On insular power systems : drawing up an inventory of phenomena and research possibilities

Research Report
ISSN 0167-9708
Coden: TEUEDE

Eindhoven
University of Technology
Netherlands

Faculty of Electrical Engineering

On Insular Power Systems: Drawing up an Inventory of Phenomena and Research Possibilities

by
M.H.J. Bollen
M.A. van Houten

EUT Report 93-E-274
ISBN 90-6144-274-5
May 1993

Eindhoven University of Technology Research Reports

EINDHOVEN UNIVERSITY OF TECHNOLOGY

Faculty of Electrical Engineering
Eindhoven, The Netherlands

ISSN 0167-9708 Coden: TEUEDE

ON INSULAR POWER SYSTEMS

Drawing up an inventory of phenomena and research possibilities

by

M.H.J. Bollen

M.A. van Houten

EUT Report 93-E-274
ISBN 90-6144-274-5

Eindhoven
May 1993

CIP-DATA KONINKLIJKE BIBLIOTHEEK, DEN HAAG

Bollen, M.H.J.

On insular power systems : drawing up an inventory of
phenomena and research possibilities / by M.H.J. Bollen,
M.A. van Houten. - Eindhoven : Eindhoven University of
Technology, Faculty of Electrical Engineering. - Fig.,
tab. - (EUT report, ISSN 0167-9708 ; 93-E-274)
ISBN 90-6144-274-5
NUGI 832
Subject headings: insular power systems / power system
disturbances.

Abstract.

This report aims to give an overview of the reliability aspects of the electricity supply on small and medium-sized islands. The two phenomena that are considered to be important for the reliability (loss of a generation unit and short circuits) are discussed in detail. For both phenomena their turns out to be a sharp transition between a reliable systems and a not-so-reliable system.
The report also proposes a classification of insular power systems, with each class having its specific reliability and design aspects. The use of wind energy in insular power systems is briefly discussed. Recommendations for future research are given in the form of 24 tasks.

Keywords: insular power systems / power system disturbances / power system operation / power system reliability.

Bollen, M.H.J. and M.A. van Houten
ON INSULAR POWER SYSTEMS: Drawing up an inventory of phenomena and research possibilities.
Eindhoven: Faculty of Electrical Engineering, Eindhoven University of Technology, 1993.
EUT Report 93-E-274

Address of the authors:

M.H.J. Bollen
Eindhoven University of Technology
Faculty of Electrical Engineering
P.O. Box 513
5600 MB Eindhoven, The Netherlands

M.A. van Houten
University of The Netherlands Antilles
P.O. Box 3059
Curaçao, Netherlands Antilles

ACKNOWLEDGEMENTS.

Thanks are due to the electricity compagnies of Aruba, Bonaire and Curaçao for providing us with information on existing insular power systems. We look forward to a long-lasting cooperation.

The investigations described in this report were performed in the second half of 1992 in the Electrical Engineering Department of the University of the Netherlands Antilles and in the Group of Electrical Energy Systems of Eindhoven University of Technology, under the authority of the University of the Netherlands Antilles.

Contents. pag.

1. INTRODUCTION

It is evident that the electricity supply on a small island is less reliable than on the continent (a large island). If this was not the case there would be no need for extended transmission grids. The explanation for this lower reliability is simple: the smaller number of generating units makes the supply more vulnerable. And indeed: a system with one generator is less reliable than one with 250 generators. But is a system with 3 generators less reliable than the same system with 4 slightly smaller generators ? A large transport grid (like in Western Europe or North America) is certainly more reliable than a distribution grid. But is a small transport grid always more reliable than a small distribution grid ? Loss of a generating unit in a small systems will lead to loss of load. But what should be considered as a small system ? Will a short circuit (another large disturbance in an insular power system) also lead to loss of load ?

It is not easy to answer these questions. They are however of major importance for the design of the electricity generation, transport and distribution on small and medium size islands (we will shortly speak of "insular power systems"). The University of The Netherlands Antilles is situated on Curaçao, one of the five islands of The Netherlands Antilles. Curaçao has an area of 444 km^2, 146.000 inhabitans (January 1990) and an electric peak load of 84 MW (in 1992).

Due to a number of large and small interruptions of the electricity supply on Curaçao, The Department of Electrical Engineering of the University of The Netherlands Antilles decided to start a research project after the reliability aspects of insular power systems. It was considered a project with special inportance to the islands. The project was also expected to have a considerable spin-off to the education in electrical engineering. In May 1990 an international symposium was held on the reliability of power systems in general. In 1992 the authors worked together for about five months to get some basic insight in the reliability aspects of insular power systems.

In this report the authors present the results of this three-month investigation. In chapter 2 an overview of insular power systems (from small to large) is given. The consequences of the two major disturbances in insular power systems: loss of generating units and short circuits are discussed in chapter 4 and 5, respectively. The power system model used to study these disturbances is described in chapter 3. Chapter 6 gives some thoughts about the incorporation of wind energy in insular power systems. Chapter 7 summarizes the conclusions and gives a number of suggestions for future work.

2. SMALL AND LARGE INSULAR POWER SYSTEMS

2.1. Two generators with concentrated load

The smallest insular power system contains two generating units and some load concentrated near those generators (see Figure 1). This kind of systems is often used by industries as a back-up system in case of failure of the public supply. The reliability demands are fairly low, although the transition from public supply to insular supply needs to be fairly reliable. A non-availability of a few procent is, in most cases, acceptable. Because this type of insular power systems are essential to the reliability of many industrial power systems, a considerable amount of research has been done on them. They are outside of the scope of the research at the University of The Netherlands Antilles.

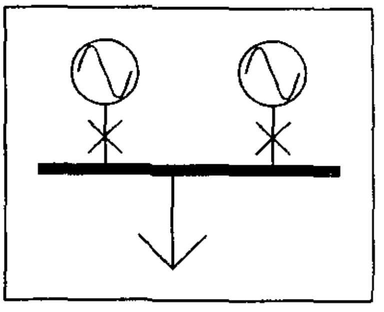

Figure 1: Insular power system consisting of two generators with concentrated load.

2.2. More generators with concentrated load

If there are only two generating units present, there is no reserve during maintanance on one of the units. This is acceptable for the back-up systems of the previous section, but nor for the primary supply in a real insular system. In such a case more generators are needed (see Figure 2).

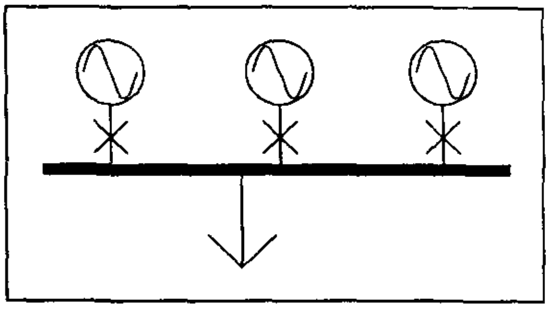

Figure 2: Insular power system consisting of more than two generators with concentrated load.

Suppose an availability of 80% for the generating units. In case of two generators, the probability of system non-availability (lack of standing reserve) is 4%. That is acceptable for the back-up systems above, but not for a public supply system. Table 1 gives the non-availabilty due to lack of standing reserve for a system consisting of 2 to 6 units. One unit can supply all load. The unit non-availability ranges from 10% to 30%. The system non-availability is expressed in hours or minutes per year. Especially for units with a high non-availability, a considerable amount of reserve units should be present.

If the load is supplied by more than one generator, the number of generators needed in operation will vary with the load. If there is a clear and predictable off-peak period, maintenance should be done preferably then. This will reduce the probability of lack of standing reserve. The more units are used in operation (i.e. the smaller the relative size of the units) the more possibilities to schedule maintenance in an off-peak period.

number of units	unit non-availability		
	10%	20%	30%
2 units	90 hours	350 hours	800 hours
3 units	9 hours	70 hours	240 hours
4 units	1 hour	14 hours	70 hours
5 units	5 minutes	3 hours	21 hours
6 units	1/2 minute	30 minutes	6 hours

Table 1: system non-availability (hours per year) for a system consisting of a number of generating units. One generating unit is able to supply the whole load.

There are more advantages of having more than two units in operation. The more generators in operation, the less the loss of load during failure of one of them. We will discuss loss of a generator unit in detail in chapter 4. The consequences of a failure of one generating unit not only depend on the number of units. It also depends on the type of unit used. For small systems engine-driven generators can be used. They are able to increase production in a very short time. They can have a large spinning reserve without much loss of efficiency. Interruption of the supply due to loss of one unit can be prevented by using the spinning reserve of the other units. In larger systems gas turbines and steam turbines are more suitable. For these units a large spinning reserve leads to a lower efficiency. In that case there should always be enough standing reserve available. If the spinning reserve is limited to 5% (for reasons of efficiency) at least 20 units should be present to prevent loss of load. For reasons of reliability it is therefore preferable to have smaller units and/or a large spinning reserve. Unfortunately, this is not preferable from an economic point of view.

An advantage of steam units is the fact that a common-steam system can be used. This will in most cases increase the reliability, as loss of one unit will automatically lead to the required increase in steam pressure (i.e there will always be the required amount of spinning reserve). We have not taken into account the steam generation part in our models. It will certainly be worthwhile to conduct such a study in the future.

We will see in chapter 4 that, even in case of sufficient spinning reserve, at least 6 to 10 units need to be in operation to prevent loss of load due to the failure of one of them. For a small insular system (up to 10 or 20 MW) it might be suitable to run 6 fast diesel generators in parallel, with 20% spinning reserve each. For a larger system (e.g. 200 MW) it is not suitable to use 10 steam units with 10%

spinning reserve each or 20 units with 5% spinning reserve each. An alternative for the larger system is to have 5 steam units in operation, each providing for one sixth of the power. These large units are operated without any spinning reserve. The remaining one sixth of the power is provided for by a couple of fast diesel units with 100 % or more spinning reserve.

As the load is concentrated, there can be no selection between important and non-important users. A lack of power will therefore always lead to an interruption for all users. So will a short circuit. The existence of this type of insular power system will therefore be limited to very small islands. The spinning reserve problems, as discussed above, are however present in almost all insular power systems.

2.3. Concentrated generation and a distribution network

If the load is spread over a larger area, like in most insular public supply systems, more emphasis has to be put on the short-circuit protection (see Figure 3). For smal systems each feeder can be protected by means of over-current time relays, eventually graded with over-current time relays further away from the generators. If the fault clearing times get too long other solutions should be shought. It is shown in chapter 5 that the maximum fault clearing time that is acceptable is about 400 milliseconds. One of the ways to reduce the fault clearing time is to use different voltage levels. The transformers will then form a large impedance making it possible to use current grading to distinguish between a fault on high-voltage side and a fault on low-voltage side. Another solution is to use fast reclosing combined with time grading.

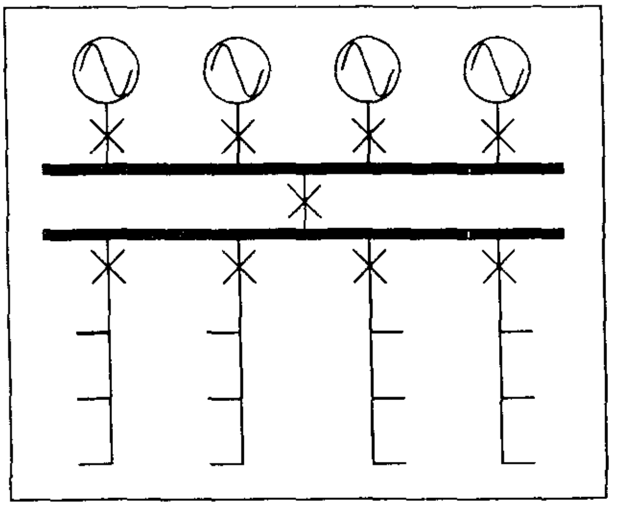

Figure 3: Insular power system with concentrated generation and a distribution network.

To prevent loss of all users due to loss of one generating unit, minimum frequency relays should be placed on the feeders. The setting of these minimum frequency relays remains a difficult problem. In chapter 4 we will see that uncertainty in the percentage of load tripped by a minimum frequency relay, causes intense frequency transients. This might be prevented by installing more frequency relays with more frequency levels.

The availability of the supply to the users will increase considerable when a radial operated ring-type network is used, in stead of a radial network. In sparsely populated regions, it is non always economically advisable to do so. One should however keep in mind that, even in insular power systems, the non-availability for most users might be decreased more by investments in the distribution network than by investments in generating units.

2.4. Concentrated generation and a transport grid

If the load grows the number of substations grows and it becomes attractive to change from a radial operated ring-type network to a closed-ring network. Distance relays and/or differential relays can be used for the short circuit protection. Such a system is shown in Figure 4. A short circuit in any of the connections in the grid will not lead to an interruption of the supply anymore. Now fault clearing no longer leads to loss of load, it turns out to be more difficult to control the post-fault frequency transients. It will be shown in chapter 4 that short circuits should be cleared in 200 milliseconds or less. If the fault clearing time gets too long, the minimum-frequency relays will trip part of the load.

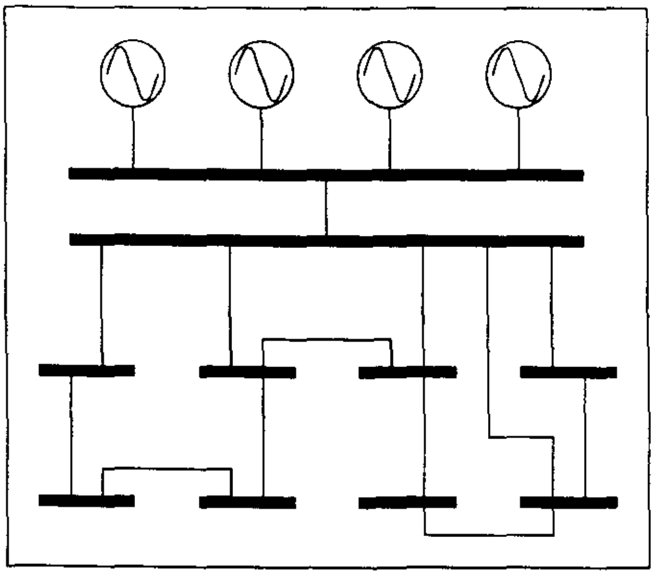

Figure 4: Insular power system with concentrated generation and a transport grid.

The grid should be dimensioned such that loss of one connection will probably not lead to an overload elsewhere. If the probability of overlaod gets too high, one can decide to increase the maximum permissable load of the connection. In a growing system it might however be more suitable to decrease the normal load flow by spreading the generating units through the network.

The minimum-frequency relays can also be spread through the grid, leading to a more accurate load shedding.

2.5. Distributed generation and a transport grid

As the number of generating units grows, the final step can be made. The generation can be distributed through the system. This will decrease the normal loading of the system and thus decrease the chance of overload due to failure of a connection. It will also decrease the normal power losses. The resulting system is shown in Figure 5. In smaller systems with distributed generation the insular phenomena still appear. If the distances between the substations are small a short circuit in the grid will still lead to a frequency increase equal for all units. If the number of units is too small loss of one of them will still lead to loss of a part of the load. If both phenomena no longer lead to loss of load (under normal operating conditions) we suggest to label the system as a "continental power system". These

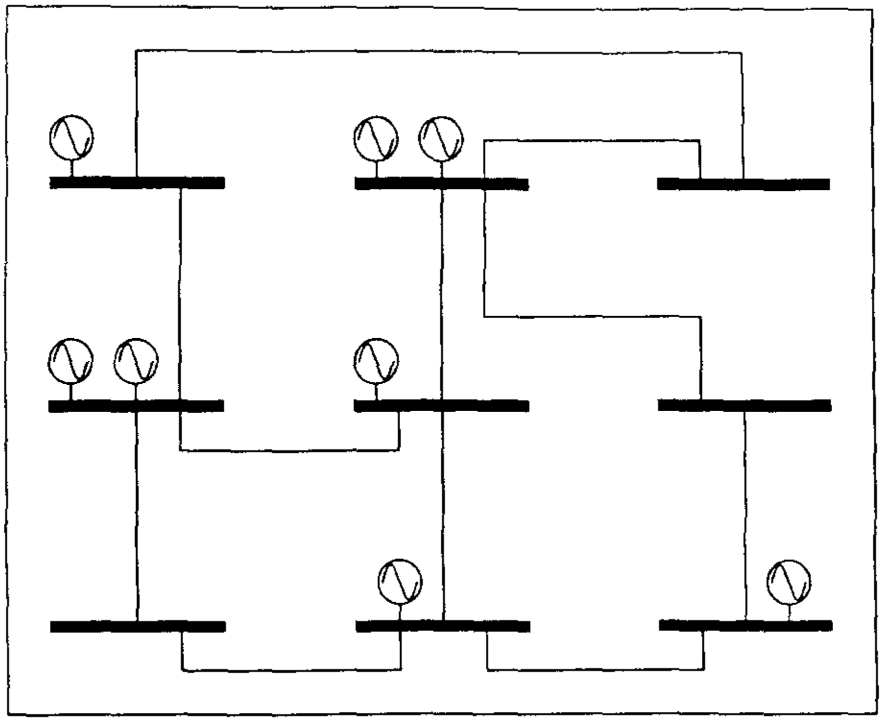

Figure 5: Power system with distributed generation.

systems are outside of the scope of the research at the University of The Netherlands Antilles. Insular power systems with distributed generation can arise from connecting two or more smaller systems (e.g. the connection of oil platforms by cables[1]). The more typical cases are those systems that only show "insular properties during period of low loading like Ireland[2] or West Berlin[3].

---

[1] Fielding, G. and M.M. Elkateb, *Economics, design and emergency control of electrically-connected offshore gas/oil installations.* In: Advances in Power System Control, Operation and Management, 5-8 November 1991, Hong Kong. Hong Kong: Institition of Electrical Engineers, 1991. P.907-913.

[2] McNamara, F. and P. Brown, M. Duggan, J. Fitzgerald, *Optimising unit commitment in an island power system.* In: Universities Power Engineering Conf., 23-25 September 1992, Bath (UK). Bath: University of Bath, 1992. P.322-324.

[3] Haubrich, H.-J. and P.E. Mercado, *The optimum seconds reserve in isolated power systems.* In: Electric Power Systems Reliability, 16-18 September 1991, Montreal (Canada). Paris (France): CIGRE, 1991. Paper 1B-06, p.1-5.

3. FREQUENCY CONTROL IN INSULAR POWER SYSTEMS

3.1. Theoretical background

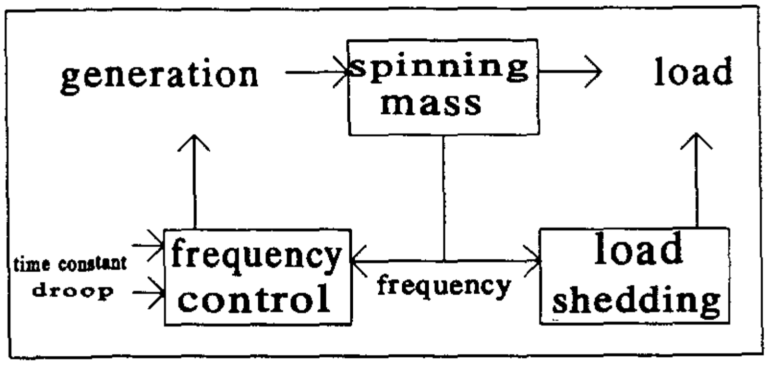

Figure 6: Schematic representation of power system model.

To study phenomena in insular power systems, we have used the model shown schematically in Figure 6. The power system is represented by its spinning mass. If generation and load are in equilibrium the frequency in the system is constant, i.e. the kinetic energy of all rotating mass does not change. To control the frequency two mechanism are present. The frequency control of the generators adjusts the generated power to compensate fluctuations in load. The frequency control is represented through a time constant and a droop setting. To prevent large frequency drops, minimum frequency relays for load shedding are included in the model.

The following equation holds for the spinning mass of the generators (the "swing equation"):

$$\frac{d}{dt}\left\{ \frac{1}{2}J\omega^2 \right\} = P_{gen} - P_{load} \ , \tag{1}$$

where J is the moment of inertia of all rotating masses;
ω is the angular frequency;
P_{gen} is the generator power;
P_{load} is the power consumed by the load.

We introduce the "inertia constant" H by

$$H = \frac{1}{2}J\omega^2 \ . \tag{2}$$

Equation (1) now transfers into:

$$\frac{2H}{\omega_0}\frac{d\omega}{dt} = P_{gen} - P_{load} \ , \tag{3}$$

where ω_0 is the nominal angular frequency.

In terms of frequencies in stead of angular frequencies (3) reads as:

$$\frac{2H}{f_0} \cdot \frac{df}{dt} = P_{gen} - P_{load} \ , \qquad (4)$$

The model for the frequency control is a simplified version of the "general purpose governor block diagram" given by Anderson and Fouad[4]. They give three time constants for small machines. We simplified the model to one time constant to reduce the behaviour of the governor plus system to its essential part. For the power-frequency control of the generator a first order model results:

$$P_{gen} + \tau_{gov} \cdot \frac{dP_{gen}}{dt} = P_{set} + \frac{P_{rated}}{R f_0}(f_0 - f) \ , \qquad (5)$$

where τ_{gov} is the time-constant of the control loop (the control time constant plus the servo time constant plus the steam valve bowl time constant, according to Anderson and Fouad);
P_{set} is the power setting;
R is the droop (normally around 4 or 5%, related to the rated power);
P_{rated} is the rated power.

Equation (4) and (5) are transferred to p.u. values:

$$\pi_{gen} = \frac{P_{gen}}{P_{rated}}$$
$$\pi_{load} = \frac{P_{load}}{P_{rated}}$$
$$\pi_{set} = \frac{P_{set}}{P_{rated}}$$
$$h = \frac{H}{P_{rated}}$$

This results in the following set of equations:

[4] Anderson, P.M. and A.A. Fouad, *Power system control and stability*. Ames, Iowa: Iowa State University Press, 1977.

$$\boxed{\begin{aligned} 2\frac{h}{f_0}\cdot\frac{df}{dt} &= \pi_{gen} - \pi_{load} \\ \pi_{gen} + \tau_{gov}\cdot\frac{d\pi_{gen}}{dt} &= \pi_{set} + \frac{f_0-f}{Rf_0} \end{aligned}} \tag{6-7}$$

3.2. The trapezoidal rule

Although the set of equations (6-7) can be solved analytically we use a numerical method here. This makes it easier to include relay tripping and other system changes. We make use of the trapezoidal rule[5].

An equation of the form

$$\dot{X} = F(X,t) \ , \tag{8}$$

where X is the vector of unknown variables, can be numerically solved through the following recursive equation:

$$X(t+\Delta t) = X(t) + \frac{\Delta t}{2}\{ F(t) + F(t-\Delta t) \} \ , \tag{9}$$

where Δt is the time-step.

Equations (6) and (7) have to be written in the form (8):

$$\frac{df}{dt} = \frac{f_0}{2h}\left(\pi_{gen} - \pi_{load}\right) \ . \tag{10}$$

$$\frac{d\pi_{gen}}{dt} = \frac{\pi_{set}}{\tau_{gov}} - \frac{\pi_{gen}}{\tau_{gen}} + \frac{f_0-f}{R\cdot\tau_{gov}f_0} \ . \tag{11}$$

By using (8) and (9) one gets the following recursive expressions for frequency and power:

[5] e.g.: Heydt, G.T. *Computer analysis methods for power systems.* New York: Macmillan, 1986.

$$
\begin{aligned}
f(t+\Delta t) = f(t) &+ \frac{f_0 \cdot \Delta t}{4h}\, \pi_{gen}(t) + \frac{f_0 \cdot \Delta t}{4h}\, \pi_{gen}(t-\Delta t) \\
&- \frac{f_0 \cdot \Delta t}{4h}\, \pi_{load}(t) - \frac{f_0 \cdot \Delta t}{4h}\, \pi_{load}(t-\Delta t)
\end{aligned}
\tag{12}
$$

$$
\begin{aligned}
\pi_{gen}(t+\Delta t) = \pi_{gen}(t) &+ \frac{\Delta t}{2\tau_{gov}} \pi_{set}(t) + \frac{\Delta t}{2\tau_{gov}} \pi_{set}(t-\Delta t) \\
&- \frac{\Delta t}{2\tau_{gov}} \pi_{gen}(t) - \frac{\Delta t}{2\tau_{gov}} \pi_{gen}(t-\Delta t) \\
&+ \frac{\Delta t}{R \cdot \tau_{gov}} - \frac{\Delta t}{2R\tau_{gov}} \frac{f(t)}{f_0} - \frac{\Delta t}{2R\tau_{gov}} \frac{f(t-\Delta t)}{f_0}
\end{aligned}
\tag{13}
$$

3.3. Representing the disturbances

We have modelled a couple of disturbances and studied the resulting frequency transients. The results of these studies are discussed in the forthcoming chapters. The implementation of these disturbances in the power system model (i.e. the update of the trapezoidal rule to represent a disturbance) is discussed below. For more details please refer to the listing of the essential parts of the computer programs in the appendix.

3.3.1. Loss of generation

In the studies to be discussed in chapter 4, a certain loss of generation takes places at time zero. Before time zero, the system is in equilibrium: load and generation are equal; the power system frequency is 50 Hz; the generated power is equal to the generator settings. At time zero, a part of the generated power is lost, due to failure of a generator. The trapezoidal rule is started for $t=0$, as follows:

$$
\begin{aligned}
f(t) &= f(t-\Delta t) = f_{start} \\
\pi_{load}(t) &= \pi_{load}(t-\Delta t) = \pi_{load,start} \\
\pi_{gen}(t) &= \pi_{set}(t) = \pi_{load,start} - \pi_{loss} \\
\pi_{gen}(t-\Delta t) &= \pi_{set}(t-\Delta t) = \pi_{load,start}
\end{aligned}
\tag{14}
$$

3.3.2. A short circuit

In the studies to be discussed in Chapter 5, a short circuit takes place at time zero. After a fault clearing time t_5 the faulted part of the system is removed from the healthy part. The short circuit protection also removes a fraction $\pi_{load,loss}$ of the load. The trapeziodal rule is started as follows at time zero:

$$
\begin{aligned}
f(t) &= f(t-\Delta t) = f_{start} \\
\pi_{load}(t) &= 0 \\
\pi_{load}(t-\Delta t) &= \pi_{load,start} \\
\pi_{gen}(t) &= \pi_{gen}(t-\Delta t) = \pi_{load,start} \\
\pi_{set}(t) &= \pi_{set}(t-\Delta t) = \pi_{load,start}
\end{aligned}
\tag{15}
$$

Before time zero the system is again considered to be in equilibrium. The short circuit is modelled as a loss of all (active) load.

3.3.3. Intervention by relays

In the power system model, four minimum frequency relays and one relay for short circuit protection are present. The minimum frequency relay with the lowest frequency setting will trip all load. If this relay intervenes at time t_1, the following correction is made to the trapezoidal rule's results at time t_1:

$$\pi_{load}(t_1) = 0 \ . \tag{16}$$

The other three minimum frequency relays trip only a fraction p_{shed} of the (original) load. If such a relay intervenes at time t_2, this is implemented as follows:

$$\pi_{load}(t_2) = \pi_{load}(t_2-\Delta t) - p_{shed}\ \pi_{load,start} \ . \tag{17}$$

The intervention of the relay for short circuit protection at time t_5 is implemented as follows:

$$\pi_{load}(t_5) = \pi_{load,start} - \pi_{load,loss} \ , \tag{18}$$

where $\pi_{load,loss}$ is the load tripped by the short circuit protection.

4. LOSS OF GENERATION

In a large interconnected power system, loss of one generating unit never leads to an interruption. The percentage loss is so small that all the other generators simply produce slightly more power. The user does not notice anything of this disturbance. In a small insular power system, loss of one generator constitutes a large percentage of the total power. Loss of one generator will often lead to an interruption for some of the users. We have therefore studied the system behaviour due to loss of generation. For this, the simple power system model described in the previous chapter has been used. The results are presented in this chapter.

4.1. Loss of generation without load shedding

In case of loss of generation the power system frequency will go down, the governors of the other generators will react to this and cause an increase in generated power untill the frequency settles down at a new stationary value. It has to be assumed for this that the remaining generators have enough spinning reserve available. Table 2 shows the minimum frequency reached when one generator fails in a system with two generators. The minimum frequency is given for different values of the governor time constant and of the droop setting[6]. Figure 7 shows the results in a graphic way. The frequency drop clearly increases for increasing time constant and increasing droop. The spinning reserve of both units should at least be 100%.

time constant	droop = 5%	droop = 3%	time constant	droop = 5%	droop = 3%
10 sec	43.4 Hz	44.9 Hz	5 sec	45.3 Hz	46.4 Hz
9 sec	43.7 Hz	45.2 Hz	4 sec	45.7 Hz	46.7 Hz
8 sec	44.1 Hz	45.5 Hz	3 sec	46.2 Hz	47.1 Hz
7 sec	44.4 Hz	45.7 Hz	2 sec	46.9 Hz	47.6 Hz
6 sec	44.8 Hz	46.0 Hz	1 sec	47.3 Hz	47.7 Hz

Table 2: mimimum frequency due to loss of one of two generators.

time constant	droop = 5 %	droop = 3 %	time constant	droop = 5%	droop = 3%
10 sec.	45.6 Hz	46.6 Hz	5 sec.	46.8 Hz	47.6 Hz
9 sec.	45.8 Hz	46.8 Hz	4 sec.	47.1 Hz	47.8 Hz
8 sec.	46.1 Hz	47.0 Hz	3 sec.	47.5 Hz	48.1 Hz
7 sec.	46.3 Hz	47.0 Hz	2 sec.	47.9 Hz	48.4 Hz
6 sec.	46.6 Hz	47.4 Hz	1 sec.	48.4 Hz	48.8 Hz

Table 3: mimimum frequency due to loss of one of three generators.

[6] Here, and everywhere else in this report, a rated inertia constant (h in equation (6)) equal to 4 seconds has been used.

Table 3 and Figure 8 give the same information for the loss of one of three generators. The frequency drop is (as expected) less than in the two-generator case. The minimum frequency is still fairly low. The spinning reserve, at least 50% for each unit, cannot prevent these low frequencies, because it cannot be made available fast enough.

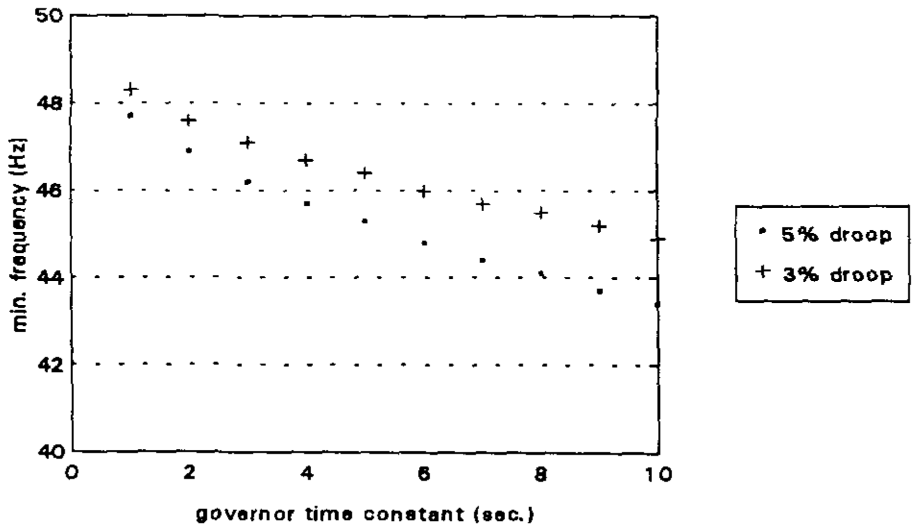

Figure 7: Minimum frequency due to loss of one of two generators, with sufficient spinning reserve.

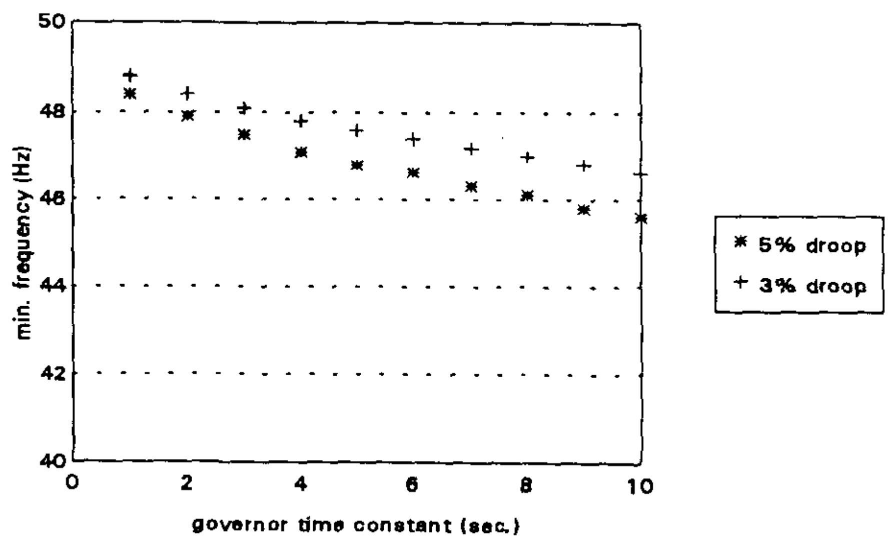

Figure 8: Minimum frequency due to loss of one of three generators, with sufficient spinning reserve.

A fast increase in power is needed to reduce the frequency dip. This can be done through a small governor time constant and/or through a small droop setting. However, one has to keep in mind that the minimum value of the governor time constant is determined by the construction of the turbine and generator, whereas a smaller droop setting increases the risk of instability.

4.2. Load shedding by minimum frequency relays

In case no preventive measures are taken, a loss of generation larger than the spinning reserve, leads to a total blackout. To prevent this some of the load should be tripped. As the frequency drops very fast, this load shedding has to be done automatically. The most often used method is by means of minimum frequency relays. We assume here the following load shedding protocol:

remove 25% of the load when the frequency gets below 49 Hz;
remove another 25% at 48.5 Hz and at 48 Hz;
remove the remaining load at 47.5 Hz.

In case of the loss of 25% of generation, the frequency drops untill it reaches 49 Hz. The minimum frequency relay disconnects 25% of the load and generation and load are balanced again.

In reality it is almost impossible to disconnect exactly 25% of the load. One selects a group of users with an average power consumption equal to 25% of the total power consumption. The momentary load will then fluctuate around this 25% value. To get an impression of this fluctuation we observed the load of two parts of an island. The results for three days are given in Table 4.

Friday 2 October 1992					Sunday 4 October 1992					Saturday 10 October 1992				
Feeder A		Feeder B		Tot.	Feeder A		Feeder B		Tot.	Feeder A		Feeder B		Tot.
MW	%	MW	%	MW	MW	%	MW	%	MW	MW	%	MW	%	MW
12.8	27	13.0	27	47.8	12.5	27	13.5	29	47.0	13.8	29	13.0	27	47.8
12.0	27	12.0	27	44.0	11.8	27	12.5	28	44.3	12.8	29	12.0	27	44.8
11.6	27	12.0	28	43.6	11.2	26	12.0	28	42.7	11.8	28	12.0	29	41.8
10.8	26	12.0	29	41.8	11.3	27	12.0	28	42.3	10.0	25	12.0	30	40.0
9.8	19	16.0	31	51.8	9.6	23	13.0	31	41.6	10.0	20	17.0	33	51.0
10.4	19	17.0	31	55.4	9.4	22	14.0	33	42.4	10.0	20	10.0	33	51.0
10.4	19	17.0	31	54.4	9.5	22	14.0	32	43.5	9.8	20	18.0	36	50.0
11.4	20	18.0	31	58.4	9.6	22	14.0	32	43.6	10.2	20	17.0	34	50.2
10.2	19	18.0	33	54.2	9.2	22	14.0	33	42.7	10.1	21	16.5	34	49.1
13.0	24	16.2	30	54.2	12.1	24	15.0	30	50.1	11.5	23	16.0	32	49.5
14.1	26	16.0	29	55.1	13.7	26	15.0	28	52.7	13.5	25	16.0	30	53.5
13.9	26	14.5	28	52.4	13.3	27	14.0	28	49.3	13.5	26	15.0	29	51.5
12.9	27	13.5	28	48.4	12.4	27	13.0	28	45.9	12.0	27	13.0	29	45.0

Table 4: Load distribution for two feeders on an island. Both feeders have an average load of about one fourth of the total load.

From this table, one can conclude that an average load of 25% implies an actual load between 20% and 30%. The situation might then arise that only 20% of the load is removed after loss of 25% of generation. The frequency continues to decrease leading to removal of another part of the load. Figure 9[7] shows the power and frequency transient due to loss of one unit out of four. At 49.0 Hz a minimum frequency relay trips 20% of the load. At 48.5 Hz another relay trips a further 30% of the load. A spinning reserve of 6% and a governor time constant of 5 seconds have been used.

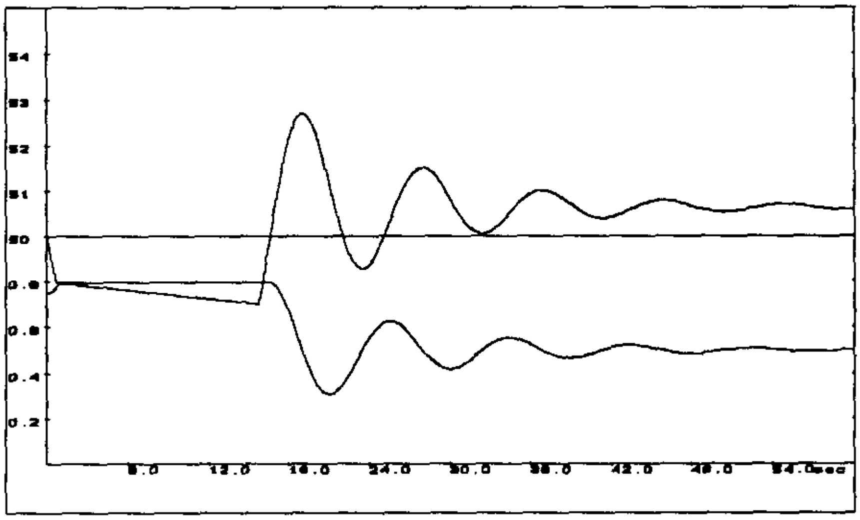

Figure 9: Frequency and power transient due to loss of one of four generators, with 6% spinning reserve and a governor time constant of 5 seconds. The minimum frequency relays trip 20% and 30% of the load.

The frequency decreases till 49 Hz (0.7 seconds after the loss of power). By that time the generated power has already reached is maximum value (79.5% of the original load). This is not enough to supply the remaining 80% of the load, so the frequency continues to decrease, reaching a value of 48.5 Hz 16 seconds after the loss of power. At this instant another 30% of the load is removed, causing a surplus of generation and thus an increase in frequency. The power-frequency control reduces the generated power and the frequency settles at a value somewhat higher than 50 Hz (due to the droop setting). During the transient phenomenon, the frequency reaches a maximum value of 52.7 Hz.

This high frequency can be prevented by using a somewhat higher spinning reserve. Figure 10 shows the situation for a spinning reserve of 10%. After the loss of one unit, the remaining generation plus the spinning reserve is sufficient to supply 80% of the load. In stead of one out of two users, only one out of four users experiences an interruption. Whether this increase in reliability compensates the reduced efficiency of the generating units, depends on the specific situation. This problem cannot be solved easily here.

[7] In Figure 9, and in all other power and frequency plots, the vertical scale reaches from 45 Hz to 55 Hz for the frequency and from 0 to twice the pre-disturbance load for the generated power. The lower half of the vertical axis gives the rated power value, the upper half gives frequency values in Hz.

In case a higher spinning reserve is not an economical solution, one should use a fast governor and a low droop setting. This will make the reaction of the governer faster and so reduce the maximum frequency. The maximum frequency is given in Table 5 for governor time constants between 1 second and 10 seconds and droop settings of 5% and 3%. All values are calculated for 6% spinning reserve, and a rated inertia constant of 4 seconds. The maximum frequency is shown graphically in Figure 11. The frequency rise increases for increasing time constant and increasing droop. Like in the case without load shedding, a fast governor (small time constant) and a small droop setting (strong feedback) leads to small frequency deviations.

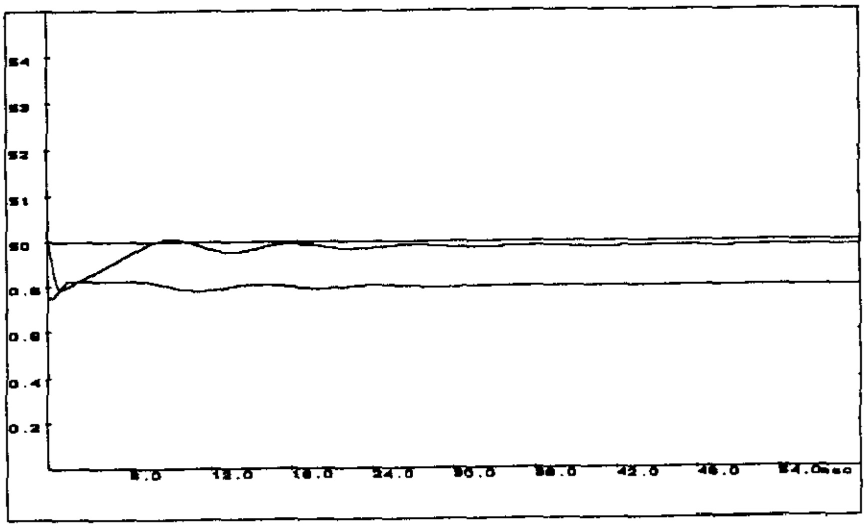

Figure 10: Frequency and power transient due to loss of one out of four generators, with a spinning reserve of 10% and a governor time constant of 5 seconds.

	5% droop setting		3% droop setting	
time constant	max. frequency	min. gen. power	max. frequency	min. gen. power
1 second	51.3 Hz	0.39 p.u.	51.0 Hz	0.36 p.u.
2 seconds	51.7 Hz	0.35 p.u.	51.3 Hz	0.32 p.u.
3 seconds	52.1 Hz	0.33 p.u.	51.6 Hz	0.30 p.u.
4 seconds	52.4 Hz	0.32 p.u.	51.9 Hz	0.29 p.u.
5 seconds	52.7 Hz	0.31 p.u.	52.1 Hz	0.29 p.u.
6 seconds	52.9 Hz	0.30 p.u.	52.3 Hz	0.28 p.u.
7 seconds	53.2 Hz	0.29 p.u.	52.5 Hz	0.27 p.u.
8 seconds	53.4 Hz	0.29 p.u.	52.6 Hz	0.27 p.u.
9 seconds	53.6 Hz	0.29 p.u.	52.8 Hz	0.27 p.u.
10 seconds	53.8 Hz	0.28 p.u.	52.9 Hz	0.26 p.u.

Table 5: maximum frequency and minimum generated power after 25% loss of power and 20% + 30% load shedding.

Figure 12 shows the transient phenomena for a governor time constant of 1 second. Figure 13 shows the situation for a governor time constant of 10 seconds. All other values are as in Figure 9. Its clear from these two figures that a fast governor would be preferable.

Figure 14 shows the situation for a governor time constant of 12 seconds and 5% droop. The transient phenomenon after removal of 30% of the load is such that the frequency reaches a maximum of 54.1 Hz and a value of 48 Hz, 24 seconds after the loss of power. This causes the third minimum-frequency relay to remove another 25% of the load. The maximum frequency reached by the new transient phenomenon is 54.7 Hz. As a result of all this, three out of four users experience an interruption due to the loss of one of four generating units. Such a situation should be prevented as much as possible.

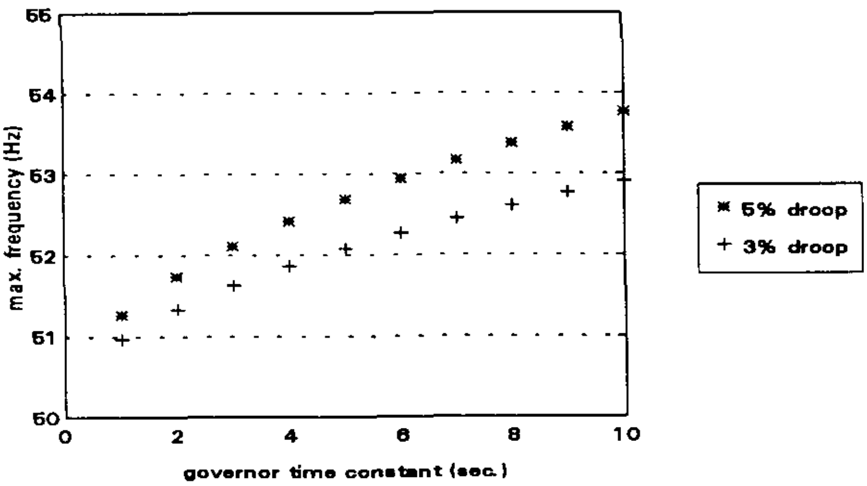

Figure 11: Maximum frequency due to one of four generators, with 6% spinning reserve. Minimum frequency relays trip 20% of the load at 49.0 Hz and 30% of the load at 48.5 Hz.

The setting of minimum frequency relays remains a difficult subject. The uncertainty in setting can cause intense frequency transients. This can be prevented by removing more load than in average neccessary. Another possibility is to use more frequency levels.

One might also solve the problem by using df/dt-relays, that trip a part of the load when the frequency drops too fast. As the rate of change of frequency is directly related to the power deficit, the amount of load to be shed can be determined more accurately by the relays.

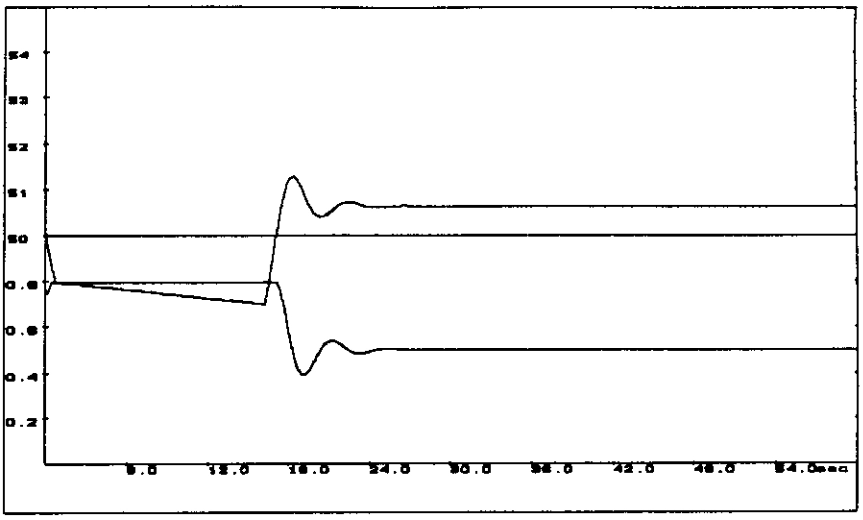

Figure 12: Power and frequency transient due to the loss of one of four generators, with 6% spinning reserve and a governor time constant of 1 second.

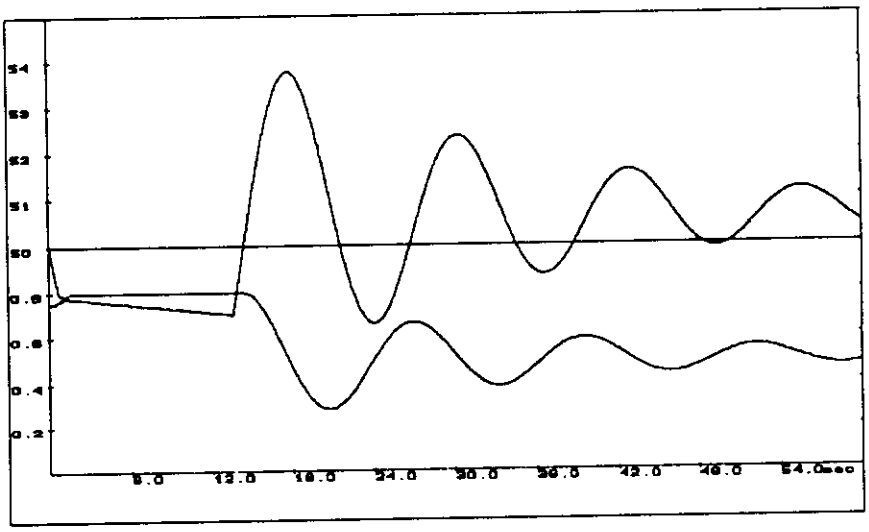

Figure 13: Power and frequency transient due to the loss of one of four generators with 6% spinning reserve and a governor time constant of 10 seconds.

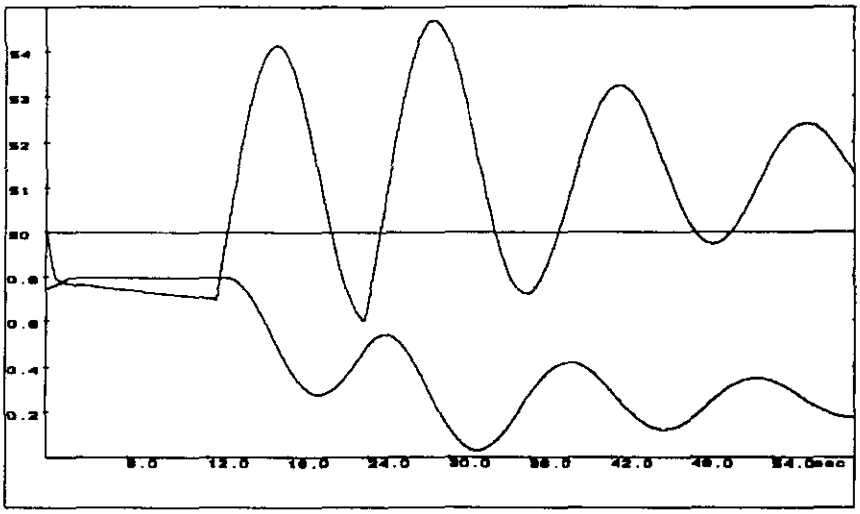

Figure 14: Power and frequency transient due to the loss of one of four generators, with 6% spinning reserve and a governor time constant of 12 seconds.

4.3. Preventing load shedding

In case of the loss of one generator, a certain amount of load is lost. This is to prevent loss of the whole system (i.e loss of all loads). As mentioned before loss of load can be prevented if there is enough spinning reserve available and the governor is fast enough. Table 6 and Figure 15 show the value of the governor time constant that is needed to prevent loss of load in case of loss of one generator. The governor time constant should be equal to or smaller than the given value. All this is done for droop settings of 5% and 3%. For realistic governor time constants (3 to 5 seconds) load shedding cannot be prevented in systems with less than 6 to 10 generating units (depending on the droop setting). A large percentage of spinning reserve is therefore of no use. Although the extra power is available, it cannot be used fast enough to prevent load shedding.

	maximum time constant			maximum time constant	
number of generators	droop = 5%	droop = 3%	number of generators	droop = 5%	droop = 3%
2	-	0.2 sec	9	4.4 sec	7.8 sec
3	0.4 sec	0.6 sec	10	5.6 sec	9.7 sec
4	0.6 sec	1.3 sec	11	6.8 sec	11.9 sec
5	1.2 sec	2.2 sec	12	8.2 sec	14.3 sec
6	1.8 sec	3.2 sec	13	9.7 sec	16.8 sec
7	2.5 sec	4.5 sec	14	11.4 sec	19.6 sec
8	3.4 sec	6.1 sec	15	13.1 sec	22.6 sec

Table 6: governor time constant needed to prevent loss of load after loss of one generating unit.

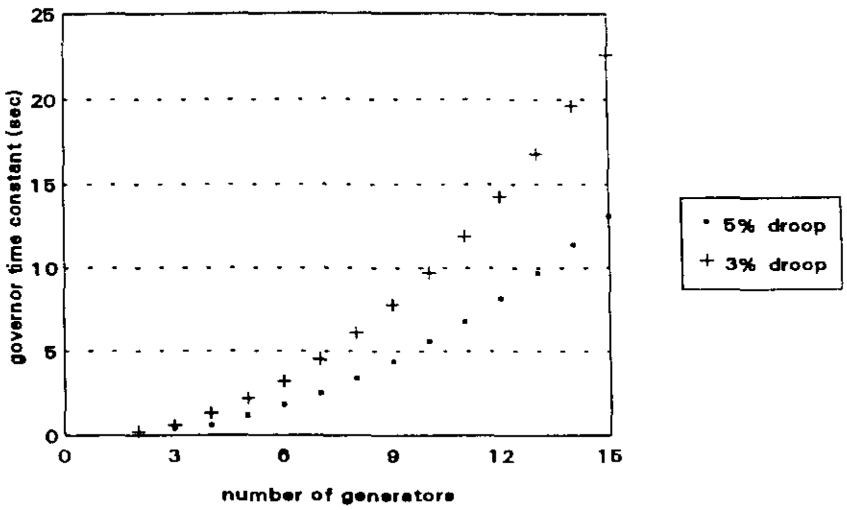

Figure 15: Time constant needed to prevent load shedding after the loss of one generator.

4.4. Consequences for the reliability

With increasing number of generators in operation, the expected loss of load (not supplied kWh) will decrease. Figure 16 shows the expected loss of load per year

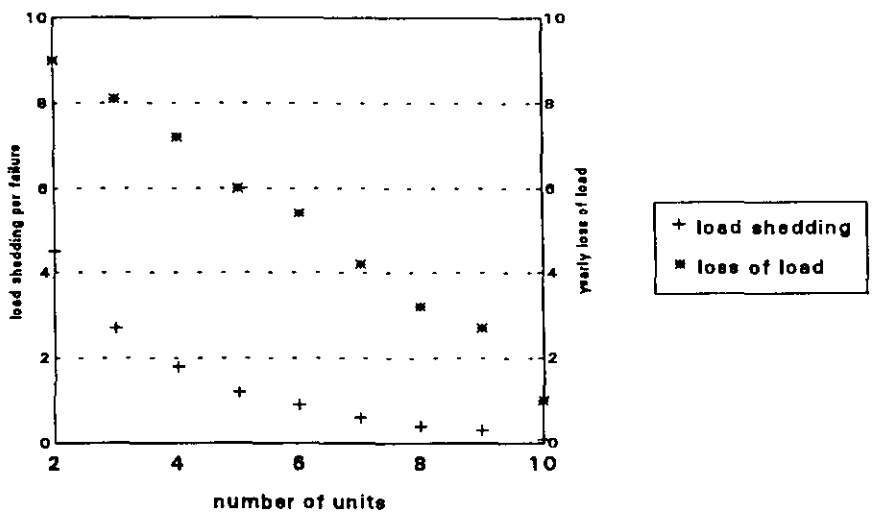

Figure 16: Expected loss of load per generator failure and per year as a function of the number of generators in operation in a 10 MW insular power system.

as a function of the number of generators, for an island with a total power consumption of 10 MW. The expected time to failure is 1 year, for each generator. The standing reserve is available one hour after the loss of power. Each unit has a spinning reserve of 10%.
From Figure 16 is follows that the reliabity of the supply increases for increasing

number of generating units. Looking at individual users however, gives a completely different view. With increasing number of generating units, the probability that one of the units fails will increase proportionally. In small systems every generatir failure will lead to an interruption for some of the users, due to the intervention of the minimum-frequency relays. For those users tripped by the minimum-frequency relays with the highest frequency setting, the number of interruptions will therefore increase proportionally with the number of generating units[8]. The reliability will thus decrease with increasing number of generating units, for those users. For the important users, that are only tripped by large shortages of power, the reliability will not change. The gain in "system reliability" is from the reduction of the number of users tripped by the first level of minimum-frequency relays.

---

[8] The reliability of the important users is kept high by reducing the reliability of the less-important users. It appears to be reasonable to make a distinction in tariffes between the different groups of users. The price of the electricity should then be lower for the users that are tripped faster.

5: SHORT CIRCUITS IN INSULAR POWER SYSTEMS

5.1. Short circuits

A short circuit close to a generator causes the generator to accellerate. Due to the short circuit the generator almost only produces reactive power. In an insular power system almost every short circuit is close to all generators. Where in a large system one generator looses sychronism with the other generator, in an insular power system all generators keep (almost) the same frequency but that common frequency shows a fast increase.

In a small insular system the grid will be of the distribution type where overcurrent and overcurrent time relays form the protection. In that case the fault clearing times of will be long and a tripping of the relay wil cause a substantial loss of load. In a larger insular system a transport grid will be present with differential or distance relays for the short cicruit protection. In that case the fault clearing times will be shorter and tripping of a short circuit will (in general) not cause any loss of load.

Some consequences of short circuits in insular power systems will be described in this chapter.

The simulations to be discussed below have all been performed with the following settings for the minimum frequency relays:

> 25% load shedding at 49.0 Hz, 48.5 Hz and 48.0 Hz;
> shedding of remaining load at 47.5 Hz.

It is further assumed that the spinning reserve is 6% and that the rated inertia constant of the power system is 4 seconds.

5.2. Power and frequency transients

Figure 17 shows the frequency and the generated power after a short circuit with a duration of 500 milliseconds. The governor time constant is 5 seconds and the droop setting 5%. No load is tripped by the short-circuit protection. The frequency increases during the short circuit due to the large surplus of generation (the generator load is considered zero). When the short circuit is removed by the protection a value of 53.1 Hz is reached. During the short circuit the generated power is somewhat reduced by the governor. After fault clearing the frequency is much above its setting so the governor further decreases the power production. This power deficit leads to a fast decrease of the frequency. The frequency transient reaches 49 Hz 2.7 seconds after fault clearing (3.3 seconds after fault initiation). This causes the minimum frequency relay to trip 25% of the load. This causes a power surplus and thus an increase in frequency. The governor is able to stabilize the frequency at 50.625 Hz (corresponding to a loss of 25% of load and a droop setting of 5%). The generated power also fluctuates. It reaches a mimimum of 65% of the setting about 5 seconds after the load shedding.

Figure 18 shows the situation when the short-circuit protection trips 25% of the load. Again a frequency value of 53.1 Hz is reached at the instant of fault clearing. But the short circuit protection not only removed the fault but also trips 25% of the load. Although the generated power is somewhat decreased during the fault, there is still a surplus of generation after fault clearing. Therefor the frequency continues to increase until it reaches a value of 53.6 Hz. This increase can however not prevent the frequency from reaching the value of 49 Hz. Therefore also in this case 25% of the load by the minimum frequency relay. It has been assumed here that there is no overlap between the 25% load tripped by the short circuit protection and the 25% load tripped by the minimum frequency relays. When the frequency stabilizes, 50% of the load has been tripped. The frequency therefore stabilizes at 51.25 Hz (with a droop setting of 5%).

Figures 19 and 20 show the situation for 5% droop and a governor time constant of 1 second. They should be compared with Figure 17 and Figure 18. In Figure 19 no load is tripped by the short circuit protection. The faster governor causes a larger decrease of generated power during the short circuit and thus a larger power deficit after fault clearing. Although the governor is also faster in bringing the power production back to its original value, it is not fast enough to prevent the minimum frequency relays from tripping 25% of the load. In Figure 20 25% of load is tripped by the short circuit protection. The generated power is already reduced below 75% during the fault, due to the fast governor (1 second time constant). The tripping of 25% of load by the short circuit protection no longer causes a surplus of power. The frequency therefore starts to decrease at the instant of fault clearing. After that, the governor is fast enough to prevent further loss of load. The minimum frequency reached is 49.8 Hz. The frequency stabilizes at 50.625 Hz.

In the case belonging to Figure 20, 25% of the load is tripped by the short circuit protection. This is a correct intervention by the protection. In the case belonging to Figure 19, 25% of the load is tripped by the minimum frequency relays. This is an incorrect intervention by the protection. The coordination between short circuit protection and minimum frequency relays is an interesting subject for further research.

Figures 21 and 22 show the situation for a droop setting of 3% and a governor time constant of 5 seconds. Figure 23 and 24 are for the same droop setting but for a governor time constant of 1 second. The lower droop (i.e. stronger feedback from the system frequency to the power control) leads to a small reduction of the maximum frequency, but it causes more intense frequency transients. It also causes more stress on the generating units due to the faster fluctuations in generated power. The frequency stabilizes at a value closer to 50 Hz due to the lower droop setting. Especially Figures 23 and 24 (1 second time constant) show intense fluctuations in generated power.

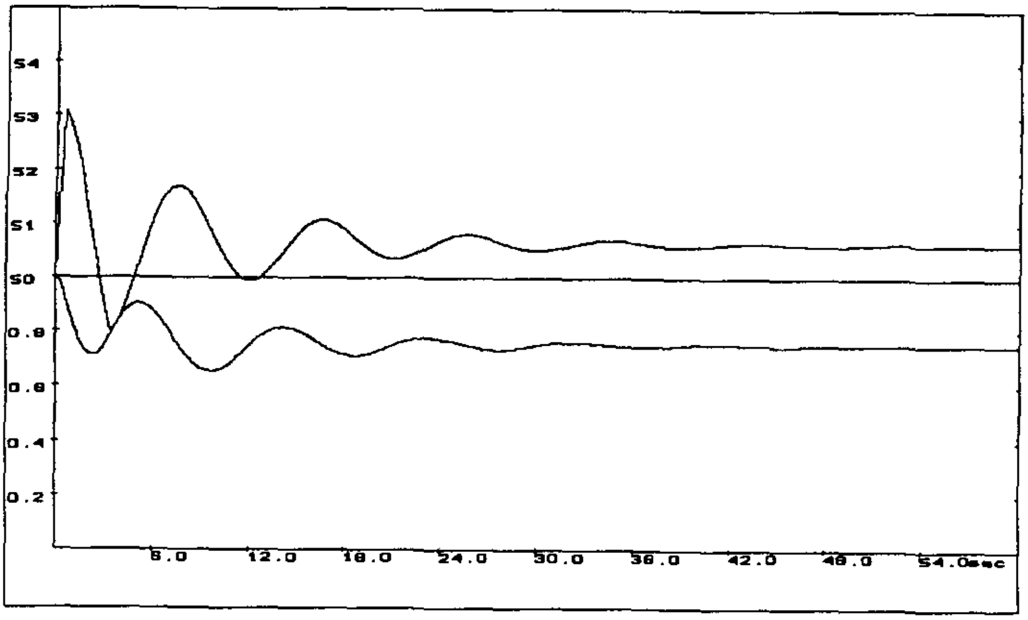

Figure 17: Frequency and power transient due to short circuit of 500 milliseconds; droop setting 5%; governor time constant 5 sec; no load tripped by protection; 25% load (incorrectly) tripped by minimum frequency relays.

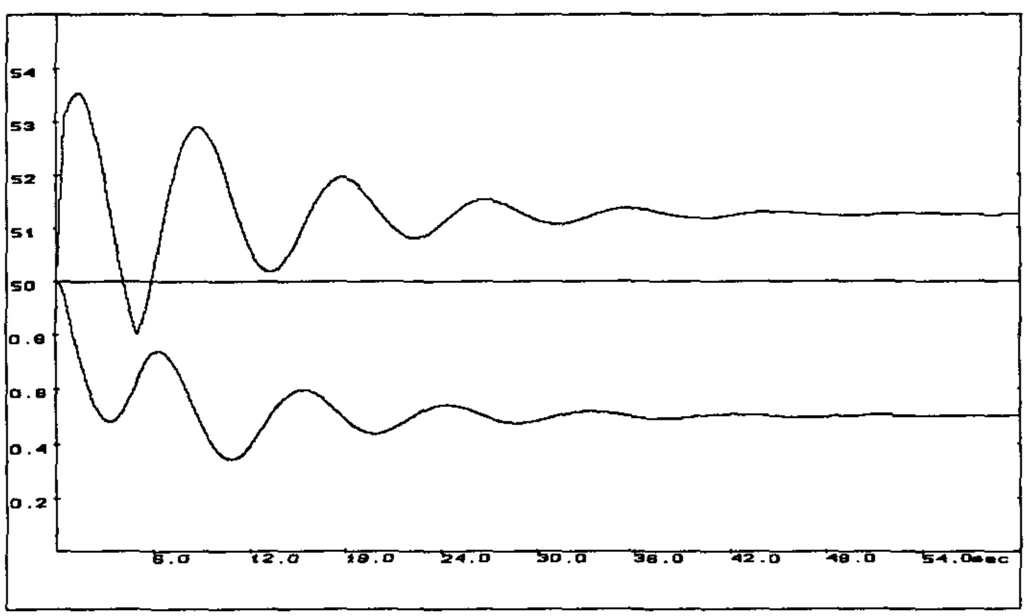

Figure 18: Power and frequency transient due to short circuit of 500 milliseconds; droop setting 5%; governor time constant 5 sec; 25% load tripped by protection; 25% load (incorrectly) tripped by minimum frequency relays.

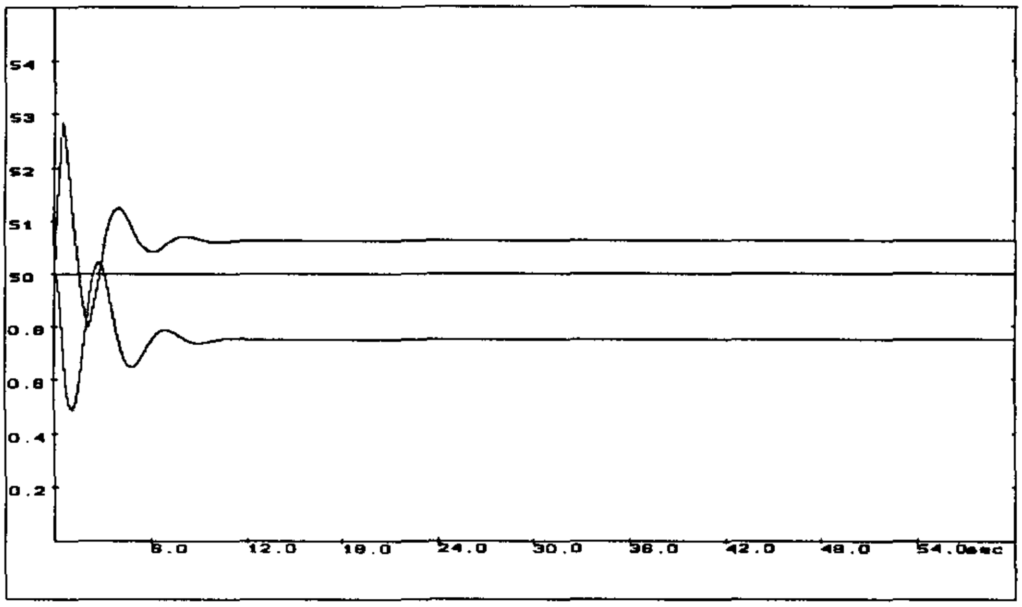

Figure 19: Power and frequency transient due to short circuit of 500 milliseconds; droop setting 5%; governor time constant 1 sec; no load tripped by protection; 25% load (incorrectly) tripped by the minimum-frequency relays.

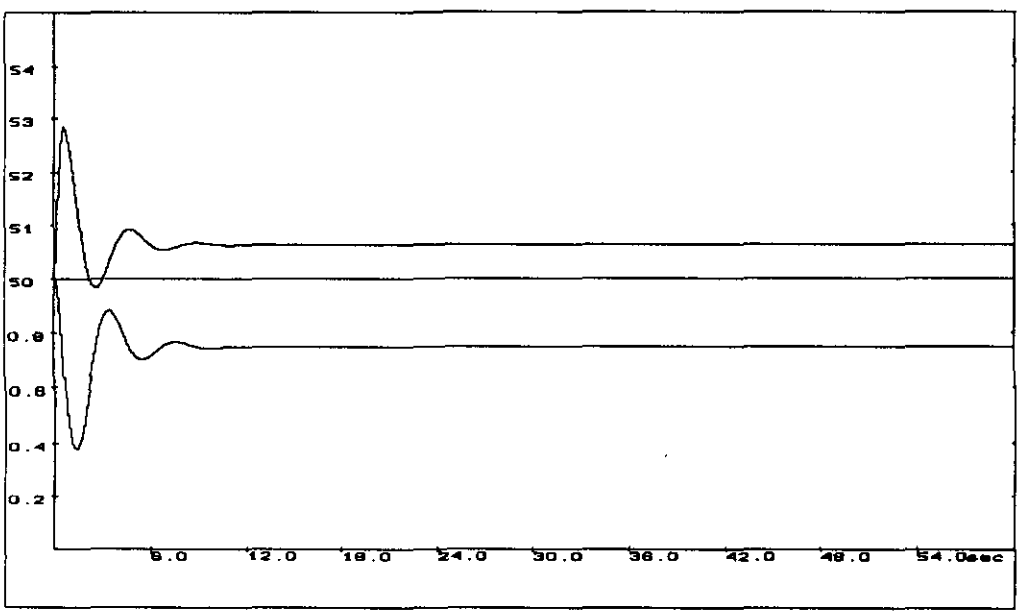

Figure 20: Power and frequency transient due to short circuit of 500 milliseconds; droop setting 5%; governor time constant 1 sec; 25% load tripped by protection; no load tripped by the minimum frequency relays.

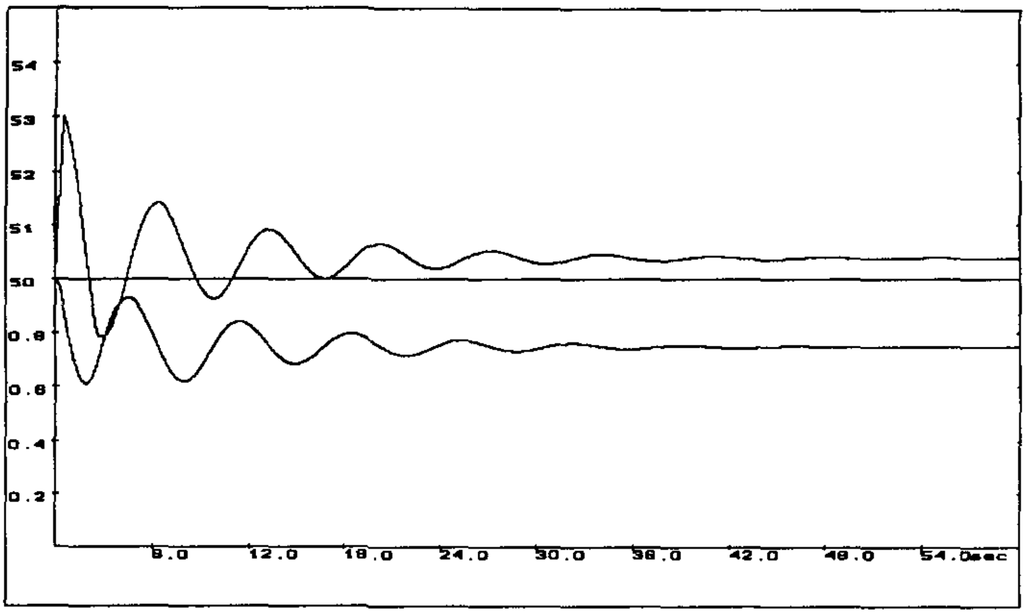

Figure 21: Power and frequency transient due to short circuit of 500 milliseconds; droop setting 3%; governor time constant 5 sec; no load tripped by protection; 25% load (incorrectly) tripped by minimum frequency relays.

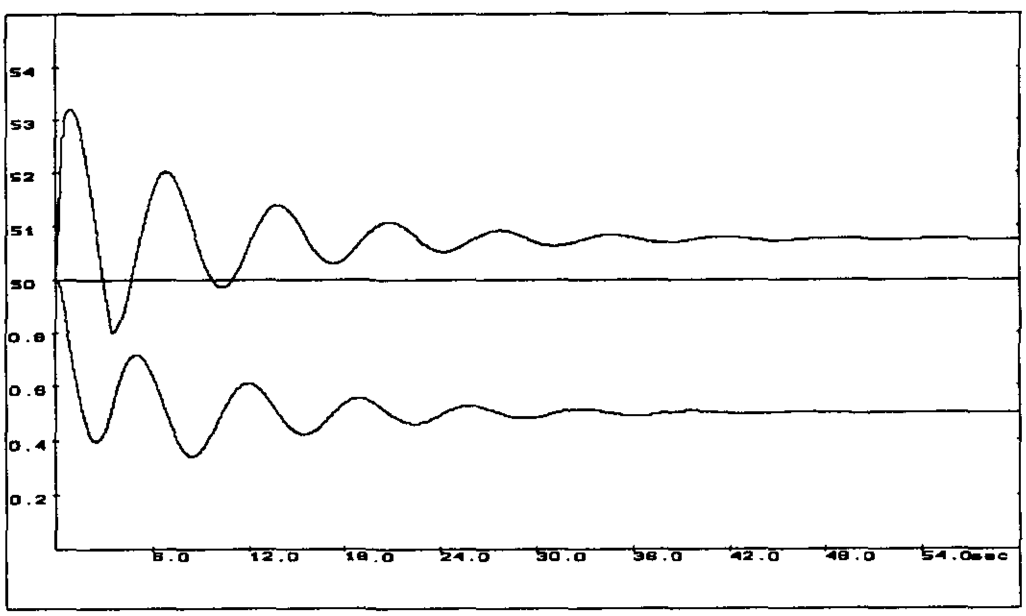

Figure 22: Power and frequency transient due to short circuit of 500 milliseconds; droop setting 3%; governor time constant 5 sec; 25% load tripped by protection; 25% load (incorretly) tripped by minimum frequency relays.

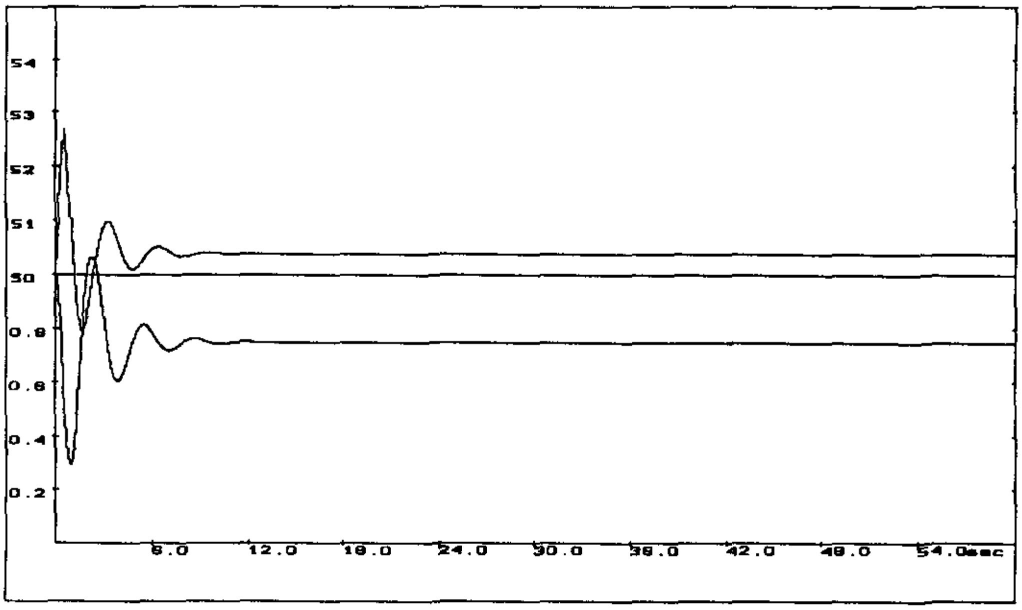

Figure 23: Power and frequency transient due to short circuit of 500 milliseconds; droop setting 3%; governor time constant 1 sec; no load tripped by protection; 25% load (incorrectly) tripped by mimimum frequency relays.

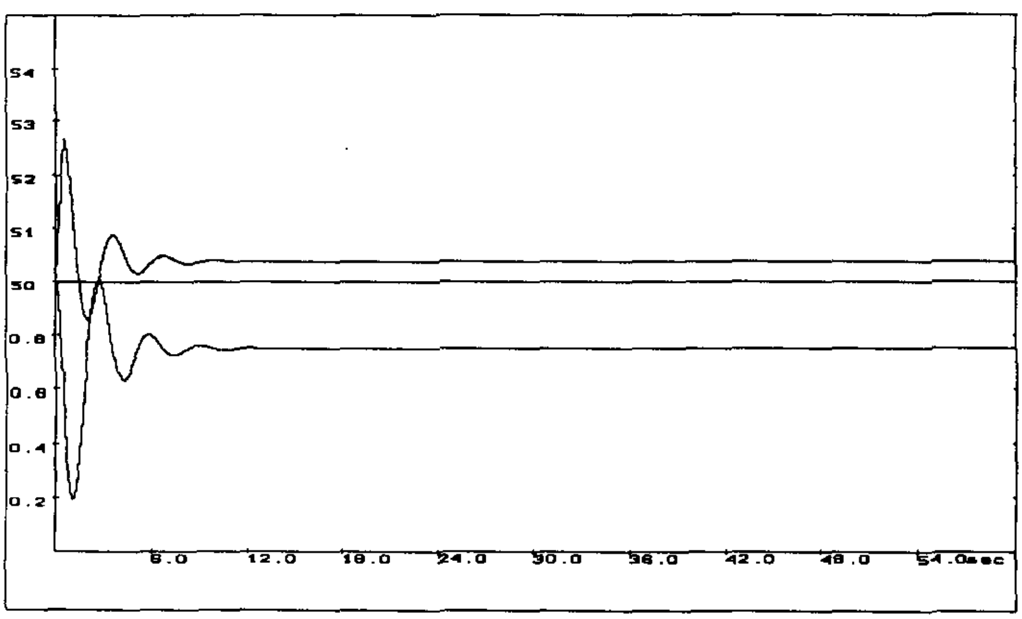

Figure 24: Power and frequency transient due to short circuit of 500 milliseconds; droop setting 3%; governor time constant 1 sec; 25% load tripped by protection; no load tripped by minimum frequency relays.

5.3. Influence of the fault clearing time

Table 7 gives the maximum frequency and the minimum generated power for different values of the tripping time. One has to keep in mind here that a small value of the generated power corresponds to a strong power transient. The column "load shed" gives the amount of load (incorrectly) tripped by the minimum frequency (load shedding) relays.

	5% droop 5 sec. time constant			3% droop 1 sec. time constant		
clearing time	max freq.	min. power	load shed	max freq.	min. power	load shed
100 ms	50.7	0.94	-	50.7	0.84	-
200 ms	51.3	0.88	-	51.3	0.64	-
300 ms	52.1	0.62	25%	51.8	0.54	-
400 ms	52.3	0.64	25%	52.3	0.40	25%
500 ms	53.1	0.65	25%	52.7	0.27	25%
600 ms	53.7	0.65	25%	53.1	0.14	25%
700 ms	54.2	0.60	25%	53.3	0.04	25%
800 ms	54.8	0.54	25%	53.5	0	25%
900 ms	55.3	0.32	50%	53.5	0	25%
1000 ms	55.8	0.33	50%	53.5	0	25%

Table 7: Influence of fault clearing time on frequency and power transient. No load is tripped by the short circuit protection.

Figure 25 shows the maximum frequency reached during the transient phenomenon, as a function of the fault clearing time. As expected the maximum frequency increases for increasing tripping time. For the system with fast control (3% droop, 1 second governor time constant) the maximum frequency stabilizes for tripping times of 800 milliseconds and higher. That is because the governor is able to reduce the generator output to zero within 800 milliseconds[9]. In the graph for the system with slow control (5% droop, 5 seconds governor time constant) a sudden increase in maximum frequency is visible around 250 milliseconds fault clearing time. This is due to the operation of the minimum frequency relays for tripping times of 245 milliseconds and more. For tripping times of 830 milliseconds and more the second group of minimum frequency relays operates (at 48.5 Hz) leading to the loss of 50% of load.

The mimimum power production as a function of the fault clearing time is shown in Figure 26. For the system with fast control the mimimum power production is much lower than for the one with slow control. This leads to higher stress on the

[9] This is not realistic as most generators cannot be brought back to zero power output and in most cases some generating unit are running on base load, i.e. their power production is not regulated.

generating units during a short circuit. It is probably not realistic to assume a zero power output. This is clearly a limitation of the model used. For the system with slow control, the power transient is mainly caused by the (incorrect) load shedding. The two strong increases in amplitude (decreases in minimum power) correspond to 25% load shedding (around 250 milliseconds) and 50% load shedding (around 830 milliseconds). This is a further reason for coordination between short circuit protection and load shedding.

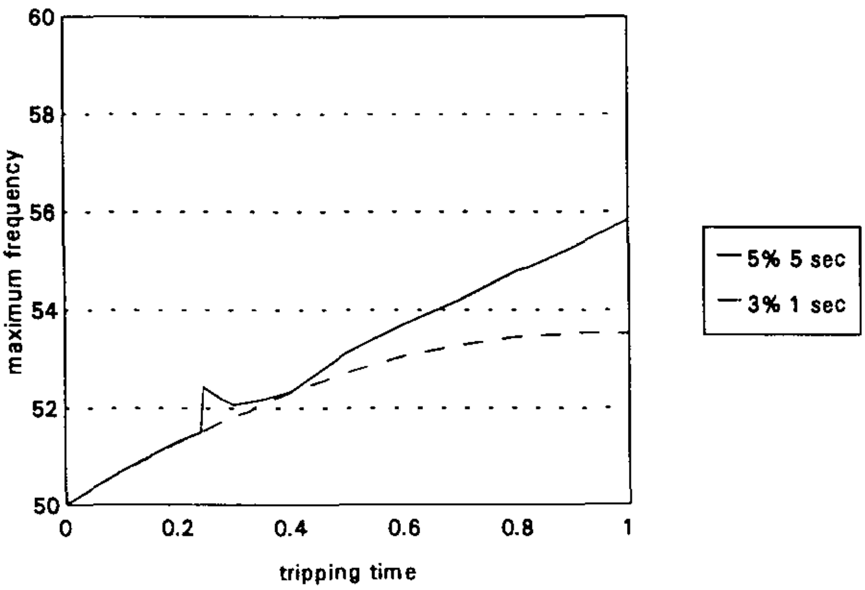

Figure 25: Maximum frequency as a function of fault clearing time. No load is tripped by the short circuit protection. The solid line is for a system with moderate control, the dotted line for fast control.

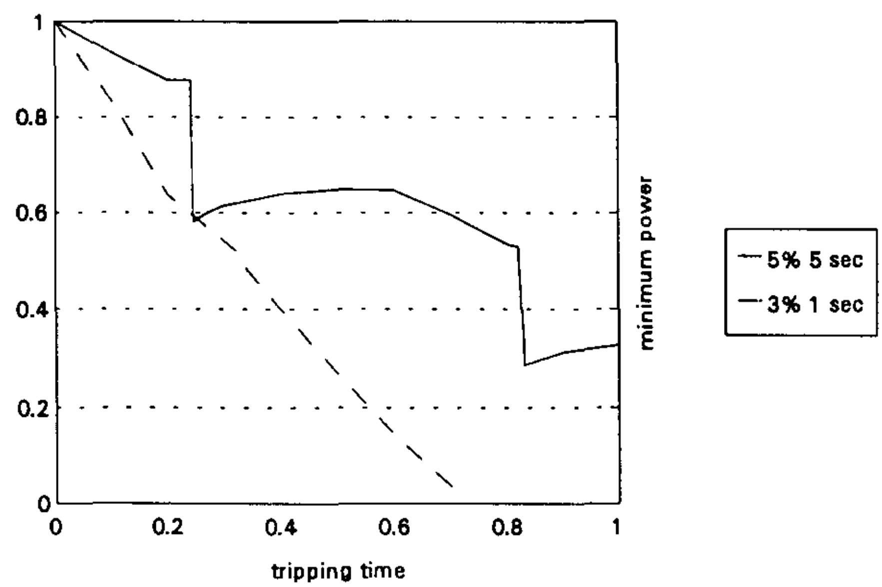

Figure 26: Minimum power generation as a function of fault clearing time. No load is tripped by the short circuit protection. The solid line is for a system with moderate control, the dotted line for fast control.

Table 8 gives maximum frequency and minimum power for the case in which the short circuit protection not only removes the fault, but also 25% of the load. Table 8 shows a similar shape as table 7. For the system with fast control the minimum power decreases steadily. For the system with slow control the decrease is stepwise, with a strong step around 380 milliseconds. This step corresponds to 25% load shedding.

	5% droop, 5 sec time constant			3% droop, 1 sec time constant		
clearing time	max. freq	min. power	load shed	max. freq	min. power	load shed
100 ms	52.4	0.58	0	51.0	0.58	0
200 ms	52.6	0.57	0	51.4	0.50	0
300 ms	52.9	0.54	0	51.9	0.39	0
400 ms	53.2	0.32	25%	52.3	0.28	0
500 ms	53.6	0.35	25%	52.8	0.17	0
600 ms	54.0	0.36	25%	53.1	0.06	25%
700 ms	54.4	0.36	25%	53.3	0	25%
800 ms	54.9	0.35	25%	53.5	0	25%
900 ms	55.3	0.31	25%	53.5	0	25%
1000 ms	55.9	0.26	25%	53.5	0	25%

Table 8: Influence of fault clearing time on frequency and power transient. 25% of the load is tripped by short circuit protection.

In case of fast control 25% additional load is shed by the short circuit protection for clearing times of 600 milliseconds and more. For slow control this happens for clearing times of 380 milliseconds and more. These values are the maximum permissable clearing times for short circuits close to the generator, in small insular systems[10].

5.4. Influence of governor time constant

Table 9, figure 27 and Figure 28 give the influence of the governor time constant on the transient phenomenon, characterized by the maximum frequency and the minimum power production. It has been assumed that the fault clearing time is 500 milliseconds and that no load is tripped by the short circuit protection. The influence on the maximum frequency is shown graphically in Figure 27; the influence on the minimum power in Figure 28.

---

[10] This only holds in case every short circuit leads to the (correct) tripping of 25% of the load. If there is a spread in this percentage (as will always be the case) the maximum permissable fault clearing time will almost certainly be less. This is again a direction for further investigations.

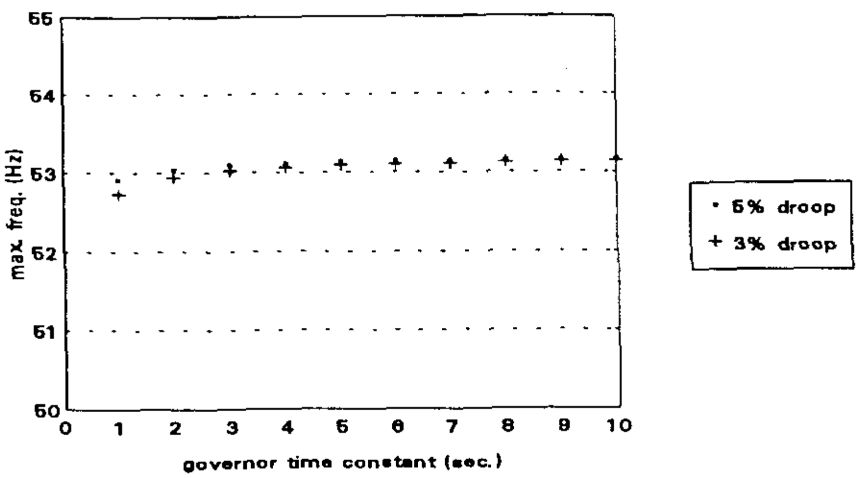

Figure 27: Influence of governor time constant on maximum frequency due to a short circuit of 500 milliseconds; no load tripped by the protection.

The influence on the maximum frequency is small, because non of the governors is able to reduce the generated power substantially within half a second. The power transient gets somewhat less intense for increasing time constants. The influence of the droop is only visible for small time constants.

	droop = 5%			droop = 3%		
time constant	max. freq	min. power	load shed	max.freq	min. power	load shed
1 sec	52.9	0.47	25%	52.7	0.27	25%
2 sec	53.0	0.58	25%	52.9	0.43	25%
3 sec	53.1	0.64	25%	53.0	0.51	25%
4 sec	53.1	0.65	25%	53.1	0.56	25%
5 sec	53.1	0.65	25%	53.1	0.60	25%
6 sec	53.1	0.65	25%	53.1	0.62	25%
7 sec	53.1	0.65	25%	53.1	0.63	25%
8 sec	53.2	0.66	25%	53.1	0.64	25%
9 sec	53.2	0.66	25%	53.1	0.64	25%
10 sec	53.2	0.66	25%	53.1	0.65	25%

Table 9: Influence of governor time constant on power and frequency transients; fault clearing time 500 milliseconds; no load tripped by the short circuit protection.

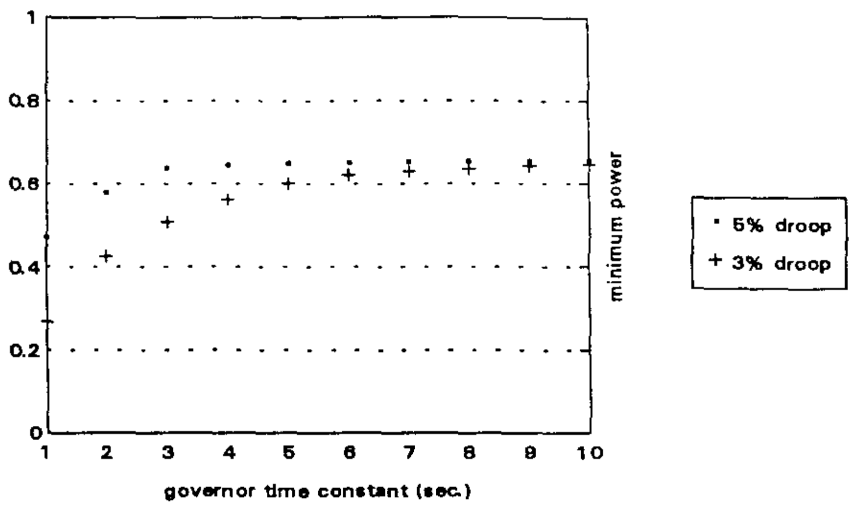

Figure 28: Influence of governor time constant on minimum generated power due to short circuit of 500 milliseconds; no load tripped by the short circuit protection.

Table 10 gives the same information in case the short circuit protection trips 25% of the load. The influence on the maximum frequency is shown in Figure 29, the influence on the minimum power in Figure 30. The time constant of the governor has considerable influence now. This is due to the surplus of power after fault clearing. This surplus has to be controlled by the governor. The smaller droop setting somwhat decreases the maximum frequency, but is also decreases the minimum power (thus increases the power dip). For time constants of 2 and 3 seconds, the smaller droop setting causes the loss of another 25% of load.

	5% droop			3% droop		
time constant	max. freq.	min. power	load shed	max. freq.	min. power	load shed
1 sec	52.9	0.36	0	52.7	0.17	0
2 sec	53.1	0.42	0	53.0	0.28	25%
3 sec	53.3	0.45	0	53.1	0.32	25%
4 sec	53.5	0.33	25%	53.2	0.33	25%
5 sec	53.6	0.35	25%	53.3	0.34	25%
6 sec	53.7	0.36	25%	53.4	0.35	25%
7 sec	53.9	0.36	25%	53.5	0.35	25%
8 sec	54.0	0.37	25%	53.6	0.36	25%
9 sec	54.1	0.37	25%	53.6	0.37	25%
10 sec	54.3	0.38	25%	53.7	0.37	25%

Table 10:Influence of governor time constant on transient phenomena due to short circuit of 500 milliseconds; 25 % load tripped by the short circuit protection.

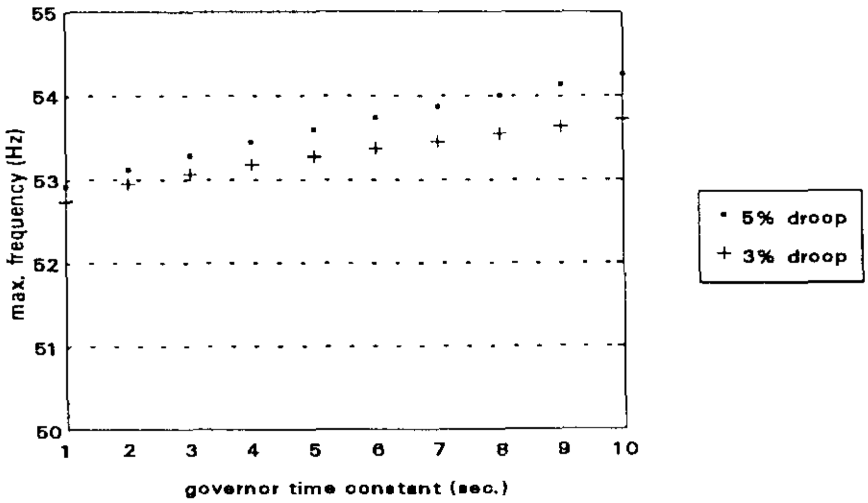

Figure 29: Influence of governor time constant on maximum frequency due to short circuit of 500 milliseconds; 25% load tripped by short circuit protection.

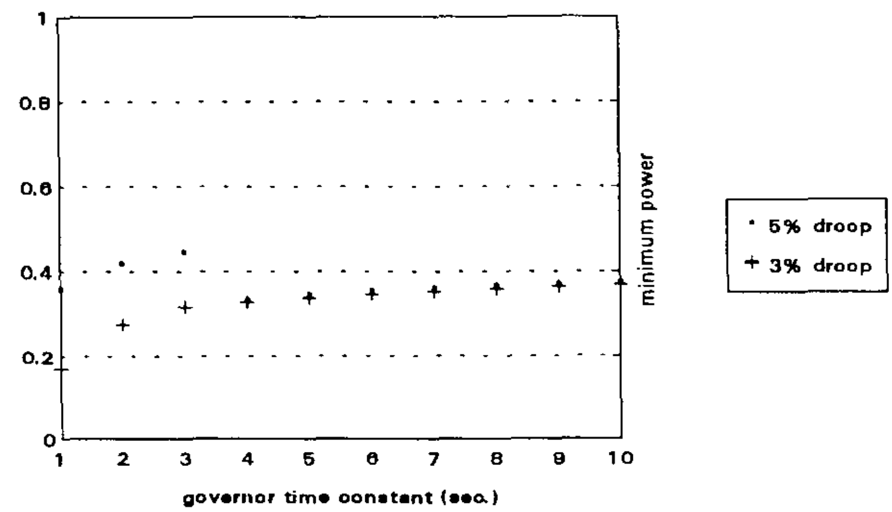

Figure 30: Influence of governor time constant on minimum generated power due to short circuit of 500 milliseconds; 25% load tripped by the short circuit protection.

5.5. Maximum-permissable fault clearing time

As can be seen in Table 9 and 10, the governor time constant should be below a certain value to prevent tripping of the minimum frequency relays. This maximum permissable governor time constant is given in Table 11, as a function of the fault clearing time. The results are shows graphically in Figure 31 for the case without load tripped by the protection and in Figure 32 for the case with 25% of load tripped. The lower droop setting makes it more difficult to prevent further load shedding. In case of no load tripped by the short circuit protection (i.e in large insular systems) it is almost impossible to prevent load shedding for fault clearing times above 250 milliseconds. For smaller systems (where the protection trips 25% of the load) this limit is about 500 milliseconds. A minimum governor time constant of 3 seconds has been assumed. Faster power-frequency control permits longer fault-clearing times.

	5 % droop		3 % droop	
clearing time	no load tripped	25% load tripped	no load tripped	25% load tripped
100 ms	>25 sec	7.4 sec	>25 sec	6.7 sec
200 ms	12.1 sec	6.8 sec	6.8 sec	5.6 sec
300 ms	2.1 sec	5.8 sec	1.2 sec	4.0 sec
400 ms	1.1 sec	4.6 sec	0.6 sec	2.4 sec
500 ms	0.8 sec	3.3 sec	0.4 sec	1.4 sec
600 ms	0.6 sec	2.4 sec	0.4 sec	0.9 sec
700 ms	0.5 sec	1.8 sec	0.4 sec	0.8 sec
800 ms	0.5 sec	1.3 sec	0.4 sec	0.8 sec
900 ms	0.4 sec	1.1 sec	0.4 sec	0.8 sec
1000 ms	0.4 sec	0.9 sec	0.4 sec	0.8 sec

Table 11: Governor time constant needed to prevent extra loss of load after a short circuit.

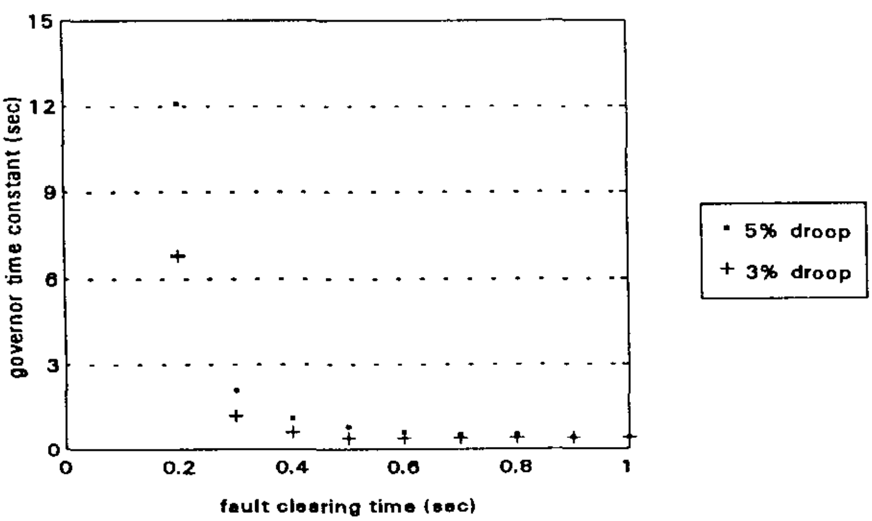

Figure 31: Governor time constant needed to prevent loss of load after a short circuit; no load tripped by the short circuit protection.

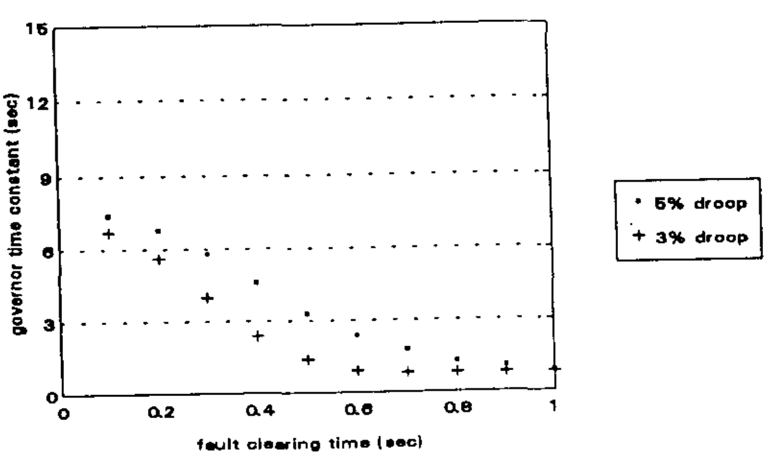

Figure 32: Governor time constant needed to prevent extra loss of load after a short circuit of 500 milliseconds; 25% load tripped by the short circuit protection.

6: WIND ENERGY IN INSULAR POWER SYSTEMS

6.1. Block Island

In an insular power system a limited amount of wind power can be incorporated. This is mainly due to the fact that wind turbines do, in general, not possess a power control. The harder the wind blows the more power is generated by the wind turbines. These fluctuations have to be compensated by the power frequency control of the conventional units. With a growing fraction of wind power a shrinking number of conventional units should compensate the growing fluctuations in wind power. Thus, the spinning reserve has to increase with increasing wind power, unless the user accepts a reduced reliability of the supply.

In the late 70's an experimental wind turbine was installed on Block Island, Rhode Island, USA[11]. The Block Island Power Compagny operated an isolated electric power system consisting of diesel generation and the experimental wind turbine. The 150 kW wind turbine was operated in parallel with two diesel units to serve an average winter load of of 350 kW. That implies a fraction of about 40% wind power. This figure is based on maximum power output, it does not imply that 40% of the electrical energy is supplied by wind[12]. The wind turbine was operated from mid-1979 through mid-1982. During this period there were 4,300 start-stop cycles but voltage fluctuations were not noticable to costumers. Even during the winter period, with wind power penetration up to 60% of the total load demand, no problems were encountered. One of the diesel units was equipped with voltage and frequency control. The excitation units on the diesels where characterized by terminal voltage recovery times in the 1 to 2 seconds range and for the governor control between 3 and 5 seconds.

6.2. Simulation results for measured wind data

To model the behaviour of the power system frequency due to fluctuations in wind power we assumed a system with (on average) a fraction f_{wind} generated by wind energy. The remaining is generated by conventional units.

---

[11] Scott, G.W. and V.F. Wilreker, R.K. Shaltens, *Wind turbine generator interaction with diesel generators on an isolated power system*, IEEE Transactions on Power Apparatus and Systems, Vol. 103 (May 1984), p.933-938.
Smith, R.F. and V.F. Wilreker, R.K. Shaltens, *Measured effects of wind turbine reactive power control on an isolated utility*, IEEE Transactions on Power Apparatus and Systems, Vol. 103 (June 1984), p.1531-1536.

[12] The wind turbine has generated 588,000 kWh during 8500 hours of synchronous operation, that implies an average output of 69 kW. Compared to the average winter load (350 kW), 20% of the electrical energy is supplied by wind during the winter period.

For the wind fluctuations we have used measurements of generated power by the wind turbine on Tera Cora, Curaçao[13]. The generated power has been measured every 10 seconds during one hour. Details about the measurement are not available at this moment. The wind power fluctuations are shown in Figure 33. The average power production is set to one. The wind power fluctuates strongly between 20% and 185% of its average value. It has been assumed further on that all wind turbines in our hypothetical system have this same power profile.

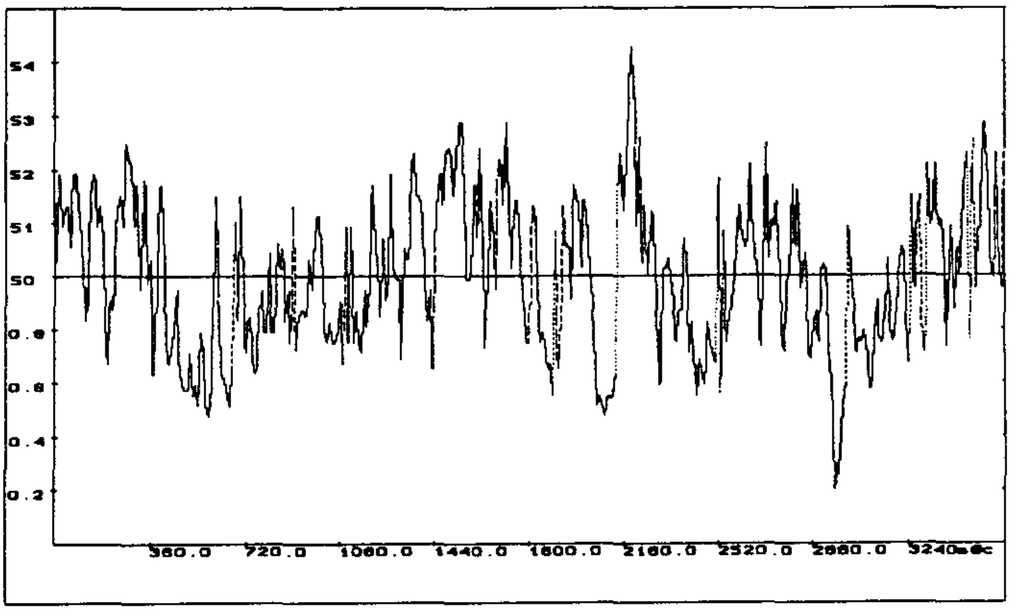

Figure 33: Power generated by a wind turbine during one hour.

Figure 34 shows (from top to bottom) the system frequency, the power generated by the conventional units, and the power generated by the wind units. The average wind power equals 20% of the total power, i.e. during this one hour 20% of the electrical energy is supplied from wind, comparable to the Block Island winter situation. A droop setting of 5% and a governor time constant of 5 seconds have been assumed. The frequency fluctuates between 49.5 and 50.5 Hz. In case of 40% wind power (Figure 35) the frequency fluctuates between 49 and 51 Hz.

---

[13] Oleana, E.C. *Windmolens op Bonaire (Windmills at Bonaire*, In Dutch). University of The Netherlands Antilles, Faculty of Engineering, September 1986. M.Sc. Thesis.

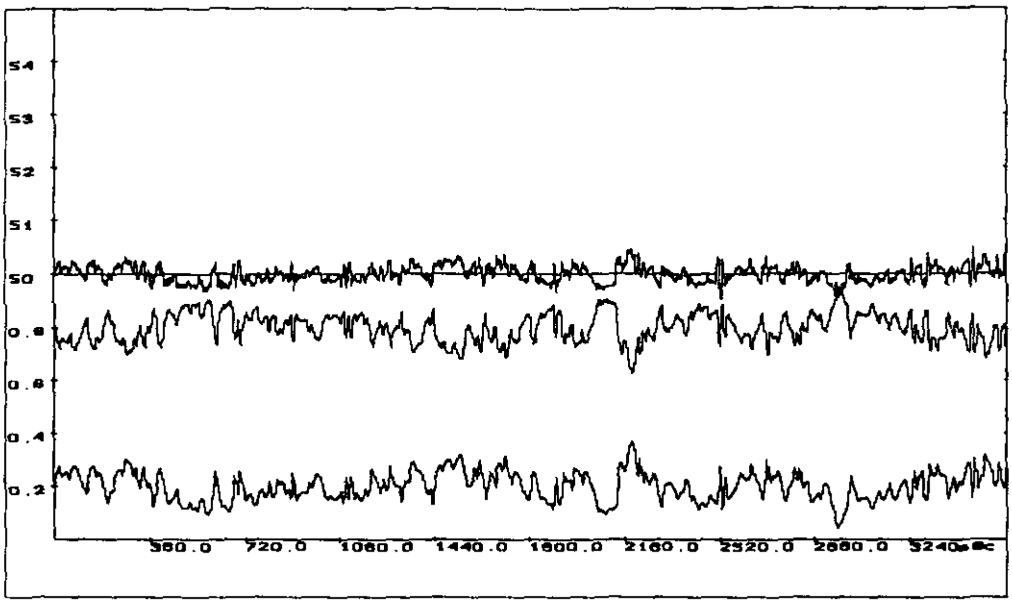

Figure 34: Power and frequency fluctuations in a system with 20% wind energy. Governor time constant 5 seconds; droop setting 5%.

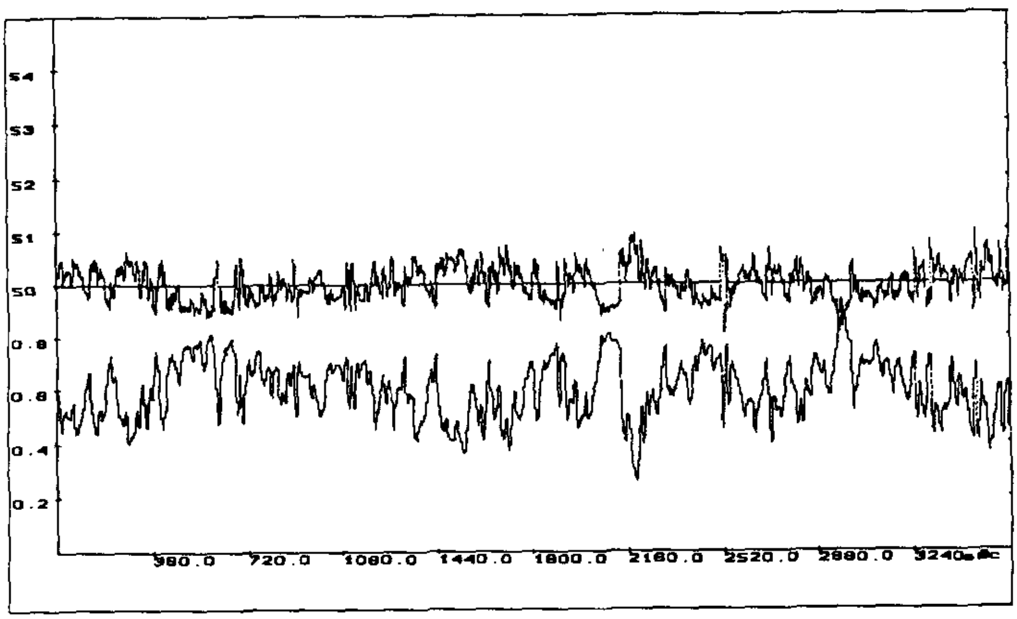

Figure 35: Power and frequency fluctuations in a system with 40% wind energy. Governor time constant 5 seconds; droop setting 5%.

Table 12 and Figure 36 show the frequency spread due to different fractions of wind power. It has been assumed that the droop setting is 5% and the governor time constant 5 seconds. The frequency spread turned out to be mainly due to the droop setting. This leads to the conclusion that the governor is able to follow the wind power fluctuations. It had to be assumed here that there was always enough spinning reserve available. If the fraction of wind energy gets above 53%, the maximum wind power production is above the power consumption. This leads to an instable system[14].

fract. wind	min. freq.	max. freq.
5%	49.9 Hz	50.1 Hz
10%	49.8 Hz	50.3 Hz
15%	49.6 Hz	50.4 Hz
20%	49.5 Hz	50.5 Hz
25%	49.4 Hz	50.6 Hz
30%	49.3 Hz	50.7 Hz
35%	49.2 Hz	50.9 Hz
40%	49.0 Hz	51.0 Hz
45%	48.9 Hz	51.1 Hz
50%	48.8 Hz	51.2 Hz

Table 12: Frequency spread for different fractions of wind power.

Table 13 and Figure 37 show the influence of the governor time constant on the frequency spread[15]; the droop is 5% and 25% of the electrical energy is supplied from wind.

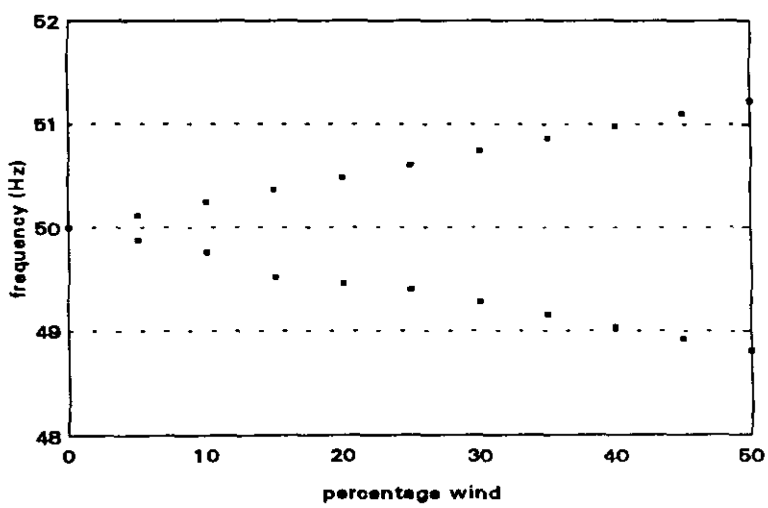

Figure 36: Frequency spread for different fractions of wind energy. Governor time constant 5 seconds; droop setting 5%.

[14] This only holds for this wind power profile. We do not know if the values obtained are optimistic or pessimistic. More profiles have to be obtained before a large fraction of wind power is installed.

[15] It has been assumed here, and everywhere in this chapter, that there are no minimum frequency relays present.

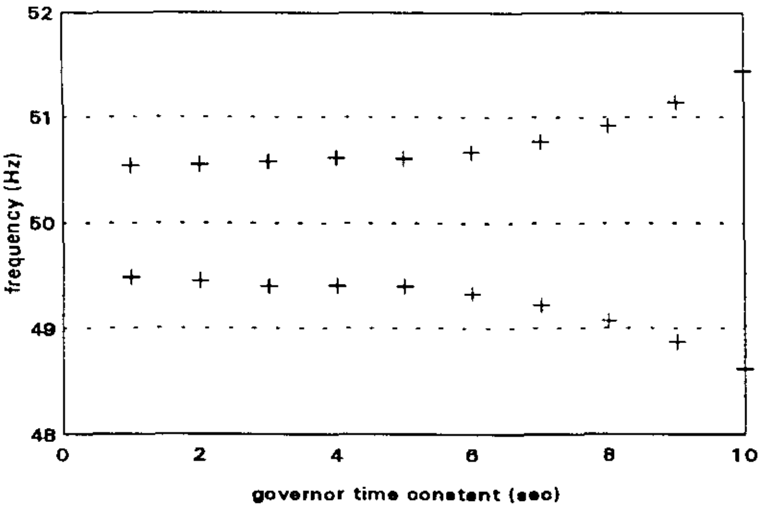

Figure 37: Frequency spread in a system with 25% wind energy, as a function of the governor time constant. Droop setting 5%.

For time constant 6 seconds and less, the influence is small. For larger time constants, the governor cannot follow the power fluctuations anymore. This causes a considerable increase in frequency spread. It can thus be concluded that high percentages of wind power, need conventional units with fast governers. The values in Table 13 have been obtained for a wind power profile with fluctuations on a time scale of 10 seconds. No data was available on a smaller time scale. As the frequency spread grows for increasing governor time constant, it is also expected to grow for fluctuations on a decreasing time scale. The influence of this has been studied and described in the following section.

time constant	min. freq.	max. freq
1 second	49.5 Hz	50.5 Hz
2 seconds	49.5 Hz	50.6 Hz
3 seconds	49.4 Hz	50.6 Hz
4 seconds	49.4 Hz	50.6 Hz
5 seconds	49.4 Hz	50.6 Hz
6 seconds	49.3 Hz	50.7 Hz
7 seconds	49.2 Hz	50.8 Hz
8 seconds	49.1 Hz	50.9 Hz
9 seconds	48.9 Hz	51.1 Hz
10 seconds	48.6 Hz	51.4 Hz

Table 13: Influence of governor time constant on frequency spread in system with 25% wind power.

6.3. A hypothetical wind profile

To study the influence of fluctuations on a smaller time scale we assumed a triangular shape for the wind power, as shown in Figure 38. The wind power fluctuates periodically between 20 and 180% of its average value. The time scale has been varied to study its influence. Some results are shown in Table 14 and Figure 39.

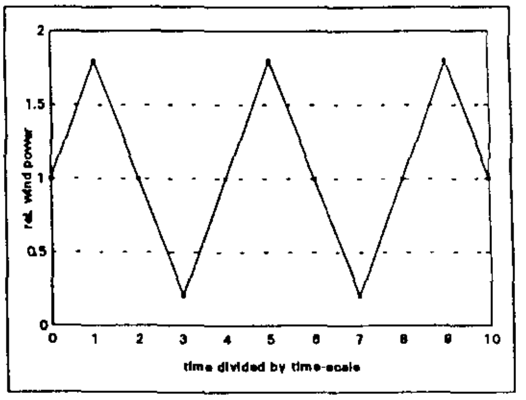

Figure 38: Hypothetical wind power profile.

time scale	min. freq.	max. freq.	time scale	min. freq.	max. freq.
20 seconds	49.5 Hz	50.5 Hz	2.50 sec.	47.0 Hz	52.3 Hz
15 seconds	49.4 Hz	50.6 Hz	2.25 sec.	47.0 Hz	52.3 Hz
10 seconds	49.4 Hz	50.6 Hz	2 seconds	47.2 Hz	52.2 Hz
9 seconds	49.4 Hz	50.6 Hz	1.75 sec.	47.7 Hz	52.1 Hz
8 seconds	49.3 Hz	50.7 Hz	1.50 sec.	48.2 Hz	51.8 Hz
7 seconds	49.1 Hz	50.9 Hz	1.25 sec.	48.5 Hz	51.2 Hz
6 seconds	49.1 Hz	50.9 Hz	1 second	49.0 Hz	50.8 Hz
5 seconds	48.9 Hz	51.1 Hz	0.75 sec.	49.4 Hz	50.7 Hz
4 seconds	48.5 Hz	51.2 Hz	0.5 sec.	49.6 Hz	50.5 Hz
3.75 sec.	48.5 Hz	51.4 Hz	0.4 sec.	49.7 Hz	50.4 Hz
3.50 sec.	48.3 Hz	51.7 Hz	0.3 sec.	49.8 Hz	50.3 Hz
3.25 sec.	47.9 Hz	52.0 Hz	0.2 sec.	49.9 Hz	50.2 Hz
3 seconds	47.4 Hz	52.3 Hz	0.1 sec.	49.9 Hz	50.1 Hz
2.75 sec.	47.2 Hz	52.4 Hz			

Table 14: Influence of time scale of wind power fluctuations on frequency spread in system with 25% wind power.

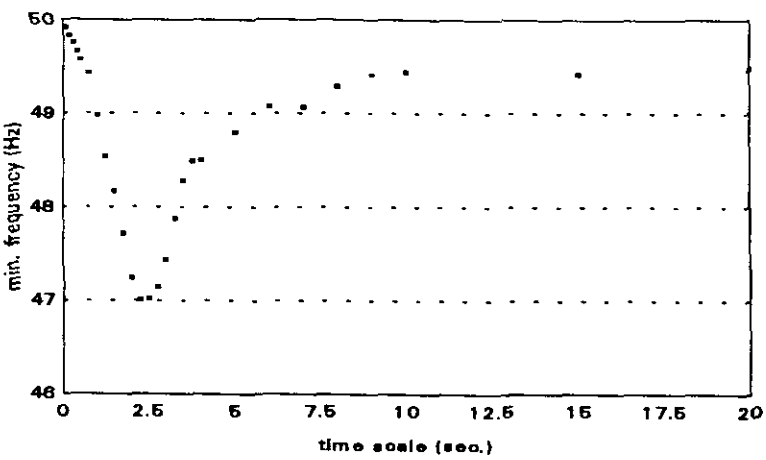

Figure 39: Minimum frequency in a system with 25% wind energy if the wind power profile is according to Figure 38. Governor time constant 5 seconds; droop setting 5%.

The highest frequency spread appears for time scales between 2 and 3 seconds. The corresponding period in the wind fluctuations is about 10 seconds. Fluctuations with a larger time scale are damped by the governor, fluctuations with a smaller time scale are damped by the inertia of the rotating mass in the power system (the inertia time constant is taken 4 seconds everywhere in our study).

The conclusion of the above study is not that the frequency spread in a system with 25% wind power will be from 47 to 52 Hz. The assumption that the wind power fluctuates between 20% and 180% of its average value is not neccesarily true for all time scales. (It's even almost certainly not true). The only conclusion is that fluctuations on a time scale of a few seconds have a strong influence on the frequency spread.

7: CONCLUSIONS AND FUTURE WORK

In this chapter we will summarize the conclusions of the previous chapters. As the main purpose of our study was to investigate the possibilities of future research, we will give in this chapter some suggestions for future work as well. We will give these suggestions in the form of a couple of tasks. Most of the tasks can be handled by one student. Others will need an academic staff member to do the job, either part-time or full-time.

We have not ranked the tasks according to their importance or order of realization.

7.1. Small and large insular power systems

Power systems for the public supply of electrical energy on islands can be divided into four types:

1. concentrated generation and concentrated load;
2. concentrated generation and a distribution network;
3. concentrated generation and a transport grid;
4. distributed generation.

The difference between the first three types is mainly a matter of protective concept used. The difference with the fourth type is the physical position of the generation units. Each type of system has its own specific reliability aspects.

7.1.1. Task 1

A series of lectures should be set up, based on the four types of insular power systems. In these lectures all aspects of power system engineering important for insular systems should be discussed. The result will be a power engineering course that is better fit to the situation on the Netherlands Antilles than the current courses (based on European and North-American power systems).

7.1.2. Task 2

Find out the (economic, technical and other) criteria that determine for what situation each type of power system is most suitable. The most important situations are power systems that are in a transition from one type to the other. Find out if there are special reliability problems in such a transition state.

7.1.3. Task 3

For the generation of electrical energy one can choose between

- diesel generators;
- gas turbines;
- steam turbines.

What are the advantages and disadvantages of these units? An interesting study will be to find out the optimal choose of generating units for insular power systems of different size. An aspect of this study will be to identify which other conditions (apart from the system size) influence this choice.

7.1.4. Task 4

Identify advantages and disadvantages of a common steam system for steam turbines.

7.1.5. Task 5

Study the power systems on several islands and classify them according to the classification proposed in chapter 2. For this study a questionnaire should be made as a guideline for a meeting with representatives from the utilities.

7.1.6. Task 6

A literature search should be conducted after "insular power systems". The search should be directed towards public supply systems on islands, but some aspects of insular back-up systems might be interesting as well. We expect more publications on insular back-up systems than on insular public supply systems. This literature search should give a state of the art on the field of "design and operation of insular power systems" and give information on existing insular power systems.

7.1.7. Task 7

An analogue model of a power system can be made by using a couple of very small generators driven by electrical motors. The generator's output can be of the order of 1kW. The control of these units can be studied by creating disturbances in the system. A first version of such a model has been build by students of the University of the Netherlands Antilles[16]. The authors consider such an analogue model an important tool in power engineering education.

7.2. The power system model

To study transients in insular power systems we have used a model based on the

---

[16] A.D. Zwueste, *Toerenregeling voor een seriemotor (Speed control for a series motor,* In Dutch). University of The Netherlands Antilles, Faculty of Engineering, August 1991. M.Sc. Thesis.

F.R. Tromp, *Koppel-toeren regeling voor een generator (Torque-speed control for a generator,* In Dutch). University of The Netherlands Antilles, Faculty of Engineering, November 1992. M.Sc. Thesis.

C.K. Wong, *Het analyseren van een eiland net met behulp van PRONET en het bouwen van een spannings-blindvermogen regelaar voor het gebruik van parallel bedrijf van generatoren (To analyse an insular power system by using PRONET and to build a voltage reactive power control for parallel operation of generators,* In Dutch). University of The Netherlands Antilles, Faculty of Engineering, November 1992. M.Sc. Thesis.

swing equation (conservation of kinetic energy for the spinning mass in the system) and a first order approximation for the power-frequency control of the generators (the governor).

7.2.1. Task 8

Include voltage control in the power system model. Find out whether the voltage control has any influence on the power system behavior during the transient phenomena. For those power systems in which the voltage control has considerable influence (we expect this in systems with distributed generation) all the studies mentioned below should use the extended model in stead of the simple model used in the present report.

7.2.2. Task 9

Design a voltage control and a frequency control for power generating units in an insular power system. The design of these controls should be such that the probability of an interruption is minimized. In an insular power system with concentrated generation communication between the generating units is simple. One control system for all generating units might be desirable above one control system for each unit.

At first sight the power system model looks linear, but this is not true. A decrease in frequency leads to load shedding, an increase in frequency not; the generating units can only produce slightly more power than their set point, but they can produce much less than their set point. This asymmetric behavior might also be incorporated in the control system. One might think of a control system that is fast for frequencies below 50 Hz (when there is a power deficit and a minimum frequency relay that should be avoided) and slow for frequencies above 50 Hz (where there is a power surplus that can easier be handled and where there are no maximum frequency relays close).

7.2.3. Task 10

In all our studies it has been assumed that the load of the system equals the sum of the nominal loads of all generating units in operation. In case the load is less (as will be the case most of the time) the frequency drop due to loss of a unit is less (the rated inertia constant appears to increase). This should be taken into account in studies of more realistic power systems. For the present study, in which phenomena were more important than exact values, this is not of much importance.

7.2.4. Task 11

To represent existing insular power systems the model should at least be slightly extended. Some extensions that should be made are the following:

* including the possibility that different units in the system have different governor time constants;
* including the possibility that only a part of the units are equipped with power frequency control where the others are operated on base load;

* setting a minimum power output for the generating units;
* including the possibility that the power frequency control only operates between certain frequency limits;
* including the possibility that the power frequency control does not operate during an under voltage (i.e during a short circuit).

7.3. Loss of generation

The first disturbance we have studied is the loss of a part of the generation. In an insular power system, with a limited number of generating units, the loss of one unit constitutes a severe disturbance of the power balance. This causes a fast decrease of the power system frequency (i.e. of the kinetic energy of the spinning mass in the system). The power frequency control of the remaining units is able to stop the frequency decrease and bring the frequency back to a value close to 50 Hz. This will still cause a severe frequency dip and it only works in case there is enough spinning reserve available. As spinning reserve decreases the efficiency, a large spinning reserve is not preferable.

Therefore minimum frequency relays are installed in the system. If the frequency gets below a certain value, these relays trip a part of the load. This prevents a total black-out without the need for a large spinning reserve. As the percentage of load tripped by minimum frequency relays shows an uncertainty the situation can arise that the first relay trips a bit too little load. The frequency continues to decrease and another relays trips another part of the load. The latter causes an intense frequency transient where frequencies of 53 Hz and more can be reached.

Even in case of sufficient spinning reserve it is in practice not possible to prevent a frequency dip below 49 Hz in a system with less than 6 generating units in operation. (A time governor time constant of 3 seconds and a droop setting of 3% have been assumed.) In these small systems it is therefore inevitable that the loss of a generating unit leads to the loss of part of the load.

For an increasing number of generating units, the expected loss of load decreases. However, for the least-important users the expected number of interruptions increases.

7.3.1. Task 12

Determine the spread in the percentage of load tripped by minimum frequency relays, as a function of the system size. If a probability distribution for this percentage is available the expected loss of load can be determined for a given failure rate of the generating units.

7.3.2. Task 13

A method should be developed to calculate the expected loss of load due to loss of generation for an insular power system. The method has the following input parameters:

* the frequency setting of the minimum frequency relays;
* the probability distribution for the percentage of load tripped by the minimum frequency relays (as the total load equals 100% there will be dependencies between the distributions);
* the percentage of load supplied by each generating unit plus its failure rate.

When developing this method one has to keep in mind that the expected loss of load is not the only reliability criterion. The expected number of interruptions for the different load points is another one.

7.3.3. Task 14

The method developed in the previous task can be used to determine optimal settings for a given configuration of generating units. This will be a complex problem as the percentage of load supplied by each generator varies during the day and during the year. For this a probability distribution might be used too.
The optimal setting can be determined by trial and error, but maybe some more intelligent method can be developed.

7.3.4. Task 15

For a given (optimal) setting of the minimum frequency relays the influence of the frequency control can be studied. By designing a good control system the expected loss of load can be reduced.

7.3.5. Task 16

In our study minimum frequency relays have been used. By using rate-of-change-of-frequency relays (df/dt relays) a more precise load shedding scheme can be designed. It has to be studied whether the use of these df/dt relays can lead to a reduction of the expected loss of load due to loss of a generating unit.

7.4. Short circuits in insular power systems

The frequency transient due to a short circuit is more or less opposite to the one due to the loss of a generating unit. The latter one shows a decrease in frequency followed by an increase due to the shedding of too much load. The transient due to a short circuit shows a fast increase (because of the loss of all active load) followed by a decrease because of the regulating action of the governor. The latter causes frequencies much below 50 Hz which lead to the (incorrect) intervention of minimum frequency relays.

We found out that the transients are more intense in large systems (where no load is tripped due to the intervention of the short circuit protection) than in small systems. We also found that a decreasing droop causes a more intense transient. This is opposite to the behaviour in case of loss of a generating unit where a decreasing droop causes a less intense frequency transient.

For small systems (with 25% load tripped by the short circuit protection) the maximum fault clearing time is 300 milliseconds for a 3% droop setting and 500 milliseconds for a 5% droop setting. For large systems the maximum fault clearing time is slightly more than 200 milliseconds. (A minimum governor time constant of 3 seconds has been assumed.)

7.4.1. Task 17

Design a power frequency control system that minimizes the expected loss of load due to incorrect tripping of the minimum frequency relays after a short circuit. Compare this control system with the one that minimizes the expected loss of load due to loss of a generating unit.

7.4.2. Task 18

It has been assumed in our study of small insular power systems that each short circuit leads to the tripping of 25% of the load. In reality this percentage depends on the time of day (week, year) and on the fault location. A probability distribution has to be found for the percentage of load tripped.
A method should be developed to determine the expected loss of load due to short circuits for a given probability distribution.

7.4.3. Task 19

The problems after a short circuit are a matter of protection coordination. This is a very interesting subject. It is certainly worthwhile to be studied in more detail by including more detailed models of the power system and of the protection (see section 7.2). A comparison can be made between the different types of insular power systems to see what kind of protective relays can be used (over-current, over-current time, under-voltage time, distance, differential etc.) and what their specific coordination problems are.

7.4.4. Task 20

If df/dt relays lead to a reduction of the loss of load due to the loss of a generating unit, it should be studied what is the influence of installing these relays on the expected loss of load due to a short circuit.

7.4.5. Task 21

In previously mentioned tasks, methods have to be developed to determine the loss of load due to loss of generation and due to incorrect tripping of the minimum frequency relays after a short circuit. These methods can be combined with a method to determine the loss of load due to other phenomena (correct and incorrect intervention by the short circuit protection, lack of standing reserve, overload of connections, maintenance).
This method can be used for an (overall) reliability analysis of insular power systems. It is a tool to compare different types of insular power systems and to

find weak spots in existing insular power systems.

7.5. Wind energy in insular power systems

We showed that a large fraction of wind energy (up to 25%) is not impossible in an insular power systems. The problem will be the necessity of an large spinning reserve (about 35% in case of 25% wind energy). It is not clear yet how fast this spinning reserve should be available. But the experiment on Block Island suggest that a governor time constant of 3 to 5 seconds is fast enough.

We found out that more information is needed on the fluctuations in the power output of a wind turbine on a time scale of seconds.

7.5.1. Task 22

More information is needed on the fluctuations of the power output of wind turbines on time scales from 1 second (too fast for the governor) to 1 hour (slow enough to be handled by the standing reserve). Information is also needed on the correlations in power output between wind turbines on different parts of an island (with separations from 100 meter to 10 kilometers). This information is needed to determine the required speed of the governor and the amount of spinning reserve, to prevent a reduction of the reliability due to the introduction of wind turbines.

7.5.2. Task 23

Research can be done towards the possibilities of power frequency control of wind turbines. Also some way of energy storage in combination with wind energy can be investigated. This might reduce the amount of spinning reserve required during the operation of wind turbines. The latter is an important reason for not introducing large portions of wind energy in power systems.

7.5.3. Task 24

The same studies as above can be made for solar energy.

APPENDIX A: COMPUTER PROGRAM FOR THE LOSS OF A GENERATING UNIT

Below are given the relevant parts of the listing of the program to calculate the power and frequency transient due to loss of a generating unit. Input and output of parameters are omitted from the listing.

```
PROGRAM FreqPow1.PAS;

PROCEDURE UpdateTrapezoidalRule(VAR Freq,FreqOld,PiGen,PiGenOld,PiLoad,PiLoadOld,PiSet,PiSetOld : REAL);
         {This procedure calculates the frequency and generated power for the next
          time step by using the trapezoidal rule}

VAR FreqNew,PiGenNew: REAL;

BEGIN
    FreqNew:=Freq+Freq0*DeltaT*(PiGen+PiGenOld-PiLoad-PiLoadOld)/(4*h);
    PiGenNew:=PiGen+DeltaT/(2*TauGov)*(PiSet+PiSetOld-PiGen-PiGenOld)
           +DeltaT/(R*TauGov)-DeltaT/(2*R*TauGov*Freq0)*(Freq+FreqOld);
    FreqOld:=Freq;Freq:=FreqNew;
    PiGenOld:=PiGen;PiGen:=PiGenNew;
    PiLoadOld:=PiLoad;
    PiSetOld:=PiSet
END;

CONST FreqSetting1=47.5; { minimum frequency setting of generator; trip all load }
      FreqSetting2=49.0; LoadShedding2=0.20; {setting of minimum frequency relays}
      FreqSetting3=48.5; LoadShedding3=0.30;
      FreqSetting4=48.0; LoadShedding4=0.25;
      Freq0=50.0;  {nominal frequency}

VAR h                                           : REAL;     { inertia constant }
    R                                           : REAL;     { droop setting }
    PiLoss                                      : REAL;     { loss of power at time zero }
    TauGov                                      : REAL;     { time constant of governor }
    FreqStart                                   : REAL;     { frequency value before disturbance}
    PiLoadStart                                 : REAL;     { load at time zero }
    MaxOverLoadGenerators                       : REAL;     { overload factor of the generators }
    PiSet,PiSetOld                              : REAL;     { power setting, current and previous }
    PiLoad,PiLoadOld                            : REAL;     { load, current and previous }
    Freq,FreqOld                                : REAL;     { frequency, current and previous }
    PiGen,PiGenOld                              : REAL;     { generated power, current and previous }
    Time                                        : REAL;     { time }
    DeltaT                                      : REAL;     { time step }
    Tmax                                        : REAL;     { period of interest from zero to Tmax }
    Nstap                                       : LONGINT;  { number of time steps }
    MaxFreq,MinFreq                             : REAL;     { minimum and maximum value of frequency }
    MaxPiGen,MinPiGen                           : REAL;     { idem for generated power }
    i                                           : LONGINT;  { counter that steps through time }
    GraphDriver,GraphMode,ErrorCode             : INTEGER;  { needed for graphics routines }
    Xnul,Ynul                                   : INTEGER;  { position of axis }
    trip1,trip2,trip3,trip4                     : BOOLEAN;  { TRUE of relay has tripped }
    TripTime1,TripTime2,TripTime3,TripTime4     : REAL;     { tripping time of the relays }
    UitvoerFile                                 : STRING;
    Keuze                                       : INTEGER;

BEGIN
    ClrScr;
    { initialization of trapezoidal rule }
    Freq:=FreqStart;
    FreqOld:=Freq;
    PiGen:=PiLoadStart-PiLoss; {Loss of power at time zero}
    PiGenOld:=PiLoadStart;
    PiSet:=PiLoadStart-PiLoss;
    PiSetOld:=PiLoadStart;
    PiLoad:=PiLoadStart;
    PiLoadOld:=PiLoadStart;
    trip1:=FALSE; trip2:=FALSE; trip3:=FALSE; trip4:=FALSE;
    FOR i:=1 TO Nstap DO
    BEGIN
```

```
        Time:=i*DeltaT;
        UpdateTrapezoidalRule(Freq,FreqOld,PiGen,PiGenOld,PiLoad,PiLoadOld,PiSet,PiSetOld);
        IF PiGen<0 THEN PiGen:=0;
        IF PiGen>PiSet*MaxOverLoadGenerators THEN PiGen:=PiSet*MaxOverLoadGenerators;
          { Generated power cannot become higher than its maximum value }
        IF (NOT trip1) AND (Freq<FreqSetting1) THEN  { trip all load by minimum frequency relay }
        BEGIN
            trip1:=TRUE;
            TripTime1:=Time;
        END;
        IF TRIP1 THEN PiLoad:=0;
        If (NOT trip2) AND (Freq<FreqSetting2) THEN  {tripping of first mimimum frequency relay }
        BEGIN
            trip2:=TRUE;
            PiLoad:=PiLoad-LoadShedding2*PiLoadStart;
            TripTime2:=Time;
        END;
        If (NOT trip3) AND (Freq<FreqSetting3) THEN  { tripping of second minimum frequency relay }
        BEGIN
            trip3:=TRUE;
            PiLoad:=PiLoad-LoadShedding3*PiLoadStart;
            TripTime3:=Time;
        END;
        If (NOT trip4) AND (Freq<FreqSetting4) THEN  { tripping of third minimum frequency relay }
        BEGIN
            trip4:=TRUE;
            PiLoad:=PiLoad-LoadShedding4*PiLoadStart;
            TripTime4:=Time;
        END;
    END;
END.
```

APPENDIX B: COMPUTER PROGRAM FOR A SHORT CIRCUIT

The listing below gives relevant parts of the computer program used to calculate power and frequency transients due to a short circuit in an insular power system.

```
PROGRAM FreqPow2.PAS;

CONST FreqSetting1=47.5; { trip all loads }
      FreqSetting2=49.0; LoadShedding2=0.25;
      FreqSetting3=48.5; LoadShedding3=0.25;
      FreqSetting4=48.0; LoadShedding4=0.25;
      Freq0=50.0;

VAR h                                     : REAL;    { inertia constant }
    R                                     : REAL;    { droop setting }
    PiLoadStart                           : REAL;    { load at time zero }
    PiLoadLoss                            : REAL;    { loss of load due to intervention by protection }
    MaxOverLoadGenerators                 : REAL;    { overload factor of the genetors }
    TauGov                                : REAL;    { time constant of governor }
    FreqStart                             : REAL;    { frequency before disturbance }
    PiSet,PiSetOld                        : REAL;    { power setting, current and previous }
    PiLoad,PiLoadOld                      : REAL;    { load, current and previous }
    Freq,FreqOld                          : REAL;    { frequency, current and previous }
    PiGen,PiGenOld                        : REAL;    { generated power, current and previous }
    Time                                  : REAL;    { time }
    DeltaT                                : REAL;    { time step }
    Tmax                                  : REAL;    { period of interest from zero to Tmax }
    Nstap                                 : INTEGER; { number of time steps }
    MaxFreq,MinFreq                       : REAL;    { minimum and maximum value of frequency }
    MaxPiGen,MinPiGen                     : REAL;    { idem for generated power }
    i                                     : INTEGER; { counter that steps through time }
    GraphDriver,GraphMode,ErrorCode       : INTEGER; { needed for graphics routines }
    Xnul,Ynul                             : INTEGER; { position of axis }
    TripTime1,TripTime2,TripTime3,TripTime4,
    TripTime5                             : REAL;    { tripping times of the relays }
    trip1,trip2,trip3,trip4,trip5         : BOOLEAN;
    UitvoerFile                           : STRING;
    Keuze                                 : INTEGER;

BEGIN
     { Initialize trapeziodal rule }
    Freq:=FreqStart;
    FreqOld:=Freq;
    PiGen:=PiLoadStart;
    PiGenOld:=PiLoadStart;
    PiSet:=PiLoadStart;
    PiSetOld:=PiLoadStart;
    PiLoad:=0; { no load during the short circuit }
    PiLoadOld:=PiLoadStart;
    trip1:=FALSE;trip2:=FALSE;trip3:=FALSE;trip4:=FALSE;trip5:=FALSE;
    FOR i:=1 TO Nstap DO
    BEGIN
        time:=i*DeltaT;
        UpdateTrapezoidalRule(Freq,FreqOld,PiGen,PiGenOld,PiLoad,PiLoadOld,PiSet,PiSetOld);
        IF PiGen<0 THEN PiGen:=0;  { generated power cannot become negative }
        IF PiGen>PiSet*MaxOverLoadGenerators THEN PiGen:=PiSet*MaxOverLoadGenerators;
          { generated power ceiling }
        IF (NOT trip1) AND (freq<FreqSetting1) THEN
        BEGIN
            trip1:=TRUE;
            TripTime1:=Time
        END;
        IF trip1 THEN PiLoad:=0;
        IF (NOT trip2) AND (Freq<FreqSetting2) THEN
        BEGIN
            trip2:=TRUE;
            PiLoad:=PiLoad-LoadShedding2*PiLoadStart;
            TripTime2:=Time
        END;
        IF (NOT trip3) AND (Freq<FreqSetting3) THEN
        BEGIN
```

```
            trip3:=TRUE;
            PiLoad:=PiLoad-LoadShedding3*PiLoadStart;
            TripTime3:=Time
        END;
        IF (NOT trip4) AND (Freq<FreqSetting4) THEN
        BEGIN
            trip4:=TRUE;
            PiLoad:=PiLoad-LoadShedding4*PiLoadStart;
            TripTime4:=Time
        END;
        IF (Time>TripTime5) AND (NOT TRIP5) THEN
        BEGIN
            PiLoad:=PiLoadStart-PiLoadLoss;
            Trip5:=TRUE
        END;
    END;
END.
```

APPENDIX C: COMPUTER PROGRAM FOR WIND ENERGY

The listing below gives relevant parts of the computer program used to calculate the influence of wind energy on the power system frequency.

```
PROGRAM FREQPOW4.PAS;

VAR h                                      : REAL;    { inertia constant }
    R                                      : REAL;    { droop setting }
    TauGov                                 : REAL;    { time constant of governor }
    FreqStart                              : REAL;    { frequency value before disturbance}
    PiLoadStart                            : REAL;    { load at time zero }
    MaxOverLoadGen                         : REAL;    { overload factor of the generators }
    PiSet,PiSetOld                         : REAL;    { power setting, current and previous }
    PiLoad,PiLoadOld                       : REAL;    { load, current and previous }
    ActualPiLoad                           : REAL;    { the load before subtraction of the wind power }
    Freq,FreqOld                           : REAL;    { frequency, current and previous }
    PiGen,PiGenOld,PiGenWind               : REAL;    { generated power, current and previous }
    WindFract                              : REAL;    { fraction of power generated by wind at time zero}
    Time                                   : REAL;    { time }
    DeltaT                                 : REAL;    { time step }
    Tmax                                   : REAL;    { period of interest from zero to Tmax }
    TimeStepWindData                       : REAL;    { interval between two wind data points }
    NumberSmallSteps                       : INTEGER; { number of time steps between two wind data points}
    Nstap                                  : LONGINT; { number of time steps }
    MaxFreq,MinFreq                        : REAL;    { minimum and maximum value of frequency }
    MaxPiGen,MinPiGen                      : REAL;    { idem for generated power }
    i                                      : LONGINT; { counter that steps through time }
    CurrentWindDatum                       : INTEGER; { counter that steps through the wind data }
    SmallCounter                           : INTEGER; { counter that steps through time between two wind
                                                         data points }
    GraphDriver,GraphMode,ErrorCode        : INTEGER; { needed for graphics routines }
    Xnul,Ynul                              : INTEGER; { position of axis }
    trip1,trip2,trip3,trip4                : BOOLEAN; { TRUE of relay has tripped }
    TripTime1,TripTime2,TripTime3,TripTime4 : REAL; { tripping time of the relays }
    UitvoerFile                            : STRING;
    InvoerFile                             : TEXT;
    Keuze                                  : CHAR;
    WindData                               : ARRAY[0..361] OF REAL;
    Dummy1, Dummy2                         : REAL; { needed to skip two colomns of wind data file }

BEGIN
    Nstap:=Round(Tmax/DeltaT);
    NumberSmallSteps:=Round(TimeStepWindData/DeltaT);
    { Read Wind Data from File }
    ASSIGN(InvoerFile,NaamInvoerFile);
    RESET(InvoerFile);
    FOR i:=1 TO 10 DO READLN(InvoerFile);
    FOR CurrentWindDatum:=0 TO 360 DO
    BEGIN
        READLN(InvoerFile,Dummy1,Dummy2,PiGenWind);
        WindData[CurrentWindDatum]:=PiGenWind*WindFract*PiLoadStart;
    END;
    WindData[361]:=WindData[0];
    CLOSE(InvoerFile);
    { initialize trapezoidal rule }
    Freq:=FreqStart;
    FreqOld:=Freq;
    PiGenWind:=WindFract*PiLoadStart;
    PiGen:=PiLoadStart-PiGenWind; {Loss of power at time zero}
    PiGenOld:=PiLoadStart-PiGenWind;
    PiSet:=PiLoadStart-PiGenWind;
    PiSetOld:=PiLoadStart-PiGenWind;
    PiLoad:=PiLoadStart-PiGenWind;
    PiLoadOld:=PiLoadStart-PiGenWind;
    ActualPiLoad:=PiLoadStart;
    InitializeMaxMin(Freq,PiGen,MaxFreq,MinFreq,MaxPiGen,MinPiGen);
      { setting of relays }
    trip1:=FALSE; trip2:=FALSE; trip3:=FALSE; trip4:=FALSE;
    CurrentWindDatum:=0;
    SmallCounter:=0;
    FOR i:=1 TO Nstap DO
```

```
    BEGIN
        Time:=i*DeltaT;
        PiLoadOld:=PiLoad;
        PiGenWind:=WindData[CurrentWindDatum]+(SmallCounter/NumberSmallSteps)*
                                          (WindData[CurrentWindDatum+1]-WindData[CurrentWindDatum]);
        PiLoad:=ActualPiLoad-PiGenWind;
        SmallCounter:=SmallCounter+1;
        IF SmallCounter=NumberSmallSteps THEN
        BEGIN
            SmallCounter:=0;
            CurrentWindDatum:=CurrentWindDatum+1;
        END;
        UpdateTrapezoidalRule(Freq,FreqOld,PiGen,PiGenOld,PiLoad,PiLoadOld,PiSet,PiSetOld);
    END;
END.
```

(249) Zhu, Y.C. and A.C.P.M. Backx, P. Eykhoff
MULTIVARIABLE PROCESS IDENTIFICATION FOR ROBUST CONTROL.
EUT Report 91-E-249. 1991. ISBN 90-6144-249-4

(250) Pfaffenhofer, F.M. and P.J.M. Cluitmans, H.M. Kuipers
EMDABS: Design and formal specification of a datamodel for a clinical research database system.
EUT Report 91-E-250. 1991. ISBN 90-6144-250-8

(251) Eijndhoven, J.T.J. van and G.G. de Jong, L. Stok
THE ASCIS DATA FLOW GRAPH: Semantics and textual format
EUT Report 91-E-251. 1991. ISBN 90-6144-251-6

(252) Chen, J. and P.J.I. de Maagt, M.H.A.J. Herben
WIDE-ANGLE RADIATION PATTERN CALCULATION OF PARABOLOIDAL REFLECTOR ANTENNAS. A comparative study.
EUT Report 91-E-252. 1991. ISBN 90-6144-252-4

(253) Haan, S.W.H. de
A PWM CURRENT-SOURCE INVERTER FOR INTERCONNECTION BETWEEN A PHOTOVOLTAIC ARRAY AND THE UTILITY LINE.
EUT Report 91-E-253. 1991. ISBN 90-6144-253-2

(254) Velde, M. van de and P.J.M. Cluitmans
EEG ANALYSIS FOR MONITORING OF ANESTHETIC DEPTH
EUT Report 91-E-254. 1991. ISBN 90-6144-254-0

(255) Smolders, A.B.
AN EFFICIENT METHOD FOR ANALYZING MICROSTRIP ANTENNAS WITH A DIELECTRIC COVER USING A SPECTRAL DOMAIN MOMENT METHOD
EUT Report 91-E-255. 1991. ISBN 90-6144-255-9

(256) Backx, A.C.P.M. and A.A.H. Damen
IDENTIFICATION FOR THE CONTROL OF MIMO INDUSTRIAL PROCESSES.
EUT Report 91-E-256. 1991. ISBN 90-6144-256-7

(257) Maagt, P.J.I. de and H.G. ter Morsche, J.L.M. van den Broek
A SPATIAL RECONSTRUCTION TECHNIQUE APPLICABLE TO MICROWAVE RADIOMETRY
EUT Report 92-E-257. 1992. ISBN 90-6144-257-5

(258) Vleeshouwers, J.M.
DERIVATION OF A MODEL OF THE EXCITER OF A BRUSHLESS SYNCHRONOUS MACHINE.
EUT Report 92-E-258. 1992. ISBN 90-6144-258-3

(259) Orlov, V.B.
DEFECT MOTION AS THE ORIGIN OF THE 1/F CONDUCTANCE NOISE IN SOLIDS
EUT Report 92-E-259. 1992. ISBN 90-6144-259-1

(260) Rooijackers, J.E.
ALGORITHMS FOR SPEECH CODING SYSTEMS BASED ON LINEAR PREDICTION.
EUT Report 92-E-260. 1992. ISBN 90-6144-260-5

(261) Boom, T.J.J. van den and A.A.H. Damen, Martin Klompstra
IDENTIFICATION FOR ROBUST CONTROL USING AN H-infinity NORM
EUT Report 92-E-261. 1992. ISBN 90-6144-261-3

 ISSN 0167-9708
Coden: TEUEDE

(262) Groten, M. and W. van Etten
LASER LINEWIDTH MEASUREMENT IN THE PRESENCE OF RIN AND USING THE RECIRCULATING SELF HETERODYNE METHOD.
EUT Report 92-E-262. 1992. ISBN 90-6144-262-1

(263) Smolders, A.B.
RIGOROUS ANALYSIS OF THICK MICROSTRIP ANTENNAS AND WIRE ANTENNAS EMBEDDED IN A SUBSTRATE.
EUT Report 92-E-263. 1992. ISBN 90-6144-263-X

(264) Freriks, L.W. and P.J.M. Cluitmans, M.J. van Gils
THE ADAPTIVE RESONANCE THEORY NETWORK: (Clustering-) behaviour in relation with brainstem auditory evoked potential patterns
EUT Report 92-E-264. 1992. ISBN 90-6144-264-8

(265) Wellen, J.S. and F. Karouta, M.F.I. Schemmann, F. Smalbrugge, L.M.F. Kaufmann
MANUFACTURING AND CHARACTERIZATION OF GAAS/ALGAAS MULTIPLE QUANTUMWELL RIDGE WAVEGUIDE LASERS.
EUT Report 92-E-265. 1992. ISBN 90-6144-265-6

(266) Cluitmans, L.J.M.
USING GENETIC ALGORITHMS FOR SCHEDULING DATA FLOW GRAPHS
EUT Report 92-E-266. 1992. ISBN 90-6144-266-4

(267) Józwiak, L. and A.P.H. van Dijk
A METHOD FOR GENERAL SIMULTANEOUS FULL DECOMPOSITION OF SEQUENTIAL MACHINES
Algorithms and implementation
EUT Report 92-E-267. 1992. ISBN 90-6144-267-2

(268) Boom, H. van den and W. van Etten, W.H.C. de Krom, P. van Bennekom, F. Huijskens, L. Niessen, F. de Leijer
AN OPTICAL ASK AND FSK PHASE DIVERSITY TRANSMISSION SYSTEM.
EUT Report 92-E-268. 1992. ISBN 90-6144-268-0

(269) Putten, P.H.A. van der
MULTIDISCIPLINAIR SPECIFICEREN EN ONTWERPEN VAN MICROELEKTRONICA IN PRODUKTEN (in Dutch)
EUT Report 93-E-269. 1993. ISBN 90-6144-269-9

(270) Bloks, R.H.J.
PROGRIL: A language for the definition of protocol grammars.
EUT Report 93-E-270. 1993. ISBN 90-6144-270-2

(271) Bloks, R.H.J.
CODE GENERATION FOR THE ATTRIBUTE EVALUATOR OF THE PROTOCOL ENGINE GRAMMAR PROCESSOR UNIT.
EUT Report 93-E-271. 1993. ISBN 90-6144-271-0

(272) Yan, Keping and E.M. van Veldhuizen
FLUE GAS CLEANING BY PULSE CORONA STREAMER
EUT Report 93-E-272. 1993. ISBN 90-6144-272-9

(273) Smolders, A.B.
FINITE STACKED MICROSTRIP ARRAYS WITH THICK SUBSTRATES
EUT Report 93-E-273. 1993. ISBN 90-6144-273-7

(274) Bollen, M.H.J. and M.A. van Houten
ON INSULAR POWER SYSTEMS: Drawing up an inventory of phenomena and research possibilities.
EUT Report 93-E-274. 1993. ISBN 90-6144-274-5