EE4-48
EE9CS6-2

IMPERIAL COLLEGE LONDON

DEPARTMENT OF ELECTRICAL AND ELECTRONIC ENGINEERING
EXAMINATIONS 2011

MSc and EEE PART IV: MEng and ACGI

POWER SYSTEM CONTROL, MEASUREMENT AND PROTECTION

Thursday, 26 May 10:00 am

Time allowed: 3:00 hours

There are SIX questions on this paper.

Answer FOUR questions.

All questions carry equal marks.

Any special instructions for invigilators and information for candidates are on page 1.

Examiners responsible	First Marker(s) :	B.C. Pal
	Second Marker(s) :	B. Chaudhuri

The Questions

1. a) Why is the current so important a consideration in lightning protection design? [2]

b) How is the switching transient in power transmission networks characterised? [3]

c) How does the phenomenon of sub synchronous resonance (SSR) develop and manifest in the system? [3]

d) A 3-phase, star connected, 23.5 kV (V_t) (line-line) 600 MVA alternator is connected to grid operating at 50 Hz. The resistance is negligible and the synchronous reactance (X_s) is 2.0 Ohm. Derive the power angle relationship as a function of terminal voltage (V_t), excitation voltage (E_{fd}), reactance (X_s) and power angle (δ) and subsequently solve the following: [5]

i) Find the excitation voltage (line-line) and the machine angle (delta) when the generator is delivering full load at 0.85 power factor lagging. [4]

ii) Keeping the excitation voltage at the value obtained in (i), if the prime mover power is gradually increased the generator will continue to deliver increased MW before the steady state stability limit is reached. Compute the stability limit (in terms of MW). [3]

2.

a) Briefly describe the functions of the following components in excitation systems:

i) voltage regulator [3]

ii) power system stabiliser [3]

iii) limiter and protective circuits [3]

iv) field forcing. [3]

b) Other than synchronous generator, mention various other options of voltage control and describe any two of them in reasonable detail. [8]

3.

a) Answer the following:

i) Why is the direct axis synchronous reactance of the synchronous machine designed to be so high (1.5 to 2.2 p.u.)? [3]

ii) How does a salient pole synchronous generator produce MW even after loosing excitation? [3]

b) Starting from the inertia constant J (Kg-m^2), rated VA as VA base, basic torque and angle equations in a rotational system, derive the following swing equations of a synchronous generator connected to the grid:

$$\frac{d\delta}{dt} = \omega_r - \omega_s$$

$$\frac{2H}{\omega_s}\frac{d\omega_r}{dt} = P_{mech} - P_{elec} - D(\omega_r - \omega_s)$$

δ is the angle of the rotor with respect to a synchronously rotating reference frame;

ω_r, ω_s: speed of the rotor and synchronous reference frame respectively in rad/sec.

P_{mech}, P_{elec} : mechanical power input and electrical power output in p.u. respectively

H = H-constant in seconds

D : mechanical damping co-efficient in p.u-sec/rad [7]

c) The moment of inertia of a generator-turbine mass is 45,000 Kg-m^2. The generator has a rating of 500 MVA and operates at 3000 RPM. Find the

i) stored kinetic energy [3]

ii) H-constant (H) [2]

iii) M-constant (M) [2]

4.

a) Briefly describe the necessity of area wise load frequency control.

[2]

b) Establish the steady state power frequency characteristics of a two-area system. Assume that each area has the following characteristic parameters:

Area 1: inertia constant: M_1, droop: R_1 and damping co-efficient: D_1

Area2: inertia constant: M_2, droop: R_2 and damping co-efficient: D_2

[6]

c) Consider two interconnected areas as follows: Area 1: Gen 19,000 MW, Load 20,000 MW: Area 2: Gen 41000 MW, Load: 40,000 MW. The load in each area varies by 1% with 1% change in frequency (D = 1.0). The speed regulation, R, is 5% for all the units. Area 1 is importing 1000 MW from Area 2.

Area 1 is operating with a spinning reserve of 1000 MW spread uniformly over a generation of 4000 MW capacity, and Area 2 is operating with a spinning reserve of 1000 MW spread uniformly over a generation of 10,000 MW. The nominal frequency is 50 Hz.

Determine the steady state frequency, generation and load of each area, and the tie line power for each of the following contingencies, when the generation carrying spinning reserve in each area is on supplementary control with frequency bias factor settings of 250 MW/0.1 Hz for Area 1 and 500 MW/0.1 Hz for Area 2.

i) Loss of 1000 MW load in Area 1 without supplementary control

[6]

ii) Loss of 2000 MW generation in area 1 which is not part of spinning reserve with supplementary control.

[6]

5

a) Describe the basic components and operating principle of numerical/digital relays. [5]

b) Distinguish between dependability and security of a relay [4]

c) The performance of an over current relay was monitored for a period of three years. It was found that the relay operated 35 times, out of which 29 were correct trips. If the relay failed to issue trip decisions on 3 occasions, compute dependability, security and reliability of the relay as a percentage. [6]

d) How is selectivity achieved in transformer differential protection? [5]

6.

a) Why should the secondary of a current transformer never be left open?

[3]

b) By mistake someone has interchanged the terminals of measurement CT and protection CT. Both CTs are at the same place and have the same current ratings. What will happen in normal and abnormal condition?

[3]

c)

i) What is the function of a tuning inductor in a capacitive coupled voltage transformer (CCVT)?

[3]

ii) How is it related to CCVT capacitance?

[3]

d) A 1200/5, C400 CT is connected on the 1000/5 tap. The secondary winding resistance is 0.51 Ω. Obtain the maximum allowable burden in the CT at 20 times the rated symmetrical secondary current with rated accuracy

[8]

The Answers

1. a) *Why is the current so important a consideration in lightning protection design?*

[2]

The electrical property of lightning is characterised by very short lived high current (micro-seconds-kA). The specification of the pilot wire, tower and tower footing resistance to limit the impact of the current is very much influenced by the current.

b) *How is the switching transient in power transmission networks characterised?*

[3]

In EHV lines when circuits are opened because of fault, large over voltage appears across the switch (circuit breaker). Typically for a 400 kV system, this can be around 2 times (depends on the switching arrangement) the rated value and last for 200 microseconds to 2000 microseconds.

c) *How does the phenomenon of sub synchronous resonance (SSR) develop and manifest in the system?*

[3]

During network events (switching) high current will flow temporarily through generator stator circuits. Usually these are due to transformer EMF and have power frequency (50/60 Hz). The contribution of this component during transient to total generation voltage is insignificant. Their exclusions from modelling make the analysis simpler to establish better understanding. Various sections of turbine mass dynamically interact with the network particularly when long transmission lines are series compensated. The frequencies of oscillations are in the range of 10 to 48 Hz and that is why they are classified as sub synchronous resonance (SSR).

d) *A 3-phase, star connected, 23.5 kV (V_t) (line-line) 600 MVA alternator is connected to grid operating at 50 Hz. The resistance is negligible and the synchronous reactance (X_s) is 2.0 Ohm. Derive the power angle relationship as a function of terminal voltage (V_t), excitation voltage (E_{fd}), reactance (X_s) and power angle (δ) and subsequently solve the following:*

[5]

A synchronous machine is normally connected to a fixed voltage bus and operates at constant speed. There is a limit on the power that can be delivered by the machine to the system or the torque that can be applied to it when working as a motor. Analytical expressions for the steady state power transfer between the machine and the infinite bus or the torque developed by the machine are derived in terms of bus voltage, machine voltage and machine parameters on per phase basis. The per phase voltage, current and reactance are shown in the equivalent circuit:

Induced or excitation voltage $E_{fd}=\overline{E} = E\angle\delta$, Terminal voltage or infinite bus voltage: $\overline{V_t} = V_t\angle 0$

Stator impedance: $\overline{Z}_s = R_s + jX_s = Z_s\angle\theta_s$

The complex power delivered to infinite bus:

$$S = V_t I_s^{*};$$

$$I_s^{*} = \left|\frac{E - V_t}{Z_s}\right|^{*} = \frac{E}{Z_s}\angle\theta_s - \delta - \frac{V_t}{Z_s}\angle\theta_s$$

$$S = \frac{EV_t}{Z_s}\angle\theta_s - \delta - \frac{V_t^2}{Z_s}\cos\angle\theta_s$$

$$S = P + jQ;$$

$$P = \frac{EV_t}{Z_s}\cos(\theta_s - \delta) - \frac{V_t^2}{Z_s}\cos\theta_s \text{ watt/phase}$$

$$Q = \frac{EV_t}{Z_s}\sin(\theta_s - \delta) - \frac{V_t^2}{Z_s}\sin\theta_s \text{ VAR/phase}$$

when stator resistance is neglected (normally $\frac{X_s}{R_s} > 400$);

$$P_{3\phi} = 3\frac{EV_t}{X_s}\sin\delta = P_{\max}\sin\delta \qquad Q_{3\phi} = 3\frac{EV_t}{X_s}\cos\delta - 3\frac{V_t^2}{X_s}$$

When the voltages are expressed in line to line and the , the power flow equations are

$$P_{out} = \frac{EV_t}{X_s}sin\delta = P_{max}\,sin\delta$$

$$Q_{out} = \frac{EV_t}{X_s}cos\delta - \frac{V_t^2}{X_s}$$

i) *Find the excitation voltage (line-line) and the machine angle (delta) when the generator is delivering full load at 0.85 power factor lagging.*

[4]

Find the full load current from full MVA rating ($\sqrt{3}V_t I_t = MVA$) at 0.85 pf lagging

The current is 14741 A at -31.78 degree taking Vt as reference

[1]

$E_{fd}\angle\delta = V_t + j\sqrt{3}\bar{I}X_s$:

One can obtain E_{fd}=66.51 kV and machine angle delta (δ) = 40.73 degree

[3]

ii) *Keeping the excitation voltage at the value obtained in (i), if the prime mover power is gradually increased the generator will continue to deliver increased MW before the steady state stability limit is reached. Compute the stability limit (in terms of MW).*

[3]

Maximum power from power angle equation derived in (a) is $\frac{E_{fd}V_t}{X_s}$ and occurs at machine angle 90 degree which is 781.5 MW; For delta of 40.73 degree , output power is 510.0 MW. The stability margin in MW is 781.5-510.0=271.5 MW

[3]

2.

a) *Briefly describe the functions of the following components in excitation systems:*

i) *voltage regulator* [3]

ii) *power system stabiliser* [3]

iii) *limiter and protective circuits* [3]

iv) *field forcing* [3]

Regulator

It processes and amplifies input control signals to a level and form appropriate for control of the exciter. This includes regulating and excitation system stabilising function (rate feedback and lead-lag compensation). In early days it used to be amplidyne or alternator. Modern voltage regulator is high gain fast acting thyristor system to produce high DC excitation.

Voltage and current sensor

Senses generator terminal voltage and currents and feed to the regulator block for voltage regulation and load current compensation. These quantities are important to compute the excitation level of the machine, flux level in stator and rotor and also current loading in stator as well as rotor winding. Through voltage and current transducers high voltage and current are brought down to control level and operating point of the machine is assessed.

Power system stabilizer

This block provides an additional input signal to the regulator to damp power system oscillations. Some commonly used input signals are rotor speed deviation, accelerating power and frequency deviation. This is very important for post fault small signal stability of the system. This results when machine is equipped with high gain fast acting excitation system for improved transient stability performance.

Limiter and protective circuits

These include a wide array of control and protective functions that ensure that the capability limits of the exciter and synchronous generator are not exceeded. Some of the commonly used functions are the field current limiter, maximum excitation limiter, terminal voltage limiter, volt/Hz regulator and protection and under excitation limiter. These are normally distinct circuits and their output signals may be applied to the excitation system at various locations as a summing input or a gated input.

b) *Other than synchronous generator, mention various other options of voltage control and describe two of them in reasonable detail.* [8]

Overhead lines and cables
Tap changing transformer
Loads

- Typically a 400-KV single circuit line produces 60-70 MVAR per 100 km
- 400-KV cable produces 20 MVAR per km.

The line is modelled as nominal pi or T section to represent effect of series inductance and capacitance

- At light load (during night) generation is more than the absorption: hence the system voltage is higher than nominal.
- At higher load (during peak hours) absorption in the series branch is considerably higher than the generation in the shunt branch: the net effect brings the system voltage lesser than normal.
- At surge impedance load (when shunt var generation is line inductor absorption) voltage remains fault along the length of the line or cable, the voltage and current at any section of the line are in phase too. This is ideal situation but rarely achieved in practice.

Tap changing transformer:

- Provides discrete voltage control
- Can be on-load or off-load.
- Transformers always absorb as the leakage impedance is reactive.

For a transformer with $X_T\,p.u.$ and full load rating $3VI_{rated}$

The var absorbed

$$X_T(\Omega) = VX_T(p.u.)/I_{rated}$$

$$3I^2X_T(\Omega) = 3I^2VX_T(p.u.)/I_{rated} = 3I^2V^2X_T(p.u)/VI_{rated}$$

$$\left(\frac{VA_{load}}{VA_{rated}}\right)^2 X_T(p.u)$$

3.

a) Answer the following

i) *Why is the direct axis synchronous reactance of the synchronous machine designed to be so high (1.5 to 2.2 p.u.)?* [3]

Low air gap machines are preferred because of over all reduced cost. The low air gap machine results in higher magnetic circuit inductance. This has effect on poor voltage regulation. However, automatic voltage regulator (AVR) regulates the voltage so higher reactance is not a problem. The only concern is the machine, rotor and stator copper losses are generally more.

ii) *How does a salient pole synchronous generator produce MW even after loosing excitation?*

Because of the difference in direct and quadrature axis reactance, the reluctance torque is developed. This is purely because of the air gap geometry and is not dependent on excitation. About 10 to 15 % of total power is produced by the machine because of the reluctance. This can be easily seen in the power angle equation of salient pole machine.

$$P = V_d I_d + V_q I_q = \frac{E_{fd} V_t}{X_d} sin\,\delta + \frac{V_t^2}{2}\left(\frac{1}{X_q} - \frac{1}{X_d}\right) sin\,2\delta$$

The second term in the RHS of the above equation is independent of excitation voltage E_{fd}

[3]

b) *Starting from the inertia constant J (Kg-m^2), rated VA as VAbase, basic torque and angle equations in a rotational system, derive the following swing equations of a synchronous generator connected to the grid:*

$$\frac{d\delta}{dt} = \omega_r - \omega_s$$

$$\frac{2H}{\omega_s}\frac{d\omega_r}{dt} = P_{mech} - P_{elec} - D(\omega_r - \omega_s)$$

δ is the angle of the rotor with respect to a synchronously rotating reference frame;

ω_r, ω_s: speed of the rotor and synchronous reference frame respectively in rad/sec.

P_{mech}, P_{elec}: mechanical power input and electrical power output in p.u. respectively

H = H-constant in seconds

D: mechanical damping co-efficient in p.u-sec/rad

[7]

Our general notion is that the generator shaft accelerates or decelerates during disturbance. Let ask ourselves with a question what governs this process.
Balance of torque (mechanical input (Tmech) – electrical output (Telec)). Let's assume that the combined inertia of the generator and prime mover is J (Kg-m2). If the rotational speed is ω_m (rad/sec); the following equation of motion can be written

$$J\frac{d\omega_m}{dt} = T_a = T_{mech} - T_{elec}$$

Generator manufacturers provide machine inertia constant as H.

Where, $H = \frac{1}{2}\frac{J\omega_{0m}^2}{VA_{base}}$ (Stored energy per rated VA at rated speed)

The substitution of this into above will yield following set of equations

$$\frac{2H}{\omega_{0m}{}^2} VA_{base} \frac{d\omega_m}{dt} = T_{mech} - T_{elec}$$

$$\frac{2H}{\omega_{0m}} VA_{base} \frac{d\omega_m}{dt} = P_{mech0} - P_{elec0}$$

Multiplying ω_m by number of pole pairs will result electrical speed ω_r ; ω_{0m} accordingly will correspond to synchronous speed ω_s

The final equation will appear as:

$$\frac{2H}{\omega_s}\frac{d\omega_r}{dt} = P_{mech} - P_{elec}$$

The mechanical damping effect is to retard the acceleration; This can be included as a term proportional to speed deviation on the right side of the above equation

The resulting equation can be written as:

$$\frac{2H}{\omega_s}\frac{d\omega_r}{dt} = P_{mech} - P_{elec} + D(\omega_r - \omega_s)$$

The angle equation: The rotor rotates at speed ω_r ; The angle (δ) of the rotor at any point of time t with respect to a synchronously rotating reference speed ω_s is

$$\delta(t) = (\omega_r - \omega_s)t + \delta_0$$

The initial rotor position at time t = 0 is δ_0

The rate of change of angle is therefore

$$\frac{d\delta}{dt} = \omega_r - \omega_s$$

These two differential equations are known as swing equations

$$\frac{d\delta}{dt} = \omega_r - \omega_s$$

$$\frac{2H}{\omega_s}\frac{d\omega_r}{dt} = P_{mech} - P_{elec} + D(\omega_r - \omega_s)$$

c) *The moment of inertia of a generator-turbine mass is 45,000 Kg-m^2. The generator has a rating of 500 MVA and operates at 3000 RPM. Find the*

i) stored kinetic energy

[3]

Stored energy $= \frac{1}{2} J \omega_m{}^2 = 0.5 * 45{,}000 * (100\pi)^2 = 2218.4$ *MJoules*

ii) H-constant (H)

[2]

H constant: 2218.4/500 = 4.43 seconds

iii) M-constant (M)

[2]

M-constant (M) = 2H/synchronous speed = 8.86/314 = 0.0282 s^2

4.

a) Briefly describe the necessity of area wise load frequency control

[2]

When two utility connect together they do for several reasons. One is to be able to buy and sell power with neighbouring systems whose operating costs make such transactions profitable. Further even if no power is being transmitted over ties to neighbouring systems, if one system has sudden loss of generating unit, the units throughout all the interconnection will experience a frequency change and can help in restoring frequency.

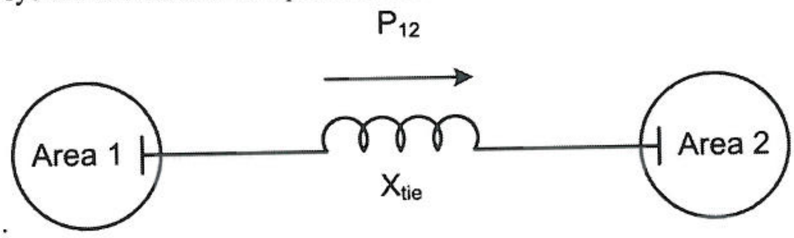
b) Establish the steady state power frequency characteristics of a two-area system. Assume that each area has the following characteristic parameters:

Area 1: inertia constant: M_1, droop: R_1 and damping co-efficient: D_1

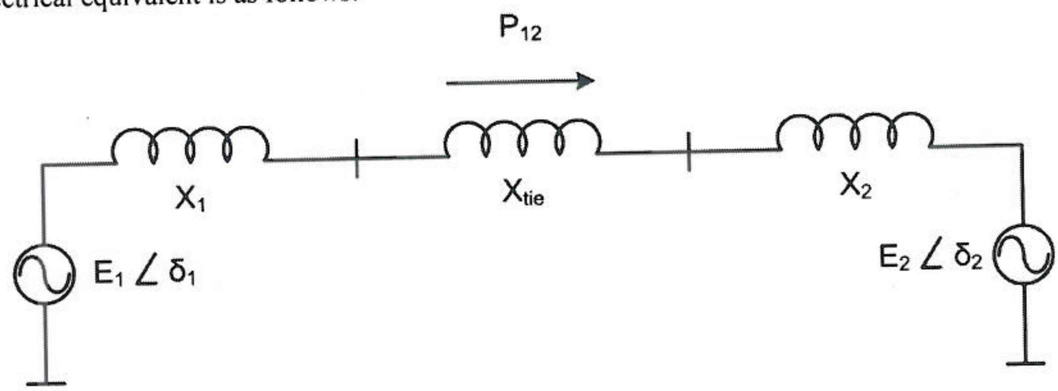
Area2: inertia constant: M_2, droop: R_2 and damping co-efficient: D_2

[6]

For interconnected system schedule tie line power is an additional variable.



The electrical equivalent is as follows:

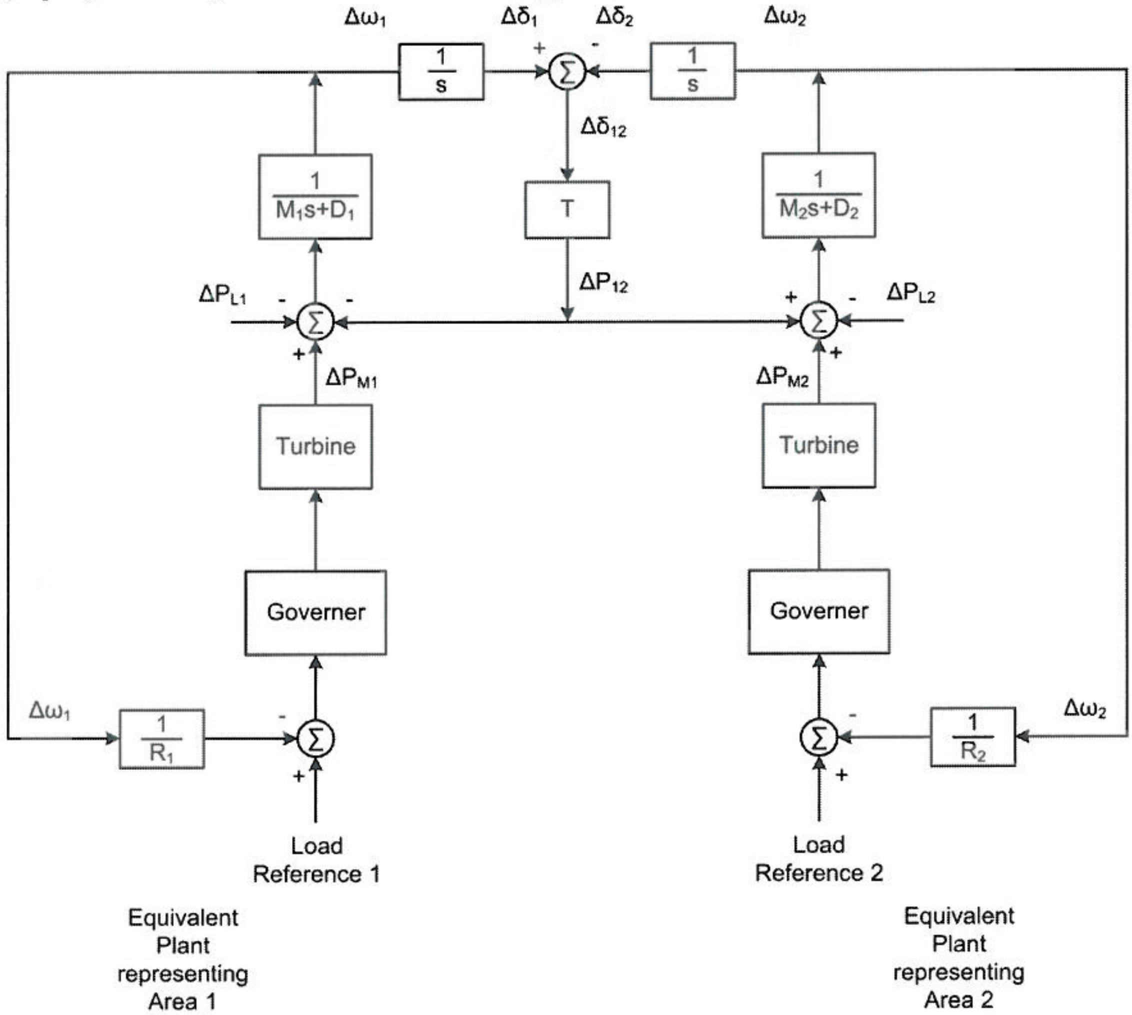


In an interconnected system operation as shown in the figure, it is important to consider the scheduled interchange power. These two areas can be modelled as two equivalent voltage sources behind source reactance and tie line reactance.

$$P_{12} = \frac{E_1 E_2}{X_T} sin(\delta_1 - \delta_2)$$

The linearized form of the above equation is:

$\Delta P_{12} = T(\Delta\delta_1 - \Delta\delta_2)$ where $T = \frac{E_1 E_2}{X_T} cos(\delta_{10} - \delta_{20})$ is the synchronising power co-efficient. The block diagram below shows this. Note each area is represented by its composite load damping and frequency characteristic. The frequency deviation $\Delta\omega_1 = \Delta\omega_2 = \Delta\omega = \Delta f$ is common in both area connected by tie. The tie power deviation ΔP_{12} will be seen as load in area 1 and generation in area 2 (import) and its sign will be assumed accordingly.



This two area system with primary governor control can easily be characterised by the following equation or relation:

$$\Delta f = -\frac{\Delta P_L}{D_1 + D_2 + \frac{1}{R_1} + \frac{1}{R_2}}$$ (I would learn it by heart for ever or till the final exam)

Let us assume that there is a change in area 1 load. It will be natural to see the implication of this change on system frequency, area loads and interchange.

In the steady state following hold

Area1: $\Delta P_{m1} - \Delta P_{L1} - \Delta P_{12} = D_1 \Delta f$

Area 2: $\Delta P_{m2} + \Delta P_{12} = D_2 \Delta f$

From droop characteristics: $\Delta P_{m1} = -\frac{\Delta f}{R_1}; \Delta P_{m2} = -\frac{\Delta f}{R_2}$

On substitution $\Delta P_{m1}, \Delta P_{m2}$ into the first two equations and solving for Δf

$$\Delta f = -\frac{\Delta P_{L1}}{D_1 + D_2 + \frac{1}{R_1} + \frac{1}{R_2}} = -\frac{\Delta P_{L1}}{\beta_1 + \beta_2} \quad \Delta P_{12} = \left(D_2 + \frac{1}{R_2}\right)\Delta f = \beta_2 \Delta f$$

Where β_1, β_2 are defined as composite area stiffness. Tie power deviation can also be expressed as: $\Delta P_{12} = -\frac{\beta_2}{\beta_1 + \beta_2}\Delta P_{L1}$

Similarly implications on frequency and tie power deviation for change in area 2 load can be derived to be

$$\Delta f = -\frac{\Delta P_{L2}}{\beta_1 + \beta_2}; \Delta P_{12} = \Delta P_{L2}\frac{\beta_1}{\beta_1 + \beta_2}$$

c) *Consider two interconnected areas as follows: Area 1: Gen 19,000 MW, Load 20,000 MW: Area 2: Gen 41000 MW, Load: 40,000 MW. The load in each area varies by 1% with 1% change in frequency (D = 1.0). The speed regulation, R, is 5% for all the units. Area 1 is importing 1000 MW from Area 2.*

Area 1 is operating with a spinning reserve of 1000 MW spread uniformly over a generation of 4000 MW capacity, and Area 2 is operating with a spinning reserve of 1000 MW spread uniformly over a generation of 10,000 MW. The nominal frequency is 50 Hz.

Determine the steady state frequency, generation and load of each area, and the tie line power for each of the following contingencies, when the generation carrying spinning reserve in each area is on supplementary control with frequency bias factor settings of 250 MW/0.1 Hz for Area 1 and 500 MW/0.1 Hz for Area 2.

i) *Loss of 1000 MW load in Area 1 without supplementary control* [6]

ii) *Loss of 2000 MW generation in area 1 which is not part of spinning reserve with supplementary control.* [6]

1/R1 = 20000/(0.05*50) = 8000 MW/Hz ; 1/R2 = 42000/(0.05*50) = 16800 MW/Hz

1/R1+1/R2 = 24800 MW/Hz; D1 = 19000/100 *(100/50) = 380 MW/Hz

D2 = 40000/100*(100/50) = 800 MW/Hz

Total effective damping D1+D2 = 1180 MW/Hz

Change in system frequency for 1000 MW of loss of load = - (-1000)/ (D1+D2+1/R1+1/R2) = 0.0385 Hz, steady state frequency is 50.0385 Hz

Change in area1 load for change in frequency = D1*0.0385 = 14.62 MW, change in load in area 2 load D2*0.0385 = 30.79 Hz; change in generation in area 1 is -1/R1*0.0385 = -307.92, in area 2 -1/R2*0.0385 = -646.65 MW

Area 1 generation: 19000-307.92 = 18692 MW, load = 20000+14.62-1000 = 19014.62 MW

Area 2: generation: 41000-646.65 = 40353.34 MW, load 40000+30.79 = 40030.79 MW

Tie line flow = Area2 gen – Area2 load = 677 MW

Part (ii) = area1 bias factor, beta1 = 2500 MW/Hz; area2 bias factor beta2 = 5000 MW/Hz

Area1 has lost generation of 2000 MW not part of spinning reserve of 1000 MW. The spinning reserve will meet 1000 MW and the balance has to come from area 2. It is possible to have t from area 2 as it has that much of reserve. The area control error in area 2

Delta_P21+beta2*delta_f = 0. ; delat_P21 = -delta_P12 = delta_f*beta2; the total change in generation in area 1 will be equal to export from area2 (delta_P21) and change in demand in area D1*delta_f;

Beta2*delta_f+D1*delta_f = delta_PG1 = -1000 (negative sign for drop in generation), the frequency drop is -0.1858 Hz; delta_P12 = -5000*0.1858 = 929 MW; change in load in area 1 = D1*delta_f = -70.63 MW ; in area 2 D2*delta_f = -148.7 MW

Area1 geneartion: 20000-2000+1000 = 18000, load = 20000-70.63 = 19929.3 MW

Area2 generation: 41000+delta_P21+D2*delta_f = 41780 MW, load = 40000-148.7 = 39851.3 MW

5

a) Describe the basic components and operating principle of numerical/digital relays.

[5]

Numerical relays

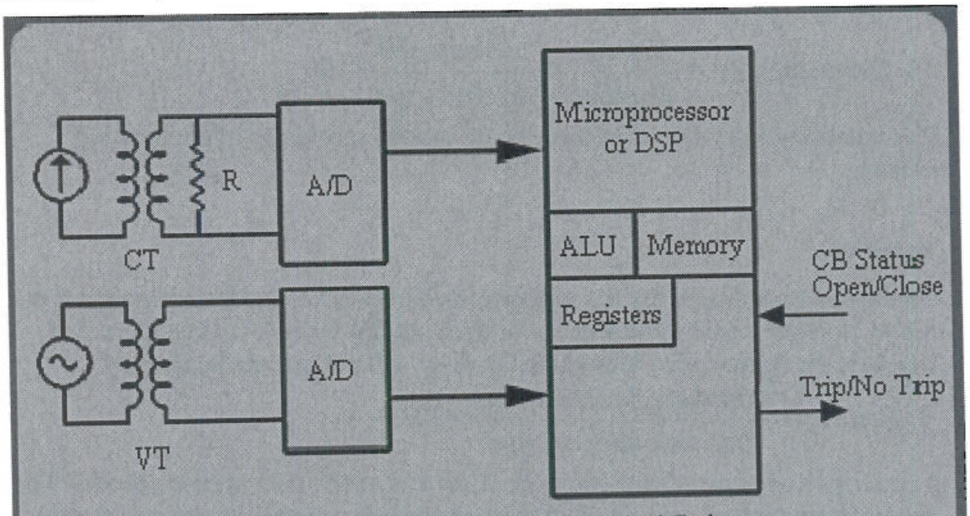


Fig 9.4 Block Diagram of Numerical Relay

The block diagram of a numerical relay is shown in Fig 9.4. It involves analogue to digital (A/D) conversion of analogue voltage and currents obtained from secondary of CTs and VTs. These current and voltage samples are fed to the microprocessor or Digital Signal Processors (DSPs) where the protection algorithms or programs process the signals and decide whether a fault exists in the apparatus under consideration or not. In case, a fault is diagnosed, a trip decision is issued. Numerical relays provide maximum flexibility in defining relaying logic.

The hardware comprising of numerical relay can be made scalable i.e., the maximum number of v and i input signals can be scaled up easily. A generic hardware board can be developed to provide multiple functionalities. Changing the relaying functionality is achieved by simply changing the relaying program or software. Also, various relaying functionalities can be multiplexed in a single relay. It has all the advantages of solid state relays like self checking etc. Enabled with communication facility, it can be treated as an Intelligent Electronic Device (IED) which can perform both control and protection functionality. Also, a relay that communicates can be made adaptive i.e. it can adjust to changing apparatus or system conditions. For example, a differential protection scheme can adapt to transformer tap changes. An overcurrent relay can adapt to different loading conditions. Numerical relays are both "the present and the future".

b) Distinguish between dependability and security of a relay

[4]

Dependability

A relay is said to be dependable if it trips only when it is expected to trip. This happens either when the fault is in its primary jurisdiction or when it is called upon to provide the back-up protection. However, false tripping of relays or tripping for faults that is either not within its jurisdiction, or within its purview, compromises system operation. Power system may get unnecessarily stressed or else there can be loss of service. Dependability is the degree of certainty that the relay will operate correctly:

$$\%\ Dependability = \frac{Number\ of\ correct\ trips}{Number\ of\ desired\ trips} \times 100$$

Dependability can be improved by increasing the sensitivity of the relaying system.

Security

On the other hand, security is a property used to characterize false tripping of the relays. A relay is said to be secure if it does not trip when it is not expected to trip. It is the degree of certainty that the relay will not operate incorrectly:

$$\%\ Security = \frac{Number\ of\ correct\ trips}{Total\ number\ of\ trips} \times 100$$

False trips do not just create nuisance. They can even affect system security. For example, tripping of a tie-line in a two area system can result in load-generation imbalance in each area which can be dangerous. Even when multiple paths for power flow are available, under peak load conditions, overloads or congestion in the system may result. Dependability and security are contrasting requirements. Typically, a relay engineer biases his setting towards dependability. This may cause some nuisance tripping, which can in the worst case, trigger partial or complete blackout! Security of the relaying system can be improved by improving selectivity of the relaying system

c) The performance of an over current relay was monitored for a period of three years. It was found that the relay operated 35 times, out of which 29 were correct trips. If the relay failed to issue trip decisions on 3 occasions, compute dependability, security and reliability of the relay as a percentage.

[6]

Number of correct trips: 29

Number of desired trip 29+3 = 32;

Number of incorrect trip 35-29 = 3;

The definition of dependability, security and reliability in percentage are respectively as follows:

$$\%\ Dependability = \frac{Number\ of\ correct\ trips}{Number\ of\ desired\ trips} \times 100$$

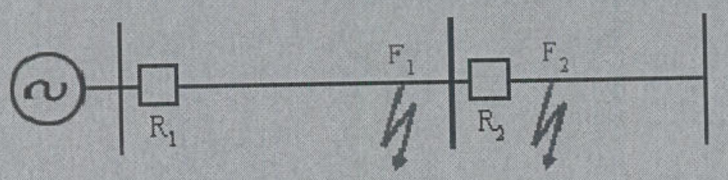
$$\% \, Security = \frac{Number\, of\, correct\, trips}{Total\, number\, of\, trips} \times 100$$

$$\% \, Reliability = \frac{Number\, of\, correct\, trips}{Number\, of\, desired\, trips + Number\, of\, incorrect\, trips} \times 100$$

%Dependability = 29/32*100= 90.36; %Security = 29/35*100 = 83; %Reliability = 29/38*100=76.

d) How is selectivity achieved in transformer differential protection?

[5]



Relay R_1 cannot discriminate between F_1 and F_2 accurately as $I_{F1} \approx I_{F2}$
Time discrimination between R_1 and R_2 provides a solution.

Fig 9.12 Distance or over current protection

Like sensitivity, selectivity also implies an ability to discriminate. A relay should not confuse some peculiarities of an apparatus with a fault. For example, transformer when energized can draw up to 20 times rated current (inrush current) which can confuse, both over current and transformer differential protection. Typically, inrush currents are characterized by large second harmonic content. This feature is used to inhibit relay operation during inrush, there by, improving selectivity in transformer protection. Also, a relay should be smart enough, not just to identify a fault but also be able to decide whether fault is in its jurisdiction or not. For example, a relay for a feeder should be able to discriminate a fault on its own feeder from faults on adjacent feeders. This implies that it should detect first existence of fault in its vicinity in the system and then take a decision whether it is in its jurisdiction. Recall that directional over current relay was introduced to improve selectivity of over current relay.

This jurisdiction of a relay is also called as **zone of protection.** Typically, protection zones are classified into primary and backup zones. In detecting a fault and isolating the faulty element, the protective system must be very selective. Ideally, the protective system should zero-in on the faulty element and only isolate it, thus causing a minimum disruption to the system. Selectivity is usually provided by (1) using time discrimination and (2) applying differential protection principle. With over current and distance relays, such boundaries are not properly demarcated (see Fig 9.12). This is a very important consideration in operation of power systems.

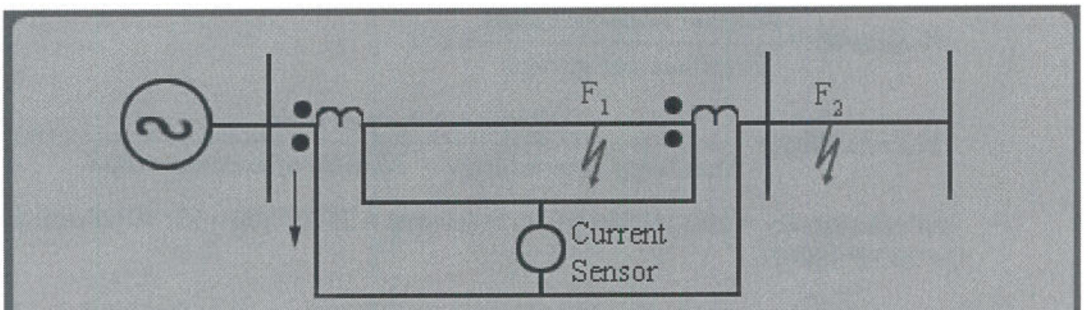


Fig 9.13 Differential protection scheme

However with a differential protection the CT location provides 'crisp' demarcation of zone of protection of CT (see Fig 9.13). The fault F_1 is in the relay's zone of protection, but fault F_2 is not in its jurisdiction. Because differential protection scheme does not require time discrimination to improve selectivity, they are essentially fast.

6.

a) Why should the secondary of a current transformer never be left open?

[3]

The working principle of an electromagnetic current transformer is very simple. It is essentially a simple transformer with large number of secondary turns and few or even one (bar primary) primary turn. The primary is connected in series with the line supplying load. Current in the secondary has to flow through a low impedance (known as burden) otherwise high excitation voltage will develop that would saturate the magnetic core of the CT. The CT secondary should never be open circuited otherwise the primary ampere turn would be magnetically unbalanced leading to damagingly high voltage at the CT secondary terminal. This clearly suggests that a CT is essentially a current source as far as secondary side is concerned.

b) By mistake someone has interchanged the terminals of measurement CT and protection CT. Both CTs are at the same place and hav the same current ratings. What will happen in normal and abnormal condition?

[3]

The relay will receive the current from the measurement CT. Under normal condition it will produce faithful reproduction primary current with very high accuracy in magnitude and phase angle error. Under abnormal condition, particularly for high fault current, the core will saturate and the relay will be fed with incorrect reflection of primary current. The dependability, security and sensitivity of the relay will be affected. The meter will receive current from the secondary of protection CT. The ratio and phase angle error will be small as such but if the meters poses high burden they may saturate even at normal condition. The accuracy of the metered output may be affected in case they have high burden otherwise not. During abnormal condition the protection CT will produce faith representation of primary current, but the metering is not any useful here as the system goes through abnormal operating conditions.

c)

i) What is the function of a tuning inductor in a capacitive coupled voltage transformer (CCVT)?

[3]

In CCVT, because of voltage division across capacitor and drawal of primary magnetising current the input voltage to electromagnetic transformer is phase shifted from the line voltage. This affects the voltage received by the relay. To achieve high level of accuracy, it is therefore necessary to compensate for this voltage drop and phase shift by connecting a tuning inductor.

ii) How is it related to CCVT capacitance?

[3]

The tuning inductor's value is so chosen that it compensates for the 'net C' at power frequency (50/60Hz).

$$\omega L = \frac{1}{\omega(C_1 + C_2)}$$

With this arrangement the voltage drop across C is neutralized and the relay sees the actual voltage to be measured.

d) *A 1200/5, C400 CT is connected on the 1000/5 tap. The secondary winding resistance is 0.51 Ω. Obtain the maximum allowable burden in the CT at 20 times the rated symmetrical secondary current with rated accuracy*

[8]

The secondary voltage V_S corresponding to the tap 1000/5, $V_S = \frac{1000}{1200} \times 400$ = 333V

Secondary current $I_S = 20 \times 5 = 100A$

$V_S = I_S(R_S + R_B)$

$R_S = 0.51\Omega$

333 = 100(0.51+R_B)

Secondary burden = 3.33 - 0.51 = 2.72 Ω

This is the maximum allowable secondary burden