The Analysis of Thermal Power Stations and their Interaction with the Power System using Simulator Test Methods

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by

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To Elvie, Carleen and
my parents.

List of abbreviations and symbols

BFK	load shedding (In Swedish BelastningsFrånKoppling)
BTK	load reconnection (In Swedish: BelastningsTillKoppling)
DUBA	automatic restoration equipment (In Swedish: DriftUppByggnadsAutomatik)
EBK	power shedding (In Swedish: EffektBortKoppling)
EHV	Extra High Voltage
HV	High Voltage
HVDC	High Voltage Direct Current
hrs.	hours
PID	Proportional Integrating Derivative
PSS/E	Power System Simulator for Engineering
ROBO	rotating disconnection of load (In Swedish: ROterande BOrtkoppling)
SVC	Static Var Compensator
α	firing angle [degrees]
α_s	steady state active load voltage dependence
α_t	transient active load voltage dependence
γ	extinction angle [degrees]
Δf	stationary frequency fault [Hz]
ΔP	active power peak [pu]
ΔP	mismatch between mechanical and electrical power [MW]
ΔP_0	connected single load at nominal frequency [MW]
ΔP_G	increase of generator production [MW]
ΔP_L	load decrease due to frequency decrease [MW]
τ_1, τ_2	time constants for cooling down of a house [hours]
ω	angular velocity [rad/s]
ω_0	pre-disturbance angular velocity [rad/s]

A, B	constants associated with the cooling down of a house
a_0, a_1, a_2	parameters for the load frequency dependence
Ep0-Ep3'	operating modes of the hydro turbine governor
f	system frequency [Hz]
f_0	reference value of system frequency [Hz]
H_n	unit inertia [s]
I_d	dc current [kA]
J_n	moment of inertia [kgm^2]
k	load frequency dependence [pu/Hz]
k_1	load frequency dependency in the system [MW/Hz]
L_c	commutation inductance [H]
L_d	inductance at the dc side of a HVDC station [H]
L_s	short circuit inductance [H]
L_t	transformer inductance [H]
n_p	exponential load frequency dependency
P	proportional regulation [pu]
P	active power consumption [MW, pu]
P_{tot}	total system load [MW]
P_0	total load before load connection [MW]
P_0	active power consumption at pre-fault voltage [pu]
P_r	active power recovery [pu]
Q	reactive power production [MVAr]
R	permanent droop [pu]
S	total static gain [MW/Hz]
S_G	static gain from the generators [MW/Hz]
S_L	"static gain" from the load [MW/Hz]
S_n	rated generator power [MVA]
S_s	short circuit power [MVA]

T_G	servo time constant [s]
T_i	inside house temperature [°C]
T_{i0}	pre-outage inside house temperature [°C]
T_o	outside temperature [°C]
T_{pr}	active load recovery time constant [s]
T_r	integrating time constant [s]
U_1, U_2	line voltage at the feeding and the receiving end [pu]
U_{di}	dc voltage over the line [kV]
U	phase to phase voltage [kV]
u	commutation angle [degrees]
V	supplying voltage [pu]
V_0	pre-fault value of the supplying voltage [pu]
W_k	kinetic energy [MWs]
Y_{ekv}, Z_{ekv}	parameters for the line equivalent circuit [Ω/phase]
X_L, X_π	parameters for the simplified line equivalent circuit [Ω/phase]
X_s	series capacitor [Ω/phase]

Abstract

This thesis describes a new method of testing power stations with regard to their frequency control behaviour and analyses results obtained using this new method.

The test concept is based on that the power station unit to be tested remains synchronized onto its normal strong network, whereas the frequency control behaviour is set up to be that of the conditions if the unit was working on a much smaller network, using a computer based simulator system and feeding simulated control signals to the input of the units frequency control system. For preliminary tests or for testing conditions that could be hazardous to test on a real unit, the system can also be connected to a power station simulator simulating the unit, where such a simulator is available.

The method has been tested extensively, first on a power station simulator and then in field tests against three different real power station units at the Stenungsund power station, Stenungsund, Sweden.

Based on these tests models are developed for the turbine systems, the steam systems, the frequency control systems and other vital systems of a thermal power plant. It analyses how the expected response of this type of a unit would be under different conditions,e.g. island operation and gives tools and recommendations for testing of such power plants with this method.

A certain analysis is also done with regard to the ability of a thermal power station of the type tested to be responsible for the frequency control of a small island network, if such operation should become necessary. It concludes that these possibilities are perhaps better then what would be generally expected. In certain cases such a thermal power station can even outperform hydroelectric units when it comes to the ability to exercise frequency control.

This project has been a research project at the Department of Electric Power Engineering at Chalmers University of Technology, Gothenburg, Sweden, sponsored by the Swedish National grid authority, Svenska Kraftnät, before 1992 by Vattenfall. It has earlier been presented in a licentiate thesis in January 1994 [2] and in a report presented at the MEPS conference, Wroclaw, Poland in September 1996.

Keywords: network simulator, frequency control, island operation, thermal power station, turbine model

Acknowledgements

Contents

Chapter 1   Introduction

Many power stations are operated in a mode where their frequency control systems are not active, as these units are operated with a fairly large governor deadband, which makes them insensitive to normal frequency variations and which leaves the task of frequency control to other stations on the network. However situations can well be anticipated where it becomes a necessity to activate the frequency control systems of such power stations in order to maintain the security of the network. In particular this will be the case if the network, intentionally or accidentally, is subdivided into islands in such a way that the power stations performing the normal frequency control are separated from those that are operated with a deadband. In such a situation the security of the network in some such islands will depend entirely on whether or not the power stations that normally use deadband operation are able to suddenly have their frequency control systems put into an active mode and thus assume the responsibility for maintaining the network frequency.

It is easy to imagine that a need to rely on the behaviour of a system that has never been tested for such operation would mean a low level of security and leave much up to chance. It is therefore necessary that the behaviour of the power stations under such circumstances can be tested and verified as part of the proper planning for emergencies that is an integral part of network security. However such tests are difficult to make without that the test would in itself be a threat to network security. To actually divide the network into islands and run a test would be costly and involve taking large risks.

To rely entirely on computer simulations using standard power station models and industry standard simulation programs, such as PSS/E or Simpow, is not a sufficient way of testing in order to obtain a reliable forecast as to how the system will behave in island operation either. There are too many uncertain factors regarding the behaviour of the power station units themselves and there is also the big problem that the *theoretical* behaviour of the power station is all that can be accounted for. This is a considerable limitation compared to an actual field test, which will also detect all the factors that deviate from the planned or modelled behaviour: settings on control systems may be different from what the specifications were, the systems may have a different behaviour due to the aging of components or similar and also

the way that the plant is operated by the station operators may influence the result to a large extent.

It is a well known fact from power systems all over the world that if such a special operating situation occurs it is quite often that the situation can not be handled properly, sometimes with an outage as a direct result. A typical example was when the Danish island Zealand was disconnected from the main nordic power grid as a result of a network voltage collapse in Sweden. The danish power stations suddenly had to take over the frequency control of the island network and large frequency and voltage swings occurred. Only through several corrective operator interventions could the system be made to survive. Similarly, a recent test with island operation in the Ätran valley in Sweden resulted in a blackout, as the frequency control system, that had not been tested for this purpose, failed to maintain stability, leading to a large frequency drop, followed by disconnection. These are just two of many cases that illustrate the need for a reliable method of testing the frequency control systems and the behaviour of entire power stations with regard to frequency control and island operation.

Previously the only available test method has been to actually divide the power system up so that the unit to be tested gets its own island network to supply. This will surely be a good test of the unit in question, as it is a 100% realistic island operation, but it also means a considerable calculated risk that there may be large frequency oscillations within that island network or in the worst case a complete blackout. Taking such risks in order to perform the tests in question may in some cases be justified, but is very often completely unacceptable. A typical case where this can never be done is the Stenungsund power station, north of Gothenburg, Sweden. Here the local loads consist mainly of a number of petro-chemical industries that are all very sensitive to any network disturbances and that all of them suffer very high costs if the process is interrupted and has to be restarted again. Not only will many hours of production be lost, in addition virtually all chemicals that are in the process have to be dumped and burned, with both high costs and impact on the environment as well. In such a network the idea of actually disconnecting from the main power grid is unrealistic and such tests would never be accepted.

An opposite approach of just isolating the unit to be tested and letting it run in in-house operation is not realistic either. In house load is very low and reasonably constant and offers no realistic test environment. To build an artificial, controllable load would of course be one

approach, but the cost of building such a load, capable of burning off the full power of the generator of the power station unit to be tested, often several hundred MW, would be extremely high, in addition to that the tests would be very expensive to perform as all the produced power would be dumped.

What is needed is instead a method that allows for the testing of the power station units while they remain synchronized onto the main grid but where it is still possible to get a good tests of how they would behave if they were in active frequency control mode and responsible for the frequency control of a limited-size island type power network.

In order to develop a safe test method a project has been conducted at Chalmers University of Technology, with the support of the Swedish national grid authority Svenska Kraftnät, up to 1992 by Vattenfall. The project has been aimed at developing a test method where the frequency control characteristics of a power station unit can be tested by the use of a simulator while the unit remains connected to the normal network, and where e.g. the behaviour of the unit during island operation can be tested without any need for actually dividing up the network.

The project has included simulations, measurements, field tests as well as developing and building the simulator system. It has also included a large amount of computer software development.

This test method, where the control signal is simulated but where the unit to be tested remains synchronized onto the normal, strong network is a new approach, that as far as is known to the author, has never been used before anywhere in the world.

Most of the diagrams presented in this report are from tests on actual power station units, in operation. Where tests have been made against a power station simulator it is explicitly stated.

Chapter 1: Introduction

Chapter 2   Background and previous work within this project

The simulator is based on the fact that there is in most cases no inter-change of information between the power station and the network, except the information that is given by the network itself in terms of its voltage level and its frequency at the point of delivery. The status of the network is recorded by the voltage and frequency control systems, whereas the generator itself will deliver its output in a like manner regardless of frequency variations; at least within the frequency limits that can be accepted on a network in operation. There can of course be secondary effects of frequency variations due to frequency dependencies of the auxiliary systems of the power station, but these effects are normally quite limited and are normally quite effectively counteracted by internal control systems. Hydro power units have few auxilliarysystems, but thermal power stations have several; such as the feedwater system, fuel system, firing fans etc.
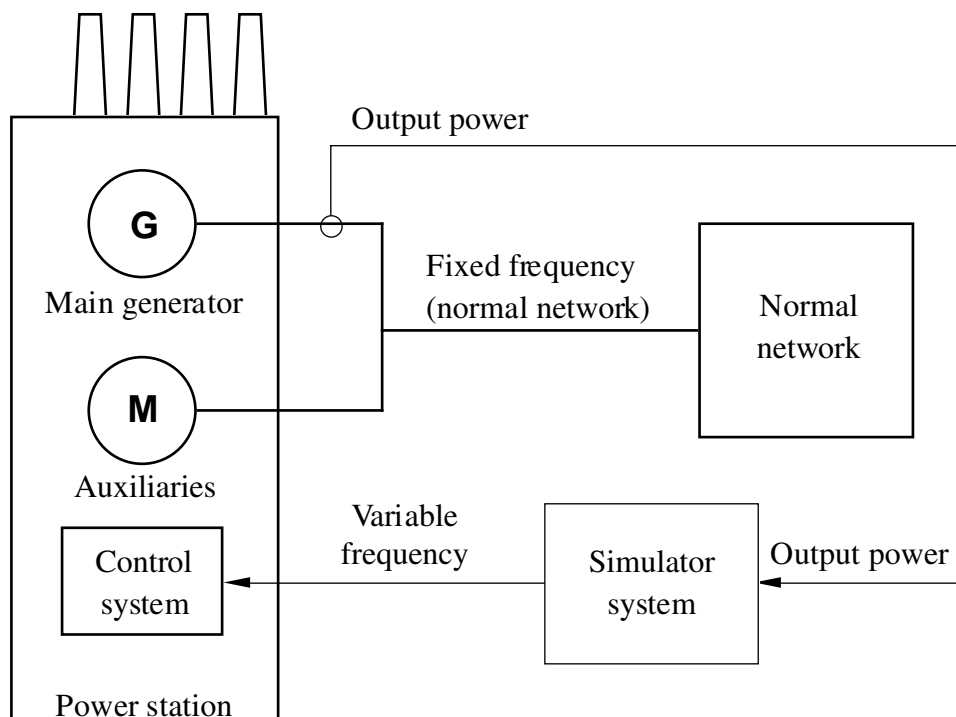
Figure 2.1   Basic principle of the simulator system.

If the effects on the auxiliary systems due to variations in frequency can be said to be very small, within the range of frequencies that can be

anticipated, then a simulator can be built by using a setup as indicated in . In this case the simulated frequency is used only to supply a signal to the control systems and we will then need just a few watts, whereas the main generator as well as the auxiliary systems of the power station remain connected to the normal network. In order to use this concept it is important to verify that the effects of frequency variations, at least within the range of frequency variations that can be anticipated or tolerated, onto the power station unit through the auxiliaries can be neglected. If this would not be the case this concept of a simulator could not be used. Therefore one of the first tasks within this project had to be to try to estimate the effects of reasonably sized frequency deviations unto the auxiliary systems.

2.1   Measurements regarding the auxiliaries.

When estimating the effects onto the auxiliaries one must take into account that frequency deviations during system emergencies can be substantially beyond the size of such variations during normal undisturbed operation. However, the goal of preparing for e.g. island operation is to obtain an operation that is at least reasonably stable and that provides for a fairly stable network frequency. In particular unstable operation where the frequency oscillates up and down even during fairly constant network load must clearly be avoided. Whereas normal frequency deviations in e.g. the Swedish national grid normally stay below 0.1 Hz on a continuous basis, deviations in island operation could maybe be allowed to oscillate in the range of ± 0.25 Hz or so. If very large frequency oscillations, say ±1 Hz or more, were to occur on a more or less continuous basis the operation must be said to be cumbersome and sensitive loads may experience serious disturbances. The exact limits will have to be set for each planning case on an individual basis, depending on the type of loads that are connected to the network in question. In most cases a much larger deviation can be tolerated as a slow drift in frequency compared to the case where the frequency oscillates. If the frequency drifts up or down slowly even a deviation of a couple of Hz can be tolerated for most types of loads.

The ideal way to verify the effects of frequency change on the auxiliary systems would have been to vary the network frequency while the station was in operation and then make measurements on the various auxiliary systems in question. That could not be done by in-house operation, as then it would be impossible to separate the cause from the

effect, and to alter the main network frequency just to perform these measurements is of course not feasible.

There are however natural frequency changes on the network all the time. Most these are fairly slow and quite subtle changes that are just a result of the normal frequency regulation and such changes are not sufficient when it comes to verifying he behaviour of the auxiliaries. However, there are also certain changes that are of a more drastic nature. These are the result of sudden loss of a major generating unit and if the unit in question is e.g. a major nuclear generating station then the effects are quite noticeable. They often show a frequency drop of 0.4 to 0.6 Hz under a few seconds, until the networks responds to the change.

Frequency changes of this type are almost always due to the loss of a nuclear generating unit. The 12 nuclear power plants that are in operation in Sweden show operating statistics such that around 10 such cases per year would be typical; i.e. one case every month. By simply making measurements of all critical system parameters of a thermal power plant in actual normal operation it would therefore be possible to sooner or later trap such an event and get recordings of the actual behaviour of the auxiliary systems.

Measurements of this nature has been performed on units 2,3 and 4 at the Stenungsund power plant. On a couple of occasions frequency dips of the kind described above were observed. These involved a frequency drop of about 0.2 Hz and no effects of significance in were observed on the auxiliaries. A typical recording (Figure 2.2), made on unit 4 of the Stenungsund power station, shows the network frequency, the generator output, the combustion airflow and the total fuel flow to the burners.

In the case listed above the frequency dip was about 0.2 Hz which with an static droop of say 5%, taken as an average of the generator units that perform the frequency control duties of the network at the time, would correspond to a load-change equal to about 8% of the rated output power of these units. That is a substantial change and more than what could be expected in most island operating situations.

A report to the IERE workshop on power system simulators 1992 [1] shows a study where tests have been made with very large network disturbances with regard to the interaction on the auxiliary systems of the power plant. Here frequency oscillations as large as 2.3 Hz are tested and effects onto the auxiliaries are simulated. Part is this is verified through field measurements. Even during the very large perturbations

tested in this report the effects of network frequency changes unto the auxiliaries were found to be quite limited.
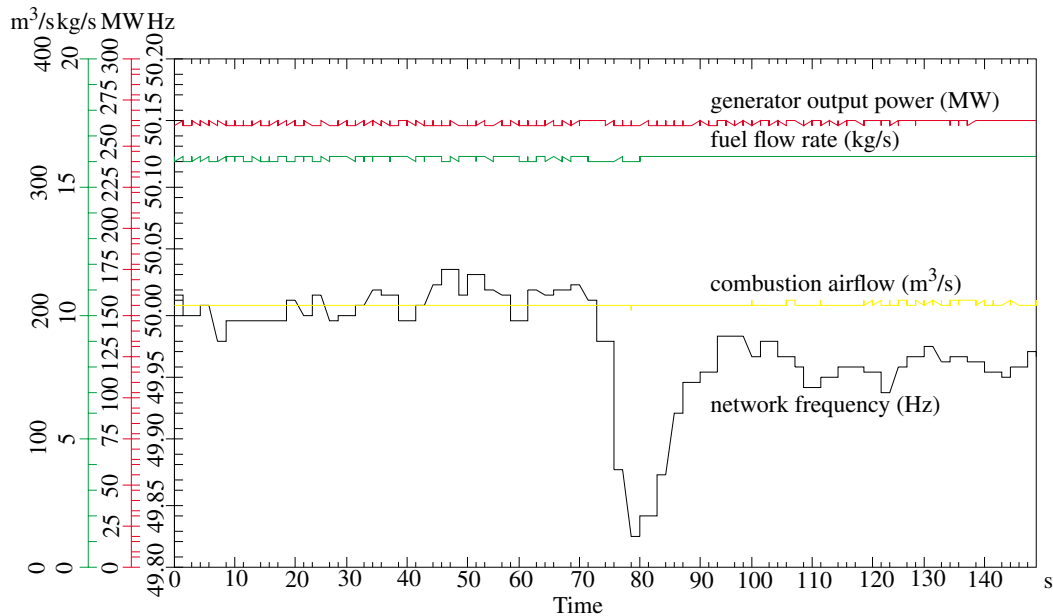
Figure 2.2   Behaviour of unit 3, Stenungsund, when subjected to a frequency dip.

The Stenungsund power station is equipped with triple superheaters plus a reheater. This design is generally known to be more sensitive to disturbances than a once-through system, but on the other hand the units are equipped with relatively large steam dome volumes, which very clearly increases their suitability for any type of operation where a fast reaction to a load or frequency change is required.

2.2   Simulator construction and design

Once it had been established that the effects due to the frequency dependency of the auxiliaries could be neglected for these testing purposes it was possible to build a simulator system that allows for the testing of a power station unit in the manner desired; i.e. that one can

simulate its behaviour during special operating conditions while actually the unit remains synchronized onto the normal network.

The system designed consisted of three interconnected computer systems with some associated hardware that allowed it to be tied to the power station. One of the three system allows for interaction with the operator running the simulation and does some basic calculations as well, one system runs the power station interface and collects measurement data to be logged during the test. The third system allows for a graphic network status display during the simulation. If the data is to be analysed after the tests rather than checked on line this third system can be dispensed with. However, in cases where a simulation of this kind is used in order to train operators on how to handle emergency operating procedures then such a display system can be highly valuable. A basic block diagram of the simulator system is shown in Figure 2.3.
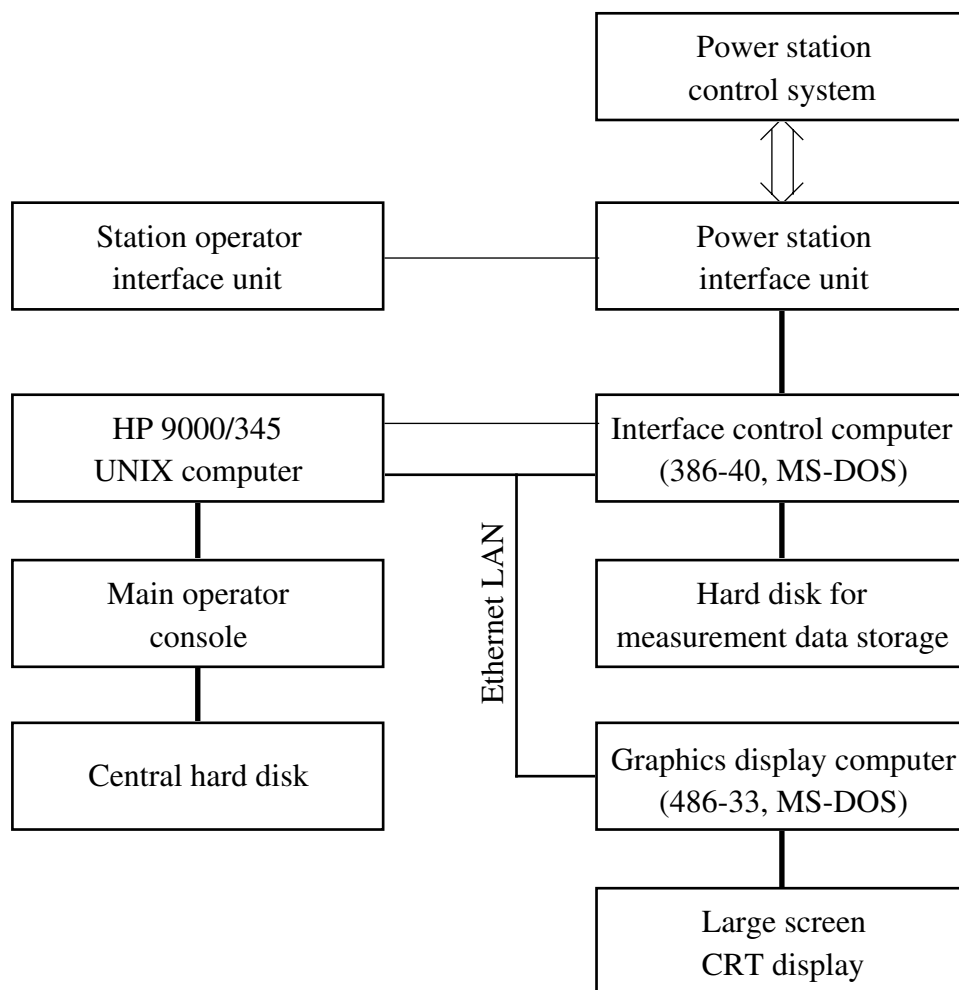
Figure 2.3   Basic simulator design.

The design as it was when the first real tests started in 1992. Since then there have been upgrades and improvements, in particular with regard to the safety of operation and with regard to keeping the computer systems up to modern standards. In todays design the 386-40 computer has been upgraded to a 486DX100-4 and the 486-33 has been upgraded to a Pentium-75 computer.

2.3 Software on the interface computer

The most important software routines actually reside in the power station interface computer which is part of the simulator system. These routines are responsible for all measurements (except network frequency and voltage), as well as calculating the swing equation and running all connections to the power station unit and also controls the generation of the output control signal that is fed to the frequency control system of the unit. The programming language for this software package is C, as the interface card drivers could only be delivered in this language. These routines are also responsible for the log-keeping, in that all measured values as well as all actions taken by the simulator system are continuously recorded onto the hard disk of this computer. The interface computer communicates with the main unix computer system via an Ethernet LAN connection and via a special parallel interface. The latter was not found to be a real necessity and most measurements were done using only the LAN connection.

The interface and measurement systems are designed to complete three to five simulation cycles per second. As most processes involved have at least two to three seconds time constants this was deemed sufficient. Tests were done with much faster updates (20 per second) (possible only if some log data is discarded) and this showed no noticeable differences in the patterns recorded. In addition such fast measurement speeds generate enormous amount of log data and data handling and storage becomes a problem for any measurements that extend over some period of time.

The interface computer system also calculates automatic load shedding, which is set up in accordance with the standard setup for the Swedish national grid system, allowing for the shedding of up to 50% of the total load in five steps of 10% each, where each step has two different activation frequencies, one with a short time constant and one with a longer. The automatic load reconnection system is also mod-

elled here and works with a reconnection frequency plus a time delay for each step.

In addition to these duties the interface computer performs a large number of security and supervisory tasks to ensure that the simulation will not put the unit under test into any potentially hazardous situation. A more detailed description of the security situation is found in Section 9.2.

The software also includes basic load models. These are discussed further in Section 9.9.

A basic block diagram of the software residing on the interface computer is shown in Figure 2.4.
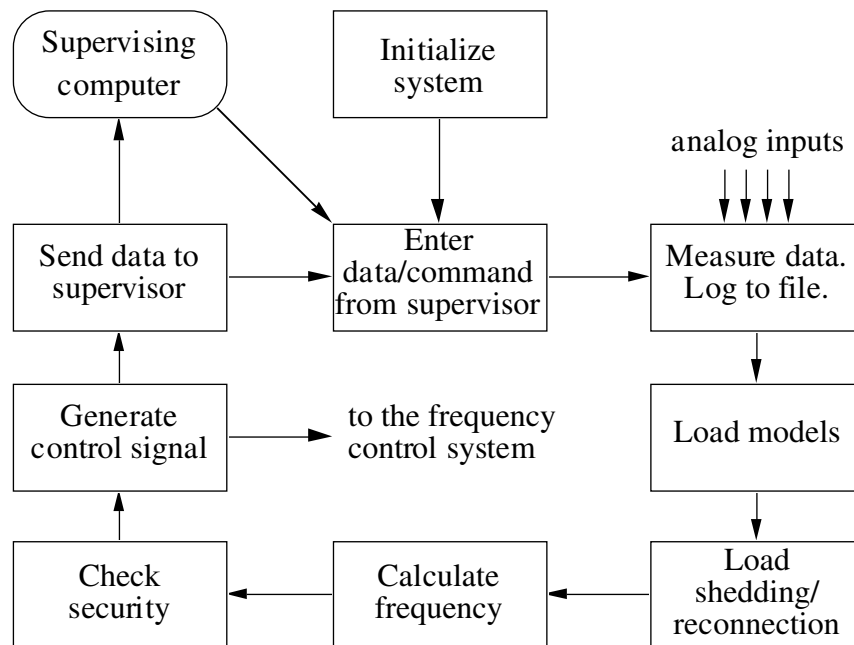
Figure 2.4   Block diagram of the operation of the simulator system.

2.4   Software on the supervising computer

The software running on the unix computer serves three purposes: supervising and controlling the simulation process, allowing for a proper operator interface to the operator running the simulation and making basic network calculations, primarily load flow to allow for networks beyond the size of a single node representing the generator bus.

Chapter 2: Background and previous work within this project

The routines handling supervising and control, as well as operator interface, are written in HP Basic and runs separately from the other routines. They allow the operator to monitor the process and to make changes, like changing the load level or the total moment of inertia present in the system, while the simulation is in process. Pertinent data, such as the current frequency of the simulated network and the current power station unit output are displayed to the operator on a continuous basis.

These routines do also include automatic security routines that check pertinent data against limits that are set prior to the start of the simulation. If any such limit is exceeded the simulation is automatically terminated. These security routines are described more in detail in Section 9.2.

The network representation routines are all written in FORTRAN and serve to update the simulated network on a continuous basis. In the case of a minimal network, i.e. only the generator bus with a a load connected to it, these routines can be dispensed with, but if the network is large enough so that losses within it have to be taken into account or if other power stations that are part of the frequency control of the network are included then these routines are required.
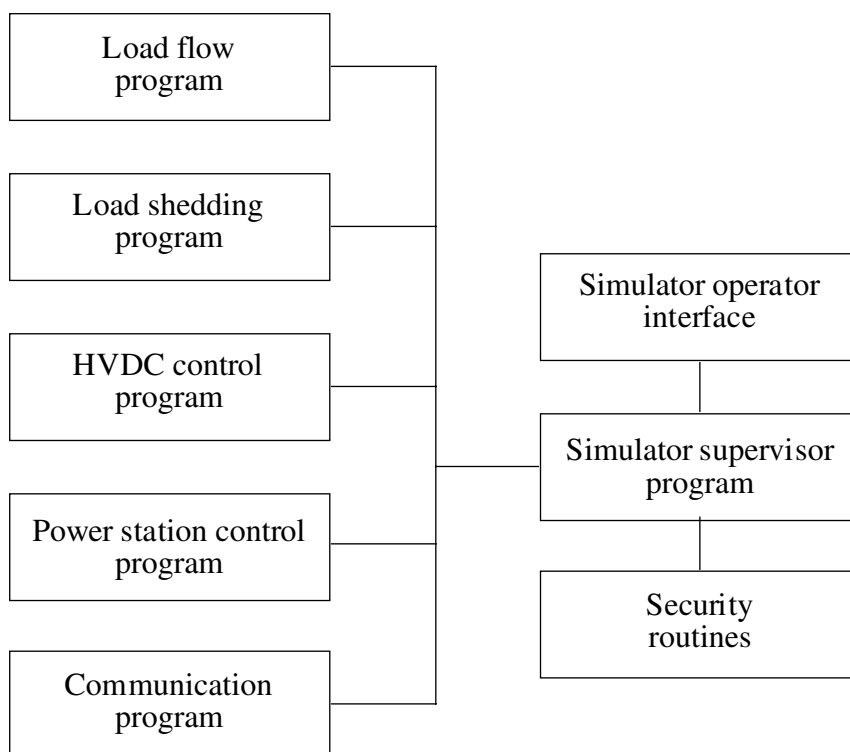
Figure 2.5   Software on the supervising computer; block diagram.

The load flow routines allow the operator to define a local network with up to 120 nodes and to specify load conditions and control criteria for these. Load models of different types can be used.There are routines for load shedding and for HVDC emergency power control schemes. Also the frequency and voltage control criteria for all participating power stations can be entered. For a further description of the network representation part see Section 9.9.

There are also communications routines that allow for communication in between the different computer systems that form the simulator system.

2.5   The power station interface

The power station interface was initially designed with units three and four at the Stenungsund power station in mind, but has later on been upgraded so that the system can be easily adapted to various types of frequency control systems and thus used for testing of many different power plants.

The frequency control systems of power stations can have mainly two input sources: either they use the network (generator voltage) frequency directly or they use the turbine speed, using some kind of speed transducer or a tacho generator, fitted directly to the turbine axis). The latter principle is more common, but there is no problem in fitting a simulator to either type, as long as there is an electric signal involved. Very old systems sometimes use a direct-acting mechanical governor system, with e.g. a centrifugal type regulator directly linked to the control valves etc. Such systems can not easily be adapted for use with the simulator system.

The interface system can be set to deliver different types of signals, depending on the control system that it is connected to:

1   an AC signal with a nominal frequency of 50 Hz and with an output up to 100 V, corresponding to what is delivered from a normal generator voltage PT.

2   an AC signal with a nominal frequency of 100, 200 or 400 Hz, corresponding to a normal output from a tacho generator.

3   a DC signal in the range –15 V to +15 V, corresponding to the output of common type analog discriminators, commonly used in older turbine systems.

4   a DC signal in the range –10 V to +10 V, corresponding to the signal level in control systems using analog electronic circuitry, such as Turbitrol or similar.

5   a digital signal with almost any given specification, delivered on an RS-232C port, suited for feeding to computerized control systems.

The large variety of signals available allow for the simulator to be used against almost all power stations, except as mentioned above that if will not work on systems old enough to have purely mechanical turbine control systems.

A block diagram of the interface system is shown in Figure 2.6.
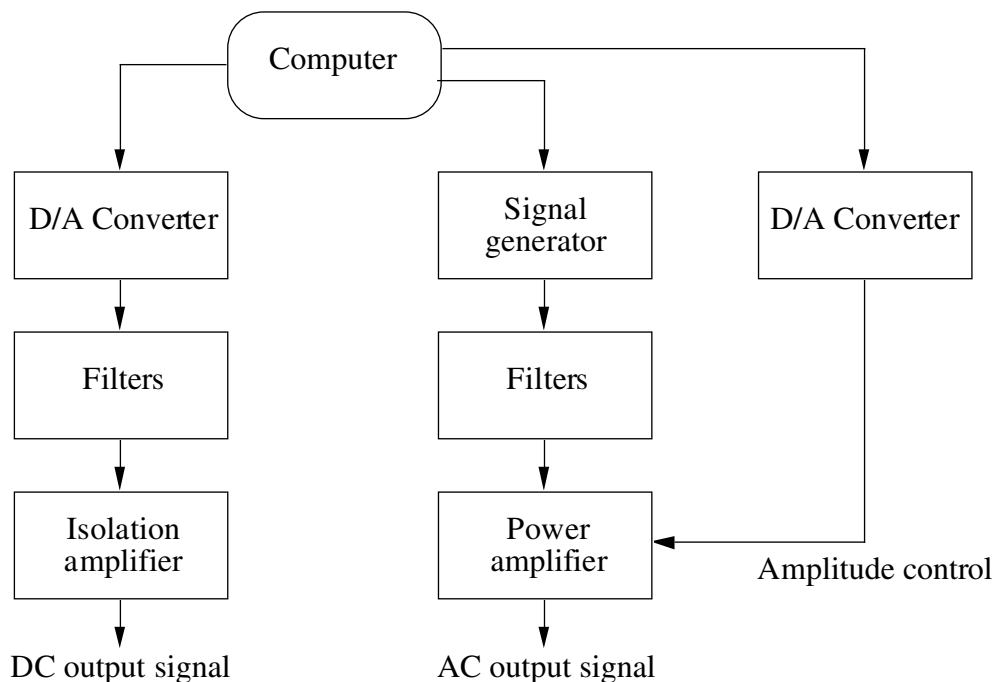
Figure 2.6   Power station interface unit.

2.6   Measuring system

The simulation process itself requires only one input signal, which is the generator output power. However, in order for it to be possible to

correctly analyse the results of a test it is vital that a number of the process parameters will be recorded continuously during the test. Exactly which parameters that are the most important ones will vary with the type of power station and the construction of its control systems. In some cases there may also be design constraints in that certain parameters of interest are not available for measurement at the installation in question. As a general guideline one can say that the following quantities are highly interesting:

1. unit generator output power (an absolute must in order for a simulation to be possible)

2. high pressure steam flow

3. control valve position

4. combustion airflow

5. dome pressure (if dome type boiler) or steam pressure at boiler head

6. fuel flow (total fuel input to boiler)

7. feedwater flow

8. boiler or dome water level

Many other quantities can be of interest, depending on the local conditions and on tests to be made.

Temperatures at various points in the process can be of interest, but unfortunately these are normally not available except in the case where the long term dynamics of the unit are of interest. The reason for this is that the industry standard type temperature transducers, pt100 elements, are very slow and usually show a response time in the order of one minute or more, making their output of no value for short term dynamics studies, where the time span involved is in the order of seconds.

All quantities are measured once for every simulator cycle; i.e. three to five times per second. All data is recorded on the system hard disk for further analysis after the test. The only quantity used by the simulation is the output power, however certain other quantities, such as the dome level, are monitored by the simulator security system in order to ensure a safe operation. For further details about this see Section 9.2.

All measurement connections are done via isolation amplifiers so that there is no risk of causing interference to the plants control system by

introducing ground loops or by interconnecting systems with different signal ground potential.

Some input channels require level shifting, filtering or current to voltage conversion.
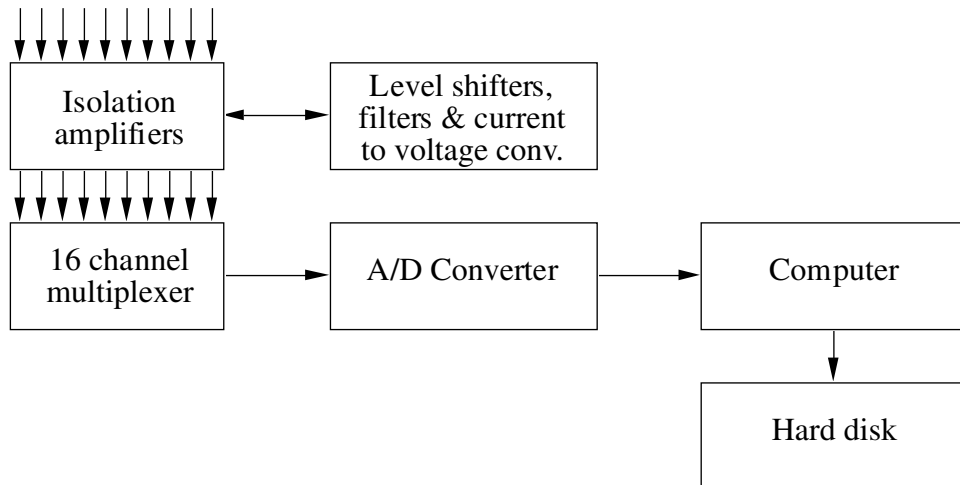
Figure 2.7   Measuring system.

Chapter 3   Measurements and simulations at the Stenungsund power station

The Stenungsund power station, at Stenungsund, some 50 km north of Gothenburg, Sweden, has been used as the test and reference station for this work. The station is a traditional oil heated thermal power station. It was designed and built in the 1960s, first with just two units, shortly afterwards completed with two more. It is located by the sea and uses a once-through sea water cooled condenser. It was primarily designed as a peak load station and hence the steam data are moderate. Due to a national power shortage it was used extensively during the first few years, until the introduction of nuclear power into the Swedish power system made the station revert to peak load use only.

The total output power is about 820 MW, with 150 MW each on units 1 and 2 and 260 MW each for units 3 and 4. The two larger units were the ones primarily used for this project and this was primarily because of the existence of a power station simulator for these. The power station simulator was built in 1985 as an operator training simulator. As the station is used for peak load service only and as the power situation in Sweden has been such that plenty of power has been available until very recently, there were very few times when the station was in operation and hence a problem came up with the training of the operators. Earlier this was solved by starting the station now and then just for training purposes, but the high prices of fuel oil made this system too expensive and instead a simulator, using a full-scale model of the real control panel, was built.

Even though this simulator was built for the purpose of training operators it models the physical processes of the power station units quite well. The simulator is built to model units 3 and 4 (these two are identical with the exception of that one of them has a cyclone system for reducing the dust emissions). The simulator proved very valuable for the purpose of developing this simulator system and it also allowed for the safe testing of many special operating conditions that for security reasons could never be tested against the real units.

The Stenungsund power station uses a special kind of turbine design that is further described in Chapter 4. These turbines have comparatively low moment of inertia compared to their output power and are light as far as its dynamic behaviour is concerned. This is of course a

drawback if such a unit is the only one supplying power to a small island network.

The moment of inertia must always be compared to the rated power of the unit in order to get an indication of whether the figure is low or high. For this reason one uses the H value, which is defined as:

$$H = \frac{W_{kin}}{S_n} \qquad (3.1)$$

and

$$W_{kin} = \frac{1}{2} \cdot J \cdot \omega_n^2 \qquad (3.2)$$

where W_{kin} is the kinetic energy stored in the unit when it is running at its rated speed

S_n is the rated output of the unit (normally in MVA)

J is the moment of inertia (normally in kgm^2)

ω_n is the angular speed of the unit when it is running at its nominal frequency

The unit for H is strictly speaking MWs/MVA, but it is normally listed as s, which is the same if the specification is taken for a power factor of 1 (MVA=MW). H is normally referred to as the constant of inertia.

Most thermal power stations have H values somewhere in the range of 3 to 10. Units 3 and 4 at Stenungsund have H=3.6, whereas units 1 and 2 have an exceptionally low value of 2.2. This means that units 1 and 2 provide little stability if they are alone on a network.

When the simulator was developed it was first tested extensively against the power station simulator. After this tests were run against the actual units. Tests have been run against units 1, 3 and 4. The tests were run as step-wise load changes when the unit under test was simulated as being alone responsible for the frequency control of an island network of a given size. The moment of inertia of the system was varied to simulate different network situations.

In order not to get the units into any uncontrollable situation each test was done starting with a higher moment of inertia, corresponding to several units being on line, and then moment of inertia was reduced so

that the final testing was always done with a moment of inertia equal to that of the single unit under test, corresponding to the situation that this unit is the only one on line.

During the tests the units were synchronized onto the normal network whereas a smaller network was simulated and the corresponding control signal was fed to the frequency control system of the unit. The unit output power and the frequency of the simulated network were recorded continuously along with several different process parameters.

During the last series of tests run on unit 4 measurement circuitry was connected so the output power of the high pressure turbine assembly and the medium pressure assembly were measured separately, which allowed for a much more detailed analysis of the turbine system. Also, the positions of the turbine control valve and the control valve limiter were recorded accurately for these tests. During the earlier tests these quantities were also recorded, but due to signal noise problem these recordings were less accurate. For the final tests filters were developed that filtered the signal so that it could be accurately recorded.

The first test run against unit number 1 is shown in Figures 3.1 and 3.2. The recordings shows the situation where step load changes were applied to a simulated island network having the four units at Stenungsund on line but with only unit one being responsible for the frequency control. The unit behaves quite well in this situation and the network frequency is maintained within quite tight limits and without any major oscillations, but it should be noted that the test was done at a very low power level.

In either case there is a quite considerable overshoot but after that the unit settles quite well and there is no major standing oscillation. Unfortunately the duration of the power reduction was a bit too short at this early test, but the well damped behaviour of the curve shows clearly that there is a reasonable margin to the units stability limit, at least at this very low power level.

This series of tests run against unit 1 at Stenungsund were the first complete tests on an actual unit and for security reasons they were all performed at a very low power level, in order to minimize the costs and trouble involved if the tests should lead to a trip of the unit.

Figure 3.1   Stenungsund; unit 1; load reduction from 15 MW to 10 MW.
J value corresponds to all four units at Stenungsund.

Figure 3.2   Stenungsund; unit 1; load increase from 10 MW to 15 MW.
J value as above.

The units response to a step load increase in the simulated network is shown below. The moment of inertia (J-value) is the same as for the test above, namely that of all four units at the Stenungsund power station.

The following recordings (Figures 3.3 and 3.4) shows the same tests, but with the moment of inertia of the system reduced to that of unit 1 only, corresponding to the situation that this unit is the only one delivering power to a small island network. Here the unit response is very different, with large oscillations that are not damped but remain standing, and this in spite of the low power level. In most cases the behaviour can expected to be better at low power levels, as the moment of inertia is then larger compared to the power that the unit is actually running. An oscillatory behaviour of this kind is clearly undesirable and continuous operation with standing oscillations can not be tolerated. It is obvious that there is a need for improvements to its frequency control capability if this unit alone should be capable of supplying power to a small island network.

As mentioned earlier units 1 and 2 have exceptionally low H values and it is therefore not surprising that problems can arise when one of these units is left alone on a network. The moment of inertia present is simply insufficient to get a stable operating frequency, at least with the control settings that the unit had at the time of testing.

The governor droop (permanent droop) during these tests was about 4%, which is fairly low. This is the present controller setting for unit 1 and its low value is likely to be a further main contributing factor, along with the low moment of inertia, to the unstable behaviour of the unit. Several tests have shown, as is further discussed in Section 8.2, that the lower the droop value the more problems arise with regard to obtaining a stable operation. On the other hand too high a droop value lead to other problems, as is also mentioned later on.

This example also shows that obtaining an quantitative estimate of the ability of a power station unit to undertake the task of frequency control of a limited network can be done very easily with this method. There is no need for elaborate network simulations, at least not at the initial stage. In a border-line case one may need more sophisticated testing, but if the unit can not pass this simple test then it is obvious that further investigations are required if the unit is expected to undertake this type of duty.

Figure 3.3 shows a typical load reduction response (reduction of the load in the simulated island network) and 3.4 shows a load increase.

Figure 3.3   Unit 1; load reduction response (reduction of the load in the simulated island network). Load goes from 25 MW to 15 MW. J value is that of unit 1 alone.

Figure 3.4   Unit 1; load increase from 15 to 20 MW.

Units 1 and 2 have a more modern turbine control system design compared to units 3 and 4. The original equipment was replaced and the equipment now in use is of the 4th generation as defined Section 4.12.

The next series of test shown here are from unit 3 at the Stenungsund power station, running a fairly low load of about 25-50 MW. The test sequence used was similar to that mentioned above, with step-wise load changes up and down, first with a moment on inertia corresponding to all units at Stenungsund, then with a lower value corresponding to this single unit only. This is a recording from the test with an operating situation where all four units are on line, with Figure 3.5 showing a step load reduction and Figure 3.6 a load increase.

We can see that the unit manages to respond quite well to these changes and that a new operating point is found quite soon and without any excessive oscillation.

Next a series of step-wise load changes with the moment of inertia equal to the single unit only (Figures 3.7 and 3.8). Note that the governor droop was here set to 4%, which was the original setting for the units at Stenungsund, same as for the tests above.

There are certain oscillations, but these are still quite manageable, even though the damping is fairly poor. This test ran a low power level and the test was later on repeated at a somewhat higher load. Same as with the above test, it was first run for a high moment of inertia and then for that of the single unit. The first test, with four units on line in the simulated network, behaves very well, with a soft settling to each new load level.

Fig. 3.9 shows a step power reduction and Figure 3.10 a step increase.

If we look at the second series of load changes, with a moment of inertia corresponding to that of unit 3 alone, the situation raises certain questions that are of concern when considering the units ability to operate on an island network as the only unit on line.

As for the previous tests, Figure 3.11 shows a step load reduction response whereas the diagram in Figure 3.12 shows the response to a step load increase.

Figure 3.5   Unit 3; step load reduction; 40 MW to 30 MW. J value set to that of all four units.

Figure 3.6   Unit 3; load increase; 30 MW to 45 MW. J value as above.

Figure 3.7   Unit 3; load reduction; 50 MW to 25 MW. J value of unit 3 only.

Figure 3.8   Unit 3; load increase; 25 MW to 50 MW. J value as above.

Figure 3.9   Unit 3; load reduction; 100 MW to 95 MW. J value corresponds to all four units.

Figure 3.10   Unit 3; load increase; 95 MW to 100 MW. J value as above.

Figure 3.11   Unit 3; load reduction; 100 MW to 80 MW. J value of unit 3 only.

Figure 3.12   Unit 3; load increase; 80 MW to 100 MW. J value as above.

We can see that the unit still responds quite well, but that there is now a considerable overshoot which indicates that the system is not very well damped. There are also oscillations, with a period in the range of 8–9 s. They are clearly damped for these tests and these oscillations shown would not present any security problem for the unit, but the oscillating and poorly damped response raised questions as to whether the unit would truly be stable if subjected either to a larger disturbance or when operating at a higher power level. A special test was made that introduced a somewhat larger power oscillation and this showed a very slow damping and also these oscillations were of such a nature that they presented a problem for the feedwater system. This test is shown in Figure 3.13.

Figure 3.13   Unit 3; test with added disturbance. J value of unit 3 only.

Considering that the actual ratio of moment of inertia to output power would be reduced to less than half if the unit operated on full power one must here question the operating security for such a condition.

These series of tests on unit 3 were the only one where the intercept control was actually connected to the simulator interface, so that in case the simulated conditions would warrant it the intercept valves

would also be activated. However, there were no intercept activations, not even when the special test described above was done.

The last set of tests against one of the actual units was run in february 1996 on unit 4. These tests was set up to allow separate measurements for the power from the two turbine assemblies and filters had also been added to allow for a correct recording of the positions of the control valve and of the limiter for the same. The governor droop was now set to 8%. This higher setting gave a smoother response and the unit responded extremely well to all the step load changes that were made. The response was quite good even with the moment of inertia reduced to that of the single unit only.

First a sample from the tests with the moment of inertia equal to that of the four units (Figures 3.14 and 3.15).

Similar tests but with the moment of inertia set to that of unit 4 alone (Figures 3.16 and 3.17).

A special test was made also here in that a step signal was applied to the unit corresponding to a brief but very significant load reduction (Figure 3.18). This test gave a rapid closing of the control valve from about 45% down to about 20% and hence gave good data regarding the rate of response and the time delays for the turbine systems. For a further discussion of this see Chapter 4.

In addition to these tests that were performed on actual units, synchronized onto the network, there has also been a large number of tests using the Stenungsund power station simulator. Some of these test were done in the first part of this project and are further discussed in [2]. Other tests were done at a later stage; either to test the behaviour certain specific subsystems of the power station or to test long term dynamics that could not be tested on an actual unit due to availability constraints. Certain more drastic tests that for security reasons could not be done on an actual unit (situations involving a large risk of tripping the unit) were also performed using the simulator.

The tests using the power station simulator are mentioned under their respective subsections in the following and not listed here.

Figure 3.14   Unit 4; load reduction; 144 MW to 125 MW. J value corresponds to all four units.

Figure 3.15   Unit 4; load increase; 124 MW to 135 MW. J value as above.

Figure 3.16   Unit 4; load reduction; 144 MW to 120 MW. J value of unit 4 only.

Figure 3.17   Unit 4; load increase; 124 MW to 144 MW. J value as above.

Figure 3.18   Rapid power reduction test; unit 4.

It should be noted that whereas the simulated network frequency underwent substantial changes the frequency of the real network remained unchanged. This can be clearly seen in Figure 3.13 where the real network frequency is also plotted. It can be clearly seen that the latter remains constant even when the unit undergoes large output power oscillations. This is a natural consequence of the fact that the network that the unit is synchronized onto is very large (the combined Nordic power system), so the changes introduced by the unit under the test will be negligible.

The real network frequency was recorded during all the tests made, but in order not to degrade the readability of the graphs it has not been plotted except in Figure 3.13. The variations of the real frequency were in all test cases very small and of the typical random variation type that occurs on the network at all times.

Chapter 4 Turbine system models

The modelling of the steam cycle of a thermal power plant as a whole is quite complex as there are several interconnected systems, each with its own dynamics and with its own associated control systems. The most important ones are the boiler system, the fuel and burner system, the combustion process, the turbine system, the generator system and the feedwater system.

To create a composite model where all these systems are properly accounted for can hardly be done without that the model gets so complex that its usefulness for proper simulations and for understanding the processes involved gets lost. It is therefore highly necessary to divide the process up into these different systems and to study them one by one. Luckily there are in most cases time frame differences that often allow this to be done without sacrificing too much of the accuracy.

A reasonable approach is to start with a composite crude block model of a thermal power plant. This block model is then so general that it can be made to fit any conventional thermal power plant.
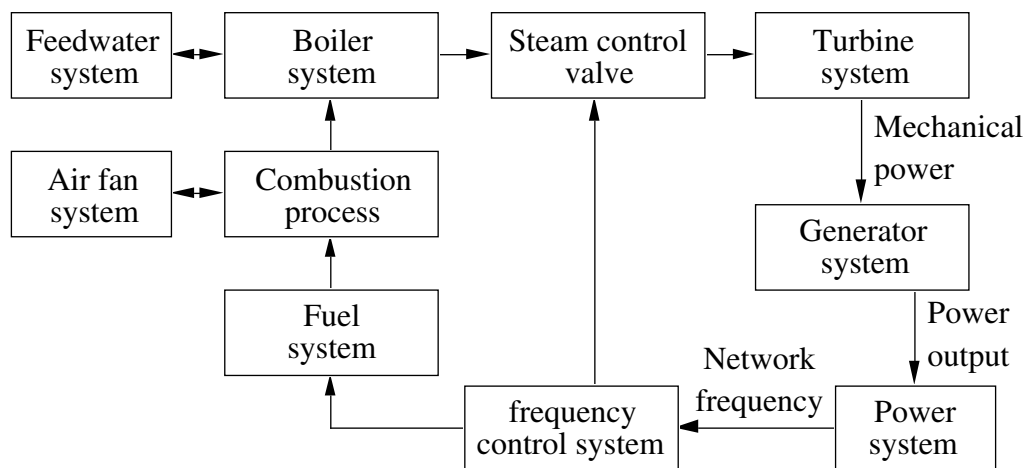
Figure 4.1   A thermal power station and its interaction with the power network. General block diagram.

The various control paths can be very different depending on the construction of the plant and on the control mode that is in use. On plants that operate in true sliding pressure mode, i.e. where the steam pressure varies with the output power rather than being regulated to a certain

value, the steam control valve, and its associated control path from the frequency control system, can be eliminated, as the valve typically remains fully open all the time and the frequency/output power control is exercised entirely by controlling the fuel flow and the combustion. Plants that implement this to 100% have a sluggish response to demand changes and are in most cases not suitable for assuming the responsibility of network frequency control in an island network of limited size. In such a small network all changes are quite rapid and a fast response is essential. In practice most plants that are run using sliding pressure will not do this all out; at the very least the control valve is used to reduce the power output in case of a sudden increase in frequency.

The fuel system control is indicated as coming from the frequency control system in the figure above, but in most cases it does so indirectly via either the steam pressure, the steam flow, or usually by a combination of these two

4.1   The Stenungsund power station

As a base for this study we have used the Stenungsund power station. This station is of a quite common design, typical for condensing, oil-fired power stations built in the 1960's. In more modern installations the basic design often remains the same, but in the quest for higher and higher over all efficiency the steam data of modern plants have been pushed much higher, as better steel alloys allow for higher steam temperatures and pressures.

The Stenungsund power station has units with three superheaters plus a reheater and with turbine systems consisting of both a high pressure (HP) turbine, a medium pressure (MP) turbine and low pressure (LP) turbines. In general this can be said to be the most complex type of a conventional thermal, condensing power plant, as each step in the steam chain adds another time delay and thus adds to the complexity of its control model. Simple plants with only one turbine stage will also have simpler control equivalents. Back-pressure stations get some additional complications, as the heat production control and the heat load are factors that have to be taken into account when considering the response of such a plant, but this type of stations are basically beyond the scope of this study.

The design at Stenungsund is a bit special in that there is no one common turbine shaft. Instead there are four generators per unit, two per

turbine assembly. One turbine assembly holds the high pressure turbine plus two low pressure turbines (axial type), the other assembly holds the medium pressure turbine plus again two low pressure turbines. The fact that these assemblies are separate made the station extra suitable for this type of a study as that allows for separate measurement of the power output from the two turbine assemblies, and thus for an estimation of the power delivered by each turbine stage, something which is not possible on stations using one common turbine shaft.

The reason for having two separate generators for each turbine assembly is that the turbines at Stenungsund are of a very special design. Instead of having one fixed sets of vanes and one set of moving vanes this design uses two sets of moving vanes that move in opposite direction. One generator is connected to each set of vanes. Thus each turbine assembly has two axes, with no other connection between them then the synchronizing torque of the generators. See Figure 4.3. This design, by Stal Laval, Sweden, had very many difficulties with it initially, causing expensive breakdowns and loss of production. For this reason this design was no longer used. However, after the initial problems had been overcome the Stenungsund turbines have proven very reliable and as of today their reliability and performance is excellent.
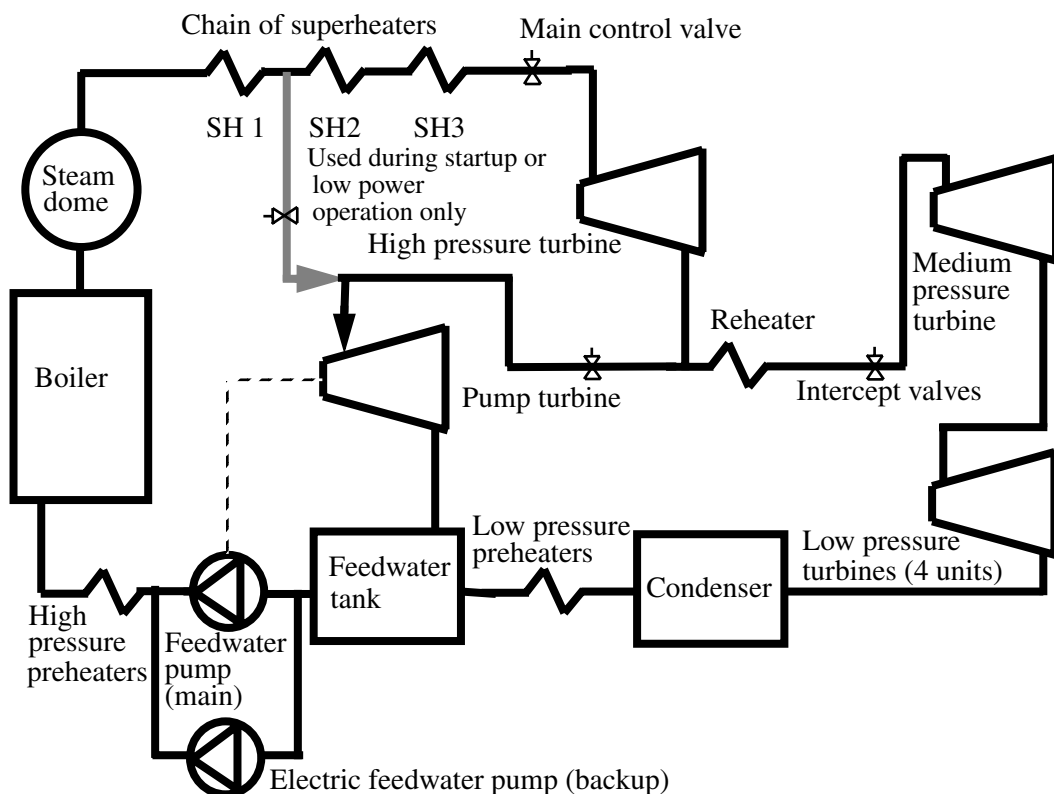
Figure 4.2   Stenungsunds power station, units 3 & 4, overview.

Chapter 4: Turbine system models
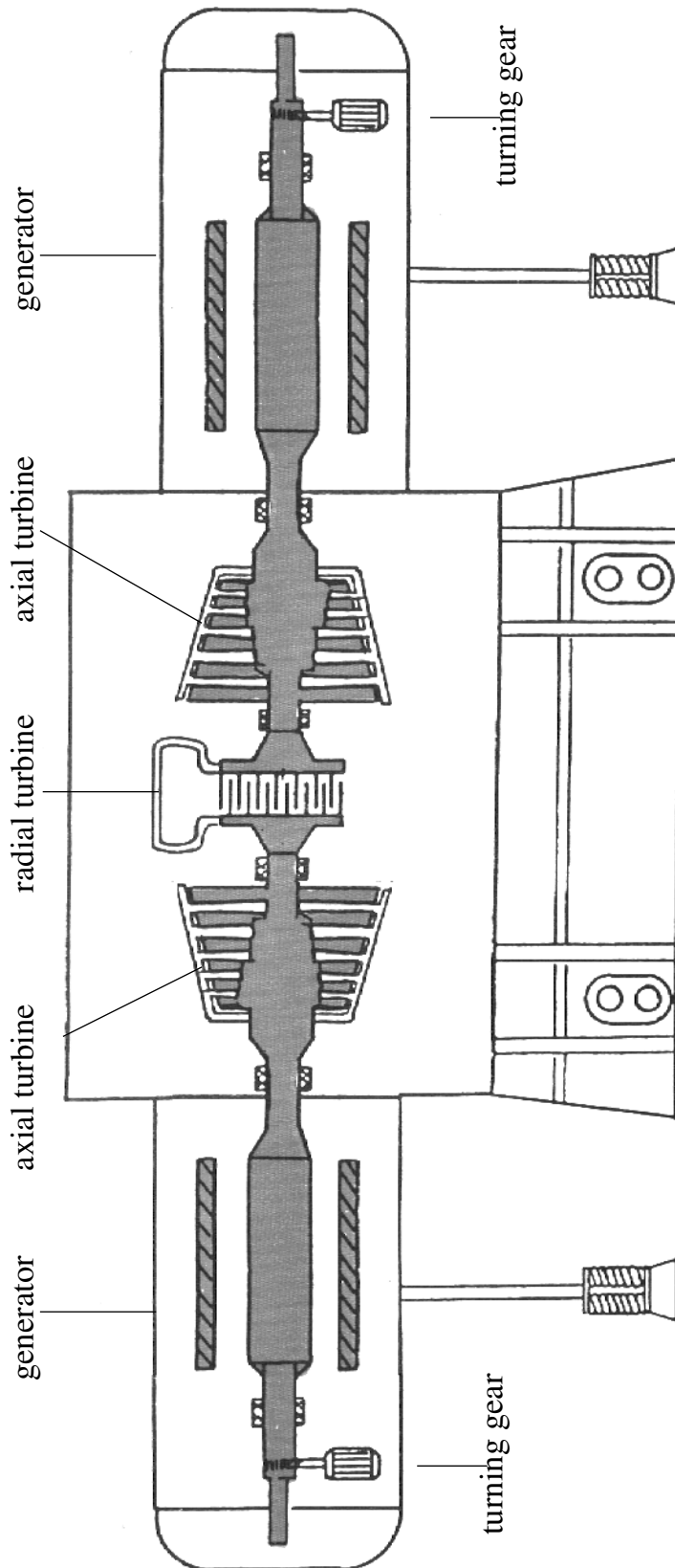
Figure 4.3   DURAX turbine unit, Stenungsunds power station.

4.2 Basic steam cycle models

In order to reduce the circuitry that has to be taken into account when designing a model of a thermal power plant unit it is important to ascertain whether or not the steam pressure at the source, i.e. at the boiler or the steam generator depending on the plant design, can be said to be constant when the plant is subjected to a load change. If it can it considerably simplifies the modelling, as that means that the actual boiler system with all its associated circuits can be eliminated.

An important consideration is what time frame that we are considering. Most frequency oscillations and similar in island operation mode or other limited network structure are in the range of seconds.

A block diagram for a steam/turbine system of the kind used for this study is shown in Figure 4.4.
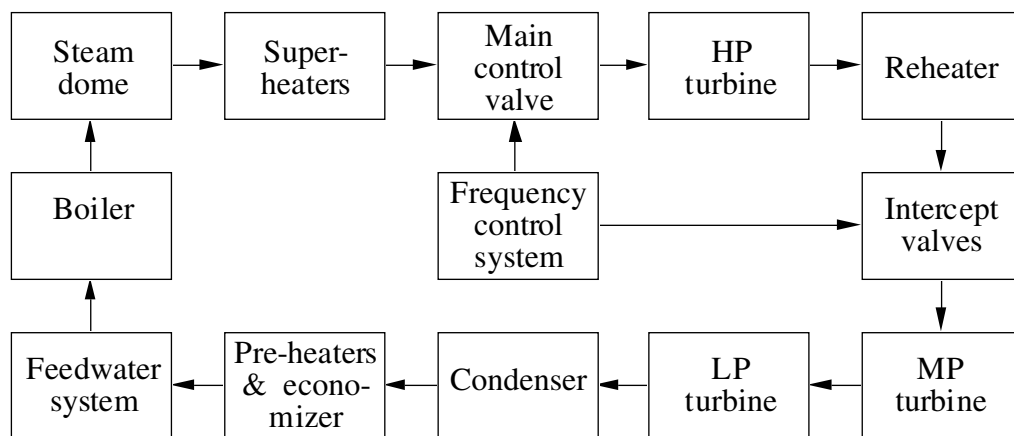
Figure 4.4   Basic block diagram of the steam cycle.

4.3 Steam source pressure, constant or not

In a short term perspective (less than say 15 s) the boiler system and the combustion system can be eliminated out of the main control loop for all plants having a reasonable steam storage value. In such a case the steam pressure at the outlet from the boiler can be said to remain constant when the unit undergoes fast perturbations. This can be shown clearly on the recordings from the tests at the Stenungsund station, where no significant changes in dome pressure could be recorded during the oscillations that occurred when the system was subjected to a sudden load change. E.g. in Figure 4.5 the maximum pressure oscilla-

tion is approximately 1.2% for an output power swing of 30%. This is natural as there are two large time constants; each of them larger then the typical period time of the oscillations:

1. the dome storage time constant, given by the dome volume in relation to the maximum steam flow.

2. the boiler time constant, basically being the delay from the point when the supply of fuel is increased to that the corresponding generated heat has travelled through the boiler tubes or walls and can be transferred into additional steam generation, or vice versa in case of a reduction in power.

The tests made at the Stenungsund power station were mainly made with a short term response in mind and the main system of interest will then be the turbine system, along with its associated control valves, and of course the frequency control system itself.

In power plants of this design, with a large steam dome storage the steam pressure out of the steam dome can be said to be constant for short term purposes. This is clearly supported by the tests made at Stenungsund. Figure 4.5 shows the dome pressure as recorded during a series of quite violent perturbations with regard to the steam flow and the output power:

Figure 4.5   Steam pressure variations during stepwise load changes, unit 3.

The fact that the dome pressure remains fairly constant does however not mean that the inlet pressure as presented to the main control valve is constant. In between these points we have the chain of superheaters and the main HP steam line. These have pressure drops that depend on the steam flow rate, even though these pressure drops should be quite limited for a well designed unit, as all such pressure drops represent system losses and thus a lower efficiency. Also, the steam line introduces a time delay when it comes to rapid changes in steam flow. The superheaters also influence the temperature of the steam and thus its energy content. The picture is further complicated by the fact that each superheater normally has its own temperature control system with associated spray nozzles. These systems are designed to prevent excessively high steam temperatures and to regulate the steam temperature to optimal values. This is further discussed below.

4.4   Steam temperature, constant or not

To make any assertions regarding any possible changes of temperature is much harder. The steam temperature was measured during some of test, at three different points immediately following superheater 1, superheater 2 and superheater 3. However it was not possible to measure these in such a way that one can conclude that the steam temperatures showed no variations. The reason for this is that the only available means of measuring the temperatures was to use the temperature transducers that are present in the steam system and that e.g. controls the spray systems that regulate the steam temperature. These are industry standard pt-100 transducers mounted in mounting wells. This means that they are slow to respond and as opposed to the pressure transducers that are just about instantaneous the temperature transducers have very long response times.

Recordings done on the actual units show no temperature variations during any of the short time changes that were introduced. A typical recording from a test on unit 3 at Stenungsund is shown in Figure 4.6. A quite large perturbation passes without that any temperature changes can be noticed.

These temperature recordings from an actual unit in operation stand in contrast to the recordings done using the power station simulator. On recordings done against the simulator quite large variations in the temperatures following superheaters 2 and 3 can be seen whenever there

are substantial variations of the steam flow rate. A typical case is shown in Figure 4.7, where one can see that the temperature of the steam following superheaters two and three vary considerably as the process oscillates.

Figure 4.6   Steam temperatures during stepwise load changes, unit 3.
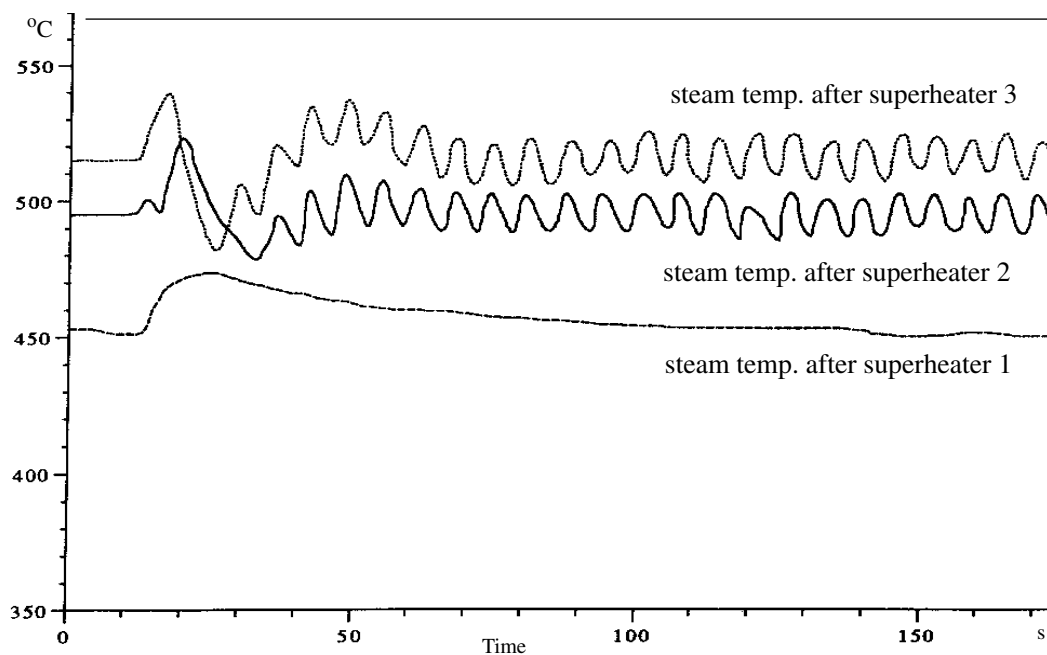
Figure 4.7   Simulator test. Steam temp. during output power oscillations.

It seems very probable that there are actual changes in temperature as the steam flow rate changes, as the steam flow rate transfers into the steam velocity rate through the superheaters and hence into the amount of heat transfer that will take place in the superheaters. There are, as previously mentioned, temperature control systems that are designed to keep the steam temperature constant, but these are not fast enough to have any effect for fast changes (for a further discussion of the spray systems see Chapter 5 where the boiler system is discussed).

To determine as to whether or not these changes in temperature are of sufficient magnitude to have to be included in the steam/turbine model one has to rely on calculations. Measurements will be of virtually no value due to the long time constants of the standard transducers, as the following calculations show:

The time constants of the pt100 transducers combined with the mounting wells are listed as 180 s for the units used here. This time constant is specified for 63% response, measured on the full temperature range of 350 to 600 degrees. Exactly what fraction of the response that would be necessary in order to notice a change would of course depend on the temperature change as such.

For the response of a transducer of this type we have the formula:

$$T_t = T_A + (T_P - T_A) \cdot e^{-\frac{t}{t_c}} \tag{4.1}$$

where: T_t = transducer output at time t after a step change in temperature
T_A = actual temperature after the step change
T_P = temperature before the step change
t_c = transducer time constant

In this testcase it is reasonable to expect two temperature changes: first a temperature increase when the steam flow rate drops (at a given pressure the output power of the unit is approximately proportional to the steam flow rate and hence a reduction in output power must be correlated to a similar drop in steam flow rate) as the firing is not reduced instantaneously in spite of the lower flow rate. Once that the firing is reduced a temperature reduction could be anticipated.

For the first of the possible temperature changes mentioned above we have a reasonably well defined time limit: from that the output power

(and the steam flow rate) drops until there is a corresponding reduction of the firing (fuel flow rate) there is a period of approximately 6 s. Our measurement resolution is about 0.5%, but with some noise present the smallest temperature change we could detect would most likely be in the range of 1%. For such a small change and such a short period of time (6 s compared to 180 s) the formula of (4.1) can be reduced to:

$$\Delta T_M = \Delta T_A \cdot \left(1 - e^{-\frac{\Delta t}{t_c}} \right) \tag{4.2}$$

where: ΔT_M = recorded temperature change

ΔT_A = actual change in temperature

Δt = period of time that the change is applied

With a transducer time constant of 180 s the formula above gives us a limit of detection of approximately 30% of the full range, i.e. 75 degrees. This would be the minimum temperature change over the 6 s period of time that we would at all be able to detect.

The total temperature increase of the steam when passing the super-heaters is in this particular case about 39 degrees for superheater 2 and 42 degrees for superheater 3 as measured for this specific testcase. The change through superheater 1 can not be read from these measurements, as there was no recording of the temperature before superheater 1, but if the temperature increase across superheater 1 is estimated to be on level with those of the two other superheaters we get a total temperature increase in the order 120 degrees across the entire line of superheaters.

The heat transfer in the superheaters is governed by the heat transfer equation, which in this case becomes a system of coupled differential equations with the temperature difference between the fire side and the steam side and the flow rates of the steam and of the exhaust fumes as the prime variables. Taking an extreme worst case and linearizing this equation as to depend primarily on the steam flow rate we get:

$$\Delta T_S = (T_E - T_S) \cdot \frac{C}{Q} \tag{4.3}$$

where: ΔT_S = the increase of the steam temperature when passing the superheater

T_E = the temperature of the exhaust fumes heating the superheaters

T_S = the steam temperature inside the superheater (assumed constant in this rough linearization, which is approximately true if ΔT_S is small compared to $(T_E\text{-}T_S)$

C is a proportionality constant.

Q is the steam flow rate

In the test case shown above the reduction of the steam flow rate was about 20%. This reduction should then lead to an increase in ΔT_S. Actually also T_S will increase, especially for the last two superheaters, and this would counteract the change of ΔT, but estimating a worst case we can neglect this fact.

We then get, assuming T_E and C to remain constant, that ΔT should increase by 20% when the flow rate is reduced. Calculating over the whole chain of superheaters based on the total ΔT prior to the change of 120 degrees we would then get a new ΔT of about 144 degrees. This is an increase of only 24 degrees and clearly less then the level of detection as calculated above.

If there is such a change of temperature then what effect that have on the turbine output power? The power generated by a steam turbine can be written as:

$$P \;=\; (H_I - H_O) \cdot Q_S \cdot \eta \tag{4.4}$$

where   P is the turbine output power

        H_I is the enthalpy of the steam at the inlet port

        H_O is the enthalpy of the steam at the output port

        Q_S is the steam flow rate

        η is the turbine efficiency

The enthalpy of superheated steam depends on two variables: the steam pressure and the steam temperature. The exact relationship is non-linear, but an approximate calculation can be made using a linearization. This is done in two steps: first one calculates the dry-line enthalpy at the temperature and pressure in question and then an extra factor is added due to the fact that the steam is superheated.

Using these approximations and the steam data pertaining to the test shown above the enthalpy of the steam, as it leaves the chain of super-heaters, was calculated, both for the temperature recorded (550 degrees C) and for temperatures 24 degrees higher and lower, in accordance with the worst case as mentioned above. The enthalpies thus calculated were as follows:

All calculations were made for P=7.3 MPa=”the dome pressure at the test”. Pressure drops through the chain of superheaters were neglected.

For   T = 550 ^{o}C, H = 3.35 MJ/kg

            T = 574 ^{o}C, H = 3.40 MJ/kg

            T = 526 ^{o}C, H = 3.30 MJ/kg

This shows that even if these worst-case temperature changes did occur the changes in enthalpy, and hence in turbine output power, would only be in the order of ± 1.5%. This is for a load / output power change of 20%, which is a large step change that is not likely to occur frequently. The effects of the temperature changes will therefore be negligible for the purposes of determining the dynamic response of the unit. If they are taken into account they will counteract the main change, as the temperature and hence the enthalpy increases with a reduced steam flow rate and this would then be similar in effect to a slightly higher droop value for the unit. But this effect would only last for a few seconds, until the firing has been adjusted accordingly and the temperature of the steam has gone back to its expected value.

We can therefore conclude that for the purpose of creating models used for e.g. network simulations the steam temperature can be assumed to be constant for power changes of this nature.

4.5   The intercept valves and control system

The intercept valves serve to reduce turbine overspeed in case of a sudden load loss or similar. They are not used for power or frequency control purposes. Any frequency control scheme that is to work in case of islanding operation and that shall be able to maintain a stable operation must be designed so that the intercept valves are not actuated during perturbations that occur e.g. when the load level on the network changes. Tests made at Stenungsund shows that the intercept valves

were not actuated even during very large power output oscillations. See diagram in Figure 4.8.

Another reason for omitting the intercept valves and their control system from the models used is that operation where the intercept valves try to accomplish some kind of frequency control can never be tolerated. The intercept valves are to serve as "emergency brakes" for the turbine system only and neither their design nor their place in the steam cycle allow for any continuous regulator service.
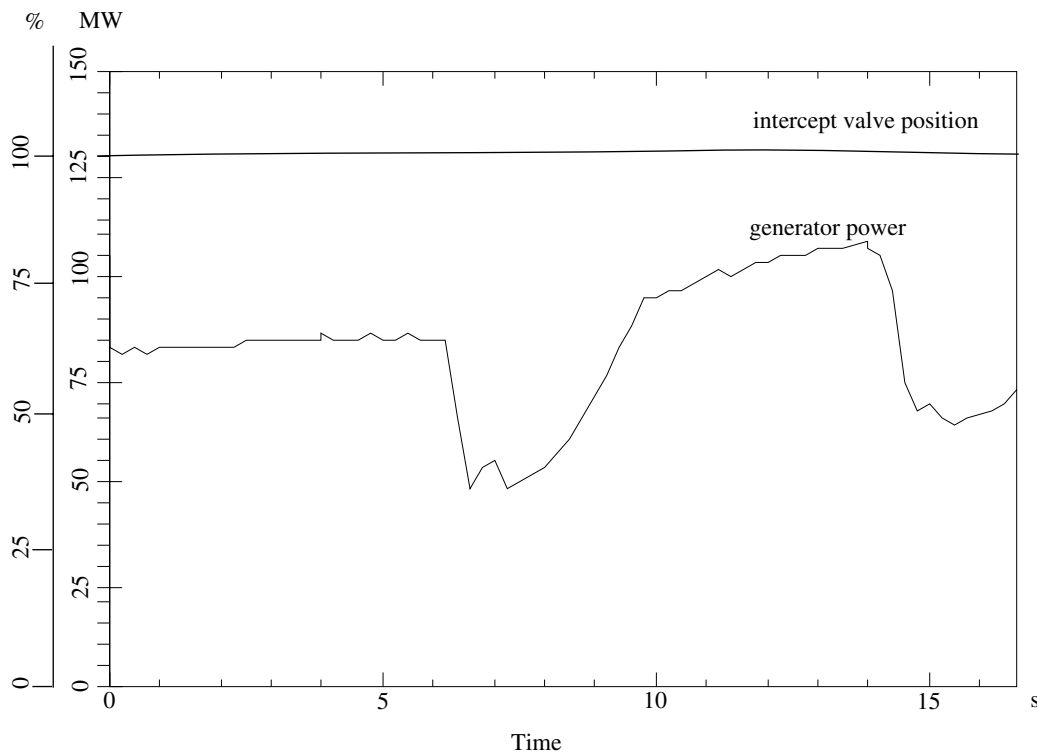
Figure 4.8   Unit 3. Intecept valve behaviour during a large output power oscillation.

All tests made against the Stenungsund power station simulator show that extremely unstable operation does occur IF the setpoints and the oscillations are such that the intercept valves are really trying to take part in regulating the output power. This situation can occur if the static droop of the frequency control system is set to such a high value that a sudden load reduction will correspond to a frequency increase such that the turbine speed moves into the activation area of the intercept valves. In such a case we get a very unstable power regulation and the unit is not likely to be able to remain on line for very long. A typical such case is shown in Figure 4.9, which is a run against the Stenung-

sund power station simulator. It shows a case where 8% static droop is used and where has first been an initial load reduction, bring the frequency up to approximately 51 Hz. When a second load reduction, from 110 MW to 50 MW, comes, the frequency (and hence the turbine speed) increases that much that the intercept valve starts closing and continues to close/open for each swing in frequency. As a result the operation becomes extremely unstable, to an extent that such operation could never be tolerated.

Intercept valve control is usually exercised by a control circuit that is sensitive both to the absolute speed (rpm) of the turbine and to the rate of increase of the speed (positive derivative). The latter function is designed mainly to trap a condition where the turbine is accelerating rapidly due to a load-loss condition and its settings are normally such that it will not be activated by normal network load changes and their corresponding changes in frequency. The absolute speed sensing will however actuate the intercept valves as soon as the speed (=frequency) goes above a certain set limit, regardless of what caused the system to get to this condition and this effect must therefore be considered so that the system is not inadvertently driven into a speed region where the intercept system becomes active.

Figure 4.9   Simulator run. Intercept valve gets activated.

The restraint that the intercept valves should be left out of the frequency control process sets a limit for how much governor static droop that can be tolerated, when compared to the maximum uncompensated (meaning that there has been no operator power setpoint changes) load changes that are to be handled.

The maximum allowable static droop setting, compared to the maximum sustainable uncompensated (meaning that there has been no operator intervention by power setpoint changes) load reduction can be calculated thus:

By the definition of static droop:

$$K = \frac{\Delta f}{f_n} \cdot \frac{P_n}{\Delta P} \qquad (4.5)$$

where: K = static governor droop
Δf = resulting frequency deviation from a load change = ΔP
P_n= nominal power rating of the unit
f_0= nominal network frequency

From this we get the maximum allowable droop as:

$$K_{max} = \frac{f_I - f_0}{f_0} \cdot \frac{P_n}{\Delta P} \qquad (4.6)$$

where: K_{max} = maximum allowable static governor droop
f_i = activation frequency for the intercept valve controller
f_0= nominal network frequency
P_n= nominal power rating of the unit
ΔP= maximum load decrease that must be handled without operator intervention

4.6   The condenser system

The condenser system can normally be represented as having constant pressure (=vacuum) and almost constant temperature. This is certainly true for all once-through water cooled condensers, as the variations in temperature of the sea or river water during a perturbation will certainly be negligible. For air cooled systems corrections for changes in cooling may be necessary, especially if the condensers are of the forced

air or evaporative type with some kind of temperature control system of its own. The same applies of course to an even greater extent for plants of the counter-pressure type. Here it will be necessary to model the behaviour of the counter-pressure and heat-exchanger part of the process in order to get a correct model.

4.7   A simplified steam cycle model

Under the assumptions made above (constant dome pressure, constant condenser pressure and temperature and no intercept valve interaction) the model of the steam and turbine system can be simplified as shown in Figure 4.10.
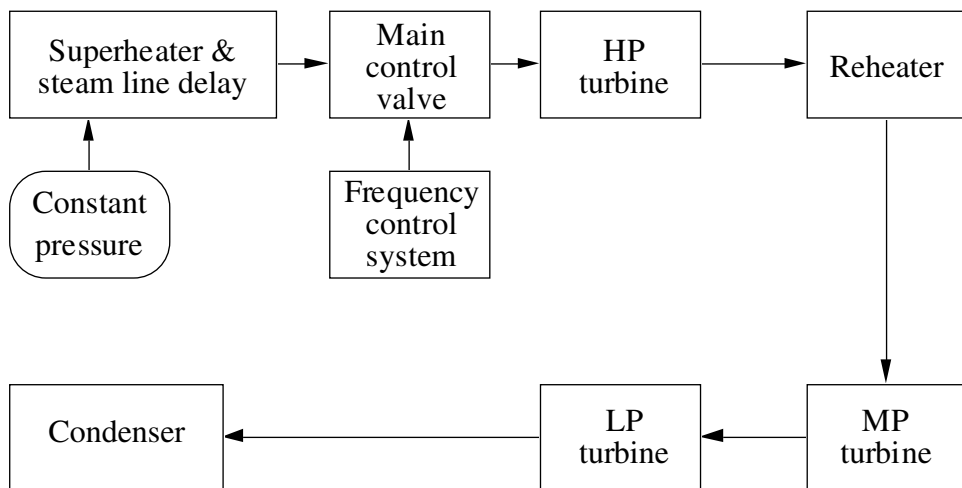
Figure 4.10   Simplified steam cycle block diagram.

There is however one matter that complicates the modelling of the steam cycle and that is the fact that steam is extracted at points in between for various purposes. Most of these steam extractions are relatively small and reasonably constant, as is the case for steam taken to the pre-heaters or for running the vacuum ejectors that keeps up the condenser vacuum. However there is in the case of the Stenungsund power station one large steam extraction and that is for the pump turbine for the feedwater system.

The feedwater system in these units is run by a pump turbine that extracts steam from the main cycle. In normal operation this steam is

taken from the MP steam system, before the reheater. Only during start-up or at very low power levels is an additional steam boost from the HP steam system necessary.

The feedwater flow is controlled in two different ways: during low load it is controlled by running the pump turbine at constant speed and regulating the feedwater flow by means of a control valve. In medium or high power operation the feedwater flow is controlled by controlling the steam flow to the pump turbine and thus the turbine speed. In either case this means that we get a control influence from the feedwater system onto the main steam cycle process. This influence will be more pronounced in the case of pump turbine speed control and as this is also the normal mode of operation in the normal power output range of the unit the latter mode is the one that will be considered here.

It should be noted that this arrangement with a pump turbine is rather an exception. Most thermal power plants use some kind of electrical drive system for driving the feedwater pump. The feedwater flow will then be controlled by other means. This can either be done through variable speed gear/coupling systems, through frequency control of the pump motors or through valve control. In either case this means that the direct influence onto the steam cycle is eliminated and instead we may have an influence onto the network/generator load.
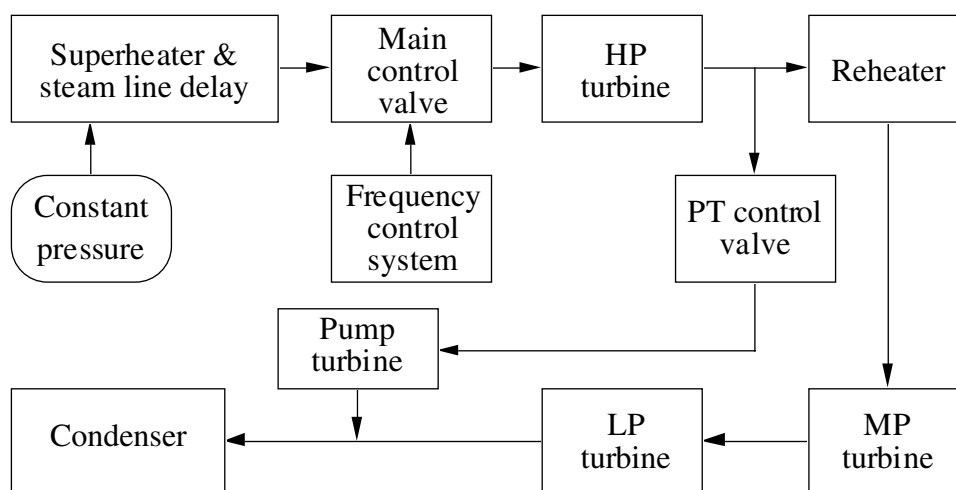
Figure 4.11   Simplified steam cycle block diagram, with the pump turbine included.

It should be noted that the units at Stenungsund are also equipped with electric feedwater pumps, but these serve as backups in order to

increase the plant availability only. Their capacity is lower than that of the pumps driven by the pump turbines and hence a reduction in output power is required when operating with the electric feedwater pumps. For units 3 and 4 this means a reduction from 260 MW to 170 MW as the maximum output power.

For a power plant of the type used at Stenungsund a simplified steam cycle block diagram will thus be as shown in Figure 4.11.

4.8　Power/steam consumed by the feedwater system

In order to allow for further simplifications we must try to estimate the amount of steam drawn to the pump turbine, as compared to the main steam flow. The data used refer to Stenungsund, units 3 and 4, but similar calculations can of course be made for other units or stations having the same kind of arrangement with a pump turbine, driven from the medium pressure steam.

The output power of the pump turbine is about 6.3 MW. In order to compare with the generator output power we must reduce the generated power by a certain coefficient in order to get the output power of the medium and low pressure stages of the main turbine only. Normally these stages account for about 70% of the generated output power. With a nominal power of the unit being 260 MW, the power of the medium and low pressure stages will be about 182 MW. This means that the steam extraction to the pump turbine will be in the order of:

$$\alpha = \frac{P_p}{P_n} = \frac{6.3}{182} = 0.0346 \tag{4.7}$$

Thus the maximum steam extraction to the pump turbine is in the range of 3.5% when compared to power output of the two turbine stages that are parallel to the pump turbine. If compared to the total unit output the same figure gets about 2.4%. This is a fairly typical figure: most thermal power plants have a total power load from the auxiliary systems of about 4 to 6% of the plants output power, and the feedwater pump is by far the largest auxiliary; typically accounting for about half of the auxiliary power consumption.

For a fairly crude model this steam extraction can be neglected when considering a control model for the turbine system. It is however possible to go one step further and include this factor as well. The advantage is of course increased accuracy, but the cost in complicating the setting up of a model and of obtaining the necessary data from a particular plant do outweigh the advantages. The main reason for this is that the steam extraction is linked to the feedwater control system, which controls the pump turbine. Therefore, in order to get a correct representation of the behaviour of this system when dynamic response is considered one has to include the entire dynamics of the feedwater control system, as well as the dynamics of the pump turbine and the feedwater pump. Because of this the cruder model, where the steam extraction to the feedwater pump is neglected, will be used in the further analysis. However, before leaving this topic there will be a minor analysis as to how an extra correction for the steam extraction to the pump turbine can be made.

For any centrifugal pump the power consumed when pumping liquid can be written as:

$$P = \eta \cdot p \cdot Q \tag{4.8}$$

where:　　P is the power consumed by the pump
　　　　　η is the pump efficiency
　　　　　p is the pressure difference inlet to outlet
　　　　　Q is the flow rate of the liquid

If the efficiency can be assumed to be constant (on a real pump it is not really constant but varies somewhat with the operating point of the pump, but as we are then considering a second order effect on a steam extraction that is only in the order of 3.5% to start with this effect can be neglected here) then the power used can thus be said to be proportional to the flow rate Q.

In order for the boiler to maintain a correct water level (steam dome level) the feedwater flow rate must always be made to balance with the steam flow rate out from the boiler; i.e. the same number of kg/s of water must be pumped back into the boiler as the number of kg/s that is leaving it via the high pressure steam line. If this fails the dome level changes and quite soon a situation will occur that will trig first an alert and then if the situation gets worse a total trip of the unit. The reason for this is that operation with an incorrect dome water level is potentially hazardous for the plant: a low level may mean that some boiler surfaces run dry, thus leading to destruction through overheating, and a

high level can lead to water being passed on the chain of superheaters and to the turbine, possibly causing turbine damage and also reduction of life expectancy for vital components due to rapid changes in temperature.

As already stated the dome pressure is assumed to be constant when analysing the units behaviour with regard to short term response. This means that the output of the high pressure turbine is almost directly proportional to the steam flow rate of the high pressure steam line. This assumes that the backpressure (pressure at the main discharge port of the turbine) for the high pressure turbine can be said to be reasonably constant, but this is normally the case.

The direct correspondance between steam flow rate and high pressure turbine output can be seen in all the measurements made and Figure 4.12 shows a quite typical case, where unit 4 at the Stenungsund power station is subjected to three changes in load level, first down, then up and then again down.

Figure 4.12   Unit 4, HP steam flow and HP turbine power during step load changes.

Thus, if the feedwater system was absolutely ideal (zero response time, absolutely correct tracking at all times etc.) the power used by the feed-

water system would be in direct proportion to the power of the high pressure turbine. This is however not the case with any real feedwater system. The number one deviation is that there is a significant time delay in the system, due to the response time of the control system as well as the delays caused by valve set times, steam travel and expansion time etc. This leads to that the feedwater flow will approximately track the high pressure steam flow (and thus the high pressure turbine output power) with a certain, system dependant time delay. This can be shown clearly in Figure 4.13, which shows the performance of the feedwater system during the test shown above (recorded at the same test and showing the same time frame).

One can see that the feedwater system is tracking the changes in the HP steam flow with a time delay in the range of 8 to 10 s, with an initial dead time of about 1 s before the system responds at all.

Figure 4.13   Unit 4, feedwater and steam flow during the test above.

However, more striking is the fact that whereas the feedwater system is tracking the steam flow it does not do so to the full extent; instead it leaves a difference up or down. This can easily be understood when the control circuit for the feedwater system is studied (Figure 4.14).
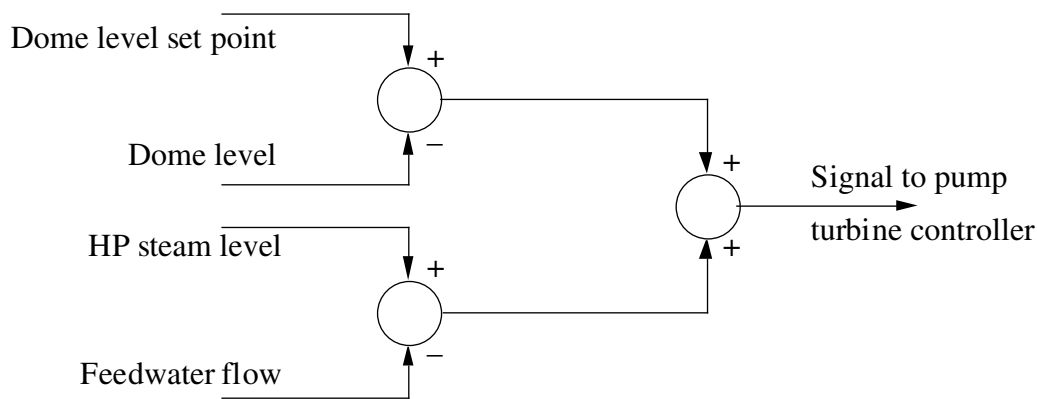
Figure 4.14   Stenungsund power station, units 3&4, feedwater control system.

Obviously the feedwater control depends not only on the steam flow rate but also on the current dome level, compared to the set point value of the same. This is of course necessary as the tracking of the steam flow can never be a perfect match and even if it was additional compensation would be required as water can leave or enter the system by other means: a small quantity of water is constantly drawn from the bottom of the steam dome, and sometimes from other parts of the system as well, in order to reduce the amount of impurities in the boiler water. On the other hand fresh water is added to compensate for any losses.

The above means that a control model taking the effects of the steam used by the pump turbine is very difficult to construct and to get accurate. One can fairly easily model the steam flow dependent part, but the level dependant control depends on the history of the case, i.e. how the operation has been PRIOR to the disturbance that we want to check the response to. There are really only three ways to deal with this:

1. to model the entire feedwater control system, complete with an integrating part representing the flow differences integrated by the system volume.

2. to use a simplified model where the dome level is assumed to be correct (i.e. equal to its set point value) prior to the situation that one wants to test. In such a case a simple representation of the feedwater system will do, typically involving only the steam flow rate as the controlling variable.
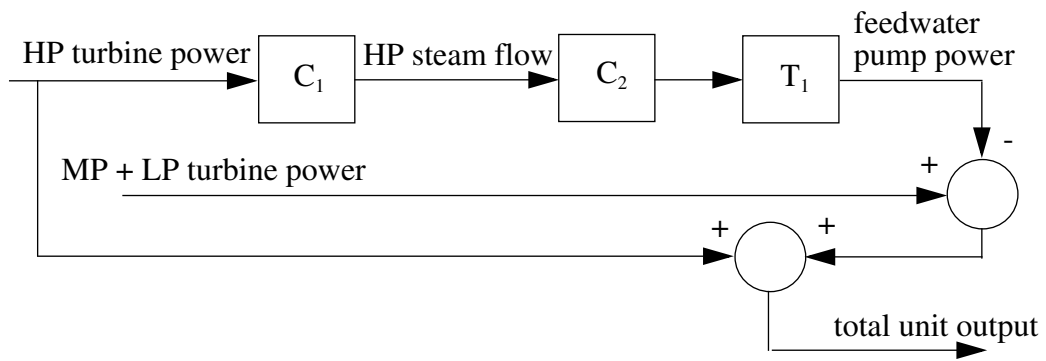
Figure 4.15   Simple turbine system model with steam-driven feedwater pump accounted for. C_1 is a proportionality constant linking the HP steam flow to the HP turbine power. This constant will depend on the current dome pressure. C_2 is a proportionality constant linking the required feedwater pump power to the feedwater flow. Also this constant has a depends directly on the dome pressure, as the pump power required is roughly proportional to the pump pressure, which must balance the dome pressure. T_1 is the time delay of the feedwater system and its control system.

3. To use a much simpler model, neglect the time delay involved and simply reduce the output power of the medium and low pressure turbines by a set figure calculated based on the power data of the feedwater pump an the MP and LP turbines; in this case 3.5%. This will normally give sufficient accuracy and gets around many of the modelling problems that come up if the feedwater system has to be included in the main turbine model. This approach is therefore used in the following.
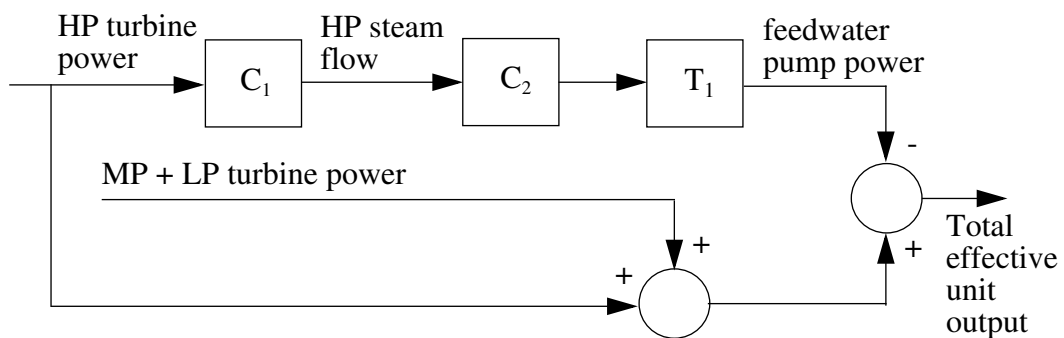
Figure 4.16   Simple model where an electric feedwater pump is used.

The above discussions have been based on a feedwater pump driven by a pump turbine, but a very similar reasoning will apply to the more

common case where the feedwater pump is driven by an electric motor. In this case there is no steam extraction for this purpose, but the motor presents a load on the network and thus on the generator and the result becomes the same, except that the pump power should, for the case that is described under 2. above, instead be subtracted from the total power:

Note that the output here is the effective output, taken as the generator output minus the power consumed by the feedwater pump motor.

4.9   High pressure turbine response

The high pressure turbine responds extremely fast to any changes of the control valve position. As the control valve is normally located right next to the turbine inlet port there are no time delays pertaining to steam line lengths or system volumes involved and the response is hence almost instantaneous.

A typical recording (Figure 4.17) shows how the high pressure turbine assembly responds to a step change in the control valve position within less then half a second. The response at the "bottom" is slowed down somewhat by the fact that there are also two axial low pressure turbines in the HP assembly; if the output of the HP radial stage could be measured separately the response would be even more distinct.

If the downramp part is enlarged one can see that the response is actually extremely fast, as can be seen on the diagram in Figure 4.18.

From this diagram can be seen that the high pressure turbine assembly power tracks the position of the control valve within a fraction of a second, the time shift being less then 0.1 s.

Another interesting effect can also be clearly seen: there is a kind of back-lash effect in that the power oscillates up for a very brief moment, following the initial drop. This can not be explained by the behaviour of the valve, as the valve position recording, which is measured directly from the valve position potentiometer, shows no such oscillatory motion or bounce effect. The explanation must instead come from the steam dynamics of the high pressure steam line and be due to a pressure variation in the steam line. This is further discussed in the next paragraph which addresses the dynamic effects of the steam lines.

Figure 4.17   Unit 4; HP turbine response related to the control valve position.

Figure 4.18   Enlargement of the downramp in Figure 4.17 with the HP steam
flow plotted.

4.10 Effects of the steam lines

The main steam lines are of considerable length and cross-section and do thus hold a considerable amount of steam. This steam is in motion and forms a dynamic system. Primarily three effects of the steam lines can be expected:

1. A pressure drop, which according to the laws of kinematics is proportional to the square of the steam velocity.

2. A time delay which relates to the length of each line compared to its steam velocity.

3. An induction effect in that it tries to resist all changes in steam velocity / steam flow: if the flow is increased rapidly it takes time and power to accelerate the steam and if it is reduced suddenly the momentum of the steam tries to keep the motion up.

As for the pressure drop this is of prime interest if one is investigating the overall efficiency of a plant at the design stage, but it is also of interest with regard to the dynamic response of the plant. Though all it means in steady-state operation is a slightly (very slightly if the system is properly dimensioned) reduced output power, especially at full load where the steam flow is at maximum, it can give rise to certain dynamic effects that will be discussed in the following, as it can lead to changes in the admission pressure present at the inlet port of the control valve.

The time delay is of little interest with regard to the dynamic response if we are considering the high pressure steam line. The reason for this is that the main control valve is not located at the beginning of the line but at the very end, in immediate proximity of the turbine admission port. This is done exactly in order to minimize the time delay caused by the HP steam line. The distance between the main control valve and the admission port can of course not be made equal to zero for design reasons, but it is kept very low, as the valve is usually located right along the side of the turbine.

The above applies to the high pressure steam line only. When it comes to the medium pressure steam lines the length becomes significant as here there is no control valve at the end. There are the intercept valves, but as mentioned earlier these should normally always be open when we have some kind of operation that is at least reasonably stable. Instead the steam inlet control to this system is simply exercised by the

high pressure system: what ever steam that comes out of the high pressure turbine outlet port will, with associated time delays, travel through the medium pressure steam lines back to the boiler, through the reheater and then through the steam lines again back to the turbine system, to enter into the medium pressure turbine. This long path of travel, plus that the steam will not even be available to the medium pressure system until it has expanded its way through the high pressure turbine, means that the response of the medium pressure system to any changes in the control valve settings will be considerably delayed. A similar delay will apply as the steam moves on to the low pressure turbines, but this delay is much shorter as there is no reheater involved and the steam lines are much shorter as they do not go back to the boiler but instead they just transfer the steam from one part of the turbine system to another.

As mentioned in Chapter 3 it has not been possible to separate the measured power from the medium and the low pressure systems. Instead the two systems have been considered as one thermodynamic system and the time delay that has been established as a part of the model refers to this combined system as related to the high pressure system.

For the case of the Stenungsund power station, unit 4,the time delay has been measured for various types of sudden load changes and typical cases are shown below, Figure 4.19 showing a step increase of the network load and Figure 4.20 a step reduction.

Describing the system as a first order system and defining a time constant as per the normally used definition that the change in the output variable should be complete to 63% one can determine this time constant for the steam system delay from the high pressure system to the combined medium and low pressure system. This figure will have a slight uncertainty in it, in that the input in the form of the change of the position of the control valve is not a real step change. Due to the fact that the control valve can only move with a finite speed, plus that the frequency control system has some damping/delay built into it, this input will always be a gradual change rather then a step function. Due to the fact that the control valve is normally built so that it closes much faster than what it opens the two cases, increasing or decreasing power, will have to be treated differently.

Figure 4.19   Unit 4; turbine responses during a power increase.

Figure 4.20   Unit 4; turbine responses during a power reduction.

Taking the case in Figure 4.20 the time constant for the closing of the control valve, defined as above as the 63% limit, is about 0.7 s. This is in the range of 7 times the corresponding time constant of the MP/LP turbine system, and it is a reasonable estimation to regard the input signal as a step function, in which case the turbine time constant can be measured to approximately 5.2 s. However observing the curve one can see that this time consists of two parts: a dead-time of approximately 0.7 s and a time constant for the consequent change of approximately 4.5 s.

For the case of the power increase as shown in Figure 4.19 it is harder to get a correct estimation of the MP/LP turbine time constant. The control valve moves slower and the approximation used above is now less correct. The slower motion of the control valve will naturally slow down the final response. On the other hand the control valve motion shows a larger overshoot in this case and that tends to act the opposite way. The larger overshoot is a natural consequence of the fact that the valve moves slower on opening then on closing, as the control valve position is used as the feedback loop controlling the valve position. If one does not compensate for any of the above the time constant as measured for the power reduction case will be 4.2 s, which can as above be divided into a dead-time of 0.7 s plus a first time system time constant of approximately 3.5 s. The turbine seems to respond somewhat faster on increase then on decrease. The most plausible explanation is that in the case of the power reduction there is a slight addition expansion time for the steam trapped inside the turbine whereas for the increase the steam will hit the vanes with less delay. However, an analysis of several test cases show variations in the order of one second, primarily due to difficulties in getting a correct assessment of the time constant when the input signal is not a perfect step function. Therefore a cruder estimation, using the same time constant for increase and decrease will be used in the following.The fact that the dead-time is similar in the two cases is natural, as this consists of mere travel time for the steam pressure wave through the high pressure system and the reheater plus the associated steam lines. The MP and LP systems will not be affected by a change in the control valve position until this pressure wave reaches the inlet port of the MP turbine. Note that the fact that this wave has reached the system is only the beginning of the change process, for the actual bulk of the steam to do the same takes longer and as a result the first order time constant is considerably longer.

An extra factor to be considered is of course the actions of the control valve limiter. This one will be discussed in the following and is of course of prime importance when it comes to determining how the unit can respond to a very fast increase of the load.

As for the dynamic effects of the steam in motion this can be clearly seen only in cases where there is a very sudden and fairly substantial change in the steam flow rate. The two cases of a sudden reduction and of power increase must be treated separately as there are two somewhat different phenomena that occur. The first case to be considered is the power reduction, where the dynamic effects are most obvious.

Figures 4.21 and 4.22 show the behaviour of unit 4 at the Stenungsund power station when subjected to a step-wise load reduction in the simulated network (simulated island operation, real unit under test). The load reduction is the same in both cases. The difference is that in Figure 4.21 the total moment of inertia of the system has been set equal to the total for all four units at Stenungsund, assuming that they are all on-line, but that only unit 4 is responsible for the frequency control; the other units being operated with an active governor dead-band, whereas in Figure 4.22 the moment of intertia has been set to that of unit 4 alone; thus assuming that this one is the only unit on the island network. In the case of all four units the changes become slower and no dynamic effects of the kind described above can be noticed, neither on the power reduction nor on the. In the case of the single machine however, the changes are rapid enough to produce a significant dynamic effect, clearly noticeable as on oscillation of the high pressure turbine assembly output power right after the drastic reduction. Note that there is no corresponding oscillation of the control valve position. This shows clearly that we are dealing with a steam dynamics phenomena and not with some kind of unstable controller action. Network load versus generator oscillations are automatically ruled out as during the test the unit was, as is normal for this test method, synchronized onto the normal, strong network. Also, the latter is ruled out by the fact that the oscillations are clearly visible on the steam flow curve, which would not be the case if they were network induced.

The same dynamic effect is seen more clearly in Figure 4.23, where the same unit was subjected to a faster and more drastic power reduction by the sudden injection of a larger control signal. Here one can see very clearly that following the initial power drop there is a marked increase in power and in the steam flow and this without that the control valve bounces back in any way.

Figure 4.21   Unit 4; system responses to a load reduction. High J value.

Figure 4.22   Unit 4; system responses to a load reduction. Low J value.

Figure 4.23   Step power reduction response.

The extra "boost" of the power and steam flow is caused by a pressure buildup across the control valve. When the steam is in rapid motion and the valve quickly closes, the momentum of the steam tries to keep up the steam velocity and as a result the steam is compressed on the up side of the valve. At the same time the same effect causes a drop in the pressure on the down side of the valve. The result is an increased differential pressure across the valve and hence and increased steam flow. The same effect will arise whenever a rapid flow of a liquid or a gas is suddenly interrupted by an obstacle, in this case a closed control valve. A simple figure (4.24) below with a fluid moving in a pipe illustrates the effect.

suddenly inserted obstacle

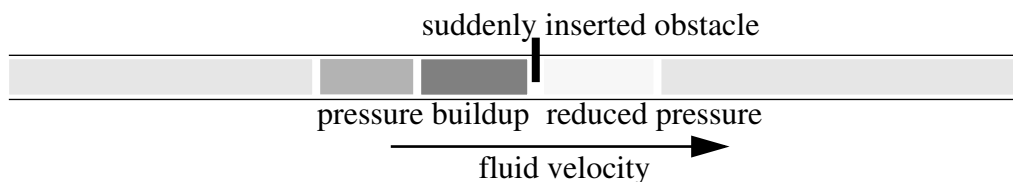pressure buildup reduced pressure

fluid velocity

Figure 4.24   Dynamic effects when the flow of a fluid is suddenly restricted.

The dynamic pressure effect acts as a pressure wave that travels back and forth in the system. E.g. it will bounce in between any two points where the characteristics of the steam flow path changes in a major way. It seems plausible that the main such bouncing effect will be in the high pressure steam line; i.e. between the control valve and the last superheater, superheater three in this case. The recording above clearly shows this oscillatory behaviour.

This dynamic effect is undesirable in several ways. One is that any oscillatory changes of the turbine power means an increased mechanical load onto the turbine shafts. In power stations with long turbine shafts, which is common for stations having a one-all turbine shaft, there is always a risk that if such oscillations are close in frequency to the natural mechanical resonance frequency of the shaft/turbine system these oscillations can grow much larger than anticipated and in extreme cases there can be a risk of fractioning the shaft assembly.

Another drawback resulting from this dynamic effect is that we get a power boost at a time when we do not want it; that is when we have had an overfrequency and thus a sudden reduction in power. Having this extra power boost will just drive the frequency still a little higher.

The third problem with this dynamic behaviour is that we may get problems with the auxiliary systems, in particular with the feedwater system. In virtually all thermal power stations the steam flow is used as a variable controlling the feedwater system. Often a derivative action is included in this controller so that any increase in steam flow automatically will lead to an increase in feedwater. In a case like that of Figure 4.23 this is an incorrect action. We have just had a drastic reduction in power and we do not want an *increase* in the feedwater flow at this point. Oscillations in the steam flow can therefore lead to oscillations in the dome level, as a result of that the feedwater controller can not handle the oscillating situation properly. If the dome level oscillates too much this can lead to a total trip of the unit. This problem is discussed further in Chapter 7.

What has been said above about the feedwater system also applies to the firing fan control system. Here we often have a dependency on changes of the steam flow so that we can get incorrect action in cases like this. Also this is discussed further in Chapter 7.

The dynamic oscillations of this kind should normally not be included in a turbine model as such, as they do not occur in normal operation

where steam flow changes are less rapid. Instead it should be thought of in the design of the control system for the control valve that one should try to eliminate or at least minimize these oscillations. With modern, computerized control systems this should be fully possible, e.g. by including software that will detect a rate of change above a certain value that is considered critical with regard to such oscillations and then take appropriate action, e.g. by moving the control valve in an optimized fashion. The oscillations in this case have a period time of about 0.8 s in this case (this time is of course different for every installation and will depend on pipe lengths and cross-sections etc.).The control valve moves in a fraction of a second (closing time 0.2 s as specified for full range for this unit) and is thus fast enough so that it can be controlled in an intelligent manner in order to minimize these oscillations.

When the power is instead rapidly increased, corresponding to a rapid opening of the control valve, we get two dynamic effects. One is the above effect in reverse, in that due to the change of momentum involved in increasing the steam velocity it takes finite time, as no matter can be accelerated instantaneously. This merely leads to a slowing down of the process, plus that we also here get a pressure wave that travels in the system and can cause various difficulties. In this case these are however of little actual concern, as the control valve opens slower than it closes and thus it is rare that we get a flow increase that is rapid enough to cause any sizeable oscillations.There is however one additional dynamic effect that is involved in this situation. This is due to a change in steam pressure at the inlet point of the turbine system. We have earlier concluded that the dome pressure can be regarded as constant for short term changes, but this applies to the dome pressure and not to the pressure present at the inlet port of the control valve. In between we have the chain of superheaters plus the high pressure steam line and we have some losses (=pressure drops) as the steam passes through these. These pressure losses are by the laws of gas kinematics proportional to the square of the steam velocity:

$$\Delta p \ = \ C \cdot v^2 \qquad\qquad (4.9)$$

where: Δp is the pressure drop

                v is the steam velocity

                C is a proportional constant.

The steam velocity is given by:

$$v = \frac{Q}{A} \qquad (4.10)$$

where: Q is the steam flow rate

A is the cross-section of the pipe etc. at a given point

v is the steam velocity at that same point

As the cross-section does not change in time we get:

$$\Delta p = C \cdot \left(\frac{Q}{A}\right)^2 = C_2 \cdot Q^2 \qquad (4.11)$$

where: C_2 is a new constant

As the steam flow increases with an increase of power we get on increased pressure drop through the systems and hence a lower pressure present at the control valve input port, the latter being:

$$p_{input} = p_{dome} - \Delta p = p_{dome} - (C_2 \cdot Q^2) \qquad (4.12)$$

where: p_{input} is the pressure at the input port of the control valve

p_{dome} is the dome pressure

The result is that when we get an increase of the steam flow (i.e. the control valve opens) we get a reduction in the input pressure. This reduction is small, as minimal losses must always be a design objective and hence the cross-section so chosen that this drop is kept low, but not completely insignificant. But when the valve has just opened this effect is not applied instantaneously, as the high pressure steam line acts as a reservoir and the pressure will therefore be kept high for a very short while, until the effect of the pressure drop is noticeable. This leads to an extra power boost for a very brief moment following the opening of the valve. This effect can be noticed in the recording in Figure 4.25, from unit 4 at the Stenungsund power station. Note there is no overshoot in the motion of the control valve, but that we get what looks like an overshoot effect on the steam flow and hence on the power output.

This dynamic effect is not insignificant. In the case above it represents an extra power boost with a top amplitude of about 3 MW. As the applied load increase was 15 MW it represents 20% of the increase and

it has a pulse duration of about 1 s. If a detailed model is to be made of the unit, e.g. to study possibly oscillatory behaviour in island operation, in a critical case, it may be necessary to model the same. This can be done, as the steam flow rate, the flow resistance of the superheater and of the steam lines, as well as the volume (=storage capacity) of the steam lines, are all known quantities. In order to get a simple model that can be used for more normal studies of networks in emergency operation and similar this effect can however be neglected, due to its short duration.

Figure 4.25   Unit 4; system response as the control valve opening increases.

As mentioned earlier all oscillations are negative from the point of the stresses presented unto the mechanical systems. This effect is however a one-swing phenomena and should not be able to cause any major problems. From the network point of view this effect is instead a positive one, as it produces an extra power boost at a time when power is needed; i.e. when there has just been a load increase and a corresponding drop in frequency.

4.11   The control valve and the control valve limiter

The control valve itself has a valve characteristic that is not quite linear if one considers its entire operating range, but in the mid-range, where it is normally used for any operation that involves frequency control and that is at least reasonably stable it can be assumed to be linear. Also, a compensation for the main non-linearities of the valve is normally included in the control system. However its actuator is normally asymmetric, in that it is designed to close the valve faster then it can open. Several different designs are possible here; either consisting of one main valve that can be operated at different speeds or one governor control valve plus a fast-acting extra shutdown valve, or as an in-between a valve where there are two actuators, one fast and one slow, connected to the same valve.

The normal mode of operation is the slow mode. This is by no means slow e.g. compared to say the vane controllers of hydroelectric power stations, which are way much slower. However, even though this mode is relatively fast by comparison, it is normally not fast enough for the extreme situations, such as a sudden load-loss at full power. In such a situation the valves must be closed extremely fast to prevent the turbine from reaching overspeed. A typical design is shown in Figure 4.26.
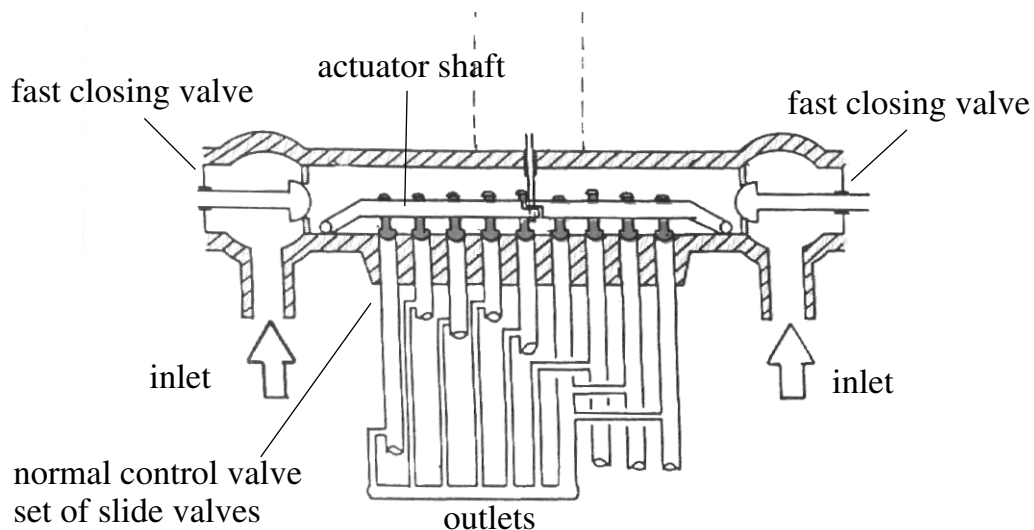

Figure 4.26   Steam control valve.

If fast operation is obtained by a separate valve or by a separate extra actuator on the main valve, then this usually employs heavy springs to

close the valve and a corresponding opening of the same is therefore extremely slow compared to its closing time. This fast closing should only be actuated in cases where there is an immediate problem with overspeed (such as a load-loss condition). This mode does not have to be modelled as part of the turbine model, as it should not be activated in normal operation, even on a very unstable and oscillating network. If it is activated then there is normally no way back, as opening it again is too slow, so in such a case the unit will have to be tripped from the network, re-started and re-synchronized.

The control valve limiter has to be given special attention in cases where there are large perturbations on the network. Most power stations have some kind of limiter, however the designs vary. The purpose of the limiter is primarily to prevent excessive step increases of the valve position and hence of the steam flow, as this could lead to damages. On older systems (such as units 1 & 2 at the Stenungsund) this limiter is completely manual and is set by the station operators to a suitable value a bit above the current point of operation, whereas more modern systems (e.g. units 3 & 4 at Stenungsund) have some kind of automatic tracking, so that the limiter runs itself, moving with the changes of the power and allowing for slow changes while still blocking rapid and large increases.

Several tests run against the power station simulator at Stenungsund show clearly that the ability of the power station to exercise frequency control, without excessive oscillations of both power and of frequency, deteriorates considerably if the station comes into an oscillating mode to the extent that the limiter gets activated. This is natural, as suddenly we have slowed down one side of the regulating process, in that increases can only take place slowly, whereas decreases can still be fast. It must therefore be one objective in obtaining a well functioning island operation mode that one can operate the station in such a way so that the control valve limiter is not at all taking part in the process. Note that for normal load increases, which for a network of limited size have been estimated at a maximum of 5% of the load the system is not at all active, as the normal tracking margin is in the range of 10%.

The recordings below, from Stenungsund unit 4, shows the behaviour of the limiter and the control valve when the unit was subjected to a series of step load changes. In Figure 4.27 a network with all four units at Stenungsund on line was considered, and as a result the total moment of inertia was high enough to slow down the changes enough

to keep up with the rate of change of the tracking limiter and as a result the limiter never became active.

Figure 4.27   Unit 4; control valve limiter behaviour during a load increase with a high J value.

Figure 4.28 on the other hand shows a test case where the corresponding simulated island network has no generator other then that of unit 4 on line. The moment of inertia is now smaller and as a result all changes get more rapid. Still, it takes a fairly large power change to for its control valve to get into contact with the limiter. In two cases this has occurred and as expected the shape of the curve is altered in these cases and it can be concluded that this the limiter had a significant influence on the process. In these cases the load increase was equal to about 8 and 15% of the output power (thus somewhat beyond expected normal load fluctuations) and the limiter became active but only for a short time. It did in this case not result in any problem in maintaining the network frequency, but for a complete model for the case that effects of large disturbances are to be studied, then the limiter must be part of the model. These models will of course be very different for different power stations, due to the wide scope of designs in this field, so the models stated below apply to the Stenungsund station only. They

can of course also be applied to other stations with the same type of control systems.

Figure 4.28   Unit 4; control valve limiter behaviour during load changes. Low J value.

Figure 4.29 shows the second step increase from Figure 4.28, where the limiter had the greatest impact. Studying the response from the two turbine assemblies one can see the action of the limiter.

As can be clearly seen the limiter prevents the control valve from opening as fast as it would do if no limit was imposed. As a result the power increase from the turbines is also slowed down. The high pressure system, which normally would respond within a fraction of a second, now reaches its maximum power after about 6 s, and the medium pressure system after about 17 s, counting from the time of the load change, which is equal to the time when the frequency of the simulated network starts changing. As a result it takes quite long before the system finally restores the network frequency to the new operating point (=previous frequency minus the difference caused by the static droop).

Figure 4.29   Unit 4; detail of the second step increase in Figure 4.28.

A control valve limiter of the type used for units 3 and 4 at Stenung-sund uses one sole input parameter: the control valve position and it also acts on (limits) exactly the actuator signal controlling that same valve position. There is also a manual mode, where the limiter is controlled by the operators by giving increase/decrease signals, but the automatic tracking mode is the normal mode of operation. The time constant for this particular installation is 50 s and the normal tracking margin is 10%, giving a control model as in Figure 4.30.
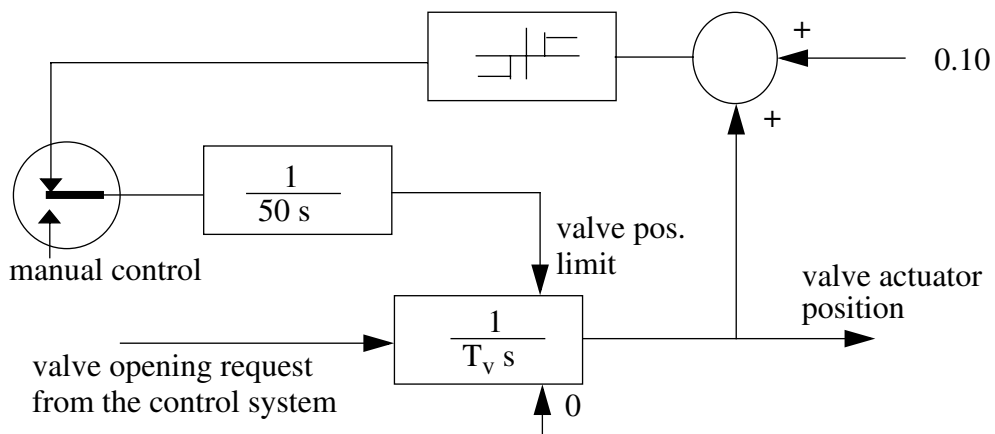
Figure 4.30   Tracking control valve limiter.

4.12   The frequency control system

The frequency control system itself is of course of prime importance when it comes to the units ability to maintain proper operating frequency. There are very many design concepts for these systems and the system used at Stenungsund, units 3 and 4, which will be the base for the discussion below does only represent one such design. The same design *concept* in the sense of the control blocks involved is however found in virtually any governor system.

Basically there are five generations of frequency control equipment in use in different power stations throughout the world:

1st generation, used up to the 1930s, had completely mechanical governors, with centrifugal controllers as the frequency sensing element and purely mechanical or hydraulic control elements. These systems offered no more than a basic setting of a couple of main variables, such as the frequency set point and the governor droop. It should be noted that very many of these systems are still in active duty and they are often remarkably reliable, mainly due to their simple design and the high degree of mechanical perfection that was used in manufacturing them.

2nd generation used electrical controllers, but with no electronic parts in it, amplification by rotating amplifiers or transductors, only in rare cases with vacuum tubes and similar. These systems are now in most cases replaced by more modern ones, as lack of both spare parts and staff with the required technical knowledge of these systems make it hard to maintain them. Their overall reliability is usually actually lower then for the older 1st generation systems.

3rd generation used electronic control systems, with transistors and other solid-state devices, sometimes with transductor amplifiers or similar for the more high-powered parts of the systems. Also these systems are now getting obsolete and are being replaced by more modern ones. This is often easily feasible as the systems are designed for low level electrical control and it is often possible to keep the costly parts and just replace the electronics with modern systems.

4th generation used linear integrated circuits, primarily operation amplifiers and allowed for a more exact and sophisticated control of the behaviour of the systems. Many such systems are in operation and as this technology has as of yet no maintenance or spare components

problems there are so far no compelling reasons for replacing/modernizing it, unless it is done as a part of a general upgrade of the whole station or the entire control equipment.

5th generation is the state of the art today, with digital, computerized control systems. These allow for tailoring the control characteristics in virtually any way that the designer wants and allow for easy ways of adding several different control modes, so that e.g. the system can, automatically or by operator command, switch to a different set of control variables if certain unstability criteria with regard to the network, such as frequency variations beyond set limits, are met. A drawback with this generation is that the extremely fast development in the field of microcomputers make the systems obsolete quite fast and it is therefore highly unlikely that these systems will attain anywhere near the lifespan of the older control systems.

The test / simulator system designed within this research project can be applied to all cathegories of control systems, except the 1st generation. As the latter has no electrical input for the frequency there is no way that the system can be fed a simulated control signal and hence the basic idea of this technique can not be applied.

A block diagram for the frequency control systems of units 3 and 4 at the Stenungsund power station is shown in Figure 4.31. This control equipment can be said to belong to the third generation as described above. Units 1 and 2 at Stenungsund have more modern control systems, belonging to generation four as above.

Two of the systems shown in Figure 4.31 can for modelling purposes normally be eliminated. This applies to the dome pressure turbine control and the system for controlled shutdown. As for the linearizer this can sometimes be eliminated, but if an accurate model is to be obtained it must be included.

The purpose of the linearizer is to compensate for the fact that if the control valve is opened only to a small percentage of its full opening the effect of a certain change of its position is greater then if we make the same change in a situation where the valve is already open to a larger extent. This is a consequence of the laws of kinematics and it also involves a certain compensation for non-linearities of the control valve itself. Sometimes this block is therefore referred to as a control valve non-linearity compensation.
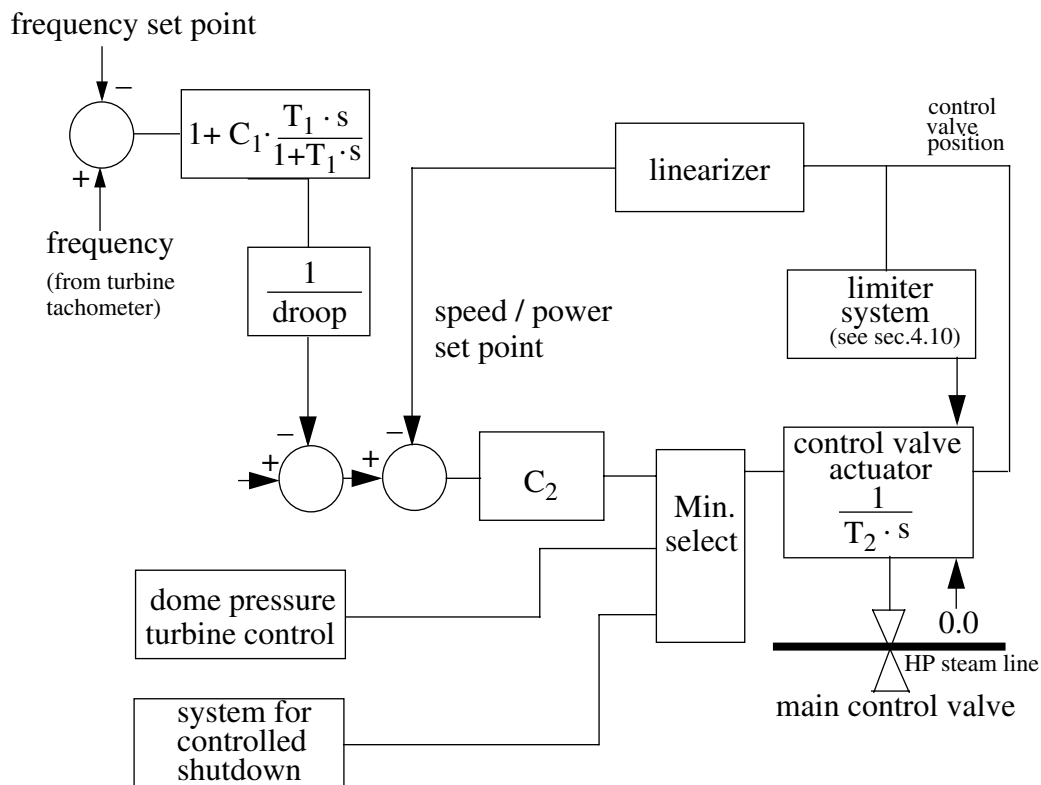
Figure 4.31   Frequency control system, Units 3 & 4, Stenungsund power station.

In the case of units 3 and 4 at Stenungsund the linearizer is modelled to have the characteristics shown in Figure 4.32.
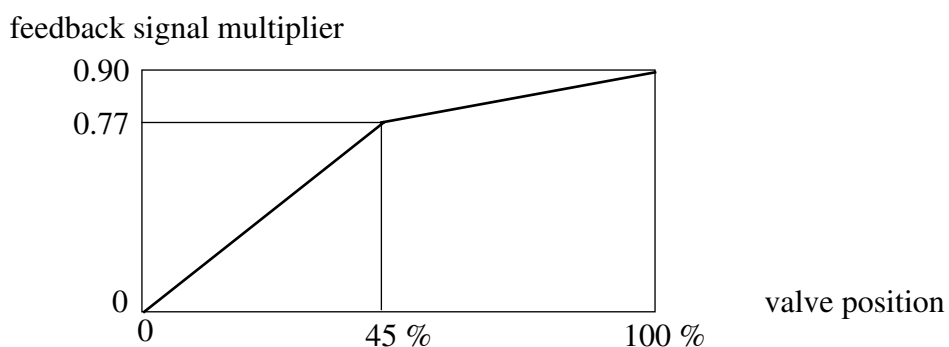
Figure 4.32   Model curve for the non-linearity compensation of units 3 & 4 at Stenungsund.

The linearizer can be removed from the model by simply assuming that the valve together with the behaviour of the steam form a system that is linear. After all, what we are interested in is the actual amount of steam

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coming through the valve at a given pressure difference and the parameter "control valve position" is in itself not interesting. What we want to set is a steam flow rate at a given pressure difference; i.e. a flow resistance. If we combine the valve characteristics, with its non-linearity, the valve actuator and the non-linearity compensation into one control system we can remove the compensation and the valve non-linearity, getting a control block like Figure 4.33.
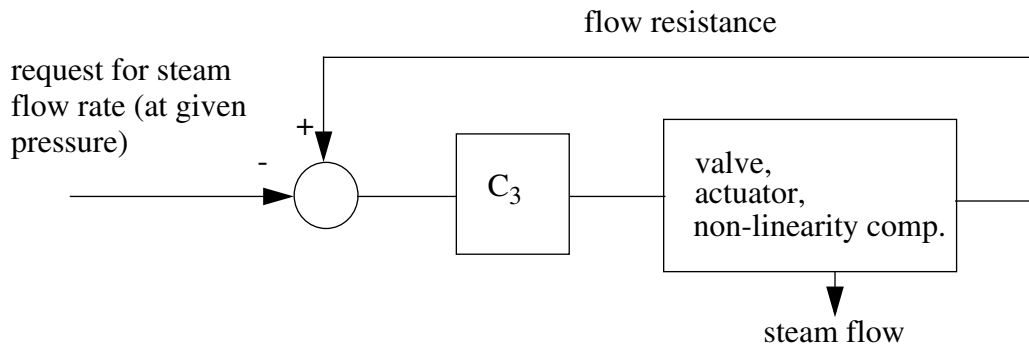
Figure 4.33   Valve control; basic block diagram.

Assuming that the non-linearity compensation reasonably compensates the valve characteristic non-linearity we are left with a simple control block where the time delay due to the fact that the speed of the valve actuator is always a limited value is the only parameter of interest. The proportionality constant C_3 should of course be set a correct value, but this is just a scaling of the sensitivity. We therefore end up with a control block of the type shown in Figure 4.34.
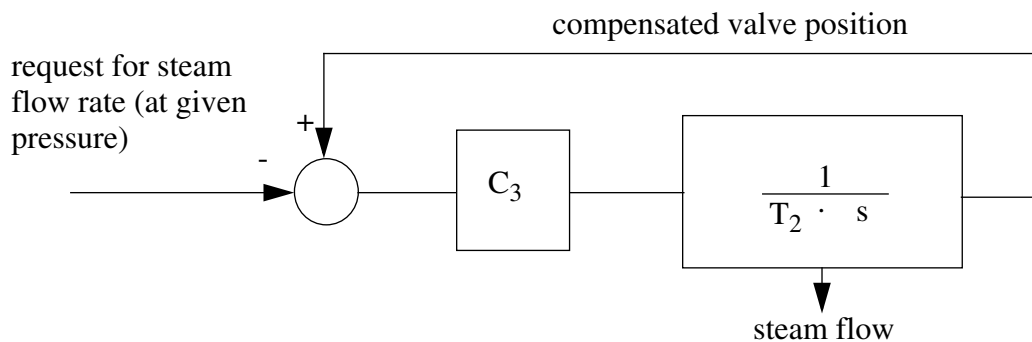
Figure 4.34   System with the linearizer included rather than modelled separately. T_2 is the valve actuator time constant.

Note though that in the case of the Stenungsund units 3 & 4 this simplification will lead to another complication. This is because the setting value used for the tracking control valve limiter uses the "raw" control valve position as its input. If we will use the simplification described above we must therefore apply a compensation to the limiter control circuit, as otherwise we get an incorrect value for the margin between the current valve position and the limiter, as this margin is for steady-state operation set to 10% of the actual control valve position. So whereas the linearizer can be neglected for crude models it must still be kept in the circuit if a detailed and highly accurate model of units with this design should be made.

The dome pressure turbine control system is designed to prevent excessive pressure drop in a situation where the frequency control system demands more power, and hence more steam, than what the boiler can supply at that given moment. In a situation like this the dome pressure turbine control system will become active and will reduce the output power in order to preserve steam so that the steam pressure of the dome can be held to an acceptable level. When this system is activated it takes over control from the frequency control system and the unit drops out as far as performing frequency control goes. Clearly, if this machine is the only one on line this means that we can no longer maintain the network frequency and hence the frequency will drop. There are then only two ways that the network can be returned to a controllable situation: either the boiler manages to respond so that it delivers the steam required, hence rising the dome pressure and de-activating the dome pressure turbine control system, or the load is reduced through load shedding to such a level that the steam available allows the unit to find a new stable point of operation.

From this can be concluded that for modelling the power station as a part of setting up a functioning island operation network this system can be eliminated. The operation *must* always be such that a reasonable margin is maintained with regard to the minimum required dome pressure and hence the boiler system must be taken into account in order to determine as to whether this puts restraints on the possible conditions of operation. For a further discussion of this see Chapter 5, where the boiler system and its behaviour is discussed. For now, we conclude that this system need not be included in the turbine / steam system model, as it should never become active.

The systems for controlled shutdown should also remain inactive during any acceptable operating conditions. These systems are activated

by some of the various protection systems of the power station and reduce the power in order to obtain safe operating conditions when the security situation so require. In the case of the Stenungsund station, units 3 and 4, there are two levels of controlled shutdown or power reduction. One is reduction to a minimum steam flow as required for the cooling of the turbine, the other is reduction to 50% of the rated power. As an example a controlled shutdown can be ordered if the fuel to power differential protection is activated; i.e. if the amount of fuel injected does not stand in a reasonable relation to the output power of the unit at the time. This protection is to protect against bad fuel oil, primarily against large amounts of water in the oil. In such a case there is no immediate danger and hence no need for tripping the unit, but instead a controlled shutdown will be ordered. Several other protection systems give the same kind of response.

As these systems are part of the unit protection they should obviously not in any way interfere with normal operation of the unit. If they are activated they take over the control of the output power from the frequency control system and should this unit be the only one on line at the time it will, short of possible operator intervention, lead to the tripping of the unit and a blackout on the network. Again we have a situation where a condition that can not be tolerated in operation does not need to be modelled, as if we get to this condition it is normally too late to save the system anyhow. There is an exception to this and that is that under certain circumstances the fuel to power differential can be triggered if we have extreme power reductions; i.e. drastic disconnection of load on the network. Test against the power station simulator at Stenungsund showed that e.g. a sudden load reduction from 250 MW to 100 MW could trigger this circuit. In such a case operation can be restored by the operators, who can override or reset the controlled shutdown. It is however still not meaningful to model these systems as the only way out of an ordered shutdown, other then a unit trip, is by operator intervention and the behaviour of the operators, their alertness etc. can not be modelled in any case.

4.13   The importance of the feedback variable

A design factor that must be considered is what feedback variable that is used in the second level control loop that controls the unit output power to a desired level. In the case of the units 3 & 4 at Stenungsund

this quantity is, as shown above, the control valve position. This has the drawback that one has to introduce a linearizer to get a more linear behaviour, but otherwise the use of the valve position for feedback is an excellent choice, as the valve position is not at all under any direct influence of any possible events in the power network. We get a second level control system of the type shown in Figure 4.35.
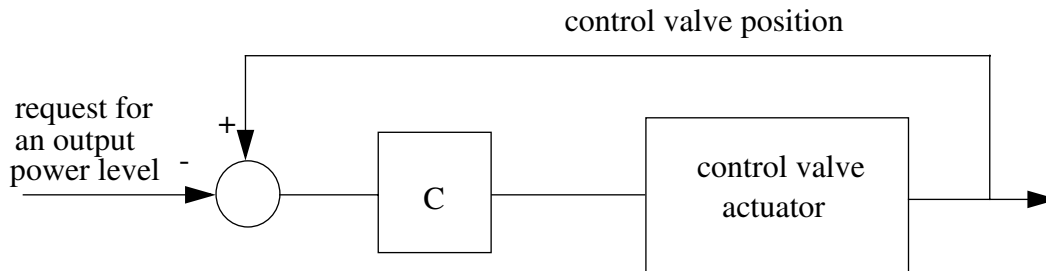
Figure 4.35   Control valve position used as the feedback variable.

If we instead use the electrical output power as our feedback variable we get a control circuit of the type shown in Figure 4.36.
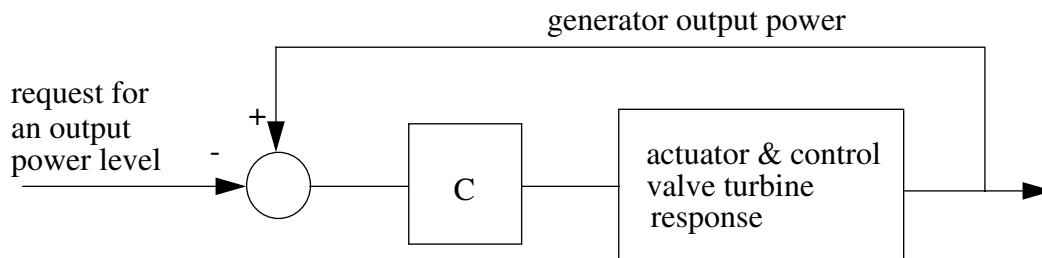
Figure 4.36   Generator output power used as the feedback variable.

It would be tempting to think of the system shown in Figure 4.36 as the preferred system, as we get the true electrical power output from the generator as our real output variable, and hence no compensation for the non-linearity of the control valves or of the steam behaviour is required. There is however a very serious drawback that will considerably degrade the performance of such a system. This comes from the fact that the actual generator output is not just a function of the conditions internal to the power station unit in questions but depends on conditions in the network as well. Consider the following situation:

Assume that we suddenly get a load increase due to that another unit on the network is tripped. This means that more power must be supplied from the unit we consider. Initially the frequency does not change, as the frequency can not change instantaneously. Instead power is derived from the momentum of the rotating generator/ turbine system. The feedback loop rightly senses this as an increase in the generator power and hence orders the valve controller to reduce the valve opening, i.e. reduce the output power, whereas what we actually need is the opposite. Only after the network frequency has dropped enough for the frequency deviation signal to override the initial order to reduce the power will the control valve once again be opened and more power delivered. This means that during the initial, often critical, phase of a disturbance of this type we get a control action that is the opposite of the desired one.
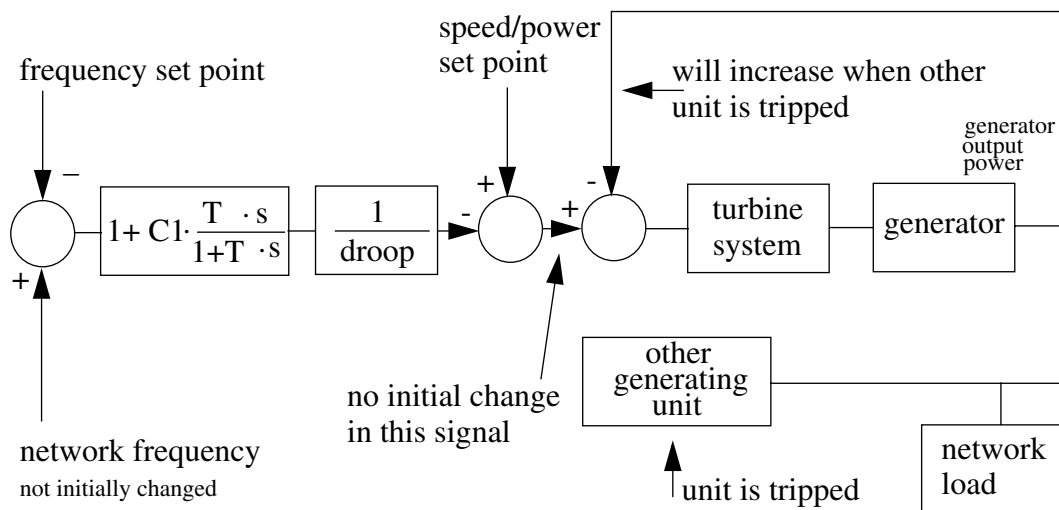
Figure 4.37 System behaviour when a unit on the network trips for a control system using the generator output power as the feedback variable.

In spite of these drawbacks this design is commonly used, mainly for the simplicity of design, as the output power from the generator is a quantity that is easy to measure and as mentioned above one avoids the need for non-linearity compensations etc. During stable network operating conditions these systems work fine, but in an island operation situation where drastic changes in the network conditions are more likely the drawbacks with possible incorrect controller action will become obvious.

In order to avoid this type of incorrect controller action the feedback variable in the governor valve control loop should be a quantity that is not affected by changes in the network. The control valve position is one such choice. The steam flow rate could be another useful alternative.

4.14   Control system dead time

A certain dead time from the time that the control signal (=frequency) was applied to the system until there was any response (change of control valve position) was observed in the frequency control system during the tests made. Such a dead time would of course be system dependant and could vary considerably from one installation to another. The exact origin of the dead time could not be established, but it seems likely that mechanical delays in relays and in the valve actuator would be the main components in this. A typical recording (Figure 4.38) shows the size of the dead time. Its size could only be estimated, as its duration is of the same order as the simulator updating sequence and hence as the time in between samples.

In the test shown above the dead time is in the order of 0.2 s. In a detailed model used for testing the behaviour of a particular power station unit in a critical situation it should be modelled, but for more general network behaviour simulations the time is too short to be significant. As one has a time constant for the medium and low pressure systems of several seconds these time delays will take precedence.

There is however one situation where this dead time is really one of the main time factors and that is if we have a power station unit with only a high pressure turbine. As shown earlier in Section 4.9 the response of the high pressure turbine itself is extremely fast and hence any dead time in its control system becomes very significant if the high pressure unit is the only turbine on line. This may be the case if the power station is a very old one, one designed for emergency power production only or one where steam is extracted for district or industrial heating applications. All other power stations normally have at least two, often three turbine systems, as using a single high pressure turbine system will lead to a low overall efficiency and hence high operating costs. In a single stage design the unit can be made to respond extremely fast to any changes, should this be desired. If so, any dead time involved is of prime importance and must clearly be part of any model of such a unit.

Figure 4.38   Unit 4; system dead-time on power increase.

Using the simulator in its present form for normal simulations will not give an exact figure for the control system deadtime, due to the comparatively low sampling rate. However, the same equipment can be used for a special test in order to determine this dead time and this test procedure is described in Chapter 9.

This control circuit dead time has a significance also for the design of the frequency control system and hence it enters into the control system models in an indirect way as well. Considering that the dead time is almost certainly located in the valve actuator mechanisms and the associated control relays etc. (almost certainly the case as the frequency control system as such is purely electronic and electronic circuits may well have time delays but not a dead time, at least not of this order, unless such a dead time has been designed into the circuitry on purpose), then it puts a limitation on the speed at which the inner control loop that controls the control valve position can operate. This inner loop will be of the form shown in Figure 4.39.
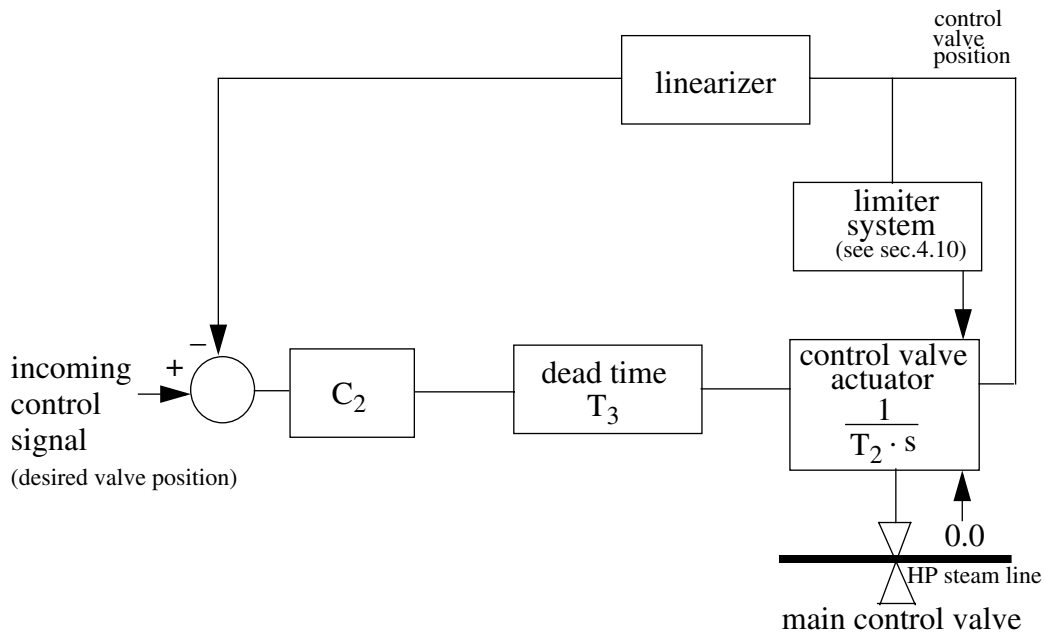
Figure 4.39   Inner control loop.

General control theory shows that a system of this kind becomes unstable and possibly self-oscillating if the dead time T_3 is not considerably smaller than the integrating response time T_2. The latter is mainly made up of the time delay caused by the fact that the control valve servo motor moves with a finite speed, but if this time delay would not be sufficient additional integrating delay (or a valve speed reduction, which would be the equivalent as for as the control response is concerned) would have to be added in order to guarantee the stability of the control system.

As for units 3 and 4 at Stenungsund the actuator time delay T_2 is according to the specifications of the units in the order of 1 s, and hence a dead time in the order of 0.2 s should be acceptable.

Chapter 5   Boiler system models

5.1   Is there a need for a boiler model?

There are numerous different boiler and power station designs and this project is not at its present stage meant to be an exhaustive investigation of all these. The main focus has been on thermal power stations of designs similar to the Stenungsund power station, that is where there is a substantial steam storage due to a well sized steam dome and where the primary control of the units output power, and hence the frequency control if the frequency control system is active, is accomplished by using the control valve and where the boiler systems just follow along to keep the dome pressure constant.

As shown in Section 4.3 the dome pressure can be assumed to be constant when the short term dynamic behaviour of the unit is considered. This actually means that once that one has established that the boiler system is able to regulate the steam pressure accordingly, including keeping it from dropping when the unit takes on an increased load, then there is really no need to model the boiler system at all. It will be the turbine system and its associated control systems that will give the response characteristics of the unit and this virtually regardless of what happens with regard to the boiler, as long as the steam pressure requirements can be met.

In order to establish whether or not the above holds true for a particular power station certain tests can be made, as is described in chapter 9. It is also fully possible to calculate this based on the design data of the power station if the following data is known:

1. steam storage capacity.

2. approximate response time of the boiler system, counting from that an order to increase the firing is given until the extra amount of steam generated is available to the turbine system.

3. steam demand per unit power output; i.e. how much steam that is required in order to generate a certain amount of power. This figure will depend on the steam pressure and of the efficiency of the turbine and generator.

4. network pre-requisites; mainly the questions of how big a load increase that the station should be able to handle over a specified period of time.

5. operating pressure margin; i.e. how much above the minimum operating pressure at the given power (minimum pressure= control valve 100% open) that the dome pressure is kept.

5.2   Manufacturers limits

Note that the above will only help in determining as whether or not the power station is *able* to keep the steam pressure constant, or rising if required, in order to keep up with an increased demand for output power. Even if this is the case this may not always be *allowed*. The boiler manufacturer will always give certain limits for the allowed power increase over a specified period of time. These limits are to ensure that the boiler itself is not subjected to excessive strain due to rapid changes in pressure or temperature. Exceeding such limits may mean a risk for the system: metal fatigue can in the long run lead to breakages or cracks can form, also in a shorter time perspective. Especially welded joints and similar may be sensitive to this.

If one is considering emergency operation and operation in very rare cases where the availability of the power is the prime concern one may well be able to operate the station above the manufacturers limits mentioned above. It may lead to a reduced life-span of certain components, but given the very few times that the station will be subjected to such operation this can often be tolerated. However, one can not totally disregard the limits; exceeding them grossly may have more immediate penalties that also affects the availability of the power station at that critical time: should a boiler tube burst then the unit will have to be shut down; no matter how urgently needed on the network that it is.

The constraints imposed by the manufacturers limits can usually be overridden by the operators in some way. On older type control systems, such as the ones in use at the Stenungsund power station, there is no connection between the actual system and these constraints at all. It is then left to the station operators to keep track of what rates of increase etc. that are allowed and to run their station accordingly. On modern control systems with computerized control some of these limits may have been programmed into the system so that the control sys-

tem will enforce the limits automatically. Even when this is the case it is usually possible for the operators to temporarily suspend this function so that manual judgement can be made as for how much that can be allowed in each individual case.

5.3   Sliding pressure operation

Many thermal power stations operate in sliding pressure operation, that is the control valve is kept fully open and the output power of the unit is regulated by controlling the steam pressure at the point of steam generation. This is done by controlling the firing; i.e. by regulating the amount of fuel that is supplied to the boiler.

Sliding pressure operation gives a somewhat higher overall efficiency in most cases, as when valve control is used there are inevitably losses involved. However valve control gives a considerably faster response. Opening the control valve is a fast way of responding to a load increase, whereas in the case of sliding pressure operation the amount of fuel has to be increased, the extra heat generated has to transfer through the boiler surfaces and more steam has to be generated before there is any increase in the output of the turbines. This usually means response times in the order of ten of seconds or more. Units that have been designed for fast response may achieve response times down to 10 to 15 s, but for many power stations using sliding pressure operation the response time is in the order of minutes.This is often the case for units that fire solid fuels. If there is to be an increase in the fuel supply this may involve the milling or liquifying of coal or the moving of large amounts of solid substances by conveyor belts and similar, and all these processes do take time. There are designs where e.g. the milling of coal can be regulated in such a way that fairly short response times can be achieved, but the response of such a fast unit will still be much slower than for a unit operating with valve control, where the response time is order of a fraction of a second for the high pressure turbines and a few seconds for the medium and low pressure systems.

As further discussed in Chapter 8, island operation on small networks requires that the power station can respond very fast to any changes of the load on the network. The exact response time allowed will vary considerably depending on the size of the network and the size of load perturbations on it, but in most cases response within a few seconds is required if the frequency is to be kept within acceptable limits. Plants

in true sliding pressure operation are generally not capable of this. Sliding pressure operation units are designed for base load production, normally with governor dead-band operation. If such a unit is to take on the task of regulating the network frequency in a small island network its mode of operation must be changed into valve control mode. Almost all power stations, including those specifically designed for sliding pressure operation, are capable of this.

5.4   A general boiler model

A very general boiler model can be built considering the main subsystems that make that are of importance with regard to the steam output of a boiler. In the following it will be assumed that the power station under discussion is a station that is burning liquid fuel (oil) or gas (natural gas or similar). Plants burning solid fuels have additional subsystems for the handling and possibly processing of the fuel prior to combustion and will not be dealt with here. This general boiler system model will then be of the form shown in Figure 5.1.
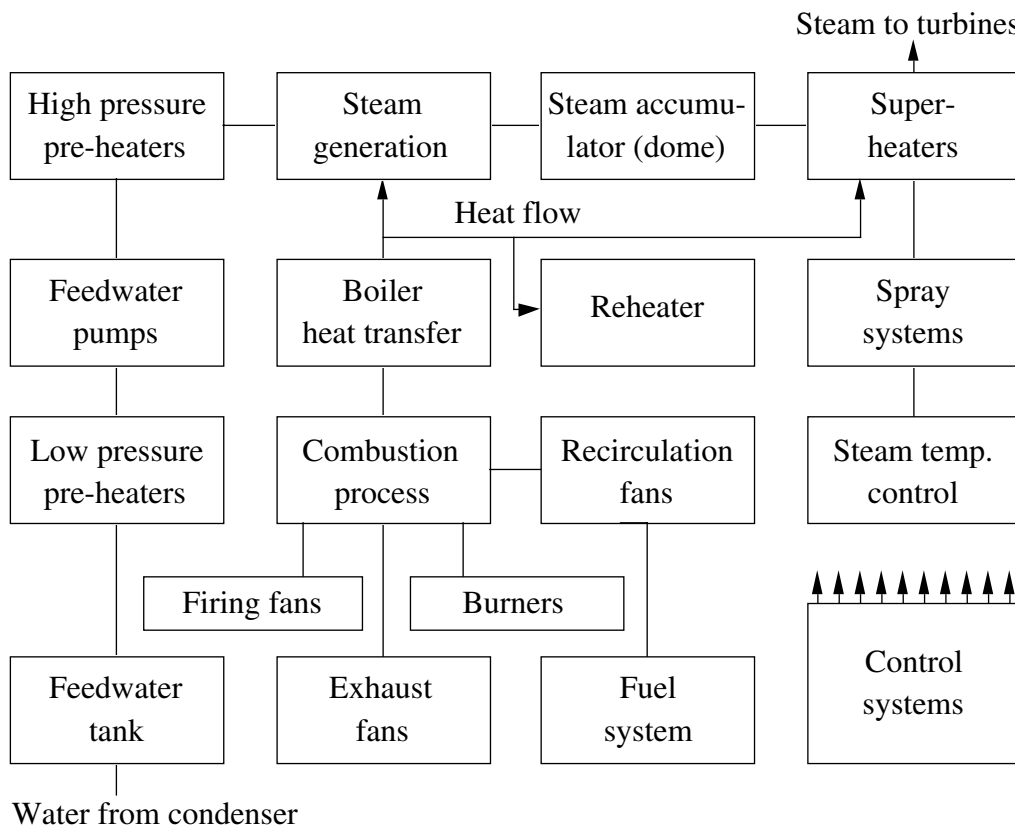
Figure 5.1   Boiler and associated systems.

Together all these systems, sub-systems and controls form a complicated web that can not easily be translated into a simple control model. However, for the purpose of network modelling, most of these systems can be neglected, as their influence on the behaviour of the power station with regard to network control is non-existent or small enough not to need to be taken into consideration.

Before going into details about different subsystems it should be noted that it is normally only the capacity to respond to a sudden increase in demand, i.e. in output power, that has to be verified. If the situation is the opposite, a reduction in output power, we never have any boiler problems as far as the network response goes. Even units and power stations that normally run in full sliding pressure mode with their control valves 100% open can in such a case always reduce the output power by partially closing the control valve, until the effects of changes in the fuel systems have reduced the steam production to such a level that the system can again run with a fully open control valve. If the response of the fuel system is slow we may have an overtemperature problem that may have the potential to trip the unit, but short of that it will not have any major effects on the output.

First of all, all subsystems that are designed to keep the combustion correct can be eliminated. The systems that belong to this cathegory are the firing fans, the exhaust fans, the recirculation fans, the burners and all the control systems associated with these systems. All these systems are primarily controlled by the amount of fuel that enters the process and each has its own control system in order to keep e.g. the fuel/air ratio or the furnace pressure at correct levels. Assuming that they manage to do so correctly they will have no influence on the dynamic behaviour of the plant in relation to the network. It is the amount of fuel that will determine the heat available for making steam, provided that the conditions for correct combustion can be maintained. Diversions in e.g. air rates could have a small influence due to changes in the specific heat output from the fuel burned (changes in the combustion efficiency) but this will then be a small secondary effect only.

It should be noted that whereas there is no immediate influence from these systems unto the output power these systems are still highly important in a situation with large perturbations, as they have the potential capacity to trip the unit off line if they are unable to properly handle the rapid changes that may occur. The influence of these systems from that point of view is discussed further in Chapter 7.

Chapter 5: Boiler system models

As mentioned in Chapter 4 the spray systems and the steam temperature control systems can largely be eliminated out of the circuit for network modelling purposes. There are two reasons for this:

1   they are too slow to at all influence short term dynamics, as their control input is almost invariably industry standard pt100 thermocouple transducers. Usually these are mounted in wells and a well-mounted pt100 transducer has a time constant in the order of minutes (e.g. 3 minutes for full response). This makes the spray systems incapable of any short term response.

2   their influence on what power that actually comes out of the unit, which is really all that matters as far as the network is concerned, is very limited. Their prime function is to ascertain that the steam temperature does not reach values such that the design limits of turbines or steam lines are exceeded. They have a slight influence on the combustion efficiency, but any effect onto the output would be a very small second order effect only.

Figure 5.2   Unit 3; steam temperatures.

That the temperature control systems are immune to short term perturbations is shown very clearly in the recording (Figure 5.2), made at a

test on unit 3 at Stenungsund. Note that the temperatures were recorded using the same pt100 temperature transducers as are used for the control of the spray systems. This means that the recordings are identical to the values used for the temperature control but not necessarily reflect the true steam temperatures during the perturbation. If there were any fast temperature changes these would have gone unnoticed.

It is obvious that the spray systems are not the ones responsible for any lack of temperature variations, as the temperature inputs that are their input control signals never change and thus these systems can take no action.

5.5   Long term tests and models

Long term tests have not been performed within this project. There are two reasons for this: for power stations like the one at Stenungsund, with large steam storage volumes and valve control operation, long term models are far less important as compared to the short term behaviour, and also the units have not been available for such tests due to their low usage. Stenungsund is primarily a backup/peak load station and is in operation only a few days per year.

For other types of power stations, such as drum type boiler units, or any thermal power plants operating in sliding pressure mode, the long term response is however highly interesting. As a continuation of this project it is therefore desirable that long term tests on such units can be performed as well. Certain such tests can possibly also be done as simulations against power station simulator units.

Certain long term models have been presented by E. Cheres [3]. These models are specifically designed for drum type boilers.

Chapter 5: Boiler system models

Chapter 6 Composite models of entire power plants

This chapter deals with composite control models that can be substituted for thermal power plants in network control studies and similar. The modelling is limited to units burning liquid or gaseous fuels, as the tests done as a part of this project gives no reference for models for plants burning solid fuels, where the response time of devices such as coal milling or liquifying equipment, fuel conveyor systems have to be taken into account in case that the unit is operating in a sliding pressure mode. If however the unit operates in valve control mode with a sufficiently large steam accumulator and a sufficient pressure margin then these models will also be valid for units burning solid fuels, as the response time of the fuel cycle equipment will then be of no importance with regard to the network behaviour of the unit.

Different level models will be discussed in the following, as the need varies widely depending on what the model is to be used for. For many network studies a very simple representation of the behaviour of a power station can be used, while certain special studies may require a very detailed and accurate model.

6.1 Units in valve control mode with sufficient steam storage capacity

If it has been established, either through calculations as mentioned in Chapter 5 or through measurements as discussed in Chapter 9, that for a specific unit the steam pressure can be kept up to its required value even when the unit taken on a load increase, i.e. that the steam storage capacity is equal to or exceeds the boiler response time so that there is no pressure drop, then the boiler system and its associated subsystems can be completely disregarded as far as the network response of the unit goes and only the turbine systems their associated control circuitry need to be taken into account.

A simple model for this type of a unit will therefore be of the form shown in Figure 6.1.
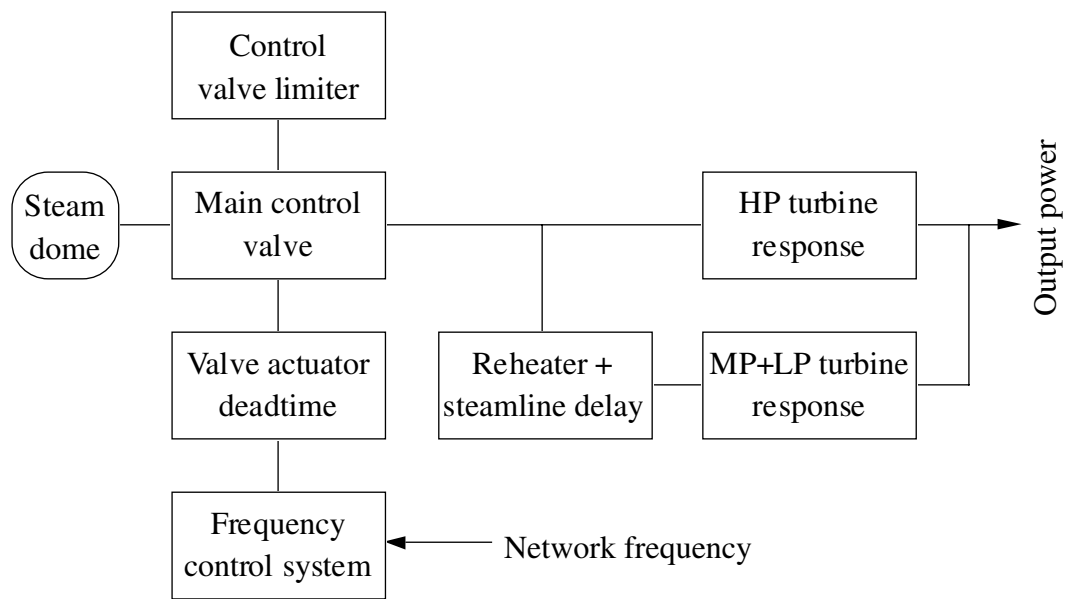
Figure 6.1   Simple power plant model.

Some of these systems can clearly be seen in a typical response recording (Figure 6.2), this one being from a test of unit 4 at Stenungsund.

Figure 6.2   Unit 4; system response during a load increase. Note: This diagram serves to illustrate the combination of events when the load is increased but does not, due to the gradual motion of the control valve, allow for an exact determination of the response times involved. For an indepth discussion, see Chapter 4.

Note that the fact that we have a control valve limiter makes the response of the power station unsymmetric: we have a limiter that can slow down the response to a load increase, but there is no corresponding limiter when the load is reduced. All other main components give a more or less symmetric response, with similar response characteristics whether the load changes up or down. That the limiter in certain situations have a considerable influence on the response of the unit is clearly shown by the example above. However, if we have a network situation where the load changes that can be anticipated are not large enough compared to the output power the control valve may never get into contact with the limiter. This would for the system used at Stenungsund mean load changes less than 10% of the current output power. In such a situation the limiter can be eliminated out of the circuit.

We have to make a distinction at this point as to which feedback variable that is used. The choice of the feedback variable is, as was pointed out in Section 4.13, that important in influencing the response of the unit, especially when it comes to the initial response to a disturbance, that the same model can not be used for units that have a difference at this point.

For a power station unit with a construction similar to that of the units at Stenungsund; i.e. where the feedback variable used is the control valve position and where a linearizer is used in the circuit control diagram for the model in Figure 6.1 gets the form shown in Figure 6.3.

In this model there are three input variables, whose values must be decided on before the model is used for a simulation of some kind: 1) the steam pressure setting; which determines the power output for a certain valve opening and also gives the margin available in case of oscillations etc. 2) the speed/power set point, which is normally operator controlled and therefore normally constant in a short time perspective and 3) actual network frequency, which in most studies of this kind will be the input variable that we want to study the response to.

Note that any time delays in the high pressure turbine are neglected; i.e. the high pressure turbine output is modelled as instantly following the control valve position (for a given steam pressure).
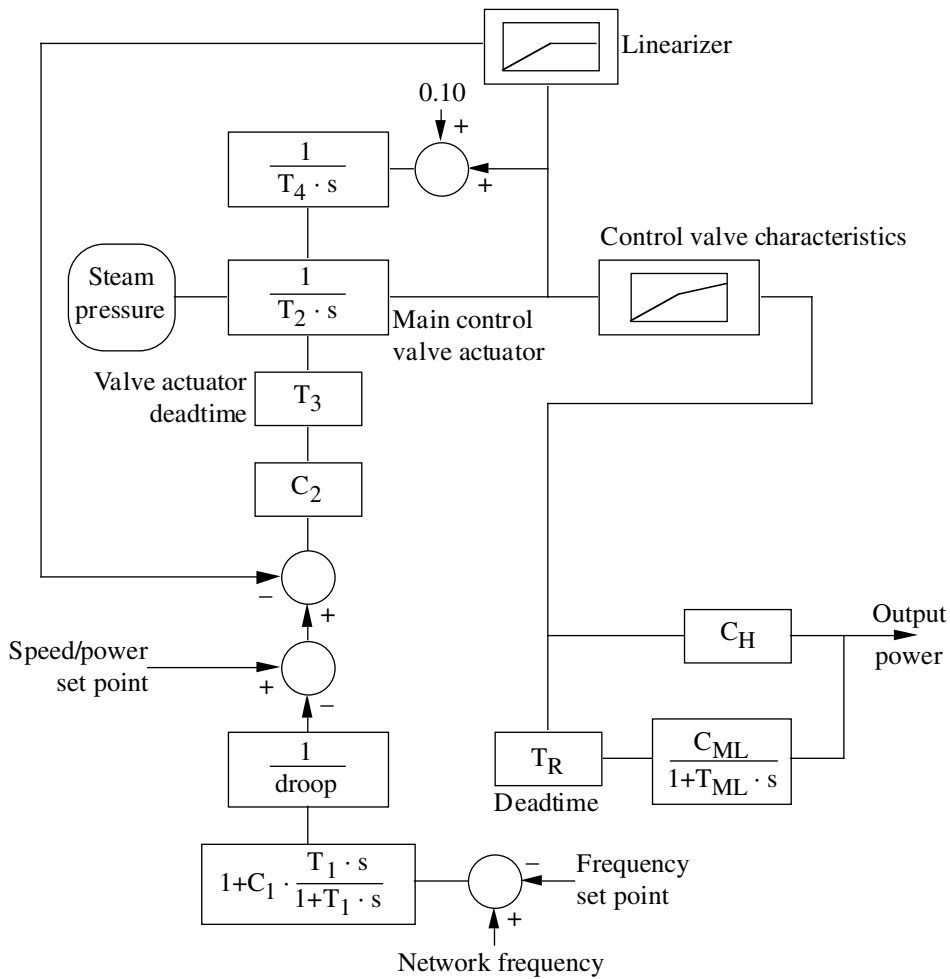
Figure 6.3   Power plant model, neglecting the feedwater system power consumption. T_1 is the time constant of the frequency controller. T_2 is the time constant of the valve actuator. T_3 is the deadtime of the valve actuator system. T_4 is the time constant of the control valve limiter control system. T_R is the deadtime of the reheater and the medium pressure steam lines. T_{ML} is the time constant of the medium and low pressure turbine systems, including reheater and steam lines. C_1, C_2 are amplification factors. C_H and C_{ML} are the amplification factors of the high pressure and the medium+ low pressure turbines respectively. These constants give the power ratio between the turbines.

6.2   Including the feedwater system

The model shown in Figure 6.3 can be extended to include the feedwater system, or rather the power that is consumed by the feedwater system. This is the only aspect of the feedwater system that we need to

consider here, as that is the only aspect in which this system influences the power output. The issue as to whether in a certain situation the feedwater system may cause the unit to be tripped off the network is dealt with in Chapter 7. There are three main cases to be dealt with here: 1) feedwater pump driven by a pump turbine, extracting steam from the medium pressure circuit; 2) feedwater pump driven by an electric motor, with speed control through variable speed; 3) systems with valve control of the feedwater flow. For a further discussion of these systems see Chapter 7.
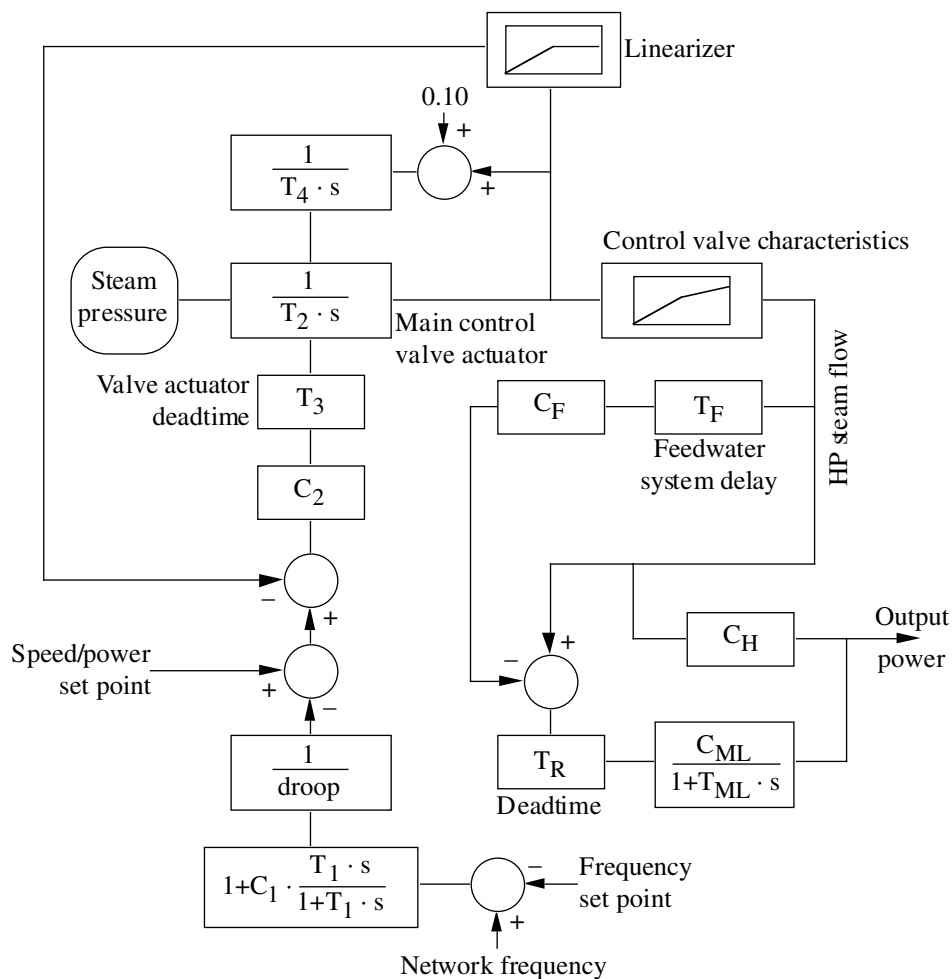
Figure 6.4   Model including feedwater system power drain. Feedwater system powered by pump turbine using steam extracted from the medium pressure system. T_F is the time delay of the feedwater system, including controller, pump turbine or electric motor, pump and water system. C_F is a proportionality constant that depends on the amount of power used by the feedwater system. This constant is steam pressure dependant. In the case of valve controlled system this constant will have to be replaced by the pump characteristics, see above.

Systems type 2) and 3) leads to the same block model, with the following differences: for units type 3) the time constant T_F will be considerably shorter and C_F will no longer be a simple proportionality constant, as the dependency of the power consumed on the feedwater flow will now include the pump characteristics; i.e. how the power load of the pump will vary with the feedwater flow. Figure 6.5 shows a system of type 2) as this kind is considerably more common than the valve controlled units.

With a simplified model of the feedwater system these different feedwater systems can be included in the power plant model as shown in Figures 6.4 and 6.5 respectively.
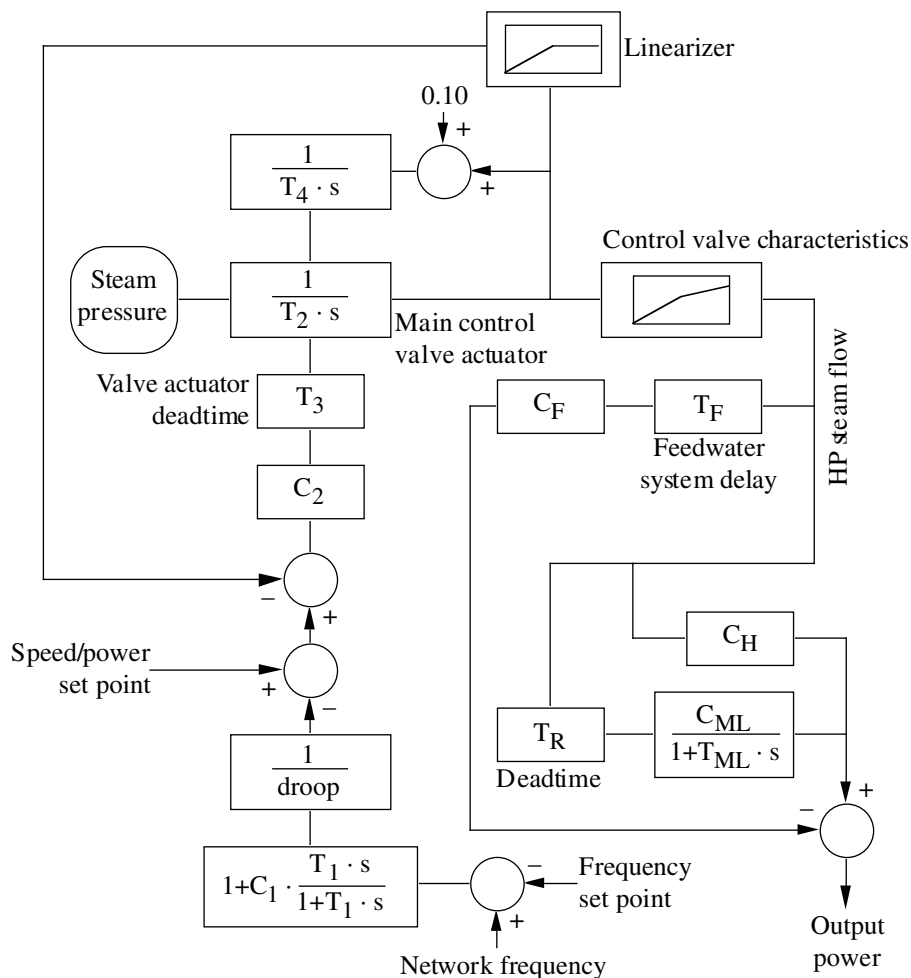

Figure 6.5   Model including feedwater system power drain. Feedwater system powered by electric motor with variable speed control system.

6.3   Simplified models

In most cases sudden load increases will not exceed 10%. The exact representation of the control valve limiter may therefore be less important. If we eliminate the linearizer and the control valve characteristics, as these are basically set to equal out, as indicated in Section 4.12, we get a certain error in the signal controlling the control valve limiter, but we get a much simpler model, and this one should be sufficient for most cases.

If we furthermore can conclude that most network load changes are gradual rather than instantaneous steps, then the deadtime of the control valve actuator in the model can be eliminated. This one is very small: the control valve actuator deadtime is in the order of 0.2 to 0.3 s. This should be compared to the natural oscillation period times for the case that the system becomes oscillatory. This time will of course vary with the moment of inertia of all machines that are synchronized onto the network at each given time: the higher the moment of inertia the longer the period of the oscillations. But even in the most extreme case, a single unit of the type like units 1 and 2 at Stenungsund, taking into account that these units with their H value of just 2.2 are extremely light machines, the oscillation period is in the order of 4 to 5 s and the actuator deadtime will then be in the order of 5% of the cycle time, which means it is not significant for the nature of the oscillations. It is of course, as mentioned in Section 4.14 highly important when one is looking at the inner control loop that is controlling the valve position, as here the cycle time is in the order of 1 s, but this is a control system design problem and not relevant when it comes to the behaviour of the unit versus the network.

One must here assume that the inner control loop in this type of a circuit, with its relationship between the actuator deadtime and the speed of the actuator, plus any integrating time delay that may have been added, is designed in such a manner that it is not self-oscillatory; i.e. any kind of order for a certain valve position must be executed without that it gives rise to an oscillatory response.

A further simplification can be done by ignoring the reheater deadtime T_R and instead compensating for this by a small increase of the medium/low pressure turbine time constant T_{ML}.

Considering that the influence of the feedwater system is limited to a few percent this system is not represented in the simplified models.

Chapter 6: Composite models of entire power plants

With these simplifications we get a model of the type shown in Figure 6.6.
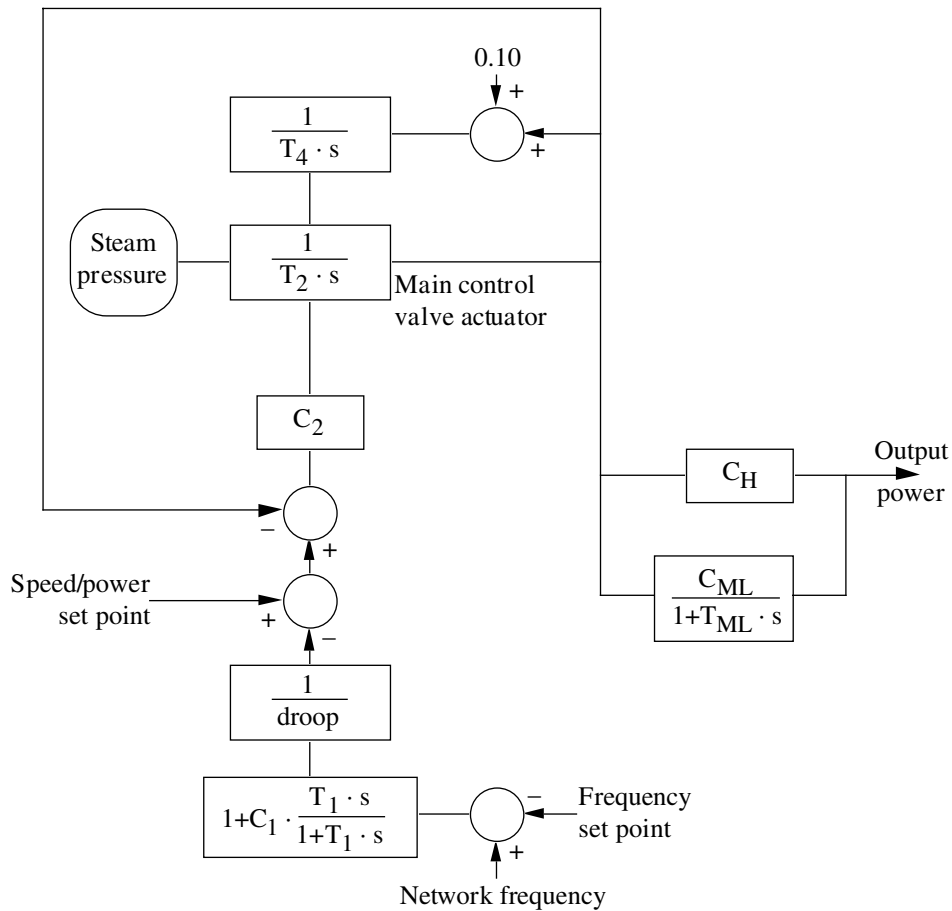
Figure 6.6   Simplified power plant model.

A further simplification can be made IF the cases to be studied are such that there is no likeliness of the control valve limiter being activated. This will basically apply to all cases where no momentary power increases beyond a certain limit, usually about 10%, are to be expected in the case that is to be studied. In such a case the limiter system can also be eliminated. In cases where it is actually limiting the control valves motion the influence of the limiter can clearly not be ignored, but bearing in mind that in most networks the step load increases that can be expected tend to be below 5% this is a simplification that can be made quite often.

For this case we get a model of the type shown in Figure 6.7.
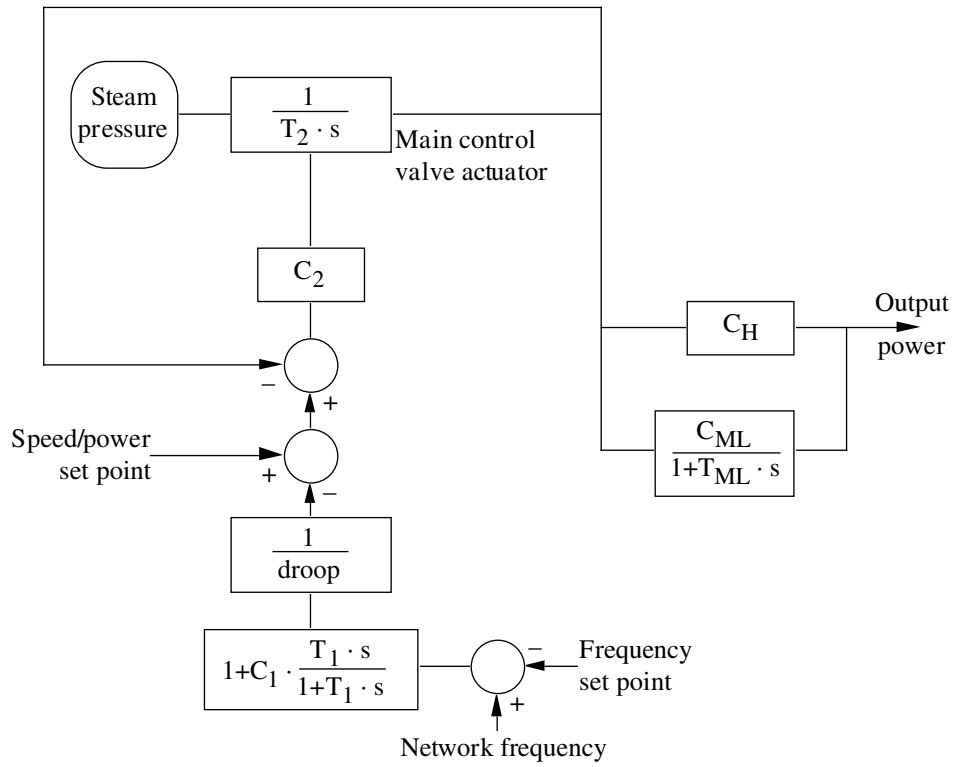
Figure 6.7   Simplified power plant model, no control valve limiter.

Chapter 6: Composite models of entire power plants

Chapter 7   Auxiliary systems of the power station

All power stations need certain auxiliary systems. In thermal power stations these systems are quite extensive and of several different kinds. The most important ones are the feedwater system, the fuel system and the firing fans. All these have a very direct influence on the boiler operation and a serious malfunction of any of these will most likely trip the boiler. Other systems may have a less direct position in the chain leading to power output from the unit but are never the less important; such as the condenser evacuation systems and the turbine lubrication system. There are also certain systems that are not at all part of the power production units but that are still necessary in order to allow for proper operation of the power station; e.g. ventilation systems to keep the temperature inside the station down to acceptable levels, environmental protection systems to make sure that the station complies with allowed operating limits for emissions etc.

In the case of a severe network disturbance or in a situation where the power station is running in island operation on a small network these different systems may respond in different ways that may in some cases be less desirable. Where there is a marked influence of a particular auxiliary system on the output power of the unit to the extent that the system has to be included in a network model of the power station then this has been dealt with in Chapters 4, 5 and 6. That aspect will therefore not be in focus in this chapter. Instead there is another aspect which will have to be considered: can the auxiliary systems keep up with e.g. large and rapid changes of the output power of the unit without that there is a risk that the entire unit trips due to the shortcoming of an auxiliary system. Almost all the auxiliary systems have the potential to trip the unit if things go radically wrong and this risk must therefore be investigated if one wants to get a correct picture of the ability of a certain unit to operate under disturbed network conditions or in island operation mode on a small network.

7.1   The feedwater system

The feedwater system is the most high powered of all the auxiliary systems and also the one that is likely to be the main restriction as for as the auxiliary systems go when it comes to the ability of the unit to withstand perturbations. The proper operation of this system is abso-

lutely vital to the operation of the unit. The feedwater system must be controlled in such a fashion that the amount of feedwater pressed into the boiler at all times matches the amount of water leaving the boiler, either as steam or as water if any drains are used (most boilers are operated with a certain small drain from the bottom of the steam dome in order to reduce the amount of impurities present in the steam and in the water). If this balance can not be kept up accurately then the water level of the boiler system and the steam dome will change. If these changes go outside of certain quite tight limits the boiler, and hence the entire unit, is tripped.

Many different designs are possible when it comes to the feedwater control. The oldest kind is to use valve control on the feedwater itself; just regulate the flow by controlling the valve, whereas the feedwater pumps run at full speed all the time. This control mode does allow for quite fast response in the case of disturbances or rapid changes of the output power of the unit, but is clearly uneconomical, as the feedwater pumps have to be run at full power at all times, whether the actually demand for feedwater would require that amount of pump power or not. This means higher losses and increased costs. As the feedwater system, as was mentioned above, is very high powered these costs may be quite substantial. It is normal for the feedwater pumps to consume in the order of three to five percent of the output power of the unit and this is high enough to make economical operation of the feedwater system an important issue.

Another mode of control is used in stations like the one at Stenungsund, where the feedwater pumps are steam powered, with their own pump turbines. In this case the feedwater flow rate can be controlled by valve controlling the steam flow rate to the pump turbines and hence the speed of the turbines and the pumps. This type of valve control show considerably lower losses but it has the drawback that there is an additional delay built into the system: if there is a change in the demand for feedwater both the control valve and the pump turbines and the pumps themselves have to respond and the response time is therefore comparatively long. Later on in this section we will look at the difficulties that this can lead to.

If the feedwater pumps are driven by electric motors rather then by steam turbines then there are basically three ways of controlling the feedwater flow: the old way with a valve directly on the feedwater, pump speed control by the means of a variable coupling and pump speed control by means of controlling the electric motors themselves,

either by the use of DC drives or by the use of frequency converters. The former is expensive, as DC motor systems are expensive both to purchase and to operate. The latter is a promising method that may well be more commonly used as the price of the necessary frequency converters is gradually going down. So far this method have not been used much, due to the high price of the converters.

The variable coupling method is in common use and allows for a reasonable economy. There are losses involved, but these are clearly lower then for valve feedwater control. The response is unfortunately not very fast, as just in the case with the steam turbine pump systems, the pump has to be regulated first and only after that will we see any control influence unto the feedwater flow rate itself. The response time will therefore be similar in order to that of the pump turbines with steam valve control. Due to its common use this type of feedwater control is the one used for most power station models, including the IEEE standard models.

The various types of feedwater systems are shown in Figure 7.1-7.5.
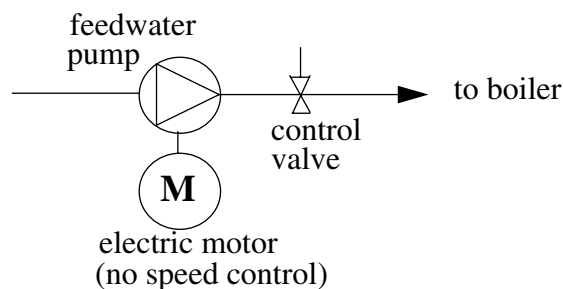
Figure 7.1   Basic valve control.
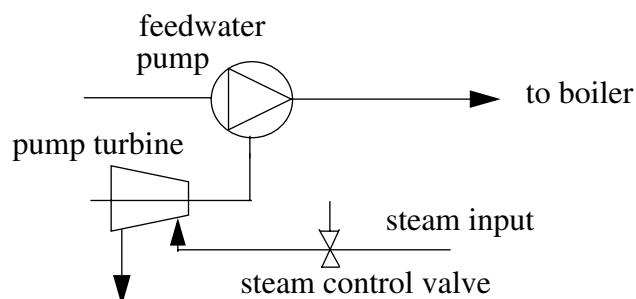
Figure 7.2   Pump turbine with turbine speed control.

feedwater
pump

to boiler

variable
coupling

M

electric motor
(no speed control)
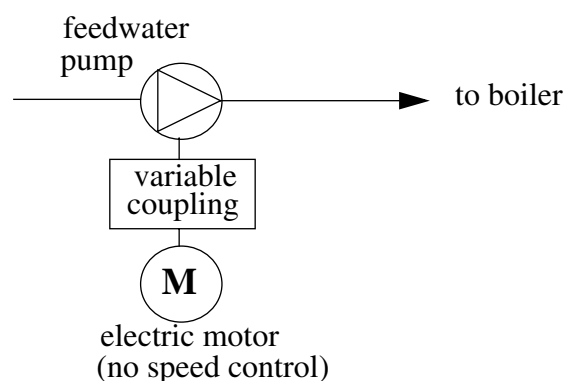
Figure 7.3   Electric drive with variable speed coupling.

feedwater
pump

to boiler

M DC motor

SCR
rectifier
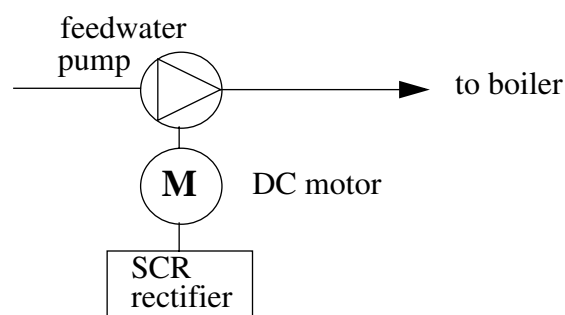
Figure 7.4   DC motor drive system.

feedwater
pump

to boiler

M AC motor

Frequency
converter
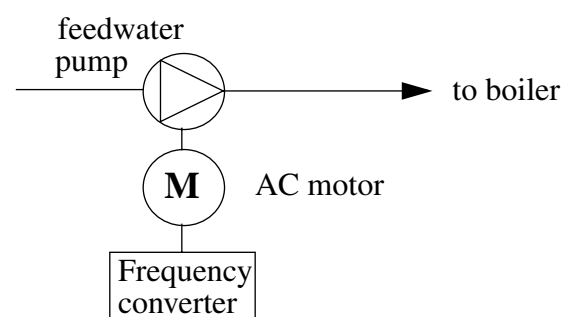
Figure 7.5   Variable frequency drive system.

The Stenungsund power station is equipped with steam turbine driven feedwater pumps and the feedwater is for low power operation controlled by a valve and for medium and high power by controlling the speed of the pump turbine, using a steam control valve. Electric feedwater

pumps are available as backups. These are used only if the pump turbine or its pump is for some reason not available and operation using the backup pump does not allow for running the units at full power. E.g. for units 3 and 4 the power has to be reduced from 260 MW to 160 MW in such a case. If the electric pumps are in use feedwater control is achieved by a control valve on the feedwater line.

As for the feedwater control system there are many different designs as well, but the basic principle of operation tends to be the same. The system shown below is for the units at Stenungsund, but similar types of systems are used almost universally. The steam flow rate of the high pressure steam line is the main control variable for this system. The second variable is the dome level, as was briefly discussed in Chapter 4. The control system outlay is shown in Figure 7.6.
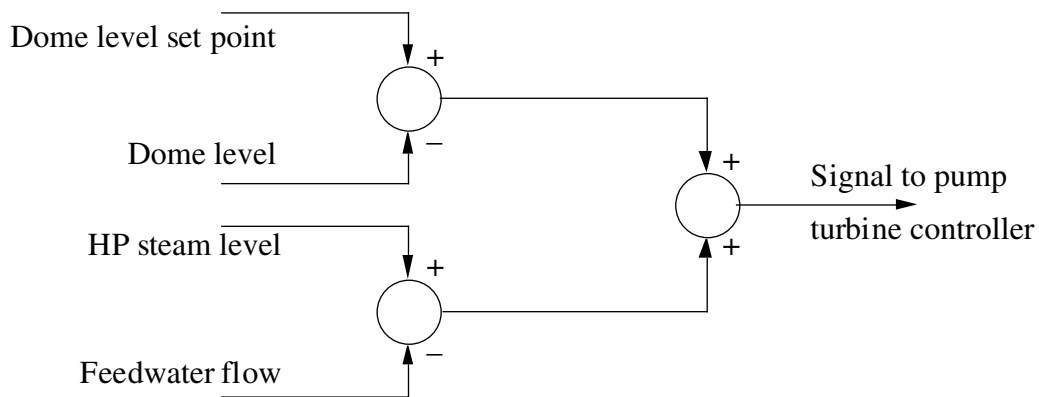
Figure 7.6   Stenungsund power station, Units 3 & 4, Feedwater control system.

When the different tests were done on the units at Stenungsund the feedwater system mostly responded reasonably well, but there was a marked delay which could cause trouble if the perturbations during a severe network disturbance got serious enough, or if the unit during island operation on a very small network should come into an oscillatory mode with large variations in the output power.

The problem involved comes from the time delay between the change of the HP steam flow rate and the actual change of the feedwater flow rate. This delay turned out to be of the same order as the period of oscillations that could sometimes occur when the unit was operating on a network all alone; i.e. with only the moment of inertia of the unit itself present on the network. In such a case the feedwater system could

come out of phase with the steam flow variations and a potentially serious situation could develop, where the unit could possibly be tripped due to excessive dome level variations. The recording in Figure 7.7 shows this problem clearly (the somewhat rugged form of the feedwater curve was due to an isolation amplifier mismatch that caused a loss of resolution on the feedwater values during this test).

Figure 7.7   Unit 3; feedwater system behaviour during system oscillations.

As can be seen the feedwater flow rate ends up in almost complete counterphase to the steam flow out of the boiler. I.e. when we need the most water we get a minimum and vice versa. Obviously this must lead to large dome level variations. As the dome level itself also enters into the control circuit as shown above there is a risk that this can amplify the oscillations still further. During the test shown in Figure 7.7 the dome level reached the upper alarm level, a condition that caused the simulation to be terminated in order not to risk tripping the unit.

The above describes an obviously troublesome situation. Whereas large oscillations normally should be avoided also in island operation such oscillations may at time occur for a shorter period of time and it is clearly undesirable that such oscillations can lead to an alarm situation in just about 30 seconds. The main objective must of course be to

adjust the main frequency control system parameters in such a way that any such oscillations are damped much more rapidly, but a higher level of tolerance against oscillations on the part of the feedwater system would also be of a clear advantage.

An obvious way of getting the feedwater system to better track the steam flow would of course be to speed up the response of the feedwater system. This is however very difficult to do. The response time is mostly a function of the physical design of the systems and whereas it may be possible to have this in mind when constructing a new power station it can not be made as a retrofit, at least not without excessive costs. The only parameters we can control will therefore normally be the settings of the feedwater controller: the balance between the influence of the steam flow versus that of the dome level and the normal controller settings such as gain and integration time. One can of course also add a reasonable portion of derivative action, but this must be done with great care, as too much derivative action is likely to make the control system unstable. Another option is, unless the unit normally uses valve control, to temporarily switch to such a mode when the unit undertakes tasks like island operation on a small network.

Virtually all units do have a control valve, also if the prime mode of control is something else than valve control. The reason for this is that a feedwater pump system can not operate at very low speeds. The pressure generated drops by the square of the pump speed and would for a very slow-running pump be too low to overcome the boiler pressure, in addition to that speed controlled pumps often show tendencies of instability if the speed gets too low. Normally a pump of this type is not operated below approximately half of its rated speed, and for low power operation there is always a control valve fitted. Provided that one has verified that the pump system and the valve can stand this it could be possible to switch to valve control mode manually when the unit is operated in extreme operation modes where the feedwater control may need to respond faster than what it does normally. Such a change of control mode will of course be at the expense of efficiency, but that is hardly a prime consideration during emergency operation where the main matter is to make sure that the unit survives on the network.

7.2   Fuel system

The fuel system response characteristics are usually of importance only for units running in sliding pressure operation or for units where the steam storage capacity is comparatively low so that a fast response on the part of the fuel control system and the boiler is required in order to take on a load increase without a drop in the boiler steam pressure. In certain situations there can however be a risk of resonance phenomena due to the inherent control loop delays and in such cases a further investigation may be necessary.

In the case of sliding pressure operation the response time is usually, even with the fastest of fuel control systems, too slow to allow the unit to perform frequency control duties on a very small network. Typical time constants are in the order of several hundred seconds, which in turn requires either a fairly large network or that there are other, faster, units on the network that can take care of the necessary fast initial response in the case of a large change of the network load.

For units operating in sliding pressure mode the fuel control is integrated into the output power control system; i.e. the frequency control system if the unit is performing frequency control. For other units there are usually three basic control modes that can be used for fuel control: dome pressure regulation, power output tracking and manual control (fixed firing). Dome pressure regulation is a quite safe and basic form. In this case there is hardly any risk of resonance problems and the control system should, if correctly designed, be stable under all operating conditions. The drawback is a somewhat slower response: the system will not respond to a load change until there has been an actual change of the dome pressure, and as a result there would be constant up/down variations of the dome pressure, which causes increased wear and risk for metal fatigue. Instead most systems are designed to also track the output power, so that the firing is adjusted immediately when the output power is changed. This means a faster response, but also a certain risk for instability or resonance.The control system will basically be designed as in Figure 7.8.
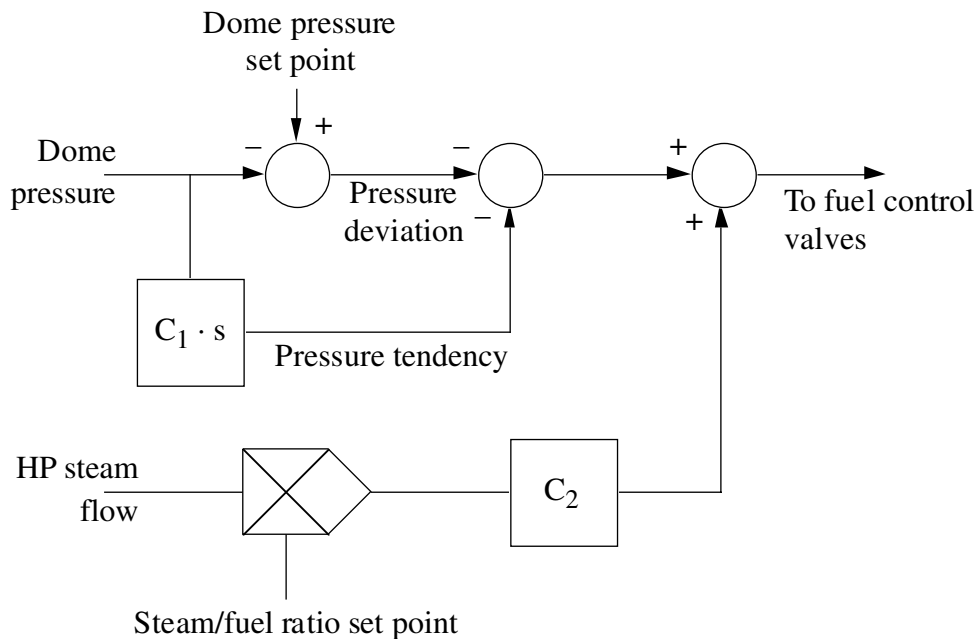
Figure 7.8   Basic fuel control system based on steam flow and dome pressure.

The tests run at the Stenungsund power station showed that the fuel control system tracked the steam flow, and hence the power output, quite well, though with a delay in the order of 6 seconds. A typical response is shown in Figure 7.9. As can be seen there are considerable oscillations at one point and such oscillations could be observed at several times, always following a reduction of the fuel rate. It seems to indicate some kind of instability in the fuel control system that could warrant further investigation.

An oscillation in the fuel supply rate is undesirable from several points of view. One is that it produces unnecessary thermal/mechanical strain on the boiler as the temperature varies. Another one is that it may lead to improper combustion and increased emissions. One should note that due to the time delay of the firing fan system the air supply to the combustion does not vary when the fuel supply oscillates in this manner. That must inevitably lead to that some of this combustion is done at a non-optimum fuel/air mix ratio and hence to a degradation of the combustion.

It should be noted that the developed test method with step-wise load changes is very suitable for detecting these kind of problems. No special test was made to check the fuel system, instead the above could be

observed when analysing the results from a general test run of the unit connected to the simulator system. As all main control systems get verified at the same time valuable time is saved when it comes to the need for using the actual unit for testing.

Figure 7.9   Fuel system response.

7.3   Combustion airflow control

The combustion airflow control is directly linked to the fuel control system. In most cases it is based on a ratio air to fuel, but certain other input signals may be added as well. In the case of the Stenungsund power station, units 3 and 4, there is a special connection to the steam flow rate, which will add extra air in case of a steam flow increase. The reason for this is to avoid incomplete combustion due to a shortage of air if there is an increase in the steam flow: the increased steam flow will soon be followed by an increase in the fuel flow rate and if the airflow is not increased accordingly we get a combustion with a shortage of air and hence a black puff of smoke may be discharged to the environment. By letting the steam flow influence the airflow one can ascertain that the increase of the airflow comes a little ahead of the increased

fuel rate and this way the problem can be avoided. The circuit is connected as in Figure 7.10.
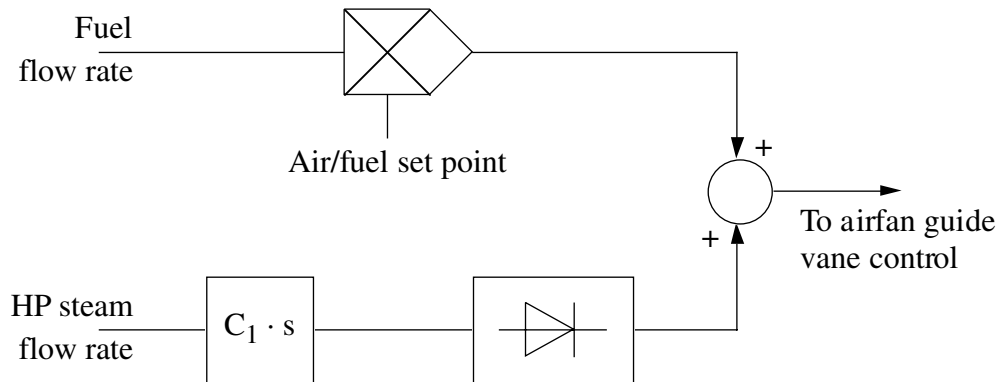
Figure 7.10   Combustion airflow control system.

This system has an inherent unsymmetry built into it: as for changes of the HP steam flow rate it will respond to increases in the steam flow but not when the flow decreases. This will for a highly oscillating steam flow lead to a buildup of ever more and more air, as if the oscillations are fast the system will not have the time to return back to a point where the airflow is based on the fuel flow rate and the ratio air to flow before the next "increase" pulse will come.

The above situation was shown very clearly when running against the power station simulator, where it in certain highly oscillatory situations lead to an extreme buildup of airflow, which in turn resulted in high boiler temperatures and eventually to the tripping of the unit. A typical case is shown in Figure 7.11.

When testing on real units this effect could not be observed anywhere to this extent, but smaller changes in a similar manor could be observed and an analysis of the control circuitry of the units show that such a "pump up" effect is fully possible. However, in real operation such a wildly oscillating operation as the one that gave rise to the severe problems when running against the simulator could never be tolerated and the problem is therefore less severe. One should however be observant on the fact that the introduction of control circuits with a one-sided derivative response can be highly dangerous in situations where the prime control quantity oscillates, and oscillations are common in situations where the network situation is critical with regard to the fre-

quency control capability of the units responsible for maintaining the network frequency.
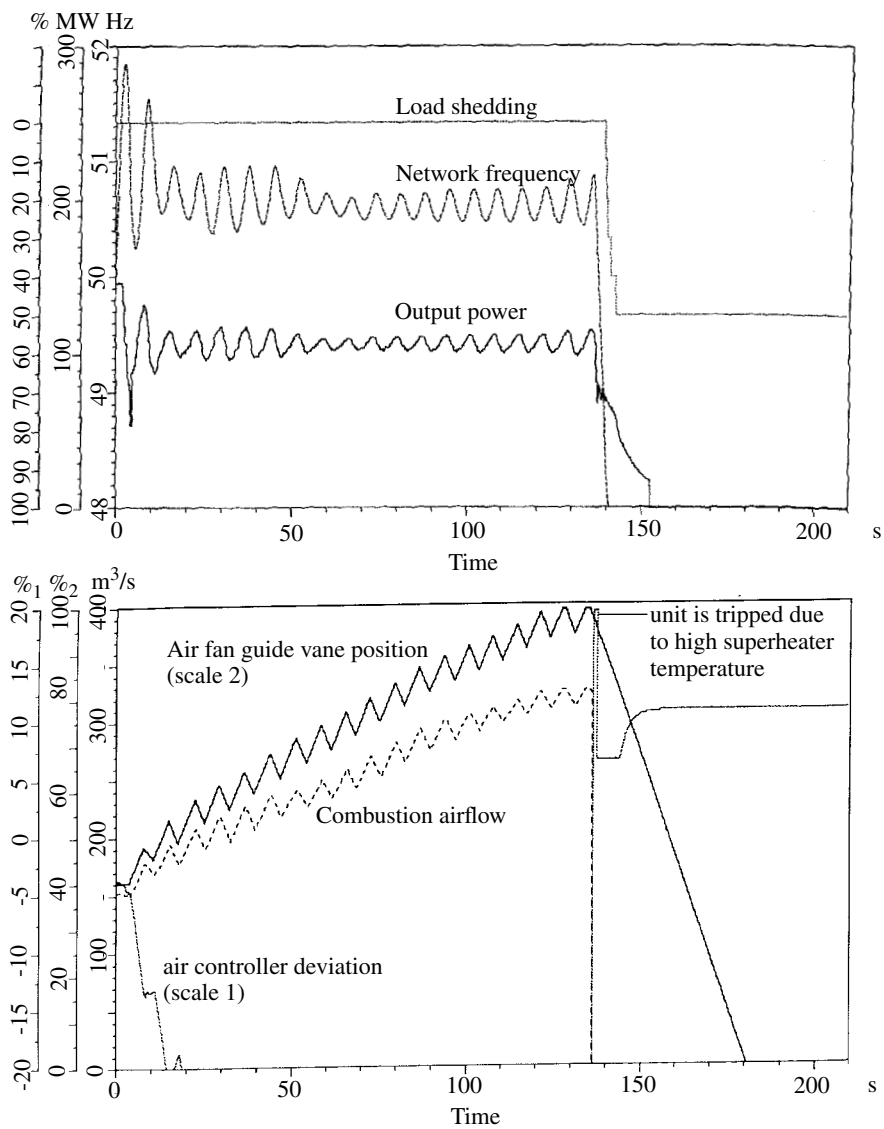
Figure 7.11   Simulator run with large oscillations and automatic fan control increasing the combustion airflow out of control.

Chapter 8   Island operation. Problems, prerequesites and operating recommendations

Island operation is normally used to refer to a situation where a normally interconnected larger network has been subdivided into smaller networks that operate as autonomous islands, with no connection in between these islands. Networks that are designed to be operated separately, like on a group of real physical islands are not included in this terminology, although some of the problems would be identical. However, this latter situation is normally easier to manage, as all control systems would then be specifically designed for this kind of a system.

A power station running on a larger interconnected network can end up in island operation in basically two ways. One is intentionally if the network has crashed for some reason and there are such problems (e.g. serious damage to main network components) that the main network can not be brought up again within a reasonable amount of time. In such a situation one may decide that one has to start up island systems wherever possible in order to be able to resume deliveries to as many customers as possible. The other possible way is that in interconnected network inadvertently breaks up into smaller islands as a result of serious faults on the network; like the tripping of main transmission lines or interties, loss of synchronism between different parts of the network etc.

There are several different problems that can cause serious difficulties when a power network is forced into island operation. The most serious ones are linked to maintaining correct network frequency and in regulating the network voltage. Especially the frequency can be cumbersome, as the total moment of inertia in the system is quite small and any imbalance between the power produced and the power consumed by the loads will therefore quickly lead to a shift in network frequency. In addition the power stations available for frequency control purposes may not be very well suited for frequency control; either because of their design or because control system settings are only optimized for operation on the interconnected network. In many cases these stations never perform any frequency control duties at all in normal operation and hence the frequency control systems are not properly tested and the stations operators are also neither trained for it or experienced in this mode of operation.

Chapter 8: Island operation. Problems, prerequesites and operating

As shown in Chapter 3 the total moment of inertia is of great importance when it comes to the behaviour of a power plant when it is in island operation. The higher the moment of inertia, the better the stability and the smaller the oscillations and frequency deviations that occur when there are transients. This effect is an obvious result of the swing equation that governs the dynamic behaviour of the network:

$$\frac{d}{dt}\left(\frac{1}{2} \cdot J \cdot \omega^2\right) = \Delta P \qquad (8.1)$$

where: J is the total moment of inertia present in the system

ω is the angular velocity of the system

ΔP is the difference at the given time between the total power produced within the network and the power consumed (including system losses)

As the frequency of the network is directly proportional to ω:

$$\omega = 2 \cdot \pi \cdot f \qquad (8.2)$$

where: f is the network frequency; we see that the rate at which the frequency will change for a given change in the load P is directly proportional to the total moment of inertia J.

8.1   Moment of inertia considerations

As shown in Chapter 3 the difference of e.g. running a single unit and that of running four units (all units at the Stenungsund station) is sufficient to make the difference between smooth operation and a more oscillatory behaviour.

The moment of inertia of a certain power station unit is a design parameter and can of course not be altered afterwards by any reasonable measures. However, one can influence the moment of inertia present on the network by the strategy used in dispatching of the units. Taking again the Stenungsund power station as an example; if the station is to supply a total of 200 MW to a small local island network this can be done using a single unit, if one of the two larger units is used (260 MW capacity each). However, the same power can also be delivered by both these units operating in parallel at 100 MW each. In the

latter case the moment of inertia is twice as high and this will then give a significant improvement to the stability of the network. It will mean somewhat higher costs, as the efficiency of a power station unit is usually somewhat less at operation down as low as below 50% of its rated capacity, plus that it is likely that more operators will be needed in order to run the two units, but cost efficiency is hardly a main concern in an emergency situation where the survival of the network is the number one consideration.

It is a major advantage of the test and simulation method developed within this project that the behaviour of a power station unit in operation on networks with different levels of moment of inertia can very easily be tested. The J value can even be changed by a simple command in the middle of a simulation and it is thus easy to verify how much moment of inertia that is required in order to obtain a stable operation with regard to the network frequency control.

8.2   The importance of the droop value

An other parameter of main concern is the droop. The droop is in the power industry perhaps mainly thought of as a control deviation that is necessary in order to distribute the load changes in correct proportions unto different units that operate in parallel on the same network. This is because the load changes are distributed in inverse proportion to the droop of the units. Thus, if a unit has a low droop value it will be taking on a large proportion of load changes on the network. On the other hand, a unit with a high droop value will be less active when it comes to participating in the network frequency control, in that its response to changes of frequency will be much smaller. With very low droop values successful parallel operation becomes impossible, as the slightest change in frequency will produce large changes in output power and even differences in frequency set points will have severe influences. A simple figure can illustrate this far the case of only two units operating onto the same island network.

Figure 8.1 shows how two units in parallel respond to a load increase in the network. As can be seen unit 2 has a lower droop (lower inclination of the frequency/power curve) and will take on a larger part of the power increase than will unit 1.

Figure 8.2 shows the result of insufficient droop. Here stable operation is not possible as even the smallest change in frequency will change the output power dramatically and chance and slight discrepancies in settings will determine the power distribution between the two units. Normal values of the droop are in the range of 2 to 8%, with the droop of a unit in principle defined as:

$$\text{droop} = \frac{\Delta f}{P_n} \tag{8.3}$$

where: Δf is the difference in frequency that will cause the unit to reduce its output from full power to zero (completely closed control valve)

P_n is the rated power of the unit
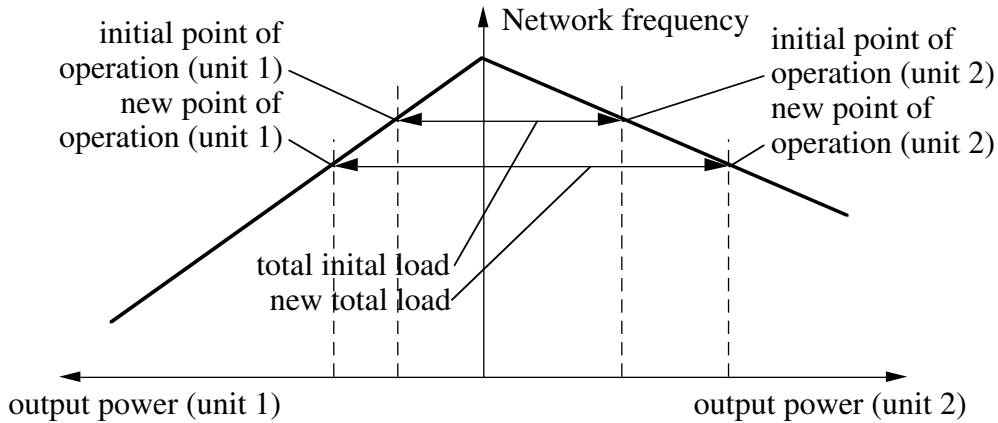
Figure 8.1   Load distribution onto units depending on the droop value.
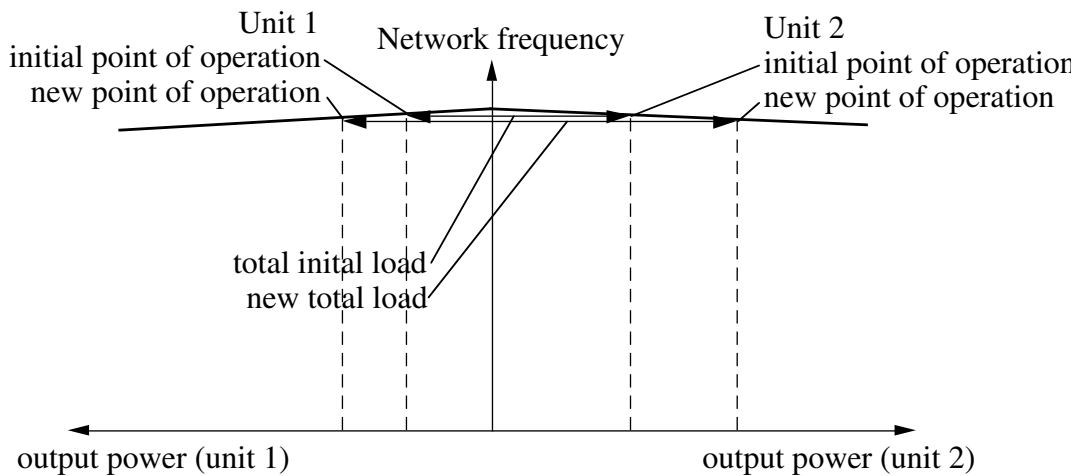
Figure 8.2   Load distribution onto units depending on the droop value.

The droop value does however for very small networks also have another impact than on the load distribution, namely on the control stability of the unit and on its tendency to oscillate before settling to a new load level when the network is subjected to a sudden load change. Comparisons between the tests at the Stenungsund power station on unit 4 with 8% droop and unit 3 with 4% droop, as shown in Chapter 3, show clearly that the operation becomes much more stable and the response much less oscillatory when a higher droop setting is used. This is natural, as the droop actually enters into the control loop as an amplification factor and higher amplification factors will normally lead to more accurate but less stable control, with an oscillatory response, or in the extreme case with amplification factors way beyond the allowable, to a self-oscillating behaviour. A very simple control loop for the unit and the network can be thought of as in Figure 8.3.
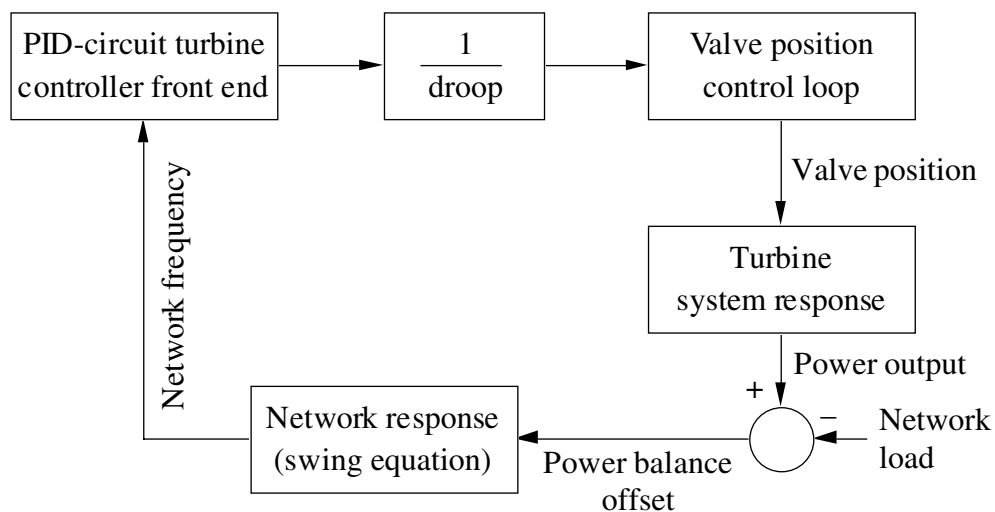
Figure 8.3   Frequency regulation control loop.

The above shows that in the case of island operation higher droop values may be desired, as compared to normal network operation. This will prevent oscillations and will provide for a smoother regulation. This will of course be at the expense of frequency correctness, but this should hardly be a main concern in an emergency operating situation, where absolute frequency correctness is hard to achieve anyhow and where problems with e.g. synchronous clocks must be considered of secondary importance only. Most industrial and domestic loads can handle frequency variations of up to ±5% without any major change in their mode of operation and this gives very free limits compared to the

extreme accurateness that is normally kept when it comes to maintaining the network frequency.

However, there are other factors that also set an upper limit for the droop value. One such factor, which was mentioned in Chapter 4, is that with a high droop value we get a lower value of the load reduction that the unit can handle without that the intercept valves are activated. This must clearly be avoided and either the droop value has to be kept low enough to prevent operation of the intercept valves, or the station operators must closely monitor the load changes and adjust the speed/power settings accordingly, so that the point of operation used by the automatic frequency control system is close enough to the nominal frequency to prevent this. Note that the latter possibility exists only if either one power station is alone on the network or if there is a well planned and properly functioning central load dispatch centre that can undertake to coordinate different units on the network in this respect (secondary frequency control schemes).

8.3   Load distribution based on the speed of response

If we go by the droop value of the units that are on line in a small island network it should be easy to predict how a change of the load level would be distributed between the different units. However, one must bear in mind that the droop value as a measure for the distribution of the load is only valid once that all units have reached a new equilibrium state. Before that happens it will be the speed of response of the different units and not the droop that will be the key factor in determining how the load is distributed. If different types of production units are on line on the network then there may well be very substantial differences in the speed of response and this can definitely not be ignored when the behaviour of the network is discussed. As an example, a unit with a high droop value but a very fast response will initially take on much more than its share when a load increase hits the system. Eventually, when the other slower units catch up, it will then return down to the load level that is determined by the droop value of the units.

This fact may mean that a unit with a fast response will get more load than what it can handle, at least for a short period of time. In this kind of a situation the control valve limiter is highly important. It serves to prevent the unit from taking on more load than allowable, but one should note that this is of course done at the expense of frequency cor-

rectness: it will clearly take longer for the system to get out of the frequency dip that a sudden load increase creates as compared to if there was no limiter and the fast unit would be allowed to take on a higher load right away.

8.4   Mixed sources of production

If the production resources available on a small island network are of different types; e.g. thermal and hydro power or thermal units with valve control plus units with sliding pressure operation then it is clearly highly important to take this into account when planning for such an island operation mode. The very different speeds of response will, as indicated above, be of great importance when it comes to the instantaneous load distribution and this can prove both a problem and a condition that can be used to advantage.

It is generally believed in the power industry that if hydro power is available for frequency control purposes then that should be given that task whereas thermal units should only be used for frequency control when there is no other alternative. This may perhaps not always be true. It is undoubtedly so that hydro electric power stations are very reliable for control purposes and that they are also very rugged, in that it is possible to change the output power up or down without concern for temperature gradients, risk for a reduction of component lifespan etc., and in a normal network with a reasonably large moment of inertia the frequency can be kept very accurately at the desired value using the hydro units governor systems. However, hydro units have one drawback that is normally not thought of: they are fairly slow compared to the control characteristics of the steam turbine systems. In a very small network, where there is only very limited moment of inertia available and where the frequency changes very rapidly in case of a sudden load change this may be highly important.

As the tests made within this project show thermal power units can be extremely fast. The the control valve moves in fractions of a second and the high pressure system responds almost instantaneously. For hydro units the response is much slower. It takes several seconds for the guide vane control system to move the vanes, water has to be accelerated etc. In some cases extremely slow governor systems have to be used because of the hydraulic conditions; this is the case where sudden increases in the flow of water could lead to severe erosion of riverbanks

and similar. In such cases the restrictions of the allowed rate of increase of the water flow and hence of the power output may be very stringent.

With a suitable mix of units and suitable control settings it should be fully possible to use this to achieve a more optimized frequency control of an island network. Suppose for instance that we have a thermal unit plus a hydro unit as the two sole supplier to the network. If we set the response of the thermal unit as fast as possible (no additional intentional delays, apart from what is required in order to make internal control loops stable etc.) and give that unit a large droop setting and give the hydro unit a much lower droop setting we will get the following response to a load increase: the thermal unit will respond almost instantaneously. Provided that the unit has a reasonable steam storage, either through a dome or in the steam generators, then there is no need to wait for an increase in the firing. After a number of seconds the hydro unit will respond. As it has a lower droop value it will take on the bulk of the load increase and relieve the thermal unit of any substantial change in the firing and thus of additional strain and wear on the boiler systems. We then get the very fast response of the steam turbine system and at the same time the rugged reliability of the hydro system.

A typical example is shown in the two simulations shown in Figures 8.4 and 8.5. These are simulations that were done using the models discussed in Chapter 6. Two sources of production were considered. One is a 300 MW unit of a type similar to the large units at Stenungsund, nominal power of 300 MW, time constants similar to those of the Stenungsund units (4.5 s reheater/steam line delay) and using the simplified model of Figure 6.6. The other unit is assumed to be a slow hydro unit, with a governor motion time constant of 25 s, using the same model but with the medium/low pressure part taken out, as we now have only one turbine, namely the water turbine.

In the first simulation the thermal unit was given a droop of 8% and the hydro unit 2%. Normally this would mean that a greater portion of the load would be taken care of by the hydro unit, but because of the difference in the speed of response the thermal unit helps out more than its share initially. The test is for a step load increase from 200 MW to 220 MW on the network, with just these two units being on the network and with an assumed total moment of inertia of $0.045 \cdot 10^6$ kgm^2, which should be a fairly normal value for this type of a combination.

The frequency is rapidly restored and the network does not receive any major disturbance. We see here that the thermal unit takes on a larger portion of the load for a period of about 5 s, until the slower hydro unit catches up and allows for the thermal unit to reduce its output. It should be noted that this kind of a power boost can be done without any additional thermal stress onto the thermal unit, as with proper control settings there is no need to increase the firing for this extra boost, as the steam stored in the dome or the steam generators will for most designs of thermal units be sufficient.
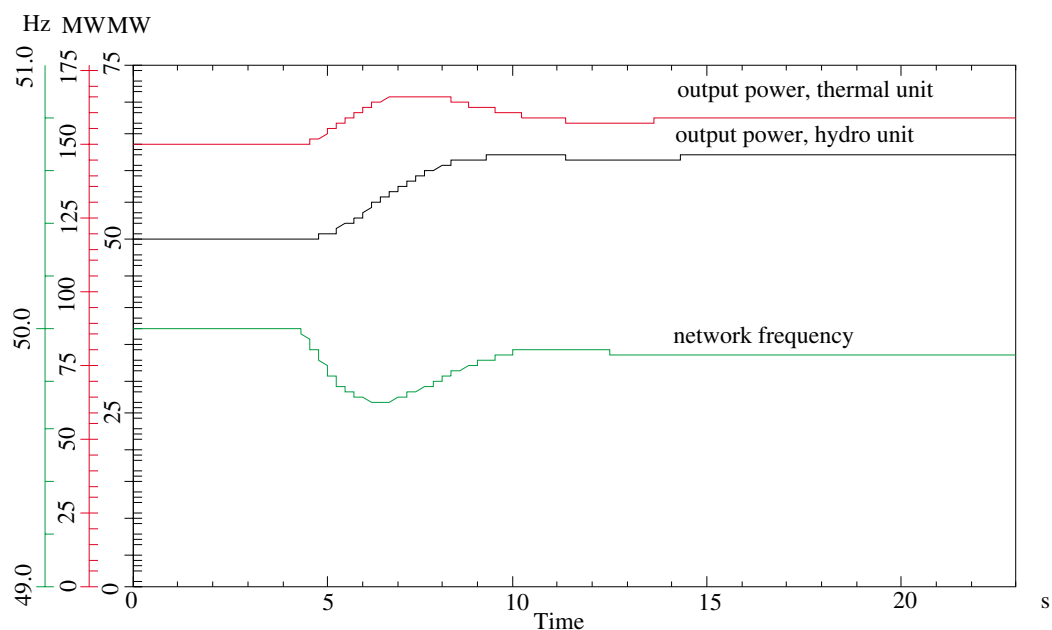
Figure 8.4   Thermal and a hydro unit sharing the responsability for the frequency control.

If instead we run the same simulation, with the same controller settings, but with what would be a more conventional dispatch strategy: the thermal unit running a fixed base load and the hydro unit alone being responsible for the frequency control, we get a totally different response. The frequency dip on the network gets far more severe and in addition we have large oscillations that are only slowly damped. The controller settings were in this case not optimized for the hydro unit and with another set of control system settings these oscillations could maybe be prevented or reduced, but the large initial frequency dip

could not. It is a direct consequence of the slow response of the unit responsible for maintaining the frequency. (note that the time scale is different from that of Figure 8.4).

The above example shows clearly that when it comes to island operation on a limited network each case has to be studied carefully and without prejudices with regard to one kind of power stations being generally more suited for frequency control purposes compared to another.
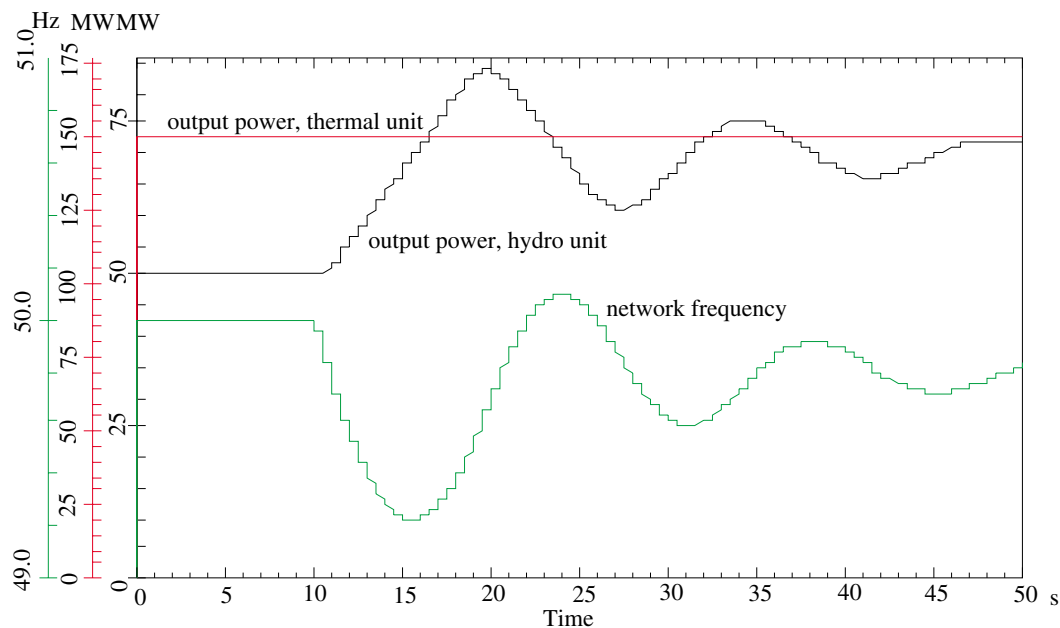
Figure 8.5   As in Figure 8.4 but with the thermal unit running with constant power.

If island operation in accordance with the principles mentioned above of a certain area is being planned as part of e.g. making up emergency power distribution plans then the test method developed in this project is an excellent tool to test and verify the operation. The simulator system can then be connected to the thermal unit and the hydro units can be included in the network description that is fed to the simulator system prior to a test. As the hydro units due to their simplicity can fairly easily be modelled quite accurately this is a quite easy way of testing the cooperation between the different units and making certain e.g. that there are no stability problems in the system e.g. as a result of the cooperation of control systems with completely different characteristics.

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8.5   Operating recommendations

Obviously the operating recommendations will be quite different for operation on an island network, as compared to operating on a large, normal one.

One clear difference is that the trade-off between control reliability and the economy of operation will be very different in an emergency situation where supplying power to the network is the main and almost the only concern. A typical consequence of this is to maintain a higher dome pressure compared to the point of operation than what would normally be used. Keeping a higher steam pressure means a larger margin in case of perturbations or sudden load increases, but also means higher losses and a somewhat lower overall efficiency.

Another such consequence is that one must operate the units, at least those responsible for the frequency control, with a lower output power. This serves to achieve stable operation and to ascertain that there is enough additional power available in the case of a sudden load increase or if a unit of production is tripped. As pointed out earlier it can e.g. be better to run two 250 MW units at 100 MW each rather then running 200 MW on one unit.

If control stability of the fuel control is a problem it may be more advantageous to change to manual fuel control in a situation of this type.

Certain protection systems may also need to be changed. A typical example is the fuel/output power differential protection system that some units are fitted with. Such systems are designed to operate in case of e.g. excessive amounts of water in the fuel or similar, but they are not vital to the safety of the unit and there is always an inherent risk that they can trip the unit if there are large perturbations. This happened several times when running tests against the Stenungsund power station simulator. It may therefore be recommendable to set systems like these to signal only (no tripping) for emergency operation on small island networks, where large perturbations are more likely then when the unit is in normal operation.

It may be tempting to put many of these suggestions into the programming for a computer controlled control system. A special set of settings for emergency operation can then be set up and the switching to such emergency operation can then be done at the touch of a button or even

automatically upon certain network behaviour conditions. This may be quite recommendable but it should be done with due caution, so that it does not put severe restraints on what the station operators can do manually. Emergencies are always unpredictable and the way a certain emergency will develop can not always be accurately predicted. Station operators with a long experience often know every part of the behaviour of their station very well and can often find ways to improvise their way through situations that were not thought of when the automatic control system was programmed. A possibility for the operators to do certain things manually in the case of emergency may often be the difference between being able to handle an extreme and unforeseen situation and getting tripped off the network.

Chapter 9 Recommended test procedures for testing power plants

The test system and method that has been developed within this project allow for the testing of power station units, e.g. with regard to their behaviour in island operation, while they are still synchronized onto the normal network. In order to use these possibilities to their full capacity any tests that are run should be carefully planned so that maximum information can be extracted from the results. This is of course especially true for units that are only rarely in operation and where the availability of the unit for testing may be a major limitation.

9.1 Connecting a unit for testing

Before a unit can be tested using this method one must of course make sure that proper connections to the unit can be made. There are only two connections that are absolutely required if a test of this kind should be possible: an output signal from the unit which is a measure of the total electric power (active power) that is being delivered to the network and an input signal to the unit that takes the place of the normal network frequency input that is supplied to the frequency control system.

The output power measurement is normally the easiest one to connect. In most cases there is some signal transducer that outputs a signal proportional to the output power, often on a 0–20, 0–50 or 4–20 mA current loop base. Such a signal can easily be transferred, normally via an isolation amplifier in order to maintain galvanic separation, to the measurement system of the simulator. For some older units the output power may not be directly available, as the meter that shows the output power is directly connected to the PTs and the CTs of the unit. In such a case a separate transducer may have to be mounted for the tests.

The input to the frequency control system may have to be done in different ways depending on how the frequency control system of the unit is constructed. The most common is for older units that the signal used comes from a tachometer generator connected directly to the turbine shaft. This signal is then normally converted to a DC signal in some way. On older units this is done using discriminator circuitry, on newer

ones through various electronic circuits. This signal chain can then be interrupted in different ways in order to allow for an external signal to be input. In some cases this can be done very easily as some turbine controllers are fitted with a separate test input.

More modern units may often have speed transducers rather then tacho generators as their speed input source. These are often built for outputting a low level DC signal that can be easily intercepted. Some of the most modern constructions use digital transducers, in which case the transfer of information must be done by computer communication means.
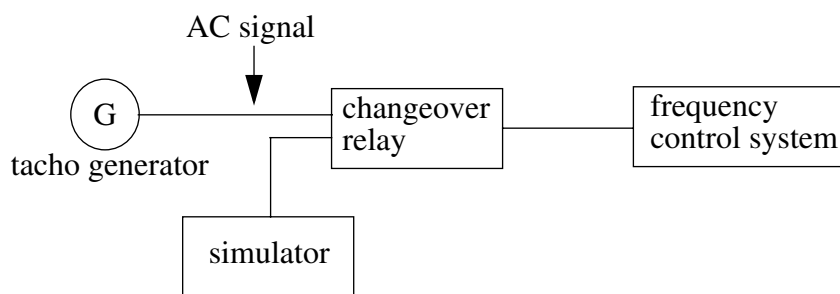
Figure 9.1   AC connection.
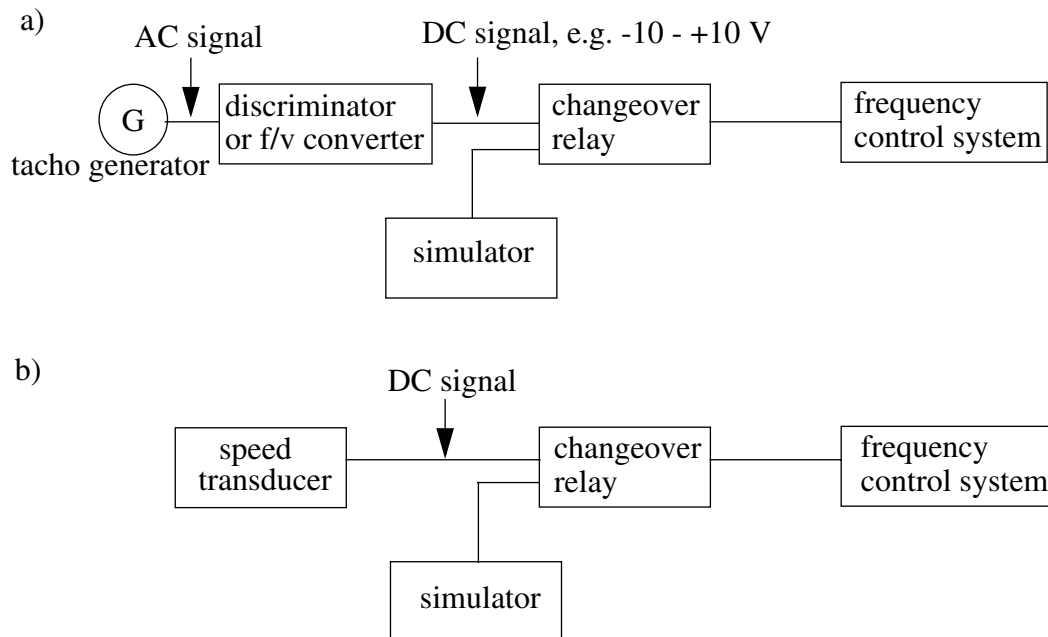
Figure 9.2   DC connections.

digital signal

```
┌──────────────┐    │    ┌──────────────┐    ┌──────────────────┐
│    speed     │    ▼    │   control    │    │    frequency     │
│  transducer  │─────────│   computer   │────│  control system  │
└──────────────┘    ┌────└──────────────┘    └──────────────────┘
              └─────┤
           ┌──────────────┐
           │   simulator  │
           └──────────────┘
```
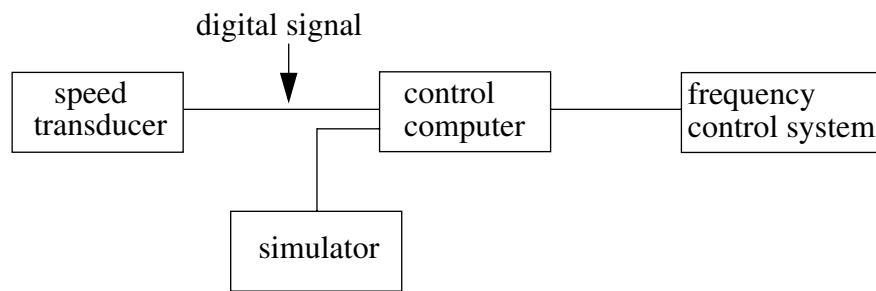
Figure 9.3   Digital connection.

Where connection to a low level DC input or a digital input can be made this is always preferable, as using AC input usually means a higher risk of noise entering the circuits and it may also lead to an incorrect action by circuits sensitive to the rate of change of the network frequency. When the simulator system has completed one cycle it will update the frequency. If one uses an AC connection this will take place momentarily, whereas for a DC signal a smoothing RC filter can easily be applied so that the sudden change is turned into a gradual one. The time constant of such an RC filter should then be of the same order as the time between simulator updates (cycle time).

A connection to a power station unit can either be done as an auxiliary control signal input, if the turbine control system is equipped with one, or via a changeover relay that switches between normal operation and signal input from the simulator. If the latter approach is used the relay chosen should be of a reliable type for security reasons and all wiring to/from it be made in such ways that there is no risk that the signals are accidentally disconnected from the control system. A return to normal operation must always be possible in a reliable manner; i.e. when the control voltage from the simulator interface unit is removed the system MUST reconnect the turbine control input to its normal source. A malfunction in this respect could leave the unit void of turbine control.

9.2   Security considerations

Before any tests can be made the security situation must be analysed. There are basically three aspects of security with regard to tests of this nature: 1) avoiding any negative consequences to the network; 2) avoiding the risk of tripping the unit; 3) avoiding any situation that

could possibly result in damage to the unit. These will be discussed separately below.

As for the risk of negative consequences to the network these risks are small as long as only the frequency control system of the unit under test is put under the influence of the simulator system and not the voltage control system. In virtually all cases the main network that the unit is phased in to is of sufficient strength so that variations in output power of a few tens of MWs can not in any way seriously influence the real network frequency. The moment of inertia of a combined national power system is large enough to prevent this and in addition the frequency control systems of the power stations that are responsible for maintaining the network frequency will quickly counteract any changes. If however the station is working on a smaller network where the influence on the network frequency can not be said to be negligible, then a separate analysis has to made, where the total moment on inertia of the network is compared to the power step changes that will be made and thus the frequency deviations that this can cause can be calculated. If these changes are slow enough so that the regulating power stations on the network can counteract them effectively then there is no problem.

As for the risk of tripping the unit this risk is more of a problem, though it can be fairly effectively counteracted by proper test procedures. The simulator system has built in safeguards that will interrupt the simulation if certain key parameters, such as network frequency, dome level, superheater temperatures etc. go outside of set limits the simulation will immediately be interrupted. By setting these limits tight enough one can make sure that the risk of tripping the unit is minimal. Nevertheless one can never ascertain that a unit trip is totally impossible, and all testing of this nature should therefore be done under such network conditions that a unit trip does not cause havoc on the network. In other words, there should always be enough power reserve available on the network to make up for the power lost in the case of a unit trip, without the need for any load shedding or similar.

When it comes to the risk of somehow damaging the unit this is of course far more serious than what a unit trip would be and one must be assured that any such risks are minimized to an extent that they are almost non-existent.

Provided that the unit is fitted with normal correct protection systems there should exist no risk that matters like oscillations leading to e.g. extreme dome levels or extreme combustion zone air pressures or simi-

lar could cause any damage to the unit. Just like in normal operation all potentially hazardous operating conditions will lead to either automatic countermeasures or if that fails a unit trip. The only extra security problem that can be added by the test procedure is therefore one that is a result of the fact that the frequency control system does not take its input signal from its normal source but from the simulator system, via the power station interface unit. This means that if there is a change of the network frequency then this will pass unnoticed by the unit. If the unit normally operates with a dead-band on the frequency control system, then this system will in normal operation still become active if the frequency would suddenly fall outside of the dead-band limits. If it is connected to the simulator this will not automatically happen. The danger here lies in the case of a load-loss condition: if the power station loses its connection to the power network, e.g. through a line fault that just happen to come during a test with the simulator, then the turbine would spin up to overspeed if no preventive measures were taken. Turbine overspeed can mean a serious risk of causing damage to the turbine and to the generator.

In order to eliminate this danger the simulator system has to have protective circuitry that will automatically terminate the simulation in the case of a load-loss condition or similar. In practice, any serious deviation from the normal network frequency is an indication on which any simulation in progress should immediately be terminated. A network frequency deviation of more than say 0.5 Hz indicates either a load-loss condition (disconnection from the main network) or a major disturbance on the network. In either case the simulation should be terminated immediately and the control passed back to the normal frequency/turbine control system.

Due to the extreme importance of this protection it should consist of two independent circuits that both monitor the network frequency, or the turbine speed which really is the same quantity as long as the unit is synchronized onto the network, and that each of them can instantly terminate the simulation if operation out of bounds is indicated.

Another security matter to be considered is of course what could happen if there is a problem, such as a computer getting stuck or malfunctioning, within the simulator system while a simulation is in progress. First of all, this is not a very serious condition, as the units normal protection systems are still active and would trip the unit if conditions got unsafe. Also, the simulator operator has continuous display of how the

simulation is progressing, and can interrupt the simulation immediately if something unexpected would happen.

Nevertheless the simulator system has been fitted with internal self-test systems to make sure that e.g. a stuck computer is rapidly detected and the simulation then terminated. The UNIX server computer and the PC responsible for controlling the power station interface unit both check each other. If either of them would detect that there is a system malfunction, then the simulation would be terminated. Also, there is an independent system in hardware that will check either computer every three seconds and that will also terminate the simulation if a fault condition is detected.
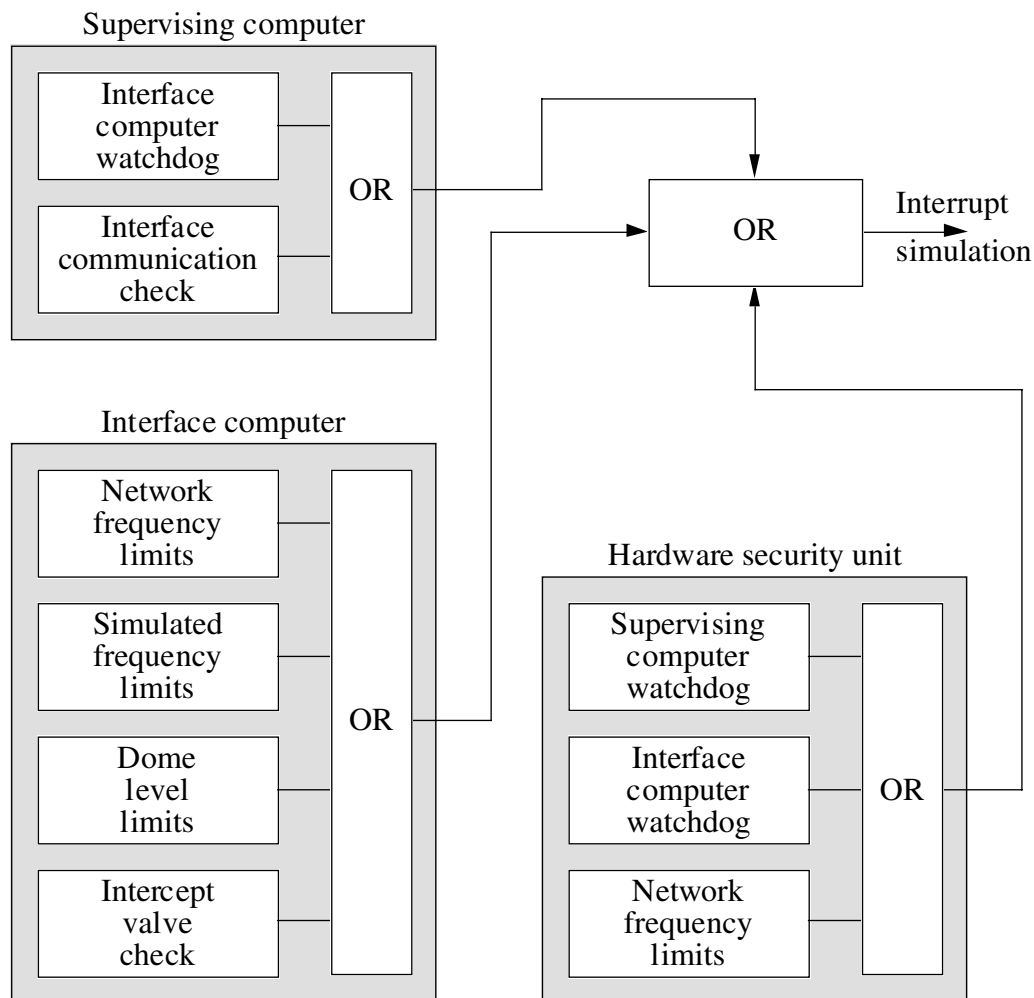
Figure 9.4   Simulator security systems.

A separate circuit checks that the intercept valve is not activated during longer than at the most 5 s. Running for more than approximately 10 s with a closed intercept valve can lead to a unit trip.

The different security systems are indicated in Figure 9.4.

9.3   Data needed for a test

Certain data both for the unit to be tested and for the planned island network for which the unit is to be tested will have to be acquired before a test can be done.

For the unit to be tested the main data that are required will be those needed to fit the control signal to the unit (e.g. in the case of a DC connection, what voltage out should correspond to what frequency, what is the proportionality factor etc.), the various limits that need to be supplied to the security system of the simulator and the moment of inertia of the unit.

The control signal values can normally easily be found in the documentation of the units turbine control system. These values are then programmed into the PC that controls the power station interface unit. Typical values would be something like:

a) for an AC connection:

   If the frequency control system uses the generator voltage frequency then the relationship between control signal and the network frequency is simply one to one. If instead a 400 Hz tachometer generator, then the interface output must be set to 400 Hz and a proportionality factor of 8 entered.

b) for a DC connection:

   –10 to + 10 V may correspond e.g. to 45 to 55 Hz, sometimes inversely. These data need to be entered so that a correct control signal can be calculated.

c) for a digital connection:

   If the signal is supplied to a control system computer then this is usually done by an RS232C serial interface link. Data needed will then include the baud rate, 7 or 8 bit code, parity, number of stop bits etc. The data form (real, integer, etc.) will have to match as well.

Also, the control system computer has to be told to accept input from such an external input.

As for the security data part this will include maximum and minimum values for the network frequency, for the dome level etc. Most of these values are supplied to the interface PC, but as the network frequency is also monitored by the supervising computer and directly by hardware the frequency information will have to be entered for these functions as well.

The moment of inertia of the units turbines and generators (total moment of inertia) can normally be found in the units specifications. Usually it is presented as an H value and the J value can be calculated using the formulas:

$$H = \frac{W_{KIN}}{P_n} \tag{9.1}$$

$$W_{KIN} = \frac{1}{2}J\omega^2 \tag{9.2}$$

$$\omega = 2\pi \cdot f_n \tag{9.3}$$

where: W_{KIN} is the kinetic energy stored in the unit when it is running at its rated speed

P_n is the rated output power of the unit (MW)

ω is the angular frequency

f_n is the nominal network frequency

Note here that the values used are the electrical units. The mechanical moment of inertia J_m is equivalent to its electrical counterpart J_e for a turbine units with two poles (speed 3000 rpm for 50 Hz or 3600 for 60 Hz). Same for such units ω_m is equivalent to ω_e. For units with a higher number of poles the relationship between the units will be:

$$\omega_e = \frac{n}{2} \cdot \omega_m \tag{9.4}$$

$$J_e = \left(\frac{2}{n}\right)^2 \cdot J_m \tag{9.5}$$

where: n is the number of poles of the unit

As for information about the network that the unit may be working onto in an emergency situation the following information is needed:

1. expected maximum step load change on the network

2. load level of the unit to be tested while in island operation

3. if other units are active on the simulated network one must have data for their moment of inertia and, if they do take part in the frequency control of the network, what model that should be used to simulate them and what the time constants and droop values that their systems have.

9.4   Basic step response tests

A step response test similar to what is shown in Chapter 3 is not only the simplest test to perform but also the one that is the easiest to evaluate. If a slower rate of change of the load level of the simulated network is used then it becomes harder to determine time constants and harder to separate different effects from each other. Therefore e.g. ramp load changes would give less information.

As mentioned in Chapter 3 it is recommended with regard to security that the first tests are done with a fairly high value for the total moment of inertia present on the network (high J value). This gives a smoother operation and large oscillations are far less likely. If such a test passes in a well behaved manner then one can easily repeat the test with lower J values. The lowest value that is meaningful to test is of course that of the unit under test. This is then equivalent to that this unit is the sole one supplying power to the island network and that no additional moment of inertia is present; e.g. large synchronous machines on the load side.

The size of the power step should for security reasons first be quite small. Then if the behaviour of the unit is stable and no problems are observed one can test with larger steps. The maximum step size is set by what can be considered safe for the unit, with regard to thermal and mechanical stress. Steps of up to 10% of the rated power of the unit should never present a problem in this respect, and for most types of units up to 20% would be safe as well.

For the basic step response tests it is always assumed that the unit under test is the only one that performs any frequency control duties on the network. Other units on the network are assumed to be operating in constant power mode and their only presence in the simulation is that they contribute power (=reduce the load of the tested unit) and moment of inertia (increase the J value).

These tests are made with the simulator in its normal mode; i.e. with a closed control loop where the simulator simulates the network and feeds the frequency information back to the unit under test. This closed loop means that the test is made with a considerably higher level of security than if one would be using open loop test methods, where errors will have no way of correcting themselves.

9.5   Steam storage versus boiler response test

If one of the objectives of the test is to be able to build a control model of the unit that is being tested then a test should be made to determine whether or not there is a need for a boiler model for the unit in question. The determining factor here is whether or not the steam storage capacity of the steam dome or the steam generators, or of the boiler itself, depending on design, is large enough compared to the speed of response of the boiler. If the steam storage capacity is large enough in this respect the steam pressure at the point of delivery can for short term dynamics be assumed to be constant and there is then no need for creating a boiler model.

This test should be done as follows: the unit is run at a power level similar to what would be the case if the unit is used for island operation. The measuring system must be connected so that the steam pressure at the point of delivery from the boiler (dome pressure if the unit has a steam dome) is recorded. A step increase of the load in the simulated network is then done. The step should be similar to the largest step load change that one can anticipate on the simulated island network. A value of 10% of the current load should normally be sufficient. The higher load should be maintained for a period of time well beyond the time constant of the boiler system. If this is not known a time of 5 to 10 minutes could be used.

Evaluating this test is quite simple. If the steam pressure at the end of the test is the same or slightly higher than what it was just before the

step increase was applied, then there is no need for modelling the boiler. Obviously the firing control system and the boiler manage to keep the pressure up also when the load increases.

If the pressure drops continuously during the test then the boiler system shows no response to the increased output power and the reason for this must be checked up. Either the system is in a manual control mode and the operators failed to react or there is some technical malfunction, or some unit protection system has been activated. In the latter case one will notice this easily, as the power output will also fail to respond to the load increase and the simulated network frequency will drop rapidly.

Should however the steam pressure first drop in a significant manner and then increase then the boiler response is obviously slower than the time constant given by the steam storage and there may well be a need for modelling the boiler and the fuel control system if a correct model of the behaviour of the unit shall be made.

9.6   Parallel operation test

If one wants to test how the unit would behave in island operation working parallel with other units that also take part in the frequency control of the network, then these tests should be made in accordance with the operating plans for such emergency operation. The other units should be entered into the simulator with their models and their frequency control systems should be modelled with correct time constants and droop values. Simple step load changes within the simulated network will then show the response of the different units. This result will be only approximate for all but the tested unit, as the models used are quite crude ones, but as it is primarily the unit under test that we want to have the operation characteristics of this will most of the time be sufficient.

Note that this type of test will only give the response characteristics of the power stations with regard to their output power. This simulator system, at least at its present state, does not take into account electromechanical oscillations between different units that could occur due to their coupling through the network. The network is assumed to be stiff in this respect. Such oscillations are normally faster than the oscillations that come from the frequency control process, the former having

typically a period of 1–2 s, the latter having 7–15 s or more. Network oscillations due to the network coupling can be studied with commercial network simulation programs, such as Simpow or PSS/E.

9.7 Time constant test

The time constant of the high pressure turbine system and the deadtimes of the same system and of the medium/low pressure systems, as well as the control valve deadtime, are so short that the normal step response tests will not give accurate information about them, as the simulator cycle time is of the same order as these time constants. Using the same equipment one can however make a special test to determine these with greater accuracy.

For this test the system is not running as a closed simulator control loop but as an open circuit. A suitable value of the step signal to be applied to the control input of the unit must first be determined based on the basic step response tests mentioned above. This step of the output value is then applied to the unit for a few seconds. After this the simulator returns to its normal operation.

As the simulator works in an open loop fashion during this test and also does not need to communicate with the supervising computer, the measurement speed can be increased considerably. Instead of one measurement per normal cycle in its normal mode (about 0.2 s) there can be one measurement approximately every 20 ms, which is enough in order to get a correct value of the short time constants of the system.

Note that since this test is made with an open loop, one has to be much more careful with the selection of the size of the disturbance; as there is no selfcorrecting mechanism in action.

9.8 Power System Stabilizer test

If the unit to be tested is equipped with a Power System Stabilizer (PSS) then this one should be turned off during the initial tests. The reason for this is that the PSS works through the voltage control system and tries to stabilize the operation of the unit (minimize electrodynamic oscillations between this unit and other units on the network).

This may mean that if there are oscillations of the output power during the tests, as is quite likely when the unit is tested for small values for the moment of inertia, then there will be substantial changes in the output voltage. This is usually undesirable and often unacceptable.

Changes in the active power output of a unit that is synchronized onto a large power system will have very small effects as far as the network is concerned. The frequency is always the same in different parts of the network, unless there are very large perturbations, something which a test of this type can not induce, and there is no need to worry about local effects on the network. With changes in the reactive power output, as the action of the PSS would lead to, it is quite different. Such changes translate immediately into local voltage variations and if the power station is located in an area where the loads are sensitive to such variations then such operation will clearly not be allowed.

In addition, testing with the PSS active may not always give the information that we want primarily. As the PSS responds to a type of oscillations that we have not included in the simulator system, as the network is not modelled in such a way that inter-machine oscillations can be represented, the actions of the PSS will in most cases not be typical for the way it would act in a real situation.

If one wants to test the behaviour of the PSS during a series of tests then this should be done towards the end, when the approximate behaviour of the unit with different load changes and J values is known reasonably well. A suitable combination of step size and J value should then be chosen so that the resulting oscillations are quite small and thus the actions of the PSS are limited. Before such a test one should make an assessment of how much voltage variations that can be tolerated in the local area.

9.9   Tests on a planned network

If the power station is planned to be a part of a particular network setup for emergency island operation then its behaviour in such a case can be tested in a more direct way. The simulator system that was developed contains load and network models that can be set to resemble the planned network and thus give a more direct indication of how the unit to be tested can handle the situation.

If a test like this is to be made one needs more data; primarily a full description of the network and a reasonable assumption as to the characteristics of the loads. After these have been entered the simulator performs a basic load-flow calculation, to get a start-up condition, and after that the tests are done in the same manner as for the basic step response tests described in Section 9.4. The difference is that we now get a full network response, rather then just the response of one load seemingly connected directly to the unit generator.

The network is described through a matrix representation. The program will build an admittance matrix of the system, based on supplied data for lines, transformers and shunts, add units of production and loads and runs a load-flow calculation.

The load model used is a quite simple one, where the loads are divided up into three parts: a constant load with no dependence on frequency (typical for e.g.electric heating), a load which is proportional to the frequency (typical for electric motors running against a constant torque) and a load which is proportional to the frequency to the power of three (typical for motors that run pumps and fans):

$$P \ = \ P_0 + P_1 \cdot \frac{f}{f_n} + P_2 \cdot \left(\frac{f}{f_n} \right)^3 \tag{9.6}$$

where: P = total load power

P$_0$ = load that does not depend on frequency

P$_1$ = load that is proportional to the frequency

P$_2$ = load that is proportional to the frequency to the power of three

f = network frequency

f$_n$ = nominal network frequency

Tests run against the power station simulator indicate that the behaviour of the power station with regard to frequency control characteristics are more critical when the load is constant, as compared to when it depends on frequency. This is natural, as any dependence on the frequency means that the load is to some extent part of the frequency control: when there is a shortage of power production the frequency will drop and if the loads then drop as well it will relieve the situation, and vice versa if there is too large a production.

With the above in mind and also considering that it is generally hard to know beforehand the load characteristics of the loads on a planned emergency network, it may be safe to use only constant load for these tests, unless one has clear figures showing that a major portion of the load to be handled in such a situation is highly frequency dependant, in which case this dependence should of course be modelled.

For a further description of the system used in the simulator to describe the network, see [2], where these systems are discussed in detail.

9.10   Load shedding tests

As the simulator has a load shedding model included in its network description it is also possible to perform tests against a load shedding system, to test under which circumstances that it will get activated and what influence it will have on the system and on the unit under test.

The setup is the same as for the tests described above and a load shedding test can either be done in combination with a basic step response test as described in Section 9.4 or as a part of a more complete network test as described in Section 9.9.

To perform such a test the load is increased to beyond what the unit can respond to. This can be in two ways: either as a direct step increase, in which case the problem will primarily not be that the unit can not deliver the power needed but merely that it can often not do so fast enough, which will then trigger a load shedding, which will relieve the system situation, or the load can be gradually increased, pushing the unit towards what it is capable of responding to. The latter case can generally be thought of as less interesting, as the situation that we end up in that case is one where the outcome depends less on the automatic control systems of the unit and more on the station operators and the network dispatchers.

The load shedding system of the simulator consists of five steps of load shedding. For each step two time limits and two activation frequencies are set. The higher frequency limit will activate the step with a longer time delay, whereas a much shorter delay will be used if the lower limit is reached.

Corresponding to the load shedding there is a also an automatic load reconnection system. If the network frequency has been restored to normal for a set period of time the loads will gradually be reconnected.

Chapter 10 Future work

There is a potential to develop this test method still further and to be able to build more correct models of different power station units using this method.

Accuracy can be increased by the use of faster computer systems and faster methods for the interchange of information between the different parts of the simulator system. In addition the simulator system can be developed into a commercial testing tool by developing a version that is easily portable, based on a lap top computer system, and that can thus easily be brought to any unit that one wants to test.

The power station interface unit can also be improved, making it much more portable and making it able to connect to a broader range of turbine control systems.

Improvements can also be made to the security systems. These systems are today developed far enough so that the risks of damage to the unit under test can be said to be eliminated, but by improving these system so that they can use computer prediction methods to determine what will happen next in the simulation process the risk of tripping the unit can be still further reduced.

In addition to the hardware and security routine improvements mentioned above there are also many possibilities for further improvements to the software. Including any kind of inter-machine oscillations in the specifications was considered to be impossible when this project was started. It may still be, but with the extremely fast development of computers it should soon be possible to achieve enough processing capacity so that this kind of a simulator can also be built.

The software should also be structured and documented so that it can be part of a commercial class software package. At the moment it is documented only in preliminary form; a documentation that is kept at the Department of Electric Power Engineering at Chalmers.

As for the tests done within this project many more such tests should be made with different types of power stations in order to be able to build models for different designs of power plant units. In order to be able to make long term models it is also necessary that such tests can be made over longer period of time. During this project the availability of the power station for testing has been quite limited and such tests could therefore not be made.

Chapter 10: Future work

Chapter 11   Conclusions

The simulator testing method that has been developed in this project, where a simulator system is connected to the frequency control system of the unit to be tested while the unit itself remains synchronized onto the main network, is well suited for a variety of tests of a power station unit. It is a simple and reliable way of testing the behaviour of the frequency control system and of other vital parts of the unit in particular when it comes to determining how the unit would respond if it was used for island operation on a very limited network. The method has the potential to be developed into a standard test method for tests of this nature.

Tests made in this project show that thermal power plants with valve control mode and with sufficient steam storage capacity are well suited to be used for frequency control purposes. They have a very fast response to network load changes and with proper settings there should be no major problems in using them in this fashion.

The widespread idea that thermal power plants are far less suited for frequency control purposes as compared to hydro-electric units which is well rooted in Sweden, as Sweden has always had a situation where hydro power has been available in sufficient amounts to take care of all frequency control duties, may not always be true. While hydro-electric units are sturdy and reliable their speed can in most cases not compare with thermal units of the types tested in this project.

In island operation it is essential to consider the moment of inertia on the network, as well as the droop values of the frequency control systems of the units responsible for the frequency control of the network. Both dispatch plans and controller settings may need to be modified compared to what is used in normal operation on the main interconnected network.

Simple models can be built in order to model the dynamic behaviour of this cathegory of thermal power plants. For many purposes such models may be fully sufficient.

Chapter 11: Conclusions

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Appendix A Specific results for the Stenungsund power station

The Stenungsund power station was used as a test object for this project for several reasons. One is that it was suitably located, being one of the few conventional thermal power stations in Sweden. It is also, with the exception of the turbines, of a quite conventional and internationally very common design with an oil fired boiler, three superheaters, a high pressure turbine, a reheater, plus medium- and low pressure turbines.

Apart from these general reasons for the choice of the Stenungsund power station as the test object there was another important reason as well: the station is located in a strategic position in case of emergency operation of the Swedish national network and it is therefore of prime interest the study as whether e.g. island operation on a local network is possible or not.

The results presented in this appendix are therefore results that are worth considering e.g. when making operating and discharge plans for the local area around the Stenungsund power station.

Island operation using the Stenungsund power station, background

The Stenungsund power station is located in a strategic position, reasonably near Gothenburg, the second biggest city in Sweden. With its 800 MW of total power it is by far not only the largest conventional thermal power station of the region but also the largest station of any type with exception of the nuclear power station at Ringhals, south of Gothenburg. The latter has four reactors with a combined output of about 3000 MW, but for security reasons it is unlikely that this or any nuclear generating station can be used in emergency situations.

The Stenungsund station is also built to be very well protected also in the case of war or similar, as it is completely enclosed inside a mountain.

Another special circumstance that makes the Stenungsund station interesting as far as emergency planning goes is the fact that it is connected to the regional 130 kV network rather then to the Swedish national transmission grid (400 kV), as is the case with e.g. the Ringhals units. This means that if there is an emergency situation such that the 400 kV system is not available then the Stenungsund station will still be able to deliver power, and it will then be the only station of its size in the region. Power can in such a situation not be transferred from other regions e.g. from hydroelectric units in the north of Sweden or from Norway, as without the 400 kV system the required transmission capacity is not available.

Situations where the 400 kV system is unavailable for a fairly long period of time can well be anticipated. Such situations could arise from major line faults, e.g. following hurricanes or other natural disasters, major transformer faults for main 400/130 kV transformers etc., plus of course several situations that could arise in the case of war or sabotage.

In such a situation the Stenungsund power station would most likely be the only large power station that would be able to supply power to western Sweden. Other stations that would be likely to count on would be the hydroelectric units at Olidan (130 MW) and Hajom (150 MW), plus a few smaller units. A special problem arises from the fact that the Stenungsund station depends on external supplies for start-up as it has no local emergency generator large enough to handle this. Therefore power has to be transferred from either Olidan or Hajom. A direct 130 kV line runs between these location so this start operation should not be a major problem. However, if a local start power generator was to be added to the Stenungsund plant it would add to its emergency capacity in this respect.

Moment of inertia

The Stenungsund units are, as mentioned earlier in this report, "light" units, i.e. they have unusually low H values. This is especially the case with units 1 & 2, whose H value of 2.2 is extremely low. This is a clear drawback in island operation and as the tests discussed in chapter 3 clearly shows these units are likely to show a very unstable and oscillating behaviour if such a unit is left as the only machine on line in an island system. A typical such oscillating behaviour is shown in the test series below, which shows a series of step load changes applied to unit

1, in a situation corresponding to this one being the only unit on line. One should note here that these oscillations behaviour comes in spite of the fact that the power level is low. A higher load level will generally cause the situation to deteriorate, as the ratio between the power produced and the kinetic energy stored in the rotating machine is reduced. The kinetic energy depends only on the moment of inertia and the speed of the unit and neither of these will increase with the power level.
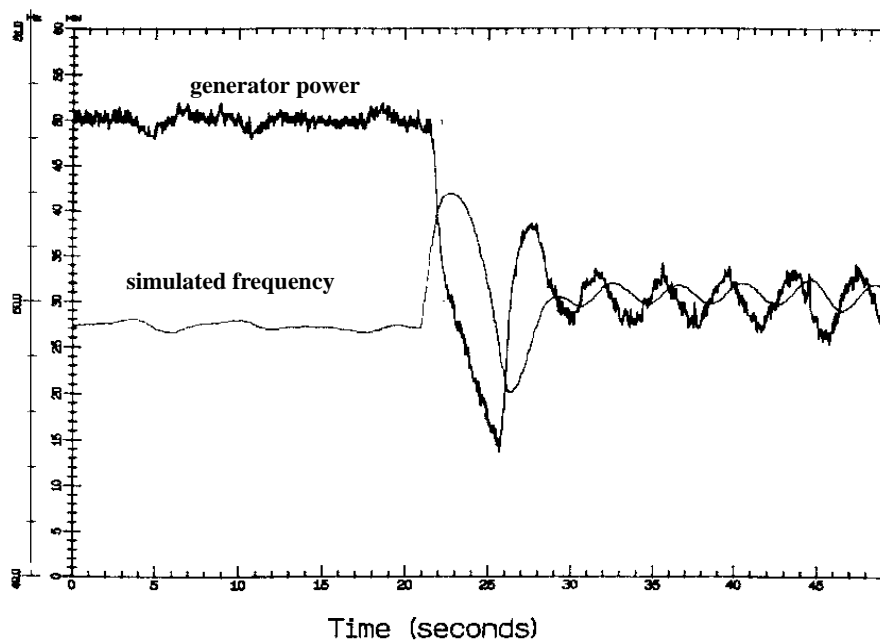
Figure A.1   Stenungsund, unit 1; power oscillations following a load reduction.

If all four units at Stenungsund are in operation and there is most likely some contributions to the moment of inertia from the participating hydro power stations as well, then the combined moment of inertia gets high enough so that the stability of the operation should not be a problem.

As pointed out earlier it may be advantageous to use a higher number of units than may be required by the load level simply to keep the moment of inertia up. For a load of 200 MW two units running at 100 MW each are likely to give more stability than one unit at 200 MW, assuming that units 3 and 4 are used.

Frequency control strategy

There are different frequency control strategies that can be used in a situation where Stenungsund and e.g. the units at Trollhättan (Olidan and Hajom) are to supply a local island network. Due to its speed of response it may well be advantageous to use the Stenungsund units for frequency control also when the hydro units are available. A scheme where the hydro units operate with a lower droop but a slower response and a thermal unit with higher droop but faster response may well prove to provide the best frequency regulation.

However, it may not be recommended that all four units at Stenungsund participate in the frequency control. There are two reasons for this: one is that unless one has specifically tested such operation with two or more units in parallel one can not be certain that oscillations between the two units will occur when there are sudden load level changes. The other reason is that a unit should not be run at or near maximum load in order to be suitable for frequency control. But in an island operation situation all power that can possibly be delivered may well be needed. In such a case the maximum yield will result from a dispatch situation where three of the units are run at constant power, with the frequency control system deadband active, most likely full rated power, and one unit at a lower level so that it will exhibit optimal frequency control behaviour.

Special operating recommendations

Certain adjustments and changes may be required in an islanding situation. One such adjustment could be to increase the droop value in order to get a more stable operation and a better load distribution versus the hydro units, at the expense of course of the frequency accuracy.

Also the fuel/electric output differential protection system should probably be set to signal only to prevent this system from incorrectly tripping the unit when there are large perturbations of the system; something which is far more likely on a small system.

Furthermore, several simulations have shown that keeping a good margin with regard to the dome pressure is essential for stable operation. Normally one does not want to keep the dome pressure much higher than required, as this translates into a lower overall efficiency and hence less economic operation. However, stability of operation must in

an emergency situation be given priority over efficiency and hence the unit should be operated with a somewhat higher dome pressure than what would otherwise be used for the power level at which the unit is operating. It seems preferable to keep the control valve opening in the range of 40 to 60%, as in this range the units have a quite sturdy and stable operation, provided that the moment of inertia of the system is sufficiently high to aid in the damping of oscillations that may occur.

The feedwater system

The feedwater system appears to be the most critical system with regard to oscillations and island operation. At least this is the case for units 3 and 4; for units 1 & 2 it is not possible to come to any conclusions regarding the behaviour of the feedwater system from the very limited tests made on these units.

As pointed out in Chapter 7 the feedwater control system has time delays that have a very unfortunate relationship to the time constant of the unit and power system oscillations as they occur if the unit is on its own on the system. This means a highly increased risk of tripping the unit if oscillations occur.

The feedwater system time delays are for the most part built into the system; i.e. they consist of system time constants that can not be altered without a major rebuilding of the system. Modifications made to the control system itself may offer some improvements but these can not be expected to be very radical. The main object of any such changes would be to speed up the response of the feedwater system to changes in the high pressure steam flow rate. If the system could have its response time reduced to about 60% of its present value the problem would most likely be solved. This is however beyond what can be expected from simple adjustments to the feedwater controller.

In a situation where the unit is alone on an island system and there is a problem with oscillations then it may be well worth considering running the feedwater system on manual control only. This will of course require the constant attention of the operators, but at least it will prevent the system from coming into counterphase with the steam flow in its attempts to follow the oscillating steam flow rate. If several units are on the network the moment of inertia is sufficient to slow the oscillations down enough so that the feedwater system can follow the power / steam rate oscillations correctly.

Appendix B   Measurement system, detailed description

current loop
inputs

DC voltage
inputs

AC voltage
(potentiometer)
inputs

current to
voltage
converters

voltage
dividers

rectifiers

RC filters

source select
switches

isolation
amplifiers

16 channel
multiplexer

A/D converter

Supervising
computer

LAN

interface
computer

hard disk

transformer

universal
counter

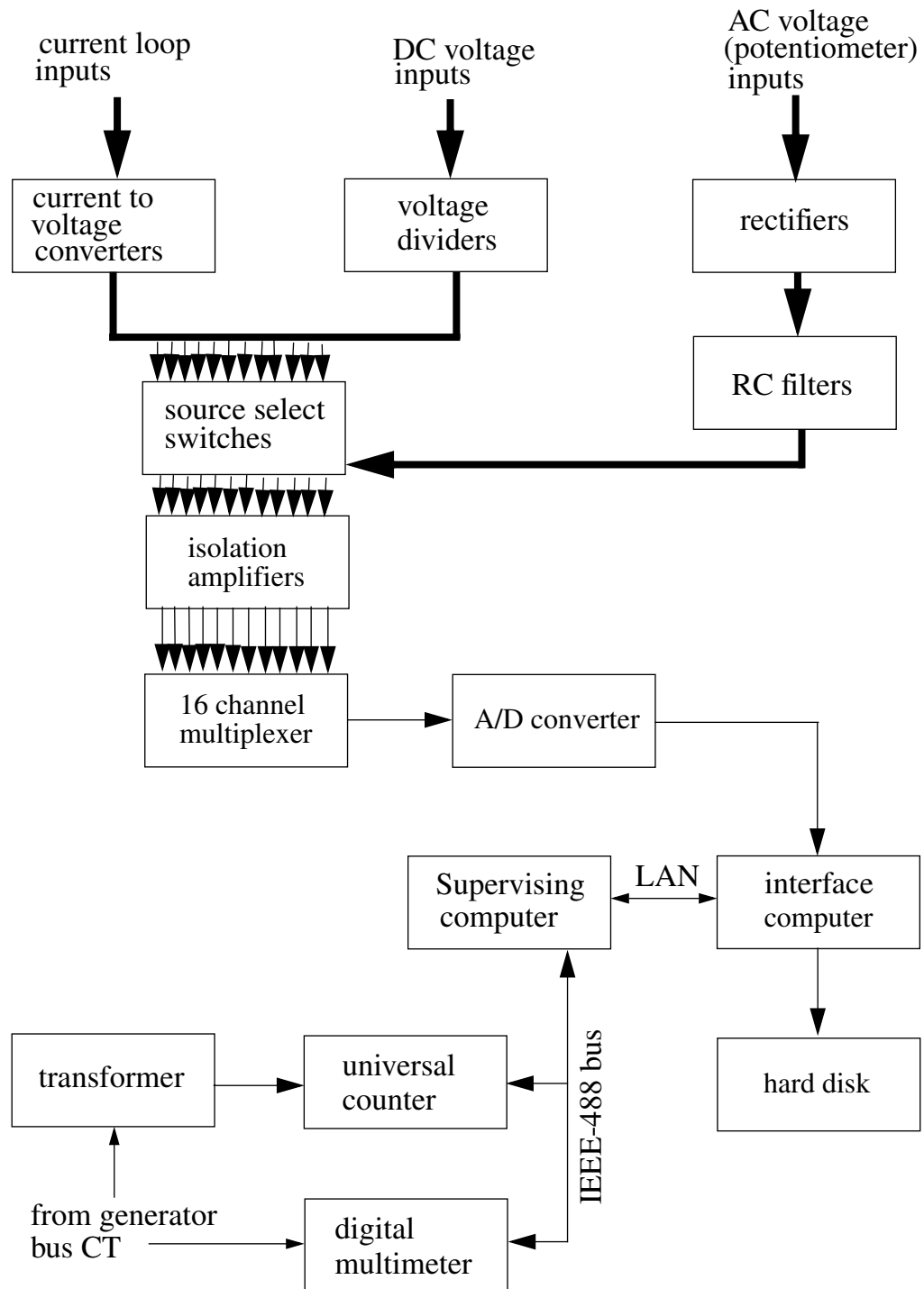from generator
bus CT

digital
multimeter

IEEE-488 bus

Figure B.1   Measuring system, block diagram.

The measurement system consists of a PC A/D system with certain signal processing systems. It is adapted so that it can be fitted to all signal levels that are commonly in use in power stations, e.g. 0 - 10 V DC, 0 - 1 V DC, 0 - 20 mA, 0 - 50 mA,0 - 100 mA and 4 - 20 mA. All connections are done via isolation amplifiers so that there will be no galvanic connections and no ground loops between the measurement system and the systems of the power station. The system also allows for digital input signals, e.g. to monitor alarm signals and similar. The same system also has digital output ports as well as D/A converters that are used to generate signals that are fed to the power station and to the operators, but these are discussed in Appendix C.

The A/D converters

There are 16 analog input channels that are A/D converted on a Boston Technology PC30 general purpose measurement card. The card is inserted directly into the ISA bus of the PC that controls the power station interface.

The A/D converters are 12 bit converters, which gives a resolution of approximately + - 0.25%. Their input range can be set either to 0 - 10 V DC or to -10 - +10 V DC. The second range was normally used, except where a second A/D card was used for some special tests. This second card was then set to 0 - 10 V.

The converters are capable of a sampling rate of up to 30 kHz, but when the system is used as a simulator the measurement rate is limited to one measurement per simulator cycle (i.e. every 0.2 s). Unfortunately this rate is limited by the data transfer rate between the different computers making up the simulator.

Data from the A/D converters is fed to the computer over the bus as a stream of 2 byte integers. This allows for a faster data transfer rate then if floating point representation was to be used. It also highly reduces the data storage requirements for the data. Very large datasets are generated if longer tests are run, because of the many channels recorded. These values are stored in their integer form and conversion to floating point will not be done until when the values are to be plotted during the evaluation at a later time.

The system is somewhat sensitive to the PC setup and the type of PC used. It was found that in certain cases the input channel multiplexer could come out of sequence with the controlling program. This is unacceptable as it means incorrect input to the simulation process. Fortunately this never happened on a sudden, random basis; instead certain PC combinations worked fine, others did not.

It should be noted that the original software drivers delivered with the PC30 card were extremely sensitive and too unreliable to be trusted for an application of this kind where 100% reliability is a necessity. The version tested was the FORTRAN language version, and when using these the system would sometimes just freeze or it would deliver completely incorrect values. Much work was spent trying to solve these problems, but finally it was concluded that this driver package could not be used for this purpose if the simulator was to show a high degree of reliability.

Instead of the original drivers a software package from Techsell, Stockholm, was used. These drivers were considerably more reliable but unfortunately not available in Fortran. Instead all code running on the power station interface computer had to be re-written in the C language. This was a quite large job, but the difference in reliability made it worth it.

Measurement system front end inputs

All signals fed to the A/D converters have to be properly conditioned first. This is necessary in order to adapt the system to the transducers of the power station and in order to minimize noise on the signals and also in order to ascertain that all critical parts of the system have sufficient immunity to the high level of electrical interference present in a power station.

In order to allow for using the simulator on different units and at different power stations it was also necessary to design the system so that a variety of input signals could be used. Acceptable input includes current loops of different values and DC signals at different levels. For certain signals, such as the generator voltage, the network frequency and positions for valves and limiters AC signals can also be used.

All signals are fed via isolation amplifiers. This ascertains that there will be no ground loops between the simulator and the control systems of the power station. For most channels an integrated isolation amplifier chip, ISO 122 (Burr Brown). This amplifier provides an excellent linearity (non-linearity less than 0.008% FSR), high speed (bandwidth 50 kHz) and a high isolation voltage (1500 V) so that the integrity of the system will be guaranteed even in the event of large transients, "spikes" or similar on the input lines. A total of 12 such amplifiers were built. Each channel has its own dual power supply, which minimizes cross-talk and eliminates the risk of circuit to circuit flashovers.

The isolation amplifier has a normal input voltage range of -10 to +10 V DC. Where lower levels were measured another amplifier was used, which had a 0 to 1 V DC input range.This input level was also used for recording signals based on 0 to 20 mA, 0 to 50 mA or 0 to 100 mA current loops, using 50,20 and 10 ohms series resistors.

Most modern power station transducers or signal converters use an interface based on a 4 to 20 mA current loop. For these a converter based on the RCV 420 KP (Burr-Brown) IC. This chip has a very high accuracy, with a non-linearity of 0.0002% (typical value) and also a very fast response (1.5 V/µS, typ.). Each of the ISO 122-based isolation amplifiers was fitted with such a converter so that the input range can be chosen as either -10 to + 10 V DC or 4 to 20 mA.

The transducers that translate the position of the control valve, the control valve limiter and the intercept valve at the Stenungsund power station are based on potentiometer circuits that give an AC signal of up to approximately 25 V. These signals were rectified using a diode bridge and then attenuated to a 0 to 10 V DC range. An RC filter circuit with a time constant of about 0.1 s was added to produce a smooth DC signal. The signals were then fed to isolation amplifiers before being sent to the A/D converters.

Frequency measurements

A precise and accurate way of measuring the network frequency is essential to the system. These frequency measurements are not as such used during the simulation but monitoring the network frequency is vital to the operation of the security systems. The main reason for terminating a simulation prematurely is that the network frequency devi-

ates from its normal value. This would then indicate either a load loss condition or that there is a major disturbance on the power network. In either case the simulation has to be terminated and the unit switched over to normal operation immediately. Failure to do so could in the case of load loss lead to turbine overspeed and in the case of a network disturbance to that the disturbance is aggravated.

The prime frequency measurements are made using a Hewlett-Packard HP 5328A universal counter, which is connected via an IEEE-488 measurement bus to the supervising computer. The data is then transferred via the file I/O communication to the interface computer where it is logged to the data file.Input to the universal counter is taken from the generator voltage: the output from one of the generator bus CTs is fed to a transformer that will reduce it to appr. 4 V AC which is then fed to the counter.

A backup frequency measurement channel is set up by measuring the normal output of the frequency sensing parts of the frequency control system. This signal is, via an isolation amplifier, fed to an A/D converter and measured just like any process parameter. The decision as to whether it is out of bounds or not is made by the interface computer, so that this vital checkup will function even if there should be a communications problem between the interface computer and the supervising computer. In the event of a problem with the interface computer the supervising computer will in any case terminate the simulation; using a special relay link set up for this purpose.

The universal counter is operated in time period mode and measures the average period time of ten periods of the AC voltage. Thus a measurement is obtained at an interval of approximate 0.2 s and a high degree of accuracy is achieved.

Generator voltage measurements

The generator voltage is continuously measured by a Hewlett-Packard HP 34401A multimeter, connected to one of the generator bus CTs and delivering its output via an IEEE-488 interface to the supervising computer, for transfer to the interface computer and recording onto the log file there. Measurements are made at a rate of one per second.

Appendix C   The power station interface

The interface to the actual power station was considerably more complicated than the interface to the power station simulator. It consists of several different units, even though they were all built into one box.

The station interface is controlled by a PC that is dedicated to this purpose. The actual interface to the computer is via a Boston Technology PC-30 multipurpose measurement and control card. The card is inserted into the PC and communicates with it via the PC bus.

The PC-30 card has 16 channels for A/D input, 2 channels for D/A output of 12 bits each, 2 channels for D/A of 8 bits each, three 16 bit counters that can be set under program control and three digital I/O ports of 8 bits each.

The A/D channels are used for the measurement system as described in Appendix B.

In order for the simulations to be possible it was of course necessary to develop a way of feeding a false control signal to the frequency control system of the power station, and in the case of a voltage simulation also a voltage signal.

The frequency control system of units 3 and 4 at the Stenungsund power station consists of a tachometer generator on the turbine axis and various control circuits. A simplified block diagram is shown in Figure C.1.

The first approach for supplying a simulated signal to the system was to build a computer controlled power signal generator, able to generate a 400 Hz sine signal at 110 V level just like the tachometer generator. The frequency could then be accurately controlled by the computer and it was thought that this would be a true representation of the tachometer signal.A further description of the signal generator is found in [2].

The above approach failed. Several tests showed that the output signal from the discriminator circuit was very different when it was fed from the simulator and its signal generator as opposed to its normal operation when the signal comes from the tachometer generator. The reason for this was that whereas the frequency of the tachometer generator

signal varies on a continuous basis the frequency of the signal generator would change step-wise each time that the simulator had completed one loop and thus updated the frequency. Even when the change in frequency was very modest the output of the discriminator still became unpredictable, with lots of chirp and unwanted spurious signals each time that there was a change of frequency.
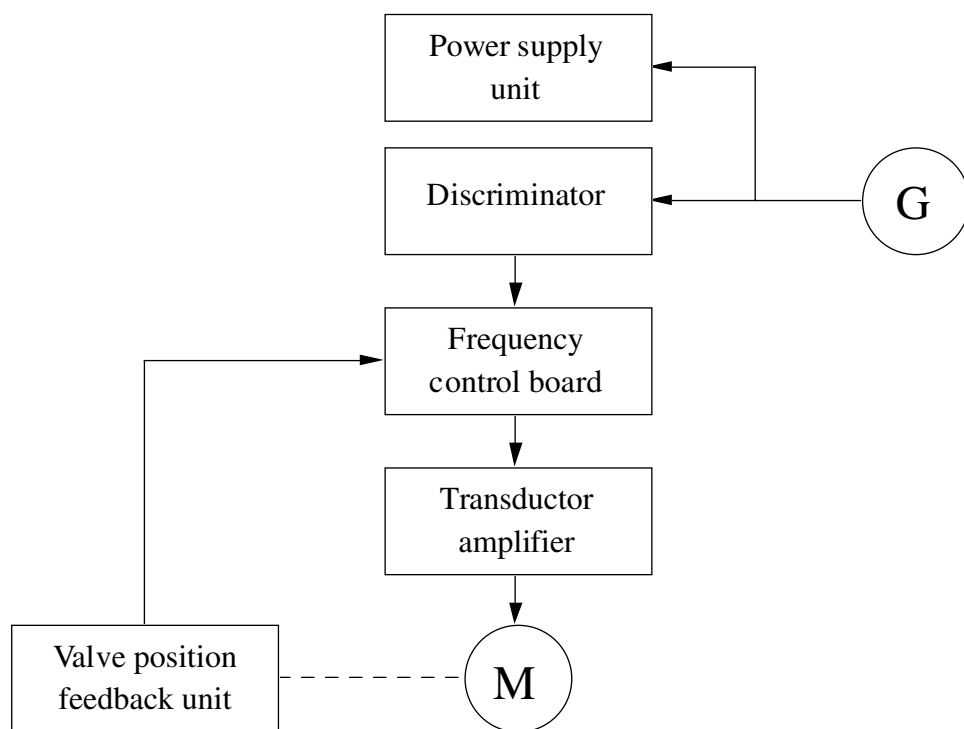

Figure C.1   Basic diagram for the frequency control system used for units 3 & 4 at Stenungsund.

The approach above therefore had to be abandoned. Instead the signal generator was used to supply a controllable signal to the discriminator and the output of the discriminator was recorded. This was done by applying a signal of a certain frequency, waiting for a couple of seconds so that the discriminator would settle to its final output and then recording the output of the discriminator, using the measurement system. For this purpose the measurement system had temporarily been readjusted for bipolar measurements, as the output of the discriminator is normally in the range of +-10 V.

Using a special computer program these measurements were done for each 0.005 Hz in the range 47.0 Hz to 53.0 Hz. The resulting discriminator output signals were recorded in a special file. Thus, instead of

using the signal generator for the actual simulations, it was possible to use a DC signal.

The value of the DC signal is calculated for each update by taking the value recorded in the discriminator file for the frequency that is the closest fit to the simulated frequency at any given point of time. One of the 12-bit D/A outputs is then used to generate the requested D/A signal. The signal is then fed, via a precision isolation amplifier, to the frequency control system. The system is outlined in Figure C.2.
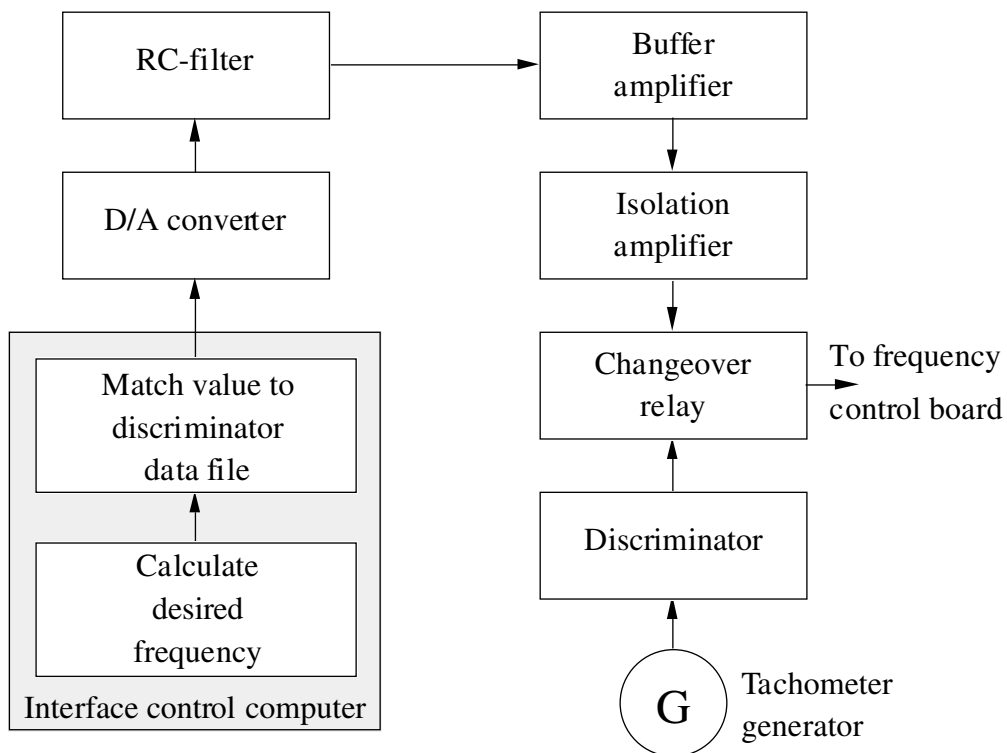

Figure C.2   System for frequency simulation.

The frequency control card contains circuits that are sensitive to the derivative of the frequency. This is to speed up the response in situations where there is a rapid change of frequency, e.g. in case of a loss of load or similar. In order for these circuits to react correctly during simulations the signal must change on a continuous basis and not in steps. A simple RC circuit with a time constant approximately equal to the normal cycle time of the simulator program (appro. 50 mS) was therefore inserted in between the D/A converter and the isolation amplifier. In order to avoid errors due to the fairly low input impedance of the isolation amplifier an OP-amp was introduced as a buffer amplifier.

The system must of course allow for switching between the simulator and normal operation in an easy and controllable fashion. This is done by a switch-over relay that is activated by program control. The relay is controlled using one of the digital outputs of the PC-30 card.

In a similar way it was necessary to be able to control the voltage control system in case of simulations involving voltage control. The simulator system was built to allow for voltage control simulation although this feature was never used during this project, as the risk of unacceptable voltage variations in the local area would have been unacceptably high.

The voltage control system of units 3 and 4 of the Stenungsund power station is outlined in Figure C.3. The electronic control circuitry controls an SCR rectifier, who's output is fed to the exciter. The exciter is mounted directly on the generator axis.
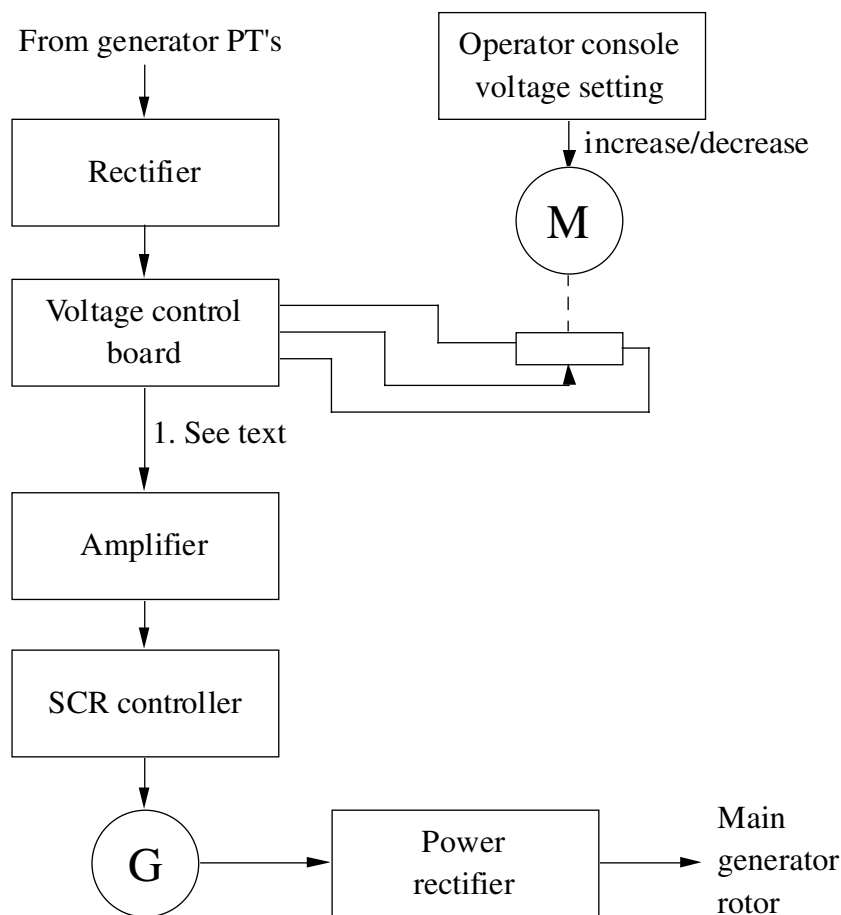

Figure C.3   Voltage control systems, units 3 and 4 at Stenungsund.

One approach would have been to simply take over the control signal from the voltage control system (point 1 in Figure C.3) and to supply that from the interface via a D/A converter. This approach was however considered too risky, as if for some reason the simulator did not respond correctly to any changes in voltage then the voltage would become uncontrollable and hazardous situations could occur in two ways: one could be the generation of overvoltages, even though the protection systems would of course disconnect the generator in case of excessive voltages; another and more likely risk would be that the generator would under such circumstances influence the voltage to the surrounding actual power network in such a way that it could crete problems for power consumers. This would be particularly undesirable at Stenungsund, as several petro-chemical industries in the area are very sensitive to voltage variations.

Instead it was decided that the correct way of controlling the voltage was to control the actual request value, normally set by the voltage potentiometer, and then let the normal control system handle the voltage control in the normal fashion. In this case there would be no hazards involved if the computer system should get stuck or similar; the voltage would just settle to its new value.

Just as for the frequency control system it was found proper to introduce an RC circuit so that the control inflicted on the system would be continuous rather then step-wise; even though there is no circuit in the voltage control system that uses the voltage derivative in any way.

The voltage request signal is generated by one of the 8-bit D/A converters, as the 12-bit ones had already been assigned to the signal generator and to the disciminator output simulator circuit. In order to allow for a good resolution a fixed voltage of an adjustable value (adjusted manually via a potentiometer) was added to the signal, so that the entire 8-bit range of the D/A converter could be used for controlling the voltage within the limits that it could possibly vary within.

A changeover relay, controlled via one of the digital I/O lines of the PC-30 card, switches between simulator mode and normal operation.

The final design of the voltage control system of the simulator is shown in Figure C.4.

The interface unit also contains the circuitry that is required for driving the power station operator interface unit. This unit allows the operators to monitor the progress of the simulation and also to immediately terminate the simulation, should that become necessary.
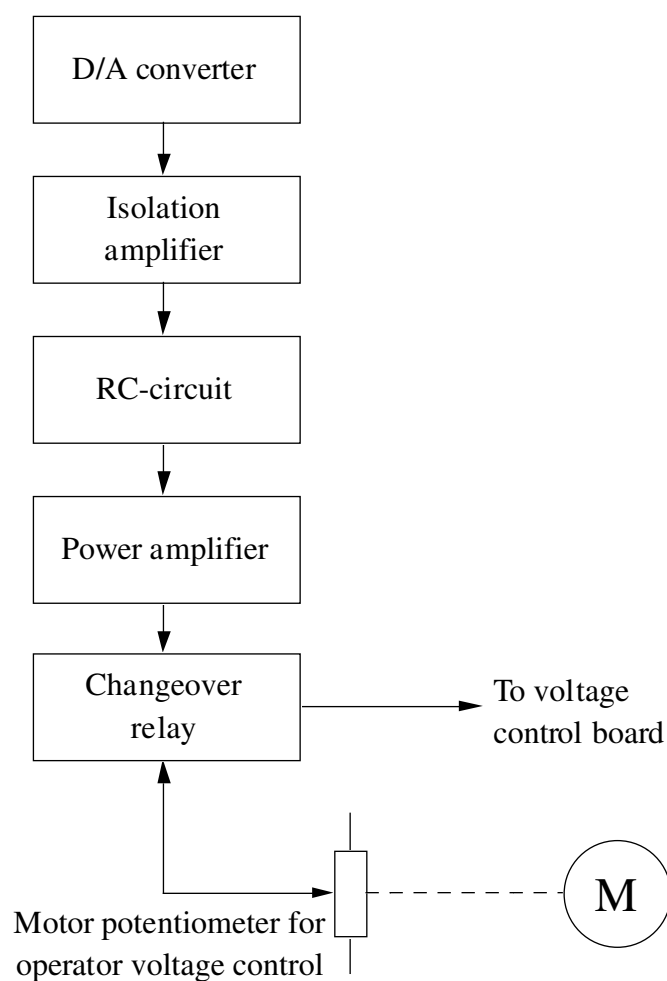
Figure C.4   Voltage simulation circuit.

During the tests performed at the Stenungsund power station it was found that various kinds of interference or transients could sometimes enter the circuits. This could result in that certain measured values were completely in error and this in turn could lead to incorrect action by the simulator.

In order to prevent these problems from presenting a risk for malfunction certain precautions had to be taken. Some were implemented in hardware; e.g. by adding decoupling capacitors and RC or LC filters to certain connections within the interface unit. Other measures were included in the software; like automatic rejection of unreasonable values and double or triple checks that e.g. a certain command has been received before any action is taken on the same.

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