PHASE TO PHASE

Synchronous Machine Turbine-Governing Systems
Vision Dynamical Analysis

Manual

16-036 CW

May 11, 2016

Phase to Phase BV
Utrechtseweg 310
Postbus 100
6800 AC Arnhem
The Netherlands
T: +31 (0)26 352 3700
F: +31 (0)26 352 3709
www.phasetophase.nl

CONTENTS

1 INTRODUCTION

The Dynamic module of the Vision Network Analysis software is developed for the analysis of electromagnetic transients. For a correct representation of synchronous generators both the excitation system and the prime mover including its governing system need to be modelled. This document provides a description of the turbine and governing system models implemented in the Vision Network Analysis software. Those models are selected to be suitable for use in large-scale system stability studies.

The parameters provided as default must be considered as sample data only, the default parameters are neither typical nor representative.

The outline of this report is as follows: first, a general description of the turbine and governing systems is provided in Chapter 3. The implemented steam turbine models are presented in Chapter 4 together with their default parameters and possible parameter restrictions. The implemented gas turbine is treated in Chapter 5. Finally, an example of a dynamic study for a small industrial network is provided.

This manual is applicable to the Vision Network Analysis version 8.7.1 or higher.

2 ABBREVIATIONS

AGC	Automatic Generation Control
ESM	Excitation System Model
SMTGS	Synchronous Machine Turbine Governing System
pu	per unit
RMS	Root Mean Square
AVR	Automatic Voltage Regulator

3 SYNCHRONOUS MACHINE TURBINE-GOVERNING SYSTEMS

The conventional primary energy sources used for electrical power generation are typically of hydro or thermal nature. The prime mover converts these sources of energy into mechanical energy, which is then used to drive the synchronous generator. Thermal energy can be obtained from nuclear or fossil fuels. A simplified functional relationship of the turbine and governing system with the overall system is shown in Figure 3.1. The electric system performance is affected via the change in the mechanical input power or torque which will influence the generator active power and rotor angle. Changes of generator active power have effect on active power balance in a network and respectively on the network frequency/generator speed.

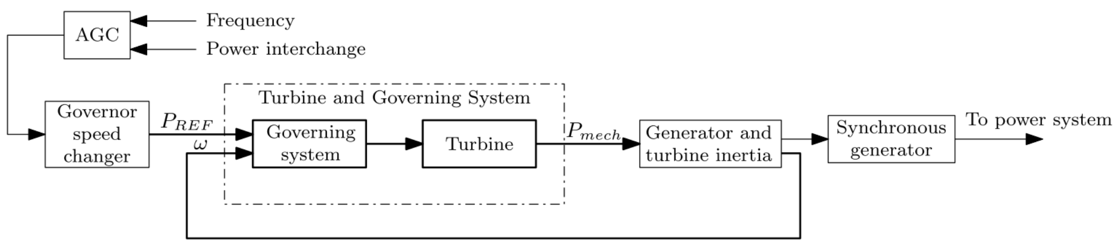


Figure 3.1 Functional block diagram of a turbine and its governing system

The basic elements of a governing system are:

- speed governor;
- speed control mechanism;
- governor-controlled valves and gates.

The speed governor will provide the control action based upon the reference input P_{REF} and synchronous generator speed, ω. The speed control mechanism could be a servomotor, which controls the valves, and gates, which in turn control the flow of water, steam, or gas into the turbine.

3.1 Speed Governing

The governing system can either be in 'isochronous' or 'speed droop' control. When the governor is tuned to be isochronous, the governor will tend to keep the system frequency at its reference value. This type of control is typically used on island systems. An isochronous governor cannot be used when generators are operating in parallel. A small variation in speed set-point would result in generators trying to control the system frequency independently, resulting in generators continually acting against each other. The droop characteristic is used to control the magnitude of the governor response for a given change in frequency. This results in a stable load sharing between units operating in parallel.

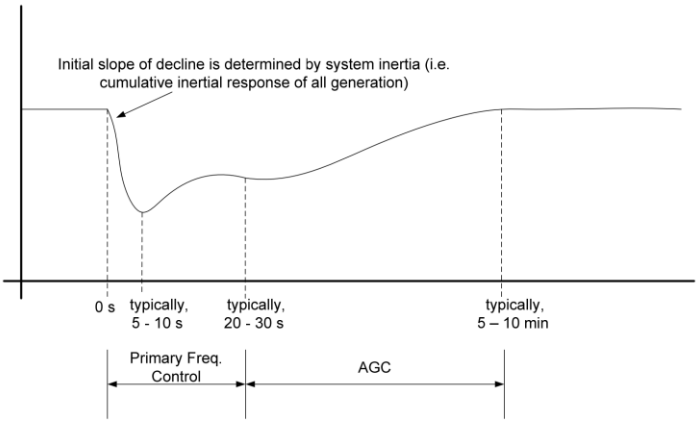


Figure 3.2 Typical power system frequency response [IEEE2003]

In the above figure a frequency response to a loss of generation in a typical power system is shown. In this plot three periods of response can be observed: first, the initial response down to the nadir (lowest point of the frequency deviation), second, the initial stabilisation of frequency, and the final return to the nominal frequency. The governor operating in a droop control mode prevents the drop in frequency and the system stabilises at this new frequency. After that, the frequency is restored to nominal by the Automatic Generation Control (AGC) system by an update of P_{REF}.

In Figure 3.3 the steady-state characteristic of a droop controlled generating unit (speed versus load) is plotted. The slope that represents the ratio of speed deviation (Δω) to the change of power output, can be expressed in percent as:

$$\%R = \frac{speed\ or\ frequency\ change\ in\ percent}{power\ output\ change\ in\ percent} \cdot 100\%$$

$$= \left(\frac{\omega_{NL} - \omega_{FL}}{\omega_0}\right) \cdot 100\%$$

where

ω_{NL} = *steady-state no load speed (rad/sec)*
ω_{FL} = *steady-state full load speed (rad/sec)*
ω_o = *rated speed (rad/sec)*
R = *governor speed-droop (%)*

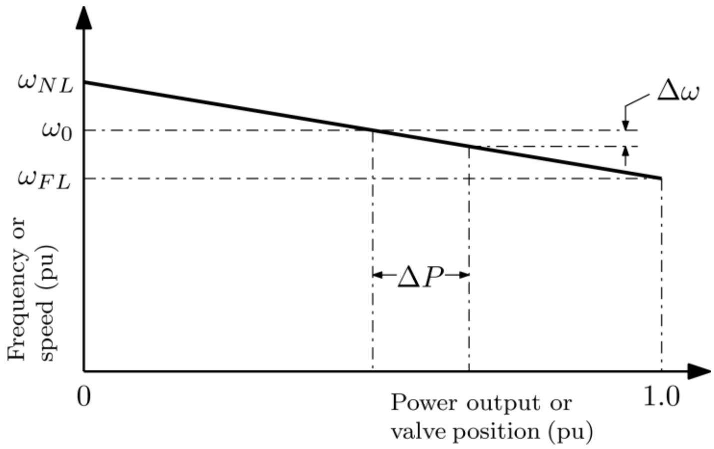


Figure 3.3 Steady-state governor speed-droop characteristics

The droop settings will normally be specified by the TSO within the range of 2 – 12 %. A droop of 4% (or R=0.04 pu) would mean that a 4% frequency deviation results in a 100% change in valve position or power output. The steady state equation of frequency-power relation used in governing modelling is provided below:

$$P_{CV} = P_{REF} - \frac{1}{R}\Delta\omega$$

where P_{cv} is the control valve position.

The parameter ***f/P-droop*** in the form **Synchronous Generator | General** equals ***R****·100%* for the TGOV1 and GAST models, 100/$\boldsymbol{K_1}$ for the IEESGO model and 100/**K** for the IEEEG1 model. In Section 6.2 an example of three generators operating in parallel with different speed-droop settings is provided.

3.2 Turbine and Governing System Implementation

During initialisation of the models the system is initialised based upon the generator output electric power. However, in case of a reference step the reference P_{REF} is adjusted and thus the mechanical power and not electric. When analysing a reference step in power, the mechanical turbine output power is thus controlled to the specified set-point and not the generator active power.

By disabling the **Turbine and Governing System** or by choosing **Constant** as type, the system functions as a *Blocked Governor*. The governing feedback is bypassed when this type of control is employed and the turbine mechanical output power is fixed, the value of which is determined during initialisation of the system (load-flow results).

3.3 Per Unit System

Care must be taken in selecting the per unit system for specifying the turbine parameters. In Vision this per unit base ($\boldsymbol{MW_{base}}$) can be specified in the ***Turbine and Governing system parameters*** form. A convenient per unit system is the maximum turbine power at rated main steam pressure with the control valve fully open. Normally the per unit base is provided in the turbine specifications. Hence, this per unit base is not to be confused with the $\boldsymbol{S_{base}}$ of the synchronous machine. The input and output variables of the turbine and governing system are automatically converted to the appropriate per unit base.

In the plot options all per unit variables are at the synchronous machine base (S_{base}).

4 STEAM TURBINE MODELS

Large steam turbines are commonly used in the large fossil fuelled power plants. The steam turbine converts stored energy (boiler) of high pressure and high temperature steam into rotating energy, which in used to drive the generator. In the models described below the boiler is treated as an infinite and constant source of steam, boiler dynamics are thus neglected.

Steam turbines normally consist of two or more turbine sections coupled in series. Currently only tandem compound turbines are modelled, i.e. all turbine sections are on the same shaft.

4.1 Type TGOV1 SMTGS

The TGOV1 model is a simplified representation of a steam turbine. The model represents the turbine-governor droop $\boldsymbol{R}$ (equal to f/p-droop / 100%), the main steam control valve time constant $\boldsymbol{T_1}$, and limitations $\boldsymbol{V_{max}}$ and $\boldsymbol{V_{min}}$. The motion of steam through the reheater and turbine stages is represented by the lead-lag element with time constants $\boldsymbol{T_2}$ and $\boldsymbol{T_3}$. Parameter $\boldsymbol{D_t}$ is used to model the turbine mechanical damping. The ratio, $\boldsymbol{T_2/T_3}$, equals the fraction of the turbine power that is developed by the high-pressure turbine stage and $\boldsymbol{T_3}$ is the reheater time constant [IEEE 2013].

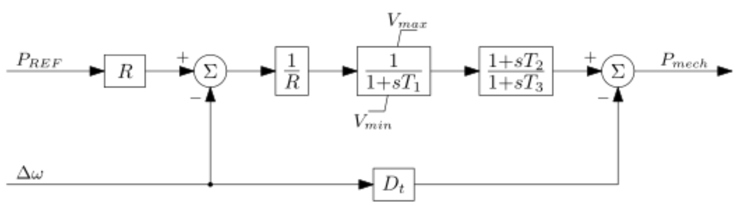


Figure 4.1 Type TGOV1 – steam turbine model

4.1.1 TGOV1 - PARAMETERS

Parameter	Unit	Description	Default	Min	Max
R	pu	Turbine-governor droop	0.05	**0.001**	0.1
D_t	pu	Turbine damping coefficient	0.05	0	0.5
V_{max}	pu	Main steam control valve max limit	1	0.5	1.2
V_{min}	pu	Main steam control valve min limit	0	0	0.4
T_1	sec	Time constant associated with the motion of steam through reheater and turbine stages	0.2	**0.01**	0.8
T_2	sec	Time constant associated with the motion of steam through reheater and turbine stages	0.6	0	5
T_3	sec	Time constant associated with the motion of steam through reheater and turbine stages	2	0	10

4.1.2 PARAMETER RESTRICTIONS

Time constant T_3 can only be set to zero if the time constant T_2 equals zero.

4.2 Type IEESGO 1973 SMTGS

The IEESGO model was originally introduced in the 1973 paper [IEEE1973] to represent tandem compound, single reheat turbine governing systems. In this model three steam turbine stages are modelled, respectively the high pressure, intermediate pressure, and the low pressure stage. The portion that each stage is contributing to the total mechanical output of the turbine is represented by the fractions F_{HP}, F_{IP}, and F_{LP}. The time constants T_{CH}, T_{RH}, and T_{CO} represent the delays associated with the motion of steam through the steam chest and inlet piping, the reheater, and the crossover piping, respectively. The limits P_{min} and P_{max} represent the limits imposed by valve or gate travel. Droop is modelled by gain K_1, which is equivalent to 1/R in the TGOV1 model.

This model can also be used to represent hydro systems through an appropriate choice of parameters (see [IEEE1973]). The representation of hydro systems using this model only provides accuracy within a very limited bandwidth, therefore one should be careful using this model for hydro systems.

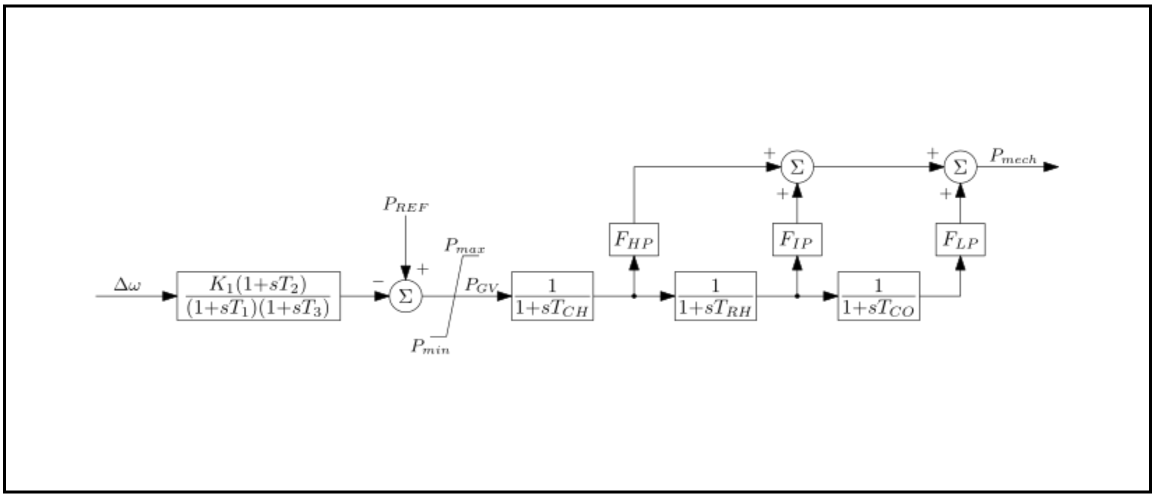


Figure 4.2 Type IEESGO 1973 – steam turbine model

4.2.1 IEESGO 1973 - PARAMETERS

Parameter	Unit	Description	Default	Min	Max
K_1	pu	Total effective speed-governing system gain (1/droop)	20	1	100
T_1	sec	Controller lag compensation	0.2	**0.001**	100
T_2	sec	Controller lead compensation	0	0	20
T_3	sec	Governor lag	0.1	**0.001**	100
P_{max}	pu	Max power limit imposed by valve or gate control	0.98	0.5	1.2
P_{min}	pu	Min power limit imposed by valve or gate control	0	0	0.4
F_{HP}	pu	High pressure turbine power fraction	0.3	-2	1
F_{IP}	pu	Intermediate pressure turbine(s) power fraction	0.4	0	3
F_{LP}	pu	Low pressure turbine(s) power fraction	0.3	0	1
T_{CH}	sec	Steam chest time constant	0.25	0	1
T_{RH}	sec	Reheat time constant	7	**0.01**	20
T_{CO}	sec	Crossover time constant	0.4	**0.01**	1

4.2.2 PARAMETER RESTRICTIONS

There are the following parameter restrictions:

- Sum of F_{HP}, F_{IP}, and F_{LP} should be equal to 1 pu (except for hydro systems).

4.3 Type IEESGO 2003 SMTGS

The steam turbine model previously described is used in another form in the IEEE report [IEEE2013] and presented here as IEESGO 2013. In this model three different turbine stages are represented by the fractions K_2 and K_3. The relation to the IEESGO 1973 model is as follows:

$$F_{HP} = 1 - K_2$$
$$F_{LP} = K_2(1 - K_3)$$
$$F_{LP} = (K_2.K_3)$$
$$T_{CH} = T_4, \quad T_{RH} = T_5, \quad T_{CO} = T_6$$

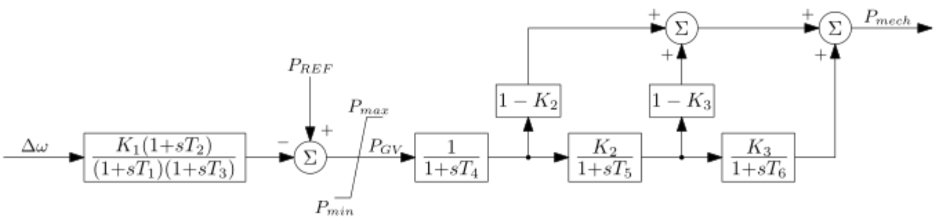


Figure 4.3 Type IEESGO 2013 – steam turbine model

4.3.1 IEESGO 2013 - PARAMETERS

Parameter	Unit	Description	Default	Min	Max
K_1	pu	Total effective speed-governing system gain (1/droop)	20	1	100
T_1	sec	Controller lag compensation	0.2	**0.001**	100
T_2	sec	Controller lead compensation	0	0	50
T_3	sec	Governor lag	0.1	**0.001**	100
P_{max}	pu	Max power limit imposed by valve or gate control	0.98	0.5	1.2
P_{min}	pu	Min power limit imposed by valve or gate control	0	0	0.4
K_2	pu	Gain used to compute HP, IP and LP fraction	0.7	0	1
K_3	pu	Gain used to compute HP, IP and LP fraction	0.4	-1	1
T_4	sec	Low pressure turbine(s) power fraction	0.25	**0.01**	1
T_5	sec	Reheat time constant	7	**0.01**	20
T_6	sec	Steam chest time constant	0.4	**0.01**	1

4.4 Type IEEEG1 SMTGS

The IEEEG1 model is used for tandem compound, double reheat steam turbine systems. Again the droop is modelled by gain $\boldsymbol{K}$ (equal to 1/R). The speed relay is represented by a lead-lag compensator with time constants $\boldsymbol{T_1}$ and $\boldsymbol{T_2}$. The servomotor is modelled by an integrator with time constant $\boldsymbol{T_3}$ and direct feedback. Valve position limits are indicated with parameters $\boldsymbol{P_{min}}$ and $\boldsymbol{P_{max}}$ and rate limiting of the servomotor (which may occur for large and rapid speed variations) is represented by a limit on $\dot{\boldsymbol{P}}_{GV}$ using parameters $\boldsymbol{U_c}$ and $\boldsymbol{U_o}$. The time constants $\boldsymbol{T_4}$, $\boldsymbol{T_5}$, $\boldsymbol{T_6}$, and $\boldsymbol{T_7}$ represents delays due to the steam chest and inlet piping, reheater 1, reheater 2, and crossover piping, respectively. The gains $\boldsymbol{K_1}$, $\boldsymbol{K_3}$, $\boldsymbol{K_5}$ and $\boldsymbol{K_7}$ are defined as the portions (in pu) of the total power developed at the various turbine stages.

The frequency of the power system is varying continuously due to continuous load variation. Those frequency variations are innocuous in absence of a major disturbance. To avoid constant valve control action a dead-band controller is applied. The dead-band controller is implemented as a non-step. The non-step dead-band controller is mathematically represented as follows (x and y are the input and the output of the block, respectively, and D is the dead-band amplitude):

$$\begin{cases} y = 0 & -D \le x \le +D \\ y = x - D & x \ge +D \\ y = x + D & x \le -D \end{cases}$$

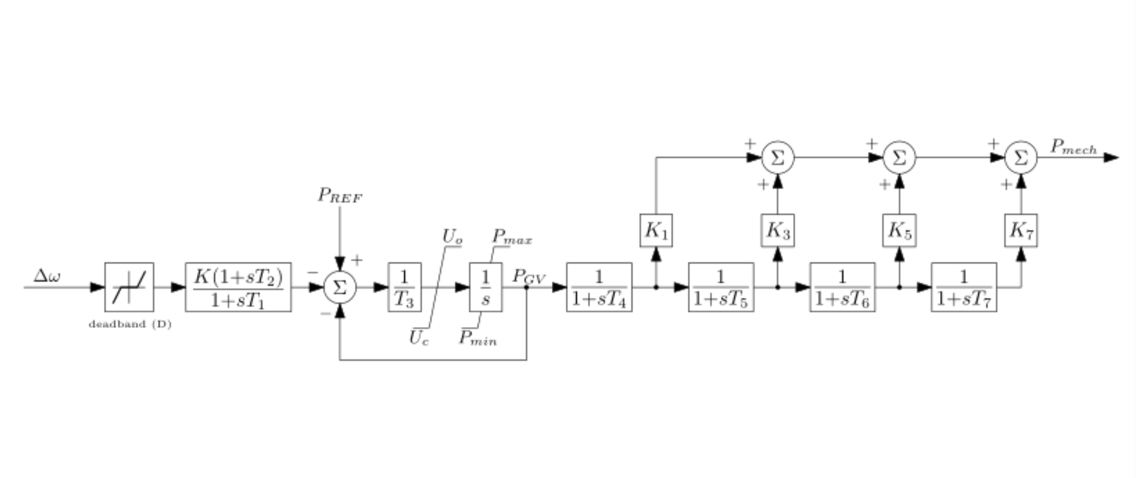


Figure 4.4 Type IEEEG1 – steam turbine model

4.4.1 IEEEG1- PARAMETERS

Parameter	Unit	Description	Default	Min	Max
K	pu	Total effective speed-governing system gain (1/droop)	20	1	100
T_1	sec	Controller lag compensation	0.2	**0.001**	50
T_2	sec	Controller lead compensation	0	0	100
T_3	sec	Valve position time constant (servomotor mechanism)	0.1	**0.01**	5
P_{max}	pu	Max power limit imposed by valve or gate control	0.98	0.5	1.2
P_{min}	pu	Min power limit imposed by valve or gate control	0	0	0.4
UO	pu/s	Max main control valve rate of change	0.1	0.01	2

U_C	pu/s	Min main control valve rate of change	-0.1	-2	-0.01
D	Hz	Dead-band amplitude	0.02	0	0.06
K_1	pu	Fvhp, very high pressure turbine power fraction	0.22	0	1
K_3	pu	Fhp, high pressure turbine power fraction	0.22	0	1
K_5	pu	Fip, intermediate pressure turbine power fraction	0.3	0	1
K_7	pu	Flp, low pressure turbine power fraction	0.26	0	1
T_4	sec	Tch, steam chest time constant	0.25	**0.01**	1
T_5	sec	Trh1, reheat time constant	4	**0.01**	20
T_6	sec	Trh2, reheat time constant	4	**0.01**	20
T_7	sec	Tco, crossover time constant	0.4	**0.01**	1

4.4.2 PARAMETER RESTRICTIONS

The sum of K1, K3, K5, and K7 should be equal to 1 pu.

4.5 Type LCFB1 Outer-Loop MW Controller

The LCFB1 model is a simple representation of an outer-loop MW controller, which acts to maintain the turbine power on a pre-set value by continuous adjustment of the turbine load reference. The error developed by comparison of the MW setting and the actual measured real load is applied to a PI controller which will correct the control valve position to reduce any MW deviation. The LCFB1 model is only needed in cases where there is an active secondary outer-loop MW controller in the plant, which is not always the case.

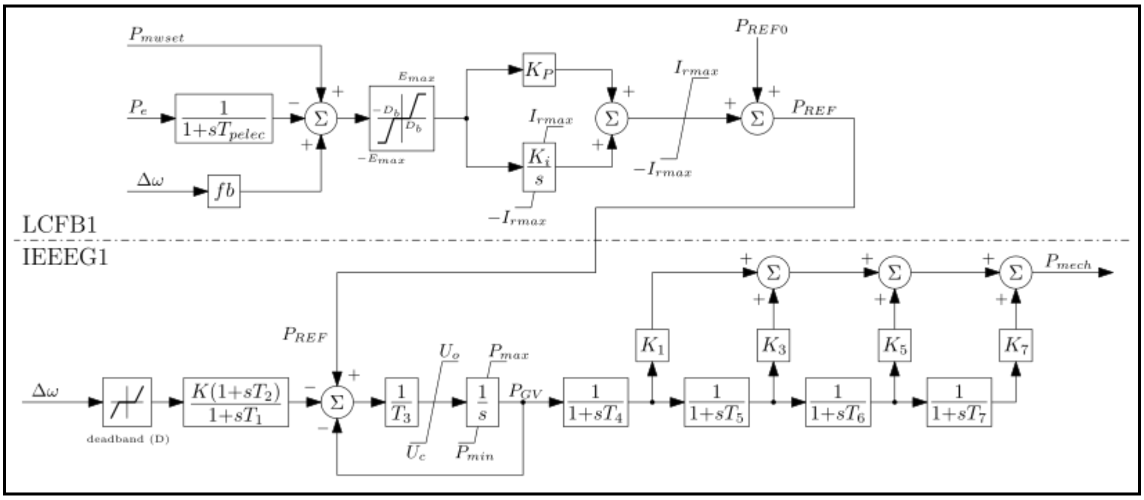


Figure 4.5 **Type LCFB1 - Outer-loop MW Controller in combination with the IEEEG1 steam turbine model**

4.5.1 LCFB1- PARAMETERS

Parameter	Unit	Description	Default	Min	Max
Fb	pu	Frequency bias gain	0	0	100
D_b	pu	Controller dead-band amplitude	0	0	0.2
E_{max}	pu	Maximum error	0.1	0	2
K_P	pu	Controller proportional gain	0	0	20
K_I	pu	Controller integral gain	0.05	0	2
T_{pelec}	sec	Power transducer time constant	3	**0.01**	10
I_{rmax}	pu	Maximum controller output	0.1	0.01	1

5 GAS TURBINE MODELS

Currently only the GAST gas turbine model is implemented, in the near future more models (e.g. the GGOV1 and the GT1) will be added. On request special or preferably standardised models can be implemented.

5.1 Type GAST SMTGS

The GAST model represents the basics of a gas turbine. Parameter T_1 characterizes the fuel valve positioning time constant, the output of which is limited by V_{min} and V_{max}. The turbine response is represented by a single lag time constant, T_2. Turbine damping is taken into account by setting parameter D_{turb}.

The temperature of the hot gasses entering the turbine need to be kept below a certain limit in order to preserve life of the hot gas-parts of the turbine. However, it is extremely difficult to measure the gas temperature directly. Therefore, the temperature of the exhaust is measured. Its measuring time constant is represented by parameter T_3. The ambient temperature load limit is indicated by A_T and the temperature control loop gain by K_T.

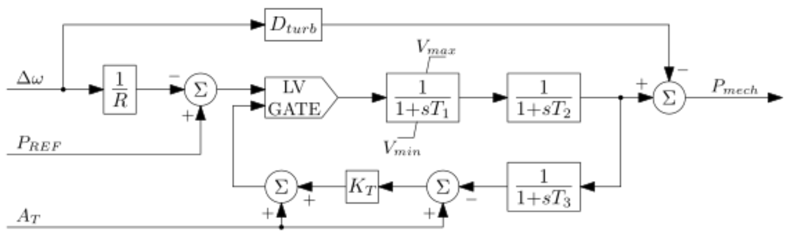


Figure 5.1 Type GAST – gas turbine model

5.1.1 GAST - PARAMETERS

Parameter	Unit	Description	Default	Min	Max
R	pu	Governor speed droop	0.05	0.001	0.1
T_1	sec	Governor mechanism time constant (fuel valve response)	0.1	**0.01**	1
T_2	sec	Turbine time constant	0.2	**0.01**	1
T_3	sec	Turbine exhaust temperature time constant	3	**0.01**	5
V_{max}	pu	Main steam control valve max limit	1	0.5	1.2
V_{min}	pu	Main steam control valve min limit	0	0	0.4
D_{turb}	pu	Turbine damping factor	0.3	0	1
A_T	pu	Ambient temperature load limit	1	0	1
K_T	pu	Temperature control loop gain	2	0	10

6 EXAMPLE

Below an example of a dynamic study is provided where the system operates in island mode. For this example a single dynamic study case is treated: the sudden application of a 30 MVA (25 MW and 16 Mvar) load. This load-step is applied to the node ***KP 10 kV*** at 10 seconds.

6.1 System description

The single-line diagram shown below represents a simple island network. The Vision Network File (vnf) of this example is made available on our website, you can download this example using the following link: http://www.phasetophase.nl/vnf/DemoVisionManualSMTGS.vnf

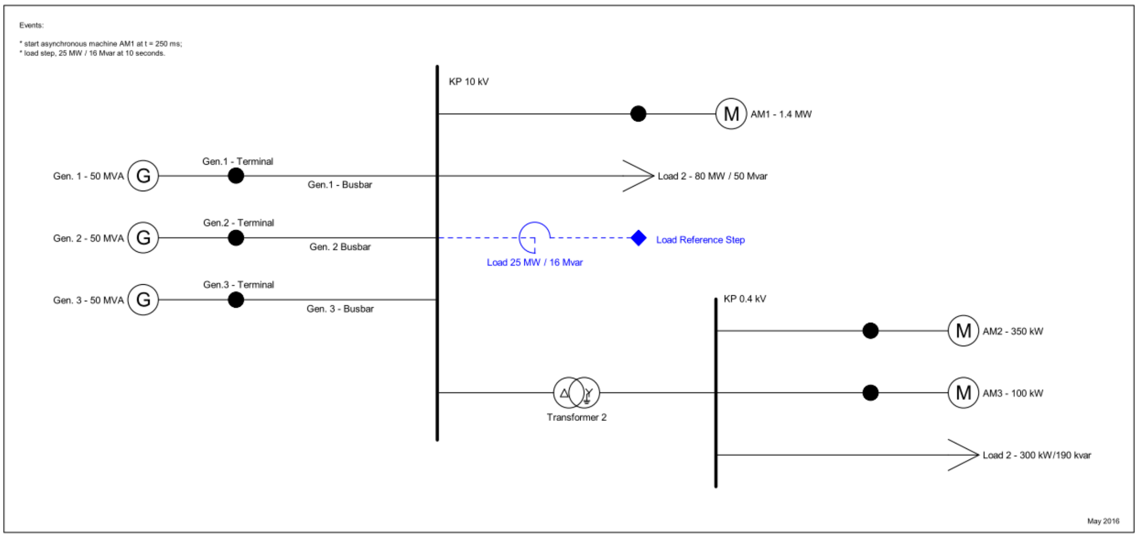


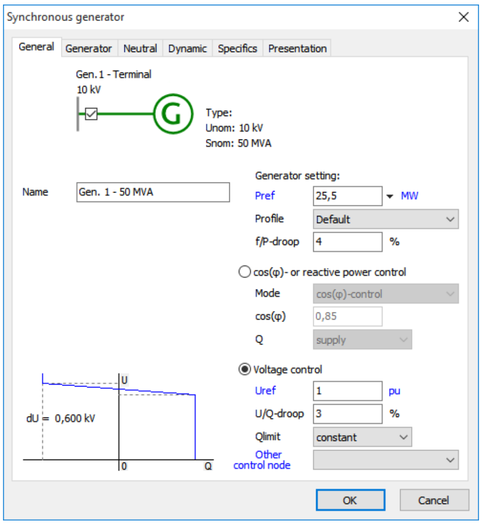
Figure 6.1 Single-line diagram demo network

The synchronous generators are all identical including their control elements, the only differences can be found in the specified droop characteristics. This is done just for the purpose of demonstrating the load sharing. The generator field is excited by a PID controlled alternator-rectifier excitation system represented by the IEEE type AC8B ESM. The generators are operating in voltage control mode. The U/Q-droop of Generator 1 equals 3%, for Generator 2 the U/Q-droop equals 2.5%, and for Generator 3 the U/Q-droop is 2%.

The synchronous generators are connected to the 10 kV node ***KP 10 kV*** via links (representing connecting cables). This is done since the generators with different values of U/Q-droop cannot be connected to one node.

Mechanical power is provided by steam turbines, the turbine and governing systems are represented by the TGOV1 model. The f/P-droop settings are 4% for generator 1, 6% for generator 2, and 8% for generator 3. The asynchronous motor AM1 is connected to the 10 kV node by two parallel 50 meter 35 mm^2 Cu cables. At the low voltage side of the 2 MVA, 10/0,4 kV Dyn5 transformer (Transformer 2) two asynchronous machines and a 300 kW, 190 kvar load are coupled. The asynchronous machines AM2 and AM3 are 350 kW and 100 kW, respectively.

Below the input forms of the 50 MVA synchronous generator (Generator 1) are shown, the tab sheets of interest are **General** and **Dynamic**. When the field of the synchronous generator is controlled by an excitation system, the generator could either be in **voltage control** or in **PF- or reactive power control** mode. For this example where the island operation is considered, all generators operate in voltage control mode with both U/Q-droop and f/P-droop characteristics.



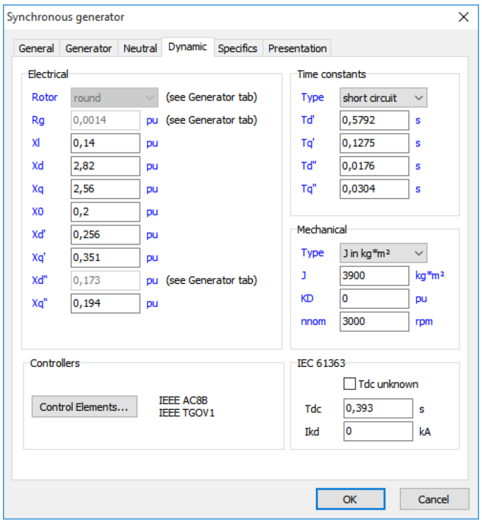


Figure 6.2 Input forms General and Dynamic of the synchronous generator Gen. 1 – 50 MVA

The form below provides an overview of the control elements of the synchronous generator. The control elements can be enabled/disabled there, and the model and its parameters can be specified.

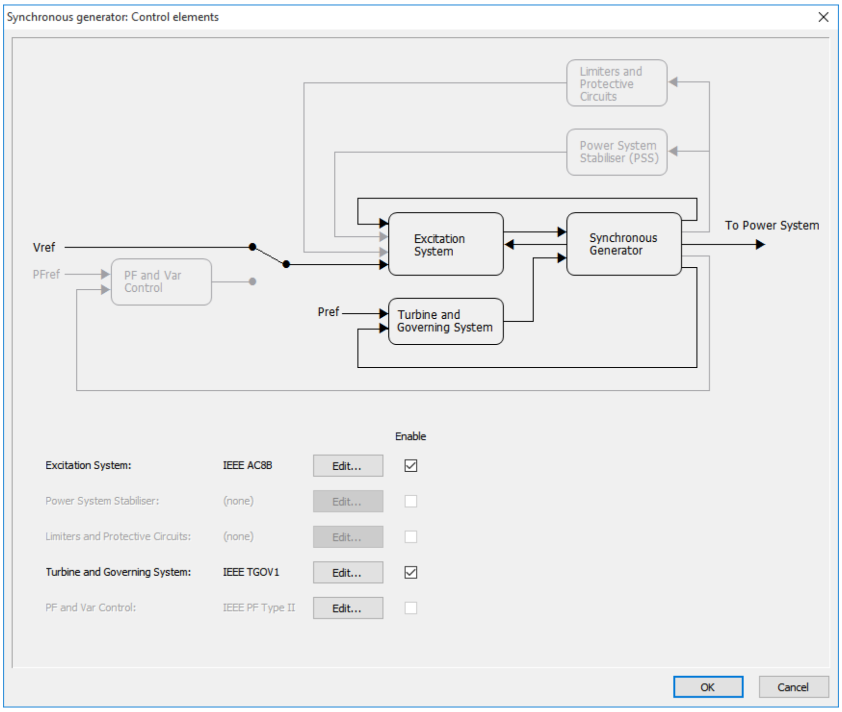


Figure 6.3 Synchronous generator control elements input form

The excitation system selection and parameter input form (see the figure below) can be accessed via the synchronous generator options using tabs **Dynamic | Control Elements | Edit**. The PID controller of the excitation system is tuned for this specific case to meet the desired specifications.

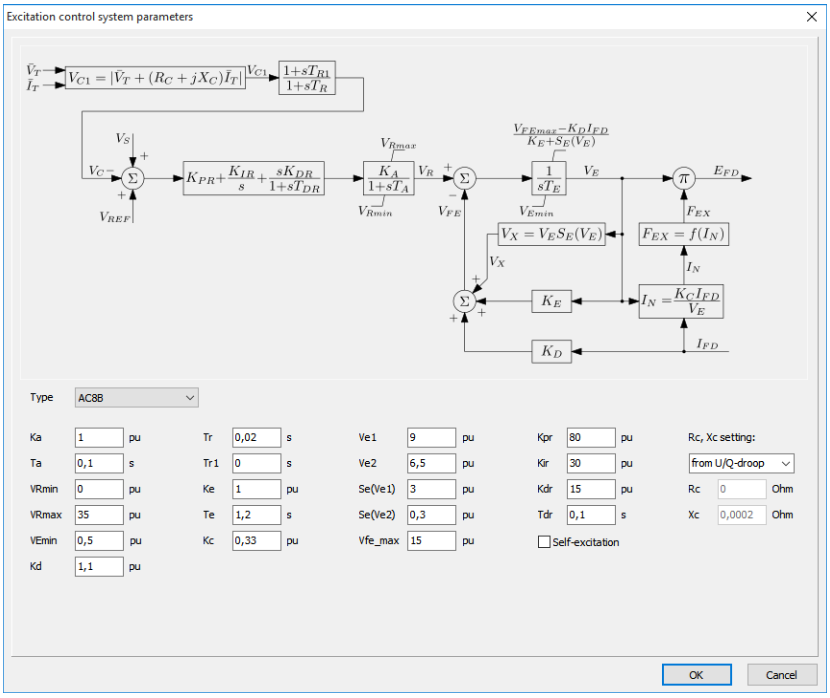


Figure 6.4 Excitation system selection and parameter input form

The parameters of the TGOV1 governing and turbine model are specified in the form below. Care must be taken in selecting the per unit system for specifying the turbine parameters. The first parameter can be used to specify the per unit base, MW_{base}. A convenient per unit system is the maximum turbine power at the rated main steam pressure with the control valve fully open. Normally the per unit base is provided in the turbine specifications.

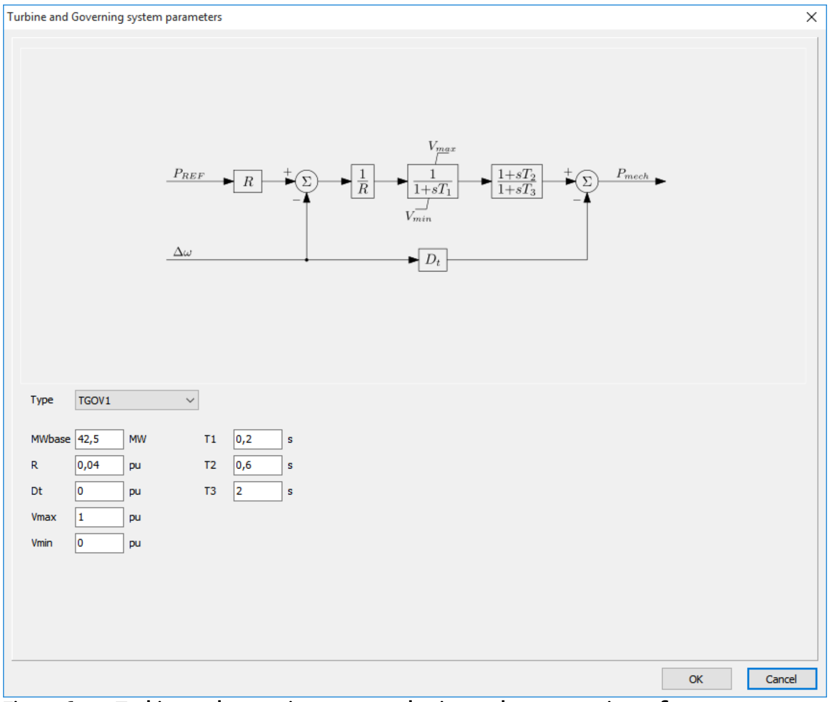


Figure 6.5 Turbine and governing system selection and parameter input form

In this case the maximum turbine power is 42,5 MW, which is used as the per unit system base by the turbine manufacturer to provide the above parameters. Hence, the synchronous machine per unit base is S_{nom} which is equal to 50 MVA. In the plot options all per unit variables are at the synchronous machine base.

6.2 Dynamic study

Using this example the effect of droop control on a system operating in island mode will be illustrated. The system is subjected to a sudden application of a 25 MW / 16 Mvar load. The response of the system, and, in particular, the response of the generators, are to be studied in this example.

6.2.1 DYNAMIC CASE

The load-step is simulated using a workaround, since it is at this point not possible to change the system topology during a dynamic simulation. It is however possible to apply a three phase short circuit. By connecting a reactance coil between the node, on which the load step is to be employed, and a fictitious node, which is used to apply the short-circuit to create a star connected load. The amplitude of both the active- and the reactive-power step can be set by an appropriate choice of parameters R and X of the reactor. The reactor can been seen on Figure 6.1, where it is dotted, since it is not a part of the physical network. Below the actual dynamic event is shown, a short circuit at *Node Load Reference Step*.

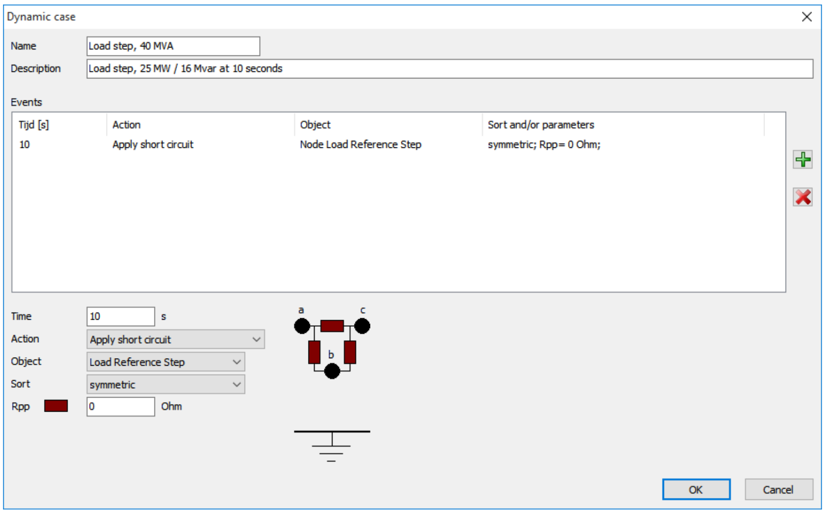


Figure 6.6 Load step by applying a short circuit behind a reactor

To simulate a reference step of 30 MVA with a power factor of 0.85 the parameters for R and X are determined to be 2.8574 Ω and 1.7708 Ω respectively.

6.2.2 EXPECTED BEHAVIOUR

The initial reference active power output of the three generators equals 60 % (25.5 MW). To match the load demand each generator will contribute based upon the user specified f/P-droop characteristic. The system will initially be at the nominal frequency, ω_0. By applying the short-circuit after the reactance coil at 10 seconds, the system load demand increases. This increase is responsible for a decrease in both system frequency and voltage. The governors will increase the mechanical output until they reach a new common operating frequency, ω'. The active power output of each generator depends on the droop characteristic, which is illustrated in Figure 6.7.

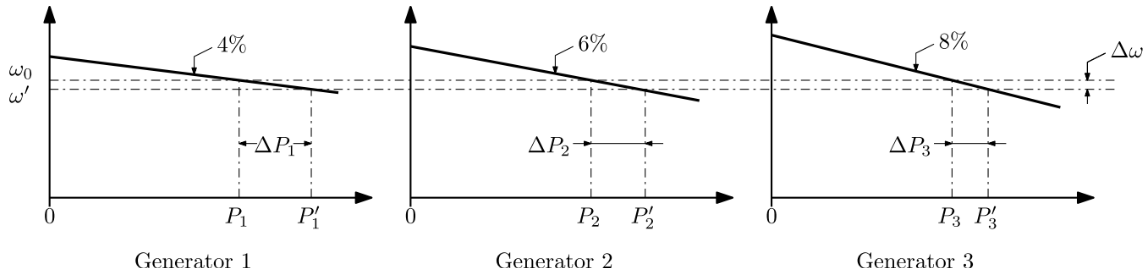


Figure 6.7 Load sharing parallel generators with drooping governor characteristics

It can been seen that Generator 1, with a f/P-droop of 4% contributes more to the load sharing than the other two generators. From the specified f/P-droop the contributions of each generator can be computed. They are as follows: 46.15 % (Generator 1), 30.77 % (Generator 2) and 23.08 % (Generator 3). The system will find its equilibrium at ω' with generator outputs P_1', P_2', and P_3'.

The voltage drop in response to the change in reactive power demand, will cause the AVRs to respond. The amount of reactive load picked up by each generator depends on the U/Q-droop characteristics. Since Generator 3 has the smallest U/Q-droop setting we can expect that this generator is going to deliver the most reactive power. For more details on excitation systems and the U/Q-droop see: http://www.phasetophase.nl/pdf/SynchronousMachineExcitationSystems.pdf

6.2.3 SIMULATION

A dynamic simulation can be started using **Calculate | Dynamic analysis**. For this example some advanced settings are used: (1) for the initialisation of the system, where time domain initialisation is employed, and (2) for the resistance of the short circuit, which is set to 1e-6 pu. Time domain initialisation is used in case if a dynamic simulation does not start in steady-state. This might occur due to the differences between models used for the loadflow and the dynamic calculation. With this initialisation method an "empty" dynamic simulation (without selected dynamic case) is performed first. After that, the states obtained at the specified end time (100 seconds in the example below) are used to initialise the actual dynamic simulation (with the selected dynamic case). Below the windows with calculation parameters are shown, the end time of the simulation of the selected dynamic case is 200 seconds.

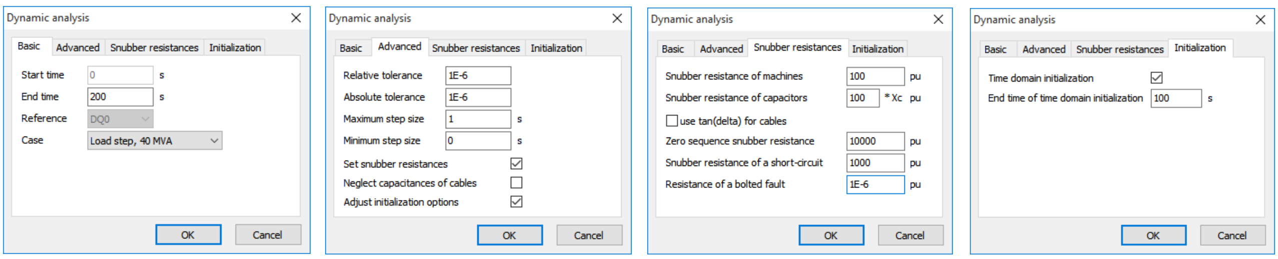


Figure 6.8 Dynamic calculation settings

6.2.4 SIMULATION RESULTS

The frequency of the system in response to the load step is shown below in Figure 6.9. Since all generators are identical, the system frequency can be obtained by observing the speed of one of the generators. The system is initialised at the nominal frequency (50 Hz), after applying the load step the frequency stabilizes at 0.9904 pu or 49.52 Hz.

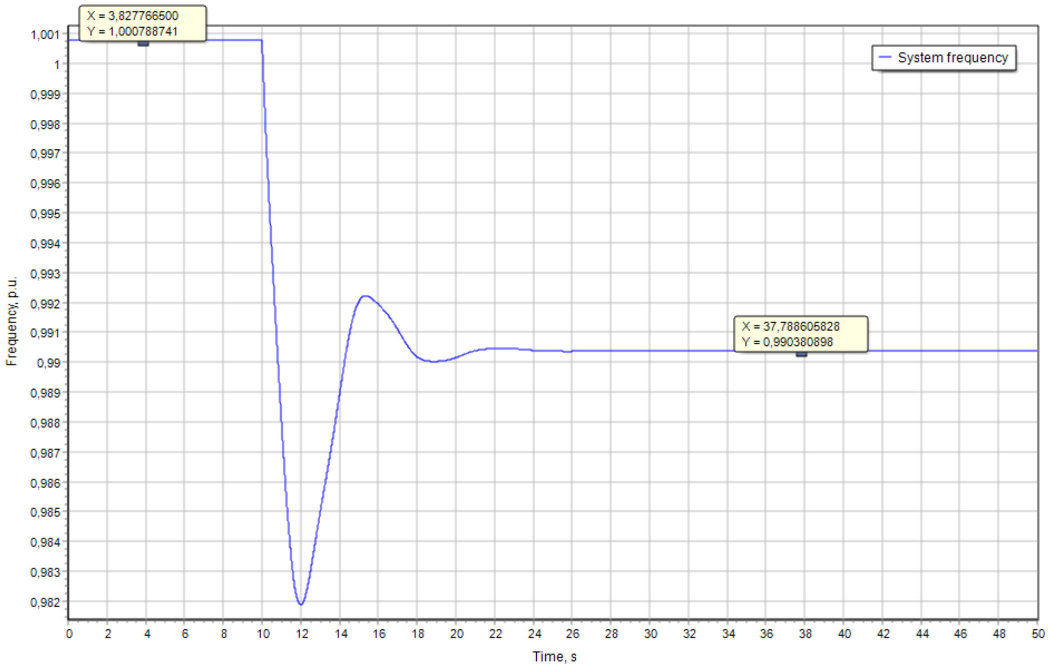


Figure 6.9 System frequency in response to a 25 MW / 16 Mvar load step

To stabilise the system the three governors will increase the turbine mechanical power output based upon the frequency drop and the specified f/P-droop. The mechanical outputs of the three turbine governing systems are shown below in Figure 6.10

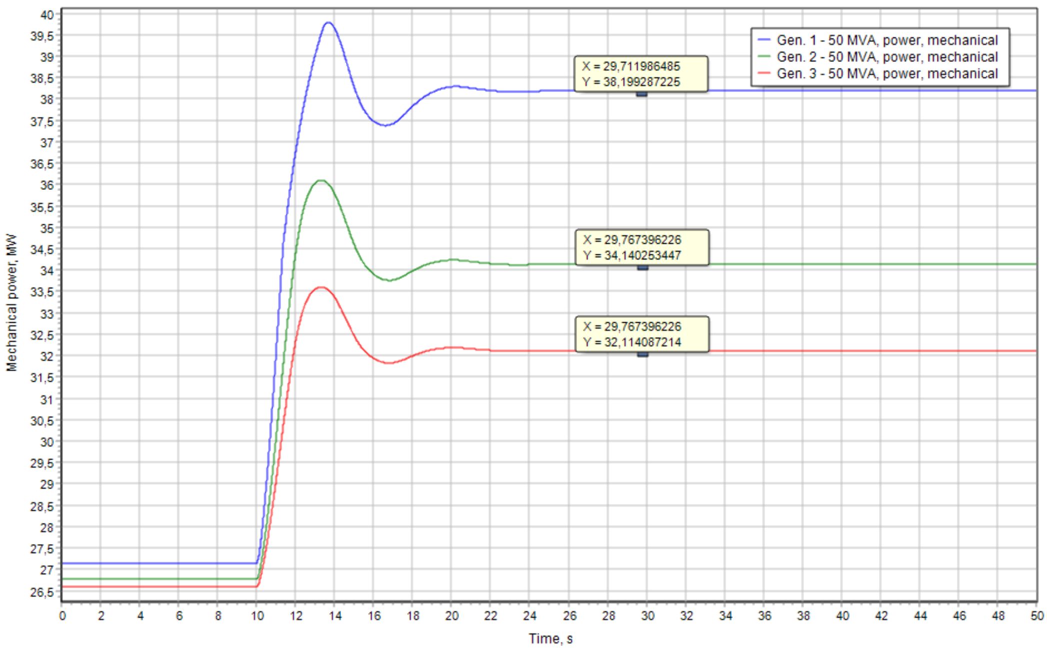


Figure 6.10 Mechanical turbine output in MW

The mechanical power input of Generator 1 after the application of the 30 MVA load equals 38.2 MW, which can be validated as follows:

$$\Delta P_1 = \frac{\Delta\omega}{R_1} = \frac{1.000789 - 0.99038}{0.04} = 0.260225 \quad pu$$

The total turbine mechanical power output should be equal to:

$$\begin{aligned} P_1' &= P_1 + \Delta P_1 \\ &= 27.14 + (0.260225 * 42.5) \\ &= 38.2\ MW \end{aligned}$$

This corresponds to the obtained simulation results. The steam control valve position (governor output) of the three units is plotted in Figure 6.11, where at 11.4 seconds (1.4 seconds after applying the load step) the control valve position of Generator 1 is limited at 1 pu. This limitation can also be observed in Figure 6.10, where the slope of the blue curve changes around 35 MW.

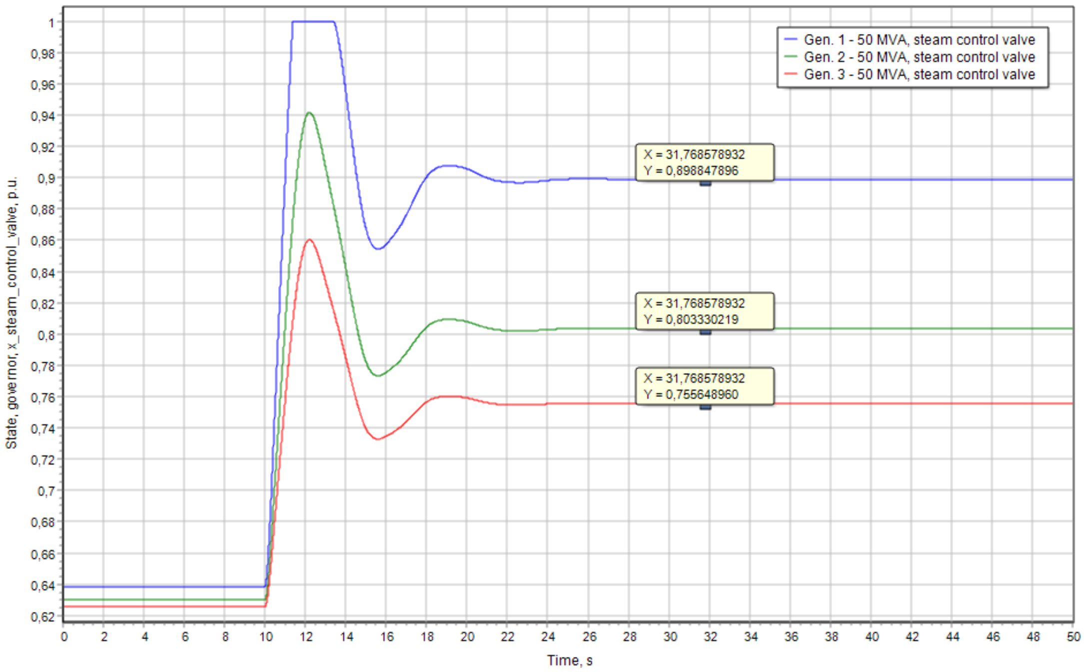


Figure 6.11 **Steam control valve position**

Since the 30 MVA load step also includes a step of reactive power of 16 Mvar, the system terminal voltage will drop. All generators are operating in voltage control mode with U/Q-droop characteristics. Below the terminal RMS voltage of Generator 1 is shown in pu.

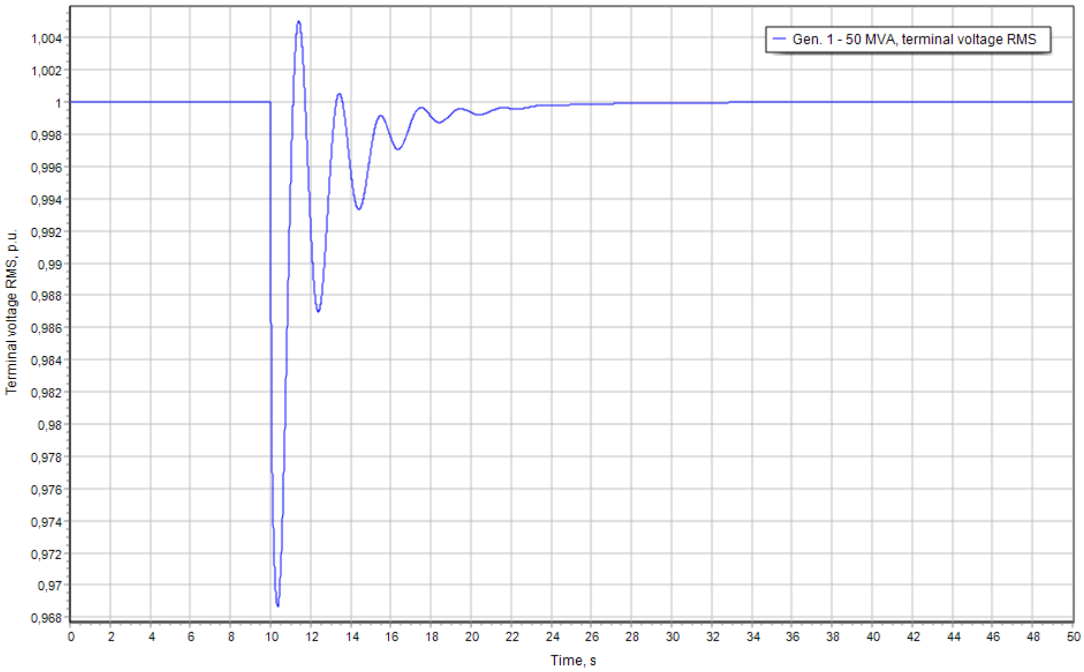


Figure 6.12 Terminal RMS per unit voltage generator 1

The influence of the U/Q-droop can be observed in the excitation system response. The droop setting of Generator 3 is smaller than that for the other two generators and this can be directly seen in the plot below. The contribution of Generator 3 to the reactive power demand is therefore larger than the contribution of the other two generators.

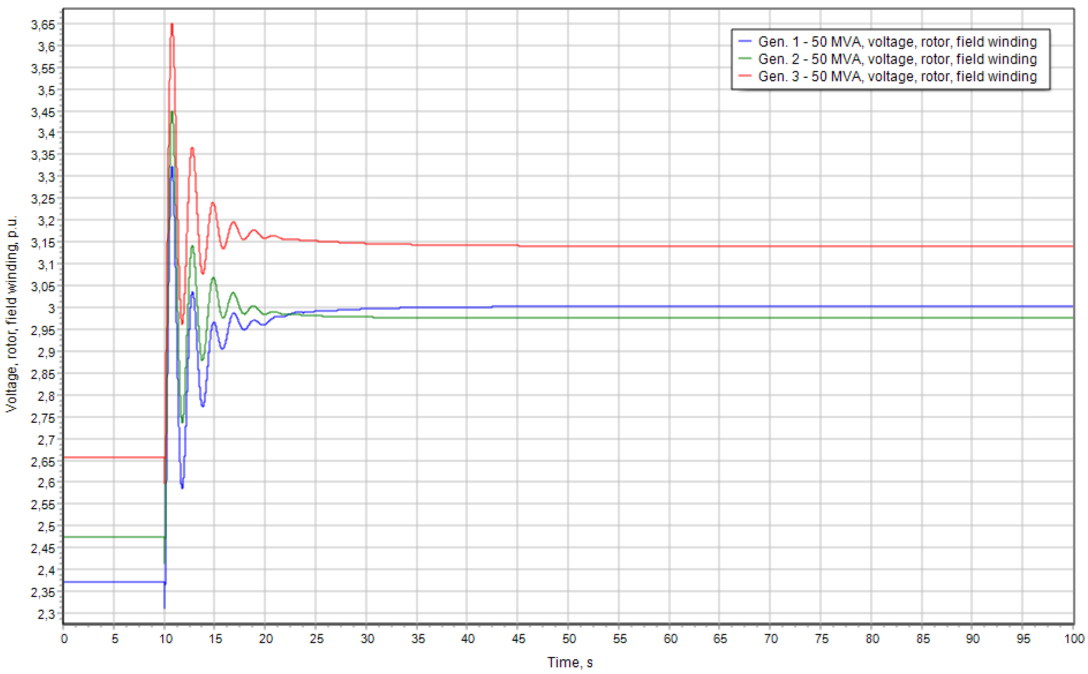


Figure 6.13 Excitation system output voltage, E_{FD}

Below the actual reactive power output of the three generators is shown. The steep slopes that can be observed at 10 seconds are the results of the computation method of the instantaneous reactive power.

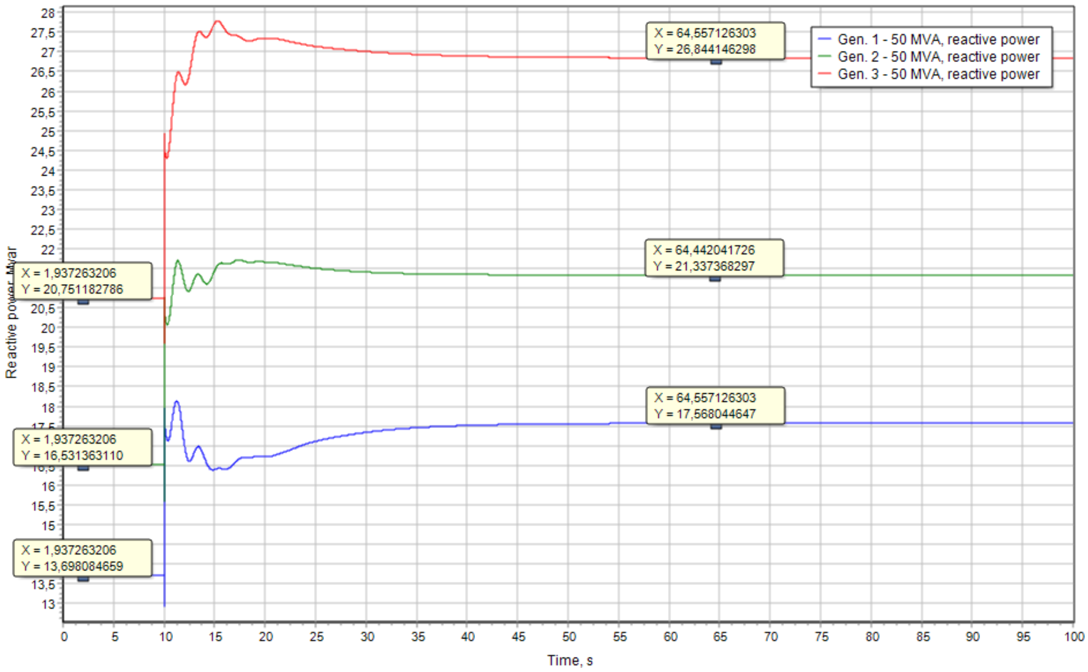


Figure 6.14 Reactive power output of Generators 1, 2, and 3

In order to stabilise the perturbed system both the excitation control, and the turbine and governing systems become active. This is a logical consequence since the dynamic case implies both a step of active and reactive power. It is however difficult (in this example) to perform a separate analysis of excitation and governor-turbine system behaviour. A step of the active power influences active power balance and the system frequency, but besides that also the terminal voltage (although to a less extent). Both controllers are acting at the same moment, which has an effect on the dynamic behaviour and the final steady-state values of active and reactive powers of generators. To analyse those effects separately one can easily change the dynamic case to a purely active or purely reactive load step.

7 BIBLIOGRAPHY

[IEEE1973] I. C. Report, “Dynamic Models for Steam and Hydro Turbines in Power System Studies,” in IEEE Transactions on Power Apparatus and Systems, vol. PAS-92, no. 6, pp. 1904-1915, Nov. 1973. doi: 10.1109/TPAS.1973.293570

[IEEE2013] I.C. Report, “Dynamic Models for Turbine-Governors in Power System Studies,” IEEE PES-TR1, 2013.