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LONG TERM DYNAMICS
PHASE II
FINAL REPORT

Task Force 38.02.08

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Long Term Dynamics Phase II

Final Report

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GLOSSARY

ADVANCE	:	Analyser of Dynamics with Visual Aids using Network Calculation on EWS
AGC	:	Automatic Generation Control
APSA	:	Advanced Power System Analyser
AVR	:	Automatic Voltage Regulator
BPA	:	Bonneville Power Administration (USA)
CEZ	:	CEZCH Power Company (Czech Republic)
CHAMPS	:	CRIEPI High Aggregated Master-Tool of Power-System Stability
CRIEPI	:	Central Research Institute of Electric Power Industry (Japan)
EDF	:	Electricité de France (France)
ESB	:	Electricity Supply Board (Ireland)
FACTS	:	Flexible AC Transmission System
GE	:	General Electric Company (USA)
KEPCO	:	Kansai Electric Power COmpany (Japan)
LTD	:	Long Term Dynamics
LTSP	:	Long Term Stability Program
OEL	:	Over Excitation Limiter
PSS	:	Power System Stabilizer
PSS/E	:	Power System Simulator for Engineering
PTI	:	Power Technologies, Inc. (USA)
REE	:	RED Electrica (Spain)
TNS	:	Transient Network Simulator
UEL	:	Under Excitation Limiter
ULTC	:	Under Load Tap Changer

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CHAPTER 1

INTRODUCTION

Introduction

TF 38-02-08 under the leadership of Convenor Prof. Y. TAMURA, produced an important document entitled "An international Survey of the Present Status and the Perspective of Long Term Dynamics in Power Systems". In this report, an attempt to produce a new definition of Long Term Dynamics (LTD) led to the following conclusions : "The dynamics of a power system include slow and rapid phenomena which are mixed together. Sudden transient stability phenomena may occur during slow frequency control actions and manual changes. A limited definition of LTD assumes that no unstable rapid phenomena occur. Thus the LTD may be defined as voltage and frequency dynamics that assume quasi stationary angle differences between generators". A more extended definition was also proposed, considering the real behaviour of the power system during a period of time ranging from ten seconds up to hours, including electro-mechanical rotor transients, turbine and boiler dynamics, protections, automatons, centralized controller actions and operator actions. This extended definition will be applied in the present report.

In the concluding remarks of the same report, the requirements for simulation tools were pointed out. It was observed that the real behaviour of a system over a disturbed period of several tens of minutes cannot be simulated by means of a classical slow dynamics program which is not able to display fast electro-mechanical transients. Several participants reported that they had developed of they were developing a new generation, universally applicable tool to study LTD.

The aim of second phase of TF 38-02-08 was twofold :

1. To proceed to a practical assessment of the performances of simulation tools.
2. To provide the researchers or practitioners with benchmarks or test systems to be used for the assessment of existing tools or of new developments in the field of LTD.

The Task Force succeeded in building five test systems :

- The so called "BPA test system" presented by Canada. It is a small system already used in TF 38-02-10, tuned to demonstrate the mechanisms leading to voltage collapse.
- The so called "Belgian - French test system". A 32 bus meshed system undergoing a 2 hour load pick-up followed by a cascade tripping of generators due to loss of synchronism and undervoltage protection functioning and leading to a voltage collapse.
- The so called "Swedish test system". A 32 bus long distance system with large power transfers. The proposed scenario shows a mixture of transient stability, interarea oscillations and voltage collapse over a quite short period of about two minutes.
- The so called "Irish test system". A 174 bus island system suffering the loss of a large portion of generation. The resulting imbalance between production and demand leads to widespread customer load shedding and to voltage rise. The customer load which was shed is then restored by a combination of the action of the automatic load restoration scheme and rapid synchronization of stand-by plant.

- The so called "Spanish test system". A 83 bus system which represent an equivalent of the Spanish, Portuguese and French networks. A severe three phase fault at the 400 kV bus of a power station provokes the loss of two large units leading to the separation of the system because of the action of the loss of synchronism protection of the tie lines. The scenario is then related to the analysis of an island with generation deficit.

The Task Force succeeded in gathering 19 cross calculations run with 10 different tools (2 analog simulators and 8 digital programs). The following table summarizes the different cases (circles indicate the reference simulation, as defined hereafter).

Test system Simulation tool	BPA	Belgian - French	Swedish	Irish	Spanish
LTSP	⊗	X			
EUROSTAG	X	⊗	X	X	X
PSS/E		X	⊗	⊗	⊗
CHAMPS V1 - V2		X			
APSA		X			
TNS	X				
ADVANCE		X			
EXSTAB		X			X
MODES		X			
POSSUM				X	

Ideally, to compare the ten tools, 100 cross-calculations on 10 different test systems (each being presented with a reference simulation run on a different tool) had been necessary. Of course, this requirement was impossible to reach. Nevertheless, the 19 simulations available brought far more than 19/100 of the information requested.

By giving an in depth analysis of the simulations and reaching an agreement between the proposer of the test system and the authors of the cross calculations on the interpretation of results discrepancies, the report allows to draw conclusions about the state of the art in the field of simulation of LTD.

The method of the Task Force is summarized hereafter :

- In a first step the members gathered a set of test systems. These benchmarks had to be delivered by the proposer with a simulated scenario. The test systems being inspired by existing systems having a behaviour known by the proposer, this simulation and the corresponding modelling were considered a priori as references.

- In a second step, participants simulated the same scenarios with their own tools. Generally, the first attempt was not completely satisfactory and revealed some misunderstandings in the data definition. The proposer of the test system concerned accepted to answer all the questions of the participants and to comment on the preliminary results.

This method was applied rigorously for the three first test systems.

The Irish and Spanish cases were managed in a somewhat different way.

In both cases, the proposers provided the Task Force with detailed transient stability data and simulation results on 20 s time span. General guidelines for a long term scenario were also suggested.

These test systems were accepted by the Task Force with the condition that the simulated scenario and the data be extended to the long term. The members from PTI (USA) and EDF (France) accepted to collaborate with Ireland and so did the members from GE (USA) and EDF (France) with Spain.

For the case of the Irish test system the following steps took place :

- The US member produced a first long term simulation using a special boiler/turbine model incompatible with the turbine model used in the initial Irish transient stability run.
- The French member reproduced the transient stability simulation of Ireland and proposed a simplified modelling and a long term run.
- The UK member, on the basis of the preceding works delivered a simulation report emphasizing the needs to add boiler models in the benchmark data.

As it is observed, the initial goal of building an international benchmark made of an island system is not completely achieved. Taking into account the great interest of the dynamic properties shown by the Irish test system, it is strongly recommended to continue the work and to prepare an improved data set, with possibly modified numerical data to avoid any confidentiality constraints.

The case of the Spanish system is closer to the general method followed by the Task Force. The French and the US contributors agreed on the modelling and on the scenario in such a way that a direct comparison of simulation results and the setting up of a complete test system data set were possible.

CHAPTER 2

PRESENTATION OF THE TEST SYSTEMS

2.1. The BPA test system

2.1.1. Description of the power system

The one line diagram of this test system is shown in Fig. 2.1.a. The system consists of a local area connected to a remote area by five 500 kV transmission lines. All the load (6850 MW, 1045 Mvar) is in the local area. The local generator at bus 3 generates 1155 MW, and the remaining power is supplied by the two remote generators (bus 1 and bus 2) through the five 500 kV transmission lines. Shunt capacitors are connected at various buses in the local area.

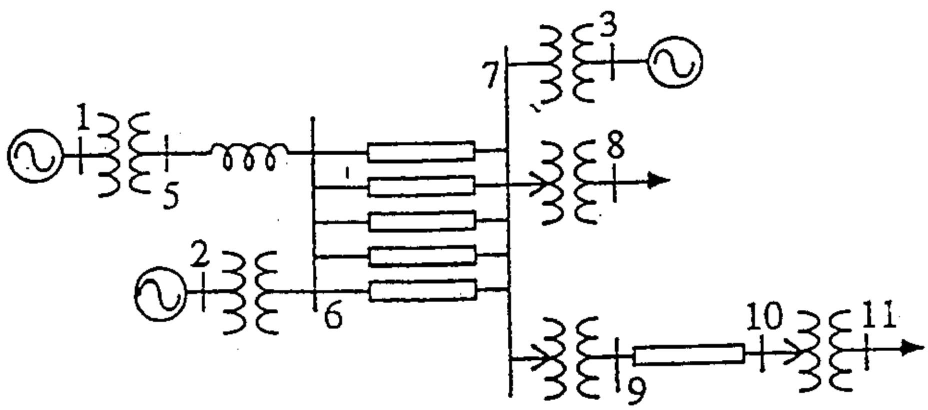


Fig. 2.1.a : Single Line Diagram of Test System

2.1.2. Description of the scenario

The disturbance considered is the opening, without a fault, of one of the 500 kV transmission lines between bus 6 and bus 7 (see Fig. 2.1.a).

Simulation results demonstrate how the actions of different devices following the disturbance eventually lead to system voltage instability.

2.1.3. Description of system modelling

Details of system modelling and data associated with all the device models are given in Appendix A1. Here we briefly summarize how each device is modelled.

Network

Equivalent circuits same as the ones used in power flow programs are used to represent transmission lines, transformers, and bus shunts.

Generators

The two axis Park's model with damper windings on both the direct and quadrature axes is used. Saturation characteristics of both the direct and quadrature axes reactances are considered. Stator transients and the effect of speed variations on stator voltages are neglected.

Governors and Turbines

The IEEE recommended model for steam turbines is used. This model takes into account the effect of governor loop gain, control valve servo, high pressure turbine, and the intermediate and low pressure turbines. The effect of intercept valve is not included. See appendix A.1 for detailed block diagram.

Excitation Systems

The exciter model represents both the Automatic Voltage Regulator (AVR) and the over-excitation limiter (OEL). The AVR model is simply a high gain static exciter. The OEL limits the field current to a pre-set value. The response time of the OEL is a function of the actual field current. The higher the field current, the faster the OEL operates to reduce the field current to within its continuous limit. The OEL will not operate if the field current is always below its continuous limit. See appendix A.1 for detailed block diagram.

Power System Stabilizers (PSS)

The PSS model with generator speed deviation as input signal is used. See appendix A.1 for detailed block diagram.

Under Load Tap Changer (ULTC)

ULTC model which takes into account the effect of time delays and controlled bus voltage deadband is used.

Loads

Load at bus 11 is modelled as constant impedance because the ULTC dynamics of the distribution transformer is explicitly modelled. Load at bus 8 is modelled as either constant power or induction motor. Induction motor load is represented by the single cage induction motor.

2.2. The Belgian - French test system

2.2.1. Description of the power system

The system displayed on Fig. 2.2.a looks like a part of the 400 kV and 150 kV Belgian system as it was in the early 80's. The external system is simulated by means of three "infinite" buses. Two important power stations, N1 and N10 produce most of the power : N1 has a total rated power of 2200 MVA and N10 has 5000 MVA. The total generation at 150 kV level is about 500 MW. The global load of the system amounts to about 5000 MW and is mainly located at the subtransmission level, downstream 150/70 kV transformers.

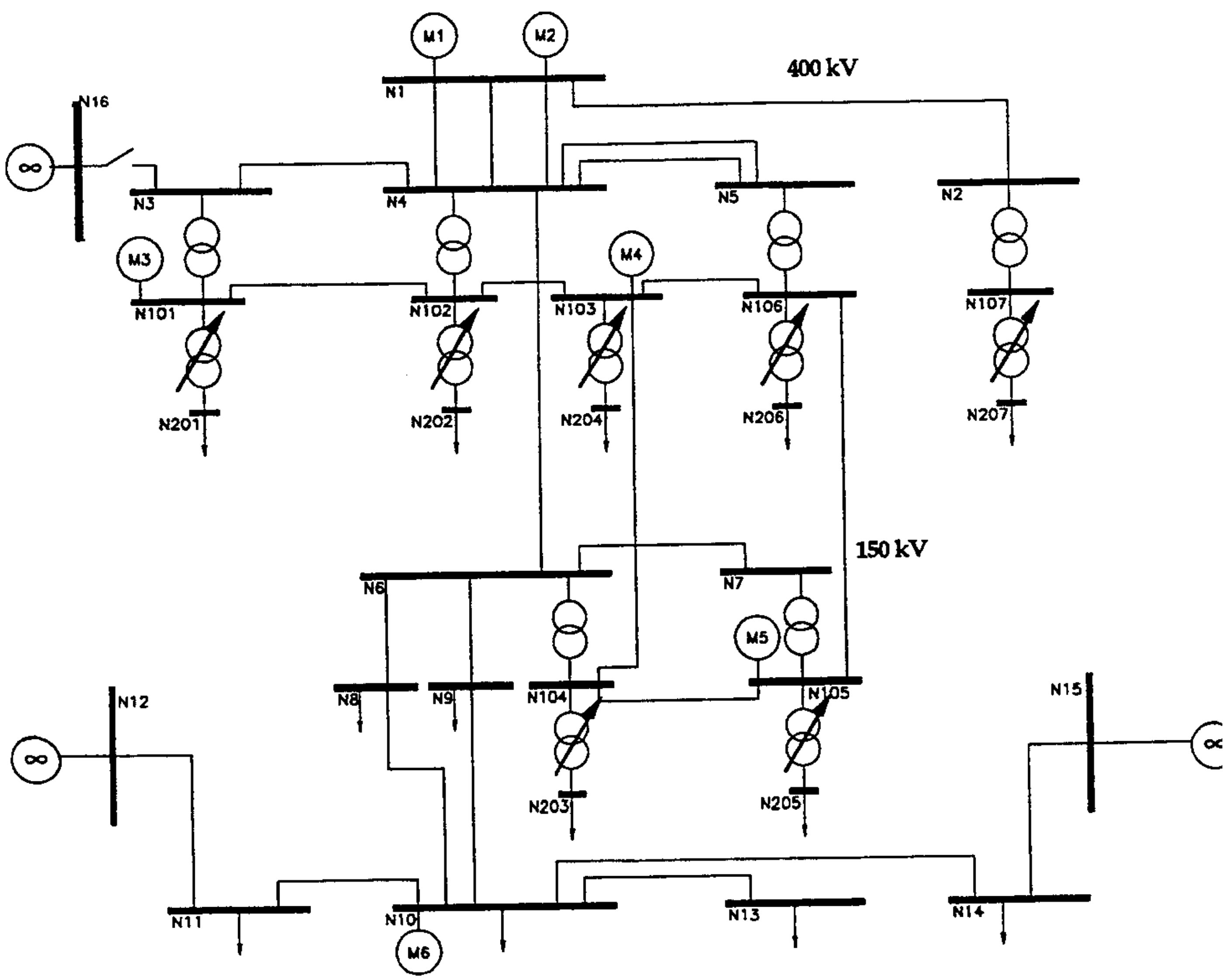


Fig. 2.2.a : Single line diagram of test system

2.2.2. Description of the scenario

In a first step a load increase of 30 % in two hours occurs in the subtransmission system.

During the load pick-up the voltage set points of the generators, the 400/150 kV transformer tap settings and the active power output of the 150 kV generators are changed by the operator in order to maintain a good voltage profile and to control the active power import.

After about 2/3 of the load increase, the Northern international tie line N16-N3 trips.

A more severe incident occurs a few minutes after the end of the load pick-up : unit M2 trips for unknown reasons.

As a consequence of this tripping and of the action of the automatic tap-changers, the rotor current limiter of unit M1 enters into action.

This limiter is ill tuned and reduces drastically the excitation, provoking the loss of synchronism of the unit M1 about 2 minutes after M2 tripping.

After this second unit tripping, the voltage on the terminals of the other machines is progressively reduced as a result of further tap-changes and rotor current limiter actions, and the generating units successively trip by undervoltage protection or by loss of synchronism, up to the final black-out of the system.

2.2.3. Description of the modelling

Network

The classical load flow modelling is used.

Generators

A Park model is used, with 4 winding rotors and saturation in both axes. Stator transients are neglected.

A.V.R.

The AVR model, beside the voltage and active power (PSS) loops, is fitted with a rotor current limiter, modelled at the functional level (see Fig. 2.2.b.) : when the field current goes beyond a limit (IFSEUIL) a set-reset unit is switched, provoking, after a delay equal to (PLEXP1 - PLEXP3)/KTEMPO, (typically equal to a few tens of seconds), a reduction of the excitation up to a preset value (PLEXPS2).

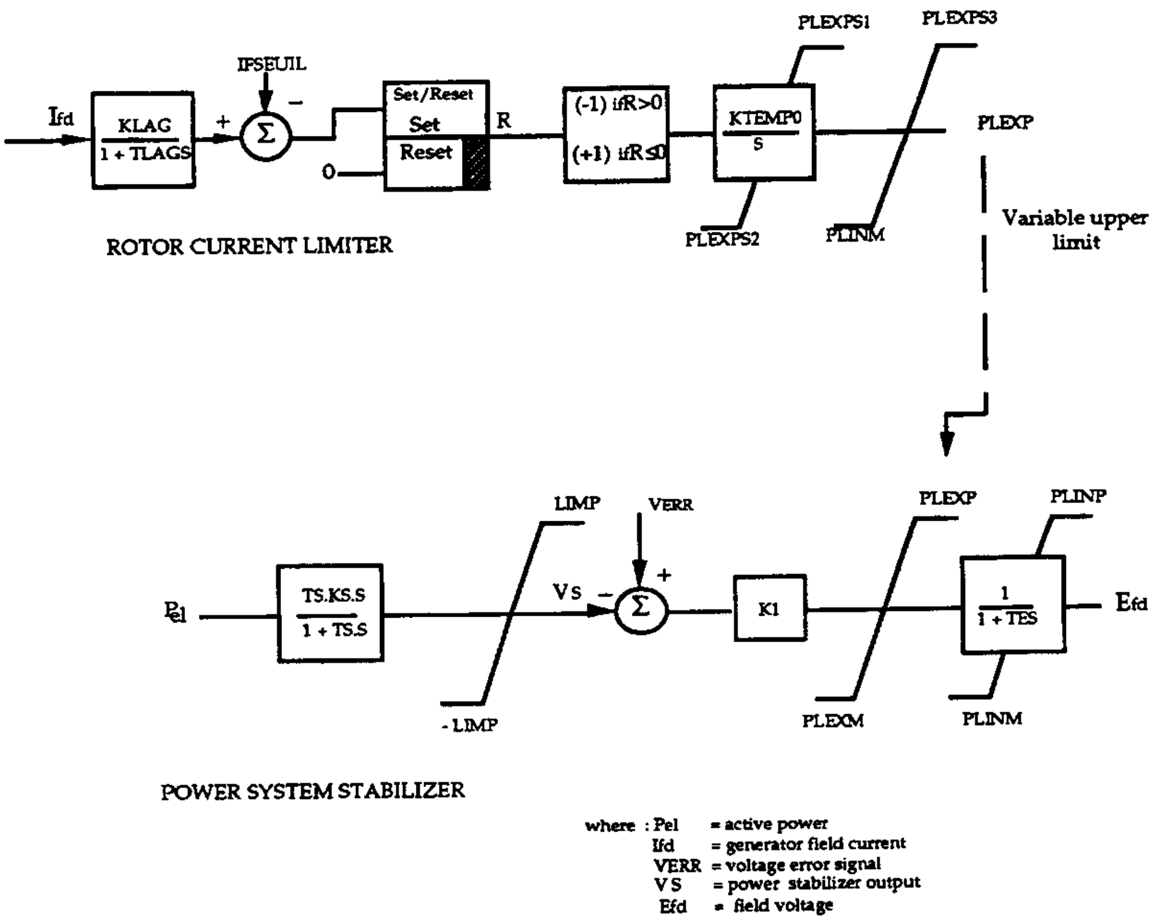


Fig. 2.2.b : Block diagram of AVR

Governor and turbine

Thanks the presence of fixed frequency buses (infinite buses), the prime movers may be utterly simplified.

Generators M1, M2 and M6 have a constant mechanical torque prime mover. Generators M3, M4 and M5 are fitted with a simplified governor-turbine model. There is no modelling of the boilers.

Transformer tap-changers

The 400/150 kV transformers have remote controlled taps. The 150/70 distribution transformers are fitted with automatic tap-changers regulating the low voltage side.

Loads

The 70 kV loads are made of a mix of an induction motor, a constant impedance load and a compensation capacitor. The other loads are of constant impedance type.

Protection

Out-of-step relays and undervoltage relays protecting the generating units are modelled.

2.3. The Swedish test system

2.3.1. Description of the power system

2.3.1.1. Introduction

The Swedish test system is fictitious but has dynamic properties that are similar to the Swedish and Nordic power system. The system is intended for simulation of transient stability and long term dynamics.

The system is long with large transfers from a hydro dominated part to a load area with a large amount of thermal power. The voltage support of the transmission system is essential.

The transmission capacity with respect to certain single faults (tripping of lines, generators) is determined by transient stability and voltage instability. It is found that current limiters on generators and load restoration due to tap changer operation play a very important role.

Network data as well as models are standardized. For example, only one type of excitation model is used, with a few sets of data. The number of nodes and generators is quite limited, 32 and 23 respectively. In addition there are generator buses and some load buses.

2.3.1.2. Network - general outline

The system character may be illustrated by the geographic outline (approximately) as shown in Fig. 2.3.a. Some of the lines are series compensated.

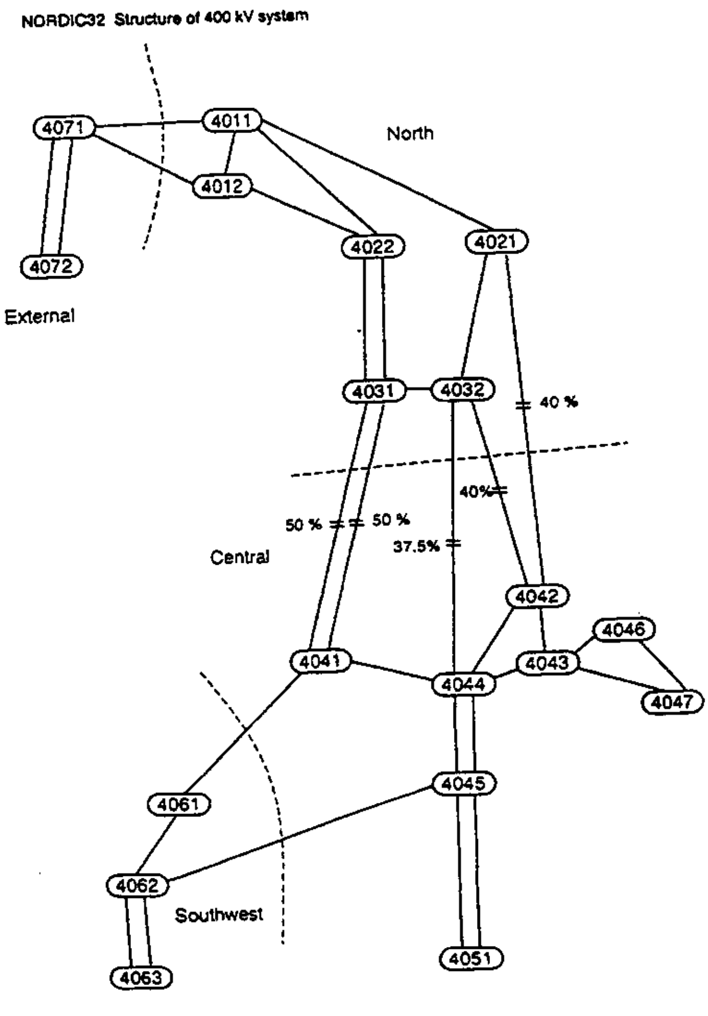


Fig. 2.3.a Structure of 400 kV system

The network consists of four major parts (see Fig. 2.3.b).

- "North" with basically hydro generation and some load
- "Central" with much load and rather much thermal power generation
- "Southwest" with a few thermal units and some load
- "External" connected to the "North". It has a mixture of generation and load.

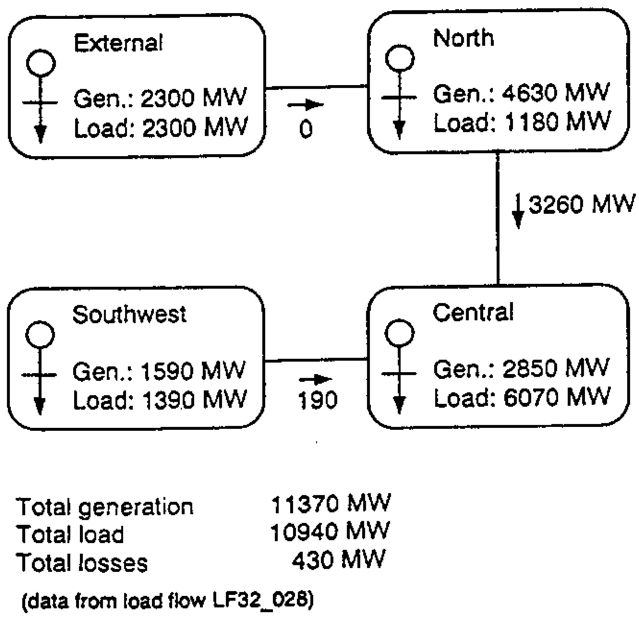


Fig. 2.3.b : System regions

The network is rather long. The "Southwest" area is rather loosely connected to the rest of the system. The "External" system consists of a very simplified network. The transfers at peak load is basically from the "North" to the "Central" part.

The main transmission system is designed for 400 kV. There are also some regional systems at 130 kV and 220 kV. The number of nodes are 19, 11 and 2 respectively. In addition, some load buses are modelled that are connected to the lower side of transformers with tap changers. In the data set, the generator buses are defined as an internal part of the generator model.

The transfer system North to South has got very limited voltage support in the intermediate region (bus 4021, 4031 etc.). Thus basically two types of voltage collapses may occur.

1) A contingency that weakens the transfer system from "North" to "Central" may lead to a voltage collapse in the intermediate region (bus 4031 etc.).

2) A contingency that decreases the voltage support of the "Central" load area may cause a voltage collapse of that region (bus 4044 etc.).

2.3.1.3 Load flow

Basic load flow for scenario

In the basic load flow (lf32_028) the load level is at peak load. The transfers are large from region "North" to "Central". In fact, the transfers are higher than should be allowed with respect to normal design standards.

As will be shown below, some trippings of a certain line or tripping of single generation units result in a collapse. The initial transient stability can be managed in most cases, but the generator current limiters and the transformer tap changers may cause a delayed system collapse. For a critical line fault not even the initial transient stability can be managed, without forced generator tripping.

It is estimated that the transfer limit with respect to single faults should be about 400 MW lower from "North" to "Central" region.

Alternative load flow

Another load flow (lf32_029) is presented for further studies on a normally loaded system. It is similar to the basic load flow but transfer from "North" to "Central" is lower. The design requirements of the system is that single faults shall be managed, such as trippings of single lines and generators with or without initial three-phase short circuit. The load flow fulfils those requirements, possibly with some exceptions (tripping of line 4011 to 4021 in the North).

2.3.1.4 Control characteristics

Frequency control characteristics

All frequency control is dedicated to the hydro units in the "North" and "Central" regions. The total steady-state gain is 4375 MW/Hz. In addition generator trippings are also compensated by load frequency dependence 165 MW/Hz and voltage dependence. The latter play an important role as the voltage may decay some 10 % in case of major trippings.

Voltage control

All generators are equipped with AVR with normal gain and response time. All are also equipped with PSS, power system stabilizers. Tests show that the latter play an important role. If no PSS would be at hand, many single contingencies would result in sustained oscillations and even undamped oscillations.

All generators are equipped with rotor current limiters. The thermal unit generators are also equipped with stator current limiters. In the simulations the time delay is 20 seconds. In reality, the delay may be shorter, maybe 10 seconds. The longer time has been chosen to damp out initial system oscillations before the limiters operate.

Transformer tap changers and load dynamics

The load has got voltage and frequency dependence. In addition transformer tap changers are modelled, which slowly tend to restore the load.

Tap changers are delayed by 40 seconds before the first step change may occur. After that they operate every 6 - 8 second. In a real system, the time delay should be same for the initial and the subsequent switchings. The special modelling is chosen to speed up the simulation.

Also the initial voltage dead band is somewhat too large.

In the Swedish system there are two kinds of tap changer control - constant time and inverted time characteristics. The former has a time delay of 30 seconds to 2 minutes. In the latter the time is dependant on the voltage deviation. In case of large voltage deviation it may be 10 seconds and in case of small variations up to 2 minutes.

2.3.2 Description of the scenarios

Contingencies

The following contingencies are proposed.

Case 1: a unit in the 'central' area (no. 2 at bus 4047) is tripped.

Case 4: a transmission line (4011-4021) is tripped. Automatic forced tripping of a generation unit (1012) is assumed 0.10 seconds later.

Case 14: a unit (no. 1 at bus 4062) is tripped.

Dynamic performance

All simulations result in a collapse.

Case 1: a voltage collapse occurs of the central region.

Case 4: a collapse occurs in the transfer section between the "Northern" and "Central" regions.

Case 14: a voltage collapse occurs in the "Central" region.

All of the cases passes a number of subsequent "time stages", as follows

0-20 The initial transient is managed. The oscillations are damped. The voltages are reasonable.

20-40 s The generator current limiters act, which result in a sudden decrease in voltage. The oscillations are still damped and the amplitude is reasonable.

40- s The voltages slowly decrease as the tap changers tend to increase the loads.

\- Suddenly the voltages decrease considerably, and very large oscillations occur. After some time units go out of phase etc. in some cases, and/or the calculation indicate 'non convergence'.

2.3.3 Description of the modelling

The detailed data are found in Appendix A.3. In this chapter some general comments are given.

Basic load flow

As already has been stated, high transfers are assumed.

The loads in the "Central" and "South-western" regions are connected to the 400 kV grid via explicit 400/130 kV transformers. They have automatic tap-changers that are modelled in the dynamic data. The loads to 130 kV have no tap-changers.

Bus 4011 serves as slack bus.

Generators and controls

Only a few standard sets of data are used. For example, all thermal units have the same reactance data etc.

The units are equipped with PSS (Power System Stabilizers) to achieve acceptable damping conditions.

All the generators have rotor current limiters. The thermal units have also stator current limiters. The limiters all affect the excitation system. The logics are in principle the same.

- The present current value is compared to a maximum limit. If it exceeds the limit for a certain time a signal, K x (I_{limit} - I_{actual}), is sent to the excitation system.
- A logic unit chooses the signal that will give the lowest excitation level, i.e. it chooses between the ordinary voltage difference V_{set} - V_{actual} and the signal from the limiter

Although the scenario is built upon a special type of current limiter, approximately the same result as concerns voltage collapse will be obtained, also with other current limiters. The only requirement is that they bring the rotor currents down to about 110 % of rated value, and the stator currents down to about 105 % of rated value.

2.4. The Irish test system

2.4.1 Description of the Power System and Scenario

A hypothetical "island" test system and scenario is proposed in this Chapter based on, but not identical to, that of the Electricity Supply Board (ESB), Ireland. The test system comprises 400 kV, 220 kV and 110 kV voltage levels and is depicted in Figure 2.4.a. The test system exhibits many of the dynamic properties associated with small island power system where the largest generation infeed can represent a significant fraction of the customer demand.

The scenario involves the loss of a substantial portion of the generation at a period of low system demand. The resulting imbalance between active production and active demand leads to a large change in system frequency and widespread customer load shedding. Moreover, the loss of both active and reactive generation and demand at this low load period leads to large reactive power imbalances which may lead to the operation of overfluxing relays on transformers. The customer load which was shed is then restored by a combination of the action of the automatic load restoration scheme and rapid synchronisation of standby plant - pumped storage, hydro and combustion turbines.

In common with the Spanish test system described in Chapter 2.5, the long-term scenario for the Irish test system was developed during the course of the work of the Task Force. Accordingly, Chapter 4.4.1 describes an initial 20 second simulation carried out by ESB using PSS/E illustrating the scenario and discusses phenomena, and the event sequence which must be modelled to extend the time-frame of simulation. Chapters 4.4.2, 4.4.3 and 4.4.4 describe extended time-frame simulations carried out by PTI, Nuclear Electric and EDF using PSS/E, POSSUM and EUROSTAG respectively. Chapter 4.4.5 draws some conclusions.

2.4.2. General Description of the System

Transmission System

An outline of the transmission system is shown in Figure 2.4.a. which includes meshed 220 kV and 110 kV system operating in parallel. There are three 400 kV circuits which operate as 'tail feeders' to three generating units at station MP due to the sectionalising arrangement there. For the purposes of the scenario, all circuits are connected with the exception of two 220 kV cables between station PB and IE which are disconnected for voltage control. Shunt Reactors are connected at stations IE, RE, FS and CK. Appendix A4.1 tabulates the network data under standard headings used in power flow programs.

Under-frequency load shedding and restoration is modelled as if it occurred at 110 kV busbars.

Generation System

The generation profile for this study is illustrated in Table 1 with the total customer load being augmented by two pumps at a pumped storage station TH. Generation reserve is a major consideration for island power systems and this is catered for in this test system by ensuring that the minimum total values of primary (PR) and secondary reserve (SR) are not less than 45% and 80% of the largest infeed as illustrated in Table 1.

STATION	TYPE	OUTPUT (MW)	PR (MW)	SR (MW)
MP	Drum	3x275	35	80
PB	Once-Through	40	0	0
AD	Once-Through	40	0	0
Indigenous Fuel Sets		200	0	0
		1105		
Pumped Storage		140	140 175 (60%)	140 220 (80%)
Transmission Losses		15		
Generator House Load		86		
Customer Demand		864		

Table 1. Generation Pattern For Case Study

Dynamic Models Required for Short-Term Simulation

Appendix A4.2 gives a description of all the dynamic modules used to model

the power system components is given with associated data items.

Governors - Turbine speed governors are modelled with standard modules (TGOV1 and BBGOV1).

Excitation Systems/Power System Stabilisers - The simplified, solid and Brown Boveri excitation systems and power system stabilisers were modelled with standard modules (SEXS, SCRX, BBSEX1, IEEEST).

Generators - round rotor generator and salient pole generators were modelled with standard modules (GENROU, GENSAL).

Load Modelling - The customer load was modelled using the standard module IEELCA. The active load was to be sensitive to voltage and frequency whereas the reactive load was assumed to be sensitive only to the square of voltage.

Transformer Saturation - Transformer saturation was modelled with the standard modules (SAT2).

Load Shedding Relays - Load shedding relays were modelled at the appropriate buses with a maximum of five stages of shedding. The total customer load that can be disconnected in this way is approximately 60%.

Pumped Storage Under-Frequency Relays - The pumped storage machines were modelled as load with under-frequency relays set at 49.6 Hz and 49.2 Hz. This simplification neglects the dynamic effect of the pumps but it is assumed that the frequency fall will be so rapid that the disconnection of pumps is prompt and this effect is negligible.

Dynamic Models Required for Long-Term Simulation

Automatic Load Restoration Scheme - When the frequency remains above 49.8 Hz for more than 9 seconds, 1% of the system peak is restored every 6 seconds provided the frequency remains above 49.8 Hz. For this study,1 % of the system peak will be 11 MW which will be reinstated 15 (9+6) seconds after the frequency rises and remains above 49.8 Hz.

The relays are restored in reverse order. If at any time the frequency drops below 49.0 Hz restoration ceases. The frequency must rise above 49.8 Hz for greater than 9 seconds before restoration is restarted.

If the frequency drops below 49.8 Hz and remains above 49.0 Hz restoration pauses. It re-commences immediately when the frequency rises above 49.8 Hz.

Total restoration of all load would occurs within 360 seconds if there were no pauses or restarts.

Pumped Storage - It should be noted that simultaneous pumping and generating can not occur at a pumped storage station. When the second pump is tripped, both pumps would now begin to reverse and act as generators. They would synchronise approximately 75 seconds later at 0 MW.

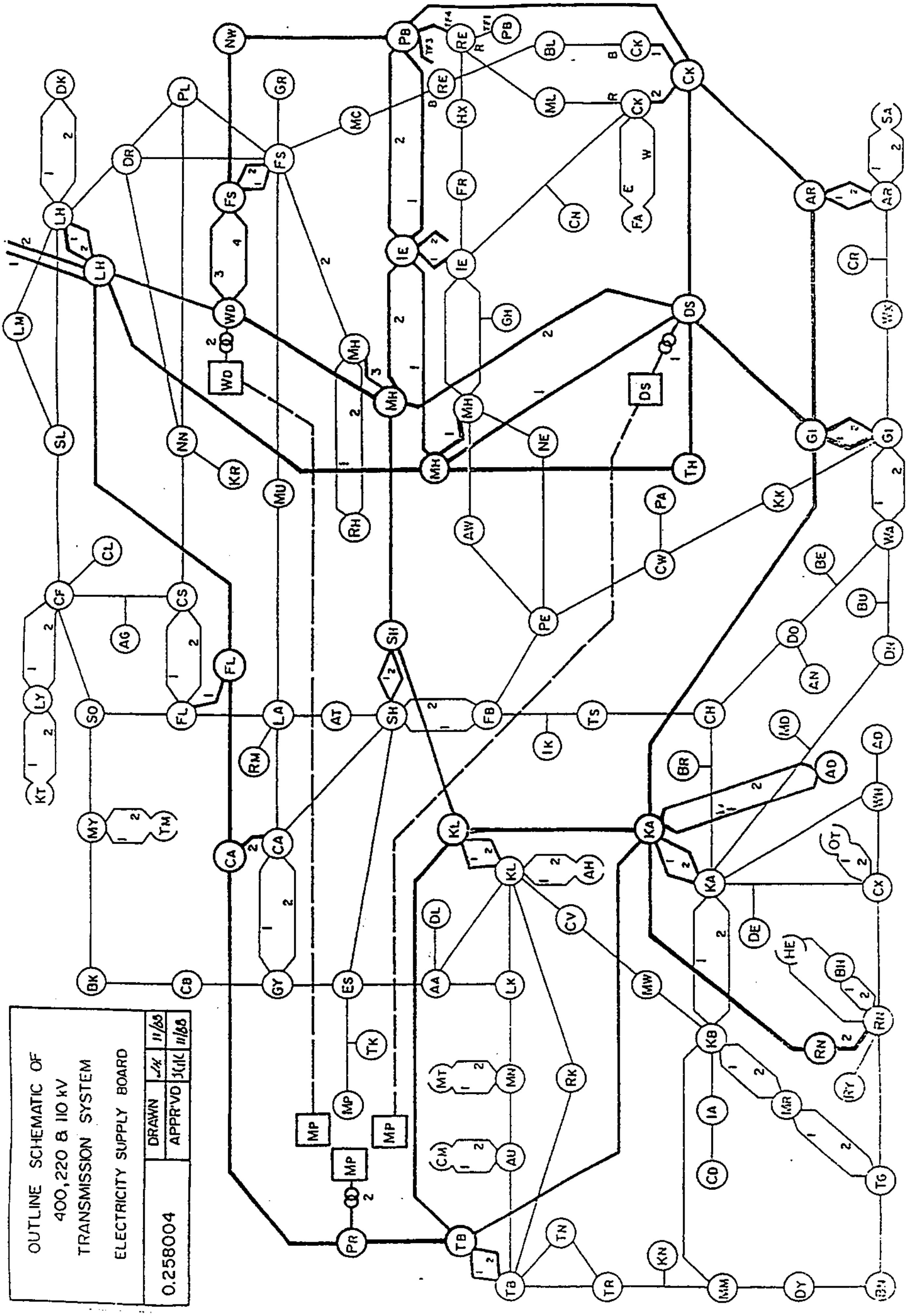
If the frequency dropped below 49.0 Hz the remaining sets would be automatically initiated to generator mode and would synchronise approximately 65 seconds later at 0 MW.

All machines would rise to full load within 8-10 seconds if the frequency was still low i.e. not greater than 50.1 Hz. Otherwise they would rise to minimum load (5 MW) where governor action would take over.

UNIT	PREVIOUS MODE	RELAY SETTING (Hz)	SYNCHRONISATION TIME AS GENERATOR
G3	Pumping	49.6	75 seconds after trip
G2	Standby	9.4	65 seconds after f < 49.4 Hz
G1	Pumping	9.2	75 seconds after trip
G4	Standby	49.0	65 seconds after f < 49.0 Hz

Table 2. Response of Pumped Storage Station

Response of Generators - The once-through units, G1 at AD and G3 at PB should rise at 10 MW/minute. The hydro plants would be started under manual instruction within 5 minutes and rise at a rate of between 2-10 MW/min.


OUTLINE SCHEMATIC OF
400, 220 & 110 kV
TRANSMISSION SYSTEM
ELECTRICITY SUPPLY BOARD
DRAWN
APPR'VD
11/68
11/68
0.258004

2.5. The Spanish test system

2.5.1 Description of the power system

2.5.1.1. Introduction

The Spanish test system, partially shown in figure 2.5.a, corresponds to an equivalent of the Spanish, Portuguese and French real networks. This equivalent does not try to reproduce, in an exact way, the real behaviour of the mentioned power systems. However, certain dynamics, that are similar to the reality, have been kept.

2.5.1.2. Network. General description

The outcoming system consists of two main geographic areas (area A and B) that are interconnected by two 220kV tie-lines and two 400kV tie-lines. The dimensions of these areas are as follows:

	Area A	Area B	TOTAL
Buses	55	28	83
Branches	110	137	247
Groups	11	12	23

Load demand of area A is almost 24000 MW and the power imported into this area, from area B, is very small (less than 100 MW).

2.5.2. Description of the scenario

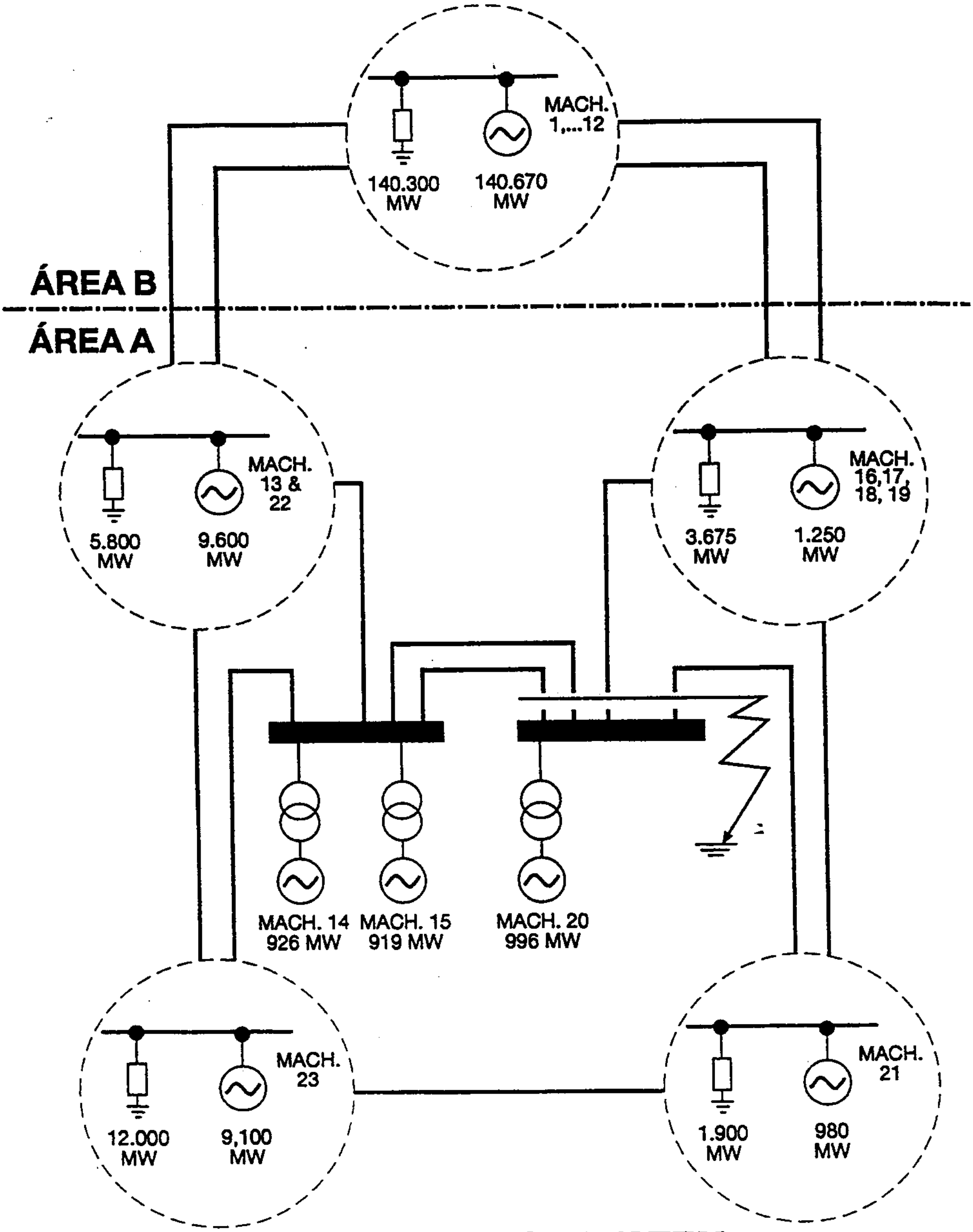
The initial disturbance is a ten cycles three phase to ground short circuit at the 400 kV evacuation bus of an important plant (machine 20, 996 MW).

This scenario is based on a real incident. However, the real conditions have been modified and the short circuit duration has been increased in order to obtain a much more unfavourable scenario. In this way, the actuations of the load shedding system, loss of synchronism relays of the tie-lines and load-frequency control, are forced. The analysis of these three dynamics is one of the main goals of this study.

2.5.3. Description of system modelling

A great effort has been made in order to represent the most important dynamics in a frequency scenario (load depending on the frequency, load shedding system, load-frequency control and power plant regulation models). A more detailed information is found in Appendix A5.

- Network: Algebraic PI schemes are used for transmission lines. The auxiliary services of two important plants (units 14 an 15, 926 and 915 MW, respectively) have been included in the study network.
- Generator: Full Park model with 4 rotor windings and saturation in both axes.
- Excitation system: In order to facilitate the modelling several standard models have been used. (SEXS, EXAC4, IEEEX1, IEEEX2A).



SPANISH TEST SYSTEM
SIMPLIFIED REPRESENTATION

Fig. 2.5a

- Turbine/governor: Standard models have also been used to represent this dynamic. (TGOV1, IEEEG1).
- Power plant: Only power plants receiving load-frequency control signal have been modelled, these are: 16, 18, 22 and 23. To represent them, simplified models of steam power plant and nuclear plant have been used.
- Protection systems: The following protections have been considered:
  - Overspeed protection: This protection closes the main steam valves if the machine speed reaches a value greater than 110%.
  - Auxiliary services undervoltage relay: This protection has been included at the machines where auxiliary services have been modelled, these are: units 14 and 15. The relay adjustment is as follows: Set-point: 70% of the nominal voltage, timing: 0.405 sec., relay reset voltage: 80% of the nominal voltage. (Nominal voltage: 6.9 kV). This protection causes the main steam valves closing.
  - Unit loss of synchronism protection: This protection checks the angle rotor value of the generating unit to identify possible loss of synchronism.
  - Tie-line loss of synchronism protections: These protections are installed in the tie-lines between area A and B, in particular in the substations located at the corresponding extreme of the area B.

  These relays base their operating mode on the survey of the voltage crest values that are reached in the respective substations and they only take into account the voltage oscillations included in the following interval: 1 Hz<f<5 Hz.

  To consider an appropriate oscillation frequency it is necessary to identify the existence of, at least, 10 successive descending semiperiods followed by, at least, 4 successive rising semiperiods (a semiperiod is equal to 10 msec.). There are, also, two additional controls based on the voltage value. The first one verifies the absence of a very close short circuit condition, and the second one assures the existence of a low enough voltage value, as associated to a loss of synchronism condition.

  This protection system is complemented with an automatism that opens all the tie-lines if a trip on a 400 kV tie-line occurs. However, if the trip occurs on a 220 kV tie-line, this protection only produces the trip of itself.
- Loads:
  - Load buses have been represented, by a combination of standard static load models, as follows:
    - Active component (P):

      50% constant current and frequency dependent.

      50% constant impedance and no frequency dependent.
    - Reactive component (Q):

      100% constant impedance and no frequency dependent.

- The auxiliary services of machines 14 and 15 are an exception to the mentioned modelling. They have been modelled using a combination of static load and induction motor models.

- Load shedding system: A four steps load shedding system has been modelled and applied to all the loads of the area A, with the logical exception of auxiliary services loads of machines 14 and 15.

  The four steps are as follows:

Step number	Frequency	Load shed
1	49.0 Hz	15% of the initial load
2	48.7 Hz	15% of the initial load
3	48.4 Hz	10% of the initial load
4	48.0 Hz	10% of the initial load

- Load-frequency control: A simplified AGC model has been used for the load-frequency regulation of the area A.

  With both areas A and B interconnected, this model controls system frequency and the interchanged power through the interconnection. However, when area A becomes separated this model only controls the frequency of this area.

  Four regulating units (16, 18, 22 and 23) follow the AGC orders according to the unit participation factors (0.3, 0.3, 0.3 and 0.1, respectively).

CHAPTER 3

PRESENTATION OF THE TOOLS

3.1. Introduction

The tools presented in this chapter can be classified as follows :

- real time analog simulators : APSA (large scale) and TNS (R & D prototype);
- quasi steady state tools : CHAMPS V1, and CHAMPS V2 are tools specialized in voltage stability assessment, using extended load flow Jacobian matrix and complex load flow solution;
- time domain simulation programs with explicit integration method and fixed time step : LTSP (option), PSS/E, CHAMPS, EXSTAB (option);
- time domain simulation program with implicit integration method and fixed time step : LTSP (option), PSS/E (option);
- time domain simulation program with explicit integration method and variable time step : MODES;
- time domain simulation programs with implicit integration method and variable time step : EUROSTAG - EXSTAB - POSSUM (option).

Four programs have the possibility to use different algorithms (LTSP, PSS/E, EXSTAB and POSSUM, based on a general solver) and the possibility to switch from one to another integration method during a run; but the choice of the method remains with the user, except for EXSTAB where an automatic switching from implicit to explicit algorithm is foreseen. The same program is also the only one using a manual switch in the modelization to speed up long term simulations.

In PSS/E the coding of dynamic models must be in duplicated to allow the use of both explicit and implicit integration methods.

Network modelling

Algebraic PI schemes are used for lines in all digital programs. Both analog simulators use 3 phase circuits with iron core and coil. Sensitivity of line parameters to frequency is available in EUROSTAG, PSS/E and ADVANCE. Transformer with ULTC are available most generally, but transformer saturation modelling is less frequent.

Generators

Park's model with 3 or 4 rotor windings is a standard, even for analog simulators. Saturation modelling is available in six out of ten tools.

Loads

Voltage and frequency dependencies of the passive load is generally available.

Dynamic loads model are generally available under the form of induction motors. Moreover, special synthetic models are used (LTSP - EUROSTAG, ADVANCE, EXSTAB and PSS/E). User defined dynamic load models are possible in LTSP and EUROSTAG.

Controllers and power plant modelling

All tools have a library of models.

The flexibility and the accuracy of the simulation are achieved mainly by the size of the library of models (LTSP, PSS/E), and, to a larger extend, by the disposal of user defined models as in LTSP, EUROSTAG and ADVANCE.

PSS/E has also to a certain extend user defined modelling possibilities but this facility has not been used by the participants to the simulation of the Task Force.

Protection devices

Very few information about relay modelling has been gathered in this chapter.

Interactive operations

Operator actions can be taken into account interactively in six out of ten tools (EUROSTAG - PSS/E - APSA - TNS - ADVANCE -MODES).

Output facilities

All tools offer the possibility to plot any system variable and most of them allow to monitor some variables during the runs. The possibility to plot a variable vs another variable (PV curves, ...) is frequent. All tools require a prior declaration to define the output files, except EUROSTAG which stores all state variables and allows to compute a posteriori any observable quantity by means of an interactive program.

3.2. LTSP

LTSP is capable of simulating fast as well as slow dynamics of power systems and is based on the Extended Transient/Midterm Stability Program (ETMSP) [1]. In addition to all the features of ETMSP, LTSP includes detailed models for fossil-fuelled, nuclear, and combustion turbine plants [2]. The basis for and the details of modelling and solution techniques used in these programs can be found in [3].

3.2.1. Power system component modelling of LTSP

The following are the component modelling capabilities of LTSP :

3.2.1.1. Transient stability models

Synchronous generators and associated controls

- synchronous generator models with various degrees of complexity
- all the IEEE standard exciters and more
- different types of power system stabilizers
- different types of governors
- transient excitation booster
- stabilizer torsional filter
- under excitation current limiter

Induction motors

- single cage rotor
- deep bar rotor
- double cage rotor

Static non-linear loads

- various functions to represent the voltage and frequency dependencies of load active and reactive power

HVDC links

- user-defined based models which provide high degrees of flexibility
- both two-terminal and muti-terminal models

Flexible AC transmission systems (FACTS)

- static Var compensators (SVC)
- thyristor controlled series compensation
- thyristor controlled tap changer and phase regulator
- thyristor controlled braking resistor and braking capacitor

Relays

- frequency and voltage relays for the disconnection of generators, loads, and transmission lines
- impedance and distance relay
- series capacitor protection gap

3.2.1.2. Dynamic voltage stability

Under load tap changer (ULTC)

- time delay
- controlled bus voltage deadband

Thermostatically controlled loads

- model the switching on of heaters as voltage decreases
- response time in the order of minutes

Maximum excitation current limiter

- instantaneous and continuous field current limit
- response time depends on the actual value of field current

3.2.1.3. User-defined models

In addition to the above mentioned models, LTSP allows the set-up of user-defined models based on a set of about 30 basic control blocks. The user specifies the way these basic control blocks are connected in order to model a particular device. A variety of system variables can be used as inputs to the basic control blocks. User-defined models can be used to model : (1) excitation systems, (2) prime movers and governors, (3) shunt elements and, (4) series elements.

3.2.2. Power plant dynamic models in LTSP

The plant models are very detailed and serve to model all the important physical characteristics of a plant. Models include fossil-fuelled plants, combustion turbine units, and nuclear plants. Two types of fossil-fuelled plants can be modelled : (1) plants with drum type boilers and, (2) plants with once-through type boilers. Three types of nuclear plant models have been developed : (1) pressurized water reactor (PWR) plant, (2) boiling water reactor (BWR) plant, and (3) Canadian Deuterium (CANDU) reactor plant.

The fossil-fuelled plant model includes representation of the following major components :

- furnace;
- fuel system;
- the secondary air system;
- the flue gas system;

- feedwater flow;
- boiler;
- main and reheat steam system;
- control system;
- protection system.

The combustion turbine unit model includes representation of the following components:

- hydraulics and process dynamics;
- thermodynamics;
- fuel control;
- inlet guide vanes control;
- bleed valve control;
- start-up sequence;
- protection system.

The BWR nuclear plant model includes representation of the following major components:

- reactor core;
- reactor coolant system;
- main steam and turbine system;
- feedwater and feedwater heater system;
- control system;
- protection system.

The PWR nuclear plant model includes representation of the following major components:

- reactor core;
- reactor coolant system;
- steam generator;
- pressurizer;
- feedwater control and feedwater heater system;
- main steam and turbine system;
- control system;
- protection system.

The CANDU nuclear plant model includes representation of the following major components:

- reactor core;
- primary heat transport system;
- pressurizer;
- steam generator;
- feedwater system;
- main steam and turbine system;
- control system;
- protection system.

3.2.3. Solution algorithms

3.2.3.1. Solution of algebraic equations

The general form of algebraic equations solved in each integration step of LTSP is

$$YV = I(x, V) \tag{1}$$

where I (x, V) is a current injection vector, which includes currents from all dynamic and non linear static devices, and Y is the network admittance matrix, which includes constant impedance loads. Equation 1 is a set of non-linear equations and thus an iterative approach is usually required to obtain the solution. In LTSP, however, Equation 1 is modified so that a non-iterative solution method can be applied. Details on how Equation 1 is solved in LTSP to avoid iteration is described in [1].

The Y matrix is refactorized only when discontinuities such as switching of network elements and moving of transformer taps occur. LTSP uses highly efficient sparse matrix and sparse vector techniques to solve the linear algebraic equations associated with Equation 1 at each integration time step.

3.2.3.2. Solution of differential equations

Both explicit and implicit integration methods have been implemented in LTSP. Explicit integration methods include the following :

- fourth order Runge-Kutta method;
- third order Runge-Kutta method;
- second order Runge-Kutta method;
- modified Euler method;

and implicit integration method used in LTSP is based on the trapezoidal rule.

Different integration algorithms can be used during different periods of a simulation run. All the numerical integration methods implemented in LTSP use fixed time steps. However, the user can explicitly change the integration time step at any time during a simulation run. The typical step size for explicit integration method is 0.02 seconds during the initial transient period and 0.05 seconds after the initial transient period. Typical step sizes with implicit integration method is at least twice as large as those for explicit integration method.

3.2.4. Interactive operations

LTSP has been designed to read in load flow and dynamic device data in different formats. All the formats commonly used by North American utilities can be directly used as input files to the program.

The data for dynamic devices can be modified interactively without editing the input files.

3.2.5. Output facilities

The user can specify any of the system variables to be monitored and outputted. The volume of the output files depends on the number of variables monitored. Plotting facilities on different computer platforms are supported. Postscript files of the plotted curves can also be generated. ASCII listings of the monitored variables can also be produced.

3.2.6 References

[1] EPRI Research Project RP1208-9, "Extended Transient Midterm Stability Program", Final Report, Prepared by Ontario Hydro, December, 1992.

[2] EPRI EL 6627, Research Project 3144-01, "Addition of Nuclear and Thermal Power Plant Models to Long Term Stability Program" Final Report, Prepared by Ontario Hydro, October, 1993.

[3] P. KUNDUR, Power System Stability and Control, Mc GRAW-HILL, 1994.

3.3. EUROSTAG

EUROSTAG has been developed by TRACTEBEL and Electricité de France. It is a general purpose stability program using an extended modelling of the power system and allowing the simulation of its dynamic performance over a long period of time, even in case of intermingling of fast (transient) and slow (long term) phenomena.

3.3.1. Power system components modelling

Generators

Full Park model with 4 rotor windings or simplified models. Saturation in both axes depending on the position of the flux.

Network

Algebraic PI schemes are used for lines. Their parameters will depend on the frequency. Unsymetrical PI are available for the modelling of network equivalents. Transformers are represented in detail (saturation of the magnetizing circuit, variation of the leakage reactance as a function of the tap position, operating law of the tap controller, phase shifting).

Direct Current links (two terminal or multi-terminal models) can be integrated in a single AC network or can tie AC systems together. Models are user defined.

Loads

a) Static loads

Active and reactive loads are sensitive to the voltage and the frequency and their nominal values Po and Qo are explicitly time dependent :

$$P = P_0(t)\left(\frac{V}{V_0}\right)^{\alpha}\left(\frac{f}{f_0}\right)^{\gamma}$$

$$Q = Q_0(t)\left(\frac{V}{V_0}\right)^{\beta}\left(\frac{f}{f_0}\right)^{\delta}$$

b) Dynamic loads

Induction motor	:	full two cage rotor model or simplified model (no rotor transients).
$P(s) + j\,Q(s)$	:	active and reactive parts of the load are the output of a transfer function or any block-diagram defined by the user.
$G(s) + j\,B(s)$	:	same as $P + jQ$ where $G + jB$ represents an admittance load.
$I(s)\,e^{j\varphi(s)}$	:	same as $P + jQ$ where $Ie^{j\varphi}$ represents a current injected in a bus.

Bulk distribution load : takes into account the time response of the step down transformer.

Controllers and power plant modelling

a) Standard library

A library of standard models of AVR's, governors, boilers, SVC's, ... , allows the user to build his own plant models.

b) Models defined by the user

It is often necessary to define certain controllers or processes in a very specific way. At the required detail level no standard model library can take into account all the specific cases. A graphic and interactive software allows to model the dynamic systems through the application of the block diagram technique. This technique allows the user to describe his own models for the prime mover, the boiler, the primary control of generator units, loads, compensating devices, FACTS, etc. Any block diagram drawn by the user may be fed by variables coming from everywhere in the power system, not only local variables defined at the node where the component is linked. This feature allows a straightforward modelling of remote feedback, cross compound units, secondary controllers, etc ...

Protection

Relay models operate automatically the network, the generating units or loads according to standard functionalities (distance relay, overload relay, under voltage relay, loss of synchronism relay, etc.).

3.3.2. Algorithms

The use of unique and full models of which the field of validity goes from transient stability through to slow changes, and the needs to simulate, over long time periods, a system which has very diverse time constants and in which numerous discontinuities can appear are very demanding, as regards the integration method.

The shortest time constants of the system are of the order of a few hundredths of a second whereas the duration to be simulated can be 10^6 times as long. At the same time, rapid transient phenomena are generally damped in a few seconds.

As a result, a numerical method having variable integration steps which will allow a faithful description of the excited phenomena which retaining their damping is necessary to enable the system to be numerically integrated within a reasonable computing time.

EUROSTAG uses an A-stable variable step algorithm with the simultaneous resolution of algebraic and differential equations which owns to the family of Adam's methods in their predictor-corrector implementation due to Gear, Byrne, Hindmarsh and Petzold.

The control for the integration step (increase, decrease) is done automatically by forcing the norm of the correction vector to remain less than a given precision. This ensures constant precision of the numerical simulation whatever the speed of the excited phenomena. The step will thus vary, in practice, in the same rate as the extreme eigenvalues (typically 10^5).

3.3.3. Processing of discontinuities

Discontinuities may concern the algebraic variables or the derivatives of the differential variables. When crossing a discontinuity on algebraic variable, i.e. a network change (short circuit, line tripping, ...), the program adjusts the time step to reach the exact time of the change and than reinitialises the full set of algebraic equations and calculates the new derivatives before restarting the integration process.

Discontinuities on derivatives occur often inside controller models (switches, logic devices, ...). If the problem remains numerically local (doesn't affect immediately the whole system), a local integration process will occur and will take into account accurately this discontinuity without changing the general stepsize. Otherwise, the general stepsize will be adapted in order to take into account the exact time of switching and to maintain the general precision.

3.3.4. Interactive operations and on-line control

EUROSTAG is normally used in interactive mode, the user watching the results of the simulation in order either to interact on the system or to stop the simulation, or to ask for a snapshot of the state of the system. Further simulations can be run later starting from this snapshot. The user can also interactively order the computation of the eigenvalues of the system in its current state to help him to tune a controller or to assess stability margins.

A simulation over a long time period calls for taking into account operator actions on the system.

The following operations can be carried out interactively during a simulation :

- opening or closing of circuit breakers;
- control of transformer taps;
- switching on or off loads;
- change of set points (load pick-up, reactive dispatch, ...);
- synchronization of generating units or subsystems, ...

3.3.5. Output facilities

A post-processing program allows to display any variable or observable quantity defined by the user, according to a spontaneous investigation process, i.e. without initial declaration.

3.3.6. Description of the simulation method

L.T.D. simulation by means of EUROSTAG most of the time asks for a stepwize method and an iterative analysis.

1st step : Modelling of the system

The components are modelled by using the standard library, or in case of specific needs, by coding special block diagrams. Model parameters are gathered or guessed.

2nd step : Validation of models and parameters

Controller models and their tuning are validated by means of steady state stability analysis (eigenvalue analysis) or by performing standard tests (simulating well known behaviour).

3rd step : Interactive simulation

The dynamic scenario is built progressively and the modelling is refined, if necessary.

4th step : Interactive analysis of the results with the post-processing program

The 3rd and 4th steps are repeated iteratively until the results are satisfactory. In this process the domain of validity of the modelling is checked and put in accordance with the operating points reached and the phenomena displayed during the simulation.

3.3.7. References

[1] M. STUBBE, A. BIHAIN, J. DEUSE AND J.C. BAADER.
"STAG - A New Unified Software Program for the Study of the Dynamic Behaviour of Electrical Power Systems", IEEE Transactions on Power Systems, vol. 4, N° 1, pp. 129-138, February 1989.

[2] B. MEYER and M. STUBBE
"EUROSTAG - A Single Tool for Power System Simulation"
Transmission & Distribution International Review - March 1992.

[3] M. JEROSOLIMSKI, J-Y ASTIC and A. BIHAIN
"The mixed Adams - BDF variable stepsize algorithm to simulate transient and long-term phenomena in power systems", IEEE/PES.
Summer Meeting, Vancouver, Canada, July 1993.

[4] "A digital model for a HVDC system for system planning studies"
Cigre TF 38-05-05,
T. ADIELSON, G. LIES

3.4. PSS/E

PSS/E, the power systems simulator for Engineering, first introduced by Power Technologies, Inc., in 1976 has been continually enhanced and updated, in part through input from its users.

PSS/E is an integrated, interactive program for simulating, analyzing, and optimizing power system performance. PSS/E is designed for use in detailed studies ranging from transmission system performance and interconnection to machine, plant, and control system dynamics and protection calculations.

3.4.1. Power system components modelling

3.4.1.1. Synchronous machine modelling

While PSS/E includes a wide variety of machine models ranging from a classical treatment up to one with an unlimited number of branches in the rotor equivalent circuits on each axis, the standard models are the subtransient level representations for salient pole and solid iron rotor machines, respectively.

The recommended dynamic simulation practice is to use the subtransient level models for machines (except arbitrary remote equivalents) in the power system. This practice is advocated because :

1. The strongest contribution to electrical rotor speed damping in the .5 to 5 Hz frequency band of principal interest in the majority of system dynamics investigations is that of amortisseur or pole surface currents, which are associated with the subtransient reactances and time constants.
2. The accuracy of the voltages and currents calculated throughout the transmission network in the periods just after switching, which are vital to the correct simulation of relays and fast acting controls, is acceptable only if subtransient modelling is used.

The data required by the comprehensive subtransient level machine models is available for most generating units built since 1965. The recommended treatment for older units, for which detailed data is not available, is to use the full subtransient models and to use representative, but conservative, estimates for parameters whose exact values are unknown.

3.4.1.2. Network and load modelling

While load modelling is just as important as generator modelling, the number of loads appearing in most power system studies is too large to allow specific dynamic characteristic data to be provided for each load as is done for generators. Rather, all loads are assumed, unless otherwise indicated, to have a standard voltage dependence that is a polynomial characteristic of the form :

(a + b v+ c v**2)

In addition to their voltage dependence, the standard load representation makes each individual load a function of the frequency of its bus. The P, I_p, I_q components of load may be assigned the polynomial form :

(a + b f + c f**2)

where f is the local bus frequency.

The frequency is not assumed to be uniform across the system, or any system segment, during a disturbance. Rather the local frequency at every bus is determined at each time step of the simulation and all network and load inductive and capacitive impedances are adjusted to recognize the deviation of frequency from nominal value.

Besides static load models which are dependent on voltage and/or frequency, dynamic load models such as induction motors are provided. Synthetic models are also available for fluorescent lighting, small motors, large motors, and saturation effects.

3.4.1.3. General equipment modelling

In addition to generator and load representations, the equipment model library includes subroutines to represent the whole spectrum of equipments that affect power system dynamics. The program includes models for thermal plants, nuclear plants, hydro plants, gas turbines, diesels and battery storage. Speed governor models for thermal plants, nuclear plants, hydro plants, gas turbines and diesel are provided. Boiler effects may be modelled. Both synchronous pole and round rotor generator models are provided for and represented by a detailed Park's model and optionally a swing equation for individual units or groups of parallel machines. Both the steady-state model and a model including rotor transients is available for induction generators and motors. All IEEE types plus other (over 30) excitation system models are provided. All power system stabilizers in use can be modelled. Minimum excitation and maximum excitation system models are provided.

While detailed discussion of all modelling capabilities is not appropriate here, some general comments are in order :

- The models library is never complete. New models are added whenever the need to represent a new item of equipment arises. While some of the more complex models, such as detailed generator representations, require expensive knowledge of PSS/E internal programming, the great majority of control element models, such as voltage regulator and stabilizer representations, are written by program users who are not experts in its programming.

- Relay models have the capability to print flag messages indicating change of status, to execute direct and transfer trips automatically while the simulation progresses, and to place their input signals such as apparent impedance or rate of change of power, for example in output channels for subsequent inspection.

- All equipment models are implemented to be valid over the entire perturbation bandwidth, and for all types of system disturbance, for which the use of algebraic power frequency transmission network modelling is valid.

- User defined models of arbitrary complexity may be readily defined by the user for application in the same way as a library model. That is, there is not limitation on the number of model invocations and solution speed is not impacted by the inclusion of user models.

3.4.2. Algorithms

PSS/E has available a user selection of an explicit integration algorithm (modified Euler) and implicit scheme (trapezoidal rule). The integration choice depends on the speed and fidelity desired.

For the majority of production dynamic simulation studies the interest is in short time frames (say less than one minute) with design or reliability decisions as the decisive outcome of the studies. Therefore a premium value is assigned to preserving the fidelity and detail of the model. Explicit integration with normal state-space differential equation representation is the preferred method due to its numerical simplicity and overall solution speed. These advantages are offset by the numerical stability considerations which require integration time steps smaller than the smallest time constant, or the reciprocal of the largest eigenvalue of the linearized state space equations.

Other class of dynamic simulation problems characterized by :

(1) Islanding with significant imbalances between load and generation where prime mover action in response to frequency deviations is significant.

(2) Problems of dynamic stability and voltage collapse.

In either case stability problems can arise due to a gradual long term drift into an unstable state. The transition could be due to load restoration through tap changing transformers, control actions, capacitor or reactor switching, or redistribution of generation due to primary or secondary prime mover control action. Problem detection requires simulation fidelity up to about 5 Hz and extended simulation durations.

Because lower fidelity is acceptable, and traditional small time step simulations can be unacceptable long an implicit integration algorithm may be the preferred choice. The numerical stability limitation on time step is eliminated at the expense of algorithmic complexity and preservation of high frequency transients. The state-space differential equation representations are replaced with the use of time delay operator Z^{-1} (Z form).

The advantage of longer time steps is moderated however, as the burden computing the differential equation solution leads to a greater number of iterations in the network algebraic equation solution.

The PSS/E dynamic model library is provided in both state space and Z transform representation designed and coded for bumpless switching during discontinuities and time step switching. PSS/E also preserves both model structures and data base in both integration regimes so that the high frequency effects are recallable at any time by switching for a long to a short time step. User defined models may be readily applied in both state space and Z form. Experience shows that many long term simulation problems usually involve important non-linear effects such as signals at ceiling, run-back action, etc. that are best represented using detailed equipment models, and requires careful coding and testing in Z form.

Coupled with either numerical integration, the load flow solution at each time step is of the form I = YE where I is a vector of complex source currents, and E is a vector of complex bus voltages. In the case of a network of pure impedance elements (including loads), the solution is a straightforward algebraic operation without iterations. More realistically, load characteristics are non-linear, and the network load flow solution involves iterations with non-linear load effects introduced as current injections.

3.4.3. Processing of discontinuity

Faults, loss of transmission, loss of generation, loss of load, load change, loss of load feeders, loss of generating plants, loss of switching stations, and substations can be modelled. A scenario comprising of the combination of the above can be processed. The above can be done either interactively or via batch input or via addition of some simple user code.

3.4.4. Interactive operations/on-line control

The user has a variety of ways to operate PSS/E, depending upon the type of study being performed.

Interactive

The user manipulates data or performs functions using commands entered either by :

- Window and mouse-driven data input, calculation, and output summaries.
- Mouse or cursor control in one-line schematic or other diagrams.
- Activity names at a command prompt.

Batch

Command files can be created and used for long or routine production runs.

3.4.5. Output facilities

Any variable (state of algebraic) can be chosen as an output.

3.4.6. Description of the simulation study method

Typical method would be to first create the base case power flow using the interactive power flow available. The user would then run several dynamic simulations (0-5 sec.) to determine shorter term problems if they exist. The user would then execute several different longer term simulation scenarios.

3.4.7. References

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[2] F.P. De Mello, "Z Transform Techniques for the Analysis of Systems", AIEE Conference Paper CP-60-1291.

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[4] F.P. De Mello, R.J. Mills, and J.M. Undrill, "Interactive Computations in Power System Analysis", IEEE Proceedings, Vol. 62, pp. 1009-1018.

[5] F.P. De Mello, J.W. Feltes, T.F. Laskowski, and L.J. Oppel, "Simulating Fast and Slow Dynamic Effects in Power Systems", IEEE CAP, Volume 5, Number 3, July 1992.

[6] R.J. Koessler and J.W. Feltes, "Time-Domain Simulation Investigates Voltage Collapse" IEEE CAP, Vol. 6, N° 4, October 1993.

3.5. CHAMPS-V1, CHAMPS V2 and CHAMPS

CHAMPS-V1, CHAMPS-V2, and CHAMPS have been developed by CRIEPI. CHAMPS-V1 is a quasi-dynamic simulation program for studying voltage instability phenomena. CHAMPS-V2 is an analysis program for calculating voltage instability indices and identifying weak area. CHAMPS is a dynamic simulation program for verification of the stability of synchronous machines. These three programs are widely unitized by many Japanese utilities and are standard software of power system analysis in Japanese utilities.

3.5.1. Power System components modelling

(1) Generator model

Static model, represented algebraically

(2) Load model

Static load characteristics :	PL and QL are sensitive to node voltage and system frequency.
Dynamic load characteristics :	Effect of ULTC is included.

(3) Controllers

GOV and AVR are represented by algebraic equations disregarding short time constants.

3.5.2. Algorithms / solution techniques / operating modes

Generators and their controllers (AVR and Governors) are incorporated into Jacobian matrix of the load flow calculation.

3.5.3. Processing of discontinuities

The load flow solutions are calculated successively along the simulation time.

3.5.4. Interactive operations/on-line control

The following operations can be programmed:

- trip of line, generator and load;
- change of generator output and load ;
- control of transformer taps manually and automatically;
- central control functions such as automatic generation control and centralized voltage control.

3.5.5. Output facilities

To assess output data efficiently, all the simulation results such as P-V curves, behaviors of bus voltages, outputs of voltage regulating devices, and voltage stability indices can be drawn in various forms.

3.5.6. Description of the simulation study method

In order to study the long-term simulation, CRIEPI utilizes 3 different types of software tools (CHAMPS-V1, CHAMPS-V2, CHAMPS).

CHAMPS-V1 is a long term simulation tool from the viewpoint of the voltage instability. The system profile in a time phase can be calculated by iterating the load flow solution algorithm which incorporates generator and load characteristics in static form. As the effects of fast dynamic terms on voltage instability can be thought small, CHAMPS-V1 disregards fast dynamic terms of system components. Because CHAMPS-V1 does not ensure synchronism of generators, the transient stability after a large disturbance like a generator trip has to be made sure by CHAMPS.

CHAMPS-V2 is one of the multiple load flow solution software. This tool's main functions are (1)complex solution function, (2)automatic P-V curve formation & multiple voltage solution and (3)P-MARGIN estimation. From a point of static voltage instability analysis, CHAMPS-V2 offers the information of voltage stability margin and weak-area.

CHAMPS is a tool for analyzing the transient stability of power system. Dynamic characteristics of generators, AVR, Governors, etc. are modelled strictly by differential equations and they are calculated by numerical integration based on the fourth-order Runge-Kutta method. By CHAMPS, system behaviour such as node voltage, generator output, system frequency, etc. can be taken and system stability or synchronism after a disturbance can be confirmed.

When simulating the long term instability phenomena, we have three steps as follows :

1 step : By CHAMPS-V1, we grasp an outline of time domain system behaviour under the condition of keeping the system synchronism.

2 step : By CHAMPS-V2, we get information of stability margin and weak area of the system.

3 step : By CHAMPS, we confirm the synchronism of the system after a large disturbance.

3.5'. CHAMPS-V2

3.5'.1. Power System components modelling

(1) Generator model

Static model represented by P,V or P,Q specification of load flow calculation.

(2) Load model

Static load characteristics : PL and QL are sensitive to node voltage

(3) Controllers

AVR, Governors are neglected.

3.5'.2. Algorithms / solution techniques / operating modes

In CHAMPS-V2, by increasing P and Q at load nodes, load flow solutions are calculated repeatedly and in each load flow condition, by increasing the admittance of remarked load node, multiple load flow solutions are calculated easily.

The result of above calculation, P-V and Q-V curves are drawn and the indices of voltage instability, P-MARGIN at the load nodes and Q-LOSS of the system, can be taken.

3.5'.3 . Processing of discontinuities

Omission

3.5'.4. Interactive operations/on-line control

Nothing

3.5'.5. Output facilities

To assess output data efficiently, all the simulation results such as P-V curve, P-MARGIN, Q-LOSS, etc. can be drawn graphically in various forms.

3.5'.6. Description of the simulation study method

See 3.5.6.

3.5". Tool CHAMPS

3.5".1. Power System components modelling

(1) Generator model

Park's model with 3 damper windings and saturation effect. The model is represented by differential equations.

(2) Load model

Static load characteristics :	PL and QL are sensitive to node voltage and system frequency.
Dynamic load characteristics :	The induction motor is modelled by a simplified Park's model with 2 damper windings.

(3) Controllers

Some standard block diagrams and constants are available in the program.

AVR,PSS:	12 types of AVR and 3 types of PSS are available.
GOV :	2 types for hydro power plant, 3 types for steam powerplant and 1 type for nuclear power plant are available.

3.5".2. Algorithms / solution techniques / operating modes

Initial load flow solution is calculated by the Newton-Raphson method and time domain solutions are calculated by numerical integration based on the fourth-order Runge-Kutta method.

The eigenvalues of the linearized equations of the power system can be calculated at the request of the user.

3.5".3 Processing of discontinuities

Omission

3.5".4. Interactive operations/on-line control

The following operations can be programmed:

- 1, 2 or 3 line-to-ground fault;
- line opening and closing;
- change of set point (load picking up, transformer tap position, and constants of AVR or GOV).

3.5".5. Output facilities

To assess output data efficiently, all the simulation results such as node voltages, generator outputs, phase angles, controllers' outputs, etc. can be drawn graphically in various forms.

3.5".6. Description of the simulation study method

See 3.5.6.

3.6. APSA

The analog simulator APSA (Advanced Power System Analyzer) has been developed by the Kansai Electric Power Co., inc. (KEPCO) in co-operation with Fuji Electric Co., Ltd. and Hitachi Ltd. [1]. The aim of this simulator is to verify KEPCO's power system when new or additional power stations, transmission lines or substations are built, according to many scenarios. Such scenarios include cascade tripping of lines due to protection relays, island operation, and restoration by the operators. In addition, the simulator can be used for evaluating the control units of actual equipment, taking account of balance and/or imbalance phenomena.

3.6.1 Power System Component modelling

APSA consists of more than 500 model elements, including 30 generator units, 300 transmission-line circuits and 50 transformers. All model elements are operated as 3-phase circuits. The rating of APSA is 50 V/phase-phase and 0.5 A/phase. The generators are represented by Park equations including armature and damper windings, taking into account saturation of flux. AVR and governor with turbine and servo motor models can be selected from several standard control blocks. Load models have frequency, voltage, and time-depending characteristics. The transmission line and transformer are modelled with an iron core and coil. Transformers are equipped with automatic on-load tap changers. Various relays such as out-of-step and undervoltage relays are also available.

3.6.2 Algorithms / Solution techniques / Operation modes

Each model element equipped with controllers produces system phenomena independently, based on current and voltage through the transmission system. A host computer organizes the simulation schedule of each model.

3.6.3 Proceeding of discontinuities

In the analog simulator, it is not necessary to use a specific numerical procedure for discontinuities. Therefore, faithful representation of change in the system structure can be guaranteed.

3.6.4 Interactive operations / On-line control

The real time system controller is combined with a front-end-processor to analyze long term phenomena concerning LFC (Load Frequency Control) and ADC (Automatic Dispatch Control). Reference values for generator controllers can also be handled manually through the operation controller.

3.6.5 Output facilities

During the simulation, the behavior of model elements can be observed through real-time monitoring panels that provide analog meters and displays of real-time trends, and through them a bird's-eye-view of a real system. Power flow on a network diagram, specified wave forms from data storage, and comparison with digital computation results can be used to analyze and assess the results of simulation.

3.6.6. Description of the simulation method

Prior to and during the execution of simulation, workstations are used to achieve high efficiency and to maintain accuracy by checking analog and digital simulation results at various stages. The simulation is executed as follows,

1. Input of data through workstation using interactive mode.

   All simulation data such as a system configuration, line impedance, machine constants, controller constants, and operation conditions are input through the workstation supported block diagram drawing system. These simulation data are compatible with those of the digital simulation program "CHAMPS", which was developed by CRIEPI and is used in every utility in Japan.

2. Set up of the analog simulation system.

   Simulation data are realized as analog and digital devices in APSA. In particular, the automatic network configuration system can connect all model elements. The configuration system can also select the shortest possible wiring distance between model elements, and select appropriate elements to satisfy simulation conditions such as base impedance and measurement precision.

3. Start up and execution of the simulation through the system controller.

   The initial state for the simulation should be determined by starting up all model elements. This kind of operation confirms physical stability and feasibility, because it allows unstable points in numerical procedure to be avoided.

3.6.7. Reference

[1] H.Doi et al, "Advanced Power System Analog Simulator", IEEE Trans. on Power Systems, vol.5, no.3, August 1990

3.7. TNS

The analog simulator TNS (Transient Network Simulator) has been developed by Fuji Electric Co., Ltd.[1] This simulator is used for research and development purposes in Fuji Electric Co., Ltd. who has produced the largest power system simulator for real system analysis and some small analog simulators for education [2] [3].

3.7.1. Power System Component modelling

Structurally TNS consists of two blocks :

- A power system block composed of active and passive models. The generator represented by Park's model is modelled with active analog devices using electronic circuits, and the load with a hybrid device consisting of analog and digital parts. The transmission line and transformer are modelled with an iron core and coil. All of the models are carried in 3-phase circuits. The maximum rating common to elements of TNS is 10 Vpeak/phase and 1 Apeak/phase.
- A digital control block composed of programmable controllers. AVR, Governors, and switching sequence including protective relays are modelled with programmable microprocessors. A program loader, which is a versatile personal computer, is used for programming, debugging, and loading these blocks to programmable controllers by a graphic representation language.

3.7.2. Algorithms / Solution techniques / Operation modes

Each model equipped with controllers produces system phenomena independently, based on current and voltage through the transmission system.

3.7.3. Proceeding of discontinuities

In the analog simulator, it is not necessary to use a specific numerical procedure for discontinuities. Therefore, faithful representation of change in the system structure can be guaranteed.

3.7.4. Interactive operations / On-line control

In the program loader, a function block diagram for setting values in each control block can be designed in advance. During the simulation, reference values in the controller can be changed suddenly and easily through the program loader without adding any hardware.

3.7.5. Output facilities

Fast dynamic phenomena that last only milliseconds and/or seconds can be observed on a wave memory display or a program loader display on the spot. Slow dynamics can be readily and realistically perceived on a analog meter or a wave memory display. The impedance domain and the positive-, negative-, and zero-phase-sequence domain can also be observed, because 3-phase phenomena are produced faithfully.

3.7.6. Description of the simulation method

The simulation is executed as follows :

- Connection of transmission line models are made on the front patch-board, while individual line units are inserted into the cabinet from the back. Line constants are adjustable on the unit panel of each lines.
- According to the simulated system rating, the current amplifier's ratio is adjusted on the output stage of generator and load models.
- Functions of AVR and Governor implemented on a programmable controller are fed through a loading device using the graphic representation language on the CRT screen. The standardized control block diagrams for these equipments are available. A programmable controller is also used to manage both fault sequence and CB switching.

3.7.7. Reference

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[2] H.Doi et al., "Advanced Power System Analog Simulator", IEEE Trans. on Power Systems, Vol.5, No.3, pp.962+pp.968, August 1990

[3] Y.Tamura, E.dan, I.Horie, Y.Nakanishi, and S.Yokokawa, "Development of Power System Simulator for Research and Education", IEEE Trans. on Power Systems,Vol.15, No.2, pp.492-pp.498, May 1990

3.8. ADVANCE

ADVANCE has been developed by MITSUBISHI ELECTRIC CORP.. It is a power system stability program useful for a wide range of dynamic simulation studies, including transient stability, voltage stability, and longer-term dynamic analyses. It is specially designed considering features of Engineering Work Station(EWS) for studies of advanced control systems for generators or new power system equipment, e.g. FACTS.

3.8.1. Power System components modelling

The tool has a lot of component models.

Generators

Generators are modelled as Park's model with a 3 winding rotor. Since the model is represented with a dynamic simulation macrolanguage, a 4 winding rotor model or another model can also be easily modelled in the same manner. Saturation is not modelled in present generator model. Dynamics of mechanical torque can also be modelled. Standard models of AVR,PSS, and governor model are prepared, and user can make a more precise model easily, if it is necessary.

Network

Algebraic PI representation, where any branch can have series R, X, charging B, tap ratio and phase shift. Frequency dependency of line impedance can be modelled. Automatic tap-changing transformers and other controlled network devices(FACTS devices) are represented by universal dynamics simulation module. Direct Current links can be included. Multiple ac subsystems, connected by dc links or completely isolated(e.g. during system islanding) can be solved.

Loads

Loads can be represented by a combination of static impedance models and other dynamic and non-linear models. Chronological load profile can be specified by the user.

Induction motors are also prepared. Mechanical torque characteristic can be modelled flexibly, e.g. an algebraic function of the motor speed or external variables.

Controllers and power plant modelling

a. Standard library

A library of standard models of AVR's, PSS's, governors, turbines, SVC's, ... , are prepared.

b. Models defined by the user

It is often necessary to define certain controllers or protection systems in a very specific way. New model can be added by defining it with universal dynamics simulation module. As various components, e.g. integration, gain, delay, ... , are prepared, it is easy for user to define new controller or equipment. A subroutine for new component can be written in FORTRAN. Any model may be fed by variables coming from everywhere in the power system, not only local variables defined at the node where the component is linked. This feature allows a modelling of AGC, advanced AVR, etc... These modelling tools are open for user, and some developed models are listed in standard library mentioned above.

3.8.2. Algorithms / solution techniques / operating modes

Algorithms

The tool models a combination of components, such as network and dynamics model of generators, loads, etc. Fig. 3.8.a shows a flow-chart of a simulation algorithm. The tool supplies us with the integral calculation of state variables for generator, load, and network controller, network admittance matrix modification, and network condition calculation. This tool is applicable for power swing phenomena up to several hundred seconds.

Solution techniques

An explicit integral method is applied. The matrix equation for network power flow condition is algebraically solved at each time step. Since no iterative calculation is applied, the method is free from problems caused by the iterative calculation, such as numerical instability.

Operating modes

The ADVANCE's operating mode is basically interactive. The so-called "what-if" study can be achieved easily.

3.8.3. Processing of discontinuities

Discontinuities can be modelled. Even if a system is separated by tripping transmission line, separated sub-systems are connected in graph theory by the ground node. There is no discontinuity problem. Because network matrix equation is algebraically solved, no special calculation is necessary in the discontinuity period.

3.8.4 Interactive operations / on-line control

Interactive operations

Interactive operation is available. Layout of graphical output, open/close of circuit breakers, transformer tap, switches for load, change of reference voltage and reference value of AVR and PSS, governor, or control equipments, etc.. can be controlled interactively. Synchronization of generating units is also achieved interactively.

(On-line control)

On-line control operation is available for all functions mentioned above. Off-line analysis is also available.

3.8.5. Output facilities

The primary outputs from ADVANCE are plots of variables vs. time or vs. other variables (e.g. P-V, Q-V curves). Variables that may be of interest, are selected by the user in the graphics specification file. On-line numerical and graphical output and post-execution numerical and graphical output are available. Usually on-line graphical output is used. Time domain charts and X-Y plane charts are available.

3.8.6. Description of the simulation study method

The steps required to execute a study with ADVANCE normally include the following:

1. Input file editing for power system data, control equipment data, and graphical output layout data.
2. Load flow calculation and initial condition check. Mismatch between load flow condition and control equipment condition are checked and reported.
3. Transient dynamics simulation and graphical output.
4. Evaluation of outputs and decision for new case data, by on-line graphical output and recorded numerical output.

3.8.7. Reference

[1] Iyoda, et al: "CONTROL OF LINE IMPEDANCE AND PHASE SHIFTER AND ITS ANALYSIS WITH A MACHINE FLUX BASED SIMULATION PROGRAM," IEE International Conference APSCOM, November 1991, Hong-Kong.

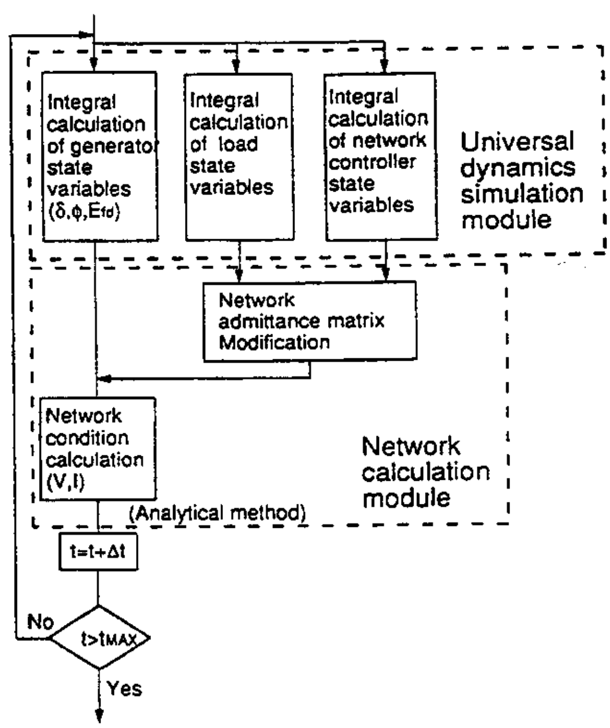

Fig. 3.8.a : Flow chart of algorithm

3.9. EXSTAB

EXSTAB has been developed by GE Power Systems Engineering with the support of Tokyo Electric Power Co. (TEPCO). It is an extended time scale power system stability program useful for a wide range of dynamic simulation studies, including transient stability, voltage stability, and longer-term dynamic analysis.

3.9.1. Power system component modelling

Generators

Full Park model with 4 rotor windings and saturation in both axes.

Simplified (2 winding, classical) models.

Network

Algebraic PI representation, where any branch can have series R, X, charging B, tap ratio and phase shift. Automatic tap-changing transformers and other controlled network devices (FACTS devices) are represented by dynamic models. Direct Current links can be included. Multiple ac subsystems, connected by dc links or completely isolated (e.g. during system islanding) can be solved.

Loads

Loads can be represented by a combination of "standard" static models and other dynamic or special static models :

a. "Standard" static load model

P and Q are represented by polynomial in voltage with frequency sensitivity :

$$P = P_0(t)\left[\left[Kps + Kpi\left(\frac{V}{V_0}\right)\right] \; (1.+Kpf\,\Delta f) + Kpz\left(\frac{V}{V_0}\right)^2\right]$$

$$Q = Q_0(t)\left[\left[Kqs + Kqi\left(\frac{V}{V_0}\right)\right] \; (1.+Kqf\,\Delta f) + Kqz\left(\frac{V}{V_0}\right)^2\right]$$

Parameters for this model can be specified for the entire system, all buses in a zone, or individual buses. These loads change to impedance below a voltage threshold specified by the user. The approximate effect of distribution tap-changer action can be included - - the program will restore "low side voltage" continuously through a time constant within a specified tap range.

b. Dynamic and special static load models :

Several special load models can be specified to represent all or part of the load at a bus :

INDMOT	:	standard 3-state (rotor inertia, rotor flux) induction motor model
SQLOAD	:	a special static load model including feeder series impedance, and different polynomial parameters for the base load and the incremental load added during a load change scenario.
DYNLOD	:	model with different transient and steady-state load characteristics, usually used to represent thermostatically-controlled load.
AIRCND	:	models static voltage characteristics of several types of (Japanese) inverter-supplied air conditioners.
POWAUX	:	model of power plant auxiliary load including both static and motor components, with motor power consumption a function of plant output.

Excitation Systems

Several standard and special models for excitation systems are available. Power system stabilizers (PSS), overexcitation limiters (OEL) and underexcitation limiters (UEL) can be included.

Turbine/governor, power plant models

Several simplified models of governor/turbine systems for steam turbine, gas turbine, and hydro plants are available, as well as simplified models of fossil and BWR nuclear plant dynamics. These models were designed to represent the essential dynamics for analysis of system problems, but not for detailed analysis of power plant internal problems.

Automatic Generation Control (AGC) model

One or more AGC systems can be included to adjust power orders to generating plants to regulate area control error (based on frequency and/or tie line flows). Economic base points and participation factors are included.

Protective devices

Standard protective devices are available including distance and over-current line relays, generator volts. Hz., undervoltage, and loss of synchronism protection, and under-frequency or under-voltage load shedding.

Active network devices

Models have been developed to represent most available devices, including static var systems (SVS), voltage-switched shunt capacitors & reactors (VSSCR), thyristor-controlled series capacitors (TCSC), thyrister-controlled phase-angle regulators (TCPR), static condenser (STATCON), and load tap-changing transformer (LTC).

New models

Models for EXSTAB are written in Fortran, following well-defined rules. All code for a particular model, including initialization, is contained in a single structured subroutine. New model subroutines can be added to the program with only minimal changes to permit the program to recognize the new model by name.

3.9.2. Algorithms

In order to permit efficient computation for different types of studies, EXSTAB provides several modes of computation using different solution algorithms :

Transient Stability Simulation (TSS) mode

For short duration transient stability analysis, the differential equations are solved using a second-order explicit integration with fixed time step. The algebraic network equations are solved by direct iteration of the sparse factorized admittance matrix equations. Time steps of less than about half the smallest equivalent time constant are required for numerical stability.

Extended Time Simulation (ETS) mode

For longer simulations, implicit integration with automatically-adjusted time steps is used. EXSTAB uses a modification of the trapezoidal method together with a special predictor, which permits easy estimation of integration error for use in controlling the time step. The differential and algebraic equations are solved simultaneously using a Newton iteration. It has been found that Jacobians for the Newton solution need not be recomputed during the run, unless there is a problem with convergence, in which case it is done automatically. Time steps vary between a minimum of about 1 msec. and a maximum of about 10 sec. For a few seconds after a severe disturbance, when small time steps are required, the program automatically shifts to the explicit integration (TSS) mode for improved efficiency.

Quasi-Steady State Simulation (QSS) mode

The QSS mode provides for fast computation of slowly evolving scenarios with mainly slow motion of system variables. The model differential equations are replaced with algebraic equations and a special generator model is used to regulate power and voltage while observing field current limits. Limits, protective devices, and discrete control actions, such as LTC transformer tap changes, are represented, and properly sequenced in time by retaining dynamic modelling of delay timers. This mode has proven very useful in analyzing voltage stability scenarios initiated by increasing load. Plots of P-V and Q-V can be readily generated from QSS runs.

3.9.3. Processing of discontinuities

Major discontinuities, such as network faults and switching operations, require that the network equations be solved twice at the switching time. In the ETS and QSS modes, the time step is adjusted to a first-order method for one time step in order to build up the historical values required for the normal second-order method.

3.9.4. Interactive operation/on-line control

EXSTAB is designed for large-scale system studies by batch execution from a control file prepared by the user. Control over the simulation can be exercised by means of discrete switching operations, which include faults, branch outages with or without automatic reclosing, branch modifications, branch addition, load modification, tripping of a plant or other device, and step change in any model independent variable (e.g. set points, nominal load). Continuous changes in any dependent variable can also be specified by a table of values vs. time. This latter capability is essential for representing load ramp and other load variation scenarios.

3.9.5. Output facilities

The primary outputs from EXSTAB are plots of variables vs. time or vs : other variables (e.g. P-V, Q-V curves). Variables that may be of interest, selected by the user in the execution control file, are written in binary form to an output file. A companion plotting program can then be used to plot any of these variables in any combination and a variety of formats. A printed output file is also produced, with a log of the solution, error messages, etc. and optional tabulations of input data and selected output variables. An additional printed output file, which has proven very useful in complicated simulations, provides a "discrete event log". This is a table showing all of the discrete actions, both user initiated and automatic (e.g. LTC tap changes, protective device operation, plant trips), that occurred during the run.

3.9.6. Simulation method

The steps required to execute a study with EXSTAB normally include the following :

1. Load flow solution - the initial conditions for the dynamic simulation are established by use of a load flow program. EXSTAB can accept initial condition and network data directly from either GE's load flow programs or from the PTI PSS/E program.

2. Model selection - appropriate models are selected for each piece of equipment. If necessary, new models are written and tested using simple test systems.

3. Model data preparation - each EXSTAB model has a data form showing the block diagram of the model and the input data items. These data forms are either filled in or used for reference in keying in the model data. All model data is keyed into the "apparatus model data file".

4. Execution control file preparation - The execution control file for EXSTAB is a free-format file, which includes :

   - case identification and comments;
   - execution control parameters and options (changes from default value);
   - identification of load flow solution file and apparatus model data file;
   - parameters for "standard load models";
   - linkage data defining the connection of apparatus models to the network buses and to each other;

- selection of variables to be output;
- switching event specification;
- linkage of "drivers" for continuous changes to specific variables.

An execution control file is created for the initial case to be run and later modified for additional cases.

5. Validation of models and parameters - several steps can be taken to validate the case set-up, including running a no-disturbance run and running simple disturbances with known responses. EXSTAB also permits single-machine/infinite bus simulations for any or all of the generators on the system to be run simultaneously using a Thevenin equivalent computed automatically from the network data. This can be useful in checking the tuning of plant controls. The system state matrix can also be built automatically from the simulation model and used to compute eigenvalues to check for steady-state instability and poorly damped oscillations.

6. Initial scenario execution and analysis - After execution of the initial case, careful examination of the discrete event log, any program warning messages, and plots of key system variables is made to ensure that proper results are being obtained.

7. Production runs - Often, many cases are specified to examine different system design options, sensitivity of results to parameter variations, etc. A command procedure is usually created to execute each case and create the plots of the results, so that many cases can be run with little interaction by the user. Review of the results of these cases may lead to specification of additional cases to run to further evaluate system problems or design options.

3.9.7. References

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[3] N.W. Miller and W.W. Price, "Planning and Operations Benefits of High Fidelity Voltage Collapse Simulations", Int. J. of Electrical Power & Energy Systems, Vol. 15. No. 4, pp. 245-250, Aug. 1993.

[4] J.J. Sanchez-Gasca, R. D'Aquila, J.J. Paserba, W.W. Price, D.B. Klapper, I. Hu, "Extended-Term Dynamic Simulation Using Variable Time Step Integration", IEEE Computer Applications for Power, Vol. 6, No. 4, pp. 23-28, October 1993.

3.10. MODES

MODES is a general purpose stability program allowing the dynamic modelling of power system behaviour. It is based on a object oriented power system description and the user friendliness principles. It is operated under MS-DOS in 32bit protected mode on personal computers. The MODES has been developed in the Czech Technical University for education purposes. Then it has been used in the Power Research Institute of Prague for the secondary voltage design and testing. This software is utilised by the Czech Power Company (CEZ) for short term and long term dynamic calculations.

3.10.1. Power system components modelling

Generators

Full Park 3 rotor windings model without saturation and simplified "classical" model.

Network

Algebraic π schemes are used for lines, switches and transformers. Their parameters will not depend on frequency. The transformers are modelled without saturation and with the constant leakage reactance. ULTC is modelled by the standard library model or by the general purpose automatics model.

Loads

The next load models are possible:

a. Static load model

- static characteristic;
- constant active and/or reactive current;
- auxiliary selfconsumption of unit.

b. Dynamic model - Two cage quasi-steady state model (no rotor transients)

c. Constant admittance model.

Step or ramp changes are possible. The four stages load shedding model is implemented.

Excitation Systems

Four types of IEEE exciter models (DC1, AC1, AC4 and ST1) are implemented in the program library. The general purpose excitation control model with OEL, UEL and PSS is used.

Prime Mover Systems

The steam and hydro turbine, boiler and PWR models are implemented. The general purpose prime mover control model with the variable structure (power or pressure control) is used. The special control modes (speed control and fast closing) are available.

Automatic Generation Control

The general purpose AGC model is possible. The regulated units may be divided into two groups controlled by control signals or/and they may be controlled individually.

Protective Devices and Relays

The general purpose automatics model makes possible to take into account the different types of protective devices and relays. It is possible to simulate for example distance relay, overload relay, synchrocheck relay, over/under voltage/frequency relays, loss of synchronism relay, ULTC, AGC blocking etc.

3.10.2. Algorithms

The special algorithm was developed to solve the system of algebraic-differential equations. The proposed sequence of solution saves the computational storage and time. This is very important, because the program is used on personal computers.

The first step is solving the voltages $\underline{U}$ from the matrix equations:

$$\underline{I}_{EQV}(Eq'',Ed'',Eq',\delta,\underline{U}^{*},U,f,\Delta t) = \underline{Y}_{MOD}\underline{U}$$

where $\underline{I}_{EQV}$ is an injected current vector, which includes contributions from dynamic/static load and generator models (the solution of the rotor damping winding differential equations and the stator algebraic equations for generator are involved). $\underline{Y}$mod is the modificated network admittance matrix, which includes serial and shunt branch admittances, constant admittance loads and special terms depending on generator parameters and the integration step Δt. The variables Eq',δ,U,f must be predicted to use the efficient sparse technique LU decomposition.

The second step is the excitation and prime mover systems equations and remaining generator equations (excitation winding and swing equations) solving. The implicit integration method based on the trapezoidal rule is used .

The third step is the check of the prediction error. An iterative process (the above steps repetition) including the integration step changing is carried out if necessary. The detailed description is in Appendix B1.

3.10.3. Processing of discontinuities

When a discontinuity occurs, the $\underline{Y}$mod matrix is refactorized and the above mentioned matrix equations are solved. The variables $\underline{U}^{*}$ and U must be predicted only, because of the integrable variables Eq',δ and the frequency f have the constant values. An iterative process takes place when the difference between predicted and solved voltage $\underline{U}$ is greater than allowed voltage error.

3.10.4. Interactive operations and on-line control

The following operations can be carried out by user (with the help of hot keys) during a simulation:

opening or closing the branch breakers

changing of transformers taps

switching on or off of loads

changing of excitation and prime mover controller set points
tripping/synchronization of generator units
pumped operation of hydro storage units.

3.10.5. Output facilities

The program MODES includes a graphical interface, which makes possible:

showing the time course and instantaneous value of chosen variables
signalling of the scenario, on-line and automatics actions
signalling of limit exceeding of chosen network variables
above mentioned on-line actions.

Besides these it is possible to create the different types of output reports files for the post-processing analysis.

3.10.6. Description of the simulation method

a) Load flow solution - the MODES can accept results directly from the PSS/E program or it uses an internal load flow program. The dynamic input data is created from a database already used cases or like a set of standard models with default parameters.

b) The suit models is chosen from the program library and the proper set of parameters from the program database. When the ready model is not possible to use, the new models must be created and tested and then included into the program library. The same process is necessary for the new model parameters.

c) Check the initial conditions, especially to keep the different types of limiters. The result is the steady state.

d) The scenario of faults and events is created and tested.

e) The models for automatics are created and tested.

f) The checked network and output variables are chosen.

i) The simulation is carried out and it may be checked and controlled "on line".

i) The simulation results are investigated and analysed.

3.10.7. References

[1] J.Feist, K.Maslo: Power System Dynamic Behaviour Modelling and Simulation of the Primary Control Test; Proceeding of the Second International Workshop on Electric Power System Control Centres; 1993 Alghero (ITALY)

[2] K.Maslo: Modelling of Transient Phenomena in the Power System
Program Application Guide; 1994 Praha

3.11. POSSUM

3.11.1. The PMSP simulation environment

POSSUM [1] is a suite of power system macros running under the simulation language PMSP [2]. PMSP (Plant Modelling and Simulation Program) is a FORTRAN like, macro based, simulation language with functional keywords to invoke a variety of standard simulation tools. For example, users may select from 13 different integration algorithms and may carry out automatic linearisation and state space matrix generation [2, 3].

PMSP is used at Nuclear Electric for whole plant modelling of nuclear and conventional plant and in such applications provides for the integration of thousands of first order non-linear differential equations. The results of simulations may be post-processed graphically or may be processed interactively using screen touch sensitive workstations displaying mimic diagrams of plant components driven by PMSP variables.

In the study of the Irish test system, all analysis was carried out by non-interactive simulation and graphical post-processing of simulation results.

3.11.2 POSSUM macros

POSSUM consists of a suite of 6 callable macros whose modelling is described below :

Macro NET

A network may consist of transmission lines, cables, transformers and shunt reactors and capacitors. Three types of demand can be represented : induction motors, impedance loads and L.V. cable susceptance. The dependence of demand loads upon voltage and frequency is modelled by exponent forms. Machines are represented by a voltage behind a reactance and stator resistance; this is made equivalent to an injected current across an admittance. An admittance matrix is formed from the line data and machine equivalent admittances. As the admittances vary with the network frequency, a load flow solution is obtained at each time step, yielding the voltages of the equivalent circuit, from which the machine currents are calculated.

Macro GEN

Three models of the electrical side of the generator are available :

Subtransient reactance model

The rotor is simulated by a field winding, a direct axis winding and two damper windings in the q-axis. The derivatives of the stator flux linkages are neglected resulting in the integration of four differential equations relating the rotor linkages, rotor current and field voltage.

Transient reactance model

The rotor is modelled by a field winding and a damper winding on the q-axis. Only two differential equations need to be integrated to give the field and ammortisseur flux linkages.

This model was used to simulate the Irish test system.

Synchronous reactance model

In this model, the ammortisseurs are neglected and the synchronous reactances in the d and q axes are assumed to be equal. This is a steady state model where only algebraic equations are present.

In all the models, the mechanical equation of motion is integrated to determine the generator speed and rotor position.

Macro AVR

This macro contains a standard AVR model. Other AVR models may be represented by using the CDF macro.

Macro GOV

This macro contains a standard governor model. Other governor models may be represented by using the CDF macro.

Macro CDF

The CDF macro provides a link to the Controller Design Facility which allows the user to specify a control system representing an A.V.R. or a governor. The control system is described by an interconnected block diagram of basic elements, functions and devices.

3.11.3. User generated macros

The user may create additional case study specific macros, as required, to simulate features which are not represented in the pre-existing POSSUM suite of macros and which do not lend themselves easily to block diagram representation via the CDF facility described above.

In the application of POSSUM to the Irish test system, some governors were represented in macro form not in CDF form. Special macros were generated to model load restoration and transformer saturation effects.

3.11.4. Data structures

The data required for the POSSUM suite of macros is stored in a databank structure which may also be accessed by other electrical network analysis packages held at Nuclear Electric. Data may be entered into a databank via a terminal making use of a network drawing facility or directly from a PC floppy disk. A databank may contain data for simulations of many different networks.

Data for the load shedding schedule and the dependence of busbar demands upon frequency and voltage are stored outside the databank system.

Data for user generated macros are contained in macro specific structures called data macros which are invoked by their parent macros.

3.11.5. References

[1] S.P. Meilton, " POSSUM : Power System Macros - User Guide for Version 0.3", CEGB Report No. : CISD/CC/P850, November 1988.

[2] M. J. Whitmarsh-Everiss, "The mathematical modelling of plant behaviour : An evolutionary history and forward projection", Nuclear Engineer, Vol. 30. No. 3. May/June 1987; Vol. 32. No. 6, November/December 1991; Vol. 34, No. 2, March/April 1993.

[3] T.H.E. Chambers, M. J. Whitmarsh-Everiss; "A method for the Design of Plant Analysers", Advances in Nuclear Science and Technology, Vol. 17. 1984 (1).

CHAPTER 4

PRESENTATION OF THE SIMULATIONS ON TEST SYSTEMS

4.1. The BPA test system simulations

4.1.1. Reference simulation with LTSP (run by POWERTECH)

In this section we demonstrate how the actions of different devices following the disturbance of losing one of the 500 kV lines affect overall system voltage stability.

Effect of Load Modelling without ULTC - Cases A and B of Table 1 consider the effect of load modelling at bus 8.

Fig. 4.1.1.a shows, for both the cases, the voltages at bus 11 following the contingency. It is seen that system voltage stability is maintained in both cases.

Table 1 - System Modelling for Case A and Case B

		Case A	Case B
Loads	Bus 8	100% Constant Impedance	100% Constant MVA
	Bus 11	100% Constant Impedance	100% Constant Impedance
I_{fd} Limits	Machine 1	Infinite Bus	Infinite Bus
	Machine 2	Limited	Limited
	Machine 3	Limited	Limited
ULTC	Bus 10-Bus 11	Disabled	Disabled
	Others	Disabled	Disabled

Effect of ULTC Operation

Case C of Table 2 considers the effect of changing the taps of the transformer between bus 10 and bus 11. Time delays for ULTC operation are assumed to be 30 seconds for the first tap movement and 5 seconds for the subsequent tap movements.

Table 2 - System Modelling for Case C

Loads	Bus 8	100% Constant MVA
	Bus 11	100% Constant Impedance
I_{fd} Limits	Machine 1	Infinite Bus
	Machine 2	Limited
	Machine 3	Limited
ULTC	Bus 10-Bus 11	Enabled
	Others	Disabled

Fig. 4.1.1.b shows the plot of voltage at bus 11 following the contingency. ULTC restores the voltage at bus 11 to its pre-contingency value at about 45 seconds. At 60 seconds, voltage at bus 11 is reduced to below its pre-contingency value due to generator field current limiter action, and the ULTC starts to operate again. At about 65 seconds following the disturbance, voltage at bus 11 starts to decrease with the increase in the transformer turns ratio, resulting in voltage instability. At about 120 seconds following the disturbance, the system loses synchronism, as indicated by the large oscillation in bus voltages. However, it is important to observe that transient instability is the result, rather than the cause, of voltage reduction. The cause of system instability is the restoration of load power by ULTC operation and the limiting of field currents of machines 2 and 3 (see hereafter).

Effect of Induction Motors

To demonstrate the effect of induction motor load, we consider Case D of Table 3, which is the same as Case C except that the load at bus 8 is modelled as 50% constant MVA and 50% induction motor.

Voltages at bus 11 following the contingency for Cases C and D are shown in Fig. 4.1.1.c. We see that, with induction motor load, voltage instability occurs slightly earlier following the contingency. Fig. 4.1.1.d shows the time response of the motor reactive power.

Table 3 - System Modelling for Case D

Loads	Bus 8	50% Constant MVA, 50% Motor
	Bus 11	100% Constant Impedance
I_f Limits	Machine 1	Infinite Bus
	Machine 2	Limited
	Machine 3	Limited
ULTC	Bus 10-Bus 11	Enabled
	Others	Disabled

Effect of Field Current Limiter

Generators generally represent the most important sources of reactive power and voltage support to a system. AVR action attempts to maintain the generator terminal voltage at its pre-set reference value by continuously adjusting the field voltage and consequently the field current. However, an AVR is able to control generator terminal voltage only if the field current is within its steady state continuous limit. Once the field current becomes higher than its continuous limit, field current limiter action starts to reduce the field current to within its limit.

Field Currents of Both Machine 2 and Machine 3 limited

Fig. 4.1.1.e shows the field currents for machine 2 and machine 3 for Case C. As ULTCs operate, machine 3 reaches its field current limit first, and at about 60 seconds the field current limiter starts to reduce the field current. At about 80 seconds the field current for machine 3 is reduced to within its continuous limit. The field current limiter for machine 2 starts to actuate at about 120 seconds. At about 130 seconds, before the field current for machine 2 reaches its continuous limit, the system starts to oscillate. It is seen that voltage instability occurs as soon as the field current of machine 3 is limited at about 60 seconds. At this time the voltage at bus 11 starts to decreases as ULTCs attempt to increase the bus voltage.

Field Currents of all Machines Unlimited

In this case, all the machines have their field currents unlimited, as described in the following Case F of Table 4.

Table 4 - System Modelling for Case F

Loads	Bus 8	100% Constant MVA
	Bus 11	100% Constant Impedance
I_{fd} Limits	Machine 1	Unlimited
	Machine 2	Unlimited
	Machine 3	Unlimited
ULTC	Bus 10-Bus 11	Enabled
	Others	Disabled

Fig. 4.1.1.f shows the unlimited field currents for machine 2 and machine 3, and Fig. 4.1.1.g shows the voltage at bus 11 for the same case. It is seen that voltage stability is maintained if all the machines have their field currents unlimited.

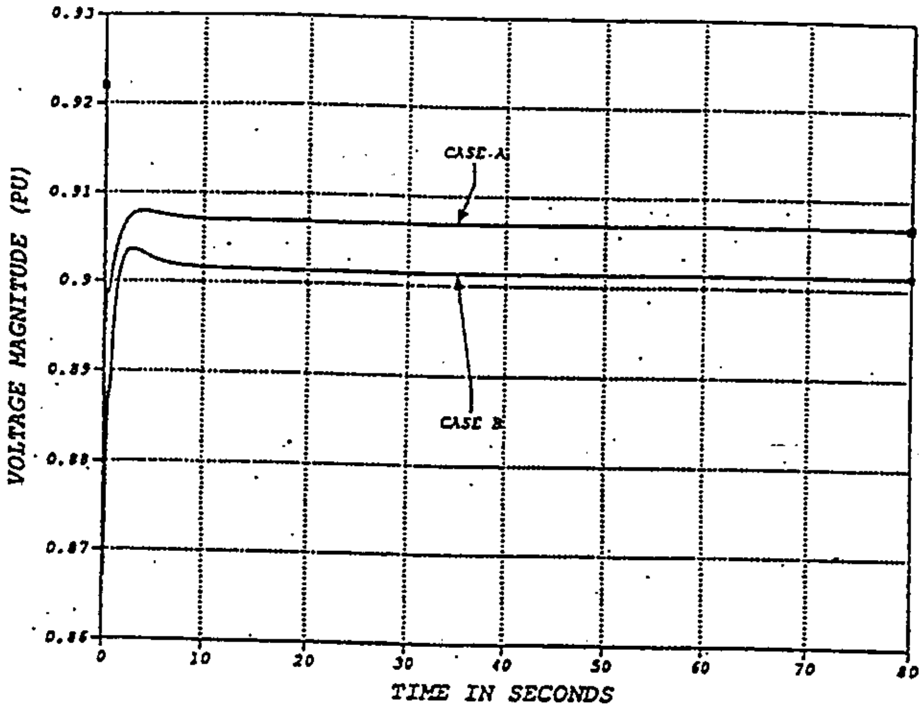


Fig. 4.1.1.a. : Voltage at bus 11 for Case A and Case B

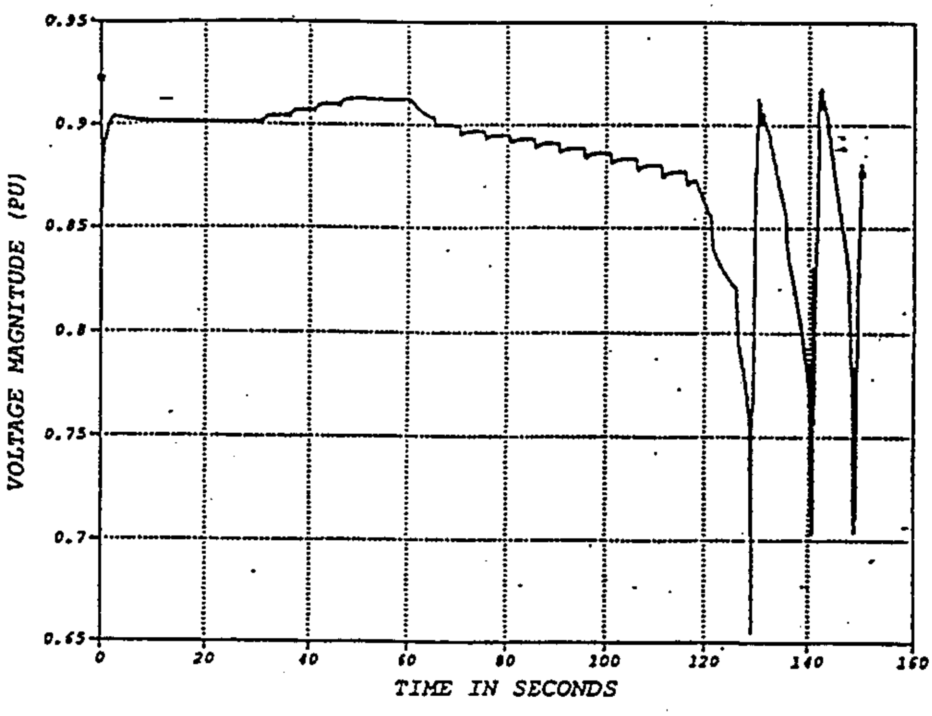


Fig.4.1.1.b. : Voltage at bus 11 for Case C

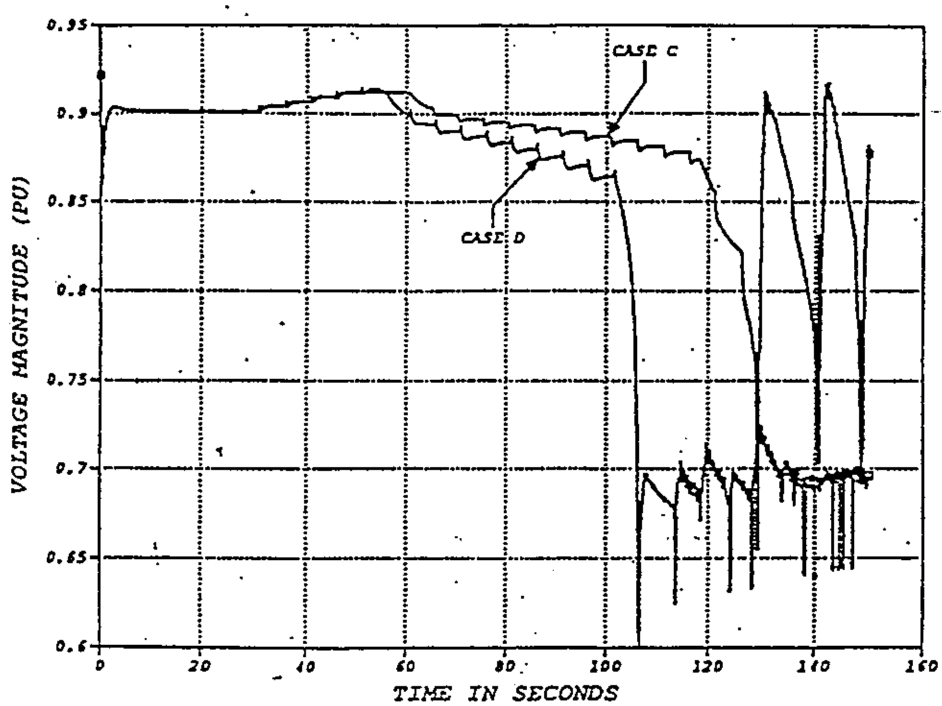


Fig. 4.1.1.c. : Voltage at bus 11 for Case C and Case D

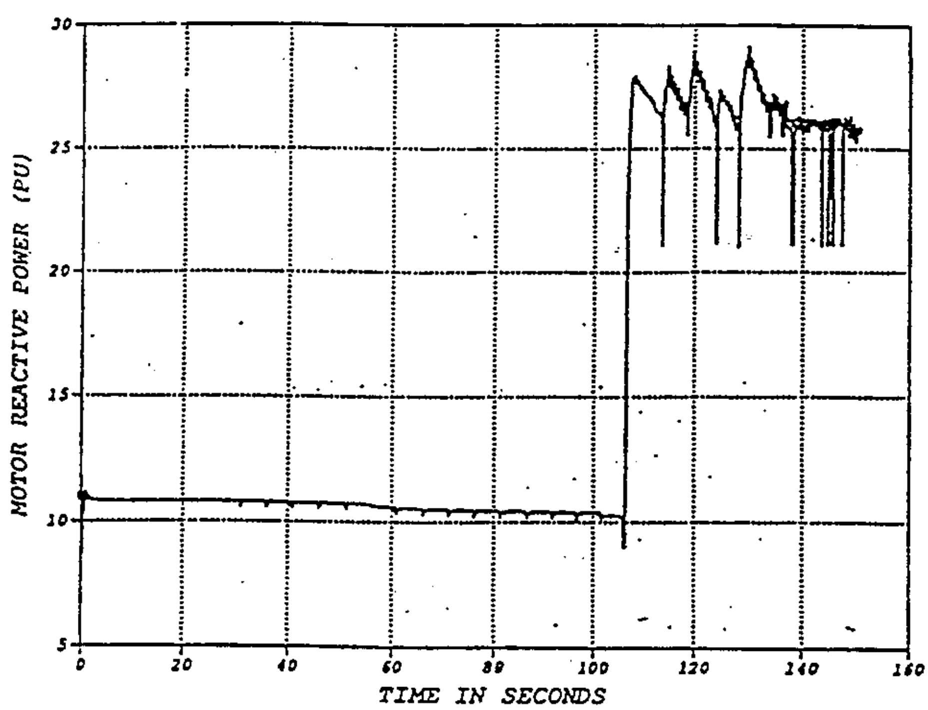


Fig.4.1.1.d. : Motor reactive power for Case D

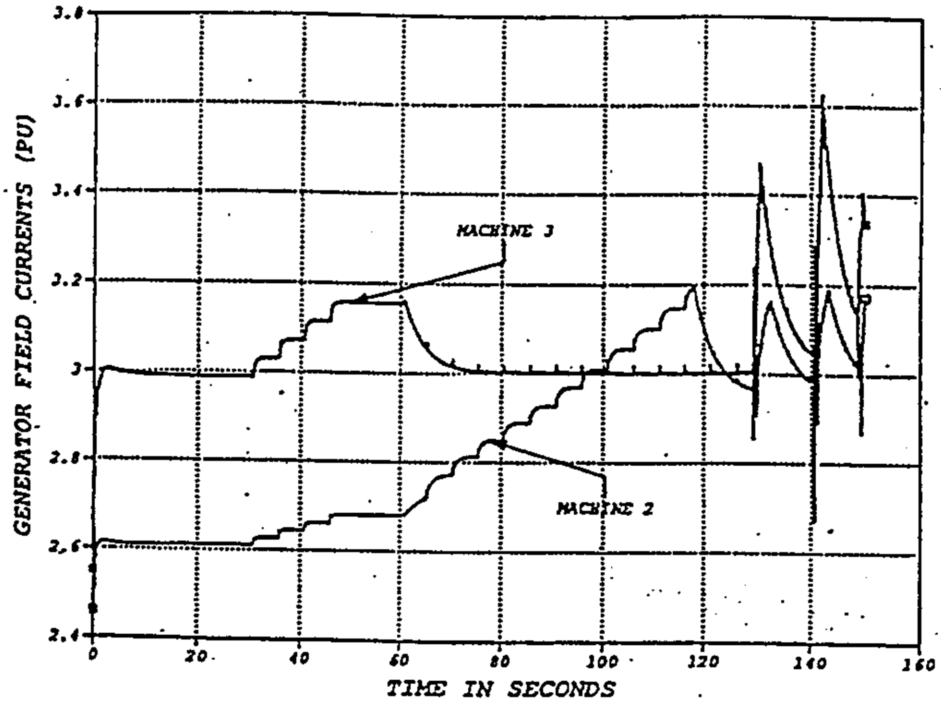


Fig. 4.1.1.e. : Field currents of machines 2 and 3 for Case C

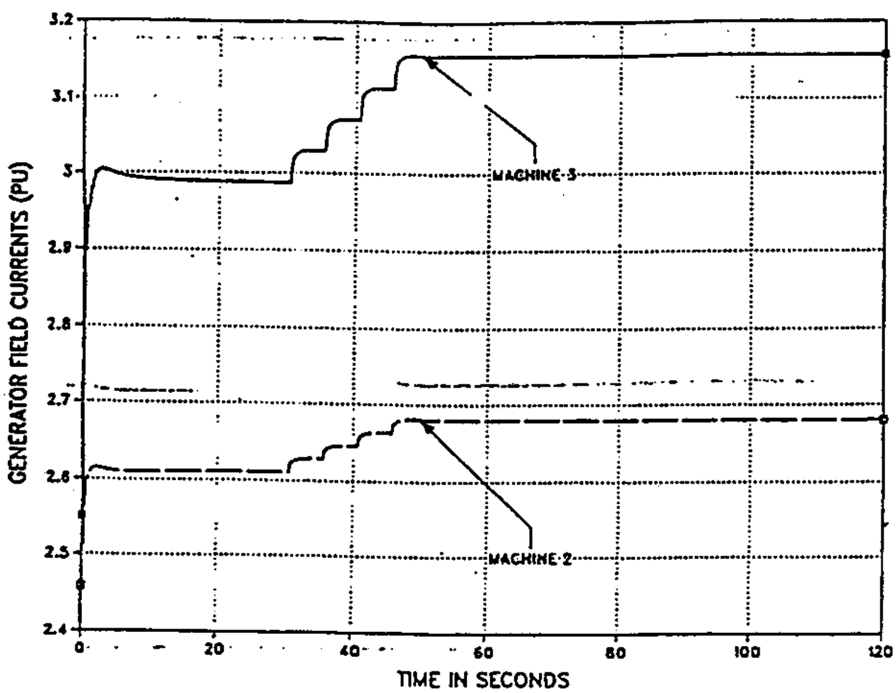


Fig.4.1.1.f. : Field currents of machines 2 and 3 for Case F

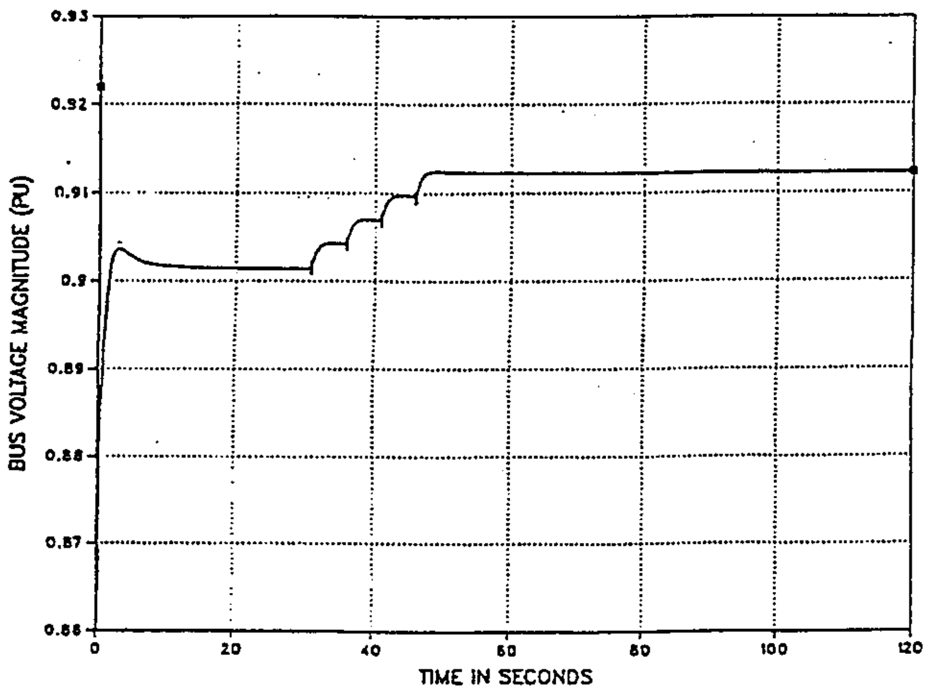


Fig. 4.1.1.g. : Voltage at Bus 11 (Case F)

4.1.2. Simulation with EUROSTAG (run by Tractebel)

4.1.2.1. Description of the modelling

Network

The system model is identical as shown by the obtained load-flow which is nearly the same as the reference (less than 1 MW/1 MVAR error at the slack bus).

Dynamic models

Generators

A full 4 rotor winding Park generator model is used for machines 2 and 3. To represent generator saturation, EUROSTAG uses the so called Shackshaft model in which mutual inductances in both axes are expressed as non-linear functions of the magnitude and the position of the air gap flux. In LTSP, generator saturation is modelled by varying the mutual reactances as non-linear functions of the magnitude of the air gap flux.

As in the reference, machine 1 is modelled by an infinite node.

Controllers

AVR, PSS and OEL : the reference models are fully reproduced with the EUROSTAG macrolanguage.

Automata and relays

ULTC : in relevant cases, the transformer between bus 10 and bus 11 is fitted with an ULTC automaton having the proposed parameters and dynamic data.

Load

The observed differences concern induction motors. The equivalent circuits used to model double cage induction motors are different for the two programs. Also, different models are used to model the speed torque characteristics of the motor mechanical load. In LTSP, the torque is assumed to be a continuous non-linear function of the speed. In EUROSTAG, the torque speed curve is approximated by a piece-wise linear function.

4.1.2.2. Scenario specials

The events proposed in the reference cases have been reproduced exactly.

4.1.2.3. Simulation results

The following discussion is illustrated by means of plots of LTSPand EUROSTAG compared. The scales of EUROSTAG plots have been adapted to fit the scales of LTSP.

Case A

EUROSTAG results are quasi identical to those of the reference case (see fig. 4.1.2.a and b).

Case B

The global behaviour of the system is very close to the reference one (see fig. 4.1.2.a and b).

Unlike LTSP results, the threshold value of Ifd (3 p.u.) is exceeded (3.04 p.u.) and the maximum rotor current limiter (OEL) acts, bringing Ifd back to its limited value about 100 s after the line tripping.

If the identification of the saturation parameters is done at no load conditions, Ifd threshold is not exceeded and as in the reference case, there is no OEL action (case of fig. 4.1.2.b).

Case D

Although the global behaviour of the system is reproduced, some differences may be pointed out (see fig. 4.1.2.c and d) :

- the collapse occurs ± 15 s. later;
- the number of tap changes before the collapse is higher in EUROSTAG results than in the reference;
- the cyclical behaviour of the 40 last seconds of the reference results is not reproduced. In EUROSTAG calculations, the system collapses completely.

4.1.2.4. Conclusions

Generally, the EUROSTAG results are very close to those obtained using LTSP. Differences exist mainly because of the discrepancies in generator saturation and induction motor models.

The EUROSTAG program has the modelling capability to do dynamic voltage stability study. Macrolanguage models of EUROSTAG provide high degree of flexibility to simulate the effect of special control schemes such as maximum field current limiters.

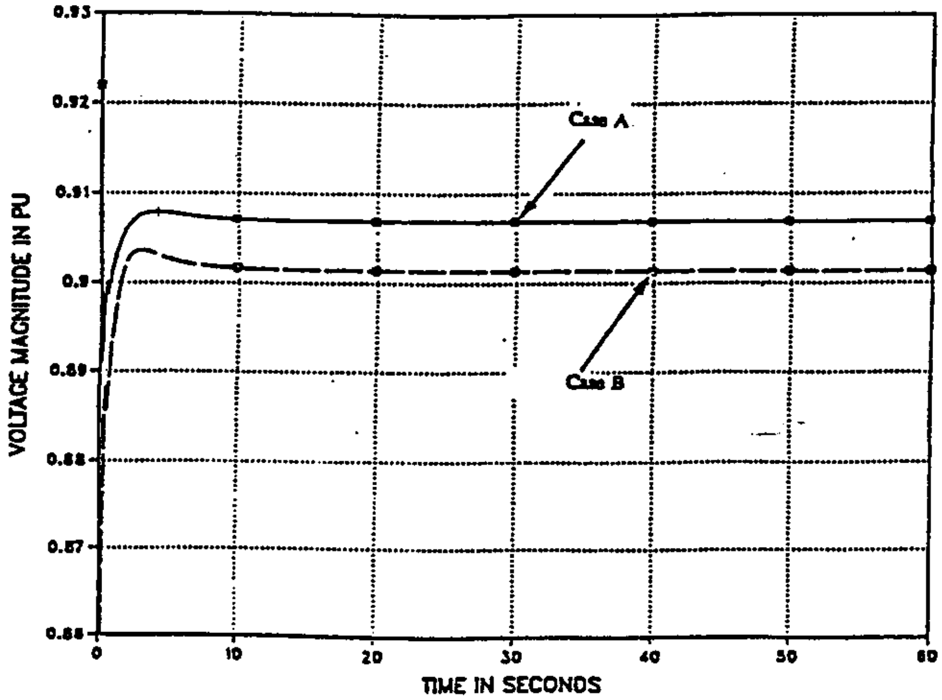


Fig. 4.1.2.a : LTSP - Voltage at bus 11 (Case A and B)

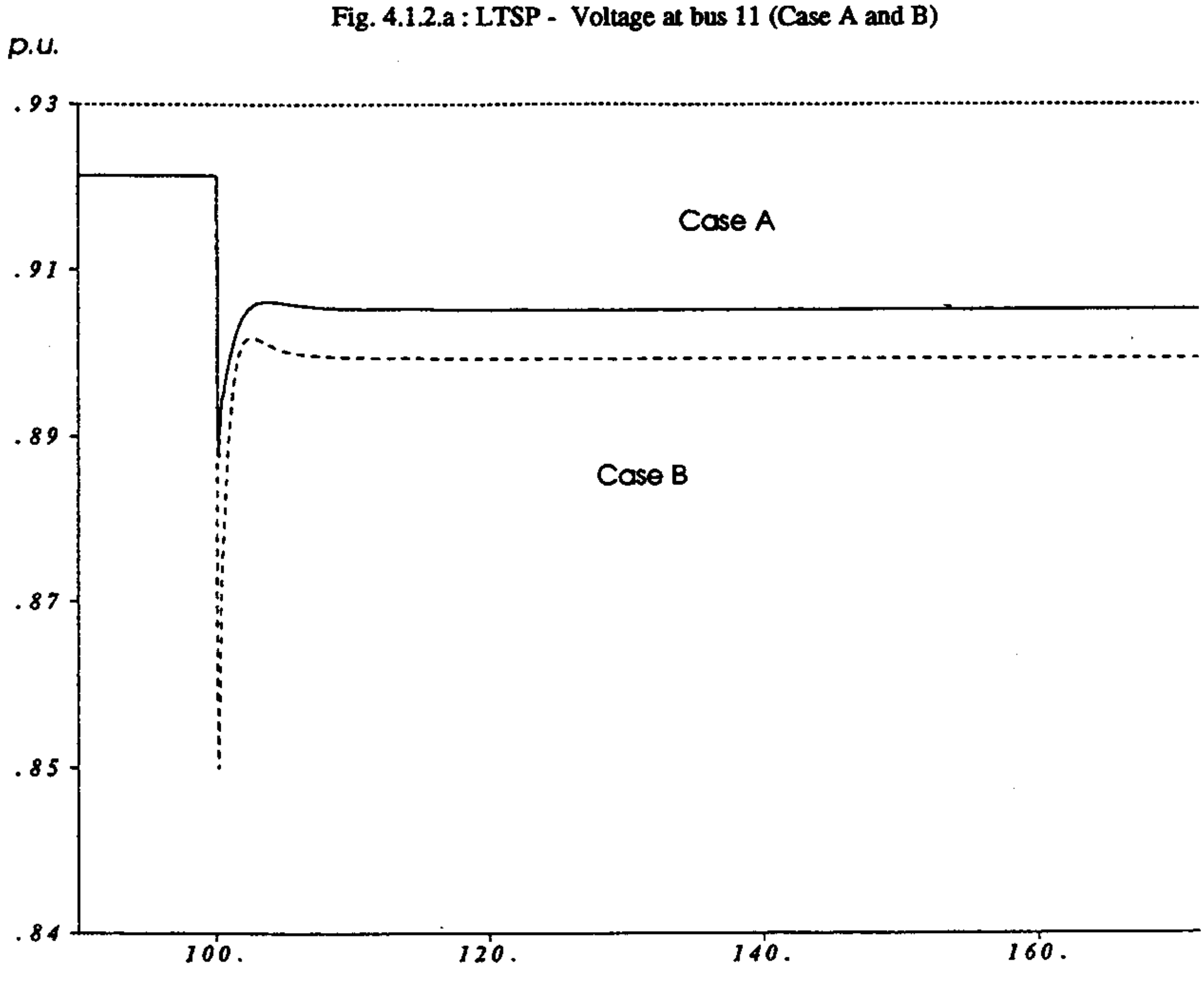


Fig. 4.1.2.b : EUROSTAG - Voltage at bus 11 (Case A and B)

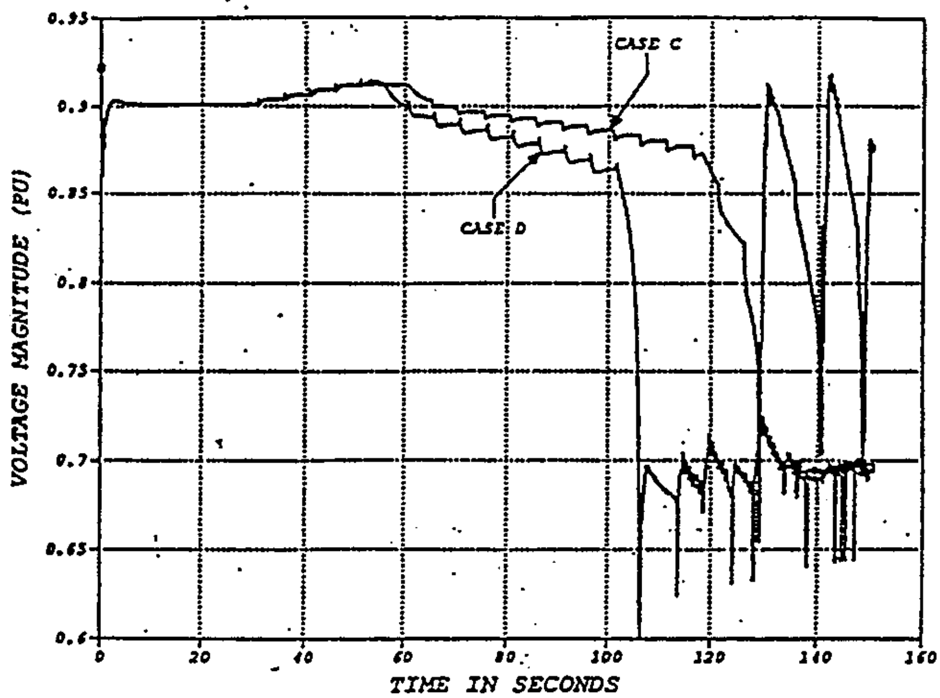


Fig. 4.1.2.c : LTSP - Voltage at bus 11 (Case C and D)

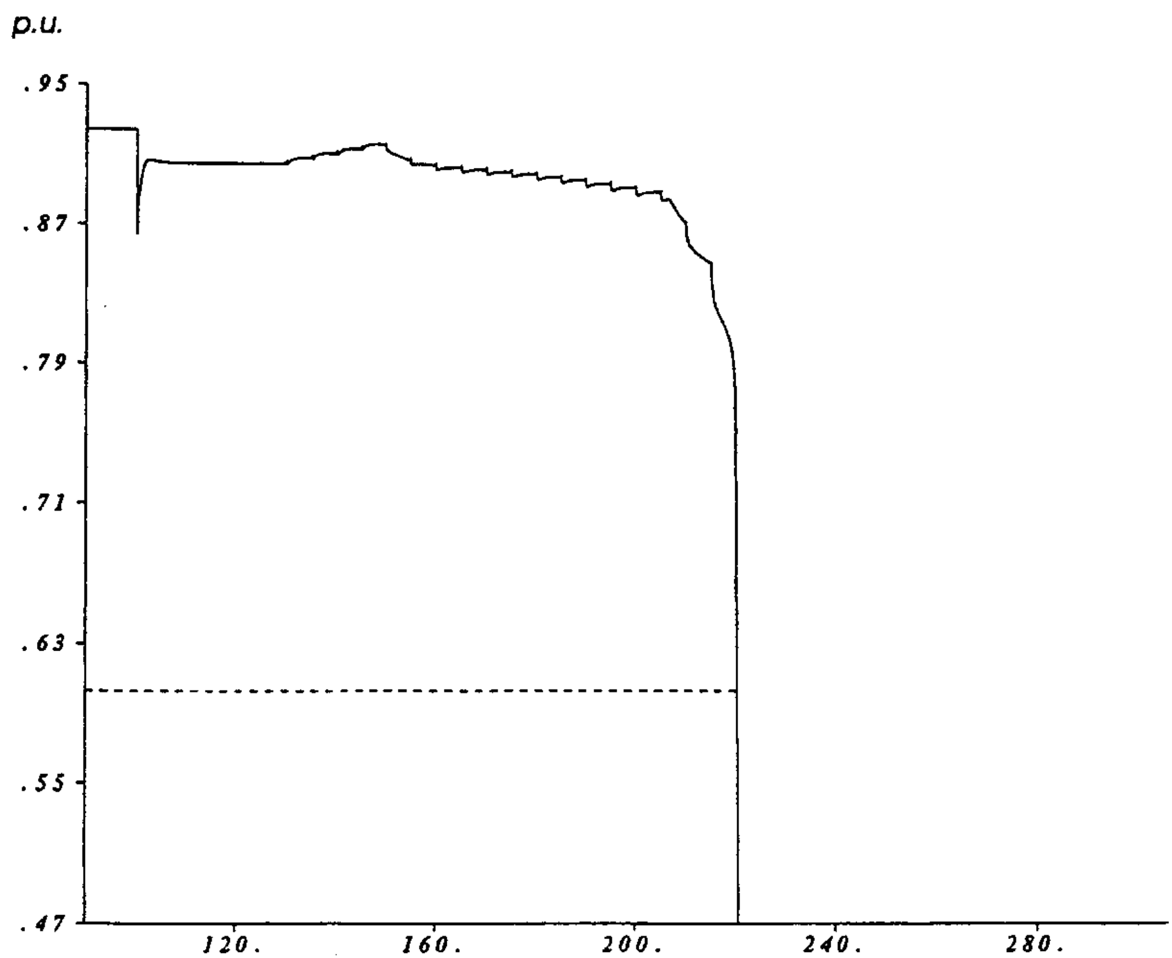


Fig. 4.1.2.d : EUROSTAG - Voltage at bus 11 (Case D)

4.1.3 Simulation with TNS (run by FUJI Electric)

4.1.3.1. Description of the modelling

Network

The transformation ratios of step up transformers has only 4 steps (5% step size, ±10% width, on the high voltage side). The transformation ratio of step down transformers has only 8 steps (2.5% step size, ±10% width).

As a consequence the initial load flow is different from the reference. Moreover, the voltage of bus 2 is changed from 0.96 to 1. p.u. to approach the reactive power balance of the reference load flow.

Dynamic models

Generators : represented by a Park model including armature and damper windings. Saturation model is different from the reference one.

Controllers :

AVR, OEL and Governor	:	set up on the Programmable Controller;
PSS	:	not taken into account.

Automata and relays

ULTC	:	modelled through the Programmable Controller. Case F results show that their dynamic is different (higher time intervals between tap changes).

Loads

The passive load model is the same as in the reference. The cases with induction motor loads are not simulated.

4.1.3.2. Scenario specials

- The rated frequency of TNS is 50 Hz so that all models are changed to 60 Hz. Therefore the time constants and the simulation time are adapted by a factor of $\frac{6}{5}$.
- As the TNS transformers have a smaller ratio range than in the reference, two transformers (N7-N9 and N10-N11) instead of one have been equipped with ULTC. Both control the node N11; they act so that the first ULTC starts after the second has reached its limits.

4.1.3.3. Simulation results

The following discussion is illustrated on fig. 4.1.3.a to c.

Case A, B, C and F

initial and static voltage deviation are lower than in the reference. Differences in the saturation model explain this result.

Case C

as in the reference, the OEL of machine 3 enters into action. TNS results show that a static instability appears when OEL of machine 3 acts. At that moment, the field current of machine 2 is still far from the OEL threshold and thus from the voltage collapse obtained in the reference case.

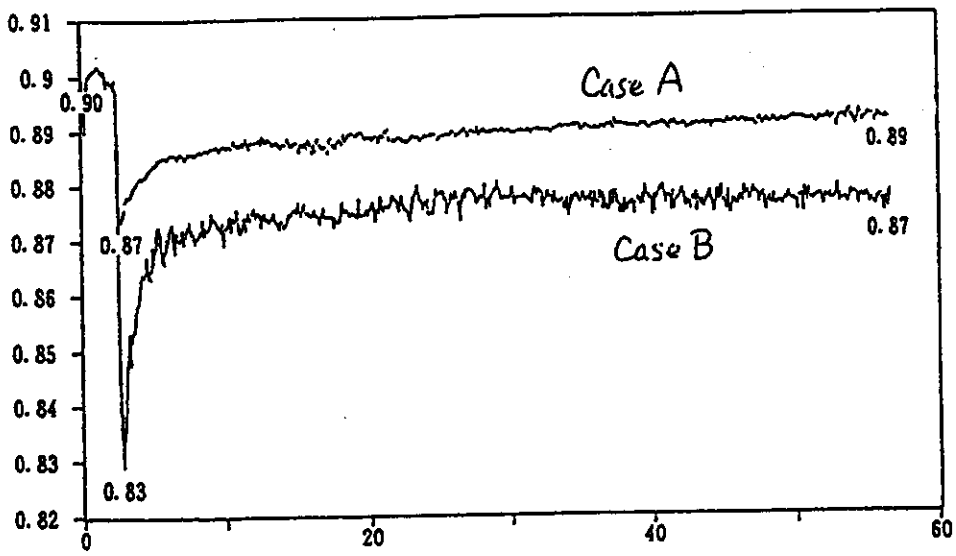
4.1.3.4. Conclusions

TNS has the modelling capability to do dynamic voltage stability study. TNS uses a programmable controller to model the special control schemes such a maximum excitation current limiters.

Nevertheless, generator saturation and stepsize of the TNS iron core transformer don't match the modelling used in LTSP. The results obtained using TNS show the same general trend of voltage collapse as the results obtained using LTSP.

Again the differences between TNS and LTSP results are most likely to be caused by the modelling discrepancies between the two programs.

(a) TNS



(b) POWERTECH Calculation

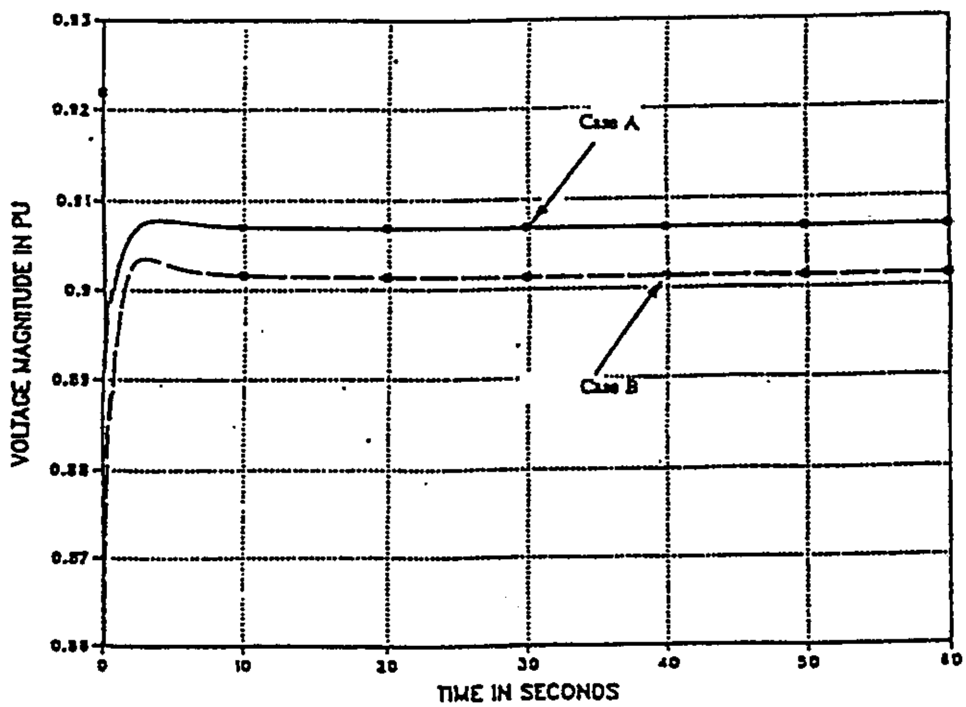
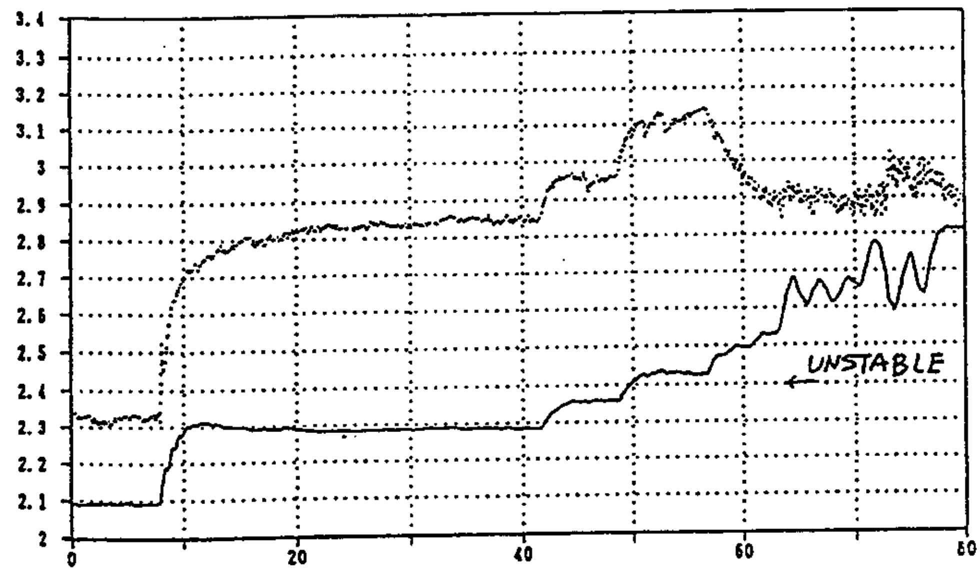


Fig. 4.1.3.a : Comparison between TNS and LTSP.
Voltage at bus 11 (Case A and B)

(a) TNS



(b) POWERTECH Calculation

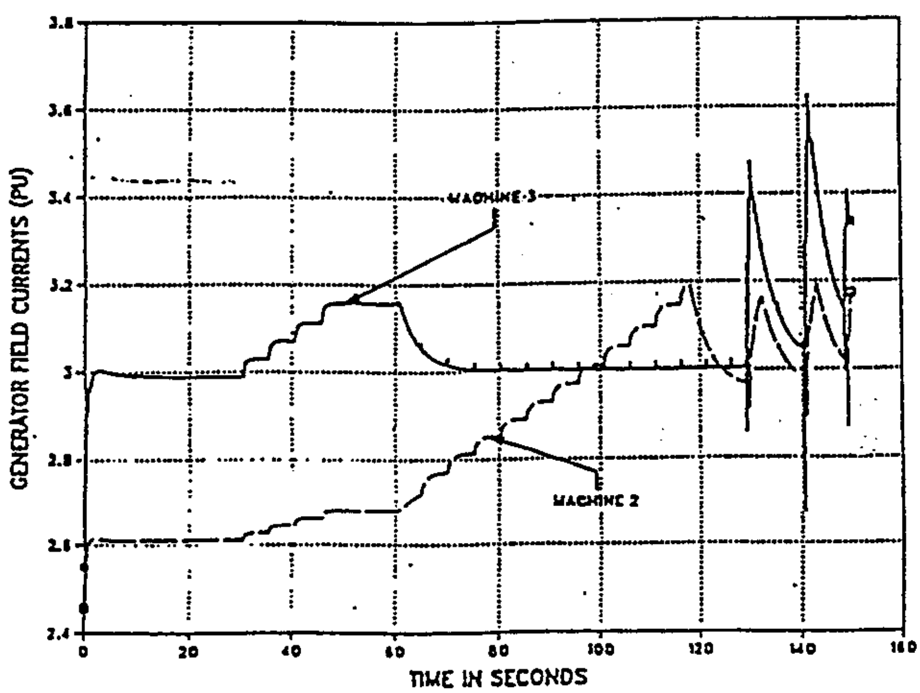
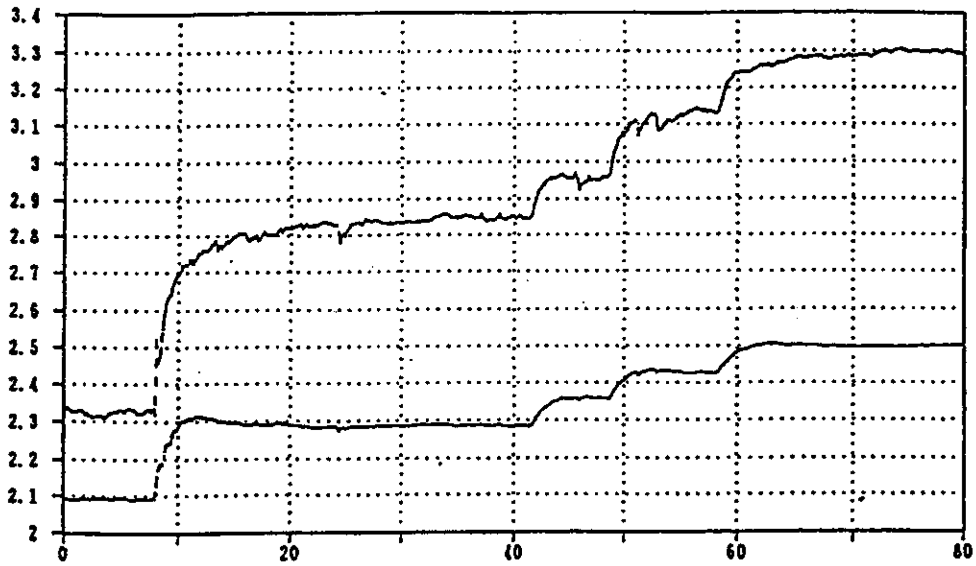


Fig. 4.1.3.b : Comparison between TNS and LTSP.
Field Current of machines 2 and 3 (Case C)

(a) TNS



(b) POWERTECH Calculation

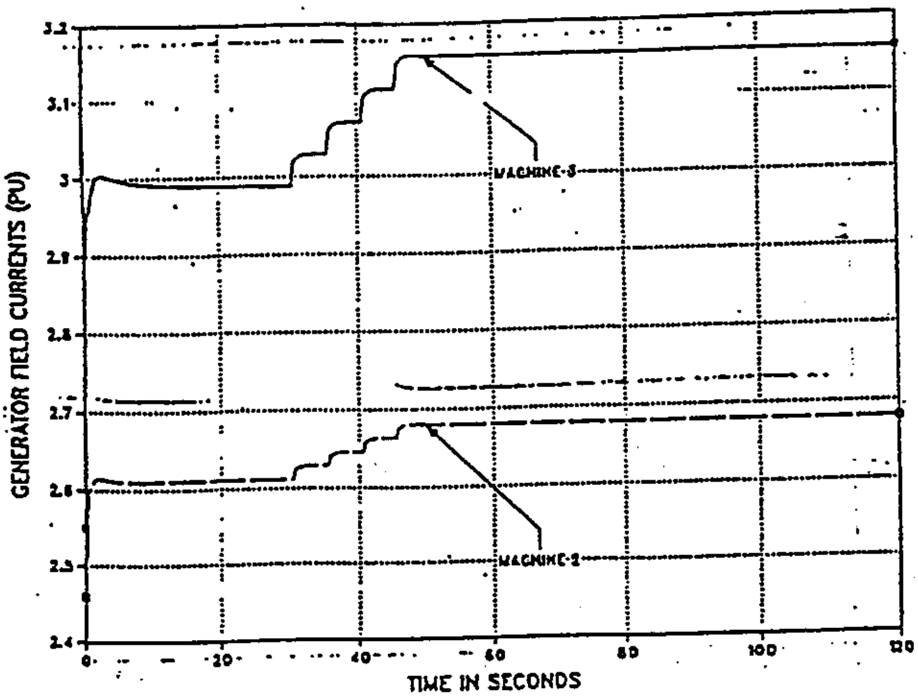


Fig. 4.1.3.c : Comparison between TNS and LTSP.
Field Current of machines 2 and 3 (Case F)

4.1.4. Summary comments on the simulations on the BPA test system

Three simulation tools, LTSP, EUROSTAG, and TNS were used to study the voltage stability of the BPA test system. LTSP and EUROSTAG are digital simulation programs. TNS is an analog simulator.

The objective of the exercise was to compare the capabilities and simulation results of the three programs for dynamic voltage stability analysis and to assess the capabilities of EUROSTAG and TNS to reproduce the results initially obtained with LTSP, considered as reference to bench mark the results obtained using the other two programs.

A further comparison between EUROSTAG and LTSP can be found after the Belgian - French test system.

Comparison between EUROSTAG and LTSP

Both programs have the modelling capability to do dynamic voltage stability study. Macrolanguage modelling of EUROSTAG provides high degree of flexibility to reproduce the effect of special control schemes such as maximum field current limiters.

The main differences between EUROSTAG and LTSP calculations lies in the way they model generator saturation and induction motors.

Generally, the EUROSTAG results are very close to those obtained using LTSP.

Comparison between TNS and LTSP

TNS has the modelling capability to do dynamic voltage stability study. TNS uses a programmable controller to model the special control schemes such as maximum excitation current limiters.

Generators saturation and ULTC models used in TNS are different from those used in LTSP. Although the TNS results are not as close to the LTSP results as those obtained using EUROSTAG, it is encouraging to see that an analogic simulator such as TNS shows the same general phenomenon of voltage collapses as digital simulation programs such as LTSP and EUROSTAG. Again, the difference between TNS and LTSP results is most likely to be caused by the modelling discrepancies between the two programs.

Conclusions

Simulations of the BPA test system have shown that all the three tools have the capabilities to be used to do dynamic voltage stability analysis. The results obtained are close enough to conclude that all the tools work properly. The differences in simulation results obtained using the three tools are most likely to be caused by the modelling discrepancies. In particular it seems that generator saturation model has a large impact on the system dynamic response leading to voltage collapse.

It is particularly encouraging to see that an analog simulator such as TNS predicts the same trend of voltage collapse as do the digital simulation programs such as LTSP and EUROSTAG.

Future work in comparing these different tools should be focused on resolving the differences in modelling.

4.2. The Belgian - French test system simulations

4.2.1. Reference simulation with EUROSTAG (run by Tractebel)

The reader has to refer to section 2.2. and to have in mind at least the one line diagram of the system and the functioning of OEL when looking to the following simulations results.

Initial load pick-up (see Fig. 4.2.1.a)

A linear load pick-up of 30 % in two hours occurs in the 70 kV subtransmission system. It is simulated by a linear increase of the impedance of the 70 kV loads .

To keep a satisfactory voltage profile, the set point of all the generator AVR's and the 400/150 kV transformer tap settings are manually changed. Although equipped with ULTC, the 150/70 kV transformer ratio remains nearly constant during the load pick-up.

In order to maintain nearly constant the active power flow on the tie lines, of the North region, the active powers of units M3, M4 and M5 are linearly increased.

After the $\frac{2}{3}$ of the load pick-up (t = 5 000 s), the Northern international tie line N16-N3 trips. As a consequence, the 60 MW flowing in the tie line are transferred on the North-South 400 kV interconnection line (N6-N4).

After the load pick-up

At time 7 400 s (200 s after the end of the load pick-up), unit M2 is manually tripped. After the related rotor transients, the value of the field current of unit M1 stays just below the OEL threshold (I_{fd} = 3.18 p.u. when I_{fseuil} = 3.2 p.u.). All other units field currents are largely below their OEL threshold (see Fig. 4.2.1.b).

36 s after M2 tripping, the first ULTC changes occur to restore the 70 kV voltages. As a consequence, M1 unit OEL threshold is exceeded which generates a few tens of seconds later a drastic reduction of the unit excitation to 2.3 p.u. (which is a too low value and corresponds to an ill setting in the scenario) (see Fig. 4.2.1.b).

During the M1 excitation reduction, M4 exceeds its field current threshold which activates M4 unit OEL. Joined together, these two phenomena lead to the loss of synchronism of M1 (see Fig. 4.2.1.c).

After M1 tripping and also due to 70 kV ULTC operations, terminal voltage of unit M4 becomes lower than its minimum terminal voltage relay setting. At time 7 520 s, M4 is tripped.

During the OEL action of M1, M3 and M5 OEL thresholds are exceeded (see Fig. 4.2.1.c) and their OEL become effectively active around ≈ 7 525 s. Their actions provoke the loss of synchronism of the two units and their tripping by out of step relay (see Fig. 4.2.1.c).

Fig. 4.2.1.d displays the evolution of the voltage at nodes N107 and N207 and the tap position of transformer N107/N207 after M2 tripping.

The voltage curves show clearly the voltage collapse and the effect of the different cascade trippings. The reverse effect of transformer tapping on secondary voltage (N207) demonstrates the voltage instability (a tap down increases the transformation ratio).

The same figure shows the P-V curve at the low voltage side of the transformer, along the whole scenario. The horizontal part corresponds to the load pick-up, the voltage instability corresponding to the lower part of the parabola-like curve.

Stepsize evolution

Fig. 4.21.1.e illustrates the automatic stepsize variation. During the load pick-up phase, the step is reduced when an operation takes place (change of voltage set point, tap position etc ...). During this run, the typical range of stepsize is from 0.001 to 35 s (factor of 35 000), the mean value of the whole 8 000 s scenario being 4 s.

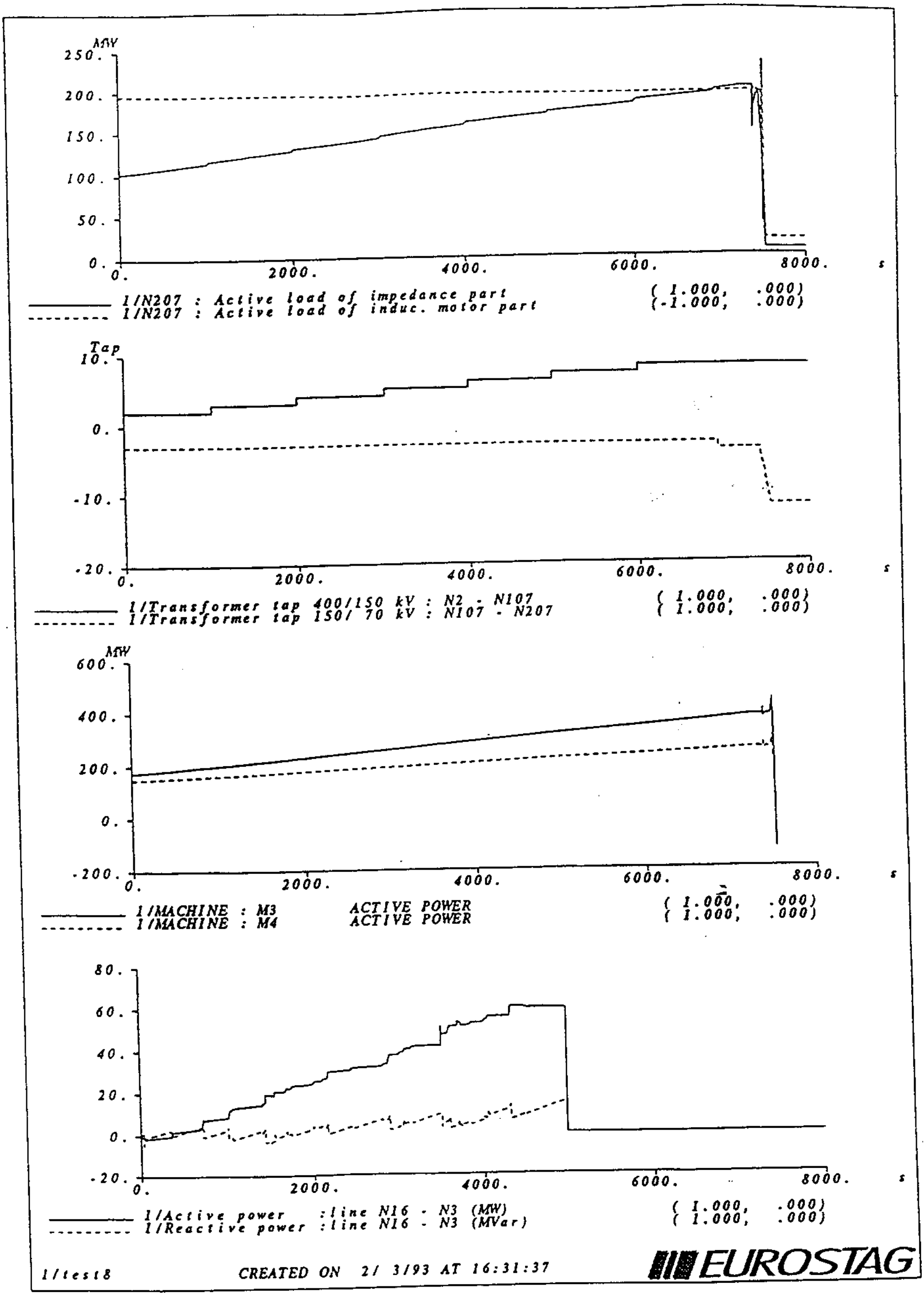


Fig. 4.2.1.a : Overview of the load pick up

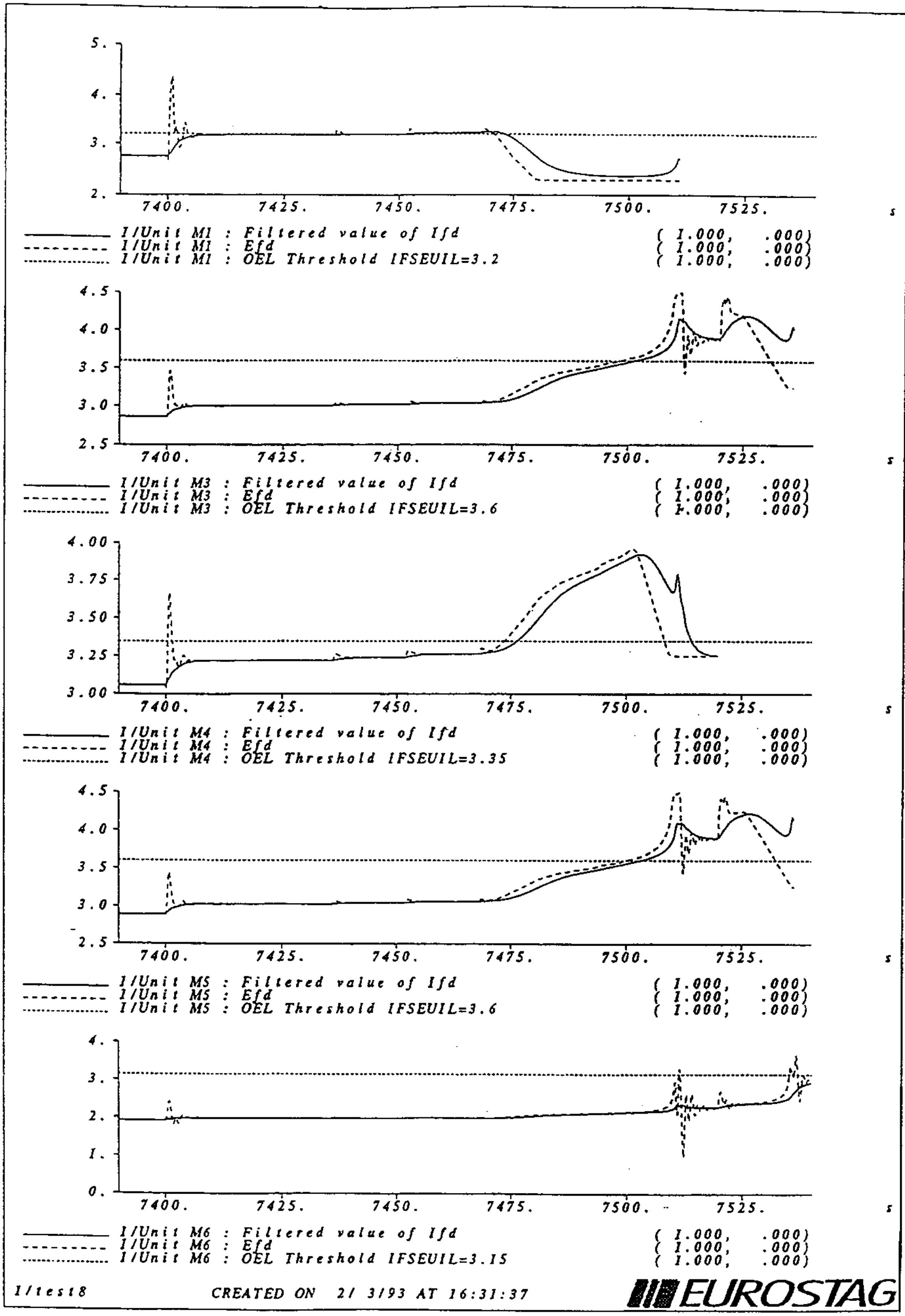


Fig. 4.2.1.b : Behaviour of the excitation of the generating units after unit M2 tripping.

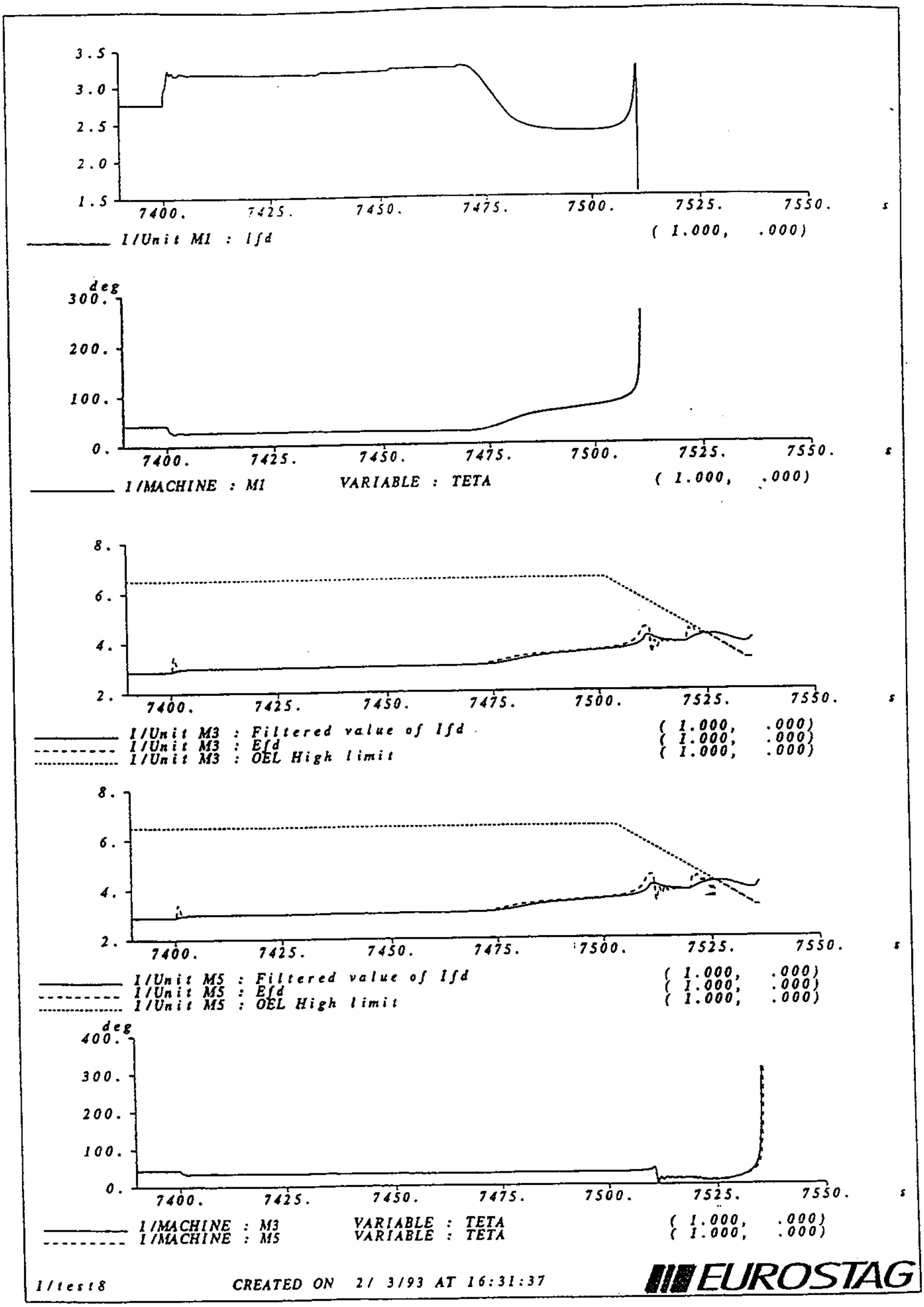


Fig. 4.2.1.c : Loss of synchronism of unit M1, behaviour of OEL of units M3 and M5 and loss of synchronism of units M3 and M5.

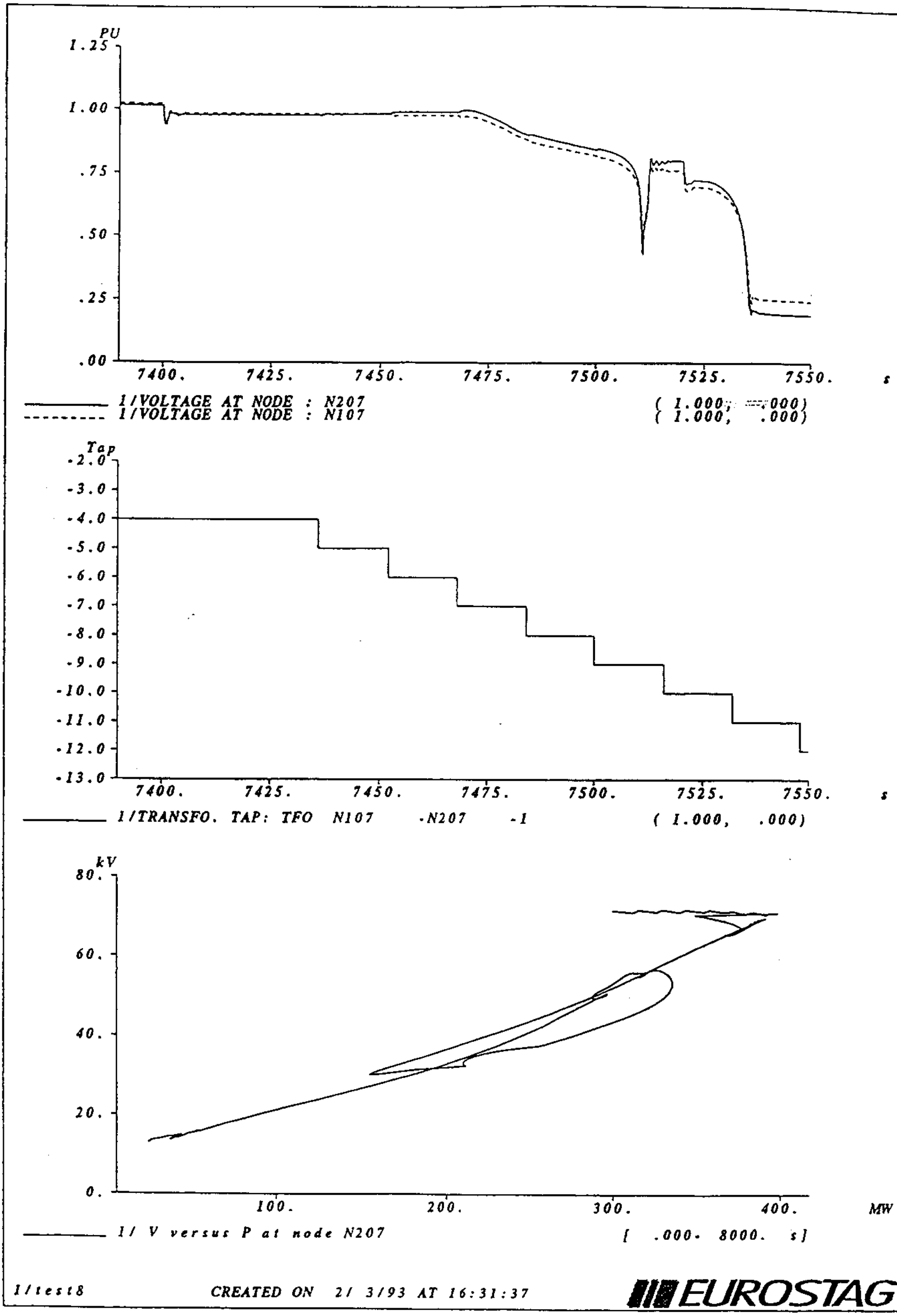


Fig. 4.2.1.d : Voltage at both sides of a 150/170 kV transformer and tap position. PV curve at node N 207.

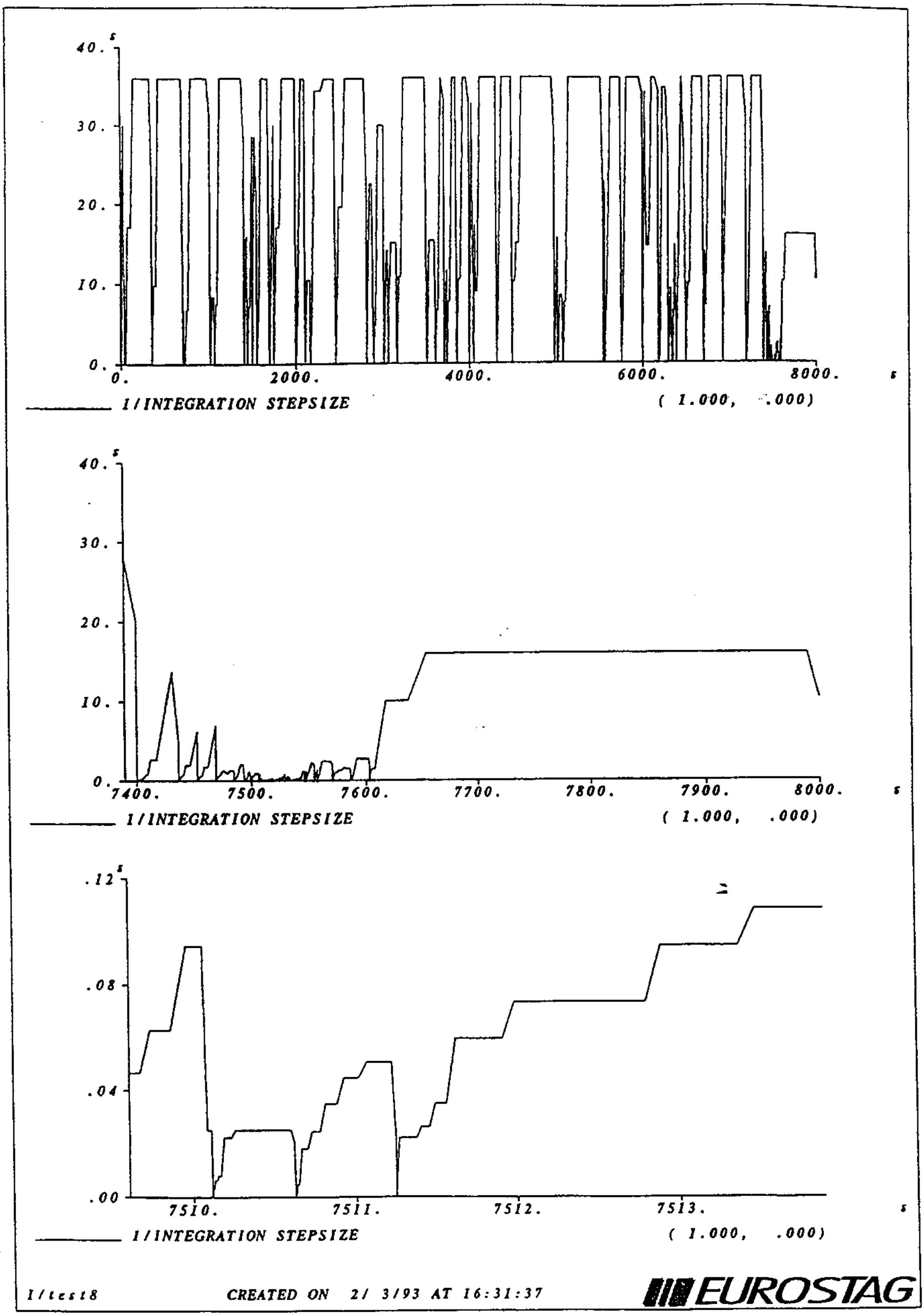


Fig. 4.2.1.e : Stepsize variation along the whole scenario and zoom on the periods of instability.

4.2.2. Simulation with CHAMPS V1, V2 and CHAMPS (run by CRIEPI)

4.2.2.1. Description of the modelling

The dynamic data of the test system have been simplified because only slow varying elements are modelled in CHAMPS V1. No dynamics are taken into account in CHAMPS V2. As regards the complementary calculations made with CHAMPS, standard models taken from the library have been used.

Network

The initial load flow is quite close to the reference. However the following differences have been observed:

- transformer resistances are automatically set to 0 in the CHAMPS V1 and V2 programs;
- voltage settings of the PV nodes and thus the obtained initial reactive productions are not the same.

The infinite nodes are treated as generators with large capacities.

Dynamic models

Generator	:	in CHAMPS V1 and V2 only static equations are considered. In CHAMPS, a full 4 winding rotor Park model is used. In both cases their is no modelling of saturation.
AVR	:	in CHAMPS V1 and V2, a static model is used. In CHAMPS, a standard AVR is selected from the library. Parameters are adjusted to cope with the reference ones.
PSS	:	not relevant in CHAMPS V1 and V2. In CHAMPS, a standard PSS is selected from the library.
Governor	:	in CHAMPS V1 and V2, a static model is adopted. in CHAMPS, a standard model is selected in a library and is similar to the proposed one. Thanks the presence of the infinite nodes, the effect of model discrepancies should remain limited.
OEL	:	in CHAMPS V1 and V2 a standard model of OEL is selected in the library. It acts on the output limiter of the AVR. Its dynamic is close to the reference one. In CHAMPS, OEL are not taken into account.

Automata and relays

ULTC	:	their effect is taken into account a first time through the dynamic load behaviour. They are taken into account a second time through automatic change of the ratio of the 150/70 kV transformers.
Loss of synchronism relay	:	in CHAMPS V1 and V2, they are not relevant. In CHAMPS, they are not modelled.

Undervoltage relay :	are not available neither in CHAMPS V1 and V2 nor in CHAMPS.

Loads

In CHAMPS V1 and V2, dynamics of induction motor cannot be considered. All 70 kV loads were modelled dynamically as constant impedance in the short term and constant power in the long term. This behaviour includes the effect of ULTC on distribution transformers.

Other loads were expressed as constant power, a difference with the reference model.

In the transient simulation realised with CHAMPS the 70 kV load is the aggregation of induction motor and the dynamic load model used in CHAMPS V1 and V2.

No information are given on the induction motor model and the associated parameters. Other loads are modelled as above.

4.2.2.2. Scenario specials

The simulation is carried out in 2 steps :

- 1st step : the proposed scenario is identified a priori as a voltage collapse problem where dynamic performance is not essential. As a consequence, two voltage stability dedicated tools are used (CHAMPS V1 and V2). After the simulation (CHAMPS V1) of the load pick-up and M2 and M1 tripping operated manually according to the results of the full dynamic simulation of the reference, a voltage instability indicator (CHAMPS V2) detects that mode N 207 falls into the unstable voltage region.
- 2nd step : the voltage instability is verified with a transient stability program (CHAMPS). A simulation is run to assess the effect of the tripping of M2 and M1 on the stability of the system

4.2.2.3. Simulation results

The load pick-up (before M2 tripping)

During the load pick-up the secondary voltage control is modelled.

The operating point of the system after 2 hours of load pick-up, as calculated, shows discrepancies with the reference because of the difference in the load models and in Mvar generated on machines M1 and M4 (about 130 Mvar).

After M2 tripping

The results obtained with CHAMPS V1 and V2 show that the voltage collapse starts at node N207 and that a way to bring back stability margin is to shed N207 load.

It is also shown that N207 load exceeds the maximum transfer capability of the network at that node and that a voltage instability point is reached.

The voltage instability is illustrated through a transient simulation with CHAMPS. The initial conditions are defined by CHAMPS-V1 at time 120 min (after load pick-up).

M2 is tripped at time 0 of the transient simulation and M1 5 s later.

Results show that after M1 tripping, the system collapses :

- M4 unit loses synchronism;
- induction motor connected at node N 207 stalls;
- voltage at node N 207 falls to 20 %, 2 s after M1 tripping.

The above discussion is illustrated through a comparison between :

- the voltages at nodes N107 and N207 obtained with CHAMPS V1 & V2 and EUROSTAG (reference) programs (Fig. 4.2.2.a and 4.2.2.b);
- the voltages at nodes N207 and N103 obtained with CHAMPS and EUROSTAG (reference) programs (Fig. 4.2.2.c, d, e and f).

The scales of EUROSTAG plots have been adapted to fit the scales of CHAMPS plots.

4.2.2.4. Conclusion

CRIEPI method is only devoted to voltage stability and is based on a complete separation between the simulation of the short term and the long term phenomena :

Long term instability or unacceptable conditions are detected through quasi steady state simulations and thanks indicators like the voltage indicator P_{margin}. Transient stability is assessed by short term simulations where the system is fully modeled.

The proposed methodological approach and mainly the long term simulation allowed to detect efficiently the voltage collapse of the test system but suffers two main limitations :

1. Lack of flexibility and accuracy of the modelling of the regulators and automata
2. Difficulty to detect unstable conditions related to fast phenomena (like the loss of angular stability) along the long term trajectory.

Ideally, in this test system, short term and long term dynamics should not be dissociated. The here proposed approach may be used at the planning level. For the tuning of defence actions or for post-mortem analysis, the full dynamical approach becomes mandatory.

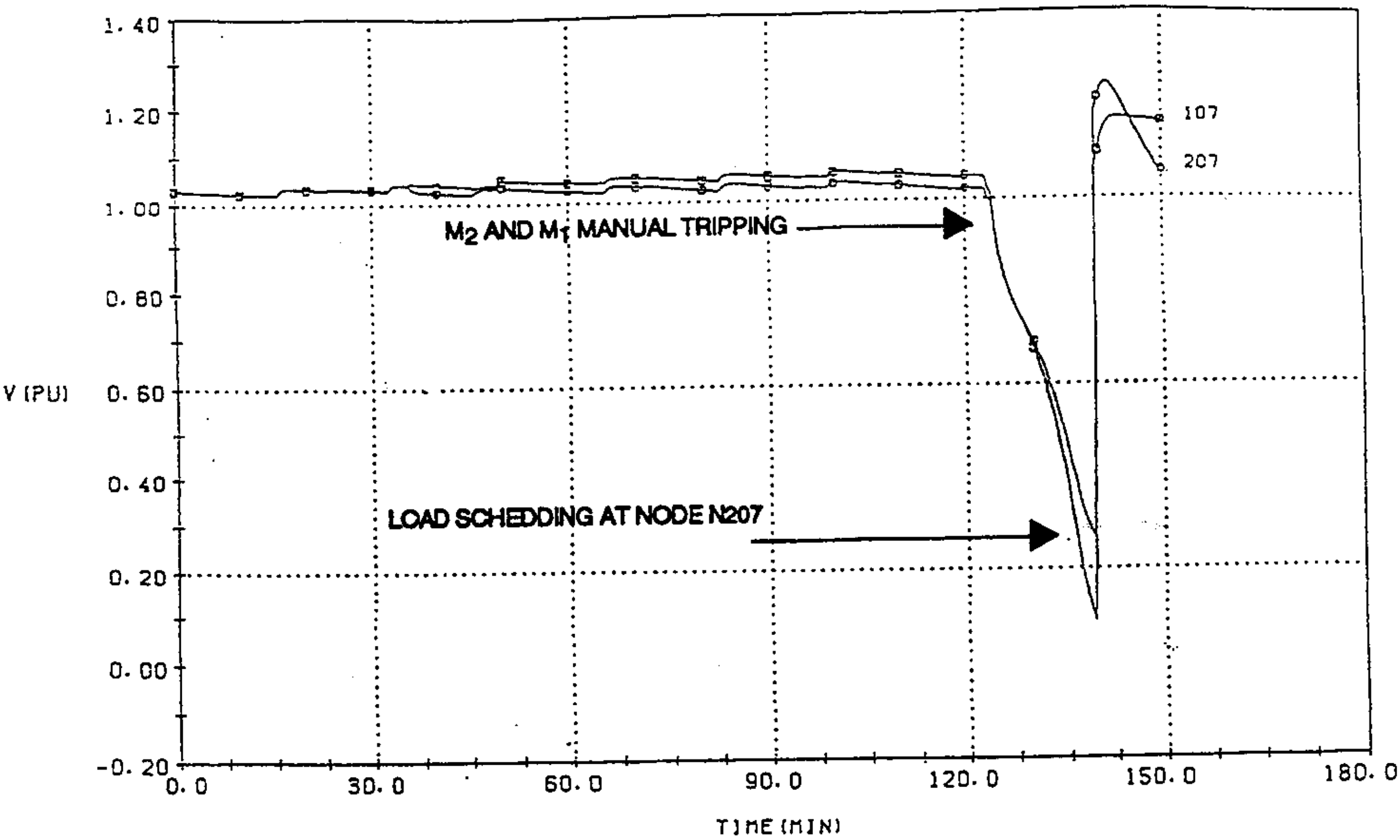


Fig. 4.2.2. a : CHAMPS V_1 & V_2 : VOLTAGES AT NODES 107 AND 207

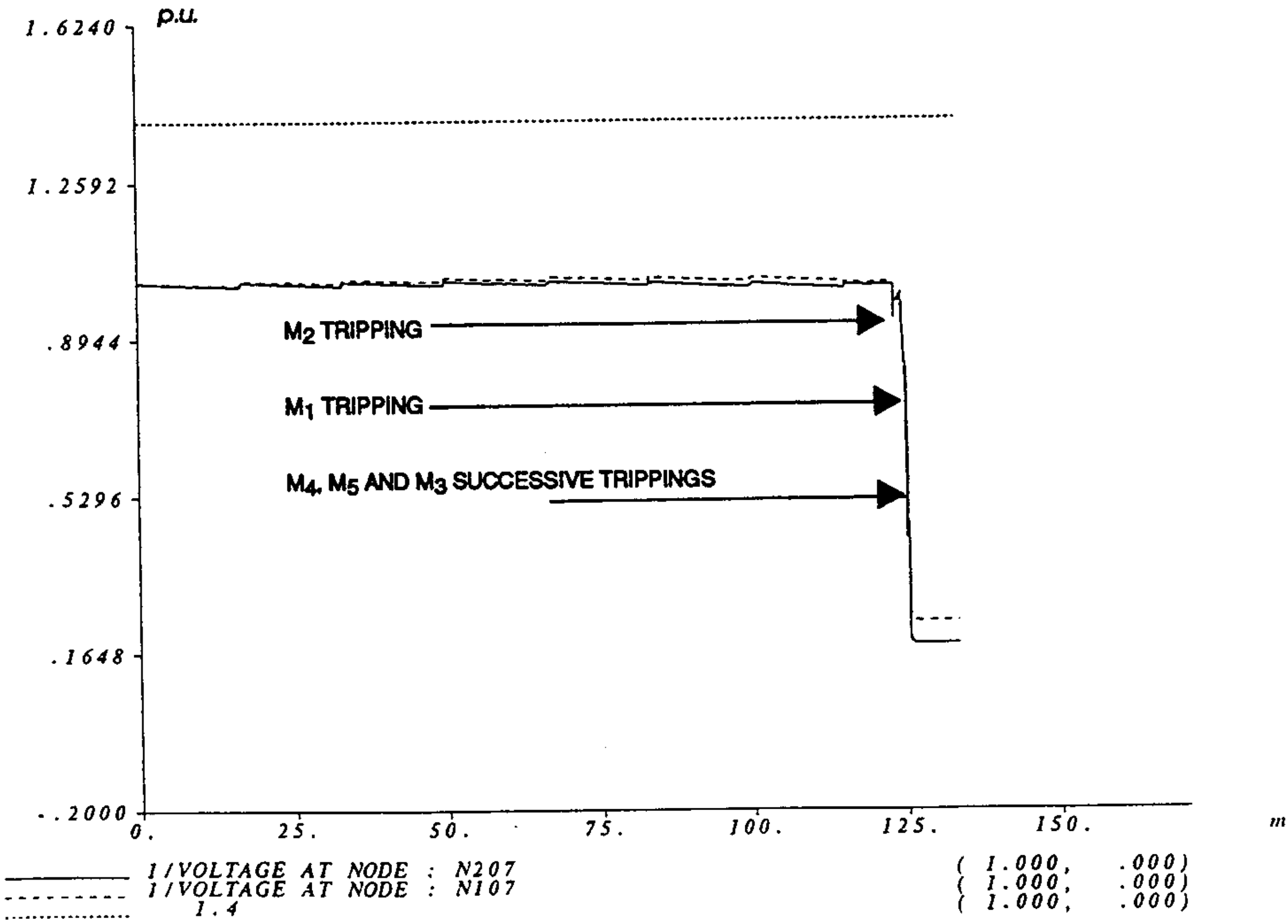


Fig. 4.2.2. b : EUROSTAG : VOLTAGES AT NODES 107 and 207

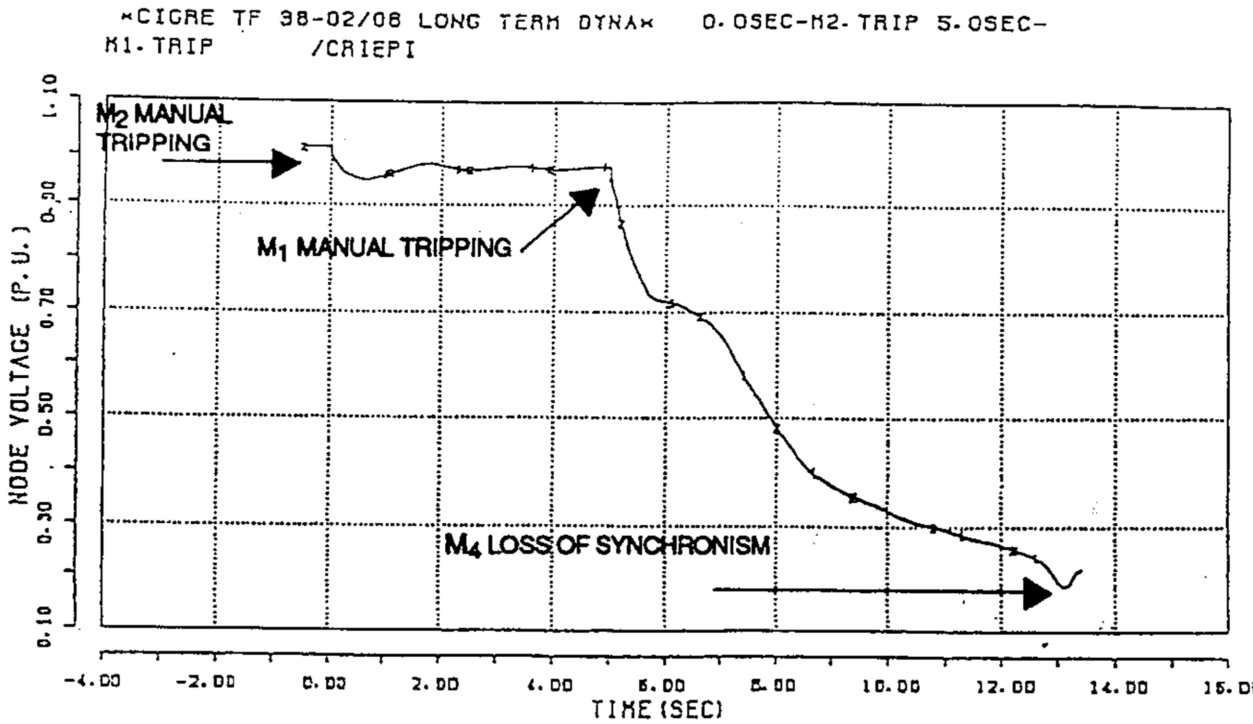


Fig. 4.2.2. c : CHAMPS - VOLTAGE AT NODE 207

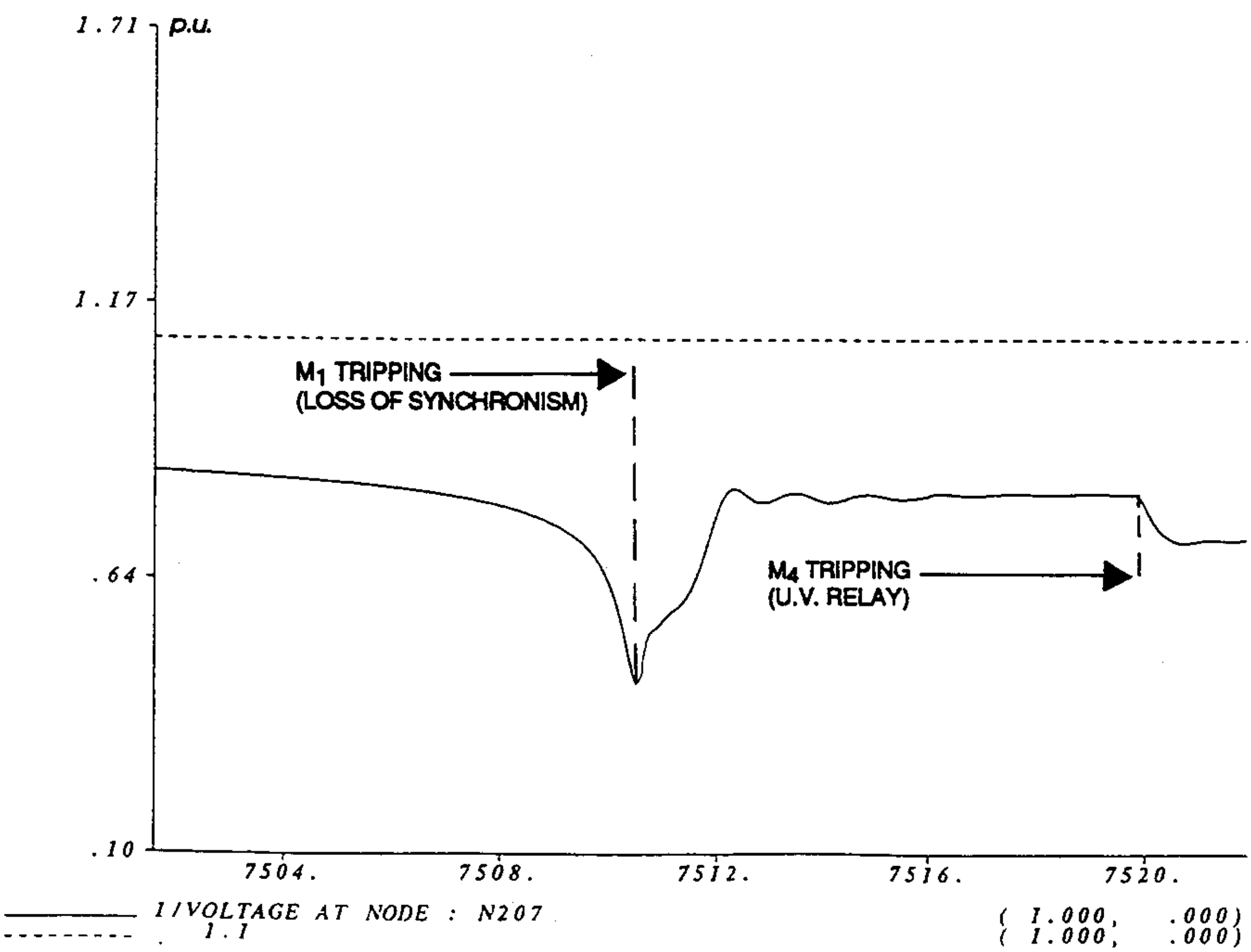


Fig. 4.2.2. d : EUROSTAG : VOLTAGE AT NODE 207

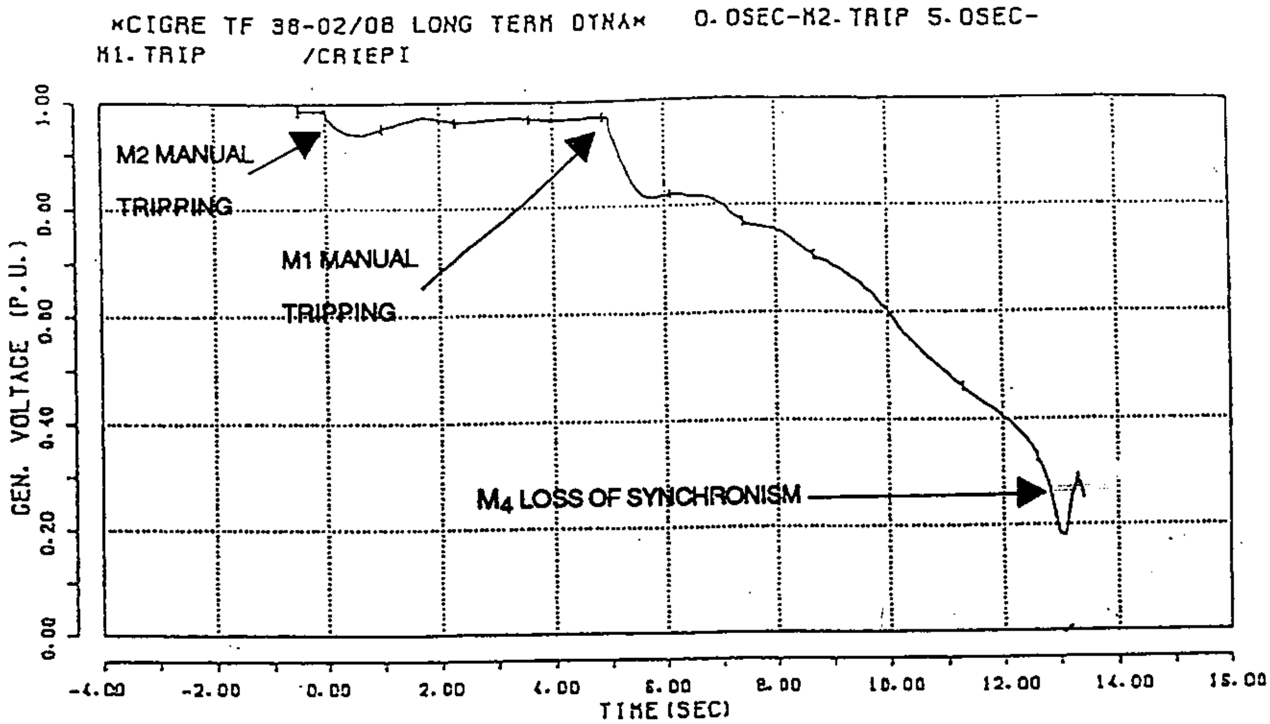


Fig. 4.2.2. e : CHAMPS - VOLTAGE AT NODE 103

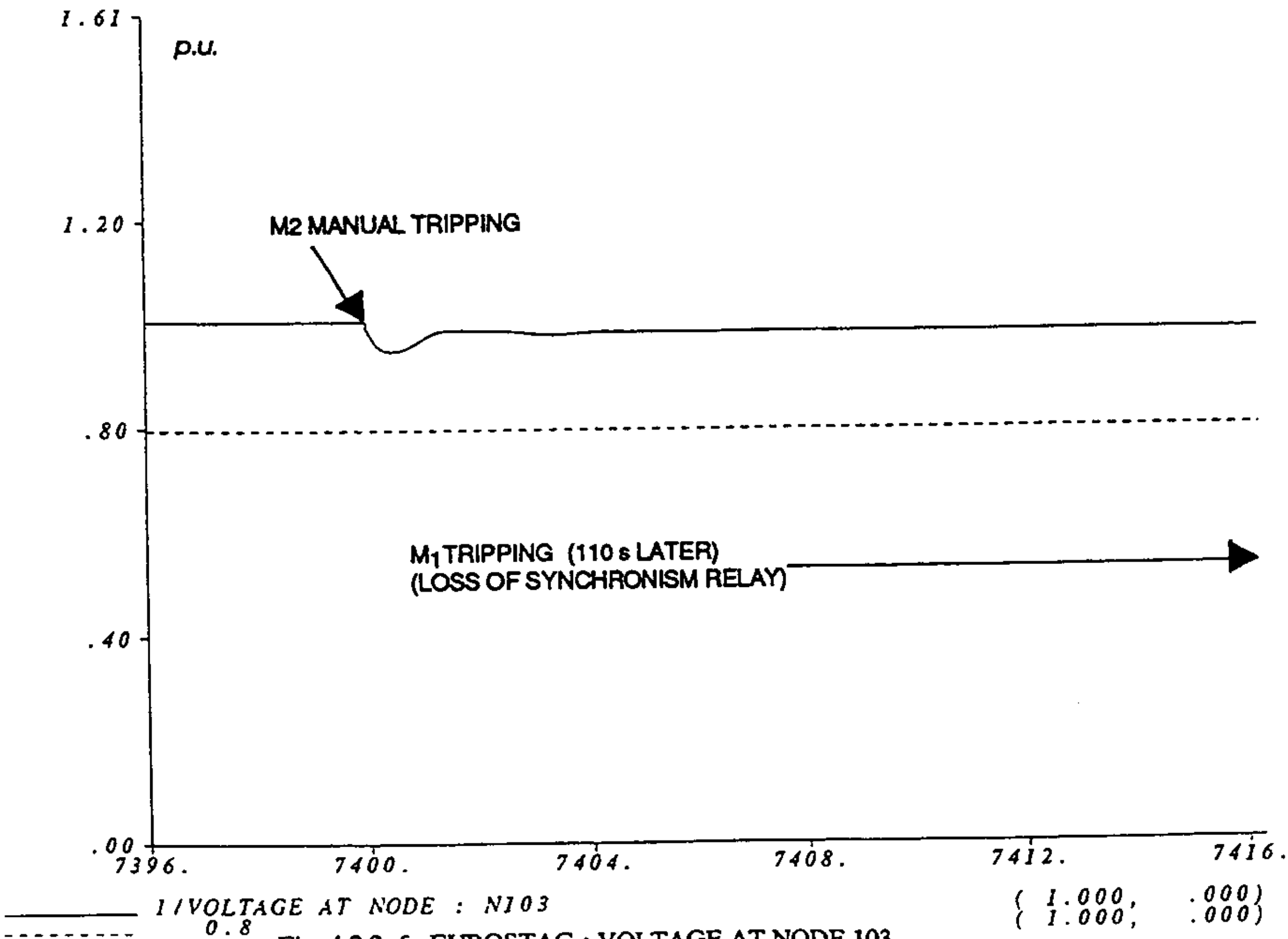


Fig. 4.2.2. f : EUROSTAG : VOLTAGE AT NODE 103

4.2.3. Simulation with APSA (run by KEPCO)

4.2.3.1. Description of the modelling

Network

The initial load flow is close to the reference one. Infinite nodes have been converted into generators with very high inertia.

Dynamic models

Generators	:	a slightly different model is used. The reference is a four rotor winding model, when APSA uses 3 winding rotor model. The saturation is represented in the flux equations of d and q axis.
AVR	:	the AVR model is selected among a standard AVR library. The parameters are adapted in order to obtain the proposed transfer function. Control scheme of generator voltage set point during the load pick-up phase is taken into account.
PSS	:	the model used is selected among a standard PSS library. The parameters are adapted in order to obtain the proposed transfer function.
Governor	:	the governor model is selected among a standard governor library. Valve opening dynamic is also taken into account. Thanks to the presence of infinite nodes, the effect of model discrepancies should nevertheless remain limited.
OEL	:	they are not represented because the proposed current limiter model is not available in the standard library. Their actions are taken into account manually by modifying the voltage set point values.

Automata and relays

ULTC	:	all the transformers 380/150 kV are fitted with tap changers. Due to APSA size limitations, only four 150/70 kV transformers are fitted with ULTC. Their characteristics are adjusted to obtain the same behaviour as in the reference.
Loss of synchronism relay	:	they are introduced in the system modelization.
Undervoltage relay	:	all generators are equipped with undervoltage relays.

Load

Due to time restriction for running the application, only one induction motor has been introduced in the modelization, the other ones were replaced by a constant power load.

The full time version (see 4.2.3.2.) adopts the following load modelization :

For loads located at nodes N201, N203, N205 (without ULTC):

- 50 % of the initial load has the following form :

  $$P_L = P_{L0}\frac{1}{1+sT_{p1}},\ Q_L = Q_{L0}\frac{1}{1+sT_{q1}}$$

  where $T_{p1} = 0.01$ s, $T_{q1} = 0.02$ s and represent the induction motor performance.

- the remaining load and additional load have the following form :

  $$P_L = P_{L0}\ \frac{1}{1+sT_{p1}},\ Q_L = Q_{L0}\ \frac{1}{1+sT_{q1}}$$

  where $T_{p1} = T_{q1} = 50$s and represent the ULTC behaviour.

  For loads located at nodes N202, N204, N206 (which are behind step-down transformers fitted with ULTC) :

- the remaining load and additional load is of constant impedance type

For N207 load (which is behind a step-down transformer fitted with ULTC) :

- 50 % of the peak load is an induction motor load;
- 50 % of the peak load is a constant impedance load.

Other loads are constant impedance type.

4.2.3.2. Scenario specials

The simulation tool is an analogic analyser where rated frequency is equal to 60 Hz. As this frequency can not be changed to 50 Hz, time scale and system parameters are modified to represent the same phenomena.

Because storage requirements could exceed the available capacity, two shortened time versions and one full time version have been executed. These short time versions consist in the speed up of the load pick-up.

The following analysis concerns only the full time version execution (case 080).

4.2.3.3. Simulation results

The load pick-up (before M2 tripping)

The end of the load pick-up network state is different from the reference :

- the active production of the M3, M4 and M5 units are higher in APSA calculations. The absence of infinite nodes and their replacement by true generators with 1 % speed droop may explain this result;
- the reactive productions (up to 45 Mvar) and the voltages (up to 4 %) are different. Thanks to the presence of the ULTC in reference results, the reactive consumption of the induction motors remains constant. Thus the observed differences may not be explained by the modelling of induction motors used in APSA (constant power) but probably by differences in voltage set points or infinite busbars representation.

After M2 unit tripping

The chronological results obtained with ASPA after M2 tripping are as follows :

- M1 is tripped by loss of synchronism relay 104 s after M2 tripping;
- M4 is tripped by undervoltage relay 109 s after M2 tripping;
- The induction motor at N207 is tripped by protection 112 s after M2 tripping. This motor is not tripped in the reference but stalls when M3 and M5 lose synchronism.
- M3 and M5 lose synchronism and the undervoltage threshold values are exceeded. The two units are tripped by undervoltage relay 180 s after M2 tripping.

A comparison between APSA and EUROSTAG results are presented through the behaviour of the 5 following variables :

- voltage in p.u. at node N4 (Fig. 4.2.3.a and 4.2.3.b);
- field voltage in p.u. of units M1, M4, M3 and M5 (Fig. 4.2.3.c, d, e and f).

Scales of EUROSTAG plots have been adapted to fit the scales of APSA plots.

The differences between the reference scenario and the APSA results can be explained mainly by the following reasons :

- the load flow after the load pick-up;
- the current limiters are not represented but taken into account manually by reducing the excitation. This leads to a very rough simulation of the phenomena. The comparison of the three APSA simulations shows that they are very sensitive to the OEL operation. It is observed that the reduction of the excitation of M3 and M5 units takes place too late with respect to the moment when the field current threshold is exceeded.

4.2.3.4. Conclusion

APSA is capable of simulating the dynamic performance of the power system during a few hours of real time, continuously, avoiding a fragmentary reproduction of the system behaviour.

The results obtained by the analogic/digital simulator APSA approach the reference results. The main discrepancies are caused by the difference in treatment of the OEL's. The time characteristic of the OEL proposed in the reference was neglected. In order to proceed with the simulation, a series of limiter actions was operated manually according to the reference scenario. The authors of the simulation claim that it would be possible to incorporate the OEL operation in APSA.

As the simulation is partly an analogic one, the analyst has to deal with noise in the recorded signals, which is a limitation as regards the accuracy of the results. However, the noise has been eliminated through a filter at the time of displaying the results.

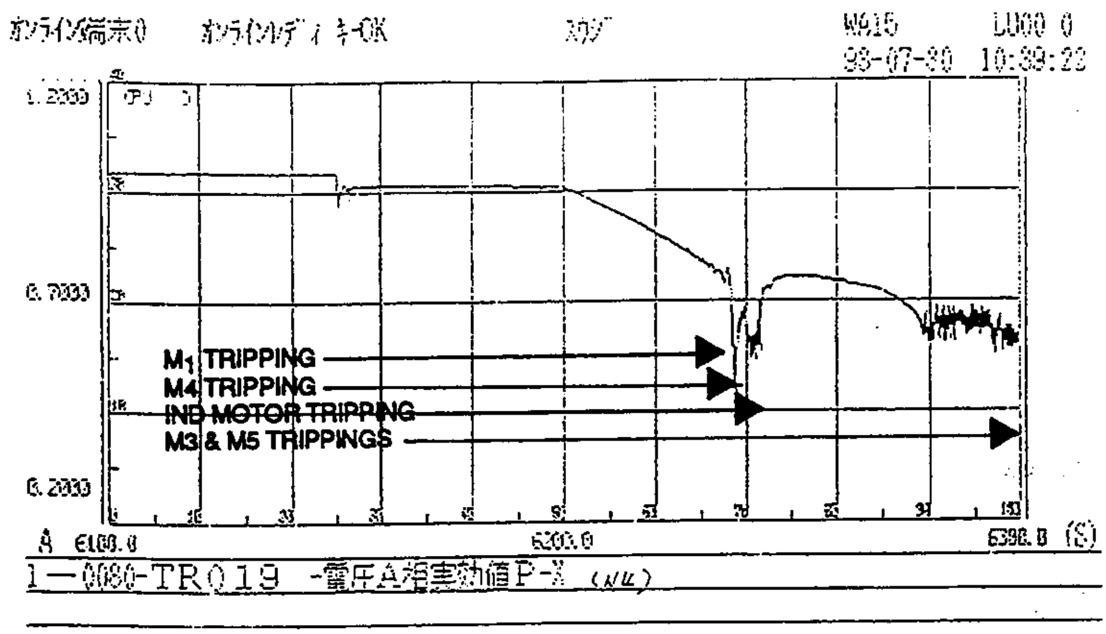


Fig. 4.2.3.a : APSA - VOLTAGE AT NODE : N4 (ZOOM)

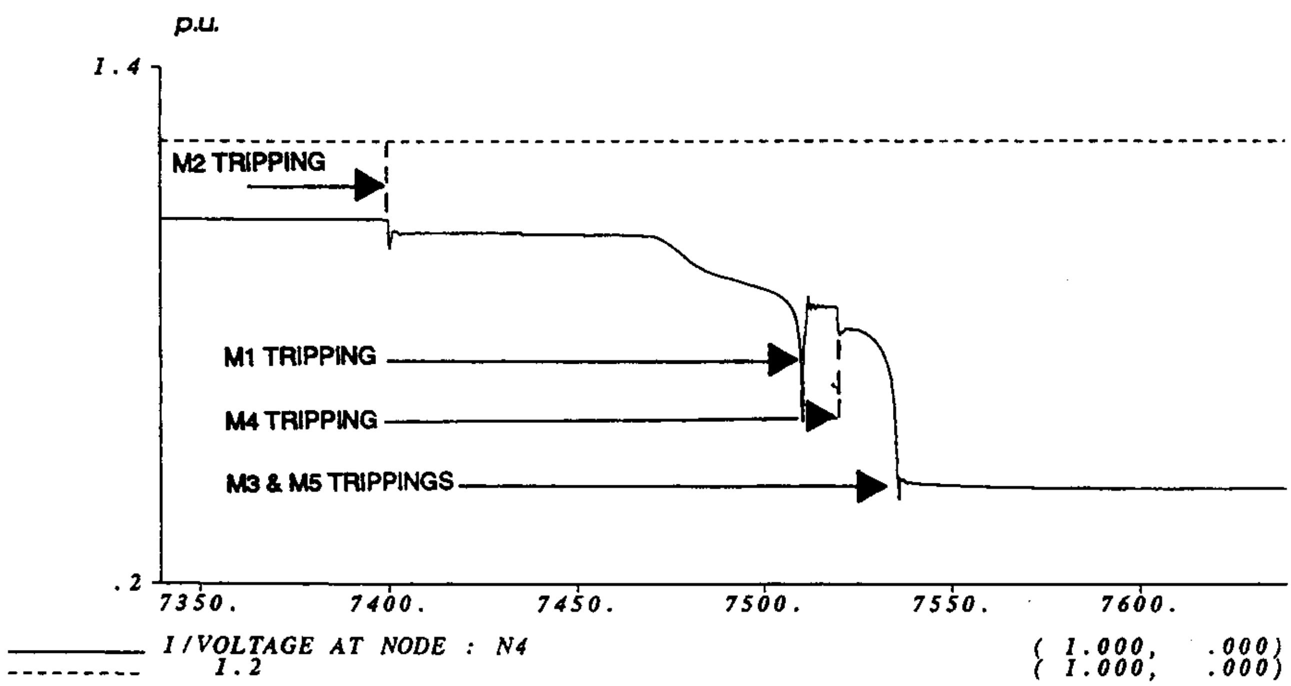


Fig. 4.2.3.b : EUROSTAG - VOLTAGE AT NODE : N4

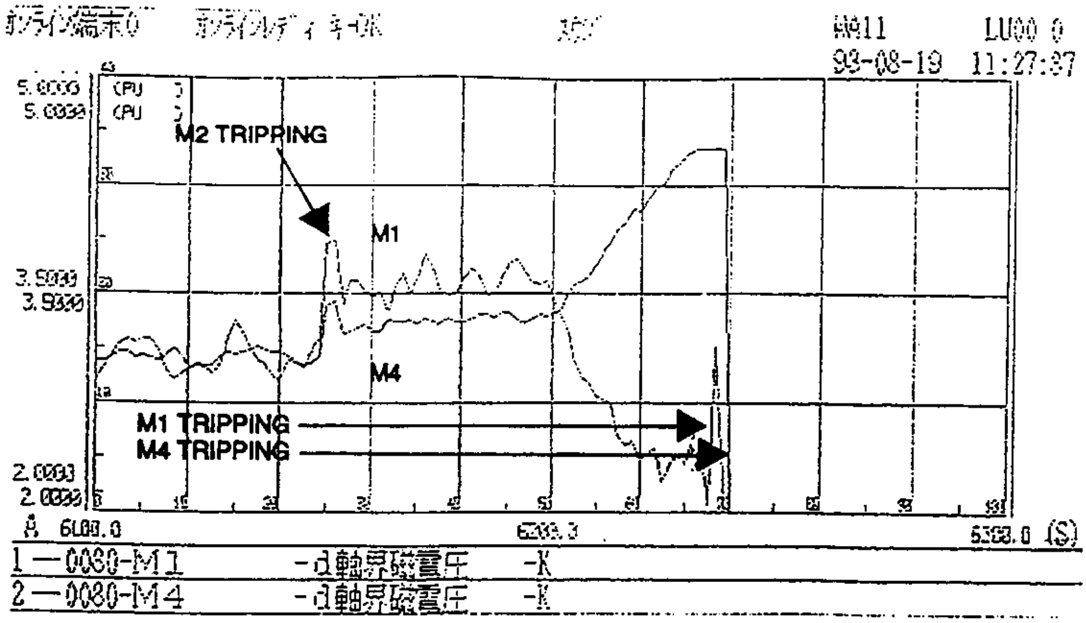


Fig. 4.2.3.c : APSA - FIELD VOLTAGE OF UNITS M1 AND M4

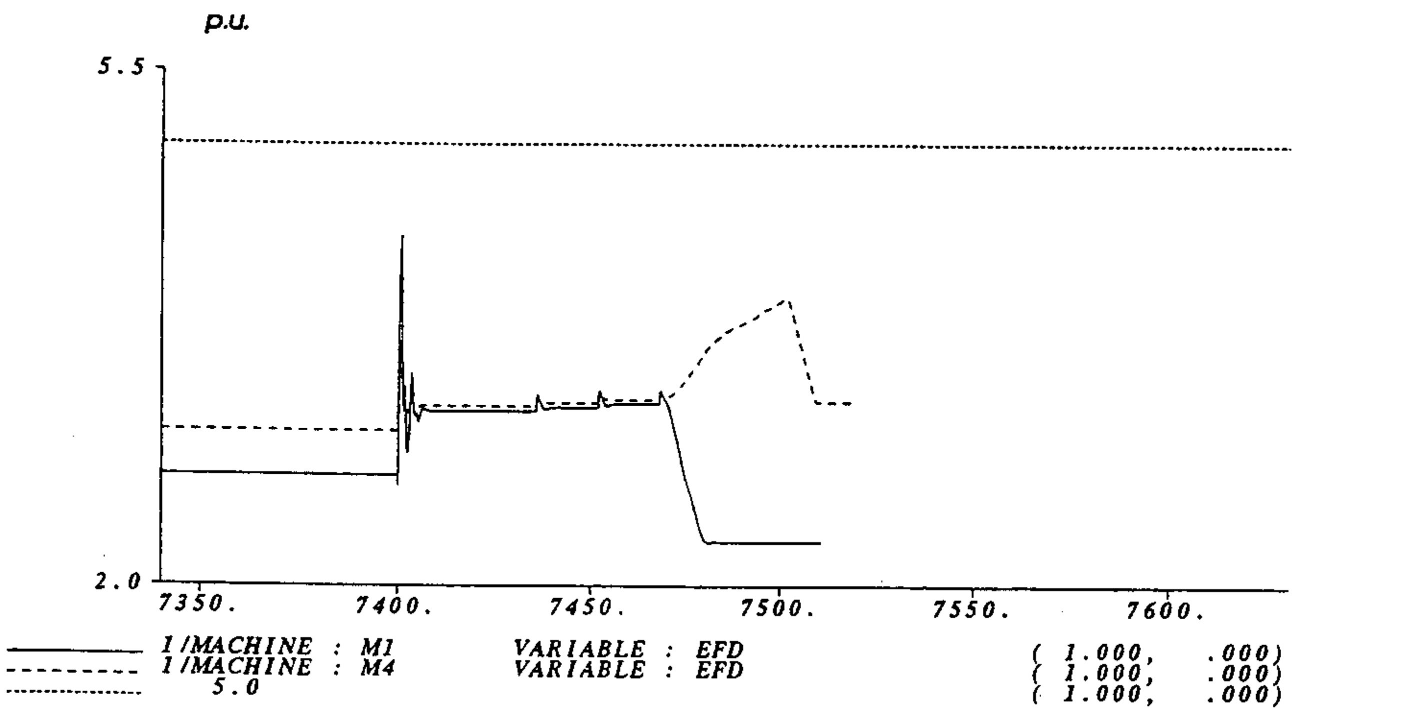


Fig. 4.2.3.d : EUROSTAG - FIELD VOLTAGE OF UNITS M1 AND M4

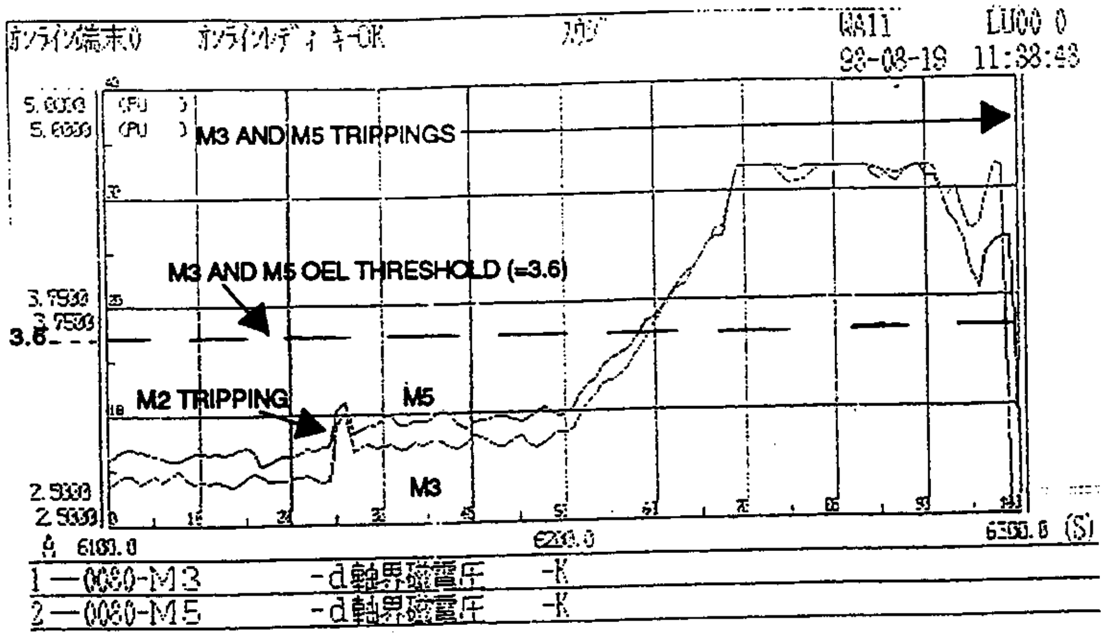


Fig. 4.2.3.e : APSA - FIELD VOLTAGE OF UNITS M3 AND M5

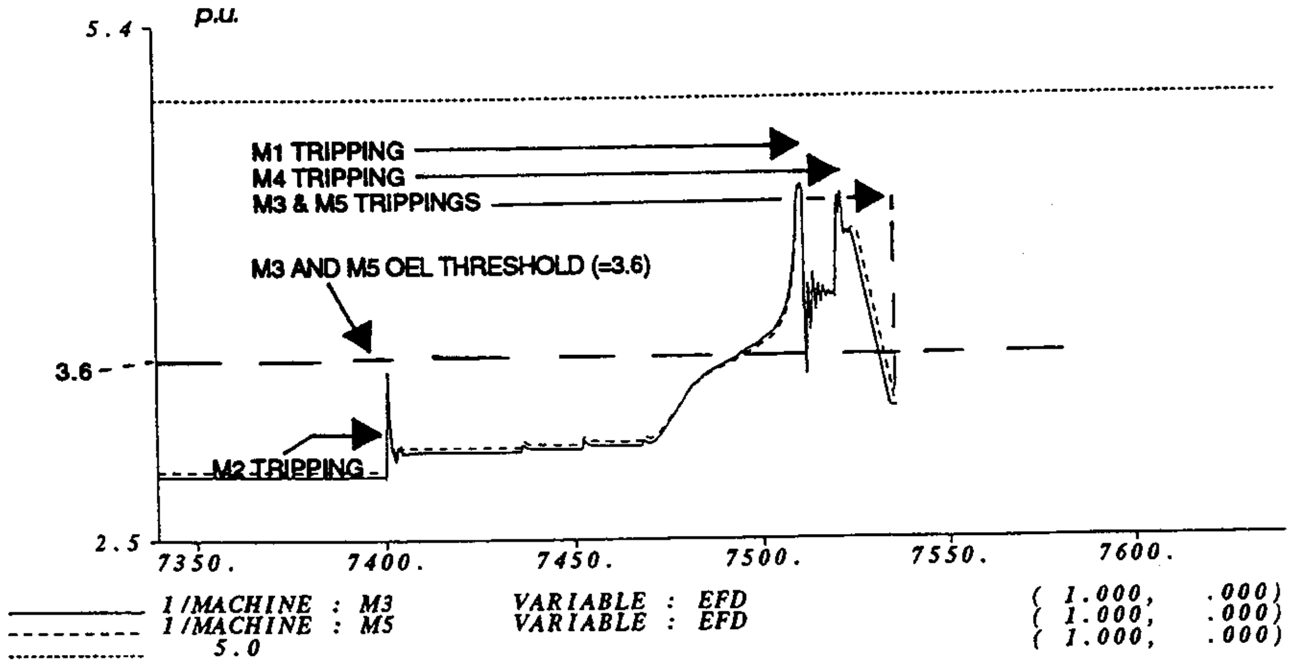


Fig. 4.2.3.f : EUROSTAG - FIELD VOLTAGE OF UNITS M3 AND M5

4.2.4. Simulation with ADVANCE (run by Mitsubishi)

4.2.4.1. Description of the modelling

Network

Although load flow calculation result was not provided, it is reported that initial load flow was adjusted to be the same as the reference. The initial conditions of simulation results were quite close to the reference. The main differences being at the level of the reactive productions of the units.

The infinite buses are modelled with generators having huge inertia.

Dynamic models

Advance has a simulation macrolanguage which allows to reproduce accurately the reference models.

Generator	:	same as the reference except the saturation of the magnetic circuit which is not taken into account.
AVR	:	same as the reference.
PSS	:	not considered.
Governor	:	same as the reference.
	:	same as the reference except the threshold of unit M3, M4 and M5 which are changed (inside brackets are the reference values) : M3 : IFSEUIL = 2.4 (3.6) M4 : IFSEUIL = 3.55 (3.35) M5 : IFSEUIL = 2.1 (3.6)

Automata and relays

ULTC	:	modelled as in the reference except during the load pick-up where the time constant were reduced.
Loss of synchronism relays	:	simulated by manual tripping.
Undervoltage relays	:	simulated by manual tripping.

Load

The model is the same as the reference one.

4.2.4.2. Scenario specials

The load pick-up period is shortened from 2 hours to 100 s. As a consequence, the response time of the secondary voltage control is adapted to cope with the reference scenario. After the load pick-up, the time scale of the simulation is the same as the reference.

4.2.4.3. Simulation results

The load pick-up (before M2 tripping)

Initial values of the proposed plots (i.e. the conditions at the end of the load pick-up) show differences at the reactive production level.

After M2 tripping

The hereunder discussion is illustrated through a comparison between ADVANCE and EUROSTAG (reference) results for the following variables :

- voltage at node N207 in p.u. (Fig. 4.2.4.a and b);
- filtered field current Ifd of machine M1 in p.u. (Fig. 4.2.4.c and d);
- field voltage Efd of unit M5 in p.u. (Fig. 4.2.4.e and f);
- reactive power of unit M3 in p.u. of SN (Fig. 4.2.4.f and g).

The scales of the plots of EUROSTAG have been adapted (except for Fig. 4.2.4.d) to fit the scales of the plots of ADVANCE. Time scale of the load pick-up has been compressed a posteriori in EUROSTAG plots.

Unit M1 loses the synchronism after action of its ill tuned OEL. Although the global behaviour is very similar, the OEL action occurs a few seconds before.

The difference of OEL occurrence time (Fig. 4.2.4.a and b) comes from very small differences of the filtered Ifd. Fig. 4.2.4.c and d show the filtered Ifd obtained by ADVANCE and EUROSTAG. The crossing point of the filtered Ifd and IFseuil is very critical to the shape of the filtered Ifd and small differences of it results in a few seconds difference in the OEL time.

Once M1 is tripped, M4, M5 and M3 lose successively synchronism and are tripped. The shape of the Efd plots presents a good similarity with the reference ones, but M4 in the reference is tripped by undervoltage protection. Since small difference in tripping time of M1 causes much difference in the tripping times of M3, M4 and M5, the threshold of the OEL of these machines were modified to keep tripping times similar to the reference ones to make easier, according to the authors, to precisely compare the behavior of the machines with the reference. More precise setting of initial conditions and modelling of system components, saturation in generator model, etc. should be studied to reproduce the threshold of reference with original setting of the result of OEL.

4.2.4.4. Conclusion

The flexibility of modelization of ADVANCE allows the system modelling to be close to the reference. Similar results and behaviour have been obtained. Following the authors, loss of synchronism and undervoltage relays were not modeled because of lack of available time to run the test systems but could be modeled in the same manner as OEL model.

As the used algorithm is based on a fixed integration timestep, long term simulations require long execution time. For this reason, the 2 hours load pick-up phase has been shortened. The authors think that high performance computing will solve this problem.

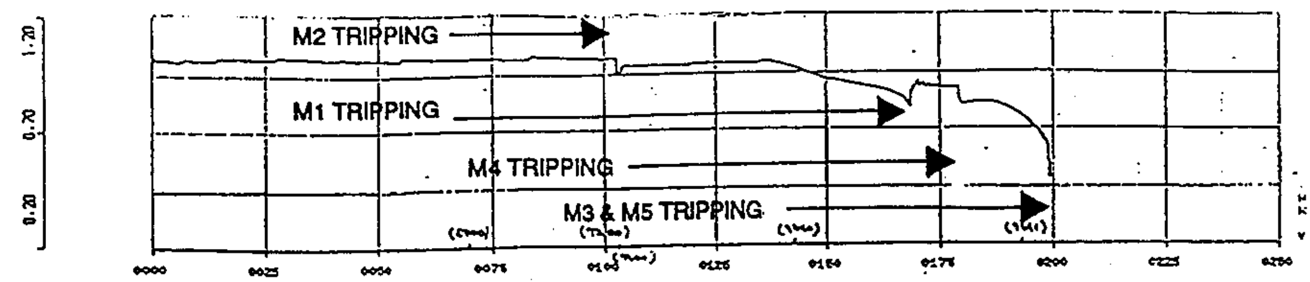


Fig. 4.2.4.a : ADVANCE - Voltage at node 207

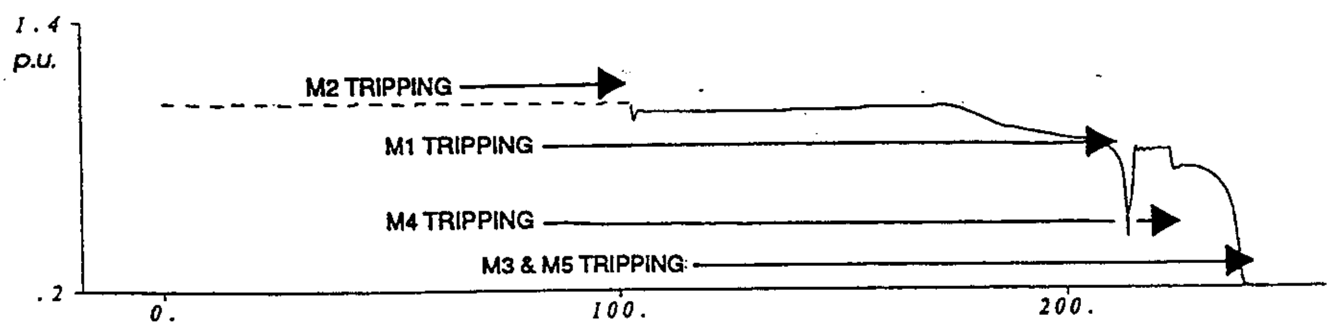
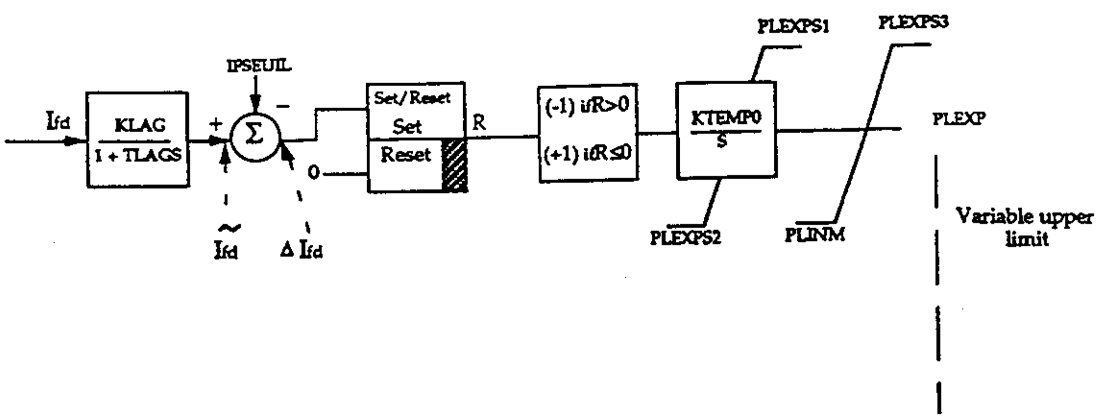


Fig. 4.2.4.b : EUROSTAG - Voltage at node 207

See Appendix A.2



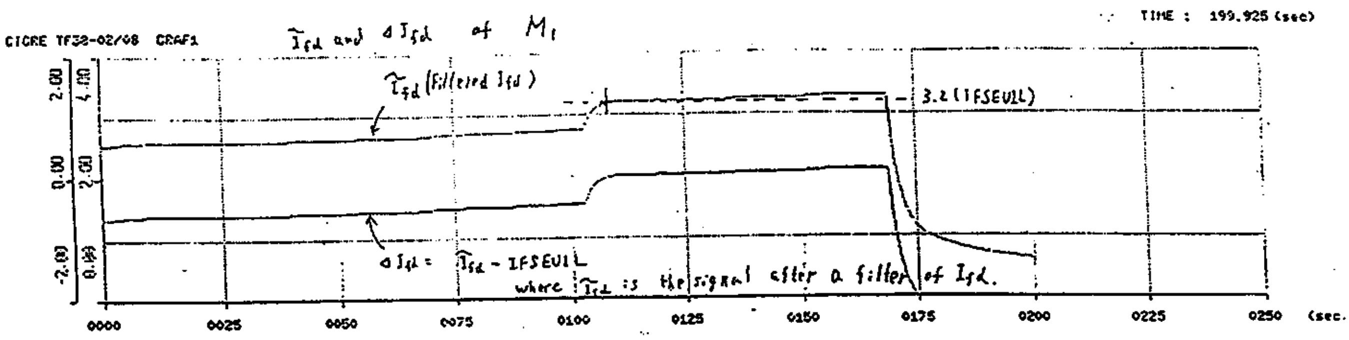


Fig. 4.2.4.c : ADVANCE - Filtered Field Current of machine M1

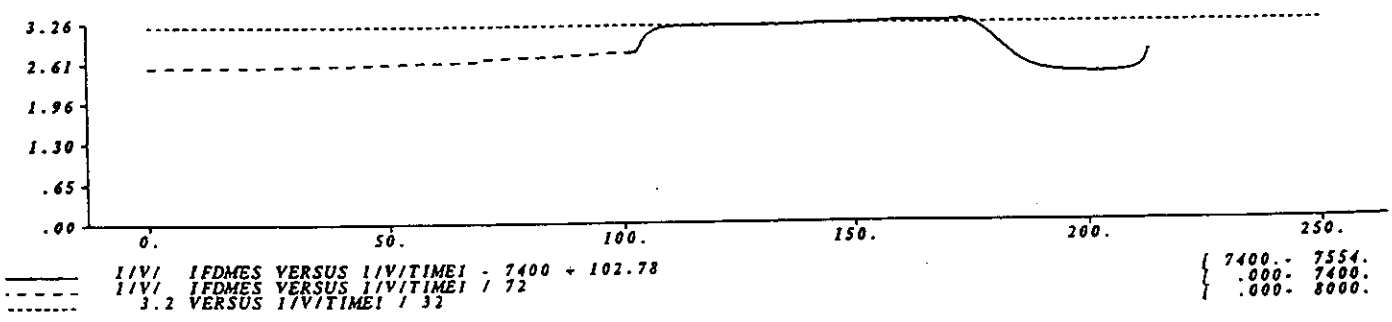


Fig. 4.2.4.d : EUROSTAG - Filtered Field Current ($\tilde{I}fd$) of machine M1

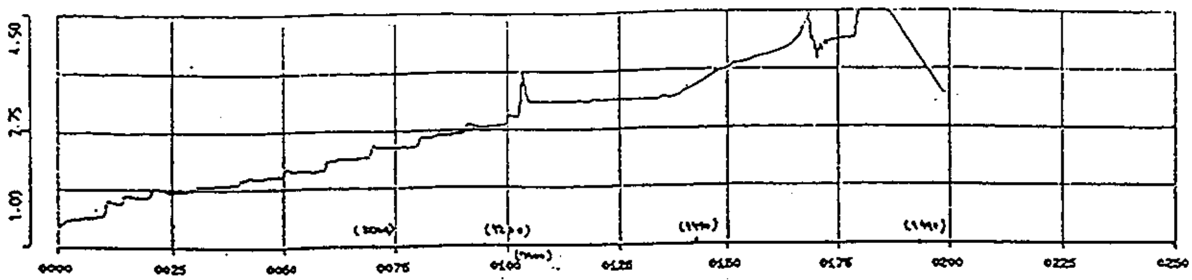


Fig. 4.2.4.e : ADVANCE - Field voltage of unit M5

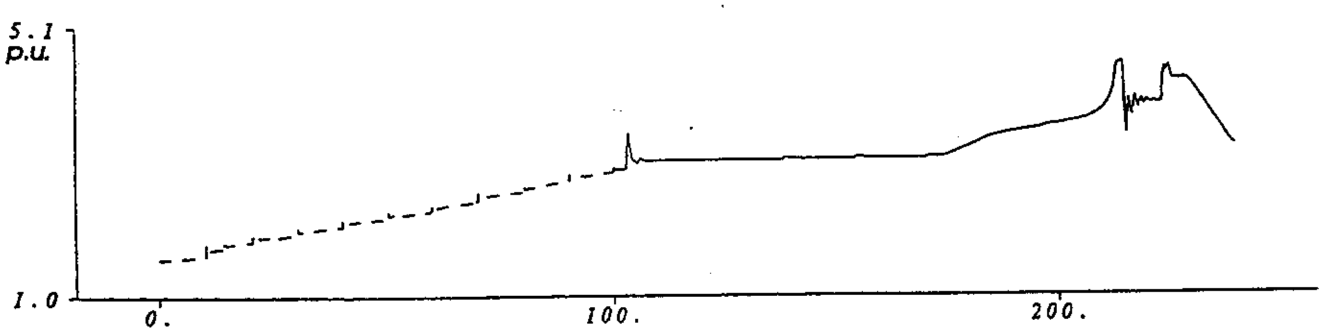


Fig. 4.2.4.f : EUROSTAG - Field voltage of unit M5

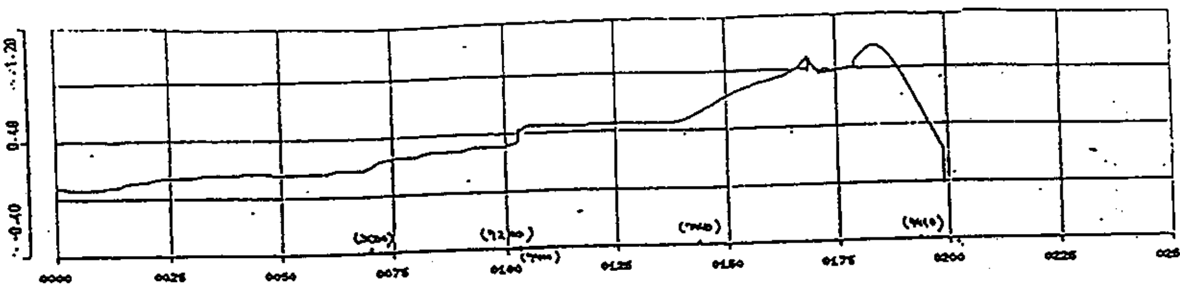


Fig. 4.2.4.g : ADVANCE - Reactive power of unit M3

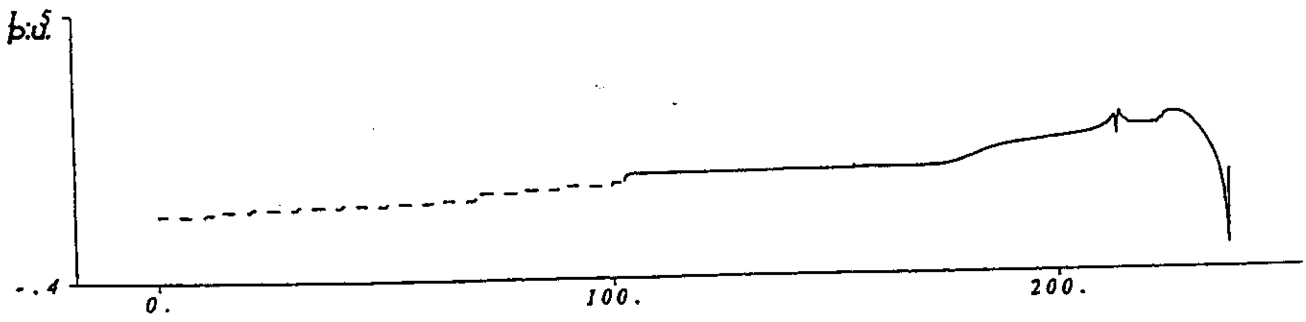


Fig. 4.2.4.h : EUROSTAG - Reactive power of unit M3

4.2.5. Simulation with PSS/E (run by Svenska Kraftnät)

4.2.5.1. Description of the modelling

Network

Detected differences with the reference at the load flow level are very small.

Infinite nodes are represented as large generators modelled by constant voltage behind a transient reactance. They are fitted with the same governor model as the one of other units.

Dynamic models

Generator	:	same as the reference. The saturation is taken into account.
AVR	:	the proposed AVR is not available in the standard library but a similar one is used. Parameters are adjusted to cope with the reference.
PSS	:	the proposed PSS is available in the standard library.
Governor	:	the governor model is selected in the standard library and is similar to the proposed one. Thanks the presence of the infinite nodes, the effect of model discrepancies should remain limited.
OEL	:	the proposed field current limiter is not available in the standard library and a different one is used.

According to the authors, the purpose of the simulation was to find results from a transient stability program, using its standard library and some user-defined models previously developed. Thus, the facility in PSS/E to create new user-defined models was not used.

The principle and functions of the chosen OEL are as follows :

When the rotor current exceeds its limit, the limiter starts counting (T1). The rotor current is allowed to stay on its overrided value during this counting phase. If the rotor current stays overrided during this timespan the limiter enters into action. Otherwise the counting will be reset.

The voltage error signal and rotor current error signal ($I_{fdmax} - I_{fd}$) are compared, and the smallest signal is picked as input signal to the controller. Once the limiter has entered into action it will stay active for a minimum timespan T2. After that time the limiter becomes inactive as soon as the rotor current error signal becomes positive.

Output signal from the limiter is added to signal from the power system stabilizer to an updated signal that will affect the excitation through the exciter.

In particular, the adopted OEL implies that the rotor current threshold and the regulated value are identical while they are different in reference modelling.

Automata and relay

ULTC	:	modelled.
Loss of synchronism relays	:	modelled.
Undervoltage relays	:	not available. Their action is simulated manually.

Load

The induction motor model used in the reference is not available. An other model is used.

Other loads are identical to the proposed ones.

4.2.5.2. Scenario specials

Due to the fact that PSS/E uses a constant time-step in all calculations, a simulation up to 7 400 s seemed unrealistic to realize. The PSS/E simulation is therefore performed up to 400 s. Without this restriction the simulation time would have been too long and the result files would become very large.

Load pick-up process is divided into three steps with enough simulation time between each step for load tap changing actions. Simulation time from one load pick-up step to another is about 60 s. Between load increase n° 2 and n° 3 the transmission line N3-N16 is tripped.

Every time the load is increased, the mechanical power at unit M3, M4 and M5 is increased stepwise by one third of total increase mentioned in the reference.

The exciter model in PSS/E doesn't allow changes in terminal set value during simulation. Consequently, the secondary manual voltage control on generators has been neglected.

4.2.5.3. Simulation results

The load pick-up (before M2 tripping)

At the end of the load pick-up the network state is different from the reference. Differences of bus voltage as large as 6 kV are observed. This is mainly the result of the absence of changes in voltage set points.

After M2 unit tripping

At time 300 s, when the load pick-up is ended and the system is stabilized, unit M2 is tripped. Already before this tripping unit M1 is working at a forced state. The rotor current is close to its limit, 3.2 p.u..

After the tripping and further tap changes the limiter of unit M1 (at 360 s) enters into action. The excitation is immediately reduced, but not enough to cause loss of synchronism. This is a difference from the result in the EUROSTAG simulation. Without changing exciter parameters it is impossible to force the PSS/E generator model out of synchronism. In order to proceed simulation according to the scenario in the reference, unit M1 is tripped manually (at 363 s) three seconds after the limiter entered into action. This action causes after some seconds low voltage at bus N103 and unit M4 is tripped manually (at 375 s).

Then again major difference occurs. Unit M3 and M5 are now supposed to loose their synchronism. This does not happen, so they are tripped manually (at 380 s). After these trippings the network immediately collapses.

An attempt to imitate the function of the rotor current limiter in the EUROSTAG simulation has also been made. The scenario is identical to the one described above except for one difference : at time 300 s, when the load pick-up phase is ended and the system is stabilized, unit M2 is tripped and the rotor current limit is forced to a lower value. This is done by changing the current limit manually during the simulation to the value 2.3 p.u. of the reference simulation.

This action does not lead to loss of synchronism of machine M1 as in the reference simulation. Instead a lot of current limiter action starts and after another 20-25 seconds the voltage collapses.

The above discussion is illustrated through a comparison between .

- voltage at node N4 obtained with PSS/E and EUROSTAG (Fig. 4.2.5.a and b.;
- reactive power of unit M4 (in base 100 MVA) obtained with PSS/E and EUROSTAG (Fig. 4.2.5.c and d).

  The scales of the plots of EUROSTAG have been adapted to fit the scales of the plots of PSS/E. Time scale of the load pick-up has been compressed a posteriori in EUROSTAG plots.

4.2.5.4. Conclusion

First of all it is important to state that the version of PSS/E, on which the test system was simulated, is not aimed for this type of simulation. It is above all a simulation tool for transient stability with simulation times around 10-50 s.

Furthermore, because user defined models were not developed, the aim of the study was to find how far the comparison could go, using only the standard models and some user defined models previously developed at Svenska Krafnät.

Despite the very good accuracy of the two initial load flows compared, the differences between the two dynamic simulations are quite considerable. This has to do with the proposed scenario which creates problems because of the several differences that exists between PSS/E and EUROSTAG. For this simulation the following major differences were discovered :

- there is a considerable difference in the rotor current limiter model;
- there is no possibility in PSS/E to make a linear increase of mechanical power. The load pick-up is however done in three steps;
- during dynamic simulation in PSS/E it is not, without a rather large programming effort, possible to change terminal voltage set values;
- there is no available undervoltage protection model in PSS/E;
- the time-step with which PSS/E works is constant.

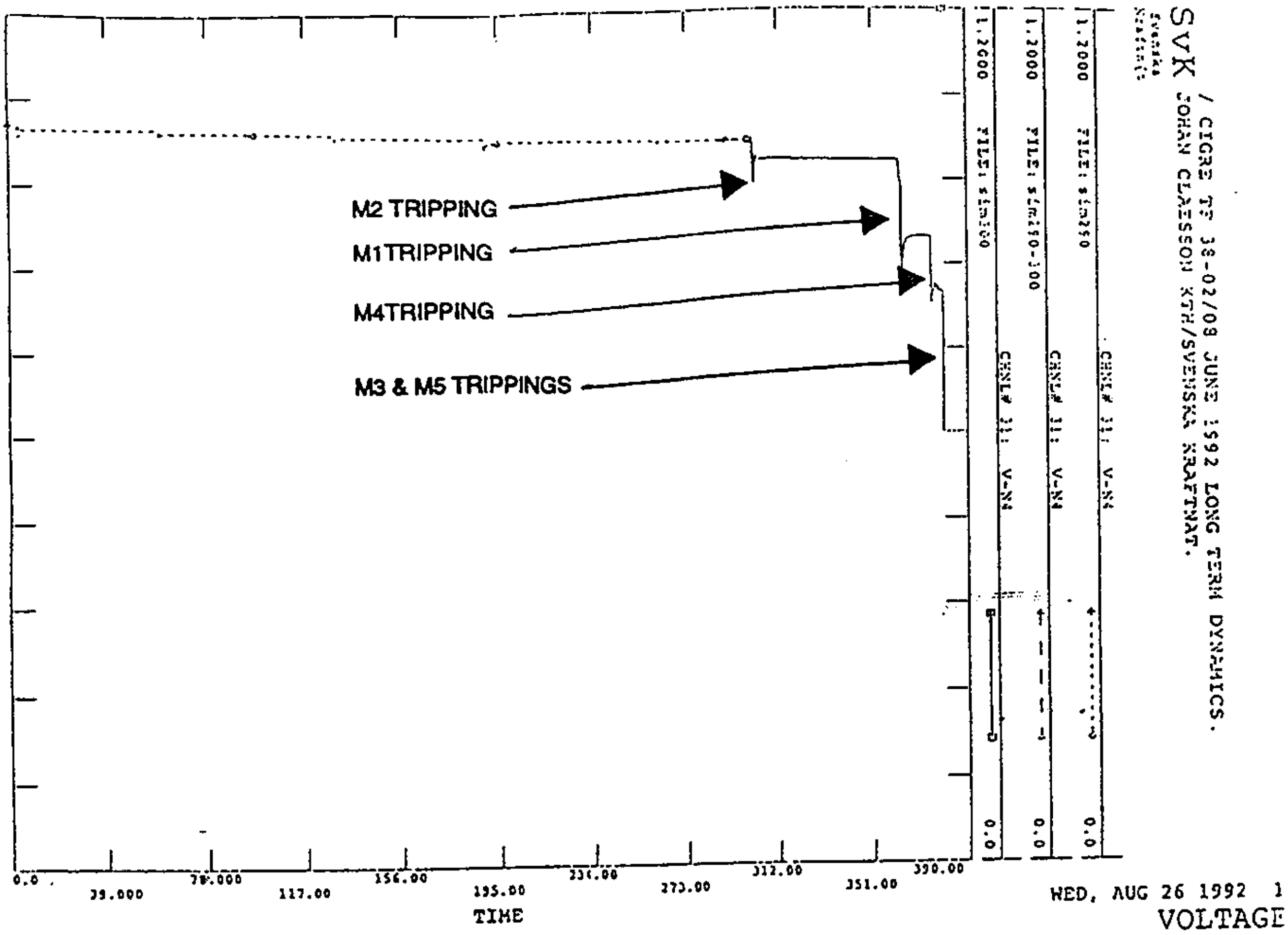


Fig. 4.2.5.a : PSS/E - Voltage at node N4

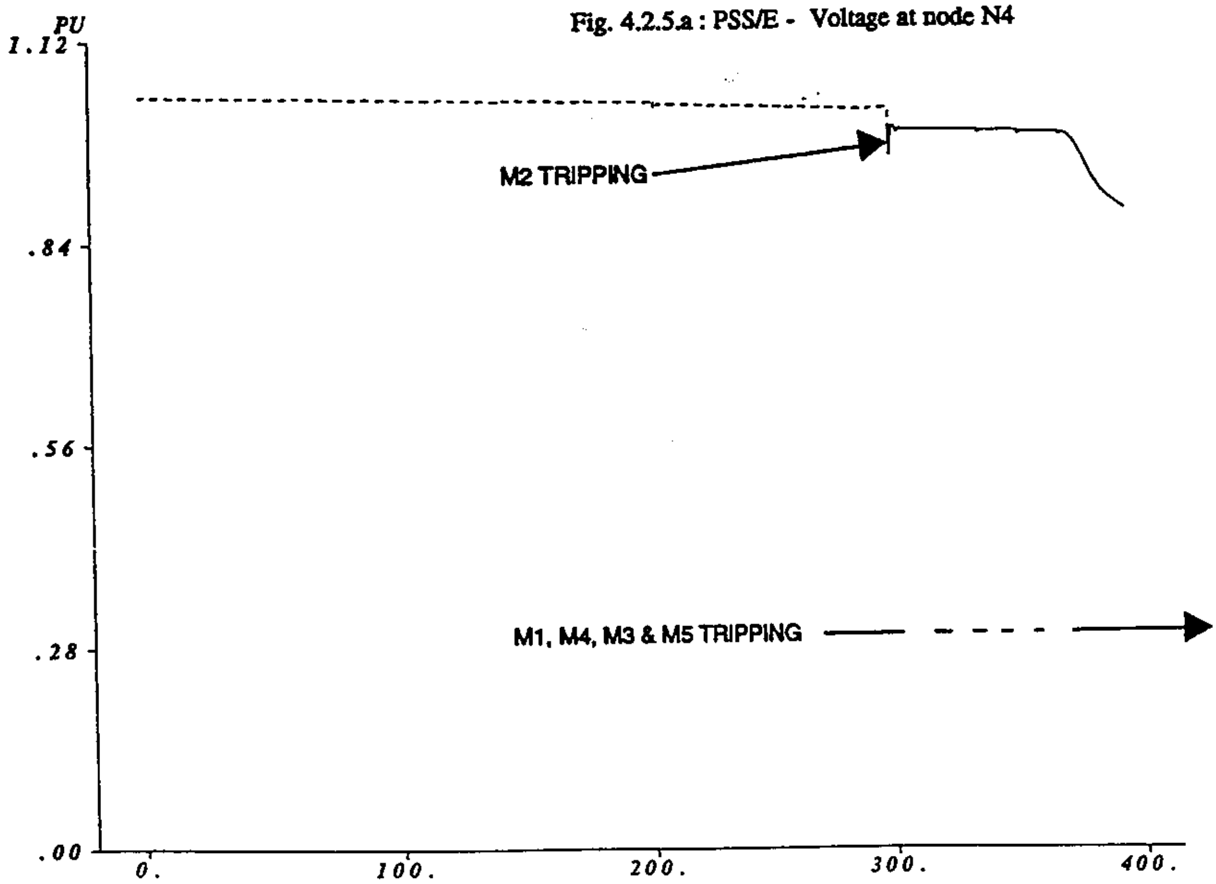


Fig. 4.2.5.b : EUROSTAG - Voltage at node N4

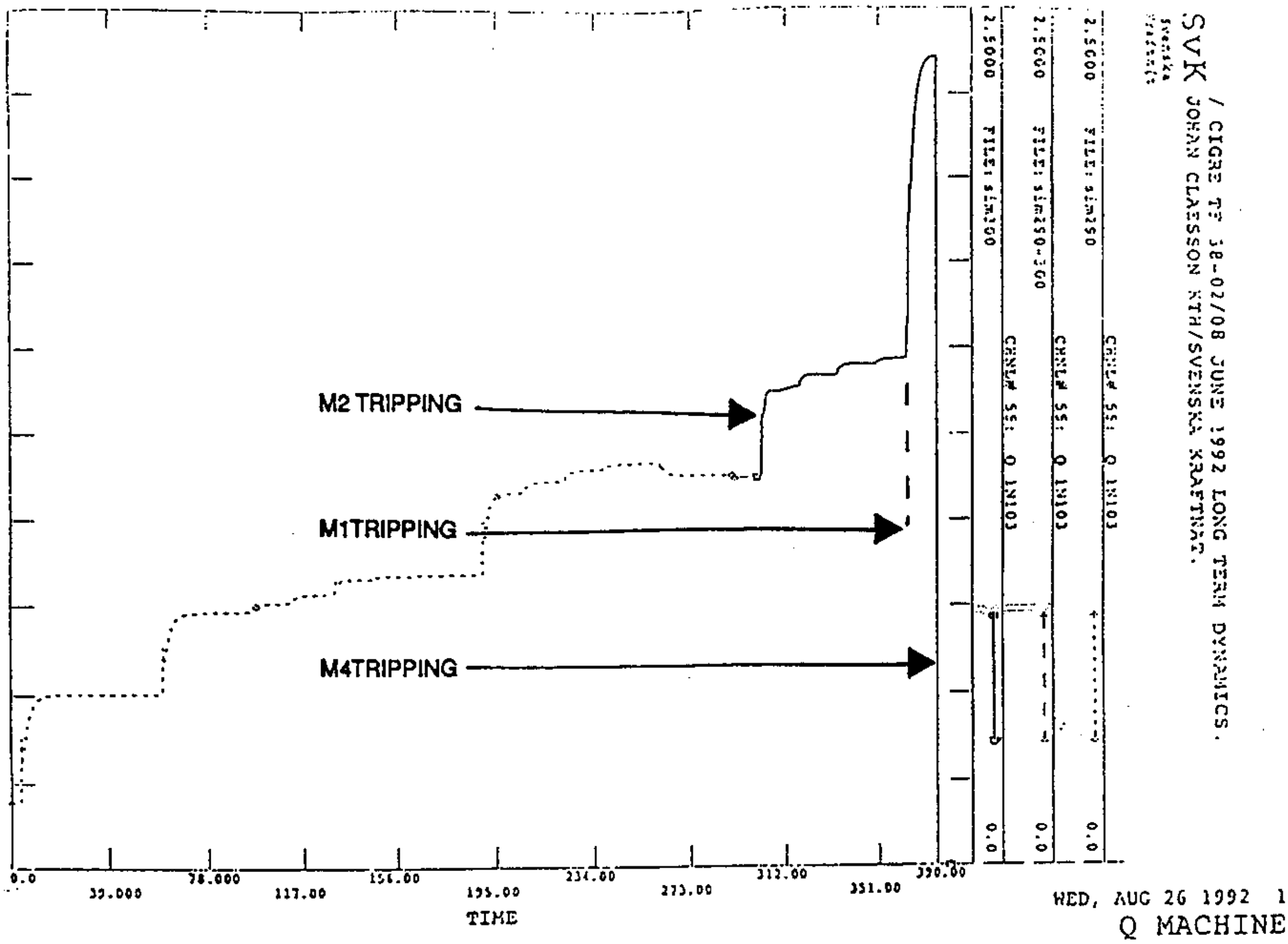


Fig. 4.2.5.c : PSS/E - Reactive power of unit M4

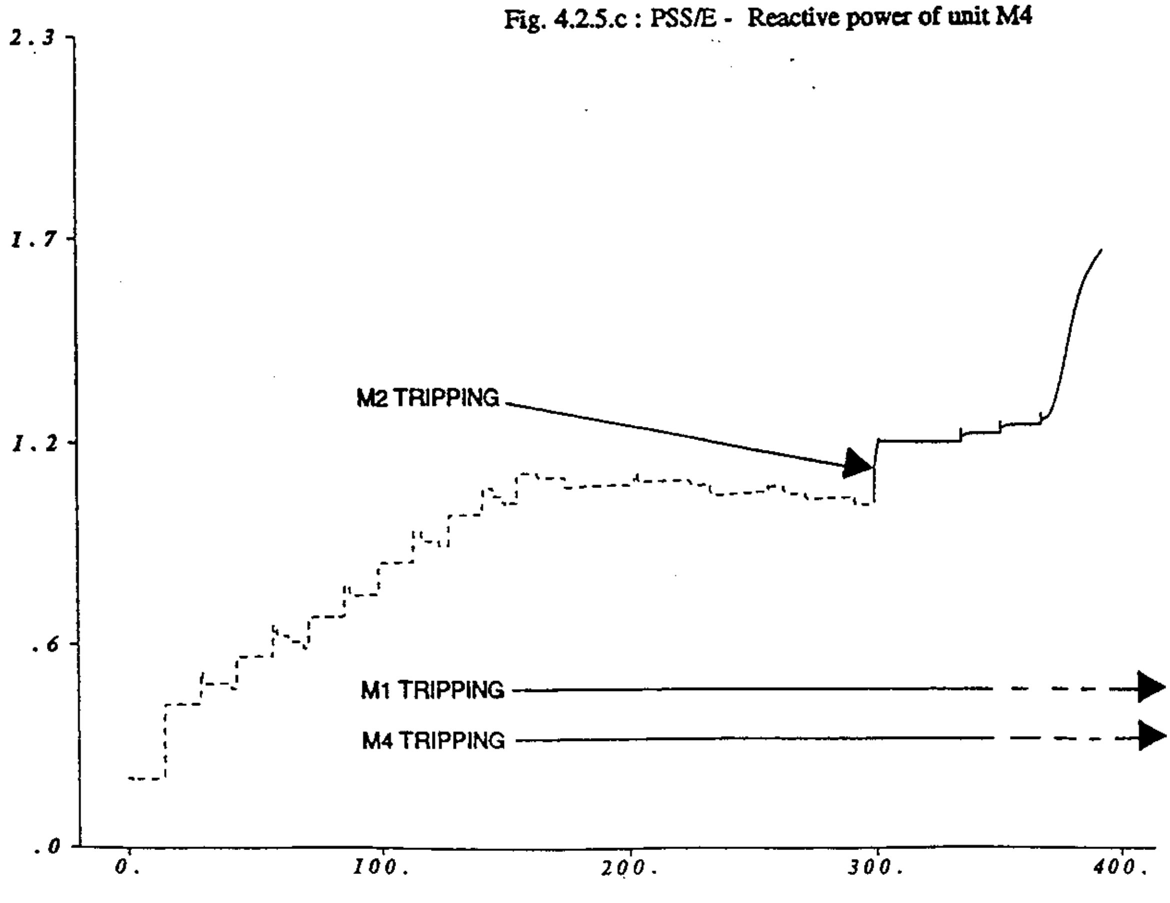


Fig. 4.2.5.d : EUROSTAG - Reactive power of unit M4

4.2.6. Simulation with EXSTAB (run by GE)

4.2.6.1. Description of the modelling

Network

The initial load flow is almost identical to the proposed one.

No information is given over the infinite node modelling.

Dynamic models

Generators : 4 rotor winding Park's model. Subtransient saliency is neglected by setting x"q equal to x"d.

The saturation is modelled in both axes but in a way different from the reference.

AVR, PSS, OEL : the proposed block diagrams have been coded in Fortran following the rules of the EXSTAB program.

Governor : an existing turbine-governor model is used. It is about the same as the reference one, except there is no integral control and an extra time constant of 0.01 s is added.

Automata and relays

ULTC : modelled as in the reference. 150/70 kV transformer tap increment are taken equal to 1.05 % instead of 1 %. Nevertheless, the effect of this discrepancy should remain very limited.

Loss of synchronism relay : available.

Under voltage relay : available.

Load

The passive load model is the same as the reference one. Induction motors are represented by a single rotor winding while two rotor windings are used in the reference.

4.2.6.2. Scenario specials

The events proposed in the reference have been reproduced exactly.

4.2.6.3. Simulation results

The following discussion is illustrated by plots of EXSTAB compared with plots of EUROSTAG. The scales of the plots of EUROSTAG have been adapted to fit the scales of EXSTAB. See Fig. 4.2.6.a and b.

The load pick-up (before M2 tripping)

The end of the load pick-up network state is slightly different from the reference :

- the only active production available on the plots delivered corresponds to M3 unit and is 40 MW lower than in the reference results;
- unit M4 reactive output increases more rapidly during the load pick-up than in the reference. Therefore its OEL acts before the end of the load pick-up and reduces its reactive power output. As a consequence, all the other units present a higher reactive production;
- for a same initial operating point, field voltage in EXSTAB is higher than in the reference. It can be explained by differences in the saturation model.

After M2 unit tripping

The chronological results obtained with EXSTAB are as follows :

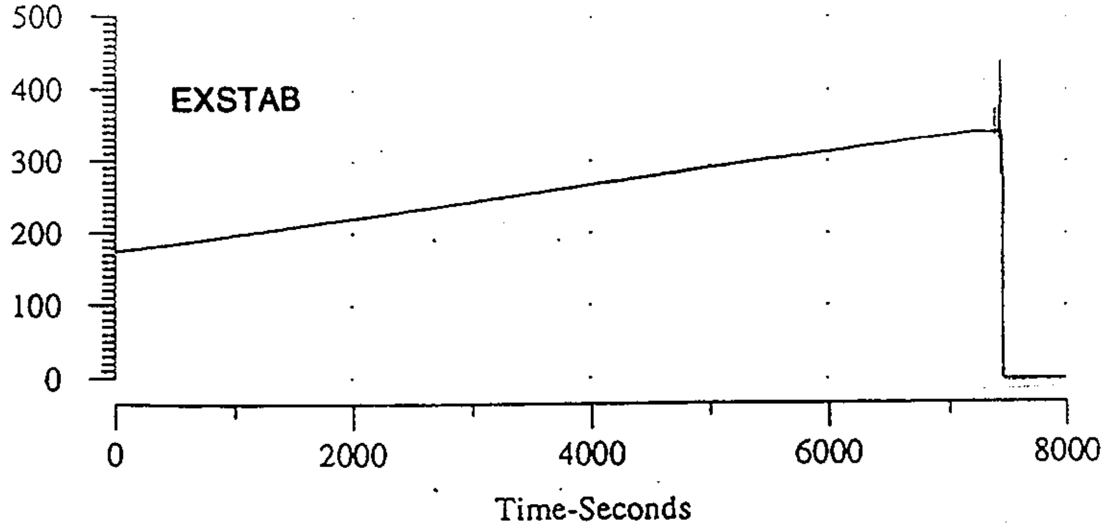
- M4 is tripped by undervoltage relay 40 s after M2 tripping;
- M1 is tripped by loss of synchronism relay 50 s after M2 tripping;
- M3 and M5 are tripped by loss of synchronism relay 72 s after M2 tripping.

We observe a shortening of the scenario in comparison with the reference and an inversion of the sequence of M1 and M4 tripping. That is explained mainly by the difference of operating point of M4 after the load pick-up.

4.2.6.4. Conclusion

The results obtained with EXSTAB reproduce the whole scenario without adapting or simplifying it. The global behaviour of the system is very close to the reference.

Thanks the variable integration stepsize algorithm, EXSTAB simulation gives an unified and complete display of the dynamics of the system.



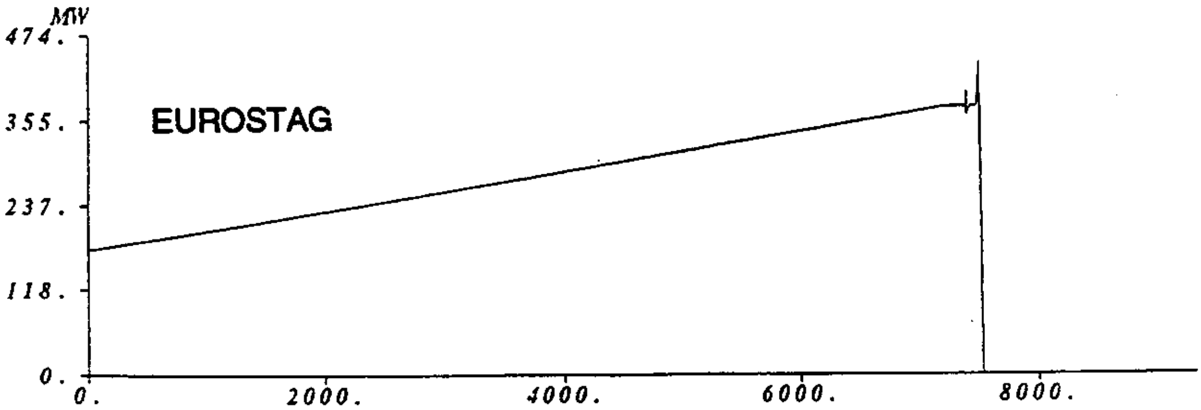
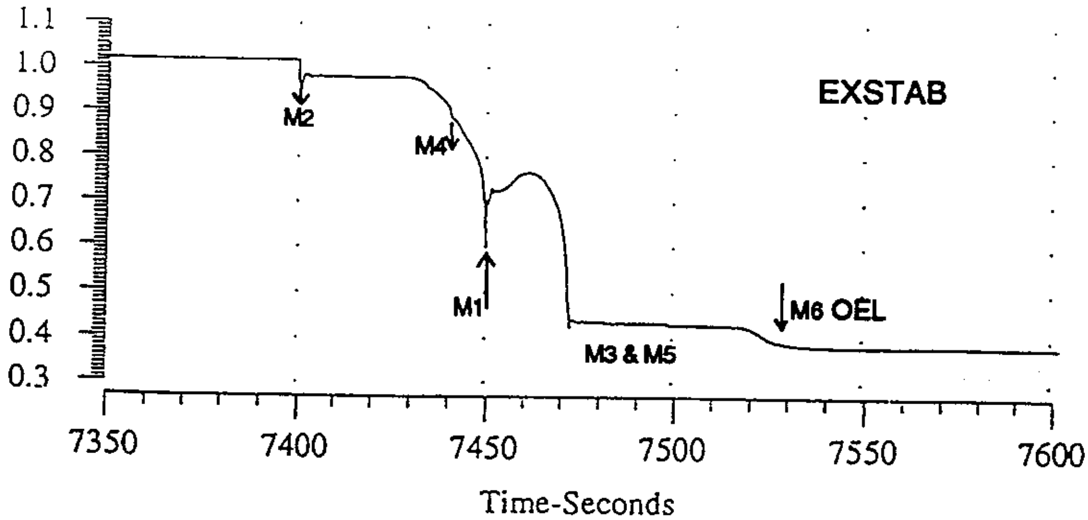


Fig. 4.2.6.a. Comparison between EXSTAB and EUROSTAG.
Active power of unit M3.



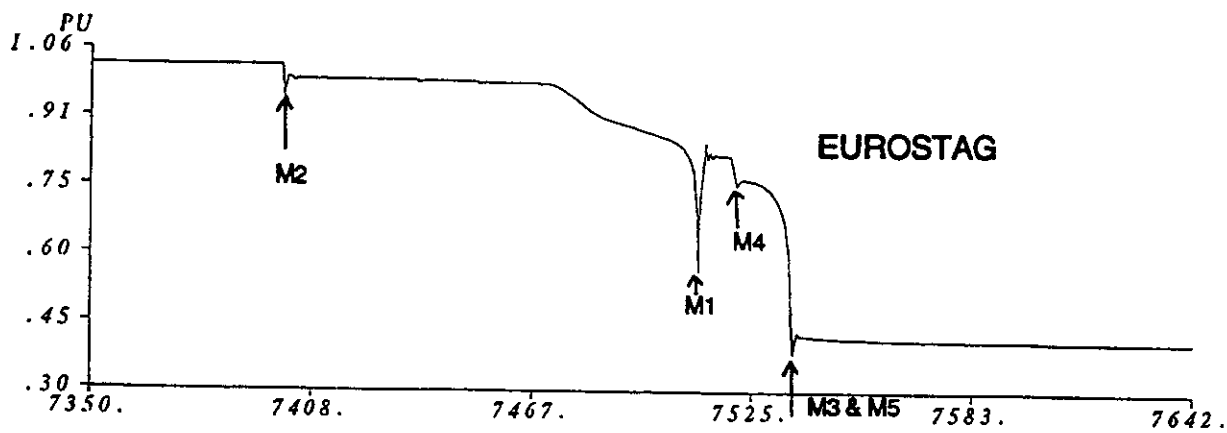


Fig. 4.2.6.b. Comparison between EXSTAB and EUROSTAG. Voltage at node N4.

4.2.7. Simulation with MODES (run by CEZ)

4.2.7.1. Description of the modelling

Network

The initial load-flow shows some discrepancies with the reference : up to 78 Mvar on unit M1 and up to about 1 % for the voltage at node N107. This discrepancies could be a result of an unidentified difference in transformer modelling.

The infinite nodes are treated as in the reference case.

Dynamic models

Generator	:	a 3 rotor winding Park model (instead of a 4 winding model) is used. However T"qo is adapted to obtain the same T"q as in the reference. Saturation is not taken into account.
AVR	:	a standard AVR model is selected from the MODES library. Parameters are adjusted to cope with the reference ones.
PSS	:	although the reference PSS model is available in the library, it has been replaced by a derivative feedback of Efd to increase the damping of the system.
Governor	:	a standard model similar to the reference one is used. Thanks the presence of infinite nodes (no variation of the mean frequency) the effect of model discrepancies should remain limited.
OEL	:	the OEL is modelled as in the reference.

Automata and relays

ULTC	:	the automaton used has a different tuning (fixed action delay of 22 s instead of 36 s and 16 s for the reference case.
Loss of synchronism relay	:	the unit is disconnected after the second pole slipping.
Undervoltage relay	:	same as in the reference.

Load

The passive load model is the same as the reference. The induction motors are modelled thanks a single winding rotor model with variable parameters. The parameters have been identified with the characteristics proposed in the reference.

4.2.7.2. Scenario specials

The reference scenario has been applied with the following changes :

- during the load pick-up, the machine voltage references were modified continuously following a predefined rate of change;
- the thresholds of the OEL were modified to compensate the absence of saturation in MODES. However, the threshold of M1 has been increased to meet the sequence of machine trippings during the voltage collapse obtained with EUROSTAG.

4.2.7.3. Simulation results

Load pick-up

The conditions at the end of the load pick-up (before M2 tripping) show differences in the reactive power and field voltage of units. They are caused by the different initial load flow and the unsaturated generator model.

After unit M2 tripping

The following observations are based on plots of MODES compared with plots of EUROSTAG. The scales of the plots of EUROSTAG have been adapted to fit the scales of MODES. See Fig. 4.2.7.a to e.

Generally, the shapes of the plots are quite similar.

The chronological results obtained with MODES are as follows :

- M1 OEL acts around 13 s and M1 tripping occurs at time 35 s after M2 tripping;
- M4 trips at time 37 s after M2 tripping;
- M3 and M5 trip at time 40 s after M2 tripping.

This quite shorter tripping timing is due to the discrepancies at the load-flow level, to the absence of saturation in the generator model and to the ULTC tuning. The reactive power plots of units M1 and M4 (Fig. 4.2.7.d and e) show important difference in AVR damping.

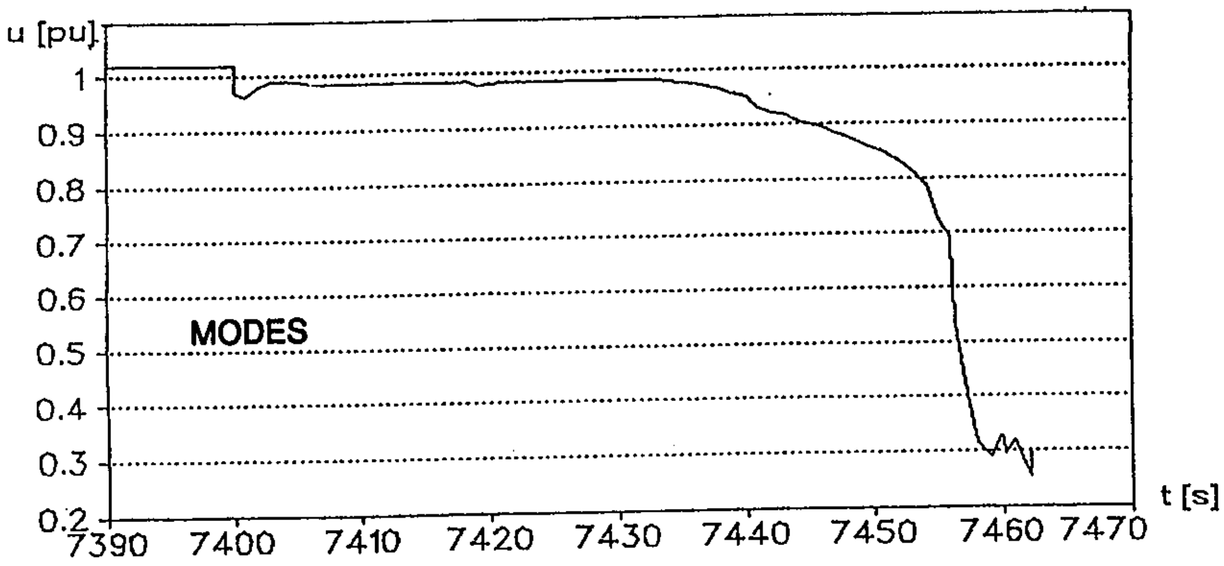
Stepsize evolution

A typical plot of stepsize evolution of MODES on the Belgian-French test system is shown on Fig. 4.2.7.f. The minimum and maximum values were limited to 0.0025 s and 0.2 s. The calculation stopped when the integration step decreased to the lower limit. Because some prediction process (see Appendix B.1) is used, the number of iterations is shown, too.

4.2.7.4. Conclusions

MODES program allows to simulate both fast and slow phenomena and reproduces the voltage collapse of the system after M2 unit tripping.

Nevertheless, the behaviour of each individual unit has not been accurately reproduced. The most probable explanations are related to the saturation of the generators and the network model.



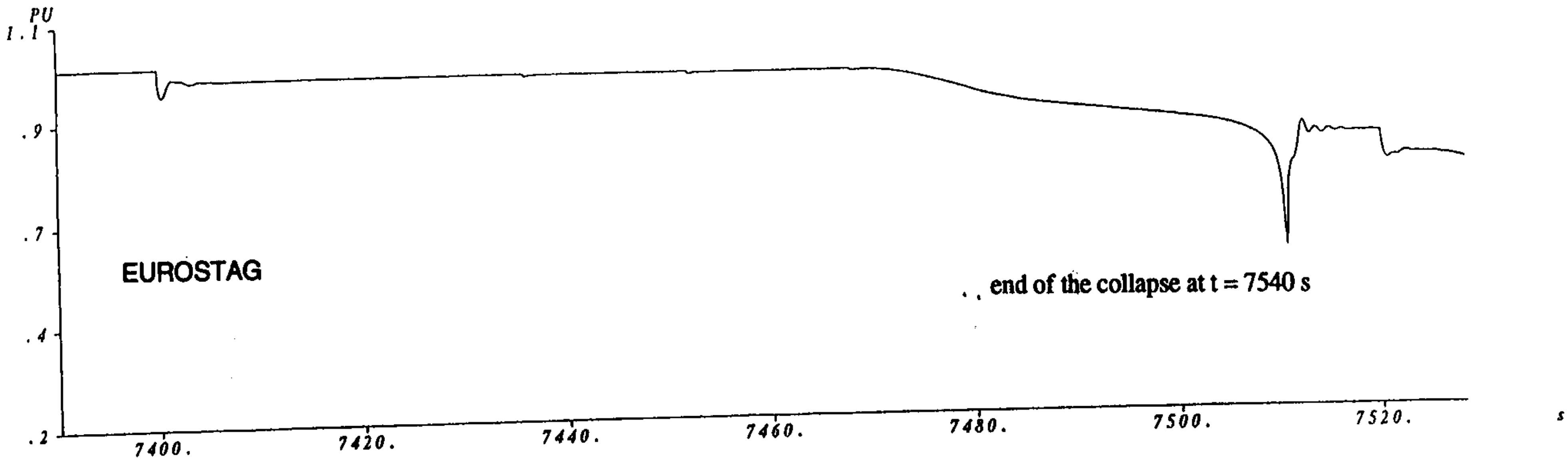


Fig. 4.2.7.a. :

Comparison between MODES and EUROSTAG. Voltage at node N4 following M2 tripping.

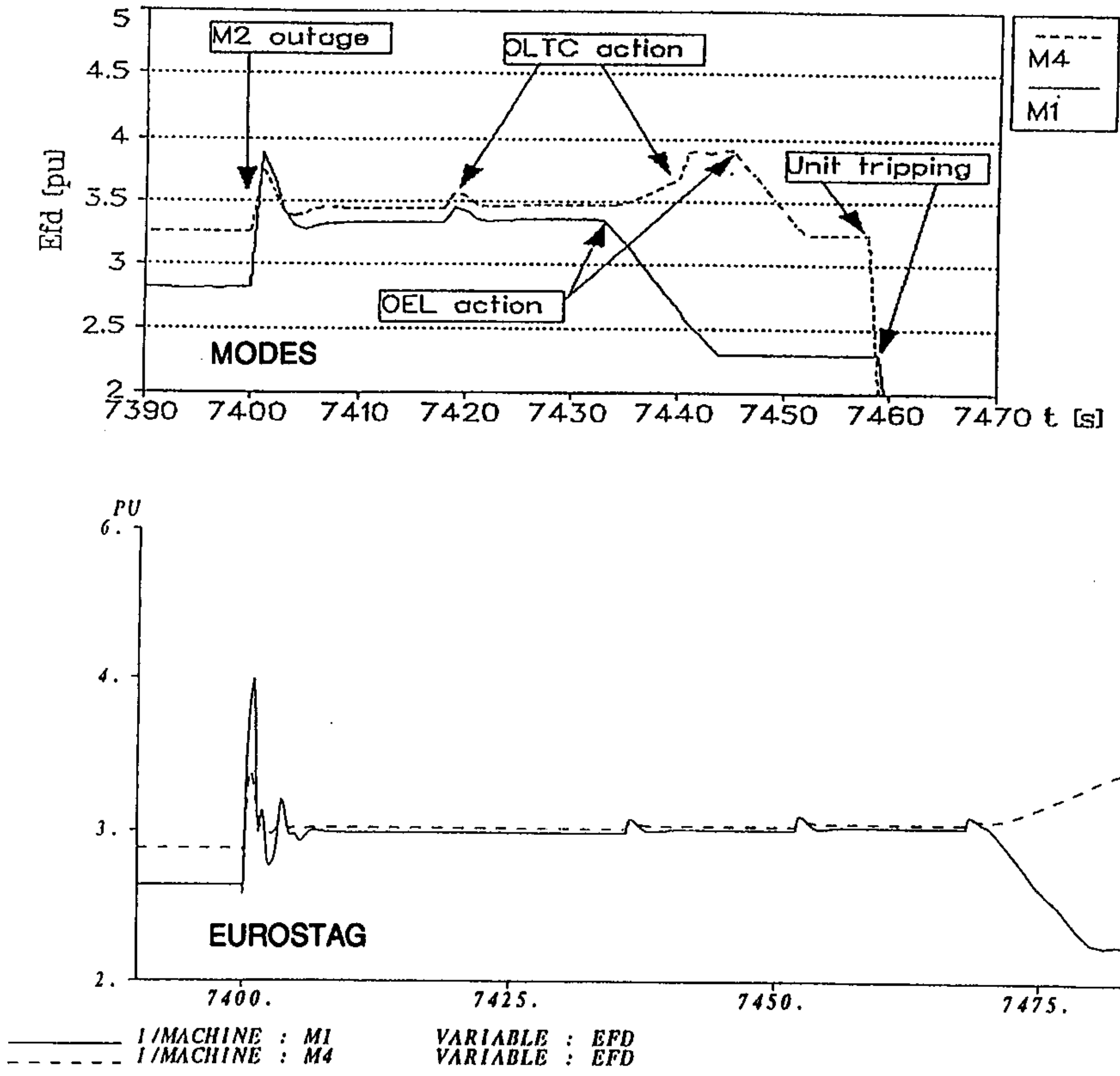


Fig. 4.2.7.b. :

Comparison between MODES and EUROSTAG. Field voltage of units M1 and M4.

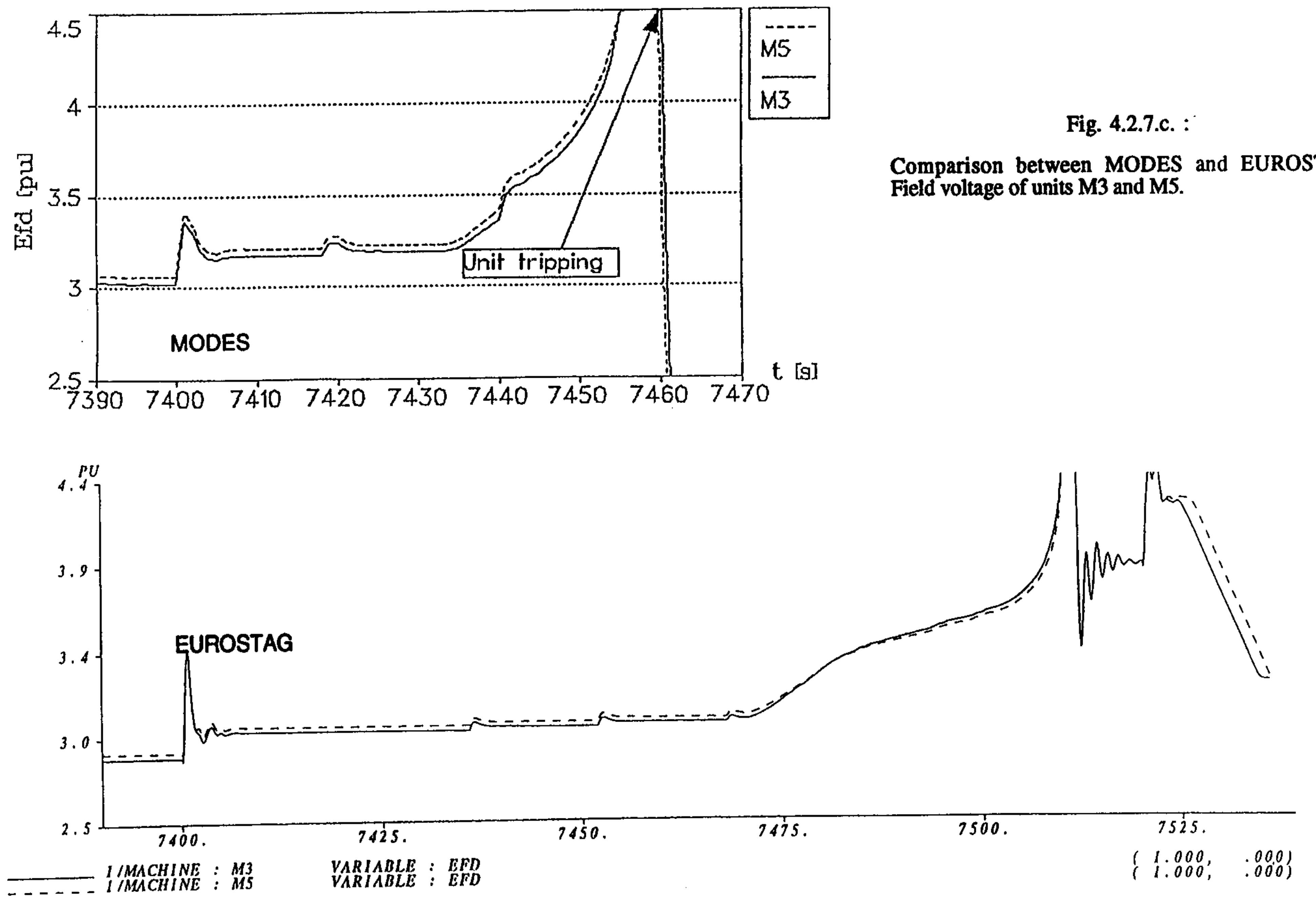


Fig. 4.2.7.c. :

Comparison between MODES and EUROSTAG. Field voltage of units M3 and M5.

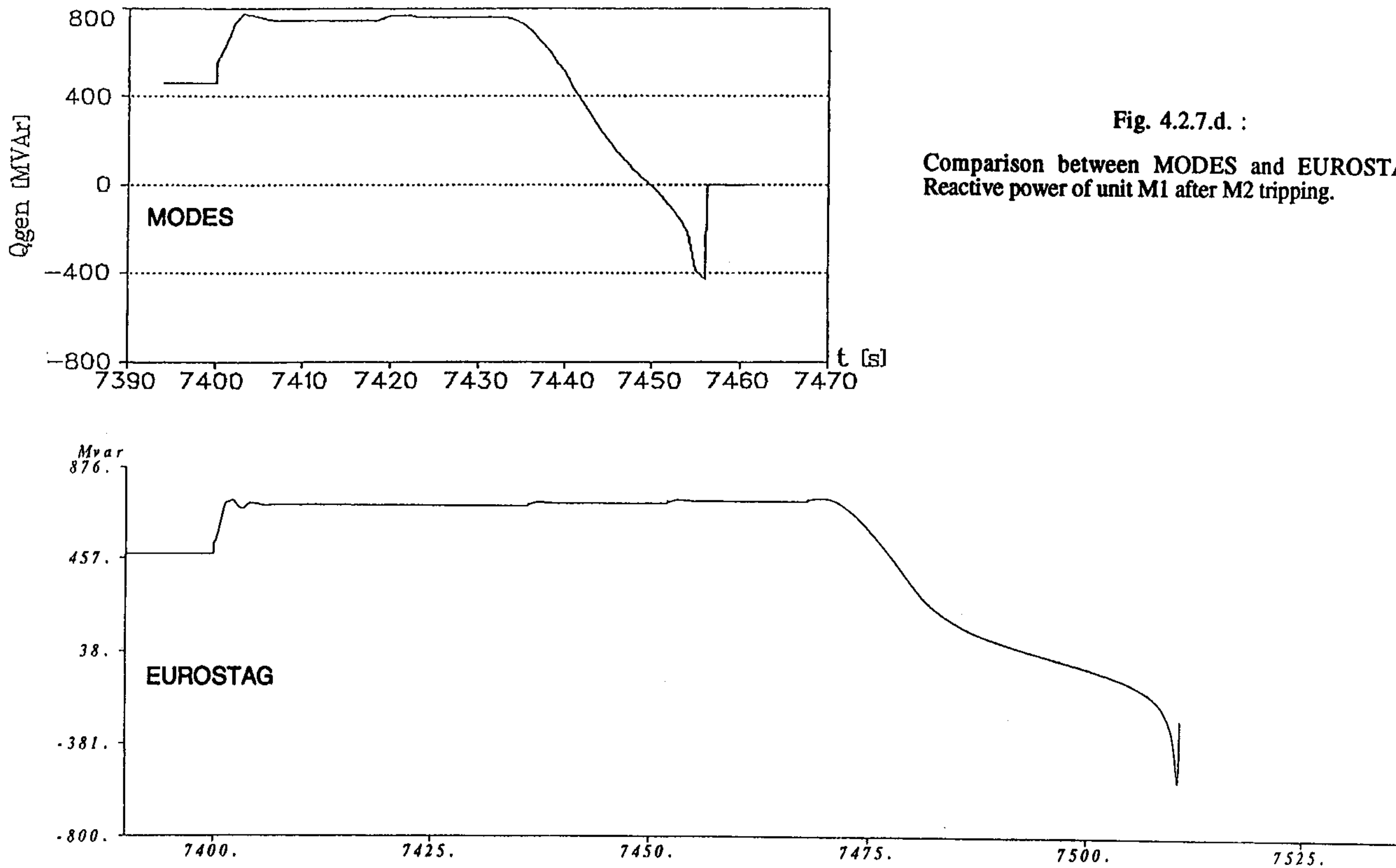


Fig. 4.2.7.d. :

Comparison between MODES and EUROSTAG. Reactive power of unit M1 after M2 tripping.

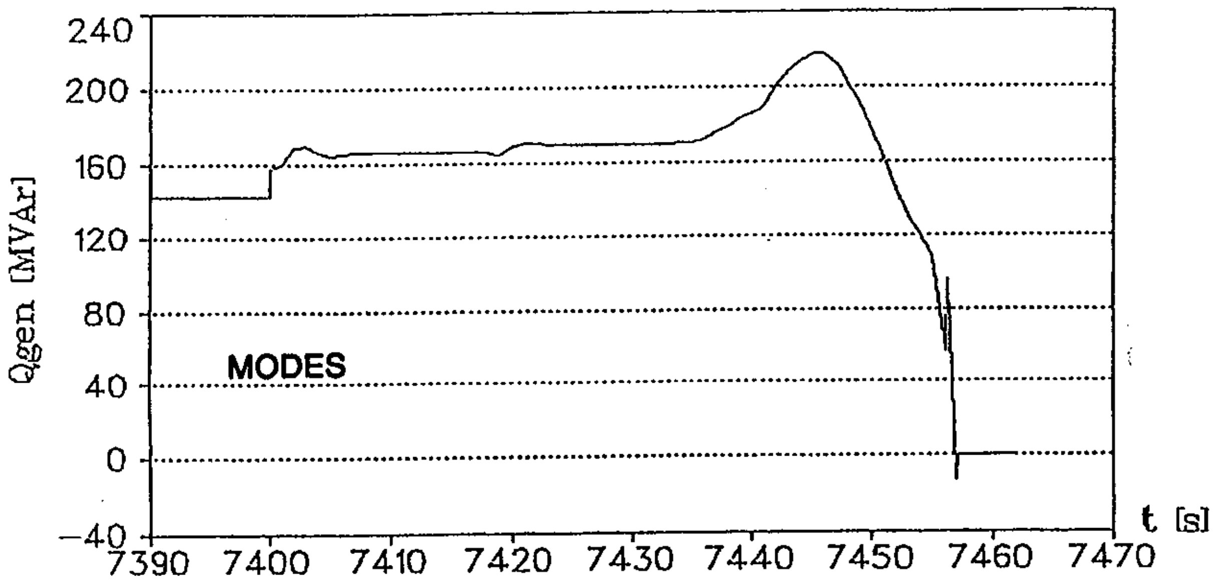
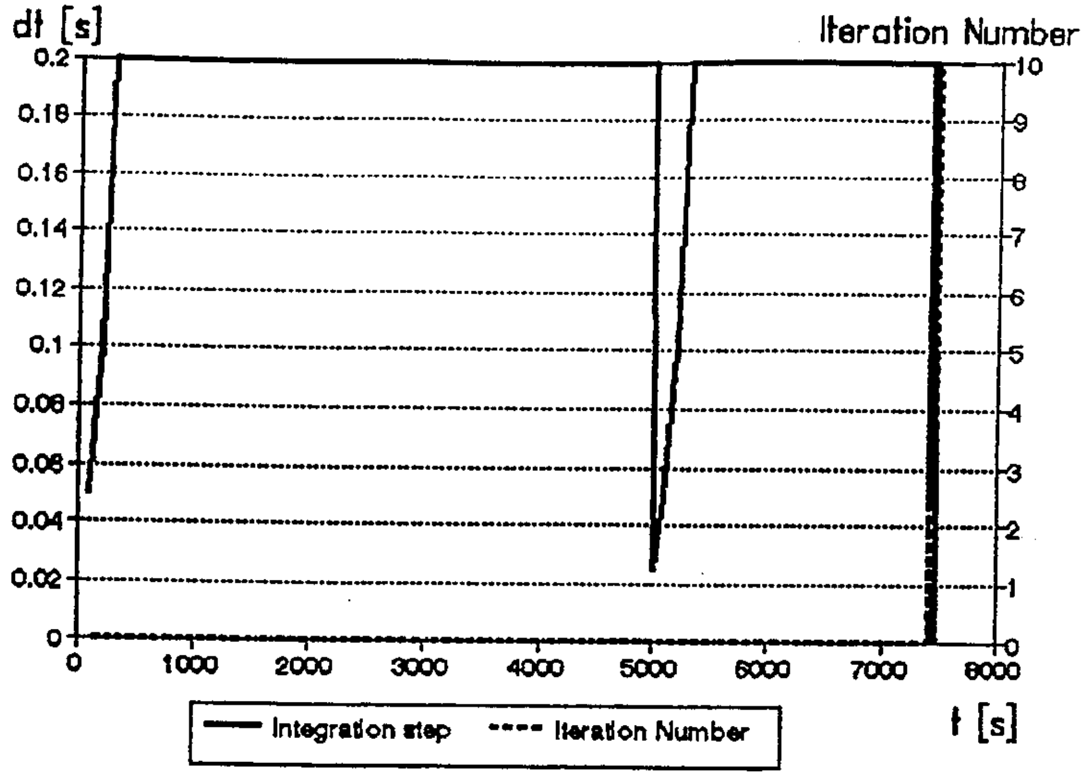


Fig. 4.2.7.e. :

Comparison between MODES and EUROSTAG. Reactive power of unit M4 after M2 tripping.



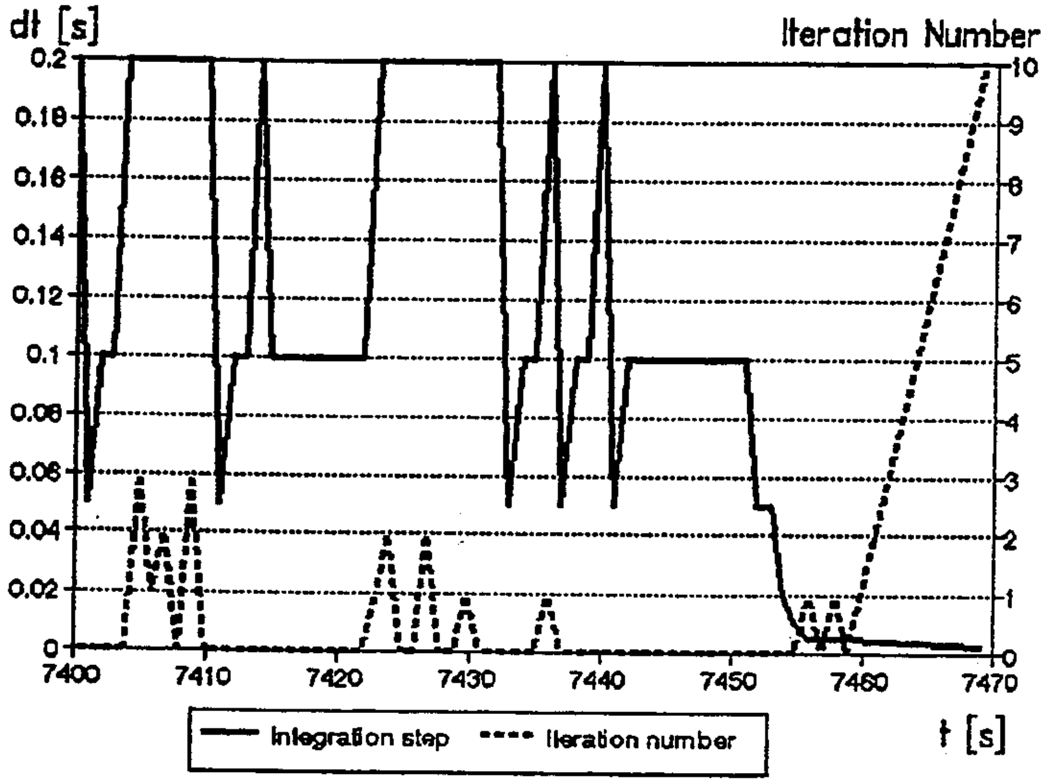


Fig. 4.2.7.f. MODES - Stepsize evolution and iteration number.

4.2.8. Simulation with LTSP (run by Powertech)

4.2.8.1. Description of the modelling

Except a few minor differences, LTSP models are practically identical to the EUROSTAG models.

Network

The initial load flow is almost the same as the reference one.

Infinite nodes are modelled with their voltage phasors kept constant at their load flow values.

Dynamic models

Generators : same as the EUROSTAG model except for the saturation model which is different.

The parameters of the saturation characteristic of all machines are chosen identical (which is not the case in the reference).

AVR, PSS, OEL, Governor : user-defined LTSP models made identical to the reference models.

Automata and relays

ULTC : regulated voltage side; stepsize; maximum and minimum tap position and time delay for the tap movements are the same as the reference.

Loss of synchronism relay, Under voltage relay : simulated by manual switching based on time responses of monitored variables.

Loads

Constant impedance loads are modelled as in EUROSTAG. Because the LTSP model for double cage induction motor is different from the double cage induction motor model used in EUROSTAG, simple cage induction motor model is used for all the motors. The torque speed characteristics of motors mechanical load are also different for the two programs. EUROSTAG uses a piece-wize linear representation and LTSP uses a second order polynomial.

4.2.8.2. Scenario specials

In order to reduce the length of simulation, the load pick-up time was reduced by a factor of 10.

LTSP does not allow continuous linear increase of load and generator power. To model effect of load pick-up, load and generator powers are increased in 10 equal steps within 700 seconds.

The integration method used is the trapezoidal rule with a fixed time step of 0.01 second.

4.2.8.3. Simulation results

Load pick-up

At the end of the load pick-up, the network operating point is quite similar to the reference. Nevertheless, it appears that reactive output of some units is higher than in the reference while field voltage is about the same.

After M2 tripping

The hereunder discussion is illustrated through a comparison between LTSP and EUROSTAG plots on Fig. 4.2.8.a and b. The scales of the plots of EUROSTAG have been adapted to fit the plots of LTSP. Time scales of the load pick-up has been compressed a posteriori in EUROSTAG plots.

The switching-off of generating units (operated manually in LTSP) after M2 tripping show differences in timing.

Switching-off	Time of LTSP (from M2 switching)	Time of reference (from M2 switching)	Criterion
generator M2	0	0	
generator M1	57.9	110.6	out of step for both programs
generator M4	100.9	119.7	low voltage for both programs
generator M3	107.7	135.7	out of step for both programs
generator M5	112.2	136.2	out of step for both programs

The general performance of the system after M2 switching and the shape of the curves of individual variables are close to the reference. Nevertheless, the time is quite different.

We observe that after M2 tripping 3 tap changes take place in EUROSTAG instead of 2 in LTSP.

We also observe a large difference in the field voltage variations of M3 and M5 at the time of M4 tripping. This seems to be linked to the functioning of the OEL which starts working earlier than in EUROSTAG simulation.

4.2.8.4. Conclusion

Thanks user defined models made identical to the reference, LTSP succeeds in reproducing accurately the behaviour of the system. The remaining differences in modelling concerns the saturation of the generators and the absence of loss of synchronism and undervoltage relays in LTSP.

It is worthwhile to note that, on the base of the knowledge of the behaviour of the system, time scale has been adapted without loss of accuracy, to deal with the very long term scenario.

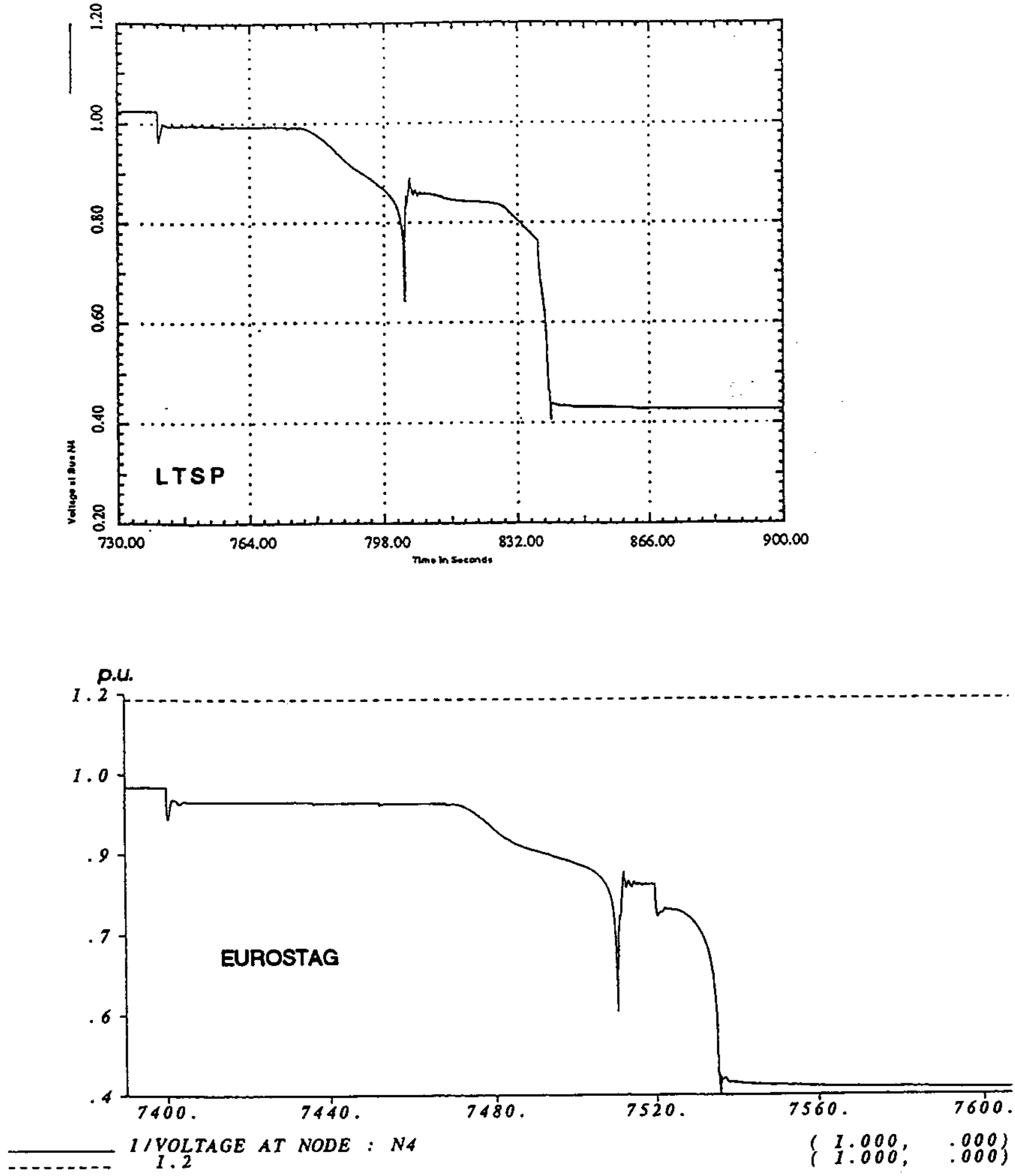


Fig. 4.2.8.a : Comparison between LTSP and EUROSTAG.
Voltage at node N4 following the tripping of unit M2.

4.2.9. Summary comments on exercises on the Belgian - French test system

The Belgian - French test system simulation is quite critical : any small change in initial conditions, or in excitation modelling (generator saturation inclusive) can lead to bifurcations in the behaviour of the system. Nevertheless, the scenario was perfectly known and so were the mechanisms leading to cascade trippings. As a consequence, the exercise focused on simulation accuracy, modelling flexibility and very long term simulation (load pick-up phase).

Another feature of the exercise was the intermigling of fast (loss of synchronism) and slow (load pick-up, tap changes) phenomena asking for an extended modelling of the system.

Finally, the simulation of the load pick-up phase asked for some interactive operation facilities.

The case of CHAMPS V1, V2 simulation must be taken apart : the voltage collapse, result of units M1 and M2 tripping, was identified but not the mechanisms (loss of synchronism of unit M1, ...). This is a demonstration that in such an exercise short and long term phenomena cannot be dissociated.

The case of the analogic real time simulator APSA is of interest. This simulator was basically able to proceed with the requested simulation but some limitations in the available modelling didn't allow to realize completely the simulation. Indeed, some automatic actions were taken into account manually. Nevertheless, it is of great interest to observe that analog and digital simulators produce close results.

The five remaining digital simulations can be compared.

The load pick-up phase

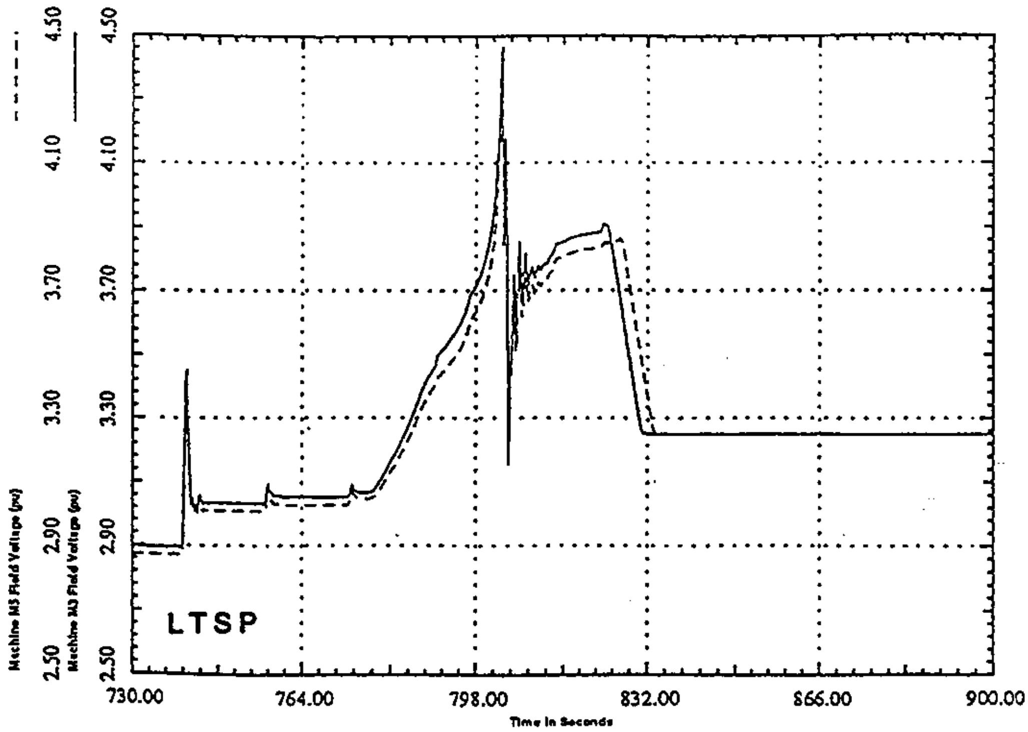
The programs having a constant integration stepsize (ADVANCE, PSS/E and LTSP) required to shorten the load pick-up phase (from 2 hours up to 100 to 700 s). Good results have been obtained, but it is quite clear that the knowledge a priori of the behaviour was mandatory to proceed with this simplification without taking the risk of erroneous conclusions.

The secondary controls during the load pick-up have been simplified or adapted in case of load pick-up shortening, and for reasons of limitations in the interactive operation facilities of the program. With PSS/E the load pick-up was divided in three phases; MODES used continuous rate of change of voltage set points; at the contrary, LTSP divided the continuous load pick-up of the generating units in 10 discrete levels; no details are given for ADVANCE. Others reproduced in a sequence of predefined events the interactive operations defined in the log of the reference simulation (MODES, EXSTAB).

The cascade trippings phase

In this phase, the accuracy of the modelling of OEL's, generator saturation and ULTC was paramount.

To that extent, PSS/E simulation didn't succeed in reproducing the mechanisms of cascade trippings. OEL's modelling can be designated as the origin of this impossibility.



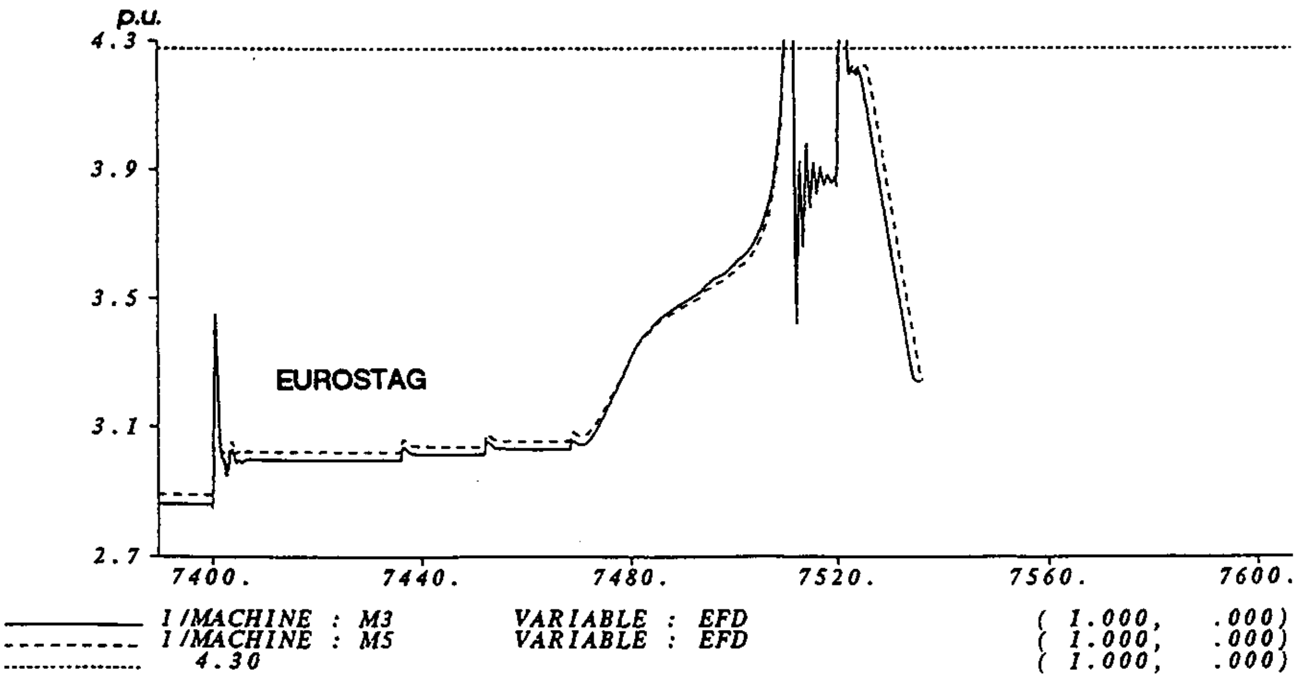


Fig. 4.2.8.b : Comparison between LTSP and EUROSTAG.
Field Voltage of units M3 and M5 following the tripping of unit M2.

Programs with user's defined modelling (LTSP, ADVANCE) succeeded quite obviously in reproducing the reference models, as did EXSTAB after the writing in Fortran of the OEL model. For these three programs results are very good, even if the timing of the scenario remains quite inaccurate : the reason can be found in small discrepancies at the level of saturation modelling (always hardcoded) and initial conditions.

MODES simulation approached also to a certain extent the reference thanks the programming of the OEL model.

Algorithmic behaviour

The stepsize evolution of variable stepsize programs shows considerable differences. The mean value of the stepsize of EUROSTAG being 4 s, the maximum value of the stepsize of MODES was only 0.2 s. No information is given about EXSTAB.

4.3. The Swedish test system simulations

4.3.1. Reference simulation with PSS/E (run by Svenska Krafnät)

4.3.1.1. Modelling

Details on modelling is shown in Appendix A.3.

All the simulations presented in the scenario below are based on the same set of data. Only the initial faults are different.

4.3.1.2. Simulations

Cases

Simulations that are of special interest to study long term dynamics are (see 2.3) :

Case 1 Tripping of generator 4047 no. 2

Case 4 Tripping of line 4011-4021, and generator 1012

Case 14 Tripping of generator 4062

Simulations up to 200 seconds have been made.

4.3.1.3. Observations

General observations (as already mentioned in 2.3)

All simulations presented result in a collapse. In fact all of them passes a number of subsequent "time stages", as follows (see Fig. 4.3.1.a. to e.).

0 - 20 s The initial transient is managed. The oscillations are damped. The voltages are reasonable.

20 - 40 s The generator current limiters act, which result in a sudden decrease in voltage. The oscillations are still damped and the amplitude is reasonable.

40 - s The voltages slowly decrease as the tap changers tend to increase the loads.

\- Suddenly the voltages decrease considerably, and very large oscillations occur. After some time units go out of phase etc. in some cases, and/or the calculation indicate 'non convergence'.

Individual cases

Case 1 The initial dynamics 0 - 20 seconds may look rather non-critical. An alarming observation is found when looking at the total load, i.e. the variable 'PLOAD AR. 0'. It shows that the load is decreased immediately by almost 350 MW due to low voltage. And when the generator current limiters act, the total load decrease becomes more than 450 MW.

The system is very weak from voltage control point of view. Thus when the tap changers start to operate the voltage decreases even further. In fact, the load is not restored but does even decrease(!).

Case 4 The line tripping in the "North" region results in voltage decay. The lowest voltages appear in the transmission system connecting "North" and "Central", not in the load area. The initial load decreases is only some 200 MW.

Once the tap changers start to operate the voltage slowly decreases. The most critical buses are 4021, 4031 and 4032. Please observe that the voltages in the load area remains higher than for the buses mentioned. The final collapse occurs in the transfer section after some large swings.

It can be noted that a temporary voltage decrease appears at about 20 seconds. The explanation may be found from the action of current limiters and from generator rotor acceleration.

Case 14 The case is similar to other generator trippings. Sustained power oscillations occur between generators in region "South-West" and other regions.

Other tests

Some simulations have been run with longer time intervals between tap changer steps. These tests are shown in the reference report on simulations.

In principle the same type of collapse occurs. Naturally it occurs at a later stage. It is also found that the large oscillations just prior to the final collapse are less dominant. The system collapse become much 'smoother' (see fig. 4.3.1.e).

4.3.1.4 Comments

Power system dynamics

The overall dynamics of the test system as found from the PSS/E simulations is a mixture of

... short term dynamics ...

Rather weakly damped oscillations occur after the initial fault and after the current limiters come into action.

The final collapse incorporates large oscillations. (This is to a large extent due to forced tap-changer operations with very short time intervals for tap changer operation.)

... and long term dynamics

The current limiters and tap changers are crucial. They causes slowly decreasing voltages which finally results in a collapse.

Still it should be noted that the exact modelling of the current limiters and tap changers are not essential for the overall simulation result. If they just keep the rotor and stator currents below 110 % and 105 % of rated values, respectively, the system will be subject to a collapse.

Data and modelling

As the simulation incorporates a number of phenomena it is essential that realistic models and data are defined. The crucial point is not that 'exact' modelling is made, but rather that realistic models of all major components are available. To follow dynamics up to the beginning collapse, generator current limiters and transformer tap changers are necessary. If cascade trippings of lines and the full break-down is to be followed, various types of relay protection have to be taken into account.

Simulation tool

PSS/E proves to be able to follow the system dynamics to the point of voltage collapse and network splitting with the models used.

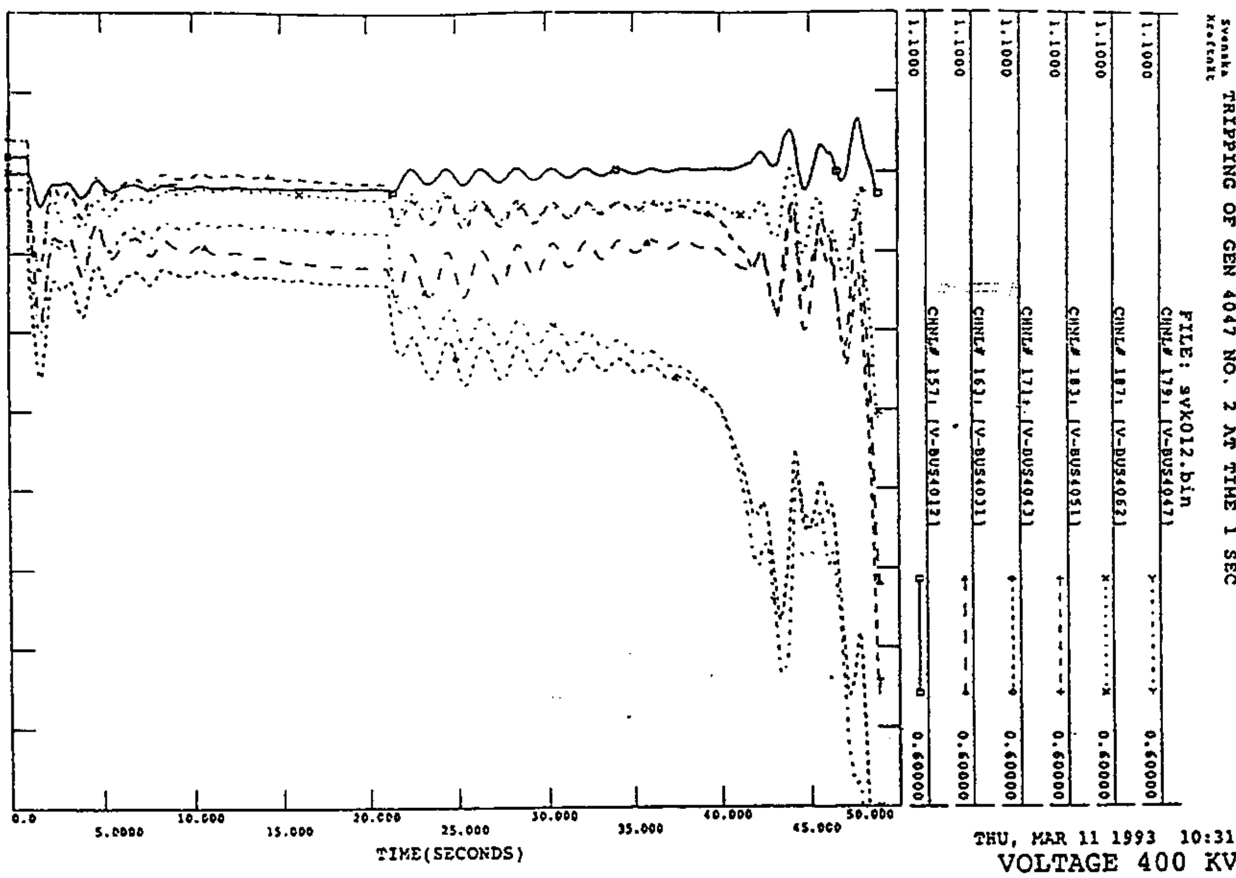


Fig. 4.3.1.a. CASE 1 - Voltages in various parts of the system after tripping of large generator in 'Central' region. Transfers increase from the 'Northern' region , and after 20 seconds current limiters act in some generators, and after 40 seconds tap changers start operate (in the simulation about every 7 second, i.e. shorter and realistic step times).

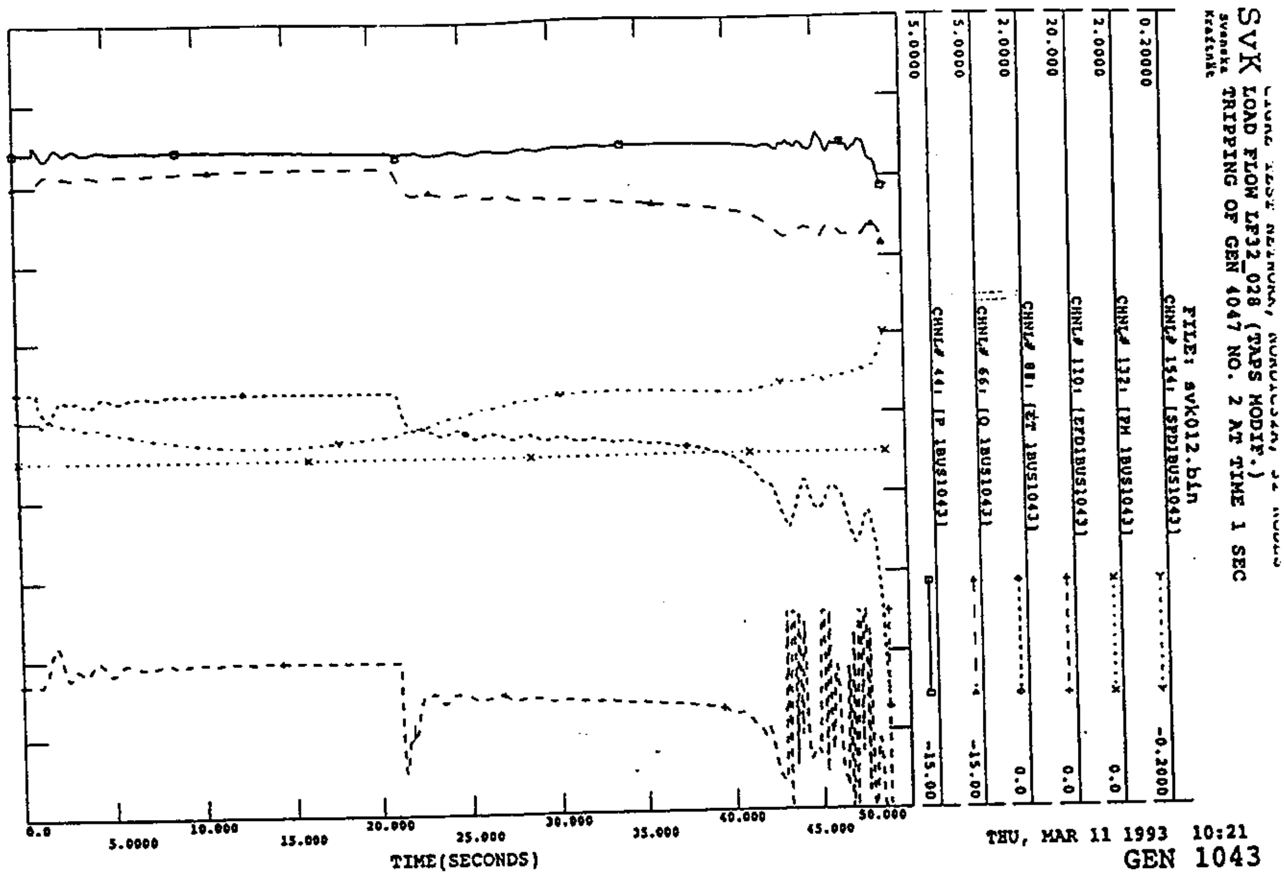


Fig. 4.3.1.b. CASE 1 - One of the generators in the 'Central' region. The stator current limiter becomes active after about 20 seconds. (Power is in system p u base)

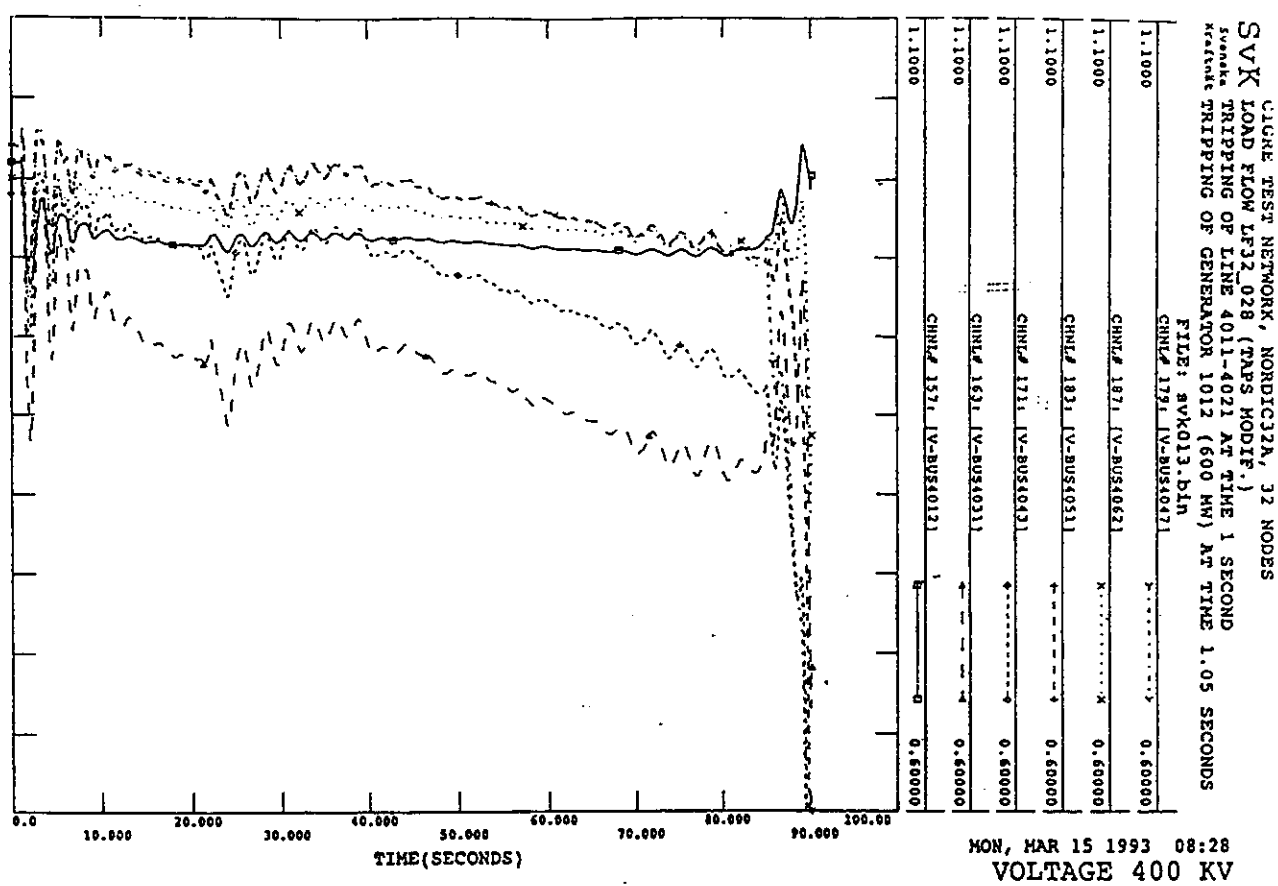


Fig. 4.3.1.c. CASE 4 - Voltages in various part of the system after tripping of a major transfer line in the 'North' and forced tripping of a generator. Transfers to the 'Central' region are decreased at the beginning but increase again due to turbine control. Current limiters act after some 20 seconds and tap changers after about 40 seconds.

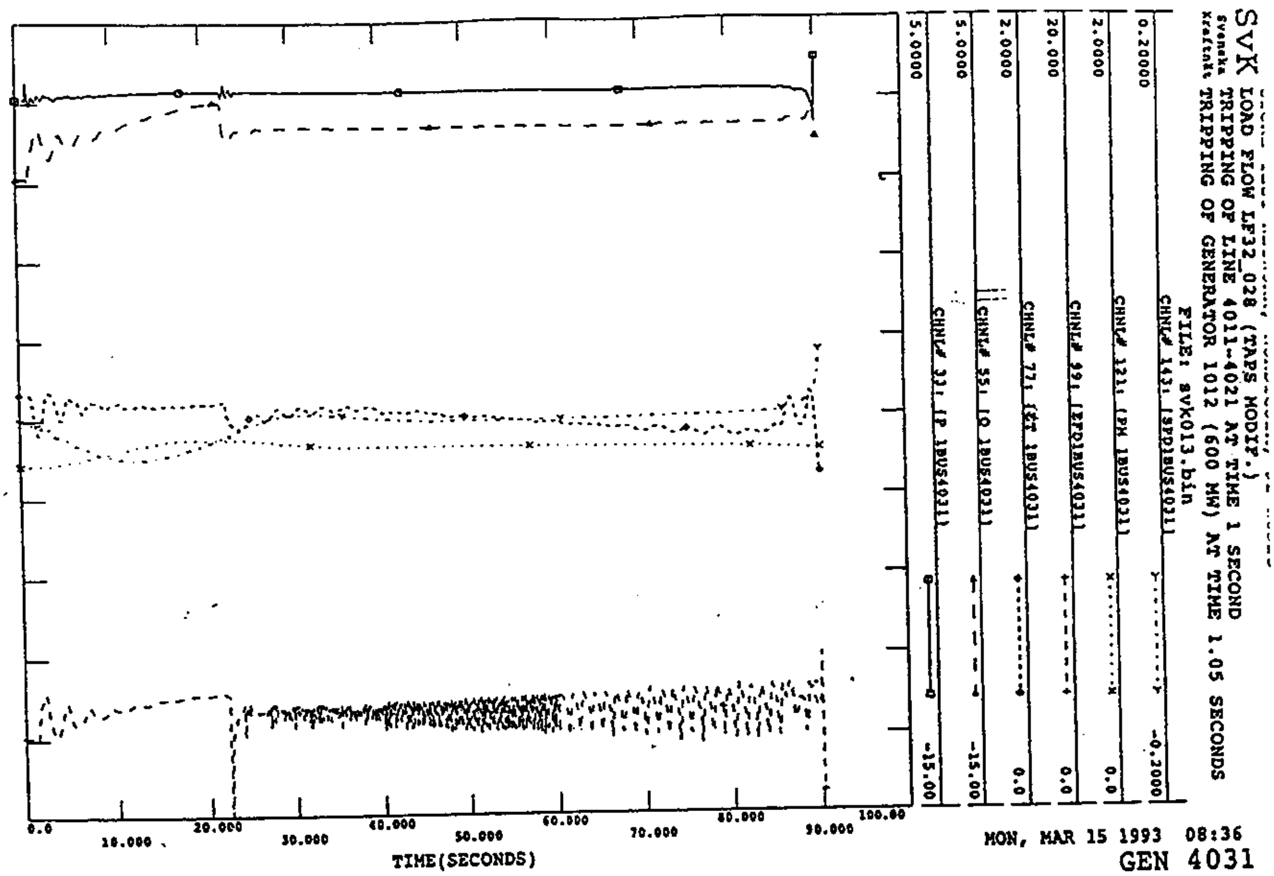


Fig. 4.3.1.d. CASE 4 - One of the hydro generators with rotor current limiter. (The oscillations are probably just related to the model not the real limiter.)

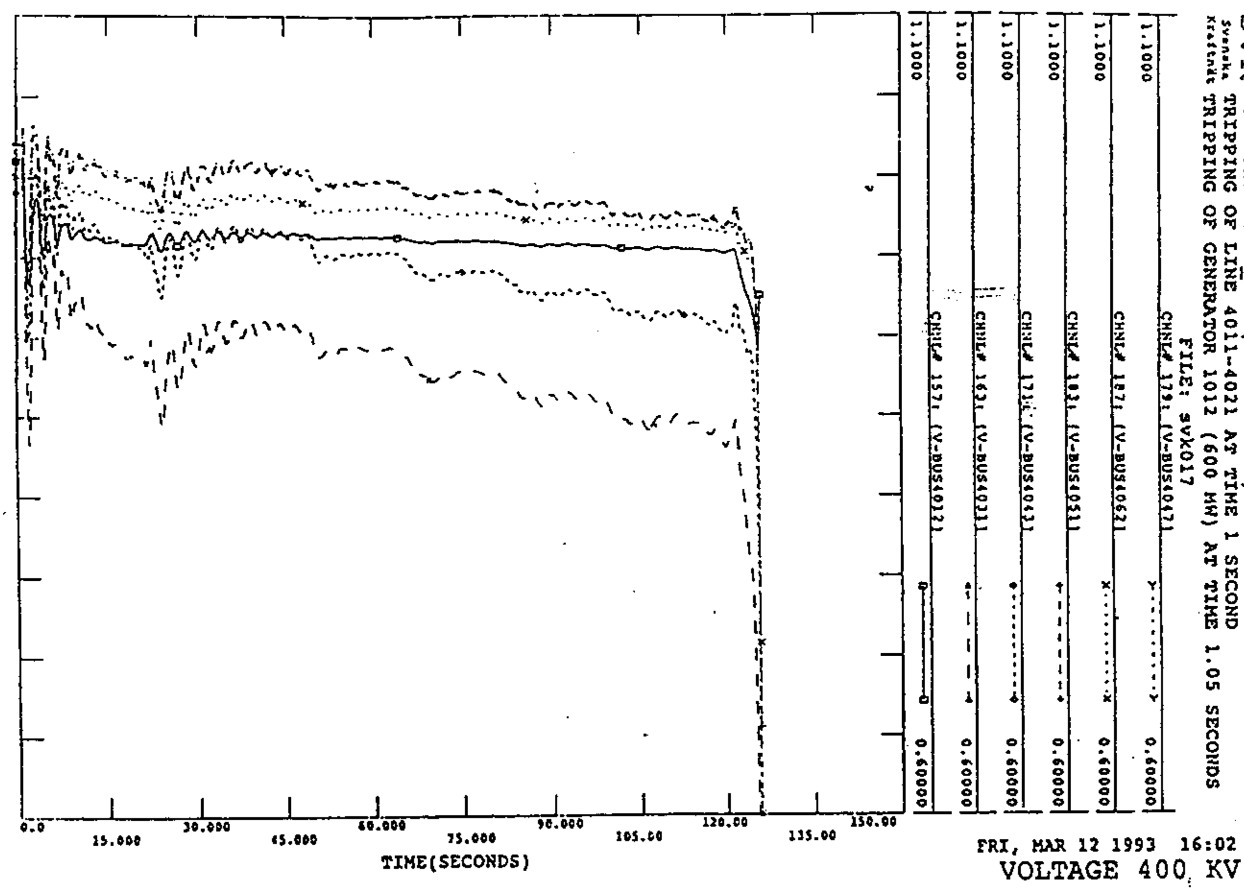


Fig. 4.3.1.e. CASE 1 - A simulation with longer time steps for the tap changer. Please notice the smoother collapse.

4.3.2. Simulation with EUROSTAG (run by Tractebel)

4.3.2.1. Modelling

Simulations have been performed by Tractebel (TBL) on the Swedish test system. The tool has been the simulation package EUROSTAG.

Great attention have been paid to model the system and the various components as in the reference simulations by Svenska Kraftnät (SVK) on PSS/E package. By using a certain pre-processor facility, very close models have been reproduced in EUROSTAG for power system stabilizers, current limiters, and tap changers.

Network and load flow

After having carefully checked the parameter definitions the initial load flow was found nearly the same as the reference one.

Generators and controls

Basically the same models are used. Some discrepancies in saturation modelling is probably at hand.
The current limiters were translated and coded by the EUROSTAG pre-processor.

4.3.2.2. Simulation results

The global behaviours are the same. The actions from current limiters and tap changers result in a collapse in the same way as in the PSS/E reference calculations.

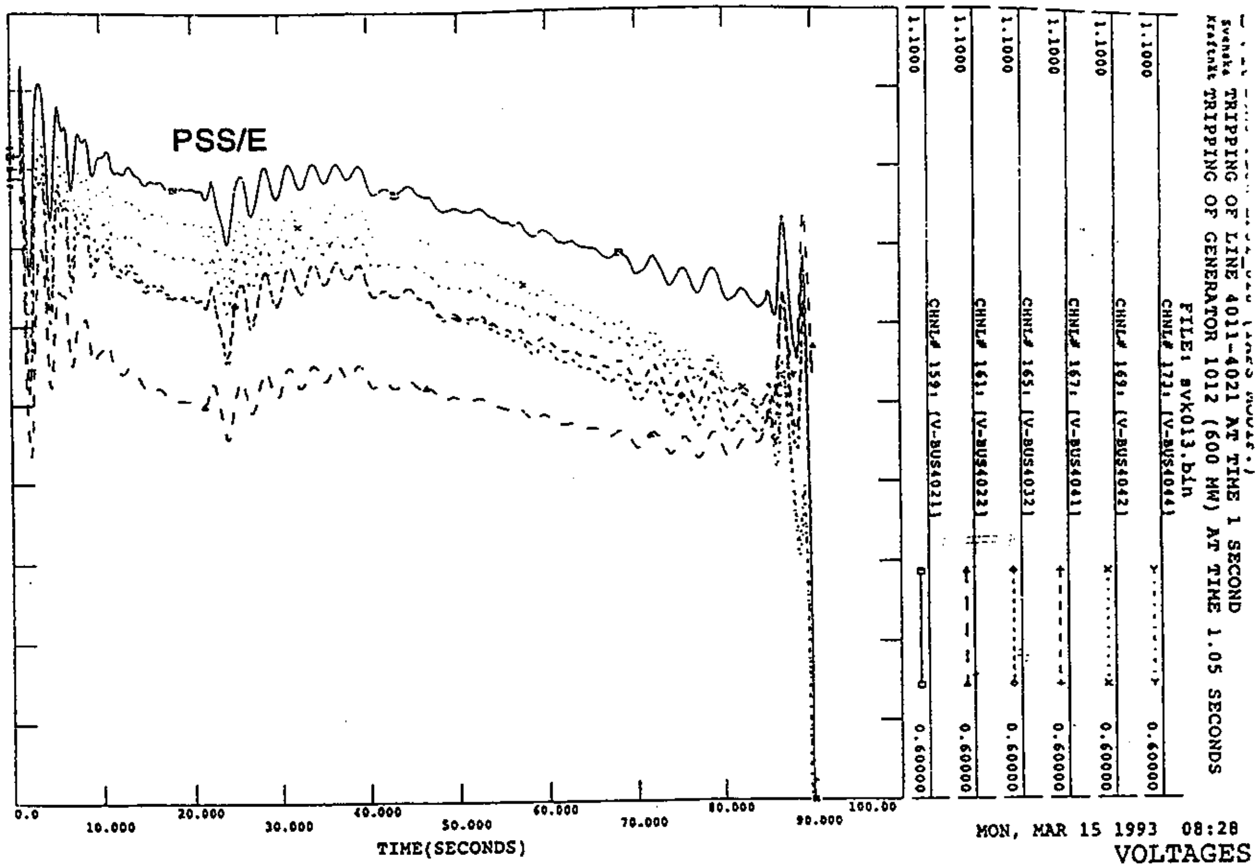
Fig. 4.4.2.a to c present comparisons between EUROSTAG and PSS/E results on case 4 : the scales of EUROSTAG plots have been adapted to fit the scales of PSS/E.

A closer look shows some differences:

- The initial values of field current are not the same. The difference is however rather minor. A probable explanation found by TBL is difference in saturation modelling.
- The actions of the current limiter are somewhat different. That is probably explained by the differences in saturation modelling.
- For a few generators some unstable very fast oscillations occur in current limiters in PSS/E. They are not reproduced in EUROSTAG calculations. The discrepancies may be due to some slight difference in modelling of logics and/or to the fact that PSS/E uses constant time step whereas EUROSTAG adapts the time step. Additional simulations have shown that the use of a constant stepsize (5 ms) with the tool EUROSTAG doesn't affect the above mentioned difference (see Fig. 4.3.2.d).

4.3.2.3. Comments

As has been already stated, the overall dynamics are the same. The major parts of the simulation show very similar behaviour, e.g. after the activation of current limiters the voltage slowly gets lower as the tap changers act. The final collapse occur in the same part in the system and in a very similar way.
As the faults are severe and large oscillations occur, any minor difference in modelling may add up to larger differences after some time. For example, time for activation of limiters will be different affecting the oscillations. Still the differences are quite limited from an overall point of view. It is furthermore believed that the model discrepancy is smaller than the uncertainty of data.



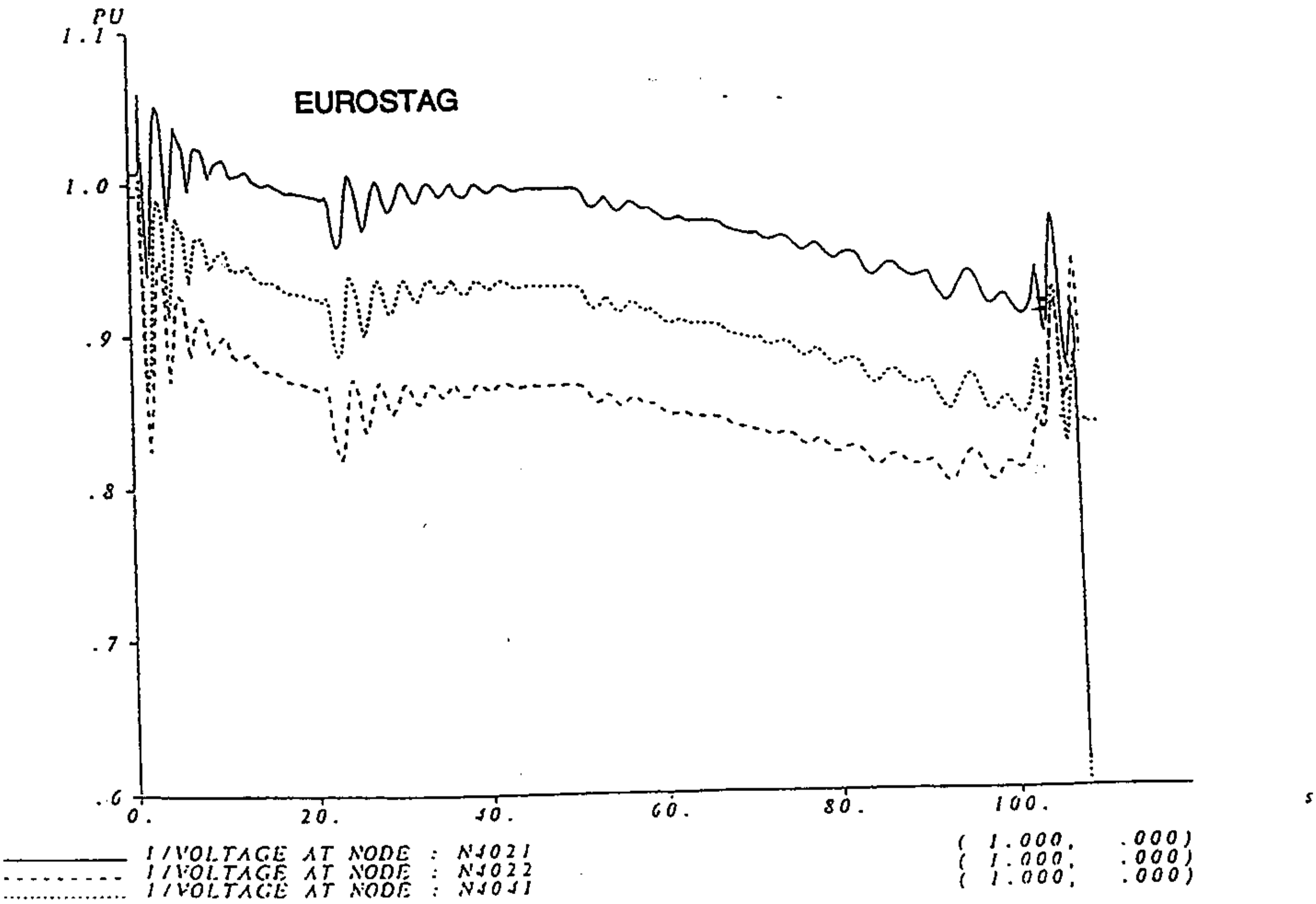


Fig. 4.3.2.a. CASE 4 - Comparison between PSS/E and EUROSTAG.
Voltage in North and Central regions.

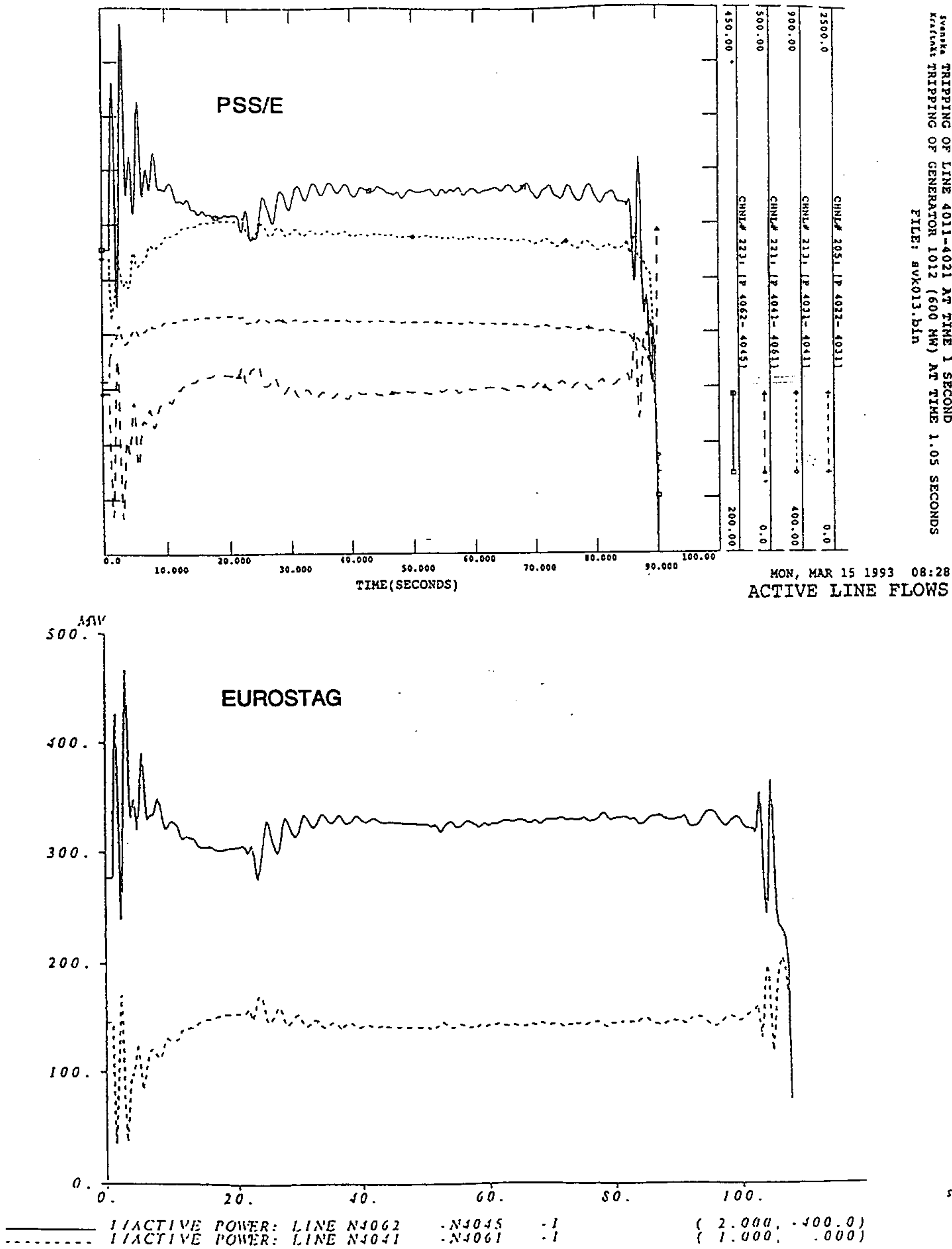


Fig. 4.3.2.b. CASE 4 - Comparison between PSS/E and EUROSTAG.
Active power flows between Central and Southwest regions.

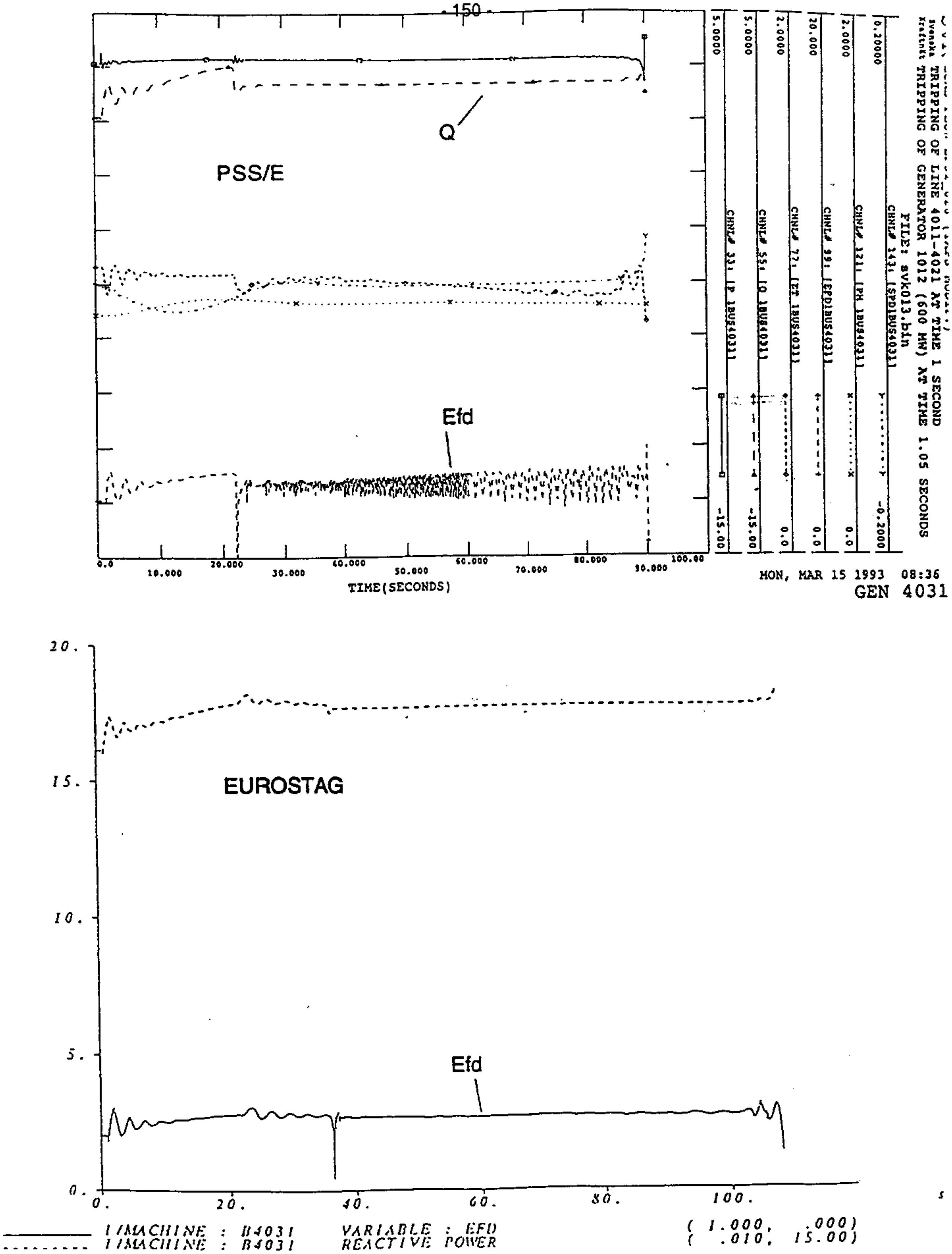


Fig. 4.3.2.c. CASE 4 - Comparison between PSS/E and EUROSTAG. Reactive power and field voltage of one of the hydro generators with rotor current limiter.

Appendix A.5

. TRANSFORMER DATA (at t=to):

FROM	TO	CKT	TP	RATIO	ANGLE	RG
301	310	1	T	1.0000	0.00	1
301	311	1	T	1.0000	0.00	1
301	3608	1	T	1.0000	0.00	1
302	320	1	T	1.0000	0.00	1
302	321	1	T	1.0000	0.00	1
302	3609	1	T	1.0000	0.00	1
312	3608	1	T	1.0000	0.00	1
322	3609	1	T	1.0000	0.00	1
3608	13005	2	T	1.0181	0.00	1
3609	13005	1	T	1.0181	0.00	1
3771	13065	1	T	1.0122	0.00	1
3781	13070	3	T	1.0499	0.00	1
3800	13005	3	T	0.9847	0.00	1
3801	13070	1	T	0.9847	0.00	1
3805	13020	1	T	1.0918	0.00	1
3865	13030	6	T	1.0000	0.00	1
3900	13050	1	T	0.9550	0.00	1
3900	23245	1	T	1.0227	0.00	1
3950	13060	2	T	1.0000	0.00	1
3950	23295	2	T	1.0716	0.00	1
3955	13060	1	T	1.0000	0.00	1
3955	23295	1	T	1.0716	0.00	1
3980	13075	9	T	0.9550	0.00	1
3980	23390	9	T	1.0227	0.00	1
13035	23210	1	T	1.0964	0.00	1
13050	23245	2	T	1.0685	0.00	1
13055	23250	1	T	1.0716	0.00	1
13060	23295	3	T	1.0714	0.00	1
13075	23390	1	T	1.0873	0.00	1
18290	28250	1	F	0.9284	0.00	1

RG=1 --> taps are locked.

4.3.3. Summary comments on exercises on the Swedish test system

Character of test system

A test system has been proposed by Svenska Kraftnät, Sweden. It is generic, but has dynamic properties that are found in the Swedish and Nordic power system. The transfer is very large from "North" to "Central" regions. In fact, all the specified faults in the scenarios result in some kind of collapse.

The type of the collapse depend on the initial fault.

- In case of line trippings in the transfer section, the voltage collapse will appear in the transfer system between the "North" and the "Central" regions.
- In case of generator trippings in the South, the voltage collapse will appear basically in the load area, i.e. the "Central" region.

The collapse occurs when the current limiters of the generators and the tap changers on loads are activated. A collapse may occur after some minutes up to several minutes after the initial fault. (In the simulations the time has been shortened by choosing very short time interval between tap changer actions, about 7 seconds instead of a more realistic value of 60 - 120 seconds.)

Dynamic phenomena involved

When the power system is brought close to and even beyond the point of collapse, both rapid and slow phenomena are often involved.

a Transient stability, including first swing stability and subsequent power oscillations. This may be critical directly after the initial fault.

b Small signal damping. That may be a problem even if the initial fault is managed successfully. If the transfer is slowly increased bad damping may occur.

c Voltage collapse. That may occur after the current limiters have acted and load restoration takes place by the help of tap changer operations.

d Frequency control. That will change the power transfer, thus affecting both small signal damping and voltage collapse. It may even be a part of the transient stability process.

Need for simulation

In order to cover all these phenomena simultaneously, simulation is the natural approach. In many cases it is the only way, for example

- when it is not known which phenomena will be limiting;
- when a large number of non-linear events occur, for example to find the consequences of a system collapse due to cascade trippings of lines

Possibilities to use static analysis

Although it has not been a part of the exercise, some comments are given on the possibility to use simplified static calculation to check the risk of voltage collapse.

Load flows or various types of indices may be used to check transfer limits if it has been proved that the collapse is due to voltage and lack of reactive resources. That is, static analysis shall be verified by simulation.

4.4. The Irish test system simulations

4.4.1. Initial simulation with PSS/E (run by ESB)

4.4.1.1. Introduction

This Chapter contains the results of a 20 second simulation on the hypothetical "island" power system described in Chapter 2.4. The simulation was carried out by ESB using a version of the PSS/E software package.

4.4.1.2. Scenario

This scenario involves the loss of two units at station MP each generating 275 MW when the total system generation is 1105 MW. When this occurs, the generators' house load (2x22 MW) is also lost, followed by the tripping of the two pumps at station TH. Subsequently, load is shed at all 110 kV busbars and this is seen, in Figure 4.4.1.b, to arrest the frequency fall within 2 seconds at 47.78 Hz (the remaining generators would begin to trip if the frequency remained below 47.5 Hz for more than 10 seconds). However, the load shedding is too great leading to an excess of generation over demand and the frequency is seen to recover quickly and overshoot nominal.

4.4.1.3 Results

The results of this study are shown in Figures 4.4.1.a to d for a duration of 20 seconds including 0.5 seconds of pre-fault information.

Figure 4.4.1.a depicts the system totals of load (customer demand and generator house load), generated mechanical power and electrical power. When the generators are lost, so also are their generators' house load, which is seen from the curve of total load (it should be noted that the curve of total load begins at a higher level than either the mechanical or electric powers due to an artefact of the module which sums the bus injections).

The deficit of load over generation results in a rapid decrease in frequency, as seen from the deviation in machine speeds in Figure 4.4.1.b (per unit with 50 Hz base) which results in prompt tripping of the load at the pumped storage station. There remains a deficit of load over generation and customer load shedding occurs after approximately 1.4 seconds of 523 MW or 60% of the initial value. As a consequence of the frequency changing so rapidly, the amount of customer load disconnected results in an excess of generation over demand and the frequency increases beyond nominal and is thereafter controlled by governor action on all sets. The non-linearities of the actual governors means that the response to over frequencies is an order of magnitude greater than to under frequencies and therefore the actual frequency would be controlled better.

Figure 4.4.1.c portrays the electrical powers at selected machines (on 100 MVA base) which, initially oscillate and eventually settle with differences being attributable to the diverse locations within the network. It will be noticed that no sets lose synchronism.

Figure 4.4.1.d shows selected voltages (in per unit of rating) at selected locations throughout the network. Clearly, the voltages in close proximity to the fault - V-MP G3, V-DN - and the voltage in SO, a weak portion of the network, are worst effected. The highest voltages suffered by the 400 kV, 220 KV and 110 kV were 430 kV, 236 kV and 118 kV respectively. Overfluxing relays would not be activated by this combination of voltage and frequency as approximately 24% overfluxing is needed for greater than five seconds to trip the transformers.

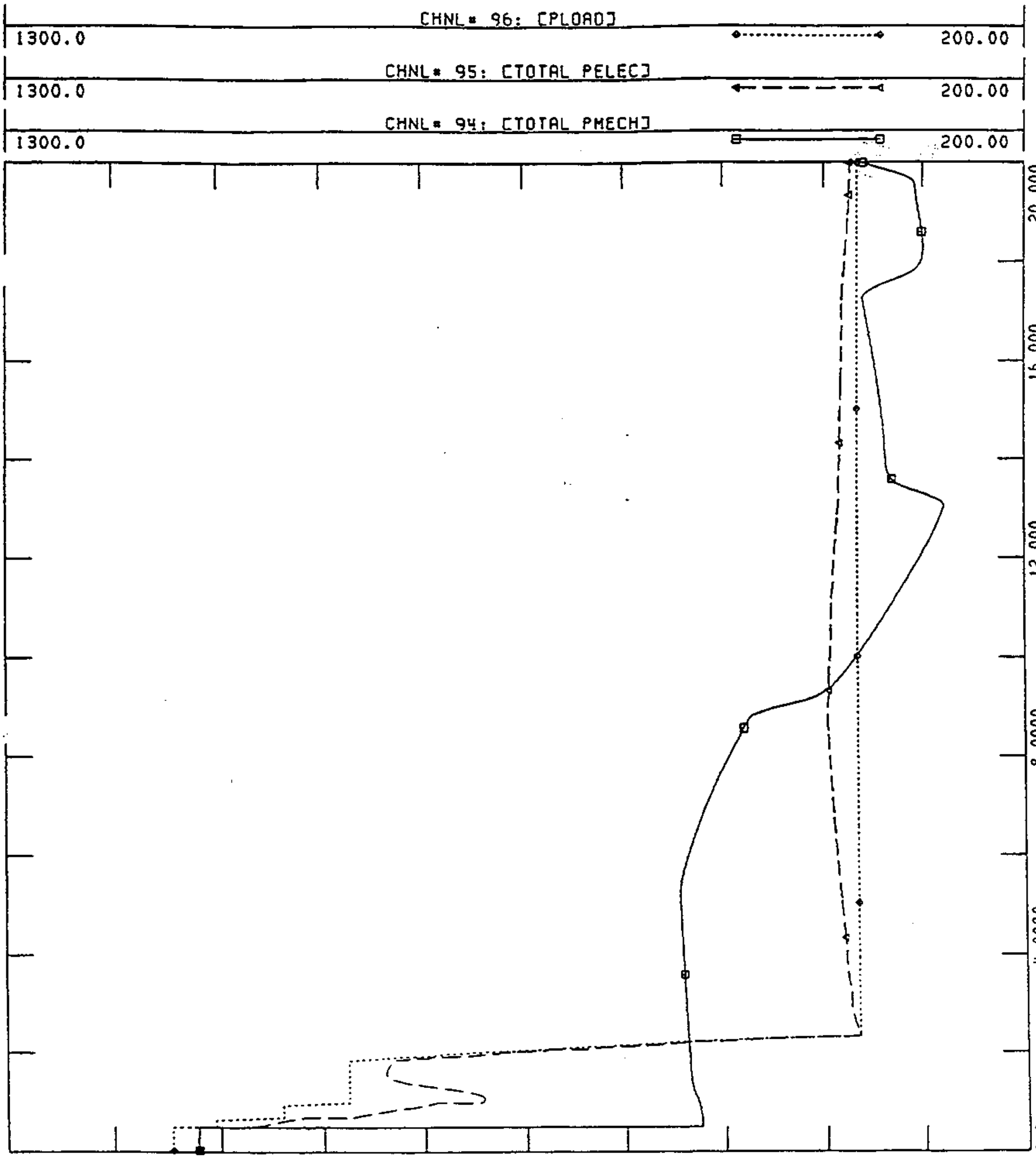
4.4.1.4. Long-Term Dynamics

The simulation described above could not credibly be extended beyond this time frame as other dynamic phenomena begin to take place. It has been pointed out that no significant transformer overfluxing took place during this initial 20 seconds. However, it would be desirable to extend the time frame of the simulation to:

- examine the operation of the automatic load restoration scheme;
- examine, as real and reactive load is restored, transformer overfluxing to ascertain whether any protection operates thereby compounding the restoration process;
- use the results as an input to the selection of the optimum settings for overfluxing relays which tradeoff system security and transformer longevity.

CIGRE STUDY OF SUMMER NIGHT: MP 3X275
NAT. 200. AD/PB 40 EA & 2 PUMPS ↑ 965 MW

FILE: OUT_T2



MON, AUG 26 1991 16:48

Fig. 4.4.1.a. : System totals

CIGRE STUDY OF SUMMER NIGHT: MP 3X275
NAT. 200, AD/PB 40 EA & 2 PUMPS ↑ 965 MW

MON. AUG 26 1991 16:51

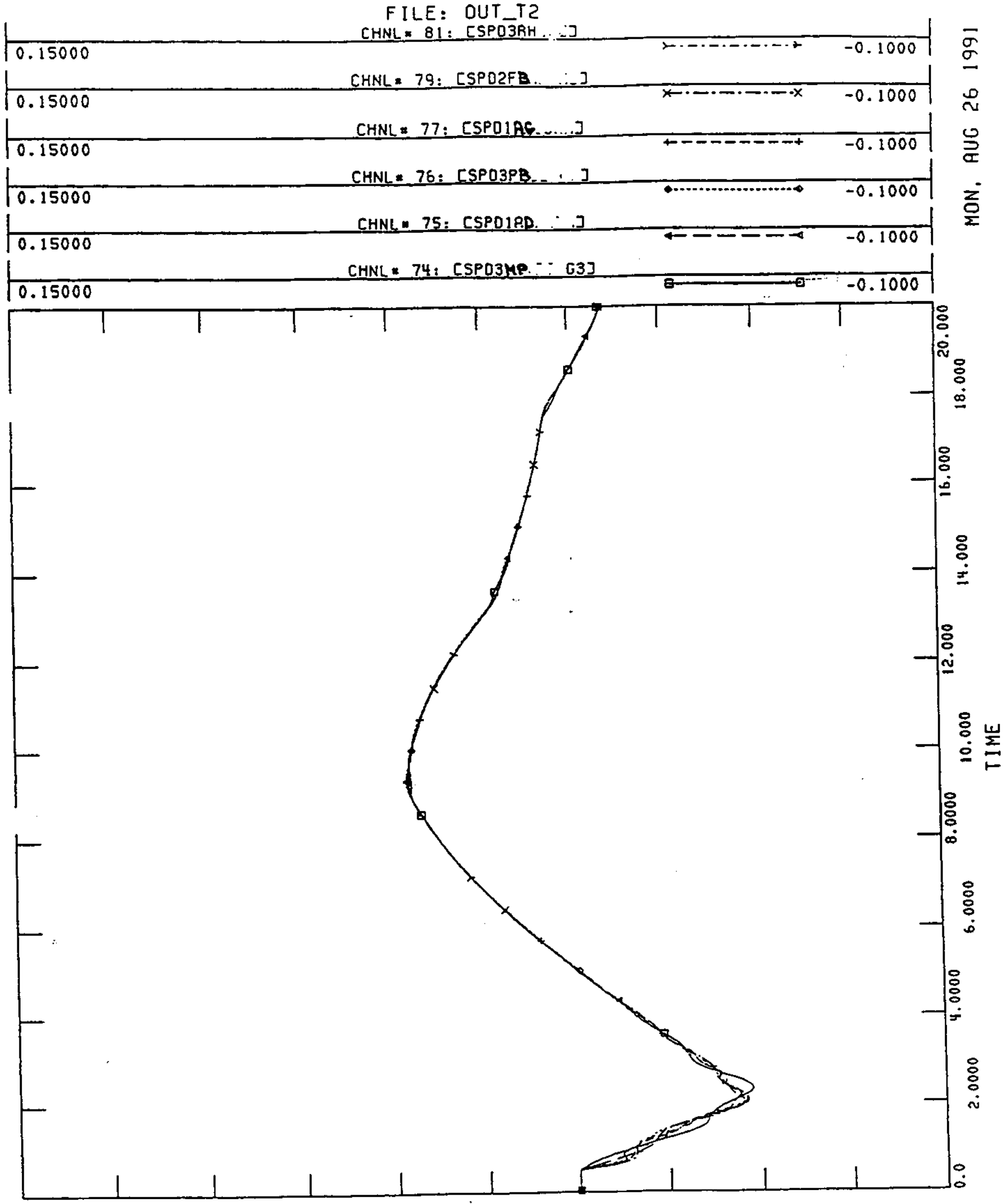


Fig 4.4.1b Speed of machines

CIGRE STUDY OF SUMMER NIGHT: MP 3X275
NAT. 200, AD/PB 40 EA & 2 PUMPS ↑ 965 MW

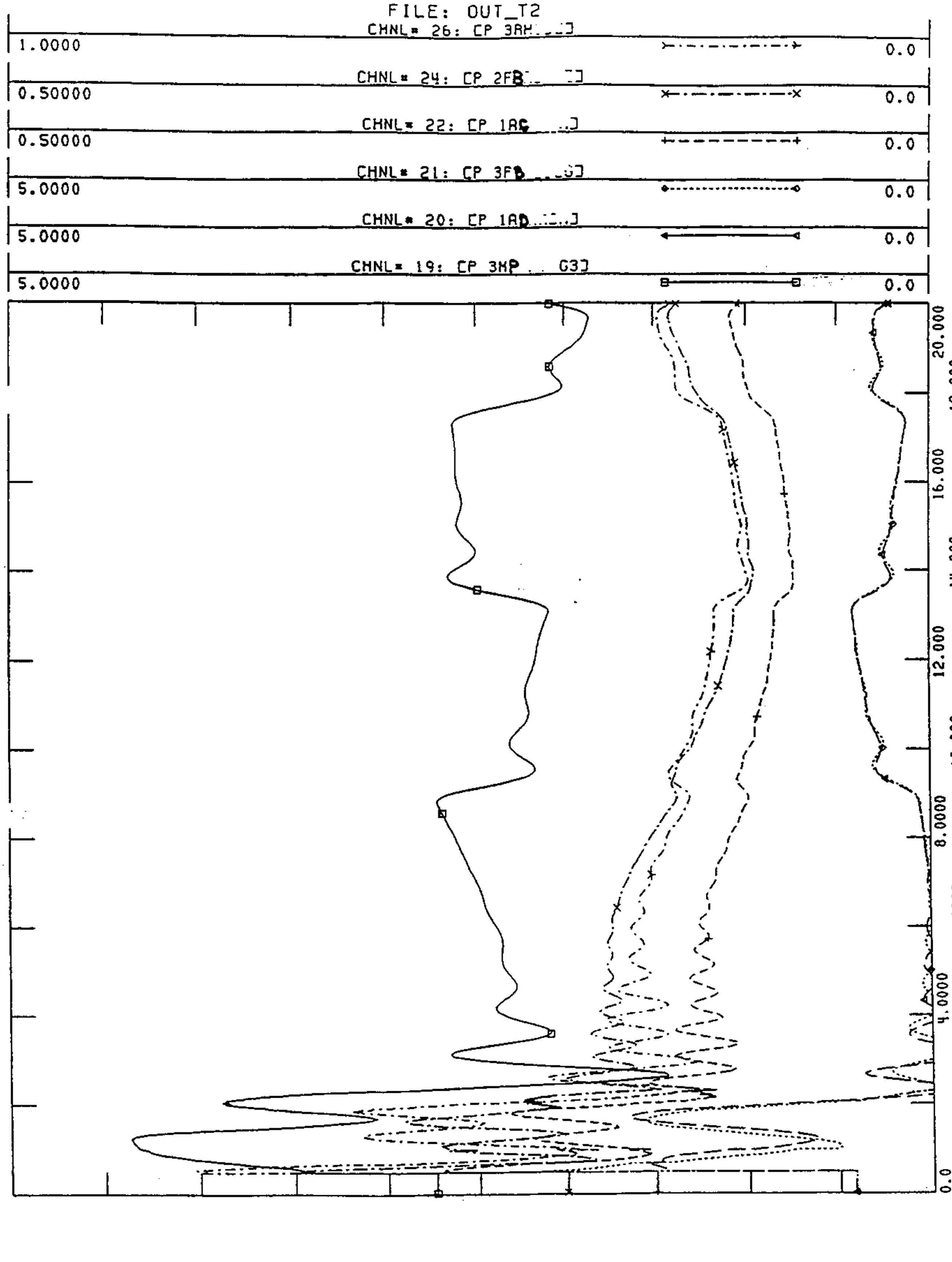


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Fig. 4.4.1.c.: Machine powers

CIGRE STUDY OF SUMMER NIGHT: MP 3X275
NAT. 200, AD/PB 40 EA & 2 PUMPS ↑ 965 MW

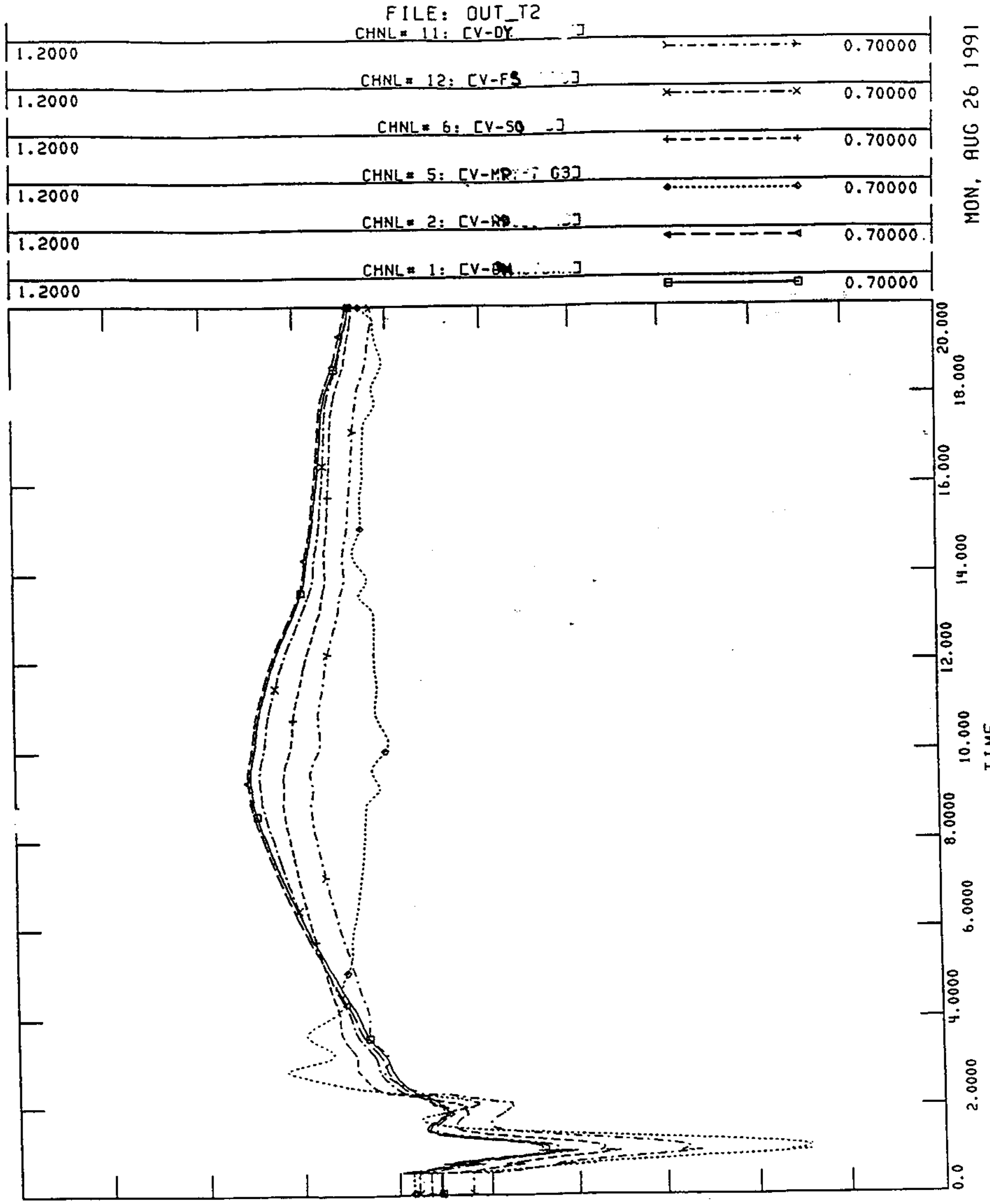

Fig. 4.4.1.d. : Selected Voltages

4.4.2. Simulation with PSS/E (run by PTI)

4.4.2.1. Introduction

This Chapter contains the results obtained by PTI using the extended term section of PSS/E (De Mello et al, 1992a, DeMello et al, 1992b) on the Irish test system described in Chapter 2.4 for which an initial 20 second simulation was provided in Chapter 4.4.1.

4.4.2.2. Study Data

The data used for the study was that given, except for the following :

All governor models were replaced with the steam turbine and boiler model "TGOV5". This model of a steam turbine and boiler represents governor action, main, reheat and low pressure effects, including boiler effects. The boiler controls will handle practically any mode of control including co-ordinated, base, variable pressure and conventional.

During the simulation pumped storage units at station TH were synchronised. These units used the PSS/E salient pole generation model, "GENSAL". The pumped storage units had simplified excitation units ("SEXS") with the same data as used by the other machines using this model. Lastly, these units had the hydro governor model "HYGOV".

4.4.2.3. Scenario

The simulation is for the loss of two units at station MP each generating 275 MW when the total system generation is 1105 MW. When this occurs, the generators' house load (2x22 MW) is also lost. The resulting frequency fall causes the under-frequency relays to trip load at the 110 kV busbars. This arrested the frequency fall within 2 seconds at approximately 47.78 Hz. However, the load shedding is too great leading to an excess of generation over demand and the frequency is seen to recover quickly and overshoot.

At 20 seconds it was assumed that most intermachine oscillation had died out so the assumption of equal machine speeds was made. This allowed the use of a time step of 0.2 seconds.

Next, the effects of an automatic load restoration scheme were modelled. The scheme is such that if frequency remains above 49.8 Hz for several seconds, 1% of system peak is restored every 6 seconds provided frequency remains above 49.8 Hz. In this simulation approximately 11 MW were reconnected at buses in inverse order of being shed starting 15 seconds after the frequency went above 49.8 Hz. The load at the highest load shedding steps of the under-frequency relays were connected first.

At 74 seconds, the pumped storage units were assumed to be synchronised as generators. Speed reference point were ramped up from 0 to the value they would have if initialised at full load in ten seconds.

The simulation was stopped at 270 seconds when the frequency went temporarily down to 49.8 Hz. If the frequency went above 49.8 Hz for 9 seconds the load restoration scheme would re-start. There are also several combustion turbine and hydro plants that could be eventually synchronised.

4.4.2.4. Results

The results of the scenario are shown in Figures 4.4.2.a to d. The plots of voltage show how because of loss of loading on lines, voltage is temporarily high and as load is restored voltages are slowly approaching their initial values.

4.4.2.5. Conclusions

The PSS/E extended term simulation program can be used to study longer term effects. The available modules make it convenient for the user.

4.4.2.6. References

DeMello, F.P., Laskowski, T.F., Feltes, J.W., Oppel, L.J., 1992a, "Computation Techniques for Simulation of Fast and Slow Dynamic Effects in Power Systems", 111 Symposium of Specialists in Electric Operational and Expansion Planning, Belo Horizonte, Brazil, May 18-22, 1992.

DeMello, F.P., Laskowski, T.F., Feltes, J.W., Oppel, L.J., 1992b, "Simulating Fast and Slow Dynamic Effects in Power Systems, IEEE Computer Applications in Power, Vol. 5, No. 3, July 1992.

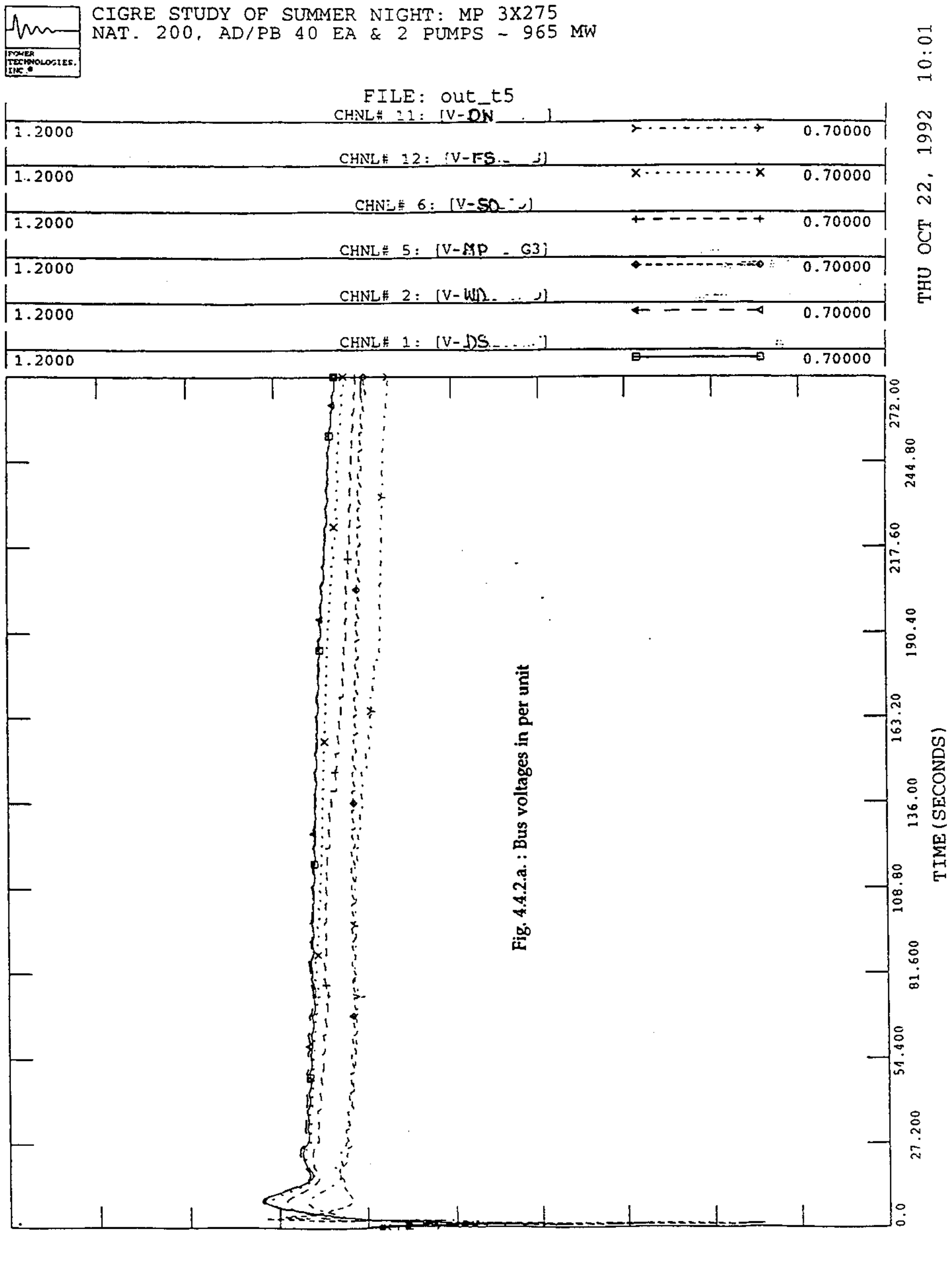

Fig. 4.4.2.a. : Bus voltages in per unit

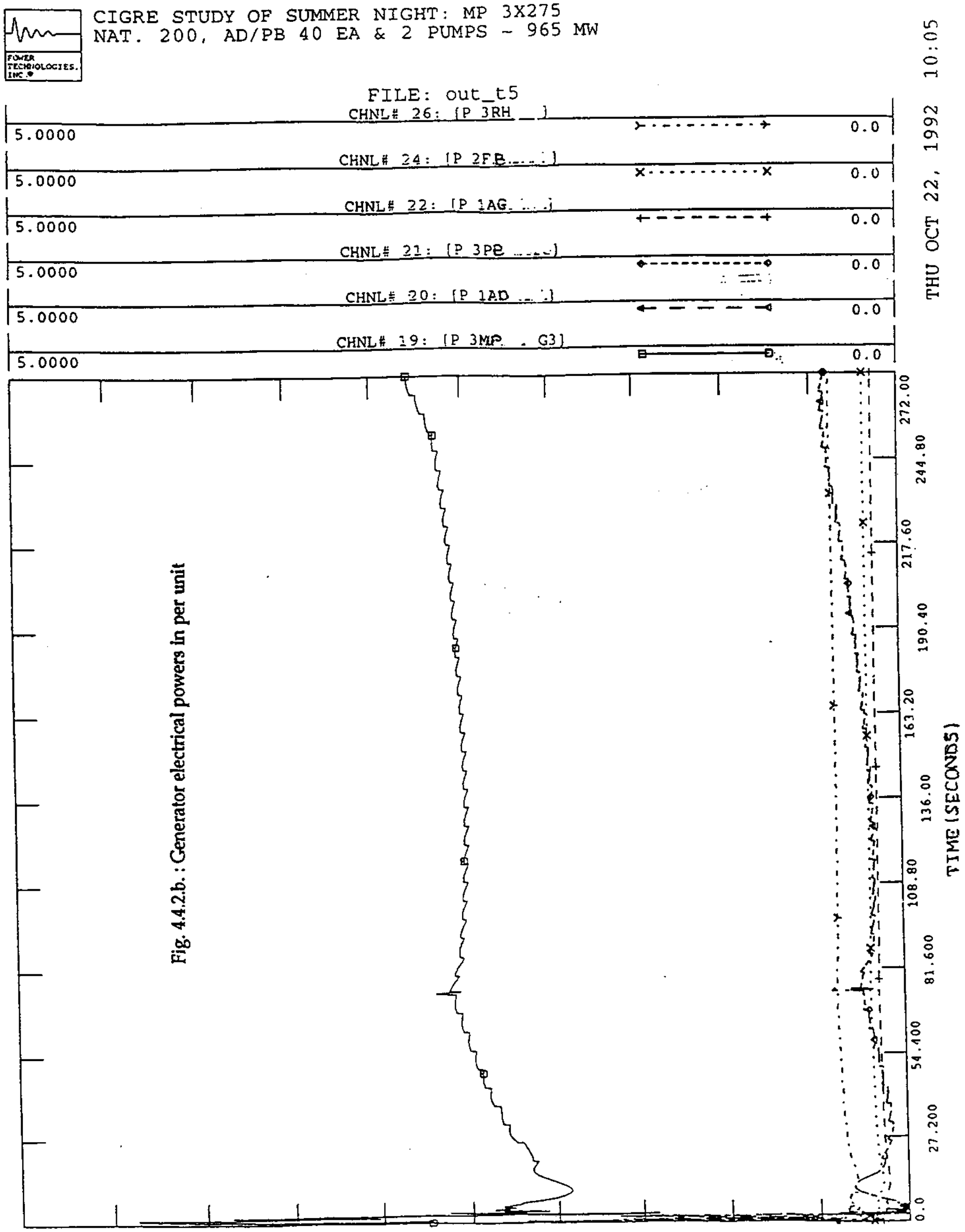

Fig. 4.4.2.b. : Generator electrical powers in per unit

POWER TECHNOLOGIES, INC.

CIGRE STUDY OF SUMMER NIGHT: MP 3X275
NAT. 200, AD/PB 40 EA & 2 PUMPS ~ 965 MW

FILE: out_t5

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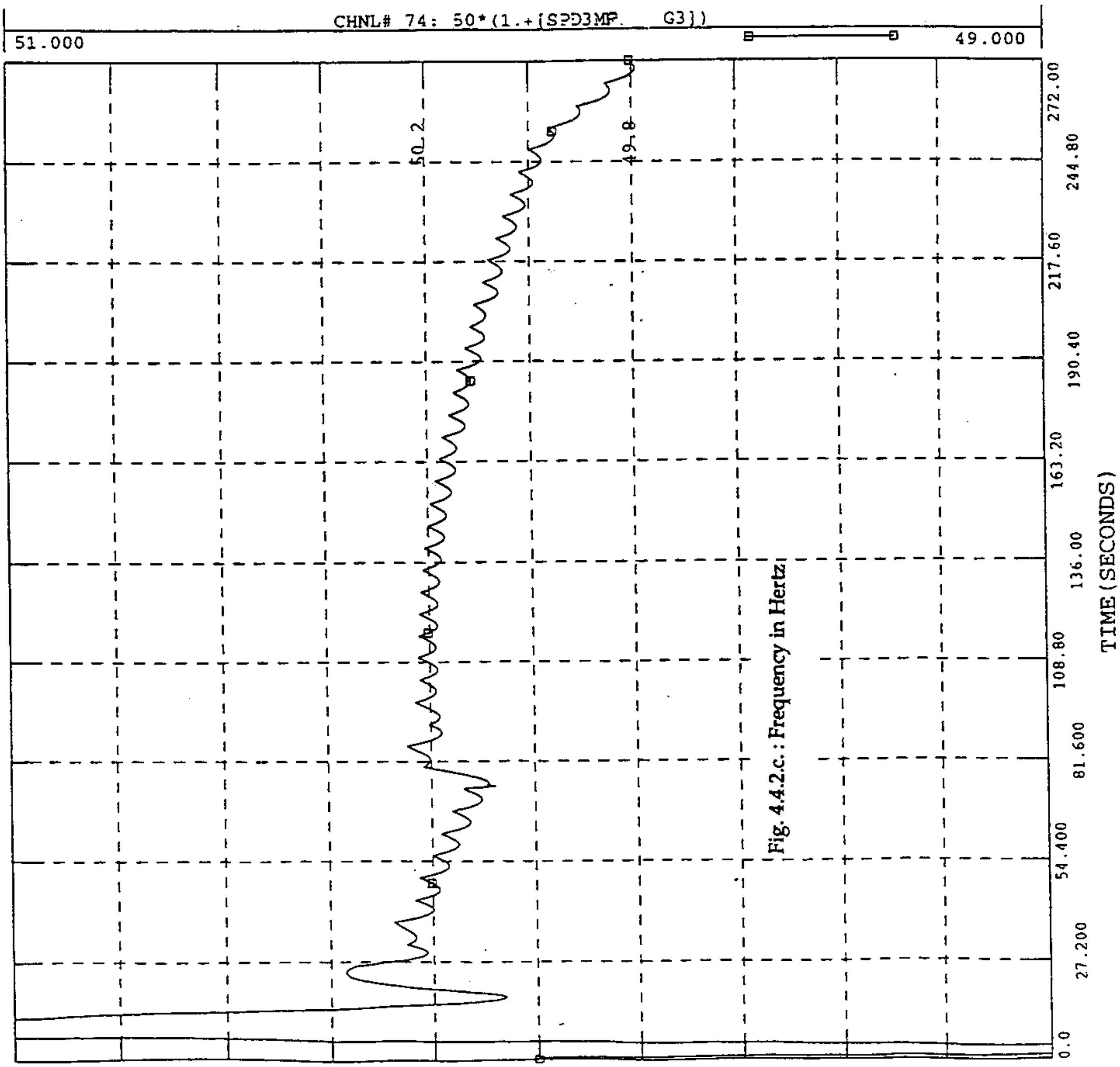


Fig. 4.4.2.c.: Frequency in Hertz

CIGRE STUDY OF SUMMER NIGHT: MP 3X275
NAT. 200, AD/PB 40 EA & 2 PUMPS ~ 965 MW

FILE: out_t5

THU OCT 22, 1992 10:09

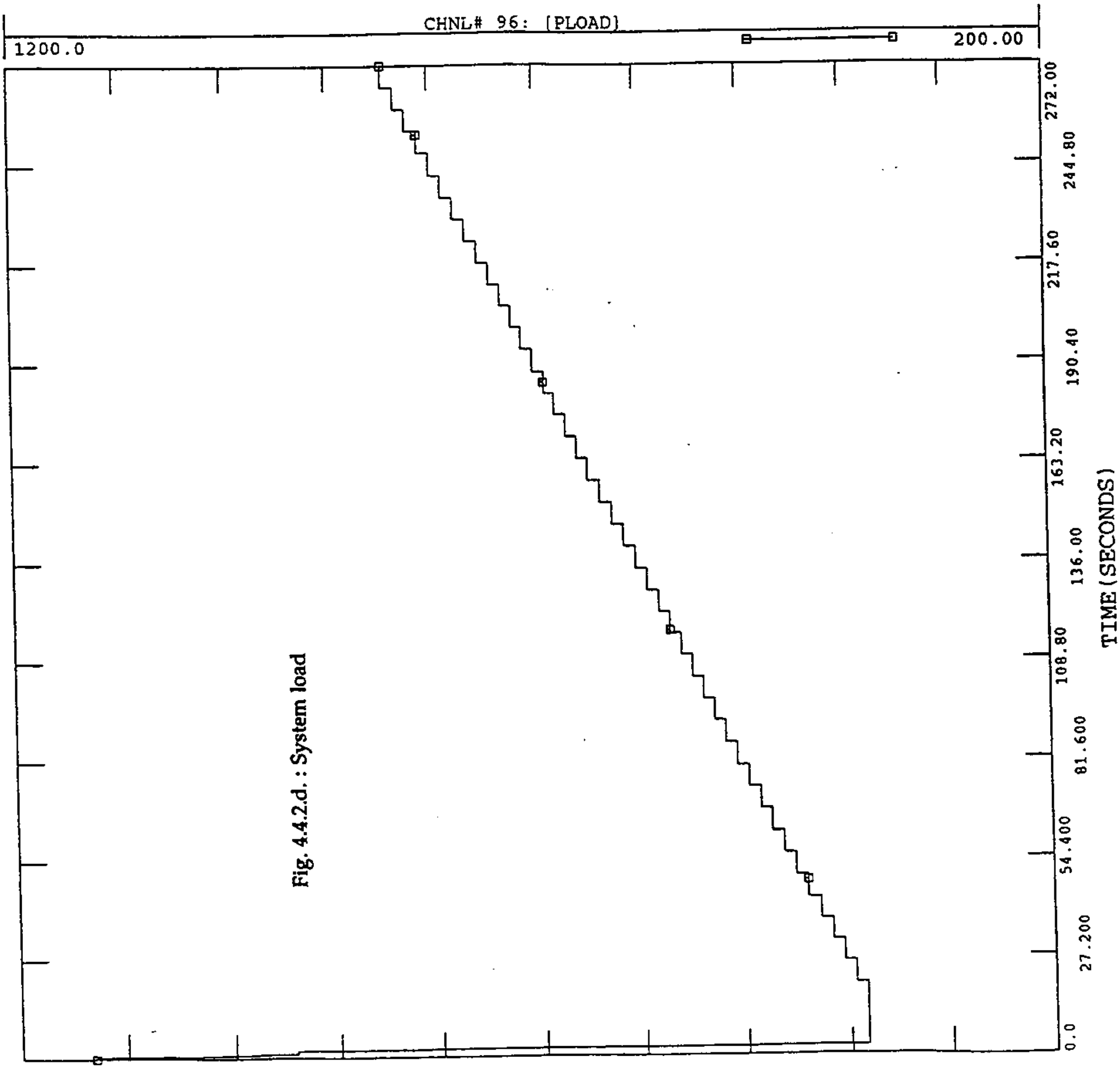


Fig. 4.4.2.d. : System load

4.4.3. Simulation with POSSUM (run by Nuclear Electric)

4.4.3.1. Study data and models

The data and models used in the POSSUM simulation of the Irish test system are as defined in chapter 2.4 with the following overriding assumptions and model changes :

i) Additional busbars were created to allow modelling of transmission transformer saturation effects as purely reactive loads dependent upon voltage and frequency in the way defined in chapter 2.4. This was done to allow the saturation admittances to be treated separately from the normal load admittances.

ii) The reactive loads associated with transformer saturation were included in the initial load-flow calculation assuming voltages and a frequency of 1 p.u. At the start of the transient the transformer saturation curves are used to determine the transformer saturation reactive powers. These curves differ from the assumptions made in the load flow about the dependency of the reactive power upon voltage and frequency. To allow a new steady state to be achieved following this discontinuity in the modelling, the transient specified in chapter 2.4. was preceded by 100 seconds during which no other events took place.

iii) The load shedding algorithm applies the load shedding fractions to the load admittances (real and imaginary). The power fraction shed therefore depends on the frequency and the local voltage.

iv) The shunt reactors on busbars 1036 and 1048 were moved to two additional adjoining busbars to keep them out of the load shedding schedule.

v) Generator transformers were represented explicitly in the network and their tap ratios were computed by initial load flow iteration to give voltages of 1 p.u. on the high voltage side with 1 p.u. set on the low voltage side under the load conditions specified in 2.4.

vi) If the system frequency drops below 49.8 Hz load restoration pauses and in all cases when the frequency rises above this limit load restoration restarts after a delay of 9 seconds.

vii) The open circuit time constants provided in 2.4. were converted to short circuit time constants as required by the POSSUM generator models.

viii) The pumped storage sets at TH and the other 4 hydro plants synchronised during this study used the "HYGOV" model used by PSS/E. This was represented in macro form and a P+I synchronising controller was added to control turbine speed prior to breaker closure. The windage loss coefficient was adjusted in each case to allow the required maximum power to be achieved. In all cases time constant TR was reduced to 0.3 seconds and the no load flow rate was reduced to 0.01 p.u.

ix) The time constant TN used in the MP governor model was set to 0.1 seconds throughout the POSSUM study.

x) The governor models specified in 2.4. contain no boiler modelling. Whilst this is an acceptable assumption for the short term transient (< 20 seconds), the running of the long term transient up to 500 seconds after the initiating event can only be regarded as an interim stage in preparing a simulation for a complete long term dynamics study in which boiler dynamics will play a significant role.

4.4.3.2. Event sequence

The following POSSUM simulation event sequence is expressed on a time base which includes the 100 seconds of quiescent state prior to the initiating event as specified in 2.4. :

t = 0	simulation begins
t = 100.5	generation lost from MP1 at 4111 and MP2 at 4211
t = 120	Vmax for AD1 at 2008 and PB3 at 2122 changed to 0.85 and governor setpoints ramped to 270 MW at 8 MW/min.
t = 166-176	all 4 machines TH1-4 at 2006 synchronised.
t = 400	hydro machines AA2 at 1117, LI2 at 1118, ER3 at 1110 and LE1 at 1115 synchronised and set points ramped at the rates specified in 2.4.
t = 600	simulation ends.

4.4.3.3. Results

(i) Short term (100-120 seconds)

Results over the period 100-120 seconds are shown in figures 4.4.3. a to e.

Figure 4.4.3.a shows that load shedding begins immediately following the generation loss at 100.5 seconds reducing the demand level to just above 400 MW compared to its initial level of 1090 MW. The new demand level accounts for the 2x22 MW houseload lost when the generators MP1 and MP2 were lost. The subsequent profiles of total system demand and total electrical generation reflect the dependency of the system loads upon frequency and voltage. Load restoration does not start within the first 19.5 seconds following the generation loss.

The short term frequency profile is detailed in figure 4.4.3.b and illustrates the effect of too much load shedding. The frequency reaches a peak of 1.041 p.u. after having recovered from a minimum of 0.955 p.u.

Voltage profiles at a selection of system busbars are shown in figure 4.4.3.c and reach as high as 1.13 p.u. as a result of lost reactive power absorption on the new lightly loaded transmission system.

The steam plant governor response are shown in figure 4.4.3.d with the MP3 mechanical power response playing the dominant role. The corresponding electrical power responses are shown in Figure 4.4.3.e..

(ii) Long term (0-600 seconds)

Results over the period 100-120 seconds are shown in figures 4.4.3.f to p) Item x in 4.4.3.1. should be kept in mind when assessing these results.

Figure 4.4.3.f shows a profile of the integration time step adopted by the WARP2 implicit integration algorithm [1] used during this simulation.

Figures 4.4.3.g to i show the system total demand and electrical generation, frequency and selected system busbar voltages over the full 600 seconds of the long term simulation. Load restoration is shown to pause at 350 seconds before restarting at 400 seconds when 4 hydro plants are synchronised.

Figure 4.4.3.j. shows the steam plant mechanical power responses and, between 200 and 350 seconds, illustrates governor responses to frequency falling to the point at which load restoration pauses. In the case of PB3, the governor frequency response dominates the ramping up of its set point. Modelling of boiler response would have an important impact on this phase of the simulation. figure 4.4.3.k shows the corresponding generator electrical powers.

Figure 4.4.3.l shows the mechanical power responses of the pumped storage and hydro plants. Only one pumped storage generator (TH2) reaches full power on account of the frequency subsequently rising above the 50.1 Hz limit for full power scheduling as specified in chapter 2.4. The other 3 pumped storage units rise to 5 MW where governor action takes over. The corresponding electrical powers are shown in figure 4.4.3.m and show the effects of imperfect synchronisation procedures.

Figures 4.4.3.n to p illustrate the events surrounding a machine angle excursion and recovery at PB3. Whilst an increase in the reactive absorption of the transmission system might be expected as the system demand and generation increase, so relieving PB3 of its reactive absorption overload, the precise reason for the apparent machine angle excursion and its subsequent recovery has not been identified. This simulated effect would beg further investigation. The field voltages in figure 4.4.3.p are on the same base as terminal voltages.

4.4.3.4. Conclusion

The use of POSSUM in simulating long term dynamics has been demonstrated on the Irish test system. The simulation presented would form an interim stage in a long term dynamics study in which, at a later stage, models of boiler dynamics would need to be included. Such models would be included in the POSSUM simulation either by block diagram entry and making use of the CDF macro or by direct macro representation in POSSUM.

4.4.3.5. Reference

[1] T.H.E. Chambers, M.J. Whitmarsh-Everiss; "A Methodology for the Design of Plant Analysers", Advances in Nuclear Science and Technology, Vol. 17, 1984 (1).

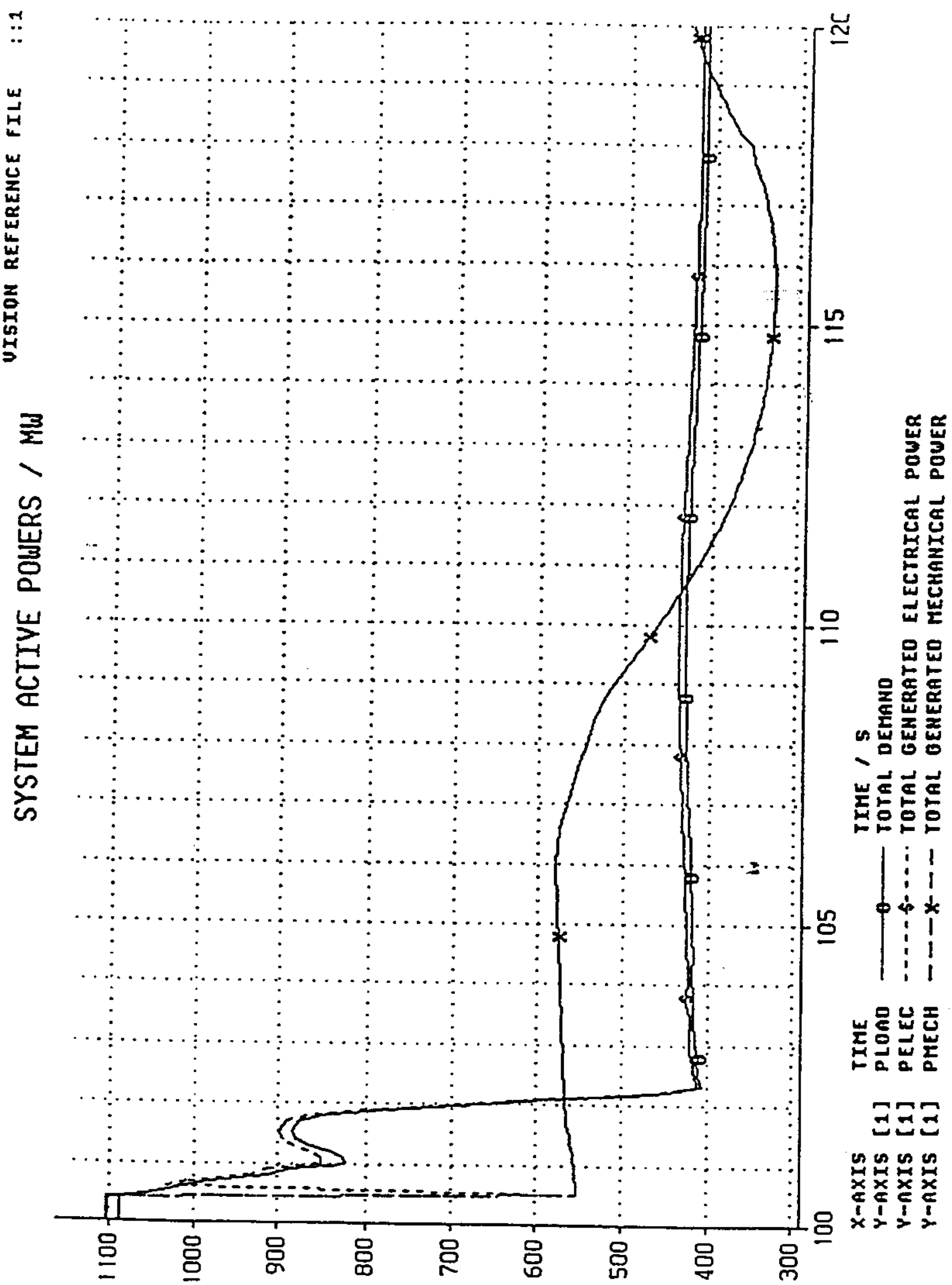

SYSTEM ACTIVE POWERS / MW
VISION REFERENCE FILE ::1
1100
1000
900
800
700
600
500
400
300
100
105
110
115
120
X-AXIS TIME TIME / S
Y-AXIS [1] PLOAD TOTAL DEMAND
Y-AXIS [1] PELEC TOTAL GENERATED ELECTRICAL POWER
Y-AXIS [1] PMECH TOTAL GENERATED MECHANICAL POWER

Figure 4.4.3.a.

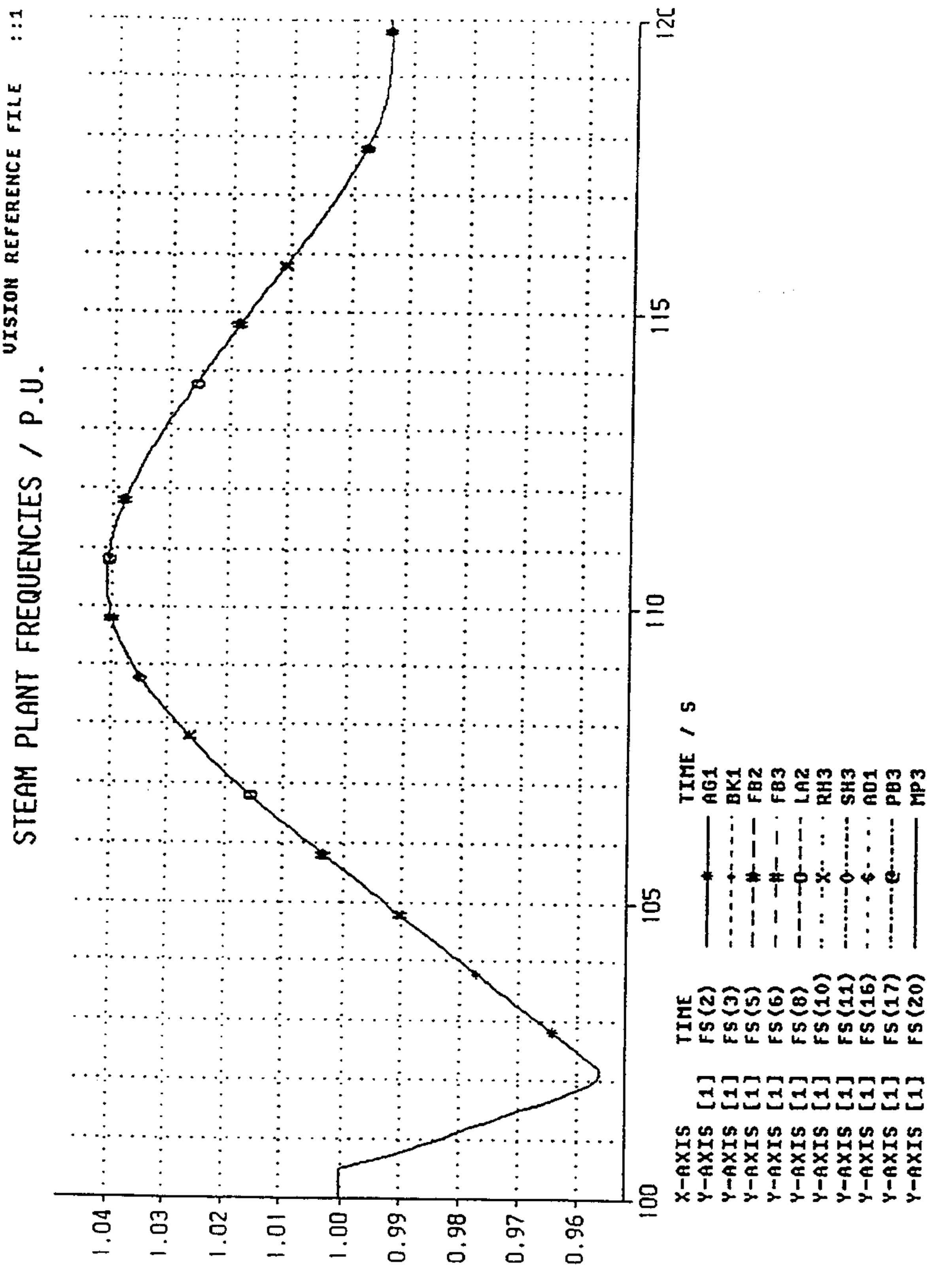

STEAM PLANT FREQUENCIES / P.U.
VISION REFERENCE FILE ::1
1.04
1.03
1.02
1.01
1.00
0.99
0.98
0.97
0.96
100
105
110
115
120
TIME / S
X-AXIS TIME TIME
Y-AXIS [1] FS(2) AG1
Y-AXIS [1] FS(3) BK1
Y-AXIS [1] FS(5) FB2
Y-AXIS [1] FS(6) FB3
Y-AXIS [1] FS(8) LA2
Y-AXIS [1] FS(10) RH3
Y-AXIS [1] FS(11) SH3
Y-AXIS [1] FS(16) AD1
Y-AXIS [1] FS(17) PB3
Y-AXIS [1] FS(20) MP3

Figure 4.4.3.b.

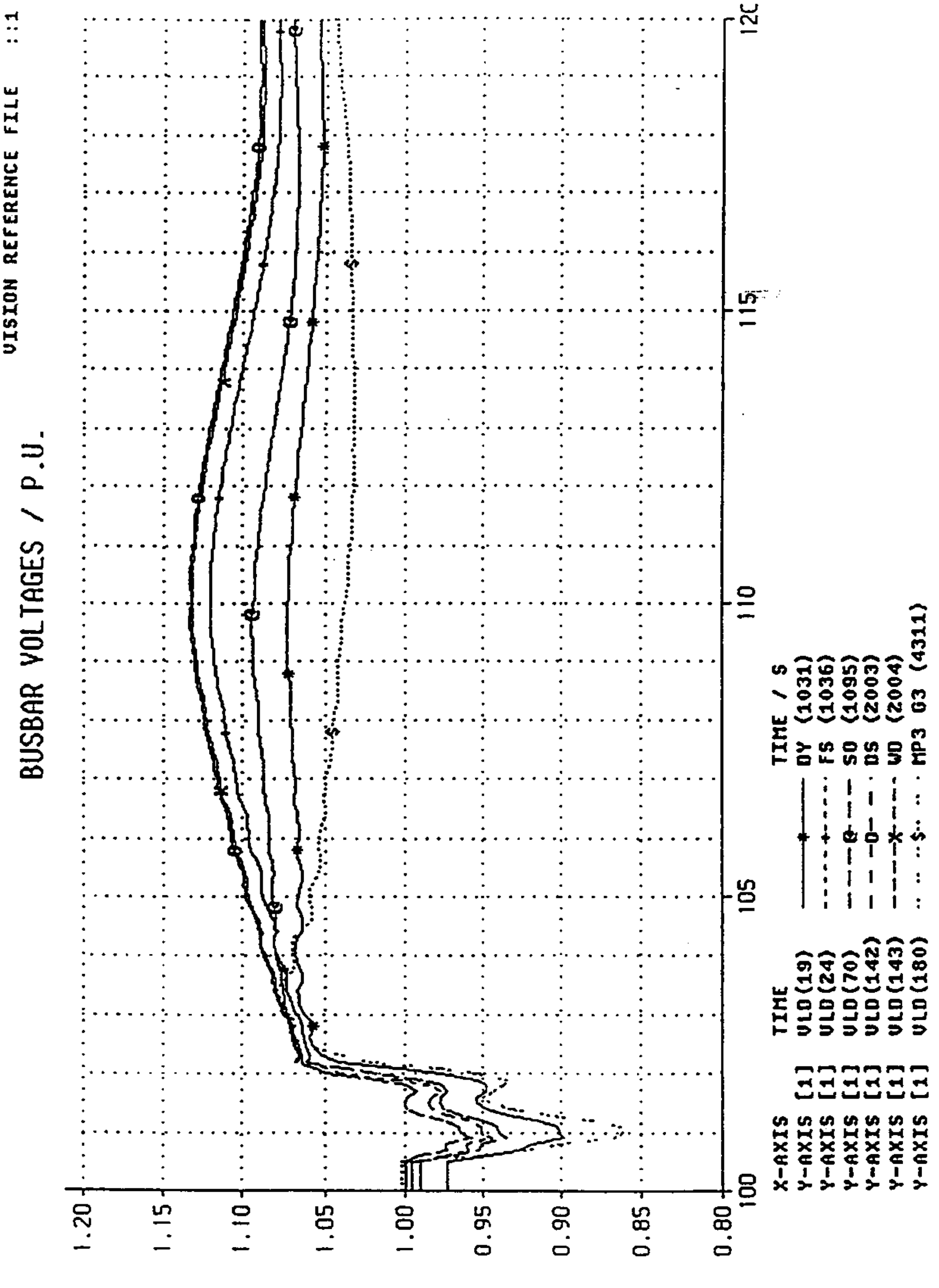

BUSBAR VOLTAGES / P.U.
VISION REFERENCE FILE ::1
1.20
1.15
1.10
1.05
1.00
0.95
0.90
0.85
0.80
100
105
110
115
120
X-AXIS TIME TIME / S
Y-AXIS [1] VLD(19) DY (1031)
Y-AXIS [1] VLD(24) FS (1036)
Y-AXIS [1] VLD(70) SD (1095)
Y-AXIS [1] VLD(142) DS (2003)
Y-AXIS [1] VLD(143) WD (2004)
Y-AXIS [1] VLD(180) MP3 G3 (4311)

Figure 4.4.3.c.

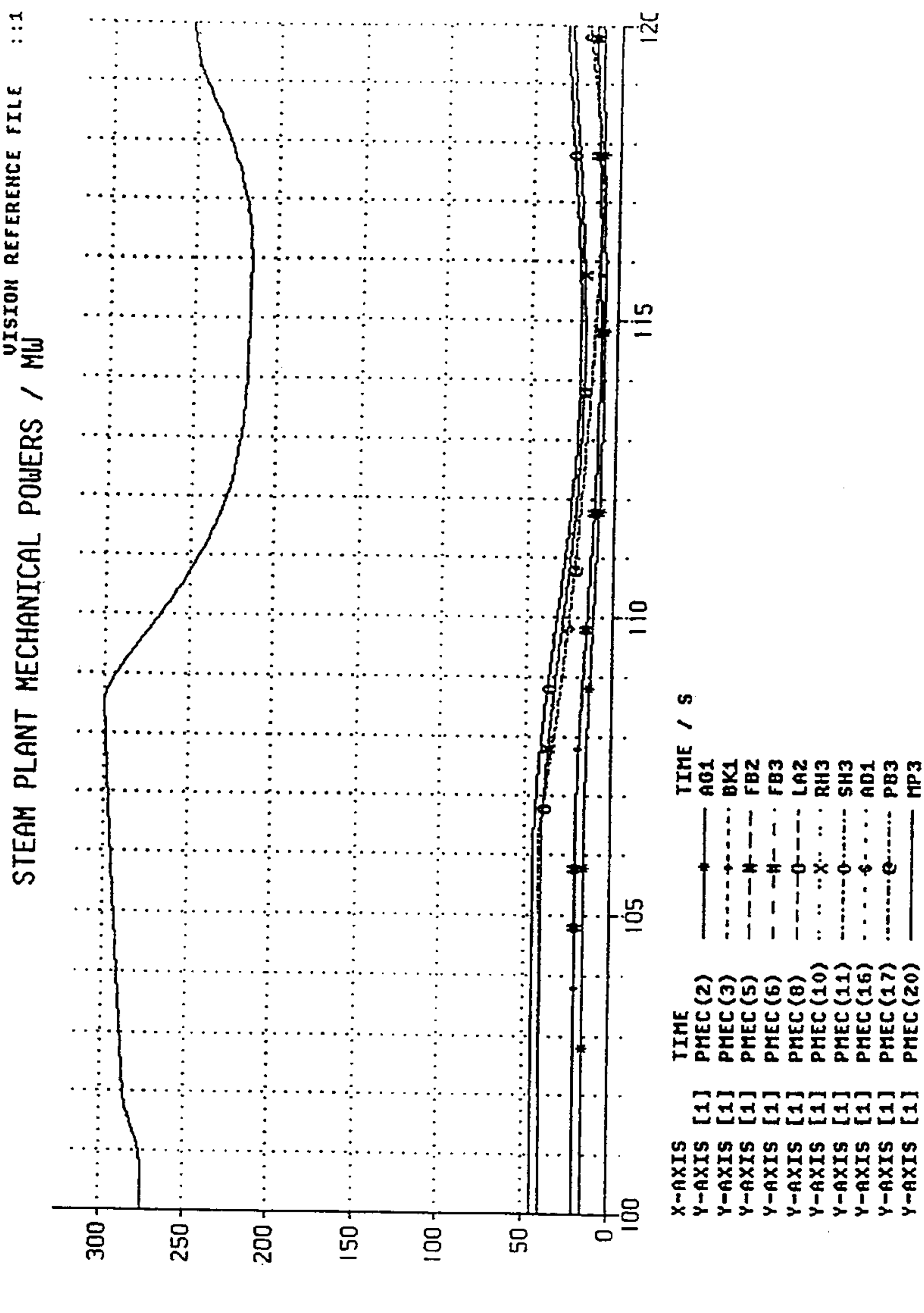

STEAM PLANT MECHANICAL POWERS / MW
VISION REFERENCE FILE ::1
300
250
200
150
100
50
0
100
105
110
115
120
TIME / S
X-AXIS TIME
Y-AXIS [1] PMEC(2) AG1
Y-AXIS [1] PMEC(3) BK1
Y-AXIS [1] PMEC(5) FB2
Y-AXIS [1] PMEC(6) FB3
Y-AXIS [1] PMEC(8) LA2
Y-AXIS [1] PMEC(10) RH3
Y-AXIS [1] PMEC(11) SH3
Y-AXIS [1] PMEC(16) AD1
Y-AXIS [1] PMEC(17) PB3
Y-AXIS [1] PMEC(20) MP3

Figure 4.4.3.d.

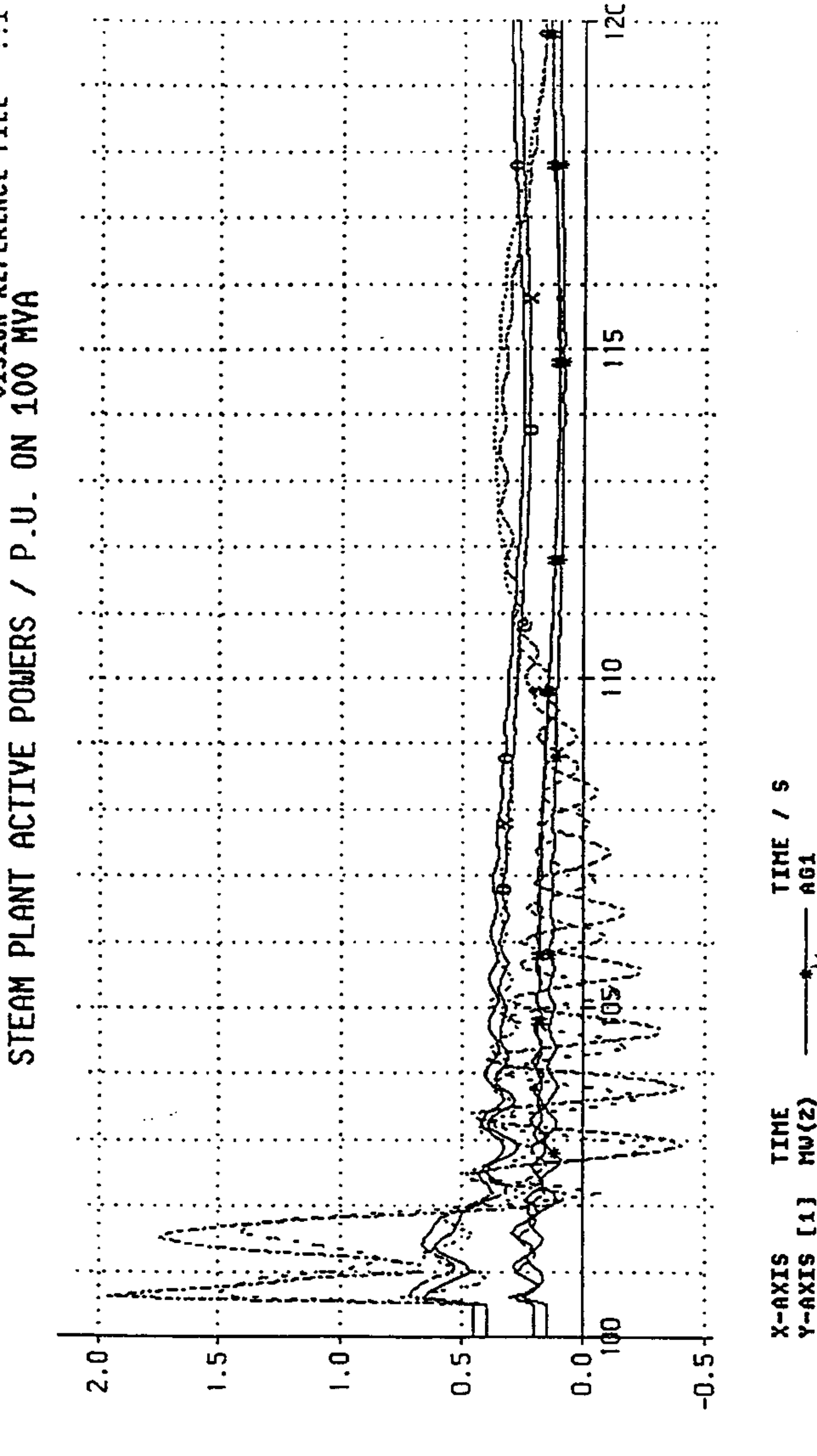

STEAM PLANT ACTIVE POWERS / P.U. ON 100 MVA
VISION REFERENCE FILE ::1
2.0
1.5
1.0
0.5
0.0
-0.5
100
105
110
115
12C
TIME / S
X-AXIS TIME
Y-AXIS [1] MW(2) AG1
Y-AXIS [1] MW(3) BK1
Y-AXIS [1] MW(5) FB2
Y-AXIS [1] MW(6) FB3
Y-AXIS [1] MW(8) LA2
Y-AXIS [1] MW(10) RH3
Y-AXIS [1] MW(11) SH3
Y-AXIS [1] MW(16) AD1
Y-AXIS [1] MW(17) PB3

Figure 4.4.3.e.

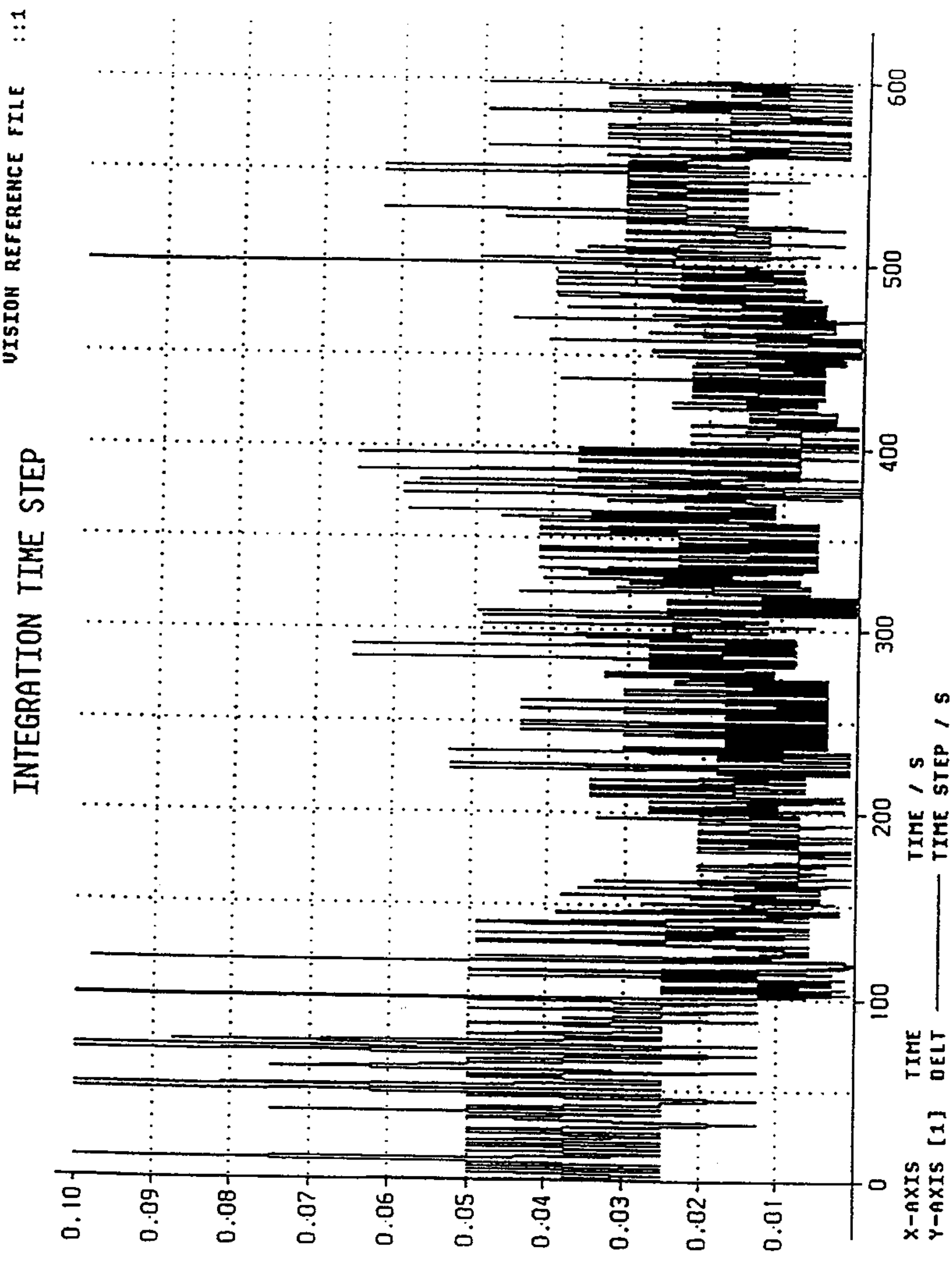

INTEGRATION TIME STEP
VISION REFERENCE FILE ::1
0.10
0.09
0.08
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0
100
200
300
400
500
600
X-AXIS TIME
Y-AXIS [1] DELT
TIME / S
TIME STEP / S

Figure 4.4.3.f.

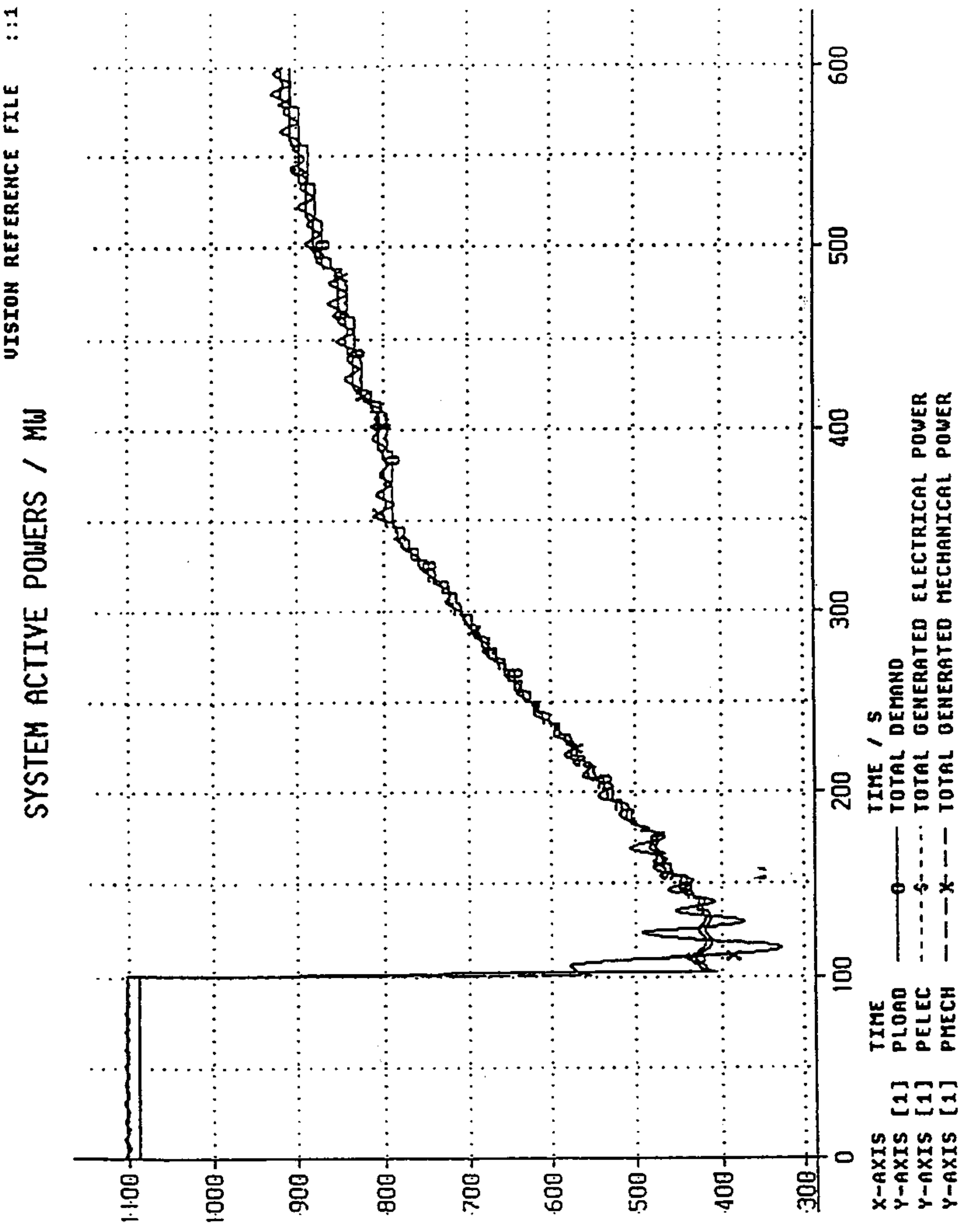

SYSTEM ACTIVE POWERS / MW
VISION REFERENCE FILE ::1
1100
1000
900
800
700
600
500
400
300
0
100
200
300
400
500
600
TIME / S
X-AXIS TIME
Y-AXIS [1] PLOAD ——0—— TOTAL DEMAND
Y-AXIS [1] PELEC ----$---- TOTAL GENERATED ELECTRICAL POWER
Y-AXIS [1] PMECH —·—*—·— TOTAL GENERATED MECHANICAL POWER

Figure 4.4.3.g.

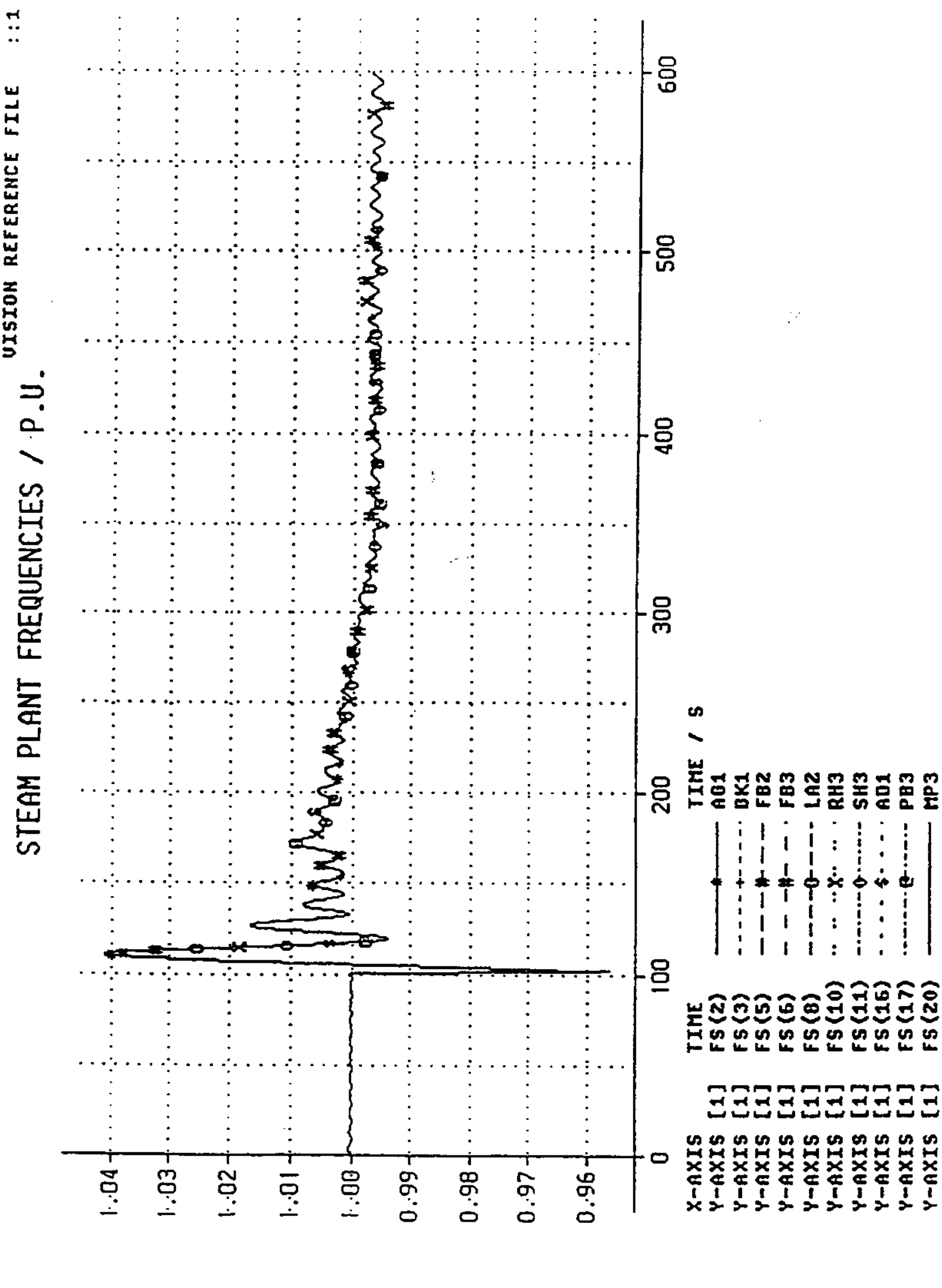

STEAM PLANT FREQUENCIES / P.U.
VISION REFERENCE FILE ::1
1.04
1.03
1.02
1.01
1.00
0.99
0.98
0.97
0.96
0
100
200
300
400
500
600
TIME / S
X-AXIS TIME
Y-AXIS [1] FS(2) AG1
Y-AXIS [1] FS(3) DK1
Y-AXIS [1] FS(5) FB2
Y-AXIS [1] FS(6) FB3
Y-AXIS [1] FS(8) LA2
Y-AXIS [1] FS(10) RH3
Y-AXIS [1] FS(11) SH3
Y-AXIS [1] FS(16) AD1
Y-AXIS [1] FS(17) PB3
Y-AXIS [1] FS(20) MP3

Figure 4.4.3.h.

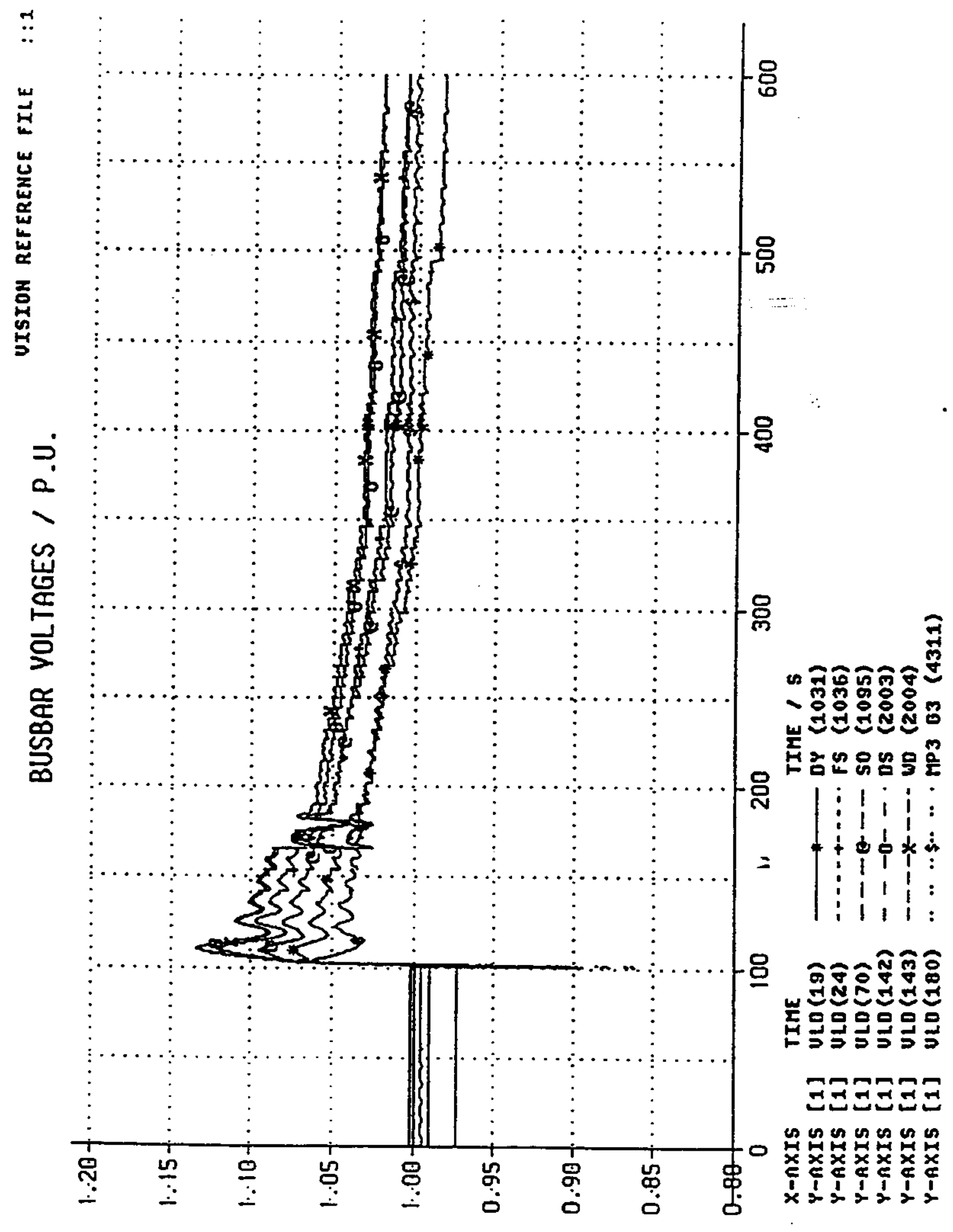

BUSBAR VOLTAGES / P.U.
VISION REFERENCE FILE ::1
1.20
1.15
1.10
1.05
1.00
0.95
0.90
0.85
0.80
0
100
200
300
400
500
600
TIME / S
X-AXIS TIME
Y-AXIS [1] VLD(19) DY (1031)
Y-AXIS [1] VLD(24) FS (1036)
Y-AXIS [1] VLD(70) SO (1095)
Y-AXIS [1] VLD(142) DS (2003)
Y-AXIS [1] VLD(143) VD (2004)
Y-AXIS [1] VLD(180) MP3 G3 (4311)

Figure 4.4.3.i.

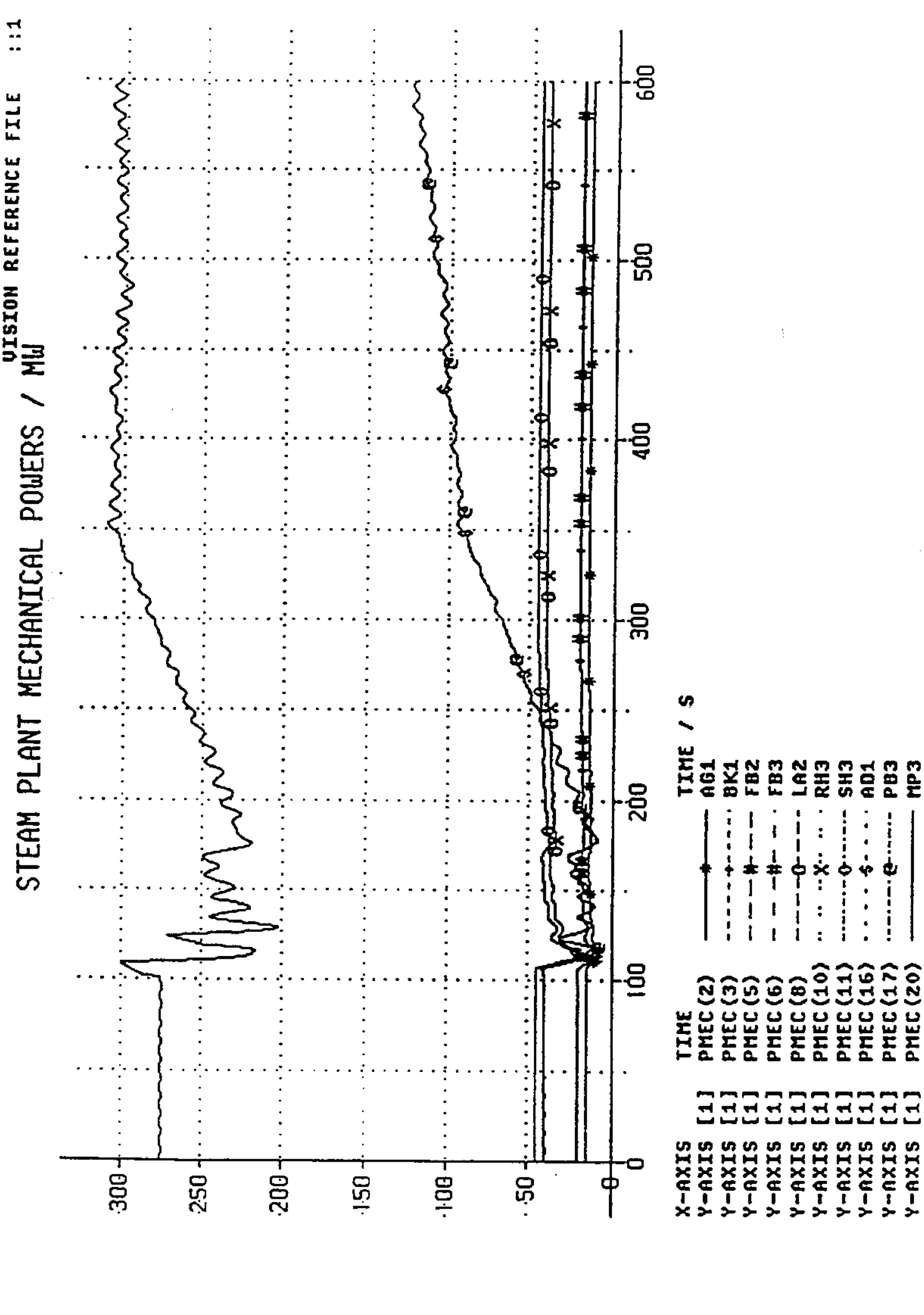
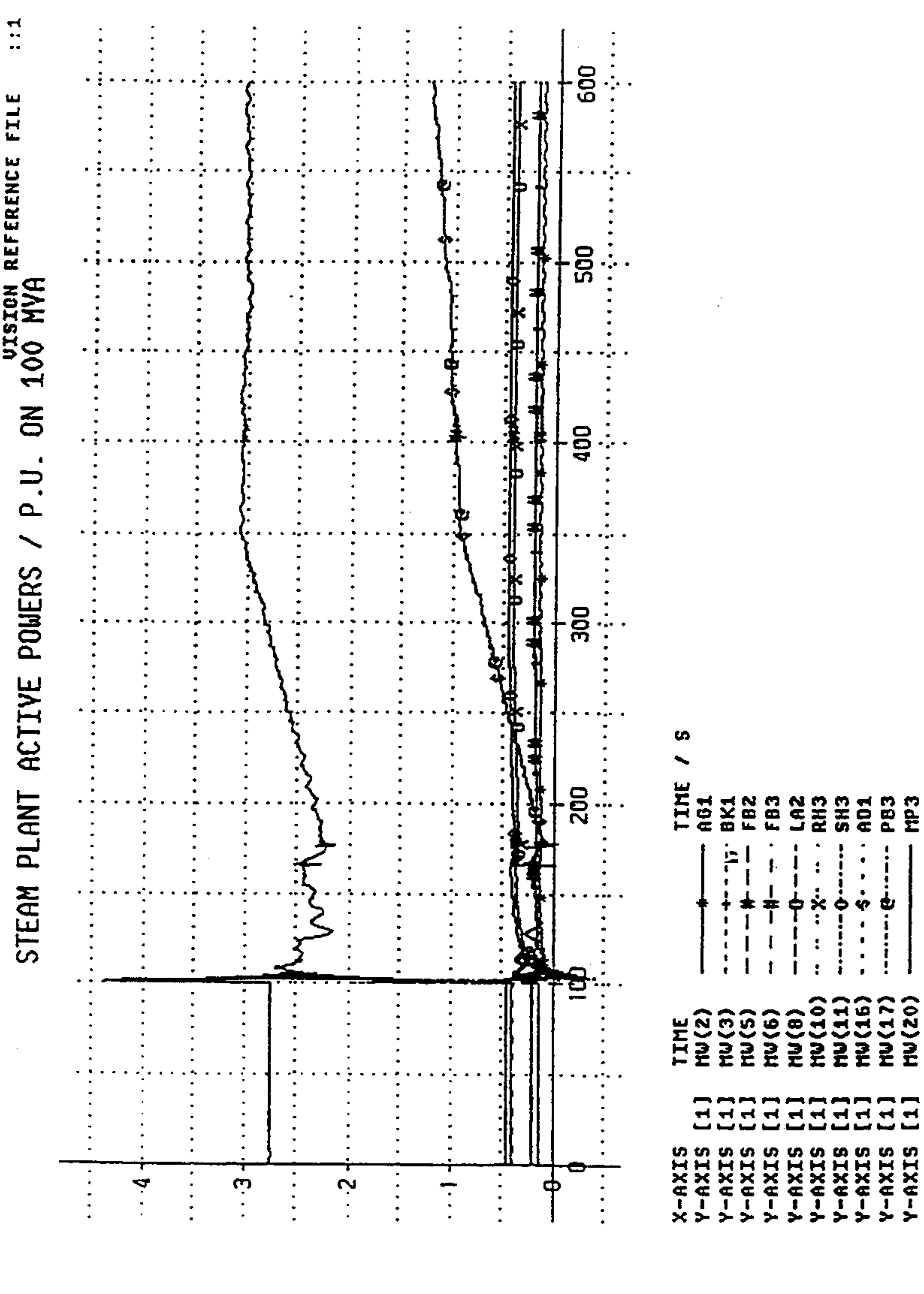

STEAM PLANT MECHANICAL POWERS / MW
VISION REFERENCE FILE ::1
300
250
200
150
100
50
0
0
100
200
300
400
500
600
TIME / S
X-AXIS TIME
Y-AXIS [1] PMEC(2) AG1
Y-AXIS [1] PMEC(3) BK1
Y-AXIS [1] PMEC(5) FB2
Y-AXIS [1] PMEC(6) FB3
Y-AXIS [1] PMEC(8) LA2
Y-AXIS [1] PMEC(10) RH3
Y-AXIS [1] PMEC(11) SH3
Y-AXIS [1] PMEC(16) AD1
Y-AXIS [1] PMEC(17) PB3
Y-AXIS [1] PMEC(20) MP3

Figure 4.4.3.j.



STEAM PLANT ACTIVE POWERS / P.U. ON 100 MVA
VISION REFERENCE FILE ::1
0
1
2
3
4
0
100
200
300
400
500
600
X-AXIS TIME TIME / S
Y-AXIS [1] MW(2) AG1
Y-AXIS [1] MW(3) BK1
Y-AXIS [1] MW(5) FB2
Y-AXIS [1] MW(6) FB3
Y-AXIS [1] MW(8) LA2
Y-AXIS [1] MW(10) RH3
Y-AXIS [1] MW(11) SH3
Y-AXIS [1] MW(16) AD1
Y-AXIS [1] MW(17) PB3
Y-AXIS [1] MW(20) MP3

Figure 4.4.3.k.

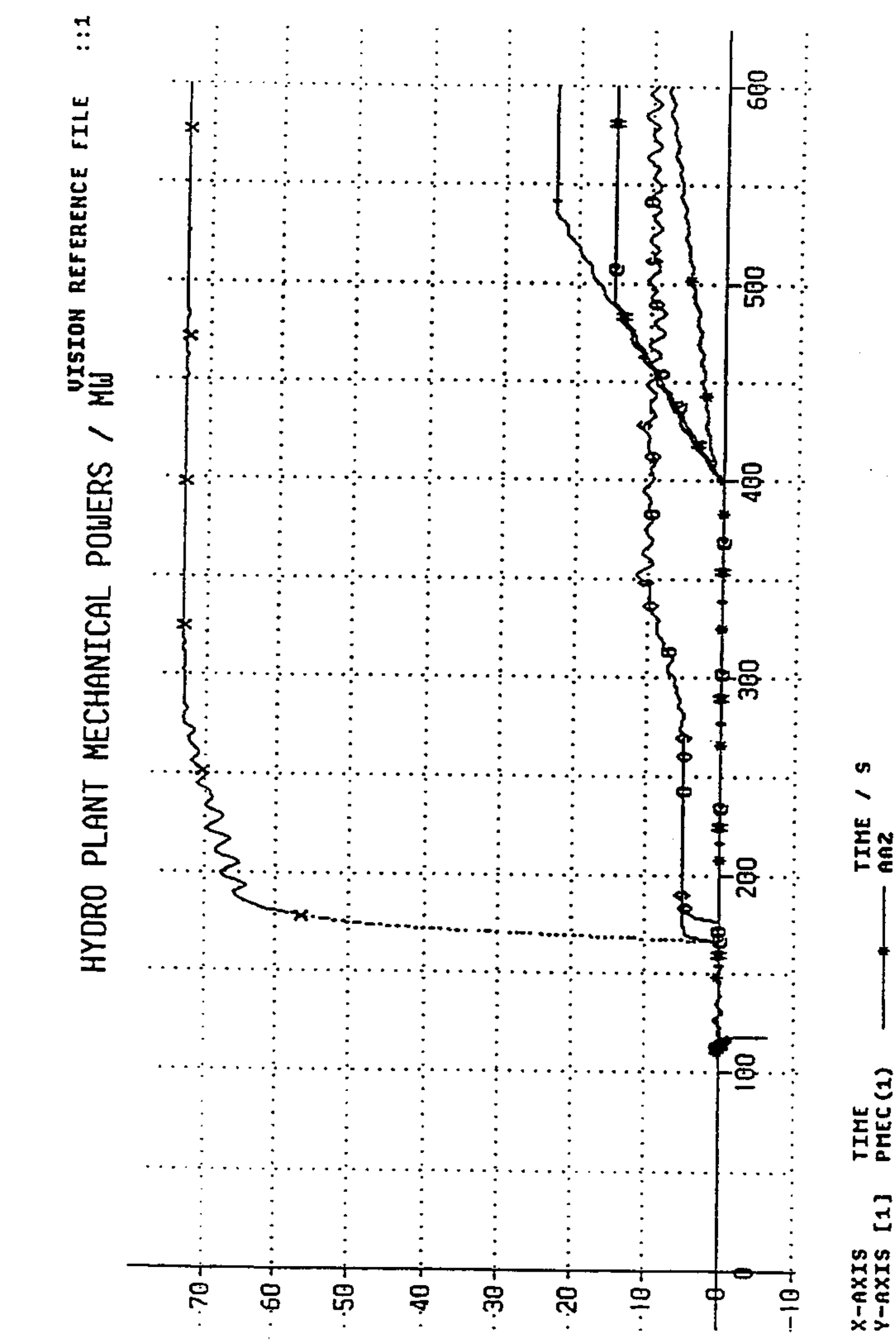

HYDRO PLANT MECHANICAL POWERS / MW
VISION REFERENCE FILE ::1
70
60
50
40
30
20
10
0
-10
0
100
200
300
400
500
600
TIME / S
X-AXIS TIME
Y-AXIS [1] PMEC(1) AA2
Y-AXIS [1] PMEC(4) ER3
Y-AXIS [1] PMEC(7) LE1
Y-AXIS [1] PMEC(9) LI2
Y-AXIS [1] PMEC(12) TH1
Y-AXIS [1] PMEC(13) TH2
Y-AXIS [1] PMEC(14) TH3
Y-AXIS [1] PMEC(15) TH4

Figure 4.4.3.1.

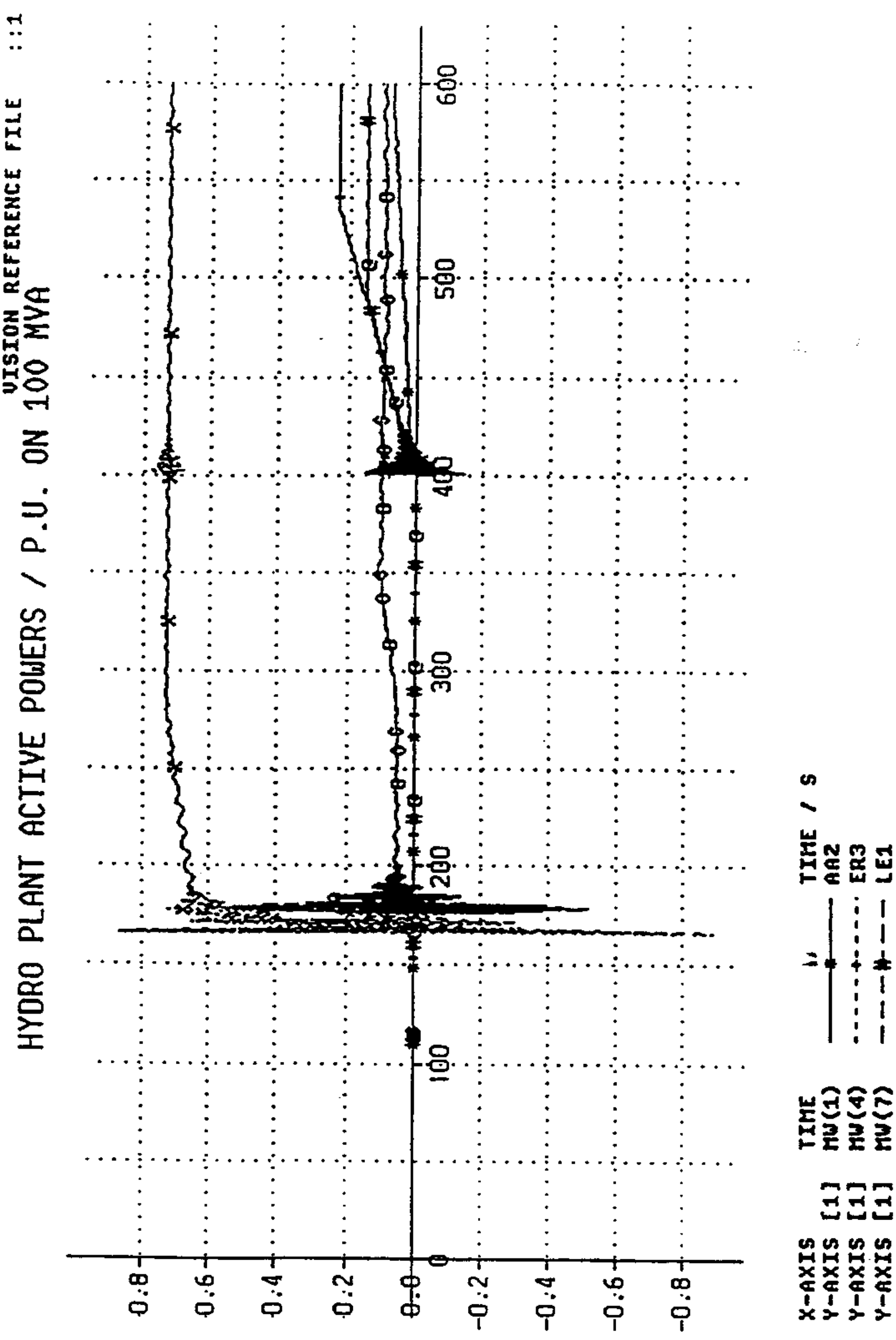

HYDRO PLANT ACTIVE POWERS / P.U. ON 100 MVA
VISION REFERENCE FILE ::1
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
-0.6
-0.8
0
100
200
300
400
500
600
TIME / S
X-AXIS TIME
Y-AXIS [1] MW(1) AA2
Y-AXIS [1] MW(4) ER3
Y-AXIS [1] MW(7) LE1
Y-AXIS [1] MW(9) LI2
Y-AXIS [1] MW(12) TH1
Y-AXIS [1] MW(13) TH2
Y-AXIS [1] MW(14) TH3
Y-AXIS [1] MW(15) TH4

Figure 4.4.3.m.

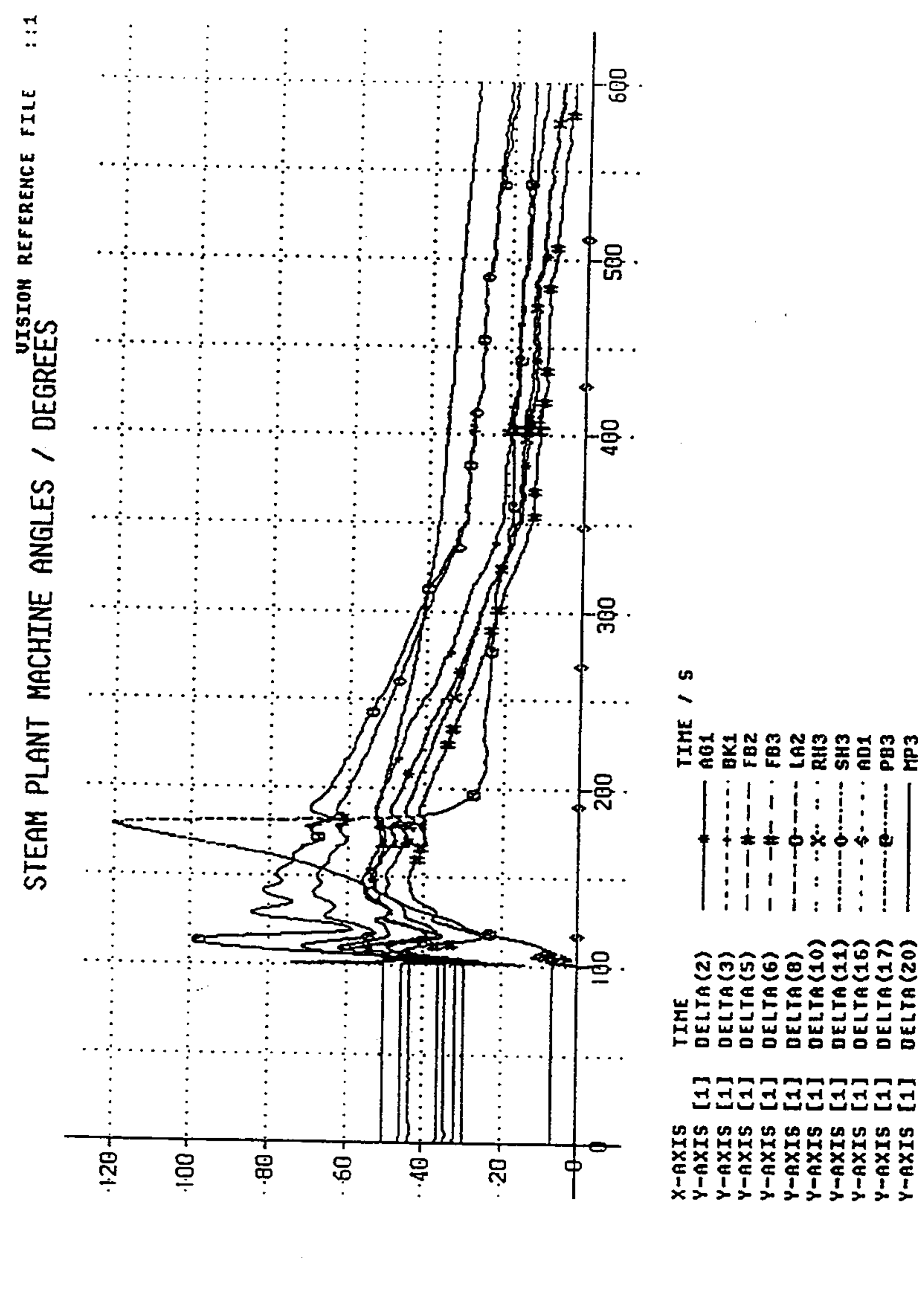

STEAM PLANT MACHINE ANGLES / DEGREES
VISION REFERENCE FILE ::1
0
20
40
60
80
100
120
100
200
300
400
500
600
TIME / S
X-AXIS TIME
Y-AXIS [1] DELTA(2) AG1
Y-AXIS [1] DELTA(3) BK1
Y-AXIS [1] DELTA(5) FB2
Y-AXIS [1] DELTA(6) FB3
Y-AXIS [1] DELTA(8) LA2
Y-AXIS [1] DELTA(10) RH3
Y-AXIS [1] DELTA(11) SH3
Y-AXIS [1] DELTA(16) AD1
Y-AXIS [1] DELTA(17) PB3
Y-AXIS [1] DELTA(20) MP3

Figure 4.4.3.n.

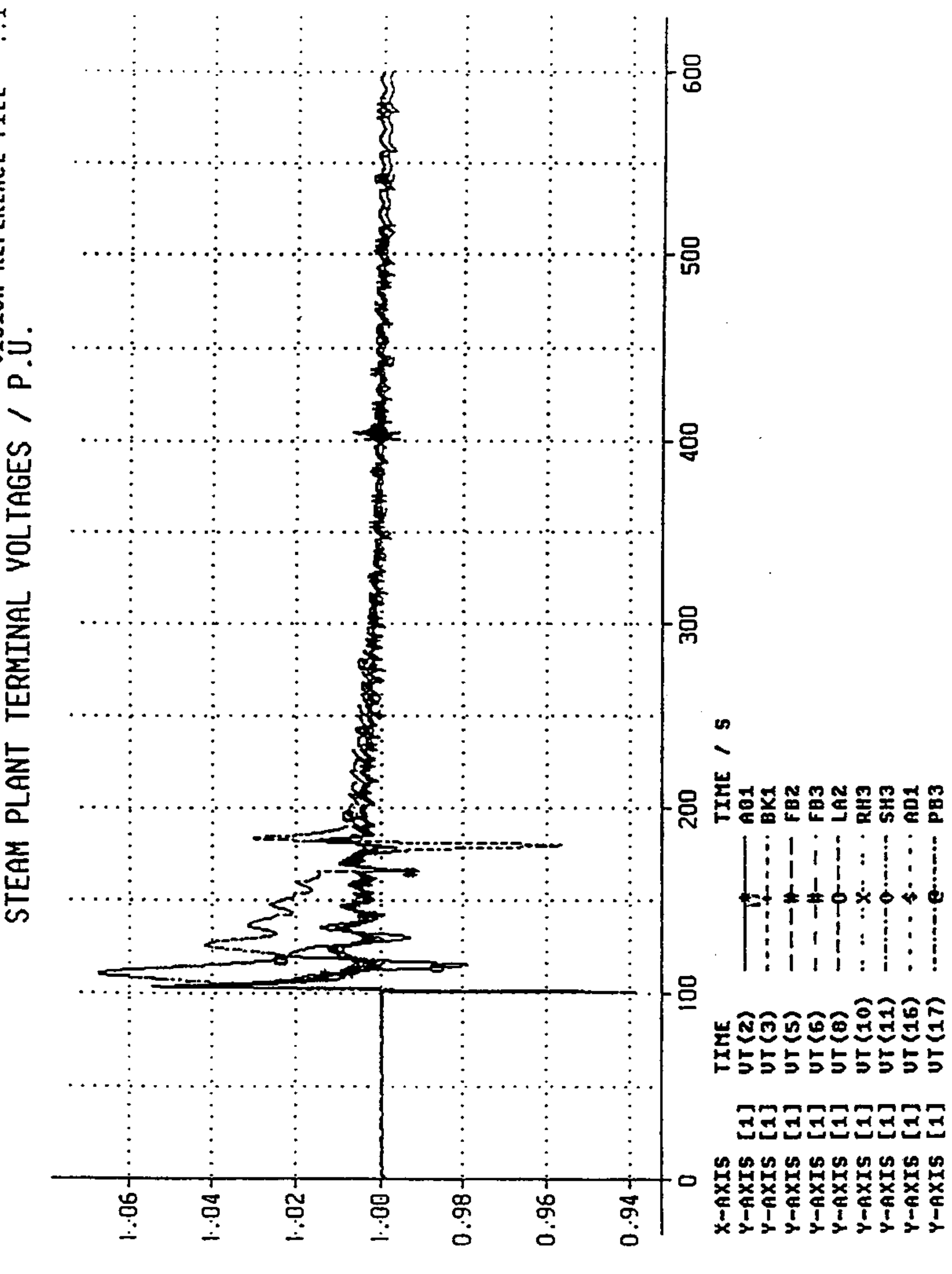

VISION REFERENCE FILE ::1
STEAM PLANT TERMINAL VOLTAGES / P.U.
1.06
1.04
1.02
1.00
0.98
0.96
0.94
0
100
200
300
400
500
600
TIME / S
X-AXIS TIME
Y-AXIS [1] VT(2) AB1
Y-AXIS [1] VT(3) BK1
Y-AXIS [1] VT(5) FB2
Y-AXIS [1] VT(6) FB3
Y-AXIS [1] VT(8) LA2
Y-AXIS [1] VT(10) RH3
Y-AXIS [1] VT(11) SH3
Y-AXIS [1] VT(16) AD1
Y-AXIS [1] VT(17) PB3

Figure 4.4.3.o.

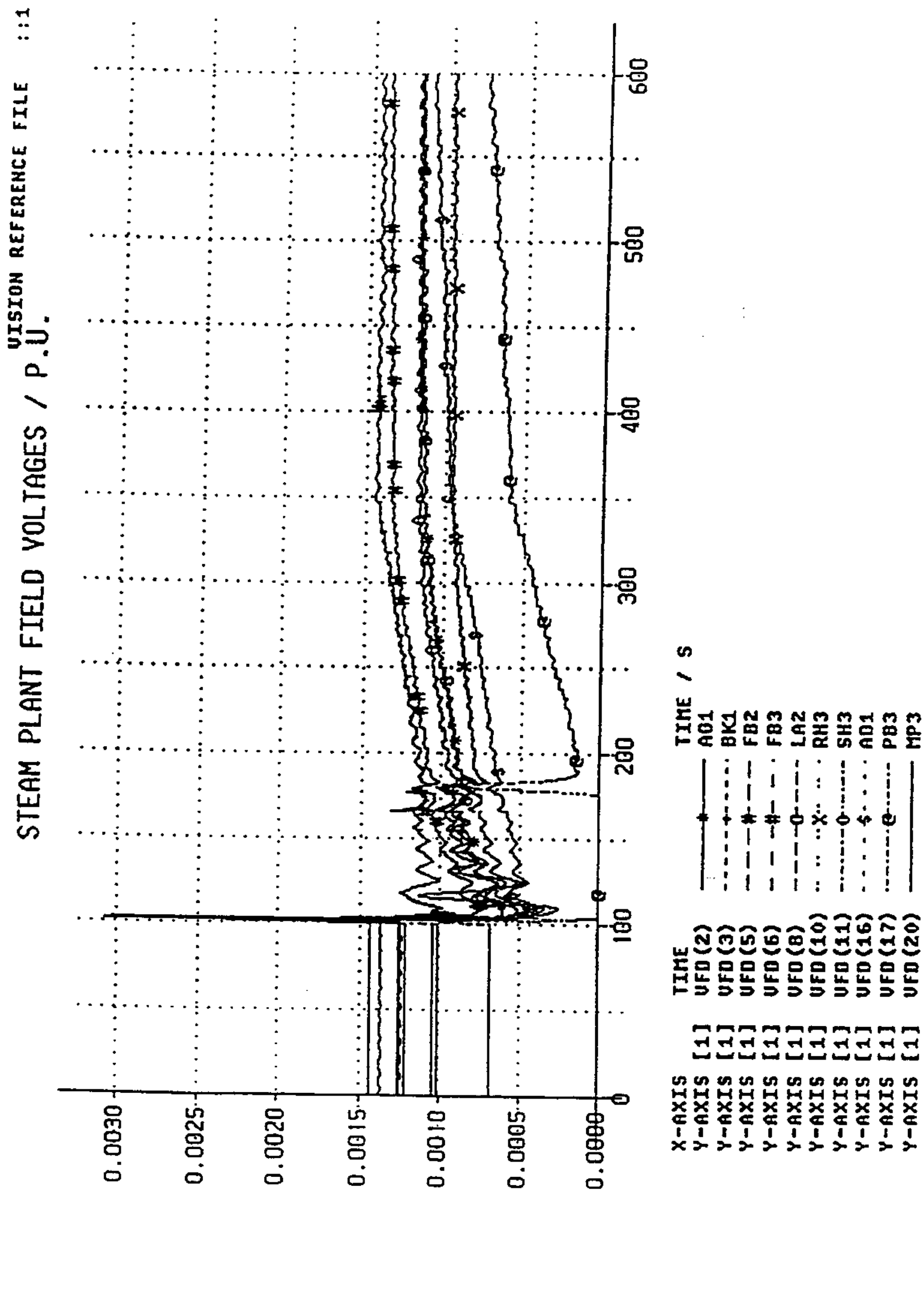

STEAM PLANT FIELD VOLTAGES / P.U.
VISION REFERENCE FILE ::1
0.0030
0.0025
0.0020
0.0015
0.0010
0.0005
0.0000
0
100
200
300
400
500
600
TIME / S
X-AXIS TIME
Y-AXIS [1] VFD(2) AD1
Y-AXIS [1] VFD(3) BK1
Y-AXIS [1] VFD(5) FB2
Y-AXIS [1] VFD(6) FB3
Y-AXIS [1] VFD(8) LA2
Y-AXIS [1] VFD(10) RH3
Y-AXIS [1] VFD(11) SH3
Y-AXIS [1] VFD(16) AD1
Y-AXIS [1] VFD(17) PB3
Y-AXIS [1] VFD(20) MP3

Figure 4.4.3.p.

4.4.4. Simulation with EUROSTAG (run by EDF)

4.4.4.1. Preamble

The hypothetical Irish Test system proposed in Chapter 2.4 and for which an initial 20 second simulation was provided in Chapter 4.4.1 was simulated at EdF using EUROSTAG. This simulation and will be compared in Chapter 4.4.5 to the simulations obtained with PSS/E by PTI reported in Chapter 4.4.2 and with POSSUM reported in Chapter 4.4.3 by Nuclear Electric.

4.4.4.2. Input Assumptions

The following assumptions were made in relation to the data and models

Network Assumptions

Network Frequency Dependence - The parameters of the network were assumed to be dependent on frequency;

Tap Changers - The tap positions of all generator and coupling transformers were assumed to be unchanged throughout the simulation i.e. all transformers have a fixed turns ratio;

Transformer Saturation - Transformer saturation was modelled as a variable shunt injection with a characteristic defined by the transformer saturation curve;

Shunt Reactors - The shunt reactors were assumed to remain connected after load shedding.

Generator Assumptions

Four winding models (i.e. round rotor models) were used to represent the generators with saturation taken into account. The speed governing systems and excitation systems were reproduced from the standard block diagrams of the modules described in Chapter 2.4.

Generator Saturation - Saturation is modelled with identical saturation parameters for both axes;

The Per Unit Value of Field Voltage - At no load and rated voltage the field voltage would be unity on the air gap line (i.e. without saturation);

Power Base - The parameters of the speed governors are in per unit of the machine MVA base.

Voltage input to Exciters - The value E_c in the exciters represents the machine terminal voltage.

Load Assumptions

Computation of load for Load Model - Active and Reactive loads are defined by the following equations

$$P = P_0 (V + V^2)*(1+0.02\ \Delta\omega)$$

$$Q = Q_0 V^2$$

where P_0 and Q_0 are defined from the load flow solution

$P_{lf} = 0.5\ P_0\ (V_{lf} + V^2_{lf})$

$Q_{lf} = Q_0\ V^2_{lf}$

Frequency Definition - The frequency used in the load model is a mean frequency (inertial weighted sum of the generator speeds). Some simulations have demonstrated that this has very little impact on the results.

4.4.4.3. Simulation Description

The events in the simulation are as follows :

Time	Event
t=0	Following convergence of the load flow, transformer saturation is included in the simulation;
t=100	New steady state achieved;
t=100.5	Two Units and associated house load lost at Station MP
t=101.6 102.1	Automatic Load Shedding Occurs
t=104/5	Frequency restored to 50 Hz
t=120	Simulation exhibited instability in the governor of the remaining generator at Station MP and the parameter TN was changed from 0.1 seconds to 1.0 seconds.
	The parameter Vmax of the governors of units G1 at Station AD and G3 at Station PB were changed to 0.85 and thus these units become responsive to low frequency and their set points were ramped up at 8 MW/min.
	Automatic Load restoration initiated with blocks restored every 6 seconds
t=166/ 176	Four Generators at Station TH started
t=300	Hydro generators G1 at Station LE, G2 at Station LI and G3 at Station ER were started and ramped at 10 MW/min
	Hydro generator G2 at Station AA was started and ramped at 2 MW/min.
t=700	Simulation ends

4.4.4.4. Discussion

The simulation begins by including transformer saturation and allowing a new steady state to be reached.

The loss of the two generators at Station MP results a large rate of change of frequency. Load shedding occurs which arrests the frequency within 1.6 seconds following the event at approximately 47.7 Hz. However, the amount of load which was shed was greater than the loss of generation and the frequency soon recovers to nominal reaching a high value of approximately 52.3 Hz at 9.5 seconds following the event. This behaviour of frequency is depicted in Figure 4.4.4.a for the period 100-120 seconds.

Selected voltages are depicted in Figure 4.4.4.b for the period 100-120 seconds where it is seen that the voltages fall initially but recover due to a combination of load shedding and lower reactive losses in the transmission circuits.

The simulation was continued and instability was observed in the response of the governor of the generator G3 at Station MP. The parameter of the governor model, TN was therefore changed from 0.1 seconds to 1.0 seconds and the simulation repeated. Figure 4.4.4.c shows the speeds and mechanical powers of the two simulations over a period 100-180 seconds demonstrating that the new value of T_N is stable.

Load restoration was started at t=20 seconds where 11 MW was restored every 6 seconds. The process of load shedding and load restoration is depicted in Figure 4.4.4.d (note the time frames). The parameters Vmax of the governors of units G1 at Station AD and G3 at Station PB were set to 0.85 and the mechanical power ramped at 10 MW/min.

The generators at the pumped storage station TH were started at t=66-76 seconds and ramped to full power and generators at some other hydro station were started at 300 seconds. Machine powers are depicted in Figure 4.4.4.e.

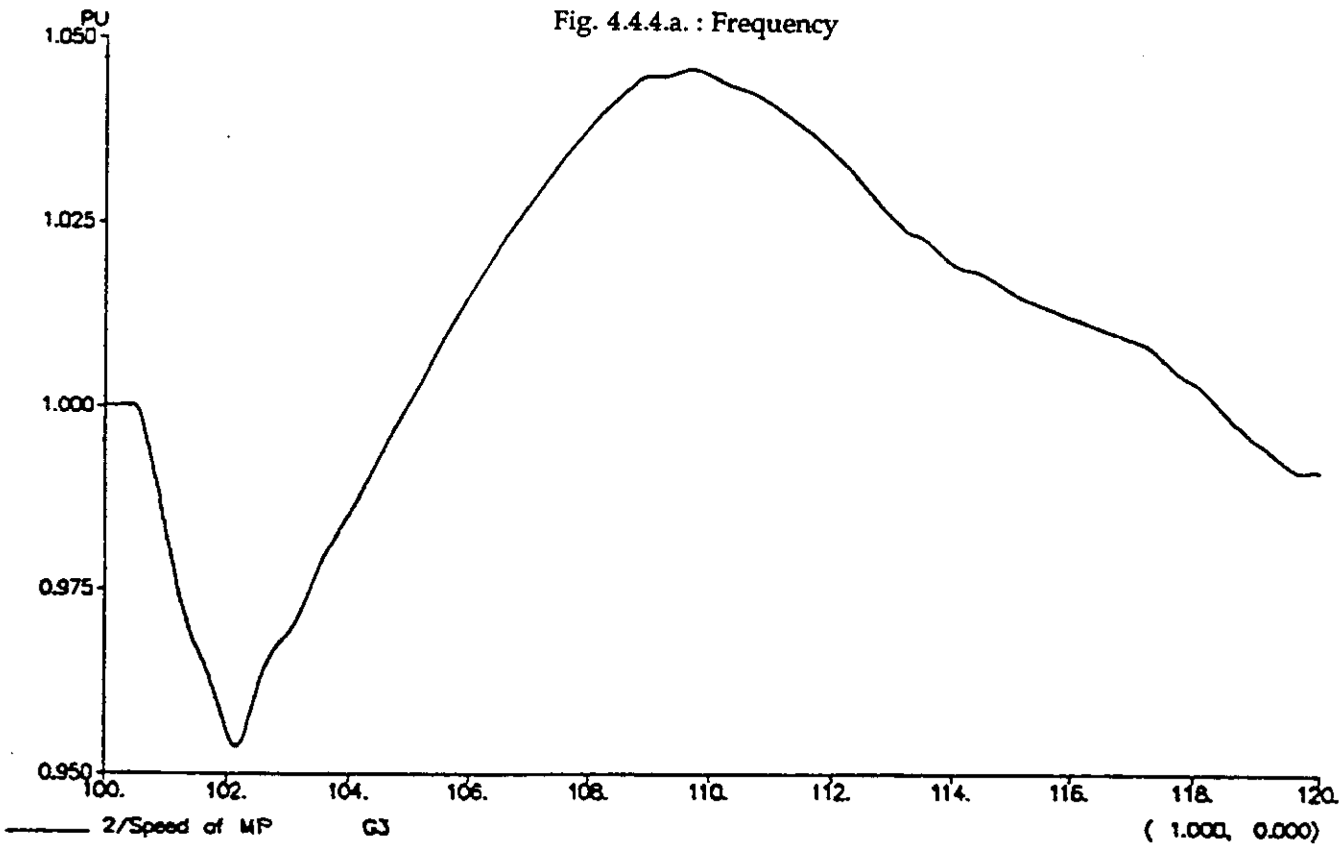
It is seen that at t=300 s all the load has been restored. Figure 4.4.4.f shows the variation in the integration stepsize used by EUROSTAG.

4.4.4.5. Conclusions

The power system remains transiently and dynamically stable. Load shedding arrests the fall in frequency prior to further losses of generation resulting from operation of generating plant's low frequency at 47.5 Hz.

The system is restored to normal and all load restored by 300 seconds.

Fig. 4.4.4.a. : Frequency



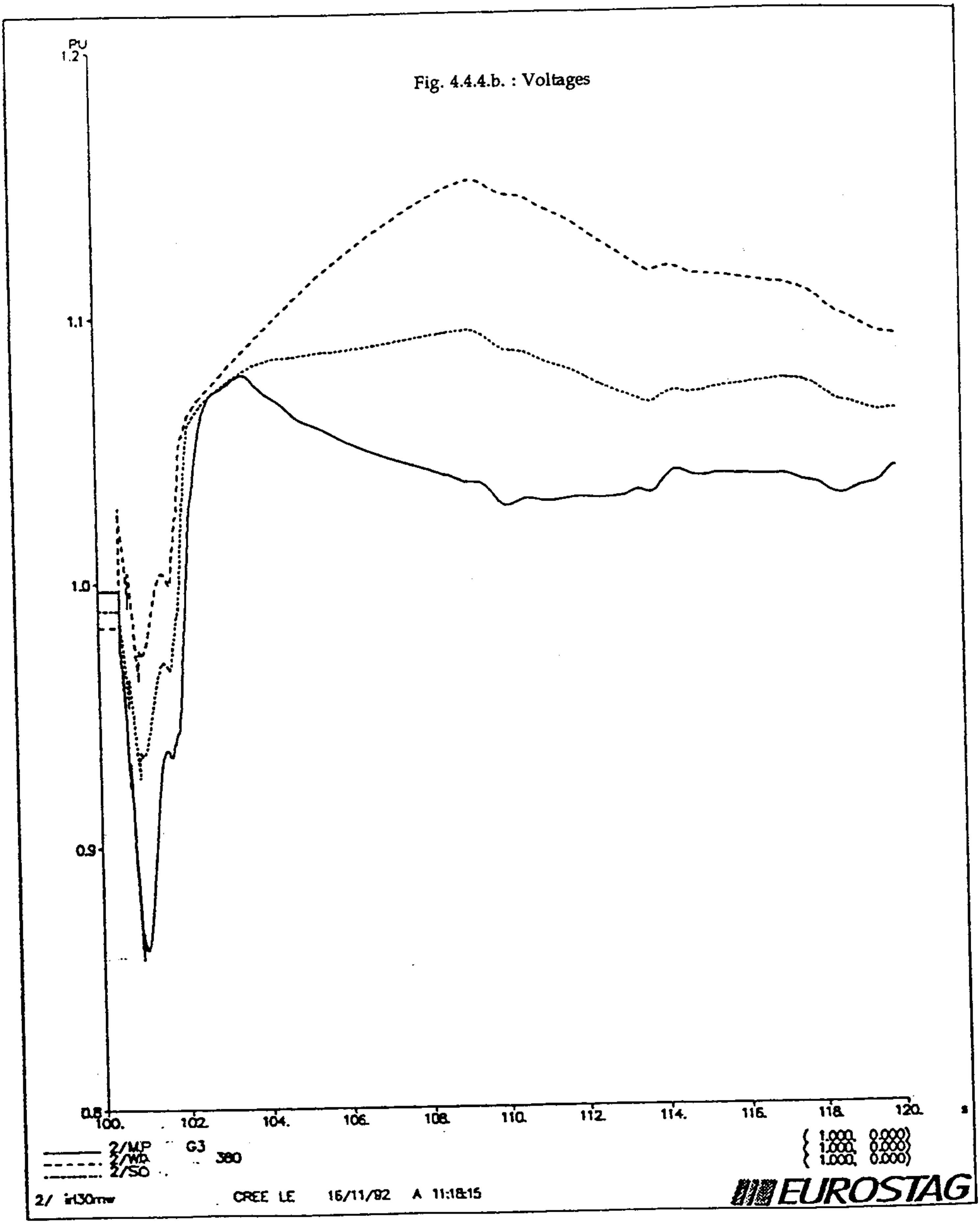


Fig. 4.4.4.b. : Voltages
PU
1.2
1.1
1.0
0.9
0.8
100.
102.
104.
106.
108.
110.
112.
114.
116.
118.
120.
s
2/MP G3
2/WA 380
2/SO
(1.000, 0.000)
(1.000, 0.000)
(1.000, 0.000)
2/ irl30mw
CREE LE 16/11/92 A 11:18:15
EUROSTAG

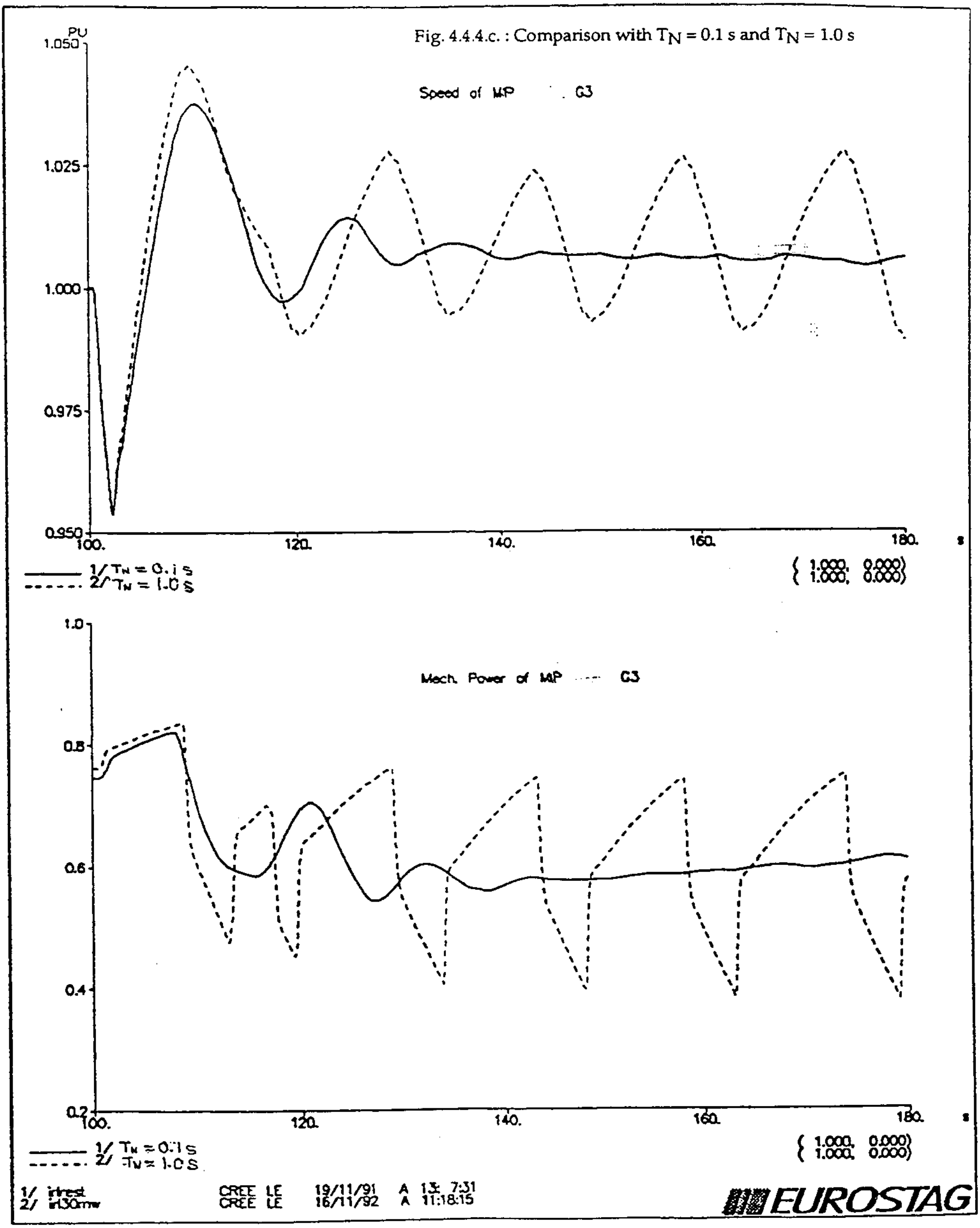
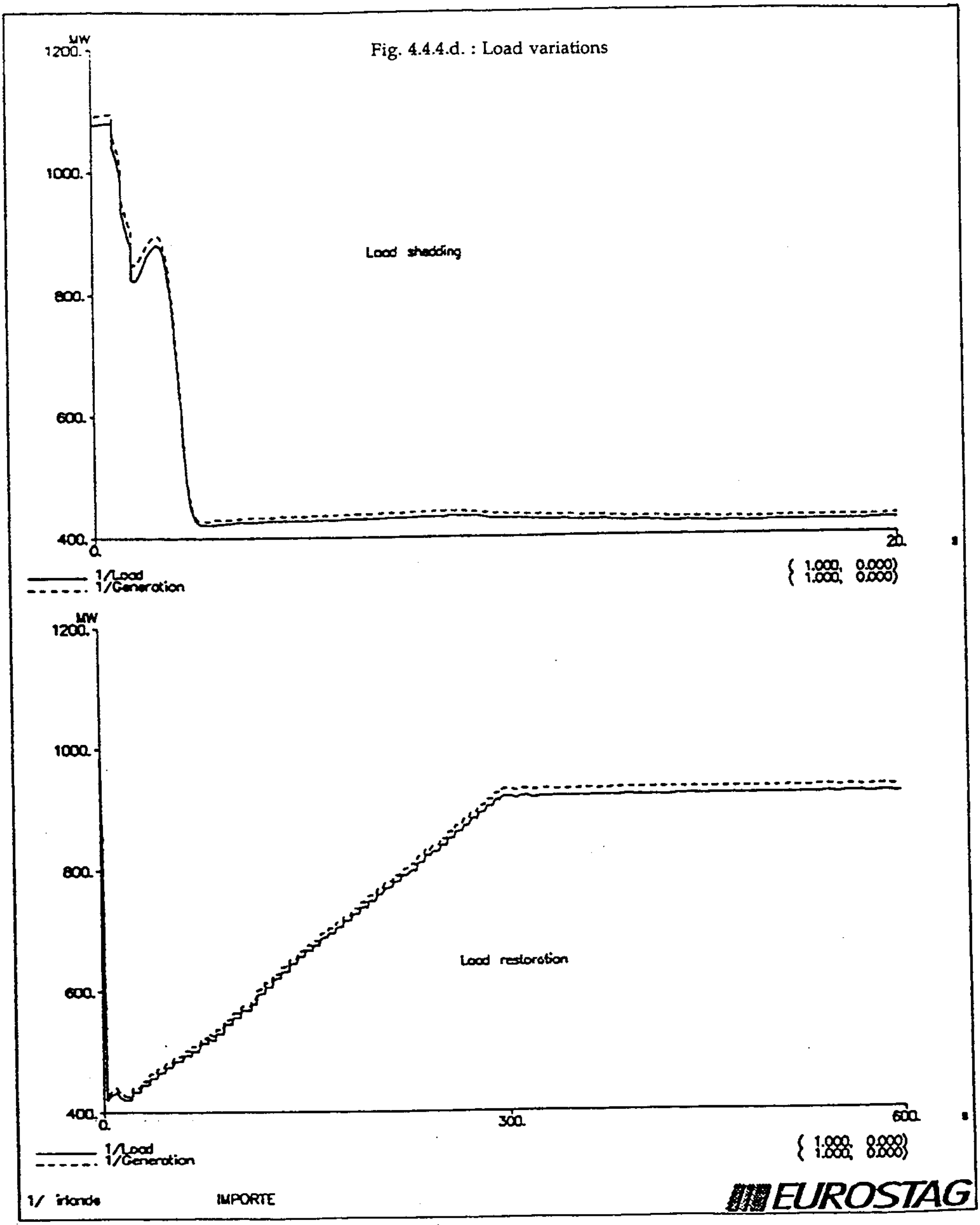


Fig. 4.4.4.c. : Comparison with $T_N = 0.1$ s and $T_N = 1.0$ s

Fig. 4.4.4.d. : Load variations



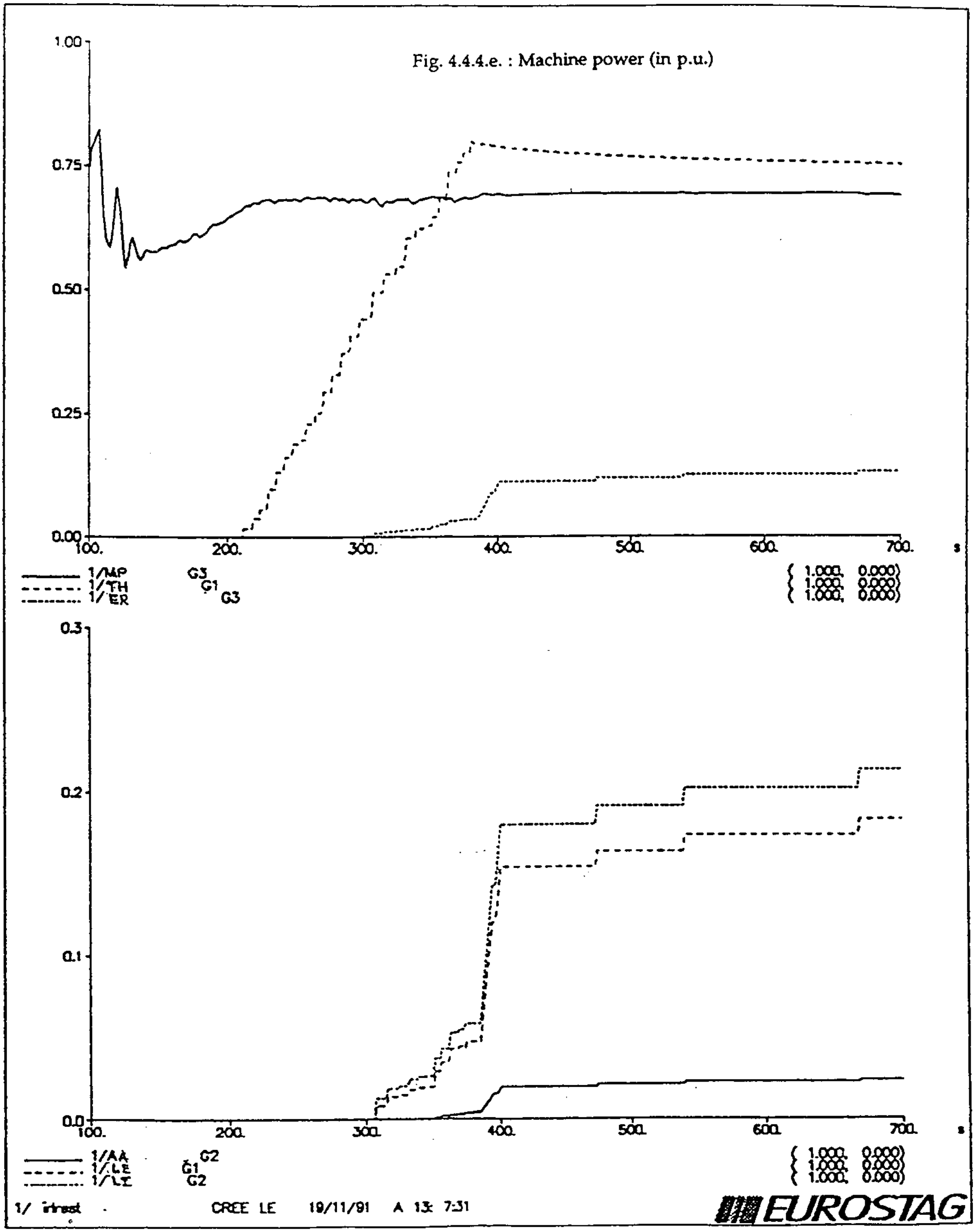


Fig. 4.4.4.e. : Machine power (in p.u.)
1.00
0.75
0.50
0.25
0.00
100.
200.
300.
400.
500.
600.
700.
s
1/MP G3
1/TH G1
1/ER G3
(1.000, 0.000)
(1.000, 0.000)
(1.000, 0.000)
0.3
0.2
0.1
0.0
100.
200.
300.
400.
500.
600.
700.
s
1/AA G2
1/LE G1
1/LT G2
(1.000, 0.000)
(1.000, 0.000)
(1.000, 0.000)
1/ inrest
CREE LE 19/11/91 A 13: 7:31
EUROSTAG

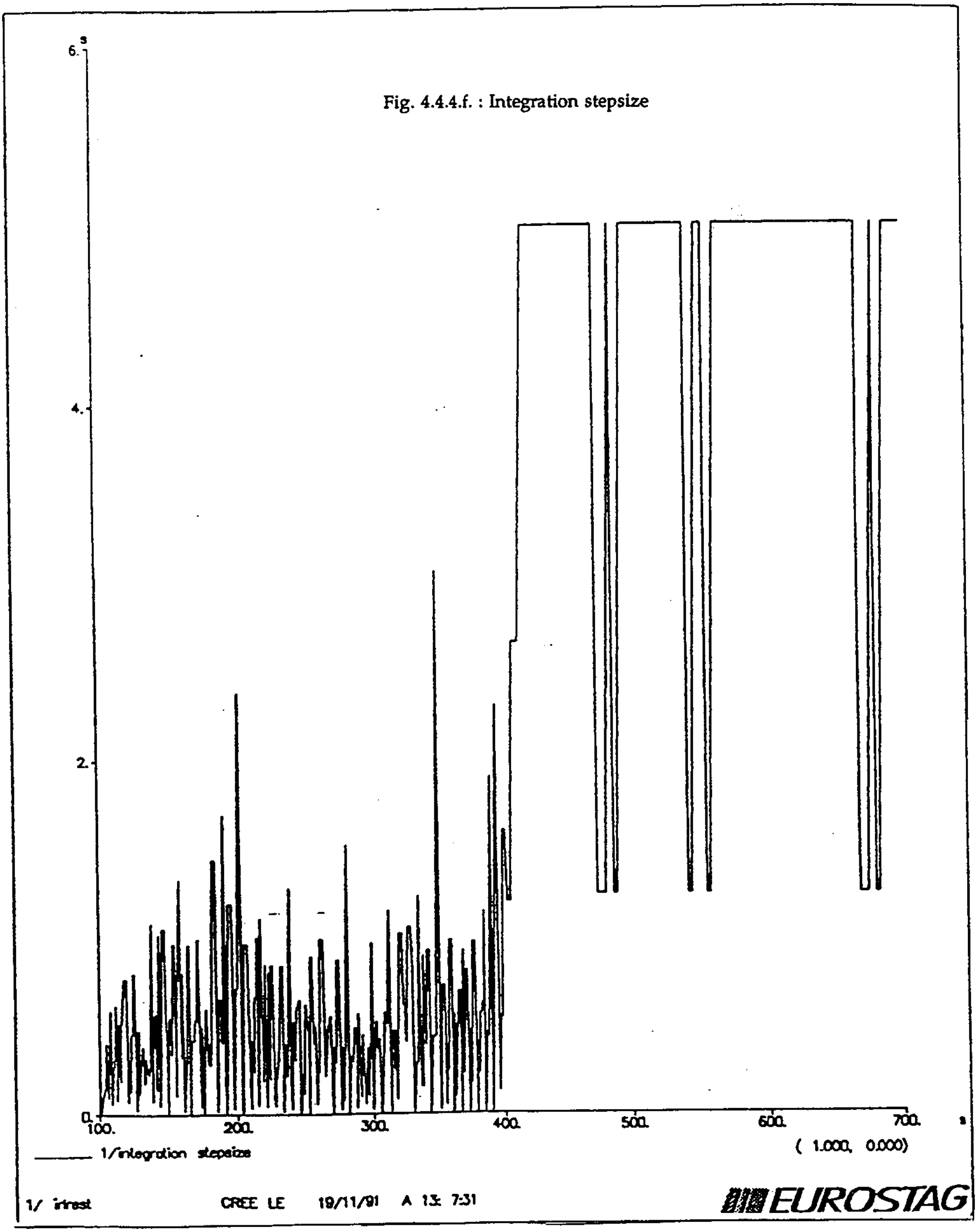


Fig. 4.4.4.f. : Integration stepsize
6.
4.
2.
0.
s
100.
200.
300.
400.
500.
600.
700.
s
1/integration stepsize
(1.000, 0.000)
1/ irrest
CREE LE 19/11/91 A 13: 7:31
EUROSTAG

4.4.5. Summary comments on exercises on the Irish test system

4.4.5.1. Preamble

The Irish Test system was not based on an actual incident which occurred and for which there existed disturbance data to validate a simulation. The test system was proposed to provide a test-bed to explore the dynamic phenomena which occur in a power system when there is a large change in frequency and voltage, such as occur in "island" power systems where the largest generator can be a high proportion of the system demand.

The contributions received on this test system, PTI using extended PSS/E, NE using POSSUM and EdF using EUROSTAG, produced long-term simulations of the scenario described in Chapters 2.4 and Chapter 4.4.1 using different assumptions about the appropriate modelling of boilers. However the simulation of the primary phenomena of interest, i.e. the macro behaviour of power system frequency, was broadly consistent throughout all the simulations.

4.4.5.2. Frequency Behaviour: Protection and Restoration

Of particular interest in this simulation was the behaviour of the frequency. There are two distinct processes occurring - the process of protection where demand is automatically disconnected by low frequency relays and the process of restoration where the demand is automatically restored when the system begins to recover. These process are clearly exhibited in Figure 4.4.4.d produced by EUROSTAG, Figure 4.4.2.c produced by PSS/E and Figures 4.4.3.b and g produced by POSSUM (Note: POSSUM uses T_N=0.1 seconds throughout).

It is clear that, in the protection phase, more demand was disconnected than the generation which was lost. This is clearly due to the initial large rate of change of frequency and the relatively narrow band of settings chosen for the relays. Further and repeat studies could be carried out on an optimisation of these settings to trade off system security, customer security and generation reserve costs.

The restoration of demand occurs quite rapidly but clearly the maximum rate of demand restoration cannot exceed the capacity of the synchronised plant to respond. The synchronised plants' capacity to restore load is seen to be reached in Figure 4.4.2.c and restoration pauses. The size of blocks of load being restored and the frequency of their restoration are important parameters to ensure that renewed load shedding will not occur. It would be undesirable to disconnect load repeatedly as the result of an ambitious restoration scheme and clearly the scheme proposed in this test system would not result in such an eventuality.

4..4.5.3. Transformer Overfluxing

Transformer Overfluxing. proportional to the ratio of the voltage to frequency, is not excessive initially (<20s) due to a combination of high voltage and high frequency. As the demand is restored, it is seen from the Voltage and Frequency plots of Figure 4.4.2.a and Figure 4.4.3.i that the voltage and frequency are restored and thereafter fluctuate around nominal.

However, further and repeat studies could be carried out to determine the optimum tradeoff between transformer longevity and system security.

4.4.5.4. Modelling of Generator and Transformer Saturation

It would appear that generator and transformer saturation has been modelled differently in Chapter 4.4.4 and 4.4.2. Prior to any transient, the field voltages required to obtain the same machine terminal voltage differed and so also did the reactive powers of the generators.

The over-voltages observed in the initial transient of Chapter 4.4.4 (Figure 4.4.4.b) and Chapter 4.4.3 (Figure 4.4.3.c) were greater than those of Chapter 4.4.2 (Figure 4.4.2.a). This may be due to the differences in saturation modelling alluded to above or due to the transformer saturation 'accelerating factor' used in the standard SAT2 module which is thought to dampen the response.

A fuller investigation involving a comparison of machine field voltages and transformer responses would be needed to completely understand these differences.

4.5. The Spanish test system simulations

4.5.1. Initial simulation with PSS/E (run by REE)

4.5.1.1. Introduction

Before the long-term data interchange, a 20 sec. transient stability simulation was run using the PSSDS4 programme of the PSS/E software package.

This simulation was carried out to determine a long-term scenario with enough study interest and also to validate the load flow data and the dynamic models used for transient stability studies (generator, governor and excitation system).

4.5.1.2. Description of the modelization

- Network: Algebraic PI schemes are used for transmission lines. The auxiliary services of two important plants (units 14 an 15, 926 and 915 MW, respectively) have been included in the study network.
- Generator: Full Park model with 4 rotor windings and saturation in both axes.
- Excitation system: In order to facilitate the modelling several standard models have been used. (SEXS, EXAC4, IEEEX1, IEEEX2A).
- Turbine/governor: Standard models have also been used to represent this dynamic. (TGOV1, IEEEG1).
- Protection systems: The following protections have been considered:
  - Overspeed protection: If the machine speed reaches a value greater than 110% this protection closes the main steam valves.
  - Auxiliary services undervoltage relay: This protection has been included at the units 14 and 15 (where auxiliary services have been modelled). In this simulation, this protection causes the main steam valves closing.
  - Unit loss of synchronism protection: This protection checks the angle rotor value of the generating unit to identify possible loss of synchronism.
  - Tie-line loss of synchronism protections : this protection has been represented by a model defined by the user.
- Loads:
  - The system loads are represented, by IEELCA model, as follows:
    - . Active component (P):

      $P = Po\ (0.5\ V + 0.5\ V^2)\ (1+ 0.75\ \Delta f)$

      Both 50% constant current and 50% constant impedance with frequency dependency.
    - . Reactive component (Q): 100% constant impedance with no frequency dependency. ($Q = Qo\ V^2$)

- Auxiliary services of units 14 and 15 are an exception to this modelling. A very detailed model of induction motor (CMOTOR) has been incorporated for the representation of the high powered motors.

No power plant and no load-frequency control models are incorporated to this simulation due to the PSS/E version that has been used. The load shedding system has not been incorporated either.

4.5.1.3. Simulation results

To accomplish the goal of this simulation, two important factors have been adjusted: the clearing time of the fault and the load characteristic.

The initial disturbance is a ten cycles three phase to ground short circuit at the 400 kV evacuation bus (bus number 13070) of an important power plant (unit 20). This long short circuit causes the following events:

- Trip of the unit 20 due to the loss of evacuation capacity.
- Trip of the unit 14 because of the minimum voltage protection of the auxiliary services. (This voltage evolution is shown in fig. 4.5.1.a).

The unbalance, produced as a consequence of the severe short circuit and the later loss of generation, leads to a high power interchange (from area B to A) through the tie-lines and to low voltage values at the buses placed at the end of these lines, causing the tie-lines opening due to the actuation of the loss of synchronism protection. (Please, see the evolution of bus 18105 voltage and active power through the tie-lines in fig. 4.5.1.b and fig. 4.5.1.c respectively).

The opening of the tie-lines increases the generation/load unbalance producing a generalized frequency fall. This frequency diminution should have caused the actuation of the load shedding system, however this protection system has not been incorporated to this simulation.

The expected actuation of the load-frequency control and the later boiler response can not be observed either because these models are not included in the PSS/E version used in this study.

4.5.1.4. Conclusions

First of all, it is very important to remark that the PSS/E version that has been used in this simulation, is not intended for long term stability studies and that this simulation has been mainly carried out to find a long term scenario.

In order to identify this major disturbance condition the clearing time of the fault and the load characteristic have played an important role. The longer the clearing time was (or the closer to a 100% constant current the load model was) the more severe the simulation results.

The analysis of this scenario has also shown how important is to incorporate the following elements in this study:

- Loss of synchronism relay of the tie-lines. The opening of tie-lines isolates the areas increasing the load/generation unbalance.
- Load shedding system. This protection system stops the frequency fall leading the system to a new working point.

- Load-frequency control (and boiler dynamic). The modelling of these dynamics is fundamental to represent the system return to the generation/load balance at the nominal frequency. However, their actuation becomes significative in a greater time than the period normally simulated in transient stability studies.

These dynamics are analysed using the long term programmes: EXSTAB and EUROSTAG.

In conclusion, both the necessity of longer simulation times and the requirement of slow dynamics modelling support the use of long term programmes to analyse this kind of scenario.

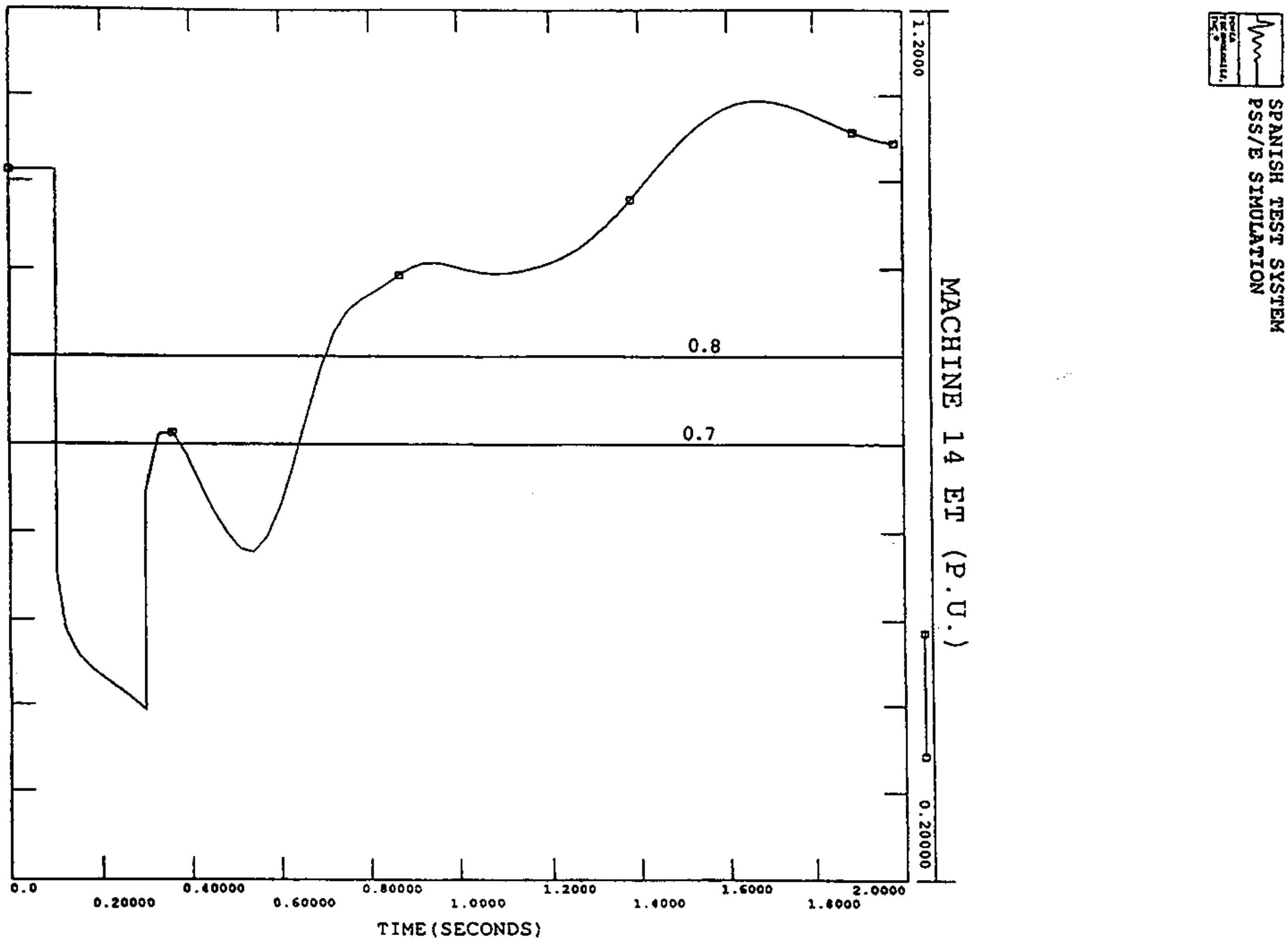


Fig. 4.5.1 .a Machine 14 ET (p.u.). PSS/E simulation.
This unit trips, at t=to+0.4 sec., because of the minimum voltage protection of auxiliary services. In this simulation, the action of this protection causes the main steam valves closing.(to=0.1 sec., at this time fault is applied).

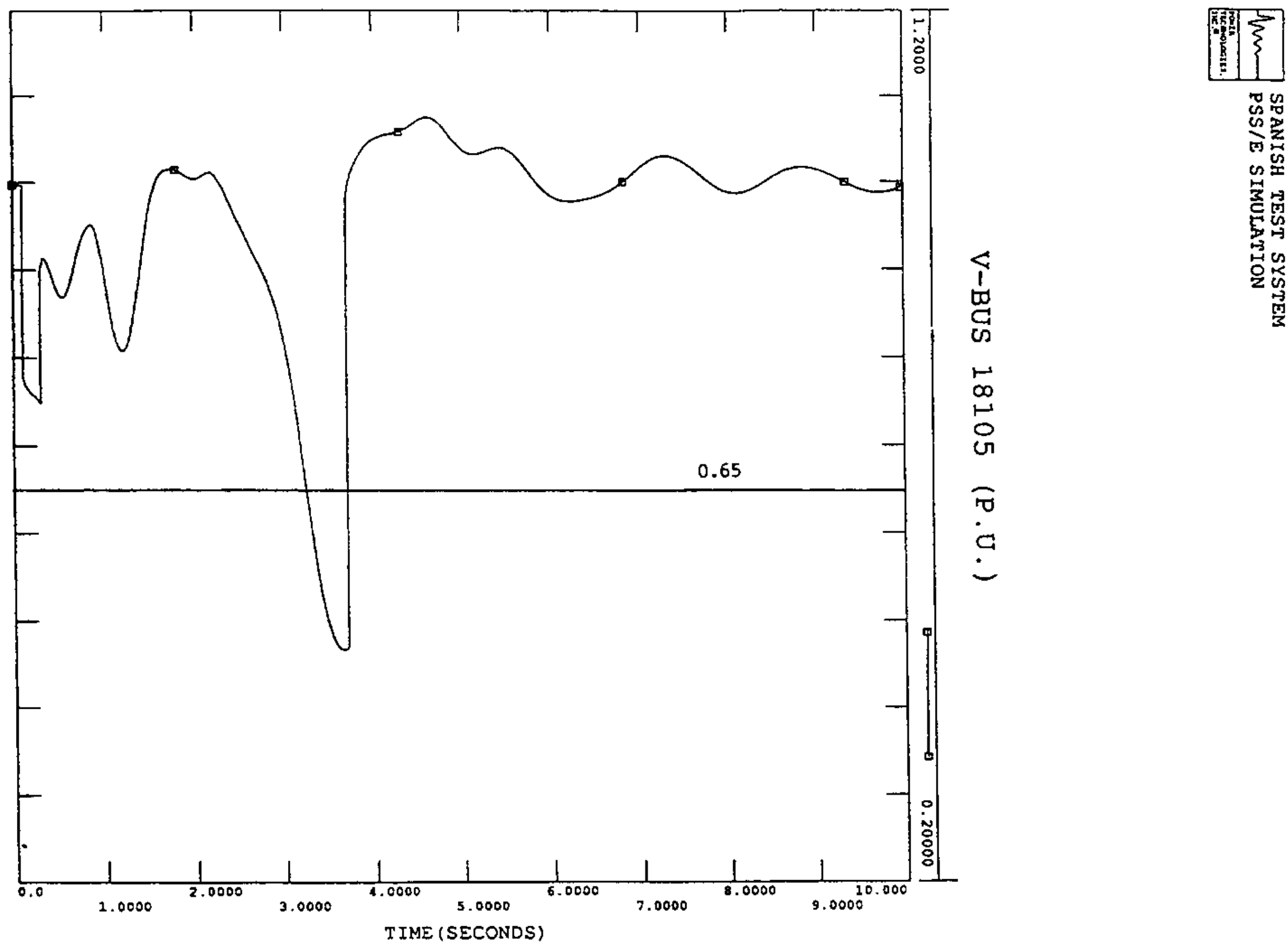


Fig. 4.5.1 .b Voltage of bus 18105 (p.u.). PSS/E simulation. This bus (area B) is the end of the tie-line that causes the opening of the interconnections (at t=to+3.6 sec.) because of the actuation of the loss of synchronism relay.(to=0.1 sec., at this time fault is applied).

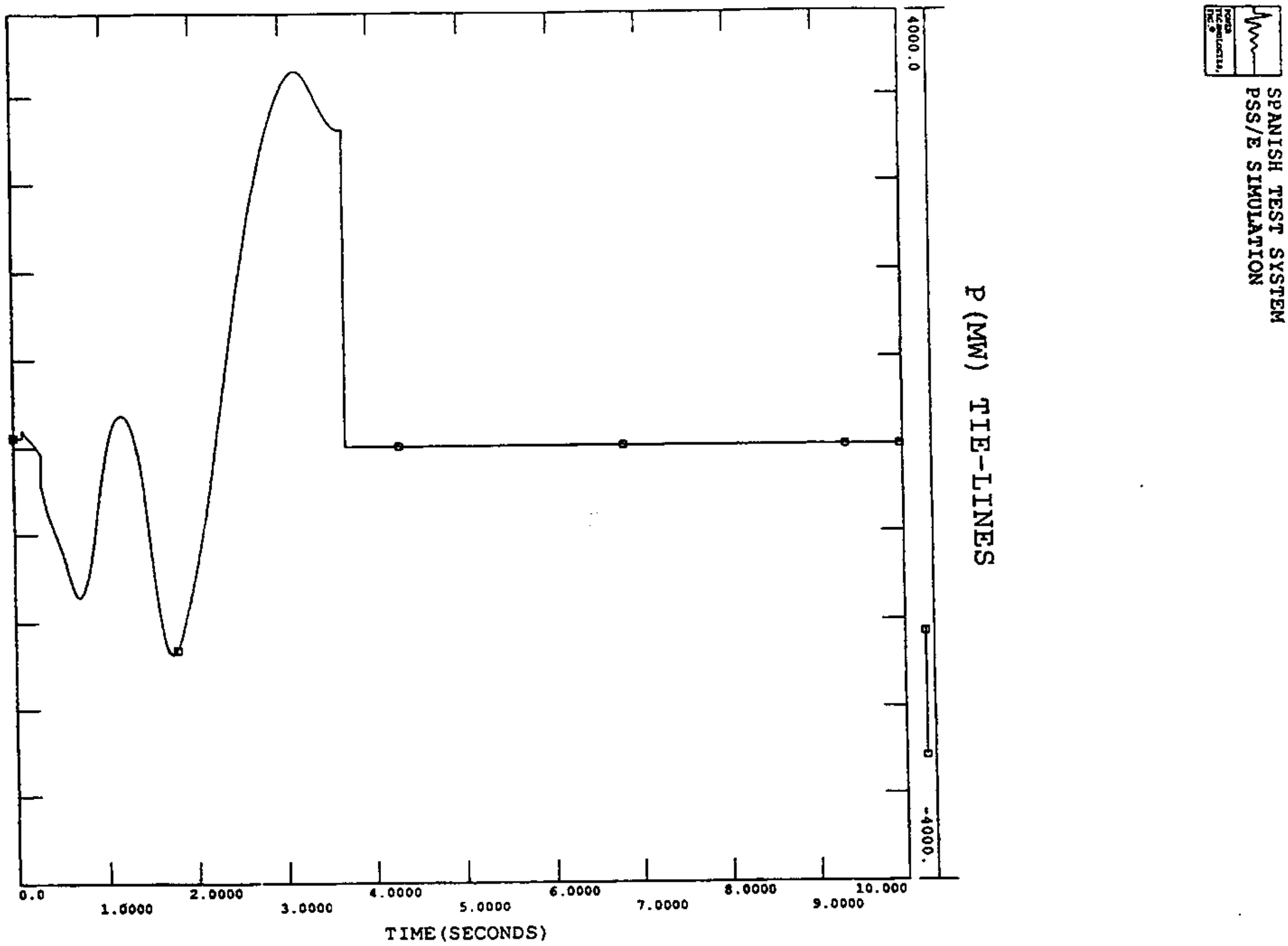


Fig. 4.5.1 .c Active power through the four tie-lines (P>0 from area B to A). PSS/E simulation. At t=to+3.6 sec. areas A and B are disconnected because of the actuation of the loss of synchronism relay.(to=0.1 sec., at this time fault is applied).

4.5.2. Simulation with EUROSTAG (run by EDF)

4.5.2.1. Description of the modelization

- Network: Load flow data provided in PSS/E format were automatically converted to EUROSTAG format. Algebraic PI schemes, as in the reference, are used for transmission lines.
- Generator: Full Park model with 4 rotor windings and saturation in both axes, as in the reference, has been used.
- Excitation system: PSS/E and IEEE standard models (SEXS, EXAC4, IEEEX1, IEEEX2A), that are included in EUROSTAG, have been used to represent these dynamics. Some complex excitation systems, initially proposed, were simplified to be represented by these standard models.
- Turbine/governor: PSS/E and IEEE standard models (TGOV1, IEEEG1), included in EUROSTAG have been used.
- Power plants: Represented by steam and nuclear plant simplified models that have been introduced using the macro-block language.
- Protection system:
  - Auxiliary services undervoltage relay: A protection similar to the proposed one has been modelled using a combination of the macro-block language and automata. In the simulation, the actuation of this protection causes the isolation of the unit.
  - Unit loss of synchronism protection: The identification of possible loss of synchronism conditions has been performed checking the difference between the phase of the terminal voltage and the rotor angle of the generating units. In the simulation, the actuation of this protection causes the isolation of the unit.
  - Tie-line loss of synchronism protection: This protection is included in EUROSTAG program as an automaton.
- Loads:

  The proposed load behaviour has been modelled with the macro-block language of EUROSTAG.

  - The system loads have been modelled as follows:
    - Active component (P):

      $P = Po\,[\,0.5\,V\,(1 + 0.75\,\Delta f) + 0.5\,V^2\,]$

      (Please, see the frequency calculation in appendix A.5)
    - Reactive component (Q): $Q = Qo * V^2$
  - Auxiliary services of machines 14 and 15 have been modelled using a combination of static load and induction motor models. Induction motors have been identically modelled to the CMOTOR model of PSS/E, using the macro-block language.

- Load shedding system: This protection system has been introduced using the macro-block language of EUROSTAG. Load restoration has not been modelled.
- Load-frequency control: A simplified model of AGC, identical to the proposed block diagram, has been introduced using the macro-block language of EUROSTAG.

4.5.2.2. Simulation results

Four simulations have been carried out with EUROSTAG program:

- Simulation A: Including the whole modelling.
- Simulation B: Without loss of synchronism relays on tie-lines.
- Simulation C: Without load-shedding system.
- Simulation D: Without load-frequency control and without power plant model.

Comparing the results of the three last simulations (B, C and D) with the results of simulation A it is possible to assess the influence of: loss of synchronism relays of the tie-lines, load shedding system and load-frequency control.

Simulation A: (Including the whole modelling)

The global behaviour of the system is very close to the reference one:

to=100 sec	Three phase to ground short circuit at bus number 13070.
to+0.2 sec	Fault is removed by the opening of all transmission lines and transformers connected to the bus number 13070. This causes the isolation of machine 20.
to+0.4 sec	Trip of machine 14 because of the minimum voltage protection of auxiliary services. (Fig. 4.5.2.a)
to+3.75 sec	Opening of the four tie-lines that interconnect areas A and B. The initial system is divided into three islands (area A, area B and machine 20). (Fig. 4.5.2.b and 4.5.2.c).
to+11.8 sec	Actuation of the load-shedding system of area A. (Fig. 4.5.2.d). Only the first step is performed.

The load-shedding actuation stops the frequency fall, establishing a new load/generation balance. Then, the system frequency returns very quickly to a value close to the nominal one, but slightly higher (this is the normal behaviour of most of the load-shedding systems).

After the load-shedding, the frequency will return to the nominal value by the load-frequency control actuation (please, see how the load-frequency control decreases the generation to lower the frequency value. Fig. 4.5.2.d, e and fig. 4.5.2.f).

As can be seen from the chronology, the results obtained using EUROSTAG program are coincident with the ones obtained in the reference case (PSS/E simulation). In the same way, this simulation shows that the modelling of load-shedding system and load-frequency control play an important role in the study of a frequency scenario.

Simulation B : (Without loss of synchronism relays on the tie-lines)

Until t = to + 3.75 sec., when the tie-line relays should actuate, both simulations A and B provide, obviously, the same results. However, after this moment the results differ.

In the simulation A, after the opening of tie-lines, the load shedding system of area A has to actuate to re-establish the system frequency. However, in this simulation, without loss of synchronism relays on the tie-lines, the frequency does not fall and the load-shedding actuation is not necessary.

This result was expected since remaining the areas interconnected, area A receives an important aid from area B. It is also observed, in this simulation, that the fact of helping area A does not cause the trip of any of the units of area B.

This remarkable difference is clearly observed comparing the evolution of system frequency with and without loss of synchronism relays on the tie-lines (fig. 4.5.2.g).

Simulation C : (Without load-shedding system)

The amount of lost generation has such a value that the frequency fall without load-shedding (simulation C) is very similar to the frequency fall with load-shedding (simulation A). However, the main difference between both simulations is not observed in the frequency fall, but in the frequency rise.

In this simulation, without load-shedding system, the frequency remains at a low value (0.984 p.u. = 49.2 Hz, fig. 4.5.2.h). Due to the present situation no protection system and no automatic control will actuate. To reach the frequency nominal value it would be necessary to connect new generator units to the system.

Simulation D : (Without load-frequency control/boiler)

In simulation A, after the load-shedding actuation, the frequency increases to a value greater than the nominal one, and then, the load-frequency control returns the frequency to its nominal value.

However, in simulation D, without load-frequency control, there is no contribution to re-establish the frequency value and it remains just over the nominal value.

Both frequency evolutions with and without load-frequency-control are shown in fig. 4.5.2.i.

4.5.2.3. Conclusions

The flexibility of EUROSTAG program allows to reproduce the whole scenario without limitation. All the proposed dynamics (power plant, load-shedding system, load-frequency control...) have been modelled using the EUROSTAG macro-block language.

The results of EUROSTAG simulation are very close to the reference and all the expected actuations and evolutions have been confirmed.

In conclusion, EUROSTAG program has the capability to study frequency scenarios thanks to its modelling flexibility, that allows to incorporate all the necessary models, as well as to its integration algorithm, that allows to analyse fast and slow dynamics in the same simulation.

PLOTS OF SIMULATION A:

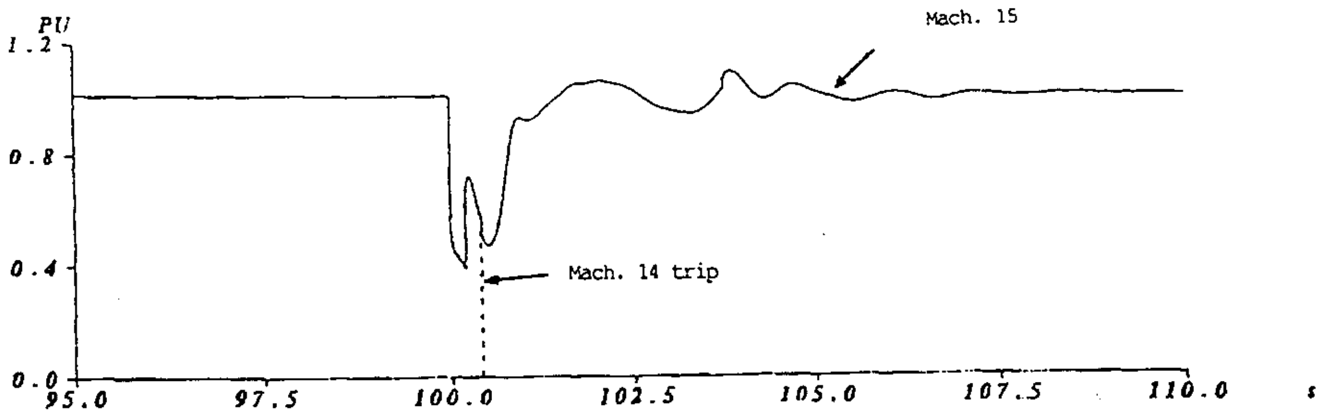


Fig. 4.5.2. a. Voltage of machine 14 and 15. Only mach.14 (dash line) trips because of the minimum voltage protection of auxiliary services.

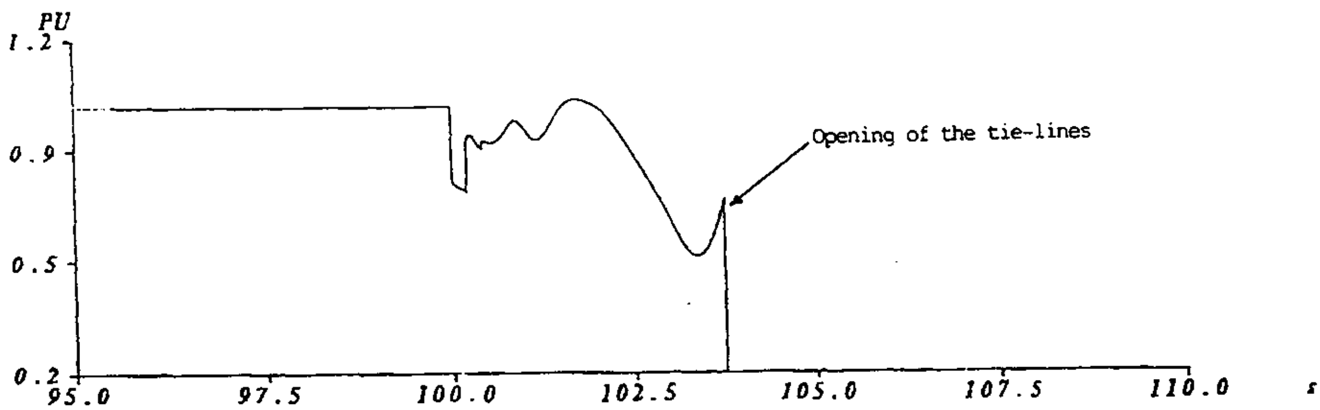


Fig. 4.5.2. b. Voltage of bus number 18105. This bus is the end of the tie-line (400kV) whose relay detects the loss of synchronism causing the disconnection of areas A and B.

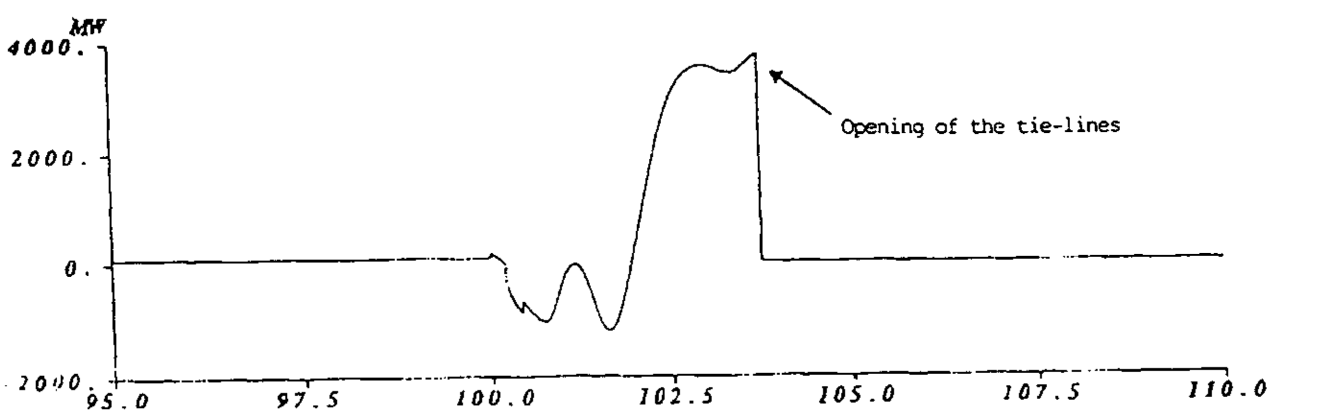


Fig. 4.5.2. c. Active Power through the tie-lines.

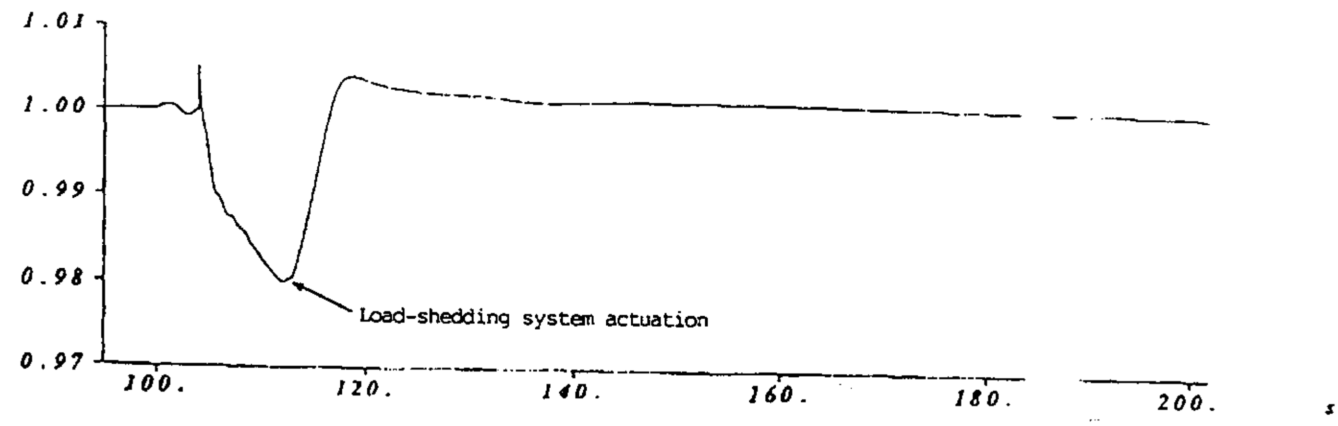


Fig. 4.5.2. d. System frequency of area A.

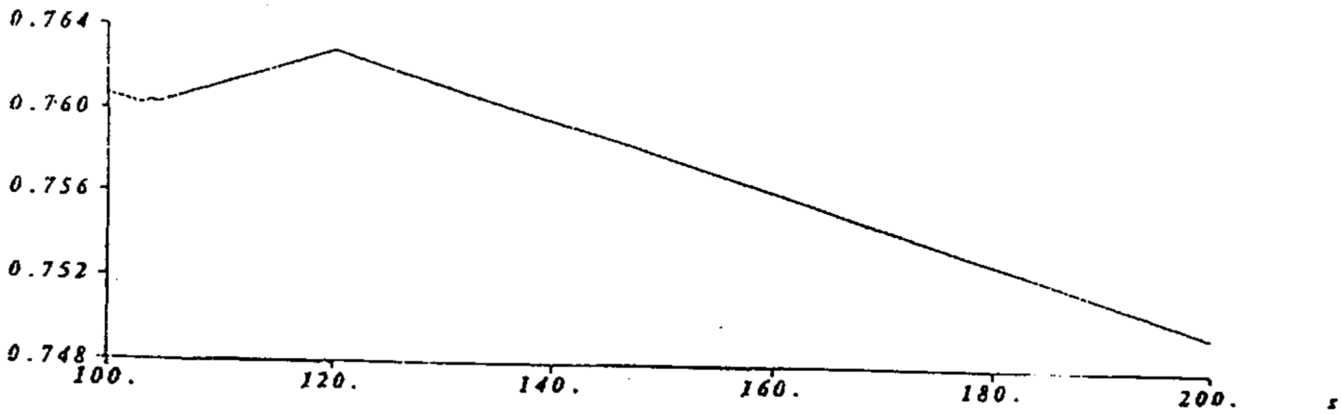


Fig. 4.5.2. e. Lodref signal (turbine load reference of mach. 22). Please, see the power plant representation in appendix A.5.

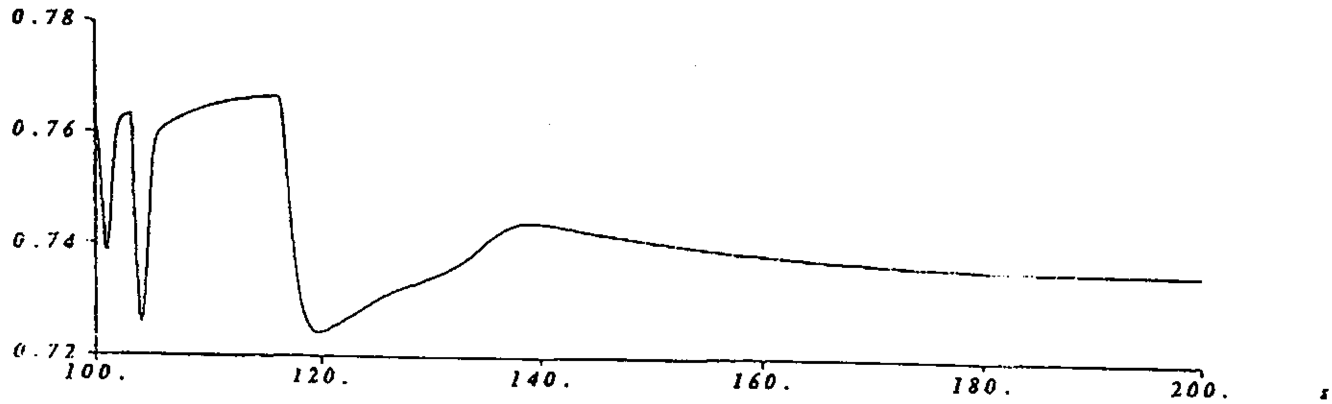


Fig. 4.5.2. f. Mechanical power of machine 22.

PLOTS OF SIMULATION B:

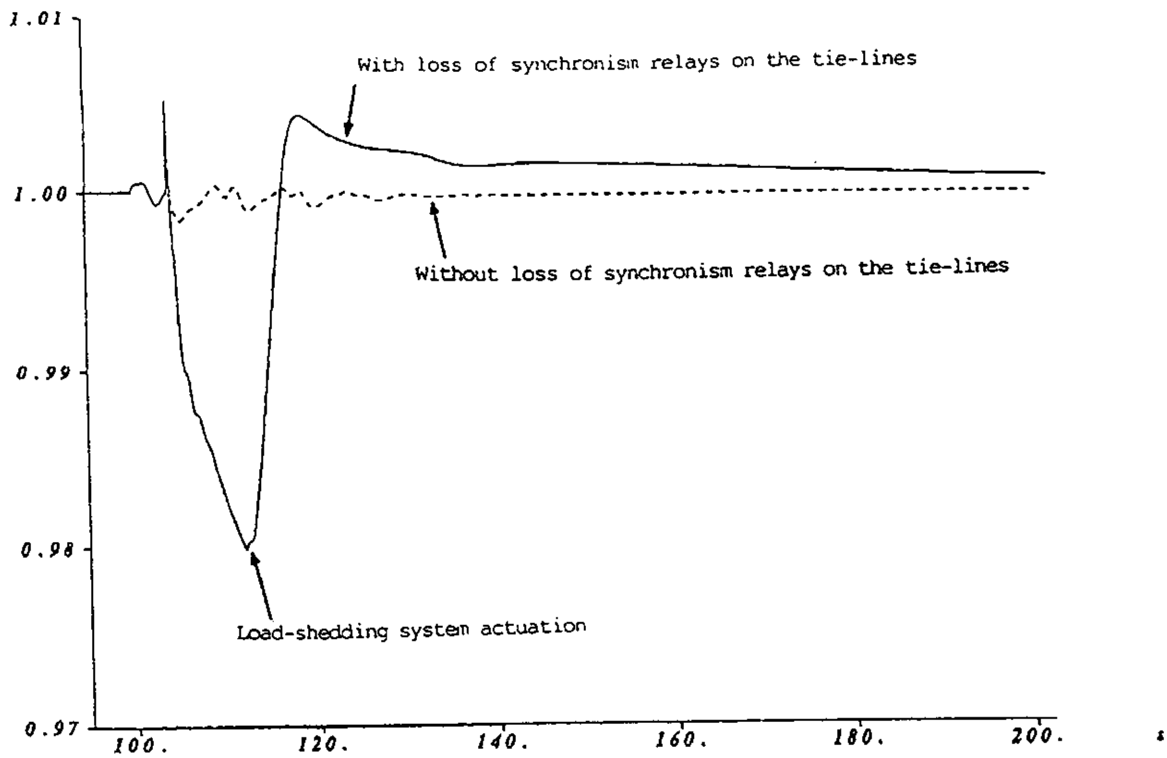


Fig. 4.5.2. g. System frequency.

.Solid line: Simulation A.
.Dash line: Simulation B.

PLOTS OF SIMULATION C:

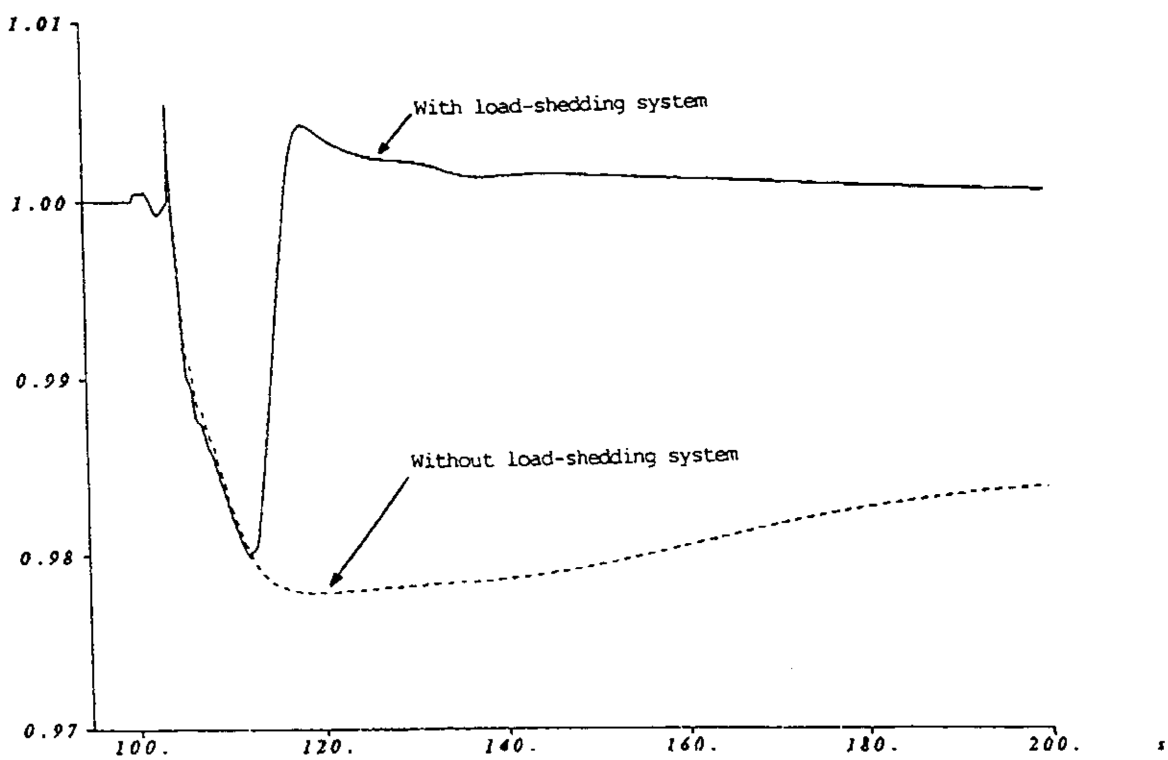


Fig. 4.5.2. h. System frequency.

.Solid line: Simulation A.
.Dash line: Simulation C.

PLOTS OF SIMULATION D:

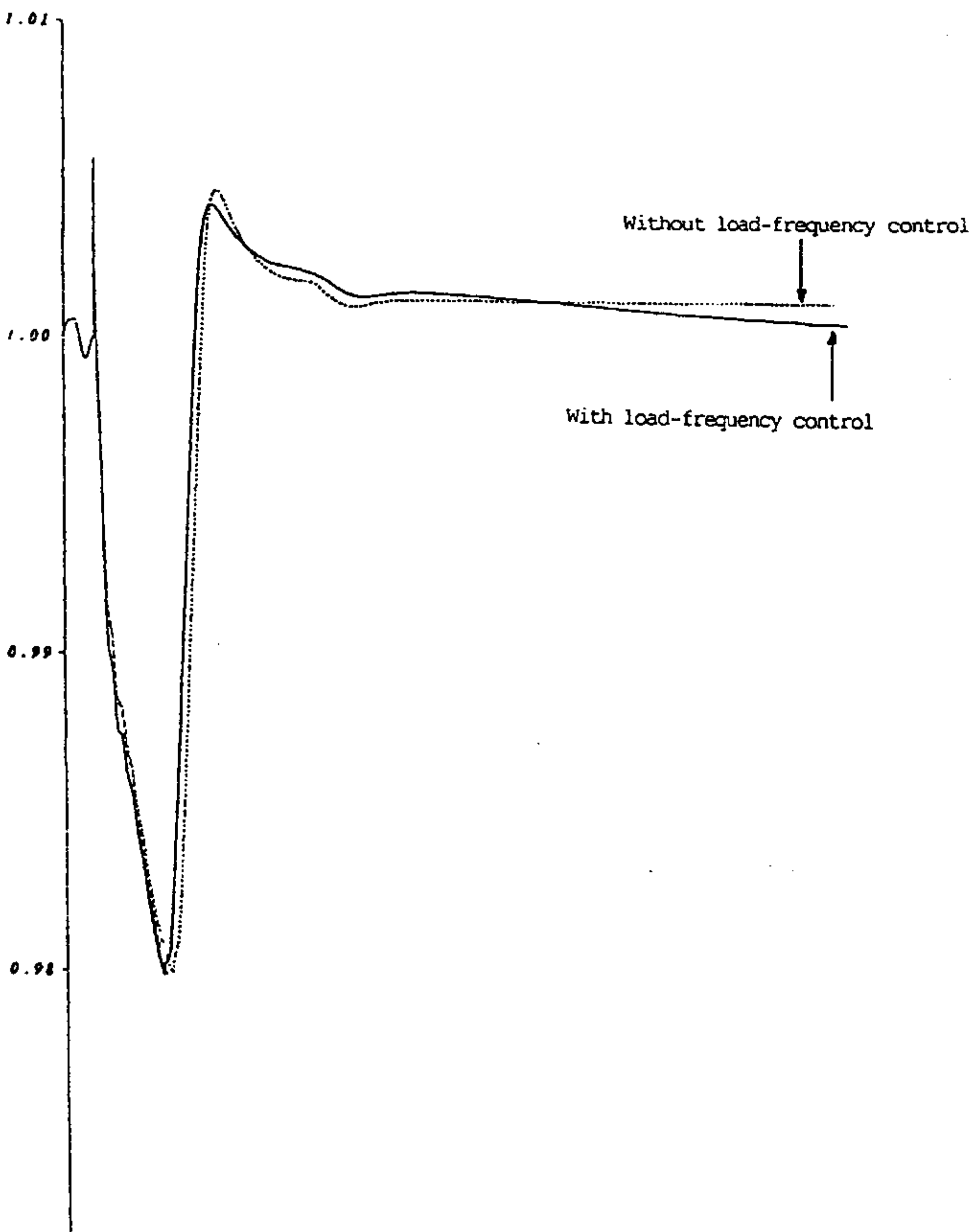


Fig. 4.5.2. i. System frequency.

.Solid line: Simulation A.
.Dash line: Simulation D.

4.5.3. Simulation with EXSTAB (run by GE)

4.5.3.1. Description of the modelization

Some block diagrams of the following system are found in appendix A5.

- Network: Load flow data provided in PSS/E format were automatically converted to EXTAB format.

  Algebraic PI schemes, as in the reference, are used for transmission lines.

- Generator: Generator data provided in PSS/E format were automatically converted to EXSTAB format. Full Park model with 4 rotor windings and saturation in both axes, as in the reference, has been used.

- Excitation system: PSS/E and IEEE standard models (SEXS, EXAC4, IEEX1, IEEEX2A), that are included in EXSTAB, have been used to represent these dynamics. Some complex excitation systems, initially proposed, were simplified to be represented by these standard models.

- Turbine/governor: PSS/E and IEEE standard models (TGOV1, IEEEG1), included in EXSTAB have been used.

- Power plant: Power plants receiving load-frequency orders (units 16, 18, 22 and 23), have been represented using the EXSTAB models ROKIPU and ROBWR.

- Protection system:

  - Auxiliary services undervoltage relay: A protection similar to the proposed one is included in the EXSTAB generator model. In this simulation, the actuation of this protection causes the isolation of the unit.

  - Unit loss of synchronism protection: To determine the unit trip due to this protection, it is checked the generator angle, referred to the center of inertia angle. (Please, see in appendix A.5 the calculation of the center of inertia).

  - Tie-line loss of synchronism protection: A simplified model of this relay has been obtained writing a Fortran subroutine.

- Loads:

  - The system loads have been represented, by a combination of standard static load models, using the EXSTAB load model SQLOAD.

    . Active component (P):

    $P = Po\ [\,0.5\ V\,(1 + 0.75\ \Delta f) + 0.5\ V^2\,]$

    (Please, see the frequency calculation in appendix A.5)

    . Reactive component (Q): $Q = Qo * V^2$

  - In order to represent the auxiliary services of machines 14 and 15, a combination of static load and induction motor models have been used.

- Load shedding system: This protection system has been represented using an EXSTAB model (UFVLS). Load restoration has not been modelled.

- Load-frequency control: A simplified model of AGC, that it is provided by EXSTAB, has been used.

4.5.3.2. Simulation results

Four simulations have been carried out with EXSTAB program:

- Simulation A: Including the whole modelling.
- Simulation B: Without loss of synchronism relays on tie-lines.
- Simulation C: Without load-shedding system.
- Simulation D: Without load-frequency control and without power plant model.

The aim of these four simulations is to compare EUROSTAG and EXSTAB results, as well as to assess the influence of: loss of synchronism relays of the tie-lines, load shedding system and load-frequency control.

Simulation A : (Including the whole modelling)

The results of this simulation are very close to the ones of the reference and EUROSTAG simulations:

to=1 sec	Three phase to ground short circuit at bus number 13070.
to+0.2 sec	Fault is removed by the opening of all transmission lines and transformers connected to the bus number 13070. This causes the isolation of machine 20.
to+0.4 sec	Trip of machine 14 because of the minimum voltage protection of auxiliary services. (Fig. 4.5.3.a)
to+4.32 sec	Opening of the four tie-lines that interconnect areas A and B. The initial system is divided into three islands (area A, area B and machine 20). (Fig. 4.5.3.b and 4.5.3.c).
to+10.59sec	Actuation of the load-shedding system of area A. (Fig. 4.5.3.d). Only the first step is performed.

As can be seen from the chronology, the results of this simulation, using EXSTAB program, are practically the same that the ones obtained in the reference case (PSS/E simulation) and in the EUROSTAG simulation. Only a slight difference in the moment at which the two last events occur can be remarked.

The system behaviour can be justified in the same way that it was done in the description of the simulations that were performed using the other programs:

The load-shedding actuation leads the system to a new load/generation balance, reaching the system frequency a value close to the nominal one, but slightly higher. After the load-shedding actuation, the load-frequency control will, apparently, return the frequency to its scheduled value (please, see how the load-frequency control decreases the generation to reduce the frequency value. Fig. 4.5.3.d and fig. 4.5.3.e).

Simulation B : (Without loss of synchronism relays on the tie-lines)

Until the moment when the tie-line relays should actuate (t=to+4.32 sec.), both simulations A and B provide, obviously, the same results. However, after this moment the results are different.

In the simulation A, after the opening of tie-lines, the load shedding system of area A has to actuate to re-establish the system frequency. However, in this simulation, without loss of synchronism relays on the tie-lines, the frequency does not fall and the load-shedding actuation is not necessary.

This result was expected since remaining the areas interconnected, area A receives an important aid from area B. It is also observed, in this simulation, that the fact of helping area A does not cause the trip of any of the units of area B.

This remarkable difference is clearly observed comparing the evolution of system frequency with and without loss of synchronism relays on the tie-lines (fig. 4.5.3.g).

Simulation C : (Without load-shedding system)

Comparing simulations A and C it is observed that the main difference between both simulations is not observed in the frequency fall, but in the frequency rise. This happens because the amount of lost generation has such a value that it causes a very similar frequency fall in both cases.

In simulation C, where no load-shedding system is included, the frequency remains at a low value (0.984 p.u. = 49.2 Hz, fig. 4.5.3.h). As no protection system or automatic control actuations are expected, it would be necessary to connect new generator units to the system to increase the frequency to its nominal value.

Simulation D : (Without load-frequency control/boiler)

As it is observed in simulation A, the frequency returns to its nominal value thanks to the load-frequency actuation.

However, in simulation D, where no load-frequency control is included, the frequency can not return to the scheduled value, since there is no contribution to re-establish it, and it remains just over this nominal value.

Both frequency evolutions with and without load-frequency-control are shown in fig. 4.5.3.i.

4.5.3.3. Conclusions

EXSTAB program provides a set of models in its library (power plant, AGC, load-shedding system...) that allows to reproduce the proposed dynamics without limitation.

The concrete events that take place in EXSTAB simulation, as well as the global behaviour of the system, are coincident with the results that have been obtained using the other programs.

In conclusion, EXSTAB program is capable of studing the proposed frequency scenario thanks to its integration algorithm, that considers at the same time both fast and slow dynamics, and thanks to its model library which provides most of the models that are important to this study (other necessary models, that are not included in the model library, can be represented writing Fortran subroutines).

PLOTS OF EXSTAB

PLOTS OF SIMULATION A:

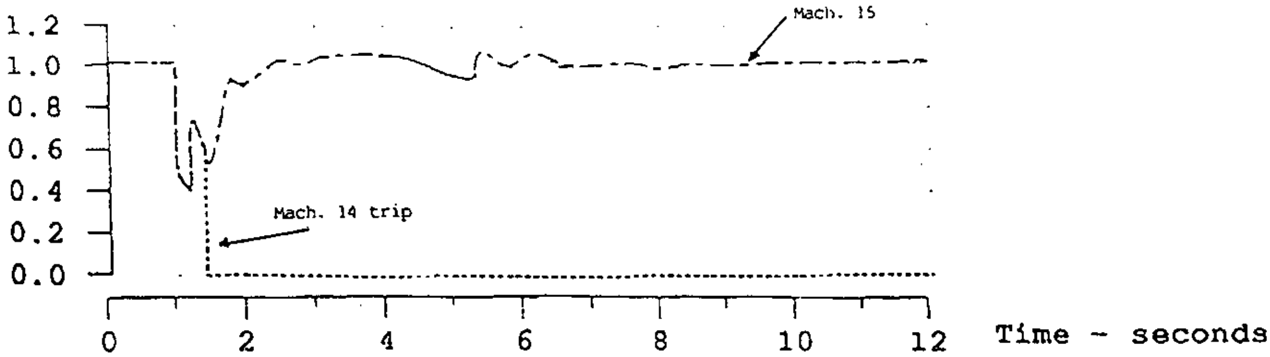


Fig. 4.5.3 a. Voltage of machine 14 and 15.

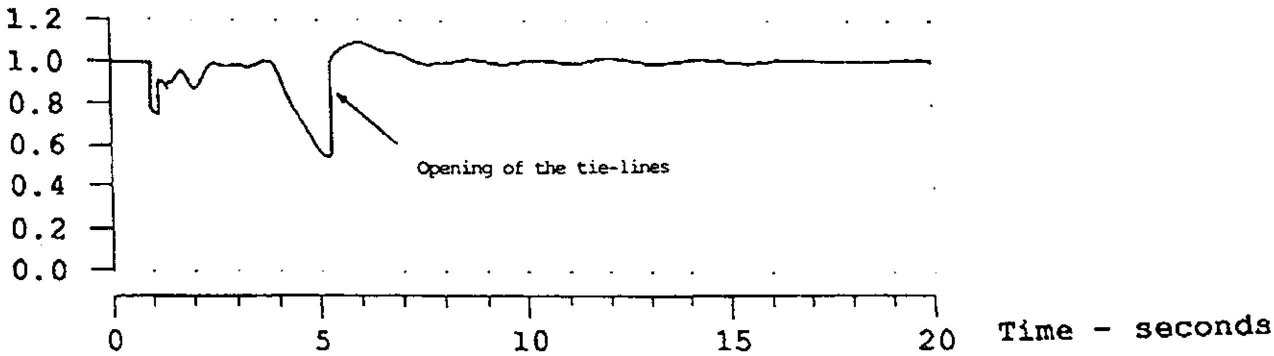


Fig. 4.5.3. b. Voltage of bus number 18105. This bus is the end of the tie-line (400kV) whose relay detects the loss of synchronism causing the disconnection of areas A and B.

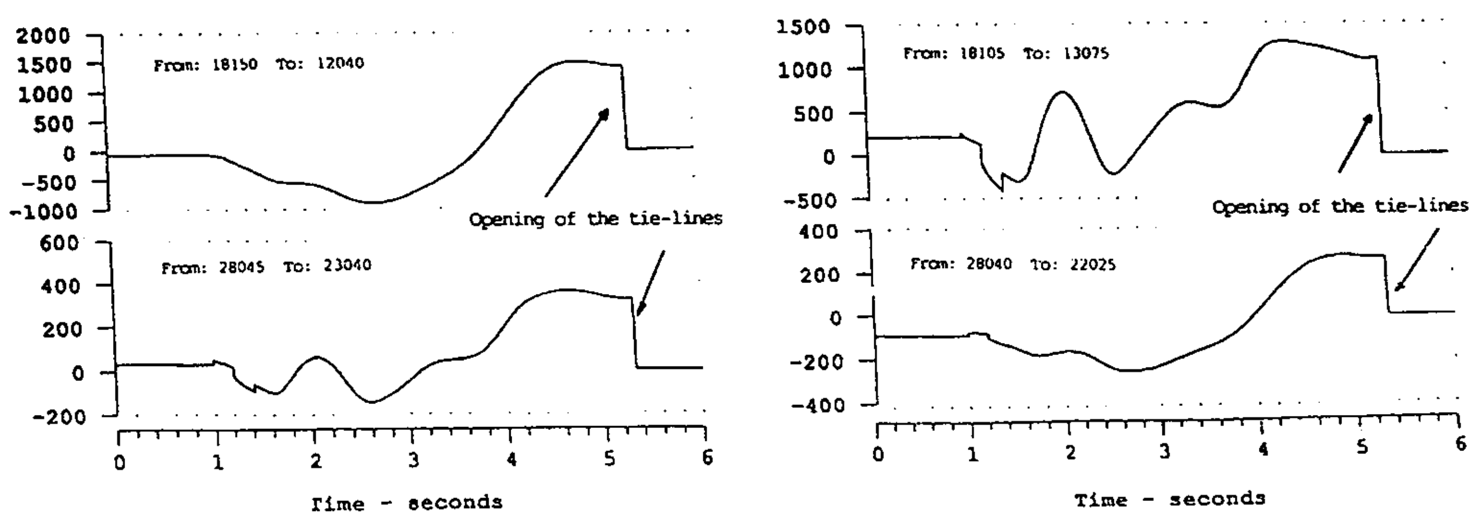


Fig. 4.5.3. c. Active Power through the tie-lines.

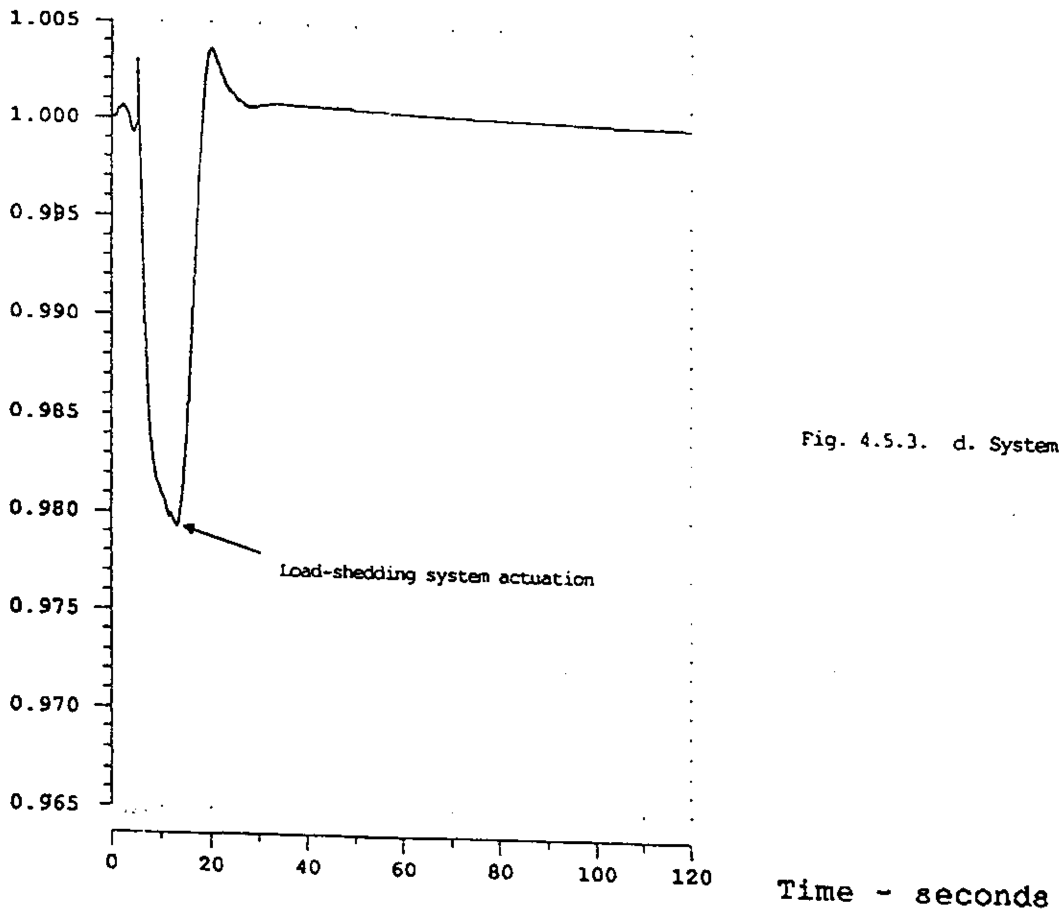


Fig. 4.5.3. d. System frequency of area A.

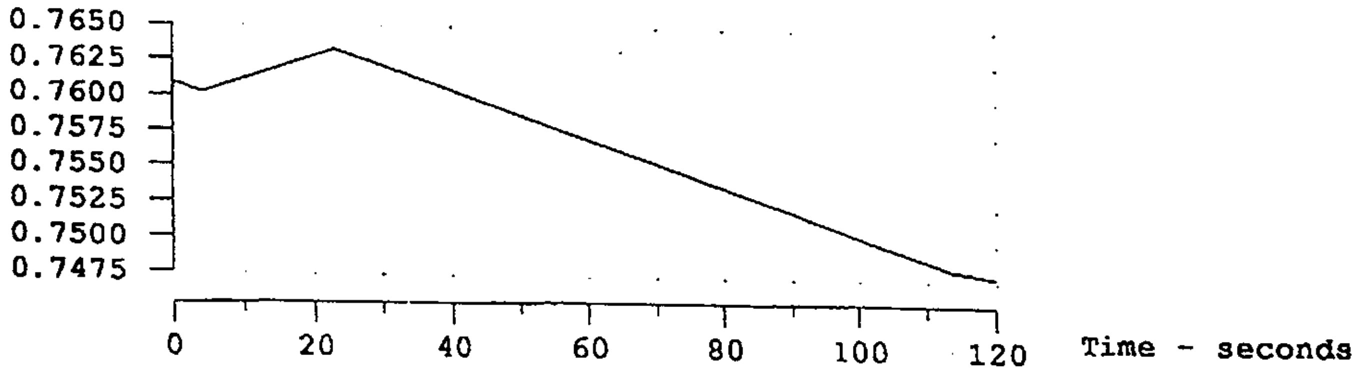


Fig. 4.5.3. e. Lodref signal (turbine load reference of mach. 22). Please, see the power plant representation in appendix A.5.

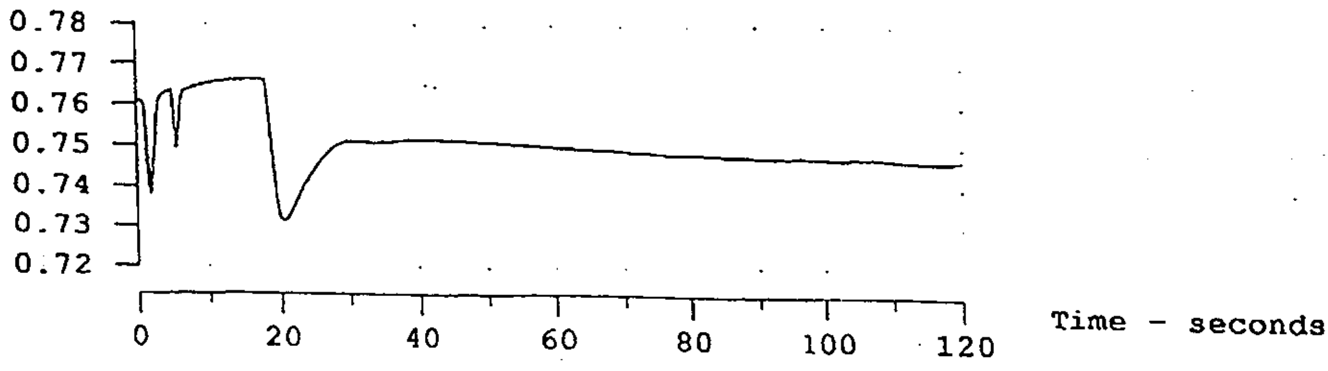


Fig. 4.5.3. f. Mechanical power of machine 22.

PLOTS OF SIMULATION B:

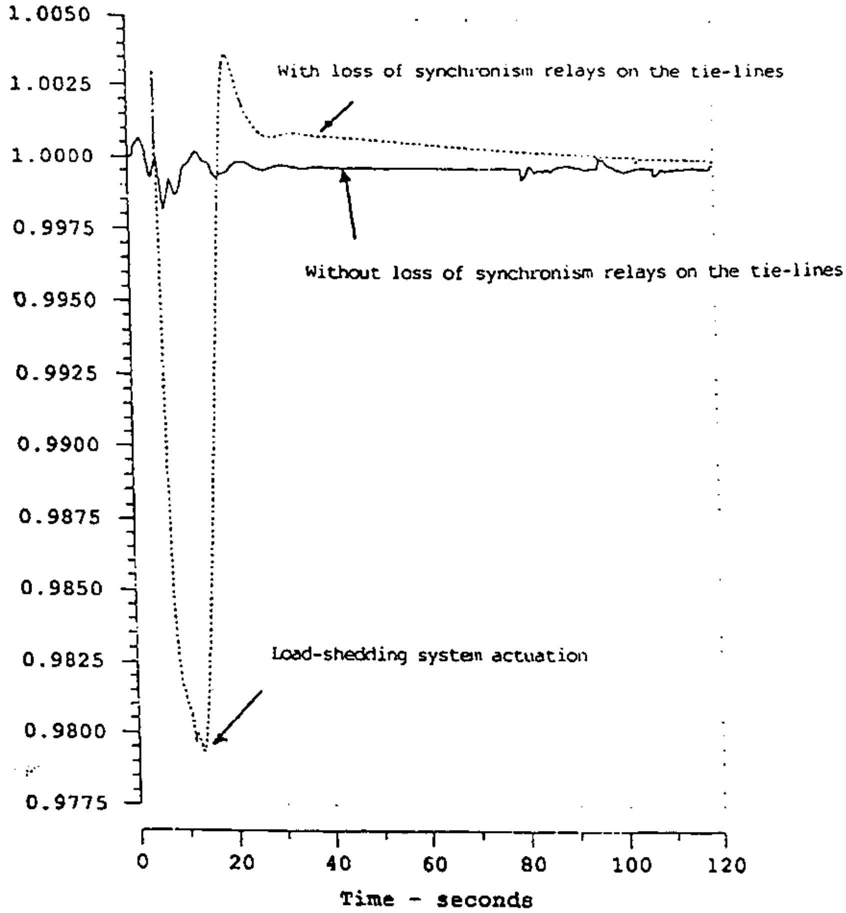


Fig. 4.5.3.. .g. System frequency.

.Dash line: Simulation .
.Solid line: Simulation :

PLOTS OF SIMULATION C:

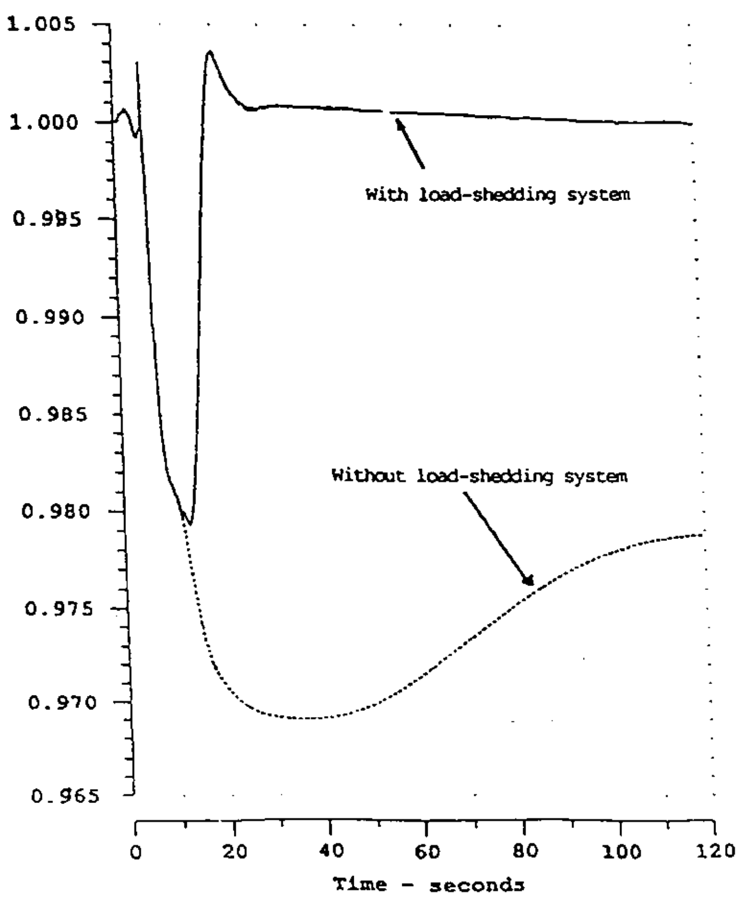


Fig. 4.5.3. h. System frequency.

.Solid line: Simulation
.Dash line: Simulation

PLOTS OF SIMULATION D:

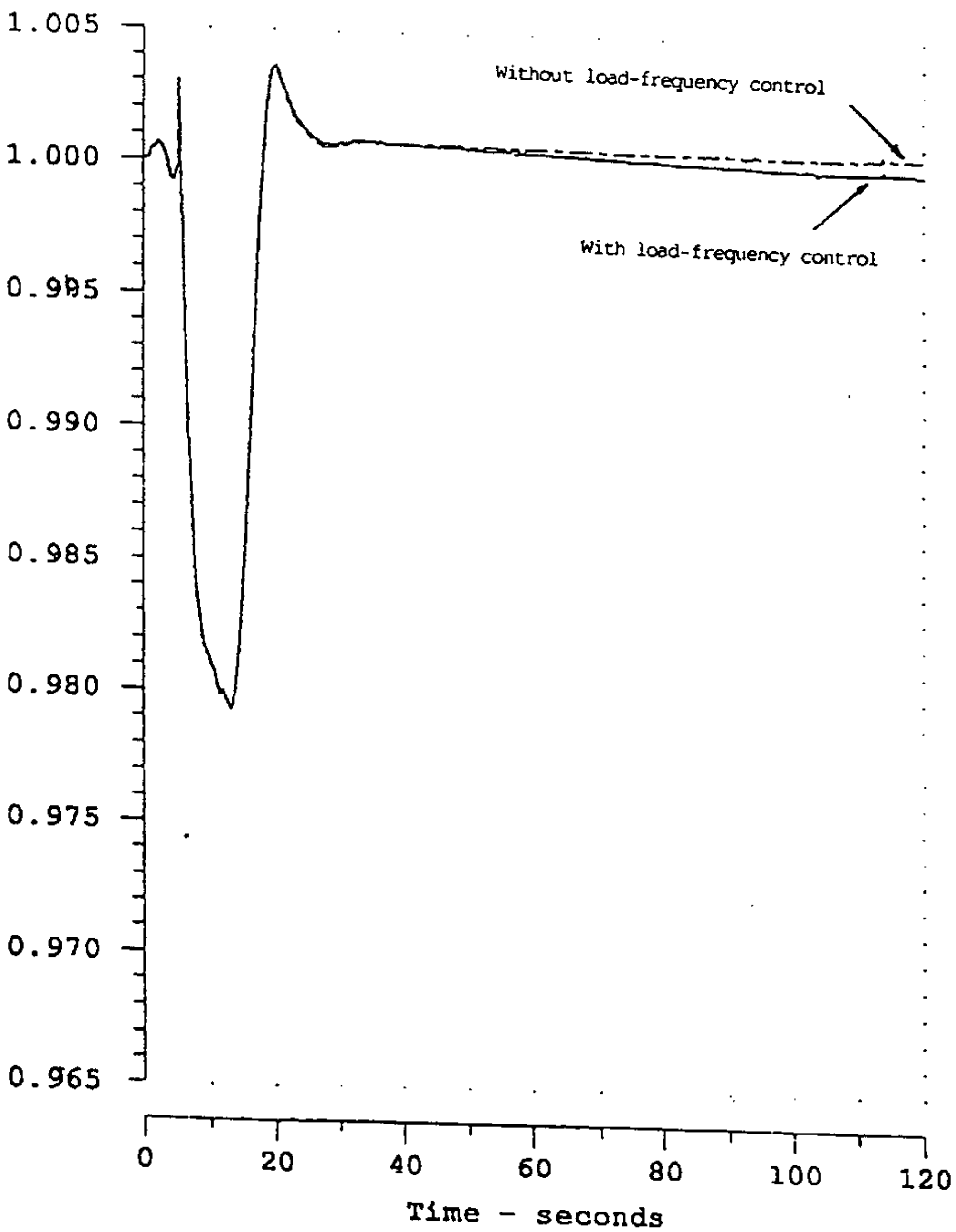


Fig. 4.5.3.. i. System frequency.

.Solid line: Simulation A.
.Dash line: Simulation D.

4.5.4. Summary comments on the simulations on the Spanish test system.

Three programs, PSS/E, EUROSTAG and EXSTAB, have been used to analyse the proposed scenario. EUROSTAG and EXSTAB are long-term stability programs whereas the PSS/E is only intended for transient stability studies.

This study has two main goals: To compare the used programs (their modelling capability and the obtained results) and to asses the influence of some important dynamics on the system behaviour (power plants, load-frequency control, load-shedding system and loss of synchronism relays of the tie-lines).

- PSS/E simulation compared with EUROSTAG and EXSTAB simulations

  First of all, it is very important to remark that the PSS/E simulation has been carried out using a version of this program that is limited to the analyse of transient stability. PSS/E simulation has two aims: To find a long-term frequency scenario and to provide a reference.

  Therefore, only the first seconds of EUROSTAG and EXSTAB simulations can be compared with PSS/E simulation. In these first seconds it is observed that the global behaviour of the system is very similar in these three simulations and the same events take place in all of them. However, PSS/E simulation is not able to show the later actuations of slower dynamics.

- EUROSTAG simulation compared with EXSTAB simulation

  Both programs have the capability of analysing long-term frequency scenarios.

  EXSTAB includes in its model library most of the models that are important to carry out this study (power plants, load-frequency control, load-shedding...). Other necessary models can be obtained writing Fortran Subroutines.

  EUROSTAG does not include these models, however, its modelling flexibility (provided by the macro-block language) easily allows to incorporate all the necessary models.

  The same event evolution is obtained in all the simulations that have been carried out with both programs, which indicates that they perform coherently. Only a small difference in the moment at which some of these events take place has been detected. These slight time discrepancies are probably produced by some not intentioned differences in the way in which the proposed dynamics have been modelled.

- Conclusions

  - Programs

    To study a frequency scenario it is necessary to use a long-term stability program, since some slow dynamics have to be considered. This long-term program has to satisfy two important requirements:

    . To have a great modelling capability or flexibility, due to the necessity of considering varied and complex system actuations that only actuate in long-lasting process.

. To have the ability of adapting to the fast dynamics, as well as to the slow ones. This condition is simplified if a single program handles fast and slow dynamics at the same time, being capable of internally modifying the time step of integration.

Both programs EUROSTAG and EXSTAB fulfil all these requirements, and they are perfectly capable of analysing this kind of scenarios.

- Scenario

A great effort has been made to represent all the long-term dynamics in this complex scenario. Thanks to this careful modelling, it has been possible to analyse the influence of several systems, focusing mainly on the following ones, that are the most relevant in this kind of long-term scenarios:

. Boilers and load-frequency control: The modelling of these elements is fundamental to consider the frequency dynamic after a great perturbation. These systems are designed to actuate with a slow time constant in the re-establishing of the nominal system frequency.

. Load-shedding system: This protection system does not have its own dynamic characteristic, but it actuates in prescheduled frequency fall conditions, causing a variation in the system dynamic that is absolutely necessary to consider.

. Loss of synchronism relay of the tie-lines: As the power system that has been studied is an interconnected one, it has been analysed the influence of these relays on the system evolution. This system does not have its own dynamic characteristic, but it actuates in prescheduled voltage oscillation conditions, causing the opening of the tie-lines and consequently affecting the global system behaviour.

The long-term analyses are very important to the development of defence plans and further studies on this kind of frequency scenarios are strongly needed. We encourage to use this case as a reference for future researches.

CHAPTER 5

CONCLUSIONS

CONCLUSIONS

The rapidly increasing interest of power system engineers for advanced simulations has mainly two origins :

- The new challenge of operating power systems nearer to their physical limits.
- The use of new powerful technologies (hardware and software) making high performance simulation easier to implement or eventually possible.

Task Force 38-02-08 has provided the community of researchers and application engineers with :

- a practical assessment of the present state of the art as regards dynamic simulation tools and, to a certain extent, as regards power system modelling;
- data sets of four test systems displaying typical long term dynamics.

We do hope that these outputs will constitute a most useful material to help power system engineers to assess their present tool, or to decide upon the development or the procurement of new tools.

To get the best of the results of the Task Force, in particular to apply them in practice, an in depth analysis of the report, and especially of the simulation results remains mandatory. Nevertheless, useful general conclusions may be drawn as follows.

Power system behaviour

As it was expected from the beginning, significant rapid (electromechanical transients of generator rotor, ...) and slow (boilers, tap changers, overload protections, secondary controls, ...) phenomena are mixed in most of the scenarios.

Modelling

An extended modelling of power system components and controls as regards frequency bandwidth is generally necessary. According to the scenario to be simulated, key elements must be modelled in a very accurate and specific way. The following points have been practically assessed as critical.

- In case of voltage collapse scenario :
  - generator magnetic saturation;
  - generator current limiters;
  - static characteristics of load versus voltage;
  - slow dynamics of aggregated load;
  - tap changers control;
  - undervoltage and loss of synchronism relays.

- In case of frequency deviation scenario :
  - governor;
  - energy supply system and its regulation;
  - load characteristic versus voltage and frequency;
  - automatic frequency load shedding and automatic restoration scheme.

According to the scenario, centralized controllers (either AGC or secondary voltage control or both) must also be modelled.

Other elements like voltage control devices in general and overcurrent or distance protections concerning the various components are deemed to be also critical.

For all those elements, generic or standard modelling is generally not sufficient.

Study approach

Unknown dynamic properties

If the power system behaviour is not fully known, any a priori simplification could lead to erroneous conclusions. As a consequence, a quite comprehensive modelling and a simulation tool capable of handling both fast and slow dynamics are mandatory. The modelling will be then progressively made more specific and accurate for the elements having demonstrated their critical role.

Known dynamics

Once the dynamic properties are better known, specialized tools [1] may be used. This was demonstrated in several cross calculations where the time was compressed in order to allow the use of transient stability only programs to simulate known long-term scenarios. It is worthwhile to note that very few simplifications at the level of rotor movement were adopted.

Sometimes the dynamics is well-known, and the most critical case will occur after the various voltage and frequency controls have stabilized. This may be true in certain voltage collapse assessment studies. In such a case even static load-flow like calculations and certain indices calculations can be used.

Anyway, when the dynamics is complex, intermingling fast and slow phenomena, the concomitant use of separated or simplified tools for transient and slow dynamics has not been proposed during the Task Force work and is not recommended.

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1 By specialized tools, we mean tools that can only simulate a part of the problem.

Tools

Recently developed digital simulation programs offer the requested frequency bandwidth and accuracy of modelling and the requested calculation speed for LTD studies. In other respects, recent large analog simulators operated in 3-phase circuits can be used for evaluating the control units of actual equipment taking into account balanced and/or imbalanced phenomena. This kind of tools, however, is costly as regards the investment and the operation. When the LTD studies don't request the special features of the analog simulators, their use seems no more recommended for general purpose studies (their interest lying more in their real time properties).

As it is derived from the study approach described hereabove, the main requirements for a LTD tool are its modelling bandwidth and its modelling flexibility :

Modelling frequency bandwidth :

Dynamic phenomena of importance for LTD, with time constants from a few tens of milliseconds up to 100 seconds or more may co-exist in the system. This calls for an implicit integration algorithm. To avoid either excessive computation time or overdamping, an automatic variable stepsize procedure is most useful. Simulations results provided in the frame of the Task Force demonstrated that variable stepsize is now a mature technology, allowing stepsize variations of a factor above 10 000, the accuracy of the integration process being constant, whatever the behaviour of the power system.

It is worthwhile to note that the different variable stepsize programs may be used as well as classical transient stability programs to run pure transient stability test.

Modelling flexibility

To cover the needs of accuracy for the modelling of critical elements, two solutions were presented :

- to build a large model library with numerous extended hardcoded models;
- to use a simulation interface allowing user's defined models to be entered easily into the program library.

Practical experiences encountered during the Task Force work showed that a model library is never large enough to manage all the modelling needs and that user's defined model facilities beside a good library are strongly recommendable.

Interactivity

To afford the simulation of LTD scenarios, all possible operator actions taking place in the real world must be taken into account in the simulation process. For that purpose, the interactive operation of the simulation program is highly desirable.

User friendliness

The amount of data to be entered and the complexity of the modelling call for advanced data engineering functions.

Outputs of the program are of paramount importance. When dealing with unknown behaviour or scenarios, the flexible a posteriori definition of plots is needed.

Further Developments

Existing tools, combined with present powerful workstations allow detailed LTD simulations to be run. It is quite clear that these tools are able to effectively use the existing models and available data. Furthermore, the Task Force has shown that modern LTD tools do not limit themselves to Long Term Dynamics only, but also cover the whole field of "pure" transient stability. As far as off-line studies are concerned, the main development area is quite obviously in the field of modelling and data identification.

A need of tools to help engineers to analyse the huge amount of outputs of the program has been identified.

LTD simulations are also applicable to real time and on-line environment :

- Dynamic security assessment
- Voltage collapse assessment
- Enhanced dispatcher training simulator engine
- Test bed for on-line applications (e.g. centralized controls)

for these fields, further developments are still needed, mainly at the level of computation speed.

Task Force members think that, thanks to foreseeable improvements of computer technology and algorithms, real time or faster than real time simulations of full size power systems will be possible, having the same accuracy and using the same data as the ones used presently for off-line studies.

Task Force recommend that SC 38 of Cigre follow, or even lead as far as specifications are concerned, these further developments.

APPENDICES

APPENDIX A.1

THE BPA TEST SYSTEM

A.1 System Diagram

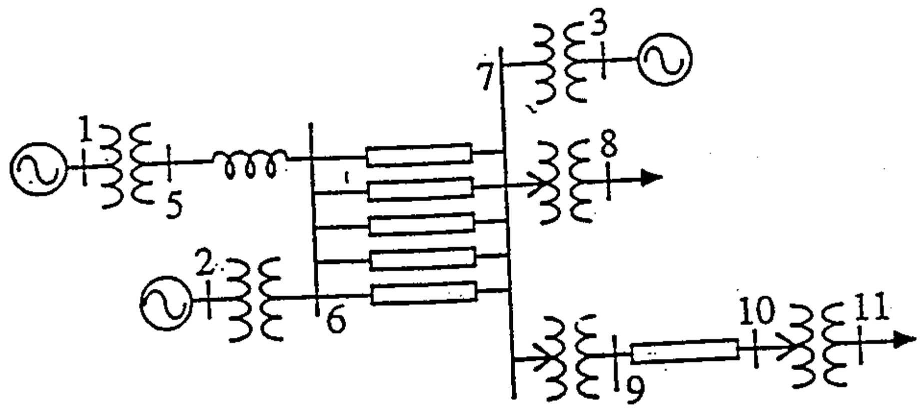


Figure A.1 : Single Line Diagram of Test System A

A.2 Load Flow Data

- Bus code : 1=PQ bus, 2=PV bus, 3=Slack bus
- Load and generation are in MW and MVAR.
- Voltage angles are in degrees
- Bus shunts are in MW and MVAR at unity voltage
- All other quantities are in P.U. on 100 MVA base

BUS DATA

BUS#	CODE	VOLT	ANGLE	PLOAD	QLOAD	BUS G	SHUNT B
1	3	0.9800	0.0	0.0	0.0	0.0	0.0
2	2	0.9646	-8.6	0.0	0.0	0.0	0.0
3	2	0.9553	-26.8	0.0	0.0	0.0	0.0
5	1	1.0874	-4.0	0.0	0.0	0.0	0.0
6	1	1.0616	-12.4	0.0	0.0	0.0	0.0
7	1	1.0196	-30.7	0.0	0.0	0.0	763.0
8	1	0.9362	-37.2	3369.4	1045.7	0.0	600.0
9	1	0.9337	-36.8	0.0	0.0	0.0	300.0
10	1	0.8850	-44.1	0.0	0.0	0.0	0.0
11	1	0.9220	-46.4	3485.6	0.0	0.0	0.0

GENERATOR DATA

BUS#	PGEN	QGEN	QMAX	QMIN	V SET	MVA RATING
1	4219	1207	1600	-1000	0.9800	5000
2	1736	725	725	-200	0.9646	2200
3	1155	700	700	-100	0.9730	1600

TRANSMISSION LINE DATA

FROM	TO	ID	LINE R	LINE X	CHARGING*
1	5	1	0.0000	0.0020**	0.0000
2	6	1	0.0000	0.0045**	0.0000
3	7	1	0.0000	0.0125**	0.0000
3	7	2	0.0000	0.0125**	0.0000
5	6	1	0.0000	0.0040	0.0000
6	7	1	0.0015	0.0288	1.1730
6	7	2	0.0015	0.0288	1.1730
6	7	3	0.0015	0.0288	1.1730
6	7	4	0.0015	0.0288	1.1730
6	7	5	0.0015	0.0288	1.1730
7	8	1	0.0000	0.0030**	0.0000
7	9	1	0.0000	0.0026**	0.0000
9	10	1	0.0010	0.0030	0.0000
10	11	1	0.0000	0.0010**	0.0000

* total line charging in pu

** transformer branch

TRANSFORMER DATA

FROM	TO	ID	RATIO
1	5	1	0.8857
2	6	1	0.8857
3	7	1	0.9024
3	7	2	0.9024
7	8	1	1.0664
7	9	1	1.0800
10	11	1	0.9600

LINE SHUNT DATA

FROM	TO	ID	LINE G,B (FROM)		LINE G,B (TO)	
1	5	1	0.0000	0.0000	0.0000	1.0000
2	6	1	0.0000	0.0000	0.0000	1.0000
3	7	1	0.0000	0.0000	0.0000	1.0000
3	7	2	0.0000	0.0000	0.0000	1.0000
7	8	1	0.0000	0.0000	0.0000	1.0000
7	9	1	0.0000	0.0000	0.0000	1.0000
10	11	1	0.0000	0.0000	0.0000	1.0000

A.3 Dynamic Data

- Generator 1 is modelled as an infinite bus
- Generator and control system data applies to generator 1 and generator 2
- All the generator and control system parameters are pu values on the respective machine MVA base

A.3.1 Stator and rotor parameters

R_a = 0.00460 X_d = 2.070 X_q = 1.990 X_l = 0.150

X_d' = 0.280 X_q' = 0.490 X_d'' = 0.215 X_q'' = 0.215

T_{do}' = 4.10 T_{qo}' = 0.560 T_{do}'' = 0.033 T_{qo}'' = 0.062

A.3.2 Generator saturation parameters

A_{sat} = 0.0220 B_{sat} = 8.33970 ψ_L = 0.850 ψ_H = 99.0

Only X_{ad} varies with saturation. If $\psi_a < \psi_L$, $X_{ad} = X_{ado}$, with ψ_a the actual air gap flux, and X_{ado} the unsaturated value of X_{ad}.

If $\psi_a > \psi_L$, then

$$X_{ad} = X_{ado} \frac{\psi_a}{\psi_a + \psi_I}$$

with

$$\psi_I = A_{sat} e^{B_{sat}(\psi_a - \psi_L)}$$

A.3.3 Generator mechanical parameters

Generator 2 :

H = 2.090 Damping Coefficient = 0.20 MVA Base = 2200.0
Frequency Base = 60.0

Generator 3 :

H = 2.330 Damping Coefficient = 0.20 MVA Base = 1600.0
Frequency Base = 60.0

A.3.4 Exciter and maximum excitation limiter data

Exciter and maximum excitation limiter model and associated data are shown in Figure A.2.

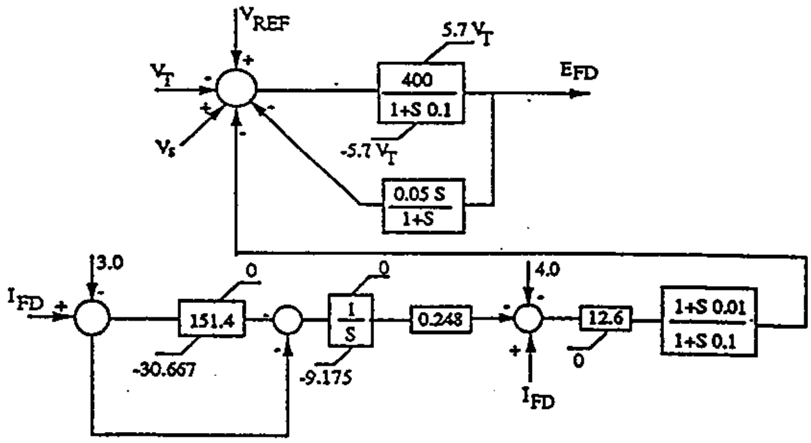


Figure A.2 : Exciter and Maximum Excitation Limiter Model

A.3.5 Power system stabilizer data

Block diagram of power system stabilizer is shown in Figure A.3. The following is the stabilizer data corresponding to the block diagram.

INPUT SIGNAL : SPEED
K_{QS} = 24.40 T_{QS} = 0.0 K_{QV} = 0.0 T_{QV} = 0.0
T_Q = 3.0 T_{Q1}' = 0.150 T_{Q1} = 0.050 T_{Q2}' = 0.150
T_{Q2} = 0.050 T_{Q3}' = 0.0 T_{Q3} = 0.0 V_{SMAX} = 0.050
V_{SMIN} = -0.050 V_C = 0.0

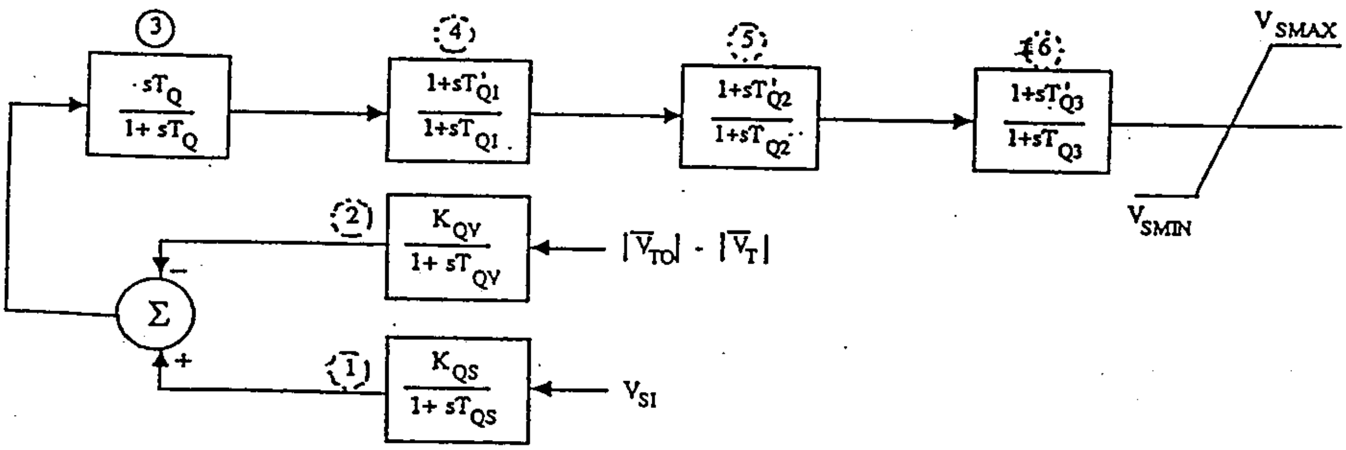


Figure A.3 : Power System Stabilizer Model

A.3.6 Governor data

Governor block diagram is shown in Figure A.4. The following is the governor data corresponding to the block diagram.

K_1 = 20.0 T_1 = 0.0 T_2 = 0.0 T_3 = 0.050
R_{MAX} = 0.10 R_{MIN} = -0.10 $P_{MAX(1)}$ = 20.0 T_4 = 0.3760
T_5 = 10.10 T_6 = 0.50 T_7 = 0.0 K_2 = 0.290
K_3 = 0.240 K_4 = 0.470

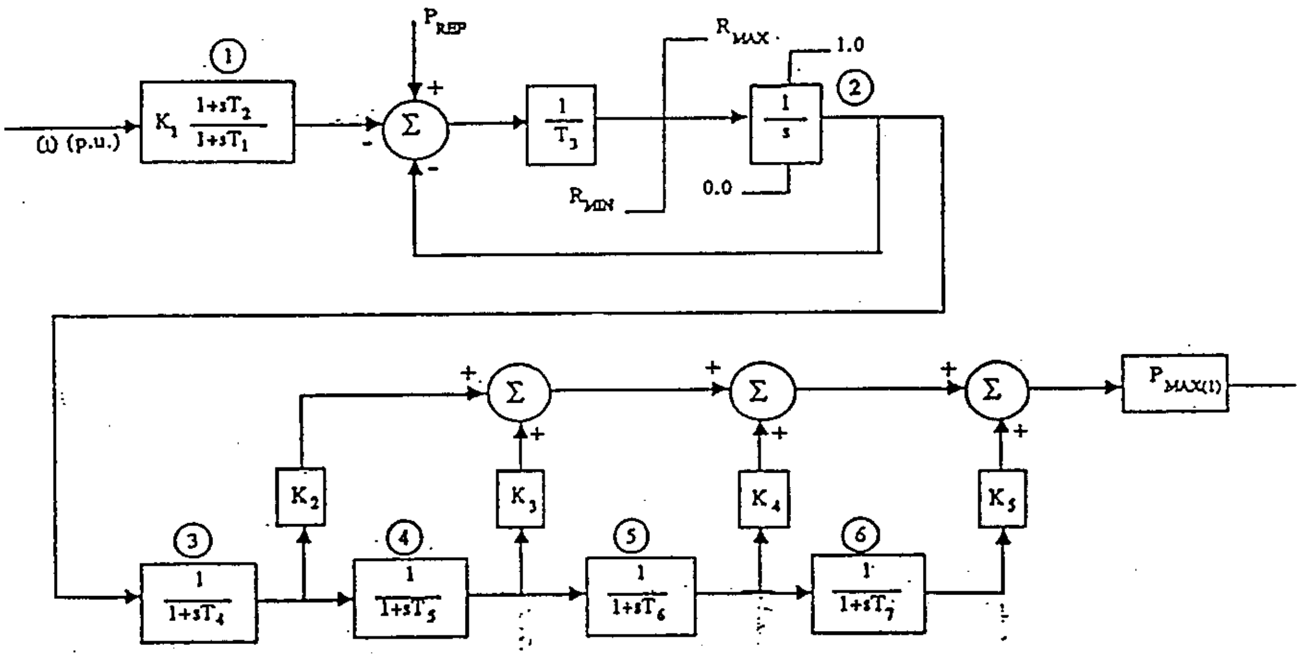


Figure A.4 : Governor Model

A.3.7 Induction motor data

Induction motor equivalent circuit is shown in Figure A.5. The following is the induction motor parameters (pu values on motor MVA base).

X_m = 3.3 R_s = 0.01 X_{so} = 0.145 R_r = 0.008 X_r = 0.145
H = 0.6 MVA Base = 3000.0 MVA
Motor Load Torque Speed Characteristic : $T_L = T_o\, \varpi^2$

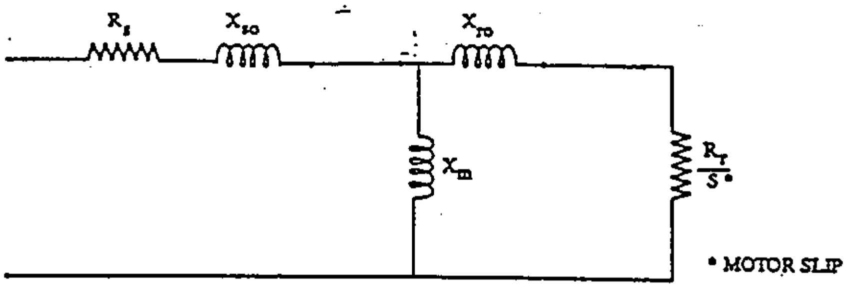


Figure A.5 : Induction Motor Equivalent Circuit

A.3.8 ULTC dynamic data for transformer 10-11

```
Controlled Bus : 11
Controlled Bus Voltage Reference : 0.922
Controlled Bus Voltage Dead Band : 0.01
Time Delay for First Tap Operation : 30 Seconds
Time Delay for the Second and Subsequent Tap Operation : 5 Seconds
Maximum Turns Ratio (Primary/Secondary) : 1.12
Minimum Turns Ratio (Primary/Secondary) : 0.82
Turns Ratio Step Size : 0.00606
```

APPENDIX A.2

THE BELGIAN-FRENCH TEST SYSTEM

THE BELGIAN-FRENCH TEST SYSTEM DATA

1. Description of the test system

The proposed hypothetical system is illustrated on Fig. 1. It has two voltage levels : 380 kV and 150 kV. The external system is simulated by means of three infinite busses. Most loads are fed at 70 kV through sub transmission transformers fitted with automatic ULTC, in series with 380/150 kV auto transformers.

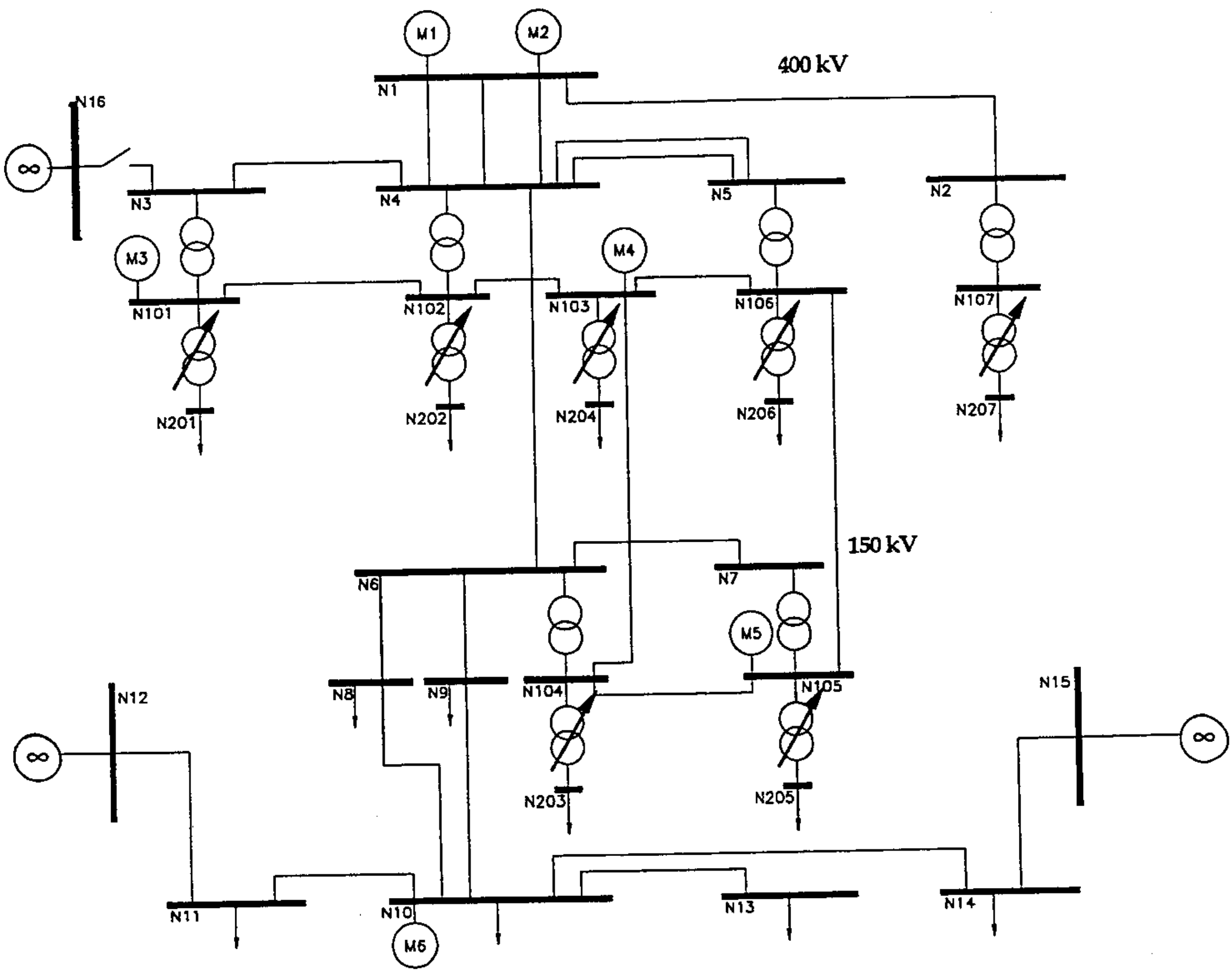


Fig. 1 : Single line diagram of test system

2. Description of the scenario

It is initiated by a load pick-up of 30 % in two hours. The amount of load increase corresponds to 700/350 MVA and is assured by the constant impedance part of the aggregated loads (see Appendix A.2.9).

During the load pick-up, the secondary voltage control is done manually by :

- increasing the terminal voltage set point of the units;
- changing the 380/150 kV transformer ratios.

the secondary frequency/power control is assured by :

- increasing linearly the mechanical power set point :
  - from 175 to 375 MW for units M3 and M5;
  - from 150 to 250 MW for unit M4.

the remaining 200 MW are supplied from infinite busses N12, N15 and N16 (which represent the external system).

At time 5000 s, the line N3-N16 trips.

Once the load pick-up is ended, and the power system stabilised, the unit M2 is tripped (at 7400 s).

As a consequence of the unit M2 tripping, and following the action of the automatic tap-changers, the rotor current limiter of unit M1 enters into action. This limiter is bad tuned and reduces drastically the excitation, provoking the loss of synchronism of the unit M1.

After this second tripping and further tap changes, the voltage at the terminals of machines M3, M4 and M5 becomes too low and these units trip successively by undervoltage protection for M4 and by loss of synchronism for M3 and M5.

3. Description of the modelization and data

3.1. System

Load flow data are detailed in Appendix A.2.1.

Initial load flow is detailed in Appendix A.2.2.

3.2. Infinite buses, generators and induction motors dynamic data

3.2.1. Infinite buses

An infinite bus is a voltage source, constant in phase and in magnitude, located behind an impedance.

Infinite buses data are detailed in Appendix A.2.3.

3.2.2. Generators

They are modelled according to a classical Park model where the rotor is represented by 4 equivalent windings and where the saturation of the magnetic circuits is taken into account in both axes. Data are expressed in external parameters.

Generator data are detailed in Appendix A.2.4.

Saturation data are detailed in Appendix A.2.5.

3.2.3. Induction motor data

Induction motors are also modelled according to a classical Park model where the rotor is represented by equivalent windings. Data are introduced using internal parameters. The mechanical torque characteristic is defined by means of a piecewise function of the motor speed.

Numerical data are given in Appendix A.2.6.

3.3. Controllers

3.3.1. Governors

A block-diagram of the governor and its related parameters are given in Appendix A.2.7.

3.3.2. AVR

A block-diagram of the governor and its related parameters are given in Appendix A.2.8.

3.4. Automata - relays

Different automata and protection devices are taken into account :

- **undervoltage protection** on generating units which trips the unit with 1 second delay, if the terminal voltage remains under a set value V_{min} p.u. during more than x seconds (x = 3, V_{min} = 0.7 for machines M1, M2, M3, M5 and x = 3.5, V_{min} = 0.83 for machine M4);
- **loss of synchronism protection** which trips the units after one or several pole slippings;
- **tap-changer automatons** regulating the low voltage side (70 kV) of sub transmission transformers. In case of voltage deviation, the first tap change takes place after 36 s, the followings after 16 s (1 step = 1.05 % x V_{nom}, ± 12 steps). The minimum time between a tap raise (lowering) and a tap lowering (raise) is 48 s. The dead band around the voltage setpoint is ± 0.01 p.u.

3.5. Load modelization

3.5.1. Composite loads

All the 70 kV loads are made of the aggregation of :

- an induction motor;
- a constant impedance load;
- a capacitor (45 Mvar when V = 1 p.u.).

Appendix A.2.9 details the share taken by each type of load at initial time and at the end of the load pick-up.

3.5.2. Other loads

Both active and reactive parts are constant impedance.

3.6. Secondary voltage control scheme

As stated in § 2, the secondary voltage control is operated manually during the load pick-up by means of :

- increasing the voltage set points of the units;
- changing the 380/150 kV transformer ratios.

A detailed control scheme is given in Appendix A.2.10.

APPENDIX A.2.1 : LOAD FLOW DATA

a. Load flow data

table 1 presents the nodes data

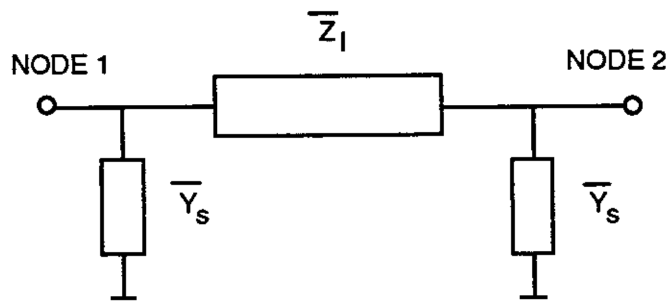
table 2 presents the special nodes data

table 3 presents the lines data

table 4 presents the transformers data

b. Line model :

It is a classical π scheme



where $\bar{Z_l} = R + jX$

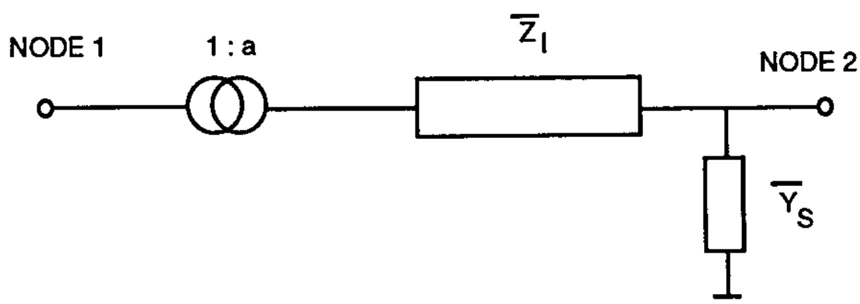
$\bar{Y_S} = G_S + jB_S$

with R, X, G_S and B_S expressed in the p.u. base :

- $S_B = 100$ MVA;
- U_B = nominal voltage of both nodes.

c. Transformer model

It is represented by the following scheme :



where $\bar{Z_L} = R + jX$

$\bar{Y_S} = G_S - jB_S$

$a = \text{ratio at no load} = \dfrac{V_2 \text{ p.u.}}{V_1 \text{ p.u.}}$

with R, X, G_S, B_S expressed in the p.u. base :

- $S_B = 100$ MVA
- U_B = nominal voltage of node 2.

TABLE 1 : NODES DATA

NODE	PG MW	QG MVAR	PL MW	QL MVAR	QSHUNT MVAR	VBASE KV
N16	0	0	0	0	0	380.
N11	0	0	98.	32.	0	380.
N6	0	0	0	0	0	380.
N13	0	0	600.	200.	0	380.
N8	0	0	237.	78.	0	380.
N9	0	0	223.	73.	0	380.
N1	0	0	0	0	0	380.
M1	850.	346.	48.	40.	0	24.
M2	500.	178.	54.	45.	0	24.
N10	2800.	498.	580.	100.	0	380.
N14	0	0	300.	75.	0	380.
N5	0	0	0	0	0	380.
N4	0	0	0	0	0	380.
N7	0	0	0	0	0	380.
N3	0	0	0	0	0	380.
N2	0	0	0	0	0	380.
N104	0	0	0	0	75.	150.
N203	0	0	300.	167.	45.	70.
N106	0	0	0	0	0	150.
N206	0	0	300.	167.	45.	70.
N102	0	0	0	0	75.	150.
N202	0	0	300.	167.	45.	70.
N105	175.	30.	0	0	75.	150.
N205	0	0	300.	167.	45.	70.
N101	175.	30.	0	0	75.	150.
N201	0	0	300.	167.	45.	70.
N107	0	0	0	0	75.	150.
N207	0	0	300.	167.	45.	70.
N103	150.	20.	0	0	0	150.
N204	0	0	300.	167.	45.	70.
N12	0	0	319.	-100.	0	380.
N15	-64.8	38.8	0	0	0	380.

TABLE 2 : SPECIAL NODES DATA

NODE	V KV	TYPE
M1	24.	PV
M2	24.	PV
N10	412.	PV
N15	415.	SL

TABLE 3 : LINES DATA

NODE1	NODE2	#	R pu	X pu	GS pu	BS pu
N11	N10		0.00079	0.00838	0.0000	0.09860
N6	N8		0.00100	0.01000	0.0000	0.12200
N6	N9		0.00094	0.00995	0.0000	0.12210
N6	N4		0.00084	0.00708	0.0000	0.08640
N6	N7		0.00084	0.00708	0.0000	0.08640
N13	N10		0.00095	0.01004	0.0000	0.11810
N8	N10		0.00150	0.01600	0.0000	0.20000
N9	N10		0.00150	0.01600	0.0000	0.20000
N1	N4	1	0.00054	0.00464	0.0000	0.05670
N1	N4	2	0.00049	0.00522	0.0000	0.06410
N1	N4	3	0.00049	0.00522	0.0000	0.06410
N1	N2		0.00014	0.00145	0.0000	0.01620
N10	N14		0.00087	0.00969	0.0000	0.11570
N4	N3		0.00073	0.00772	0.0000	0.09480
N5	N4	1	0.00046	0.00490	0.0000	0.05450
N5	N4	2	0.00046	0.00490	0.0000	0.05450
N102	N103		0.00100	0.01140	0.0000	0.00200
N102	N101		0.01700	0.06320	0.0000	0.01150
N106	N103		0.00550	0.02500	0.0000	0.00400
N106	N105		0.00800	0.04300	0.0000	0.00700
N104	N105		0.00620	0.03000	0.0000	0.00500
N104	N103		0.00620	0.03000	0.0000	0.00500
N15	N14		0.00219	0.02309	0.0000	0.14430
N11	N12		0.00126	0.01331	0.0000	0.13550
N3	N16		0.00126	0.01331	0.0000	0.13550

TABLE 4 : TRANSFORMERS DATA

NODE1	NODE2	#	R pu	X pu	GS pu	BS pu	RATIO=V2(pu)/V1(pu)
N107	N2	1	0.00060	0.04370	0.0000	0.0000	0.981
N101	N3	1	0.00050	0.04350	0.0000	0.0000	0.960
N105	N7	1	0.00050	0.04350	0.0000	0.0000	0.900
N102	N4	1	0.00080	0.04720	0.0000	0.0000	0.948
N106	N5	1	0.00029	0.02229	0.0000	0.0000	0.983
N104	N6	1	0.00028	0.02200	0.0000	0.0000	1.011
N1	M1	1	0.00023	0.01070	0.0000	0.0000	0.925
N1	M2	3	0.00009	0.00758	0.0000	0.0000	0.945
N102	N202	1	0.00060	0.02500	0.0000	0.0000	1.030
N103	N204	1	0.00060	0.02500	0.0000	0.0000	1.030
N104	N203	1	0.00060	0.02500	0.0000	0.0000	1.030
N105	N205	1	0.00060	0.02500	0.0000	0.0000	1.030
N106	N206	1	0.00060	0.02500	0.0000	0.0000	1.030
N101	N201	1	0.00060	0.02500	0.0000	0.0000	1.030
N107	N207	1	0.00060	0.02500	0.0000	0.0000	1.030

APPENDIX A.2.2 : LOAD FLOW RESULTS

GENERAL OUTPUT LISTING

BUS AREA NAME	KV	DEGREE	GENERATION REAL MW	GENERATION REACTIVE MVAR	LOAD REAL MW	LOAD REACTIVE MVAR	BRANCH BUS AREA NAME		BRANCH FLOW MW	BRANCH FLOW MVAR	LOSSES MW	LOSSES MVAR	FLOW MVA	RATE MVA	FLOW %	RATIO TAP
01 N1	398.13	-0.18	0.00	0.00	0.00	0.00										
			0.00	-0.01			10 M1	1	-800.3	-227.4	1.7	78.9	832.0	1000	83	0.93
							10 M2	3	-445.8	-116.7	0.2	16.4	460.8	1300	35	0.94
							01 N2	0	301.3	104.1	0.1	-2.2	318.8	9999	3	
							01 N4	1	340.9	82.5	0.6	-7.1	350.8	9999	3	
							01 N4	2	301.9	78.8	0.4	-9.3	312.0	9999	3	
							01 N4	3	301.9	78.8	0.4	-9.3	312.0	9999	3	
01 N11	413.56	0.78	0.00	0.00	98.00	32.00										
			0.00	0.00			10 N10	0	-418.2	87.7	1.2	-10.2	427.3	9999	4	
							90 N12	1	320.2	-119.7	1.2	-19.7	341.8	1350	25	
01 N13	402.70	-0.40	0.00	0.00	600.00	200.00										
			0.00	0.00			10 N10	0	-600.0	-200.0	3.3	8.2	632.5	9999	6	
01 N14	411.04	0.79	0.00	0.00	300.00	75.00										
			0.00	0.00			10 N10	0	-365.0	-3.6	1.0	-16.1	365.1	9999	3	
							94 N15	0	65.0	-71.4	0.1	-32.7	96.6	9999	0	
01 N2	397.42	-0.40	0.00	0.00	0.00	0.00										
			0.00	0.00			01 N1	0	-301.2	-106.3	0.1	-2.2	319.4	9999	3	
							03 N107	1	301.2	106.4	0.6	40.8	319.4	520	61	0.98
01 N3	394.61	-1.69	0.00	0.00	0.00	0.00										
			0.00	0.00			10 N101	1	175.6	70.6	0.2	14.4	189.3	520	36	0.96
							92 N16	0	-0.1	-28.7	0.0	-29.3	28.7	1350	2	
							01 N4	0	-175.5	-41.9	0.2	-18.2	180.4	9999	1	
01 N4	396.01	-0.99	0.00	0.00	0.00	0.00										
			0.00	0.00			01 N1	1	-340.3	-89.6	0.6	-7.1	351.9	9999	3	
							01 N1	2	-301.5	-88.1	0.4	-9.3	314.1	9999	3	
							01 N1	3	-301.5	-88.1	0.4	-9.3	314.1	9999	3	
							03 N102	1	237.2	159.4	0.6	35.5	285.8	520	54	0.95
							01 N3	0	175.7	23.6	0.2	-18.2	177.3	9999	1	
							01 N5	1	187.1	60.7	0.2	-10.0	196.7	1420	13	
							01 N5	2	187.1	60.7	0.2	-10.0	196.7	1420	13	
							01 N6	0	156.1	-38.8	0.2	-17.1	160.9	9999	1	
01 N5	394.51	-1.46	0.00	0.00	0.00	0.00										
			0.00	-0.01			03 N106	1	373.9	141.5	0.4	33.1	399.8	520	76	0.98
							01 N4	1	-187.0	-70.7	0.2	-10.0	199.9	1420	14	
							01 N4	2	-187.0	-70.7	0.2	-10.0	199.9	1420	14	

01 N6	396.31	-1.58	0.00	0.00	0.00	0.00										
			0.00	-0.01			03 N104	1	367.9	28.3	0.4	27.5	369.0	520	70	1.01
							01 N4	0	-155.9	21.6	0.2	-17.1	157.4	9999	1	
							01 N7	0	153.3	180.9	0.5	-14.7	237.1	9999	2	
							01 N8	0	-178.2	-113.6	0.4	-23.0	211.4	9999	2	
							01 N9	0	-187.0	-117.2	0.4	-22.7	220.7	9999	2	
01 N7	390.94	-2.08	0.00	0.00	0.00	0.00										
			0.00	0.01			10 N105	1	152.9	195.5	0.3	25.3	248.2	520	47	0.90
							01 N6	0	-152.9	-195.5	0.5	-14.7	248.2	9999	2	
01 N8	400.66	-0.71	0.00	0.00	237.00	78.00										
			0.00	0.00			10 N10	0	-415.6	-168.6	2.6	-17.8	448.5	9999	4	
							01 N6	0	178.6	90.6	0.4	-23.0	200.3	9999	2	
01 N9	400.77	-0.66	0.00	0.00	223.00	73.00										
			0.00	0.00			10 N10	0	-410.4	-167.6	2.6	-18.5	443.3	9999	4	
							01 N6	0	187.4	94.6	0.4	-22.7	209.9	9999	2	
03 N102	154.03	-7.25	0.00	0.00	0.00	0.00										
CAP TOT			0.00000	79.08												
			0.00	0.00			10 N101	0	-49.4	-29.2	0.5	-0.6	57.3	5000	1	
							10 N103	0	-14.6	87.5	0.1	0.4	88.7	5000	1	
							04 N202	1	300.6	144.7	0.6	24.9	333.6	500	66	1.03
							01 N4	1	-236.6	-123.9	0.6	35.5	267.1	520	51	0.95
03 N104	154.12	-5.86	0.00	0.00	0.00	0.00										
CAP TOT			0.00000	79.17												
			0.00	0.00			10 N103	0	79.8	18.8	0.4	0.9	81.9	5000	1	
							10 N105	0	-12.8	-83.4	0.4	0.9	84.4	5000	1	
							04 N203	1	300.6	144.6	0.6	24.8	333.6	500	66	1.03
							01 N6	1	-367.5	-0.8	0.4	27.5	367.5	520	70	1.01
03 N106	154.08	-5.99	0.00	0.00	0.00	0.00										
			0.00	0.01			10 N103	0	86.4	22.3	0.4	1.1	89.2	5000	1	
							10 N105	0	-13.5	-58.5	0.3	-0.1	60.0	5000	1	
							04 N206	1	300.6	144.6	0.6	24.9	333.6	500	66	1.03
							01 N5	1	-373.5	-108.4	0.4	33.1	388.9	520	74	0.98
03 N107	154.02	-7.54	0.00	0.00	0.00	0.00										
CAP TOT			0.00000	79.08												
			0.00	0.00			01 N2	1	-300.6	-65.6	0.6	40.8	307.7	520	59	0.98
							04 N207	1	300.6	144.7	0.6	24.9	333.6	500	66	1.03
04 N201	73.66	-9.58	0.00	0.00	300.00	167.00										
CAP TOT			0.00000	49.83												
			0.00	0.00			10 N101	1	-300.0	-117.2	0.6	23.4	322.1	500	64	1.03
04 N202	71.69	-11.18	0.00	0.00	300.00	167.00										
CAP TOT			0.00000	47.20												
			0.00	0.00			03 N102	1	-300.0	-119.8	0.6	24.9	323.0	500	64	1.03

04 N203	71.74	-9.79	0.00	0.00	300.00	167.00										
CAP TOT			0.00000	47.26												
			0.00	0.00			03 N104	1	-300.0	-119.7	0.6	24.8	323.0	500	64	1.03
04 N204	70.95	-11.12	0.00	0.00	300.00	167.00										
CAP TOT			0.00000	46.24												
			0.00	0.00			10 N103	1	-300.0	-120.8	0.6	25.4	323.4	500	64	1.03
04 N205	73.65	-9.66	0.00	0.00	300.00	167.00										
CAP TOT			0.00000	49.81												
			0.00	0.00			10 N105	1	-300.0	-117.2	0.6	23.4	322.1	500	64	1.03
04 N206	71.72	-9.92	0.00	0.00	300.00	167.00										
CAP TOT			0.00000	47.24												
			0.00	0.00			03 N106	1	-300.0	-119.8	0.6	24.9	323.0	500	64	1.03
04 N207	71.69	-11.47	0.00	0.00	300.00	167.00										
CAP TOT			0.00000	47.20												
			0.00	0.00			03 N107	1	-300.0	-119.8	0.6	24.9	323.0	500	64	1.03
10 M1	24.00	4.86	850.00	346.29	48.00	40.00										
	PV		0.00	0.00			01 N1	1	802.0	306.3	1.7	78.9	858.5	1000	85	0.93
10 M2	24.00	1.77	500.00	178.14	54.00	45.00										
	PV		0.00	0.00			01 N1	3	446.0	133.1	0.2	16.4	465.4	1300	35	0.94
10 N10	412.00	2.52	2800.00	497.65	580.00	100.00										
	PV		0.00	0.00			01 N11	0	419.4	-97.9	1.2	-10.2	430.7	9999	4	
							01 N13	0	603.3	208.2	3.3	8.2	638.2	9999	6	
							01 N14	0	366.0	-12.5	1.0	-16.1	366.3	9999	3	
							01 N8	0	418.2	150.8	2.6	-17.8	444.6	9999	4	
							01 N9	0	413.0	149.1	2.6	-18.5	439.0	9999	4	
10 N101	157.88	-5.85	175.00	30.00	0.00	0.00										
CAP TOT			0.00000	83.09												
			0.00	0.00			03 N102	0	49.9	28.6	0.5	-0.6	57.5	5000	1	
							04 N201	1	300.6	140.6	0.6	23.4	331.8	500	66	1.03
							01 N3	1	-175.4	-56.1	0.2	14.4	184.2	520	35	0.96
10 N103	152.59	-7.11	150.00	20.00	0.00	0.00										
			0.00	0.00			03 N102	0	14.7	-87.1	0.1	0.4	88.3	5000	1	
							03 N104	0	-79.4	-17.9	0.4	0.9	81.4	5000	1	
							03 N106	0	-86.0	-21.2	0.4	1.1	88.5	5000	1	
							04 N204	1	300.6	146.2	0.6	25.4	334.3	500	66	1.03
10 N105	157.86	-5.93	175.00	30.00	0.00	0.00										
CAP TOT			0.00000	83.07												
			0.00	0.00			03 N104	0	13.3	84.3	0.4	0.9	85.3	5000	1	
							03 N106	0	13.7	58.4	0.3	-0.1	60.0	5000	1	
							04 N205	1	300.6	140.6	0.6	23.4	331.8	500	66	1.03
							01 N7	1	-152.6	-170.2	0.3	25.3	228.6	520	43	0.90

90 N12	417.25	-1.33	0.00	0.00	319.00	-100.00									
			0.00	0.00			01 N11	1	-319.0	100.0	1.2	-19.7	334.3	1350	24
92 N16	395.30	-1.70	0.10	-0.54	0.00	0.00									
	SL		0.00	0.00			01 N3	0	0.1	-0.5	0.0	-29.3	0.5	1350	0
94 N15	415.00	0.00	-64.91	38.78	0.00	0.00									
	SL		0.00	0.00			01 N14	0	-64.9	38.8	0.1	-32.7	75.6	9999	0

AREA INTERCHANGE

AREA	ACTIVE POWER (MW)				REACTIVE POWER (MVAR)			
	GENERATION	LOAD	LOSSES	EXPORT	GENERATION	LOAD	LOSSES	EXPORT
01	0.00	1458.00	11.79	-1469.79	0.00	458.00	-75.74	-382.26
03	0.00	0.00	3.21	-3.21	237.33	0.00	119.46	117.88
04	0.00	2100.00	2.06	-2102.06	334.77	1169.00	85.86	-920.09
10	4650.00	682.00	8.45	3959.55	1268.24	185.00	77.78	1005.46
90	0.00	319.00	0.60	-319.60	0.00	-100.00	-9.83	109.83
92	0.10	0.00	0.00	0.10	-0.54	0.00	-14.63	14.09
94	-64.91	0.00	0.07	-64.98	38.78	0.00	-16.34	55.11
TOTAL	4585.19	4559.00	26.18	0.00	1878.58	1712.00	166.57	0.01

MVAR GENERATED BY CAPACITOR(S) 738.26 MW LOSSES 0.00

APPENDIX A.2.3 : INFINITE BUSES

a. Definition

An infinite bus is a voltage source, constant in phase and in magnitude, located behind an impedance (R and X).

The parameters R and X are given hereafter in p.u. in a 100 MVA base.

The P and Q percentages determine which part of generation of these nodes in the initial load-flow is assigned to the infinite bus.

b. Numerical values

NODE	R infinite (p.u.)	X infinite (p.u.)	P assigned (%)	Q assigned (%)
N15	.0000	.0100	100.0	100.0
N12	.0000	.0150	100.0	100.0
N16	.0000	.0150	100.0	100.0

APPENDIX A.2.4 : GENERATOR DATA

TABLE 1 - GENERAL CHARACTERISTICS OF THE GENERATING UNITS

MACHINE	NODE	SN (MVA)	PN (MW)	VN (KV)	H (MWS/MVA)	D	MACRO	DATA SET	MACRO	DATA SET
M1	M1	1100.	950.	24.0	6.00	.0	AVR	1		
M2	M2	1100.	950.	24.0	6.00	.0	AVR	2		
M6	N10	5000.	3500.	24.0	6.00	.0	AVR	6		
M4	N103	300.	260.	15.0	4.00	.0	AVR	4	STDSPEED	1
M5	N105	450.	390.	15.0	4.00	.0	AVR	5	STDSPEED	1
M3	N101	450.	390.	15.0	4.00	.0	AVR	3	STDSPEED	1
		8400.	6440.							

TABLE 2 - OPERATING POINT OF THE GENERATING UNITS

MACHINE	NODE	ACTIVE POWER P	%PN	%INJ	REACTIVE POWER Q	%INJ	APPARENT POWER S	%SN	VOLTAGE V	VTERM	W A
M1	M1	850.	89.	100.	346.	100.	918.	83.	24.0	-	
M2	M2	500.	53.	100.	178.	100.	531.	48.	24.0	-	
M6	N10	2800.	80.	100.	498.	100.	2844.	57.	412.0	-	
M4	N103	150.	58.	100.	20.	100.	151.	50.	152.6	-	
M5	N105	175.	45.	100.	30.	100.	178.	39.	157.9	-	
M3	N101	175.	45.	100.	30.	100.	178.	39.	157.9	-	
		4650.			1102.		4799.				

TABLE 4 - EXTERNAL PARAMETERS OF THE GENERATING UNITS
(IN P.U. BASE SN OR IN SECONDS)

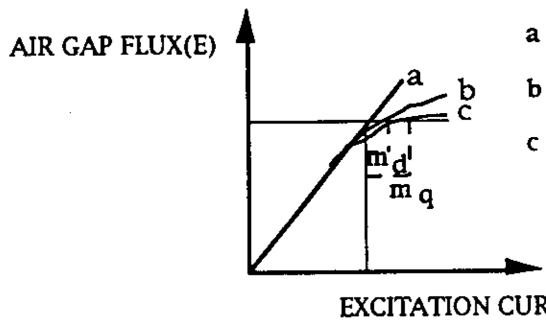
MACHINE		#	RA	WL	WLMDV	XD	XPD	XSD	TPD0	TSD0	TX	XQ	XPQ	XSQ	TPQ0	TSQ0
M1	G	4	.000	.220	2.111	2.500	.425	.300	8.000	.060	.000	2.500	.650	.301	.650	.100
M2	G	4	.000	.220	2.111	2.500	.425	.300	8.000	.060	.000	2.500	.650	.301	.650	.100
M6	G	4	.000	.220	2.111	2.500	.425	.300	8.000	.060	.000	2.500	.650	.301	.650	.100
M4	G	4	.000	.200	2.273	2.700	.360	.290	8.500	.050	.000	2.600	.700	.270	.600	.050
M5	G	4	.000	.200	2.273	2.700	.360	.290	8.500	.050	.000	2.600	.700	.270	.600	.050
M3	G	4	.000	.200	2.273	2.700	.360	.290	8.500	.050	.000	2.600	.700	.270	.600	.050

TABLE 5 - GENERATING UNITS TRANSFORMERS CHARACTERISTICS

MACHINE	H.V. NODE	RT p.u. SNTF	XT p.u. SNTF	SNTF MVA	U1N (KV)	U2N (KV)	W
M1	M1						
M2	M2						
M6	N10	.002	.130	5000.0	24.0	416.4	
M4	N103	.002	.130	300.0	15.0	165.0	
M5	N105	.002	.130	400.0	15.0	165.0	
M3	N101	.002	.130	450.0	15.0	165.0	

APPENDIX A.2.5 : SATURATION DATA

a. Definition



a air gap line

b characteristic in the direct axis

c characteristics in the quadrature axis

Let E be the module of the air gap flux. The saturation characteristics measured in the d and q axes are given by b and c respectively. These curves are modelled by the following equations :

curve b : $\frac{I_d}{E} = 1 + md\, E^{nd}$

curve c : $\frac{I_q}{E} = 1 + mq\, E^{nq}$

I_d and I_q being the stator currents.

If we let M_{do} and M_{qo} be the unsaturated mutual inductances along the direct and quadrature axes, the saturated mutual inductances (corresponding to the case where the flux is aligned along the corresponding axis), may be expressed by the following relationships :

$M_{ds} = M_{do} \;/\; (1 + m_d E^{nd})$

$M_{qs} = M_{qo} \;/\; (1 + m_q E^{nq})$

b. Numerical values

Numerical values of saturation parameters are given in the following table :

UNIT	$m_d = m_q$	$n_d = n_q$
M1	0.08	6.
M2	0.08	6.
M3	0.1	7.5
M4	0.1	7.5
M5	0.1	7.5
M6	0.08	6.

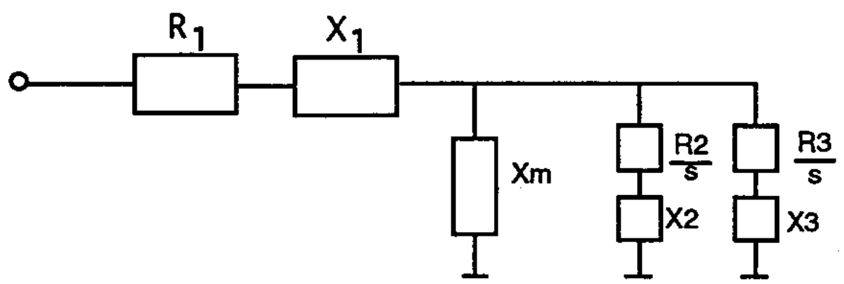
APPENDIX A.2.6 : INDUCTION MOTORS DATA

The induction motors data are given on the second page of this appendix. The piecewise function associated to the mechanical torque is given in the four last columns :

e.g. : motor MOTN203 mechanical torque is described by 5 points :

speed (p.u.)	Tm (p.u. of S_n)
- 0.01	0
0	0.01
0.5	0.15
0.75	0.338
1.	0.66

The internal parameters R_1, X_1, X_m, R_2, X_2, R_3 and X_3 are expressed in p.u. of S_N and are related to the following equivalent scheme :



where s is the slip.

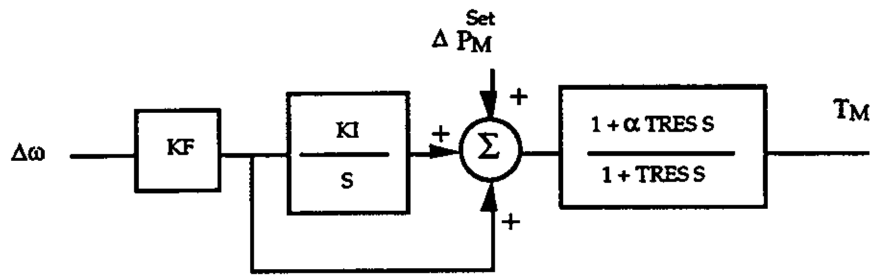
TABLE 6 - INDUCTION MOTORS CHARACTERISTICS

NODE	MACHINE		SN (MVA)	H MWS/MVA		R1 (PU SN)	X1 (PU SN)	XM (PU SN)	R2 (PU SN)	X2 (PU SN)	R3 (PU SN)	X3 (PU SN)	OMEGA (PU)	T (PU SN)	OMEGA (PU)	T (PU SN)
N203	MOTN203	ON	300.0	2.000	D	.0080	.0600	3.5000	.3600	.0600	.0150	.1200	-.010	.000	.000	.010
													.500	.150	.750	.338
													1.000	.660	-	-
N206	MOTN206	ON	300.0	2.000	D	.0080	.0600	3.5000	.3600	.0600	.0150	.1200	-.010	.000	.000	.010
													.500	.150	.750	.338
													1.000	.660	-	-
N202	MOTN202	ON	300.0	2.000	D	.0080	.0600	3.5000	.3600	.0600	.0150	.1200	-.010	.000	.000	.010
													.500	.150	.750	.338
													1.000	.660	-	-
N205	MOTN205	ON	300.0	2.000	D	.0080	.0600	3.5000	.3600	.0600	.0150	.1200	-.010	.000	.000	.010
													.500	.150	.750	.338
													1.000	.660	-	-
N201	MOTN201	ON	300.0	2.000	D	.0080	.0600	3.5000	.3600	.0600	.0150	.1200	-.010	.000	.000	.010
													.500	.150	.750	.338
													1.000	.660	-	-
N207	MOTN207	ON	300.0	2.000	D	.0080	.0600	3.5000	.3600	.0600	.0150	.1200	-.010	.000	.000	.010
													.500	.150	.750	.338
													1.000	.660	-	-
N204	MOTN204	ON	300.0	2.000	D	.0080	.0600	3.5000	.3600	.0600	.0150	.1200	-.010	.000	.000	.010
													.500	.150	.750	.338
													1.000	.660	-	-

APPENDIX A.2.7 : GOVERNOR

Only M3, M4 and M5 units are fitted with a governor. M1, M2 and M6 have a constant mechanical torque.

a. Block diagram



where : $\Delta\omega$ = speed deviation signal
α = high pressure turbine power fraction
TRES = reheater time constant
TM = mechanical torque

where • TM is expressed in p.u. of the rated power P_N

b. Parameters values of units M3, M4 and M5

KI = 0.05

KF = 25.

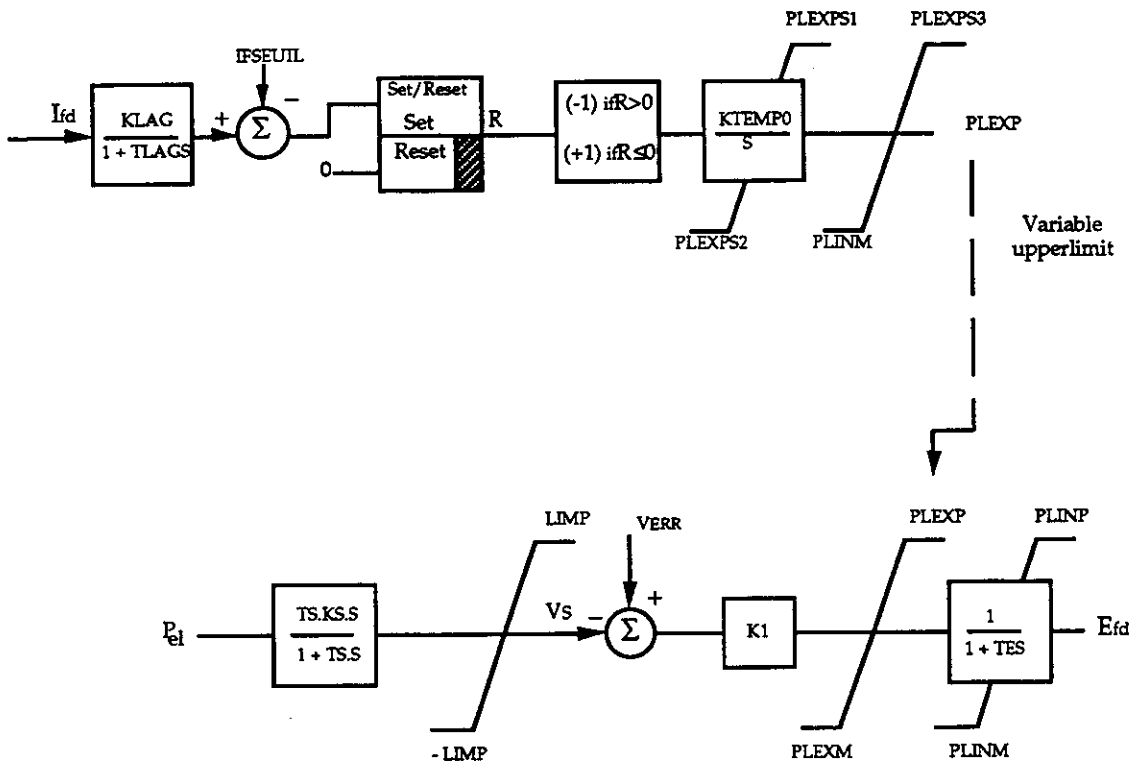
α = 0.33

TRES = 10.

APPENDIX A.2.8 : AVR, PSS AND OEL

All units have the same AVR, PSS and OEL models.

a. Block diagram



where : Pel = active power
Ifd = generator field current
VERR = voltage error signal
V S = power stabilizer output

Remarks

- Efd (Field Voltage) and Ifd (Field current) are equal to unity when the unit is at no load and when saturation is taken into account.
- Verr = Vc - V with Vc= voltage set point
  V = terminal voltage

b. Parameters values :

Parameters	UNITS					
	M1	M2	M3	M4	M5	M6
KLAG	1	1	1	1	1	1
TLAG	2	2	2	2	2	2
IFSEUIL	3.2	4.1	3.6	3.35	3.6	3.15
KTEMPO	0.1	0.1	0.1	0.1	0.1	0.08
PLEXPS1	6.5	6.5	6.5	6.5	6.5	6.5
PLEXPS2	2.3	3.25	3.25	3.25	3.25	2.8
PLEXPS3	4.5	4.5	4.5	4.5	4.5	4.5
PLINM	0.	0.	0.	0.	0.	0.
PLINP	4.5	4.5	4.5	4.5	4.5	4.5
PLEXM	- 2.8	- 2.8	- 2.8	- 2.8	- 2.8	- 2.8
K1	70	35	15	15	15	35
TE	0.3	0.3	0.3	0.3	0.3	0.3
LIMP	0.05	0.05	0.05	0.05	0.05	0.05
KS	0.44	0.44	0.44	0.44	0.44	0.44
TS	4	4	4	4	4	4

APPENDIX A.2.9
LOAD EVOLUTION

Active power

a. Load at t = 0 sec.

Node	V_{LF} [kV]	$P_{TOT, LF}$ [MW]	P_{mot} [MW]	P_{IMPED} [MW]
N201	73.7	300	195.8	104.2
N202	71.7	300	195.6	104.4
N203	71.7	300	195.6	104.4
N204	71.0	300	195.6	104.4
N205	73.7	300	195.8	104.2
N206	71.7	300	195.6	104.4
N207	71.7	300	195.6	104.4
Sub total	-	2 100	1 369.6	730.4
M1	24.0	48	0	48
M2	24.0	54	0	54
N10	412.0	580	0	580
N11	413.6	98	0	98
N13	402.7	600	0	600
N14	411.0	300	0	300
N8	400.7	237	0	237
N9	400.8	223	0	223
N12	417.3	319	0	319
Sub total 2	-	2 459	0	2 459
Total	-	4 559	1 369.6	3 189.4

b. Load supplement (additional conductance G (p.u. 100 MVA) between t = 30 sec. and t = 7 230 sec.)

Node	G at t = 30 sec.	G at t = 7 230 sec.	Linear variation (p.u. 100 MVA/hour)
N201	0	0.92	0.46
N202	0	0.97	0.485
N203	0	0.97	0.485
N204	0	0.99	0.495
N205	0	0.92	0.46
N206	0	0.97	0.485
N207	0	0.97	0.485

c. Load at t = 7 230 sec.

Node	V [kV]	P_{TOT} [MW]	P_{MOT} [MW]	P_{IMPED} [MW]
N201	72.7	396.3	195.7	200.6
N202	71.8	402.6	195.6	207.0
N203	71.9	402.6	195.6	207.0
N204	70.3	398.1	195.6	202.5
N205	71.9	392.1	195.6	196.5
N206	71.1	398.4	195.6	202.8
N207	71.2	398.8	195.6	203.2
Sub total	-	2 788.9	1 369.3	1 419.6
M1	24.0	47.9	0	47.9
M2	24.0	53.9	0	53.9
N10	412.1	580.2	0	580.2
N11	413.9	98.1	0	98.1
N13	402.8	600.2	0	600.2
N14	411.2	300.2	0	300.2
N8	397.2	232.9	0	232.9
N9	397.2	219.1	0	219.1
N12	417.7	319.7	0	319.7
Sub total 2	-	2 452.2	0	2 452.2
Total	-	5 241.1	1 369.3	3 871.8

LOAD EVOLUTION

Reactive power

a. Load at t = 0 sec.

Node	V_{LF} [kV]	$Q_{TOT, LF}$ [MVAR]	Q_{MOT} [MVAR]	Q_{IMPED} [MVAR]	Q_{CAP} [MVAR] (rated value for V = 1 p.u.)
N201	73.7	167	112.9	54.1	45
N202	71.7	167	109.1	57.9	45
N203	71.7	167	109.2	57.8	45
N204	71.0	167	107.7	59.3	45
N205	73.7	167	112.8	54.2	45
N206	71.7	167	109.1	57.9	45
N207	71.7	167	109.1	57.9	45
Sub total	-	1 169	769.9	399.1	-
M1	24.0	40	0	40	0
M2	24.0	45	0	45	0
N10	412.0	100	0	100	0
N11	413.6	32	0	32	0
N13	402.7	200	0	200	0
N14	411.0	75	0	75	0
N8	400.7	78	0	78	0
N9	400.8	73	0	73	0
N12	417.3	- 100	0	- 100	0
Sub total 2	-	543	0	543	-
Total	-	1 712	769.9	942.1	-

b. Load supplement (additional susceptance B (p.u. 100 MVA) between t = 30 sec. and
t = 7 230 sec.)

Node	B at t = 30 sec.	B at t = 7 230 sec.	Linear variation (p.u. 100 MVA/hour)
N201	0	.46	.23
N202	0	.49	.245
N203	0	.49	.245
N204	0	.50	.25
N205	0	.46	.23
N206	0	.49	.245
N207	0	.49	.245

c. Load at t = 7 230 sec.

Node	V [kV]	Q_{TOT} [MVAR]	Q_{MOT} [MVAR]	Q_{IMPED} [MVAR]	Q_{CAP} [MVAR] (rated value for V = 1 p.u.)
N201	72.7	213.1	110.9	102.2	45
N202	71.8	218.5	109.3	109.2	45
N203	71.9	218.5	109.4	109.1	45
N204	70.3	214.8	106.5	108.3	45
N205	71.9	209.7	109.4	100.3	45
N206	71.1	215.0	108.0	107.0	45
N207	71.2	215.3	108.1	107.2	45
Sub total	-	1 504.9	761.6	743.3	-
M1	24.0	39.9	0	39.9	0
M2	24.0	44.9	0	44.9	0
N10	412.1	100.0	0	100.0	0
N11	413.9	32.0	0	32.0	0
N13	402.8	200.0	0	200.0	0
N14	411.2	75.0	0	75.0	0
N8	397.2	76.6	0	76.6	0
N9	397.2	71.7	0	71.7	0
N12	417.7	- 100.2	0	- 100.2	0
Sub total 2	-	539.9	0	539.9	-
Total	-	2 044.8	761.6	1 283.2	-

APPENDIX A.2.10

SECONDARY VOLTAGE CONTROL SCHEME

Jan 18 11:31 1995 /trf07w/users/tf3802/cigre/1.1 Page 1

CONTROL SCHEME OF GENERATOR VOLTAGE SET POINT

TIME	UNIT	Vc[p.u.]
0000.000	M1	1.0363
3500.000	M1	1.0375
7200.000	M1	1.039
0000.000	M2	1.0502
1440.000	M2	1.052
2880.000	M2	1.054
4320.000	M2	1.056
5760.000	M2	1.058
7200.000	M2	1.060
0000.000	M4	1.056
0350.000	M4	1.079
0700.000	M4	1.089
1050.000	M4	1.099
1400.000	M4	1.109
1750.000	M4	1.119
2100.000	M4	1.129
2450.000	M4	1.139
2800.000	M4	1.149
3150.000	M4	1.159
3500.000	M4	1.169
3850.000	M4	1.179
0000.000	M3	1.071
0720.000	M3	1.080
1000.000	M3	1.090
1440.000	M3	1.100
2160.000	M3	1.110
2880.000	M3	1.120
3600.000	M3	1.130
4320.000	M3	1.140
5040.000	M3	1.150
5760.000	M3	1.160
6480.000	M3	1.170
7200.000	M3	1.180
0000.000	M5	1.072
0720.000	M5	1.090
1000.000	M5	1.100
1440.000	M5	1.110
2160.000	M5	1.120
2880.000	M5	1.130
3600.000	M5	1.140
4320.000	M5	1.150
5040.000	M5	1.160
5760.000	M5	1.170
6480.000	M5	1.180
7200.000	M5	1.189
0000.000	M6	1.0603
3500.000	M6	1.065

CONTROL SCHEME OF 380/150 kV TRANSFORMERS RATIO

TIME	TRANSFORMER			TAP
0000.000	N107	-	N2	2
1000.000	N107	-	N2	3
2000.000	N107	-	N2	4
3000.000	N107	-	N2	5
4000.000	N107	-	N2	6
5000.000	N107	-	N2	7
6000.000	N107	-	N2	8
0000.000	N101	-	N3	4
5100.000	N101	-	N3	3
0000.000	N105	-	N7	11
1500.000	N105	-	N7	10
3000.000	N105	-	N7	9
4500.000	N105	-	N7	8
6000.000	N105	-	N7	7
0000.000	N102	-	N4	5
0720.000	N102	-	N4	6
1440.000	N102	-	N4	7
2160.000	N102	-	N4	8
2880.000	N102	-	N4	9
3600.000	N102	-	N4	10
4320.000	N102	-	N4	11
5040.000	N102	-	N4	12
5760.000	N102	-	N4	13
6500.000	N102	-	N4	14
0000.000	N106	-	N5	2
1550.000	N106	-	N5	3
3050.000	N106	-	N5	4
4050.000	N106	-	N5	5
5550.000	N106	-	N5	6
0000.000	N104	-	N6	-1
1700.000	N104	-	N6	0
3700.000	N104	-	N6	1
6700.000	N104	-	N6	2

TAP CHANGING TRANSFORMER(S) DATA

NODE 1	NODE 2	//	Unom 1 (KV)	Unom 2 (KV)	Snom (MVA)	Tap (initial)	Tap Min	Tap Max	%/Tap (-)	%/Tap (+)	Resist. (P.U. SN)	Tap	React. (P.U. SN)	Voltage target (pu)
N107	N2	1	150.0	380.0	520.0	2	-15	15	1.0	1.0	.0031	-12	.2272	
												12	.2272	
N101	N3	1	150.0	380.0	520.0	4	-15	15	1.0	1.0	.0026	-12	.2262	
												12	.2262	
N105	N7	1	150.0	380.0	520.0	11	-15	15	1.0	1.0	.0026	-12	.2262	
												12	.2262	
N102	N4	1	150.0	380.0	520.0	5	-15	15	1.0	1.0	.0042	-12	.2454	
												12	.2454	
N106	N5	1	150.0	380.0	520.0	2	-15	15	1.0	1.0	.0016	-12	.1160	
												12	.1160	
N104	N6	1	150.0	380.0	520.0	-1	-15	15	1.0	1.0	.0016	-12	.1144	
												12	.1144	
N102	N202	1	150.0	70.0	500.0	-3	-12	12	1.0	1.0	.0030	-12	.1250	1.03(N202)
												12	.1250	
N103	N204	1	150.0	70.0	500.0	-3	-12	12	1.0	1.0	.0030	-12	.1250	1.01(N204)
												12	.1250	
N104	N203	1	150.0	70.0	500.0	-3	-12	12	1.0	1.0	.0030	-12	.1250	1.03(N203)
												12	.1250	
N105	N205	1	150.0	70.0	500.0	-3	-12	12	1.0	1.0	.0030	-12	.1250	1.03(N205)
												12	.1250	
N106	N206	1	150.0	70.0	500.0	-3	-12	12	1.0	1.0	.0030	-12	.1250	1.02(N206)
												12	.1250	
N101	N201	1	150.0	70.0	500.0	-3	-12	12	1.0	1.0	.0030	-12	.1250	1.04(N201)
												12	.1250	
N107	N207	1	150.0	70.0	500.0	-3	-12	12	1.0	1.0	.0030	-12	.1250	1.02(N207)
												12	.1250	

APPENDIX A.3

THE SWEDISH TEST SYSTEM DATA

Svenska Kraftnät

1993-03-15 (rev. 1994-03-01) P-KW

Nordic32A - A Cigré test system for simulation of transient stability and long term dynamics

by Kenneth Walve, Svenska Kraftnät[1]), Sweden

Abstract

A test system are being presented. It is intended for transient stability and long term simulations. The network consists of 32 system buses.

The system is long with large transfers from a hydro dominated part to a load area with a large amount of thermal power. The power transfer is limited by transient and voltage instability in case of certain contingencies. The voltage support of the transmission system is essential. It is found that current limiters on generators and load restoration due to tap changer operation play a very important role.

The system is ficticious but has dynamic properties that are similar to the Swedish and Nordic power system. The system is intended for simulations tools, in expecial for such that are suitable for long term dynamics. Comparison tests will be made in a Cigré task force 38-02-08.

The version A of the system Nordic32 is suitable for comparison simulations for a critical load flow case. Small units are lumped together. Some models are not specified such as transmission line relay protection. Further versions of the test system will be made with more detailed data and more sofisticated unit configuration suitable for interactive operation on simulators.

The presentation of the system is made in two reports

1. The present report, describing the data, load flow, and other assumtions.
2. An additional report presenting initial simulations

1) Svenska Kraftnät is responsible for planning and operation of the Swedish main grid. Svenska Kraftnät was formed January 1st, 1992, as a result of the reformation of the electric power sector in Sweden that the parliament 'decided on. Address: 16215 Vällingy, Sweden, Fax.no. +46-8-378405.

Contents

Appendices

Svenska
Kraftnät

Nordic32A - A Cigré testsystem for simulation of transient stability and long term dynamics

1. Introduction

A test system is being presented. It is is intended for simulation of transient stability and long term dynamics. Data and models are presented in this report. Some test runs on the program PSS/E have been made and are presented in an additional report.

Network data as well as models are standardized. For example, only one type of excitation model is used, with a few sets of data. The number of nodes and generators is quite limited, 32 and 23 respectively. In addition there are generator buses and some load buses.

The transmission capacity with respect to certain single faults (tripping of lines, generators) is determined by transient stability and voltage instability. It is found that current limiters on generators and tap changers on transformers play a very important role.

The test system is intended for comparison tests on simulation tools, in special such that are suitable for long term dynamics. That is a task of the Cigré task force 38-02-08.

Later on, further versions of the test system will be made with more detailed data and more sofisticated unit configuration suitable for interactive operation on simulators.

2. Network

2.1 General outline

The network consists of four major parts

- "North" with basically hydro generation and some load
- "Central" with much load and rather much thermal power generation
- "Southwest" with a few thermal units and some load
- "External" connected to the "north". It has a mixture of generation and load.

The network is rather long. The major transfer section is from "north" to "central". The "southwest" area is rather loosely connected to the rest of the system. The "external" system consists of a very simplified network.

The transfers at peak load is basically from the "north" to the "central" part.

The main transmission system is designed for 400 kV. There are also some regional systems at 130 kV and 220 kV. The number of nodes are 19, 11 and 2 respectively. In addition, some load buses are modelled that are connected to the lower side of transformers with tap changers. In the data set, the generator buses are defined as an internal part of the generator model.

2.2 Network data

The data refer to a load flow case LF32_028, as it is described in 2.3 below.

Per unit system

The data is sometimes given in per unit.

The general base units for the network are
- Voltage: 400 kV, 220 kV, and 130 kV, respectively
- Power: 100 MVA

Data of generation units are referred to the individual unit rating (MVA).

Bus data (appendix B-1)

The voltages, angles, loads and shunts are presented. Please observe that minus-sign on Mvar shunts indicate reactors.

Generation data (appendix B-2 and B-3)

The ratings of the individual generators including transformers are presented. In load flow LF32_029 an additional 700 MVA generator at bus 4051 is defined. The dynamic models are presented in chapter 3 below.

Branch data (appendix B-4 and B-6)

The lines are presented i per unit data. Please observe that charging refers to the total line. It is expressed in per unit susceptance. The charging at nominal voltage (i e base voltage) may be easily converted into Mvar by just multiplying the CHRGING figure by 100. See also explanations in appendix B-6.

Some of the lines are series compensated, 37.5 to 50 %. The capacitors is supposed to be located in the middle of the line. The line data in appendix B represent the total impedance including the series capacitors.

Transformer data (appendix B-4, B-5 and B-6)

The impedance figures are presented together with line data. In fact, those data would be sufficient if the tap ratio were equivalent to the base voltages, i e 400/130.

The specific transformer data, such as special tap settings, are given in a special list. See also explanations in appendix B-6.

2.3 Load flows

Two load flows are being presented.

Basic load flow, LF32_028 (appendix D-1)

This load flow is used for the comparison simulations. The transfers are high from "north" to "central". The load level is at peak load.

The case is sensitive to many types of faults. In fact the transfer situation is above what is recommended from normal reliability standards. (See also discussion in chapter 4 below). Bus 4011 serves as 'slack bus'.

Load flow with moderate transfers, LF32_029 (appendix D-2)

It is similar to the basic load flow but transfer from "north" to "central" are decreased. It is made by extra generation at bus 4051, e g generator no.2 is taken into operation with the same rating and controls as generator no. 1. The generation is modified as follows from LF32_028 to LF32_029.

Generator 1 at bus 4011	From 668.5 MW to 450.3 MW (slack bus)
Generator 1 at bus 4012	From 600.0 MW to 500.0 MW
Generator 1 at bus 1012	From 600.0 MW to 400.0 MW
Generator 2 at bus 4051	From 0 (not in oper.) to 400.0 MW

Comments on initial generator conditions

Some of the units are initialized above rated values. Generator 1043 has the stator current a few percent above rated value due to large reactive output. Some generators have the field current above rated values: 1022, 1043, 4042. For further comments, see Appendix C-1c.

3. Dynamic models

Generators (appendix C-1)

The generators are represented by Park models including damper windings.

- Salient pole model for the hydro generators (and one synchronous compensator)
- Round rotor model for the thermal generators

Only a few sets of data are used. For example, all thermal generators have the same data, but various ratings.

Excitation systems (appendix C-2 and C-3)

A simple model with three time constants are used. A few sets of data are defined.

All generators are equipped with power system stabilizers.

Governors and hydro system (appendix C-4)

Only the hydro power units are using governors. The same type of model is used with a few different sets of data.

Current limiters (appendix C-5)

Current limiters have been implemented for both rotor and stator currents in thermal power generators, and for rotor currents in hydro power generators and the synchronous compensator.

The limits have been set some percentage above rated currents. In fact, they are unrealisticly high: 120 % of rated value for round rotor generators, and 130 % for salient pole generators. More realistic figures would have been in the region 105 - 110 %.

Load characteristics (appendix C-6)

It is assumed that the load has the following characteristics.

- voltage: Active power is assumed to vary linear with voltage (constant current).
  Reactive power is assumed to have impedance character
- frequency: Active power is assumed to vary as follows
  $P = P_0 * (f / f_0)^{0.75}$

Long term response due to tap changer action or other slow phenomena are taken into account. For loads connected to 400 kV buses, explicit transformers with tap changer control are defined. For loads connected to 130 kV or 220 kV no explicit transformers are defined.

The system transformers 130/400 kV in the 'central' and 'southwest' areas are equipped with tap changer control.

4. Power system characteristics

4.1 Design requirements

The system is designed to withstand single contingencies, such as trippings of single lines and generators with or without initial three-phase short circuit.

The load flow LF32_029 fulfils those requirements, possibly with some exceptions.

The load flow LF32_028 has too high transfers. The initial transient stability can be managed in most cases, but the generator current limiters and the transformer tap changers may cause a delayed system collapse. For some line trippings not even the initial transient stability can be managed, e g line 4011-4021.

In a separate report simulations are being presented and discussed.

4.2 System character

The system character may be illustrated by the geographic outline in appendix A. As some of the lines are series compensated, a figure is also shown with distances that are equivalent to resultant line reactances.

The various parts of the system has already been presented in chapter 2.1. Here it could be added that the transfer system north to south has got very limited voltage support in the intermediate region (bus 4021, 4031 etc). Thus basically two types of voltage collapses may occur.

1) A contingency that weakens the transfer system from 'north' to 'central' may lead to a voltage collapse in the intermediate region (bus 4031 etc).

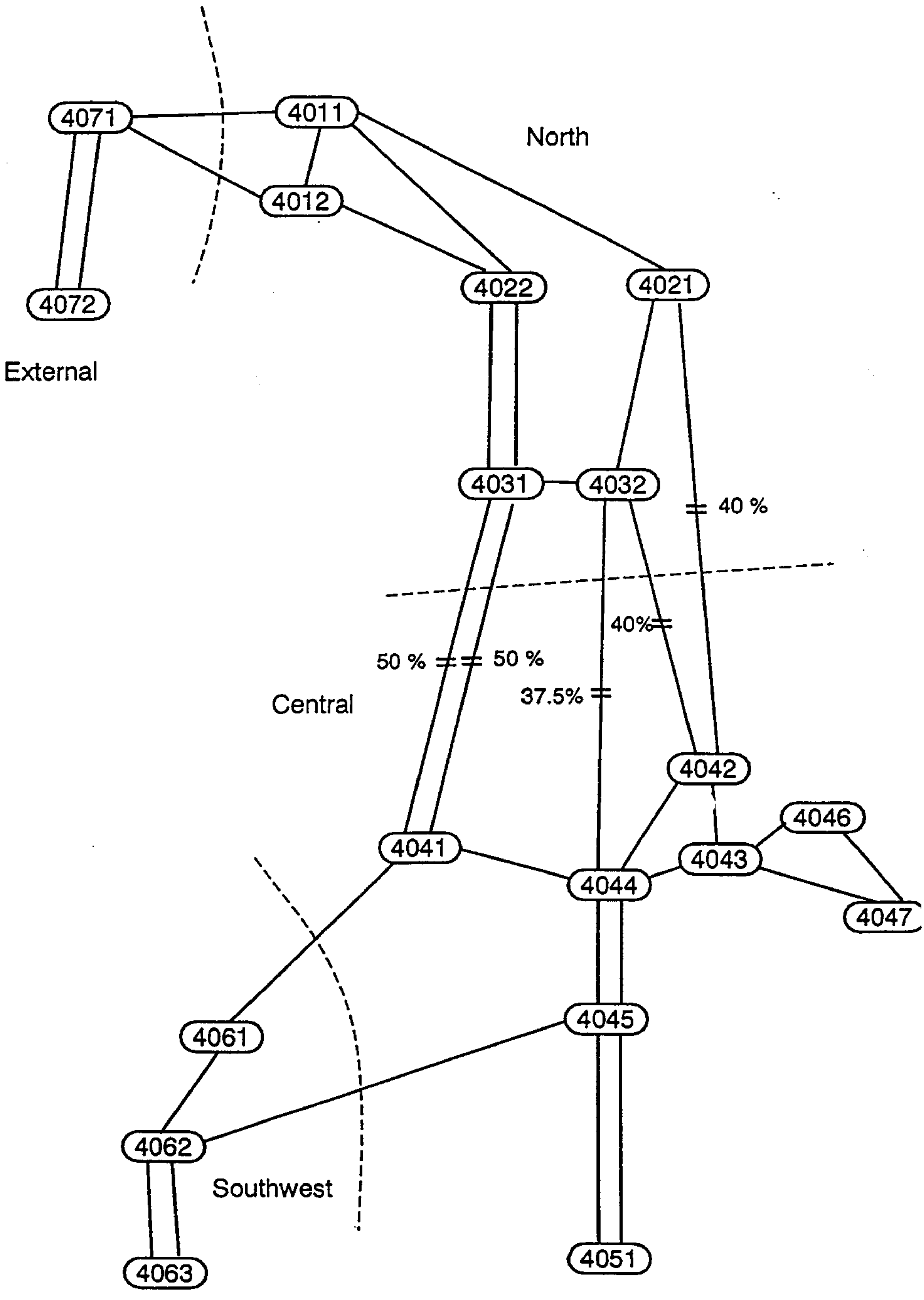
2) A contingency that decreases the voltage support of the 'central' load area may cause a voltage collapse of that region (bus 4044 etc).

Appendix A

Network outline

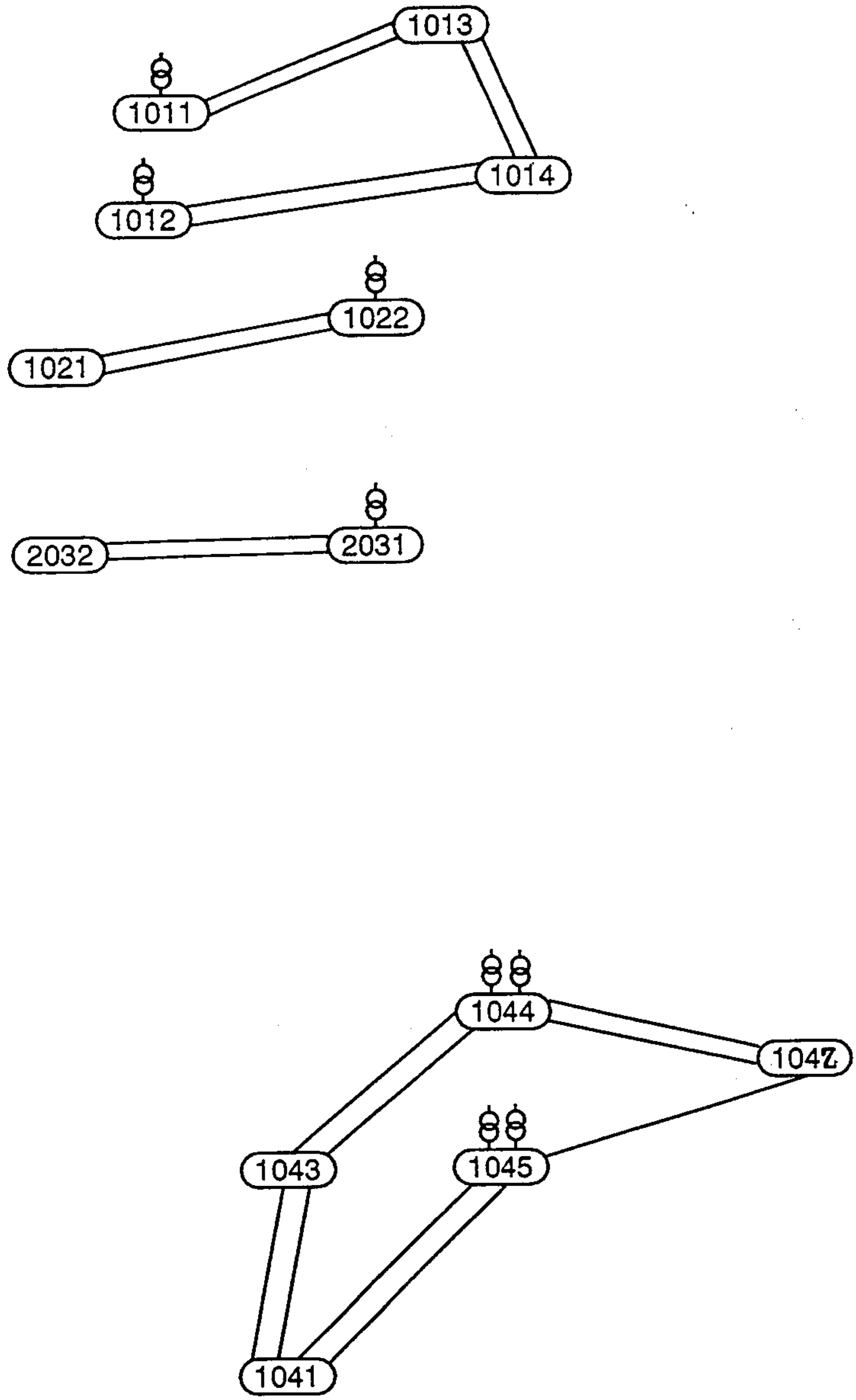
NORDIC32 Structure of 400 kV system

Appendix A-1



NORDIC32 Structure of 130 kV and 220 kV systems

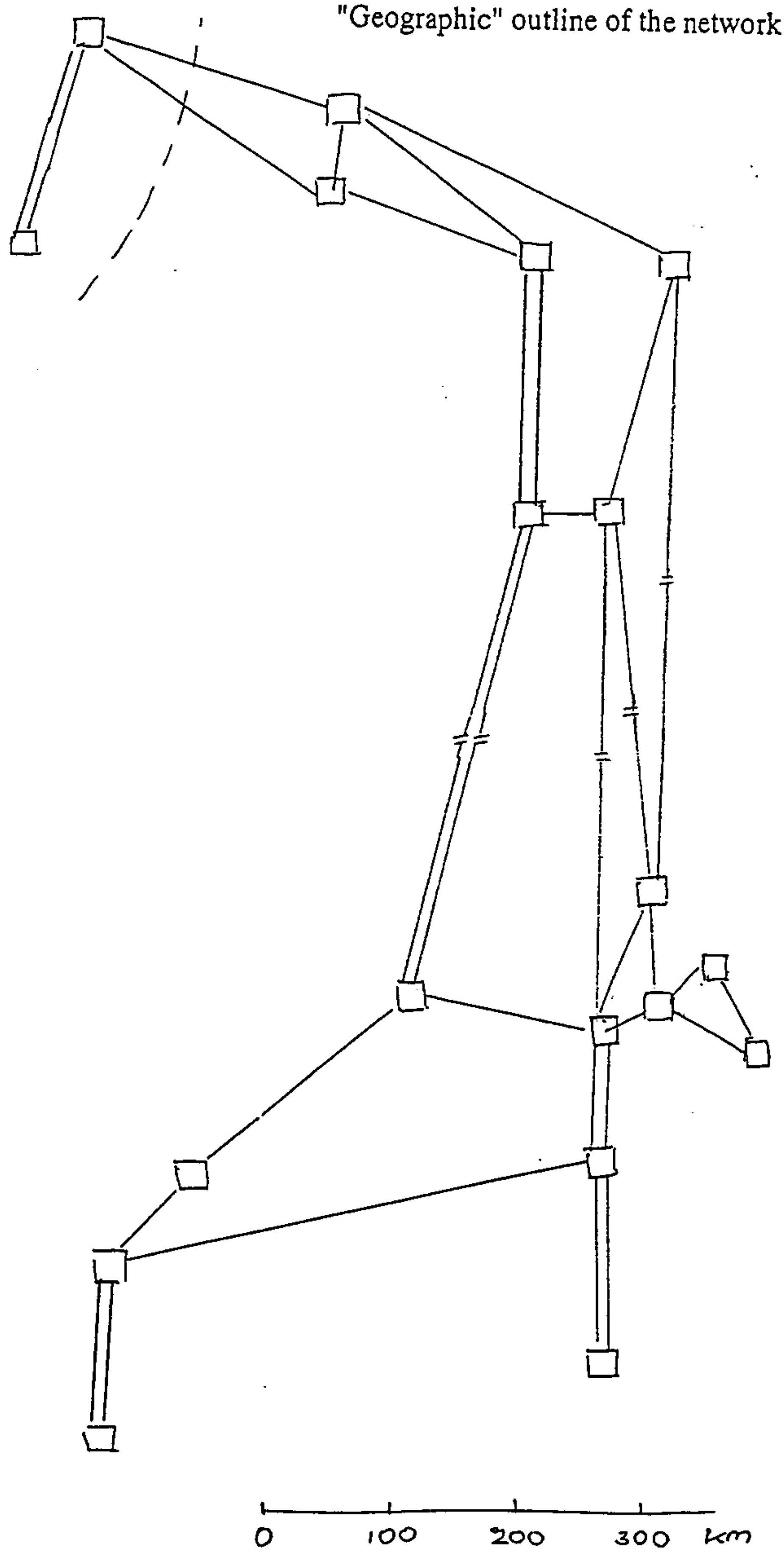
Appendix A-2



Appendix A-3

NORDIC32

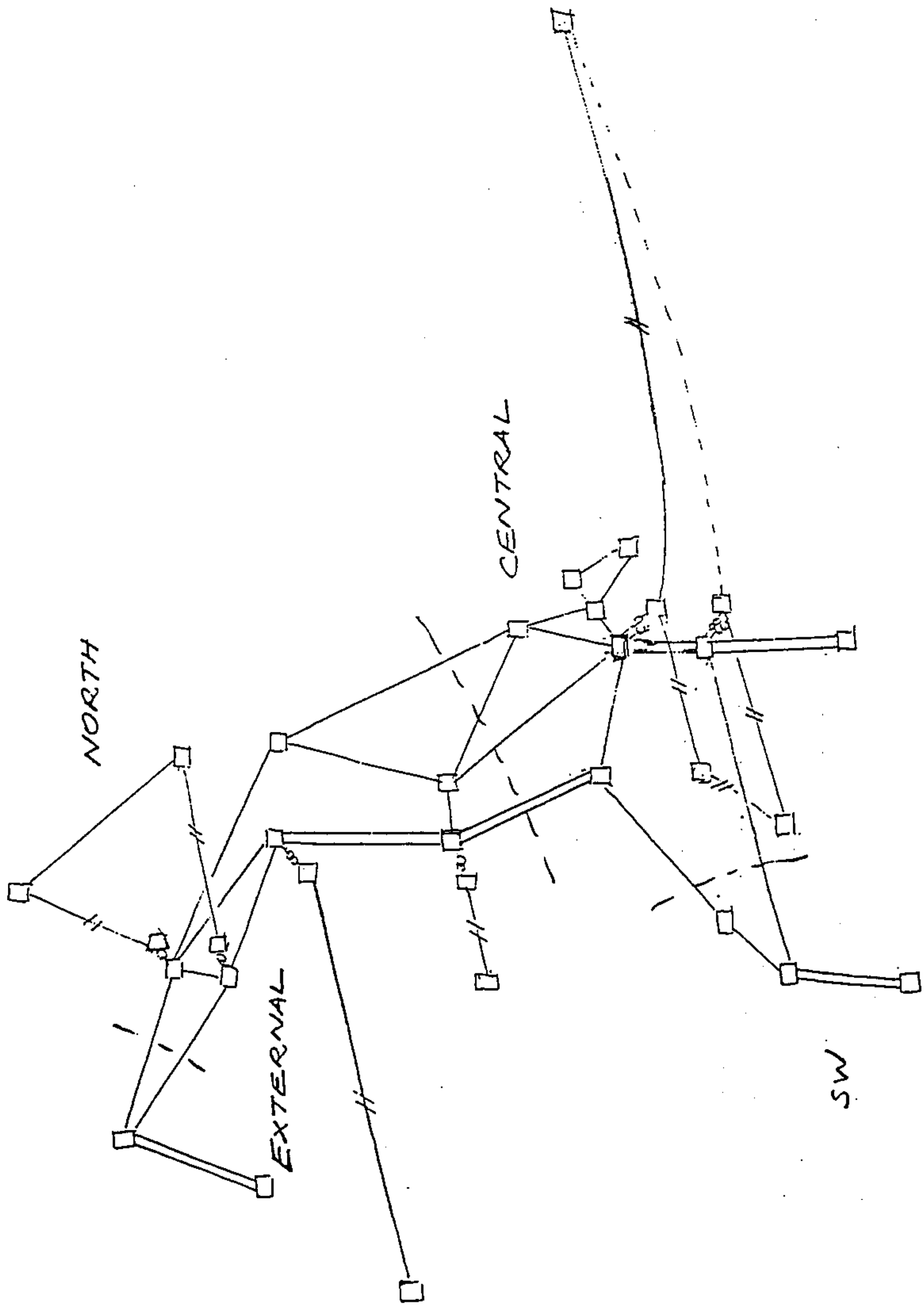
"Geographic" outline of the network



Appendix A-4

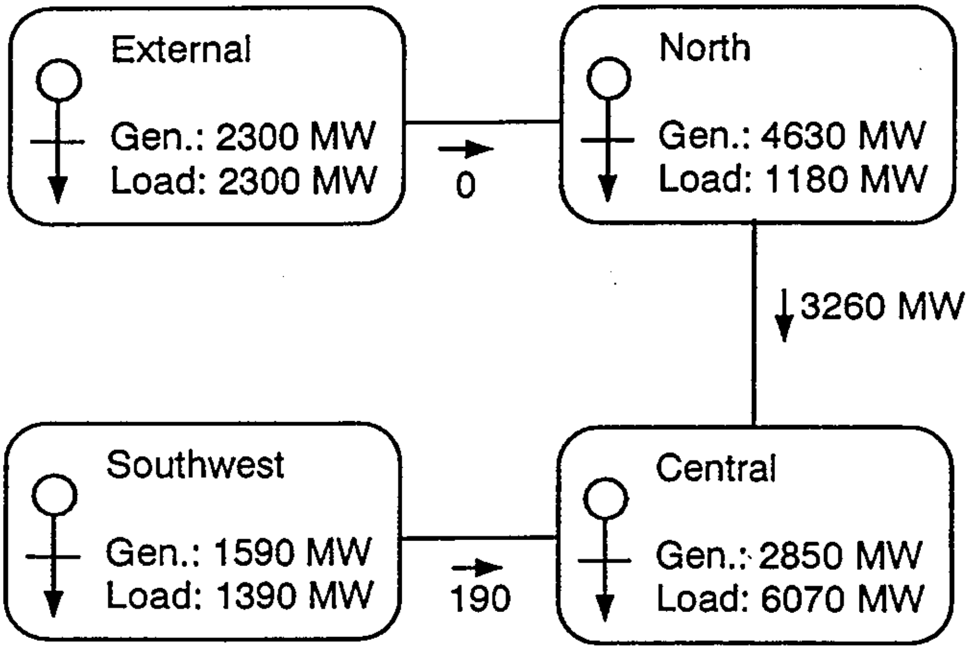
NORDIC32

Impedance outline of the network



Appendix A-5

NORDIC32 Regions



Total generation	11370 MW
Total load	10940 MW
Total losses	430 MW

(data from load flow LF32_028)

Ratings and Inertias (rotating energy)
in load flow LF32_028

Area	S_n (MVA)	$S_n \times H$ (MWs)
External	5,000	15,000
North	6,250	18,750
Central	3,500	19,800
Southwest	1,800	10,800
Total	16,550	64,350

Load flow data

CIGRE TEST NETWORK, NORDIC32A, 32 NODES
LOAD FLOW LF32_028 (TAPS MODIF.)

BUS DATA

COMMENTS
CODE: 1 Load bus, i.e. varying V and angle
2 Generator bus, i.e. varying Q generation
-2 Generator bus, at Q-limit
3 Slack bus, i.e. varying P and Q generation

SHUNT: P and Q are defined and referred to nominal voltage, i.e. the power will depend on the load flow voltage

NAME	BSKV	BUS#	CODE	VOLT	ANGLE	PLOAD	QLOAD	S H U N T		AREA	ZONE
BUS1011	130	1011	1	145.93	1.1	200.0	80.0	0.0	0.0	1	1
BUS1012	130	1012	2	146.90	4.6	300.0	100.0	0.0	0.0	1	1
BUS1013	130	1013	2	148.85	7.9	100.0	40.0	0.0	0.0	1	1
BUS1014	130	1014	2	150.80	10.5	0.0	0.0	0.0	0.0	1	1
BUS1021	130	1021	2	143.00	8.9	0.0	0.0	0.0	0.0	2	1
BUS1022	130	1022	-2	138.22	-10.8	280.0	95.0	0.0	50.0	2	1
BUS1041	130	1041	1	124.86	-74.9	600.0	200.0	0.0	200.0	4	1
BUS1042	130	1042	2	130.00	-58.3	300.0	80.0	0.0	0.0	4	1
BUS1043	130	1043	-2	128.64	-69.2	230.0	100.0	0.0	150.0	4	1
BUS1044	130	1044	1	127.85	-60.2	800.0	300.0	0.0	200.0	4	1
BUS1045	130	1045	1	128.80	-64.5	700.0	250.0	0.0	200.0	4	1
BUS2031	220	2031	1	231.71	-28.1	100.0	30.0	0.0	0.0	3	1
BUS2032	220	2032	2	242.00	-16.1	200.0	50.0	0.0	0.0	3	1
BUS4011	400	4011	3	404.00	0.0	0.0	0.0	0.0	0.0	1	1
BUS4012	400	4012	2	404.00	1.9	0.0	0.0	0.0	-100.0	1	1
BUS4021	400	4021	-2	403.31	-27.7	0.0	0.0	0.0	0.0	2	1
BUS4022	400	4022	1	397.54	-12.9	0.0	0.0	0.0	0.0	2	1
BUS4031	400	4031	2	404.00	-31.0	0.0	0.0	0.0	0.0	3	1
BUS4032	400	4032	1	405.46	-36.3	0.0	0.0	0.0	0.0	3	1
BUS4041	400	4041	2	400.00	-46.4	0.0	0.0	0.0	200.0	8	1
BUS4042	400	4042	2	400.00	-49.6	0.0	0.0	0.0	0.0	8	1
BUS4043	400	4043	1	396.10	-56.1	0.0	0.0	0.0	-200.0	8	1
BUS4044	400	4044	1	395.28	-56.8	0.0	0.0	0.0	0.0	8	1
BUS4045	400	4045	1	398.64	-61.7	0.0	0.0	0.0	0.0	5	1
BUS4046	400	4046	1	396.29	-56.8	0.0	0.0	0.0	100.0	8	1
BUS4047	400	4047	2	408.00	-51.9	0.0	0.0	0.0	0.0	8	1
BUS4051	400	4051	2	408.00	-64.2	0.0	0.0	0.0	100.0	5	1
BUS4061	400	4061	1	392.83	-50.1	0.0	0.0	0.0	0.0	6	1
BUS4062	400	4062	-2	400.18	-46.0	0.0	0.0	0.0	0.0	6	1
BUS4063	400	4063	2	400.00	-41.9	0.0	0.0	0.0	0.0	6	1
BUS4071	400	4071	2	404.00	0.9	300.0	100.0	0.0	-400.0	7	1
BUS4072	400	4072	2	404.00	0.9	2000.0	500.0	0.0	0.0	7	1
BUS41	130	41	1	128.11	-49.5	540.0	128.3	0.0	0.0	8	1
BUS42	130	42	1	127.65	-52.7	400.0	125.7	0.0	0.0	8	1
BUS43	130	43	1	126.22	-59.9	900.0	238.8	0.0	0.0	8	1
BUS46	130	46	1	125.85	-61.0	700.0	193.7	0.0	0.0	8	1
BUS47	130	47	1	130.15	-54.1	100.0	45.2	0.0	0.0	8	1
BUS51	130	51	1	130.10	-67.3	800.0	253.2	0.0	0.0	8	1
BUS61	130	61	1	125.40	-54.0	500.0	112.3	0.0	0.0	8	1
BUS62	130	62	1	127.70	-49.5	300.0	80.0	0.0	0.0	8	1
BUS63	130	63	1	126.33	-45.4	590.0	256.2	0.0	0.0	8	1

CIGRE TEST NETWORK, NORDIC32A, 32 NODES
LOAD FLOW LF32_028 (TAPS MODIF.)

GENERATING PLANT DATA

COMMENTS
CODE: See Bus Data, App. B-1

MCNS: Shows how many machines there are included in the plant, cf. UNIT DATA

NAME	BSKV	BUS#	COD	MCNS	PGEN	QGEN	QMAX	QMIN	VSCHED	VACT.
BUS1012	130	1012	2	1	600.0	84.9	400.0	-80.0	146.90	146.90
BUS1013	130	1013	2	1	300.0	44.0	300.0	-50.0	148.85	148.85
BUS1014	130	1014	2	1	550.0	82.1	350.0	-100.0	150.80	150.80
BUS1021	130	1021	2	1	400.0	44.7	300.0	-60.0	143.00	143.00
BUS1022	130	1022	-2	1	200.0	125.0	125.0	-25.0	139.10	138.22
BUS1042	130	1042	2	1	360.0	79.0	200.0	-40.0	130.00	130.00
BUS1043	130	1043	-2	1	180.0	100.0	100.0	-20.0	130.00	128.64
BUS2032	220	2032	2	1	750.0	145.8	425.0	-80.0	242.00	242.00
BUS4011	400	4011	3	1	668.5	94.3	500.0	-100.0	404.00	404.00
BUS4012	400	4012	2	1	600.0	-2.5	400.0	-160.0	404.00	404.00
BUS4021	400	4021	-2	1	250.0	-30.0	150.0	-30.0	400.00	403.31
BUS4031	400	4031	2	1	310.0	113.4	175.0	-40.0	404.00	404.00
BUS4041	400	4041	2	1	0.0	-9.0	300.0	-200.0	400.00	400.00
BUS4042	400	4042	2	1	630.0	265.0	350.0	0.0	400.00	400.00
BUS4047	400	4047	2	2	1080.0	304.2	600.0	0.0	408.00	408.00
BUS4051	400	4051	2	1	600.0	217.4	350.0	0.0	408.00	408.00
BUS4062	400	4062	-2	1	530.0	0.0	300.0	0.0	400.00	400.18
BUS4063	400	4063	2	2	1060.0	176.8	600.0	0.0	400.00	400.00
BUS4071	400	4071	2	1	300.0	54.3	250.0	-50.0	404.00	404.00
BUS4072	400	4072	2	1	2000.0	194.0	1000.0	-300.0	404.00	404.00

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E APPENDIX B-3

CIGRE TEST NETWORK, NORDIC32A, 32 NODES
LOAD FLOW LF32_028 (TAPS MODIF.)

GENERATOR
UNIT DATA

COMMENTS
ID: Individual unit no.
ST: Status, 1= in operation
TR. X: Reactance of generator transformer, TAP: Tap ratio of ditto

NAME	BSKV	BUS#	COD	ID	ST	PGEN	QGEN	QMAX	QMIN	MBASE	Z SORCE	TR. X	TAP
BUS1012	130	1012	2	1	1	600.	84.9	400.	-80.	800.	0. 0.20	0. 0.15	1.
BUS1013	130	1013	2	1	1	300.	44.0	300.	-50.	600.	0. 0.20	0. 0.15	1.
BUS1014	130	1014	2	1	1	550.	82.1	350.	-100.	700.	0. 0.20	0. 0.15	1.
BUS1021	130	1021	2	1	1	400.	44.7	300.	-60.	600.	0. 0.20	0. 0.15	1.
BUS1022	130	1022	-2	1	1	200.	125.0	125.	-25.	250.	0. 0.20	0. 0.15	1.
BUS1042	130	1042	2	1	1	360.	79.0	200.	-40.	400.	0. 0.20	0. 0.15	1.
BUS1043	130	1043	-2	1	1	180.	100.0	100.	-20.	200.	0. 0.20	0. 0.15	1.
BUS2032	220	2032	2	1	1	750.	145.8	425.	-80.	850.	0. 0.20	0. 0.15	1.
BUS4011	400	4011	3	1	1	668.5	94.3	500.	-100.	1000.	0. 0.20	0. 0.15	1.
BUS4012	400	4012	2	1	1	600.	-2.5	400.	-160.	800.	0. 0.20	0. 0.15	1.
BUS4021	400	4021	-2	1	1	250.	-30.0	150.	-30.	300.	0. 0.20	0. 0.15	1.
BUS4031	400	4031	2	1	1	310.	113.4	175.	-40.	350.	0. 0.20	0. 0.15	1.
BUS4041	400	4041	2	1	1	0.	-9.0	300.	-200.	300.	0. 0.20	0. 0.10	1.
BUS4042	400	4042	2	1	1	630.	265.0	350.	0.	700.	0. 0.20	0. 0.15	1.
BUS4047	400	4047	2	1	1	540.	152.1	300.	0.	600.	0. 0.20	0. 0.15	1.
BUS4047	400	4047	2	2	1	540.	152.1	300.	0.	600.	0. 0.20	0. 0.15	1.
BUS4051	400	4051	2	1	1	600.	217.4	350.	0.	700.	0. 0.20	0. 0.15	1.
BUS4062	400	4062	-2	1	1	530.	0.0	300.	0.	600.	0. 0.20	0. 0.15	1.
BUS4063	400	4063	2	1	1	530.	88.4	300.	0.	600.	0. 0.20	0. 0.15	1.
BUS4063	400	4063	2	2	1	530.	88.4	300.	0.	600.	0. 0.20	0. 0.15	1.
BUS4071	400	4071	2	1	1	300.	54.3	250.	-50.	500.	0. 0.20	0. 0.15	1.
BUS4072	400	4072	2	1	1	2000.	194.0	1000.	-300.	4500.	0. 0.20	0. 0.15	1.

COMMENTS
LINE R: Resistance in ohms
LINE X: Reactance in ohms
CHRGING: Charging in pu, See Appendix B-6a

BRANCH DATA
TRANSMISSION LINES

X------FROM------X			X-------TO-------X								
NAME	BSKV	BUS#	NAME	BSKV	BUS#	CKT	LINE R	LINE X	CHRGING	TP	ST
BUS1011	130	1011*	BUS1013	130	1013	1	1.69	11.83	0.26		1
BUS1011	130	1011*	BUS1013	130	1013	2	1.69	11.83	0.26		1
BUS1012	130	1012*	BUS1014	130	1014	1	2.37	15.21	0.34		1
BUS1012	130	1012*	BUS1014	130	1014	2	2.37	15.21	0.34		1
BUS1013	130	1013*	BUS1014	130	1014	1	1.18	8.45	0.19		1
BUS1013	130	1013*	BUS1014	130	1014	2	1.18	8.45	0.19		1
BUS1021	130	1021*	BUS1022	130	1022	1	5.07	33.80	0.57		1
BUS1021	130	1021*	BUS1022	130	1022	2	5.07	33.80	0.57		1
BUS1041	130	1041*	BUS1043	130	1043	1	1.69	10.14	0.23		1
BUS1041	130	1041*	BUS1043	130	1043	2	1.69	10.14	0.23		1
BUS1041	130	1041*	BUS1045	130	1045	1	2.53	20.28	0.47		1
BUS1041	130	1041*	BUS1045	130	1045	2	2.53	20.28	0.47		1
BUS1042	130	1042*	BUS1044	130	1044	1	6.42	47.32	1.13		1
BUS1042	130	1042*	BUS1044	130	1044	2	6.42	47.32	1.13		1
BUS1042	130	1042*	BUS1045	130	1045	1	8.45	50.70	1.13		1
BUS1043	130	1043*	BUS1044	130	1044	1	1.69	13.52	0.30		1
BUS1043	130	1043*	BUS1044	130	1044	2	1.69	13.52	0.30		1
BUS2031	220	2031*	BUS2032	220	2032	1	5.81	43.56	0.10		1
BUS2031	220	2031*	BUS2032	220	2032	2	5.81	43.56	0.10		1
BUS4011	400	4011*	BUS4012	400	4012	1	1.60	12.80	0.40		1
BUS4011	400	4011*	BUS4021	400	4021	1	9.60	96.00	3.58		1
BUS4011	400	4011*	BUS4022	400	4022	1	6.40	64.00	2.39		1
BUS4011	400	4011*	BUS4071	400	4071	1	8.00	72.00	2.79		1
BUS4012	400	4012*	BUS4022	400	4022	1	6.40	56.00	2.09		1
BUS4012	400	4012*	BUS4071	400	4071	1	8.00	80.00	2.98		1
BUS4021	400	4021*	BUS4032	400	4032	1	6.40	64.00	2.39		1
BUS4021	400	4021*	BUS4042	400	4042	1	16.00	96.00	5.97		1
BUS4022	400	4022*	BUS4031	400	4031	1	6.40	64.00	2.39		1
BUS4022	400	4022*	BUS4031	400	4031	2	6.40	64.00	2.39		1
BUS4031	400	4031*	BUS4032	400	4032	1	1.60	16.00	0.60		1
BUS4031	400	4031*	BUS4041	400	4041	1	9.60	64.00	4.77		1
BUS4031	400	4031*	BUS4041	400	4041	2	9.60	64.00	4.77		1
BUS4032	400	4032*	BUS4042	400	4042	1	16.00	64.00	3.98		1
BUS4032	400	4032*	BUS4044	400	4044	1	9.60	80.00	4.77		1
BUS4041	400	4041*	BUS4044	400	4044	1	4.80	48.00	1.79		1
BUS4041	400	4041*	BUS4061	400	4061	1	9.60	72.00	2.59		1
BUS4042	400	4042*	BUS4043	400	4043	1	3.20	24.00	0.99		1
BUS4042	400	4042*	BUS4044	400	4044	1	3.20	32.00	1.19		1
BUS4043	400	4043*	BUS4044	400	4044	1	1.60	16.00	0.60		1
BUS4043	400	4043*	BUS4046	400	4046	1	1.60	16.00	0.60		1
BUS4043	400	4043*	BUS4047	400	4047	1	3.20	32.00	1.19		1
BUS4044	400	4044*	BUS4045	400	4045	1	3.20	32.00	1.19		1
BUS4044	400	4044*	BUS4045	400	4045	2	3.20	32.00	1.19		1

BRANCH DATA
TRANSMISSION LINES (continued)

X------FROM------X			X-------TO-------X								
NAME	BSKV	BUS#	NAME	BSKV	BUS#	CKT	LINE R	LINE X	CHRGING	TP	ST
BUS4045	400	4045*	BUS4051	400	4051	1	6.40	64.00	2.39		1
BUS4045	400	4045*	BUS4051	400	4051	2	6.40	64.00	2.39		1
BUS4045	400	4045*	BUS4062	400	4062	1	17.60	128.00	4.77		1
BUS4046	400	4046*	BUS4047	400	4047	1	1.60	24.00	0.99		1
BUS4062	400	4062*	BUS4063	400	4063	1	4.80	48.00	1.79		1
BUS4062	400	4062*	BUS4063	400	4063	2	4.80	48.00	1.79		1
BUS4071	400	4071*	BUS4072	400	4072	1	4.80	48.00	5.97		1
BUS4071	400	4071*	BUS4072	400	4072	2	4.80	48.00	5.97		1

BRANCH DATA
TRANSFORMERS

COMMENTS
Data below only covers the impedance.
Other data such as ratio are found in Appendix B-5

SIZE: Informs about the MVA-rating, but please note that the R, X and charging refer to SYSTEM base.

For further explanation, see B-6b

X------FROM------X			X-------TO-------X									
NAME	BSKV	BUS#	NAME	BSKV	BUS#	CKT	LINE R	LINE X	CHRGING	TP	ST	SIZE
BUS1011	130	1011*	BUS4011	400	4011	1	0.0000	0.0080	0.0000	F	1	
BUS1012	130	1012*	BUS4012	400	4012	1	0.0000	0.0080	0.0000	F	1	
BUS1022	130	1022*	BUS4022	400	4022	1	0.0000	0.0120	0.0000	F	1	
BUS1044	130	1044*	BUS4044	400	4044	1	0.0000	0.0100	0.0000	F	1	
BUS1044	130	1044*	BUS4044	400	4044	2	0.0000	0.0100	0.0000	F	1	
BUS1045	130	1045*	BUS4045	400	4045	1	0.0000	0.0100	0.0000	F	1	
BUS1045	130	1045*	BUS4045	400	4045	2	0.0000	0.0100	0.0000	F	1	
BUS2031	220	2031*	BUS4031	400	4031	1	0.0000	0.0120	0.0000	F	1	
BUS4041	400	4041	BUS41	130	41*	1	0.0000	0.0100	0.0000	T	1	1000
BUS4042	400	4042	BUS42	130	42*	1	0.0000	0.0130	0.0000	T	1	750
BUS4043	400	4043	BUS43	130	43*	1	0.0000	0.0070	0.0000	T	1	1500
BUS4046	400	4046	BUS46	130	46*	1	0.0000	0.0100	0.0000	T	1	1000
BUS4047	400	4047	BUS47	130	47*	1	0.0000	0.0400	0.0000	T	1	250
BUS4051	400	4051	BUS51	130	51*	1	0.0000	0.0070	0.0000	T	1	1500
BUS4061	400	4061	BUS61	130	61*	1	0.0000	0.0130	0.0000	T	1	750
BUS4062	400	4062	BUS62	130	62*	1	0.0000	0.0200	0.0000	T	1	500
BUS4063	400	4063	BUS63	130	63*	1	0.0000	0.0100	0.0000	T	1	1000

CIGRE TEST NETWORK, NORDIC32A, 32 NODES TRANSFORMER DATA
LOAD FLOW LF32_028 (TAPS MODIF.)

COMMENTS
See Appendix B-6c

X------FROM-----X			X-------TO------X											
NAME	BSKV	BUS#	NAME	BSKV	BUS#	CKT	TP	RATIO	RG	RMAX	RMIN	VMAX	VMIN	STEP
BUS1011	130	1011	BUS4011	400	4011	1	F	1.12	1	1.50	0.51	1.5	0.51	0.0625
BUS1012	130	1012	BUS4012	400	4012	1	F	1.12	1	1.50	0.51	1.5	0.51	0.0625
BUS1022	130	1022	BUS4022	400	4022	1	F	1.07	1	1.50	0.51	1.5	0.51	0.0625
BUS1044	130	1044	BUS4044	400	4044	1	F	1.00	1	1.12	0.88	130.6	126.70	0.01
BUS1044	130	1044	BUS4044	400	4044	2	F	1.00	1	1.12	0.88	130.6	126.70	0.01
BUS1045	130	1045	BUS4045	400	4045	1	F	1.00	1	1.12	0.88	131.4	127.50	0.01
BUS1045	130	1045	BUS4045	400	4045	2	F	1.00	1	1.12	0.88	131.4	127.50	0.01
BUS2031	220	2031	BUS4031	400	4031	1	F	1.05	1	1.50	0.51	1.5	0.51	0.0625
BUS4041	400	4041	BUS41	130	41	1	T	1.00	1	1.12	0.88	130.07	126.17	0.01
BUS4042	400	4042	BUS42	130	42	1	T	1.00	1	1.12	0.88	129.35	125.71	0.01
BUS4043	400	4043	BUS43	130	43	1	T	1.00	1	1.12	0.88	128.17	124.27	0.01
BUS4046	400	4046	BUS46	130	46	1	T	1.00	1	1.12	0.88	127.80	123.90	0.01
BUS4047	400	4047	BUS47	130	47	1	T	1.00	1	1.12	0.88	132.11	128.21	0.01
BUS4051	400	4051	BUS51	130	51	1	T	1.00	1	1.12	0.88	132.05	128.15	0.01
BUS4061	400	4061	BUS61	130	61	1	T	1.00	1	1.12	0.88	127.35	123.45	0.01
BUS4062	400	4062	BUS62	130	62	1	T	1.00	1	1.12	0.88	129.65	125.75	0.01
BUS4063	400	4063	BUS63	130	63	1	T	1.00	1	1.12	0.88	128.28	124.38	0.01

X------FROM-----X			X-------TO------X					X----CONTROLLED BUS----X			
NAME	BSKV	BUS#	NAME	BSKV	BUS#	CKT	TP	NAME	BSKV	BUS#	VOLTAGE
BUS1011	130	1011	BUS4011	400	4011	1					
BUS1012	130	1012	BUS4012	400	4012	1					
BUS1022	130	1022	BUS4022	400	4022	1					
BUS1044	130	1044	BUS4044	400	4044	1	F	BUS1044	130	1044	127.85
BUS1044	130	1044	BUS4044	400	4044	2	F	BUS1044	130	1044	127.85
BUS1045	130	1045	BUS4045	400	4045	1	F	BUS1045	130	1045	128.80
BUS1045	130	1045	BUS4045	400	4045	2	F	BUS1045	130	1045	128.80
BUS2031	220	2031	BUS4031	400	4031	1	F				
BUS4041	400	4041	BUS41	130	41	1	T	BUS41	130	41	128.11
BUS4042	400	4042	BUS42	130	42	1	T	BUS42	130	42	127.65
BUS4043	400	4043	BUS43	130	43	1	T	BUS43	130	43	126.22
BUS4046	400	4046	BUS46	130	46	1	T	BUS46	130	46	125.85
BUS4047	400	4047	BUS47	130	47	1	T	BUS47	130	47	130.15
BUS4051	400	4051	BUS51	130	51	1	T	BUS51	130	51	130.10
BUS4061	400	4061	BUS61	130	61	1	T	BUS61	130	61	125.40
BUS4062	400	4062	BUS62	130	62	1	T	BUS62	130	62	127.70
BUS4063	400	4063	BUS63	130	63	1	T	BUS63	130	63	126.33

(modified 1994-12-01)

Branch data (explanation of data in appendix B-4a)

The branch data include transmission lines as well as transformers.

Transmission lines

The data is given in the following format.

LINE R	resistance in ohms
LINE X	reactance in ohms
CHRGING	total charging of the line in microfarads, C (μF), i.e.
	$B\ (p\ u) = 100 * \pi * C(\mu F) * 10^{-6} * U_{base}^{2} / S_{syst.base}$

Appendix B-6b

Branch data (explanation of data in appendix B-4a)

Transformers

Only the impedance data is given. Ratio and tap changer data is given in App. B-5

Examples (two transformers are shown):

FROM	TO	CKT	LINE R	LINE X	CHRGING	TP	ST	SIZE
BUS1011	BUS4011	1	0.0000	0.0080	0.0000	F	1	0
BUS41	BUS4041	1	0.0000	0.0100	0.0000	F	1	1000

P.u. base

The data is given in per unit, that is related to system base

Power ($S_{syst.base}$) 100 MVA,

Voltage (V_{base}) 400 kV, 220 kV, and 130 kV respectively

LINE R $R\ (p\ u) = R\ (ohm) * S_{syst.base} / V_{base}^2$

LINE X analogous

Relationship to transformer ratings

As the reactance (LINE X) is related to system base, it may be calculated from transformer ratings as follows

$$X\ (p\ u) = (e_x / 100) * (S_{syst.base} / S_n) * (U_n^2 / U_{syst.base}^2)$$

where

e_x	transformer short circuit reactance in per cent
$S_{syst.base}$	system base in MVA
S_n	transformer rating in MVA
U_n	transformer rated voltage on the impedance side
$U_{syst.base}$	system base voltage on the transformer impedance side

Comments on ratings

Impedance is always related to SYSTEM base. The SIZE is only given as information.

If that data is not given, realistic ratings can be defined by assuming that the normal e_x -value is 10 %. In the example above, the ratings would be 1250, 1000 and 1000 MVA respectively.

Appendix B-6c

Transformer data (explanation of data in appendix B-5)

The impedance data is given in the branch data as presented in Appendix B-6a.
Below the special data in Appendix B-5 is commented. It defines tap changer ratio.

Example (three examples are shown)

FROM	TO	CKT	TP	RATIO	ANGLE	RG	RMAX	RMIN	VMAX	VMIN
BUS1011	BUS4011	1	F	1.12	0.00	1				
BUS1044	BUS4044	1	F	1.00	0.00	1	1.12	0.88	130.39	126.6
BUS41	BUS4041	1	F	1.00	0.00	1	1.12	0.88	130.06	126.1

Voltage control etc

For all 400/130 kV transformers with active tap changers, the voltage is controlled on the low voltage side (130 kV). It is valied for both system transformers and load transformers. That information is not shown in the data listing in appendix B-5 and B-6, but were given in PSS/E RAW DATA.

The various data in the example on the previous page is commented. The first mentioned transformer has no active tap changer.

FROM BUS	The first mentioned bus is called the tapped side.
TO BUS	The second mentioned bus is the impedance side, i e the impedances are calculated with respect to this side.
RATIO	The original ratio. It is defined as $(U_{n,1} / U_{syst.base,1}) / (U_{n,2} / U_{syst.base,2})$ where 1 and 2 relates to from-bus and to-bus respectively
RMAX	The maximum ratio limit (1.12 pu)
RMIN	The minimum ratio limit (0.88 pu)
VMAX	The maximum bus voltage that is accepted. If it is exceeded the tap changer will act (about +0.015 pu)
VMIN	The minimum bus voltage that is accepted (about -0.015 pu)
STEP	The step is 0.01 pu (that is not shown in app. B-5

Comments

As can be seen from the data the tap changer range may be explained as ± 12 % with a stepsize of 1 %.

The dynamics of the control is explained in Appendix C-6.

The 'FROM BUS' is th tapped side, i.e. the low voltage side is assumed to be tapped. This is technically unrealistic, but it will no significant effect on the simulation.

```
 0  100.  / 1993-02-08
Nordic 32A, Cigre test network, 32 nodes
Load flow lf32_028

 Bus data

 4011  3    0.     0.  0.     0.  1  1.01   0.0  'BUS4011'  400.  1 /slack bus
 4012  2    0.     0.  0. -100.  1  1.01   0.0  'BUS4012'  400.  1
 4021  2    0.     0.  0.     0.  2  1.00   0.0  'BUS4021'  400.  1
 4022  1    0.     0.  0.     0.  2  1.00   0.0  'BUS4022'  400.  1
 4031  2    0.     0.  0.     0.  3  1.00   0.0  'BUS4031'  400.  1
 4032  1    0.     0.  0.     0.  3  1.00   0.0  'BUS4032'  400.  1
 4041  2    0.     0.  0.  200.  8  1.00   0.0  'BUS4041'  400.  1
 4042  2    0.     0.  0.     0.  8  1.00   0.0  'BUS4042'  400.  1
 4043  1    0.     0.  0.  200.  8  1.00   0.0  'BUS4043'  400.  1
 4044  1    0.     0.  0.     0.  8  1.00   0.0  'BUS4044'  400.  1
 4045  1    0.     0.  0.     0.  5  1.00   0.0  'BUS4045'  400.  1
 4046  1    0.     0.  0.  100.  8  1.00   0.0  'BUS4046'  400.  1
 4047  2    0.     0.  0.     0.  8  1.02   0.0  'BUS4047'  400.  1
 4051  2    0.     0.  0.  100.  5  1.02   0.0  'BUS4051'  400.  1
 4061  1    0.     0.  0.     0.  6  1.00   0.0  'BUS4061'  400.  1
 4062  2    0.     0.  0.     0.  6  1.00   0.0  'BUS4062'  400.  1
 4063  2    0.     0.  0.     0.  6  1.00   0.0  'BUS4063'  400.  1
 4071  2  300.   100.  0. -400.  7  1.00   0.0  'BUS4071'  400.  1
 4072  2  2000.  500.  0.     0.  7  1.00   0.0  'BUS4072'  400.  1
 1011  1  200.    80.  0.     0.  1  1.00   0.0  'BUS1011'  130.  1
 1012  2  300.   100.  0.     0.  1  1.15   0.0  'BUS1012'  130.  1
 1013  2  100.    40.  0.     0.  1  1.15   0.0  'BUS1013'  130.  1
 1014  2    0.     0.  0.     0.  1  1.15   0.0  'BUS1014'  130.  1
 1021  2    0.     0.  0.     0.  2  1.15   0.0  'BUS1021'  130.  1
 1022  2  280.    95.  0.    50.  2  1.00   0.0  'BUS1022'  130.  1
 2031  1  100.    30.  0.     0.  3  1.00   0.0  'BUS2031'  220.  1
 2032  2  200.    50.  0.     0.  3  1.10   0.0  'BUS2032'  220.  1
 1041  1  600.   200.  0.  200.  4  1.00   0.0  'BUS1041'  130.  1
 1042  2  300.    80.  0.     0.  4  1.00   0.0  'BUS1042'  130.  1
 1043  2  230.   100.  0.  150.  4  1.00   0.0  'BUS1043'  130.  1
 1044  1  800.   300.  0.  200.  4  1.00   0.0  'BUS1044'  130.  1
 1045  1  700.   250.  0.  200.  4  1.00   0.0  'BUS1045'  130.  1
   41  1  540.   128.28 0.  0.   8  1.00   0.0  'BUS41'    130.  1
   42  1  400.   125.67 0   0.   8  1.00   0.0  'BUS42'    130.  1
   43  1  900.   238.83 0.  0.   8  1.00   0.0  'BUS43'    130.  1
   46  1  700.   193.72 0.  0.   8  1.00   0.0  'BUS46'    130.  1
   47  1  100.    45.19 0.  0.   8  1.00   0.0  'BUS47'    130.  1
   51  1  800.   253.22 0.  0.   8  1.00   0.0  'BUS51'    130.  1
   61  1  500.   112.31 0.  0.   8  1.00   0.0  'BUS61'    130.  1
   62  1  300.    80.02 0.  0.   8  1.00   0.0  'BUS62'    130.  1
   63  1  590.   256.19 0.  0.   8  1.00   0.0  'BUS63    ' 130.  1


Generator data
0
 4011  1  700.  0.  500. -100.   1.01  0 1000.  0.  0.20  0.  0.15  1.  1
 4012  1  600.  0.  400. -160.   1.01  0  800.  0.  0.20  0.  0.15  1.  1
 4021  1  250.  0.  150.  -30.   1.00  0  300.  0.  0.20  0.  0.15  1.  1
 4031  1  310.  0.  175.  -40.   1.01  0  350.  0.  0.20  0.  0.15  1.  1
 4041  1    0.  0.  300  -200.   1.00  0  300.  0.  0.20  0.  0.10  1.  1
 4042  1  630.  0.  350.  0.     1.00  0  700.  0.  0.20  0.  0.15  1.  1
 4047  1  540.  0.  300.  0.     1.02  0  600.  0.  0.20  0.  0.15  1.  1
 4047  2  540.  0.  300.  0.     1.02  0  600.  0.  0.20  0.  0.15  1.  1
 4051  1  600.  0.  350.  0.     1.02  0  700.  0.  0.20  0.  0.15  1.  1
 4062  1  530.  0.  300.  0.     1.00  0  600.  0.  0.20  0.  0.15  1.  1
 4063  1  530.  0.  300.  0.     1.00  0  600.  0.  0.20  0.  0.15  1.  1
 4063  2  530.  0.  300.  0.     1.00  0  600.  0.  0.20  0.  0.15  1.  1
 4071  1  300.  0.  250.   -50.  1.01  0  500.  0.  0.20  0.  0.15  1.  1
 4072  1  2000. 0.  1000. -300.  1.01  0 4500.  0.  0.20  0.  0.15  1.  1
```

1012	1	600.	0.	400.	-80.	1.13	0	800.	0.	0.20	0.	0.15	1.	1
1013	1	300.	0.	300.	-50.	1.145	0	600.	0.	0.20	0.	0.15	1.	1
1014	1	550.	0.	350.	-100.	1.16	0	700.	0.	0.20	0.	0.15	1.	1
1021	1	400.	0.	300.	-60.	1.10	0	600.	0.	0.20	0.	0.15	1.	1
1022	1	200.	0.	125.	-25.	1.07	0	250.	0.	0.20	0.	0.15	1.	1
2032	1	750.	0.	425.	-80.	1.10	0	850.	0.	0.20	0.	0.15	1.	1
1042	1	360.	0.	200.	-40.	1.0	0	400.	0.	0.20	0.	0.15	1.	1
1043	1	180.	0.	100.	-20.	1.0	0	200.	0.	0.20	0.	0.15	1.	1

Line data

0

4011	4021	1	0.006	0.060	1.80	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4011	4012	1	0.001	0.008	0.20	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4011	4022	1	0.004	0.040	1.20	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4012	4022	1	0.004	0.035	1.05	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4021	4032	1	0.004	0.040	1.20	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4021	4042	1	0.010	0.060	3.00	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4022	4031	1	0.004	0.040	1.20	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4022	4031	2	0.004	0.040	1.20	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4031	4032	1	0.001	0.010	0.30	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4031	4041	1	0.006	0.040	2.40	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4031	4041	2	0.006	0.040	2.40	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4032	4044	1	0.006	0.050	2.40	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4032	4042	1	0.010	0.040	2.00	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4041	4044	1	0.003	0.030	0.90	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4042	4044	1	0.002	0.020	0.60	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4042	4043	1	0.002	0.015	0.50	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4043	4044	1	0.001	0.010	0.30	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4043	4046	1	0.001	0.010	0.30	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4043	4047	1	0.002	0.020	0.60	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4046	4047	1	0.001	0.015	0.50	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4044	4045	1	0.002	0.020	0.60	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4044	4045	2	0.002	0.020	0.60	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4045	4051	1	0.004	0.040	1.20	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4045	4051	2	0.004	0.040	1.20	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4041	4061	1	0.006	0.045	1.30	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4045	4062	1	0.011	0.080	2.40	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4061	4062	1	0.002	0.020	0.60	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4062	4063	1	0.003	0.030	0.90	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4062	4063	2	0.003	0.030	0.90	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4011	4071	1	0.005	0.045	1.40	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4012	4071	1	0.005	0.050	1.50	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4071	4072	1	0.003	0.030	3.00	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
4071	4072	2	0.003	0.030	3.00	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
1011	1013	1	0.010	0.070	0.014	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
1011	1013	2	0.010	0.070	0.014	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
1013	1014	1	0.007	0.050	0.010	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
1013	1014	2	0.007	0.050	0.010	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
1012	1014	1	0.014	0.090	0.018	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
1012	1014	2	0.014	0.090	0.018	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
1021	1022	1	0.030	0.200	0.030	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
1021	1022	2	0.030	0.200	0.030	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
2031	2032	1	0.012	0.090	0.015	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
2031	2032	2	0.012	0.090	0.015	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
1043	1044	1	0.010	0.080	0.016	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
1043	1044	2	0.010	0.080	0.016	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
1041	1045	1	0.015	0.120	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
1041	1045	2	0.015	0.120	0.025	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
1041	1043	1	0.010	0.060	0.012	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
1041	1043	2	0.010	0.060	0.012	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
1042	1044	1	0.038	0.280	0.060	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
1042	1044	2	0.038	0.280	0.060	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
1042	1045	1	0.050	0.300	0.060	0.	0.	0.	0.	0.	0.	0.	0.	0.	1
1011	4011	1	0.000	0.008	0.000	0.	0.	0.	1.12	0.	0.	0.	0.	0.	1
1012	4012	1	0.000	0.008	0.000	0.	0.	0.	1.12	0.	0.	0.	0.	0.	1

```
1022  4022  1  0.000  0.012  0.000  0. 0. 0.  1.07  0. 0. 0. 0. 0.  1
2031  4031  1  0.000  0.012  0.000  0. 0. 0.  1.05  0. 0. 0. 0. 0.  1
1044  4044  1  0.000  0.010  0.000  0. 0. 0.  1.00  0. 0. 0. 0. 0.  1
1044  4044  2  0.000  0.010  0.000  0. 0. 0.  1.00  0. 0. 0. 0. 0.  1
1045  4045  1  0.000  0.010  0.000  0. 0. 0.  1.00  0. 0. 0. 0. 0.  1
1045  4045  2  0.000  0.010  0.000  0. 0. 0.  1.00  0. 0. 0. 0. 0.  1
  41  4041     1  0.000  0.010  0.000 1000.00  0. 0. 1.0 0.0 0.0 0.0 0.0 0.0 1
  42  4042     1  0.000  0.013  0.000  770.00  0  0. 1.0 0.0 0.0 0.0 0.0 0.0 1
  43  4043     1  0.000  0.007  0.000 1430.00  0. 0. 1.0 0.0 0.0 0.0 0.0 0.0 1
  46  4046     1  0.000  0.010  0.000 1000.00  0. 0. 1.0 0.0 0.0 0.0 0.0 0.0 1
  47  4047     1  0.000  0.040  0.000  250.00  0. 0. 1.0 0.0 0.0 0.0 0.0 0.0 1
  51  4051     1  0.000  0.007  0.000 1430.00  0. 0. 1.0 0.0 0.0 0.0 0.0 0.0 1
  61  4061     1  0.000  0.013  0.000  770.00  0. 0. 1.0 0.0 0.0 0.0 0.0 0.0 1
  62  4062     1  0.000  0.020  0.000  500.00  0. 0. 1.0 0.0 0.0 0.0 0.0 0.0 1
  63  4063     1  0.000  0.010  0.000 1000.00  0. 0. 1.0 0.0 0.0 0.0 0.0 0.0 1


Transformer data
0
 1044  4044  1  1044  1.1200  0.8800  1.003    0.9740   0.01
 1044  4044  2  1044  1.1200  0.8800  1.003    0.9740   0.01
 1045  4045  1  1045  1.1200  0.8800  1.011    0.9809   0.01
 1045  4045  2  1045  1.1200  0.8800  1.011    0.9809   0.01
   41  4041  1  41    1.1200  0.8800  1.00048  0.97048  0.01
   42  4042  1  42    1.1200  0.8800  0.99645  0.96645  0.01
   43  4043  1  43    1.1200  0.8800  0.98710  0.95710  0.01
   46  4046  1  46    1.1200  0.8800  0.98317  0.95318  0.01
   47  4047  1  47    1.1200  0.8800  1.01616  0.98616  0.01
   51  4051  1  51    1.1200  0.8800  1.01676  0.98676  0.01
   61  4061  1  61    1.1200  0.8800  0.97889  0.94889  0.01
   62  4062  1  62    1.1200  0.8800  0.99722  0.96722  0.01
   63  4063  1  63    1.1200  0.8800  0.98679  0.95679  0.01
0
0
0
0
0
0
0
0

  COMMENTS
  The following modifications will change lf_028 to lf_029

  Generators are modified. New data shall be as follows
   4011  1  600. ....                                               (changed)
   4012  1  500. ....                                               (changed)
   4051  2  400.  350.  0. 1.02  0 700. 0.  0.20 0. 0.15 1. 1        (new)
   1012  1  400. ....                                               (changed)

  And vice verca, to change lf_029 to lf_028

  Generators are modified. New data shall be as follows
   4011  1  700. ....                                               (changed)
   4012  1  600. ....                                               (changed)
   (4051  2          )                                              (deleted)
   1012  1  600. ....                                               (changed)
```

Appendix C

Dynamic model data

C-1 Generator data

C-2 Excitation systems

C-3 Power system stabilizers

C-4 Hydro governor models

C-5 Stator and current limiters

C-6 Transformer tap changers

C-7 Raw data file listing in PSS/E format

Appendix C-1a

Generator data

TYPE	A	B	C
X_d p.u.	2.20	1.10	1.55
X_q	2.00	0.70	1.00
X_d'	0.30	0.25	0.30
X_q'	0.40		
X_d''	0.20	0.20	0.20
X_q''	0.20	0.20	0.20
X_l	0.15	0.15	0.15
X_t (transf.)	0.15	0.15	0.10
T_{d0}' seconds	7.0	5.0	7.0
T_{q0}'	1.5		
T_{d0}''	0.05	0.05	0.05
T_{q0}''	0.05	0.10	0.10
H MWs/MVA	6.0	3.0	2.0

Type A represents round rotor generators in thermal power station at buses

4042	4062	1042
4047 no.1	4063 no.1	1043
4047 no.2	4063 no.2	
4051 no.1		
4051 no.2 (not in operation)		

Type B represents salient pole generators in hydro power station at buses

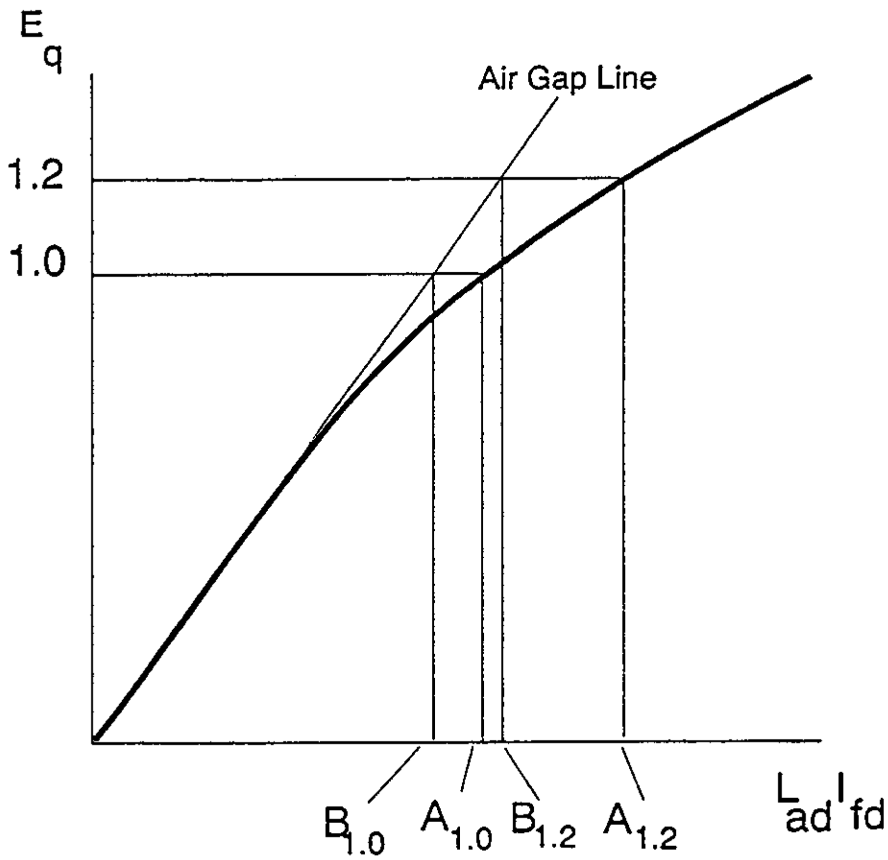
4011	4071	1014
4012	4072	1021
4021	1012	1022
4031	1013	2032

Type C represents a salient pole synchronous compensator at bus 4041

Appendix C-1b

Generator data, continued

Saturation curve (no-load operation)



All generators have the same saturation curve with the following parameters

$S_E(1.0) = (A_{1.0} - B_{1.0}) / B_{1.0} = 0.1$

$S_E(1.2) = (A_{1.2} - B_{1.2}) / B_{1.2} = 0.3$

Appendix C-1c

CIGRE TEST NETWORK, NORDIC32A, 32 NODES
LOAD FLOW LF32_028 (TAPS MODIF.)

INITIAL CONDITION LOAD FLOW USED 1 ITERATIONS

---------------------------MACHINE INITIAL CONDITIONS---------------------------

X------	BUS	-----X	ID	ETERM	EFD	POWER	VARS	P.F.	ANGLE	ID	IQ
BUS1012	130	1012	1	1.1484	1.7925	600.00	84.93	0.9901	29.64	0.3656	0.5618
BUS1013	130	1013	1	1.1565	1.6424	300.00	44.02	0.9894	25.12	0.1903	0.3982
BUS1014	130	1014	1	1.1795	1.8886	550.00	82.09	0.9890	35.31	0.3759	0.5725
BUS1021	130	1021	1	1.1139	1.6386	400.00	44.71	0.9938	32.84	0.3083	0.5262
BUS1022	130	1022	1	1.1394	2.3729	200.00	125.00	0.8480	12.84	0.7323	0.5010
BUS1042	130	1042	1	1.0384	2.7535	360.00	78.98	0.9768	-7.45	0.8226	0.4151
BUS1043	130	1043	1	1.0741	3.3831	180.00	100.00	0.8742	-28.85	0.9742	0.3652
BUS2032	220	2032	1	1.1298	1.9331	750.00	145.82	0.9816	12.90	0.5247	0.6264
BUS4011	400	4011	1	1.0288	1.5329	668.46	94.35	0.9902	27.31	0.3867	0.5452
BUS4012	400	4012	1	1.0157	1.4570	600.00	-2.53	1.0000	34.01	0.3916	0.6309
BUS4021	400	4021	1	1.0011	1.4050	250.00	-30.00	0.9929	9.56	0.4213	0.7180
BUS4031	400	4031	1	1.0663	2.0666	310.00	113.42	0.9391	-0.88	0.7180	0.5970
BUS4041	400	4041	1	0.9970	1.0403	0.00	-8.96	0.0000	-46.36	-0.0299	0.0000
BUS4042	400	4042	1	1.0654	3.1092	630.00	264.96	0.9218	-5.75	0.8968	0.3861
BUS4047	400	4047	1	1.0655	2.8492	540.00	152.12	0.9625	-4.32	0.8189	0.4121
BUS4047	400	4047	2	1.0655	2.8492	540.00	152.12	0.9625	-4.32	0.8189	0.4121
BUS4051	400	4051	1	1.0731	2.8832	600.00	217.35	0.9402	-20.10	0.8031	0.3922
BUS4062	400	4062	1	1.0092	2.4045	530.00	0.00	1.0000	13.81	0.7632	0.4440
BUS4063	400	4063	1	1.0307	2.6319	530.00	88.39	0.9864	10.62	0.7909	0.4200
BUS4063	400	4063	2	1.0307	2.6319	530.00	88.39	0.9864	10.62	0.7909	0.4200
BUS4071	400	4071	1	1.0300	1.5066	300.00	54.31	0.9840	25.55	0.3453	0.4952
BUS4072	400	4072	1	1.0185	1.3115	2000.00	193.97	0.9953	20.59	0.1883	0.4000

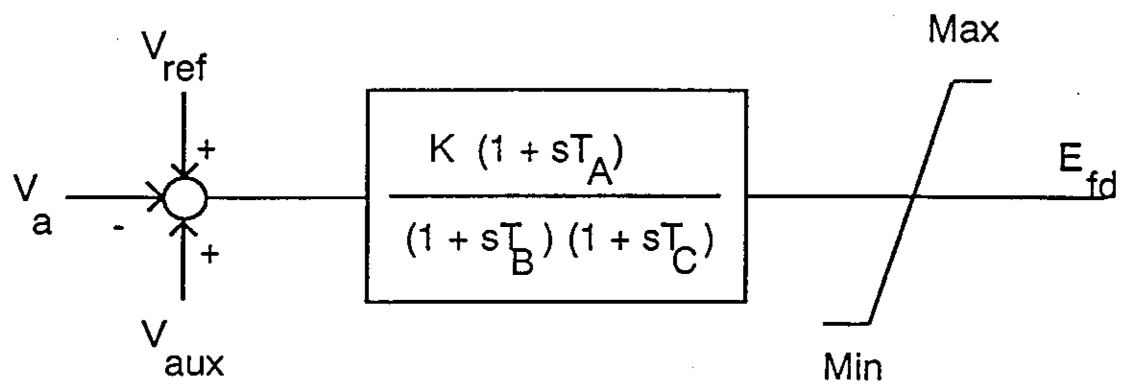
INITIAL CONDITIONS CHECK O.K.

Remarks

The initial value of Ifd (or Efd in steady-state) is above rated values for a few units.
- Salient pole generators: 1022
- Round rotor generators: 1043, 4042

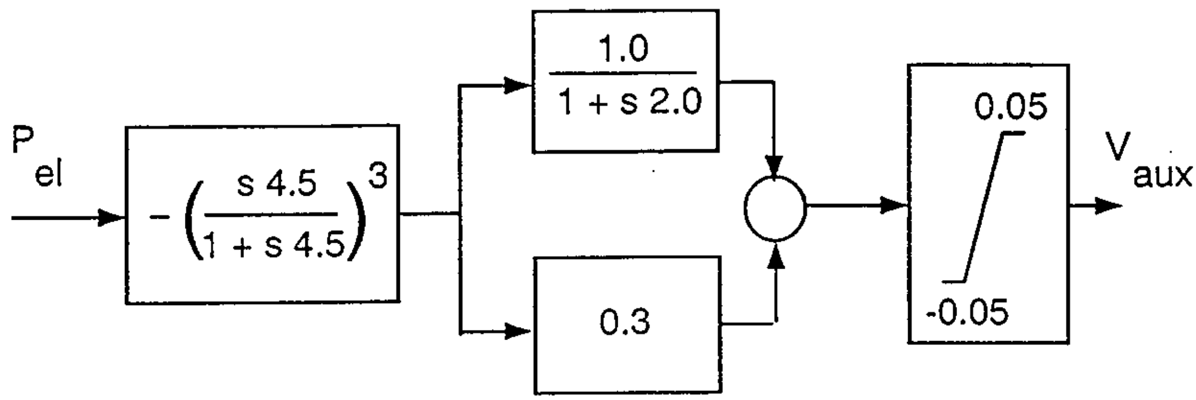
The initial stator current is above rated value for one unit:
- Round rotor generator: 1043

Excitation system



Type of generator	A	B	C
K	120	50	(as B)
T_A/T_B	0.10	0.20	
T_B	50	20	
T_C	0.10	0.10	
Max	5.0	4.0	
Min	0.0	0.0	

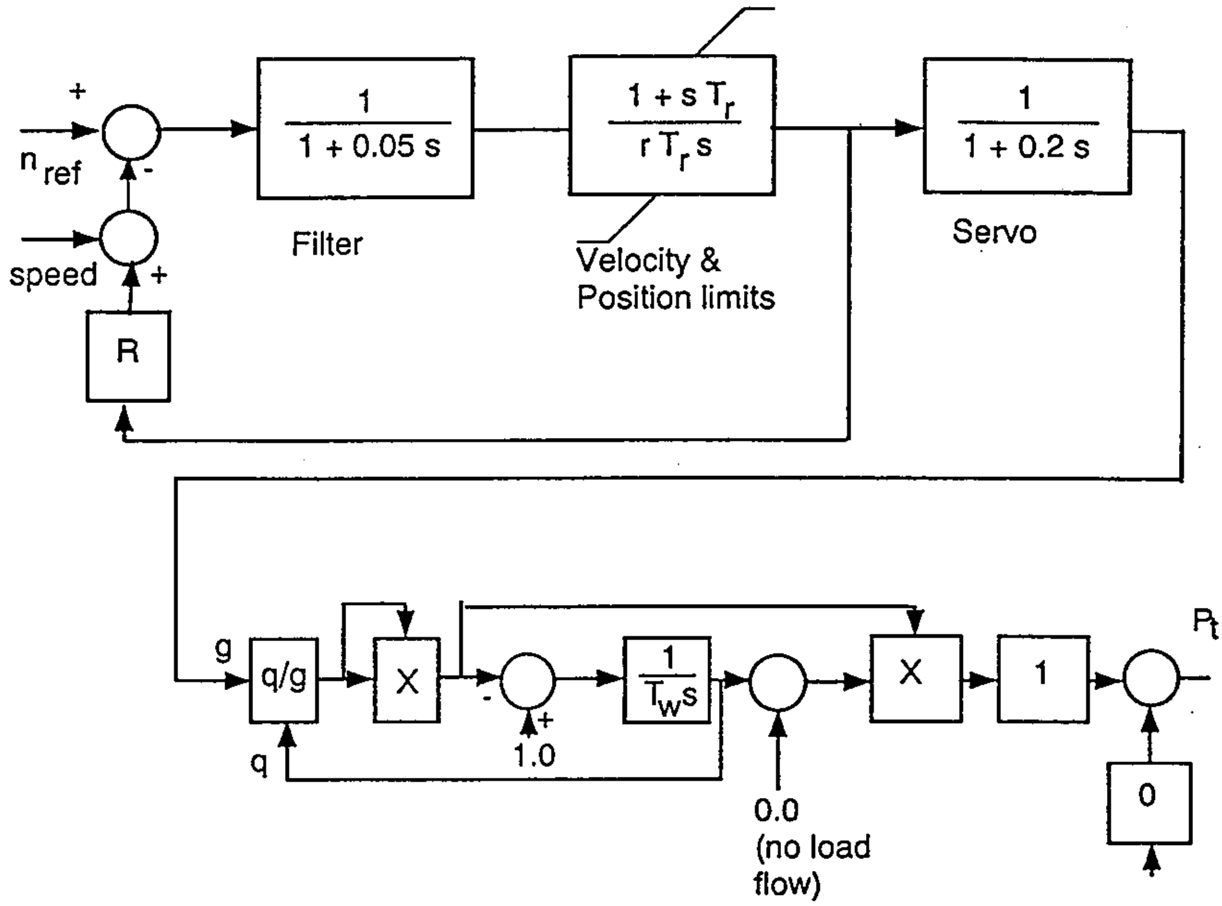
Power system stabilizer (PSS)



All generators are equipped with PSS

Appendix C-4

Hydro governor model - HYGOV (PSS/E-model from PTI)

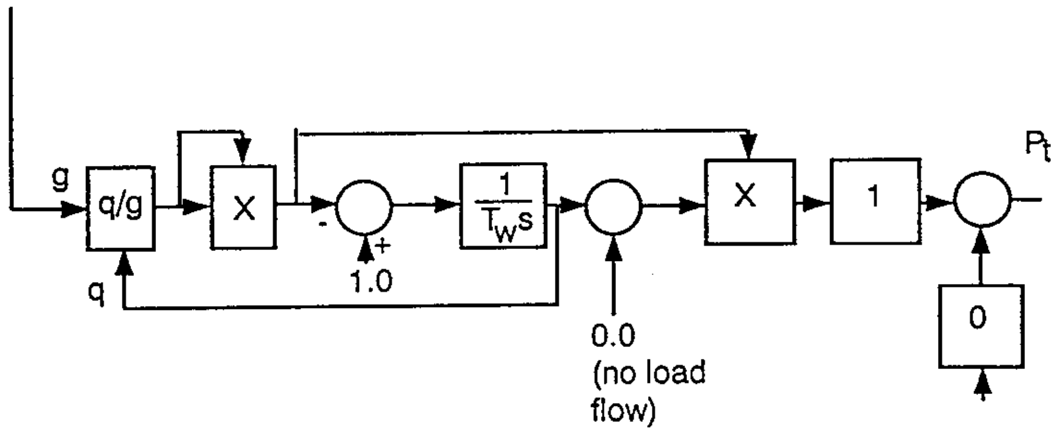


R Permanent droop (pu speed/pu power)	All units use 0.04 except from units at buses 4071 and 4072 which use 0.08. That corresponds to a static gain of 0.5 and 0.25 pu power/Hz respectively
r Temporary droop (pu speed/pu power)	All units use 0.8 except from units at buses 4071 and 4072 which use 1.60 That corresponds to a transient gain of 0.025 and 0.0125 pu power/Hz respectively
Velocity and speed limits	Max velocity 0.1 pu/sec Max position 0.95 pu, min position 0.0 pu
T Governor time constant (second)	All units use 5 seconds
T Water time constant (second)	All units use 1 second

(1 pu power is equivalent to rated power in MVA)

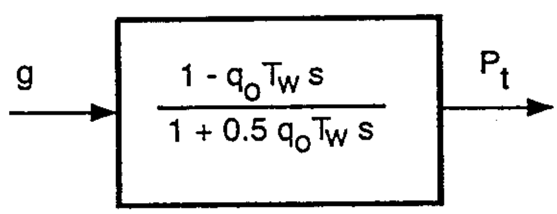
Simplification of Hydro governor model /HYGOV/

The model of water ways is defined as follows



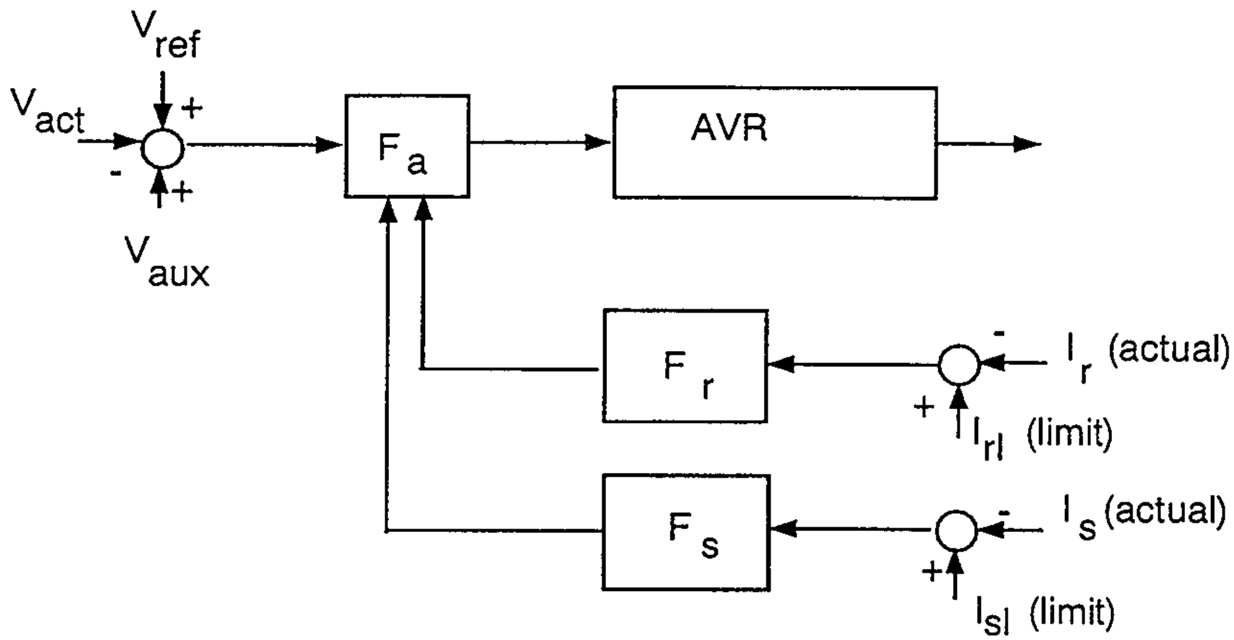
The model may be simplified by linearizing around the operating point $q = q_o = g_o$

The linearized model is specified below. It is valied for minor changes around the operating point (g may vary +- 10 %)



Appendix C-5

Model of stator and current limiters



F_r is the controller of the rotor limiter

F_s is time controller of the stator current limiter

F_a is a logic unit that is common for the rotor and stator limiters

1. The function (F_r) of the rotor current limiter acts as follows:
   Normally the signal to the logic unit (F_a) is a large positive signal.
   Once the actual current is exceeded, the clock starts. After t_{r1} seconds
   the current difference multiplied by K_r is sent to the logic unit.
   That signal is sent even if the current becomes lower than the limit.

   The stator current limiter (F_s) acts in an analogue way.

2. The logic unit (F_a) compares the three signals.
   The signal that gives lowest excitation, i.e. the smallest positive (or largest negative) signal is chosen and is sent further to the AVR.

3. If the limiters have become active as mentioned in point 1 above, the limiters remain active without any time delay for t_{r2} seconds, even if the current is temporarily oscillating below the limit.
   After that time the limiters become inactive as soon as the signal from the limiter does not affect the exciter.

4. When the limiter is active, it may happen that the field current brings the reactive output below zero, i.e. the generator starts to absorb reactive power. In that case the limiter is immediately blocked. (But it turns into action without delay as soon as the reactive power is above zero, i.e. the digital model of the limiter may 'oscillate'.)

Appendix C-5b

Model of stator and current limiters (continued)

All generators are equipped with rotor currents.
The current limits are very high in the basic scenario:
- thermal round rotor generators: about 120 % of rated values
- hydro p. salient pole generators: about 130 % of rated values
(More natural values would have been in the region of 105 - 110 %)

The thermal power generators (type A) are also equipped with stator current limiters. The current limits are set 5 % above rated values.

Rotor current limiters

Parameter			Gen.type A	type B	type C
I	(p u)	current limit	3.74	2.68	3.26
t	(s)	time delay	20.	20.	20.
t	(s)	activation time	120.	120.	120.
K	(p u/p u)	amplification	20.	20.	20.

Stator current limiters

Parameter			
I	(p u)	current limit	1.05
t	(s)	time delay	20.
t	(s)	activation time	120.
K	(p u/p u)	amplification	2.

In addition there are a few other parameters:
- to prevent the limiters to act at low voltage, e.g. a short circuits
- to limit the maximum output from the limiter

These parameters will probly affect the simulations only when the system valtages collapse.

Appendix C-6

Model of transformer tap changers

All 400/130 kV transformers are equipped with tap changers
All of them control the voltage on the 130 kV side.

The impedance, ratio and rating of the transformers are explained in appendix B-4, B-5 and B-6.

A model with constant time delay is chosen.

In order to avoid simultanous changes of the taps the time delays are slightly different. In order to shorten the simulation time the time between subsequent changes have been chosen very small.
If tap changer controls are equipped with constant time delay, one to two minutes would be more realistic. In invert time characteristic is used the time delay would be smaller, 10 seconds as the shortest.

Transformer from	to	no.	Delay for first change of tap (sec)	Time (sec) between subsequent changes
1044	4044	1	40.	7.0
1044	4044	2	40.	7.0
1045	4045	1	40.	8.0
1045	4045	2	40.	8.0
41	4041		40	6.0
42	4042		40	7.9
43	4043		40	6.5
46	4046		40	7.5
47	4047		40	6.1
51	4051		40	7.4
61	4061		40	6.6
62	4062		40	7.1
63	4063		40	6.2

Please note that the delay for the first change of tap is not given in the data list of appendix C-7. It is defined as a part of the contingency data during the simulation.

Listing of PSS/E raw data of dynamic models

Generators

```
4042 'GENROU'  1  7.0 0.05 1.5 0.05 6. 0.  2.20 2.00 0.30 0.40 0.20 0.15 0.1 0.3 /
4047 'GENROU'  1  7.0 0.05 1.5 0.05 6. 0.  2.20 2.00 0.30 0.40 0.20 0.15 0.1 0.3 /
4047 'GENROU'  2  7.0 0.05 1.5 0.05 6. 0.  2.20 2.00 0.30 0.40 0.20 0.15 0.1 0.3 /
4051 'GENROU'  1  7.0 0.05 1.5 0.05 6. 0.  2.20 2.00 0.30 0.40 0.20 0.15 0.1 0.3 /
4062 'GENROU'  1  7.0 0.05 1.5 0.05 6. 0.  2.20 2.00 0.30 0.40 0.20 0.15 0.1 0.3 /
4063 'GENROU'  1  7.0 0.05 1.5 0.05 6. 0.  2.20 2.00 0.30 0.40 0.20 0.15 0.1 0.3 /
4063 'GENROU'  2  7.0 0.05 1.5 0.05 6. 0.  2.20 2.00 0.30 0.40 0.20 0.15 0.1 0.3 /
1042 'GENROU'  1  7.0 0.05 1.5 0.05 6. 0.  2.20 2.00 0.30 0.40 0.20 0.15 0.1 0.3 /
1043 'GENROU'  1  7.0 0.05 1.5 0.05 6. 0.  2.20 2.00 0.30 0.40 0.20 0.15 0.1 0.3 /
4011 'GENSAL'  1  5.0 0.05     0.10 3. 0.  1.10 0.70 0.25      0.20 0.15 0.1 0.3 /
4012 'GENSAL'  1  5.0 0.05     0.10 3. 0.  1.10 0.70 0.25      0.20 0.15 0.1 0.3 /
4021 'GENSAL'  1  5.0 0.05     0.10 3. 0.  1.10 0.70 0.25      0.20 0.15 0.1 0.3 /
4031 'GENSAL'  1  5.0 0.05     0.10 3. 0.  1.10 0.70 0.25      0.20 0.15 0.1 0.3 /
4041 'GENSAL'  1  7.0 0.05     0.10 2. 0.  1.55 1.00 0.30      0.20 0.15 0.1 0.3 /
4071 'GENSAL'  1  5.0 0.05     0.10 3. 0.  1.10 0.70 0.25      0.20 0.15 0.1 0.3 /
4072 'GENSAL'  1  5.0 0.05     0.10 3. 0.  1.10 0.70 0.25      0.20 0.15 0.1 0.3 /
1012 'GENSAL'  1  5.0 0.05     0.10 3. 0.  1.10 0.70 0.25      0.20 0.15 0.1 0.3 /
1013 'GENSAL'  1  5.0 0.05     0.10 3. 0.  1.10 0.70 0.25      0.20 0.15 0.1 0.3 /
1014 'GENSAL'  1  5.0 0.05     0.10 3. 0.  1.10 0.70 0.25      0.20 0.15 0.1 0.3 /
1021 'GENSAL'  1  5.0 0.05     0.10 3. 0.  1.10 0.70 0.25      0.20 0.15 0.1 0.3 /
1022 'GENSAL'  1  5.0 0.05     0.10 3. 0.  1.10 0.70 0.25      0.20 0.15 0.1 0.3 /
2032 'GENSAL'  1  5.0 0.05     0.10 3. 0.  1.10 0.70 0.25      0.20 0.15 0.1 0.3 /
```

Voltage regulators and exciters

```
4011 'SEXS'    1  0.20  20.  50.   0.10  0.0  4.0  /
4012 'SEXS'    1  0.20  20.  50.   0.10  0.0  4.0  /
4021 'SEXS'    1  0.20  20.  50.   0.10  0.0  4.0  /
4031 'SEXS'    1  0.20  20.  50.   0.10  0.0  4.0  /
4041 'SEXS'    1  0.20  20.  50.   0.10  0.0  4.0  /
4071 'SEXS'    1  0.20  20.  50.   0.10  0.0  4.0  /
4072 'SEXS'    1  0.20  20.  50.   0.10  0.0  4.0  /
1012 'SEXS'    1  0.20  20.  50.   0.10  0.0  4.0  /
1013 'SEXS'    1  0.20  20.  50.   0.10  0.0  4.0  /
1014 'SEXS'    1  0.20  20.  50.   0.10  0.0  4.0  /
1021 'SEXS'    1  0.20  20.  50.   0.10  0.0  4.0  /
1022 'SEXS'    1  0.20  20.  50.   0.10  0.0  4.0  /
2032 'SEXS'    1  0.20  20.  50.   0.10  0.0  4.0  /
1042 'SEXS'    1  0.10  50.  120.  0.10  0.0  5.0  /
1043 'SEXS'    1  0.10  50.  120.  0.10  0.0  5.0  /
4042 'SEXS'    1  0.10  50.  120.  0.10  0.0  5.0  /
4047 'SEXS'    1  0.10  50.  120.  0.10  0.0  5.0  /
4047 'SEXS'    2  0.10  50.  120.  0.10  0.0  5.0  /
4051 'SEXS'    1  0.10  50.  120.  0.10  0.0  5.0  /
4062 'SEXS'    1  0.10  50.  120.  0.10  0.0  5.0  /
4063 'SEXS'    1  0.10  50.  120.  0.10  0.0  5.0  /
4063 'SEXS'    2  0.10  50.  120.  0.10  0.0  5.0  /
```

Turbine regulators and water ways

```
4011 'HYGOV'   1  0.04  0.80  5.0  0.05  0.20  0.10  0.95  0.00  1.00  1.00  0. 0. /
4012 'HYGOV'   1  0.04  0.80  5.0  0.05  0.20  0.10  0.95  0.00  1.00  1.00  0. 0. /
4021 'HYGOV'   1  0.04  0.80  5.0  0.05  0.20  0.10  0.95  0.00  1.00  1.00  0. 0. /
4031 'HYGOV'   1  0.04  0.80  5.0  0.05  0.20  0.10  0.95  0.00  1.00  1.00  0. 0. /
```

Appendix C-7

Listing of PSS/E raw data of dynamic models

Generators

4042	'GENROU'	1	7.0	0.05	1.5	0.05	6.	0.	2.20	2.00	0.30	0.40	0.20	0.15	0.1	0.3	/
4047	'GENROU'	1	7.0	0.05	1.5	0.05	6.	0.	2.20	2.00	0.30	0.40	0.20	0.15	0.1	0.3	/
4047	'GENROU'	2	7.0	0.05	1.5	0.05	6.	0.	2.20	2.00	0.30	0.40	0.20	0.15	0.1	0.3	/
4051	'GENROU'	1	7.0	0.05	1.5	0.05	6.	0.	2.20	2.00	0.30	0.40	0.20	0.15	0.1	0.3	/
4062	'GENROU'	1	7.0	0.05	1.5	0.05	6.	0.	2.20	2.00	0.30	0.40	0.20	0.15	0.1	0.3	/
4063	'GENROU'	1	7.0	0.05	1.5	0.05	6.	0.	2.20	2.00	0.30	0.40	0.20	0.15	0.1	0.3	/
4063	'GENROU'	2	7.0	0.05	1.5	0.05	6.	0.	2.20	2.00	0.30	0.40	0.20	0.15	0.1	0.3	/
1042	'GENROU'	1	7.0	0.05	1.5	0.05	6.	0.	2.20	2.00	0.30	0.40	0.20	0.15	0.1	0.3	/
1043	'GENROU'	1	7.0	0.05	1.5	0.05	6.	0.	2.20	2.00	0.30	0.40	0.20	0.15	0.1	0.3	/
4011	'GENSAL'	1	5.0	0.05		0.10	3.	0.	1.10	0.70	0.25		0.20	0.15	0.1	0.3	/
4012	'GENSAL'	1	5.0	0.05		0.10	3.	0.	1.10	0.70	0.25		0.20	0.15	0.1	0.3	/
4021	'GENSAL'	1	5.0	0.05		0.10	3.	0.	1.10	0.70	0.25		0.20	0.15	0.1	0.3	/
4031	'GENSAL'	1	5.0	0.05		0.10	3.	0.	1.10	0.70	0.25		0.20	0.15	0.1	0.3	/
4041	'GENSAL'	1	7.0	0.05		0.10	2.	0.	1.55	1.00	0.30		0.20	0.15	0.1	0.3	/
4071	'GENSAL'	1	5.0	0.05		0.10	3.	0.	1.10	0.70	0.25		0.20	0.15	0.1	0.3	/
4072	'GENSAL'	1	5.0	0.05		0.10	3.	0.	1.10	0.70	0.25		0.20	0.15	0.1	0.3	/
1012	'GENSAL'	1	5.0	0.05		0.10	3.	0.	1.10	0.70	0.25		0.20	0.15	0.1	0.3	/
1013	'GENSAL'	1	5.0	0.05		0.10	3.	0.	1.10	0.70	0.25		0.20	0.15	0.1	0.3	/
1014	'GENSAL'	1	5.0	0.05		0.10	3.	0.	1.10	0.70	0.25		0.20	0.15	0.1	0.3	/
1021	'GENSAL'	1	5.0	0.05		0.10	3.	0.	1.10	0.70	0.25		0.20	0.15	0.1	0.3	/
1022	'GENSAL'	1	5.0	0.05		0.10	3.	0.	1.10	0.70	0.25		0.20	0.15	0.1	0.3	/
2032	'GENSAL'	1	5.0	0.05		0.10	3.	0.	1.10	0.70	0.25		0.20	0.15	0.1	0.3	/

Voltage regulators and exciters

4011	'SEXS'	1	0.20	20.	50.	0.10	0.0	4.0	/
4012	'SEXS'	1	0.20	20.	50.	0.10	0.0	4.0	/
4021	'SEXS'	1	0.20	20.	50.	0.10	0.0	4.0	/
4031	'SEXS'	1	0.20	20.	50.	0.10	0.0	4.0	/
4041	'SEXS'	1	0.20	20.	50.	0.10	0.0	4.0	/
4071	'SEXS'	1	0.20	20.	50.	0.10	0.0	4.0	/
4072	'SEXS'	1	0.20	20.	50.	0.10	0.0	4.0	/
1012	'SEXS'	1	0.20	20.	50.	0.10	0.0	4.0	/
1013	'SEXS'	1	0.20	20.	50.	0.10	0.0	4.0	/
1014	'SEXS'	1	0.20	20.	50.	0.10	0.0	4.0	/
1021	'SEXS'	1	0.20	20.	50.	0.10	0.0	4.0	/
1022	'SEXS'	1	0.20	20.	50.	0.10	0.0	4.0	/
2032	'SEXS'	1	0.20	20.	50.	0.10	0.0	4.0	/
1042	'SEXS'	1	0.10	50.	120.	0.10	0.0	5.0	/
1043	'SEXS'	1	0.10	50.	120.	0.10	0.0	5.0	/
4042	'SEXS'	1	0.10	50.	120.	0.10	0.0	5.0	/
4047	'SEXS'	1	0.10	50.	120.	0.10	0.0	5.0	/
4047	'SEXS'	2	0.10	50.	120.	0.10	0.0	5.0	/
4051	'SEXS'	1	0.10	50.	120.	0.10	0.0	5.0	/
4062	'SEXS'	1	0.10	50.	120.	0.10	0.0	5.0	/
4063	'SEXS'	1	0.10	50.	120.	0.10	0.0	5.0	/
4063	'SEXS'	2	0.10	50.	120.	0.10	0.0	5.0	/

Turbine regulators and water ways

4011	'HYGOV'	1	0.04	0.80	5.0	0.05	0.20	0.10	0.95	0.00	1.00	1.00	0.	0.	/
4012	'HYGOV'	1	0.04	0.80	5.0	0.05	0.20	0.10	0.95	0.00	1.00	1.00	0.	0.	/
4021	'HYGOV'	1	0.04	0.80	5.0	0.05	0.20	0.10	0.95	0.00	1.00	1.00	0.	0.	/
4031	'HYGOV'	1	0.04	0.80	5.0	0.05	0.20	0.10	0.95	0.00	1.00	1.00	0.	0.	/

```
4071 'HYGOV'   1  0.08  1.60  5.0  0.05  0.20  0.10  0.95  0.00  1.00  1.00  0. 0. /
4072 'HYGOV'   1  0.08  1.60  5.0  0.05  0.20  0.10  0.95  0.00  1.00  1.00  0. 0. /
1012 'HYGOV'   1  0.04  0.80  5.0  0.05  0.20  0.10  0.95  0.00  1.00  1.00  0. 0. /
1013 'HYGOV'   1  0.04  0.80  5.0  0.05  0.20  0.10  0.95  0.00  1.00  1.00  0. 0. /
1014 'HYGOV'   1  0.04  0.80  5.0  0.05  0.20  0.10  0.95  0.00  1.00  1.00  0. 0. /
1021 'HYGOV'   1  0.04  0.80  5.0  0.05  0.20  0.10  0.95  0.00  1.00  1.00  0. 0. /
1022 'HYGOV'   1  0.04  0.80  5.0  0.05  0.20  0.10  0.95  0.00  1.00  1.00  0. 0. /
2032 'HYGOV'   1  0.04  0.80  5.0  0.05  0.20  0.10  0.95  0.00  1.00  1.00  0. 0. /
```

Power system stabilizers

```
4011 'STAB2A'   1  1.0  4.0  1.  2.0  0.3  1.  0.05  0.05 /
4012 'STAB2A'   1  1.0  4.0  1.  2.0  0.3  1.  0.05  0.05 /
4021 'STAB2A'   1  1.0  4.0  1.  2.0  0.3  1.  0.05  0.05 /
4031 'STAB2A'   1  1.0  4.0  1.  2.0  0.3  1.  0.05  0.05 /
4041 'STAB2A'   1  1.0  4.0  0.  2.0  0.0  1.  0.05  0.05 / (note: gain is 0)
4071 'STAB2A'   1  1.0  4.0  1.  2.0  0.3  1.  0.05  0.05 /
4072 'STAB2A'   1  1.0  4.0  1.  2.0  0.3  1.  0.05  0.05 /
1012 'STAB2A'   1  1.0  4.0  1.  2.0  0.3  1.  0.05  0.05 /
1013 'STAB2A'   1  1.0  4.0  1.  2.0  0.3  1.  0.05  0.05 /
1014 'STAB2A'   1  1.0  4.0  1.  2.0  0.3  1.  0.05  0.05 /
1021 'STAB2A'   1  1.0  4.0  1.  2.0  0.3  1.  0.05  0.05 /
1022 'STAB2A'   1  1.0  4.0  1.  2.0  0.3  1.  0.05  0.05 /
2032 'STAB2A'   1  1.0  4.0  1.  2.0  0.3  1.  0.05  0.05 /
4062 'STAB2A'   1  1.0  4.0  1.  2.0  0.3  1.  0.05  0.05 /
4063 'STAB2A'   1  1.0  4.0  1.  2.0  0.3  1.  0.05  0.05 /
4063 'STAB2A'   2  1.0  4.0  1.  2.0  0.3  1.  0.05  0.05 /
4051 'STAB2A'   1  1.0  4.0  1.  2.0  0.3  1.  0.05  0.05 /
4047 'STAB2A'   1  1.0  4.0  1.  2.0  0.3  1.  0.05  0.05 /
4047 'STAB2A'   2  1.0  4.0  1.  2.0  0.3  1.  0.05  0.05 /
4042 'STAB2A'   1  1.0  4.0  1.  2.0  0.3  1.  0.05  0.05 /
1042 'STAB2A'   1  1.0  4.0  1.  2.0  0.3  1.  0.05  0.05 /
1043 'STAB2A'   1  1.0  4.0  1.  2.0  0.3  1.  0.05  0.05 /
```

Current limiters

Both rotor and stator current limiters may be active

```
4042 'USRMDL' 1 'CEFDL2' 10 0 0 14 0 11 0.6 1.05 2.0 6.0 10. 20. 120.
                                              0.3 3.74 20. 6. 10. 20. 120. /
4047 'USRMDL' 1 'CEFDL2' 10 0 0 14 0 11 0.6 1.05 2.0 6.0 10. 20. 120. 0.3 3.74 20. 6. 10
4047 'USRMDL' 2 'CEFDL2' 10 0 0 14 0 11 0.6 1.05 2.0 6.0 10. 20. 120. 0.3 3.74 20. 6. 10
4051 'USRMDL' 1 'CEFDL2' 10 0 0 14 0 11 0.6 1.05 2.0 6.0 10. 20. 120. 0.3 3.74 20. 6. 10
4062 'USRMDL' 1 'CEFDL2' 10 0 0 14 0 11 0.6 1.05 2.0 6.0 10. 20. 120. 0.3 3.74 20. 6. 10
4063 'USRMDL' 1 'CEFDL2' 10 0 0 14 0 11 0.6 1.05 2.0 6.0 10. 20. 120. 0.3 3.74 20. 6. 10
4063 'USRMDL' 2 'CEFDL2' 10 0 0 14 0 11 0.6 1.05 2.0 6.0 10. 20. 120. 0.3 3.74 20. 6. 10
1042 'USRMDL' 1 'CEFDL2' 10 0 0 14 0 11 0.6 1.05 2.0 6.0 10. 20. 120. 0.3 3.74 20. 6. 10
1043 'USRMDL' 1 'CEFDL2' 10 0 0 14 0 11 0.6 1.05 2.0 6.0 10. 20. 120. 0.3 3.74 20. 6. 10
```

Stator current limiters will remain inactive

```
4011 'USRMDL' 1 'CEFDL2' 10 0 0 14 0 11 0.6 105  1.0 6.0 10. 20. 120.
                                              0.3 2.68 20. 6. 10. 20. 120. /
4012 'USRMDL' 1 'CEFDL2' 10 0 0 14 0 11 0.6 105  1.0 6.0 10. 20. 120. 0.3 2.68 20. 6. 10
4021 'USRMDL' 2 'CEFDL2' 10 0 0 14 0 11 0.6 105  1.0 6.0 10. 20. 120. 0.3 2.68 20. 6. 10
4031 'USRMDL' 1 'CEFDL2' 10 0 0 14 0 11 0.6 105  1.0 6.0 10. 20. 120. 0.3 2.68 20. 6. 10
4041 'USRMDL' 1 'CEFDL2' 10 0 0 14 0 11 0.6 105  1.0 6.0 10. 20. 120. 0.3 3.26 20. 6. 10
4071 'USRMDL' 1 'CEFDL2' 10 0 0 14 0 11 0.6 105  1.0 6.0 10. 20. 120. 0.3 2.68 20. 6. 10
4072 'USRMDL' 1 'CEFDL2' 10 0 0 14 0 11 0.6 105  1.0 6.0 10. 20. 120. 0.3 2.68 20. 6. 10
1012 'USRMDL' 1 'CEFDL2' 10 0 0 14 0 11 0.6 105  1.0 6.0 10. 20. 120. 0.3 2.68 20. 6. 10
1013 'USRMDL' 1 'CEFDL2' 10 0 0 14 0 11 0.6 105  1.0 6.0 10. 20. 120. 0.3 2.68 20. 6. 10
1014 'USRMDL' 1 'CEFDL2' 10 0 0 14 0 11 0.6 105  1.0 6.0 10. 20. 120. 0.3 2.68 20. 6. 10
1021 'USRMDL' 1 'CEFDL2' 10 0 0 14 0 11 0.6 105  1.0 6.0 10. 20. 120. 0.3 2.68 20. 6. 10
```

```
1022 'USRMDL' 1 'CEFDL2' 10 0 0 14 0 11 0.6 105  1.0 6.0 10. 20. 120. 0.3 2.68 20. 6. 10
2032 'USRMDL' 1 'CEFDL2' 10 0 0 14 0 11 0.6 105  1.0 6.0 10. 20. 120. 0.3 2.68 20. 6. 10
```

Tap changers

```
0 'USRMDL' 0 'TAPCHG' 0 2 3 2 0 1  1044  4044 1  7.0  1 / BUS1044  130 BUS4044  400 1
0 'USRMDL' 0 'TAPCHG' 0 2 3 2 0 1  1044  4044 2  7.0  1 / BUS1044  130 BUS4044  400 2
0 'USRMDL' 0 'TAPCHG' 0 2 3 2 0 1  1045  4045 1  8.0  1 / BUS1045  130 BUS4045  400 1
0 'USRMDL' 0 'TAPCHG' 0 2 3 2 0 1  1045  4045 2  8.0  1 / BUS1045  130 BUS4045  400 2
0 'USRMDL' 0 'TAPCHG' 0 2 3 2 0 1    41  4041 1  8.0  1 / BUS41    400 BUS4041  130 1
0 'USRMDL' 0 'TAPCHG' 0 2 3 2 0 1    42  4042 1  7.9  1 / BUS42    400 BUS4042  130 1
0 'USRMDL' 0 'TAPCHG' 0 2 3 2 0 1    43  4043 1  6.5  1 / BUS43    400 BUS4043  130 1
0 'USRMDL' 0 'TAPCHG' 0 2 3 2 0 1    46  4046 1  7.5  1 / BUS46    400 BUS4046  130 1
0 'USRMDL' 0 'TAPCHG' 0 2 3 2 0 1    47  4047 1  6.1  1 / BUS47    400 BUS4047  130 1
0 'USRMDL' 0 'TAPCHG' 0 2 3 2 0 1    51  4051 1  7.4  1 / BUS51    400 BUS4051  130 1
0 'USRMDL' 0 'TAPCHG' 0 2 3 2 0 1    61  4061 1  6.6  1 / BUS61    400 BUS4061  130 1
0 'USRMDL' 0 'TAPCHG' 0 2 3 2 0 1    62  4062 1  7.1  1 / BUS62    400 BUS4062  130 1
0 'USRMDL' 0 'TAPCHG' 0 2 3 2 0 1    63  4063 1  6.2  1 / BUS63    400 BUS4063  130 1
0 'USRMDL' 0 'FAKTOR' 0 2 0 1 0 1  70.0 /

0 'USRMDL' 0 'STOPG2' 8 0 0 1 0 0 200 /
```

Model that defines frequency characteristic of (active) loads

```
1    'LOADFA'   0.75 0.0 0.75 0.0 /
2    'LOADFA'   0.75 0.0 0.75 0.0 /     stab.data test system 32 nodes
3    'LOADFA'   0.75 0.0 0.75 0.0 /     ds32_032.raw      1993-02-08
4    'LOADFA'   0.75 0.0 0.75 0.0 /
5    'LOADFA'   0.75 0.0 0.75 0.0 /
6    'LOADFA'   0.75 0.0 0.75 0.0 /
7    'LOADFA'   0.75 0.0 0.75 0.0 /

0    'TOTA'   /
1    'TOTA'   /
4    'TOTA'   /
0    'NETFRQ' /
4031 'RELANG' 1 /
```

In case lf32_020 is run, the following dynamic data is required. It defines a new generator no 2 at bus 4051 (It is identical to generator 4051 no 1)

Generator

```
4051 'GENROU'  1  7.0 0.05 1.5 0.05 6. 0.  2.20 2.00 0.30 0.40 0.20 0.15 0.1 0.3 /
```

Voltage regulators and exciters

```
4051 'SEXS'    1  0.10  50.  120.  0.10  0.0  5.0  /
```

Power system stabilizers

```
4051 'STAB2A'   1  1.0  4.0  1.  2.0  0.3  1.  0.05  0.05 /
```

Current limiters

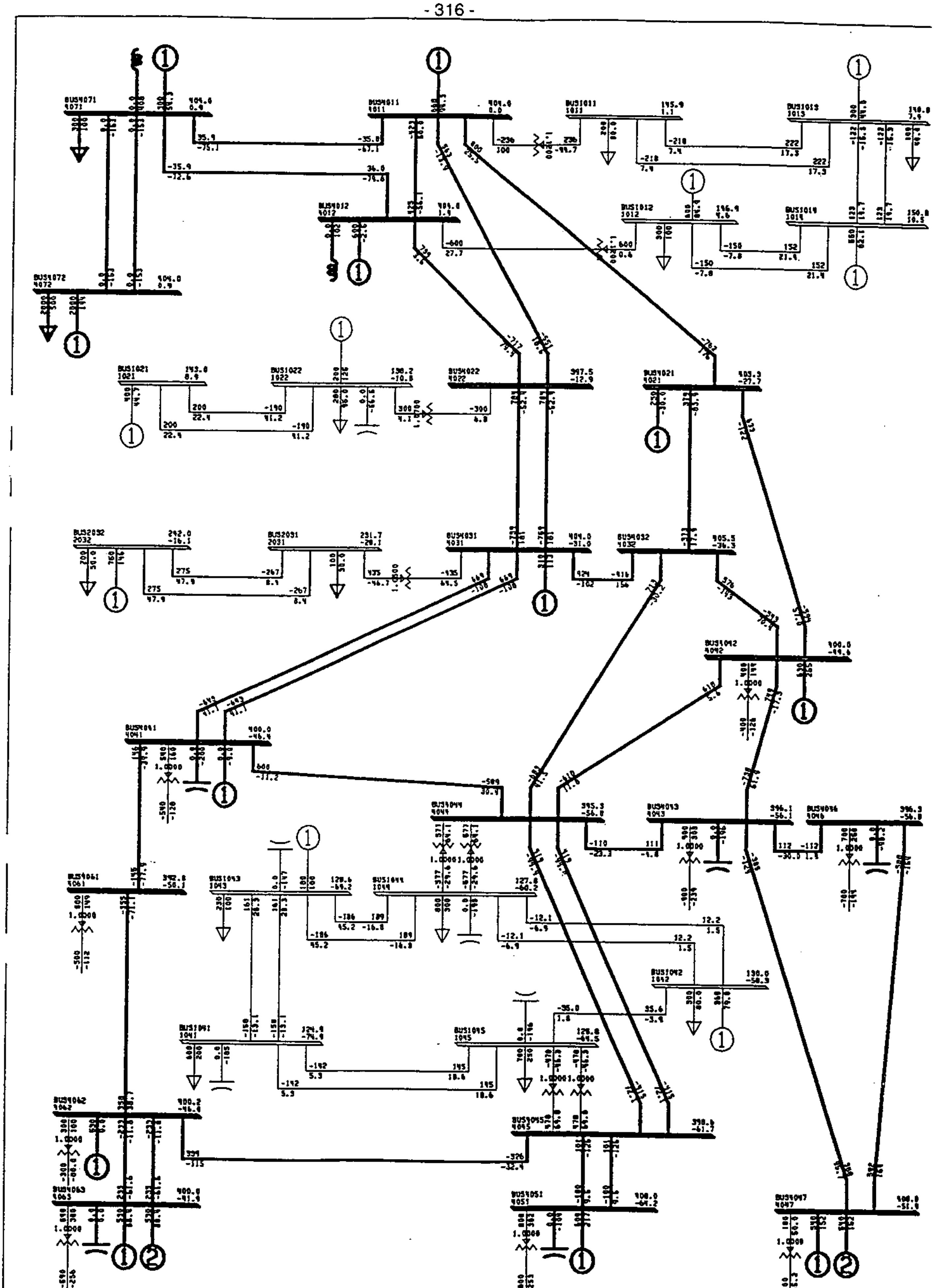
```
4051 'USRMDL' 1 'CEFDL2' 10 0 0 14 0 11 0.6 1.05 2.0 6.0 10. 20. 120.
                                                    0.3 3.74 20. 6.  10. 20. 120. /
```

Load flows

D-1 Basic load flow LF32_028 (=LF32_018 [1])) with high transfers

D-2 Load flow LF32_029 (=LF32_020 [1])) with moderate transfers

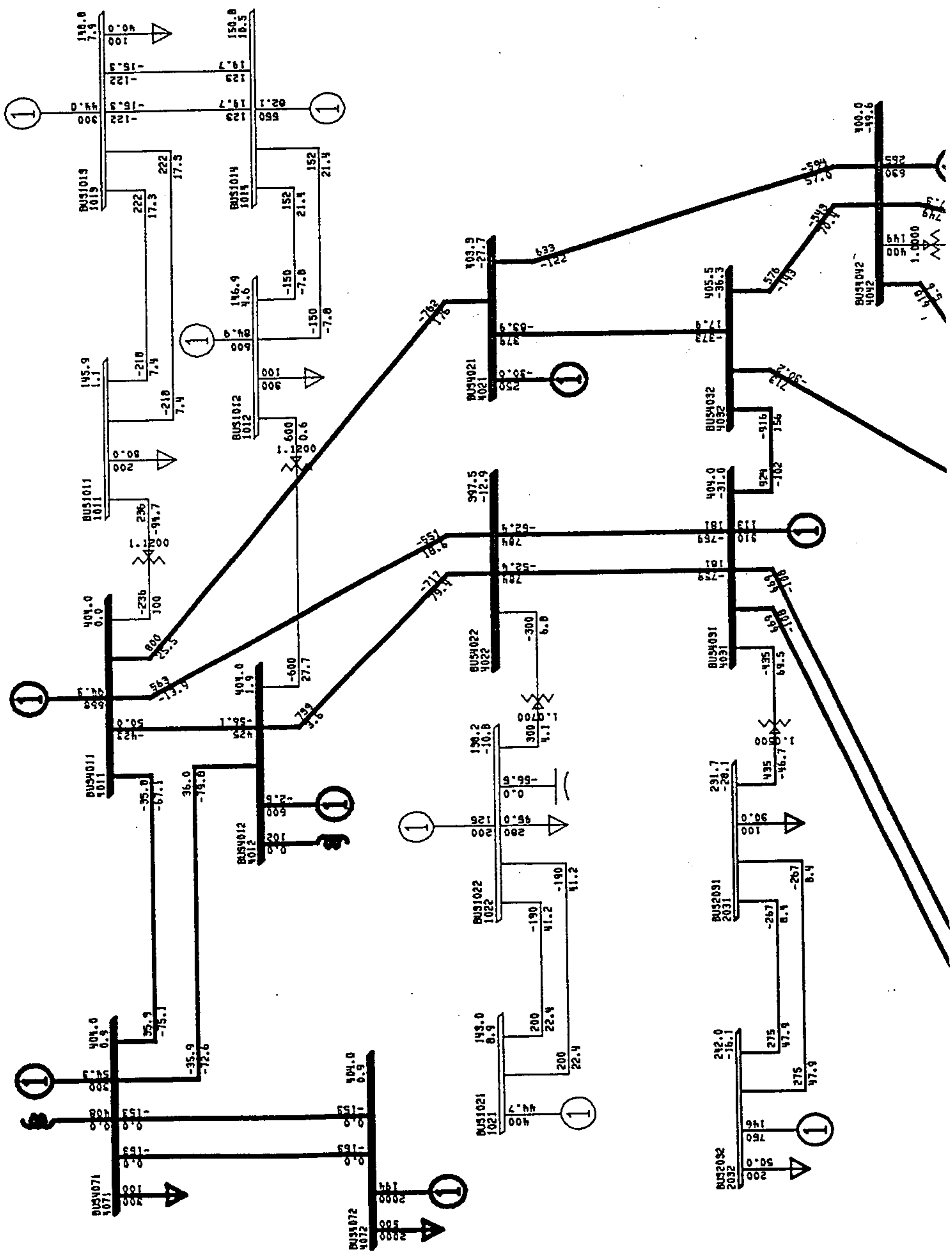
[1]) The load flows 018 and 020 are equivalent with 028 and 029 respectively, except from some tap changer definition of the transformers.

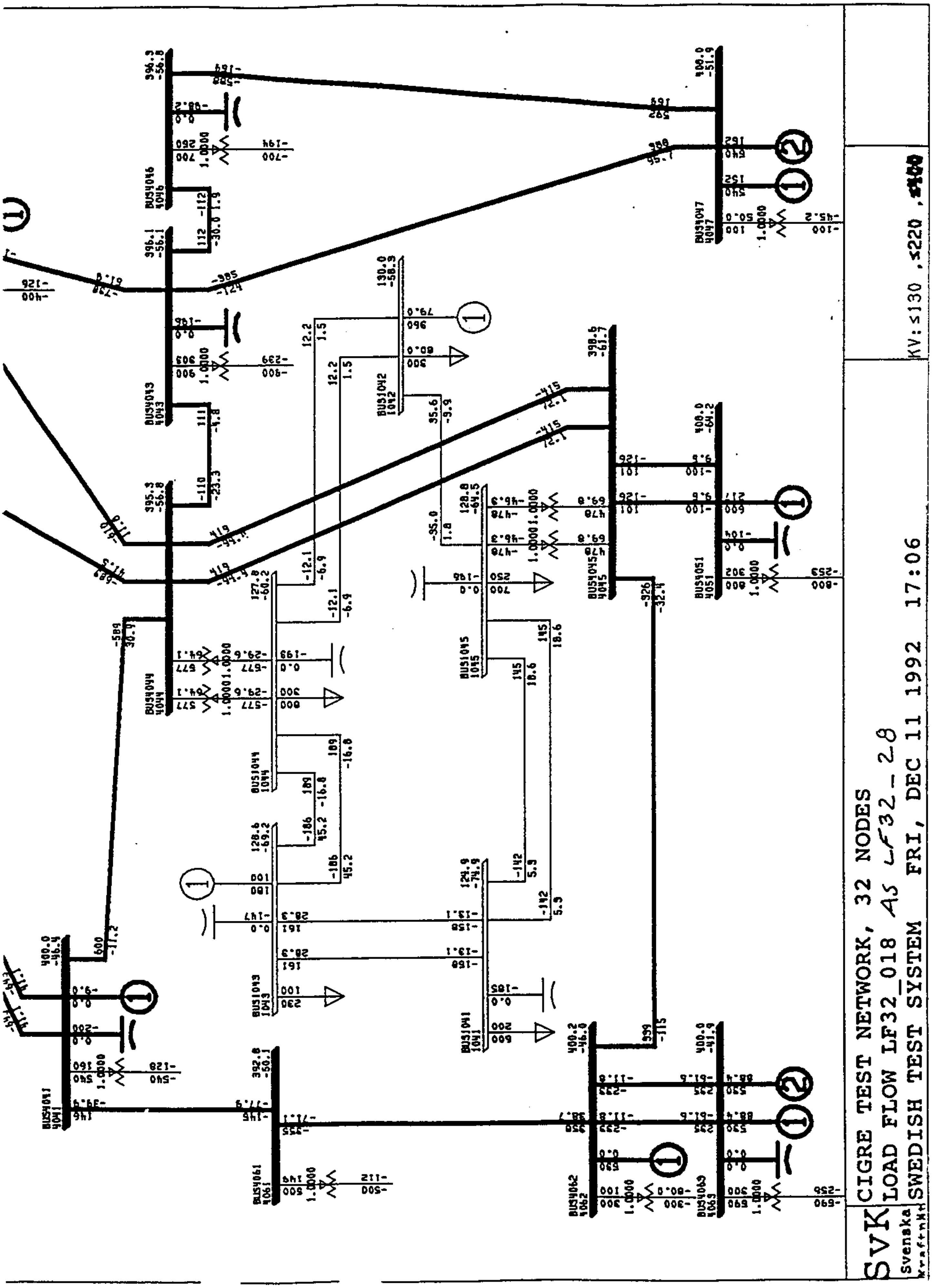


SvK Svenska Kraftnät

CIGRE TEST NETWORK, 32 NODES
LOAD FLOW LF32_018 AS LF32_28
SWEDISH TEST SYSTEM FRI, DEC 11 1992 17:06

KV:≤130 .≤220 .≤400


BUS1013
1013
BUS1014
1014
BUS1012
1012
BUS1011
1011
BUS4011
4011
BUS4012
4012
BUS4021
4021
BUS4022
4022
BUS4032
4032
BUS4031
4031
BUS4042
4042
BUS1022
1022
BUS1021
1021
BUS2031
2031
BUS2032
2032
BUS4071
4071
BUS4072
4072



BUS4046 4046
BUS4043 4043
BUS4044 4044
BUS4041 4041
BUS4061 4061
BUS4062 4062
BUS4063 4063
BUS4045 4045
BUS4051 4051
BUS4047 4047
BUS1042 1042
BUS1044 1044
BUS1043 1043
BUS1045 1045
BUS1041 1041
SvK
Svenska Kraftnät
CIGRE TEST NETWORK, 32 NODES
LOAD FLOW LF32_018 AS LF32_28
SWEDISH TEST SYSTEM FRI, DEC 11 1992 17:06
KV: ≤130 ,≤220 ,

Appendix D-1

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E THU, FEB 17 1994 13:55
CIGRE TEST NETWORK, NORDIC32A, 32 NODES RATING
LOAD FLOW LF32_028 (TAPS MODIF.) SET A

BUS BUS1011	130	1011	AREA	CKT	MW	MVAR	MVA	%I	1.1225PU	1.07	X-AREA-X	X---ZONE---X
			1						145.93KV			1
TO LOAD-PQ					200.0	80.0	215.4					
TO BUS1013	130	1013	1	1	-218.0	7.4	218.1					1
TO BUS1013	130	1013	1	2	-218.0	7.4	218.1					1
TO BUS4011	400	4011	1	1	235.9	-94.7	254.2		1.1200LK			1
BUS BUS1012	130	1012	AREA	CKT	MW	MVAR	MVA	%I	1.1300PU	4.64	X-AREA-X	X---ZONE---X
GENERATION			1		600.0	84.9R	606.0	76	146.90KV			1
TO LOAD-PQ					300.0	100.0	316.2					
TO BUS1014	130	1014	1	1	-150.0	-7.8	150.2					1
TO BUS1014	130	1014	1	2	-150.0	-7.8	150.2					1
TO BUS4012	400	4012	1	1	600.0	0.6	600.0		1.1200LK			1
BUS BUS1013	130	1013	AREA	CKT	MW	MVAR	MVA	%I	1.1450PU	7.92	X-AREA-X	X---ZONE---X
GENERATION			1		300.0	44.0R	303.2	51	148.85KV			1
TO LOAD-PQ					100.0	40.0	107.7					
TO BUS1011	130	1011	1	1	221.7	17.3	222.4					1
TO BUS1011	130	1011	1	2	221.7	17.3	222.4					1
TO BUS1014	130	1014	1	1	-121.7	-15.3	122.7					1
TO BUS1014	130	1014	1	2	-121.7	-15.3	122.7					1
BUS BUS1014	130	1014	AREA	CKT	MW	MVAR	MVA	%I	1.1600PU	10.51	X-AREA-X	X---ZONE---X
GENERATION			1		550.0	82.1R	556.1	79	150.80KV			1
TO BUS1012	130	1012	1	1	152.5	21.4	153.9					1
TO BUS1012	130	1012	1	2	152.5	21.4	153.9					1
TO BUS1013	130	1013	1	1	122.5	19.7	124.1					1
TO BUS1013	130	1013	1	2	122.5	19.7	124.1					1
BUS BUS1021	130	1021	AREA	CKT	MW	MVAR	MVA	%I	1.1000PU	8.85	X-AREA-X	X---ZONE---X
GENERATION			2		400.0	44.7R	402.5	67	143.00KV			1
TO BUS1022	130	1022	2	1	200.0	22.4	201.2					1
TO BUS1022	130	1022	2	2	200.0	22.4	201.2					1
BUS BUS1022	130	1022	AREA	CKT	MW	MVAR	MVA	%I	1.0633PU	-10.77	X-AREA-X	X---ZONE---X
GENERATION			2		200.0	125.0H	235.8	94	138.22KV			1
TO LOAD-PQ					280.0	95.0	295.7					
TO SHUNT					0.0	-56.5	56.5					
TO BUS1021	130	1021	2	1	-189.9	41.2	194.4					1
TO BUS1021	130	1021	2	2	-189.9	41.2	194.4					1
TO BUS4022	400	4022	2	1	299.9	4.1	299.9		1.0700LK			1
BUS BUS1041	130	1041	AREA	CKT	MW	MVAR	MVA	%I	0.9605PU	-74.89	X-AREA-X	X---ZONE---X
			4						124.86KV			1
TO LOAD-PQ					600.0	200.0	632.5					
TO SHUNT					0.0	-184.5	184.5					
TO BUS1043	130	1043	4	1	-158.0	-13.1	158.5					1
TO BUS1043	130	1043	4	2	-158.0	-13.1	158.5					1
TO BUS1045	130	1045	4	1	-142.0	5.3	142.1					1
TO BUS1045	130	1045	4	2	-142.0	5.3	142.1					1
BUS BUS1042	130	1042	AREA	CKT	MW	MVAR	MVA	%I	1.0000PU	-58.30	X-AREA-X	X---ZONE---X
GENERATION			4		360.0	79.0R	368.6	92	130.00KV			1
TO LOAD-PQ					300.0	80.0	310.5					
TO BUS1044	130	1044	4	1	12.2	1.5	12.3					1
TO BUS1044	130	1044	4	2	12.2	1.5	12.3					1
TO BUS1045	130	1045	4	1	35.6	-3.9	35.8					1

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CIGRE TEST NETWORK, NORDIC32A, 32 NODES                                 RATING
LOAD FLOW LF32_028 (TAPS MODIF.)                                         SET A

BUS BUS1043  130   1043 AREA CKT     MW      MVAR      MVA  %I 0.9896PU -69.25    X-AREA-X X---ZONE---X
 GENERATION                4       180.0   100.0H  205.9 103 128.64KV                         1
 TO LOAD-PQ                        230.0   100.0   250.8
 TO SHUNT                            0.0  -146.9   146.9
 TO BUS1041  130   1041    4  1    160.7    28.3   163.2                                      1
 TO BUS1041  130   1041    4  2    160.7    28.3   163.2                                      1
 TO BUS1044  130   1044    4  1   -185.7    45.2   191.1                                      1
 TO BUS1044  130   1044    4  2   -185.7    45.2   191.1                                      1

BUS BUS1044  130   1044 AREA CKT     MW      MVAR      MVA  %I 0.9834PU -60.19    X-AREA-X X---ZONE---X
                           4                                  127.85KV                         1
 TO LOAD-PQ                        800.0   300.0   854.4
 TO SHUNT                            0.0  -193.4   193.4
 TO BUS1042  130   1042    4  1    -12.1    -6.9    13.9                                      1
 TO BUS1042  130   1042    4  2    -12.1    -6.9    13.9                                      1
 TO BUS1043  130   1043    4  1    189.4   -16.8   190.2                                      1
 TO BUS1043  130   1043    4  2    189.4   -16.8   190.2                                      1
 TO BUS4044  400   4044    8  1   -577.3   -29.6   578.1      1.0000LK                         1
 TO BUS4044  400   4044    8  2   -577.3   -29.6   578.1      1.0000LK                         1

BUS BUS1045  130   1045 AREA CKT     MW      MVAR      MVA  %I 0.9908PU -64.52    X-AREA-X X---ZONE---X
                           4                                  128.80KV                         1
 TO LOAD-PQ                        700.0   250.0   743.3
 TO SHUNT                            0.0  -196.3   196.3
 TO BUS1041  130   1041    4  1    145.3    18.6   146.5                                      1
 TO BUS1041  130   1041    4  2    145.3    18.6   146.5                                      1
 TO BUS1042  130   1042    4  1    -35.0     1.8    35.0                                      1
 TO BUS4045  400   4045    5  1   -477.8   -46.3   480.1      1.0000LK                         1
 TO BUS4045  400   4045    5  2   -477.8   -46.3   480.1      1.0000LK                         1

BUS BUS2031  220   2031 AREA CKT     MW      MVAR      MVA  %I 1.0532PU -28.09    X-AREA-X X---ZONE---X
                           3                                  231.71KV                         1
 TO LOAD-PQ                        100.0    30.0   104.4
 TO BUS2032  220   2032    3  1   -267.3     8.4   267.4                                      1
 TO BUS2032  220   2032    3  2   -267.3     8.4   267.4                                      1
 TO BUS4031  400   4031    3  1    434.5   -46.7   437.0      1.0500LK                         1

BUS BUS2032  220   2032 AREA CKT     MW      MVAR      MVA  %I 1.1000PU -16.05    X-AREA-X X---ZONE---X
 GENERATION                3       750.0   145.8R  764.0  90 242.00KV                         1
 TO LOAD-PQ                        200.0    50.0   206.2
 TO BUS2031  220   2031    3  1    275.0    47.9   279.1                                      1
 TO BUS2031  220   2031    3  2    275.0    47.9   279.1                                      1

BUS BUS4011  400   4011 AREA CKT     MW      MVAR      MVA  %I 1.0100PU    0.00   X-AREA-X X---ZONE---X
 GENERATION                1       668.5    94.3R  675.1  68 404.00KV                         1
 TO BUS1011  130   1011    1  1   -235.9    99.9   256.2      1.1200UN                         1
 TO BUS4012  400   4012    1  1   -423.4    50.0   426.3                                      1
 TO BUS4021  400   4021    2  1    800.5    25.5   800.9                                      1
 TO BUS4022  400   4022    2  1    563.1   -13.9   563.3                                      1
 TO BUS4071  400   4071    7  1    -35.8   -67.1    76.1                                      1

BUS BUS4012  400   4012 AREA CKT     MW      MVAR      MVA  %I 1.0100PU    1.94   X-AREA-X X---ZONE---X
 GENERATION                1       600.0    -2.5R  600.0  75 404.00KV                         1
 TO SHUNT                            0.0   102.0   102.0
 TO BUS1012  130   1012    1  1   -600.0    27.7   600.6      1.1200UN                         1
 TO BUS4011  400   4011    1  1    425.2   -56.1   428.9                                      1
 TO BUS4022  400   4022    2  1    738.8     3.6   738.8                                      1
 TO BUS4071  400   4071    7  1     36.0   -79.8    87.5                                      1
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    PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      THU, FEB 17 1994  13:55
CIGRE TEST NETWORK, NORDIC32A, 32 NODES                              RATING
LOAD FLOW LF32_028 (TAPS MODIF.)                                      SET A

BUS BUS4021  400   4021 AREA CKT     MW      MVAR      MVA  %I 1.0083PU -27.69    X-AREA-X X---ZONE---X
 GENERATION               2        250.0    -30.0L   251.8  84 403.31KV                        1
 TO BUS4011  400   4011   1  1    -762.0    176.2    782.1                                     1
 TO BUS4032  400   4032   3  1     378.9    -83.9    388.0                                     1
 TO BUS4042  400   4042   8  1     633.1   -122.3    644.8                                     1

BUS BUS4022  400   4022 AREA CKT     MW      MVAR      MVA  %I 0.9939PU -12.86    X-AREA-X X---ZONE---X
                          2                                    397.54KV                        1
 TO BUS1022  130   1022   2  1    -299.9      6.8    300.0     1.0700UN                        1
 TO BUS4011  400   4011   1  1    -550.6     18.6    550.9                                     1
 TO BUS4012  400   4012   1  1    -717.3     79.4    721.7                                     1
 TO BUS4031  400   4031   3  1     783.9    -52.4    785.6                                     1
 TO BUS4031  400   4031   3  2     783.9    -52.4    785.6                                     1

BUS BUS4031  400   4031 AREA CKT     MW      MVAR      MVA  %I 1.0100PU -31.04    X-AREA-X X---ZONE---X
 GENERATION               3        310.0    113.4R   330.1  94 404.00KV                        1
 TO BUS2031  220   2031   3  1    -434.5     69.5    440.1     1.0500UN                        1
 TO BUS4022  400   4022   2  1    -759.0    180.8    780.2                                     1
 TO BUS4022  400   4022   2  2    -759.0    180.8    780.2                                     1
 TO BUS4032  400   4032   3  1     924.3   -102.0    929.9                                     1
 TO BUS4041  400   4041   8  1     669.1   -107.9    677.8                                     1
 TO BUS4041  400   4041   8  2     669.1   -107.9    677.8                                     1

BUS BUS4032  400   4032 AREA CKT     MW      MVAR      MVA  %I 1.0136PU -36.27    X-AREA-X X---ZONE---X
                          3                                    405.46KV                        1
 TO BUS4021  400   4021   2  1    -373.2     17.9    373.6                                     1
 TO BUS4031  400   4031   3  1    -915.8    155.8    929.0                                     1
 TO BUS4042  400   4042   8  1     575.8   -143.4    593.4                                     1
 TO BUS4044  400   4044   8  1     713.2    -30.2    713.9                                     1

BUS BUS4041  400   4041 AREA CKT     MW      MVAR      MVA  %I 1.0000PU -46.36    X-AREA-X X---ZONE---X
 GENERATION               8          0.0     -9.0R     9.0   3 400.00KV                        1
 TO SHUNT                            0.0   -200.0    200.0
 TO BUS4031  400   4031   3  1    -642.8     41.1    644.1                                     1
 TO BUS4031  400   4031   3  2    -642.8     41.1    644.1                                     1
 TO BUS4044  400   4044   8  1     599.6    -11.2    599.7                                     1
 TO BUS4061  400   4061   6  1     146.0    -39.9    151.4                                     1
 TO BUS41    130     41   8  1     540.0    160.0    563.2  56 1.0000UN                        1

BUS BUS4042  400   4042 AREA CKT     MW      MVAR      MVA  %I 1.0000PU -49.64    X-AREA-X X---ZONE---X
 GENERATION               8        630.0    265.0R   683.5  98 400.00KV                        1
 TO BUS4021  400   4021   2  1    -593.6     57.0    596.3                                     1
 TO BUS4032  400   4032   3  1    -543.4     70.4    547.9                                     1
 TO BUS4043  400   4043   8  1     748.8    -17.3    749.0                                     1
 TO BUS4044  400   4044   8  1     618.2      5.6    618.2                                     1
 TO BUS42    130     42   8  1     400.0    149.4    427.0  57 1.0000UN                        1

BUS BUS4043  400   4043 AREA CKT     MW      MVAR      MVA  %I 0.9902PU -56.14    X-AREA-X X---ZONE---X
                          8                                    396.10KV                        1
 TO SHUNT                            0.0   -196.1    196.1
 TO BUS4042  400   4042   8  1    -737.6     51.9    739.4                                     1
 TO BUS4044  400   4044   8  1     110.6     -4.8    110.7                                     1
 TO BUS4046  400   4046   8  1     112.3    -30.0    116.2                                     1
 TO BUS4047  400   4047   8  1    -385.3   -124.2    404.8                                     1
 TO BUS43    130     43   8  1     900.0    303.2    949.7  64 1.0000UN                        1
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CIGRE TEST NETWORK, NORDIC32A, 32 NODES                                 RATING
LOAD FLOW LF32_028 (TAPS MODIF.)                                         SET A

BUS BUS4044  400  4044 AREA CKT    MW      MVAR      MVA  %I 0.9882PU -56.79   X-AREA-X X---ZONE---X
                          8                                  395.28KV                    1
 TO BUS1044  130  1044  4  1   577.3     64.1   580.9     1.0000UN                    1
 TO BUS1044  130  1044  4  2   577.3     64.1   580.9     1.0000UN                    1
 TO BUS4032  400  4032  3  1  -683.0     41.5   684.3                                 1
 TO BUS4041  400  4041  8  1  -588.8     30.4   589.5                                 1
 TO BUS4042  400  4042  8  1  -610.5     11.8   610.6                                 1
 TO BUS4043  400  4043  8  1  -110.4    -23.3   112.9                                 1
 TO BUS4045  400  4045  5  1   419.0    -94.4   429.5                                 1
 TO BUS4045  400  4045  5  2   419.0    -94.4   429.5                                 1

BUS BUS4045  400  4045 AREA CKT    MW      MVAR      MVA  %I 0.9966PU -61.74   X-AREA-X X---ZONE---X
                          5                                  398.64KV                    1
 TO BUS1045  130  1045  4  1   477.8     69.8   482.9     1.0000UN                    1
 TO BUS1045  130  1045  4  2   477.8     69.8   482.9     1.0000UN                    1
 TO BUS4044  400  4044  8  1  -415.4     72.1   421.6                                 1
 TO BUS4044  400  4044  8  2  -415.4     72.1   421.6                                 1
 TO BUS4051  400  4051  5  1   100.6   -125.7   161.0                                 1
 TO BUS4051  400  4051  5  2   100.6   -125.7   161.0                                 1
 TO BUS4062  400  4062  6  1  -326.1    -32.4   327.7                                 1

BUS BUS4046  400  4046 AREA CKT    MW      MVAR      MVA  %I 0.9907PU -56.81   X-AREA-X X---ZONE---X
                          8                                  396.29KV                    1
 TO SHUNT                          0.0    -98.2    98.2
 TO BUS4043  400  4043  8  1  -112.2      1.9   112.2                                 1
 TO BUS4047  400  4047  8  1  -587.8   -153.8   607.6                                 1
 TO BUS46    130    46  8  1   700.0    250.0   743.3  75 1.0000UN                    1

BUS BUS4047  400  4047 AREA CKT    MW      MVAR      MVA  %I 1.0200PU -51.88   X-AREA-X X---ZONE---X
 GENERATION               8     1080.0    304.2R 1122.0  94 408.00KV                    1
 TO BUS4043  400  4043  8  1   388.5     95.7   400.1                                 1
 TO BUS4046  400  4046  8  1   591.5    158.6   612.4                                 1
 TO BUS47    130    47  8  1   100.0     50.0   111.8  44 1.0000UN                    1

BUS BUS4051  400  4051 AREA CKT    MW      MVAR      MVA  %I 1.0200PU -64.16   X-AREA-X X---ZONE---X
 GENERATION               5      600.0    217.4R  638.2  91 408.00KV                    1
 TO SHUNT                          0.0   -104.0   104.0
 TO BUS4045  400  4045  5  1  -100.0      9.5   100.4                                 1
 TO BUS4045  400  4045  5  2  -100.0      9.5   100.4                                 1
 TO BUS51    130    51  8  1   800.0    302.4   855.3  56 1.0000UN                    1

BUS BUS4061  400  4061 AREA CKT    MW      MVAR      MVA  %I 0.9821PU -50.11   X-AREA-X X---ZONE---X
                          6                                  392.83KV                    1
 TO BUS4041  400  4041  8  1  -144.7    -77.9   164.3                                 1
 TO BUS4062  400  4062  6  1  -355.3    -71.1   362.4                                 1
 TO BUS61    130    61  8  1   500.0    149.0   521.7  71 1.0000UN                    1

BUS BUS4062  400  4062 AREA CKT    MW      MVAR      MVA  %I 1.0005PU -46.01   X-AREA-X X---ZONE-
 GENERATION               6      530.0      0.0L  530.0  88 400.18KV                    1
 TO BUS4045  400  4045  5  1   338.7   -115.2   357.7                                 1
 TO BUS4061  400  4061  6  1   358.0     38.7   360.1                                 1
 TO BUS4063  400  4063  6  1  -233.3    -11.8   233.6                                 1
 TO BUS4063  400  4063  6  2  -233.3    -11.8   233.6                                 1
 TO BUS62    130    62  8  1   300.0    100.0   316.2  63 1.0000UN                    1

BUS BUS4063  400  4063 AREA CKT    MW      MVAR      MVA  %I 1.0000PU -41.94   X-AREA-X X---ZONE---X
 GENERATION               6     1060.0    176.8R 1074.6  90 400.00KV                    1
 TO BUS4062  400  4062  6  1   235.0    -61.6   242.9                                 1
 TO BUS4062  400  4062  6  2   235.0    -61.6   242.9                                 1
 TO BUS63    130    63  8  1   590.0    300.0   661.9  66 1.0000UN                    1
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CIGRE TEST NETWORK, NORDIC32A, 32 NODES                                 RATING
LOAD FLOW LF32_028 (TAPS MODIF.)                                         SET A

BUS BUS4071   400   4071 AREA CKT     MW      MVAR     MVA  %I 1.0100PU    0.92    X-AREA-X X---ZONE---X
 GENERATION                7        300.0     54.3R  304.9  61 404.00KV                          1
 TO LOAD-PQ                         300.0    100.0   316.2
 TO SHUNT                             0.0    408.0   408.0
 TO BUS4011   400   4011   1   1     35.9    -75.1    83.2                                       1
 TO BUS4012   400   4012   1   1    -35.9    -72.6    81.0                                       1
 TO BUS4072   400   4072   7   1      0.0   -153.0   153.0                                       1
 TO BUS4072   400   4072   7   2      0.0   -153.0   153.0                                       1

BUS BUS4072   400   4072 AREA CKT     MW      MVAR     MVA  %I 1.0100PU    0.92    X-AREA-X X---ZONE---X
 GENERATION                7       2000.0    194.0R 2009.4  45 404.00KV                          1
 TO LOAD-PQ                        2000.0    500.0  2061.6
 TO BUS4071   400   4071   7   1      0.0   -153.0   153.0                                       1
 TO BUS4071   400   4071   7   2      0.0   -153.0   153.0                                       1

BUS BUS41     130     41 AREA CKT     MW      MVAR     MVA  %I 0.9855PU -49.50    X-AREA-X X---ZONE---X
                           8                                   128.11KV                          1
 TO LOAD-PQ                         540.0    128.3   555.0
 TO BUS4041   400   4041   8   1   -540.0   -128.3   555.0  56 1.0000LK                          1

BUS BUS42     130     42 AREA CKT     MW      MVAR     MVA  %I 0.9820PU -52.68    X-AREA-X X---ZONE---X
                           8                                   127.65KV                          1
 TO LOAD-PQ                         400.0    125.7   419.3
 TO BUS4042   400   4042   8   1   -400.0   -125.7   419.3  57 1.0000LK                          1

BUS BUS43     130     43 AREA CKT     MW      MVAR     MVA  %I 0.9709PU -59.90    X-AREA-X X---ZONE---X
                           8                                   126.22KV                          1
 TO LOAD-PQ                         900.0    238.8   931.1
 TO BUS4043   400   4043   8   1   -900.0   -238.8   931.1  64 1.0000LK                          1

BUS BUS46     130     46 AREA CKT     MW      MVAR     MVA  %I 0.9681PU -60.99    X-AREA-X X---ZONE---X
                           8                                   125.85KV                          1
 TO LOAD-PQ                         700.0    193.7   726.3
 TO BUS4046   400   4046   8   1   -700.0   -193.7   726.3  75 1.0000LK                          1

BUS BUS47     130     47 AREA CKT     MW      MVAR     MVA  %I 1.0012PU -54.12    X-AREA-X X---ZONE---X
                           8                                   130.15KV                          1
 TO LOAD-PQ                         100.0     45.2   109.7
 TO BUS4047   400   4047   8   1   -100.0    -45.2   109.7  44 1.0000LK                          1

BUS BUS51     130     51 AREA CKT     MW      MVAR     MVA  %I 1.0008PU -67.31    X-AREA-X X---ZONE---X
                           8                                   130.10KV                          1
 TO LOAD-PQ                         800.0    253.2   839.1
 TO BUS4051   400   4051   5   1   -800.0   -253.2   839.1  56 1.0000LK                          1

BUS BUS61     130     61 AREA CKT     MW      MVAR     MVA  %I 0.9646PU -54.04    X-AREA-X X---ZONE---X
                           8                                   125.40KV                          1
 TO LOAD-PQ                         500.0    112.3   512.5
 TO BUS4061   400   4061   6   1   -500.0   -112.3   512.5  71 1.0000LK                          1

BUS BUS62     130     62 AREA CKT     MW      MVAR     MVA  %I 0.9823PU -49.51    X-AREA-X X---ZONE---X
                           8                                   127.70KV                          1
 TO LOAD-PQ                         300.0     80.0   310.5
 TO BUS4062   400   4062   6   1   -300.0    -80.0   310.5  63 1.0000LK                          1

BUS BUS63     130     63 AREA CKT     MW      MVAR     MVA  %I 0.9718PU -45.42    X-AREA-X X---ZONE---X
                           8                                   126.33KV                          1
 TO LOAD-PQ                         590.0    256.2   643.2
 TO BUS4063   400   4063   6   1   -590.0   -256.2   643.2  66 1.0000LK                          1
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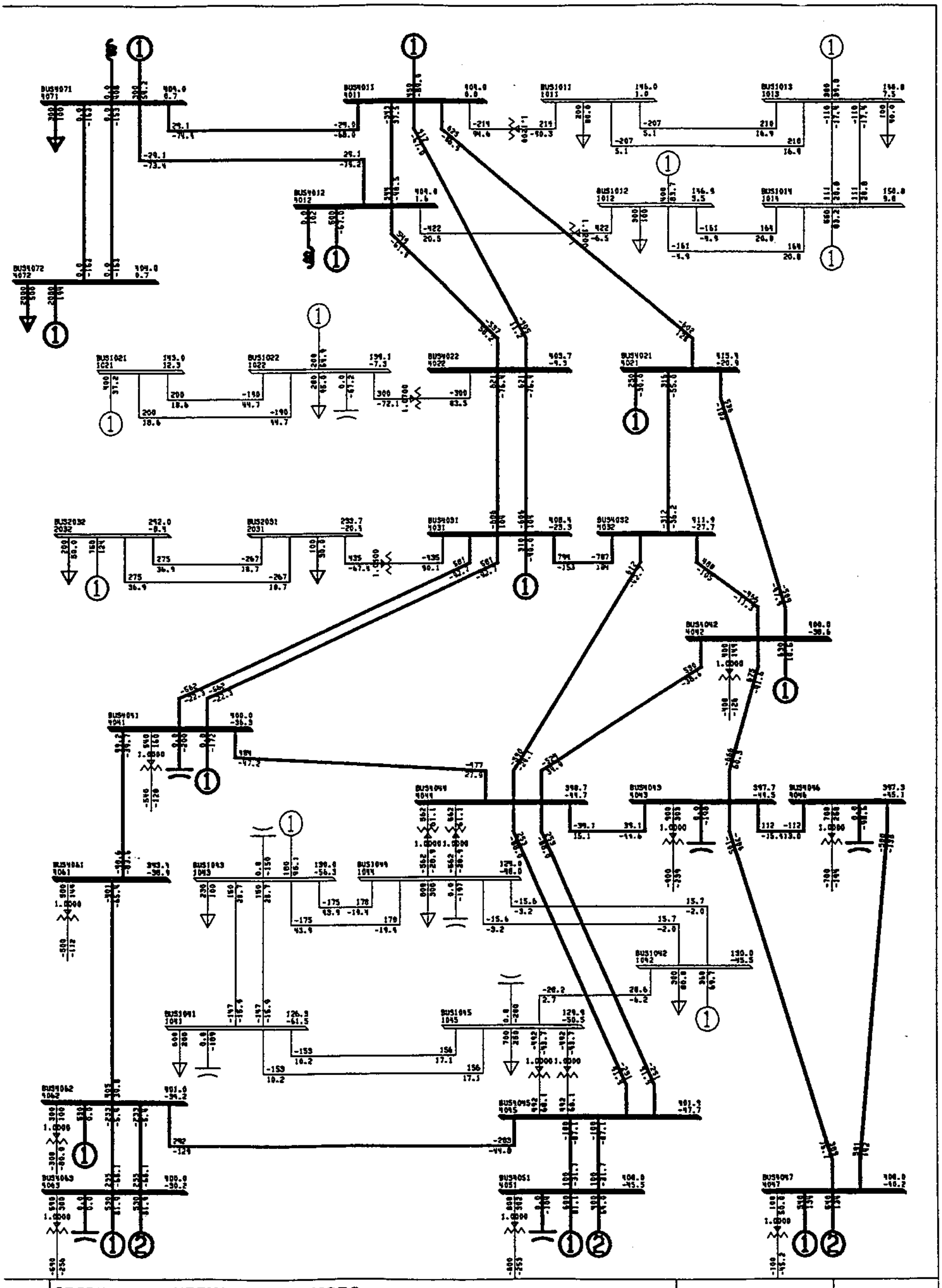
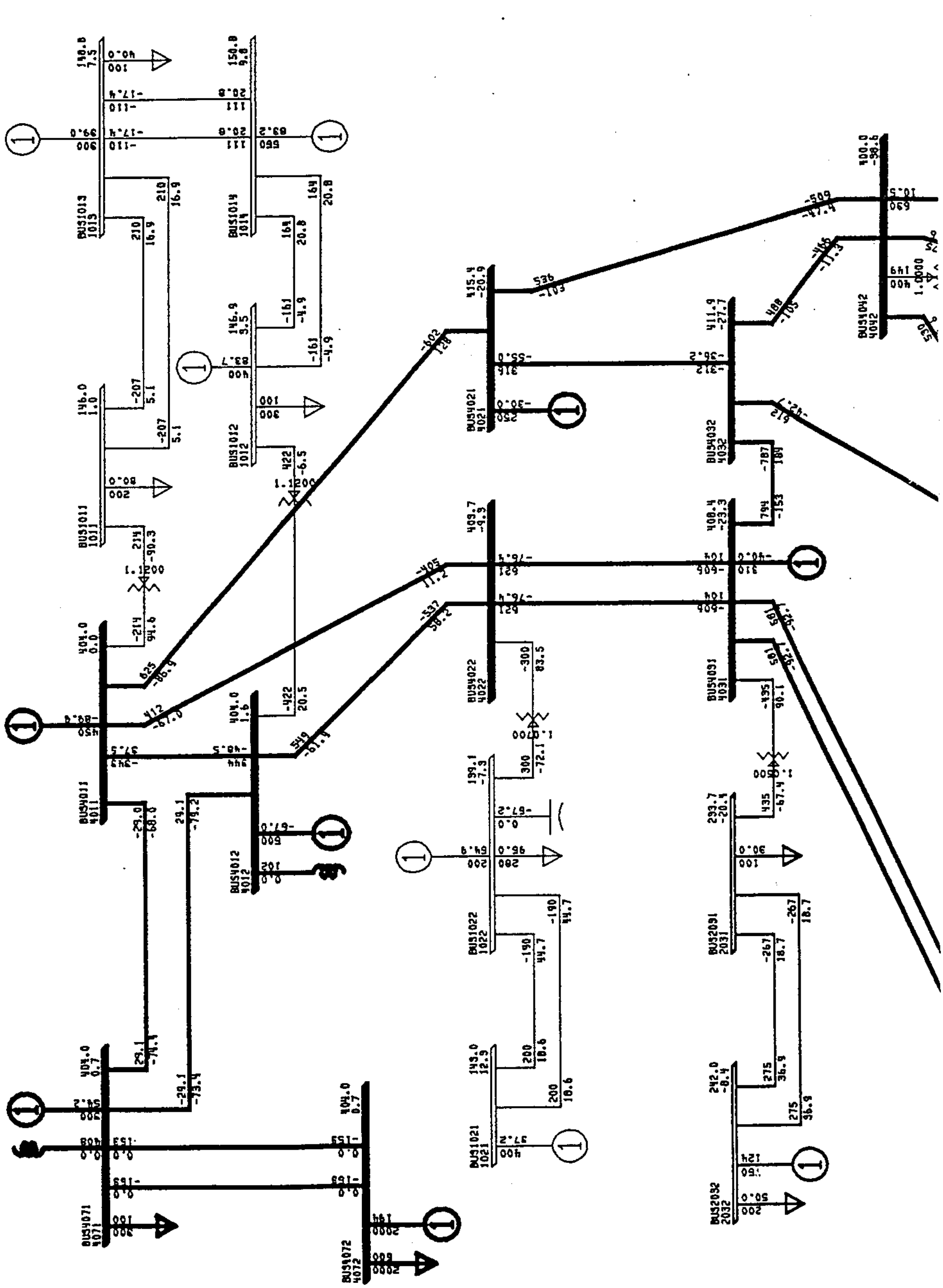
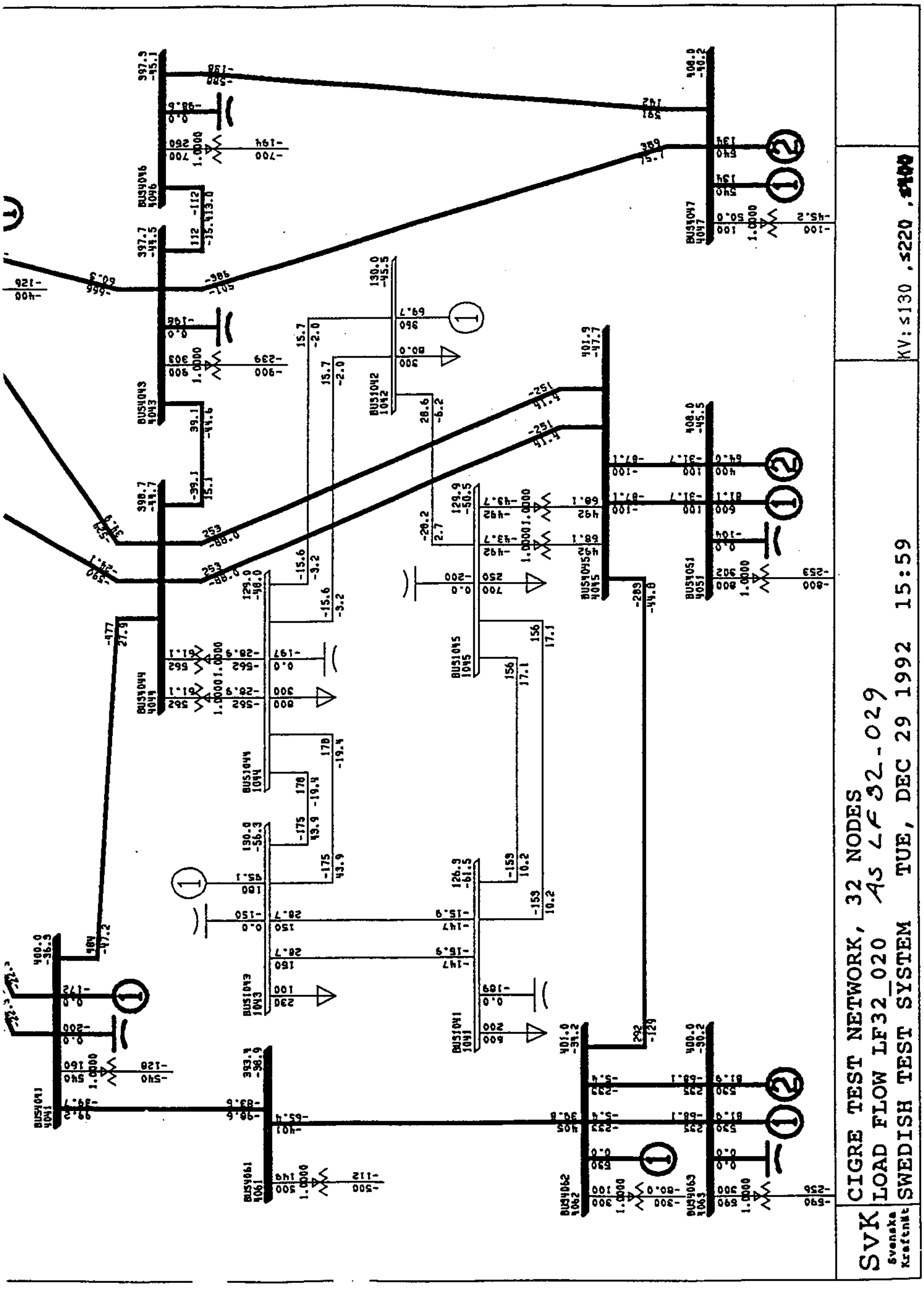


SvK Svenska Kraftnät
CIGRE TEST NETWORK, 32 NODES
LOAD FLOW LF32_020 AS LF32_029
SWEDISH TEST SYSTEM TUE, DEC 29 1992 15:59
KV: ≤130 , ≤220 , ≤400


BUS1013
1013
BUS1014
1014
BUS1012
1012
BUS1011
1011
BUS4011
4011
BUS4012
4012
BUS4021
4021
BUS4022
4022
BUS4032
4032
BUS4031
4031
BUS4042
4042
BUS1022
1022
BUS1021
1021
BUS2031
2031
BUS2032
2032
BUS4071
4071
BUS4072
4072


CIGRE TEST NETWORK, 32 NODES
LOAD FLOW LF32_020
AS LF32-029
SWEDISH TEST SYSTEM
TUE, DEC 29 1992 15:59
KV: ≤130 ,≤220 ,
SvK
Svenska Kraftnät

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E TUE, DEC 29 1992 15:58
CIGRE TEST NETWORK, 32 NODES RATING
LOAD FLOW LF32_020 SET A

BUS BUS1011	130	1011	AREA	CKT	MW	MVAR	MVA	%I	1.1230PU	0.97	X-AREA-X	X--
			1						145.99KV			1
TO LOAD-PQ					200.0	80.0	215.4					
TO BUS1013	130	1013	1	1	-207.0	5.1	207.0					1
TO BUS1013	130	1013	1	2	-207.0	5.1	207.0					1
TO BUS4011	400	4011	1	1	214.0	-90.3	232.2		1.1200LK			1

BUS BUS1012	130	1012	AREA	CKT	MW	MVAR	MVA	%I	1.1300PU	3.47	X-AREA-X	X--
GENERATION			1		400.0	83.7R	408.7	51	146.90KV			1
TO LOAD-PQ					300.0	100.0	316.2					
TO BUS1014	130	1014	1	1	-161.1	-4.9	161.2					1
TO BUS1014	130	1014	1	2	-161.1	-4.9	161.2					1
TO BUS4012	400	4012	1	1	422.2	-6.5	422.3		1.1200LK			1

BUS BUS1013	130	1013	AREA	CKT	MW	MVAR	MVA	%I	1.1450PU	7.47	X-AREA-X	X--
GENERATION			1		300.0	39.0R	302.5	50	148.85KV			1
TO LOAD-PQ					100.0	40.0	107.7					
TO BUS1011	130	1011	1	1	210.4	16.9	211.1					1
TO BUS1011	130	1011	1	2	210.4	16.9	211.1					1
TO BUS1014	130	1014	1	1	-110.4	-17.4	111.7					1
TO BUS1014	130	1014	1	2	-110.4	-17.4	111.7					1

BUS BUS1014	130	1014	AREA	CKT	MW	MVAR	MVA	%I	1.1600PU	9.80	X-AREA-X	X--
GENERATION			1		550.0	83.2R	556.3	79	150.80KV			1
TO BUS1012	130	1012	1	1	164.0	20.8	165.3					1
TO BUS1012	130	1012	1	2	164.0	20.8	165.3					1
TO BUS1013	130	1013	1	1	111.0	20.8	113.0					1
TO BUS1013	130	1013	1	2	111.0	20.8	113.0					1

BUS BUS1021	130	1021	AREA	CKT	MW	MVAR	MVA	%I	1.1000PU	12.29	X-AREA-X	X--
GENERATION			2		400.0	37.2R	401.7	67	143.00KV			1
TO BUS1022	130	1022	2	1	200.0	18.6	200.9					1
TO BUS1022	130	1022	2	2	200.0	18.6	200.9					1

BUS BUS1022	130	1022	AREA	CKT	MW	MVAR	MVA	%I	1.0700PU	-7.26	X-AREA-X	X--
GENERATION			2		200.0	54.9R	207.4	83	139.10KV			1
TO LOAD-PQ					280.0	95.0	295.7					
TO SHUNT					0.0	-57.2	57.2					
TO BUS1021	130	1021	2	1	-190.0	44.7	195.2					1
TO BUS1021	130	1021	2	2	-190.0	44.7	195.2					1
TO BUS4022	400	4022	2	1	300.0	-72.1	308.5		1.0700LK			1

BUS BUS1041	130	1041	AREA	CKT	MW	MVAR	MVA	%I	0.9714PU	-61.48	X-AREA-X	X--
			4						126.28KV			1
TO LOAD-PQ					600.0	200.0	632.5					
TO SHUNT					0.0	-188.7	188.7					
TO BUS1043	130	1043	4	1	-147.4	-15.9	148.2					1
TO BUS1043	130	1043	4	2	-147.4	-15.9	148.2					1
TO BUS1045	130	1045	4	1	-152.6	10.2	153.0					1
TO BUS1045	130	1045	4	2	-152.6	10.2	153.0					1

BUS BUS1042	130	1042	AREA	CKT	MW	MVAR	MVA	%I	1.0000PU	-45.47	X-AREA-X	X--
GENERATION			4		360.0	69.7R	366.7	92	130.00KV			1
TO LOAD-PQ					300.0	80.0	310.5					
TO BUS1044	130	1044	4	1	15.7	-2.0	15.8					1
TO BUS1044	130	1044	4	2	15.7	-2.0	15.8					1
TO BUS1045	130	1045	4	1	28.6	-6.2	29.3					1

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    PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      TUE, DEC 29 1992  15:58
CIGRE TEST NETWORK, 32 NODES                                        RATING
LOAD FLOW LF32_020                                                   SET A

BUS BUS1043  130  1043 AREA CKT    MW     MVAR     MVA  %I 1.0000PU -56.35   X-AREA-X X--
 GENERATION              4        180.0    95.1R  203.6 102 130.00KV                    1
 TO LOAD-PQ                       230.0   100.0   250.8
 TO SHUNT                           0.0  -150.0   150.0
 TO BUS1041  130  1041   4  1     149.7    28.7   152.4                                 1
 TO BUS1041  130  1041   4  2     149.7    28.7   152.4                                 1
 TO BUS1044  130  1044   4  1    -174.7    43.9   180.1                                 1
 TO BUS1044  130  1044   4  2    -174.7    43.9   180.1                                 1

BUS BUS1044  130  1044 AREA CKT    MW     MVAR     MVA  %I 0.9923PU -47.99   X-AREA-X X--
                         4                                 129.00KV                     1
 TO LOAD-PQ                       800.0   300.0   854.4
 TO SHUNT                           0.0  -196.9   196.9
 TO BUS1042  130  1042   4  1     -15.6    -3.2    15.9                                 1
 TO BUS1042  130  1042   4  2     -15.6    -3.2    15.9                                 1
 TO BUS1043  130  1043   4  1     178.0   -19.4   179.0                                 1
 TO BUS1043  130  1043   4  2     178.0   -19.4   179.0                                 1
 TO BUS4044  400  4044   8  1    -562.4   -28.9   563.1     1.0000LK                    1
 TO BUS4044  400  4044   8  2    -562.4   -28.9   563.1     1.0000LK                    1

BUS BUS1045  130  1045 AREA CKT    MW     MVAR     MVA  %I 0.9992PU -50.50   X-AREA-X X--
                         4                                 129.89KV                     1
 TO LOAD-PQ                       700.0   250.0   743.3
 TO SHUNT                           0.0  -199.7   199.7
 TO BUS1041  130  1041   4  1     156.3    17.1   157.3                                 1
 TO BUS1041  130  1041   4  2     156.3    17.1   157.3                                 1
 TO BUS1042  130  1042   4  1     -28.2     2.7    28.4                                 1
 TO BUS4045  400  4045   5  1    -492.2   -43.7   494.2     1.0000LK                    1
 TO BUS4045  400  4045   5  2    -492.2   -43.7   494.2     1.0000LK                    1

BUS BUS2031  220  2031 AREA CKT    MW     MVAR     MVA  %I 1.0623PU -20.40   X-AREA-X X--
                         3                                 233.71KV                     1
 TO LOAD-PQ                       100.0    30.0   104.4
 TO BUS2032  220  2032   3  1    -267.4    18.7   268.0                                 1
 TO BUS2032  220  2032   3  2    -267.4    18.7   268.0                                 1
 TO BUS4031  400  4031   3  1     434.7   -67.4   439.9     1.0500LK                    1

BUS BUS2032  220  2032 AREA CKT    MW     MVAR     MVA  %I 1.1000PU  -8.39   X-AREA-X X--
 GENERATION              3        750.0   123.8R  760.1  89 242.00KV                    1
 TO LOAD-PQ                       200.0    50.0   206.2
 TO BUS2031  220  2031   3  1     275.0    36.9   277.5                                 1
 TO BUS2031  220  2031   3  2     275.0    36.9   277.5                                 1

BUS BUS4011  400  4011 AREA CKT    MW     MVAR     MVA  %I 1.0100PU   0.00   X-AREA-X X--
 GENERATION              1        450.3   -89.9R  459.1  46 404.00KV                    1
 TO BUS1011  130  1011   1  1    -214.0    94.6   233.9     1.1200UN                    1
 TO BUS4012  400  4012   1  1    -343.2    37.5   345.3                                 1
 TO BUS4021  400  4021   2  1     624.8   -86.9   630.9                                 1
 TO BUS4022  400  4022   2  1     411.6   -67.0   417.1                                 1
 TO BUS4071  400  4071   7  1     -29.0   -68.0    73.9                                 1

BUS BUS4012  400  4012 AREA CKT    MW     MVAR     MVA  %I 1.0100PU   1.57   X-AREA-X X--
 GENERATION              1        500.0   -67.0R  504.5  63 404.00KV                    1
 TO SHUNT                           0.0   102.0   102.0
 TO BUS1012  130  1012   1  1    -422.2    20.5   422.7     1.1200UN                    1
 TO BUS4011  400  4011   1  1     344.4   -48.5   347.8                                 1
 TO BUS4022  400  4022   2  1     548.7   -61.9   552.2                                 1
 TO BUS4071  400  4071   7  1      29.1   -79.2    84.4                                 1
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    PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      TUE, DEC 29 1992  15:58
CIGRE TEST NETWORK, 32 NODES                                           RATING
LOAD FLOW LF32_020                                                      SET A

BUS BUS4021   400   4021 AREA CKT     MW      MVAR      MVA  %I 1.0385PU -20.93   X-AREA-X X--
 GENERATION                 2       250.0    -30.0L   251.8  84 415.38KV                     1
 TO BUS4011   400   4011    1  1   -601.9    127.7    615.3                                  1
 TO BUS4032   400   4032    3  1    316.0    -55.0    320.8                                  1
 TO BUS4042   400   4042    8  1    535.9   -102.6    545.6                                  1

BUS BUS4022   400   4022 AREA CKT     MW      MVAR      MVA  %I 1.0093PU  -9.31   X-AREA-X X--
                            2                                   403.72KV                     1
 TO BUS1022   130   1022    2  1   -300.0     83.5    311.4     1.0700UN                     1
 TO BUS4011   400   4011    1  1   -405.0     11.2    405.1                                  1
 TO BUS4012   400   4012    1  1   -536.9     58.2    540.0                                  1
 TO BUS4031   400   4031    3  1    620.9    -76.4    625.6                                  1
 TO BUS4031   400   4031    3  2    620.9    -76.4    625.6                                  1

BUS BUS4031   400   4031 AREA CKT     MW      MVAR      MVA  %I 1.0210PU -23.29   X-AREA-X X--
 GENERATION                 3       310.0    -40.0L   312.6  89 408.40KV                     1
 TO BUS2031   220   2031    3  1   -434.7     90.1    443.9     1.0500UN                     1
 TO BUS4022   400   4022    2  1   -605.8    104.2    614.7                                  1
 TO BUS4022   400   4022    2  2   -605.8    104.2    614.7                                  1
 TO BUS4032   400   4032    3  1    793.6   -153.1    808.2                                  1
 TO BUS4041   400   4041    8  1    581.3    -92.7    588.7                                  1
 TO BUS4041   400   4041    8  2    581.3    -92.7    588.7                                  1

BUS BUS4032   400   4032 AREA CKT     MW      MVAR      MVA  %I 1.0297PU -27.69   X-AREA-X X--
                            3                                   411.90KV                     1
 TO BUS4021   400   4021    2  1   -312.3    -36.2    314.4                                  1
 TO BUS4031   400   4031    3  1   -787.4    183.8    808.6                                  1
 TO BUS4042   400   4042    8  1    488.2   -104.9    499.3                                  1
 TO BUS4044   400   4044    8  1    611.5    -42.7    613.0                                  1

BUS BUS4041   400   4041 AREA CKT     MW      MVAR      MVA  %I 1.0000PU -36.34   X-AREA-X X--
 GENERATION                 8         0.0   -171.5R   171.5  57 400.00KV                     1
 TO SHUNT                             0.0   -200.0    200.0
 TO BUS4031   400   4031    3  1   -561.8    -22.3    562.3                                  1
 TO BUS4031   400   4031    3  2   -561.8    -22.3    562.3                                  1
 TO BUS4044   400   4044    8  1    484.3    -47.2    486.6                                  1
 TO BUS4061   400   4061    6  1     99.2    -39.7    106.9                                  1
 TO BUS41     130     41    8  1    540.0    160.0    563.2  56 1.0000LK                     1

BUS BUS4042   400   4042 AREA CKT     MW      MVAR      MVA  %I 1.0000PU -38.62   X-AREA-X X--
 GENERATION                 8       630.0     10.5R   630.1  90 400.00KV                     1
 TO BUS4021   400   4021    2  1   -508.9    -47.4    511.1                                  1
 TO BUS4032   400   4032    3  1   -465.7    -11.3    465.9                                  1
 TO BUS4043   400   4043    8  1    675.1    -41.6    676.4                                  1
 TO BUS4044   400   4044    8  1    529.5    -38.6    530.9                                  1
 TO BUS42     130     42    8  1    400.0    149.4    427.0  57 1.0000LK                     1

BUS BUS4043   400   4043 AREA CKT     MW      MVAR      MVA  %I 0.9942PU -44.48   X-AREA-X X--
                            8                                   397.67KV                     1
 TO SHUNT                             0.0   -197.7    197.7
 TO BUS4042   400   4042    8  1   -666.0     60.3    668.7                                  1
 TO BUS4044   400   4044    8  1     39.1    -44.6     59.3                                  1
 TO BUS4046   400   4046    8  1    112.4    -15.4    113.5                                  1
 TO BUS4047   400   4047    8  1   -385.5   -105.3    399.7                                  1
 TO BUS43     130     43    8  1    900.0    302.7    949.5  64 1.0000LK                     1
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     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E        TUE, DEC 29 1992  15:58
CIGRE TEST NETWORK, 32 NODES                                             RATING
LOAD FLOW LF32_020                                                        SET A

BUS BUS4044   400   4044 AREA CKT     MW      MVAR      MVA  %I 0.9968PU -44.73   X-AREA-X X--
                           8                                    398.72KV                     1
 TO BUS1044   130   1044    4  1   562.4      61.1    565.7     1.0000UN                     1
 TO BUS1044   130   1044    4  2   562.4      61.1    565.7     1.0000UN                     1
 TO BUS4032   400   4032    3  1  -589.9     -24.1    590.4                                  1
 TO BUS4041   400   4041    8  1  -477.3      27.9    478.1                                  1
 TO BUS4042   400   4042    8  1  -523.9      34.9    525.1                                  1
 TO BUS4043   400   4043    8  1   -39.1      15.1     41.9                                  1
 TO BUS4045   400   4045    5  1   252.7     -88.0    267.6                                  1
 TO BUS4045   400   4045    5  2   252.7     -88.0    267.6                                  1

BUS BUS4045   400   4045 AREA CKT     MW      MVAR      MVA  %I 1.0047PU -47.69   X-AREA-X X--
                           5                                    401.89KV                     1
 TO BUS1045   130   1045    4  1   492.2      68.1    496.9     1.0000UN                     1
 TO BUS1045   130   1045    4  2   492.2      68.1    496.9     1.0000UN                     1
 TO BUS4044   400   4044    8  1  -251.4      41.4    254.8                                  1
 TO BUS4044   400   4044    8  2  -251.4      41.4    254.8                                  1
 TO BUS4051   400   4051    5  1   -99.6     -87.1    132.3                                  1
 TO BUS4051   400   4051    5  2   -99.6     -87.1    132.3                                  1
 TO BUS4062   400   4062    6  1  -282.5     -44.8    286.1                                  1

BUS BUS4046   400   4046 AREA CKT     MW      MVAR      MVA  %I 0.9932PU -45.14   X-AREA-X X--
                           8                                    397.27KV                     1
 TO SHUNT                              0.0     -98.6     98.6
 TO BUS4043   400   4043    8  1  -112.3     -13.0    113.0                                  1
 TO BUS4047   400   4047    8  1  -587.7    -138.1    603.7                                  1
 TO BUS46     130     46    8  1   700.0     249.7    743.2  75 1.0000LK                     1

BUS BUS4047   400   4047 AREA CKT     MW      MVAR      MVA  %I 1.0200PU -40.21   X-AREA-X X--
 GENERATION                8          1080.0    267.6R 1112.7  93 408.00KV                     1
 TO BUS4043   400   4043    8  1   388.7      75.7    396.0                                  1
 TO BUS4046   400   4046    8  1   591.3     141.9    608.1                                  1
 TO BUS47     130     47    8  1   100.0      50.0    111.8  44 1.0000LK                     1

BUS BUS4051   400   4051 AREA CKT     MW      MVAR      MVA  %I 1.0200PU -45.52   X-AREA-X X--
 GENERATION                5          1000.0    135.1R 1009.1  72 408.00KV                     1
 TO SHUNT                              0.0    -104.0    104.0
 TO BUS4045   400   4045    5  1   100.0     -31.7    104.9                                  1
 TO BUS4045   400   4045    5  2   100.0     -31.7    104.9                                  1
 TO BUS51     130     51    8  1   800.0     302.4    855.3  56 1.0000LK                     1

BUS BUS4061   400   4061 AREA CKT     MW      MVAR      MVA  %I 0.9836PU -38.86   X-AREA-X X--
                           6                                    393.44KV                     1
 TO BUS4041   400   4041    8  1   -98.6     -83.5    129.2                                  1
 TO BUS4062   400   4062    6  1  -401.4     -65.4    406.7                                  1
 TO BUS61     130     61    8  1   500.0     148.9    521.7  71 1.0000LK                     1

BUS BUS4062   400   4062 AREA CKT     MW      MVAR      MVA  %I 1.0024PU -34.23   X-AREA-X X--
 GENERATION                6           530.0      0.0L  530.0  88 400.97KV                     1
 TO BUS4045   400   4045    5  1   291.9    -129.0    319.1                                  1
 TO BUS4061   400   4061    6  1   404.8      39.8    406.7                                  1
 TO BUS4063   400   4063    6  1  -233.3      -5.4    233.4                                  1
 TO BUS4063   400   4063    6  2  -233.3      -5.4    233.4                                  1
 TO BUS62     130     62    8  1   300.0      99.9    316.2  63 1.0000LK                     1

BUS BUS4063   400   4063 AREA CKT     MW      MVAR      MVA  %I 1.0000PU -30.15   X-AREA-X X--
 GENERATION                6          1060.0    163.7R 1072.6  89 400.00KV                     1
 TO BUS4062   400   4062    6  1   235.0     -68.1    244.7                                  1
 TO BUS4062   400   4062    6  2   235.0     -68.1    244.7                                  1
 TO BUS63     130     63    8  1   590.0     300.0    661.9  66 1.0000LK                     1
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    PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      TUE, DEC 29 1992  15:58
CIGRE TEST NETWORK, 32 NODES                                          RATING
LOAD FLOW LF32_020                                                     SET A

BUS BUS4071  400   4071 AREA CKT     MW      MVAR     MVA  %I 1.0100PU    0.74    X-AREA-X X--
 GENERATION               7       300.0     54.2R  304.9  61 404.00KV                        1
 TO LOAD-PQ                       300.0    100.0   316.2
 TO SHUNT                           0.0    408.0   408.0
 TO BUS4011  400   4011    1  1    29.1    -74.4    79.9                                     1
 TO BUS4012  400   4012    1  1   -29.1    -73.4    78.9                                     1
 TO BUS4072  400   4072    7  1     0.0   -153.0   153.0                                     1
 TO BUS4072  400   4072    7  2     0.0   -153.0   153.0                                     1

BUS BUS4072  400   4072 AREA CKT     MW      MVAR     MVA  %I 1.0100PU    0.74    X-AREA-X X--
 GENERATION               7      2000.0    194.0R 2009.4  45 404.00KV                        1
 TO LOAD-PQ                      2000.0    500.0  2061.6
 TO BUS4071  400   4071    7  1     0.0   -153.0   153.0                                     1
 TO BUS4071  400   4071    7  2     0.0   -153.0   153.0                                     1

BUS BUS41    130     41 AREA CKT     MW      MVAR     MVA  %I 0.9855PU  -39.48    X-AREA-X X--
                          8                                   128.11KV                       1
 TO LOAD-PQ                       540.0    128.3   555.0
 TO BUS4041  400   4041    8  1  -540.0   -128.3   555.0  56 1.0000UN                        1

BUS BUS42    130     42 AREA CKT     MW      MVAR     MVA  %I 0.9820PU  -41.65    X-AREA-X X--
                          8                                   127.65KV                       1
 TO LOAD-PQ                       400.0    125.7   419.3
 TO BUS4042  400   4042    8  1  -400.0   -125.7   419.3  57 1.0000UN                        1

BUS BUS43    130     43 AREA CKT     MW      MVAR     MVA  %I 0.9749PU  -48.21    X-AREA-X X--
                          8                                   126.74KV                       1
 TO LOAD-PQ                       900.0    238.8   931.1
 TO BUS4043  400   4043    8  1  -900.0   -238.8   931.1  64 1.0000UN                        1

BUS BUS46    130     46 AREA CKT     MW      MVAR     MVA  %I 0.9706PU  -49.30    X-AREA-X X--
                          8                                   126.18KV                       1
 TO LOAD-PQ                       700.0    193.7   726.3
 TO BUS4046  400   4046    8  1  -700.0   -193.7   726.3  75 1.0000UN                        1

BUS BUS47    130     47 AREA CKT     MW      MVAR     MVA  %I 1.0012PU  -42.45    X-AREA-X X--
                          8                                   130.15KV                       1
 TO LOAD-PQ                       100.0     45.2   109.7
 TO BUS4047  400   4047    8  1  -100.0    -45.2   109.7  44 1.0000UN                        1

BUS BUS51    130     51 AREA CKT     MW      MVAR     MVA  %I 1.0008PU  -48.66    X-AREA-X X--
                          8                                   130.10KV                       1
 TO LOAD-PQ                       800.0    253.2   839.1
 TO BUS4051  400   4051    5  1  -800.0   -253.2   839.1  56 1.0000UN                        1

BUS BUS61    130     61 AREA CKT     MW      MVAR     MVA  %I 0.9662PU  -42.78    X-AREA-X X--
                          8                                   125.60KV                       1
 TO LOAD-PQ                       500.0    112.3   512.5
 TO BUS4061  400   4061    6  1  -500.0   -112.3   512.5  71 1.0000UN                        1

BUS BUS62    130     62 AREA CKT     MW      MVAR     MVA  %I 0.9843PU  -37.71    X-AREA-X X--
                          8                                   127.96KV                       1
 TO LOAD-PQ                       300.0     80.0   310.5
 TO BUS4062  400   4062    6  1  -300.0    -80.0   310.5  63 1.0000UN                        1

BUS BUS63    130     63 AREA CKT     MW      MVAR     MVA  %I 0.9718PU  -33.64    X-AREA-X X--
                          8                                   126.33KV                       1
 TO LOAD-PQ                       590.0    256.2   643.2
 TO BUS4063  400   4063    6  1  -590.0   -256.2   643.2  66 1.0000UN                        1
```

APPENDIX A.4

THE IRISH TEST SYSTEM DATA

APPENDIX A.4.1

LOAD FLOW DATA

Anyone wishing to receive a copy of these data may write and request them from :

The Manager, Power System Operation,
ESB National Grid
Lower Fitzwilliam Street
Dublin
IRELAND

APPENDIX A.4.2

DYNAMIC MODELS

Anyone wishing to receive a copy of these data may write and request them from :

The Manager, Power System Operation,
ESB National Grid
Lower Fitzwilliam Street
Dublin
IRELAND

APPENDIX A.5

THE SPANISH TEST SYSTEM DATA

APPENDIX A.5.1

INTRODUCTION

Appendix A.5

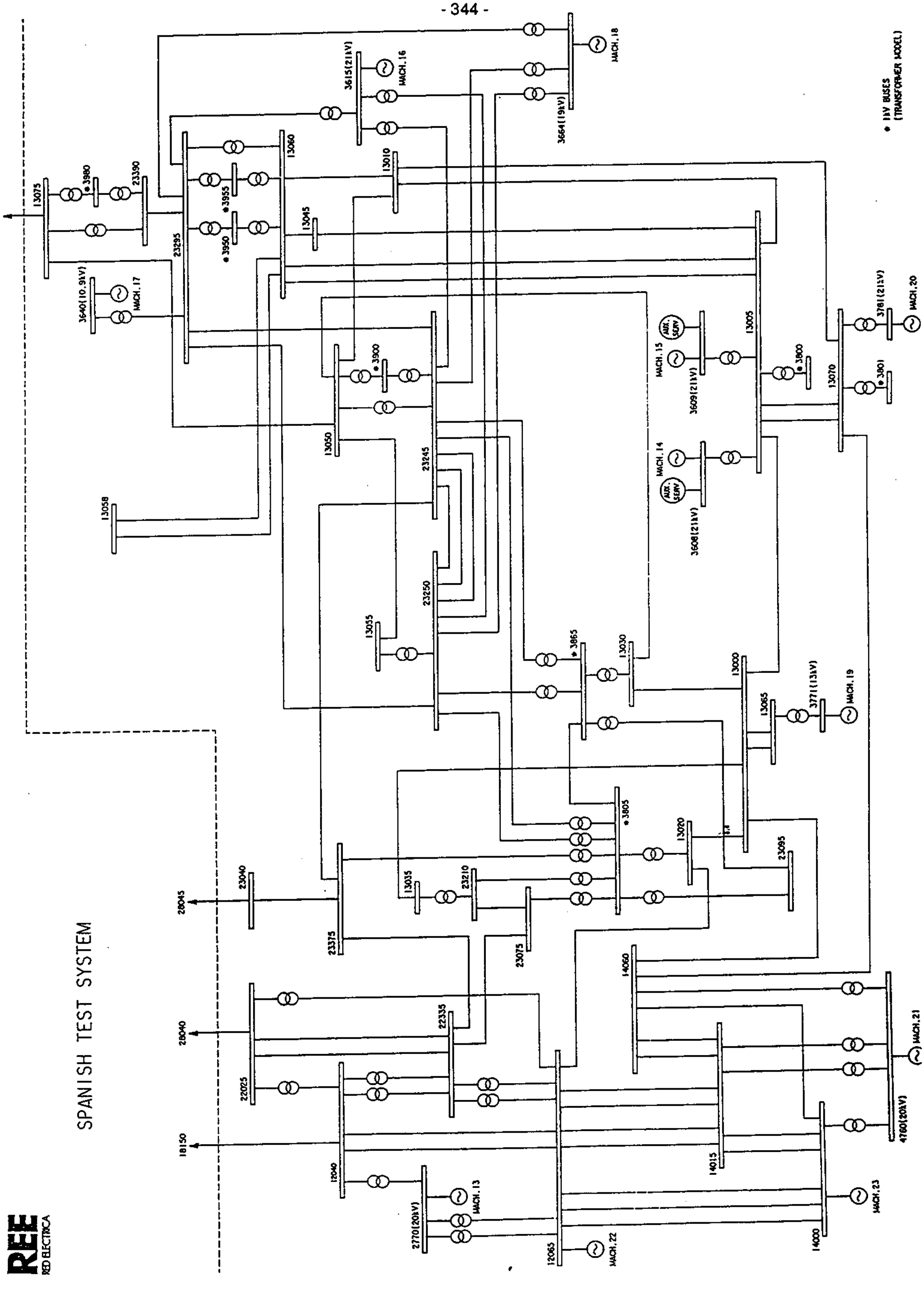
. General description:

	Area A	Area B	Total
Buses	55	28	83
Branches	110	137	247
Groups	11	12	23

Area		From generation	To load (cont. P)	To bus shunt	From line charging	Losses
A	(MW)	23602.6	16216.1	7198.8	0.0	274.75
	(MVAR)	-6990.5	7391.1	-15283.3	1405.7	2488.71
B	(MW)	140669.5	140162.2	141.2	0.0	278.98
	(MVAR)	46244.8	58565.0	-16291.7	826.8	4617.09

. Tie-lines (at t=to):

X---From area B---X		X----To area A----X		MW	MVAR
18105	400	13075	400	210.9	52.6
18150	400	12040	400	-62.5	76.2
28040	220	22025	220	-92.0	64.0
28045	220	23040	220	30.7	-11.5
TOTAL from area B to A				------	------
				87.1	181.2


SPANISH TEST SYSTEM
REE
RED ELECTRICA
* 1kV BUSES
(TRANSFORMER MODEL)
13075
3980
23390
23295
3955
3950
13060
3615(21kV)
MACH.16
3664(19kV)
MACH.18
13010
13045
3640(10.9kV)
MACH.17
13058
13050
3900
23245
23250
13055
3865
13030
13005
3800
13070
3801
3781(21kV)
MACH.20
3609(21kV)
MACH.15
AUX. SERV
3608(21kV)
MACH.14
13000
13065
3771(13kV)
MACH.19
3805
13020
23095
23040
28045
23375
13035
23210
23075
14060
22335
22025
28040
12040
18150
2770(20kV)
MACH.13
12065
MACH.22
14015
14000
MACH.23
4760(20kV)
MACH.21

APPENDIX A.5.2

LOAD FLOW DATA

Appendix A.5

. BUS DATA (at t=to):

BUS#	BSKV	CODE	VOLT	ANGLE	PLOAD	QLOAD	S H U N T		AREA
301	1.00	1	1.0250	32.4	0.0	0.0	0.0	0.0	A
302	6.90	1	1.0250	32.4	0.0	0.0	0.0	0.0	A
310	6.90	1	0.9950	29.5	9.5	5.1	0.0	0.0	A
311	6.90	1	0.9950	29.5	9.5	5.1	0.0	0.0	A
312	6.90	1	0.9885	27.8	15.0	5.4	0.0	0.0	A
320	6.90	1	0.9950	29.4	9.5	5.1	0.0	0.0	A
321	6.90	1	0.9950	29.4	9.5	5.1	0.0	0.0	A
322	6.90	1	0.9885	27.7	15.0	5.4	0.0	0.0	A
2770	20.0	2	0.9719	38.5	119.0	63.6	18.7	-145.4	A
3608	21.0	2	1.0132	31.3	0.0	0.0	0.0	0.0	A
3609	21.0	2	1.0132	31.3	0.0	0.0	0.0	0.0	A
3615	21.0	2	1.0183	13.5	48.2	25.4	3.3	-106.3	A
3640	10.9	2	1.0064	20.0	71.5	1.3	9.3	-28.1	A
3664	19.0	2	1.0247	13.5	38.9	9.1	9.3	-70.6	A
3771	18.0	2	1.0050	30.1	31.4	48.5	0.0	0.0	A
3781	21.0	2	0.9700	33.3	34.7	-1.6	0.0	0.0	A
3800	1.00	1	1.0061	21.3	97.1	43.2	0.0	0.0	A
3801	1.00	1	0.9856	19.2	173.5	70.4	0.0	0.0	A
3805	1.00	1	0.8995	20.0	94.8	58.8	877.8	-2065.2	A
3865	1.00	1	1.0333	19.4	-133.2	146.4	-409.6	623.1	A
3900	1.00	1	1.0202	10.4	0.0	0.0	0.0	0.0	A
3950	1.00	1	0.9796	11.4	0.0	0.0	0.0	0.0	A
3955	1.00	1	0.9797	11.5	0.0	0.0	0.0	0.0	A
3980	1.00	1	1.0175	9.4	0.0	0.0	0.0	0.0	A
4760	20.0	2	0.9772	24.0	553.1	300.1	5.7	372.9	A
8005	20.0	2	1.0150	9.1	12839.6	5132.8	13.4	693.2	B
8015	20.0	2	0.9850	0.8	19071.7	6820.4	21.7	1301.3	B
8030	20.0	2	1.0200	20.2	25969.1	10642.2	9.7	377.6	B
8046	20.0	3	1.0100	18.4	43256.2	13678.6	12.6	496.3	B
8060	20.0	2	1.0100	26.8	18526.7	7044.8	26.9	106.0	B
8206	20.0	2	1.0150	32.8	466.2	384.6	31.8	121.4	B
8285	20.0	2	0.9900	29.4	0.0	0.0	7.8	-241.5	B
8327	20.0	2	1.0250	31.7	813.3	369.2	19.3	39.9	B
8420	20.0	2	1.0050	27.3	10850.0	5226.4	22.8	1092.2	B
12040	400	1	1.0412	26.1	507.7	344.6	30.5	403.2	A
12065	400	2	1.0230	33.7	0.0	0.0	4601.9	7399.3	A
13000	400	1	1.0097	23.0	0.0	0.0	0.0	0.0	A
13005	400	1	1.0126	23.7	0.0	0.0	0.0	0.0	A
13010	400	1	0.9972	18.2	0.0	0.0	0.0	0.0	A
13020	400	1	1.0091	23.2	0.0	0.0	0.0	0.0	A
13030	400	1	1.0100	20.9	0.0	0.0	0.0	0.0	A
13035	400	1	1.0014	22.0	0.0	0.0	0.0	0.0	A
13045	400	1	0.9993	18.3	137.3	38.0	0.0	0.0	A
13050	400	1	0.9877	15.7	0.0	0.0	0.0	0.0	A

Appendix A.5

BUS#	BSKV	CODE	VOLT	ANGLE	PLOAD	QLOAD	S H U N T		AREA
13055	400	1	0.9875	15.7	0.0	0.0	0.0	0.0	A
13058	400	1	1.0115	17.2	0.0	0.0	0.0	0.0	A
13060	400	1	0.9966	17.3	209.4	98.9	0.0	0.0	A
13065	400	1	1.0115	24.0	0.0	0.0	0.0	0.0	A
13070	400	1	1.0086	23.8	0.0	0.0	0.0	0.0	A
13075	400	1	0.9868	15.3	0.0	0.0	0.0	0.0	A
14000	400	2	1.0420	27.4	6317.4	3232.6	2145.1	3472.6	A
14060	400	1	0.9830	17.0	1337.5	349.7	-4.6	273.3	A
14105	400	1	0.9992	22.4	3257.0	1666.6	156.9	1604.6	A
18105	400	1	0.9972	18.0	1245.7	350.0	2.6	413.8	B
18135	400	2	1.0489	26.4	592.0	150.0	-0.8	672.7	B
18140	400	1	1.0460	23.7	-464.2	123.5	16.7	-3.7	B
18150	400	1	1.0488	25.2	133.2	75.0	16.2	56.7	B
18170	400	1	1.0407	33.6	-1029.9	2213.0	-36.7	2648.6	B
18240	400	2	1.0424	40.5	336.3	218.9	2.0	174.9	B
18290	400	1	1.0427	16.8	792.1	680.7	14.5	699.7	B
18415	400	1	1.0492	16.0	1925.0	1814.6	-27.5	2368.9	B
18500	400	1	1.0465	36.5	-1939.3	207.2	3.0	513.8	B
18540	400	1	1.0387	23.5	454.5	216.1	8.9	440.2	B
18610	400	2	1.0395	38.8	2115.4	1072.7	10.3	645.1	B
18790	400	1	1.0316	19.7	1304.9	727.0	33.9	679.9	B
18791	400	1	1.0310	19.7	1320.3	737.3	33.9	679.9	B
18935	400	1	1.0476	19.4	166.2	26.3	-0.6	73.9	B
22025	220	1	1.0682	23.5	122.5	36.8	-5.3	111.5	A
22335	220	1	1.0590	21.2	190.6	155.2	-2.1	215.3	A
23040	220	1	1.0653	19.6	-7.6	12.2	-5.5	17.8	A
23075	220	1	1.0514	18.2	140.1	10.8	-59.4	156.1	A
23095	220	1	1.0410	23.3	-132.5	75.6	-130.5	400.9	A
23210	220	1	1.0634	17.7	209.8	-8.0	-123.9	317.8	A
23245	220	1	1.0456	11.8	546.7	154.2	46.2	110.9	A
23250	220	1	1.0453	11.7	1160.7	230.4	-34.3	377.0	A
23295	220	1	1.0518	12.7	561.4	100.6	6.0	109.4	A
23375	220	1	1.0644	19.3	72.2	24.2	-95.2	391.2	A
23390	220	1	1.0432	10.8	388.8	72.4	0.0	12.1	A
28040	220	1	1.0830	21.8	195.0	71.8	-16.1	161.2	B
28045	220	1	1.0619	20.3	150.0	167.3	-22.4	214.4	B
28095	220	1	1.0499	19.4	183.1	45.7	0.7	63.2	B
28135	220	1	1.0645	19.7	1010.3	154.7	-25.7	482.7	B
28250	220	1	1.1058	20.4	-121.0	214.4	-29.7	268.2	B

CODE 1: LOAD BUS (NO GENERATION)
CODE 2: GENERATOR OR PLANT BUS
CODE 3: SWING BUS

Appendix A.5

. BRANCHES DATA (at t=to):

FROM	TO	CKT	LINE R	LINE X	CHRGING	TP	ST
301	310*	1	0.0000	0.5585	0.0000	T	1
301	311*	1	0.0000	0.5585	0.0000	T	1
301	3608*	1	0.0000	-0.1064	0.0000	T	1
302	320*	1	0.0000	0.5585	0.0000	T	1
302	321*	1	0.0000	0.5585	0.0000	T	1
302	3609*	1	0.0000	-0.1064	0.0000	T	1
312	3608*	1	0.0000	0.4166	0.0000	T	1
322	3609*	1	0.0000	0.4166	0.0000	T	1
2770*	12040	99	0.0024	0.1087	0.0000		1
2770*	12065	98	0.0052	0.2859	0.0000		1
2770*	12065	99	0.0035	0.0870	0.0000		1
3608	13005*	2	0.0002	0.0150	0.0000	T	1
3609	13005*	1	0.0002	0.0150	0.0000	T	1
3615*	23245	99	0.0020	0.1510	0.0000		1
3615*	23250	99	0.0029	0.0771	0.0000		1
3615*	23295	99	-0.0043	0.2170	0.0000		1
3640*	23295	99	0.0139	0.2162	0.0000		1
3664*	23245	99	0.0026	0.1338	0.0000		1
3664*	23250	99	0.0060	0.0706	0.0000		1
3664*	23295	99	0.0070	0.1780	0.0000		1
3771	13065*	1	0.0004	0.0158	0.0000	T	1
3781	13070*	3	0.0002	0.0161	0.0000	T	1
3800	13005*	3	0.0012	0.0466	0.0000	T	1
3801	13070*	1	0.0012	0.0466	0.0000	T	1
3805*	3865	99	0.0120	0.0155	0.0000		1
3805	13020*	1	0.0004	0.0344	0.0000	T	1
3805*	23075	99	0.0363	0.0829	0.0000		1
3805*	23095	99	0.0123	0.0330	0.0000		1
3805*	23210	99	0.0177	0.0401	0.0000		1
3805*	23245	99	-0.1568	-0.1362	0.0000		1
3805*	23250	99	0.0235	0.1083	0.0000		1
3805*	23375	99	0.0133	0.0411	0.0000		1
3865	13030*	6	0.0003	0.0582	0.0000	T	1
3865*	23095	99	-0.2616	-0.1978	0.0000		1
3865*	23245	99	0.0346	0.0773	0.0000		1
3865*	23250	99	0.0839	0.2303	0.0000		1
3900	13050*	1	0.0001	0.0290	0.0000	T	1
3900	23245*	1	0.0001	-0.0072	0.0000	T	1
3950	13060*	2	0.0002	0.0323	0.0000	T	1
3950	23295*	2	0.0002	-0.0069	0.0000	T	1
3955	13060*	1	0.0002	0.0321	0.0000	T	1
3955	23295*	1	0.0002	-0.0064	0.0000	T	1
3980	13075*	9	0.0003	0.0583	0.0000	T	1
3980	23390*	9	0.0001	-0.0139	0.0000	T	1

Appendix A.5

FROM	TO	CKT	LINE R	LINE X	CHRGING	TP	ST
4760*	14000	99	0.0260	0.6156	0.0000		1
4760*	14060	99	0.0014	0.0295	0.0000		1
4760*	14105	98	0.0048	0.1174	0.0000		1
4760*	14105	99	0.0078	0.1926	0.0000		1
8005*	8015	99	0.0006	0.0182	0.0000		1
8005*	8030	99	0.0005	0.1401	0.0000		1
8005*	8046	99	0.0019	0.1375	0.0000		1
8005*	8060	99	0.1188	1.4971	0.0000		1
8005*	8420	99	0.0025	0.0977	0.0000		1
8005*	18170	99	0.0127	0.2102	0.0000		1
8005*	18290	99	0.0206	0.6162	0.0000		1
8005*	18415	99	0.0102	0.1348	0.0000		1
8005*	18500	99	0.0717	1.1236	0.0000		1
8005*	18790	99	-0.0261	0.9409	0.0000		1
8005*	18791	99	-0.0261	0.9409	0.0000		1
8015*	8030	99	0.0006	0.1137	0.0000		1
8015*	8046	99	0.0018	0.1111	0.0000		1
8015*	8060	99	0.0821	0.9775	0.0000		1
8015*	8420	99	0.0022	0.0733	0.0000		1
8015*	18170	99	0.0088	0.1335	0.0000		1
8015*	18290	99	0.0111	0.3029	0.0000		1
8015*	18415	99	0.0056	0.0705	0.0000		1
8015*	18500	99	0.0438	0.6180	0.0000		1
8015*	18790	99	-0.0119	0.4499	0.0000		1
8015*	18791	99	-0.0119	0.4499	0.0000		1
8030*	8046	99	0.0003	0.0039	0.0000		1
8030*	8060	99	0.0241	0.3441	0.0000		1
8030*	8420	99	0.0006	0.0255	0.0000		1
8030*	18170	99	0.0116	0.1568	0.0000		1
8030*	18290	99	0.0618	1.8678	0.0000		1
8030*	18415	99	0.0263	0.3513	0.0000		1
8030*	18500	99	0.0925	1.5915	0.0000		1
8030*	18790	99	-0.0709	3.0695	0.0000		1
8030*	18791	99	-0.0709	3.0695	0.0000		1
8030*	28095	99	0.6616	9.7444	0.0000		1
8046*	8060	99	0.0001	0.0327	0.0000		1
8046*	8420	99	0.0013	0.0336	0.0000		1
8046*	18170	99	0.0023	0.0406	0.0000		1
8046*	18290	99	0.0780	1.6909	0.0000		1
8046*	18415	99	0.0255	0.3010	0.0000		1
8046*	18500	99	0.0215	0.5538	0.0000		1
8046*	18790	99	-0.0261	2.8046	0.0000		1
8046*	18791	99	-0.0261	2.8046	0.0000		1
8046*	28095	99	-0.0061	0.6015	0.0000		1

Appendix A.5

FROM	TO	CKT	LINE R	LINE X	CHRGING	TP	ST
8060*	8420	99	0.0403	0.5205	0.0000		1
8060*	18170	99	0.0011	0.0147	0.0000		1
8060*	18290	99	0.2341	3.2490	0.0000		1
8060*	18415	99	0.0527	0.5019	0.0000		1
8060*	18500	99	0.0227	0.3626	0.0000		1
8060*	18790	99	0.0958	5.4999	0.0000		1
8060*	18791	99	0.0958	5.4999	0.0000		1
8060*	28095	99	-0.0007	0.1087	0.0000		1
8206*	8327	99	-0.0787	2.6202	0.0000		1
8206*	18105	99	0.0039	0.0810	0.0000		1
8206*	18135	99	0.0013	0.0352	0.0000		1
8206*	18150	99	0.0141	0.2434	0.0000		1
8206*	18240	99	0.0117	1.1896	0.0000		1
8206*	18540	99	0.0172	0.3389	0.0000		1
8206*	18610	99	0.0022	0.2429	0.0000		1
8206*	18935	99	0.0340	0.6231	0.0000		1
8206*	28045	99	0.0267	0.2368	0.0000		1
8206*	28135	99	0.0443	3.1888	0.0000		1
8285*	18540	99	0.0005	0.0156	0.0000		1
8327*	18105	99	0.0104	0.5849	0.0000		1
8327*	18135	99	0.1079	4.9121	0.0000		1
8327*	18240	99	0.0125	0.2388	0.0000		1
8327*	18540	99	0.0512	2.4467	0.0000		1
8327*	18610	99	0.0025	0.0487	0.0000		1
8327*	28045	99	0.8269	9.8108	0.0000		1
8327*	28135	99	0.0066	0.0833	0.0000		1
8420*	18170	99	0.0055	0.0851	0.0000		1
8420*	18290	99	0.0181	0.4694	0.0000		1
8420*	18415	99	0.0072	0.0890	0.0000		1
8420*	18500	99	0.0376	0.6169	0.0000		1
8420*	18790	99	-0.0134	0.7721	0.0000		1
8420*	18791	99	-0.0134	0.7721	0.0000		1
12040	12065*	98	0.0028	0.0262	0.0000		1
12040*	12065	99	0.0072	0.0832	0.0000		1
12040*	18150	1	0.0025	0.0259	0.7399		1
12040*	22025	99	0.0015	0.0274	0.0000		1
12040*	22335	98	0.0105	0.1290	0.0000		1
12040*	22335	99	0.0476	0.2518	0.0000		1
12065*	13020	1	0.0077	0.0797	1.1875		1
12065*	14000	97	-0.0121	0.0583	0.0000		1
12065*	14000	98	-0.0085	0.0402	0.0000		1
12065*	14000	99	-0.0406	0.1245	0.0000		1
12065	14105*	1	0.0031	0.0229	0.6648		1
12065*	14105	97	0.0031	0.0325	0.0000		1

Appendix A.5

FROM	TO	CKT	LINE R	LINE X	CHRGING	TP	ST
12065*	14105	98	0.0034	0.0395	0.0000		1
12065*	14105	99	0.0035	0.0346	0.0000		1
12065*	22025	99	0.0326	0.2389	0.0000		1
12065*	22335	98	0.0132	0.1389	0.0000		1
12065*	22335	99	0.0374	0.3634	0.0000		1
13000	13005*	2	0.0014	0.0136	0.4322		1
13000*	13020	1	0.0002	0.0026	0.0732		1
13000*	13030	1	0.0010	0.0109	0.3069		1
13000*	13035	1	0.0014	0.0140	0.4023		1
13000*	13065	1	0.0005	0.0050	0.1754		1
13000*	13065	2	0.0005	0.0050	0.1754		1
13000	14060*	1	0.0029	0.0284	0.8877		1
13005*	13010	1	0.0025	0.0240	0.7361		1
13005*	13045	1	0.0027	0.0270	0.8252		1
13005*	13060	1	0.0029	0.0278	0.8866		1
13005*	13060	2	0.0029	0.0278	0.8857		1
13005*	13070	1	0.0007	0.0071	0.2249		1
13005	13070*	2	0.0007	0.0071	0.2249		1
13010*	13050	1	0.0006	0.0061	0.1870		1
13010	13060*	1	0.0013	0.0125	0.3812		1
13010*	13070	1	0.0023	0.0238	0.7366		1
13030	13050*	1	0.0028	0.0309	0.8649		1
13035	23210*	1	0.0009	0.0510	0.0000	T	1
13045*	13060	1	0.0008	0.0081	0.2478		1
13050	13055*	1	0.0000	0.0003	0.0075		1
13050*	13075	1	0.0012	0.0130	0.3625		1
13050	23245*	2	0.0003	0.0238	0.0000	T	1
13055	23250*	1	0.0003	0.0227	0.0000	T	1
13058*	13060	1	0.0032	0.0304	0.9686		1
13058*	13060	2	0.0032	0.0304	0.9686		1
13060	23295*	3	0.0004	0.0255	0.0000	T	1
13070*	14060	1	0.0030	0.0317	0.8748		1
13075*	18105	1	0.0020	0.0223	0.6234		1
13075	23390*	1	0.0012	0.0821	0.0000	T	1
14000*	14060	99	0.0628	0.5048	0.0000		1
14000*	14105	98	0.0026	0.0290	0.0000		1
14000*	14105	99	0.0014	0.0143	0.0000		1
14060*	14105	98	0.0108	0.0883	0.0000		1
14060*	14105	99	0.0194	0.1578	0.0000		1
18105*	18135	99	0.0151	0.1513	0.0000		1
18105*	18150	99	0.1255	1.0445	0.0000		1
18105*	18240	99	0.0153	0.2650	0.0000		1
18105*	18540	99	0.0074	0.0754	0.0000		1
18105*	18610	99	0.0031	0.0541	0.0000		1

Appendix A.5

FROM	TO	CKT	LINE R	LINE X	CHRGING	TP	ST
18105*	18935	99	0.3122	2.6741	0.0000		1
18105*	28045	99	0.0490	0.3007	0.0000		1
18105*	28135	99	0.0438	0.7103	0.0000		1
18135*	18150	99	0.0012	0.0142	0.0000		1
18135*	18240	99	0.1379	2.2255	0.0000		1
18135*	18540	99	0.0653	0.6326	0.0000		1
18135*	18610	99	0.0278	0.4544	0.0000		1
18135	18790*	1	0.0006	0.0089	0.2773		1
18135	18791*	2	0.0006	0.0089	0.2773		1
18135*	18935	99	0.0032	0.0373	0.0000		1
18135*	28045	99	0.0730	0.4406	0.0000		1
18135*	28135	99	0.3936	5.9644	0.0000		1
18140*	18415	1	0.0060	0.0432	1.1466		1
18140*	18540	99	0.0010	0.0117	0.0000		1
18140*	28250	99	0.0093	0.0716	0.0000		1
18150*	18540	99	0.5390	4.3677	0.0000		1
18150*	18610	99	0.2554	3.1399	0.0000		1
18150*	18935	99	0.0283	0.2749	0.0000		1
18150*	28040	99	0.0050	0.0760	0.0000		1
18150*	28045	99	0.5657	3.0383	0.0000		1
18170*	18240	1	0.0025	0.0283	0.7799		1
18170*	18240	2	0.0025	0.0283	0.7799		1
18170*	18290	99	0.0245	0.3721	0.0000		1
18170*	18415	99	0.0039	0.0420	0.0000		1
18170*	18500	99	0.0003	0.0036	0.0000		1
18170*	18790	99	0.0072	0.6519	0.0000		1
18170*	18791	99	0.0072	0.6519	0.0000		1
18170*	28095	99	0.0264	0.6056	0.0000		1
18240*	18500	1	0.0016	0.0187	0.5143		1
18240*	18500	2	0.0016	0.0186	0.5120		1
18240*	18540	99	0.0675	1.1086	0.0000		1
18240*	18610	99	0.0002	0.0027	0.0000		1
18240*	28045	99	0.5526	4.4339	0.0000		1
18240*	28135	99	0.0280	0.2895	0.0000		1
18290*	18415	99	0.0014	0.0154	0.0000		1
18290*	18500	99	0.0770	0.8152	0.0000		1
18290*	18540	1	0.0043	0.0469	1.2800		1
18290*	18790	99	0.0175	0.2591	0.0000		1
18290*	18791	99	0.0175	0.2591	0.0000		1
18290*	18935	1	0.0016	0.0179	0.4788		1
18290*	28250	1	0.0004	0.0282	0.0000	F	1
18415*	18500	99	0.0030	0.0469	0.0000		1
18415*	18790	99	0.0092	0.1831	0.0000		1
18415*	18791	99	0.0092	0.1831	0.0000		1

Appendix A.5

FROM	TO	CKT	LINE R	LINE X	CHRGING	TP	ST
18500*	18790	99	0.0860	1.6351	0.0000		1
18500*	18791	99	0.0860	1.6351	0.0000		1
18540*	18610	99	0.0136	0.2263	0.0000		1
18540*	28045	99	0.2092	1.2571	0.0000		1
18540*	28135	99	0.1929	2.9710	0.0000		1
18540*	28250	99	0.0259	0.1194	0.0000		1
18610*	18935	99	0.6272	8.0378	0.0000		1
18610*	28045	99	0.1122	0.9054	0.0000		1
18610*	28135	99	0.0057	0.0591	0.0000		1
18790*	18791	99	0.0021	0.0295	0.0000		1
18935*	28045	99	1.4221	7.7804	0.0000		1
22025*	22335	98	0.0534	0.2440	0.0000		1
22025*	22335	99	0.0547	0.1571	0.0000		1
22025*	28040	1	0.0053	0.0335	0.0623		1
22335*	23075	1	0.0082	0.0476	0.0710		1
22335*	23375	1	0.0174	0.0558	0.1518		1
23040*	23375	99	0.0032	0.0126	0.0000		1
23040*	28045	1	0.0083	0.0419	0.0631		1
23075*	23210	99	0.0089	0.0745	0.0000		1
23245	23250*	5	0.0002	0.0011	0.0018		1
23245	23250*	6	0.0002	0.0011	0.0018		1
23245*	23250	99	0.0023	0.0128	0.0000		1
23245*	23295	99	0.0033	0.0267	0.0000		1
23245*	23375	99	0.0856	0.3633	0.0000		1
23250*	23295	99	0.0013	0.0078	0.0000		1
23295*	23390	99	0.0044	0.0318	0.0000		1
28095*	28135	1	0.0086	0.0432	0.1111		1

. If CKT=97 or 98 or 99 --> Equivalent line.

. TP:

T --> Taps on side TO
F --> Taps on side FROM

However, the taps are locked in the load-flow resolution and in the dynamic simulation.

Appendix A.5

. TRANSFORMER DATA (at t=to):

FROM	TO	CKT	TP	RATIO	ANGLE	RG
301	310	1	T	1.0000	0.00	1
301	311	1	T	1.0000	0.00	1
301	3608	1	T	1.0000	0.00	1
302	320	1	T	1.0000	0.00	1
302	321	1	T	1.0000	0.00	1
302	3609	1	T	1.0000	0.00	1
312	3608	1	T	1.0000	0.00	1
322	3609	1	T	1.0000	0.00	1
3608	13005	2	T	1.0181	0.00	1
3609	13005	1	T	1.0181	0.00	1
3771	13065	1	T	1.0122	0.00	1
3781	13070	3	T	1.0499	0.00	1
3800	13005	3	T	0.9847	0.00	1
3801	13070	1	T	0.9847	0.00	1
3805	13020	1	T	1.0918	0.00	1
3865	13030	6	T	1.0000	0.00	1
3900	13050	1	T	0.9550	0.00	1
3900	23245	1	T	1.0227	0.00	1
3950	13060	2	T	1.0000	0.00	1
3950	23295	2	T	1.0716	0.00	1
3955	13060	1	T	1.0000	0.00	1
3955	23295	1	T	1.0716	0.00	1
3980	13075	9	T	0.9550	0.00	1
3980	23390	9	T	1.0227	0.00	1
13035	23210	1	T	1.0964	0.00	1
13050	23245	2	T	1.0685	0.00	1
13055	23250	1	T	1.0716	0.00	1
13060	23295	3	T	1.0714	0.00	1
13075	23390	1	T	1.0873	0.00	1
18290	28250	1	F	0.9284	0.00	1

RG=1 --> taps are locked.

Appendix A.5

. GENERATOR DATA (at t=to):

BUS#	MACHINE#	BSKV	PGEN	QGEN	MBASE	AREA
2770	13	20.0	458	83	575	A
3608	14	21.0	926	191	1034	A
3609	15	21.0	919	190	1034	A
3615	16	21.0	123	65	437	A
3640	17	10.9	142	9	200	A
3664	18	19.0	127	18	630	A
3771	19	18.0	707	105	778	A
3781	20	21.0	996	124	1092	A
4760	21	20.0	978	-110	1083	A
8005	3	20.0	12639	4759	14020	B
8015	4	20.0	15959	5797	17700	B
8030	5	20.0	26602	10671	29500	B
8046	6	20.0	41165	13194	45530	B
8060	7	20.0	18367	6843	20370	B
8206	8	20.0	1343	164	1650	B
8285	1	20.0	676	-60	750	B
8327	2	20.0	815	297	960	B
8420	9	20.0	12904	4186	14310	B
12065	22	400	9129	-7559	12000	A
14000	23	400	9097	-107	12000	A
18135	10	400	3734	-85	4480	B
18240	11	400	3650	-131	4844	B
18610	12	400	2815	610	3360	B

Machines including transformer:

BUS#	MACHINE#	BSKV	AREA	XTRAN		GENTAP
12065	22	400	A	0.0000	0.1100	0.9700
14000	23	400	A	0.0000	0.1100	1.0000
18135	10	400	B	0.0027	0.1418	1.0380
18240	11	400	B	0.0032	0.1567	1.0380
18610	12	400	B	0.0058	0.3064	1.0475

Area	Generation MW	MVAR
A	23602.6	-6990.5
B	140669.5	46244.8

APPENDIX A.5.3

DYNAMIC DATA

Appendix A.5

. MODELS OF EXCITATION SYSTEMS AND GOVERNORS/TURBINES:

MACHINE#	BUS#	AREA	EXCIT. SYS.	GOVERNORS
1	8285	B	EXAC4	TGOV3
2	8327	B	EXAC4	IEEEG1
3	8005	B	SEXS	IEEEG1
4	8015	B	SEXS	IEEEG1
5	8030	B	SEXS	IEEEG1
6	8046	B	SEXS	IEEEG1
7	8060	B	SEXS	IEEEG1
8	8206	B	SEXS	IEEEG1
9	8420	B	SEXS	IEEEG1
10	18135	B	SEXS	IEEEG1
11	18240	B	SEXS	IEEEG1
12	18610	B	SEXS	IEEEG1
13	2770	A	IEEEX1	TGOV1
14	3608	A	IEEEX1	TGOV3
15	3609	A	IEEEX1	TGOV3
16	3615	A	SEXS	TGOV1
17	3640	A	SEXS	TGOV1
18	3664	A	SEXS	TGOV1
19	3771	A	IEEX2A	IEEEG1
20	3781	A	IEEEX1	TGOV3
21	4760	A	IEEEX1	IEEEG1
22	12065	A	IEEX2A	IEEEG1
23	14000	A	IEEEX1	TGOV3

. MACHINES INCLUDING AGC AND POWER PLANT MODEL:

MACHINE#	BUS#	AREA
16	3615	A
18	3664	A
22	12065	A
23	14000	A

Appendix A.5

. REDUCED ORDER STEAM PLANT MODEL

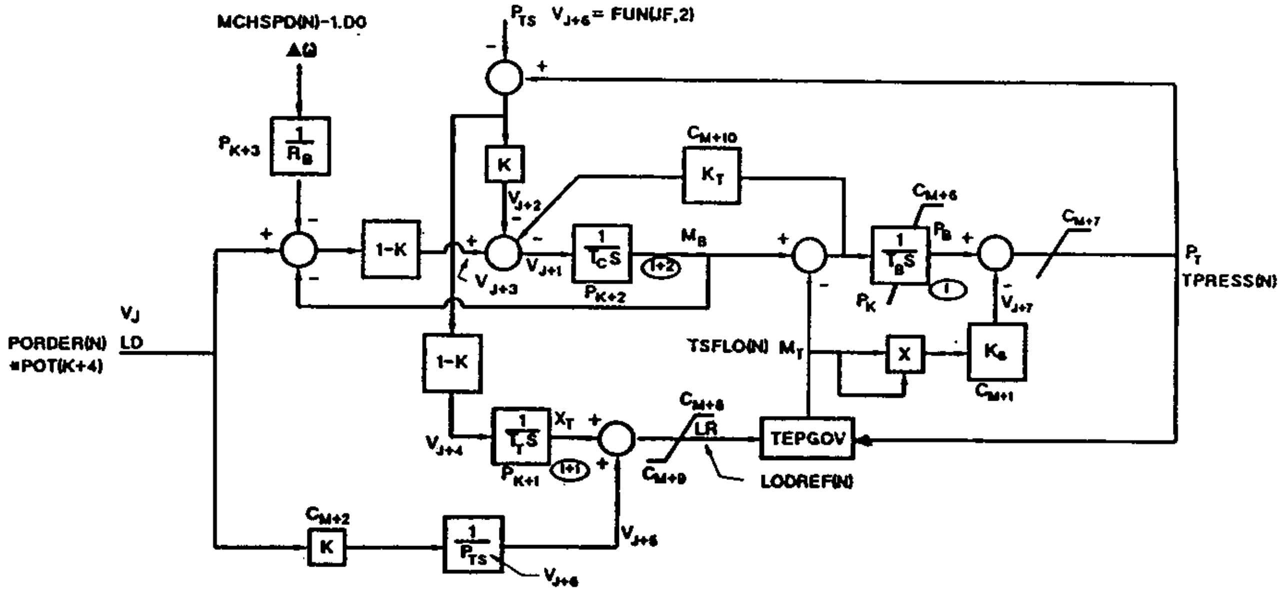
The following model has been used to represent the steam plant dynamics.

This model is provided by EXSTAB program (ROKIPU), and it has been included in EUROSTAG simulation using the macro-block language.

TEPCO XIII

REDUCED ORDER STEAM PLANT MODEL

(All Variables Per Unit)



LD = Load Demand
P_T = Throttle Pressure
C_{M+1} K_S = Superheater Pressure Drop Factor
C_{M+6} T_B = Boiler Storage TC (sec)
C_{M+3} T_C = Boiler Control TC (sec)
C_{M+4} T_T = Turbine Control TC (sec)
C_{M+2} K = Control Selection Factor:
- $K = 1$ Boiler Follow
- $0<K<1$ Coordinated
- $K = 0$ Turbine Follow

LR = Turbine Load Reference = LODREF
O_I P_B = Boiler Pressure
O_{I+2} M_B = "Boiler Steam Flow"
M_T = Turbine Steam Flow = TSFLO
C_M R_B = Speed Regulation
C_{M+10} K_T = Control Tuning Parameter
$\Delta\omega$ = Speed Error = MCHSPD - 1

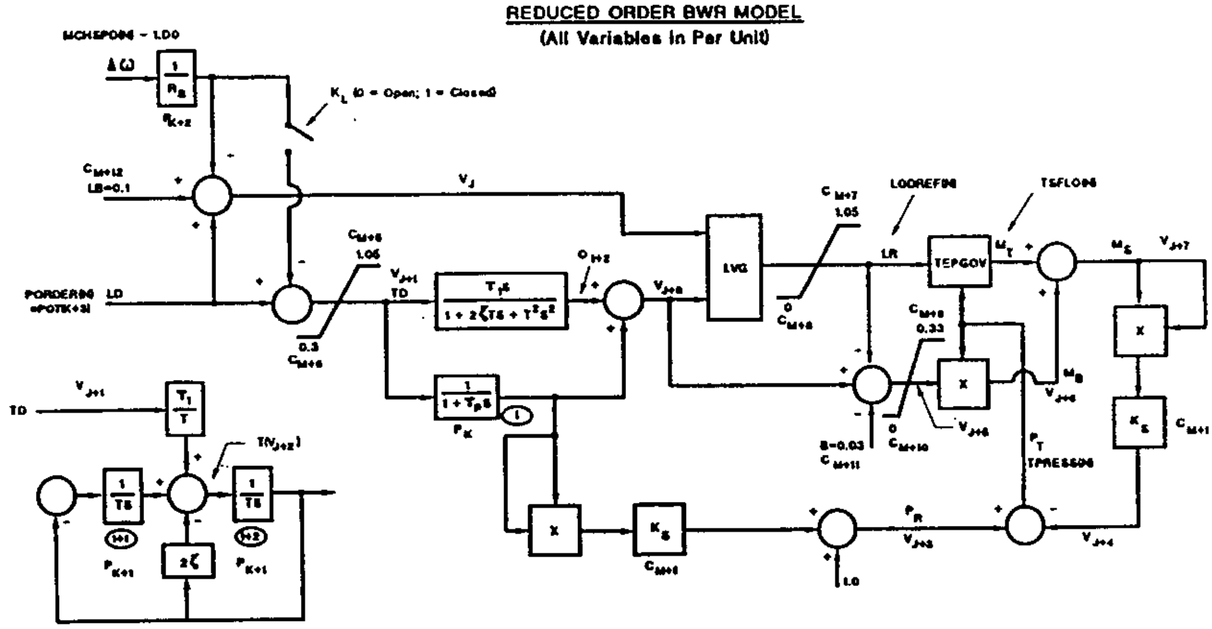
Appendix A.5

. REDUCED ORDER BWR MODEL

The following model has been used to represent the BWR nuclear plant dynamics.

This model is provided by EXSTAB program (ROBWR), and it has been included in EUROSTAG simulation using the macro-block language.

TEPCO XIII
REDUCED ORDER BWR MODEL
(All Variables in Per Unit)



LD = Load Demand = PORDER	LR = Turbine Load Reference = LODREF
P_T = Throttle Pressure = TPRESS	V_{J+3} P_R = Reactor Pressure
C_{M+1} K_s = Steam Flow Pressure Drop Factor	M_T = Turbine Steam Flow = TSFLO
C_{M+3} T = Oscillation Period (sec.)	V_{J+6} M_B = Bypass Steam Flow
C_{M+2} ζ = Oscillation Damping Factor	V_{J+7} M_S = Total Steam Flow
C_{M+13} T_1 = Oscillation Rate TC (sec.)	C_M R_B = Speed Regulation
C_{M+4} T_P = Power Response TC (sec.)	$\Delta\omega$ = Speed Error = MCHSPD-1

Appendix A.5

STEAM PLANT MODEL INPUT CONSTANT: (units 16, 18 and 22)

- CM+0 :	Speed regulation:	0.05	
- CM+1 :	Superheater pressure drop factor:	0.08	
- CM+2 :	Control selection factor:	1	
- CM+3 :	Boiler control time constant:	20	sec.
- CM+4 :	Turbine control time constant:	5	sec.
- CM+5 :	Boiler storage time constant:	20	sec.
- CM+6 :	Boiler pressure high limit:	1.25	p.u.
- CM+7 :	Throttle pressure high limit:	1.2	p.u.
- CM+8 :	Turbine reference high limit:	1.05	p.u.
- CM+9 :	Turbine load reference low limit:	0.2	p.u.
- CM+10:	Tuning gain:	0.5	p.u.
- CM+11:	High delta freq. trip point:	0.05	p.u.
- CM+12:	Low delta freq. trip point:	-0.05	p.u.
- CM+13:	High voltage trip point:	1.2	p.u.
- CM+14:	Low voltage trip point:	0.1	p.u.
- CM+15:	Turbine base (MW) for machine M: Unit 16: 437,, Unit 18: 630,, Unit 22: 12000		
- CM+16:	Turbine base (MW) for macine M+1: (Cross compound units only)	0	
- CM+17:	Voltage trip delay time:	0.21	sec.

BWR MODEL INPUT CONSTANT: (Unit 23)

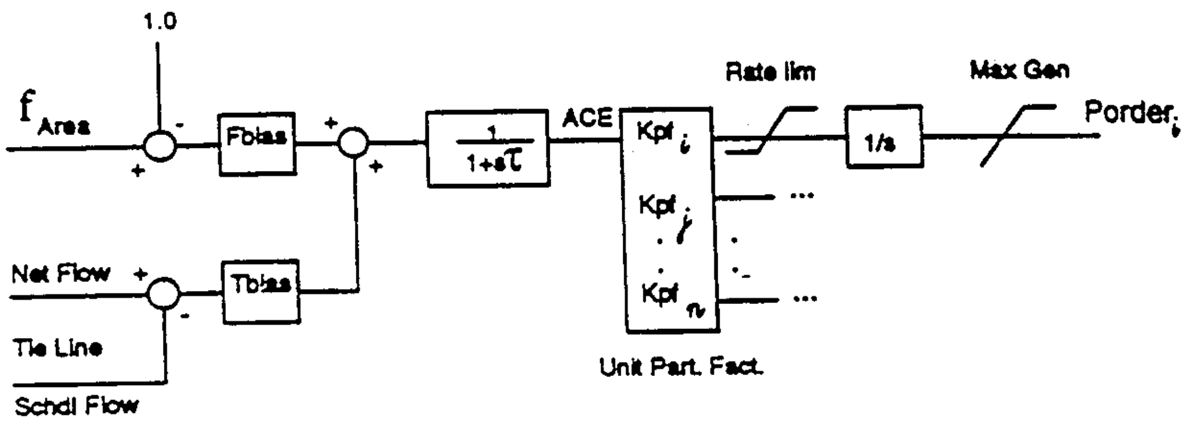
- CM+0 :	Speed regulation:	0.04	
- CM+1 :	Superheater pressure drop factor:	0.08	
- CM+2 :	Oscillation damping factor:	0.2	
- CM+3 :	Oscillation period:	1.6	sec.
- CM+4 :	Power response time constant:	3	sec.
- CM+5 :	Total demand upper limit:	1.05	p.u.
- CM+6 :	Total demand lower limit:	0.3	p.u.
- CM+7 :	Load reference upper limit:	1.05	p.u.
- CM+8 :	Load reference lower limit:	0	
- CM+9 :	Bypass valve upper limit:	0.33	
- CM+10:	Bypass valve lower limit:	0	p.u.
- CM+11:	Bypass bias:	0.03	p.u.
- CM+12:	Load bias:	0.1	p.u.
- CM+13:	Oscillation rate time constant:	0.7	p.u.
- CM+14:	High delta freq. trip point:	0.99	p.u.
- CM+15:	Low delta freq. trip point:	-0.99	p.u.
- CM+16:	High voltage trip point:	1.2	p.u.
- CM+17:	Low voltage trip point:	0.1	p.u.
- CM+18:	Turbine base (MW):	12000	
- CM+19:	Voltage trip delay time:	0.21	sec.

Appendix A.5

. LOAD-FREQUENCY CONTROL

To provide the overall AGC characteristic, but reduce the model complexities, a simplified AGC model, called SMPAGC, is included in EXSTAB program.

A similar model has also been included using the macro-block language in EUROSTAG simulation.



Tbias= 1 p.u. ,, Fbias= 2000MW/Hz (the value used in the program has units of p.u. MW (in system MVA base) per p.u. frequency,),, τ=3 sec.

	UNIT			
	16	18	22	23
Part. Factor (K)	0.3	0.3	0.3	0.1
Upward rate limit	0.016	0.0063	0.01	0.01
Down rate limit	-0.016	-0.0063	-0.01	-0.01
Max. Gen. limit	0.801	0.846	1	1
Min. Gen. limit	0.229	0.158	0.2	0.2

Upward and down rate limits are in p.u. MW on each generating unit's turbine MW base per minute, these limits are converted by the model to p.u. on system MVA base per second. Max. and Min. limits are also given in each generating unit's turbine MW base and converted internally to system MVA base.

APPENDIX A.5.4

CALCULATIONS

Appendix A.5

. Center of inertia

The center of inertia angle is calculated as:

$$\frac{\left[\ \sum_i inertia(i) * angle(i)\ \right]}{\sum_i inertia(i)}$$

Where the summations are over the number of generators in the island where the machine is located.

. Frequency calculation

- The frequency into the AGC is the area frequency calculated as:

$$\frac{\left[\ \sum_i inertia(i) * genspeed(i)\ \right]}{\sum_i inertia(i)}$$

Where the summations are over the number of generators in the dispatch area where the machine is located.

- The frequency signal used for the load models and for the load-shedding system is the individual bus frequency computed as the numerical derivative of the bus voltage angle:

$$\mathbf{f} = \frac{\mathbf{f'} + {(\theta - \theta')}/{(360 \cdot \mathbf{h} \cdot \mathbf{f_0})}}{2}$$

f,f'- p.u. frequency at present time step and last time step.
Θ,Θ'- angle (degrees) at present time step and last time step.
h - time step (seconds).
fo - System base frequency (Hz.).

For load models and for the load-shedding system EUROSTAG has used a frequency that is calculated as the center of inertia of all machines. Please, see the above AGC frequency description.

APPENDIX B.1

INTEGRATION ALGORITHM USED IN MODES PROGRAM

Appendix B1 Integration Algorithm Used in MODES Program

1. Network Model

It is possible to neglect the electromagnetic phenomena for the purpose of electromechanical and long term transient modelling. The symmetrical network and load are another presumptions, so that only the positive sequence components are taken into account. The network admittance matrix method is suitable for the description. A per unit shorthand matrix notation is simply:

$$\underline{I}_{INJ} = \underline{Y} * \underline{U} \qquad [1]$$

Where $\underline{I}_{INJ}$ is a injected currents vector and $\underline{U}$ is a nodal voltages vector. $\underline{Y}$ is a network admittance matrix.

2. Generator Model

2.1. Synchronous Machine Equations

The following presumptions are taken into account:
a) the electromagnetic phenomena in stator circuits are neglected
b) $X''_d = X''_q$ and the stator resistance is neglected
d) the speed deviations are small
e) the reactances are constant parameters (no saturation)
f) the 1st harmonic of electromotive force is taken into account only
g) the excitation winding is concentric
h) the damping winding (or massive rotor influence) is substituted by one equivalent concentric .
.....winding in each axis
i) the hysteresis losses are neglected, the eddy current losses are covered by an equivalent damping
.....winding resistance.

It is possible to write the Park equation in per unit for the rotor windings:

$$T'_{d0} * E'_q{}^{\circ} = U_{EXC} + (X_d - X'_d) * I_d - E'_q \qquad [2]$$

$$T''_{d0} * E''_q{}^{\circ} = E_q' + (X'_d - X''_d) * I_d - E''_q \qquad [3]$$

$$T''_{q0} * E''_d{}^{\circ} = (X_q - X''_d) * I_q - E''_d \qquad [4]$$

E'_q, E''_q, E''_d..........d,q components of the electromotive forces
I_d, I_q....................d,q components of stator current
U_{EXC}...................excitation voltage
$T'_{d0}, T''_{d0}, T''_{q0}$......time constants
X_d, X'_d, X''_d...........synchronous, transient and subtransient reactances.

These equations were published in /1/. The reference values are the nominal stator current, terminal voltage and no-load excitation voltage.

The swing equation is:

$$T_M * s_R{}^{\circ} = \frac{N_{TUR}}{1+s_R} - \frac{P_{GEN}}{1+s_U} \qquad [5]$$

$$\delta^{\circ} = s_R \qquad [6]$$

s_R, δ ...rotor slip and absolute rotor angle (between q rotor axis and synchronously rotating reference axis)
s_U........frequency deviation of the nodal voltage
N_{TUR}, P_{GEN}....mechanical turbine power and active generator power
T_M........mechanical time constant
°...........synchronous time derivation, where the synchronous time t is:

$$t = t * \Omega_0 \qquad [7]$$

t, Ω_0....current time ,synchronous speed 314 rad/s.

3. Coupling between Generator and Network

The equations [2] - [4] are valid for d,q co-ordinating system, which is fix connected with the rotor. The network equation [1] is valid for the synchronously rotating system. The relation between the both systems is seen from the following figure 1.

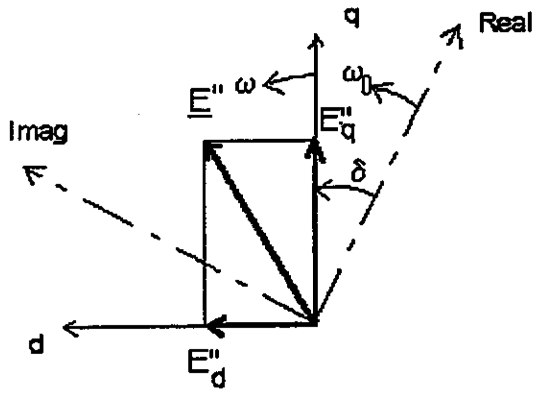


Fig. 1 The Relation between the Co-ordinating Systems

The transformation equations are:

$$E''_q + jE''_d = \underline{E}''{}^{*}\exp(-j\delta) \qquad \underline{E}'' = (E''_q + jE''_d)^{*}\exp(j\delta) \qquad [8]$$

These transformations are valit for all rotating vectors like voltages and currents.

Because the MODES program deals with the electromechanical transient, it is possible to neglect the electromagnetic phenomena in the stator windings and to substitute the generator by its electromotive force $\underline{E}''$. We will suppose $X''_d = X''_q$ and neglect stator resistance for simplification. If the generator is modelled together with its step-up transformer (it is not a part of the network model), the short circuit reactance and ratio are taken into account. A scheme is given below.

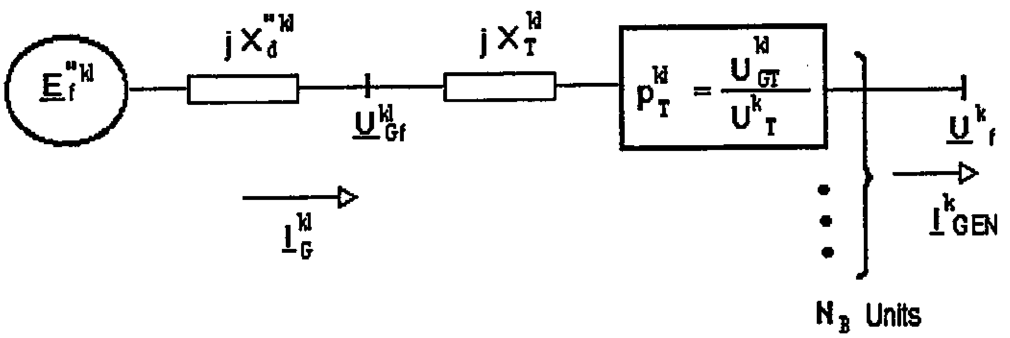


Fig.2 The Scheme of a Unit[l] Model Connecting to the Node[k]

X_T and X_{GEN} are the equivalent reactances seen from the network side and p_T is per unit ratio:

$$X_T = u_K \frac{S_V}{S_{Tn}} \left(\frac{U_{Tn}}{U_V}\right)^2 \quad X_{GEN} = X''_d \frac{S_V}{S_{GENn}} \left(\frac{U_{GENn}}{U_V}\right)^2 \quad p_T = p_T \frac{U_V}{U_{GENn}} \qquad [9]$$

u_K is per unit short circuit reactance and p_T is the turns number of generator side winding divided by turns number of network side winding. U_V and S_V are the network reference values.

4. Solving of Generator and Network Equations

4.1. Solution method

The proposed solution uses the simultaneous solution of the network equations and the rotor circuits equations [2] and [3]. These two equations were chosen, because the time constants T''_{d0}, T''_{q0} are very small, so that corresponding variables E''_d, E''_q are changing very "fast", when some discontinuities occur in the network. Another generator integrable variables E_q', s_R, δ change "slowly" and may be well predicted.

4.2. Solving of Generator Electric Equations

When we substitute dq components of the currents by the network voltages in equations [2] and [3], we obtain:

$$T''_d E''^{\circ}_q + E''_q = (1-\sigma_d) p_T U_q + \sigma_d E'_q \qquad [10]$$
$$T''_q E''^{\circ}_d + E''_d = (1-\sigma_q) p_T U_d$$

where :

$$\sigma_d = X''_d / X'_d \qquad \sigma_q = X''_d / X_q \qquad T''_d = \sigma_d T''_{d0} \qquad T''_q = \sigma_q T''_{q0} \qquad [11]$$

When the step-up transformer is modelled together with the generator, its equivalent reactance seen from the generator side is added to the generator reactances.

When we assume, that the variables on the right side of the equations [10] change by linear way during the integration step Δt, the solving of these equations are:

$$E''_q = E''_{qh} * \exp(-\Delta\tau_d) + \sigma_d E'_{qh}(1-\exp(-\Delta\tau_d)) - (1-\sigma_d) * p_T * U_{qh} * [\exp(-\Delta\tau_d) - (1-\exp(-\Delta\tau_d))/\Delta\tau_d] +$$
$$+ (1-\sigma_d) * p_T * U_q * [1-(1-\exp(-\Delta\tau_d))/\Delta\tau_d] +$$
$$+ \sigma_d \Delta E'_q [1-(1-\exp(-\Delta\tau_d))/\Delta\tau_d]$$

$$E''_d = E''_{dh} * \exp(-\Delta\tau_q) - (1-\sigma_q) * p_T * U_{dh} * [\exp(-\Delta\tau_d) - (1-\exp(-\Delta\tau_q))/\Delta\tau_q] +$$
$$+ (1-\sigma_d) * p_T * U_d * [1-(1-\exp(-\Delta\tau_q))/\Delta\tau_q]$$

$$\Delta\tau_d = \Delta t / T''_d \qquad \Delta\tau_q = \Delta t / T''_q \qquad [12]$$

The right side of these equations are possible to devide into three parts. The first part is created by "old values" of voltages and electromotive forces in the beginning of integration step (they are denoted by index $_h$. The second part is created by "new values" of voltages in the end of integration step. The last part is an increment of E'_q. The first expressions we can denote "history", because they involve the known values. The $\Delta E'_q$ is unknown, but it is possible to predict its value from the "old values" E'_q so that we can include it into the "history" terms, too. Then we can obtain the shortened form:

$$E''_q = H_q + k_q * p_T * U_q \qquad E''_d = H_d + k_d * p_T * U_d \qquad [13]$$
$$k_q = (1-\sigma_d) * [1-(1-\exp(-\Delta\tau_d))/\Delta\tau_d] \qquad k_d = (1-\sigma_q) * [1-(1-\exp(-\Delta\tau_q))/\Delta\tau_q]$$

where the "history" terms are included in a common term H.

When we use the transformation [8] we obtain :

$$\underline{E''} = \frac{k_d + k_q}{2} * p_T * \underline{U} + \frac{k_d - k_q}{2} * p_T * \underline{U}^* + \underline{H} \qquad [14]$$

When the complex conjugated value $\underline{U}^*$ is included into "history" term $\underline{H}$ (then this value must be predicted too) we obtain the final relation between the $\underline{E''}$ and $\underline{U}$ rotating vectors:

$$\underline{E''} = k_t * p_T * \underline{U} + \underline{H} \qquad k_t = (k_d + k_q)/2 \qquad [15]$$

k_t coeficient has an index $_t$,because it is a function the integration step. $\underline{H}$ term contains the variable values in the beginning of integration step ("history" terms), the prediction of the δ and E'_q integrable variables ("slowly" changing) and the prediction of the $\underline{U}^*$ in the end of the integration step.

We can calculated the current injected into the node ^{k} by N^k units connected to this node:

$$\underline{I}^k_{inj} = \sum_{l=1}^{N^k} (\underline{E''}^{kl} / p^{kl}_T - \underline{U}^k) * \underline{Y}^{kl}_{GEN} \qquad \underline{Y}_{GEN} = \frac{1}{j(X_{GEN} + X_T)} \qquad [16]$$

After some arrangements we obtain:

$$\underline{I}^k_{INJ} = \sum_{l=1}^{N^k}(\underline{H}^{kl} * \underline{Y}^{kl}_{GEN} / p^{kl}_T) - \underline{U}^k * \underline{Y}^k_{EQV} \qquad \underline{Y}^k_{EQV} = \sum_{l=1}^{N^k}(1-k^{kl}_t) * \underline{Y}^{kl}_{GEN}$$

$$\underline{I}^k_{INJ} = \underline{I}^k_{EQV} - \underline{U}^k * \underline{Y}^k_{EQV} \qquad \underline{I}^k_{EQV} = \sum_{l=1}^{N^k}(\underline{H}^{kl} * \underline{Y}^{kl}_{GEN} / p^{kl}_T) \qquad [17]$$

When we replace the injected current by the $\underline{I}_{EQV}$ current of the Norton equivalent, we obtain the final form of the matrix equation [1]:

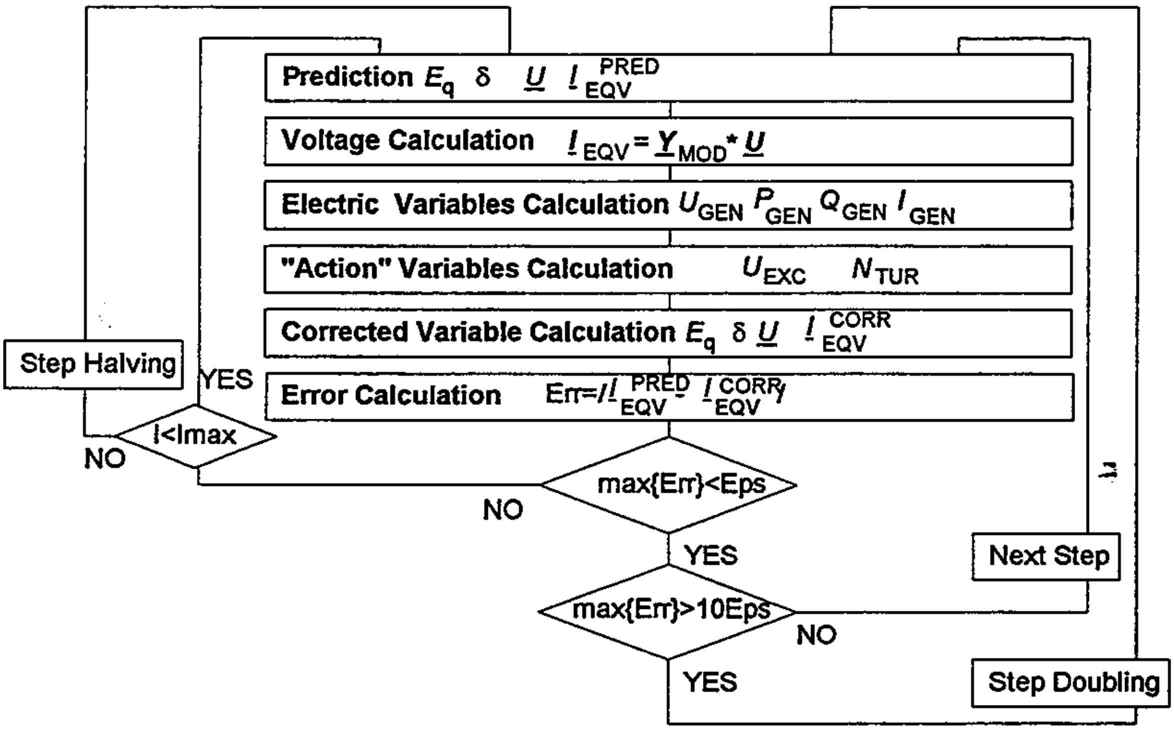
$$\underline{I}_{EQV} = \underline{Y}_{MOD} * \underline{U} \qquad [18]$$

The network admittance matrix was modificated by adding the admittance of the Norton equivalent $\underline{Y}_{EQV}$ to the diagonal terms of the original network matrix $\underline{Y}$. The modificated matrix is dependent on the network and generator parameters and on the integration step ,too.

The system of equations can be solved by using of LU factorization method. This method is very efficient, because the matrix is refactorized when network discontinuities occur or when the integration step must be changed to keep a calculating accuracy.

5. Integration algorithm

The functional block diagram of this algorithm is in the following figure:



The way of the prediction in step $n+1$ is seen from the table belove:

Prediction mode	Integrable variables $Y=\{E'_q, s_R, \delta\}$	Network variables $X=\{\underline{U}, \underline{I}\}$
Initial (after Next and Doubling)	$Y_{n+1,0} = Y_n + Y_n^{\circ}\Delta t_{n+1}$	$X_{n+1,0} = X_n$
Iteration i	$Y_{n+1,i} = Y_{n+1,i-1}$	$X_{n+1,i} = X_{n+1,i-1}$
Step halving (after i =Imax)	$Y_{n+1,0} = (Y_n + Y_{n+1,Imax})/2$	$X_{n+1,0} = (X_n + X_{n+1,Imax})/2$

Then it is possible to calculate the equivalent Norton injection from the equation [17] and the nodal voltages from [18]. The dependent variables can be calculated from the scheme in Fig.2. The utilization of the implicit trapezoidal rule is possible for the control variables calculation, because the input variables are known in the beginning and end of the integration step. Then the state variables E'_q, s_R, δ are recalculated from the equations [2], [5] and [6]. The last step is the check of the prediction error. When it is lesser then some predefined precision Eps the next step can be carried out. When it is greater some iteration process takes place and the new predicted variables are estimated (see the above table). When the iteration number exceeds predefined value Imax, the Δt integration step decreases twice and the process is repeated.

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