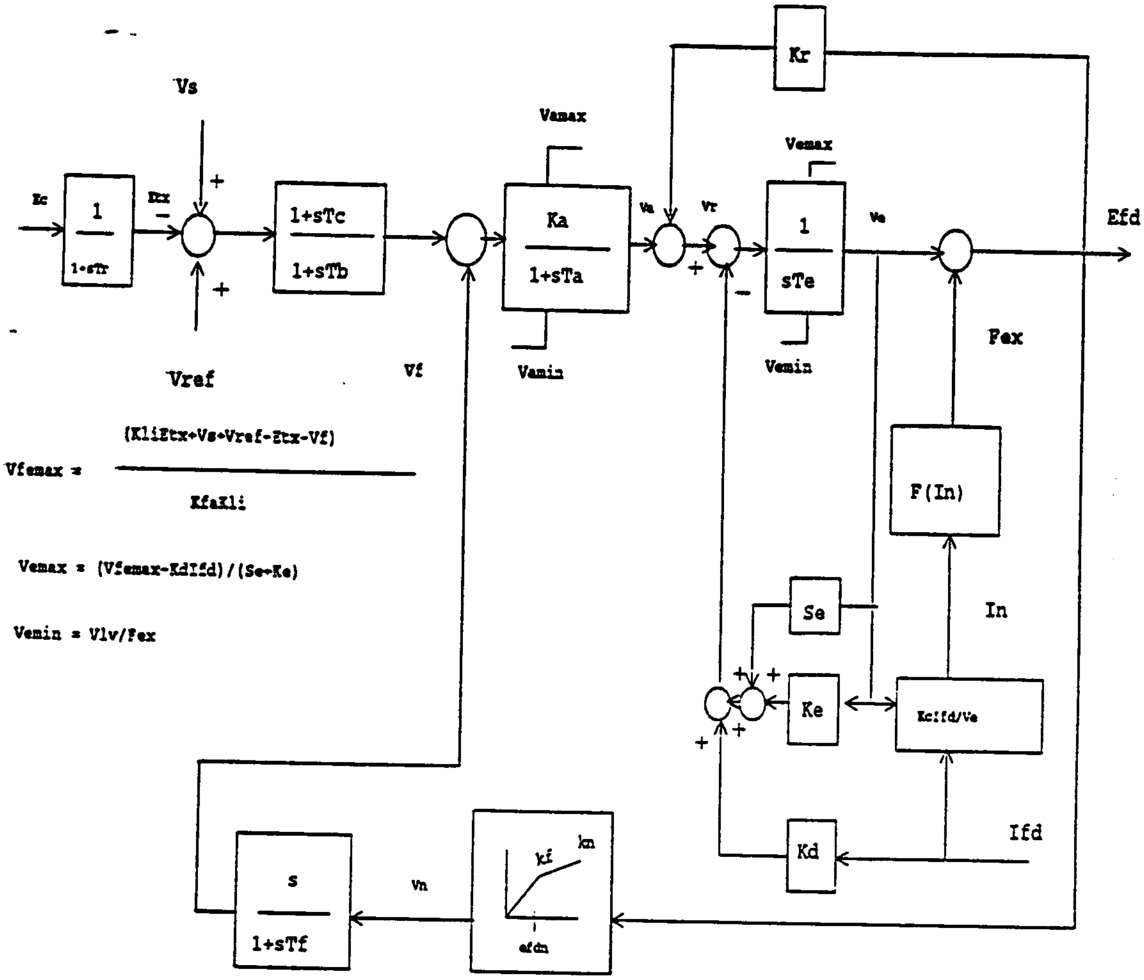
tr	Filter time constant, sec
tb	Time constant, sec
tc	Time constant, sec
ka	Voltage regulator gain
ta	Time constant, sec
vamax	Maximum control element output, p.u.
vamin	Minimum control element output, p.u.
kb	Exciter field current controllergain, p.u.
vrmax	Maximum exciter control signal, p.u.
vrmin	Minimum exciter control signal, p.u.
te	Exciter time constant, sec
kl	Exciter field current limiter gain, p.u.
kh	Exciter field current feedback gain, p.u.
kf	Rate feedback gain, p.u.
tf	Rate feedback time constant, sec
kc	Rectifier regulation factor, p.u.
kd	Exciter internal reactance, p.u.
ke	Exciter field resistance constant, p.u.
vlr	Maximum exciter field current, p.u.
e1	Field voltage value, 1
se1	Saturation factor at E1
e2	Field voltage value, 2
se2	Saturation factor at E2

exac2 IEEE type AC2 excitation system



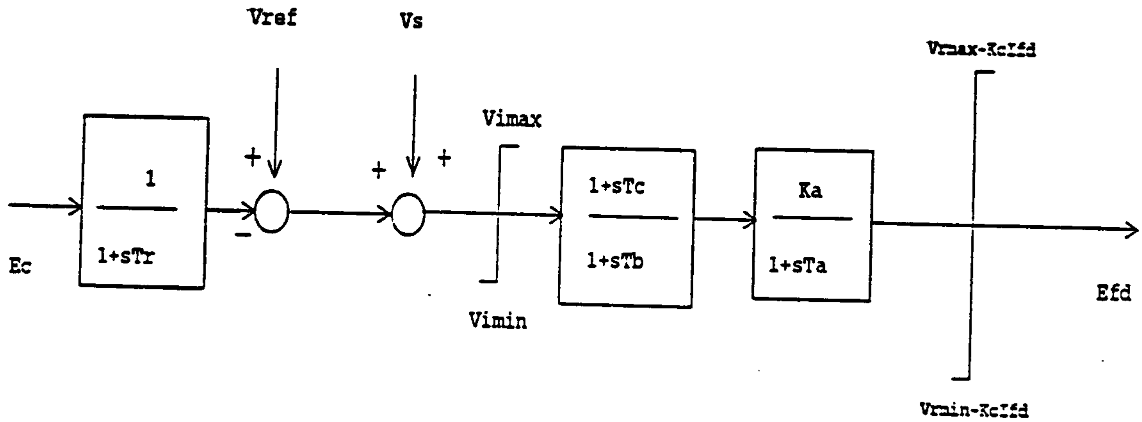
tr	Filter time constant, sec
tb	Time constant, sec
tc	Time constant, sec
ka	Voltage regulator gain
ta	Time constant, sec
vamax	Maximum control element output, p.u.
vamin	Minimum control element output, p.u.
te	Exciter time constant, sec
klv	Minimum field voltage limiter gain,p.u.
kr	Field voltage feedback gain, p.u.
kf	Low level rate feedback gain, p.u.
tf	Rate feedback time constant, sec
kn	High level rate feedback gain, p.u.
efdn	Rate feedback gain break level, p.u.
kc	Rectifier regulation factor, p.u.
kd	Exciter internal reactance, p.u.
ke	Exciter field resistance constant, p.u.
vlv	Minimum excitation limit, p.u.
e1	Field voltage value, 1
se1	Saturation factor at E1
e2	Field voltage value, 2
se2	Saturation factor at E2

exac3 IEEE type AC3 excitation system

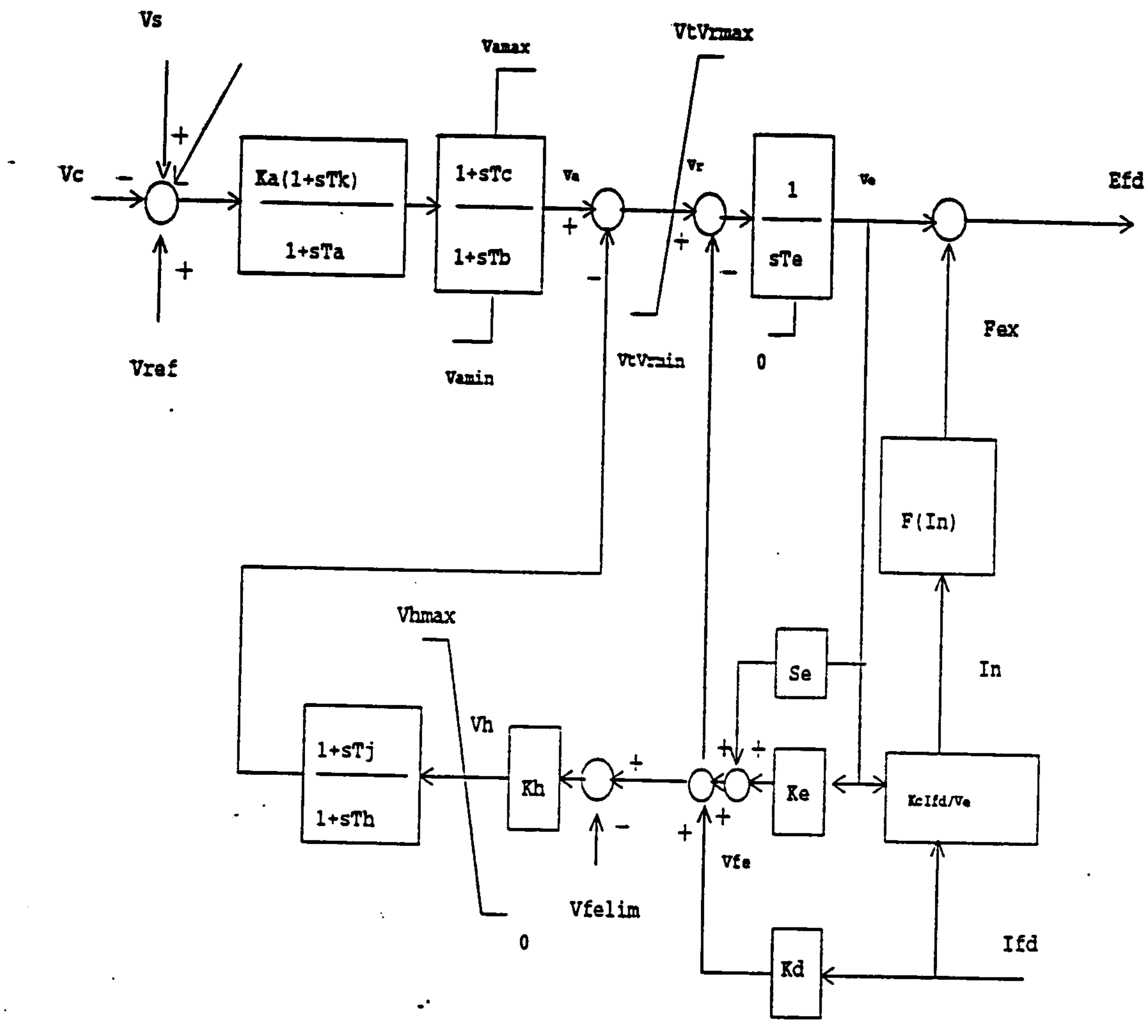


tr	Filter time constant, sec
tb	Time constant, sec
tc	Time constant, sec
ka	Voltage regulator gain
ta	Time constant, sec
vamax	Maximum control element output, p.u.
vamin	Minimum control element output, p.u.
te	Exciter time constant, sec
klv	Minimum field voltage limiter gain,p.u.
kr	Field voltage feedback gain, p.u.
kf	Low level rate feedback gain, p.u.
tf	Rate feedback time constant, sec
kn	High level rate feedback gain, p.u.
efdn	Rate feedback gain break level, p.u.
kc	Rectifier regulation factor, p.u.
kd	Exciter internal reactance, p.u.
ke	Exciter field resistance constant, p.u.
vlv	Minimum excitation limit, p.u.
e1	Field voltage value, 1
se1	Saturation factor at E1
e2	Field voltage value, 2
se2	Saturation factor at E2
kli	Field current limit parameter (=.59)
kfa	Field current limit parameter (defaults to Kf)

exac3a IEEE type AC3 excitation system

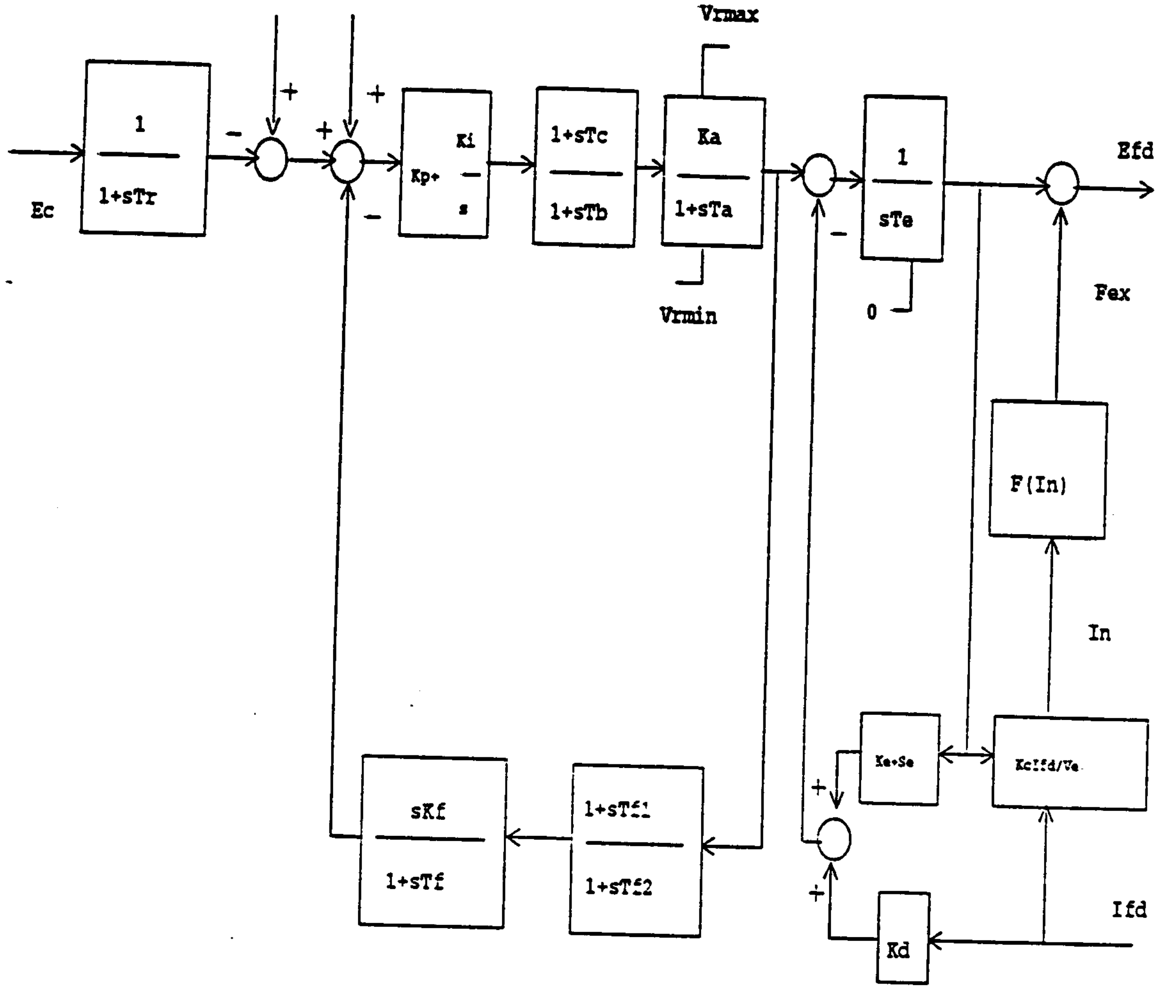


tr	Transient time constant, sec
vimax	Maximum error, p.u.
vimin	Minimum error, p.u.
tc	Lead time constant, sec
tb	Lag time constant, sec
ka	Gain
ta	Time contant, sec
vrmax	Maximum controller output, p.u.
vrmin	Minimum controller output, p.u.
kc	Excitation system regulation, p.u.



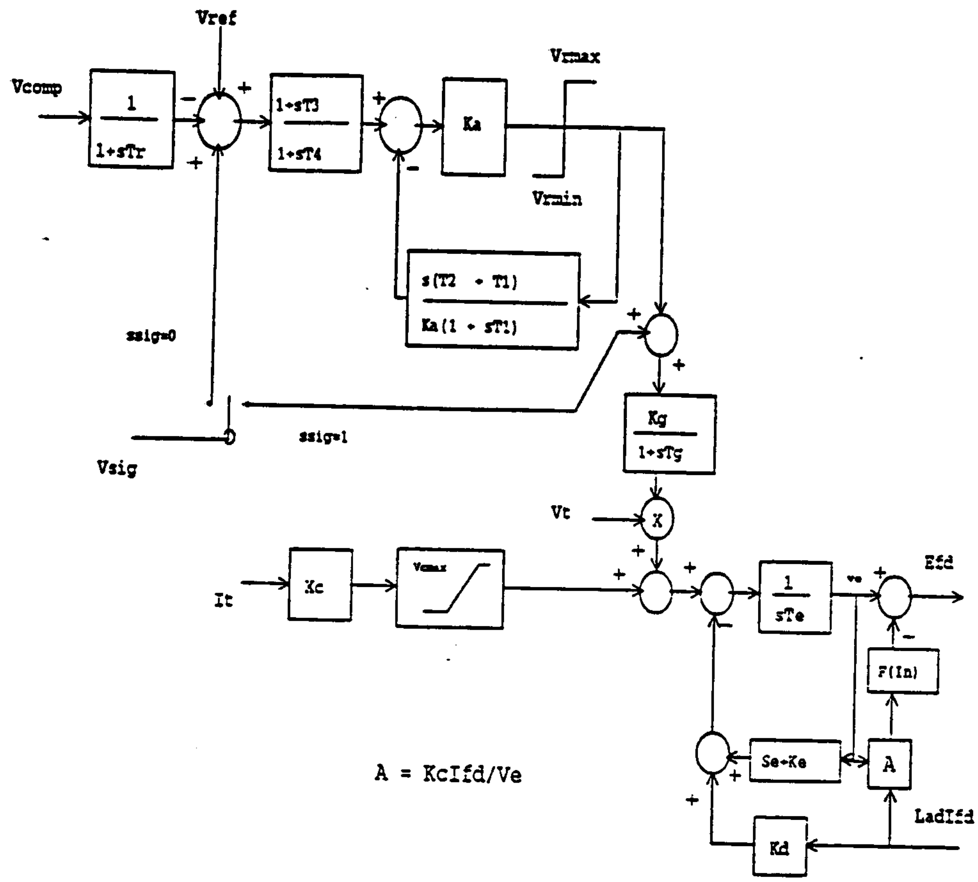
tr	Filter time constant, sec
ka	Voltage regulator gain
ta	Time constant, sec
tk	Time constant, sec
tb	Time constant, sec
tc	Time constant, sec
vamax	Maximum control element output, p.u.
vamin	Minimum control element output, p.u.
vrmax	Maximum exciter control signal, p.u.
vrmin	Minimum exciter control signal, p.u.
te	Exciter time constant, sec
kh	Exciter field current limiter gain, p.u.
tj	Field current limiter time constant, sec
th	Field current limiter time constant, sec
vfelim	Exciter field current limit reference, p.u.
vhamx	Maximum field current limiter signal, p.u.
kc	Rectifier regulation factor, p.u.
kd	Exciter internal reactance, p.u.
ke	Exciter field resistance constant, p.u.
e1	Field voltage value, 1
se1	Saturation factor at E1
e2	Field voltage value, 2
se2	Saturation factor at E2

exac6a IEEE type AC6a excitation system



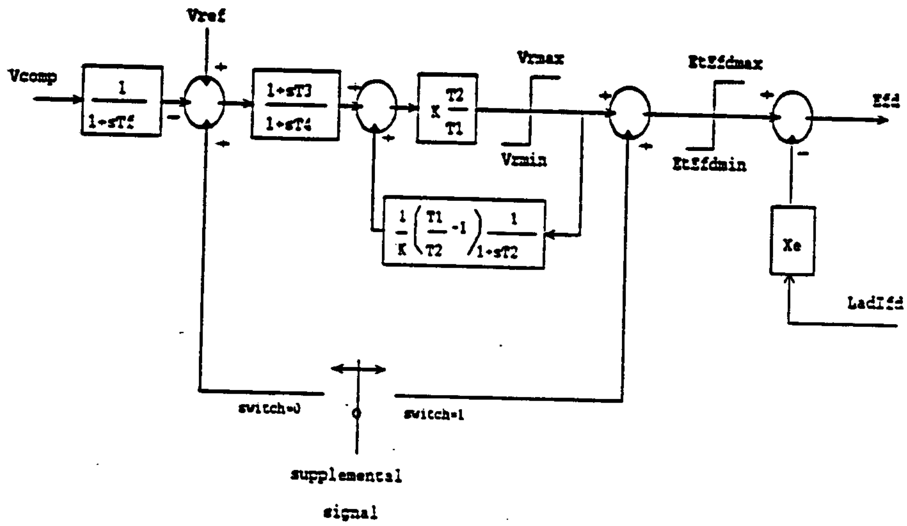
tr	Voltage transducer time constant, sec
kp	Proportional gain
ki	Integral (reset) gain
ka	Gain
ta	Bridge time constant, sec
tb	Lag time constant, sec
tc	Lead time constant, sec
vrmax	Maximum control output, pu
vrmin	Minimum control output, pu
kf	Rate feedback gain
tf	Rate feedback time constant, sec
tf1	Feedback lead time constant, sec
tf2	Feedback lag time constant, sec
ke	Exciter field proportional constant
te	Exciter field time constant, sec
kc	Rectifier regulation factor, pu
kd	Exciter regulation factor, pu
e1	Exciter flux at knee of curve, pu
se1	Saturation factor at knee of curve
e2	Maximum exciter flux, pu
se2	Saturation factor at maximum exciter flux, pu

exbas Basler static voltage regulator feeding dc or ac rotating exciter



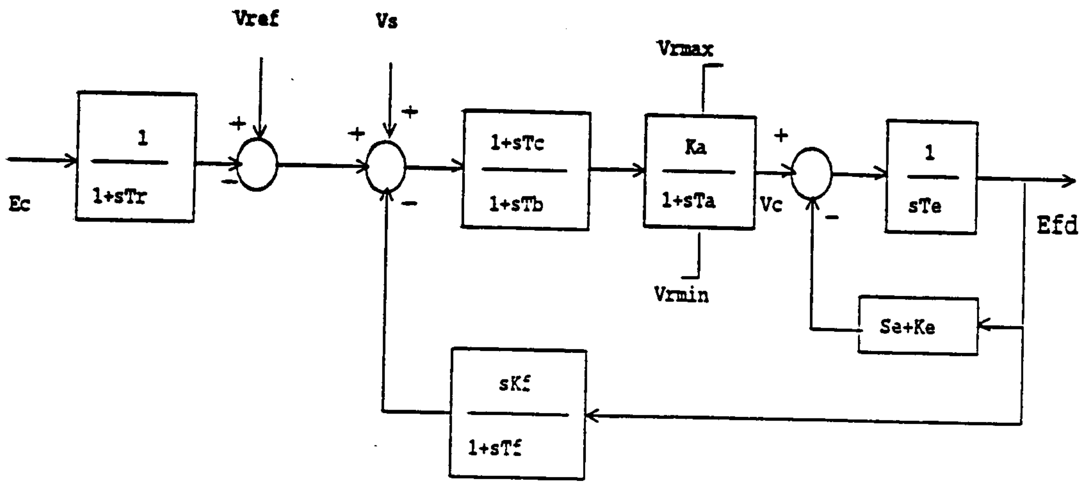
tr	Voltage transducer time constant,sec
ka	DC gain
t1	Proportional time constant, sec.
t2	Proportional time constant, sec.
t3	Derivative time constant, sec
t4	Derivative time constant, sec
vrmin	Minimum controller output, pu
vrmax	Maximum controller output, pu
kg	Gating circuit gain
tg	Firing circuit time constant, sec.
ke	Exciter field proportional constant
te	Exciter field time constant. sec.
kc	Rectifier regulation factor, p.u.
kd	Exciter regulation factor, p.u.
xc	Exciter compounding reactance, p.u.
vcmax	Maximum compounding voltage, p.u.
e1	Field voltage value, 1
se1	Saturation factor at E1
e2	Field voltage value, 2
se2	Saturation factor at E2
ssig	Supplementary signal routing switch

exbbb **ABB Unitrol Voltage Regulator with stator current compounded rotating exciter**



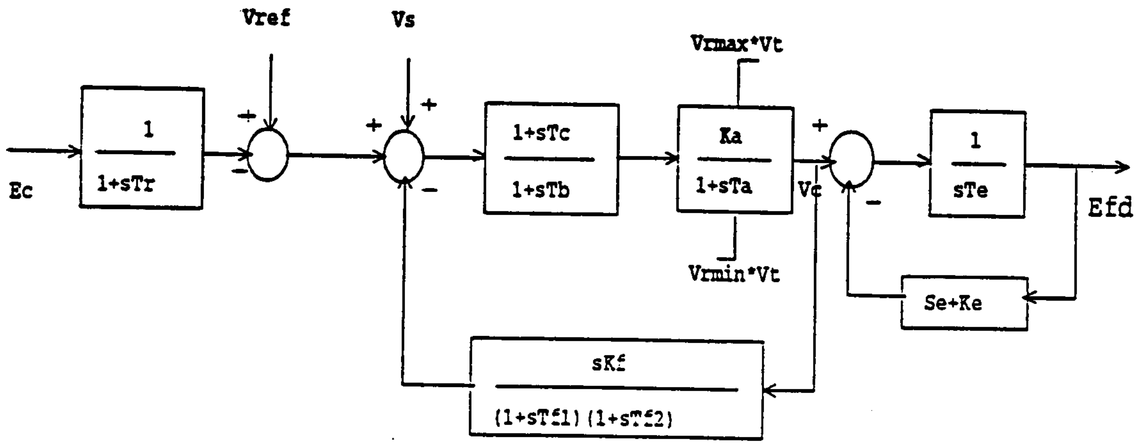
tf	Filter time constant, sec
t1	Controller time constant, sec
t2	Controller time constant, sec
t3	Lead/lag time constant, sec
t4	Lead/lag time constant, sec
k	Steady state gain
vrmin	Minimum control element output, pu
vrmax	Maximum control element output, pu
efmin	Minimum open circuit exciter voltage, pu
efmax	Maximum open circuit exciter voltage, pu
xe	Effective excitation transformer reactance, pu
sisig	Supplementary signal routing switch

exbbc **Transformer fed static excitation system**



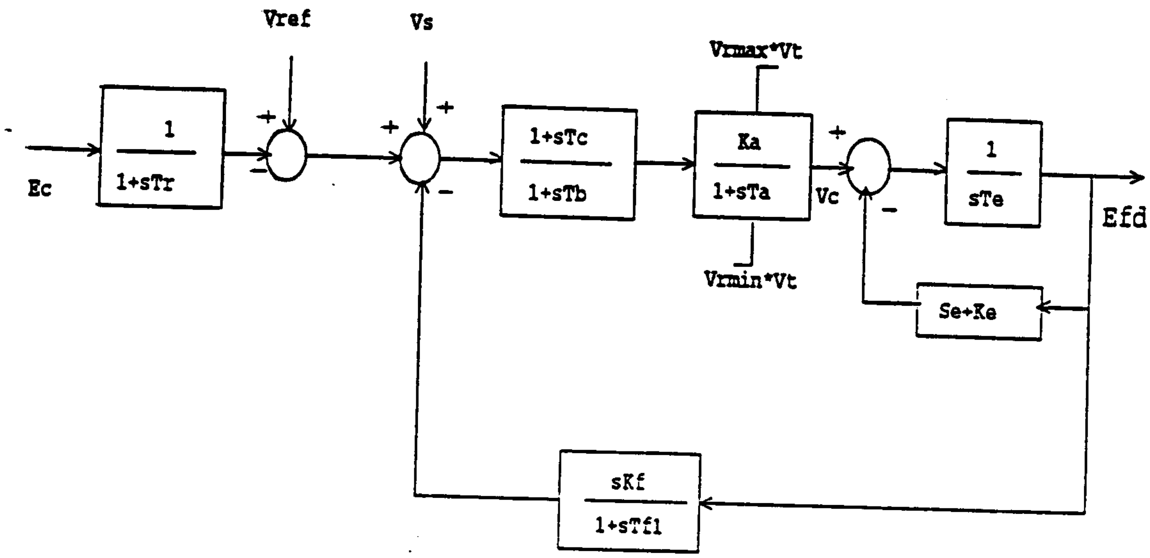
tr	Transducer time constant, sec
ka	Voltage regulator gain
ta	Voltage regulator time constant, sec
tb	Lag time constant, sec
tc	Lead time constant, sec
vrmax	Maximum control element output, pu
vrmin	Minimum control element output, pu
ke	Exciter field resistance line slope margin, pu
te	Exciter field time constant, sec
kf	Rate feedback gain, pu
tf1	Rate feedback time constant, sec
tf2	Required entry of zero
e1	Field voltage value, 1
se1	Saturation factor at E1
e2	Field voltage value, 2
se2	Saturation factor at E2

exdc1 IEEE type 1 excitation system model. Represents systems with d.c. exciters and continuously acting voltage regulators, such as amplidyne-based excitation systems



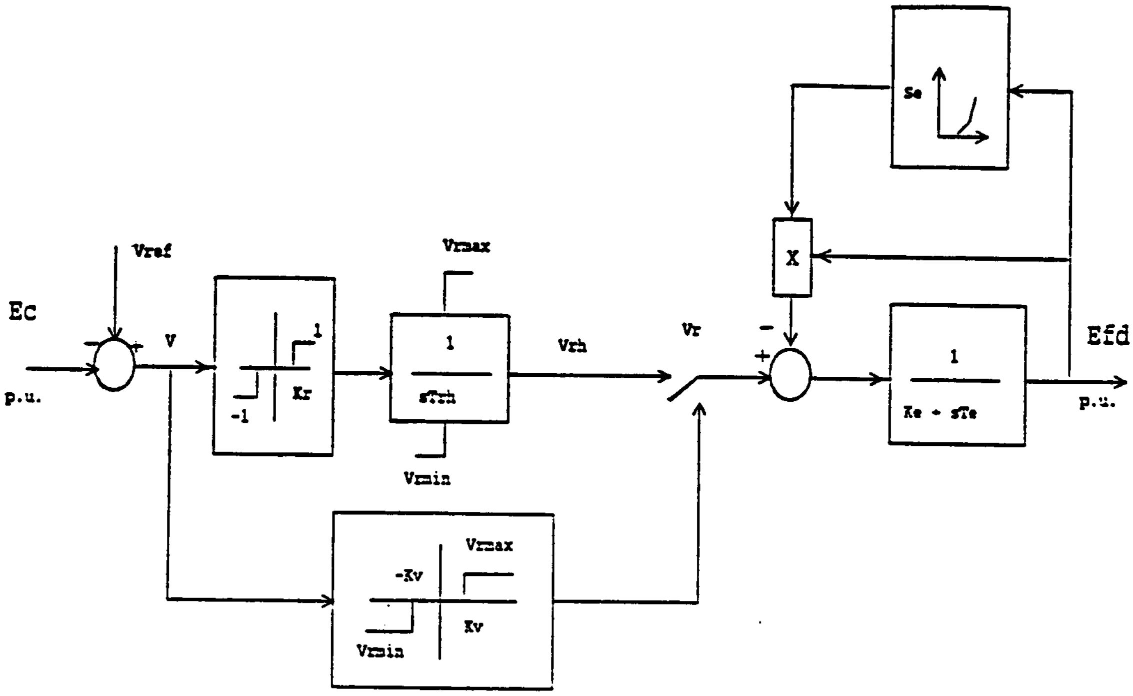
tr	Transducer time constant, sec
ka	Voltage regulator gain
ta	Voltage regulator time constant, sec
tb	Lag time constant, sec
tc	Lead time constant, sec
vrmax	Maximum control element output, pu
vrmin	Minimum control element output, pu
ke	Exciter field resistance line slope margin, pu
te	Exciter field time constant, sec
kf	Rate feedback gain, pu
tf1	Rate feedback time constant, sec
tf2	Feedback time constant, sec
e1	Field voltage value, 1
se1	Saturation factor at E1
e2	Field voltage value, 2
se2	Saturation factor at E2

exdc2 IEEE type 2 excitation system model.



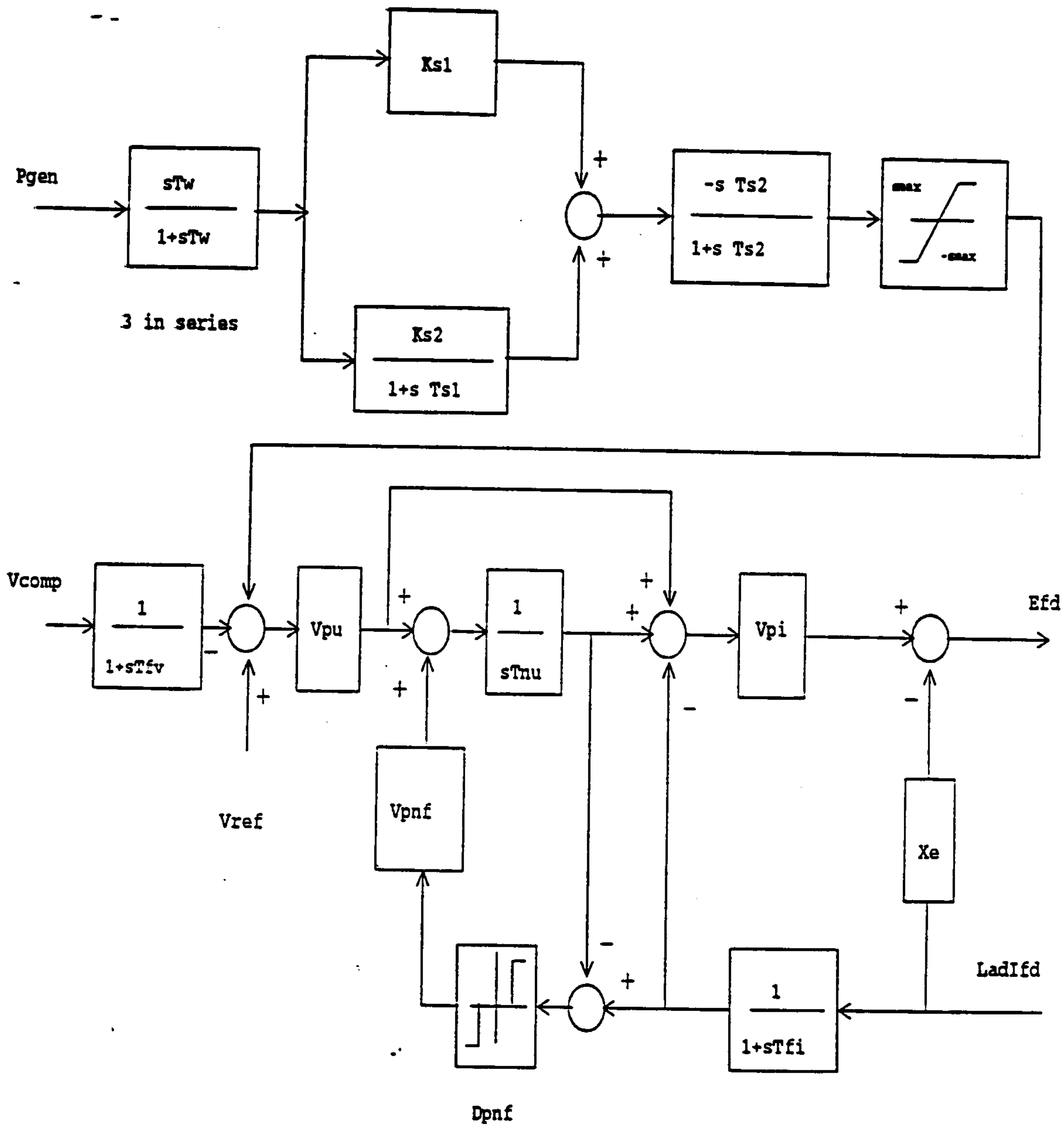
tr	Transducer time constant, sec
ka	Voltage regulator gain
ta	Voltage regulator time constant, sec
tb	Lag time constant, sec
tc	Lead time constant, sec
vrmax	Maximum control element output, pu
vrmin	Minimum control element output, pu
ke	Exciter field resistance line slope margin, pu
te	Exciter field time constant, sec
kf	Rate feedback gain, pu
tf1	Rate feedback time constant, sec
tf2	Feedback time constant, sec
e1	Field voltage value, 1
se1	Saturation factor at E1
e2	Field voltage value, 2
se2	Saturation factor at E2

exdc2a Represents systems with d.c. exciters and continuously acting voltage regulators, such as amplidyne-based excitation systems



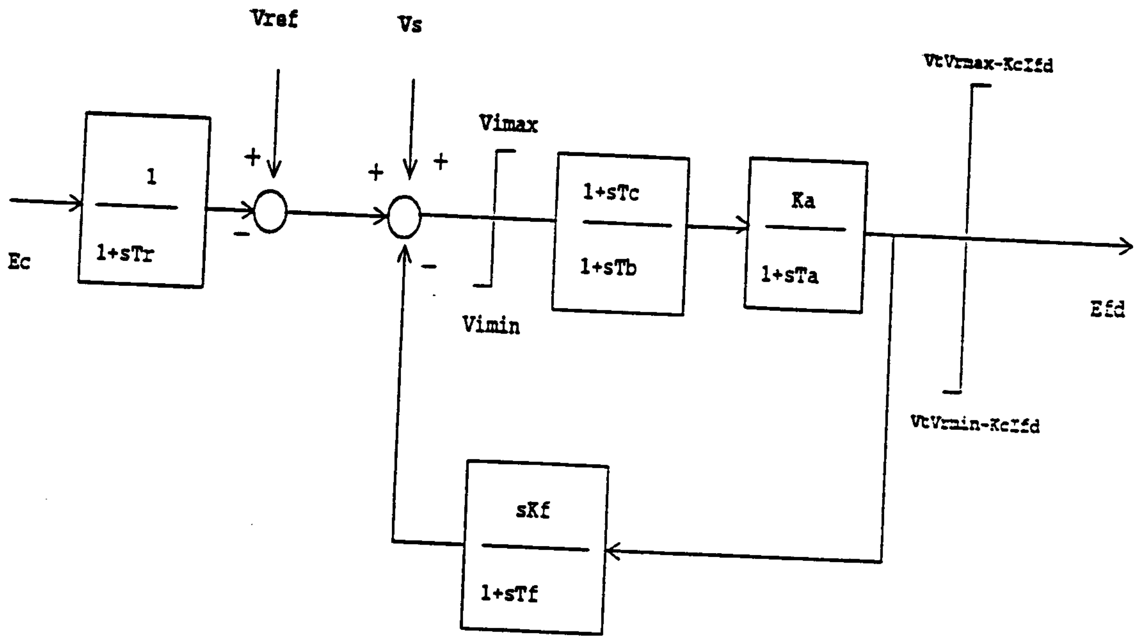
kr	Voltage error threshold for rheostat action, pu
trh	Rheostat full range travel time, sec
kv	Voltage error threshold min/max control action, pu
vrmax	Maximum control element output, pu
vrmin	Minimum control element output, pu
te	Exciter field time constant, sec
ke	Exciter field resistance line slope margin pu
e1	Field voltage value, 1
se1	Saturation factor at E1
e2	Field voltage value, 2
se2	Saturation factor at E2

exdc4 **"Old" IEEE type 4 excitation system model. Represents systems with d.c. exciters and non- continuously acting voltage regulators.**



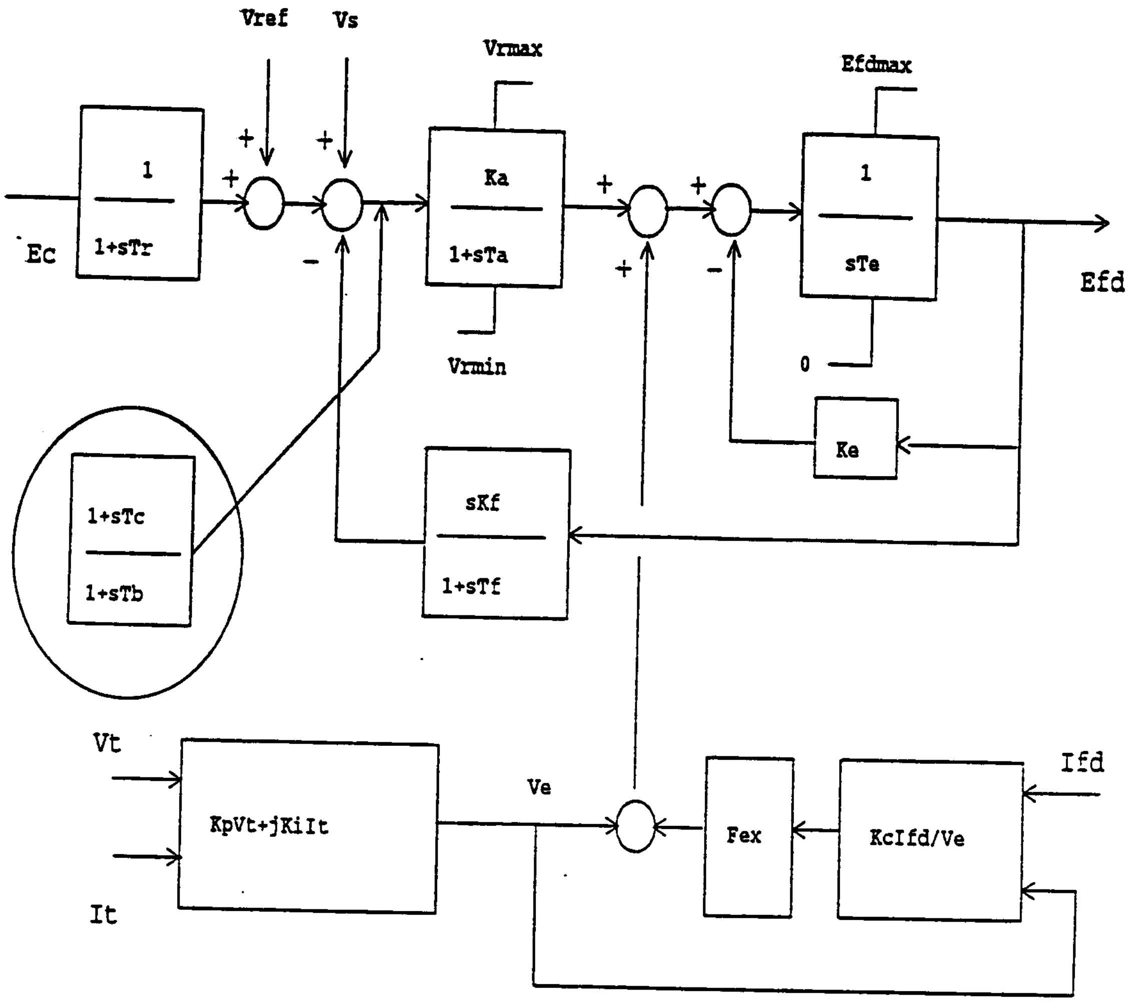
tfv	Voltage transducer time constant, sec
tfi	Current transducer time constant, sec
tnu	Controller reset time constant, sec
vpu	Voltage controller proportional gain
vpi	Current controller gain
vpnf	Controller follow up gain
dpnf	Controller follow up dead band, pu
efmin	Minimum open circuit excitation voltage, pu
efmax	Maximum open circuit excitation voltage, pu
xe	Excitation transformer effective reactance, pu
tw	Stabilizier parameters
ks1	
ks2	
ts1	
ts2	
smax	

exeli   Static PI transformer fed excitation system



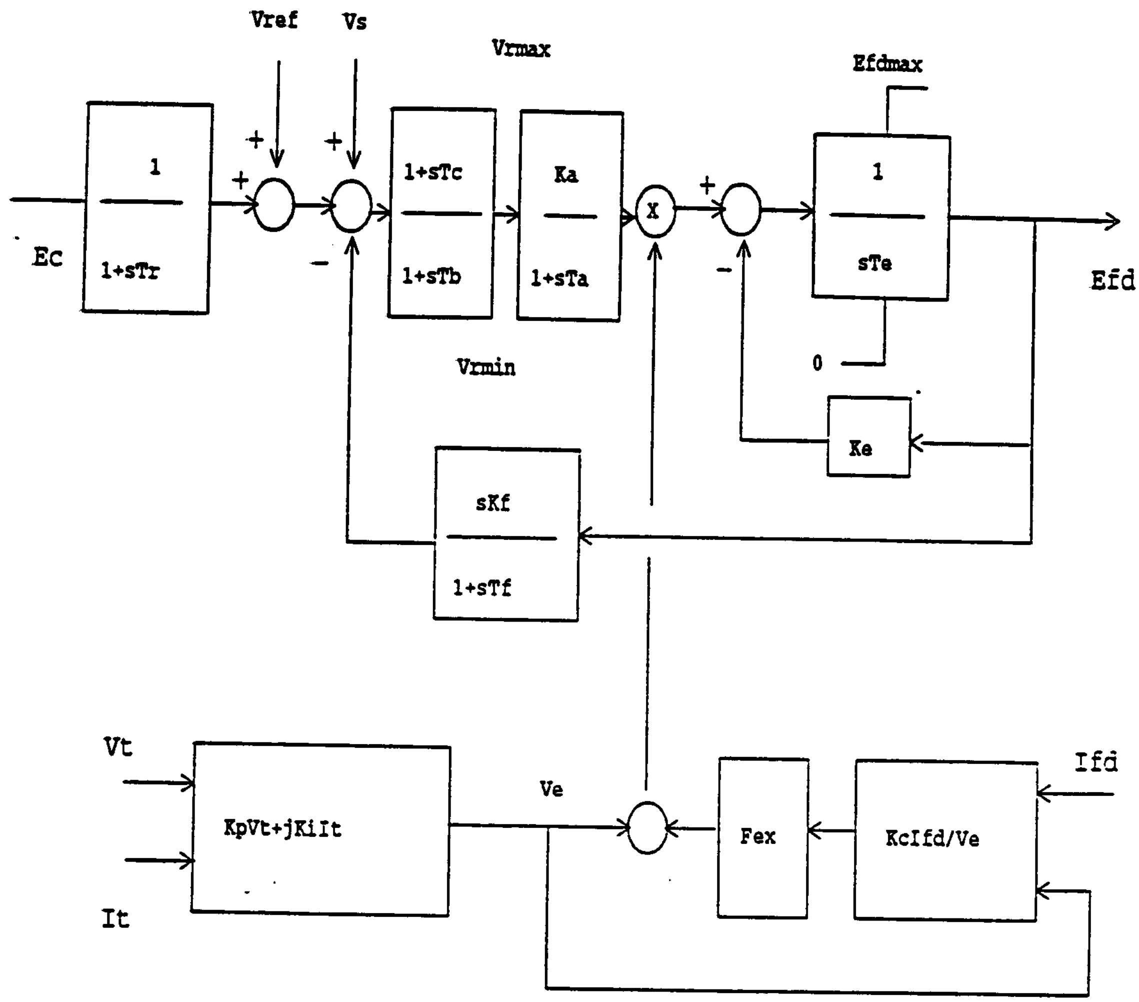
tr	Filter time constant, sec
vimax	Maximum error, pu
vimin	Minimum error, pu
tc	Lead time constant, sec
tb	Lag time constant, sec
ka	Gain
ta	Time constant, sec
vrmax	Maximum controller output
vrmin	Minimum controller output
kc	Excitation system regulation factor, pu
kf	Rate feedback gain
tf	Rate feedback time constant, sec

exst1 IEEE type ST1 excitation system



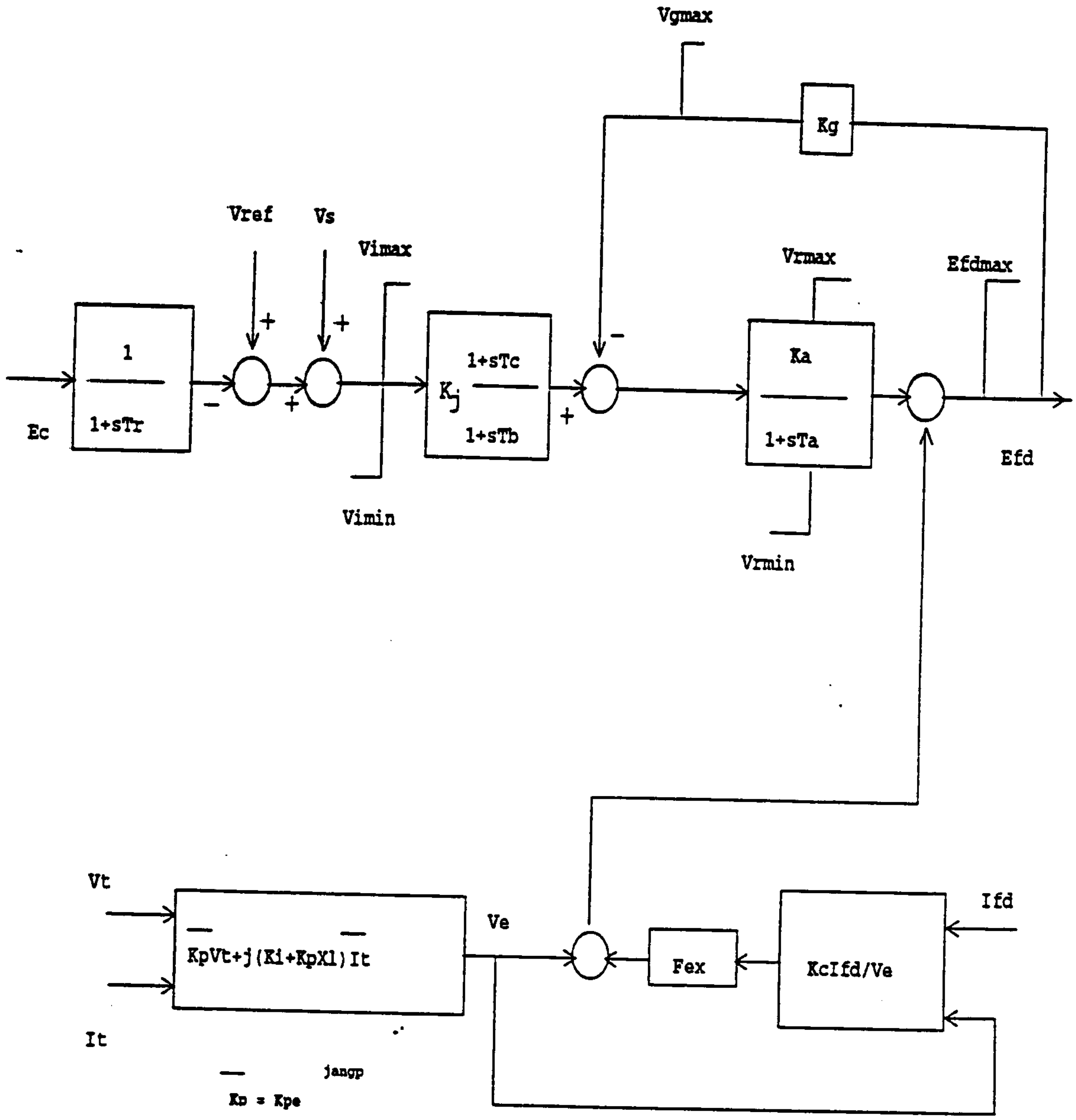
tr	Filter time constant, sec
ka	Gain, p.u.
ta	Time constant, sec
vrmax	Maximum control element output, pu
vrmin	Minimum control element output, pu
ke	Exciter field resistance time constant,pu
te	Exciter time constant, sec
kf	Rate feedback gain
tf	Rate feedback time constant, sec
kp	Potential source gain, p.u.
ki	Current source gain, p.u.
kc	Exciter regulation factor, p.u.
efdmax	Maximum field voltage
tb	Time constant, sec
tc	Time constant, sec

exst2 IEEE type ST2 excitation system



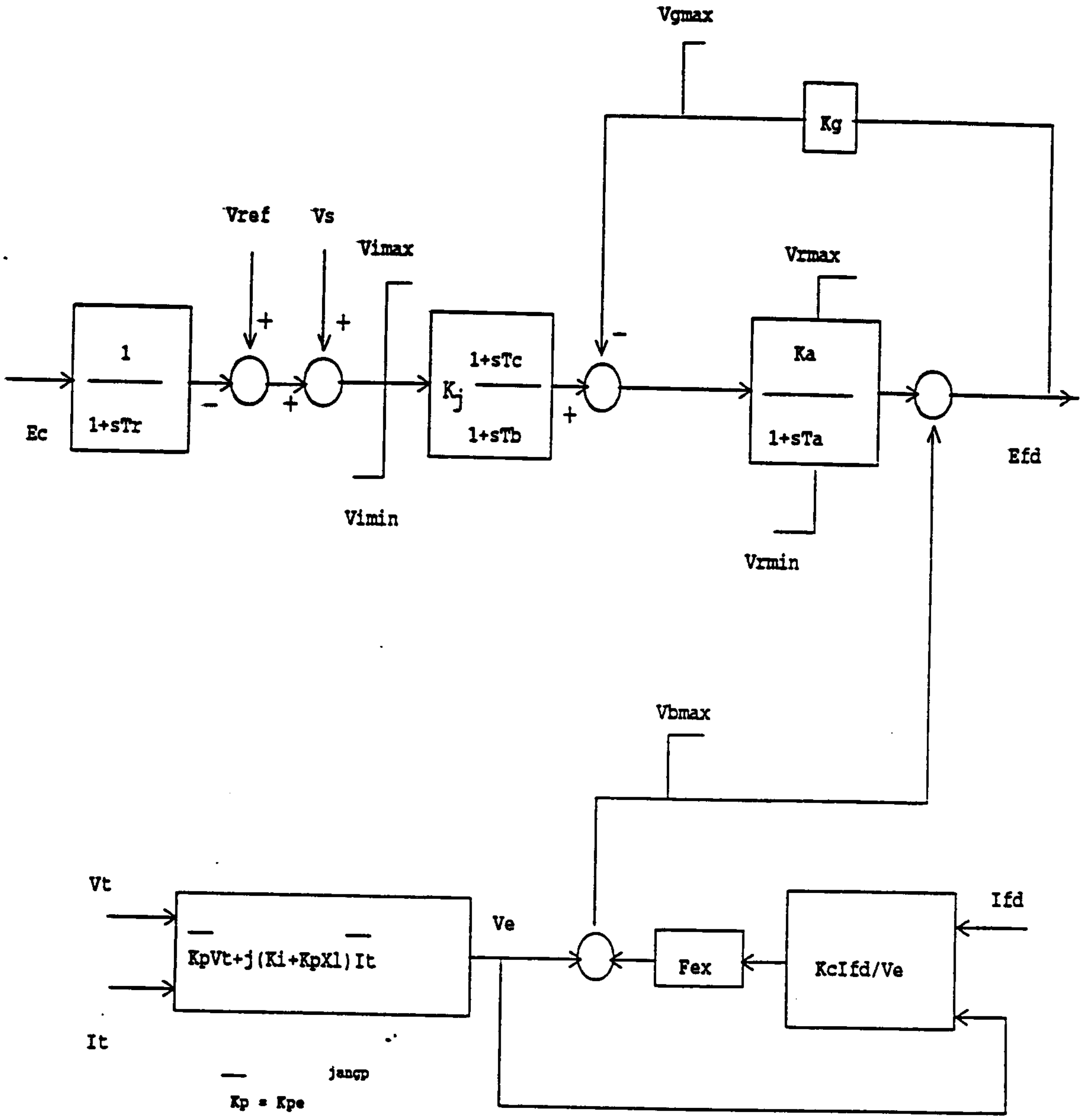
tr	Filter time constant, sec
ka	Gain, p.u.
ta	Time constant, sec
vrmax	Maximum control element output, pu
vrmin	Minimum control element output, pu
ke	Exciter field resistance time constant,pu
te	Exciter time constant, sec
kf	Rate feedback gain
tf	Rate feedback time constant, sec
kp	Potential source gain, p.u.
ki	Current source gain, p.u.
kc	Exciter regulation factor, p.u.
efdmax	Maximum field voltage
tb	Time constant, sec
tc	Time constant, sec

exst2a IEEE type ST2 excitation system



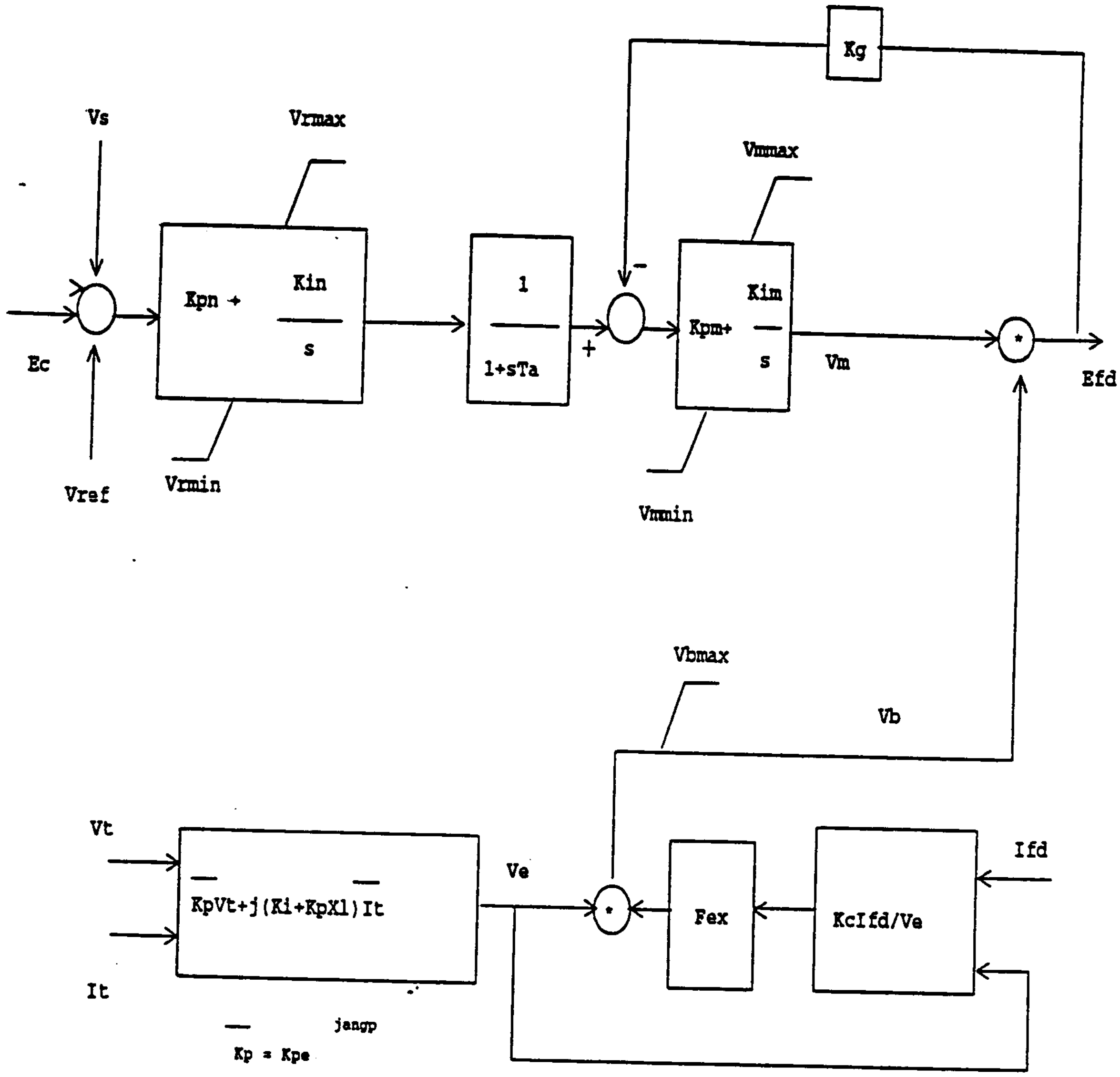
tr	Filter time constant, sec
vimax	Maximum error, pu
vimin	Minimum error, pu
kj	Gain, pu
tc	Lead time constant, sec
tb	Lag time constant, sec
ka	Gain, pu
ta	Time constant, sec
vrmax	Maximum controller output, pu
vrmin	Minimum controller output, pu
kg	Excitation limiter gain, pu
kp	Potential source gain, pu
ki	Current source gain, pu
efdmax	Maximum excitation output, pu
kc	Exciter regulation factor, pu
xl	Excitation current coupling reactance, pu
vgmax	Maximum excitation voltage
angp	Phase angle of potential source, degrees

exst3 IEEE type ST3 excitation system



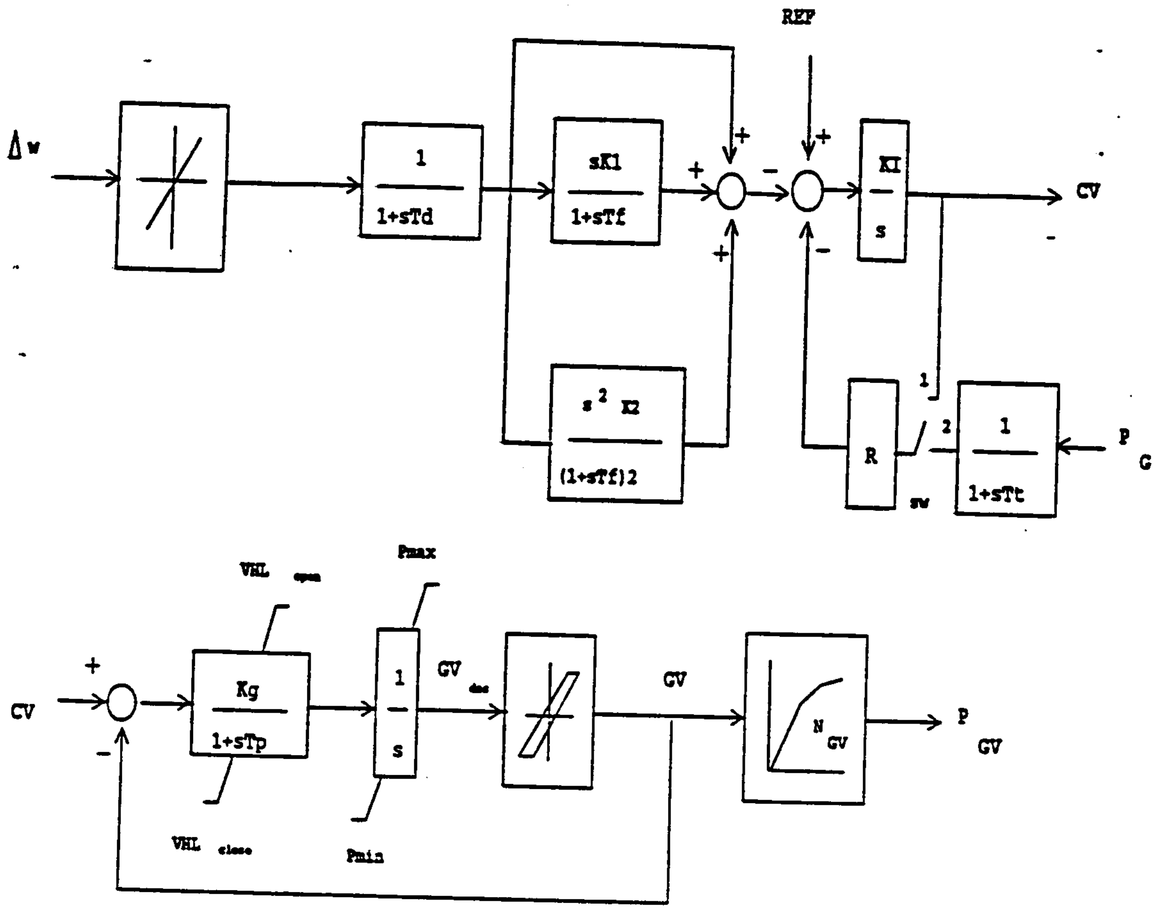
tr	Filter time constant, sec
vimax	Maximum error, pu
vimin	Minimum error, pu
kj	Gain, pu
tc	Lead time constant, sec
tb	Lag time constant, sec
ka	Gain, pu
ta	Time constant, sec
vrmax	Maximum controller output, pu
vrmin	Minimum controller output, pu
kg	Excitation limiter gain, pu
kp	Potential source gain, pu
ki	Current source gain, pu
vbmax	Maximum excitation voltage, pu
kc	Exciter regulation factor, pu
xl	Excitation current coupling reactance, pu
vgmax	Maximum excitation voltage
angp	Phase angle of potential source, degrees

exst3a IEEE type ST3 excitation system



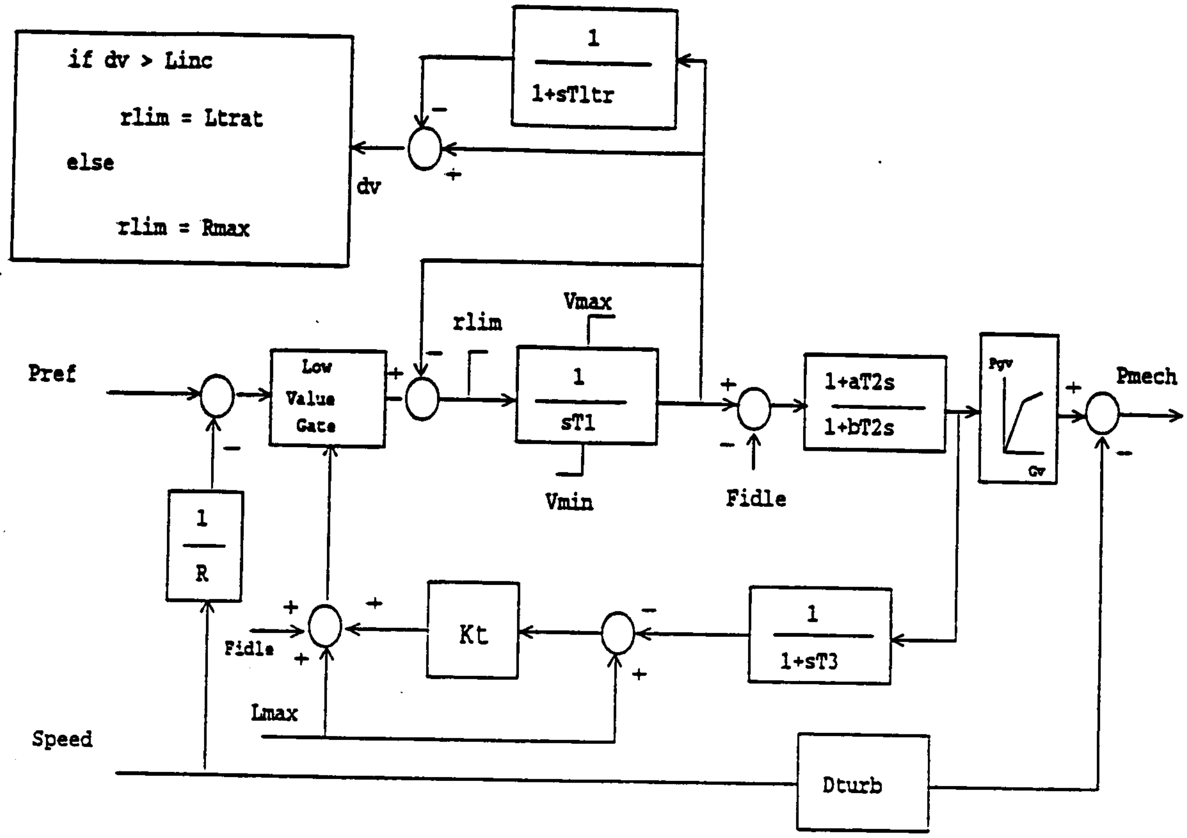
tr	Filter time constant, sec
kpr	Proportional Gain, p.u.
kir	Integral Gain, p.u.
ta	Time constant, sec
vrmax	Maximum control element output, pu
vrmin	Minimum control element output, pu
kpm	Prop. Gain of field voltage regulator, p.u.
kim	Integral Gain of field voltage regulator, p.u.
vmmax	Maximum field voltage regulator output, pu
vmmin	Minimum field voltage regulator output, pu
kg	Excitation limiter gain, pu
kp	Potential source gain, pu
angp	Phase angle of potential source, degrees
ki	Current source gain, pu
kc	Exciter regulation factor, pu
xl	Main generator leakage reactance, pu
vbmax	Maximum excitation voltage

exst4b IEEE type ST4 excitation system



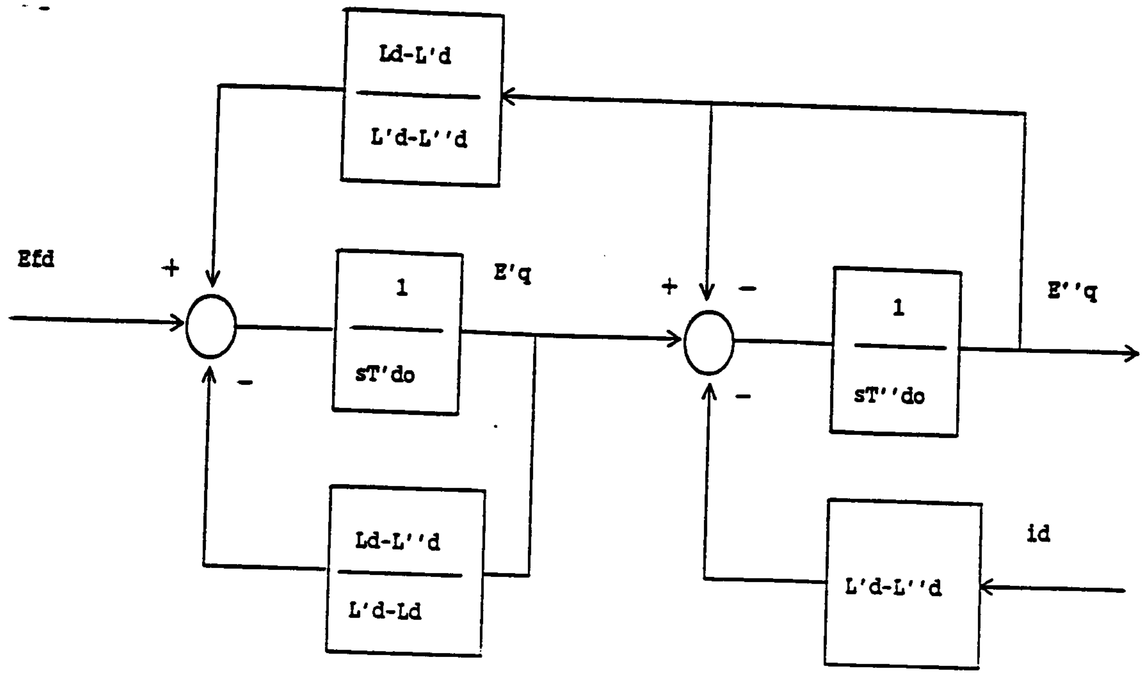
pmax	Maximum turbine output, MW
pmin	Minimum turbine output, MW
r	Steady-state droop, p.u.
td	Input filter time constant, sec
tf	Washout time constant, sec
tp	Gate servo time constant, sec
velop	Maximum gate opening velocity, p.u./sec
velcl	Maximum gate closing velocity, p.u./sec
k1	Single derivative gain, p.u.
k2	Double derivative gain, p.u.
ki	Governor gain, p.u.
kg	Gate servo gain, p.u.
tturb	Turbine time constant, sec (see note g)
aturb	Turbine numerator multiplier (see note g)
bturb	Turbine denominator multiplier (see note g)
tt	Electrical power feedback time const., sec
db1	Intentional deadband width, Hz.
eps	Intentional db hysteresis, Hz.
db2	Unintentional deadband, MW
gv1	Nonlinear gain point 1, p.u. gv
pgv1	Nonlinear gain point 1, p.u. power
gv2	Nonlinear gain point 2, p.u. gv
pgv2	Nonlinear gain point 2, p.u. power
gv3	Nonlinear gain point 3, p.u. gv
pgv3	Nonlinear gain point 3, p.u. power
gv4	Nonlinear gain point 4, p.u. gv
pgv4	Nonlinear gain point 4, p.u. power
gv5	Nonlinear gain point 5, p.u. gv
pgv5	Nonlinear gain point 5, p.u. power

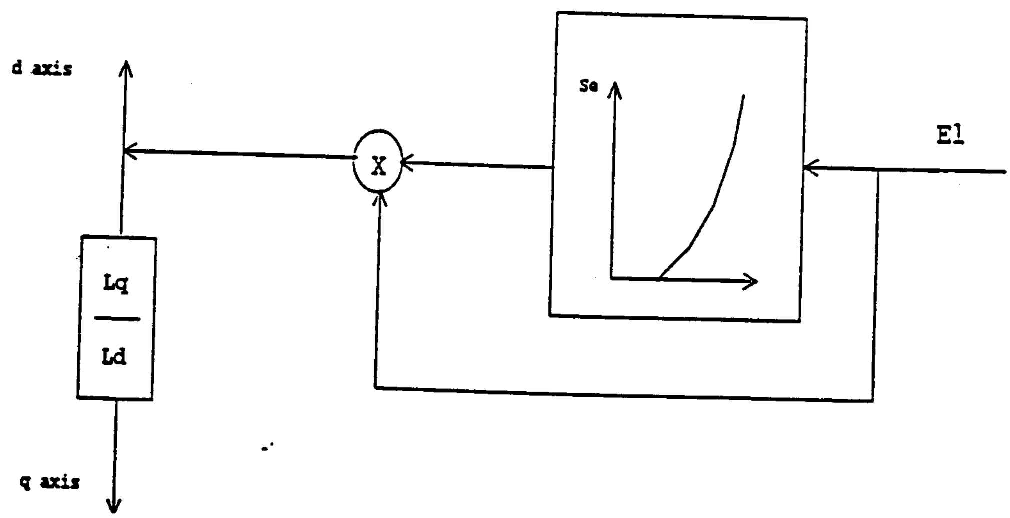
g2wscc Double derivative hydro governor and turbine.
(Represents WSCC G2 governor plus turbine model.)



r	Permanent droop, pu
t1	Governor mechanism time constant, sec
t2	Turbine power time constant, sec
t3	Turbine exhaust temperature time constant, sec
lmax	Ambient temperature load limit
kt	Temperature limiter gain
vmax	Maximum turbine power; pu
vmin	Minimum turbine power, pu
dturb	Turbine damping coefficient, pu
fidle	Fuel flow at zero power output, pu
rmax	Maximum fuel valve opening rate, pu/sec
loadinc	Valve position change allowed at fast rate,pu
tltr	Valve position averaging time constant, sec
ltrate	Maximum long term fuel valve opening rate, pu/sec
a	Turbine power time constant numerator scale factor
b	Turbine power time constant denominator scale factor

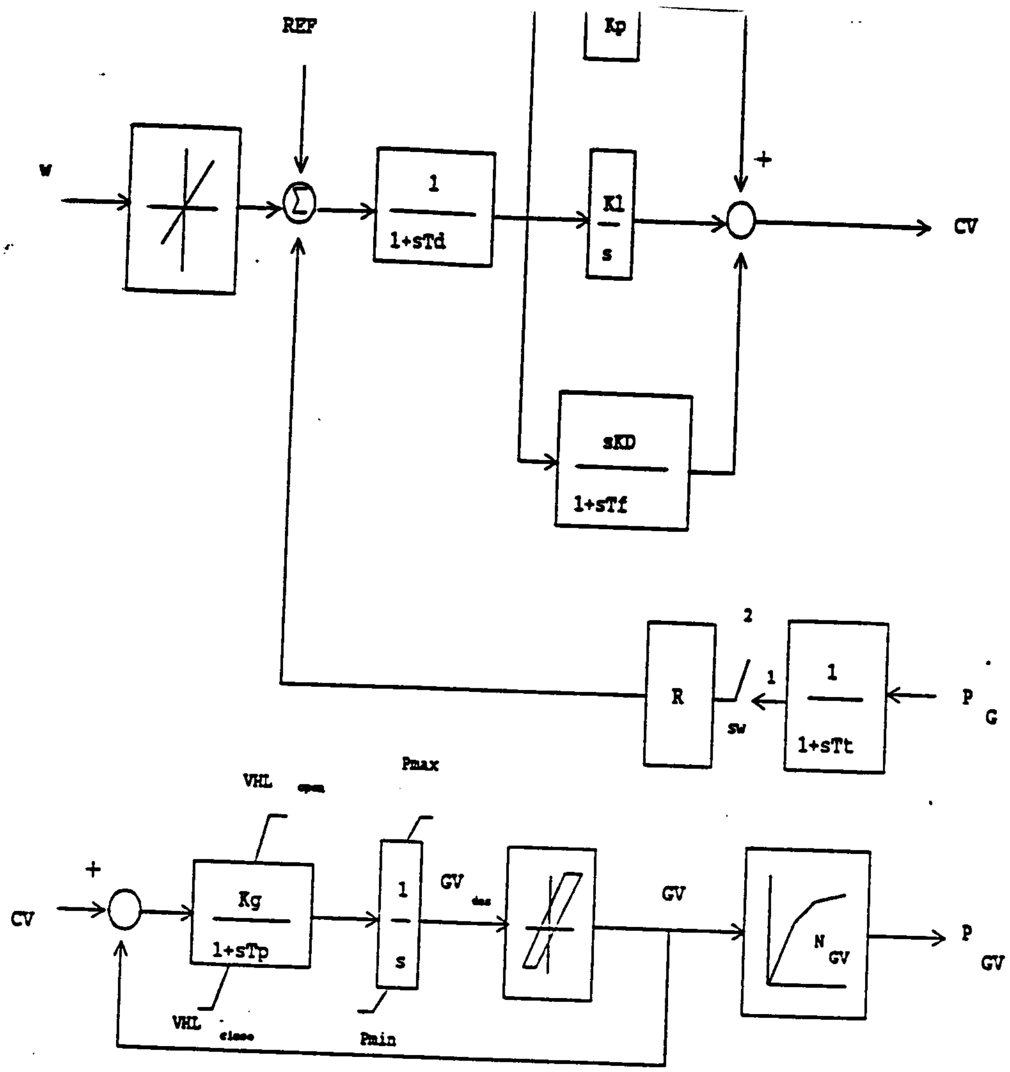
gast Single shaft gas turbine





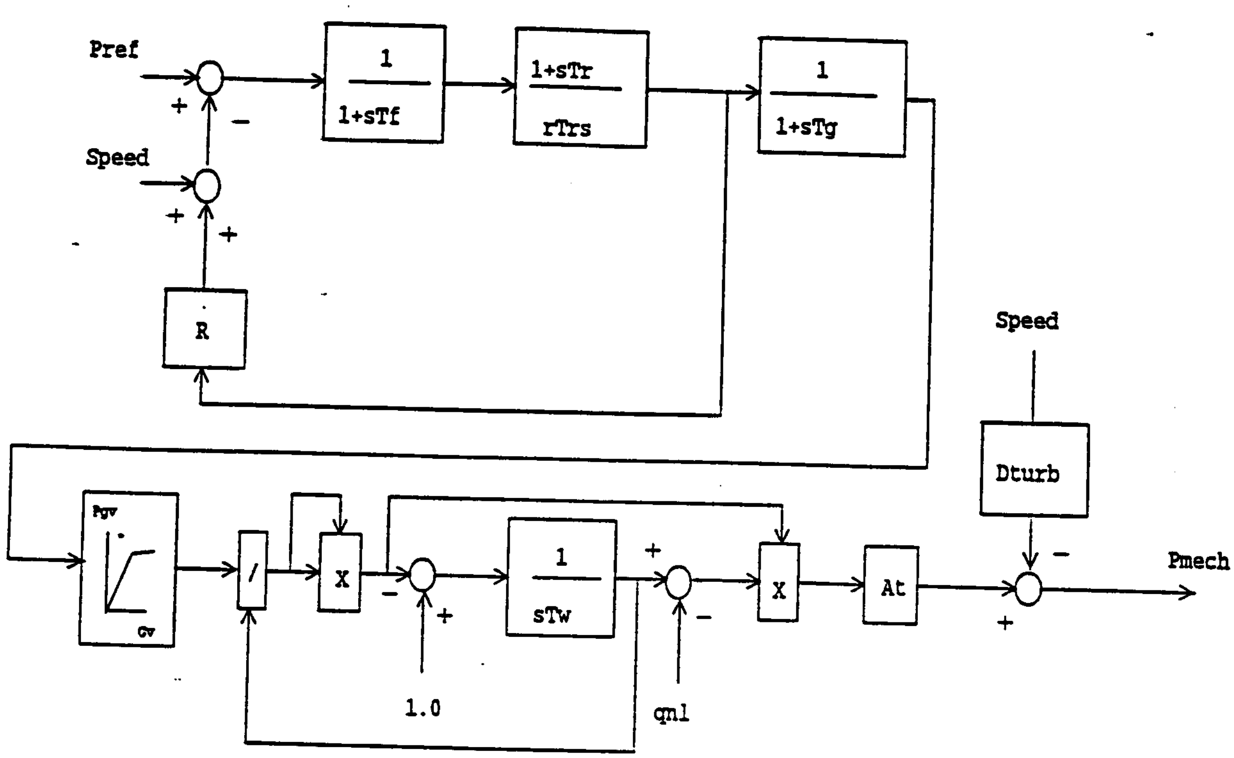
tpdo	D-axis transient rotor time constant
tppdo	D-axis subtransient rotor time constant
tpqo	Q-axis transient rotor time constant
tppqo	Q-axis subtransient rotor time constant
h	Inertia constant, sec
d	Damping factor, pu
ld	D-axis synchronous reactance
lq	Q-axis synchronous reactance
lpd	D-axis transient reactance
lpq	Q-axis transient reactance
lppd	D-axis subtransient reactance
lppq	Q-axis subtransient reactance
ll	Stator leakage reactance, pu
s1	Saturation factor at 1 pu flux
s12	Saturation factor at 1.2 pu flux
ra	Stator resistance, pu
rcomp	Compounding resistance for voltage control, pu
xcomp	Compounding reactance for voltage control, pu
accel	Acceleration factor for network boundary iteration

gentpf — Generator represented by uniform inductance ratios rotor modeling to match WSCC type F model; shaft speed effects are neglected



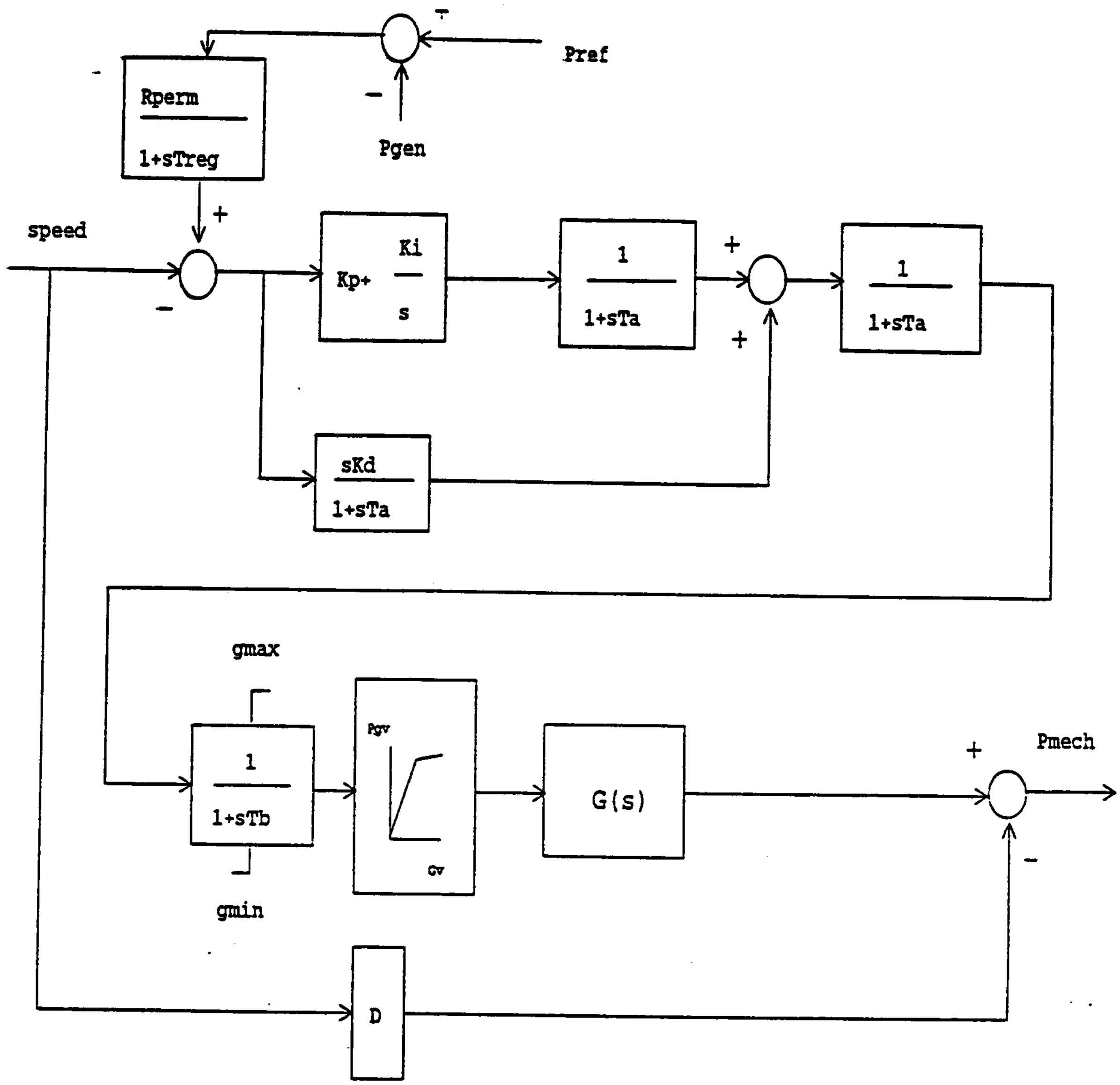
pmax	Maximum turbine output, MW
pmin	Minimum turbine output, MW
r	Steady-state droop, p.u.
td	Input filter time constant, sec
tf	Washout time constant, sec
tp	Gate servo time constant, sec
velop	Maximum gate opening velocity, p.u./sec
velcl	Maximum gate closing velocity, p.u./sec
kp	Proportional gain, p.u.
kd	Derivative gain, p.u.
ki	Integral gain, p.u.
kg	Gate servo gain, p.u.
tturb	Turbine time constant, sec (see note h)
aturb	Turbine numerator multiplier (see note h)
bturb	Turbine denominator multiplier (see note h)
tt	Power feedback time constant, sec
db1	Intentional deadband width, Hz.
eps	Intentional db hysteresis, Hz.
db2	Unintentional deadband, MW
gv1	Nonlinear gain point 1, p.u. gv
pgv1	Nonlinear gain point 1, p.u. power
gv2	Nonlinear gain point 2, p.u. gv
pgv2	Nonlinear gain point 2, p.u. power
gv3	Nonlinear gain point 3, p.u. gv
pgv3	Nonlinear gain point 3, p.u. power
gv4	Nonlinear gain point 4, p.u. gv
pgv4	Nonlinear gain point 4, p.u. power
gv5	Nonlinear gain point 5, p.u. gv
pgv5	Nonlinear gain point 5, p.u. power
gv6	Nonlinear gain point 6, p.u. gv

gpwscc PID governor and turbine.
(Represents WSCC GP governor plus turbine model.)



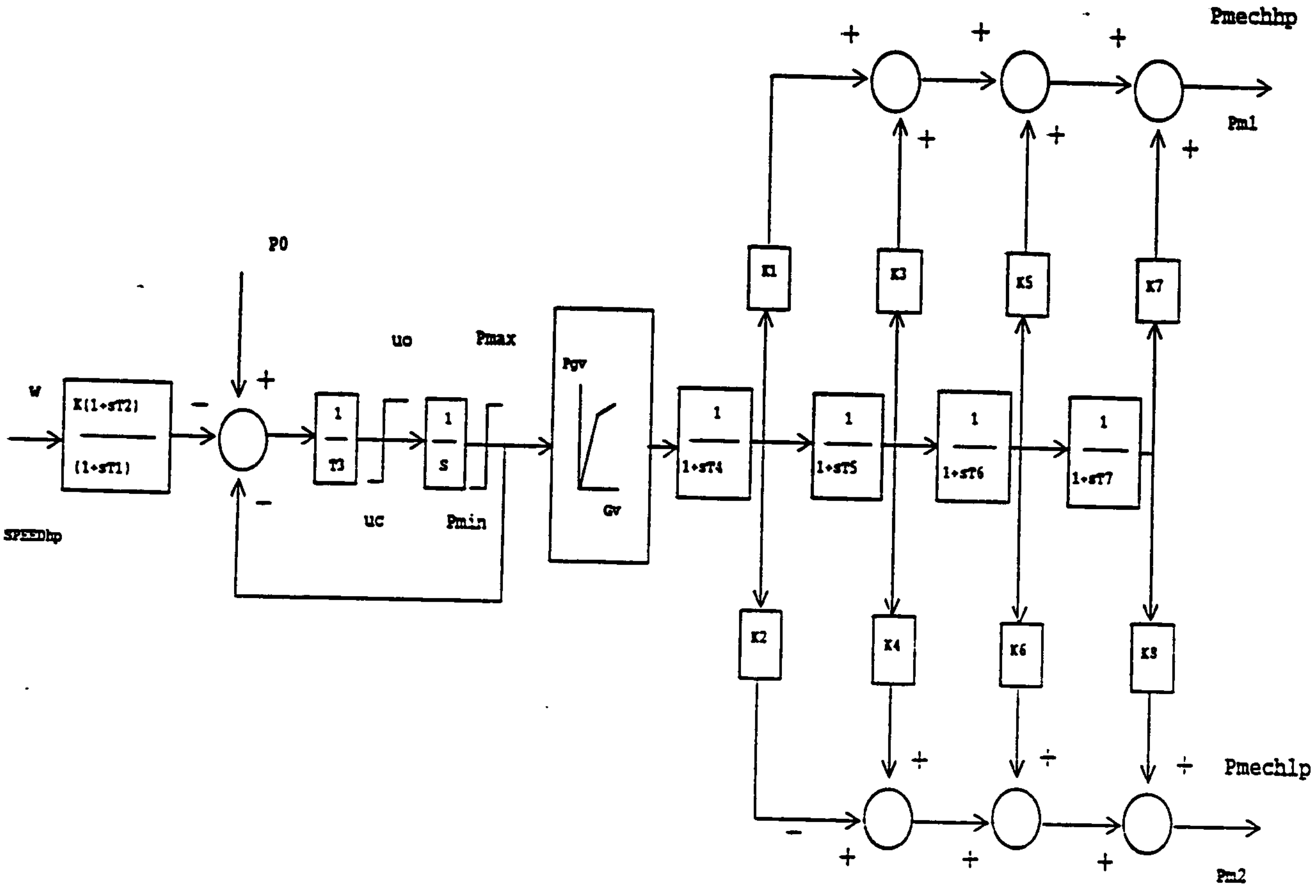
rperm	Permanent droop, p.u.
rtemp	Temporary droop, p.u.
tr	Washout time constant, sec
tf	Filter time constant, sec
tg	Gate servo time constant, sec
velm	Maximum gate velocity, p.u./sec
gmax	Maximum gate opening, p.u.
gmin	Minimum gate opening, p.u.
tw	Water inertia time constant, sec
at	Turbine gain, p.u.
dturb	Turbine damping factor, p.u.
qnl	No-load turbine flow at nominal head, p.u.
ttrip	Turbine trip flag

hygov Hydro turbine and governor. Represents plants with straight forward penstock configurations and hydraulic-dashpot governors or electro-hydraulic governors that mimic dashpot governors (i.e. Woodard hydraulic; ASEA electrohydraulic)

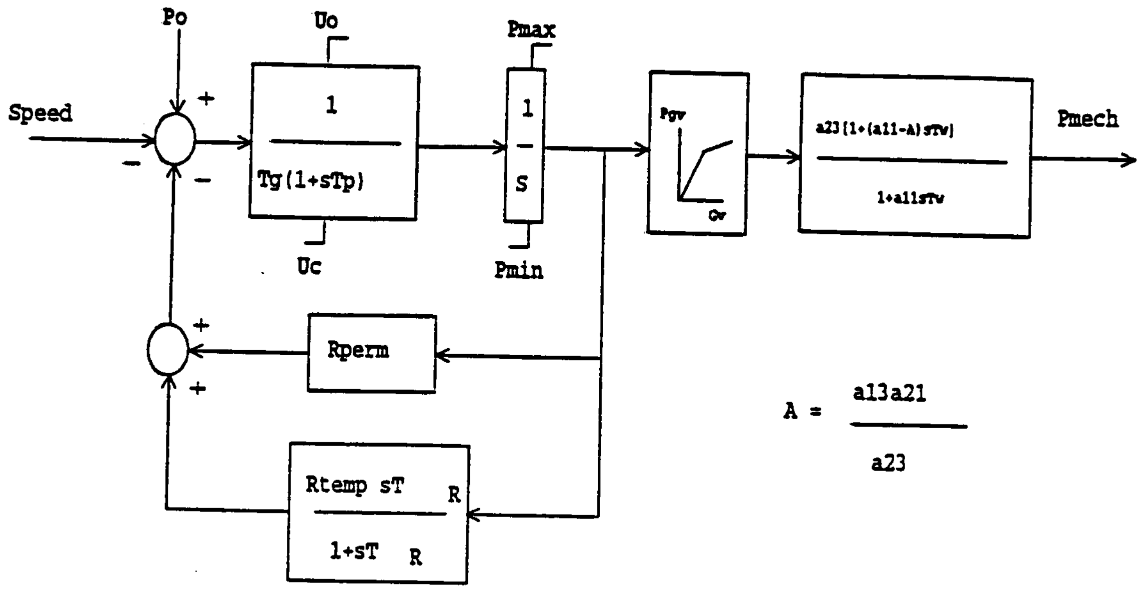


treg	input time constant of governor, sec
rperm	Governor droop, per unit
kp	Governor proportional gain
ki	Governor Integral gain
kd	Governor Derivative gain
ta	Governor High Frequency Cuttoff Time Constant
tb	Gate servo time constant
velmax	Max gate opening velocity, p.u./sec
velmin	Max gate closing velocity, p.u./sec
gmax	Max gate opening, p.u.
gmin	Min gate opening, p.u.
pmax	not used
pmin	not used
d	Turbine Damping Coefficient
twp	Penstock Water Time Constant, sec
twt	Tunnel Water Time Constant, sec
flos	Tunnel Loss Coefficient, p.u.
as1	Area constant of Upper Surge Tank, sec
as2	Area constant of Lower Surge Tank, sec
h2	Level of surge tank size change, per unit

hyst1 Hydro turbine with Woodward Electro-hydraulic PID Governor, Penstock, Surge Tank, and Inlet Tunnel

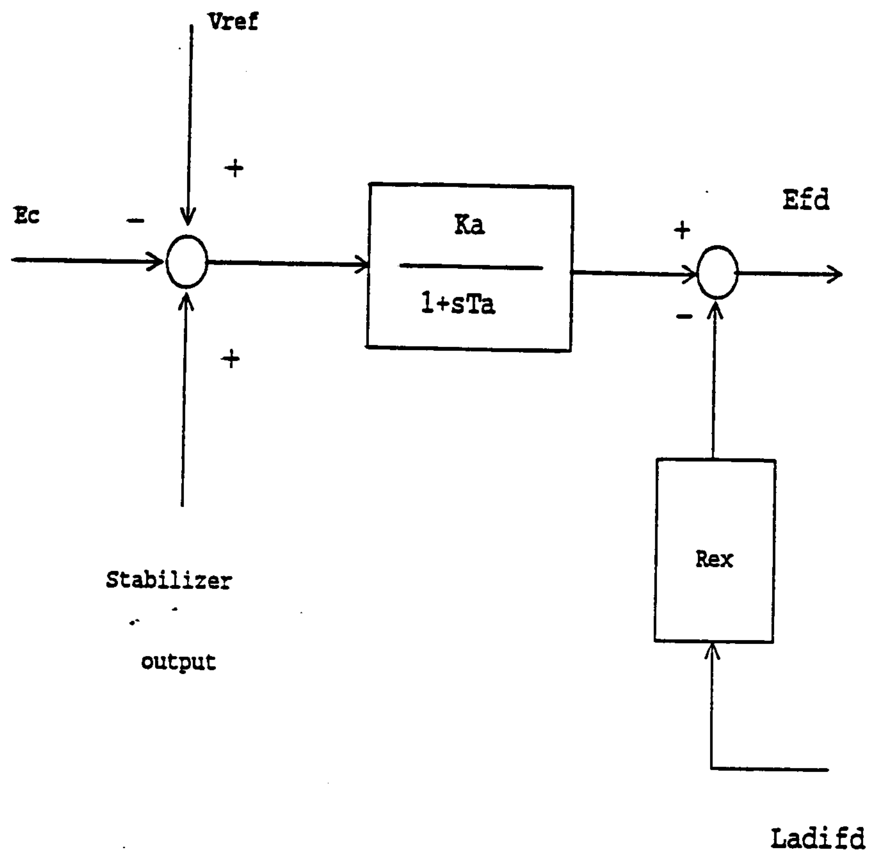


k	Governor gain, p.u. (reciprocal of droop)
t1	Governor lead time constant, sec
t2	Governor lag time constant, sec
t3	Valve positioner time constant, sec
uo	Maximum valve opening velocity, p.u./sec
uc	Maximum valve closing velocity, p.u./sec (<0)
pmax	Maximum valve opening, p.u.
pmin	Minimum valve opening, p.u.
t4	Inlet piping/steam bowl time constant, sec
k1	Fraction of hp turbine power developed after first boiler pass
k2	Fraction of lp turbine power developed after first boiler pass
t5	Time constant of second boiler pass (i.e. reheater), sec
k3	Fraction of hp turbine power developed after second boiler pass
k4	Fraction of lp turbine power developed after second boiler pass
t6	Time constant of third boiler pass, sec
k5	Fraction of hp turbine power developed after third boiler pass



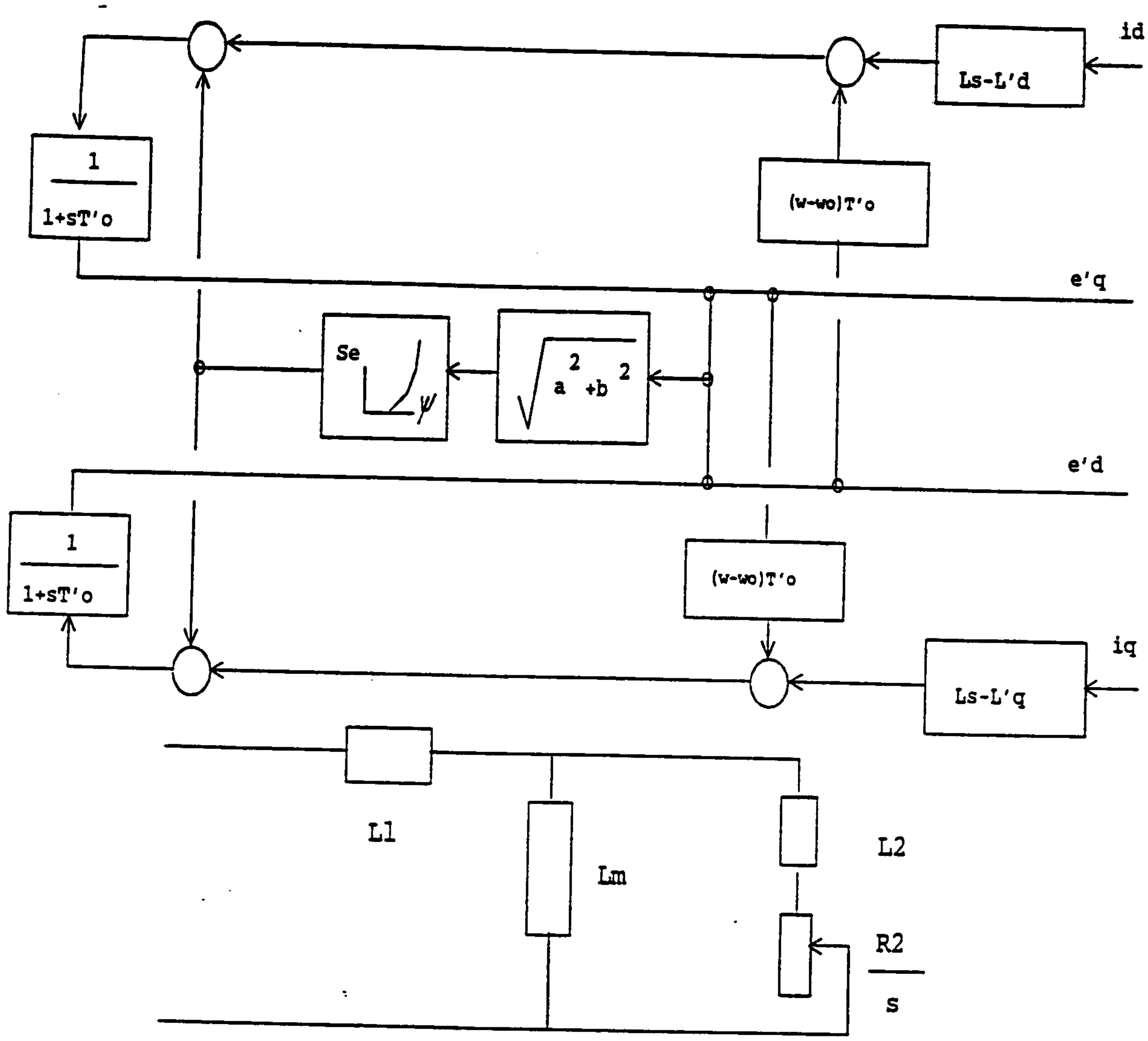
tg	Gate servo time constant, sec
tp	Pilot servo valve time constant, sec
uo	Maximum gate opening velocity, p.u./sec
uc	Maximum gate closing velocity, p.u./sec
pmax	Maximum gate opening, p.u.
pmin	Minimum gate opening, p.u.
rperm	Permanent droop, p.u.
rtemp	Temporary droop, p.u.
tr	Dashpot time constant, sec
tw	Water inertia time constant, sec
a11	Turbine parameter ( ), p.u.
a13	Turbine parameter ( ), p.u.
a21	Turbine parameter ( ), p.u.
a23	Turbine parameter (dP/dg), p.u.

ieeeg3 IEEE hydro turbine/governor model.



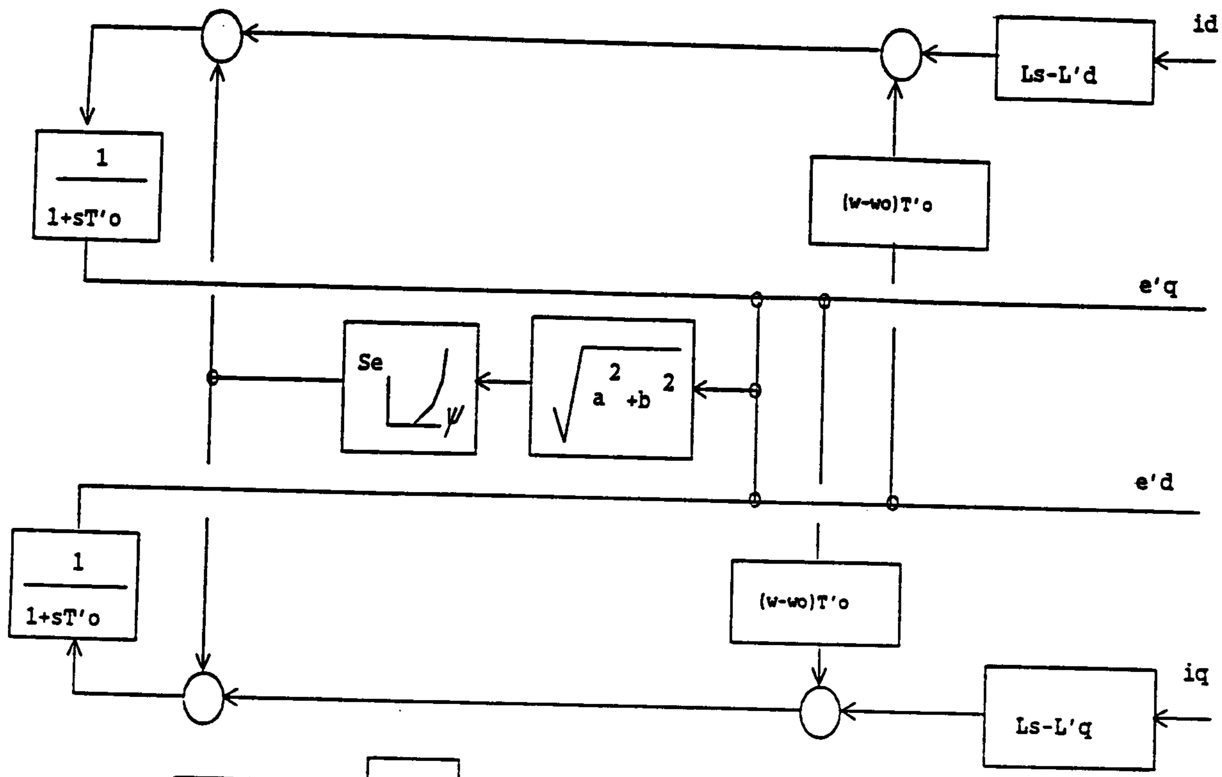
ka	Gain
ta	Time constant, sec
rex	Excitation system resistance

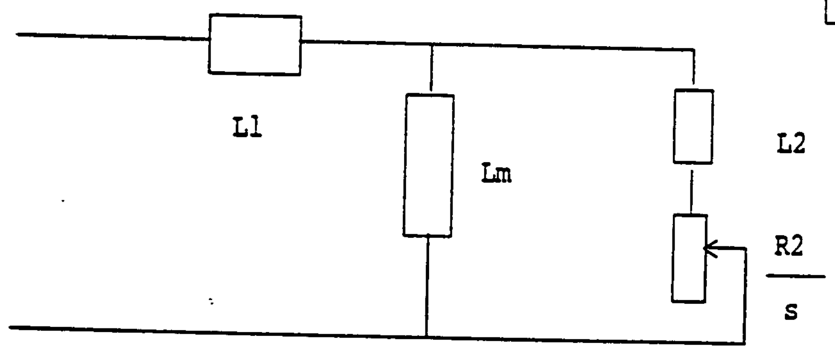
mexs **Manual excitation control with field circuit resistance**



ls	Synchronous reactance
lp	Transient reactance
ra	Stator resistance, p.u.
tpo	Transient rotor time constant
h	Inertia constant, sec
d	Damping factor, p.u.
se1	Saturation factor at 1 p.u. flux
se2	Saturation factor at 1.2 p.u. flux
vt	Voltage threshold for tripping (default = 0), p.u.
tv	Voltage trip pickup time (default = 999), sec.
ft	Frequency threshold for tripping (default = 0), Hz
tf	Frequency trip pickup time (default = 999), sec.
vr	Voltage at which reconnection is permitted (default = 1.2), p.u.
tvr	Time delay for reconnection (default = 999), sec.
acc	Acceleration factor for initialization

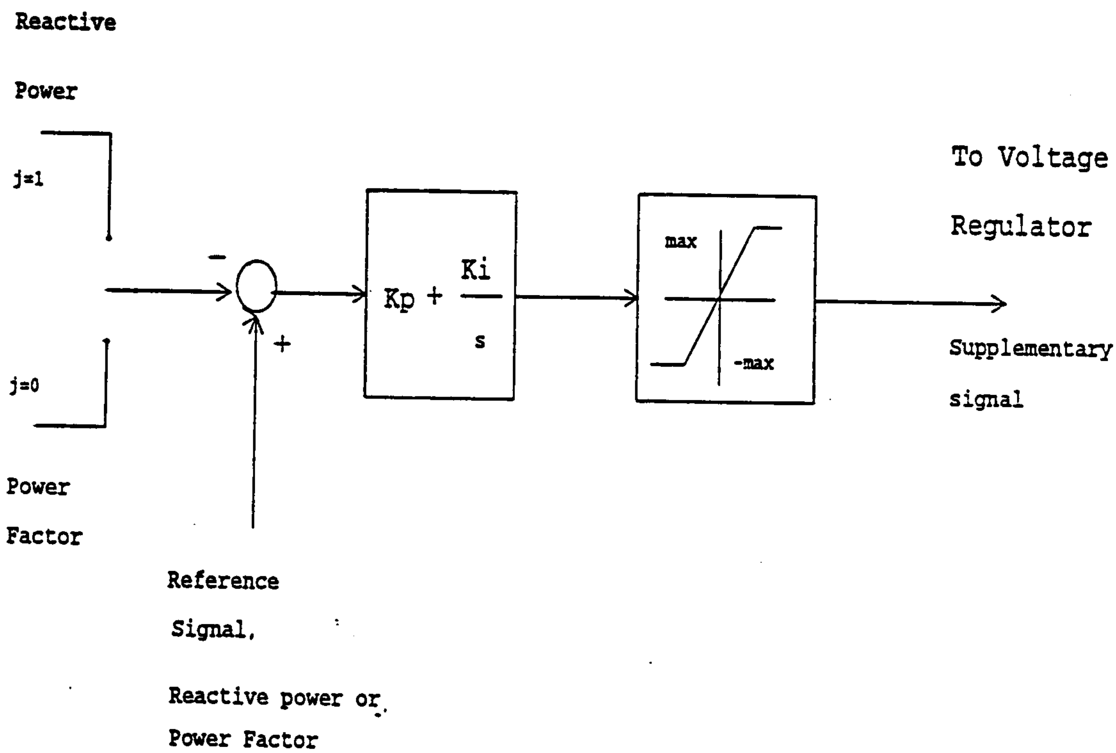
motor1 Induction machine modeled with rotor flux transients





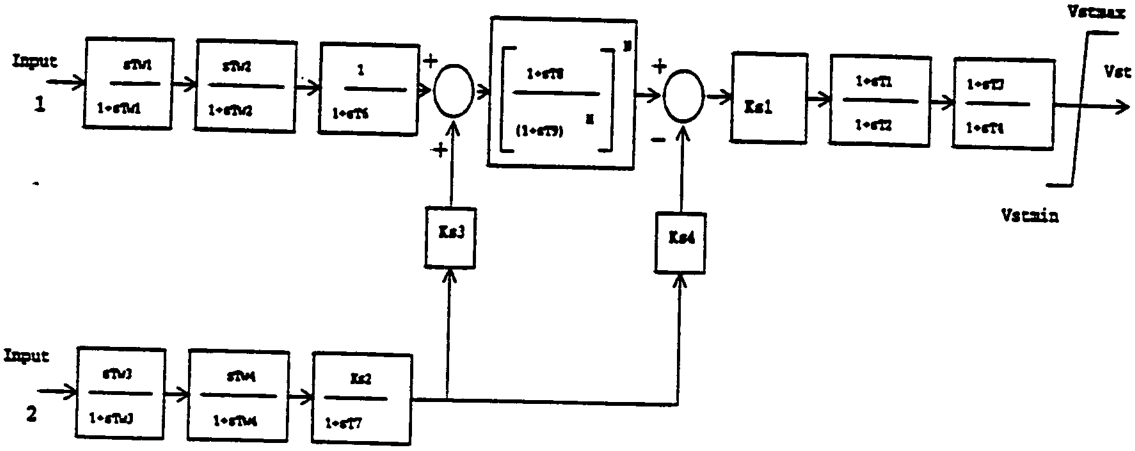
pul	Fraction of constant-power load to be represented by this motor model
ls	Synchronous reactance
lp	Transient reactance
ra	Stator resistance, p.u.
tpo	Transient rotor time constant
h	Inertia constant, sec
d	Damping factor, p.u.
vt	Voltage threshold for tripping (default = 0), p.u.
tv	Voltage trip pickup time (default = 999), sec.
tbkr	Circuit bker operating time (default = 999), sec
acc	Acceleration factor for initialization

motorw Motor model for use as a component of general purpose substation load



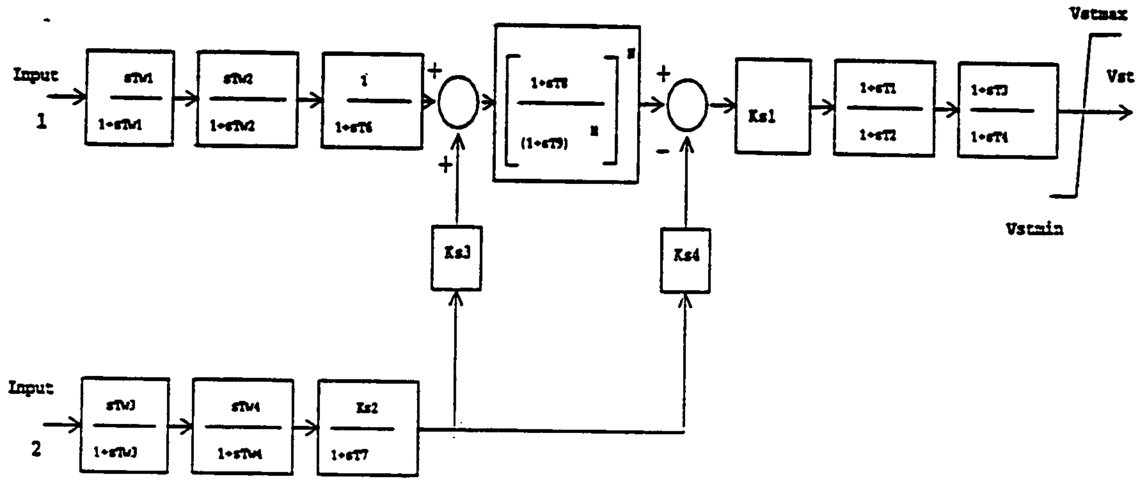
j	Control mode	1 for reactive power 0 for power factor
kp	Proportional gain	
ki	Reset gain	
max	Output limit	

pfqrg   Power factor / Reactive power regulator



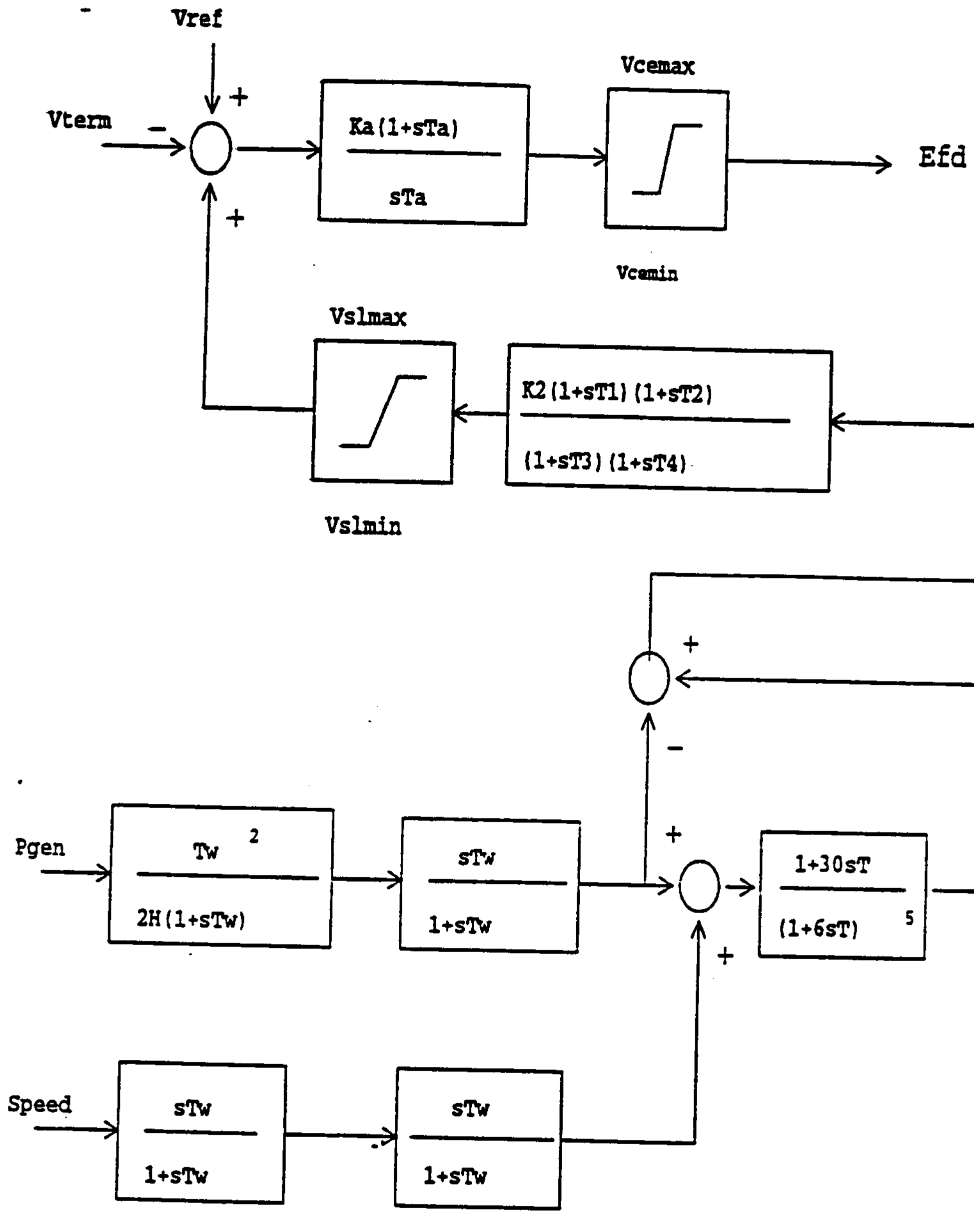
j1	Input signal #1 code
k1	Input signal #1 remote bus number
j2	Input signal #2 code
k2	Input signal #2 remote bus number
tw1	First washout on signal #1, sec
tw2	Second washout on signal #1, sec
tw3	First washout on signal #2, sec
tw4	Second washout on signal #2, sec
t6	Time constant on signal #1, sec
t7	Time constant on signal #2, sec
ks2	Gain on signal #2
ks3	Gain on signal #2
ks4	Gain on signal #2
t8	Lead of ramp tracking filter
t9	Lag of ramp tracking filter
n	Order of ramp tracking filter
m	Order of ramp tracking filter
ks1	Stabilizer gain
t1-t4	Lead/lag time constants, sec
vstmax	Stabilizer output max limit, p.u.
vstmin	Stabilizer output min limit, p.u.

pss2a Dual input Power System Stabilizier (IEEE type PSS 2A)



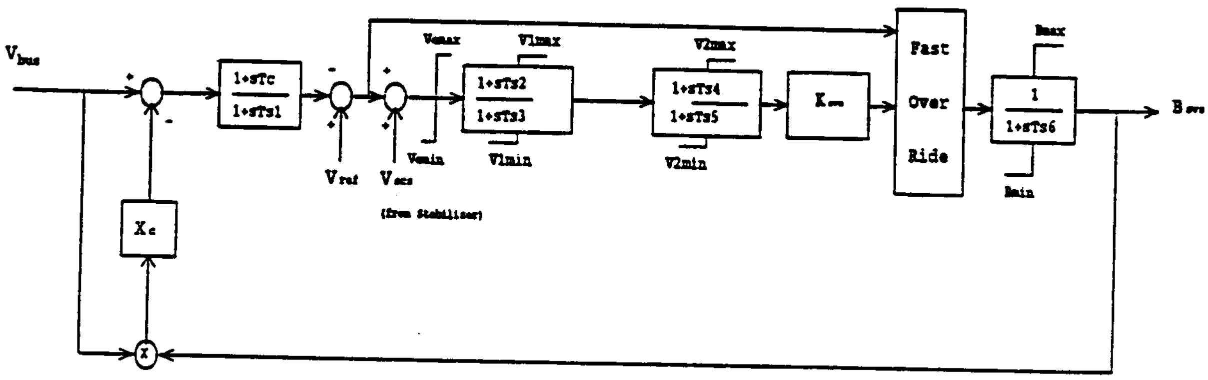
j1	Input signal #1 code
k1	Input signal #1 remote bus number
j2	Input signal #2 code
k2	Input signal #2 remote bus number
tw1	First washout on signal #1, sec
tw2	Second washout on signal #1, sec
tw3	First washout on signal #2, sec
tw4	Second washout on signal #2, sec
t6	Time constant on signal #1, sec
t7	Time constant on signal #2, sec
ks2	Gain on signal #2
ks3	Gain on signal #2
ks4	Gain on signal #2
t8	Lead of ramp tracking filter
t9	Lag of ramp tracking filter
n	Order of ramp tracking filter
m	Order of ramp tracking filter
ks1	Stabilizer gain
t1-t4	Lead/lag time constants, sec
vstmax	Stabilizer output max limit, p.u.

psssb **Dual input Power System Stabilizier (IEEE type PSS 2A) +Voltage Boost signal Transient Stabilizier and Vcutoff**

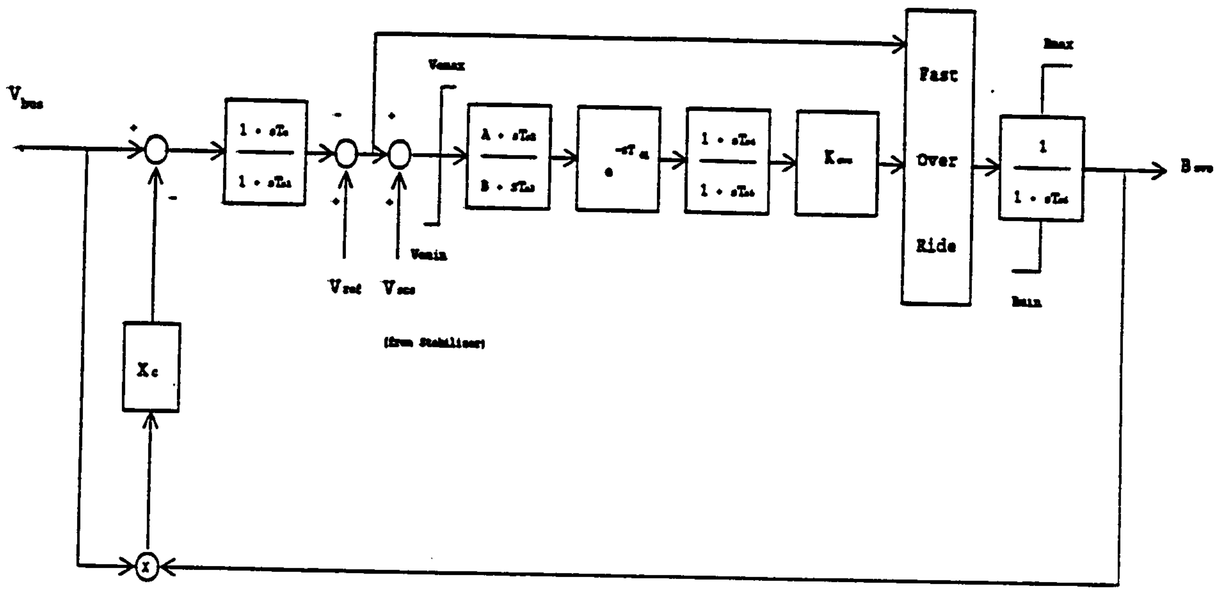


ka	Voltage regulator gain
ta	Voltage regulator reset time constant, sec
vcemin	Minimum exciter output voltage, pu
vcemax	Maximum exciter output voltage, pu
tw	Stabilizer washout time constant, sec
m	Inertia time constant (2H) for stabilizer, sec
k2	Stabilizer gain
t1	Stabilizer lead time constant, sec
t2	Stabilizer lead time constant, sec
t3	Stabilizer lag time constant, sec
t4	Stabilizer lag time constant, sec
vslmin	Minimum stabilizer output, pu
vslmax	Maximum stabilizer output, pu
t	1./(System Frequency) [0.01667], sec

silco5 Canadian GE Silco5 excitation system model

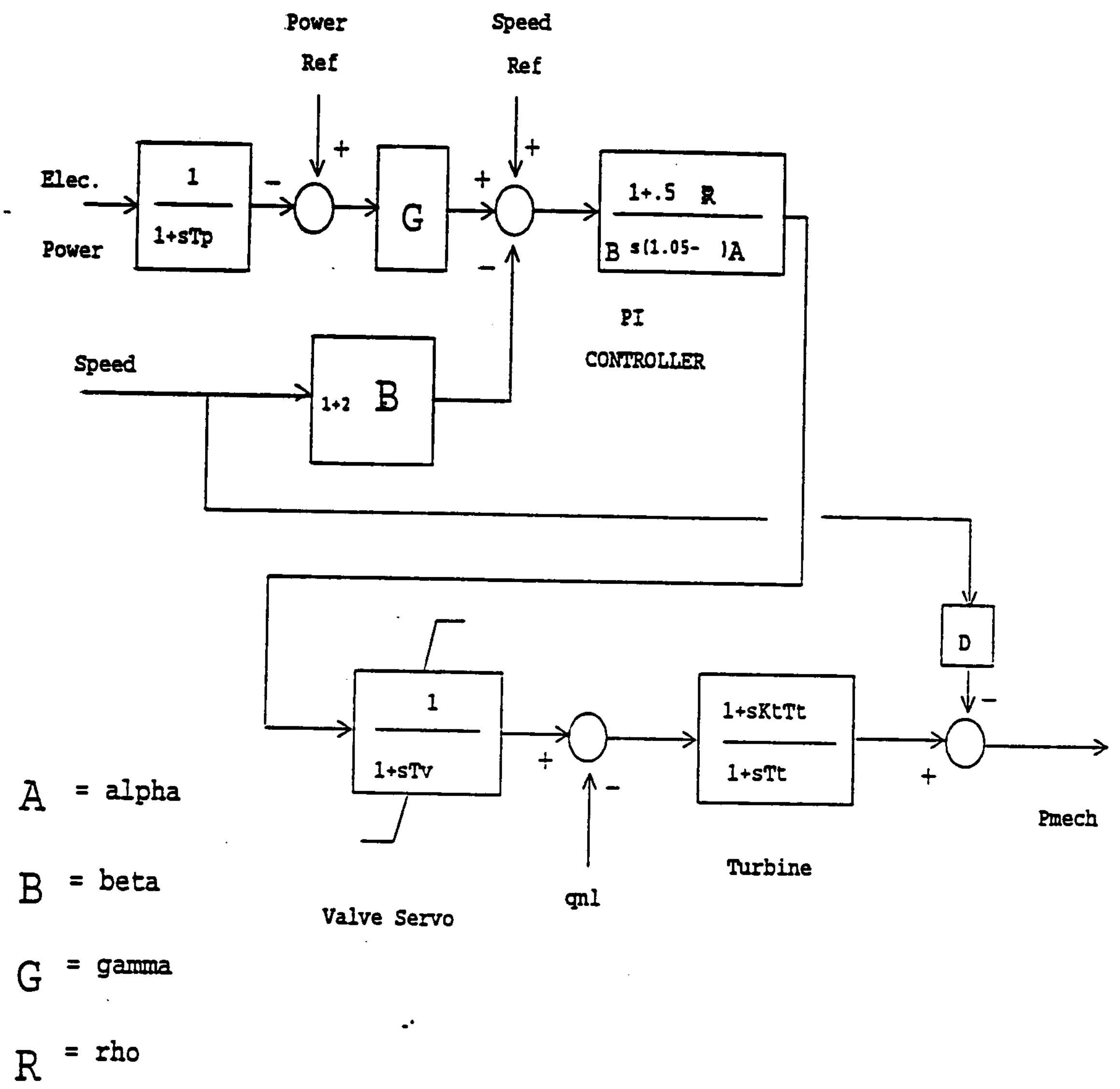


ts1	Voltage transducer time constant, sec
vemax	Maximum error signal, pu
ts2	Lead time constant, sec
ts3	Lag time constant, sec
a	Lead gain, must be 1.0
b	Lag gain, must be 1.0
ts4	Lead time constant, sec
ts5	Lag time constant, sec
ksvs	Gain, per unit b/per-unit v
ksd	Discontinuous control gain, pu
bmax	Maximum admittance, pu
bpmax	Maximum controlled admittance, pu
bpmin	Minimum controlled admittance, pu
bmin	Minimum admittance, pu
ts6	Firing control time constant, sec
dv	Threshold for switched control, pu
xc	Line drop compensating reactance, p.u.
tc	Transducer lead time constant, sec.
dv2	Threshold for added shunt switching, pu
bshunt	Additional switched shunt admittance, pu
tdelay	Time delay for switching added shunt, sec
bias	Constant "bias" shunt admittance, pu
j1	First stabilizer input signal code
k1	Stabilizer input source bus, from
k2	Stabilizer input source bus, to
j2	Second stabilizer input signal code
ks1	Stabilizer gain
ts7	Stabilizer time constant, sec
ts8	Stabilizer time constant, sec



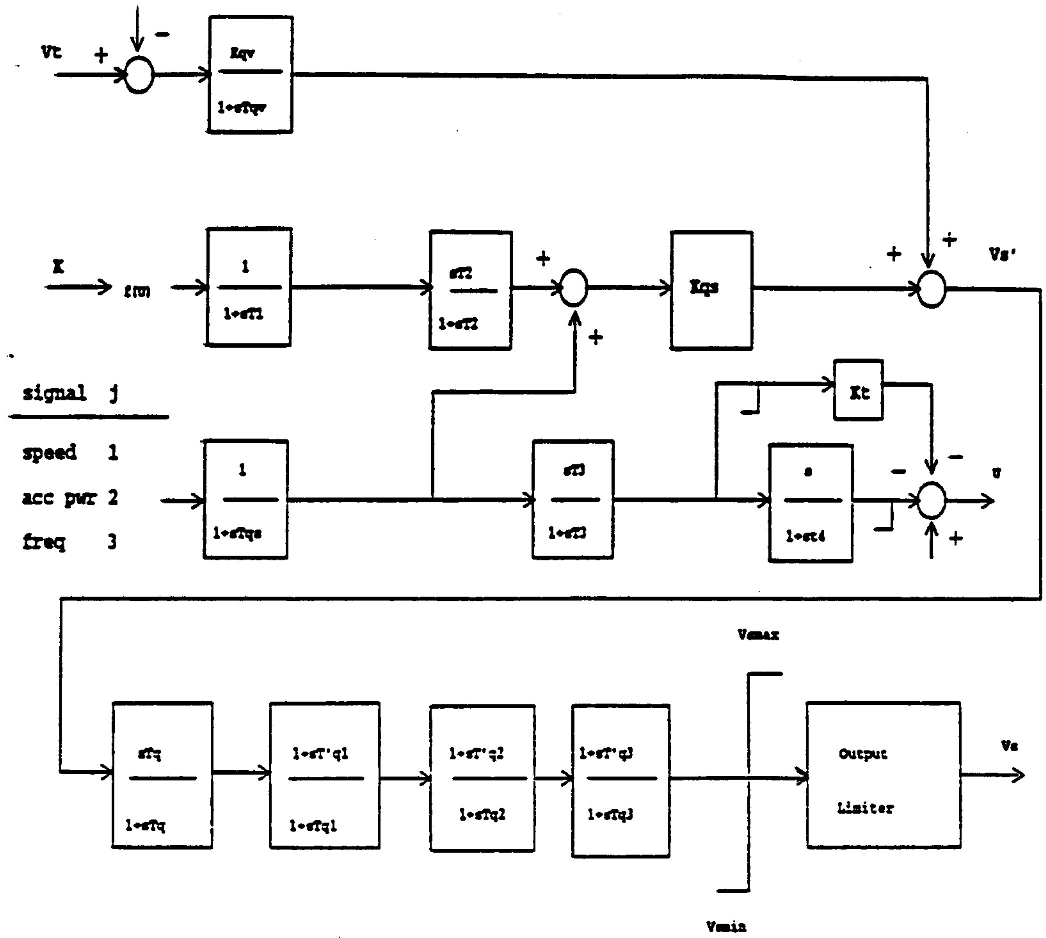
ts1	Voltage transducer time constant, sec
vemax	Maximum error signal, pu
ts2	Lead time constant, sec
ts3	Lag time constant, sec
a	Lead gain, must be 1.0
b	Lag gain, must be 1.0
ts4	Lead time constant, sec
ts5	Lag time constant, sec
ksvs	Gain, per unit b/per unit v
ksd	Discontinuous control gain, pu
bmax	Maximum admittance, pu
bpmax	Maximum admittance under continuous control, pu
bpmin	Minimum admittance under continuous control, pu
bmin	Minimum admittance, pu
ts6	Firing control time constant, sec
dv	Error threshold for discontinuous control, pu
xc	Line drop compensating reactance, p.u.
tc	Transducer lead time constant, sec.
td1	Controller delay, sec.

vwscc WSCC basic static VAR system model



tp	Power transducer time constant, sec
alpha	Gain setting
beta	Reset gain setting
rho	Proportional gain setting
gamma	Droop setting, pu
gain	Turbine gain
tv	Valve actuator time constant, sec
velmax	Maximum valve velocity, pu/sec
gmax	Maximum valve opening, pu
gmin	Minimum valve opening, pu
gnl	Valve opening at no load, pu
tturb	Turbine time constant, sec
d	Turbine damping factor
kt	non-zero for diesel, 0 for steam/gas

w2301 Woodward 2301 governor and basic turbine model



j	Input signal code: 1 for shaft speed 2 for accelerating power 3 for bus frequency
kqv	Voltage deviation gain
tqv	Voltage transducer time constant, sec
kqs	Main input signal gain
tqs	Main input signal transducer time constant, sec
tq	Stabilizer washout time constant, sec
tq1	Lag time constant, sec
tpq1	Lead time constant, sec
tq2	Lag time constant, sec
tpq2	Lead time constant, sec
tq3	Lag time constant, sec
tpq3	Lead time constant, sec
vsmax	Maximum output signal, pu
vcutoff	Voltage deviation level for stabilizer cutout, pu
vslow	Minimum output signal, sec
t1	Frequency boost signal transient stabilizer lag
t2	Frequency boost signal transient stabilizer washout time constant, sec
t3	Frequency boost signal transient stabilizer Trigger washout time constant, sec
kboost	Transient stabilizer boost signal, pu
dw1	Speed deviation 1 for trigger, pu
dw2	Speed deviation 2 for trigger, pu
ddwt	Acceleration value for trigger, pu
tdelay	Trigger delay, sec
t4	Frequency boost signal transient stabilizer Trigger circuit lag, sec

APPENDIX B

DEFINITIONS

BASE VALUES FOR PER UNIT PARAMETERS

The GE dynamic simulation program, whose data sheets and parameter lists are shown in Appendix A, requires that all per unit parameters and per unit variables are specified with respect to base values equal to *generator nameplate rated values.*

The bases to be used in converting measured electrical values and mechanical power of electrical machine rotors (volts, amps, ohms, and other physical-unit measures) to per unit values are as follows:

Parameter or Variable	**Base Value**	**Name of Base Value**
Electrical MVA	Generator rated MVA	Sbase
Electrical MW	Generator rated MVA	Sbase
Electrical MVAR	Generator rated MVA	Sbase
Shaft speed	Generator rated speed	Wbase
Electrical Torque	Generator rated torque Sbase / Wbase	Tbase
Mechanical Power	Generator rated MVA	Sbase
Mechanical Torque	Generator rated torque	Tbase
Stator AC Voltage	Generator rated voltage	Vsbase
Stator AC Current	Isbase=Sbase/(1.732*Vsbase)	Isbase
Field DC Current	DC current in field winding for AC voltage equal to Vsbase on air gap line when on open circuit at rated speed	Ifbase
Field DC Voltage	Ifbase * (DC resistance of field winding when hot)	Vfbase

The bases to be used for variables and parameters in excitation systems and associated subsystems such as power system stabilizers must be those given above.

The bases to be used for mechanical positions (such as valve openings) and other signals in governors and turbine controls should be the full-range values of these quantities. These base values are frequently related to the generator MVA base by gains other than unity.

Example:

The following example illustrates the per unit conventions:

A hydro generator is observed to require a turbine gate opening of 3 inches at speed-no-load and a gate opening of 21 inches at rated generator output. The open circuit magnetization curve shows the air gap line field current at speed-no-load and 14.4Kv to be 420 Amps, and the actual field current in this condition to be 441 Amps. The field voltage in this speed-no-load condition is 145 volts

The full stroke of the servomotor is 25 inches.
The generator nameplate ratings are

125 MVA
0.8 power factor
14.4 Kv
1050 Amps DC
350 Volts DC

The turbine nameplate ratings are

120 Ft head
1750000 Hp

The excitation transformer and rectifier can provide a maximum DC field voltage of 600V

The base values are as follows

Sbase = 125 MVA
Vsbase = 14.4 Kv
Isbase = 125e6./(1.732*14.4e3) = 5012 Amps
Ifbase = 420 Amps
Vfbase = 350 * 420/1050 = 140 Volts
Stroke = 25 inches

Running at speed no load the per unit variables are

MVA = MW = MVAR = 0.0
Stator voltage = 1.0
Stator current = 0.0
Field current = 441 / 420 = 1.05
Field voltage = 145 / 140 = 1.036
Gate opening = 3 / 25 = 0.12

Running at rated conditions the per unit variables are

MVA (= 125) = 1.0
MW (= 100) = 0.8
MVAR(=60) = 0.6
Stator voltage = 1.0
Stator current = 1.0
Field current = 1050 / 420 = 2.5
Field voltage = 350 / 140 = 2.5
Gate opening = 21 / 25 = 0.84

The maximum per unit excitation voltage is

Max Excitation Voltage = 600 / 140 = 4.3

Note that:

The per unit field voltage at speed-no-load is less than the per unit field current, but the per unit values of the field variables are equal at rated conditions. This is because the base value of field voltage is stated for rated conditions with the field winding hot while the field winding was cool when the speed-no-load measurements were taken.

Rated generator power output is *not* one per unit because the rated power factor is not unity.

The turbine ratings are information items *only*; they are not used in establishing per unit bases or values. The power rating of the turbine (175000*0.746 = 130.6MW) is substantially greater than the 100MW rated output of the generator and sufficient to run it at rated MVA and unity power factor at a head slightly below rated. (Such turbine sizing is quite common in hydro plants whose head variations can be large, but would be unusual in a thermal plant).

The gain relating gate position to turbine power must be

$$At = \frac{\text{Change in per unit power}}{\text{Change in per unit gate}}$$

$$= 1/(0.84 - 0.12) = 1.39$$

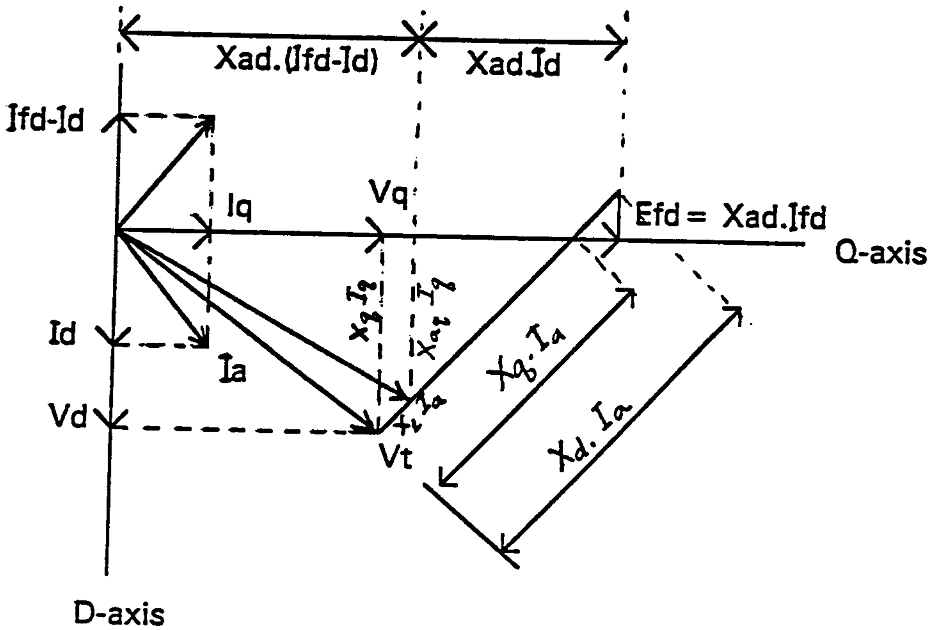


Figure 1

SYNCHRONOUS MACHINE PHASOR DIAGRAM

Reference: B.Adkins, Sugiyama et.al

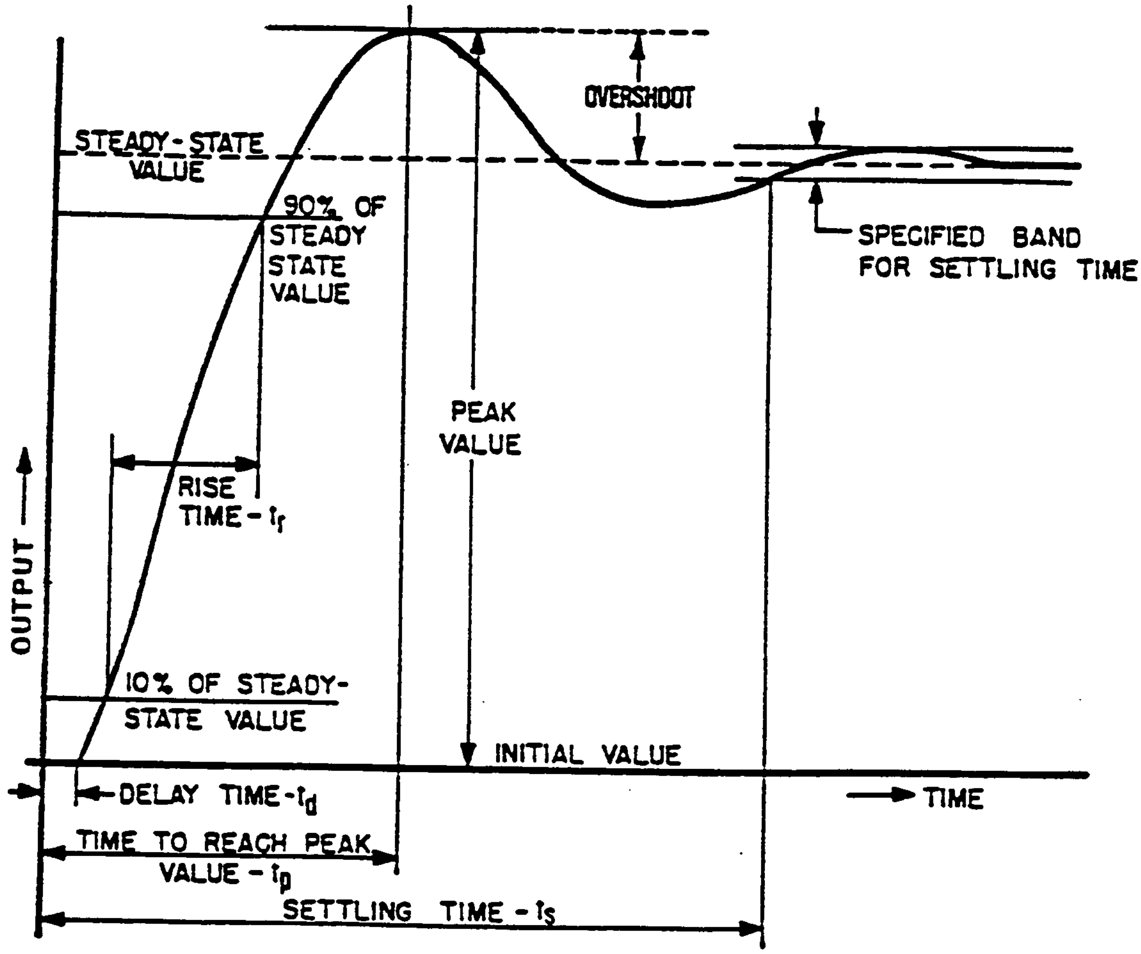


Figure 2

Typical Transient Response of a Feedback Control System to a Step Change in Input

Note: Per IEEE 421.2 -1990, for a small step change applied at the voltage regulator reference, an acceptable transient response is one having no more than two overshoots with a maximum overshoot of about 15%.

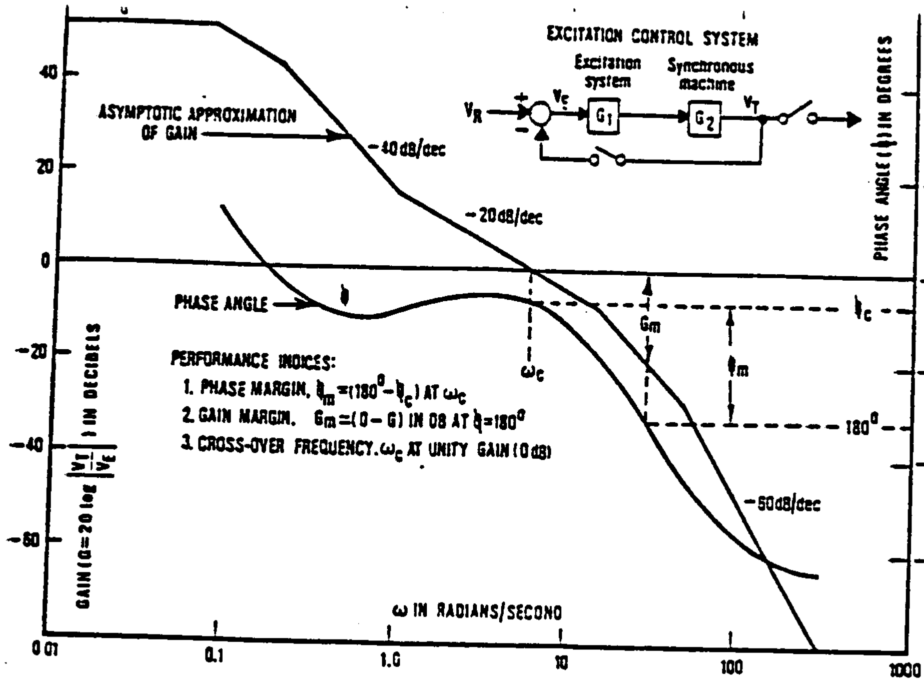


Figure 3

Typical Open-Loop Frequency Response of an Excitation Control System with the Synchronous Machine Open-Circuited

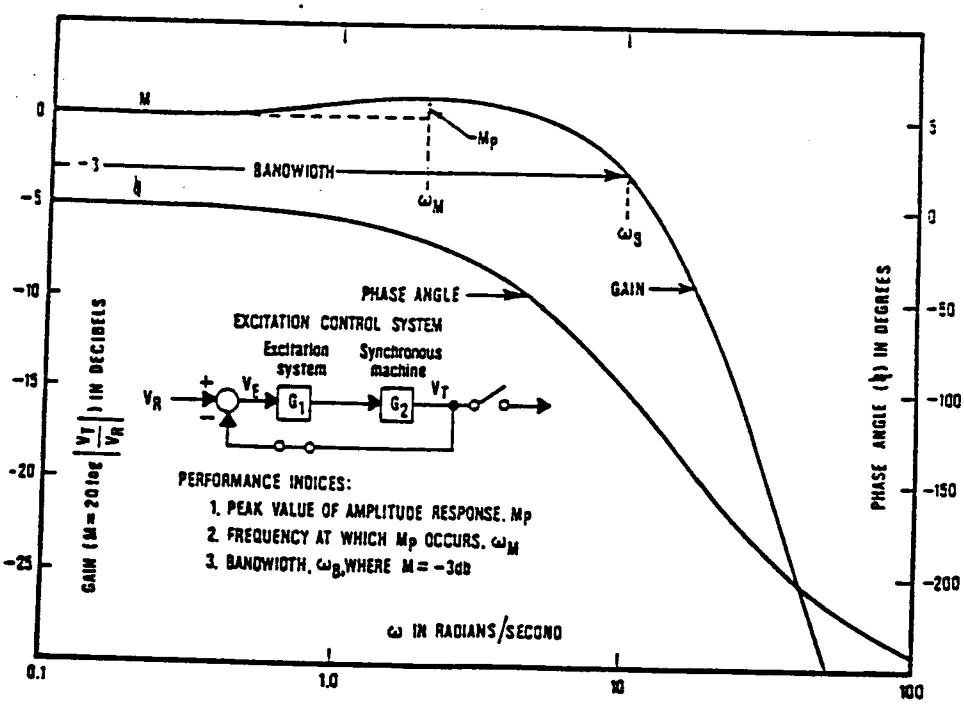


Figure 4

Typical Closed-Loop Frequency Response of an Excitation Control System with the Synchronous Machine Open-Circuitedp

APPENDIX C

SUBMISSION FORMS

All submittals shall be made to:

WSCC Technical Staff
University of Utah Research Park
540 Arapeen Drive, Suite 203
Salt Lake City, Utah 84108-1288

Generator Excitation System Summary

Utility: ______________________ Contact Person ________________ Date: ____________

Phone: ________________ Fax: ________________

		Exciter Volts				Auxiliary Control			Generator		Notes
Location Unit #	Mfg. (Type)	Model	Base	Rated	Max	PSS, UEL, OEL, LD, VHZ, PF,Other			MW	Vt	

PSS - Power System Stabilizer
UEL - Under Excitation Limiter
OEL - Over Excitation Limiter
Note: - State L for Limiter and P for Protection

LD Line Drop Compensation
PF Power Factor/VAR Controller

VHZ - Volts per Hertz Compensation
MW - Generator Rated Output (megawatts)
Vt - Geneator Rated Terminal Volts (KV)
Exciter Volts
Base: - Open circuit at Vt
Max: - Maximum Boost (short time)
Rated:- Continuous at rated generator full load and power factor.

TYPICAL SUBMITTAL FOR INFORMATION

Generator Excitation System Summary

Utility: ______________________ Contact Person ______________________ Date: ______________

Phone: ______________________ Fax: ______________________

			Exciter Volts			Auxiliary Control			Generator		Notes
Location Unit #	Mfg. (Type)	Model	Base	Rated	Max	PSS, UEL, OEL, LD, VHZ, PF,Other			MW	Vt	
Plant A #1	G.E.	Silco5	100	250	800	UEL(L)		OEL(L)	150	16.0	
Plant A #2	"		100	250	450	UEL(L)		OEL(L)	150	16.0	
Plant A #3	Hitachi	123	100	250	800	OEL(P) trips to manual	UEL(L)		150	16.0	
Plant A #4	Westinghouse	Rapicon	120	250	900	PSS	UEL(L)	OEL(L)	300	18.0	
Plant A #5	"		100	250	900	PSS	UEL(L)	OEL(L)	300	18.0	
Plant A #6	"		100	250	900	PSS	UEL(L)	OEL(L)	300	18.0	
Plant B #1	Brown Boveri		105	150	400	UEL(L)			75	14.4	
Plant B #2	English Electric		150	250	650	UEL(L)			75	14.4	
Plant B #3	Hitachi		100	250	650	UEL(L)			100	14.4	

PSS - Power System Stabilizer
UEL - Under Excitation Limiter
OEL - Overexcitation Limiter
Note: - State L for Limiter and P for Protection

LD Line Drop Compensation
PF Power Factor/VAR Controller

VHZ - Volts per Hertz Compensation
MW - Generator Rated Output (megawatts)
Vt - Geneator Rated Terminal Volts (KV)
Exciter Volts
Base: - Open circuit at Vt
Max: - Maximum Boost (short time)
Rated:- Continuous at rated generator full load and power factor.

Turbine Governor System Summary

Utility: ______________________ Contact Person ______________________ Date: ______________

Phone: ______________________ Fax: ______________________

		Governor				Turbine		Notes
Location Unit #	Mfg.	Model	Mech. PID Digital	Rated	Max	Rated MW	Speed	

TECHNICAL DATA, MODELS AND BLOCK DIAGRAMS

Typical block diagrams from stability programs based on IEEE and WSCC models have been included to assist the test and modeling engineers. The appropriate models should be selected and copied for each unit. Model data should be entered in each model block diagram sheet after validation.

If other models are used, these should be adequately described by a block diagram and corresponding data tables.

It is recognized that for some of the older units such data may be incomplete or unavailable. After model validation, all assumptions made in the derivation of the model should be clearly stated in the documentation.

For each model validated, copies of the actual test recording and the corresponding model computer simulation should be submitted to WSCC.

APPENDIX D

EXAMPLE OF TEST PLAN FOR GENERATOR EXCITATION SYSTEMS AND TURBINE GOVERNOR CHARACTERISTICS

THIS DOCUMENT WAS PREPARED FOR A PREVIOUS PROJECT. ITS CONTENT, STYLE AND FORMAT WERE APPROPRIATE FOR THE CIRCUMSTANCES OF THAT PROJECT AND MAY NOT BE SO FOR NEW PROJECTS. IT IS PROVIDED HERE AS AN ILLUSTRATION AND FOR GENERAL INFORMATION ONLY

Example of
Test Plan
Measurement of Generator-Excitation System-Governor Characteristics

1. Introduction

1.1 Objectives

This test plan covers work to be done by the engineer responsible for testing and data validation (ENGINEER) at the ________ and ________ plants of ______________ (OWNER) between __________ and __________ 1997. The objectives of the work are to:

- Verify the correct operation of the excitation controls and turbine governors of the OWNERs generating units
- Suggest revisions of control settings or modifications that might be called for or advantageous
- Verify the modeling of the units in the WSCC system studies data base

1.2 Schedule

This test plans is written with respect to a single steam or gas turbine unit. The intention is that the work outlined in this plan will be executed on each EPC unit in sequence. The suggested sequence is:

Unit	Date
Unit 1	-- -- --
Unit 2	-- -- --
etc	etc

Unless dictated differently by system dispatch, test setup will commence each day at about 0700 and should be complete by 0900. Testing will commence at about 0900 and should be complete by 1300. Signal processing and plotting will be done each day as time permits.

1.3 Staff and Procedure

ENGINEER assumes that OWNER electrician and plant engineering staff will be available each day from 0700 until the day's testing is complete. OWNER staff will have to know the location of plant manuals, of test signal pickup points, and of the protection system of each generator. All connections of test leads to OWNER equipment will be made by OWNER staff. All operation of ENGINEER test equipment will be done by ENGINEER staff. The ENGINEER will consult at all times with OWNER engineering staff and OWNER station operators in the execution of the tests. Experience has shown that it is most effective for the ENGINEER to discuss the sequencing of each test directly with the OWNER station operator, subject tot he agreement of OWNER engineers and supervisors.

1.4 Equipment required from OWNER

OWNER will provide shielded twisted pair cable for test leads from the signal points to the ENGINEER terminal blocks on the test table.

OWNER will provide a test table (with a wood or Formica top).

OWNER will provide several "Fluke" type digital multimeters.

OWNER will provide an HP Laserjet 4 printer. (or equivalent)

2. Overall Test Procedure

ALL NUMERIC DATA IN THIS SECTION APPLIES TO A GENERATOR RATED 100MVA. Numeric values for generators of different sizes will be scaled in proportion to MVA rating.

The sequence of operations of each unit under test will be as follows:

Connect test leads to OWNER signal points. ENGINEER prefers to make test connections with the unit either shut down or at speed no load; but OWNERS practices will dictate the manner of this work. In most cases all test leads can be laid out and prepared with the unit in normal service so that connections can be made quickly when the unit is brought out of normal serive for the tests

Unit off line and rotating at normal speed with main and field circuit breakers open

Defeat minimum power or reverse power relays if necessary in order to achieve near-zero MW operation.

Close field circuit breaker and bring unit to normal voltage, open circuit

Calibrate ENGINEER test instruments

Do open circuit magnetization curve test (this test may be done at any convenient point in the sequence, though there is some advantage to doing it early)

Return to normal voltage, open circuit

Trip the field circuit breaker. Record all test signals for 30 seconds

This test is made only where the type of excitation system makes it appropriate; it is particularly useful in hydro plants where a DC exciter has been retained with an old voltage regulator being replaced by a Basler-type unit.

Close the field circuit breaker and return to normal voltage

Synchronize and stabilize the unit as close as possible to zero MW

Go to zero MW and 20 MVAR underexcited
Do trip test number 1

Synchronise and go to zero MW and 30 MVAR underexcited
Excitation system in manual mode
Do trip test number 2

Synchronize and go to zero MW and 20 MVAR underexcited
Excitation system in automatic mode
Do trip test unumber 3

Synchronize and go to zero MW and 35 MVAR underexcited
Excitation system in automatic mode
Do trip test number 4

Synchronize and go to MW output of 10 to 30 percent of nameplate rating and underexcited MVAR depending on results of tests 1,2
Excitation system in manual mode
Do trip test number 5

Synchronize and go to a small "motoring" MW loading and zero MVAR
Excitation system in automatic mode
Do trip test number 6

NOTE: MVAR loadings in trip tests after the first will be decided on the basis of the initial test.

3. Open Circuit Magnetization Curve Test

Measure generator field current as a function of generator open circuit terminal voltage.

Generator at rated rpm, main circuit breaker open, excitation system in MANUAL, voltage at normal startup value.

Reduce excitation to the lowest possible value, preferrable approximately 30 percent of rated voltage or below.

Stabilize. Read stator voltage, field current, and field voltage.

Increase excitation in steps, always increasing and not "backing up".

Make readings at each step.

Reduce excitation in steps, not backing up.
Make readings at each step down to the lowest attainable voltage.

4. Trip Test

Load the generator to the required MW and MVAR loading. (MW should not exceed 30 percent of nameplate rating) (MVAR should not be greater than 40 percent of nameplate rating underexcited or greater than 25 percent of nameplate rating overexcited) (If generator is overexcited excitation system should be in AUTOMATIC mode)

Put the excitation system in the required test mode

Trip the main circuit breaker.

Generator voltage will fall in an underexcited test or rise in an overexcited test.

Bus voltage will rise slightly in an underexcited test or fall slightly in an overexcited test.

Record all test signals for 15 to 30 seconds as indicated by preliminary work.

5. Test Connections

All signal levels are typical values

Stator voltage	110 - 125 VAC	take from stator PT's one phase is essential - it may be desirable to record all three phase voltages
Stator current	0 - 5 Amps AC	take from ENGINEER clip-on transducer on CT secondary circuit
Main field voltage	0 - 500 VDC	take from field voltmeter via resistive potential divider
Main field current	0 - 100 mv	take from main field current shunt
Voltage regulator output voltage	0 - 200 VDC	take from excitation system cubicle via resistive potential divider
Voltgae regulator	0 - 10 Amps DC	take from ENGINEER clip-on transducer output current ***
Amplidyne output voltage ***	0 - 200 VDC	take from amplidyne terminals via resistive potential divider

Governor gate position	take output of LVDT or potentiometer

*** Regulator output signals are selected based on their presence and accessibility in each partcular exitation system

APPENDIX E

EXAMPLE OF GENERATOR EXCITATION SYSTEM AND POWER SYSTEM STABILIZER TEST PROCEDURE

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GENERATOR EXCITATION SYSTEM AND POWER SYSTEM STABILIZER TEST PROCEDURE

1 PURPOSE

1.1 Section 6.1- Verify the per-unit gain of the excitation/generator system - HP.

1.2 Section 6.2 - Check the gain and frequency response of the excitation / generator system in an "Open Loop Test" - HP.

1.3 Section 6.3 - Set and verify the Power System Stabilizer (PSS) gain and time constants - HP.

1.4 Section 6.4 - Verify the gain and frequency response of the PSS, Voltage Regulator, and Generator in an "Open Loop Test" - HP.

1.5 Section 6.5 - Final gain setting for stable operation - HP.

1.6 Section 6.6 - Final electrical and tripping limits settings - HP.

1.7 Section 6.7 - Overall System Stability Test - HP.

1.8 Section 6.8 - Verify the per-unit gain of the excitation/generator system - LP.

1.9 Section 6.9 - Check the gain and frequency response of the excitation / generator system in an "Open Loop Test" - LP.

1.10 Section 6.10 - Set and verify the Power System Stabilizer (PSS) gain and time constants - LP.

1.11 Section 6.11 - Verify the gain and frequency response of the PSS, Voltage Regulator, and Generator in an "Open Loop Test" - LP.

1.12 Section 6.12 - Final gain setting for stable operation - LP.

1.13 Section 6.13 - Final electrical and tripping limits settings - LP.

1.14 Section 6.14 - Overall System Stability Test - LP.

1.15 Section 6.15 - Verify Underexcited Reactive Ampere Limit - HP

1.16 Section 6.16 - Verify Underexcited Reactive Ampere Limit - LP

1.17 Section 6.17 - Test Maximum Generator Output - HP

1.18 Section 6.18 - Test Maximum Generator Output - LP

2 REFERENCES

2.1 General Electric Instruction For Thyristor Excitation System GEK - 14989B.

2.2 General Electric Co. Instruction For PSS GEK-14992D and System Drawings.

2.3 General Electric Co. Instruction For Underexcited Reactive Ampere Limit Panel GEK - 4716.

2.4 IPAC Frequency Transducer Instruction I.B. 750.1

2.5 Western Systems Coordinating Council - Test Procedure for PSS.

3 PREREQUISITE CONDITIONS

3.1.1 Unit operating on line at approximately 100% power level, normal VArs.

3.1.2 Modifications to PSS control, if required, completed.

3.1.3 The following points will be monitored during the PSS Tests:

.1 Generator Terminal Voltage (V_{gt})

.2 Generator Field Voltage (V_{gf})

.3 Power System Stabilizer Output (V_{pss})

.4 Generator Power Change (ΔMW)

.5 Generator VAr. Change (ΔMVAR)

3.1.4 Phone communication between the Excitation Switchgear and the Control Room.

4 TEST EQUIPMENT

4.1 Two (2) Digital Voltmeters.

4.2 One (1) 6-pen Gould-Brush Recorder.

4.3 One (1) 500 Vdc to 5 Vdc Transducer.

4.4 Four (4) Isolation Amplifiers.

4.5 One (1) Input / Output Signal Transducer.

4.6 One (1) Controller / Analyzer.

4.7 One (1) Watt / VAr Transducer

5 LIMITS AND PRECAUTIONS

5.1 As outlined in this procedure.

5.2 Ensure all instrumentation is ungrounded.

6 PROCEDURE

6.1 Per-Unit Gain Test of the HP Excitation / Generator System:

6.1.1 RECORD all As Found potentiometer settings in the PSS Data sheets.

6.1.2 Unit approximately 100% load, normal VArs, PSS - OFF

6.1.3 LP Excitation System in TEST control mode.

6.1.4 LIFT the Frequency Transducer input at L-1 and L-2.

6.1.5 RESET the mechanical limits on L1M to maximum.

6.1.6 RESET the positive and negative Electrical Limits P7 and P8 to 10.

6.1.7 LIFT the output amplifier LA4 input at D' and CONNECT the Signal Output Transducer to the Analyzer Channel 1 input and to the input of LA4 terminal D' and signal ground to L-8.

6.1.8 CONNECT the Generator Terminal Voltage PT secondary to the 3ϕ Voltage Transducer. Connect the output of the transducer through the isolation amplifier to the Analyzer Channel 2 Input and the recorder.

6.1.9 CONNECT the PSS Output L-6 to L-8 to the Recorder.

6.1.10 SET the gain pot P6 to 000 for unity gain.

6.1.11 With the Voltage Regulator in Auto, and a ZERO voltage on the output of the PSS, place the PSS in the ON mode.

NOTE

THE VALUES OBTAINED IN THIS TEST WILL BE USED TO CALCULATE THE GAINS AND THE LIMIT SET POINTS FOR THE SYSTEM AT THE END OF THE TEST.

6.1.12 Slowly apply a DC voltage signal via the BIAS control to the output amplifier. Apply a (+)1.00 Vdc signal from the PSS and check that an approximate 1% change in Generator voltage is recorded. If the terminal voltage change is not correct, adjust the output calibration potentiometer P14 to obtain the desired change.

6 PROCEDURE (Continued)

V_{gt} = ______Vac @ V_{pss} = ______Vdc

V_{gt} = ______Vac @ V_{pss} = ______Vdc

6.1.13 CHECK that a (-)1.00 Vdc output from the PSS will change the generator terminal voltage by 1%.

V_{gt} = ______Vac @ V_{pss} = ______Vdc

V_{gt} = ______Vac @ V_{pss} = ______Vdc

6.1.14 RECORD the change in terminal voltage, VArs, field voltage and current for the PSS output change.

6.1.15 REDUCE the BIAS voltage to zero, and turn the PSS OFF.

6.2 Gain and Frequency Response Test of the Excitation / Generator System in an "Open Loop Test". (GENERATOR LOOP TEST)

6.2.1 Create Data Files and set controller options.

6.2.2 Set the controller to cause the generator terminal voltage to swing at between 0.25 and 0.5% of its rated or set voltage, and at a rate between 0.05 and 3.0 Hertz.

6.2.3 Using the previous test connections, with output set on oscillator, place the PSS ON.

6.2.4 Initiate the measurement cycle, and repeat as required to obtain the required Unit Frequency Response.

NOTE: THE AMPLITUDE INFORMATION IS PLOTTED IN DECIBELS:

$$dB = 20 \log_{10} \frac{\text{Change in } V_{gt}/V_{gt\ base}}{\text{Change in } V_{pss}/V_{pss\ base}}$$

Change in V_{gt} = the amount of voltage change due to the voltage variation for the PSS.

$V_{gt\ base}$ = 115 Vac

Change in V_{pss} = The amount of test signal voltage change

$$V_{pss\ base} = \frac{V_{gt} @ V_{pss} = 0.0\ \text{Vdc}}{(V_{gt} @ V_{pss} = 1.0\ \text{Vdc}) - (V_{gt} @ V_{pss} = 0.0\ \text{Vdc})}$$

6.2.5 Reduce the Test signal to zero, and place the PSS in OFF.

6 PROCEDURE (Continued)

6.3 Power System Stabilizer Time Constant and Gain Adjustment. (STABILIZER LOOP TEST)

6.3.1 **DISCONNECT** the Analyzer Output from LA4 terminal D' and **RECONNECT** the lead lifted at LA4 D'.

6.3.2 **CONNECT** the Signal Output transducer to the PSS input at L-1 and Common L-8 and to the Analyzer input Channel 1.

6.3.3 **DISCONNECT** the output of the 3ϕ voltage transducer from the Analyzer Channel 2 input.

6.3.4 **CONNECT** the output of the PSS, L-6 and L-8, to the Channel 2 input of the Analyzer.

6.3.5 **ADJUST** the time constants of the PSS according to the results of the "Open Loop Test". The fundamental function of the phase shifting network in the PSS is to compensate for the phase lag in the response of the excitation / generator system. Adjustment should thus be made to offset the phase lag exhibited by the machine.

NOTE

THE TIME CONSTANTS CAN BE APPROXIMATED MOST READILY BY SELECTING THE PHASE LEAD TIME CONSTANTS AT THE FREQUENCY OF WHICH THEY WOULD PROVIDE 45 DEGREES OF PHASE ADVANCE. THE FREQUENCY TO DETERMINE THE SELECTION OF THIS PHASE ADVANCE TIME CONSTANTS IS THAT POINT WHERE THE GENERATOR / EXCITATION SYSTEM OVERALL RESPONSE LAGS THE INPUT BY 90 DEGREES. THE WASHOUT TIME CONSTANT SHOULD BE SET BETWEEN 1 AND 30 SECONDS.

6.3.6 **APPLY** a sine wave signal from the Analyzer causing the PSS output voltage to swing at least 0.5 V_{p-p}, but not more then 2.0 V_{p-p}, starting at 0.05 Hz. and ending at 100 Hz.

6.4 Gain and Frequency response Test of the Generator / Excitation System and PSS in an "Open Loop Test". (OVERALL LOOP TEST)

6.4.1 **DISCONNECT** the Analyzer Channel 2 Input from the PSS Output L-6 and L-8. Connect the Output of the 3ϕ Voltage Transducer to the Analyzer Channel 2 Input.

6.4.2 **CREATE** Data Files and set controller options.

6 PROCEDURE (Continued)

6.4.3 Set the controller to cause the generator terminal voltage to swing at between 0.25 and 0.5% of its rated or set voltage, and at a rate between 0.05 and 3.0 Hertz.

6.4.4 With the Voltage Regulator in AUTO mode, and zero voltage on the output of the PSS, place the PSS in the ON mode.

6.4.5 Initiate the measurement cycle, and repeat as required to obtain the required System Frequency Response.

6.4.6 Reduce the Analyzer Input signal to zero, and place the PSS in OFF mode.

6.5 Final Gain Setting For Stable Operation

6.5.1 REMOVE the Signal Output transducer from L-1 and L-6. (Leave PSS output to recorder connected.

6.5.2 RECONNECT the wires lifted to L-1 and L-2 to connect the IPAC frequency transducer.

6.5.3 CHECK that the output of the PSS is at or operating around zero. Check that the gain adjustment control P6 is at "000".

6.5.4 Place the PSS in the ON mode.

6.5.5 SLOWLY increase the gain of the output amplifier, by adjusting P6, until sustained oscillations are detected. These oscillations may occur in the range of 1 to 3 Hz. Oscillations will be seen in the MWatts, MVArs, terminal voltage, filed voltage and PSS output. As soon as these oscillations are detected the PSS should be placed in the OFF mode. Note P6 dial position. _______

6.5.6 LIFT the input to the LA4 board at D'.

6.5.7 Check the gain level of the output amplifier at the point where the system reached instability. This can be done by applying a DC voltage to the input of the LA4 Board, D' to Common, and measuring the output voltage at L-6 to L-8. The Gain of the amplifier is then the output voltage divided by the input voltage. Reduce the gain of the amplifier using P6 to one-third the level where oscillations occurred. This is the highest gain setting to be used for the PSS. Record this gain and P6 value. Gain _________ P6 _______

6.6 Final Electrical and Tripping Settings

6.6.1 CALCULATE the PSS output required to produce a 5% change in generator terminal voltage and record.

6 PROCEDURE (Continued)

> Example: If 1.0 Vdc from the PSS output changed the terminal voltage by 0.8% on the $V_{gt\ base}$, then a ± 5% terminal voltage change per volt from the PSS output would be
>
> $$\frac{1V}{0.8\%} \times \pm 5\% = \pm 6.25\ V.$$

Calculated 5% Limit Output _______ Vdc

6.6.2 RESET the electrical output limits by applying a DC voltage to D' on the LA4 Board it Board so that the output voltage at L-6 to L-8 measures 10 Vdc. Adjust P7 to obtain the calculated output voltage above. Repeat with a -10 Vdc input and adjust P8 for the negative calculated output voltage above.

6.6.3 RESET the Red and Blue pointers on L1M to one-half the value of the Calculated 5% Limit output above. This sets the mechanical trip points. Record the limit points. Red _________ Blue _________

6.6.4 ADJUST the tripping time delay relay T1R so that when the output of the PSS reaches the tripping limits, positive or negative, a period of two (2) seconds will elapse before the PSS will trip. This is done by applying a voltage to the LA4 Circuit Board D' that is greater than the tripping voltage and adjusting the T1R dial. Record the Final Setting. - _____________

6.6.5 REMOVE the Signal Output transducer from LA4 terminal D' and RECONECT the lifted leads.

6.7 Overall System Stability Test

6.7.1 Have operations personnel place the HP excitation in TEST.

6.7.2 At the excitation housing, CONNECT a 50 kohm switchable potentiometer across Voltage Adjust Potentiometer A201P with the resistance set for 50 kohms and the switch closed.

6.7.3 Check that the 3ϕ Voltage transducer and PSS outputs are connected to the recorder.

6.7.4 Have operations personnel place the HP excitation in AUTO control.

6.7.5 With the recorder operating, the excitation in AUTO, and the PSS in the OFF mode, adjust the 50 kohm potentiometer to obtain a 1% decrease in generator terminal voltage.

6.7.6 Alternately **OPEN** and **CLOSE** the switch to introduce step changes into the voltage regulator / excitation system with the PSS out of service. Review the chart recordings which should indicate the dynamic performance of the system.

6.7.7 After the system has stabilized, have operations personnel place the PSS **ON**.

6.7.8 Repeat the above step change tests by alternately, **OPENING** and **CLOSING** the switch to introduce step changes into the voltage regulator / excitation system with the PSS in service. Review the chart recordings which should indicate improved dynamic performance of the system.

NOTE

THE CHART RECORDINGS SHOULD SHOW THAT WITH THE PSS IN SERVICE, THE LOCAL MODE OSCILLATIONS ARE DAMPED WHEN COMPARED TO THE OSCILLATIONS WITHOUT THE PSS IN SERVICE.

6.7.9 If the stabilizer has performed as anticipated, remove the PSS from service, otherwise repeat those sections as appropriate.

6.7.10 Remove ALL instrumentation. Have operations personnel **SELECT** the excitation system to **TEST** before removing the 50 kohm potentiometer.

6.8 Per-Unit Gain Test of the LP Excitation / Generator System:

6.8.1 **RECORD** all As Found potentiometer settings in the PSS Data sheets.

6.8.2 **ADJUST** Unit for approximately 100% load, normal VArs, PSS - **OFF**

6.8.3 **SELECT** LP Excitation System in **AUTO** control mode.

6.8.4 **LIFT** the Frequency Transducer input at L-1 and L-2.

6.8.5 **RESET** the mechanical limits on L1M to maximum.

6.8.6 **RESET** the positive and negative Electrical Limits P7 and P8 to 10.

6.8.7 **LIFT** the output amplifier LA4 input at D' and **CONNECT** the Signal Output Transducer to the Analyzer Channel 1 input and to the input of LA4 terminal D' and signal ground to L-8.

6.8.8 **CONNECT** the Generator Terminal Voltage PT secondary to the 3ϕ Voltage Transducer. Connect the output of the transducer through the isolation amplifier to the Analyzer Channel 2 Input and the recorder.

6 PROCEDURE (Continued)

6.8.9 CONNECT the PSS Output L-6 to L-8 to the Recorder.

6.8.10 SET the gain pot P6 to 000 for unity gain.

6.8.11 With the Voltage Regulator in Auto, and a ZERO voltage on the output of the PSS, place the PSS in the ON mode.

NOTE

THE VALUES OBTAINED IN THIS TEST WILL BE USED TO CALCULATE THE GAINS AND THE LIMIT SET POINTS FOR THE SYSTEM AT THE END OF THE TEST.

6.8.12 Slowly apply a DC voltage signal via the BIAS control to the output amplifier. Apply a (+)1.00 Vdc signal from the PSS and check that an approximate 1% change in Generator voltage is recorded. If the terminal voltage change is not correct, adjust the output calibration potentiometer P14 to obtain the desired change.

V_{gt} = ______Vac @ V_{pss} = _______Vdc

V_{gt} = ______Vac @ V_{pss} = _______Vdc

6.8.13 CHECK that a (-)1.00 Vdc output from the PSS will change the generator terminal voltage by 1%.

V_{gt} = ______Vac @ V_{pss} = _______Vdc

V_{gt} = ______Vac @ V_{pss} = _______Vdc

6.8.14 RECORD the change in terminal voltage, VArs, field voltage and current for the PSS output change.

6.8.15 REDUCE the BIAS voltage to zero, and turn the PSS OFF.

6.9 Gain and Frequency Response Test of the Excitation / Generator System in an "Open Loop Test". (GENERATOR LOOP TEST)

6.9.1 Create Data Files and set controller options.

6.9.2 Set the controller to cause the generator terminal voltage to swing at between 0.25 and 0.5% of its rated or set voltage, and at a rate between 0.05 and 3.0 Hertz.

6.9.3 Using the previous test connections, with output set on oscillator, place the PSS ON.

6.9.4 Initiate the measurement cycle, and repeat as required to obtain the required Unit Frequency Response.

NOTE: THE AMPLITUDE INFORMATION IS PLOTTED IN DECIBELS:

$$dB = 20 \log_{10} \frac{\text{Change in } V_{gt}/V_{gt\,base}}{\text{Change in } V_{pss}/V_{pss\,base}}$$

Change in V_{gt} = the amount of voltage change due to the voltage variation for the PSS.

$V_{gt\,base}$ = 115 Vac

Change in V_{pss} = The amount of test signal voltage change

$$V_{pss\,base} = \frac{V_{gt} @ V_{pss} = 0.0 \text{ Vdc}}{(V_{gt} @ V_{pss} = 1.0 \text{ Vdc}) - (V_{gt} @ V_{pss} = 0.0 \text{ Vdc})}$$

6.9.5 Reduce the Test signal to zero, and place the PSS in OFF.

6.10 Power System Stabilizer Time Constant and Gain Adjustment. (STABILIZER LOOP TEST)

6.10.1 DISCONNECT the Analyzer Output from LA4 terminal D' and RECONNECT the lead lifted at LA4 D'.

6.10.2 CONNECT the Signal Output transducer to the PSS input at L-1 and Common L-8 and to the Analyzer input Channel 1.

6.10.3 DISCONNECT the output of the 3ϕ voltage transducer from the Analyzer Channel 2 input.

6.10.4 CONNECT the output of the PSS, L-6 and L-8, to the Channel 2 input of the Analyzer.

6.10.5 ADJUST the time constants of the PSS according to the results of the "Open Loop Test". The fundamental function of the phase shifting network in the PSS is to compensate for the phase lag in the response of the excitation / generator system. Adjustment should thus be made to offset the phase lag exhibited by the machine.

NOTE

THE TIME CONSTANTS CAN BE APPROXIMATED MOST READILY BY SELECTING THE PHASE LEAD TIME CONSTANTS AT THE FREQUENCY OF WHICH THEY WOULD PROVIDE 45 DEGREES OF PHASE ADVANCE. THE FREQUENCY TO DETERMINE THE SELECTION OF THIS PHASE ADVANCE TIME CONSTANTS IS THAT POINT WHERE THE GENERATOR / EXCITATION SYSTEM OVERALL RESPONSE LAGS THE INPUT BY 90 DEGREES. THE WASHOUT TIME CONSTANT SHOULD BE SET BETWEEN 1 AND 30 SECONDS.

6 PROCEDURE (Continued)

6.10.6 APPLY a sine wave signal from the Analyzer causing the PSS output voltage to swing at least 0.5 V_{p-p}, but not more then 2.0 V_{p-p}, starting at 0.05 Hz. and ending at 100 Hz.

6.11 Gain and Frequency response Test of the Generator / Excitation System and PSS in an "Open Loop Test". (OVERALL LOOP TEST)

6.11.1 DISCONNECT the Analyzer Channel 2 Input from the PSS Output L-6 and L-8. Connect the Output of the 3ϕ Voltage Transducer to the Analyzer Channel 2 Input.

6.11.2 CREATE Data Files and set controller options.

6.11.3 Set the controller to cause the generator terminal voltage to swing at between 0.25 and 0.5% of its rated or set voltage, and at a rate between 0.05 and 3.0 Hertz.

6.11.4 With the Voltage Regulator in AUTO mode, and zero voltage on the output of the PSS, place the PSS in the ON mode.

6.11.5 Initiate the measurement cycle, and repeat as required to obtain the required System Frequency Response.

6.11.6 Reduce the Analyzer Input signal to zero, and place the PSS in OFF mode.

6.12 Final Gain Setting For Stable Operation

6.12.1 REMOVE the Signal Output transducer from L-1 and L-8. (Leave PSS output to recorder connected.

6.12.2 RECONNECT the wires lifted to L-1 and L-2 to connect the IPAC frequency transducer.

6.12.3 CHECK that the output of the PSS is at or operating around zero. Check that the gain adjustment control P6 is at "000".

6.12.4 Place the PSS in the ON mode.

6.12.5 SLOWLY increase the gain of the output amplifier, by adjusting P6, until sustained oscillations are detected. These oscillations may occur in the range of 1 to 3 Hz. **Oscillations will be seen in the MWatts, MVArs, terminal voltage, filed voltage and PSS output. As soon as these oscillations are detected the PSS should be placed in the OFF mode.** Note P6 dial position. _______

6.12.6 LIFT the input to the LA4 board at D'.

6 PROCEDURE (Continued)

6.12.7 Check the gain level of the output amplifier at the point where the system reached instability. This can be done by applying a DC voltage to the input of the LA4 Board, D' to Common, and measuring the output voltage at L-6 to L-8. The Gain of the amplifier is then the output voltage divided by the input voltage. Reduce the gain of the amplifier using P6 to one-third the level where oscillations occurred. This is the highest gain setting to be used for the PSS. Record this gain and P6 value. Gain ________ P6 _______

6.13 Final Electrical and Tripping Settings

6.13.1 CALCULATE the PSS output required to produce a 5% change in generator terminal voltage and record.

> Example: If 1.0 Vdc from the PSS output changed the terminal voltage by 0.8% on the $V_{gt\ base}$, then a ± 5% terminal voltage change per volt from the PSS output would be
>
> $$\frac{1V}{0.8\%} \times \pm 5\% = \pm 6.25\ V.$$

Calculated 5% Limit Output _______ Vdc

6.13.2 RESET the electrical output limits by applying a DC voltage to D' on the LA4 Board it Board so that the output voltage at L-6 to L-8 measures 10 Vdc. Adjust P7 to obtain the calculated output voltage above. Repeat with a -10 Vdc input and adjust P8 for the negative calculated output voltage above.

6.13.3 RESET the Red and Blue pointers on L1M to one-half the value of the Calculated 5% Limit output above. This sets the mechanical trip points. Record the limit points. Red _________ Blue _________

6.13.4 ADJUST the tripping time delay relay T1R so that when the output of the PSS reaches the tripping limits, positive or negative, a period of two (2) seconds will elapse before the PSS will trip. This is done by applying a voltage to the LA4 Circuit Board D' that is greater than the tripping voltage and adjusting the T1R dial. Record the Final Setting. -

____

6.13.5 REMOVE the Signal Output transducer from LA4 terminal D' and RECONECT the lifted leads.

6.14 Overall System Stability Test

6.14.1 Have operations personnel place the LP excitation in TEST.

6 PROCEDURE (Continued)

6.14.2 At the excitation housing, **CONNECT** a 50 kohm switchable potentiometer across Voltage Adjust Potentiometer A201P with the resistance set for 50 kohms and the switch closed.

6.14.3 Check that the 3ϕ Voltage transducer and PSS outputs are connected to the recorder.

6.14.4 Have operations personnel place the LP excitation in **AUTO** control.

6.14.5 With the recorder operating, the excitation in **AUTO**, and the **PSS** in the OFF mode, adjust the 50 kohm potentiometer to obtain a 1% change in generator terminal voltage.

6.14.6 Alternately, **OPEN** and **CLOSE** the switch to introduce step changes into the voltage regulator / excitation system with the PSS out of service. Review the chart recordings which should indicate the dynamic performance of the system.

6.14.7 After the system has stabilized, have operations personnel place the PSS ON.

6.14.8 Repeat the above step change tests by alternately **OPENING** and **CLOSING** the switch to introduce step changes into the voltage regulator / excitation system with the PSS in service. Review the chart recordings which should indicate improved dynamic performance of the system.

NOTE

THE CHART RECORDINGS SHOULD SHOW THAT WITH THE PSS IN SERVICE, THE LOCAL MODE OSCILLATIONS ARE DAMPED WHEN COMPARED TO THE OSCILLATIONS WITHOUT THE PSS IN SERVICE.

6.14.9 If the stabilizer has performed as anticipated, remove the PSS from service, otherwise repeat those sections as appropriate.

6.14.10 Remove ALL instrumentation. Have operations personnel **SELECT** the excitation system to **TEST** before removing the 50 kohm potentiometer.

6.15 Underexcited Reactive Ampere Limit (URAL) In Service Testing - HP

6.15.1 This test will be made with both the HP and LP generators in **AUTO** regulate mode, and the LP generator should absorb most of the MVAr load from the HP generator. This will minimize the decrease in generator terminal voltage.

6.15.2 To stay within the rated capability of the generator (armature core end heating), hydrogen pressure must be greater than:

Total	Expected Limit		PSIG Hydrogen	
Net MW	HP MVAr	LP MVAr	HP	LP
700	160	150	38	30

6.15.3 The settings of the loss-of-field CEH relays are such that the calculated MVArs at which the relays would operate are greater than 425 MVAr for the HP and greater than 370 MVAr for the LP generators.

6.15.4 ADJUST load for approximately 700 MW.

6.15.5 SELECT both the HP and LP excitation to TEST mode.

6.15.6 ADJUST both HP and LP excitation to obtain approximately -20 MVArs on each generator.

6.15.7 RECORD the Limit Start setting. ________

6.15.8 While monitoring the URAL output, ADJUST the HP and LP URAL Limit Detector Start points to activate the URALs at approximately - 20 MVArs. Note the position of each. HP________ LP________

6.15.9 READJUST the HP and LP MVAr loading for zero MVArs on each generator.

6.15.10 Reset the HP and LP Limit Start dials to their AS FOUND values.

NOTE

If the URAL circuits are not functioning properly, stop and correct the problem before continuing.

6.15.11 PLACE the HP and LP regulators in AUTO.

6.15.12 ADJUST the HP and LP regulator voltmeters for zero.

6.15.13 Decrease the excitation on the HP generator in 20 MVAr steps. At each step, record the following meters:

.1 Generator kV
.2 HP and LP Mwatts
.3 HP and LP MVArs
.4 HP and LP Generator Field Amps
.5 HP and LP Generator Field Volts
.6 HP and LP Phase 1 Amps
.7 HP and LP Regulator Voltmeters
.8 HP URAL Limit Output
.9 HP URAL Limit Detector

6 PROCEDURE (Continued)

6.15.14 When the limit detector reaches zero, further attempts to reduce excitation should have little or no effect. This point should be close to the curve value of MVAr limit:

.1 If the limit does not occur at the expected value, continue to decrease excitation two additional steps only, then return to normal excitation slowly and evaluate test data.

.2 If oscillation occurs on field voltmeters, reduce gain B1P as first step.

.3 If evaluation warrants, make adjustments to URAL settings and repeat step 6.15.13.

6.15.15 READJUST HP excitation for zero MVArs.

6.16 Underexcited Reactive Ampere Limit (URAL) In Service Testing - LP

6.16.1 ADJUST the HP and LP regulator voltmeters for zero preparatory to perform LP URAL test.

6.16.2 Decrease the excitation on the LP generator in 20 MVAr steps. At each step, record the following meters:

.1 Generator kV
.2 HP and LP Mwatts
.3 HP and LP MVArs
.4 HP and LP Generator Field Amps
.5 HP and LP Generator Field Volts
.6 HP and LP Phase 1 Amps
.7 HP and LP Regulator Voltmeters
.8 LP URAL Limit Output
.9 LP URAL Limit Detector

6.16.3 When the limit detector reaches zero, further attempts to reduce excitation should have little or no effect. This point should be close to the curve value of MVAr limit:

.1 If the limit does not occur at the expected value, continue to decrease excitation two additional steps only, then return to normal excitation slowly and evaluate test data.

.2 If oscillation occurs on field voltmeters, reduce gain B1P as first step.

.3 If evaluation warrants, make adjustments to URAL settings and repeat step 6.15.13.

6.16.4 READJUST both HP and LP excitation for NORMAL reactive load at this power level.

6 PROCEDURE (Continued)

6.17 Maximum Excitation Capability of the HP Generator

6.17.1 The excitation on the HP will be increased to obtain maximum MVAr output capability without increasing generator terminal voltage more than 5% above the operating point. The LP generator will be placed in TEST position to prevent the LP generator from absorbing the reactive load from the HP generator.

6.17.2 **PLACE** the LP regulator in **TEST** position.

6.17.3 While monitoring the following parameters, **SLOWLY** increase excitation on the HP generator until generator terminal voltage has increased by 5%, or the maximum rating of any component of the unit has been attained.

.1 Generator kV
.2 HP and LP Mwatts
.3 HP and LP MVArs
.4 HP and LP Generator Field Amps
.5 HP and LP Generator Field Volts
.6 HP and LP Phase 1 Amps
.7 HP and LP Regulator Voltmeters

6.17.4 **RECORD** the above data in the attached data sheets.

6.17.5 **SLOWLY** return the HP excitation to **NORMAL**.

6.17.6 **PLACE** the LP regulator in **AUTO** control mode.

6.18 Maximum Excitation Capability of the LP Generator

6.18.1 The excitation on the LP will be increased to obtain maximum MVAr output capability without increasing generator terminal voltage more than 5% above the operating point. The HP generator will be placed in TEST position to prevent the HP generator from absorbing the reactive load from the LP generator.

6.18.2 **PLACE** the HP regulator in **TEST** position.

6.18.3 While monitoring the following parameters, **SLOWLY** increase excitation on the LP generator until generator terminal voltage has increased by 5%, or the maximum rating of any component of the unit has been attained.

.1 Generator kV
.2 HP and LP Mwatts
.3 HP and LP MVArs
.4 HP and LP Generator Field Amps
.5 HP and LP Generator Field Volts

6 PROCEDURE (Continued)

.6 HP and LP Phase 1 Amps
.7 HP and LP Regulator Voltmeters

6.18.4 **RECORD** the above data in the attached data sheets.

6.18.5 **SLOWLY** return the LP excitation to **NORMAL**.

6.18.6 **PLACE** the HP regulator in **AUTO** control mode.

6.19

7 ENCLOSURES

7.1 WSCC Test Procedure

7.2 Generator Data Sheets

7.2.1 Power System Stabilizer Data Sheet

7.2.2 Underexcited Reactive Ampere Limit Data Sheet

7.2.3 Maximum Excitation Data Sheet

Station / Unit ______________________________

Date: ______________ PSS Type: ________________

Reg. Type: ________________

Power System Stabilizer Settings:

Device	Function	Previous	As Found	Calibration Check	As Left
P1	Reset Time Constant T1				
P2	#1 Lead T.C.				
P3	#1 Lag T.C.				
P4	#2 Lead T.C.				
P5	#2 Lag T.C.				
P6	Gain				
P7	(+) Electrical. Limit Adjust				
P8	(-) Electrical Limit Adjust				
P14	DC Gain Adjustment				
Red Pointer on L1M	(+) Mechanical Limit Adjust				
Blue Pointer on L1M	(-) Mechanical Limit Adjust				
T1R	Time Delay Relay for Trip				

Station / Unit ____________________

Date: ____________

Time: ____________

PSS Type: ____________

Reg. Type: ____________

Underexcited Reactive Ampere Limit Test

Gen kV	HP MW	LP MW	HP MVAr	LP MVAr	HP Fld Current Adc	LP Fld Current Adc	HP Fld Voltage Vdc	LP Fld Voltage Vdc	HP AØ Current Aac	LP AØ Current Aac	HP Volt Regulator Vdc	LP Volt Regulator Vdc	URAL Lim. Det. mAdc	URAL Limit Output Vdc

Station / Unit ____________________

Date: ____________ PSS Type: ____________

Time: ____________ Reg. Type: ____________

Maximum Excitation Capability Test

Gen kV	HP MW	LP MW	HP MVAr	LP MVAr	HP Fld Current Adc	LP Fld Current Adc	HP Fld Voltage Vdc	LP Fld Voltage Vdc	HP AØ Current Aac	LP AØ Current Aac	HP Volt Regulator Vdc	LP Volt Regulator Vdc

APPENDIX F

EXAMPLE OF
HYDRO TURBINE GOVERNOR MODELING

THIS DOCUMENT WAS PREPARED FOR A PREVIOUS PROJECT. ITS CONTENT, STYLE AND FORMAT WERE APPROPRIATE FOR THE CIRCUMSTANCES OF THAT PROJECT AND MAY NOT BE SO FOR NEW PROJECTS. IT IS PROVIDED HERE AS AN ILLUSTRATION AND FOR GENERAL INFORMATION ONLY

EXAMPLE OF HYDRO TURBINE GOVERNOR MODELING

Introduction

Governor gains and time constants can be measured with the unit de-watered or with the unit running using either frequency response or time-domain techniques. The tests require placing a displacement transducer on a servomotor to measure gate position. Transducers can also be mounted on distributing and pilot valves for measurement of intermediate variables. With a unit de-watered, governor operation is simulated by applying appropriate speed and/or power signals to the governor. On-line testing is accomplished by quickly raising the speed adjustment by hand (to simulate a step input), or by introducing step or sine-wave signals into electronic governors. Validation is performed by introducing the same inputs (at the same operating point) into a model of the governor using either a stability program or a general purpose control system simulation tool such as Matlab.

A. Hydroelectric Dashpot Type Governor

The parameters typically required for modeling of a hydro turbine governor are Permanent Droop, Servo Time Constants, Temporary Droop, Dashpot Time Constant, Limiting rates of change of gate position, Gate Position Limits, Water Inertia Time Constant, and Turbine Gains. The following are typical procedures for estimating values of these parameters:

1. Identifying Servo Time Constants and Permanent Droop

With the generator operating at moderate load:

- Disable the dashpot by opening the dashpot needle valve to give the shortest possible dashpot time constant. (In electronic dashpot-analogy governor, set the relaxation time to its minimum value). Note the initial setting carefully before making the adjustment so that the original setting can be restored after the test.

- Increase the speed reference (speed adjustment) by a small amount to insert a step into the system
    - Record the gate position signal versus time
    - Permanent droop is determined by the change in speed reference divided by the steady-state change in gate position - (Both of these values must be in per unit)
    - Servo time constants are determined by trial and error trying to match simulations to the gate position response (recorded). This matching process can be done with a power system stability program, or a general purpose tool such as Matlab.

2. Identifying Temporary Droop and Dashpot (Relaxation) Time Constant

With the generator operating at moderate load

- Return the dashpot to the initial position
- Increase the speed reference by a small amount quickly by hand to insert a step into the system
- Record the gate position signal versus time
- Temporary Droop and dashpot time constant are determined by trial and error trying to match simulations to the gate position response (recorded). This matching process can be done with a power system stability program or a general purpose tool such as Matlab.

3. Identifying maximum gate opening and closing rates

With the generator operating at moderate load:

- Lower the gate limit (at the governor cabinet) quickly to about 10-20 percent lower than the initial gate position
  - .Record the gate position signal versus time
  - .Maximum closing rate is can be measured directly from the test record

- Raise the gate limit quickly above the initial gate position
  - .Record the gate position signal versus time
  - .Maximum opening rate can be measured directly from the test record

4. Maximum and Minimum Gate Positions

- These values should indicate the normal operating range of the unit. Their values may be the physical limits of gate motion, or may be operational limits that reflect reservoir conditions, rough running bands, and other factors.

5. Turbine Parameters

T_W - Water Starting Time

This is the classical water starting time defined as the summation of penstock length times velocity terms for each section of the penstock divided by the acceleration of gravity and the head.

$$T_W = \frac{\text{(Water Path Length)*(Water Velocity)}}{\text{(gravity) * (Head)}}$$

This is usually available as design data for the plant. Verification of this parameter is possible, but beyond the scope of this document.

Turbine Gain Factors

Turbine Gain factors should be derived from steady state observations of gate position and power output. The required turbine gain factor is typically the ratio of per unit power output to per unit change in gate position.

B. Hydroelectric PID Electro-hydraulic Governor

Parameters to identify include Proportional Gain, Reset Gain, Derivative Gain, gate servo gain and time constant, permanent droop, and position/velocity limits on the gate position. These parameters can be identified by frequency responses on portions of the circuits with the machine shut-down or running. Alternately, the parameters can be identified by the techniques listed below. In either case, model validation should be performed using the following time-domain techniques:

1. Identifying the gate servo response characteristics:

With the generator operating at a moderate load:

- Insert a small step signal in addition to the Gate Command signal
- Record the gate position signal versus time
- The gain and time constant are determined by trial and error trying to match the gate position response (recorded). This matching process can be done with a power system stability program or a general purpose program such as Matlab.

2. Identifying the proportional, reset, and derivative gains and the permanent droop:

With the generator operating at moderate load:

- Insert a small step signal (0.005 pu) in addition to the speed reference or speed signal
- Record the Gate Command signal versus time (or gate versus time)
- The change in speed reference (step signal of 0.005 pu) divided by the steady state change in the Gate Command (or gate) signal is the speed droop. If the input to the droop block is the electric power signal, then the speed regulation is : The change in speed reference (step signal of 0.005 pu) divided by the steady state change in the electric power signal.

- The controller gains are determined by trial and error trying to match the Gate Command (or gate) signal step response (recorded). This matching process can be done with a power system stability program or a general purpose tool such as Matlab.

3. To identify gate limit and the turbine parameters refer to the mechanical governor section.

C. Hydroelectric Double-Derivative Electro-hydraulic Governor

The parameters to identify in the double derivative governor and the same gate servo and turbine parameters as for other governors, the derivative gain and the double derivative gain. The methods described above can be used for gate servo and turbine parameters.

To identify the derivative gains have the generator operating at a moderate load, then:

-Wire the speed or frequency signal (input of the derivative and double derivative blocks) through a switch for disconnection and reconnection of the signal (in case of load rejection)

- With the speed or frequency signal disconnected, insert a small step signal in place of the speed or frequency signal (into the derivative and double derivative blocks)

- Record the step response of these blocks

- The derivative gain and the double derivative gain are determined by trial and error trying to match the output signal step response (recorded). This matching process can be done with a power system stability program or a general purpose tool such as Matlab.

APPENDIX G

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BIBLIOGRAPHY

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Western Systems Coordinating Council

REPLY TO:
WSCC TECHNICAL STAFF
UNIVERSITY OF UTAH RESEARCH PARK
540 ARAPEEN DRIVE, SUITE 203
SALT LAKE CITY, UTAH 84108-1288
TEL.: (801) 582-0353
FAX: (801) 582-3918

November 25, 1996

OPERATIONS COMMITTEE
POWER PLANT CONTACTS

The August 10, 1996 System Disturbance Report contained recommendations calling for all generation owning and operating entities in the WSCC region to test their generating units with a rating of 10 MVA or greater. These tests are intended to ensure proper operation of exciter controls and protection and to determine steady state and dynamic reactive capabilities. The Control Work Group has developed the attached guidelines for testing exciter controls, protection and steady state reactive capabilities. Appendix A to the guidelines lists the pertinent conclusions and recommendations stemming from the August 10 report. Guidelines for determining dynamic reactive capabilities are under development.

In the meantime, you should begin scheduling and conducting tests on your generating units in accordance with the attached guidelines. Please use the form provided (last page of the attached) to provide the data to WSCC by June 1997. Make as many copies of the form as you will need to report all your units of the appropriate size. Return the completed form(s) to WSCC, either by mail or by fax. Operations Committee representatives should coordinate with their Power Plant Contact Persons to determine who will submit their reports to WSCC.

I encourage you not to delay conducting these tests. If everyone waits until near the June deadline, we'll be faced with an excessive number of units being tested simultaneously and the resulting risk to system reliability.

Sincerely,

JW Comish

Joseph W. Comish

attachments

cc: Control Work Group Members
Technical Studies Subcommittee
w/attachment

SYNCHRONOUS MACHINE REACTIVE LIMITS VERIFICATION

BACKGROUND:

The WSCC Control Work Group has been tasked with developing procedures for testing synchronous machines (generators and condensers) and exciters due to problems noted during the Aug. 10, 1996, disturbance. The procedures outlined in this document should determine the true MVAR capability of the tested machines and reveal problems in exciter control and protection schemes (see Conclusion 4 and Recommendation 4.c. in Appendix A). Appendix A contains the text of the August 10 disturbance report pertinent to this assignment.

The procedures outlined are for steady state conditions. More comprehensive procedures for testing units outside normal operating range will be developed and distributed by the WSCC Control Work Group at a later date.

REQUIREMENTS:

All synchronous machines (Generators and synchronous condensers must be tested and the same results reported) rated at 10 MVA or greater should be tested. Machines that tripped during system disturbances (July 2 and/or August 10) due to relaying or excitation control problems should be tested first; the remainder should be tested starting with the largest machines. If machines have been tested within the last two years and the requested data are available, no additional testing is required, just data transmittal.

NOTE: To minimize the risk of tripping several large units nearly simultaneously during testing, the tests should be scheduled with your control area's dispatcher/system operator. The dispatcher/system operator should, in turn, provide the scheduled test notification for units larger than 100 MW to all systems, using the WSCC Communication System.

PROCEDURES:

In order to obtain the steady state MVAR capability of a generating unit or synchronous condenser, perform the following tests. Operating conditions should be as close to normal as practicable, including loading, unit temperatures (field, etc.) and pressures (hydrogen, boiler, etc.). Tests should be performed during periods of operation which maximize the MVAR in/output of the machine. Therefore, testing should be performed during a period when system voltage is most advantageous to yield these results . When possible other synchronous machines or power system components should be used, to obtain the most advantageous terminal voltage during these tests.. Ensure that controls such as volts/hertz limiters and UELs (see ¶ B) are coordinated and at proper settings prior to testing to prevent unnecessary relaying by volts/hertz relays or loss of excitation relays..

A. While operating in a steady state mode at net dependable MW capability (near rated output), raise excitation in automatic voltage control until one of the following conditions occurs:

1) The 100% MVA rating of the machine is reached (reach capability curve);
2) Rated field current or field voltage is reached;
3) Terminal voltage limit is reached (105-110%, depending on unit);
4) Generator temperature limits are reached;

5) The maximum/over excitation limiter is reached/alarms;
6) Maximum reference adjuster travel or limit is reached;
7) Maximum auxiliary bus voltage is reached.

Hold unit at this level for a minimum of 15 minutes (30 minutes is a preferable duration) then take the measurements outlined in C.

B. While operating in a steady state mode at net dependable MW capability, lower excitation in automatic voltage control until one of the following conditions occurs: Note: The acronym UELs (underexcitation limiters) used in this paragraph is synonymous with MELs (minimum excitation limiters) and URALs (underexcited reactive ampere limiters). CAUTION - determine first the expected MVAR limiting point, and do not proceed past that point. If this point is reached without activating the underexcitation limiters/minimum excitation limiters return to normal excitation and determine why the limiter is not functioning. Also, ensure that all transformer taps throughout the power plant are coordinated so the terminal voltage can reach the minimum (90-95%, depending on unit) without causing problems to the auxiliary power further in the plant.

1) UELs are activated;
2) 100% MVA rating is reached;
3) Generator temperature limits are reached;
4) Minimum reference adjuster travel or limit is reached;
5) Minimum auxiliary bus voltage is reached;
6) Minimum terminal voltage is reached.

Take measurements outlined in C (no need to hold as in A).

C. Measurements: The following values should be reported to the WSCC Staff at 540 Arapeen Drive, Suite 203, Salt Lake City, UT 84108:

1) Gross MW output at both test points;
2) Gross MVAR output of generator reached in tests A and B;
3) Generator terminal voltage at maximum positive and negative MVARs;
4) Actual field current at both test points;
5) Machine MVA rating, both original nameplate rating and tested rating, if different;
6) Generator rated terminal voltage and rated field current;
7) Auxiliary bus voltage at minimum and maximum points;
8) Rated power factor.

D. The following machine parameters may be recorded for use during future testing (in addition to values being reported):

1) Generator field voltage;
2) Rotating exciter field current and voltage (if appropriate);
3) Generator stator currents;
4) Field temperature.

E. PRECAUTIONS: If the generator does not normally operate in these regions, strip chart recording of exciter quantities may be helpful for problem resolution. All relay targets on the generator protection and excitation system should be reset before testing. Some excitation systems transfer to manual or backup controllers if overexcitation is detected. If this happens, record the level at which it occurs and reset the control to automatic before placing the unit back in normal service. If the machine trips for any reason during these tests, specify what tripped and why it tripped. Correct the problem and retest the unit.

F. These tests should be repeated every five years or anytime there is a major change in an excitation system including, but not limited to, stator or rotor rewinds.

G. Subject to operating economics, etc., testing the units at reduced MW loading is encouraged (do not include these values in the test results). This is especially important for units that are not usually base loaded at dependable MW capability.

Appendix A - Excerpts from August 10, 1996 Disturbance Report

4. **Conclusion:** Immediately following the loss of the Ross-Lexington 230-kV line and the Merwin-St. Johns 115-kV line, the McNary units began tripping due to excitation system protection problems, withdrawing substantial real, reactive, and inertial support from the system. Three McNary units also tripped prior to COI separation during the July 2 disturbance and were identified in the disturbance review.

Recommendation

c. The WSCC Control Work Group (CWG) shall determine what tests need to be applied to generating unit exciters to ensure proper operation of exciter controls and protection. They shall also determine what unit MVA level must be tested and develop a procedure to ensure uniform testing, including the frequency of testing and a recommended priority list of units to be tested first. (The CWG work must be completed by November 1, 1996.) All generation owning and operating entities in the WSCC region shall perform the prescribed testing and report to CMOPS. (June 1997) The results should be used to properly model generating units in system studies, and actions taken reported to CMOPS. (June 1997)

10. **Conclusion:** The system oscillations increased until voltage finally collapsed on the COI, leading to the COI opening and the subsequent formation of four islands in the WSCC. Generating units in the Northwest (such as Hermiston, and Coyote Springs) did not respond dynamically or in the steady state with reactive support as predicted in studies. The level of dynamic reactive support from generation at the northern terminus of the COI and PDCI has been greatly reduced by fish operation constraints, particularly at The Dalles.

Recommendation:

a. By November 1997, the WSCC CWG shall determine what tests should be applied to generating units to determine their steady state and dynamic reactive capabilities and provide appropriate guidelines. They shall also determine what unit MVA level must be tested and develop a procedure to ensure uniform testing, including the frequency of testing, and a recommended priority list of units to be tested first. (The CWG work must be completed by November 1, 1996.) Generation-owning and operating entities in WSCC shall test, or provide proof of tests on, their generating units with capacity of ten MW or greater to determine their steady state and dynamic reactive capabilities, adjust study assumptions to match the test results, and report to CMOPS. (June 1997)

DATA REPORTING FORM FOR REACTIVE LIMITS TESTS

Reporting Entity :____Page ____ of ____ Pages
(Organization Name) Make as many copies of this form as you need

Plant Name: ____________________________Person Reporting (Name):________________________

Phone/Fax No.: _____________________/___________________

Unit Name (Number) ______________________

Machine Ratings

Terminal Voltage: ________, Stator Current: ________, Power Factor: ________, MVA: _________,

Field Current: _____, Field Voltage: _______, Exciter Field Voltage: _______,
Exciter Field Current: ______

Test Results at Maximum Output (Procedure A)

Gross	Gross	Terminal	Field	Auxiliary Bus	Rated Power	Tested MVA

Test Results at Minimum Output (Procedure B)

Gross MW	Gross MVAR	Terminal Voltage	Field Current	Auxiliary Bus Voltage	Rated Power Factor

Unit Name (Number) ______________________

Machine Ratings

Terminal Voltage: _________, Stator Current: _________, Power Factor: _______,
MVA: __________,

Field Current: _____, Field Voltage: _______, Exciter Field Voltage: _______, Exciter Field
Current: ______

Test Results at Maximum Output (Procedure A)

Gross	Gross	Terminal	Field	Auxiliary Bus	Rated Power	Tested MVA

Test Results at Minimum Output (Procedure B)

Gross	Gross	Terminal	Field Current	Auxiliary Bus	Rated Power