ECG 742
Frequency Stability and Control

Videos

(see frequency deviations during major system disturbances)

- San Diego Blackout in 2011

https://www.youtube.com/watch?v=YsksUyeLu2Y

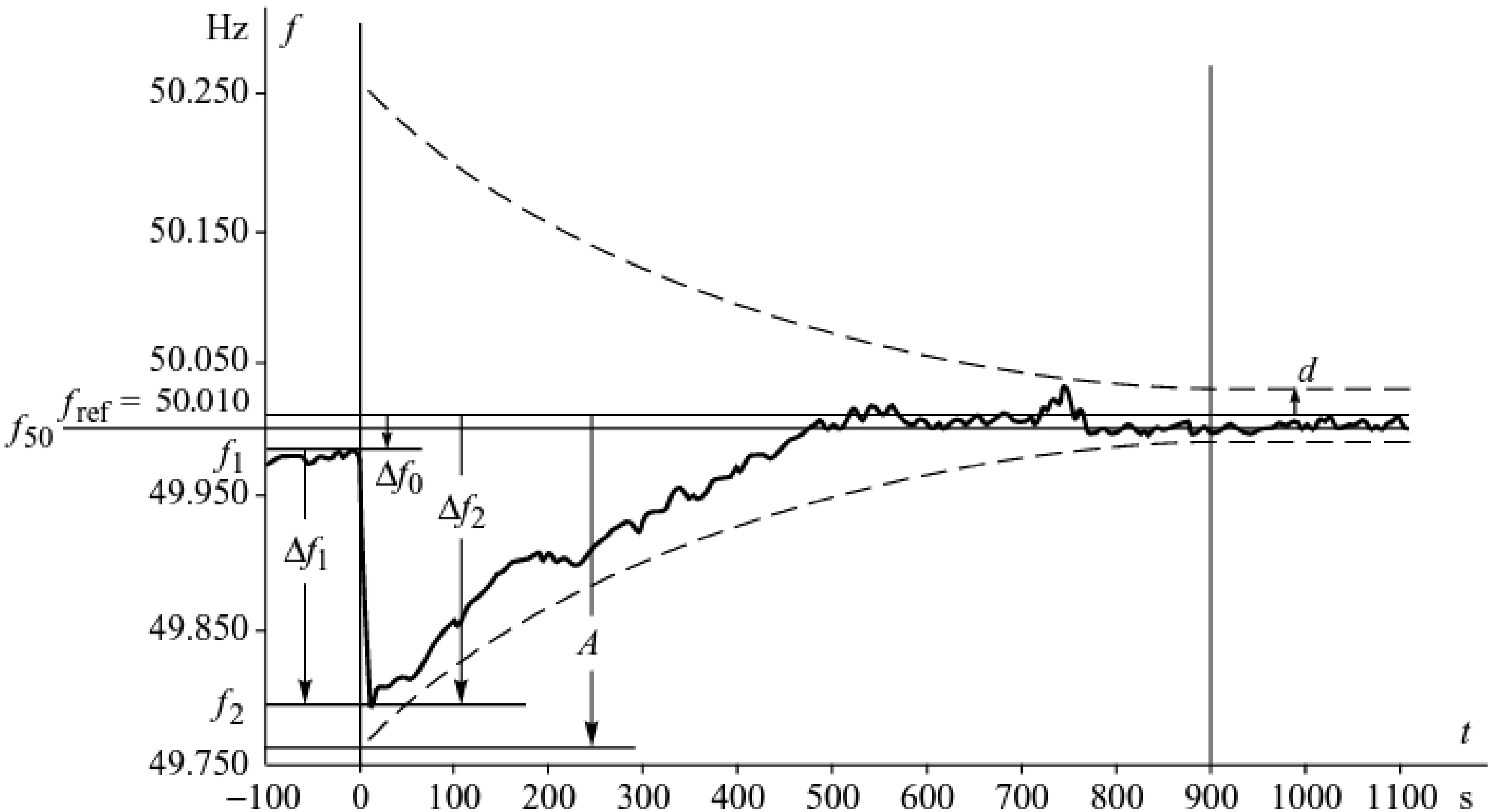
- North East blackout in 2003

https://www.youtube.com/watch?v=eBucg1tX2Q4

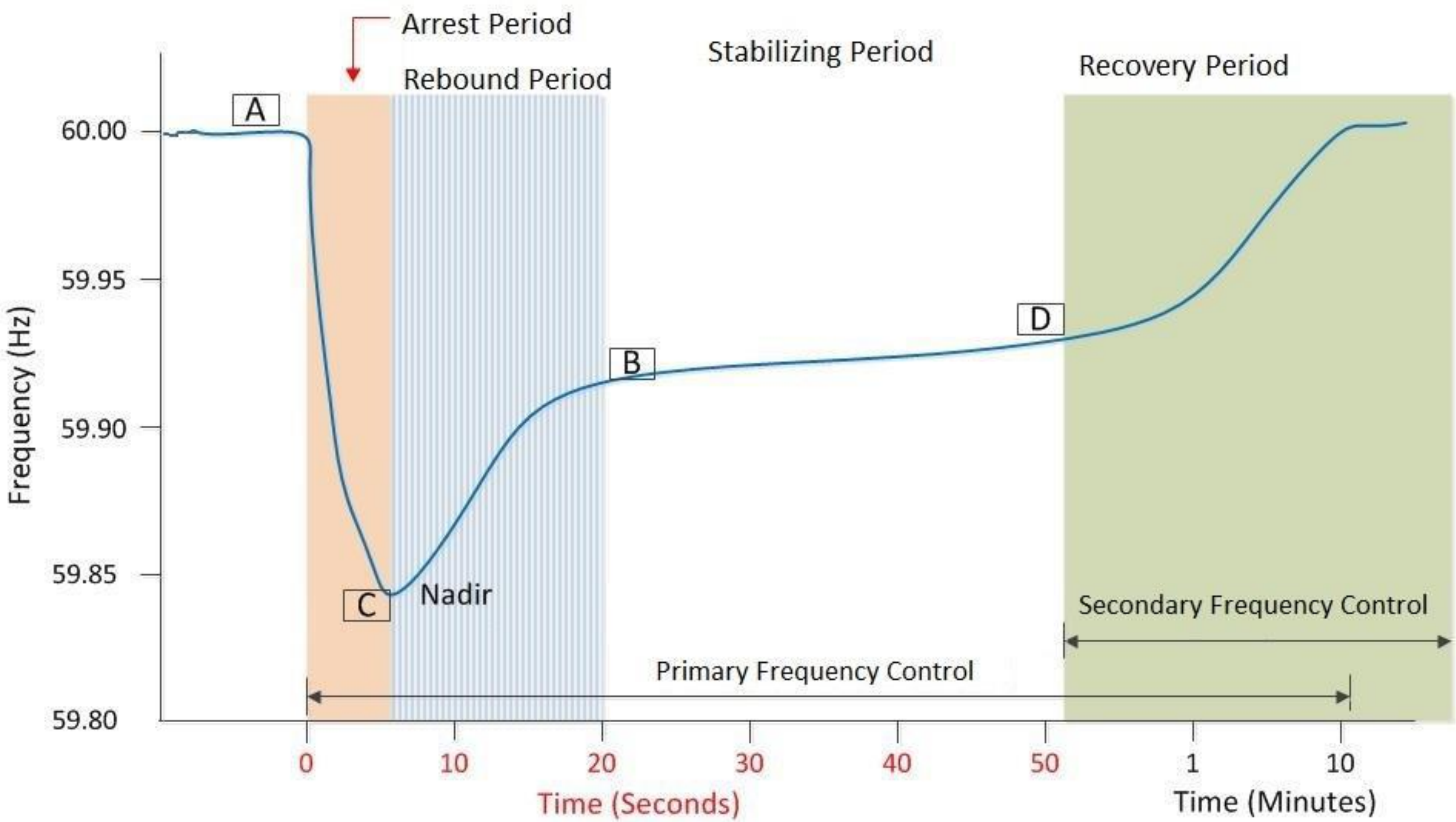
- Resource:

https://emp.lbl.gov/sites/default/files/frequency_control_requirements_es_lbnl-2001103.pdf

Example of frequency recovery following a generator outage (50 Hz system)



Under-frequency due to loss of Resource



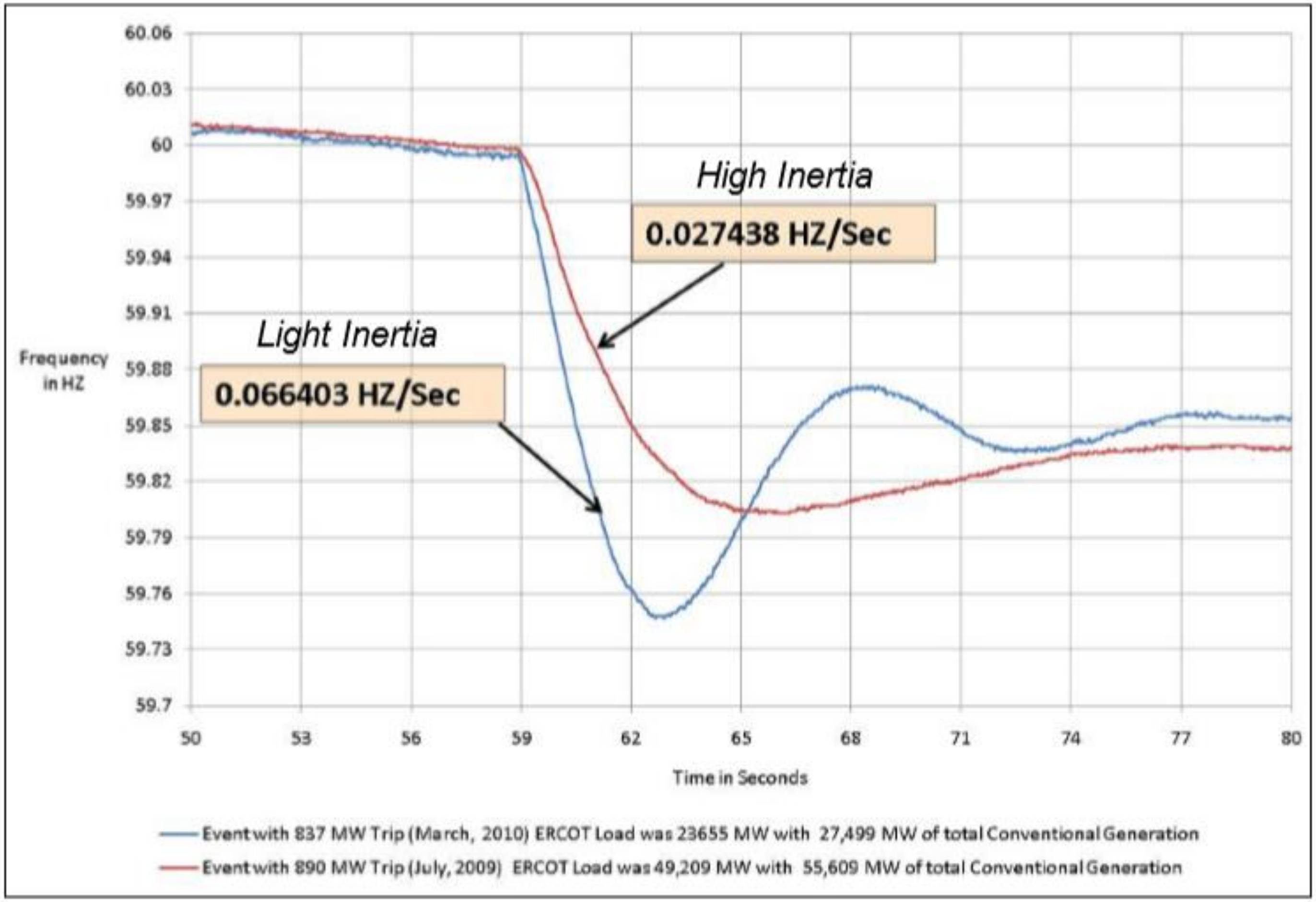
Point A - pre-disturbance frequency; **Point C** or Nadir - maximum deviation due to loss of resource; **Point B** - stabilizing frequency and; **Point D** - time the Balancing Authority begins the recovery from the loss of resource.

Source: https://www.nerc.com/comm/OC/Reliability%20Guideline%20DL/Primary_Frequency_Control_final.pdf

Breakdown of Frequency Deviation

- **Primary Frequency Response (or Frequency Response)** – Actions from uncontrolled sources in response to changes in frequency including rotational inertia and load response from frequency dependent loads.
- **Primary Frequency Control** – Actions provided by prime mover governors in an interconnection to arrest and stabilize frequency in response to frequency deviations. Primary Frequency Control comes from local control systems.
- **Secondary Frequency Control** – Actions provided by a BA to correct the resource-to-load imbalance that created the original frequency deviation that will restore the scheduled frequency. This comes from automated dispatch from a centralized control system such as AGC.
- **Tertiary Frequency Control** – Actions provided by BAs on a balanced basis that are coordinated so there is a net-zero effect on area control error (ACE). Examples of Tertiary Control include dispatching generation to serve native load, economic dispatch, dispatching generation to affect interchange, and re-dispatching generation.

Inertial Response Sensitivity

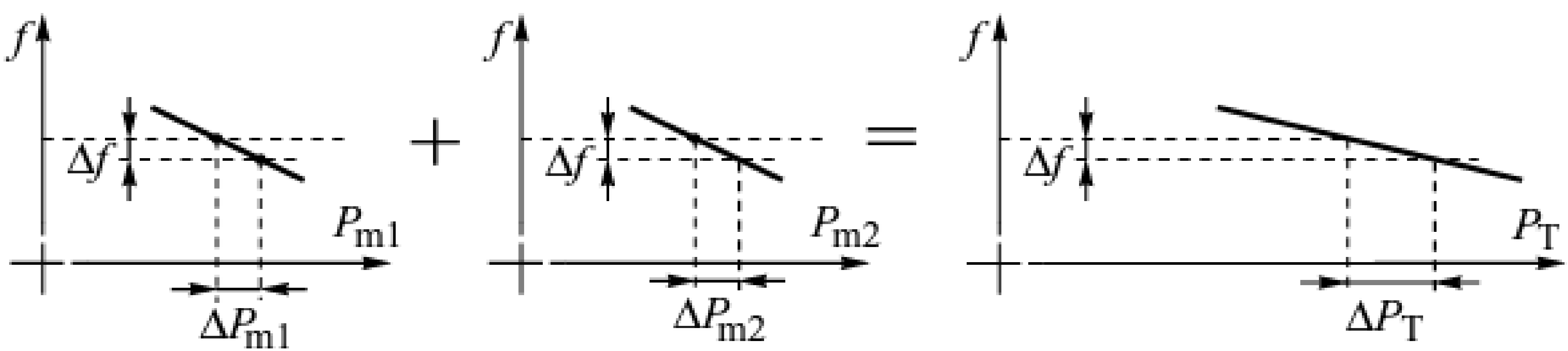


System inertia is the amount of kinetic energy stored in all spinning turbines and rotors in the system. System inertia decreases with more inverter-based generation, thus, Nadir will be lower with lower inertia.

Source:https://www.nerc.com/pa/stand/project%20200712%20frequency%20response%20dl/fri_report_10-30-12_master_w-appendices.pdf

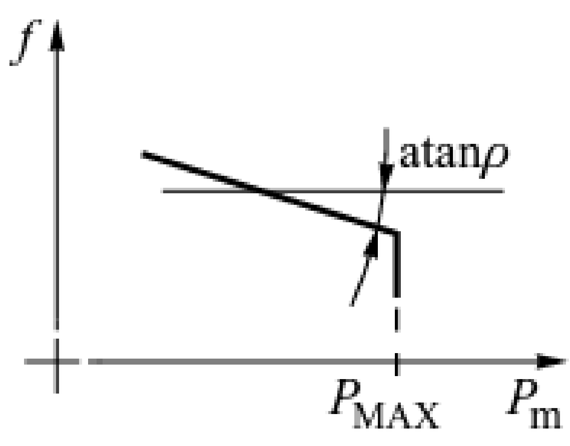
Meeting demand with generation

- Large and slow changes (24 hr) in power demand are met by *unit commitment*
- Medium and relatively fast changes (30 min) in power demand are met by *economic dispatch.*
- Small and fast changes (seconds) are met by *automatic generation and control* (AGC) to maintain
  - Frequency
  - Tie-line power exchange
  - Power allocation among the generating units
- Total generation characteristic = sum of speed-droop characteristics of each generator.



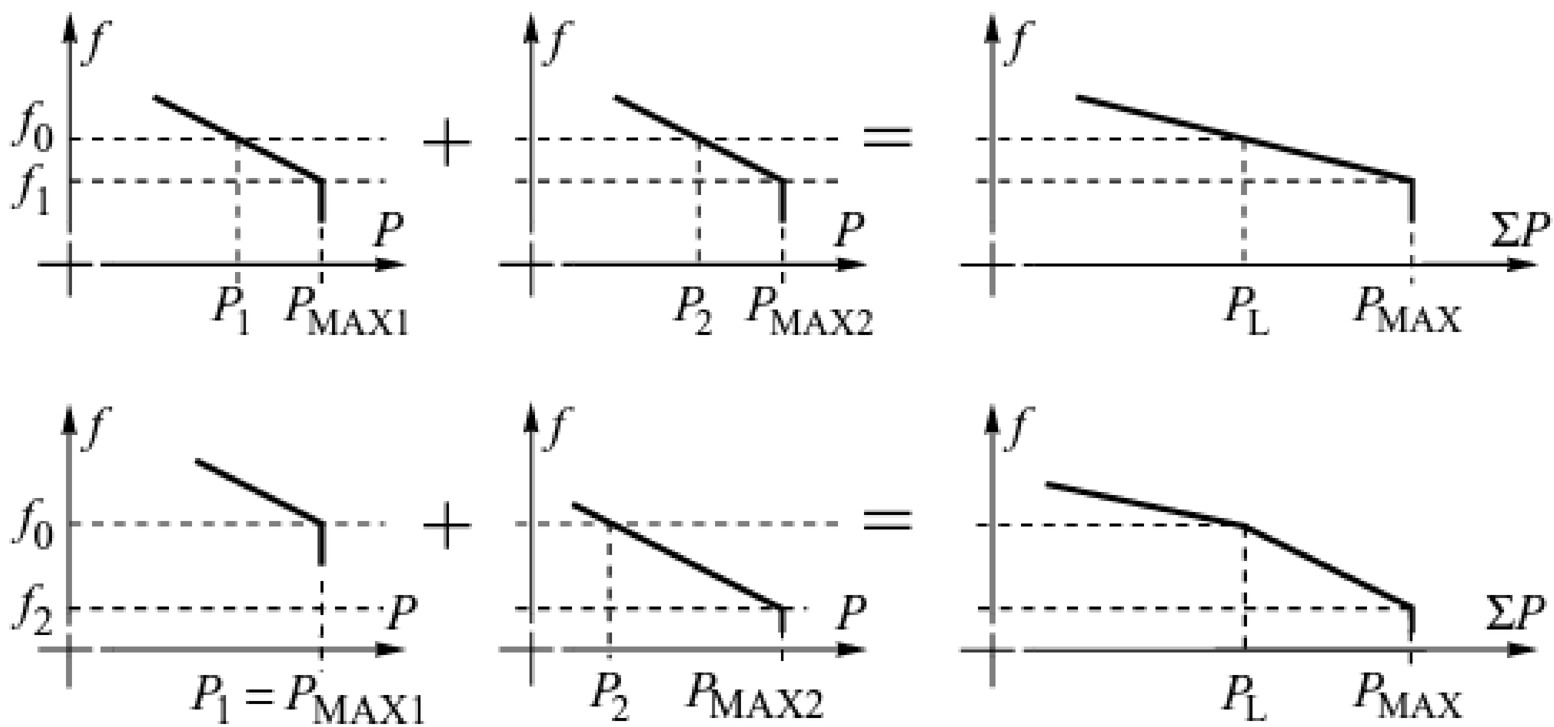
Turbine-Generator Characteristics

- The system has the ability to compensate for power imbalance at the cost of frequency deviation.
- A large interconnected system has an almost flat characteristic (i.e., a large deviation in power demand results is a very small frequency deviation).
- The turbine-generator characteristic has both a lower limit and an upper limit (see curve below).
  - The unit that reaches its limit (i.e., with no *spinning reserve*) does not contribute to an increase in power demand.



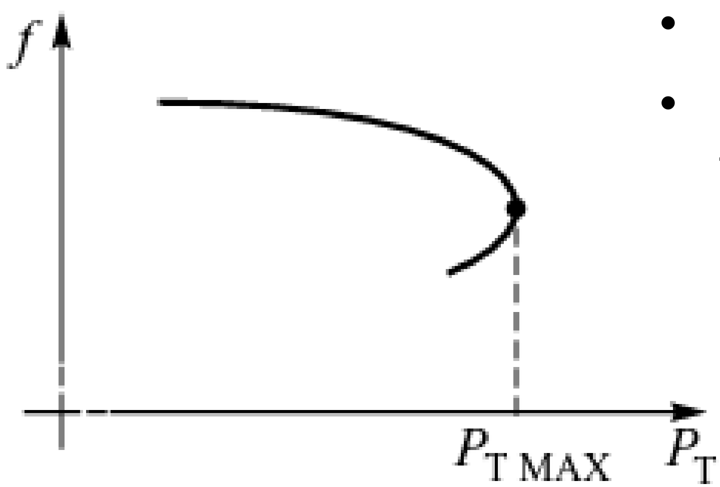
Influence of turbine upper limit and spinning reserve allocation on generation characteristic

- The generation characteristic can become nonlinear (or piece-wise linear) if some of the generators reached the maximum power limits.



System frequency-power characteristics

- In a system with a large number of generator, the piece-wise linear curve appears smooth (see figure below).
  - Linear approximation: $$\frac{\Delta P_T}{P_L} = -K_T \frac{\Delta f}{f_n} \quad \text{or} \quad \frac{\Delta f}{f_n} = -\rho_T \frac{\Delta P_T}{P_L},$$
  - at maximum power, the droop ρ_T tend to infinity.
- Load variation with frequency: $$\frac{\Delta P_L}{P_L} = K_L \frac{\Delta f}{f_n},$$
  - K_L: frequency sensitivity coefficient of power demand



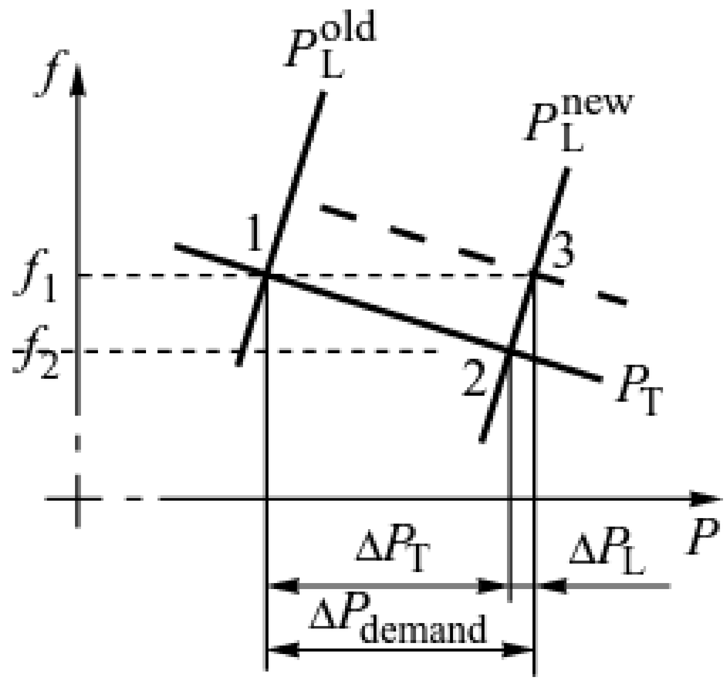
- P_T: Total power generated in the system
- P_L: Total system load (including transmission losses)

Increase in system demand

- An increase in system demand is compensated by
  - An increase in turbine generation (at the expense of a reduction in frequency)
  - A decrease in system load (due to drop in frequency)

$$\Delta P_{\text{demand}} = \Delta P_{\text{T}} - \Delta P_{\text{L}} = -(K_{\text{T}} + K_{\text{L}}) P_{\text{L}} \frac{\Delta f}{f_{\text{n}}} = -K_f P_{\text{L}} \frac{\Delta f}{f_{\text{n}}}.$$

Stiffness – exact value difficult to determine



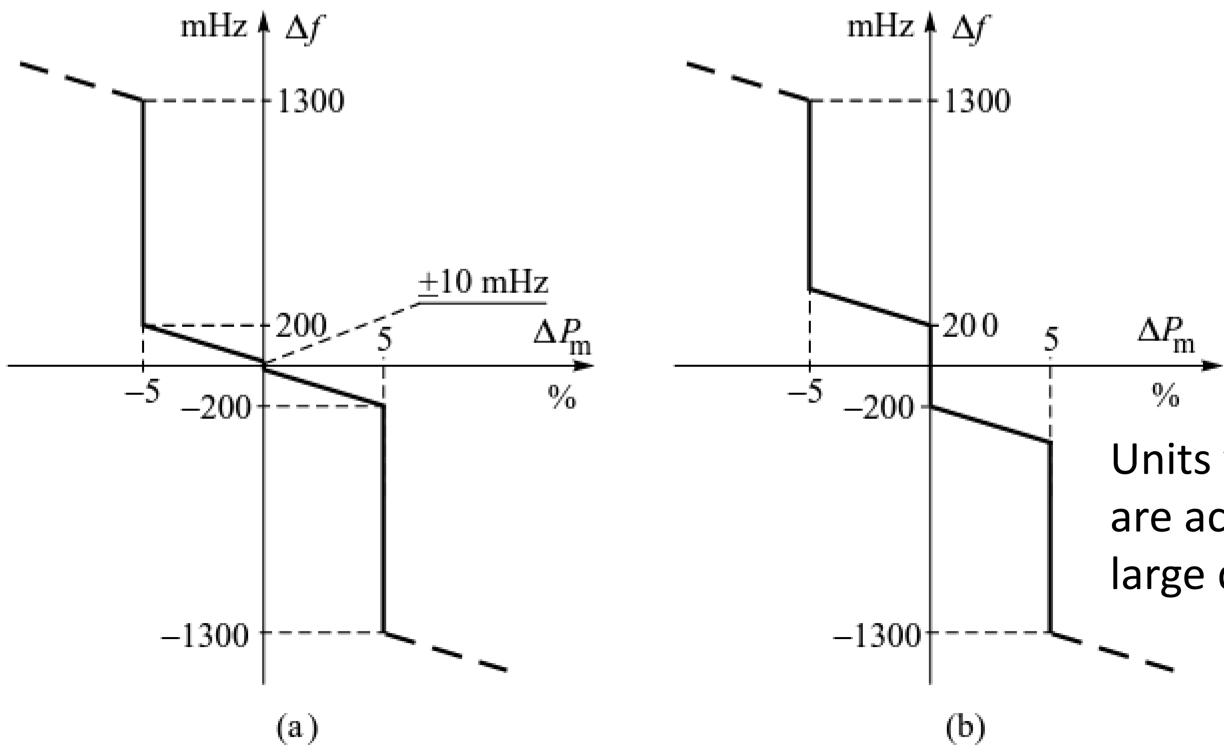
Example # 1

- An isolated and unregulated 60 Hz power system consists of two generating unit that serve a load. Assume a base of 500 MVA and the frequency sensitivity coefficients of the generating units and load are: K_1 = 100 pu, K_2 = 50 pu, K_L = 1.8 pu. Now a sudden increase in power demand of ΔP = 0.2 pu occurs. Determine the system operating frequency and the power contribution from each unit.

  - $\Delta f = -\Delta P/(K_1 + K_2 + K_L) = -0.0013175$ pu $= -0.07905$ Hz (i.e., new frequency = 59.921 Hz)
  - $\Delta P_1 = - K_1 \Delta f = 0.13175$ pu (= + 65.875 MW)
  - $\Delta P_2 = - K_2 \Delta f = 0.0658$ pu (= + 32.937 MW)
  - $\Delta P_L = - K_L \Delta f = 0.0023$ pu (= 1.185 MW)

Primary frequency control

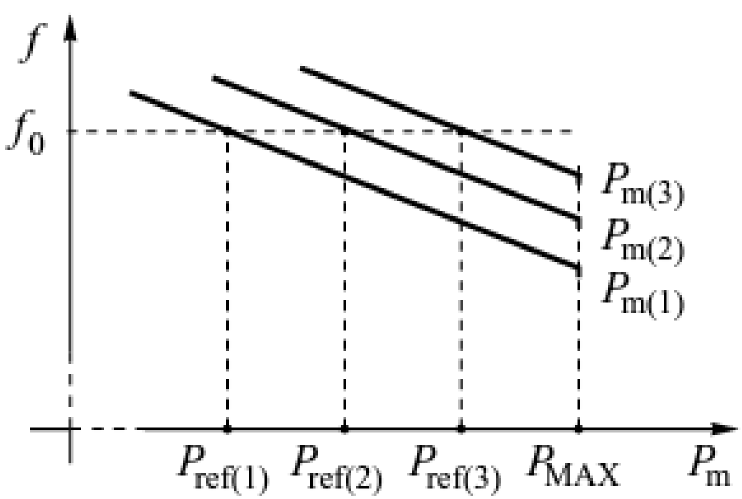
- Primary frequency control is the action of turbine governors due to frequency changes without changing P_{ref} setting.
- As the load increases, spinning reserve is released from fast-regulating units which have speed-droop characteristics with dead-zones (see examples below for 50 Hz system)

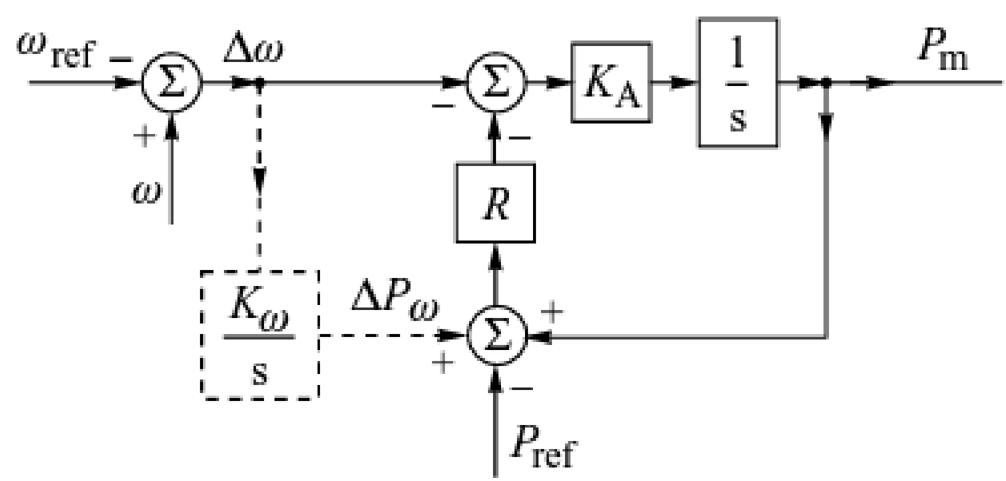


Units with larger dead-zones are activated only during large disturbances

Secondary Frequency Control

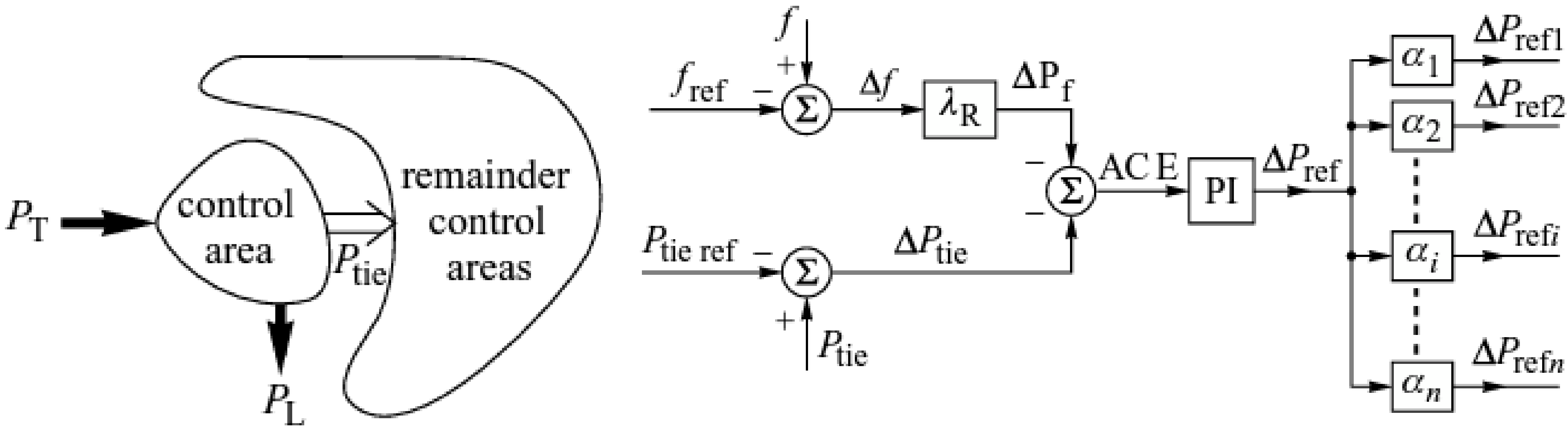
- To return to the initial frequency, the generation characteristic much be shifted by changing P_{ref} setting in the turbine governing system.
- In an isolated power system, automatic secondary control can be implemented in some units (by adding a supplementary control loop as shown below) in a decentralized way.
- In an interconnected system with a number of control areas, centralized secondary control is necessary.





AGC

- In an interconnected system, each control area has its own central regulator to maintain frequency at the scheduled level, and balance between generated power, area demand, and tie-line interchange power.
- *frequency bias factor* $$\lambda_R = \frac{K_f P_L}{f_n} = K_{f\,MW/Hz}.$$
- *Area Control Error (ACE)* $$ACE = -\Delta P_{tie} - \lambda_R \Delta f.$$
- *Participating factors:* $\alpha_1, \alpha_2, \ldots, \alpha_n$



AGC

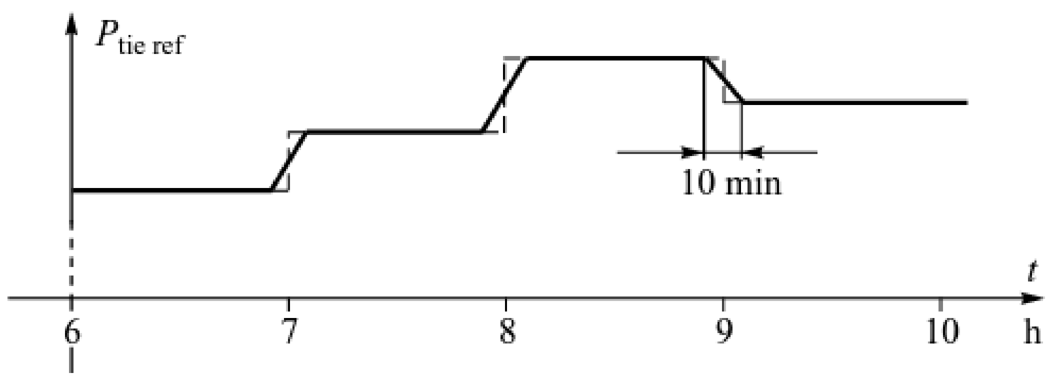
- Zeroing AGC can be achieved in two ways:
  - Zeroing both errors (more desirable outcome)

$$\Delta P_{\text{tie}} = 0 \text{ and } \Delta f = 0\,.$$

  - Achieving a compromise between the errors

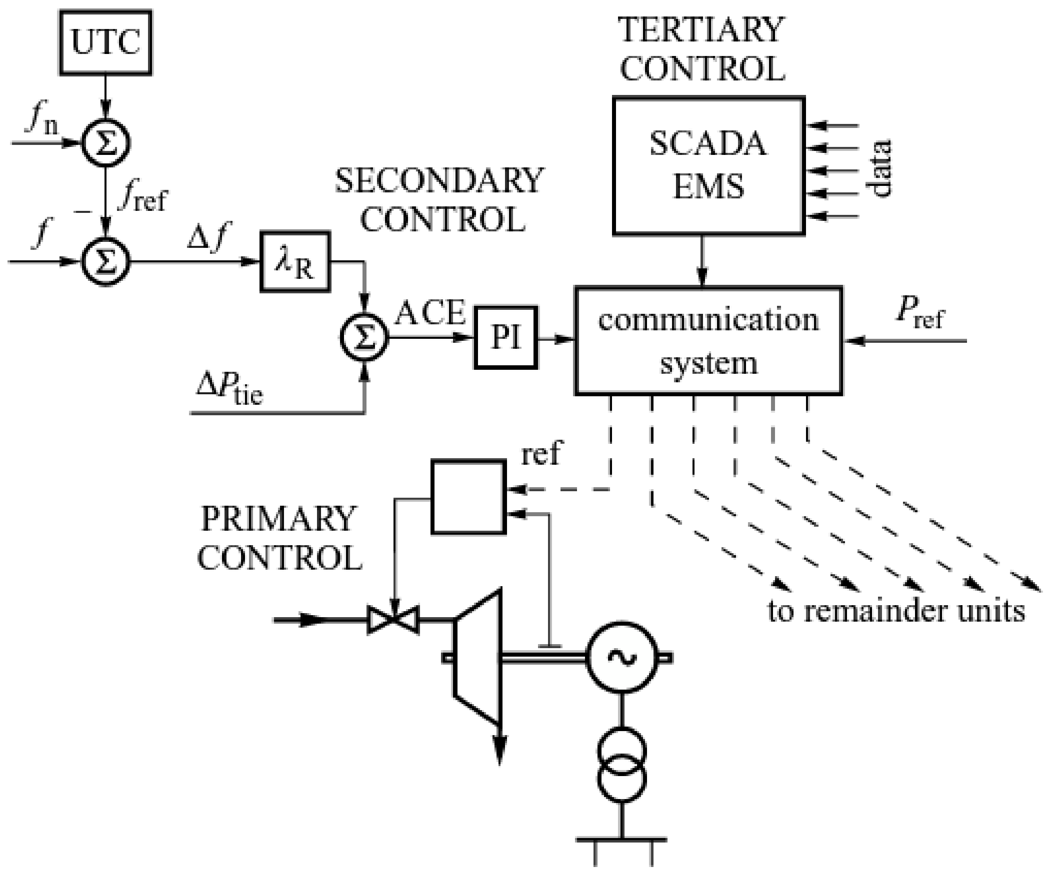
$$\Delta P_{\text{tie}} = -\lambda_{\text{R}} \Delta f\,.$$

- In the latter case which may happen if the control area exhausted its reserves, the missing power must come from the neighboring network (a violation of the non-intervention rule).
- To prevent power swings between control areas due to rapid changes in reference values, scheduled changes in tie-line power flow, ramping that last around 10 min is often used.



AGC as a multi-level control

- Synchronous clocks based on system frequency tend to build an error due to frequency deviations. These errors are eliminated occasionally (once a month) by changing the frequency reference value.

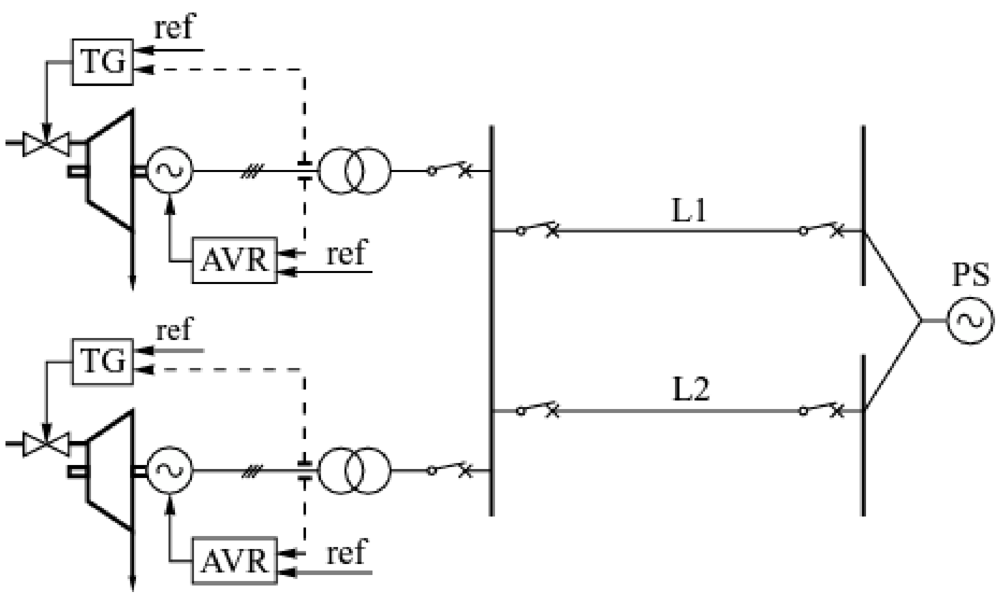


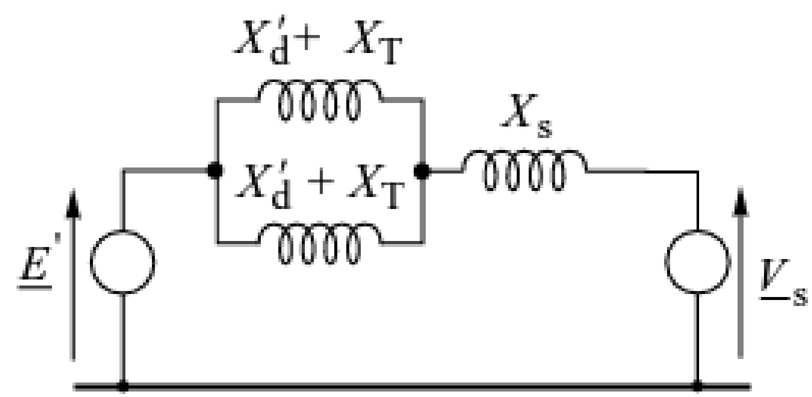
Tertiary control is associated with generator scheduling via economic dispatch

Response of a power system to power imbalance

Stage I	Rotor swings in the generators (first few seconds)
Stage II	Frequency drop (a few seconds to several seconds)
Stage III	Primary control by the turbine governing systems (several seconds)
Stage IV	Secondary control by the central regulators (several seconds to a minute).

- Consider the system below with two identical generators. The disturbance consists of the disconnection of one generator. Refer to the pre-disturbance equivalent circuit in the left figure.

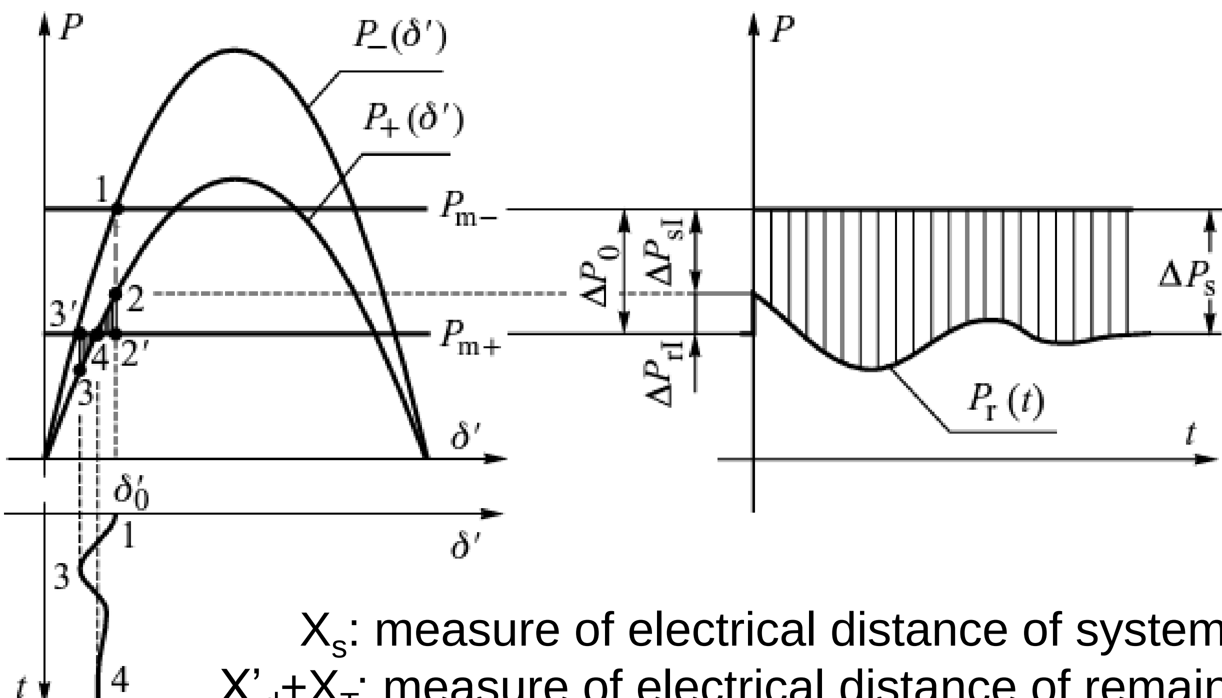




Stage I: rotor swings

- Effect of disconnection of one of the generators:
  - System reactance increases
  - Mechanical power drops

$$P_{-}(\delta_0') = \frac{E' V_s}{\frac{X_d' + X_T}{2} + X_s} \sin \delta_0', \qquad P_{+}(\delta_0') = \frac{E' V_s}{X_d' + X_T + X_s} \sin \delta_0'.$$



$$\frac{\Delta P_{rI}}{\Delta P_{sI}} = \frac{1}{\beta} = \frac{X_s}{X_d' + X_T}.$$

X_s: measure of electrical distance of system w.r.t disturbance

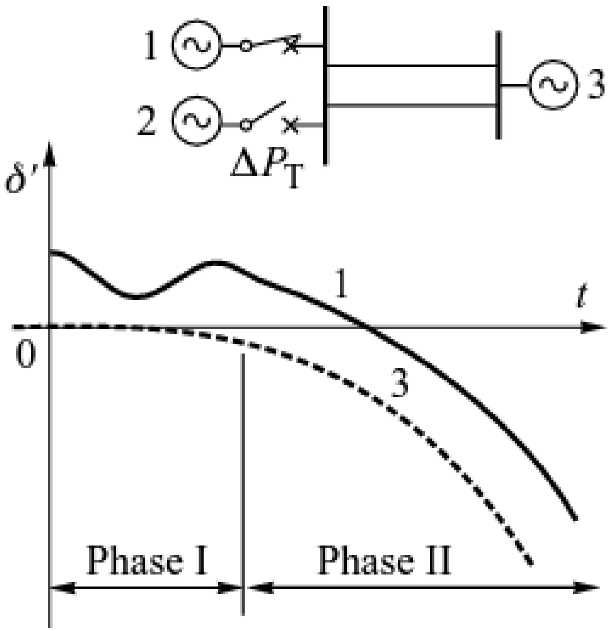
$X'_d + X_T$: measure of electrical distance of remaining gen. w.r.t disturbance

Stage II: frequency drop

- The share of any generator in meeting the power imbalance depends solely on its inertia, and not on its electrical distance.
- After few rotor swings, all generators will slow down at the same rate:

$$\frac{\mathrm{d}\Delta\omega_1}{\mathrm{d}t} \approx \frac{\mathrm{d}\Delta\omega_2}{\mathrm{d}t} \approx \cdots \approx \frac{\mathrm{d}\Delta\omega_{N_G}}{\mathrm{d}t} = \varepsilon,$$

- Hence, $$\frac{\Delta P_1}{M_1} \approx \frac{\Delta P_2}{M_2} \approx \cdots \approx \frac{\Delta P_n}{M_n} \approx \varepsilon \quad \Rightarrow \quad \Delta P_i = M_i \varepsilon = \frac{M_i}{\sum^{N_G} M_k} \Delta P_0.$$



For the case of the network to the left, the contribution of the generator remaining in operation and the rest of the system in meeting the lost power:

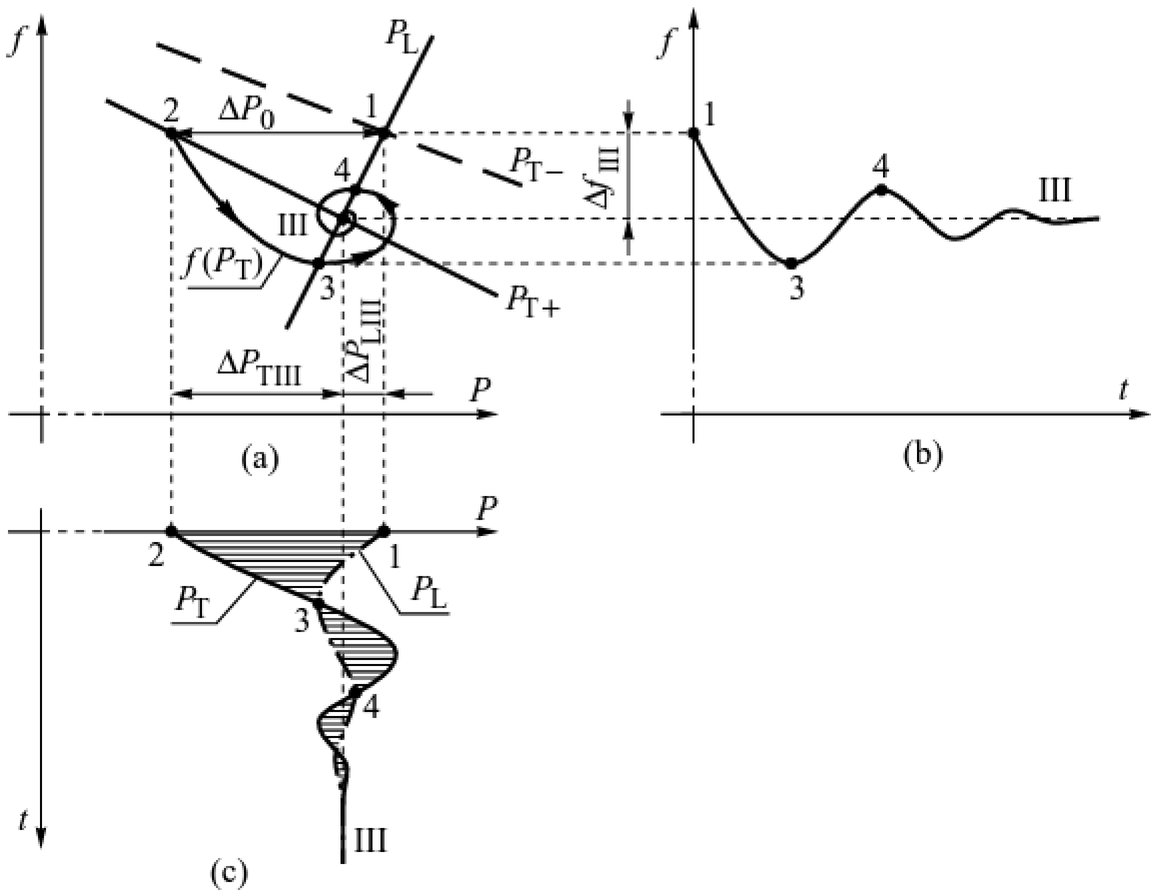
$$\Delta P_{rII} = \frac{M_r}{M_r + M_s} \Delta P_0 \quad \Delta P_{sII} = \frac{M_s}{M_r + M_s} \Delta P_0.$$

$$\frac{\Delta P_{rII}}{\Delta P_{sII}} = \frac{M_r}{M_s} \approx \frac{S_{nr}}{S_{ns}},$$

Stage III: Primary control

- The operating frequency of the system is determined at the intersection point of the generation and load curves:

$$P_{\mathrm{T}} = P_{\mathrm{T0}} + \Delta P_{\mathrm{T}} = P_{\mathrm{T0}} - K_{\mathrm{T}} \Delta f \frac{P_{\mathrm{T0}}}{f_{\mathrm{n}}} \qquad P_{\mathrm{L}} = P_{\mathrm{L0}} + \Delta P_{\mathrm{L}} = P_{\mathrm{L0}} + K_{\mathrm{L}} \Delta f \frac{P_{\mathrm{L0}}}{f_{\mathrm{n}}}.$$



$$\frac{\Delta f_{\mathrm{III}}}{f_{\mathrm{n}}} = \frac{-1}{K_{\mathrm{f}}} \frac{\Delta P_0}{P_{\mathrm{L}}},$$

$$\Delta P_{\mathrm{rIII}} = -K_{\mathrm{Tr}} \frac{\Delta f_{\mathrm{III}}}{f_{\mathrm{n}}} P_{\mathrm{nr}},$$

$$\Delta P_{\mathrm{sIII}} = -K_{\mathrm{Ts}} \frac{\Delta f_{\mathrm{III}}}{f_{\mathrm{n}}} P_{\mathrm{ns}},$$

$$\frac{\Delta P_{\mathrm{rIII}}}{\Delta P_{\mathrm{sIII}}} = \frac{K_{\mathrm{Tr}}}{K_{\mathrm{Ts}}} \frac{P_{\mathrm{nr}}}{P_{\mathrm{ns}}} \approx \frac{P_{\mathrm{nr}}}{P_{\mathrm{ns}}}.$$

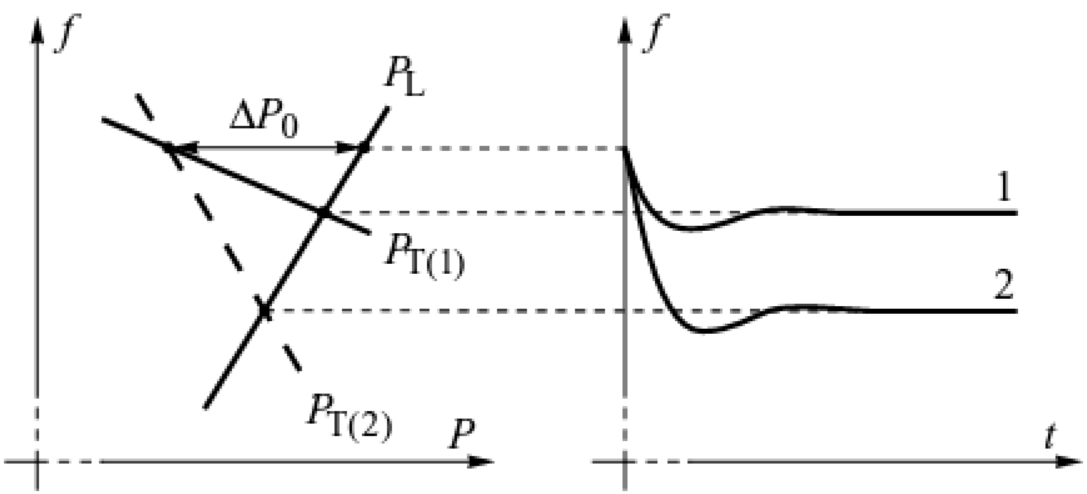
Importance of spinning reserve

- Spinning reserve coefficient:

  (R – number of units operating below their limits)

$$r = \frac{\sum_{i=1}^{N_G} P_{ni} - P_L}{P_L}, \quad p = \frac{\sum_{i=1}^{R} P_{ni}}{\sum_{i=1}^{N_G} P_{ni}},$$

- If all units have the same droop, then, $\frac{\Delta P_T}{P_L} = -K_T \frac{\Delta f}{f_n}$, and $K_T = p(r+1)K$ and $\rho_T = \frac{\rho}{p(r+1)}$.
-
- frequency drop: $\frac{\Delta f_{III}}{f_n} = \frac{-1}{p(r+1)K + K_L} \frac{\Delta P_0}{P_L},$



The smaller the spinning reserve, the bigger the drop in frequency.

Example 9.1

Consider a 50 Hz system with a total load $P_L = 10\,000$ MW in which $p = 60\,\%$ of the units give $r = 15\,\%$ of the spinning reserve. The remaining 40 % of the units are fully loaded. The average droop of the units with spinning reserve is $\rho = 7\,\%$ and the frequency sensitivity coefficient of the loads is $K_L = 1$. If the system suddenly loses a large generating unit of $\Delta P_0 = 500$ MW, calculate the frequency drop and the amount of power contributed by the primary control.

$$K_T = 0.6(1 + 0.15)1/0.07 = 9.687$$

$$\Delta f_{III} = \frac{-1}{9.867 + 1} \times \left[\frac{500}{10\,000}\right] \times 50 \approx 0.23 \text{ Hz},$$

$$\Delta P_{T\,III} = 9.867 \times \frac{0.23}{50} \times 10\,000 = 454 \text{ MW},$$

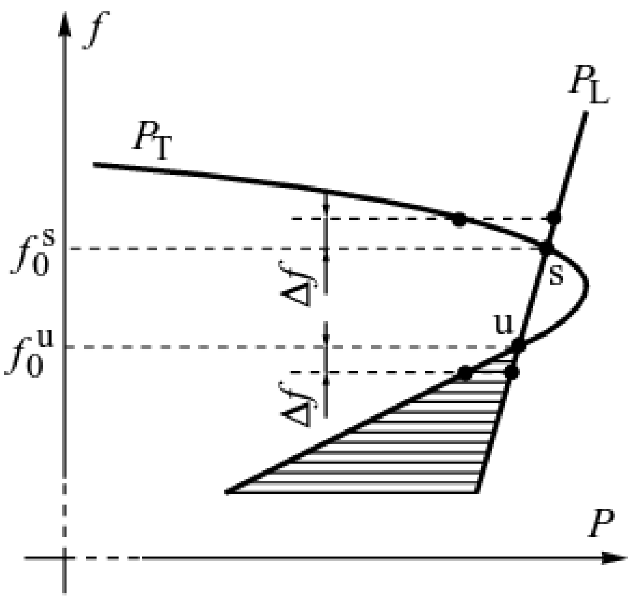
$$\Delta P_{L\,III} = 1 \times \frac{0.23}{50} \times 10\,000 = 46 \text{ MW},$$

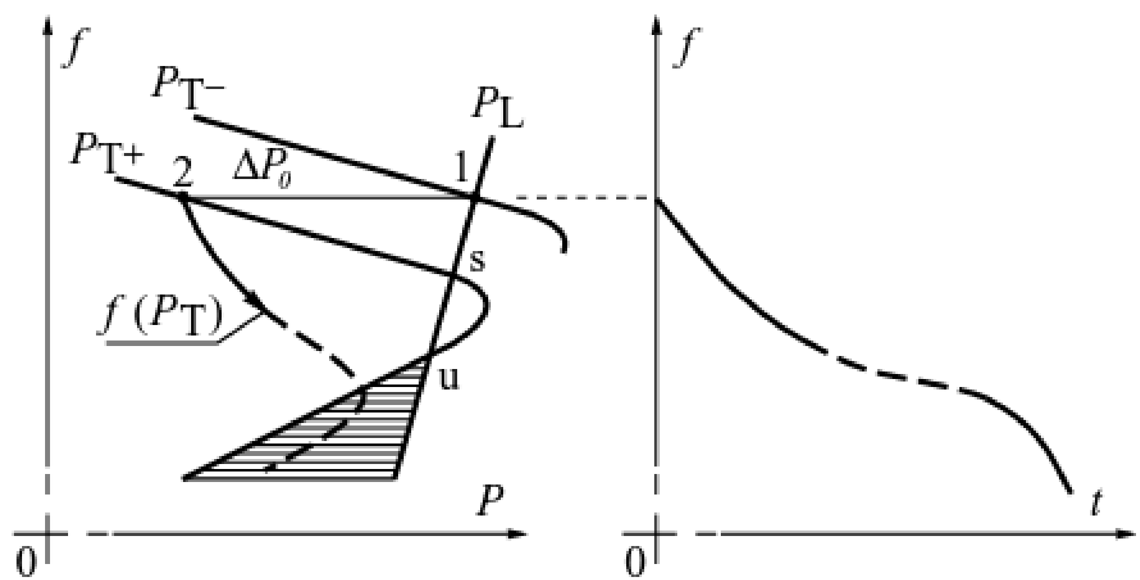
With no spinning reserves,

$$\Delta f_{III} = \frac{-1}{0 + 1} \times \left[\frac{500}{10\,000}\right] \times 50 = 2.5 \text{ Hz},$$

Frequency Collapse

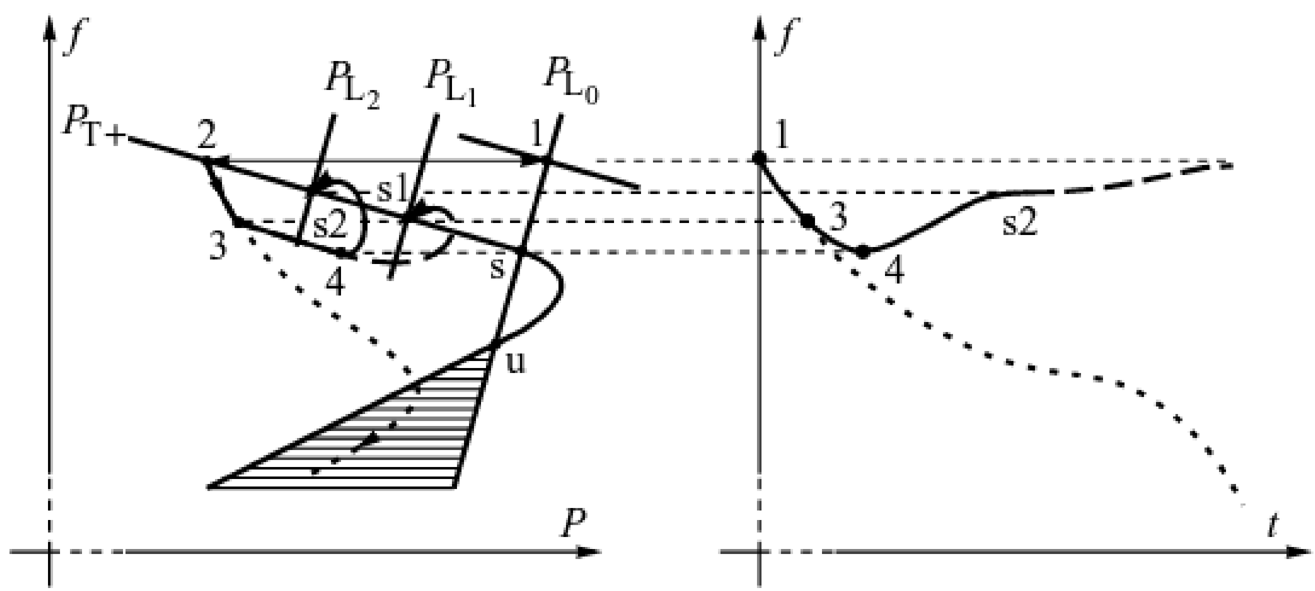
- For large frequency deviations, the linearity of generator frequency-power characteristic is no longer valid.
- In the left figure below, point *s* is stable , while point *u* is unstable (shaded are is called *area of repulsion*).
- In the right figure, the system was operating with low spinning reserve when a loss of a generator occurs. The system trajectory enters the area of repulsion thus resulting in frequency collapse.





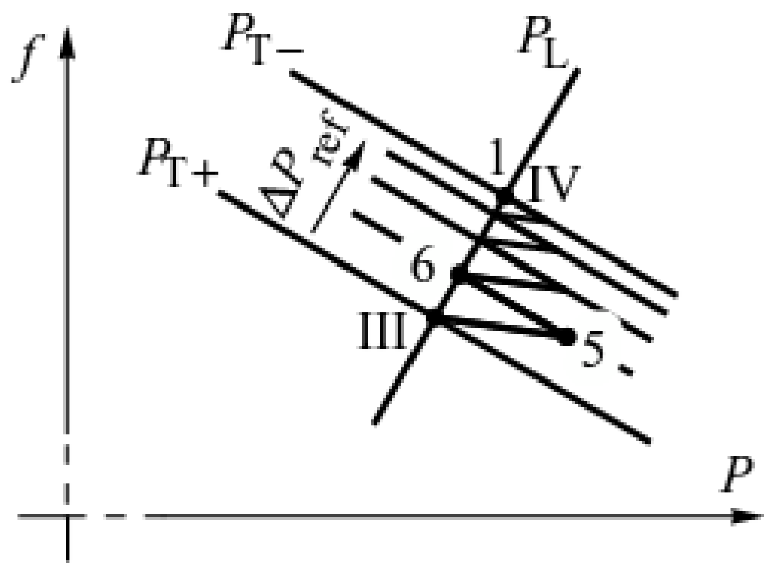
Under-frequency load shedding

- In an interconnected system with a shortage in tie-line capacity, the only way to prevent frequency collapse following a large disturbance is to employ *automatic load shedding* using *under-frequency relays.*
- Load shedding is implemented in stages starting with the least important load.
  - First shed activated at point 3, followed by the second shed at point 4



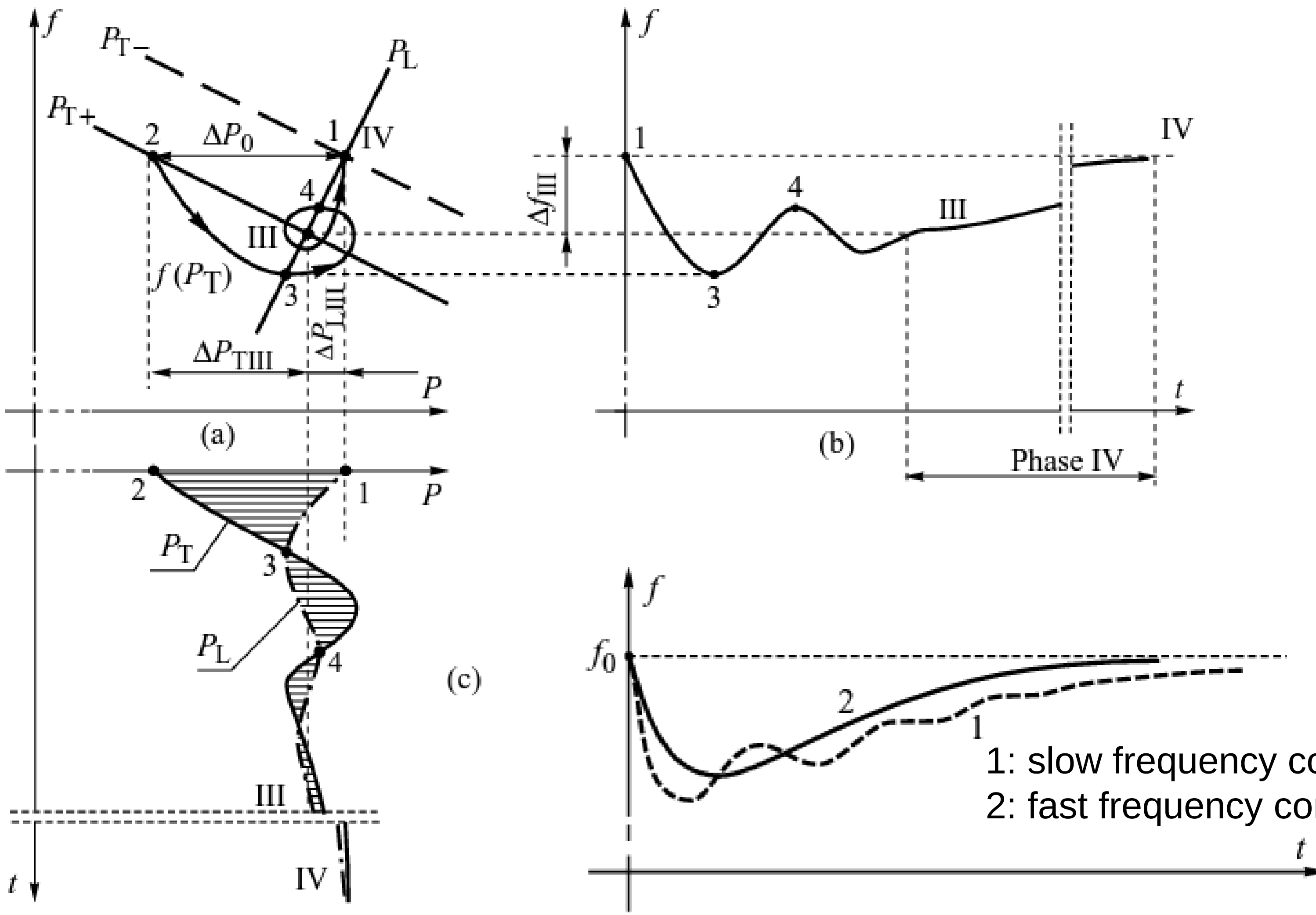
Stage IV: Secondary control

- In this final stage, the AGC is activated to correct the tie-line flow and frequency deviation.
- In an islanded system (with no tie-lines), the central regulators transmits control signals to participating generating units to increase their output power (i.e., shift the generator curve upward in increments) - see figure below.



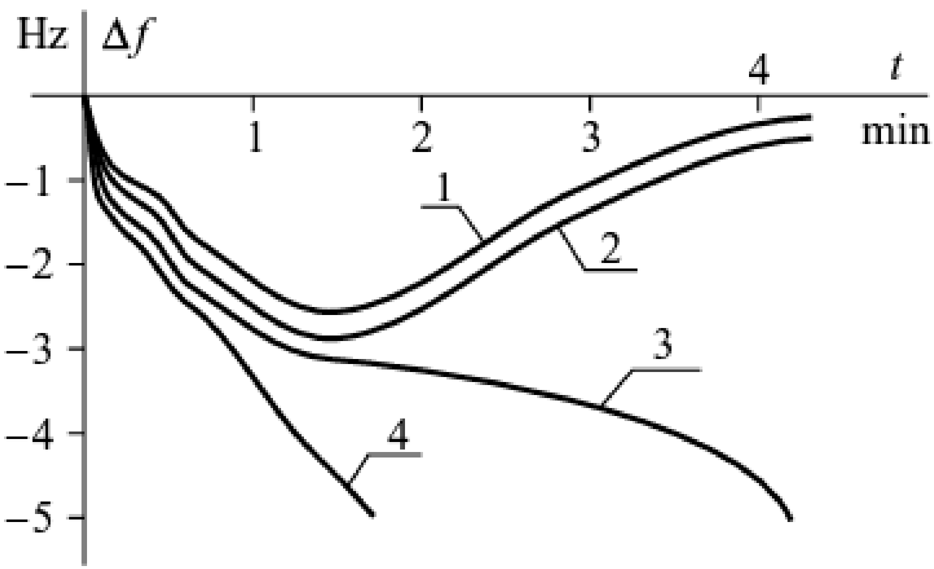
Stage IV: Secondary control

- In reality, the inertia within the power regulation process ensures smooth changes in power (instead of zig-zag lines).



Stage IV: secondary control

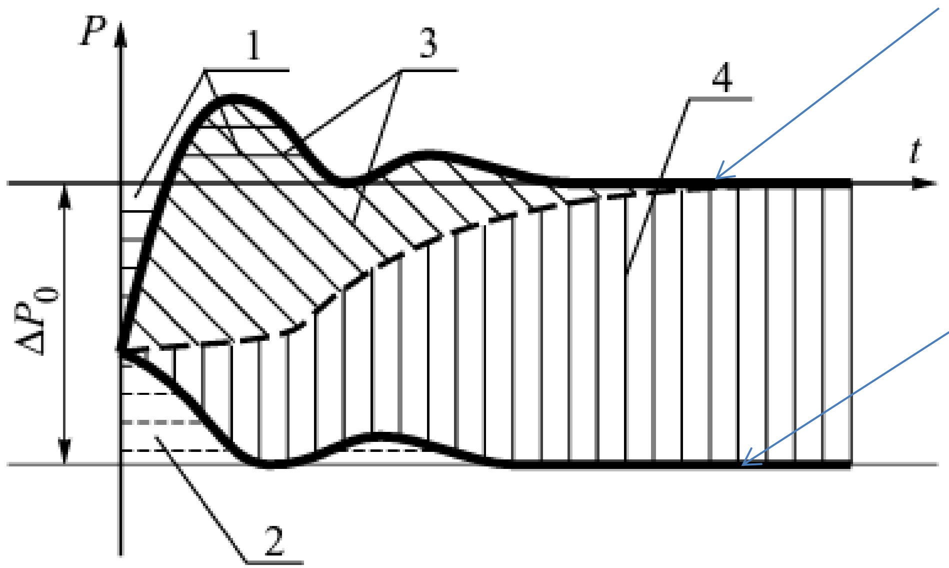
- At the end of Stage III, each generator contributes to the power imbalance. In Stage IV, the contribution to power imbalance is made only by those units participating in central control.
- Importance of spinning reserve is illustrated in the figure below for different spinning reserve coefficients (*r*). In here, the disturbance consists of loosing generation equal to 10% of the load demand.
  - In cases 1 & 2, the frequency returns to its reference value
  - In cases 3 & 4, the frequency collapses.



1: r = 16%
2: r = 14%
3: r = 12%
4: r = 8%

Energy balance over stages I, II, III and IV

- Initially, the energy shortfall is produced by converting the kinetic energy of the rotating masses to electric energy (areas 1 & 2).
- The reduction of kinetic energy causes a drop in frequency which activates the turbine governor primary control so that the mechanical energy is increased but at a lower frequency (area 3).
- Secondary control further increases the mechanical energy to generate the additional required electric energy and to increase the kinetic energy of the rotating masses (area 4).

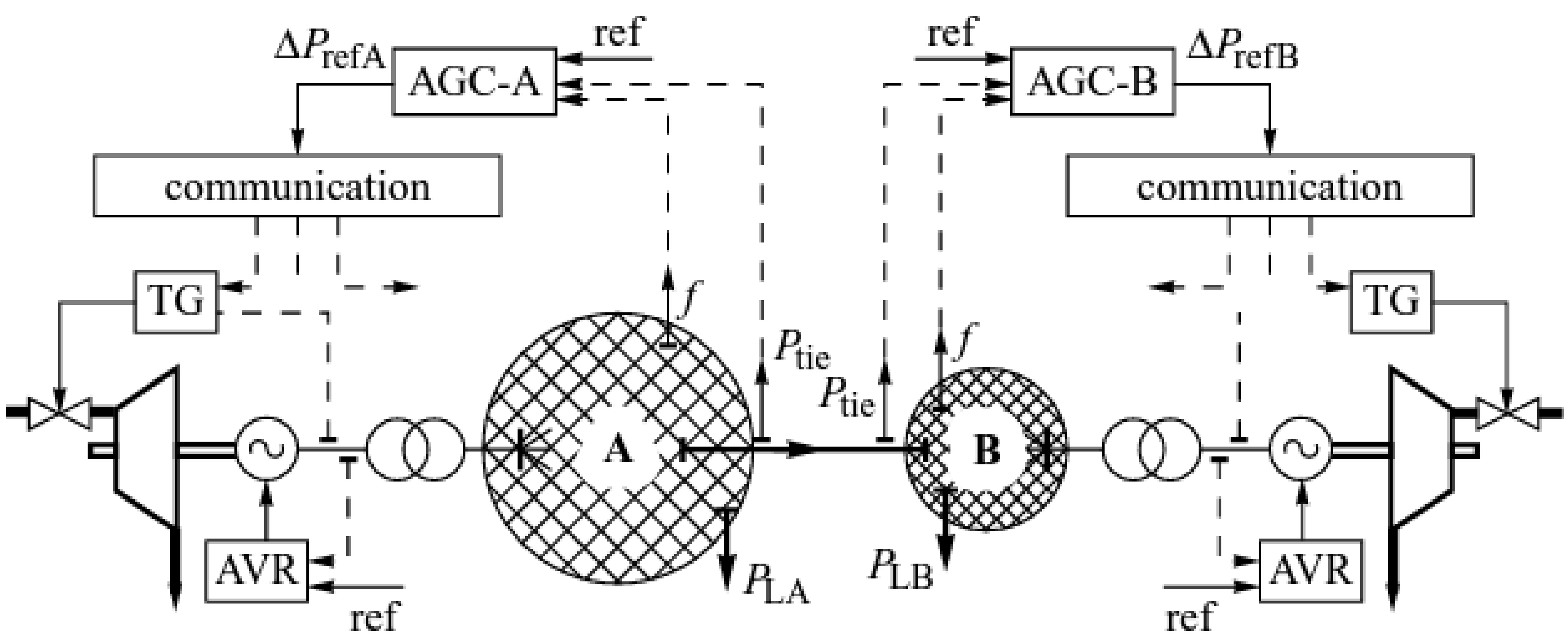


Variation of mechanical power provided by the system

Variation of electric power of the load (due to frequency deviation)

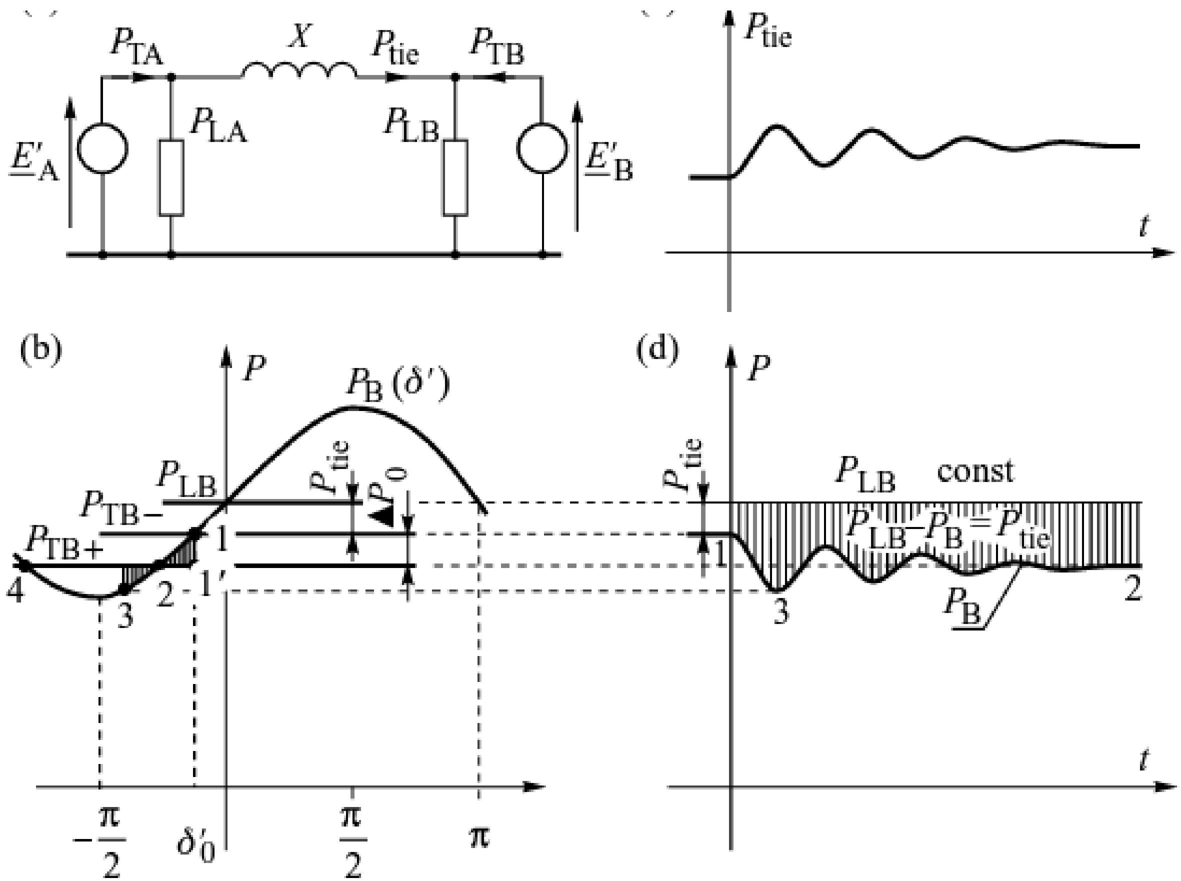
Interconnected systems and tie-line oscillations

- Consider two systems (A & B). Assumptions:
  - P_{tie} is flowing from A to B (i.e., $P_{TB} < P_{LB}$)
  - Power imbalance ΔP_o occurs in system B.
  - The influence of the central regulators during the first three stages is ignored.
- Stage I of the dynamics may be obtained by using the equal area criterion with system A acting as the infinite-busbar.



Interconnected systems and tie-line oscillations

- Initial operating point 1 (operating at negative power angle w.t. System A)
- System B loses generation equal to ΔP_o. This forces the system to move from point 1 to 2 then to 3. Kinetic energy in both systems is used to cover the lost generation.
- Since $M_A >> M_B$, the lost power almost entirely comes from the tie-line.



Interconnected systems and tie-line oscillations

- The frequency drop is determined by

$$\frac{\Delta f_{\mathrm{III}}}{f_{\mathrm{n}}} = \frac{-1}{K_{\mathrm{fA}} P_{\mathrm{LA}} + K_{\mathrm{fB}} P_{\mathrm{LB}}} \Delta P_0,$$

where $K_{\mathrm{fA}} = K_{\mathrm{TA}} + K_{\mathrm{LA}}$ and $K_{\mathrm{fB}} = K_{\mathrm{TB}} + K_{\mathrm{LB}}$

- The AGC of both systems will now intervene in stage IV:

$$\mathrm{ACE_A} = -\Delta P_{\mathrm{tieIII}} - \lambda_{\mathrm{RA}} \Delta f_{\mathrm{III}} \quad \text{and} \quad \mathrm{ACE_B} = +\Delta P_{\mathrm{tieIII}} - \lambda_{\mathrm{RB}} \Delta f_{\mathrm{III}}.$$

with $\lambda_{\mathrm{RA}} = K_{\mathrm{RA}} \frac{P_{\mathrm{LA}}}{f_{\mathrm{n}}}$ and $\lambda_{\mathrm{RB}} = K_{\mathrm{RB}} \frac{P_{\mathrm{LB}}}{f_{\mathrm{n}}}$,

Hence,

$$\mathrm{ACE_A} = -\Delta P_{\mathrm{tieIII}} - \lambda_{\mathrm{RA}} \Delta f_{\mathrm{III}} = \frac{-K_{\mathrm{fA}} P_{\mathrm{LA}} + K_{\mathrm{RA}} P_{\mathrm{LA}}}{K_{\mathrm{fA}} P_{\mathrm{LA}} + K_{\mathrm{fB}} P_{\mathrm{LB}}} \Delta P_0,$$

$$\mathrm{ACE_B} = +\Delta P_{\mathrm{tieIII}} - \lambda_{\mathrm{RB}} \Delta f_{\mathrm{III}} = \frac{K_{\mathrm{fA}} P_{\mathrm{LA}} + K_{\mathrm{RB}} P_{\mathrm{LB}}}{K_{\mathrm{fA}} P_{\mathrm{LA}} + K_{\mathrm{fB}} P_{\mathrm{LB}}} \Delta P_0.$$

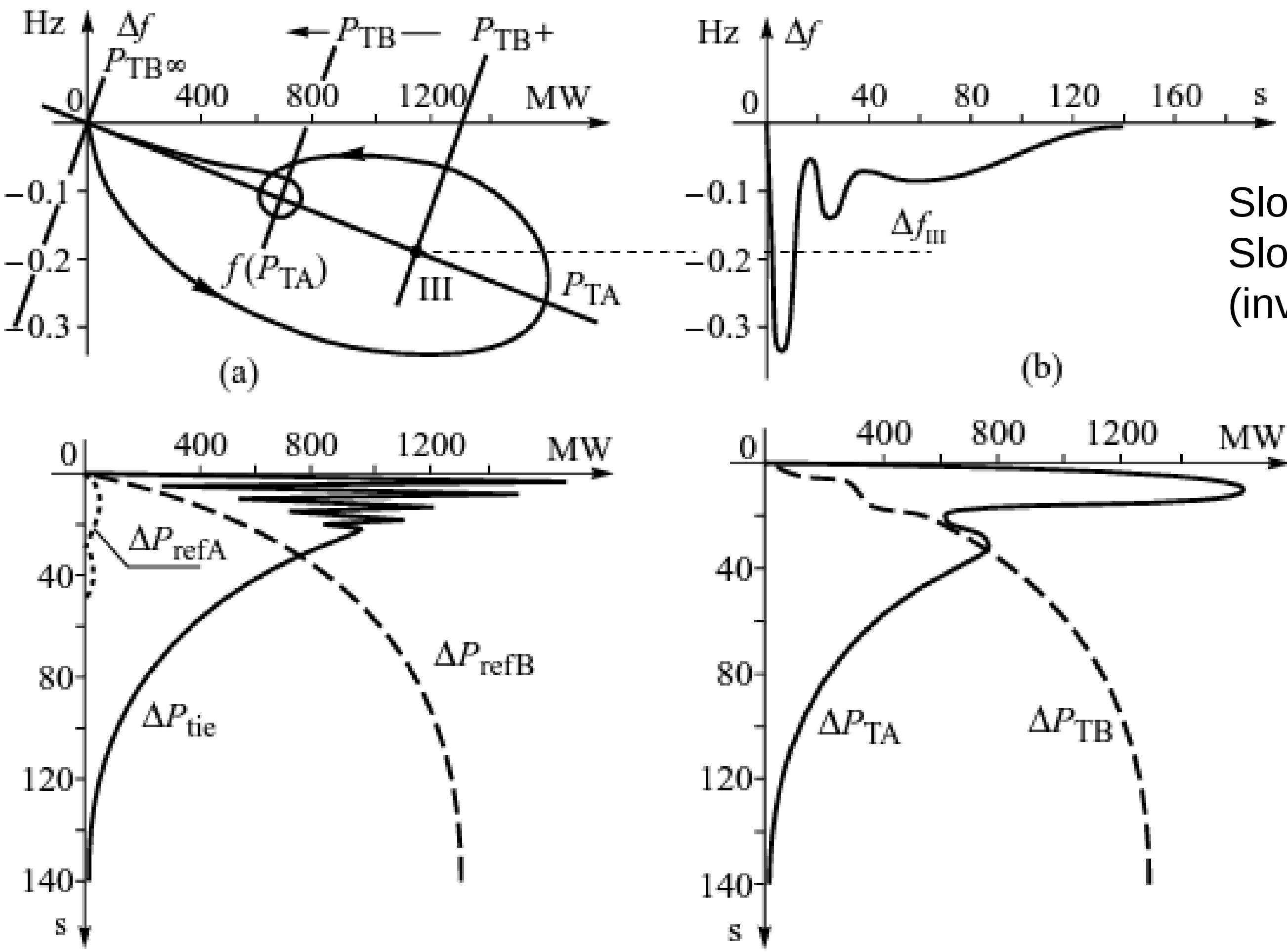
where K_{RA} and K_{RB} are estimates of K_{fA} and K_{fB}.

- If $K_{\mathrm{RA}} = K_{\mathrm{fA}}$, $K_{\mathrm{RB}} = K_{\mathrm{fB}}$. then $\mathrm{ACE_A} = 0$ and $\mathrm{ACE_B} = \Delta P_0$,

Example 9.2

An interconnected system consists of two subsystems of different size. The data of the subsystems are: $f_n = 50$ Hz, $P_{LA} = 37\,500$ MW, $K_{TA} = 8$ ($\rho_{TA} = 0.125$), $K_{LA} \approx 0$, $K_{RA} = K_{TA}$, $P_{LB} = 4000$ MW, $K_{TB} = 10$ ($\rho_{TB} = 0.1$), $K_{LB} \approx 0$, $K_{RB} = K_{TB}$.

Two large generating units are suddenly lost in the smaller system producing a power deficit of $\Delta P_0 = 1300$ MW, that is 32.5% of the total generation in this subsystem.



Slope of P_{TA}: 6000 MW/Hz
Slope of P_{TB}: 800 MW/Hz
(inverted and shifted)

Case of insufficient regulating power

- If the available regulation power in system B is less than the generation loss, then system A must intervene to cover part of the lost power; hence, its central regulator is subject to two error signals:

$$\mathrm{ACE_A} = -\Delta P_{\mathrm{tie}\,\infty} - K_{\mathrm{RA}}\, P_{\mathrm{LA}} \frac{\Delta f_\infty}{f_\mathrm{n}} = 0.$$

  with the tie-line power satisfying the power balance of system B

$$\Delta P_0 - \Delta P_{\mathrm{regB}} = \Delta P_{\mathrm{tie}\,\infty} - (K_{\mathrm{TB}} + K_{\mathrm{LB}})\, P_{\mathrm{LB}} \frac{\Delta f_\infty}{f_\mathrm{n}}.$$

- The final steady-state error signals are given by

$$\Delta P_{\mathrm{tie}\infty} = \frac{K_{\mathrm{RA}}\, P_{\mathrm{LA}}}{K_{\mathrm{RA}}\, P_{\mathrm{LA}} + K_{\mathrm{fB}}\, P_{\mathrm{LB}}} \left(\Delta P_0 - \Delta P_{\mathrm{regB}}\right),$$

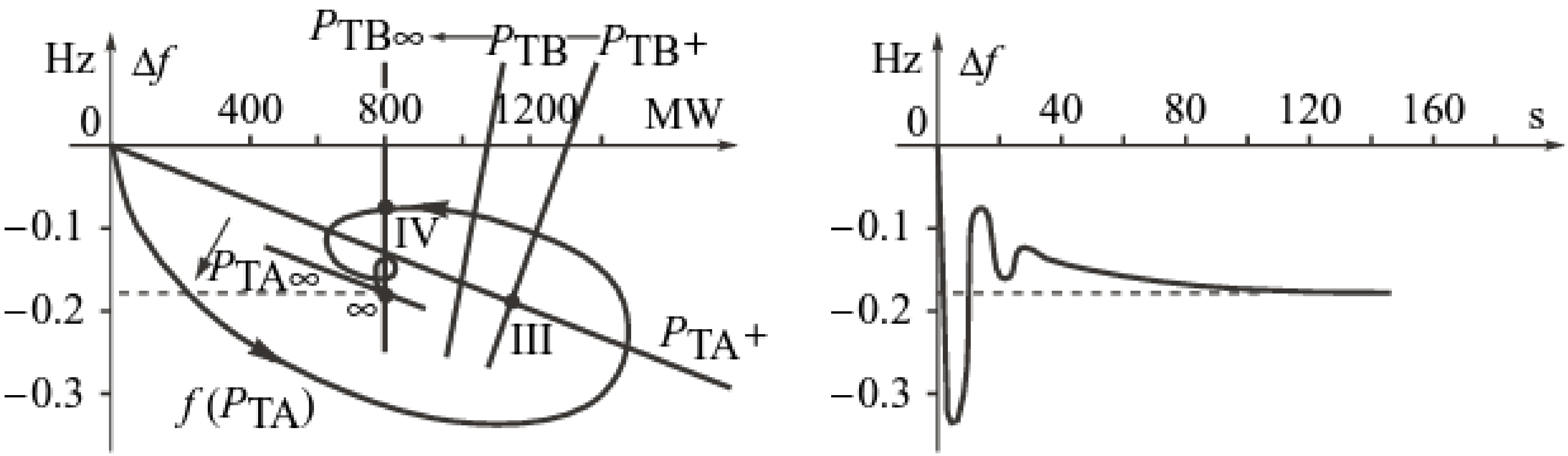
$$\frac{\Delta f_\infty}{f_\mathrm{n}} = -\frac{1}{K_{\mathrm{RA}}\, P_{\mathrm{LA}} + K_{\mathrm{fB}}\, P_{\mathrm{LB}}} \left(\Delta P_0 - \Delta P_{\mathrm{regB}}\right).$$

- Since $P_{\mathrm{LA}} \gg P_{\mathrm{LB}}$,

  $\Delta P_{\mathrm{tie}\,\infty} \cong \left(\Delta P_0 - \Delta P_{\mathrm{regB}}\right),$ and $\dfrac{\Delta f_\infty}{f_\mathrm{n}} \cong -\dfrac{1}{K_{\mathrm{RA}}\, P_{\mathrm{LA}}}(\Delta P_0 - \Delta P_{\mathrm{regB}}).$

Example 9.3

The available regulating power of the small subsystem considered in Example 9.2 is $\Delta P_{regB} = 500$ MW. The settings of the central regulators are $K_{RA} = 5.55 < K_{TA}$ and $K_{RB} = 12.5 > K_{TB}$. Neglecting the frequency sensitivity of the load, Equations (9.56) and (9.57) give: $\Delta P_{tie\infty} =$ 800 MW and $\Delta f_{\infty} = -0.16$ Hz.



The variation in tie-line power interchange is similar to example 2, except that it settles down to 800 MW (instead of zero MW).

Since $K_{RA} < K_{TA}$, the regulator of the system A will decrease its generation, thus increasing the frequency error while the tie line error is not allowed to increase.

Skip Section 9.6 – FACTS Devices