Frequency Stability

Outline

- Nature and description of frequency stability problems
- Examples of frequency instability incidents
- Analytical techniques for investigation of frequency stability problems
- Case studies
- Mitigation of frequency stability problems

Frequency Stability

- Ability to maintain a steady frequency within a nominal range, following a disturbance resulting in a significant imbalance between system generation and load
  - of interest is the overall response as evidenced by mean frequency, rather than relative motions of machines
- In a small "island" system, frequency stability could be of concern for any disturbance causing a significant loss of load or generation
- In a large interconnected system, frequency stability could be of concern only following a severe system upset resulting in the system splitting into one or more islands
- Depends on the ability to restore balance between generation and load of island systems with minimum loss of load and generation
- Generally, frequency stability problems are associated with inadequacies in equipment responses, poor coordination of control and protection systems

System Response to Generation/Load Imbalance

- Results in sustained frequency deviations
  - speed control and the subsequent responses of prime mover and energy supply systems play a major role
  - often, situation compounded by high- or low-voltage conditions
- Under-generated condition:
  - frequency will decline
  - if sufficient spinning generation reserve is not available, frequency may reach low levels at which thermal units are tripped by underfrequency protection
  - therefore, underfrequency load shedding used
- Over-generated condition:
  - speed governors respond to frequency rise
  - performance of island depends on the ability of power plants to sustain a "partial load rejection"

System Response to Generation/Load Imbalance (cont'd)

- Reactive power balance:
  - a significant mismatch could lead to high- or low-voltage conditions
  - generator under/over excitation, loss-of-excitation protections may be activated
- Power plant auxiliaries:
  - decrease in power supply voltage and frequency can degrade performance of induction motors
  - may lead to loss of condenser vacuum, high turbine-exhaust temperature, insufficient condensate/feedwater
  - many nuclear units are equipped with relays set to trip plant at low voltages (0.7 pu) and low frequency
- Power system loads respond to variations in voltage and frequency

Protections and Controls

The following protection/controls have significant influence:

- Prime mover/energy supply system
  - turbine overspeed control
  - turbine underfrequency protection
  - power plant auxiliaries protection
- Generator and excitation system
  - loss-of-excitation relay
  - under/overexcitation limiter
  - volts/Hz limiter and protection
- Electrical network
  - transmission and distribution system relays
  - underfrequency and undervoltage load shedding relays

Frequency Instability Incidents

1. April 19, 1972 disturbances in Ontario
   – islanding of Eastern Ontario

2. January 20, 1974 disturbance
   – islanding of Toronto area

3. February 13, 1978 disturbance causing separation of portions of Missouri and Illinois systems

April 19, 1972 Disturbance: Eastern Ontario

- Incident:
  - 230 kV lines east of Toronto tripped due to communication malfunction; ties to New York at St. Lawrence tripped
  - generation rich island formed in eastern Ontario (G = 3900 MW, L = 3000 MW)
  - frequency rose to 62.5 Hz and then dropped to 59.0 Hz due to speed governor
  - underfrequency load shedding
  - frequency rose to 62.6 Hz and dropped to 58.7 Hz
  - significant loss of generation and load
  - stabilized at 60.8 Hz with 1875 MW generation
- Source of problem:
  - overspeed controls associated with prime-mover governors of Pickering "A" NGS

January 20, 1974 Disturbance: Toronto Area

- Incident:
  - severe ice storm caused separation of power system in Toronto area
  - island consisting of Lakeview GS supplying Manby and Cooksville TSs
  - generation rich island
    (G = 1400 MW, L = 760 MW)
  - frequency rose to 63.4 Hz, dropped to 60.7 Hz, rose again to 62.3 Hz and oscillated for several seconds
  - boiler trips occurred on 4 of the 5 units at Lakeview
  - frequency dropped to 59 Hz
  - underfrequency load shedding restored frequency to 59.6 Hz
- Source of problem:
  - overspeed controls associated with prime-mover governors

February 13, 1978 Disturbance: Missouri and Illinois

- System separation was experienced by Union Electric Co. and portions of Illinois Power Co. and Associated Electric Cooperative Systems
- Generation rich island caused rapid closure of steam valves in 11 of 14 units at 6 plants
- 4 units tripped out
  - 2 by boiler trip
  - 1 by boiler and turbine trip
  - 1 manual trip

Analysis of Frequency Stability: Long-Term Dynamic Simulation

Modeling Requirements

- Power plant representation
  - effects of large changes in frequency and voltage
  - plant auxiliaries and associated motors
  - wide range of protection/controls
  - processes involving physical variables used as input signals to protection/controls
- Transmission network representation
  - protection/controls, VAr compensation and voltage control devices
  - effects of off-nominal frequency operation
  - effects of high voltage; transformer saturation
- Fast as well as slow processes

Analysis of Frequency Stability

Analytical Techniques

- Early programs, such as LOTDYS, assumed uniform system frequency and modelled only slow phenomena
  - allowed use of low order explicit integration
- Present approach recognizes need to model fast as well as slow phenomena
  - facilitated by use of implicit numerical integration
  - dual mode (short- and long-term) simulation
  - gear-type backward differention; automatic adjustment of time-step
- Singular perturbation analysis to decouple fast and slow transients
  - systematic derivation of reduced order models, including off-nominal frequency effects
  - tracking of fast states to determine when to switch modes

Long-Term Stability Program (LTSP)

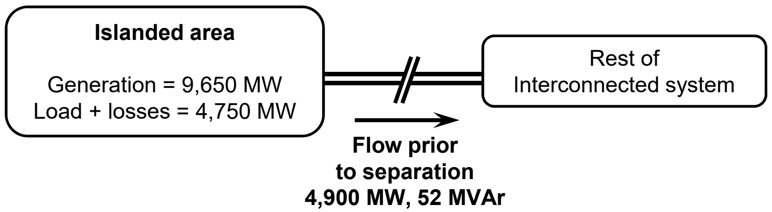
Based on ETMSP; modelling extended to include the following:

- Fossil-fuelled plant: furnace, fuel system, secondary air system, flue gas system, feed-water system, boiler, main and reheat system, control and protection systems, auxiliaries
- Nuclear plant (PWR, BWR, CANDU): reactor core, primary heat transport system, steam generator, feedwater system, main and reheat steam system, control and protection, auxiliaries

Case Study: Overgenerated Island

- Based on experiences with auxiliary governors used on some of the generating units in Ontario
- Demonstrates the impact of turbine generator overspeed controls on the performance of a generation-rich island

  Scenario
- Island formed as a result of separation from the rest of the interconnected system of an area consisting of 9,650 MW of generation and 4,750 MW of consumption (load plus losses) is considered
- Prior to separation, the area is exporting 4,900 MW; MVAr generation and consumption within the area are nearly equal



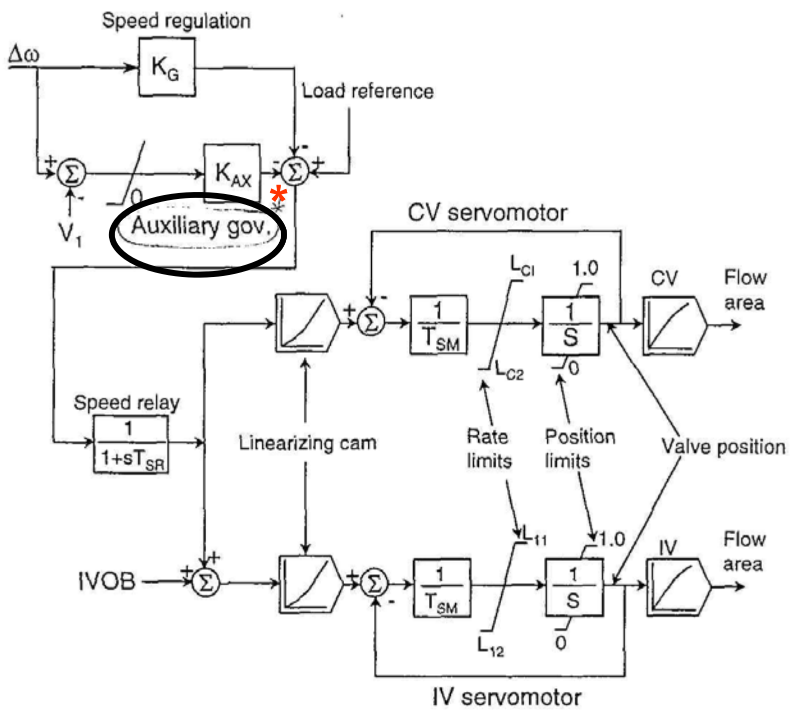
Case Study: (cont'd)

The area generation:

- 4,000 MW of nuclear generation at a plant with eight 500 MW units
- 3,850 MW of fossil-fuelled generation at two plants, each with four 500 MW units; and
- 1.800 MW of hydraulic generation at 6 plants

Turbine governing systems:

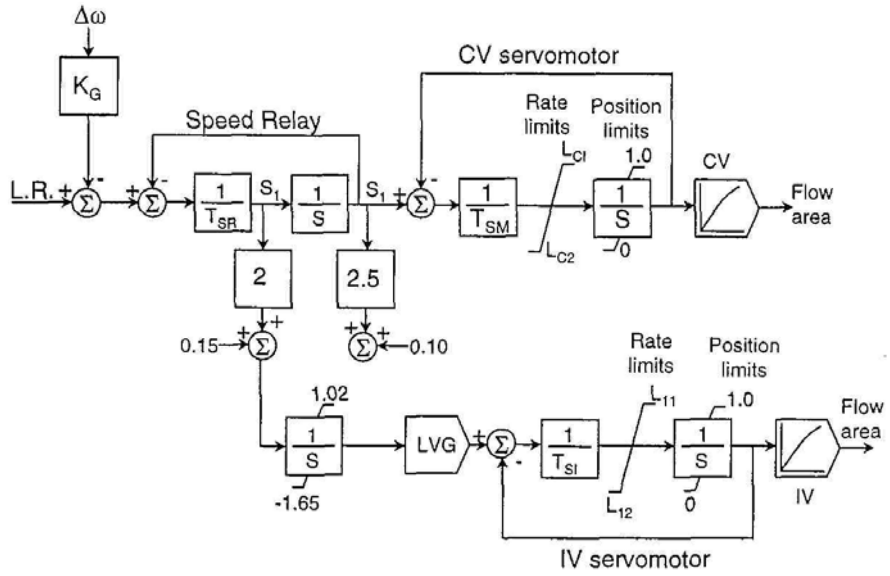
- Nuclear units are equipped with mechanical-hydraulic control (MHC) governors (Fig. 9.31)
- System uses an "auxiliary governor" for overspeed control, which becomes operative when the speed exceeds its setting V1 = 2%
  - acts in parallel with the main governor to effectively increase the gain of the speed control loop by a factor of about 8
  - limits overspeed by rapidly closing the control valves (CVs) as well as the intercept valves (IVs)
- Fossil-fuelled units have MHC governors (Fig. 9.32)



Parameters:

$K_G = 20$	$V_1 = 0.02$	$K_{AX} = 149$	$T_{SR} = 0.7$	IVOB = 1.17
$T_{SM} = 0.23$	$L_{C1} = 1.0$	$L_{C2} = -3.0$		
$T_{S1} = 0.23$	$L_{11} = 1.0$	$L_{12} = -2.5$		

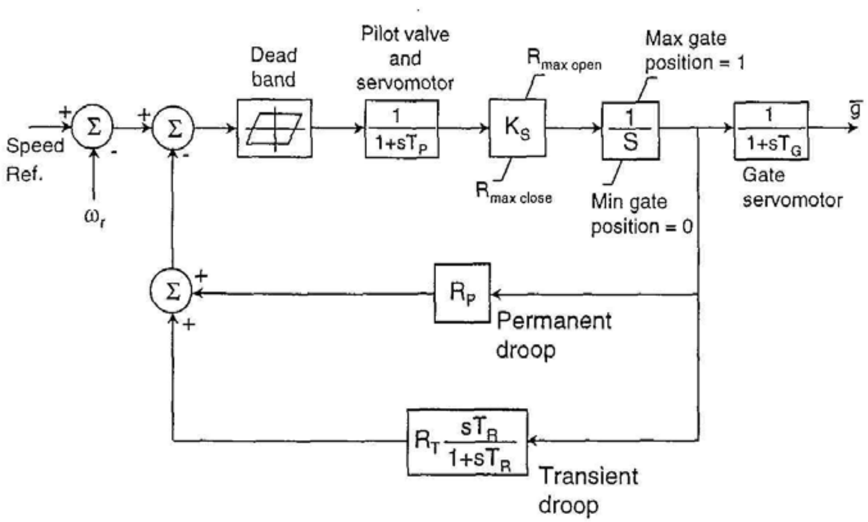
MHC turbine governing system with auxiliary governor*



Parameters:

$K_G = 20$	$T_{SR} = 0.1s$	$T_{SM} = 0.2s$	$T_{S1} = 0.2s$
$L_{C1} = 0.2$	$L_{C2} = -0.5$	$L_{11} = 0.2$	$L_{12} = -2.5$

MHC turbine governing system



Parameters:

T_P	=	Pilot valve and servomotor time constant	0.05 s
K_S	=	Servo gain	5.0
T_G	=	Main servo time	0.2 s
T_P	=	Permanent droop	0.04
R_T	=	Temporary droop	0.4
T_R	=	Reset time	5.0 s

Constraints:

Maximum gate position limit = 1.0

Minimum gate position limit = 0

$R_{max\ open}$	=	maximum gate opening rate	0.16 p.u./s
$R_{max\ close}$	=	maximum gate closing time	0.16 p.u./s
$R_{max\ buff}$	=	maximum gate closing rate in buffered region	0.04 p.u./s
G_{buff}	=	Buffered region in p.u. of servomotor stroke	0.08 p.u.

Model of governors for hydraulic turbines

Case Study: (cont'd)

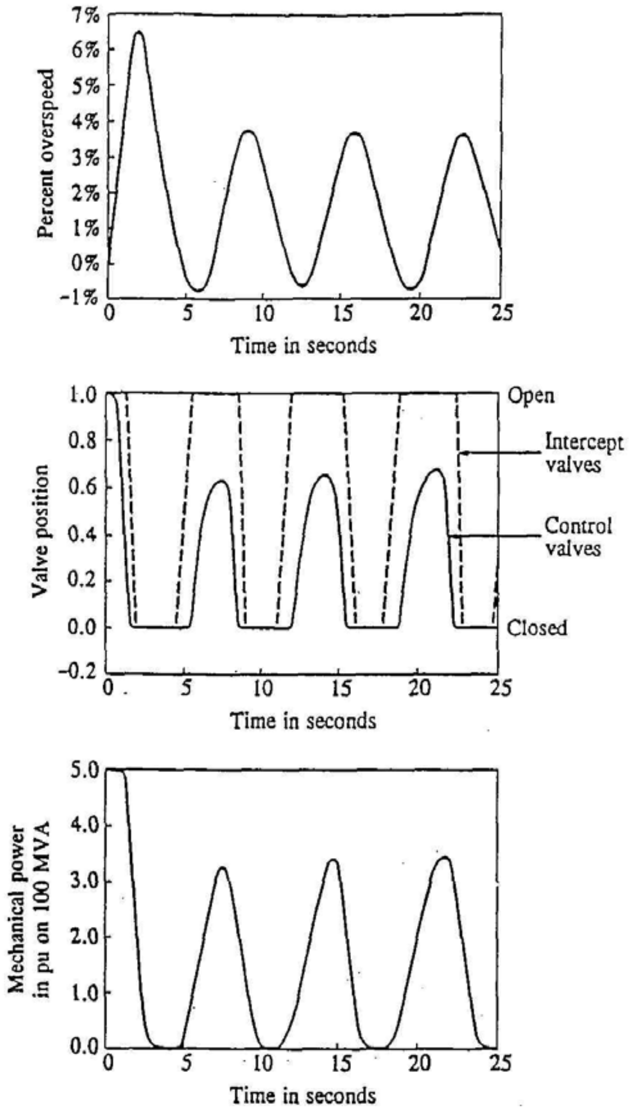
Simulation

- Simulated by simultaneous opening of all ties connecting the area to the rest of the system
  - resulting in an island with generation nearly twice the load
- Generators and excitation system are represented in detail
- Loads are represented as nonlinear functions of voltage and frequency
- Performance of the islanded system is examined with the auxiliary governors of the nuclear units in-service and out-of-service

Case Study: (cont'd)

a) With auxiliary governor in-service:

- Fig. 16.6 shows plots of speed deviation, CV and IV positions, and mechanical power of one of the nuclear units
- The speed increases rapidly to a maximum of about 6.4% above the normal speed of 1,800 rpm
  - oscillates with little damping between 3.5% above and 0.7% below the normal speed
- Oscillation due to the action of the auxiliary governors
  - when the overspeed exceeds the setting V_1 of 1%, the auxiliary governors close the steam valves and reduce the mechanical power of the nuclear units to zero
  - the deficit in the generated power reduces the speed rapidly, and the valves open again
  - resultant increase in mechanical power is such that the speed exceeds the auxiliary governor setting of 1%, and the valves close again.
  - cycle repeats with a period of about 7 seconds



Transient response of nuclear units with auxiliary governor

Case Study: (cont'd)

b) With auxiliary governor out-of-service:

- Fig. 16.7 shows the speed deviation reaches a maximum of about 7.7% and damps to a steady state value of nearly 2% above the nominal
- Removal of the auxiliary governor results in stable frequency control
  - only the CVs respond to speed changes and the IVs remain fully open because the main governor alone is not enough to overcome the intercept valve opening bias

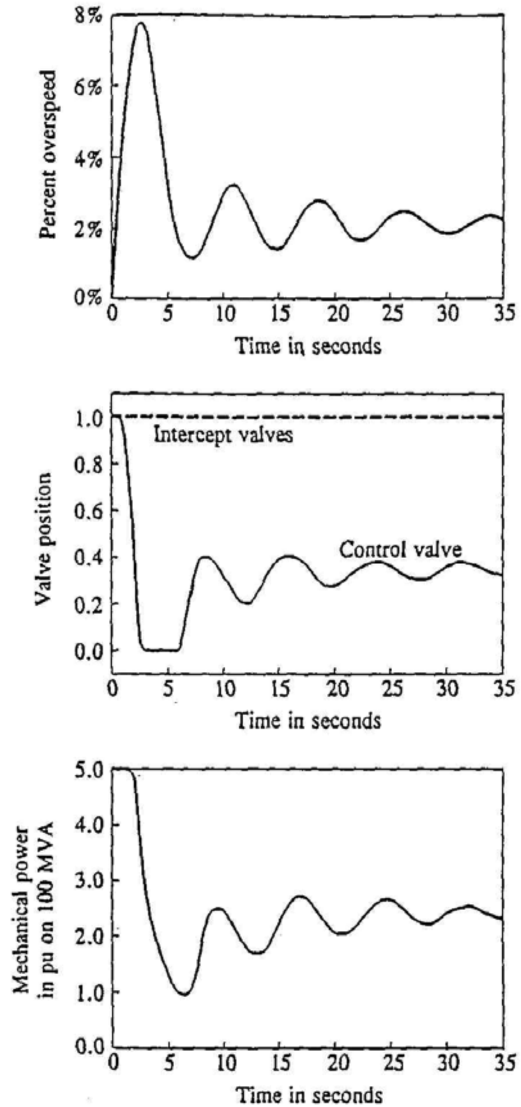


Fig. 16.7 Transient response of nuclear units with auxiliary governor out-of-service

Case Study: (cont'd)

Conclusions

- The auxiliary governors cause instability of the speed control during system islanding conditions
  - other units in the island respond to oscillations of the units with auxiliary governors
  - causes oscillations of <u>all units</u>
  - resulting movements of steam valves or wicket gates continue until the hydraulic systems of the governors run out of oil, causing unit tripping and possibly a blackout of the island
  - oscillations may also give rise to "priming" of the boilers of the fossil-fired units, causing water from the boilers to come in contact with the high temperature superheat and HP stages
- One solution is to replace the auxiliary governor with an electronic acceleration detector

Mitigation of Frequency Stability Problems

- More emphasis on appropriate setting and coordination of protections and controls
  - protective systems should recognize not only equipment safety but also power system performance requirements
- Design of power plants so as to be able to successfully withstand "partial load rejections" and islanding conditions
  - achieved by proper design of overall plant control, boiler/reactor control, and turbine overspeed control; and
  - ensuring vital auxiliaries will not trip out due to the voltage and frequency variations
- A well designed underfrequency load shedding scheme
  - selection of possible areas of separation and load blocks for shedding
  - due consideration to power plant and network protections/controls
  - recognition of requirement for adequate voltage and reactive power control

IEEE and CIGRE Reports on Major Frequency Disturbances

1. IEEE Working Group Report, "*Guidelines for Emergency Power Plant Response to Partial Load Rejections*", IEEE Trans. Vol. PAS-102, No. 6, pp. 1501-1504, June 1983

2. P. Kundur, "*A Survey of Utility Experiences with Power Plant Response during Partial Load Rejections and System Disturbances*", IEEE Trans. Vol. PAS-100, No. 5, pp. 2472-2475, May 1981.

3. Executive Summary of CIGRE TF 38.02.14 Report, "*Analysis and Modelling Needs of Power Systems Under Major Frequency Disturbances*", Final Draft, January 1999

Reference 1, prepared by an IEEE Working Group, provides guidelines for enhancing power plant response to partial load rejections. The following is a summary of these guidelines:

a) *Overall plant control.* To withstand a partial load rejection, the overall plant control must promptly decrease the input power (fuel flow) to correspond to the output electrical power. As there are time lags in this decrease, the power input must temporarily undershoot the power output. The ideal source of intelligence to determine the input power reduction is the actual power output.

b) *Boiler control.* Without a turbine bypass system, a partial load rejection appears to the boiler as a step decrease in steam flow. Prompt reduction of fuel flow is essential, as noted above.

For a *one-through boiler,* prompt reduction of the feedwater flow, tightly coupled to the fuel flow, is also required. However, one-through boilers normally have superheater/turbine bypass systems of limited capacity to protect the furnace tubes and to assist in pressure control. This bypass capability can be used to ease the rate of reduction of fuel and feed-water flow.

For a *drum type boiler,* the reduction of feed-water flow should be delayed because the immediate response of the drum water level is to decrease with steam flow and the resulting rise in drum pressure. In addition, overfeeding is required to obtain the higher-level water inventory required at the lower power level. Adequate water-level control is particularly important for large changes in steam flow. To enhance the ability of water-level control during a partial load rejection, consideration should be given to temporarily increasing the range between high and low water-level trip limits, or delaying the trip for high feedwater flow.

For either type of boiler, a delay in the reduction of air flow is generally desirable since the cooling effect of the excess air flow will tend to compensate for the lags in fuel flow response. However, the air flow to the operating burners must be controlled relative to the fuel flow to maintain stable combustion.
For feed pumps driven by auxiliary steam turbines, the closure of intercept valves will interrupt the steam flow; therefore, it is necessary either to provide an alternate steam source to the auxiliary turbine or to switch to motor-driven pumps.

c) ***Turbine-generator control.*** The turbine overspeed controls are designed to limit overspeed following full-load rejection to about 1% below the overspeed trip settings. This will obviously prevent overspeed trips during partial load rejection.

While the control valves and the intercept valves are closed, there is no steam flow through the turbine. To prevent overheating of the reheater tubes, boiler firing must be tripped off if the interruption of steam flow through the reheater is sustained. However, since the closure of the steam valves is temporary, tripping of the boiler firing can be avoided by proper coordination of boiler protection and fuel control with the turbine controls.

In addition, as recommended in reference 4, the overspeed controls must:

i. **not interfere with normal speed governing in such a way that the performance of the islanded system is adversely affected**

ii. **be capable of discriminating between unit rejections and transient system disturbances; e.g. transmission system faults that temporarily reduce unit power**

d) ***Power plant auxiliaries.*** The effect of voltage and frequency variations experienced during partial load-rejection conditions should be checked to ensure vital auxiliaries will not trip out.

e) ***Steam turbine bypasses.*** The use of a steam bypass system permits the reduction of boiler power in a controlled manner. A well-designed turbine bypass system significantly enhances the capability of the power plant to withstand a partial load rejection.

Nuclear plants normally have steam turbine bypass systems. In North America, fossil-fuelled power plants with drum type boilers are not usually equipped with turbine bypass systems. Power plants with once-through boilers have turbine and superheater bypass systems; these are installed primarily for startup and shutdown duty.