Analysis of electric power and energy systems

Lecture 9: Frequency control

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What will we learn today?

- Why do we need to control the voltage and frequency ?
- Control approaches of voltage and frequency in power systems
- Economic dispatch and optimal power flow methods (brief introduction)
- Power systems security assessment introduction (N-1 criterion)

This lecture expands on Chapter 12 from the Ned Mohan's book.

Why and how to control voltage and frequency ?

- Technical requirements
  - Power system devices are designed so as to operate within well-defined 'tolerance regions' around nominal values V_n and f_n
  - Large/persistent deviations from nominal values could lead to cascading phenomena, service interruptions, and safety problems
- Exogenous threats
  - Sudden disturbances, such as line or generator tripping
  - Fast variations of net load (cf Duck curve)
- Control resources
  - Adjusting synchronous generators' field current and mechanical power
  - Changing transformer taps, or switching lines and/or shunt compensation
  - Fast start-up of generator units and/or in extremis load curtailment

System frequency evolution: theory, example, and intuition

Let us consider a power system with loads and, for now, only synchronous generators.

Let

- $p_e(t)$ be the total power absorbed by the loads (incl. losses in the network)
  - this is thus equal to the electrical power that generators must output (Kirchhoff laws)
- $p_m(t)$ be the mechanical power input to generators

Except for the losses mentioned above, we neglect the network.

How does the frequency of the system $f(t)$ (and thus of the machines) evolve?

The swing equation

From Newton's law ($J\alpha = T_m - T_e$) we can derive similarly

$$J\frac{df}{dt} = \frac{p_m - p_e}{4\pi^2 f} - D_g(f - F_{\mathrm{nom}})$$

Where

- J is the total inertia of the generators,
  - the formula for a generator i as a function of its characteristics (H, $P_{\mathrm{max},i}$):

$$J_i = \frac{2P_{\mathrm{max},i}H_i}{4\pi^2 F_{\mathrm{nom}}^2}$$

- D_g is a damping coefficient (remember the damping windings)
- F_{nom} is the nominal frequency of the network ($50Hz$)

What happens in case there is a power imbalance (if there is little damping)?

What if the inertia of the system decreases?

To answer thes questions, let's look at some simulations

Link to the simulations

The code is organized in 3 main parts:

1. Plotting functions
2. A class encoding the power system data and the set of differential equations governing the system
3. Simulations for several cases

Let's add generator reaction to frequency change

$$T_{sm}\frac{dp_m}{dt} = P_m^0 - p_m - \frac{P_{\max}}{\sigma}\frac{f - F_{\text{nom}}}{F_{\text{nom}}}$$

Where

- T_{sm} is the primary control time constant, assumed equal to $1.5s$,
- P_m^0 is the set point for the generation
- σ is the coefficient of droop of the primary control, which is 4%,

What is the impact of the droop?

We should not forget generator limits

$$p_m \in [P_{\min}, P_{\max}]$$

Where

- $P_{\max}$ the maximum power available for primary control
- $P_{\min}$ the minimum power available for primary control

What is the consequence of these limits?

But the power consumed by the load is frequency dependent

$$p_e = P_e^0(1 + D_l(f - F_{\text{nom}}))$$

where:

- P_e^0 nominal (or initial) consumption
- D_l the sensitivity of consumption to frequency, assumed equal to 1%.

Not all loads are frequency dependent.

Do you see the impact on the curves?

Let's now add renewable generation

Assume we now have $p_{PV}(t)$ generated by a PV farm.

Which equation does it impact?

Our model so far:

$$J \frac{df}{dt} = \frac{p_m - p_e}{4\pi^2 f} - D_g(f - F_{\text{nom}})$$

$$T_{sm} \frac{dp_m}{dt} = P_m^0 - p_m - \frac{P_{\max}}{\sigma} \frac{f - F_{\text{nom}}}{F_{\text{nom}}}$$

$$p_m \in [P_{\min}, P_{\max}]$$

$$p_e = P_e^0(1 + D_l(f - F_{\text{nom}}))$$

Let's now add renewable generation

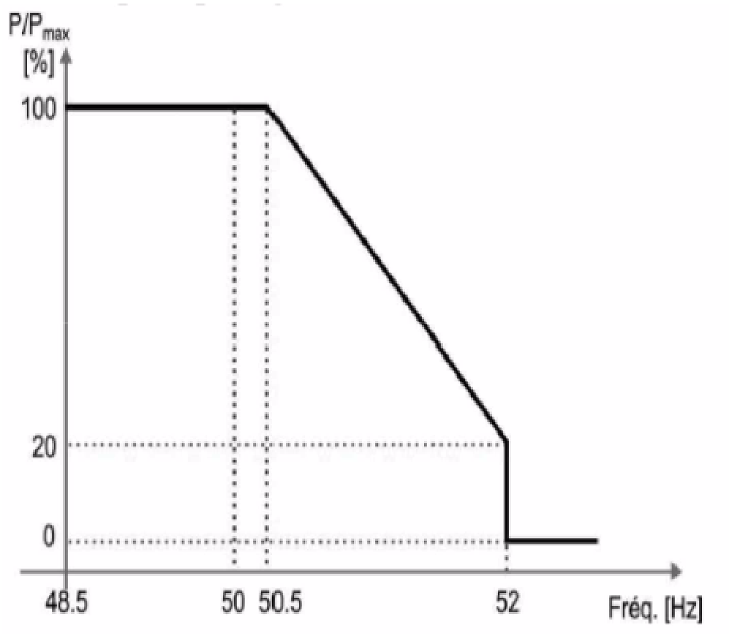
Assume we now have $p_{PV}(t)$ generated by a PV farm.

Which equation does it impact?

$$J\frac{df}{dt} = \frac{p_m - p_e + p_{PV}}{4\pi^2 f} - D_g(f - F_{\text{nom}})$$

What is the consequence?

Let's add over frequency curtailment of renewable generation



Let's add over frequency curtailment of renewable generation: model

if $f < 50.5Hz$:

$$p_{PV} = P^0_{PV}$$

else if $50.5 \leq f < 52Hz$:

$$p_{PV} = P^0_{PV}(1 - \frac{0.8}{1.5}(f - 50.5))$$

else if $f \geq 52Hz$:

$$p_{PV} = 0.0$$

where P^0_{PV} is the maximum solar output at the initial instant of simulation.

Note: With more RES, les synchronous machine, so relatively less inertia for same demand.

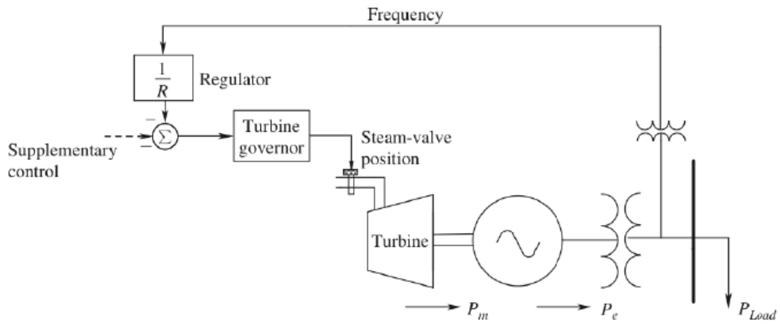
Impact of the storm on wind generation

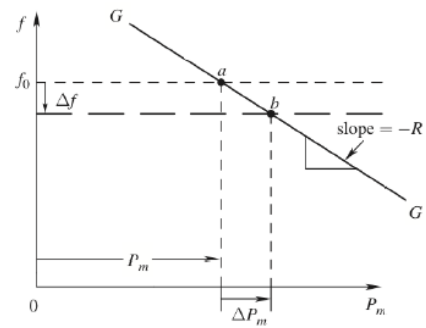
From https://www.elia.be/en/grid-data/power-generation/wind-power-generation

Principle of Automatic Frequency Control

- The main tool: primary frequency control via speed governors of large synchronous generators
- Secondary frequency control (aka Automatic Generation Control (AGC))
- Tertiary frequency control

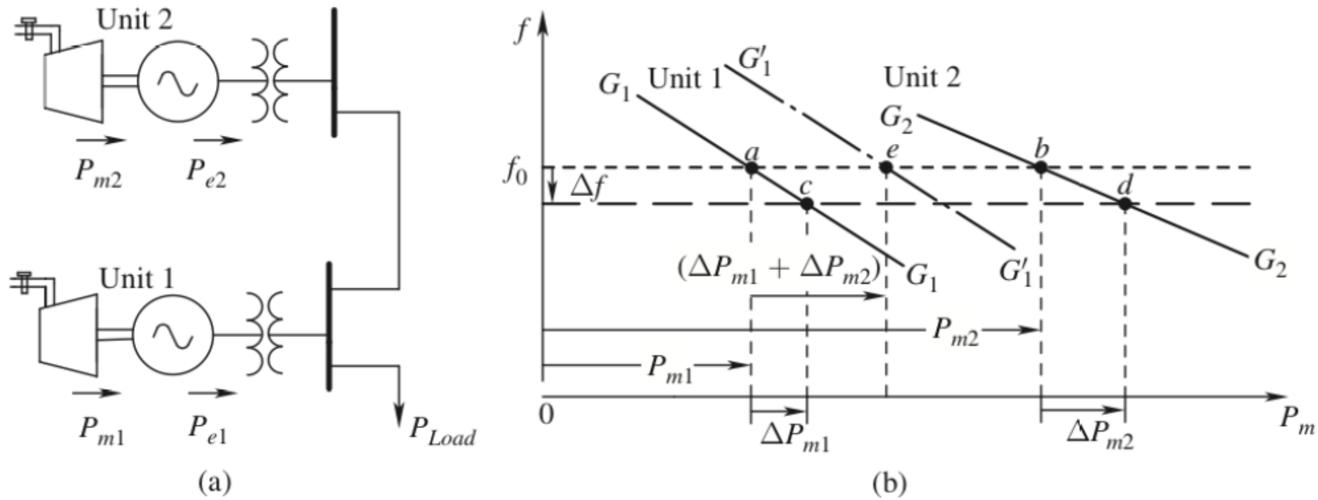
Speed governor of a synchronous generator





- Measurement of rotor speed (or stator frequency as a proxy)
- If frequency (speed) is a bit below f_0, the governor opens a bit more the valve to increase the mechanical power P_m
- In steady state, speed and mechanical power (or equivalently, frequency and electric power) are related by a linear relationship (see diagram on the right)
- This relationship allows predicting how the power generated by a certain generator would change when frequency changes
- It also shows that in order to have the generator adapt his power via this primary control loop, the frequency must change

The case of two generators helping out with a sudden increase of load



- Imagine that suddenly load power increases by ΔP_L: because of KL, total electric power of generators will also increase, hence they start to decelerate leading to a frequency drop. Both will react, according to the governor settings of their primary frequency control loop, to increase their mechanical power
- At steady state, Δf will be such that $\Delta P_1 + \Delta P_2 = \Delta P_L$; typical time to reach steady state: 10-20s
- Depending on mechanical inertia and speed of governor controls, frequency 'nadir' can be much lower than final $f_0 + \Delta f$ at steady state.

Primary frequency control in an interconnected system

- Goal: avoid too large frequency drop upon sudden loss of (the largest) generator connected to the system
  - Each area contributes in proportion to its load level,
  - Within each area, some generators are recruited to ensure area requirement,
  - There is a mutualization of primary frequency control reserves.
  - If primary frequency control is unable to prevent a too large drop in frequency, more heroic emergency controls will act, e.g. under-frequency load shedding (see Movies)

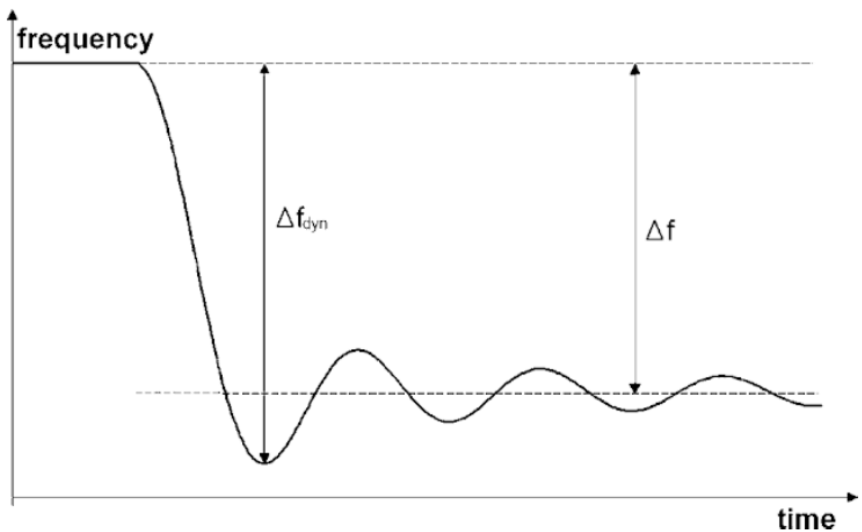
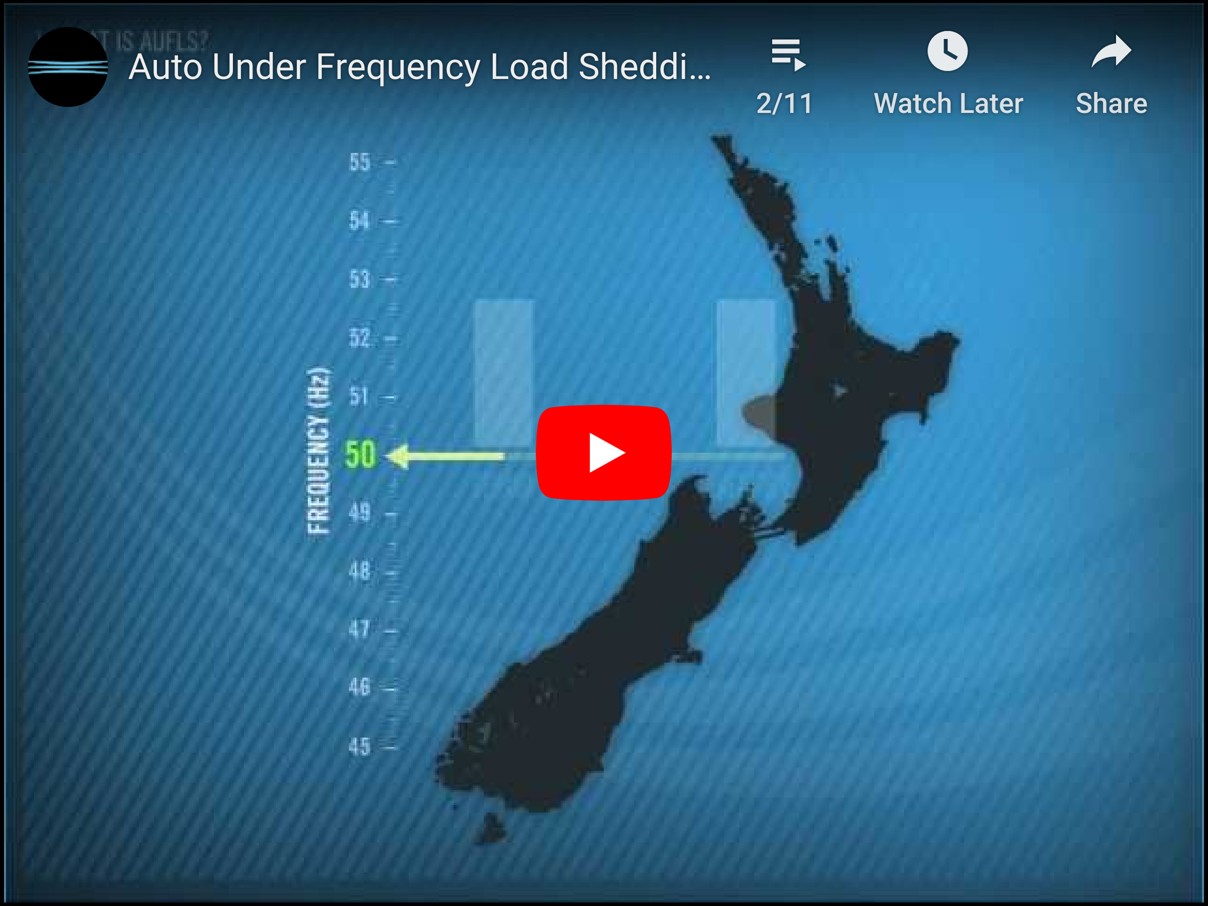


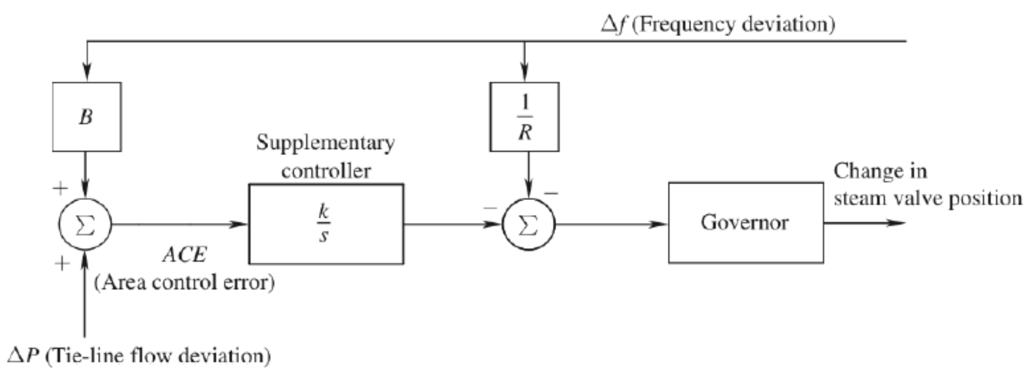
Fig from: **https://top10electrical.blogspot.com/2015/10/primary-secondary-and-tertiary.html**



Automatic under frequency load shedding

Secondary frequency control (aka AGC)

- After (gentle and successful) settlement of primary frequency control there are however some undesirable side effects:
  - Frequency has deviated from the nominal value
  - The exchanges between areas have deviated from their scheduled values
  - Part of the primary frequency control reserves have been depleted
- AGC (or secondary frequency control) aims at cancelling these side effects:



- Since AGC is an integral control, its steady state corresponds to zero Δf and zero ΔP (tie-line flows are also steered back to scheduled values)
- Once frequency is back to normal, primary control reserves are again fully available (takes 5-15 minutes)

Primary, secondary and tertiary frequency control

- First, primary control stabilizes frequency and power balance
  - response within 0-30s, fully local and fully automatic
- Second, frequency and power exchanges are brought back to nominal/contractual values, and primary control reserves are restored
  - response within 0.5-15 minutes, via area-control center (e.g. one country in Europe)
- Third, generation and exchange schedules are re-optimized, while restoring secondary frequency control reserves
  - response within 10-60 minutes, e.g. via intraday power exchange markets

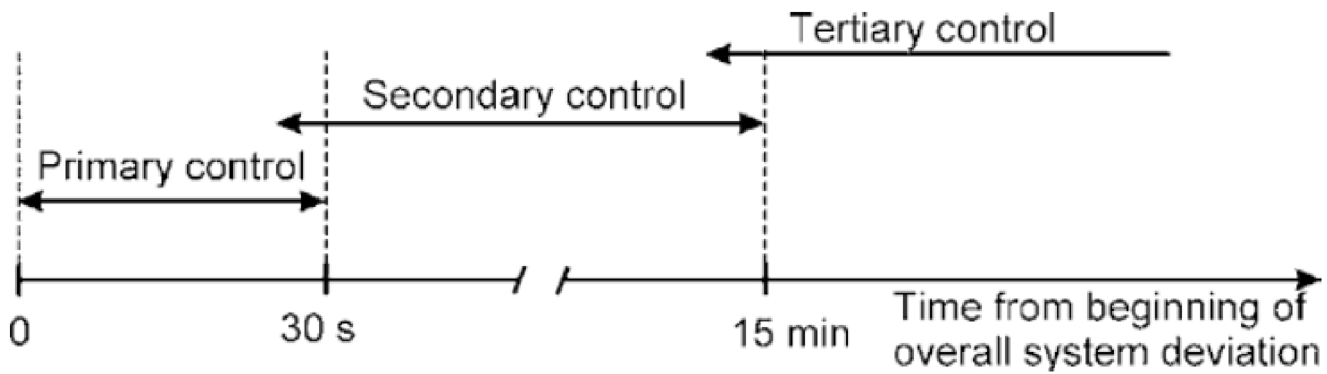
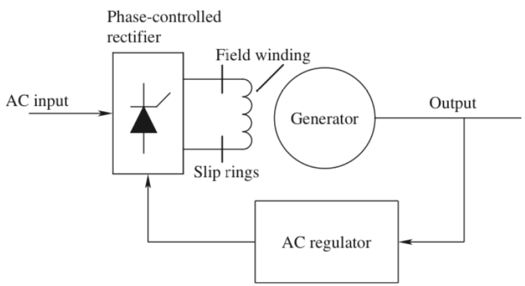


Fig from: https://top10electrical.blogspot.com/2015/10/primary-secondary-and-tertiary.html

Principle of Automatic Voltage Control

- The main tool: primary voltage control via Automatic Voltage Regulators (AVRs) of large synchronous generators and synchronous condensers
- Secondary voltage control and automatic switching of reactive compensation devices and transformer taps
- Tertiary voltage control and voltage profile optimization

Automatic voltage regulator of a synchronous machine (reminder)



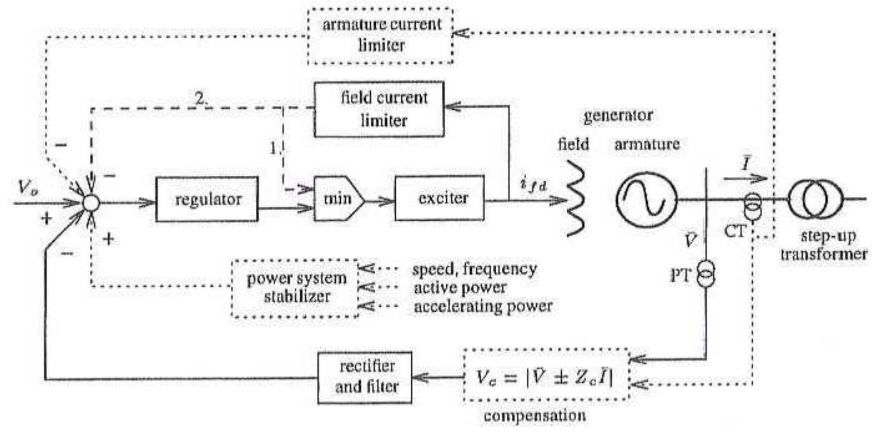


Figure on the right from: Voltage stability of electric power systems. T. Van Cutsem & C. Vournas, KAP 1998

- Notice that if several generators are connected in parallel (either at the MV or at the EHV bus), it is necessary to coordinate their AVRs so that they share the reactive power in an even way.
- The value of Z_c may be adjusted in order to ensure such a coordination.

Primary, secondary and tertiary voltage control

- When a disturbance occurs, or subsequently to following the change in load (cf. 'duck curve'), the primary voltage control loops maintain suitable voltage levels close to the large power plants equipped with AVRs.
    - However, voltages at other buses may move out of tolerance intervals (in either direction), and reactive power reserves may not be shared in an even way among generators.
- Secondary voltage control loops can be used at the zonal level, to adjust the set-points of AVRs so as to control the voltage at 'pilot nodes' in the network while distributing the required reactive power evenly among generators.
    - Secondary voltage control loops can also be used to switch shunt reactive compensation devices (capacitors/inductors) in order to increase reactive power generation margins in their zone (among a few large power plants).
- Tertiary voltage control uses OPF solvers to calculate set-points at pilot nodes and possibly adjust some transformer ratios, so as to minimize losses and maximize MVar reserves at the entire system level.
- Response times of different levels of voltage control
    - Primary: 1-3 seconds ; Secondary: 30 seconds -3 minutes ; Tertiary: 10-15 minutes

Economic dispatch and optimal power flow

Economic dispatch problem statement (ED)

Solve an optimization problem

- Given a total load P_L to serve, and a set of candidate generators $i = 1 \ldots n$, with P_i constrained to $\underline{P}_i \ldots \overline{P}_i$, and a cost function $C_i(P_i)$,
- Find optimal values P_i such that $\sum_i^n C_i(P_i)$ is minimized
  - while ensuring $\sum_i^n P_i = P_L$ (+ a loss term, possibly).
- See 12.4.1 of ref. book for some intuition about the solution to this problem

Optimal power flow problem statement (OPF)

- As above, + network constraints
- Given
  - network topology,
  - electrical parameters of lines, cables, transformers, and shunt devices,
  - current flow limits of lines and transformers, and voltage tolerance intervals at buses
- Determine the P_i such that $\sum_i^n C_i(P_i)$ is minimized
  - while modeling Kirchhoff laws and enforcing the above network-wise limits

Assessing the security/reliability of an electric power system

- General idea of security assessment
- Standard N-1 static security assessment
- Voltage stability assessment (next lecture)
- Transient stability assessment (next lecture)

General idea of security/reliability assessment

- General motivation:
  - Check the robustness of the system to a number of possible contingencies
  - NB: see examples of contingencies in subsequent slides
- Generic security assessment approach:
  - Given a list of contingencies and a steady-state base-case operating point of the system
  - Simulate the impact of each contingency if it is applied to the base case
  - For each simulation, check whether system response is acceptable
  - Summarize and display the results for all contingencies
  - If too many contingencies lead to unaccaptable response, the base-case is insecure
- Remarks:
  - Such analyses can be carried out periodically, based on real-time measurements
  - They can also be applied in look-head mode, on a set of possible future system conditions
  - Such analyses are extensively carried ou by TSOs, and when the conclusion is negative, the TSO has to decide preventive/corrective counter-measures

Standard N-1 static security assessment

- List of contingencies: all single-component outages
  - e.g. all single-line outages + all single-transformer outages
  - plus possibly all single-generator outages
- Procedure:
  - Run a power flow computation for the base case, and check pre-contingency limits
  - For each outage in the contigency list, run a power flow computation to determine post-contingency voltages and currents, and check post-contingency limits
- Precise limit values can depend on the context of security assessment:
  - e.g. in real-time operation, line/transformer permanent thermal limits and steady state voltage magnitude tolerance intervals are checked both for pre- and post-contingency
- Remarks/orders of magnitude:
  - e.g. for a system like the Belgian EHV transmission system (ELIA)
  - 1000-2000 contingencies
  - 2000-4000 limits to check for each contingency
  - Need to summarize in graphical form the results to be useful for a human operator

References

- Mohan, Ned. Electric power systems: a first course. John Wiley & Sons, 2012.

The end.