EE4-48

The Questions

1.

a) A synchronous generator has suddenly lost its excitation power. Nevertheless the generator stayed connected with the network and continued to produce power at a reduced capacity for few minutes before the excitation was restored back. Explain how this is possible.

[4]

Ans:

The power output equation of a synchronous generator contains a saliency term. This is the second term in the equation which is NOT function.

$P = V_d I_d + V_q I_q = \dfrac{E_{fd} V_t}{X_d} sin\,\delta + \dfrac{V_t^2}{2}\left(\dfrac{1}{X_q} - \dfrac{1}{X_d}\right) sin\,2\delta$. As long as the direct and quadrature axis synchronous reactance are not equal (ie. $X_d - X_d = 0.0$), even with the absence of excitation power is produced at reduced rate. This is true for salient pole generator. It also applicable to non salient pole generators as there is always slight saliency despite round rotor construction. Such operation is not encouraged for long as synchronous machine will have a tendency to self excite and also will import excessive reactive power (it operate as VAR absorber rather than being VAR generator). When the excitation comes back, it starts producing full load without any further arrangement.

b) The rotor of a synchronous generator is a solid iron structure- where as its stator is made of laminated steel. Why is it constructed in this way?

[4]

Ans:

The rotor carries direct current. There is no eddy current or hysteresis loss because of rotor current. During dynamic operation stator magnetic field induces eddy current in the rotor body. It helps stabilise the swing. The stator on the contrary carries power frequency (50/60 Hz). The iron loss is high- so it needs to be laminated to minimise those losses and heating/temperature rise.

c) Two synchronous generators (Gen A and Gen B) of similar capacity are made by two manufactures. The clearance (air gap) between the stator and rotor of Gen A is 1.5 times that of Gen B. Both generators are loaded equally. Following a temporary disturbance the rotors of the generators started swinging. Which generator will offer higher margin of stability and why?

[4]

Ans: The student is expected to relate how air gap influences the synchronous reactance. Larger gap means less reactance. This means synchronising power coefficient is high. The magnitude of power angle curve is high. This will result in relatively smaller angle –thus larger stability margin. The generator with smaller air gap will have larger reactance so stability margin will be less. Such machine will also accelerate fast (lower synchronising torque).

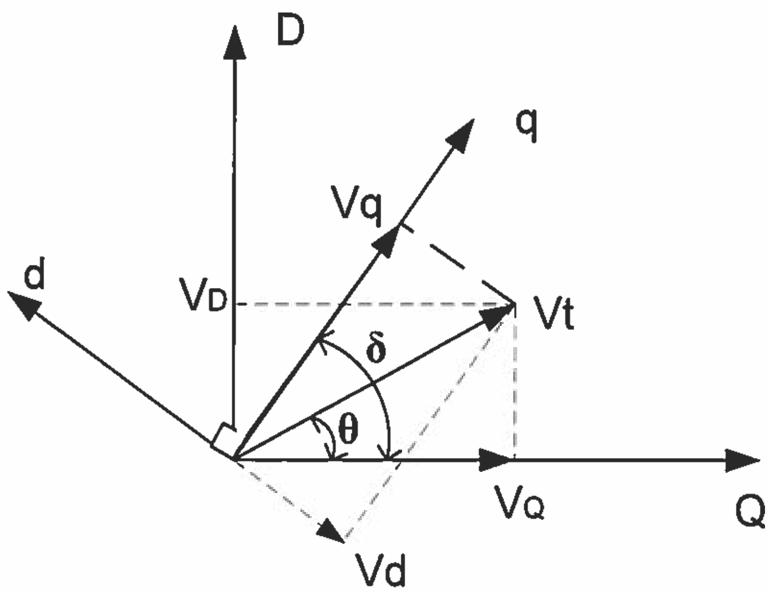
d) A synchronous generator produces a terminal voltage at 9 kV (phase). This is connected to a network which has many other machines. The power flow solution obtains a 12 degree phase angle (θ) with respect to some reference angle. The load angle delta (δ) is 35 degree with respect to the same reference angle. The output current is 10 kA and 0.85 pf lagging with respect to the terminal voltage. Find the following quantities.

i) direct and quadrature axis voltages in machine reference frame [4]

ii) direct and quadrature axis currents in machine reference frame [4]

Assume d axis is leading q axis (IEEE convention)

The student can take the help of the following diagram to establish the relationship between the reference frame.



VQ + j VD = Vt ejθ

VQ = Vt cos θ

VD = Vt sin θ

Resolving VQ and VD along machine reference d-q will produce

Vq = VQ Cos δ + VD sin δ

Vd = -VQ sin δ + VD cos δ

Vq + j Vd = Vt e-j(δ-θ)

Similarly it can be done for current. The phase angle of current is -32 degree with respect to terminal voltage. The angle of current with respect to reference angle of the voltage is 12-32 = -20 degree

Iq+jId = Ie-j(δ- (-20)); δ=35 degree.

Vt = 9kV.

Ans:

Voltage in (kV) : Vq = 8.2845, Vd= - 3.5166

Current in (kA) Iq= 5.7358 Id = - 8.1915

Note the sign of d-axis voltage and current , they are negative. Confirming the demagnetising nature for lagging power factor operation

[4+4]

2.

a) The terminal voltage of a synchronous generator is suddenly dropped by 10% because of a temporary remote fault in the network. This resulted in temporary drop in power produced by the generator. The input mechanical power remained at the pre-fault value. This resulted in a dynamic response of the generator which is characterised very approximately by the following equations:

$$\frac{d\delta}{dt} = \omega_r - \omega_s \quad (2.1)$$

$$\frac{d\omega_r}{dt} = \frac{\omega_s}{2H}\left[P_{mech} - \frac{E'V_t}{X_d'} sin\delta - D(\omega_r - \omega_s)\right] \quad (2.2)$$

δ: load angle, ω_r : rotor speed, ω_s: synchronous speed (314 rad/sec), P_{mech} : mechanical input power, E': transient speed voltage , V_t : terminal voltage, X_d' : direct axis transient reactance, *H*: H constant, *D*: damping coefficient (pu/rad).

i) What are the roles of P_{mech} and E' in influencing the dynamics characterised by the above two equations?

[4]

Ans: Mechanical input initially remains fixed unless there is fast valving is in action. This accelerate the generator – the transient speed voltage is function of filed flux and for some time filed flux remains constant, so electrical power produced decelerates the generators. Eventually filed flux starts decaying but AVR picks up and produces more filed voltage to hold the electrical power produced. So mechanical input accelerate the dynamics where as transient voltage control/prevent the swing/acceleration

ii) Treating P_{mech} and E' as inputs develop the lineralised state space equations in the form:

$$\dot{x} = Ax + Bu$$
$$x = [\Delta\delta, \Delta\omega_r], u = [\Delta P_{mech}, \Delta E']$$

[6]

$$\frac{d\delta}{dt} = \omega_r - \omega_s; \ \frac{d\omega_r}{dt} = \frac{\omega_s}{2H}\left(P_{mech} - \frac{E'V_t}{X_d'}\sin\delta - D(\omega_r - \omega_s)\right)$$
$$\Longrightarrow$$
$$\frac{d\Delta\delta}{dt} = \Delta\omega_r;$$
$$\frac{d\Delta\omega_r}{dt} = -\left(\frac{\omega_s}{2H}\frac{E'V_t}{X_d'}\cos\delta_0\right)\Delta\delta - \frac{D\omega_s}{2H}\Delta\omega_r + \frac{\omega_s}{2H}\Delta P_{mech} - \left(\frac{\omega_s}{2H}\frac{V_t}{X_d'}\sin\delta_0\right)\Delta E'$$
$$\Longrightarrow$$
$$\begin{bmatrix} \frac{d\Delta\delta}{dt} \\ \frac{d\Delta\omega_r}{dt} \end{bmatrix} = \begin{bmatrix} 0 & 1 \\ -\left(\frac{\omega_s}{2H}\frac{E'V_t}{X_d'}\cos\delta_0\right) & -\frac{D\omega_s}{2H} \end{bmatrix}\begin{bmatrix} \Delta\delta \\ \Delta\omega_r \end{bmatrix} + \begin{bmatrix} 0 & 0 \\ \frac{\omega_s}{2H} & -\left(\frac{\omega_s}{2H}\frac{V_t}{X_d'}\sin\delta_0\right) \end{bmatrix}\begin{bmatrix} \Delta P_{mech} \\ \Delta E' \end{bmatrix}$$
$$\Longrightarrow$$
$$\frac{d\Delta \boldsymbol{x}}{dt} = \boldsymbol{A\Delta x} + \boldsymbol{B\Delta u}$$

iii) Obtain the element of matrix A, B for the following values of the parameters and operating variables:

δ= 40 degree, ωs= 314 rad/sec), E'= 1.5 p.u., Vt =1.05 p.u.
Xd'= 0.3 p.u. H= 6.0 s, D=0.04 (pu/rad)

[4]

A= [0, 1
-105.2353, -1.0467]
B=[[0,0;
26.1667, -58.8698]

iv) Obtain the eigenvalues of the system and frequency of oscillations (imaginary part of the complex eigenvalue pair in Hz) and comment on the stability of the system.

[4+1+1]

Eigenvalues

-0.5233 +10.2451i
-0.5233 -10.2451i
Frequency of oscillation 10.245/6.28= 1.63 Hz
The system is stable as the eignevalues have negative real part.

3.

a)

i) Why is it necessary to control the voltage in the power network? [2]

Ans:
All electrical equipments in the system are designed to operate optimally at rated voltage within an acceptable range of variation. This is possible as long as the voltage at the transmission level is kept tightly controlled.

ii) What is *'field flashing'* in the context of excitation system control? [3]

Ans:
Sometimes it is useful to have a residual magnetism to start a synchronous machine. This is particularly true for potential source control excitation system where the excitation power is drawn from the main generator. Exciting the field winding initially through station DC power supply or battery is known as *field flashing.*

iii) Why modern synchronous generators are mostly equipped with high gain fast acting voltage regulators? [3]

Ans:
Modern power generators are of large rating (typically 500 MW or more). They are designed with small air-gap to be economical. The problem is they have large synchronous reactance leading to poor voltage regulation. This is controlled through high gain fast acting voltage regulator.

iv) Briefly describe the function of a power system stabiliser (PSS). [3]

Ans:
Following a disturbance in the network the synchronous generator swings. The AVR maintains the synchronism in first few cycles of swings- following which the oscillations starts growing and AVR contributes to the oscillations. This is stabilised by modulating the set point of the AVR through a dynamic mechanism called power system stabiliser. The bus accelerating power, filtered generator speed, bus frequency, current or combinations of them are used as stabilising signal.

b) Synchronous generators and shunt capacitor banks are both used to produce reactive power to support the system voltage. During appreciably low voltage situation in the network why are the capacitors not as effective as synchronous generators? [3]

Ans:
Synchronous generators are active source of reactive power. Shunt capacitors on the other hand depends on the voltage across them to produce leading VAR support. The reactive power output from capacitor is proportional to the square of the voltage. So a 10% drop in voltage will result in about 20% drop in reactive power output.

c) Following is a block diagram of an excitation system controller

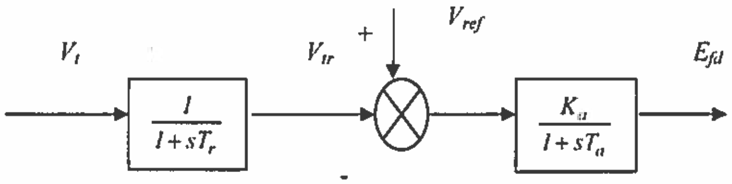


Fig 3.1 Block Diagram of a Fast Excitation System

i) Write the relevant differential equations describing the voltage control dynamics.

[3]

Solution:

A set of differential equation can be written as follows:

dVtr / dt = 1/Tr [-Vtr + Vt]

dEfd / dt = 1/TA [(Vref-Vtr)-Efd]

ii) It is required to produce 3.5 p.u. of E_{fd} to maintain a terminal voltage of 1.05 p.u. Find suitable V_{ref} to meet such condition in steady state with a voltage regulator gain $(K_a) = 300$.

[3]

At steady state

Vtr = Vt ; Efd = KA (Vref-Vtr)

Vref = Efd/KA + Vtr

Vref = Efd / KA + Vt

3.5/300 + 1.05 = 1.0617 pu

4.

a)

i) Why is droop introduced in speed governing?

[3]

Ans:
The frequency in an interconnected system is controlled by many generators. Each generator are not of similar capacity so they should share based on their available capacity. This is done through frequency power characteristics which have different non-zero slope. Flat frequency power control characteristic for governor will have a tendency to hunting amongst generators to grab disproportional share of power.

ii) Why is droop control not enough to restore the frequency to its pre-disturbed steady state value?

[3]

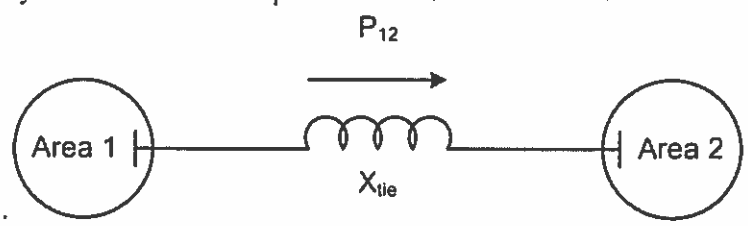
Ans:
It is understood that through primary speed control action, a change in system load results in a steady-state frequency deviation, depending on the governor droop characteristic and frequency sensitivity of the load. Restoration of system frequency to nominal value will require manipulation of load reference point in the governor block diagram. This shifts the droop characteristic up or down. This performed through secondary frequency control is commonly known as *automatic generation and control* (AGC) or *load frequency control* (LFC). This means change in steam production rate.

b) An interconnected power system has two commercial areas. The composite droop and load frequency sensitivity of Area 1 are R_1 and D_1 respectively and the same for Area 2 are R_2 and D_2. For a change in Area 1 load by ΔP_{L1} the change in the generation in Area 1 and 2 are ΔP_{m1} , ΔP_{m2} respectively. The associated change in the tie line flow is ΔP_{12}. Derive that the associated frequency deviation Δf is related as:

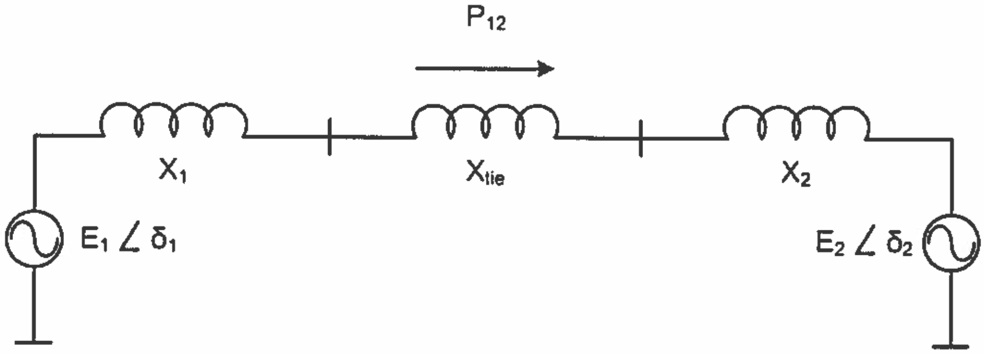
$$\Delta f = -\frac{\Delta P_{L1}}{D_1 + \frac{1}{R_1} + D_2 + \frac{1}{R_2}}$$

[6]

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



The electrical equivalent is as follows:

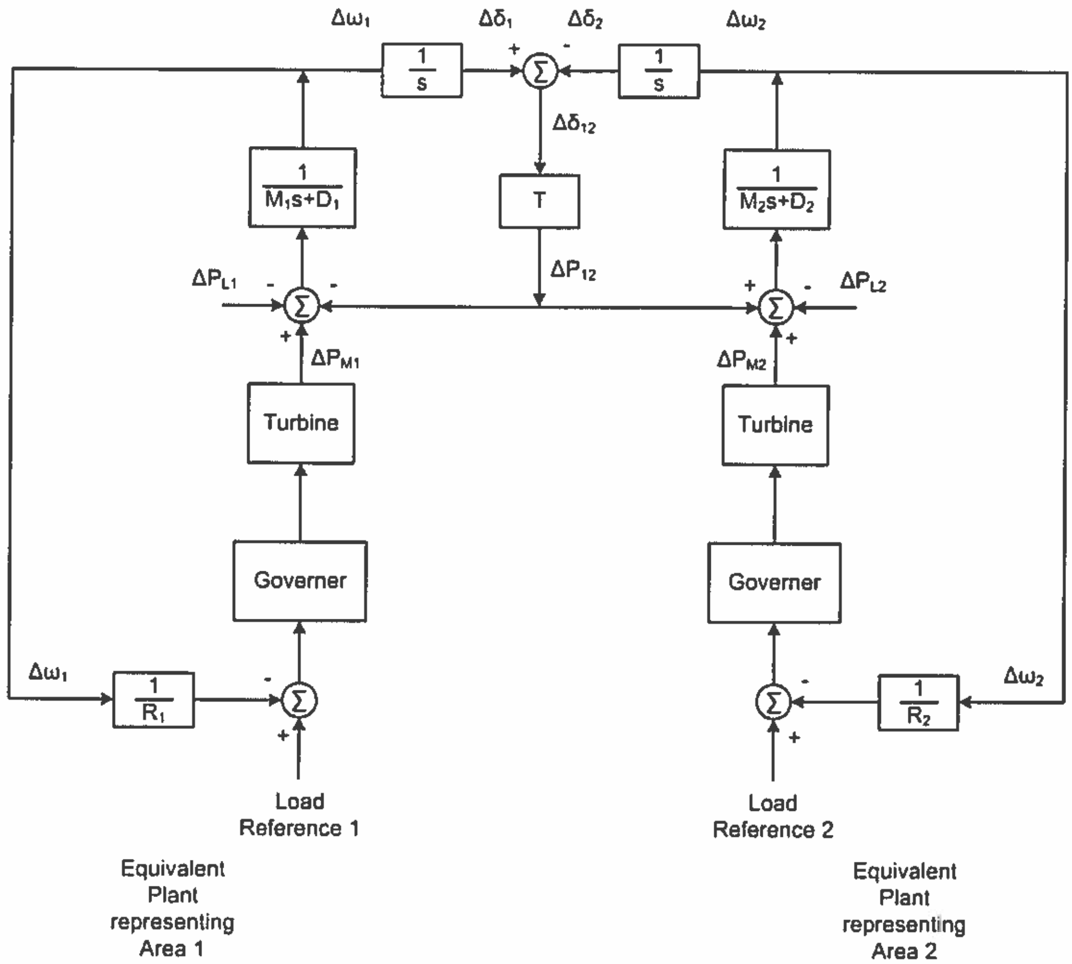


In an interconnected system operation as shown in the figure, it is important to consider the scheduled interchange power. These two areas can be modelled as two equivalent voltage sources behind source reactance and tie line reactance.

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

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)

c) Area 1 has Gen 18,000 MW, Load 18,500 MW; Area 2 has Gen 30,500 MW and Load 30,000 MW. The load in each area varies by 1% with 1% change in the frequency. The composite droop is 5% for both areas. Area 1 is importing 500 MW from Area 2. For the loss of 1000 MW load in Area 1, find the change in the system frequency when there is no tie-line supplementary control. Assume the nominal system frequency to be 50 Hz.

[8]

Ans:

First step is to obtain droop and frequency sensitivity co-efficient of the loads.

$1/R_1$ = 1/0.05*18000/50 = 7200 MW/Hz, $1/R_2$ = 1/0.05*30500/50 = 12200 MW/Hz:
Combined droop: $1/R_1+1/R_2$ = 19400 MW/Hz
D_1 = (18500- loss of 500)*1/100/(50/100) = 360 MW/Hz
D_2 = (30000)*1/100/(50/100) = 600 MW/Hz
Total effective damping = D_1+D_2 = 960 MW/Hz. Change in frequency due to loss of 500 MW load is = $\Delta f = -\dfrac{\Delta P_L}{D_1 + D_2 + \dfrac{1}{R_1} + \dfrac{1}{R_2}}$

= -(-500)/(19400+960) = 0.0245 Hz

5.

a)

i) What is the difference between apparatus protection and system protection?

[3]

Ans:

The apparatus protection focused on individual equipment. It is easy to design this. The system protection involves several parts of the system. This requires time stamped signal from different points in the network and communication means. It is generally much complex. Wide area protection is an example , controlled islanding, low frequency realy, rate of fall of frequency relay, and coordinated load shedding are examples of system protections

ii) Why is current inrush observed during power transformer switching?

[3]

Ans:

The transformer is very predominantly an inductive circuit. During switching in or energisation of power transformer , there is no control at what point of the voltage waveform the breaker is connecting the transformer with active source. While voltage waveform is going through zero – the current will lag it by nearly 90 degree in the steady state. To start with the initial current is zero. So at the worst case the switching during voltage zero crossing the current has to be zero. The AC current would ideally pass through negative maximum. Because of zero current situations just before switching – it has to be maintained just after switching. This is met by the presence of DC current which is equal in magnitude of the fundamental AC current. The resultant current will start from zero but will be time shifted. The DC current decays at a rate influenced by the inductance and resistance. Usually this current is very large in nature and can even trigger the relay as this will be picked by the differential protection of the transformer.

iii) Describe the principle that is adopted to prevent the relay to operate during current inrush in a power transformer.

[3]

Ans:

The spectrum analysis shows that this current has large second harmonics. That can be utilised to distinguished between fault and inrush. A second harmonic restraint has to be included in the differential protection. In numerical really it is very simple – just measure the second harmonics content and when a certain threshold is exceeded- block the tripping and initiate the timer. Measure both fundamental and second harmonics after a predefined set time and check –if the second harmonics has disappeared it is fine otherwise check other logics to establish if this was not closure on fault.

iv) Draw a conceptual block diagram of a relay and briefly describe the role of various inputs/outputs and other elements.

[5]

Formally, a relay is a logical element which processes the inputs (mostly voltages and currents) from the system/apparatus and issues a trip decision when a fault within the relay's jurisdiction is detected. A conceptual diagram of relay is shown in Fig below

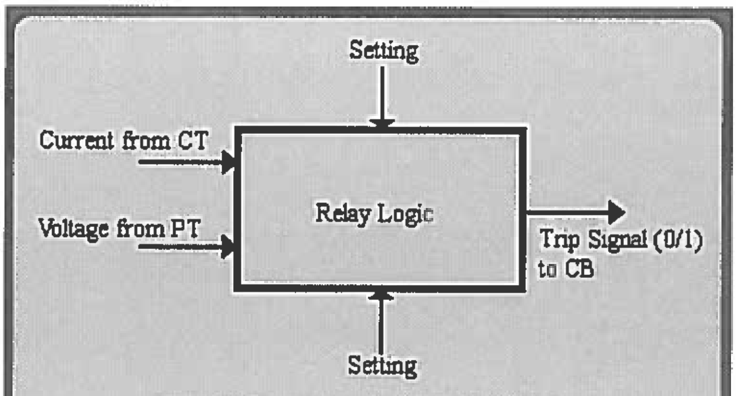


Fig 9.1: Conceptual diagram of Relay

To monitor the health of the apparatus, relay senses current through a current transformer (CT), voltage through a voltage transformer (VT). VT is also known as Potential Transformer (PT).
Settings are generally reference current or impedance. There is also time delay through TMs. For coordinated over current protection the current discrimination settings are provided through plug multiplier settings. Relay logic is comparison circuit in solid state relay, numerical equation or inequality in digital relay, in electromechanical relay it usually restraining torque through spring etc.

b) The performance of an over current relay was monitored for a period of three years. It was found that the relay operated 14 times, out of which 12 were correct trips. If the relay failed to issue trip decisions on 2 occasions, compute dependability, security and reliability of the relay as percentages.

[3x2=6]

Incorrect trips:2, desirable number of trip = 12+2= 14. Correct trip = 12. Total trip = 14

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

12/14*100=85.71%

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

12/14*100=85.71%

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

12/16*100 = 75%

6

a)

i) What are the functions of a current transformer?

[2]

Ans:

This is electromagnetic transformer that is excited by circuit current in the primary and produces an scaled down version of the primary current. The purpose is to ensure faithful reproduction of circuit current both in steady healthy state and faulted state.

ii) What are the basic differences between a measurement CT and a protection CT ?

[3]

Ans:

A measurement grade CT has much lower VA capacity than a protection grade CT. A measurement CT has to be accurate over its complete range e.g. from 5% to 125% of normal current. In other words, its magnetizing impedance at low current levels (and hence low flux levels) should be very high. Note that due to non-linear nature of B-H curve, magnetizing impedance is not constant but varies over the CT's operating range. It is not expected to give linear response (secondary current a scaled replica of the primary current) during large fault currents as it is not designed to operate accurately at abnormal condition. In contrast, for a protection grade CT, linear response is expected up to 20 times the rated current. Its performance has to be accurate in the range of normal currents and up to fault currents. Specifically, for protection grade CT's magnetizing impedance should be maintained to a large value in the range of the currents of the order of fault currents.

iii) How are the accuracies of CTs and VTs specified?

[3]

Ans:

The accuracy of current transformer is specified by phase angle and ratio errors. The ratio error is due to the magnetising current in the CT. This should be kept as small as possible. The phase angle error must also be small otherwise for metering purpose it will produce inaccurate reading. Particularly for MW level of power measurement this is very important. During fault if phase angle error.

CT performance is usually gauged from the ratio error. The ratio error is the percentage deviation in the current magnitude in the secondary from the desired value. In other words, if the current measured in the secondary is I_s, true or actual value is I_p/N, where N is nominal ratio (e.g. N for a 100:5 CT is 20) and I_p is the primary current then ratio error is given by $\frac{\left|\frac{I_p}{N}\right| - |I_s|}{|I_s|} \times 100$.

When the CT is not saturated ratio error $\dfrac{\frac{I_P}{N}-I_S}{I_S}\times 100$ is a consequence of magnetizing current I_E since $\frac{I_P}{N}-I_S=I_E$. Therefore, % ratio error is equal to $\frac{I_E}{I_S}\times 100$. When the CT is saturated, coupling between primary and secondary is reduced. Hence large ratio errors are expected in saturation. The current in the secondary is also phase shifted. For measurement grade CTs, there are strict performance requirements on phase angle errors also. Error in phase angle measurement affects power factor calculation and ultimately real and reactive power measurements. It is expected that the ratio error for protection grade CTs will be maintained within $\pm 10\%$.

Table below shows the maximum limit for the ratio and phase angle errors. It can be seen that errors of Class 2 type are double than that of class 1 type.

Table below shows the maximum limit for the ratio and phase angle errors. It can be seen that errors of Class 2 type are double than that of class 1 type.

Table : Limits for Ratio and Phase Angle Errors

VT Class	Maximum ratio error	Maximum phase angle error
Class 1	±1%	±40 min
Class 2	±2%	±80 min

iv) Why is it necessary to have a tuning inductor in capacitive voltage transformer (CVT)?

[5]

The voltage divider action of capacitor arm to cut down the cost of a VT introduces a phase difference between the network voltage and input of electromagnetic VT. This is compensated by a series inductor. The students are expected to answer this question with circuit schematic as follows:

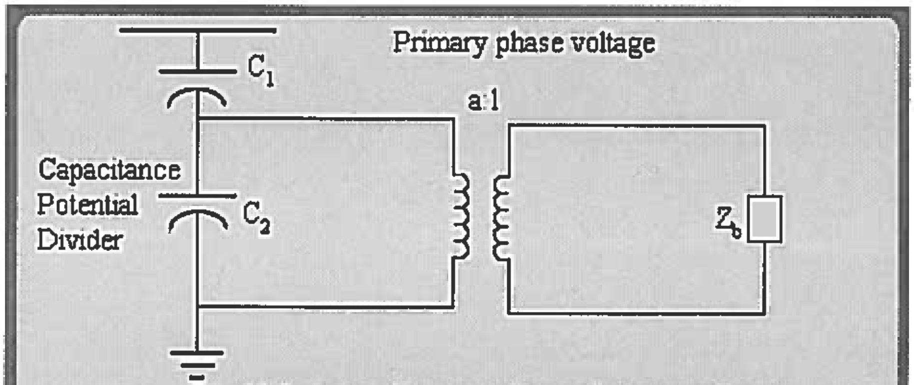


Fig 10.8: A coupling capacitor voltage transformer

Role of Tuning Reactor L: Assuming, the transformer to be ideal, and source with negligible reactance, the Thevenin's equivalent circuit of CCVT is shown in the figure below

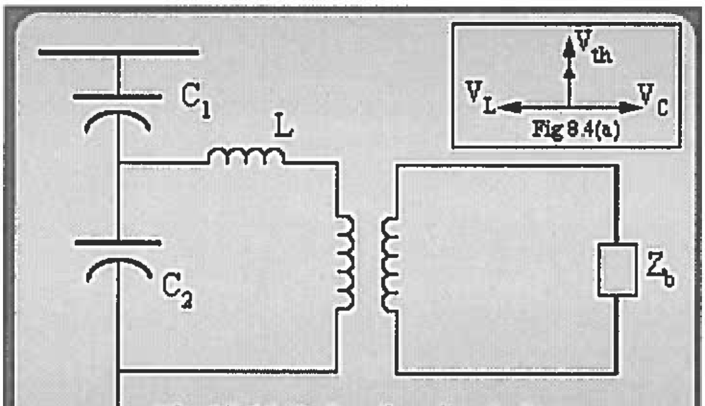


Fig 10.10 Role of tuning inductor

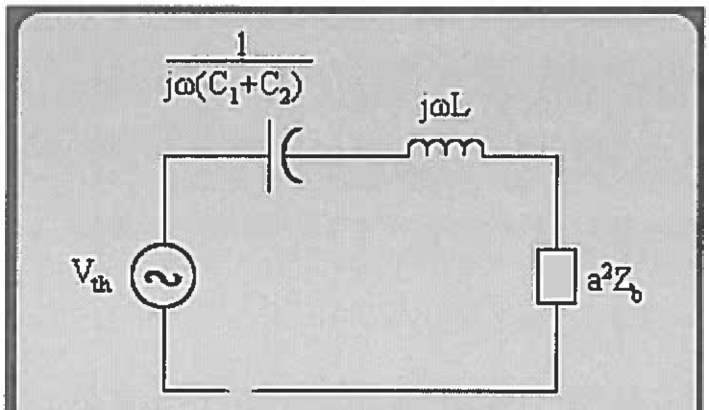


Fig 10.11: Final equivalent circuit of CCVT

It is now obvious that Z_{th} due to the capacitance divider affects the voltage received by the relay. To achieve high level of accuracy, it is therefore necessary to compensate for this voltage drop by connecting a tuning inductor. The tuning inductor's value is so chosen that it compensates for the 'net C' at power frequency (50/60Hz). $\omega L = \dfrac{1}{\omega(C_1 + C_2)}$

b) A 1200/5 C400 CT is connected on the 1000/5 tap. At 20 times the rated secondary current with this setting, the secondary resistance of the CT is 0.5 Ω. How many relays having burden of 0.5 Ω. each can be connected in order for the CT to supply relay currents without reaching saturation?

[7]

Answer:

CT ratio = 1200/5

Secondary resistance = 0.5 Ω.

Relay burden = 0.5 Ω. For 20 times rated secondary current, i.e., 100A

Secondary voltage = 100 x (0.5*n + 0.5) = 400 Volts which is the knee point of the CT.

n=7; maximum number of relays that can be connected is 7.