Power Scenario In Indian Grid

Total Installed Capacity - Source : Central Electricity Authority (CEA)

Sector	MW	% of Total
Central Sector	93,477	25.2
State Sector	1,03,322	27.9
	1,73,549	46.9
Total	3,70,348	

Fuel	MW	% of Total
Total Thermal	2,30,600	62.8
Coal	1,98,525	54.2
Lignite	6,610	1.7
Gas	24,955	6.7
Diesel	510	0.1
Hydro(Renewable)	45,699	12.4
Nuclear	6,780	1.9
RES (MNRE)	87,269	23.6
Total	3,70,348	

All India Installed Capacity (in MW) of Power stations

Region	Thermal	Nuclear	Hydro	RES (MNRE)	Grand Total
Northern	60,801.05	1620.00	20,085.77	16,870.11	99,376.93
Western	85,281.61	1840.00	7622.50	26,043.13	12,0787.00
Southern	54,509.99	3320.00	11,774.83	42,473.52	1,12,078.34
Eastern	27,385.05	4639.12	1499.16	364.64	4,523.46
North Eastern	2,581.83	0.00	1577.00	364.64	4,523.46
Islands	40.05	0.00	0.00	18.19	58.24
All India	2,30,599.57	6780.00	45,699.22	87,268.74	3,70,347.52

National and Regional load dispatching centres

- Power System Operation Corporation Limited (POSOCO) is a wholly owned Government of India enterprise under the Ministry of Power.

- It was earlier a wholly owned subsidiary of Power Grid Corporation of India Limited (PGCIL). It was formed in March 2009 to handle the power management functionsof PGCIL.
- It is responsible to ensure the integrated operation of the Grid in a reliable, efficient,and secure manner.
- It consists of 5 Regional Load Despatch Centres and a National Load Despatch Centre (NLDC).
- National Load Despatch Centre (NLDC) has been constituted as per Ministry of Power (MOP) notification, New Delhi dated 2 March 2005 and is the apex body to ensure integrated operation of the national power system.
- Function: for optimum scheduling and despatch of electricity among the Regional Load Despatch Centres.

-To monitor grid operations

-To exercise supervision and control over the inter-state transmission system

-To optimize scheduling and dispatch of electricity within the region

-To keep accounts of quantity of electricity transmitted through the regional grid.

-To carry out real time operations of grid control and dispatch of electricity within theregion in accordance with the Grid Standards and Grid Code.

Regional Load Dispatch Centers Rids

- The five RLDCs in India are owned, operated and maintained by Power Grid Corporation of India Limited (POWERGRID) which is the Central Transmission Utility (CTU) of the country
- Northern grid: Delhi, Haryana, Himachal Pradesh, Jammu and

Kashmir, Punjab, Rajasthan, Uttar Pradesh, Uttarakhand 99376.93MW

- Western grid: Maharashtra, Gujarat, Madhya Pradesh, Chhattisgarh, Goa, Daman and Diu, Dadra and Nagar Haveli 1,20,787.24MW
- Eastern grid: Bihar, Jharkhand, Odisha, West Bengal, Sikkim 33523.32MW
- Southern grid: Tamil Nadu, Karnataka, Kerala, Andhra Pradesh, Telangana, Pondicherry 1,12,078.34
- North-Eastern grid: Arunachal Pradesh, Assam, Manipur, Meghalaya, Mizoram,
- Nagaland,Tripura 4523.46MW Total: 370347.52MW

Southern Regional Grid

- Southern regional grid is an electrical system comprising of 6,51,000 Sq. km of area with 5 States namely Andhra Pradesh, Karnataka, Kerala, Tamilnadu, Telanganaand Union Territory of Pondicherry, Generating Stations at Central and State Sector, Independent Power producing stations, State DISCOMS and STUs etc.

- The Southern region has an installed capacity of 74367 MW as on 31/07/2016 with 30,347 MW in State Sector and 10490 MW in Central Sector and 33530 MW IPPs.

- The States are inter connected with each other through 765/400/220 kV network.Southern Region is connected to Western region through HVDC Back-to-back (2x500MW) link at Bhadrawathi in WR and to Eastern regions through HVDC back-to-back link (2x500 MW) at Gazuwaka in SR and ±500 kV Bipolar HVDC link (2x1000 MW) from Talcher in ER to Kolar in SR as well as 765 kV 2 x Single Circuit Sholapur- Raichur Interconnector to facilitate exchange of power from surplus to deficit region

/ State as well as wheeling of power.

- For the year 2015 – 16 had seen Southern Region in meeting a maximum demand of 40899 MW and average daily energy consumption of 780 MUs which are 7.3% and 4.7% respectively higher than the previous year. There was about 6800 MW generation addition during the year. During the year 2015-16 the Southern Region has witnessed a maximum consumption of energy of 929.57 MUs on 22nd March'16 (4.13% rise compared to 2014-15) and the maximum peak demand of 40899 MW on 21st March'16 (7.3% rise compared to 2014-15) as against the respective maximum values 892.70 MU and 38090 MW met last year.
- Southern Region has met a maximum demand of 41,607 MW on 7th April 2016

<u>Tamil Nadu State Load Despatch Centre (SLDC)</u>

Grid Operation in TN started by November 1964.The first Load Despatch Centre was operated from Erode.

Subquently, the main Load Despatch Centre was formed in 1986 at Chennai andSub Load Despatch Centre at Madurai.

In accordance with section 32 of Electricity Act, 2003 roles and functions of SLDCs are as under :
The SLDCs shall be the Apex Body to ensure integrated operation of the Power system in a State.
SLDCs shall :Be responsible for optimum scheduling and dispatch of electricity withina state in accordance with the contracts entered into with the licensees or the generation companies operating in that State.

<u>Functions of SLDCs</u>

- Monitor grid operation
- Be responsible for carrying out real time operation for grid control and dispatch of electricity within the State through secure and economic operation of the State Grid in accordance with the grid standards and state grid code
- Keep accounts of the quantity of electricity transmitted through State Grid.
- Exercise supervision and control over the inter-state transmission system.

Requirements Of Good Power System

- The function of a power station is to deliver power to a large number of consumers.
- However, the power demands of different consumers vary in accordance with their activities.
- The result of this variation in demand is that load on a power station is never constant, rather it varies from time to time.
- Most of the complexities ofmodern power plant operation arise from the inherent variability of the load demanded by the users.
- Unfortunately, electrical power cannot be stored and, therefore, the power station must produce power as and when demanded to meet the requirements of the consumers.
- On one hand, the power engineer would likethat the alternators in the power station should run at their rated capacity for maximum efficiency and on the other hand, the demands of the consumers have wide variations.
- This makes the design of a power station highly complex. In this chapter, we shall focus our attention on the problems of variable load on power stations.

Requirements Of Good Power System

- In general, each generation plant in any power may have more than one generating units. Each of the unit may have identical or different capacities. A number of power plants can be tied together to supply the system load by means of interconnectionof the generating stations.
- Interconnected electric power system is more reliable and convenient to operate andalso offers economical operating cost.
- It has better regulations characters by all the units are interconnected.
- The function of an electric power system is to convert energy from one of the naturally available forms to electrical from and to transport it to points of consumption.
- A properly designed and operated power system should meet the following fundamental requirement.

- Adequate spinning reserve must be present to meet the active and reactivepower demand.
- Minimum cost with minimum ecological impact.
- The power quality must have certain minimum standards within the tolerance or limit such as,

Constancy of frequency:

- Constancy of voltage (Voltage magnitude and load angle).
  Level of reliability.
- In simply, the generation of power is transfer to the Consumers through the transmission system. Generation unit, Transformer Unit, Converter Unit, Transmission Unit, Inverter Unit and Consumer Point. Thiscombination of all the unit is called the overall power system units.

System Load

System Load

From systems point of view, there are 5 broad category of loads:

1. Domestic
2. Commercial
3. Industrial
4. Agriculture
5. Others - street lights, traction.

Domestic:

Light Fans, domestic appliances like heaters, refrigerators, air conditioners, mixers, ovens, small motors etc.

Demand factor = 0.7 to 1.0;
Diversity factor = 1.2 to 1.3;
Load factor = 0.1 to 0.15

Commercial:

Lightings for shops, advertising hoardings, fans, AC etc.

Demand factor = 0.9 to 1.0;
Diversity factor = 1.1 to 1.2;
Load factor = 0.25 to 0.3

Industrial:

Small scale industries: 0-20kW
Medium scale industries: 20-100kW
Large scale industries: above 100kW

System load-continue

Industrial loads need power over a longer period which remains fairly uniformthroughout the day.

For heavy industries:

Demand factor = 0.85 to 0.9;
Load factor = 0.7 to 0.8

Agriculture:

Supplying water for irrigation using pumps driven by motors

Demand factor = 0.9 to 1;
Diversity factor = 1.0 to 1.5;
Load factor = 0.15 to 0.25

Other Loads:

Bulk supplies,
street lights,

traction,
government loads
which have their own peculiar characteristics

System Load Characteristics

Connected Load
Maximum Demand
Average Load
Load Factor
Diversity Factor
Plant Capacity Factor
Plant Use Factor

Plant Capacity Factor:

It is the ratio of actual energy produced to the maximum possible energy that couldhave been produced during a given period.

Plant Use Factor:

It is the ratio of kWh generated to the product of plant capacity and the number ofhours for which the plant was in operation.

Plant use factor = Station output in kWh / Plant capacity * Hours of use

When the elements of a load curve are arranged in the order of descendingmagnitudes.

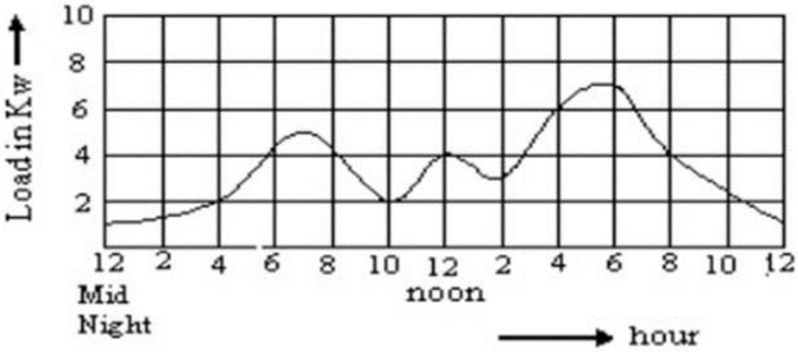
Economic of Generation

1. Load curves

The curve showing the variation of load on the power station with respect to time

The curve drawn between the variations of load on the power station with reference to time is known as load curve. Fig shows the load curve

There are three types, Daily load curve, Monthly load curve, Yearly load curve .



Types of Load Curve:

Daily load curve–Load variations during the whole day

Monthly load curve–Load curve obtained from the daily load curve Yearly load curve-Load curve obtained from the monthly load curve

Daily load curve

The curve drawn between the variations of load with reference to various timeperiod of day is known as daily load curve.

Monthly load curve

- It is obtained from daily load curve.
- Average value of the power at a month for a different time periods are calculated and plotted in the graph which is known as monthly load curve.

Yearly load curve

It is obtained from monthly load curve which is used to find annual load factor.

Load duration curve

- When the elements of a load curve are arranged in the order ofdescending magnitudes. The load duration curve gives the data in a more presentable form
- The area under the load duration curve is equal to that of thecorresponding load curve The load duration curve can be extended to include any period of time

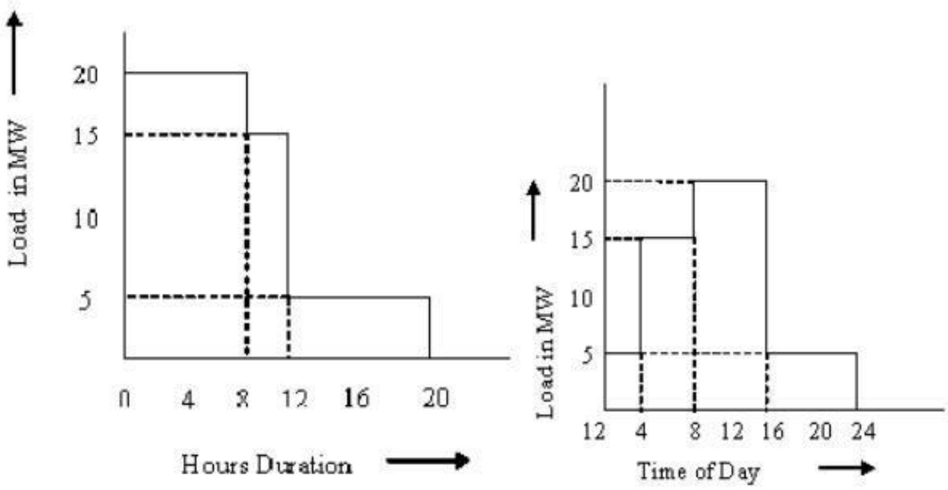


Fig 1.3 Load Duration Curve

Connected load

It is the sum of continuous ratings of all the equipments connected to supplysystems.

Maximum demand

It is the greatest demand of load on the power station during a given period.

Demand factor

It is the ratio of maximum demand to connected load.

Demand factor= (max demand)/ (connected load)

Average demand

The average of loads occurring on the power station in a given period (day or monthor year) is known as average demand

Daily average demand = (no of units generated per day) / (24 hours)

Monthly average demand = (no of units generated in month) / (no of hours in amonth)

Yearly average demand = (no of units generated in a year) / (no of hours in a year)

Load factor

The ratio of average load to the maximum demand during a given period is knownas load factor.

Load factor = (average load)/ (maximum demand)

Diversity factor

The ratio of the sum of individual maximum demand on power station is known as diversity factor.

Diversity factor = (sum of individual maximum demand) / (maximum demand).

Capacity factor

This is the ratio of actual energy produced to the maximum possible energy that could have been produced during a given period.

Capacity factor = (actual energy produced) / (maximum energy that have been produced)

Plant use factor

It is the ratio of units generated to the product of plant capacity and the numberof hours for which the plant was in operation.

Units generated per annum= average load * hours in a year

Necessity of Voltage and Frequency Regulation

Constant frequency

- Constant frequency is to be maintained for the following functions:
- All the AC motors should require constant frequency supply so as to maintain speed constant.
- In continuous process industry, it affects the operation of the process itself.
- For synchronous operation of various units in the power system network, it isnecessary to maintain frequency constant.
- Frequency affects the amount of power transmitted through interconnecting lines.Frequency fluctuations are harmful to electrical appliances.
- Speed of three phase ac motors proportional to the frequency.
  - (N=120f/p)
- The blades of turbines are designed to operate at a particular speed. Frequencyvariation leads to speed variation and results in mechanical vibration

Constant voltage

- Over voltage and under voltage Electric motors will tend to run on over speed when they are fed with higher voltages resulting vibration and mechanical damage.
- Over voltage may cause insulation failure.
- For a specified power rating, lower voltage results in more current and this results inheating problems. (P=VI)
- Kinetic energy= $1/2\ J w^2$
- N=120 f/P

Real Power Vs Frequency And Reactive Power VsVoltage Control Loops

P–f control

The Load Frequency Control (LFC), also known as generation control or P–f control, deals with the control of loading of the generating units for the system at normal frequency. The load in a power system is never constant and the system frequency remains at its nominal value only when there is a match between the active power generation and the active power demand. During the period of load change, the deviation from the nominal frequency, which may be called frequency error (Δf), is an index of mismatch and can be used to send the appropriate command to change the generation by adjusting the LFC system. It is basically controlling the opening of the inlet valves of the prime movers according to the loading condition of thesystem. In the case of a multi-area system, the LFC system also maintains the specified power interchanges between the participating areas. In a smaller system, this control is done manually, but in large systems automatic control devices areused in the loop of the LFC system

Q–V Control

In this control, the terminal voltage of the generator is sensed and converted into proportionate DC signal and then compared to DC reference voltage. The error in between a DC signal and a DC reference voltage, i.e., Δ |V | is taken as an input to the Q–V controller. A control output ΔQ is applied to the exciter

Generator Controllers (p–f and Q–V Controllers)

The active power P is mainly dependent on the internal angle δ and is independent of the bus voltage magnitude |V|. The bus voltage is dependent on machine excitation and hence on reactive power Q and is independent of the machine angle δ. Change in the machine angle δ is caused by a momentary change in the generator speed and hence the frequency. Therefore, the load frequency and excitation voltage controls are non-interactive for small changes and can be modeled and analyzed independently. Figure gives the schematic diagram of load frequency (P–f) and excitation voltage (Q–V) regulators of a turbo- generator. The objective of the MW frequency or the P–f control mechanism is to exert control of frequency and simultaneously exchange of the realpower flows via interconnecting lines. In this control, a frequency sensor senses the change in frequency and gives the signal Δf . The P–f controller senses the change in frequency signal (Δ f) and the increments in tie-line real powers (ΔP), which will indirectly provide information about the incremental state error ($\Delta\delta$). These sensor signals (Δf and ΔP) are amplified, mixed, and transformed into a real-power control signal ΔP . The valve control mechanism takes ΔP as the input signal and provides the output signal, which will change the position of the inlet valve of the prime mover. As a result, there will be a change in the prime mover output and hence a change in real-power generation ΔP . This entire P–f control can be yielded by automatic load frequency control (ALFC) loop.

The objective of the MVAr-voltage or Q–V control mechanism is to exert control of the voltage state $|V_i|$. A voltage sensor senses the terminal voltage and converts it into an equivalent proportionate DC voltage. This proportionate DC voltage is compared with a reference voltage V_{iref} by means of a comparator. The output obtained from the comparator is error signal $\Delta|V_i|$ given as input to Q–V controller, which transforms it to a reactive power signal command ΔQ_{ci} and is fed to a controllable excitation source. This results in a change in the rotor field current, which in turn modifies the generator terminal voltage. This entire Q–V control can be yielded by an automatic voltage regulator (AVR) loop

Schematic diagram of P–f controller and Q–V controller

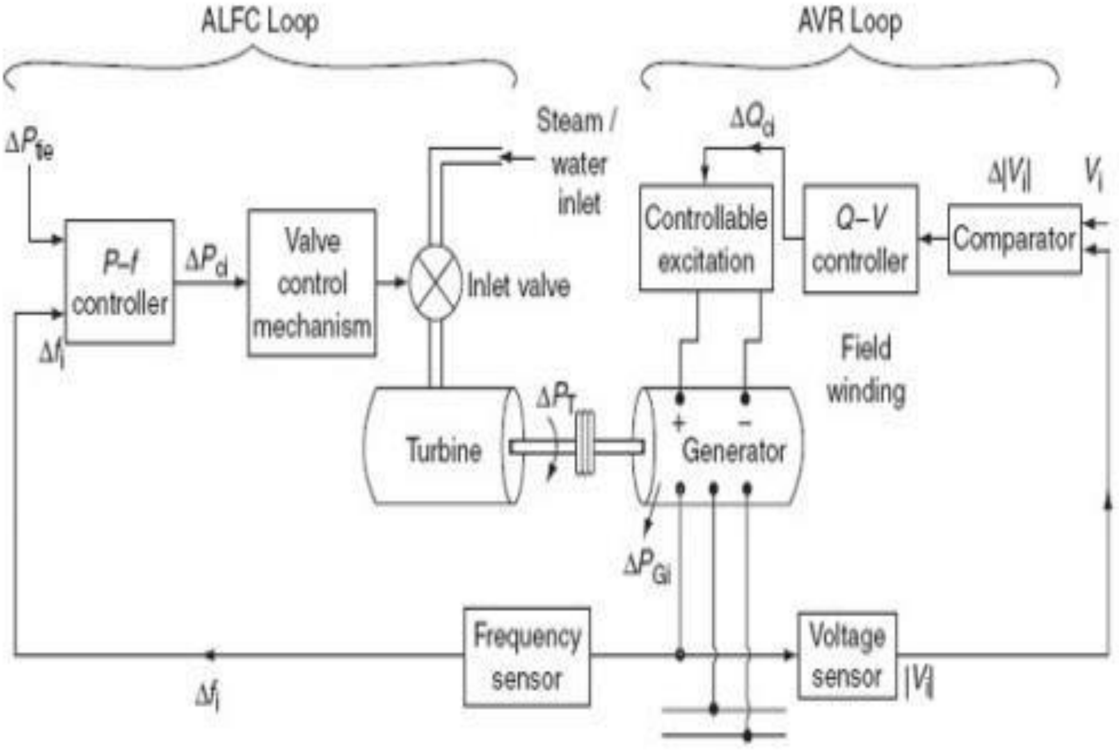


Fig. Schematic diagram of P–f controller and Q–V controller

OVERVIEW OF POWER SYSTEM CONTROL (PLANT LEVEL AND SYSTEM LEVEL CONTROL)

- The function of an electric power system is to convert energy from one of the naturally available forms to electrical from and to transport it to points of consumption.
- A properly designed and operated power system should meet the following fundamental requirement.
  1. Adequate „**spinning reserve'** must be present to meet the active and reactive power demand.
  2. Minimum cost with minimum ecological impact.
  3. The power quality must have certain minimum standards within the tolerance or limit such as,
- Constancy of frequency.
- Constancy of voltage (Voltage magnitude and load angle).
- Level of reliability.

Factor affecting power quality:

- Switching surges.
- Lightning.
- Flickering of voltage.
- Load shedding.
- Electromagnetic interference.
- Line capacitance and line inductance.
- Operation of heavy equipment.

The three main controls involved in powers are:

1. Plant Level Control (or) Generating Unit Control.
2. System Generation Control.
3. Transmission Control.

1. Plant Level Control (or) Generating Unit Control

The plant level control consists of:

I. Governor control or Prime mover control.

II. Automatic Voltage Regulator (AVR) or Excitation control.

I. <u>Governor control or Prime mover control</u>

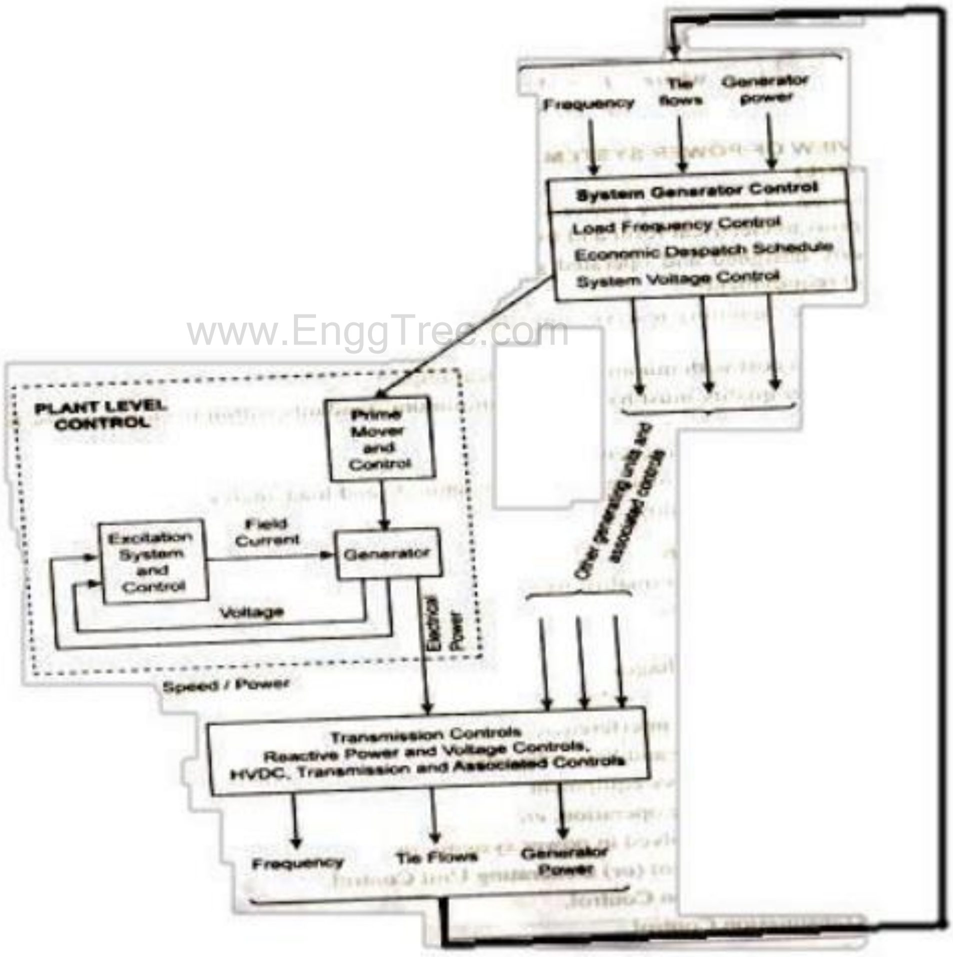
- Governor control or Prime mover controls are concerned with speed regulation of the governor and the control of energy supply system variables such as boiler pressure, temperature and flows.

➢ Speed regulation is concerned with steam input to turbine.
➢ With variation in load, speed of governor varies as the load is inversely proportional to speed.
➢ The speed of the generator varies and the governor senses the speed and gives a command signal, so that, the steam input of the turbine is changed relative to the load requirement.

II. ***Automatic Voltage Regulator (AVR) or Excitation control***

➢ The function of Automatic Voltage Regulator (AVR) or Excitation control is to regulate generator voltage and relative power output.
➢ As the terminal voltage varies the excitation control, it maintains the terminal voltage to the required standard and the demand of the reactive power is also met by the excitation control unit.

These controls are depicted in given figure 1.4



2. System Generation Control

➢ The purpose of system generation control is to balance the total system generation against system load and losses, so that, the desired frequency and power interchange with neighboring systems are maintained.

- This comprises of:

I. Load Frequency Control (LFC).
II.Economic Dispatch Control (EDC).

III.System Voltage Control.

IV. Security control.

i. Load Frequency Control (LFC).

- This involves the sensing of the bus bar frequency and compares with the tie line power frequency.
- The difference of the signal is fed to the integrator and it is given to speed changer which generates the reference speed for the governor.
- Thus, the frequency of the tie line is maintained as constant.

ii. Economic Dispatch Control (EDC).

- When the economical load distribution between a number of generator units is considered, it is found that the optimum generating schedule is affected when an incremental increased at one of the units replaces a compensating decrease at every other unit, in term of some incremental cost.
- Optimum operation of generators at each generating station at various station load levels is known as unit commitment.

iii. System Voltage Control.

- This involves the process of controlling the system voltage within tolerable limits.
- This includes the devices such as static VAR compensators, synchronous condenser, tap changing transformer, switches, capacitor and reactor.
- The controls described above contribute to the satisfactory operation of the power system by maintaining system voltages, frequency and other system variables within their acceptable limits.
- They also have a profound effect on the dynamic performance of power system and on its ability to cope with disturbances.

iv. Security control

- The main objective of real time power system operation requires a process guided by control and decisions based on constant monitoring of the system condition.
- The power system operation is split into two levels.

LEVEL 1: Monitoring and Decision

- The condition of the system is continuously observed I the control centres by protective relays for faults or contingencies caused by equipment trouble and failure.

- If any of these monitoring devices identifies a sufficiently severe problem at the sample time, then the system is in an abnormal condition.
- If no such abnormality is observed, then the system is in a normal condition.

LEVEL 2: Control

- At each sample, the proper commands are generated for correcting the abnormality on protecting the system from its consequences.
- If on abnormality is observed, then the normal operation proceeds for the next sample interval.

POWER SYSTEM OPERATION

(i) Load Forecasting

(ii) Unit Commitment

(iii) Load Scheduling.

1. Load forecasting:

The load on their systems should be estimated in advance. This estimation in advance is known as load forecasting. Load forecasting based on the previous experience without any historical data.

Classification of load forecasting:

Forecasting	Lead Time	Application
Very short time	Few minutes to half an hour	Real time control, real time security evaluation.
Short term	Half an hour to a few hours	Allocation of spinning reserve, unit commitment, maintenance scheduling.
Medium term	Few days to a few weeks	Planning or seasonal peak-winter, summer.
Long term	Few months to a few years	To plan the growth of the generation capacity.

Need for load forecasting:

- To meet out the future demand.
- Long term forecasting is required for preparing maintenance schedule of the generating units, planning future expansion of the system.
  For day-to-day operation, short term load forecasting demand and for maintaining the required spinning reserve. Very short term load forecasting is used for generation and distribution.
- generation scheduling and load dispatching.
- Medium term load forecasting is needed for predicted monsoon acting and hydro availability and allocating.

2. Unit Commitment:

The unit commitment problem is to minimize system total operating costs while simultaneously providing sufficient spinning reserve capacity to satisfy a given security level. In unit commitment problems, we consider the following terms.

- A short term load forecast.

- System reserve requirements.
- System security.
- Startup costs for all units.
- Minimum level fuel costs for all units.
- Incremental fuel costs of units.
- Maintenance costs.

3. Load Scheduling (Load Dispatching):

Loading of units are allocated to serve the objective of minimum fuel cost is known as load scheduling. Load scheduling problem can be divided into:

i. Thermal scheduling.
ii. Hydrothermal scheduling.

i. Thermal scheduling.

The loading of steam units are allocated to serve the objective of minimum fuel cost. Thermal scheduling will be assumed that the supply undertaking has got only form thermal or from steam stations.

ii. Hydrothermal scheduling.

Loading of hydro and thermal units are allocated to serve the objective of minimum fuel cost is known as hydrothermal scheduling.

Scheduling of hydro units are complex because of natural differences I the watersheds, manmade storage and release elements used to control the flow of water are difficult.

During rainy season, we can utilize hydro generation to a maximum and the remaining period, hydro generation depends on stored water availability. If availability of water is not enough to generate power, we must utilize only thermal power generation. Mostly hydroelectric generation is used to meet out peak loads. There are two types of hydrothermal scheduling.

a) Long range hydro scheduling
b) Short range hydro scheduling.

a) Long range hydro scheduling

Long range hydro scheduling problem involves the long range forecasting of water availability and the scheduling of reservoir water releases for an interval of time that depends on the reservoir capacities. Long range hydro scheduling involves

from I week to I year or several years. Long range hydro scheduling involves optimization of statistical variables such as load, hydraulic inflows and unit availabilities.

b ***Short range hydro scheduling.***

Short range hydro scheduling involves from one day to one week or hour-by-hour scheduling of all generation on a system to achieve minimum production cost foe a given period.

Assuming load, hydraulic inflows and unit availabilities are known, for a given reservoir level, we can allocated generation of power using hydro plants to meet out the demand, to minimize the production cost.

The largest category of hydrothermal system includes a balance between hydroelectric and thermal generation resources. Hydrothermal scheduling is developed to minimize thermal generation production cost.

Speed – Load Characteristics

(Load Sharing between Two SynchronousMachines in Parallel)

Speed droop is a governor function which reduces the governor reference speed as fuel position (load) increases. All engine controls use the principle of droop to provide stable operation.

The simpler mechanical governors have the droop function built into the control system, and it cannot be changed.

Droop originates from the principle of power balance in synchronous generators. An imbalance between the input mechanical power and the output electric power causes a change in the rotor speed and electrical frequency. Similarly, variation in output reactive power results in voltage magnitude deviation.

The ability to return to the original speed after a change in load is called isochronous speed control. All electronic controls have circuits which effectively provide a form of temporary droop by adjusting the amount of actuator position change according to how much off speed is sensed. Without some form of droop, engine-speed regulation would always be unstable.

A load increase would cause the engine to slow down. The governor would respond by increasing the fuel position until the reference speed was attained. However, the combined properties of inertia and power lag would cause the speed to recover to a level greater than the reference.

Droop is a straight-line function, with a certain speed reference for every fuel position. Normally, a droop governor lowers the speed reference from 3 to 5 percent of the reference speed over the full range of the governor output. Thus a 3% droop governorwith a reference speed of 1854 rpm at no fuel would have a reference speed of 1800 rpm at max fuel (61.8 Hz at no fuel and 60 Hz at max fuel).

Most complex hydraulic governors have adjustable droop. In these cases, droop may beset between 0% and 5%. Droop is not adjustable in most mechanical governors,

Percentage speed regulation or droop

The value of R determines the steady-state speed versus load characteristic of the generating unit as shown in fig.5. The ratio of speed deviation ($\Delta\omega_r$) or frequency deviation (Δf) to change in valve/gate position or power output (ΔP) is equal to R. The parameter R is referred to as speed regulation or droop. It can be expressed in percent as

$$\%R = \frac{No\ load\ speed - Full\ load\ speed}{Full\ load\ speed} \times 100$$

$$\%R = \left(\frac{\omega_{NL} - \omega_{FL}}{\omega_{FL}}\right) \times 100$$

When two generating units are operating in parallel on the system, their speed-droop characteristics low load changes are shared among them in the steady state and to operate to a common frequency.

The changes in the outputs of the units are given by

$$\text{Unit-1, } (\Delta P_{G1}) = \frac{-P_{r1}}{R_{p.u1}} \times \frac{\Delta f}{f_r}$$

$$\text{Unit-2,(} (\Delta P_{G2)} = \frac{-P_{r2}}{R_{p.u2}} \times \frac{\Delta f}{f_r}$$

Total load change in output

$$= \Delta P = \Delta P_{G1} + \Delta P_{G2} = \frac{-\Delta f}{f_r}\left[\frac{P_{r1}}{R_{p.u1}} + \frac{P_{r2}}{R_{p.u2}}\right]$$

$$\text{The system frequency change } \Delta f = \frac{-\Delta P .fr}{\frac{P_{r1}}{R_{p.u1}} + \frac{P_{r2}}{R_{p.u2}}}$$

$$\Delta f = \frac{-\Delta P}{\frac{1}{R_1} + \frac{1}{R_2}}$$

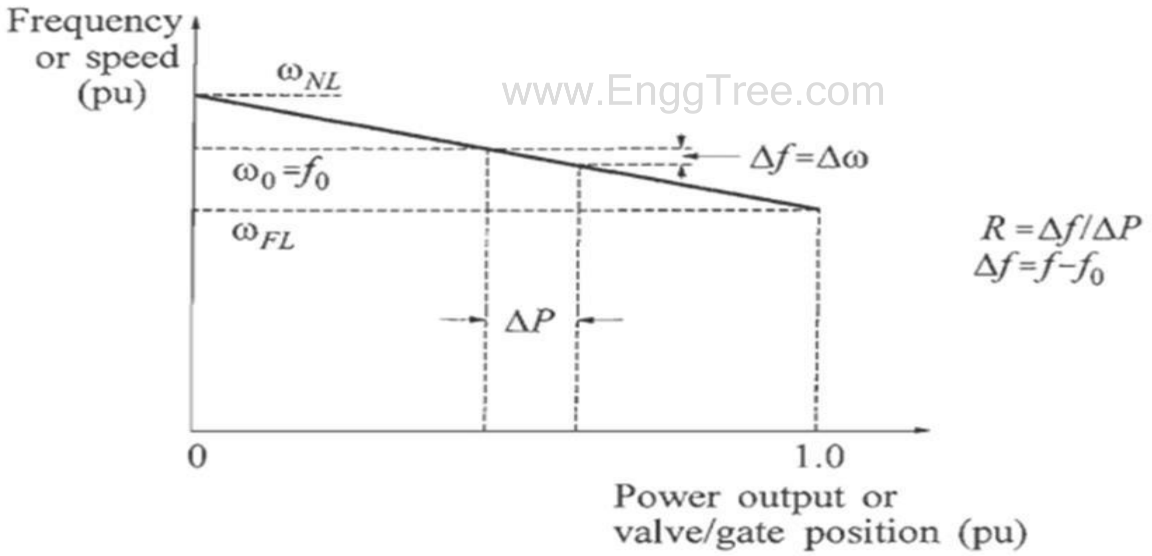
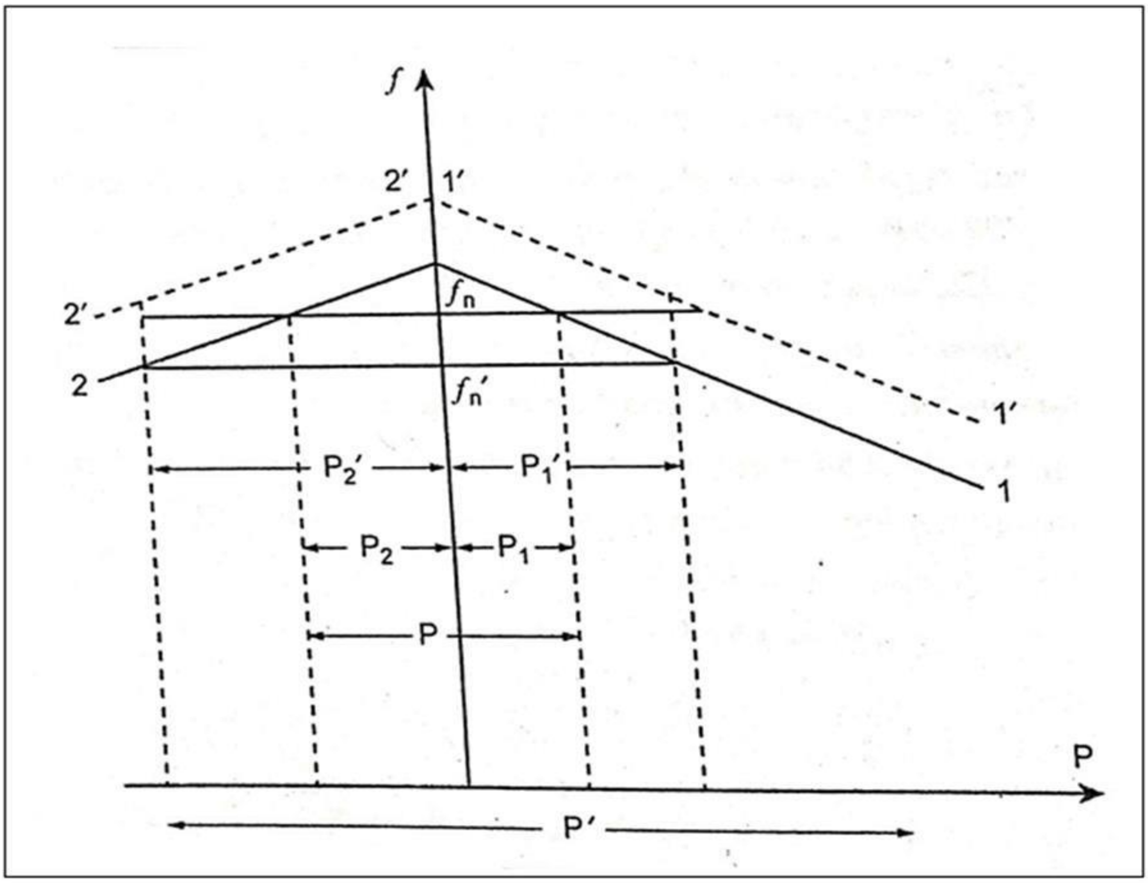


Fig.5 Ideal steady state characteristics of a governor with speed droop

Parallel operation of two alternators

Two different controls are carried out on the governor characteristics. The parameter R is adjusted during off-line condition of the unit to ensure its proper coordination with the other units, the second control shifts the straight line characteristic parallel to itself to change the load distribution among the generators connected in parallel as well as to maintain the system frequency.



The second control known as supplementary control. In Fig.7, the governor characteristics of two generating units are shown. Supposing if two generator units sharing the total load P ie. $P = P_1 + P_2$ and at constant frequency f_0.

Now if the total load increases by P’, the frequency reduces to f'_0 then the two generator units increases their output by supplying kinetic energy which in turn reduction in speed. In order to maintain the system frequency, one of the generators or both the generator increase their output which is shown in dotted lines of the figure. Now the total load P’ is hared by both the generators with increased output i.e

$P' = P'_1 + P'_2$.

It is to be noted that if the frequency of two areas are to be controlled, the static frequency drop is 50% of the isolated operation of two systems. Also, if there is changein load in any area, half of it shared by other area

Basics of Speed Governing Mechanisms and Modelling

The speed governor is the main primary tool for the LFC, whether the machine isused alone to feed a smaller system or whether it is a part of the most elaborate arrangement. A schematic arrangement of the main features of a speed-governing system of the kind used on steam turbines to control the output of the generator to maintain constant frequency is as shown in Fig.1

Its main parts or components are as follows:

Fly Ball Speed Governor:

This is the heart of the system which senses the change in speed (frequency).As the speed increases the fly balls move outwards and the point B on linkage mechanismmoves downwards. The reverse happens when the speed decreases.

(i) Hydraulic Amplifier:

It comprises a pilot valve and main piston arrangement. Low power level pilot valve movement is converted into high power level piston valve movement. This is necessary inorder to open or close the steam valve against high pressure steam.

(ii) Linkage Mechanism:

ABC is a rigid link pivoted at B and CDE is another rigid link pivoted at D. This link mechanism provides a movement to the control valve in proportion to change in speed. Italso provides a feedback from the steam valve movement.

Basics of Speed Governing Mechanisms and Modelling

(iii)**Speed Changer:** It provides a steady state power output setting for the turbine. Its downward movement opens the upper pilot valve so that more steam is admitted to the turbine under steady conditions (hence more steady power output). The reverse happens for upward movement of speed changer.

A brief explanation of the diagram is as follows:

Steam enters into the turbine through a pipe that is partially obstructed by a steam admission valve. In steady state the opening valve is determined by the position of a device called the speed changer (upper left corner in Fig.1), fixes the position of the steam valve through two rigid rods ABC and CDE. The reference value or set point ofthe turbine power in steady state is called the reference power

When the load on the bus suddenly changes, the shaft speed is modified, and a device called speed regulator acts through the rigid rods to move the steam valve. A similar effect could be produced by temporarily modifying the reference power (which justifies the name speed changer). In practice, both control schemes are used simultaneously. Amplifying stages (generally hydraulic) are introduced to magnify the output of the controller and produced the forces necessary to actually move the steam valve.

Modelling of Speed Governor

In this section, we develop the mathematical model based on small deviations arounda nominal steady state. Let us assume that the steam is operating under steady state and is delivering power $P^0{}_G$ from the generator at nominal speed or frequency f_o. Under this condition, the prime mover valve has a constant setting $\chi^0{}_E$, the pilot valve is closed, and the linkage mechanism is stationary. Now, we will increase the turbine power by ΔP_C with the help of the speed changer. For this, the movement of linkage point A moves downward by a small distance Δx_A and is given by

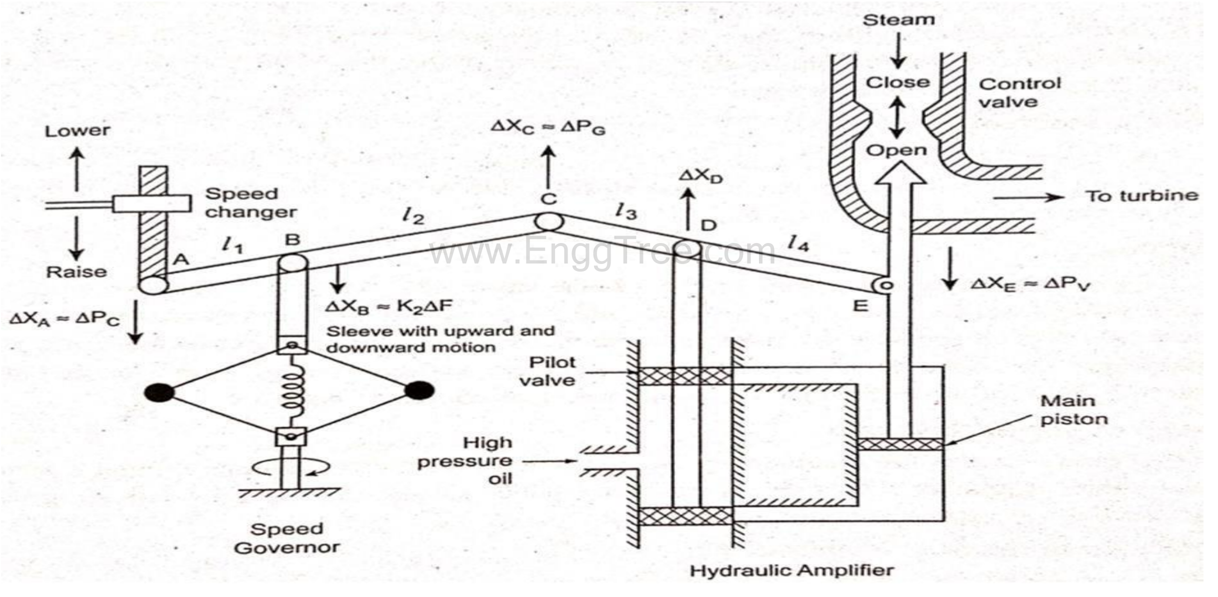


Fig.1 Schematic diagram of speed governing mechanism

$$\Delta x_A = K_c \Delta P_C \text{ ....} (1)$$

The link point 'C' will move upward because of linkage (A-B-C) action. Let it befurther, the link point 'D' moves the piston in pilot servo (V), resulting in higher pressure oil flow in the upper part of the main piston. The piston moves downward by an amount ΔX_D and the steam valve opening increases. It increases the torque developed by the turbine. This increased torque increases the speed of generator, i.e., frequency (Δf). This change of speed results in the outward movement of fly ball of the speed regulator. Thus the link 'B' moves slightly downward a small distance ΔX_B. Due to the movement of link point B, the link point 'C' also moves downward by an amount ΔX_C'' which is also proportional to Δf. Thus the net movement of link point C is

$$\Delta X_C = \Delta X_{C'} + \Delta X_{C''} \text{ .... } (2)$$

$$(-)\ \Delta X_{C'} (l_{AB}) = \Delta X_A (l_{BC})$$

$$(-)\ \Delta X_{C'} = \Delta X_A \frac{(lBC)}{(lAB)} \text{ .... } (3)$$

We know from eq-(1) $\Delta x_A = K_c\, \Delta P_C$ substitute in eq-(3) and consider

$$K_1 = \frac{(lBC)}{(lAB)}$$

$$\Delta X_{C'} = (-)\ K_c\, \Delta P_C\ K_1$$

$$\Delta X_{C'} = (-)\ K_1 K_c\, \Delta P_C \text{ .... } (4)$$

$$\text{and } \Delta X_C" = K_2\, \Delta f$$

Thus the net movement of C is therefore

$$\Delta X_C = (-)\ K_1 K_c\, \Delta P_C + K_2\, \Delta f \text{ .... } (5)$$

The movement of D, ΔX_D is the amount by which the pilot valve opens. It is contributed by ΔX_C and ΔX_E and can be written as

$$\Delta X_D = \Delta X_{D'} + \Delta X_{D''} \quad \ldots\ldots\ldots\ldots\ldots (6)$$

$$\Delta X_{D'} (l_{CD} + l_{DE}) = \Delta X_C (l_{DE})$$

$$\Delta X_{D'} = \frac{(l_{CD} + lDE)}{(lDE)} \Delta X_C \quad \ldots\ldots\ldots\ldots\ldots (7)$$

$$\Delta X_{D'} = K_3 \Delta X_C \quad \ldots\ldots\ldots\ldots\ldots (7)$$

$$\Delta X_{D''} (l_{CD} + l_{DE}) = \Delta X_E (l_{CD})$$

$$\Delta X_{D''} = \frac{(l_{CD} + lDE)}{(lCD)} \Delta X_E$$

$$\Delta X_{D''} = K_4 \Delta X_E \quad \ldots\ldots\ldots\ldots\ldots (8)$$

Thus, it can written as

$$\Delta X_D = K_3 \Delta X_C + K_4 \Delta X_E \quad \ldots\ldots\ldots\ldots\ldots (9)$$

Now, if an assumption is made that the flow of oil into the servo-motor is proportional to position ΔX_D of the pilot valve V, then the movement ΔX_E of the piston can be expressed as

$$\Delta X_E = \Delta X_V = K_5 \int_0^t (-\Delta X_D)\, dt \quad \ldots\ldots\ldots\ldots\ldots (10)$$

Taking Laplace transform of equations (5), (9) and (10) ·

$$\Delta X_C(s) = -K_1 K_C \Delta P_C(s) + K_2 \Delta f(s) \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots (11)$$

$$\Delta X_D(s) = K_3 \Delta X_C(s) + K_4 \Delta X_E(s) \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots (12)$$

$$\Delta X_E(s) = K_5 \frac{1}{s} \Delta X_D(s) \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots (13)$$

Eliminating $\Delta X_C(s)$ and $\Delta X_D(s)$

$$\Delta X_E(s)\left[1 + \frac{K_4 K_5}{s}\right] = \frac{-K_5 K_3}{s}\left[-K_1 K_c \Delta P_c(s) + K_2 \Delta f(s)\right]$$

$$\Delta X_E(s) = \frac{k5k3k1kc\left(\Delta P_c(s) - \frac{k2}{k1kc}\right)\Delta f(s)}{k4k5\left[1+\frac{s}{k4k5}\right]}$$

$$\Delta X_E(s) = \frac{K3K1KC}{K4} \quad \frac{\left(\Delta P_c(s) - \frac{k2}{k1kc}\right)\Delta f(s)}{\left[1+\frac{s}{k4k5}\right]}$$

$$K_G = \frac{K3K1KC}{K4}; \quad T_G = \frac{1}{K4K5}; \quad \frac{1}{R} = \frac{k2}{k1kc};$$

Value of TG < 100 m sec

The equation can be written as:

$$\Delta X_E(s) = \left[\Delta P_C(s) - \frac{1}{R}\ \Delta f(s)\right] \times \frac{KG}{1+STG} \quad \ldots\ldots\ldots\ldots (14)$$

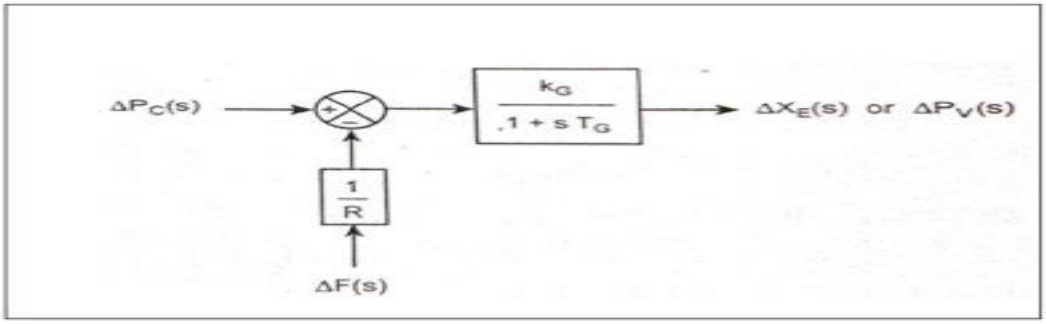


Fig.2 Model of speed governor

LOAD FREQUENCY CONTROL

The following basic requirements are to be fulfilled for successful operation of the system:

1. The generation must be adequate to meet all the load demand

2. The system frequency must be maintained within narrow and rigid limits.

3. The system voltage profile must be maintained within reasonable limits and

4. In case of interconnected operation, the tie line power flows must be maintained at the specified values.

- When real power balance between generation and demand is achieved the frequency specification is automatically satisfied.
- Similarly, with a balance between reactive power generation and demand, voltage profile is also maintained within the prescribed limits.
- Under steady state conditions, the total real power generation in the system equals the total MW demand plus real power losses.
- Any difference is immediately indicated by a change in speed or frequency
- Generators are fitted with speed governors which will have varying characteristics: different sensitivities, dead bands response times and droops.
- They adjust the input to match the demand within their limits.
- Any change in local demand within permissible limits is absorbed by generators in the system in a random fashion.
- An independent aim of the automatic generation control is to reschedule the generation changes to preselected machines in the system after the governors have accommodated the load change in a random manner.
- Thus, additional or supplementary regulation devices are needed along with governors for proper regulation.
- The control of generation in this manner is termed load-frequency control.
- For interconnected operation, the last of the four requirements mentioned earlier is fulfilled by deriving an error signal from the deviations in the specified tie-line power flows to the neighboring utilities and adding this signal to the control signal of the load-frequency control system.
- Should the generation be not adequate to balance the load demand, it is imperative that one of the following alternatives be considered for keeping the system in operating condition:

I. Starting fast peaking units.

2. Load shedding for unimportant loads, and

3. Generation rescheduling.

- It is apparent from the above that since the voltage specifications are not stringent. Load frequency control is by far the most important in power system control.
- In order to understand the mechanism of frequency control, consider a small step increase in load. The initial distribution of the load increment is determined by the system impedance; and the instantaneous relative generator rotor positions. The energy required to supply the load increment is drawn from the kinetic energy of the rotating machines. As a result, the system frequency drops. The distribution of load during this period among the various machines is determined by the inertias of the rotors of the generators partaking in the process. This problem is studied in stability analysis of the system.
- After the speed or frequency fall due to reduction in stored energy in the rotors has taken place, the drop is sensed by the governors and they divide the load increment between the machines as determined by the droops of the respective governor characteristics. Subsequently, secondary control restores the system frequency to its normal value by readjusting the governor characteristics.

AUTOMATIC LOAD FREQUENCY CONTROL

- The ALFC is to control the frequency deviation by maintaining the real power balance in the system.
- The main functions of the ALFC are to i) to maintain the steady frequency; ii) control the tie-line flows; and iii) distribute the load among the participating generating units.
- The control (input) signals are the tie-line deviation ΔP_{tie} (measured from the tie- line flows), and the frequency deviation Δf (obtained by measuring the angle deviation $\Delta\delta$).
- These error signals Δf and ΔP_{tie} a r e amplified, mixed and transformed to a real power signal, which then controls the valve position. Depending on the valve position, the turbine (prime mover) changes its output power to establish the real power balance.
- The complete control schematic is shown in Fig For the analysis, the models for each of the blocks in Fig2 are required.

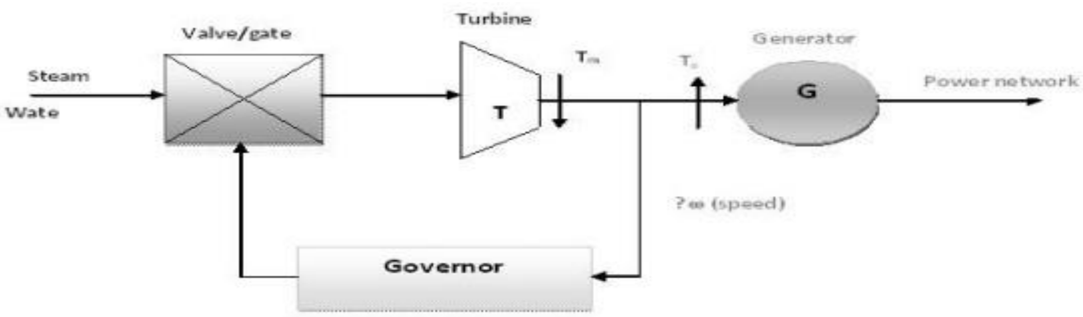


Fig 2.3The Schematic representation of ALFC system

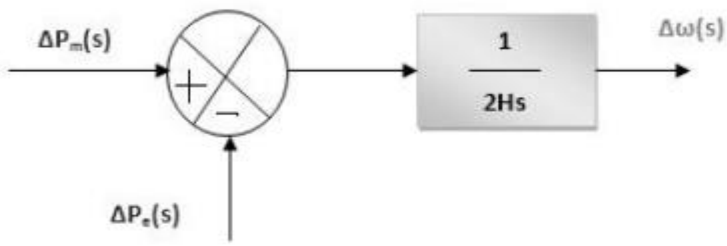
- The generator and the electrical load constitute the power system. The valve and the hydraulic amplifier represent the speed governing system. Using the swing equation, the generator can be Using the swing equation, the generator can be modeled by Block Diagram Representation Of The Generator The load on the system is composite consisting of a frequency independent component and a frequency dependent component. The load can be written as

$$Pe = P0 + Pf$$

e ^{2} $\Delta\delta = \Delta Pm - \Delta Pe$

g $\Delta Pm - \Delta Pe$

1



Pe is the change in the load;
P0 - is the frequency independent load component;
Pf - is the frequency dependent load component.

$$Pf = D$$

where,

- D is called frequency characteristic of the load (also called as damping constant) expressed in percent change in load for 1% change in frequency.
- If D=1.5%, then a 1% change in frequency causes 1.5% change in load. The combined generator and the load (constituting the power system) can then be represented as shown in Fig.
- The turbine can be modeled as a first order lag as shown in the Fig.

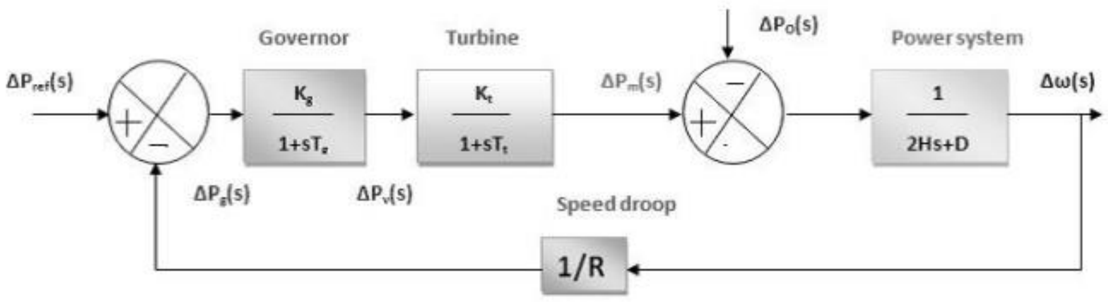
- Gt(s) is the TF of the turbine; ΔPV(s) is the change in valve output (due to action). Pm(s) is the change in the turbine output.
- The governor can similarly modeled as shown Fig. The output of the governor is by
- Where ΔPref is the reference set power, and Δw/R is the power given by governor speed characteristic.
- The hydraulic amplifier transforms this signal Pg into valve/gate position corresponding to a power PV.

Thus

$$PV(s) = (Kg/ (1+sTg)) \_Pg(s).$$

LFC CONTROL OF SINGLE AREA AND DERIVE THE STEADY STATE FREQUENCY ERROR

All the individual blocks can now be connected to represent the complete ALFC loop as



Block diagram representation of the ALFC Static

Power Generation

We have

$$\Delta PG(s) = kGkt / (1+sTG)(1+sTt)[\Delta Pc(s)-1/R\Delta F(s)]$$

The generator is synchronized to a network of very large size. So, the speed or frequency will be essentially independent of any changes in a power output of the generator ie, $\Delta F(s) = 0$

Therefore $\Delta PG(s) = kGkt / (1+sTg)(1+sTt) * \Delta Pc(s)$

Steady state response

(i)Controlled case:

To find the resulting steady change in the generator output:

Let us assume that we made a step change of the magnitude ΔPc of the speed changer For step change,

$$\Delta Pc(s) = \Delta Pc/s$$

$$\Delta PG(s) = kGkt/ (1+sTg)(1+sTt).\ \Delta Pc(s)/s \quad s\Delta PG(s) = kGkt/ (1+sTg)(1+sTt).\ \Delta Pc(s)$$

Applying final value theorem,

$$\Delta PG\ (stat) = \Delta$$

(ii)Uncontrolled case

Let us assume that the load suddenly increases by small amount ΔPD.

Consider there is no external work and the generator is delivering a power to a single load.

$$\Delta Pc = 0$$
$$Kg\ Kt = 1$$
$$\Delta PG(s) = 1/\ (1+sTG)\ (1+sTt)\ [-\Delta F(s)/R]$$

For a step change $\Delta F(s) = \Delta f/s$

Therefore

$$\Delta PG(s) = 1/(1+sTG)(1+sTt)[-\Delta F/sR]$$
$$\Delta f/\Delta PG\ (stat) = -R\ Hz/MW$$

Steady State Performance of the ALFC Loop

In the steady state, the ALFC is in „open" state, and the output is obtained by substituting $s \to 0$ in the TF.

With $s \to 0$, Gg(s) and Gt(s) become unity, then,(note that

$$\mathbf{\Delta Pm = \Delta PT = PG = \Delta Pe = \Delta PD;}$$

That is turbine output = generator/electrical output = load demand)

$$\mathbf{\Delta Pm = \Delta Pref - (1/R)\ \Delta\omega \text{ or } \Delta Pm = \Delta Pref - (1/R)\Delta f}$$

When the generator is connected to infinite bus ($\Delta f = 0$, and $\Delta V = 0$), then

$$\Delta\ Pm = \Delta Pref\ .$$

If the network is finite, for a fixed speed changer setting ($\Delta Pref = 0$), then

$$\Delta Pm\ =\ (1/R)\Delta f$$

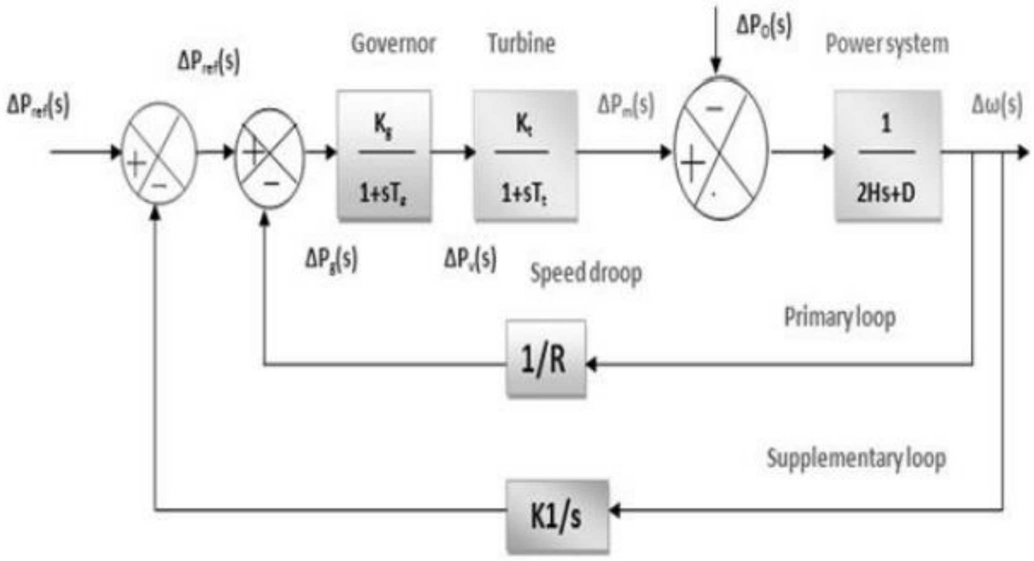
or

$$\Delta f = RPm.$$

Concept of AGC (Supplementary ALFC Loop)

- The ALFC loop shown in Fig. is called the primary ALFC loop.
- It achieves the primary goal of real power balance by adjusting the turbine output ΔPm to match the change in load demand ΔPD.
- All the participating generating units contribute to the change in generation. But a change in load results in a steady state frequency deviation Δf.
- The restoration of the frequency to the nominal value requires an additional control loop called the supplementary loop.
- This objective is met by using integral controller which makes the frequency deviation zero.
- The ALFC with the supplementary loop is generally called the AGC. The block diagram of an AGC is shown in Fig.
- The main objectives of AGC a r e
- to regulate the frequency (using both primary and supplementary controls); and to maintain the scheduled tie-line flows.

- A secondary objective of the AGC is to distribute the required change in generation among the connected generating units economically (to obtain least operating costs).



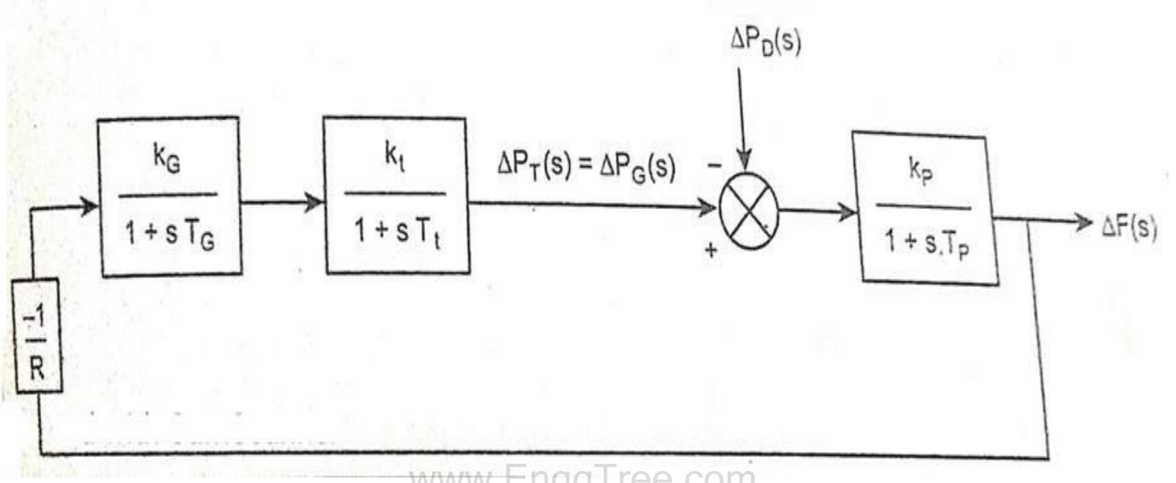
Block diagram representation of the AGC

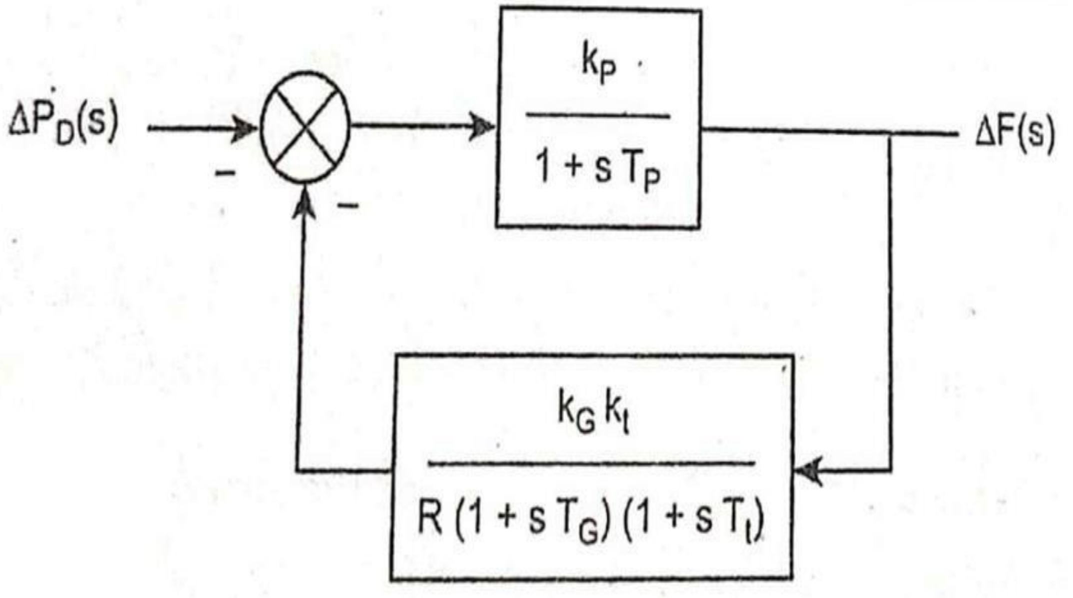
AGC in a Single Area System

- In a single area system, there is no tie-line schedule to be maintained.
- Thus the function of the AGC is only to bring the frequency to the nominal value.
- This will be achieved using the supplementary loop (as shown in Fig.) which uses the integral controller to change the reference power setting so as to change the speed set point.
- The integral controller gain KI n e e d s to be adjusted for satisfactory response (in terms of overshoot, settling time) of the system.
- Although each generator will be having a separate speed governor, all the generators in the control area are replaced by a single equivalent generator, and the ALFC for the area corresponds to this equivalent generator.

Static Analysis or Steady state response of uncontrolled case

- The basic objective of the primary ALFC loop is to maintain constant frequency in spite of changing loads. The primary ALFC loop as shown in the fig. has one output and two inputs. $\Delta P_{ref}(s)$ and $\Delta P_D(s)$
- Consider the speed changer has a fixed setting. Under this condition ΔP_C =0 and the load demand changes. This is known s free governor operation. The block diagram is shown infig drawn from substituting ΔP_C =0.





$$\Delta F(s) = \frac{\frac{Kp}{1+sTp}}{1+\frac{Kp}{1+sTp} x \frac{KgKt}{R(1+sTg)(1+sTt)}} [-\Delta P_D(s)]$$

$$\Delta F(s) = \frac{Kp}{1+\ sTp\ + \frac{KpKgKt}{R(1+sTg)(1+sTt)}} [-\Delta P_D(s)]$$

For a step load change $\Delta P_D(s) = \frac{\Delta P_D}{s}$

$$\Delta F(s) = \frac{-Kp}{1+\ sTp\ + \frac{KpKgKt}{R(1+sTg)(1+sTt)}} [\frac{\Delta P_D}{s}]$$

$$\Delta F(s) = \frac{-Kp}{1+\ sTp\ + \frac{KpKgKt}{R(1+sTg)(1+sTt)}} [\frac{\Delta P_D}{s}]$$

Applying final value theorem,

$$\Delta f_{stat} = \lim_{s \to 0} S.\Delta F(s) = \frac{-Kp}{1+\frac{KpKgKt}{R}} \times \Delta P_D \quad \text{............. (1)}$$

Practically Kg Kt =1

$$\Delta f_{stat} = \frac{-Kp}{1+\frac{Kp}{R}} \Delta PD$$

$$K_p = \frac{1}{B} \quad \text{and } \Delta P_D = M$$

$$\Delta f_{stat} = \frac{-\frac{1}{B}}{1+\frac{1}{BR}} \Delta PD$$

$$\Delta f_{stat} = \frac{-M}{B+\frac{1}{R}} = (-) -\frac{M}{\beta}\ ;\ \beta = B + \frac{1}{R}$$

In practice B<< $\frac{1}{R}$, neglecting B,

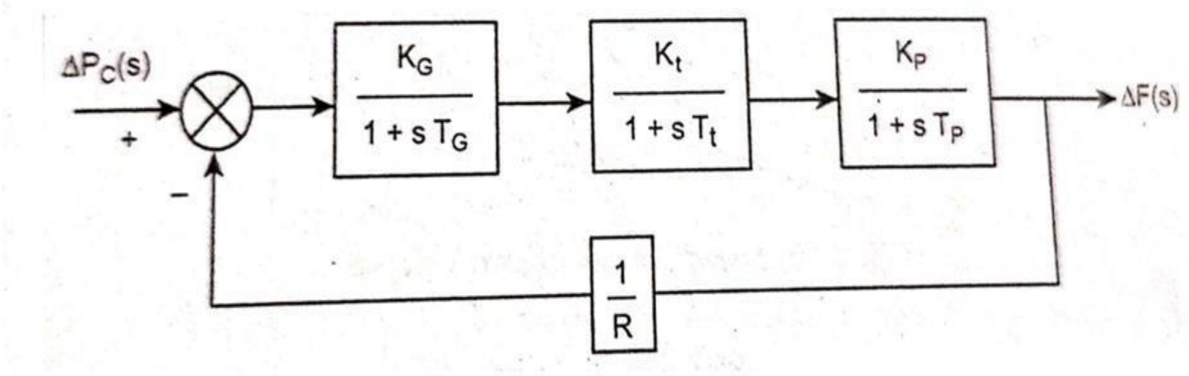
$$\frac{\Delta f_{stat}}{\Delta P_D} = (-)R \quad \text{Hz/MW}$$

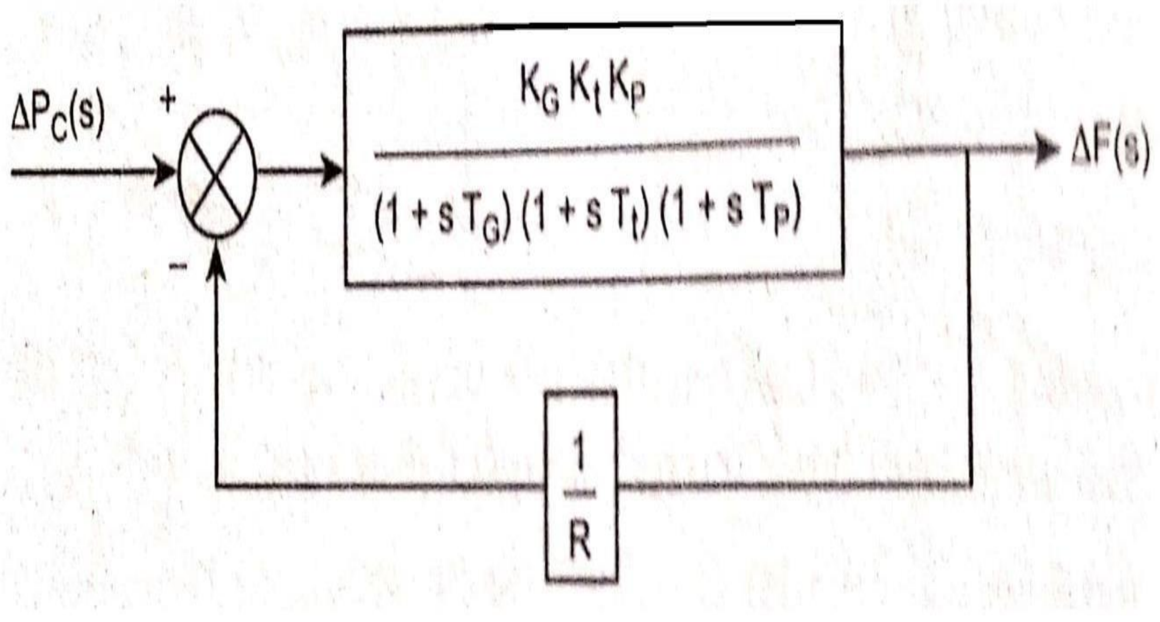
When several generators with governor speed regulations $R_1, R_{2.....} R_n$ are connected to thesystem the steady state deviation in frequency is given by

$$\Delta f_{stat} = \frac{-\Delta P_D}{B+\frac{1}{R_1}+\frac{1}{R_2}+\cdots\frac{1}{R_n}}$$

Static Analysis or Steady state response of controlled case

In this case, there is a step change ΔP_C force for speed changer setting and the load demand remains fixed i.e $\Delta P_D = 0$





$$\Delta F(s) = \frac{KgKtKp}{(1+sTg)(1+sTt)(1+sTp)+\frac{KgKtKp}{R}} \times \Delta P_C(s)$$

Practically Kg Kt =1 ; $T_g = T_t = 0$

For a step load change, $\Delta P_C(s) = \frac{\Delta P_c}{s}$

$$\Delta F(s) = \frac{Kp}{(1+sTg)(1+sTt)(1+sTp)+\frac{Kp}{R}} \times \frac{\Delta P_c}{s}$$

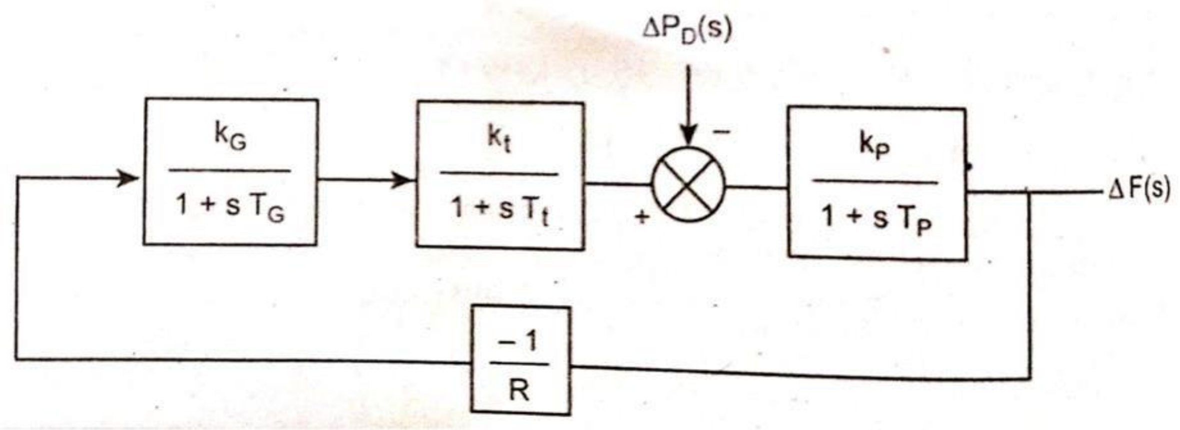
Applying final value theorem,

$$\Delta f_{stat} = \lim_{s \to 0} S.\Delta F(s)$$

$$\frac{\Delta f_{stat}}{\Delta P_C} = \frac{1}{B+\frac{1}{R}} \text{ Hz/MW}$$

Dynamic Analysis of Uncontrolled case (Single Area)

To obtain the dynamic response representing the change in frequency as a function of time for a step change in load. The block diagram reduces as shown in fig.



$$\Delta F(s) = \frac{\frac{Kp}{1+sTp}}{1+\frac{Kp}{1+sTp}\ x\ \frac{KgKt}{R(1+sTg)(1+sTt)}}[-\Delta P_D(s)]$$

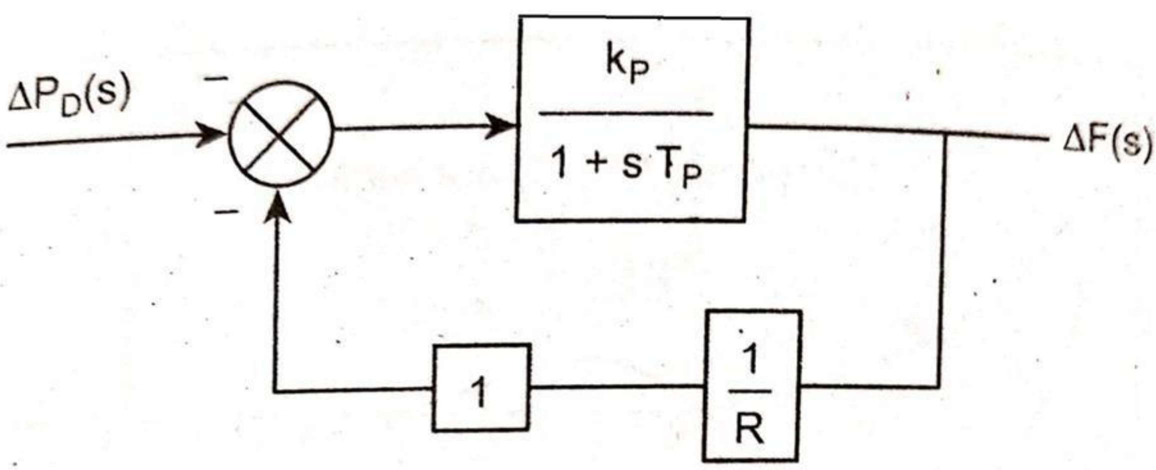
Taking inverse Laplace transform for an expression ΔF(s) is tedious, because the denominator will be third order. We can simplify the analysis by making the following assumptions.

1. The action of speed governor and turbine is instantaneously compared with rest of the power system.
2. The time constant of the power systemTp=20 sec, Tg = 0.4sec. Tt = 0.5sec

Approximate Analysis : letting $T_G = T_t = 0$

$K_G = K_t = 1$

The block diagram reduces as shown in fig.



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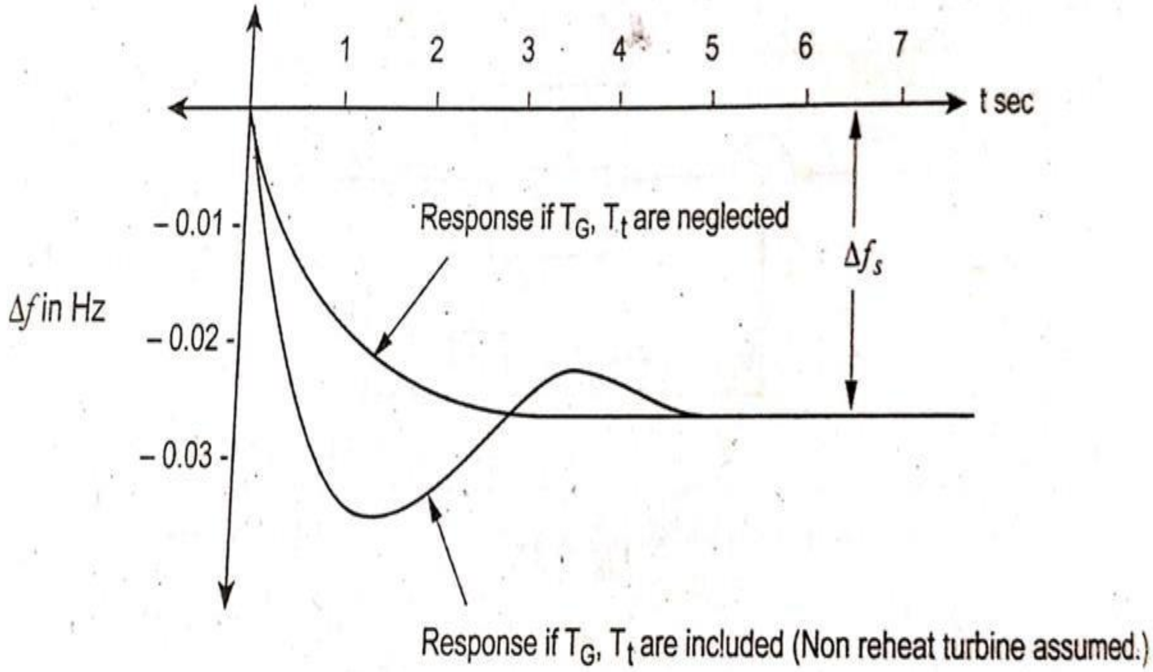


1
2
3
4
5
6
7
t sec
– 0.01
– 0.02
– 0.03
Δf in Hz
Response if T_G, T_t are neglected
Δf_s
Response if T_G, T_t are included (Non reheat turbine assumed.)

Important points for uncontrolled Single Area

1. By reducing value of R it is possible to increase AFRC. Hence static frequency error may bereduced.

2. With smaller time constant Tg and Tt, the system response shows some oscillations before settling down with a drop in frequency. But if these time constants are neglected, response is purely exponential.

3. If the overall closed loop system time constant is calculated from the response curve, it is found to be much smaller than the open loop time constant of the power system.

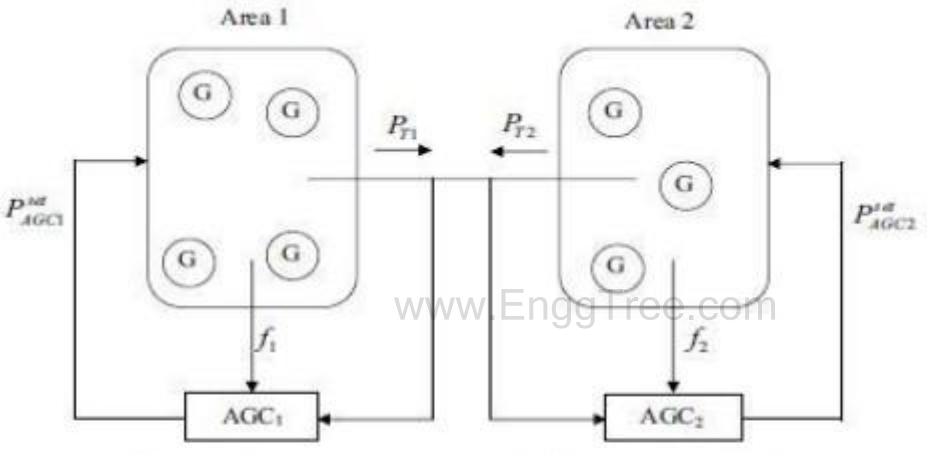
4. For the uncontrolled system there exists a steady state frequency error as a result of increasein load demand, however small it may be.

5. When the load demand increases speed or frequency of the system drops though initially kinetic energy of rotating inertia may be used to meet up the demand. Eventually it will be balanced by an increase in system generation and decrease in load as associated with the dropping frequency.

UNCONTROLLED TWO AREA LOAD FREQUENCY CONTROL SYSTEM

AGC IN A MULTI AREA SYSTEM

- In an interconnected (multi area) system, there will be one ALFC loop for each control area (located at the ECC of that area).
- They are combined as shown in Fig for the interconnected system operation.
- For a total change in load of ΔPD, the steady state Consider a two area system as depicted in Figure.
- The two secondary frequency controllers, AGC1 and AGC2, will adjust the power reference values of the generators participating in the AGC.
- In an N-area system, there are N controllers AGCi, one for each area i.



P_{T1} = Tie line power for Area 1 = $\sum_{j \in \Omega_1} P^j_{T1}$ = Sum over all tie lines

- A block diagram of such a controller is given in Figure 4.2. A common way is to implement this as a proportional-integral (PI) controller:
- Deviation in frequency in the two areas is given by

$$\Delta f = \Delta\omega 1 = \Delta\omega 2 = -\Delta PD \,/\, \beta 1 + \beta 2$$

where

$$\beta 1 = D1 + 1/\, R1$$

$$\beta 2 = D2 + 1/R2$$

E expression for tie-line flow in a two-area interconnected system Consider a change in load ΔPD1 in area1. The steady state frequency deviation Δf is the same for both the areas.

That **is**

$$\Delta f = \Delta f1 = \Delta f2.$$

Thus, for area1, we have

$$\Delta Pm1 - \Delta PD1 - \Delta P12 = D1\Delta f$$

Where, Area 2 ΔP12 is the tie line power flow from Area1to Area 2; and for

$$\Delta Pm2 + \Delta P12 = D2\Delta f$$

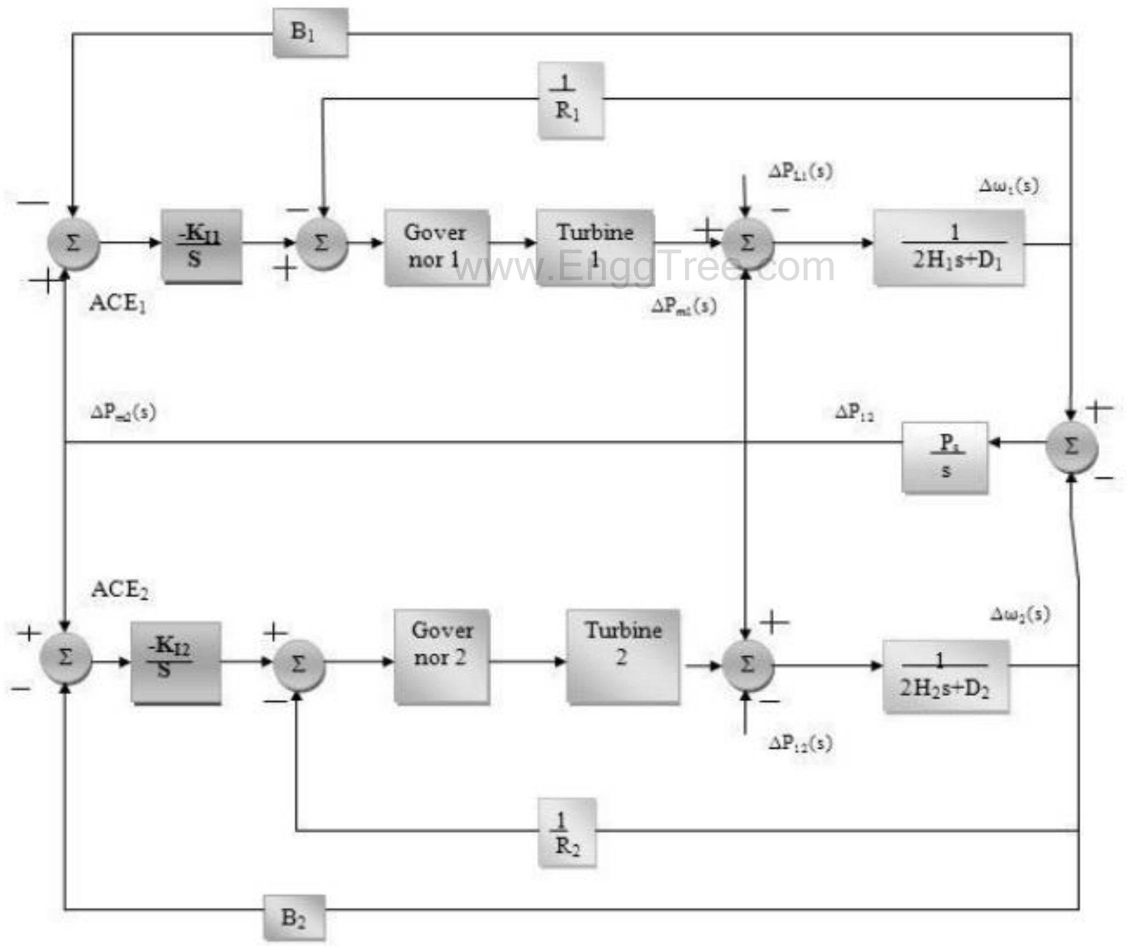
The mechanical power depends on regulation. Hence

$$\Delta Pm1 = -\Delta f\ 1\Delta Pm2 = -\Delta f\ 2$$

Substituting these equations, yields

$$(1/R1 + D1)\ \Delta f = -\Delta P12 - \Delta Pm$$

$$(1/R2 + D2)\ \Delta f = -\Delta P12 - \Delta Pm$$



A G C for a multi-area operation

Solving for Δf, we get

$$\Delta f = -\Delta PD1/\ \beta 1 + \beta 2$$

- Where $\beta 1$ and $\beta 2$ are the composite frequency response characteristic of Area1 and Area 2 respectively.
- An increase of load in area1 by $\Delta PD1$ results in a frequency reduction in both areas and a tie-line flow of $\Delta P12$.
- A positive $\Delta P12$ is indicative of flow from Area1 to Area 2 while a negative $\Delta P12$ means flow from Area 2 to Area1.
- Similarly, for a change in Area 2 load by $\Delta PD2$, we have

$$\Delta f= -\Delta PD2/ \beta 1 + \beta 2$$

State variability model

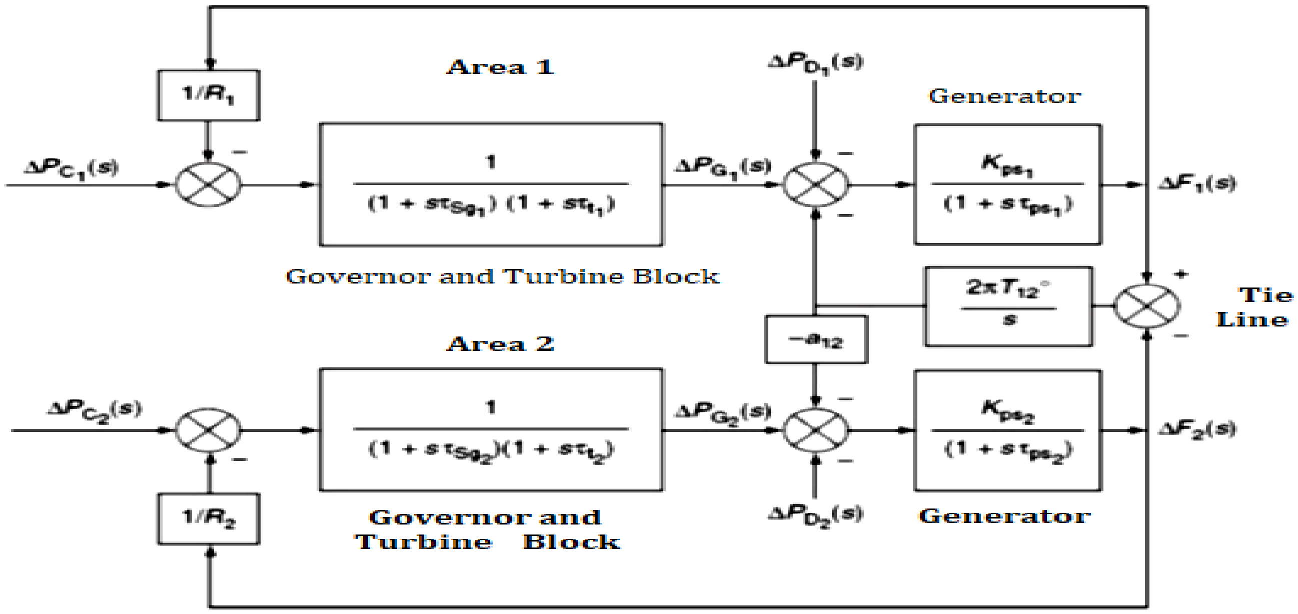
- A modern gigawatt generator with its multistage reheat turbine, including its automatic load frequency control (ALFC) and automatic voltage regulator (AVR) controllers, is characterized by an impressive complexity.
- When all its non- negligibility dynamics are taken into account, including cross-coupling betweencontrol channels, the overall dynamic model may be of the twentieth order.
- The dimensionality barrier can be overcome by means of computer-aided optimal control design methods originated by Kalman. A computer-oriented technique called optimum linear regulator (OLR) design has proven to be particularlyuseful in this regard.
- The OLR design results in a controller that minimizes both transientvariable excursions and control efforts. In terms of power system, this means optimally damped oscillation with minimum wear and tear of control valves.

OLR can be designed using the following steps:

- Casting the system dynamic model in state-variable form and introducing appropriate control forces.
- Choosing an integral-squared-error control index, the minimization of which is the
- control goal.
- Finding the structure of the optimal controller that will minimize the chosencontrol index.

Dynamic State Variable Model

- The LFC methods discussed so far are not entirely satisfactory. In order to have more satisfactory control methods, optimal control theory has to be used. For this purpose, the power system model must be in a state variable model



From the block diagram write the 's domain' equations

$$\Delta F_1(s) = \frac{K_{ps1}}{1 + s\tau_{ps1}}[\Delta P_{g1}(s) - \Delta P_{d1}(s) - \Delta P_{TL1}(s)]$$

$$\Delta F_2(s) = \frac{K_{ps2}}{1 + s\tau_{ps2}}[\Delta P_{g2}(s) - \Delta P_{d2}(s) - \Delta P_{TL2}(s)]$$

$$\Delta X_{E1}(s) = \frac{1}{1 + s\tau_{sg1}}[\Delta P_{C1}(s) - F_1(s)/R_1]$$

$$\Delta X_{E2}(s) = \frac{1}{1 + s\tau_{sg2}}[\Delta P_{C2}(s) - F_2(s)/R_2]$$

$$\Delta P_{G1}(s) = \frac{1}{1 + s\tau_{t1}}[\Delta X_{E1}(s)]$$

$$\Delta P_{G2}(s) = \frac{1}{1 + s\tau_{t2}}[\Delta X_{E2}(s)]$$

$$\Delta P_{TL1}(s) = \frac{2\pi T_{12}}{s}[\Delta F_1(s) - \Delta F_2(s)]$$

Where XE1 (s) and XE2 (s) are the Laplace transforms of the movements of the main positions in the speed governing mechanism of the two areas.

By taking inverse Laplace transform for the above equations, we get a set of seven differential equations. These are the time-domain equations, which describe the small-disturbance dynamic behavior of the power system.

$$(1 + s\tau_{ps1})\,\Delta F_1(s) = K_{ps1}\left[\Delta P_{g1}(s) - \Delta P_{d1}(s) - \Delta P_{TL1}(s)\right]$$

$$s\tau_{ps1}\,\Delta F_1(s) = -\Delta F_1(s) + K_{ps1}\left[\Delta P_{g1}(s) - \Delta P_{d1}(s) - \Delta P_{TL1}(s)\right]$$

$$s\Delta F_1(s) = \frac{1}{\tau_{ps1}}\left\{-\Delta F_1(s) + K_{ps1}\left[\Delta P_{g1}(s) - \Delta P_{d1}(s) - \Delta P_{TL1}(s)\right]\right\}$$

Taking the inverse Laplace transform of the above equation, we get

$$\frac{d}{dt}[\Delta F_1] = \frac{1}{\tau_{ps1}}\{-\Delta F_1 + K_{ps1}\,\Delta P_{g1} - K_{ps1}\Delta P_{d1} - K_{ps1}\Delta P_{TL1}\}$$

In a similar way, the remaining equations can be rearranged and an inverse Laplace transform is found. Then, the entire set of differential equations is

$$\frac{d}{dt}[\Delta F_2] = \frac{1}{\tau_{ps2}}\{-\Delta F_2 + K_{ps2}\,\Delta P_{g2} - K_{ps2}\Delta P_{d2} - K_{ps2}\Delta P_{TL1}a_{12}\}$$

$$\frac{d}{dt}(\Delta X_{E1}) = \frac{1}{\tau_{sg1}}[-\Delta X_{E1} + \Delta P_{C1} - \Delta F_1/R_1]$$

$$\frac{d}{dt}(\Delta X_{E2}) = \frac{1}{\tau_{sg2}}[-\Delta X_{E2} + \Delta P_{C2} - \Delta F_2/R_2]$$

$$\frac{d}{dt}(\Delta P_{G1}) = \frac{1}{\tau_{t1}}[-\Delta P_{G1} + \Delta X_{E1}]$$

$$\frac{d}{dt}(\Delta P_{G2}) = \frac{1}{\tau_{t2}}[-\Delta P_{G2} + \Delta X_{E2}]$$

$$\frac{d}{dt}(\Delta P_{TL1}) = 2\pi\, T_{12}\,[\Delta F_1 - \Delta F_2]$$

The state variables are a minimum number of those variables, which contain sufficient information about the past history with which all future states of the system can be determined for known control inputs. For the two area system under consideration, the state variables would be Δf1, Δf2 , ΔXE1 , ΔXE2 , ΔPsg1 , ΔPsg2 and ΔPTL1 ; seven in number. Denoting the above variables by x1, x2, x3, x4, x5, x6, and x7 and arranging them in a column vector as

$$\overline{X} = \begin{bmatrix} x_1 \\ x_2 \\ x_3 \\ x_4 \\ x_5 \\ x_6 \\ x_7 \end{bmatrix} = \begin{bmatrix} \Delta F_1 \\ \Delta F_2 \\ \Delta X_{E1} \\ \Delta X_{E2} \\ \Delta P_{sG1} \\ \Delta P_{sG2} \\ \Delta P_{TL1} \end{bmatrix}$$

Where X is called a state vector

The control variables ΔPc1 and ΔPc2 are denoted by the symbols u1 and u2, respectively, as

$$\overline{u} = \begin{bmatrix} u_1 \\ u_2 \end{bmatrix} \equiv \begin{bmatrix} \Delta P_{c1} \\ \Delta P_{c2} \end{bmatrix}$$

where u is called the control vector

The disturbance variables ΔPD1 and ΔPD2, since they create perturbations in the system, are denoted by p1 and p2, respectively, as

$$\overline{p} = \begin{bmatrix} p_1 \\ p_2 \end{bmatrix} \equiv \begin{bmatrix} \Delta P_{D1} \\ \Delta P_{D2} \end{bmatrix}$$

where P is called the disturbance vector

The above state equations can be written in a matrix form as

$$\begin{bmatrix} \dot{x}_1 \\ \dot{x}_2 \\ \dot{x}_3 \\ \dot{x}_4 \\ \dot{x}_5 \\ \dot{x}_6 \\ \dot{x}_6 \end{bmatrix} = \begin{bmatrix} \frac{1}{\tau_{ps1}} & 0 & 0 & 0 & \frac{K_{ps1}}{\tau_{ps1}} & 0 & -\frac{K_{ps1}}{\tau_{ps1}} \\ 0 & -\frac{1}{\tau_{ps2}} & 0 & 0 & 0 & \frac{K_{ps2}}{\tau_{ps2}} & -\frac{K_{ps1}}{\tau_{ps1}} \\ -\frac{1}{R_1\tau_{sg1}} & 0 & -\frac{1}{\tau_{sg1}} & 0 & 0 & 0 & 0 \\ 0 & -\frac{1}{R_2\tau_{sg2}} & 0 & -\frac{1}{\tau_{sg2}} & 0 & 0 & 0 \\ 0 & 0 & -\frac{1}{\tau_{t1}} & 0 & -\frac{1}{\tau_{t1}} & 0 & 0 \\ 0 & 0 & 0 & \frac{1}{\tau_{t2}} & 0 & -\frac{1}{\tau_{t2}} & 0 \\ 2\pi T_{12} & -2\pi T_{12} & 0 & 0 & 0 & 0 & 0 \end{bmatrix} \begin{bmatrix} x_1 \\ x_2 \\ x_3 \\ x_4 \\ x_5 \\ x_6 \\ x_7 \end{bmatrix}$$

$$+ \begin{bmatrix} 0 & 0 \\ 0 & 0 \\ \frac{1}{\tau_{sg1}} & 0 \\ 0 & \frac{1}{\tau_{sg2}} \\ 0 & 0 \\ 0 & 0 \\ 0 & 0 \end{bmatrix} \begin{bmatrix} u_1 \\ u_2 \end{bmatrix} + \begin{bmatrix} -\frac{K_{ps1}}{\tau_{ps1}} & 0 \\ 0 & -\frac{K_{ps1}}{\tau_{ps1}} \\ 0 & 0 \\ 0 & 0 \\ 0 & 0 \\ 0 & 0 \\ 0 & 0 \end{bmatrix} \begin{bmatrix} p_1 \\ p_2 \end{bmatrix} \quad (1)$$

In the present case, their dimensions are (7 × 7), (7 ×2), and (7 × 2), respectively. Equation (2) is a shorthand form of Equation (1), and Equation (1) constitutes the dynamic 'state-variable model' of the considered two-area system.

The differential equations can be put in the above form only if they are linear. If the differential equations are non-linear, then they can be expressed in the more general form as

$$\dot{\overline{X}} = f(\overline{x}, \overline{u}, \overline{p})$$

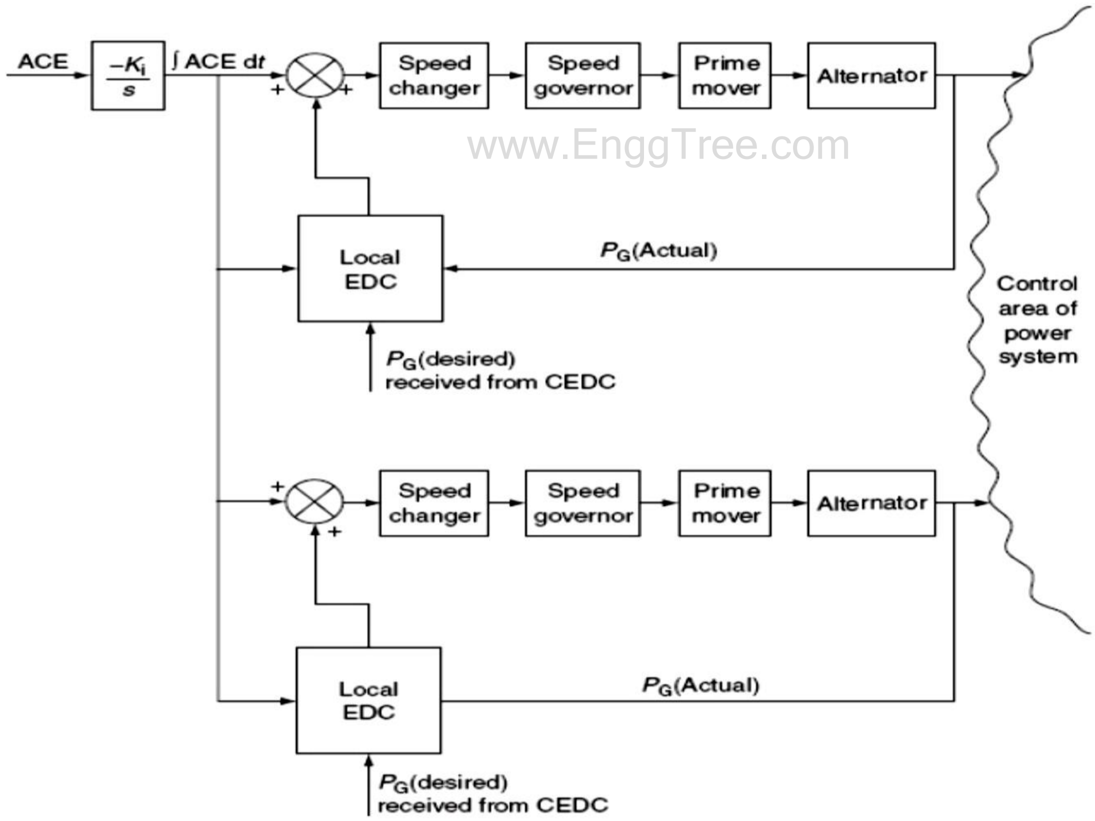
Integration of Economic Dispatch Control with LFC

- Economic load dispatch and LFC play a vital role in modern power system. In LFC, zero steady-state frequency error and a fast, dynamic response wereachieved by integral controller action.
- But this control is independent of economic dispatch, i.e., there is no control over the economic loadings of various generating units of the control area.
- Some control over loading of individual units can be exercised by adjusting the gain factors (K) of the integral signal of the ACE as fed to the individual units. But this is not a satisfactory solution.
- A suitable and satisfactory solution is obtained by using independent controls of load frequency and economic dispatch.
- The load frequency controller provides a fast-acting control and regulates the system around an operating point, whereas the economic dispatch controller provides a slow-acting control, which adjusts the speed-changer settings every minute in accordance with a command signal generated by the central economic dispatch computer.

  EDC—economic dispatch controller

  CEDC—central economic dispatch computer
- The speed-changer setting is changed in accordance with the economic dispatch error signal, (i.e., $P_{G\ desired} - P_{G\ actual}$) conveniently modifiedby the signal $\int$ ACE dt at that instant of time.
- The central economic dispatch computer (CEDC) provides the signal $P_{G\ desired}$, and this signal is transmitted to the local economic dispatch controller (EDC).
  - The system they operate with economic dispatch error is only for very short periods of time before it is readily used
- This tertiary control can be implemented by using EDC and EDC works on the cost characteristics of various generating units in the area.
- The speed-changer settings are once again operated in accordance with an economic dispatch computer program.
- The CEDCs are provided at a central control center. The variable partof the load is carried by units that are controlled from the central control center. Medium-sized fossil fuel units and hydro-units are used for control.

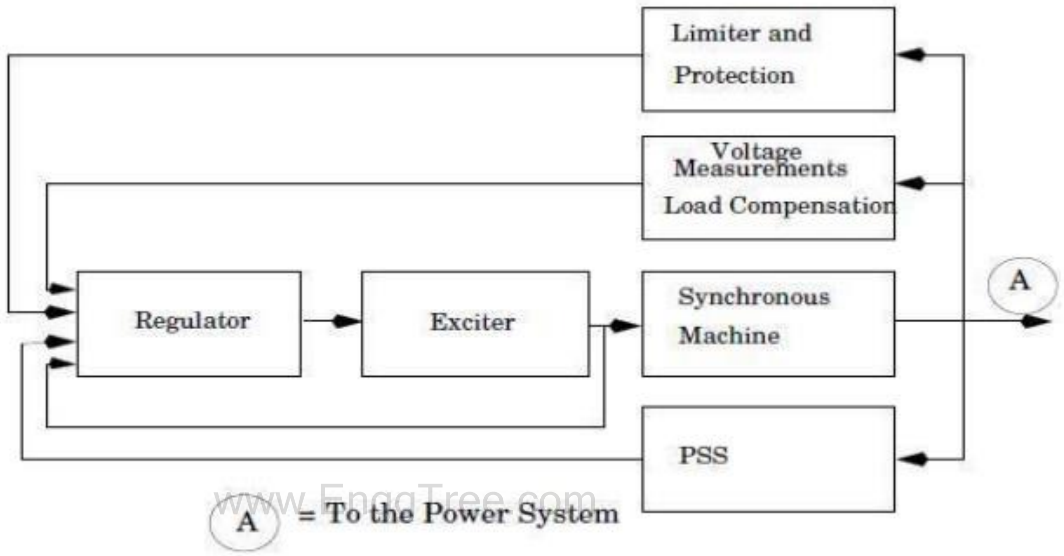
- During peak load hours, lesser efficient units, such as gas-turbine units or diesel units, are employed in addition; generators operating at partial output (with spinning reserve) and standby generators provide a reserve margin.
- The central control center monitors information including area frequency, outputs of generating units, and tie-line power flows to interconnected areas.
- This information is used by ALFC in order to maintain area frequency at its scheduled value and net tie-line power flow out of the area at its shedding value.
- Raise and lower reference power signals are dispatched to the turbine governors of controlled units. Economic dispatch is co-ordinated with LFC such that the reference power signals dispatched to controlled units move the units toward their economic loading and satisfy LFC objectives.



EXCITATION SYSTEMS REQUIREMENTS

- Meet specified response criteria.
- Provide limiting and protective functions are required to prevent damage to itself, the generator, and other equipment.
- Meet specified requirements for operating flexibility
- Meet the desired reliability and availability, by incorporating the necessary level of redundancy and internal fault detection and isolation capability.

1. **ELEMENTS OF EXCITATION SYSTEM**



Schematic picture of a synchronous machine with excitation system with several control, protection, and supervisory functions

Exciter:

- provides dc power to the synchronous machine field winding constituting the power stage of the excitation system.

Regulator:

- Process and amplifies input control signals to a level and form appropriate for control of the exciter.
- This includes both regulating and excitation system stabilizing function.

Terminal voltage transducer and load compensator:

- Senses generator terminal voltage, rectifier and filters it to dc quantity, and compares it with a reference which represents the desired terminal voltage.

Power system stabilizer:

- provides an additional input signal to the regulator to damp power system oscillation.

Limiters and protective circuits:

- These include a wide array of control and protective function which ensure that the capability limits of the exciter and synchronous generator are not exceeded.

TYPES OF EXCITATION SYSTEM

Today, a large number of different types of exciter systems are used. Three main types can be distinguished:

DC excitation system,

- where the exciter is a DC generator, often on the same axis as the rotor of the synchronous machine.

AC excitation system,

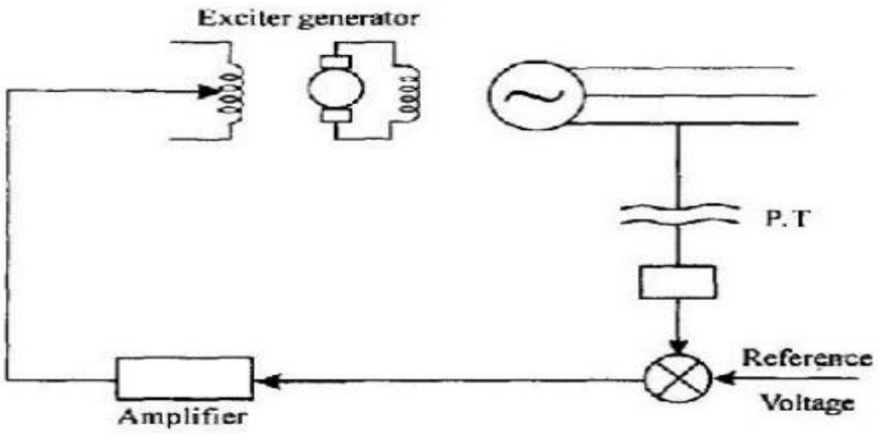
where the exciter is an AC machine with rectifier.

Static excitation system

- where the exciting current is fed from a controlled rectifier that gets its power either directly from the generator terminals or from the power plant‟s auxiliary power system, normally containing batteries.
- In the latter case, the synchronous machine can be started against an unenergised net, "black start". The batteries are usually charged from the net.

Block Schematic of Excitation Control:

➢ A typical excitation control system is shown in Fig.
➢ The terminal voltage of the alternator is sampled, rectified and com pared with a reference voltage; the difference is amplified and fed back to the exciter field winding to change the excitation current.

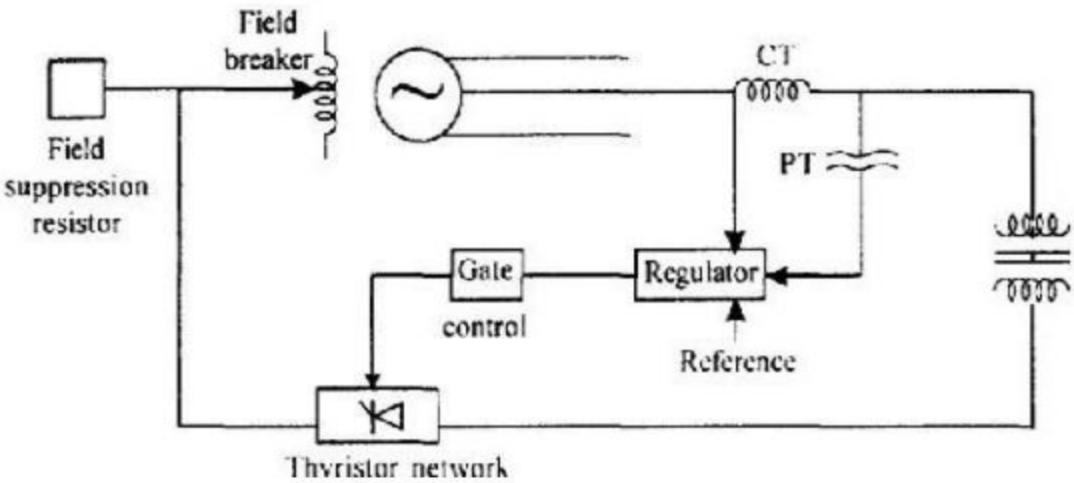


Block Diagram of excitation system

1. STATIC EXCITATION SYSTEM

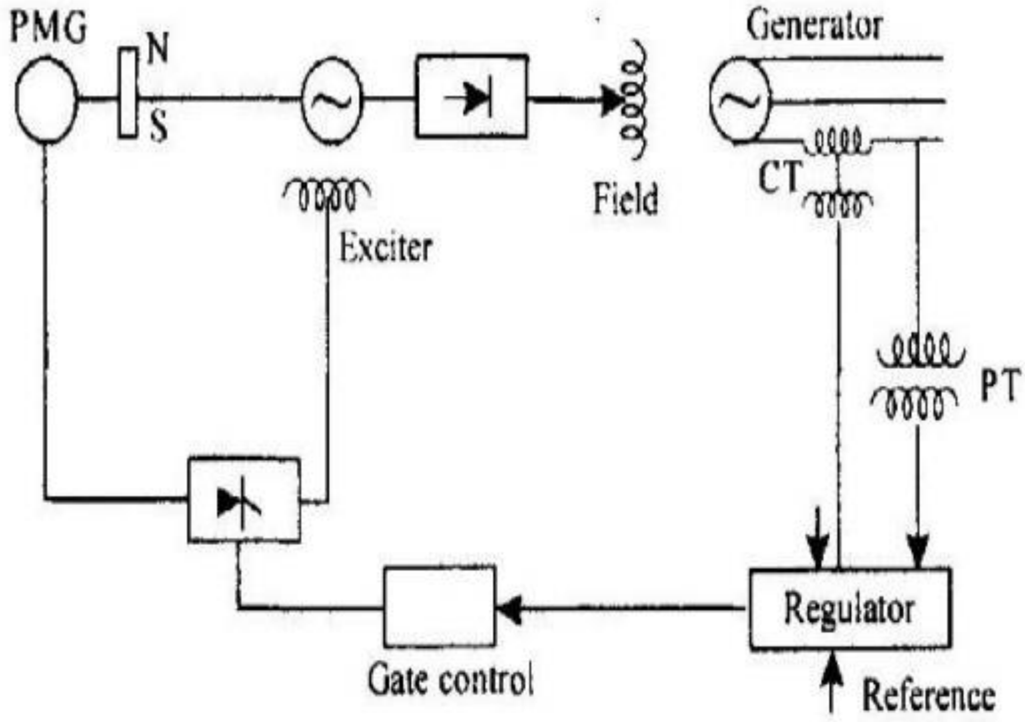
- In the static excitation system, the generator field is fed from a thyristor network shown in Fig.
- It is just sufficient to adjust the thyristor firing angle to vary the excitation level.
- A major advantage of such a system is that, when required the field voltage can be varied through a full range of positive to negative values very rapidly with the ultimate benefit of generator Voltage regulation during transient disturbances.

- The thyristor network consists of either 3-phase fully controlled or semi controlled bridge rectifiers.
- Field suppression resistor dissipates Energy in the field circuit while the field breaker ensures field isolation during generator faults.



Static Excitation System

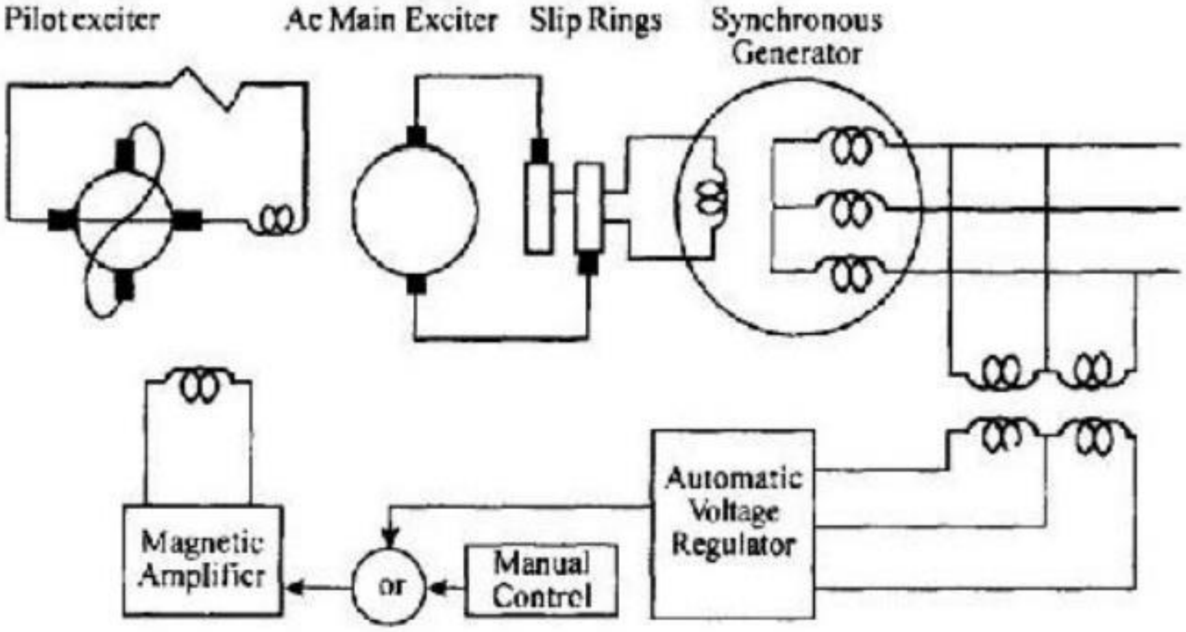
- ## 2. BRUSHLESS EXCITATION SCHEME



Brushless Excitation Scheme

➢ In the brushless excitation system of an alternator with rotating armature and stationary field is employed as the main exciter.
➢ Direct voltage for the generator excitation is obtained by rectification through a rotating, semiconductor diode network which is mounted on the generator shaft itself.
➢ Thus, the excited armature, the diode network and the generator field are rigidly connected in series.
➢ The advantage of this method of excitation is that the moving contacts such as slip rings and brushes are completely eliminated thus offering smooth and maintenance-free operation.
➢ A permanent-magnet generator serves as the power source for the exciter field.
➢ The output of the permanent magnet generator is rectified with thyristor network and is applied to the exciter field.
➢ The voltage regulator measures the output or terminal voltage, compares it with a set reference and utilizes the error signal, if any, to control the gate pulses of the thyristor network.

3. AC EXCITATION SYSTEM



Ac Excitation System

Exciter and Voltage Regulator:

The function of an exciter is to increase the excitation current for voltage drop and decrease the same for voltage rise. The voltage change is defined

$$\Delta V \underline{\Delta} (V_1 - V_{ref})$$

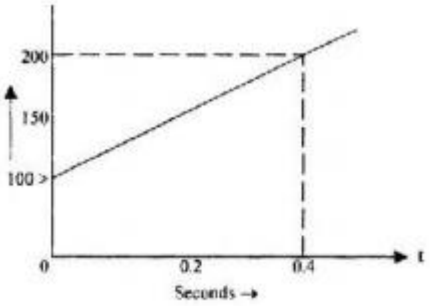
Where V_1 is the terminal voltage and
V_{ref} is the reference voltage.

Exciter ceiling voltage:

- It is defined as the maximum voltage that may be attained by an exciter with specified conditions of load.

Exciter response:

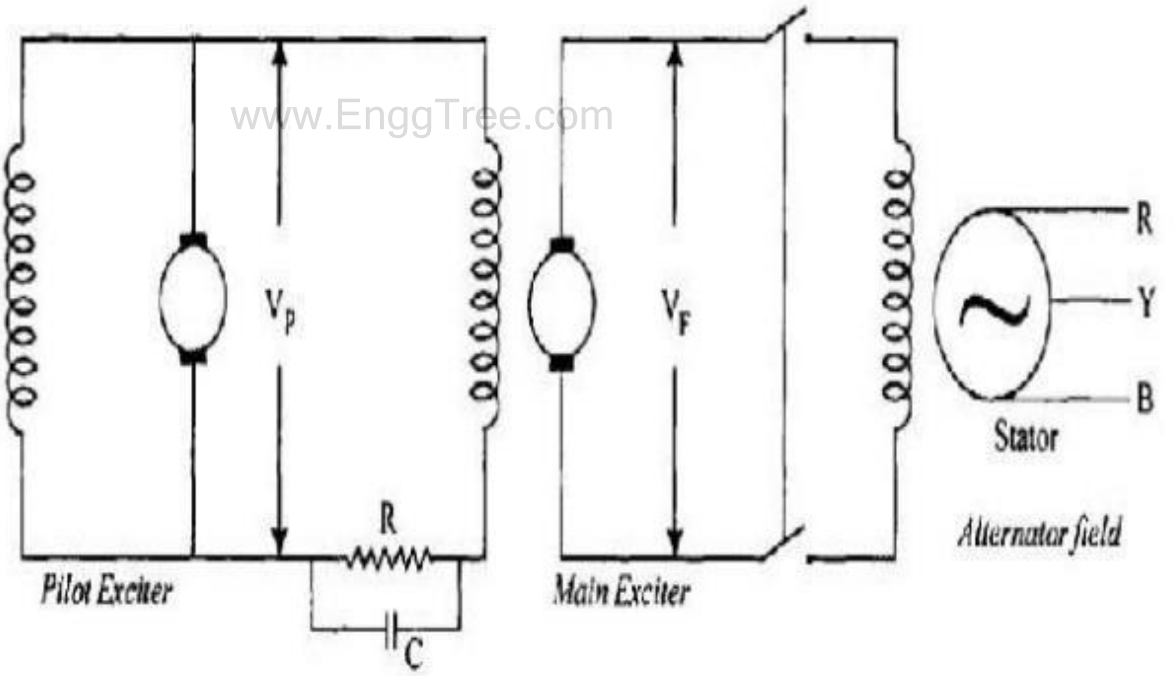
- It is the rate of increase or decrease of the exciter voltage. When a change in this voltage is demanded. As an example consider the response curve shown in Figure.



Exciter Response

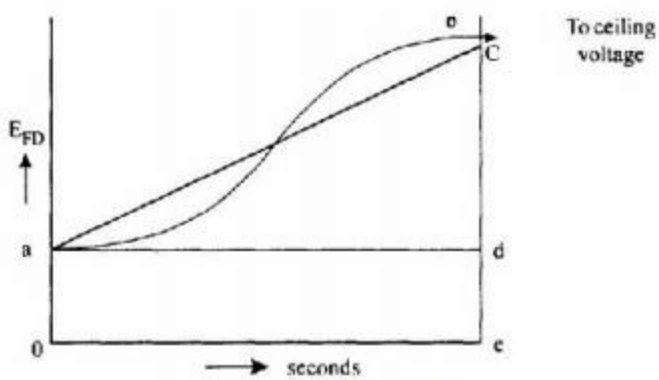
Exciter builds up*:*

- ➢ The exciter build up depends upon the field resistance and the charging of its value by cutting or adding.
- ➢ The greatest possible control effort is the complete shorting of the field rheostat when maximum current value is reached in the field circuit.
- ➢ This can be done by closing the contactor.



AC excitation operations

When the exciter is operated at rated speed at no load, the record of voltage as function of time with a step change that drives the exciter to its ceiling voltage is called the exciter build up curve. Such a response curve is show in Figure.4.14



Response Curve

$$\text{Response ratio} = \frac{Cd}{0a(0.5)}\ \text{p.u.V/sec}$$

Response ratio	Conventional Exciter	SCR exciter
0.5	1.25-1.35	1.2
1.0	1.4-1.5	1.2-1.25
1.5	1.55-1.65	1.3-1.4
2.0	1.7-1.8	1.45-1.55
4.0		2.0-2.1

➢ In general the present day practice is to use 125V excitation up to IOMVA units and 250V systems up to 100MVA units.

➢ Units generating power beyond IOOMVA have excitation system voltages variedly. Some use 350V and 375V system while some go up to 500V excitation system.

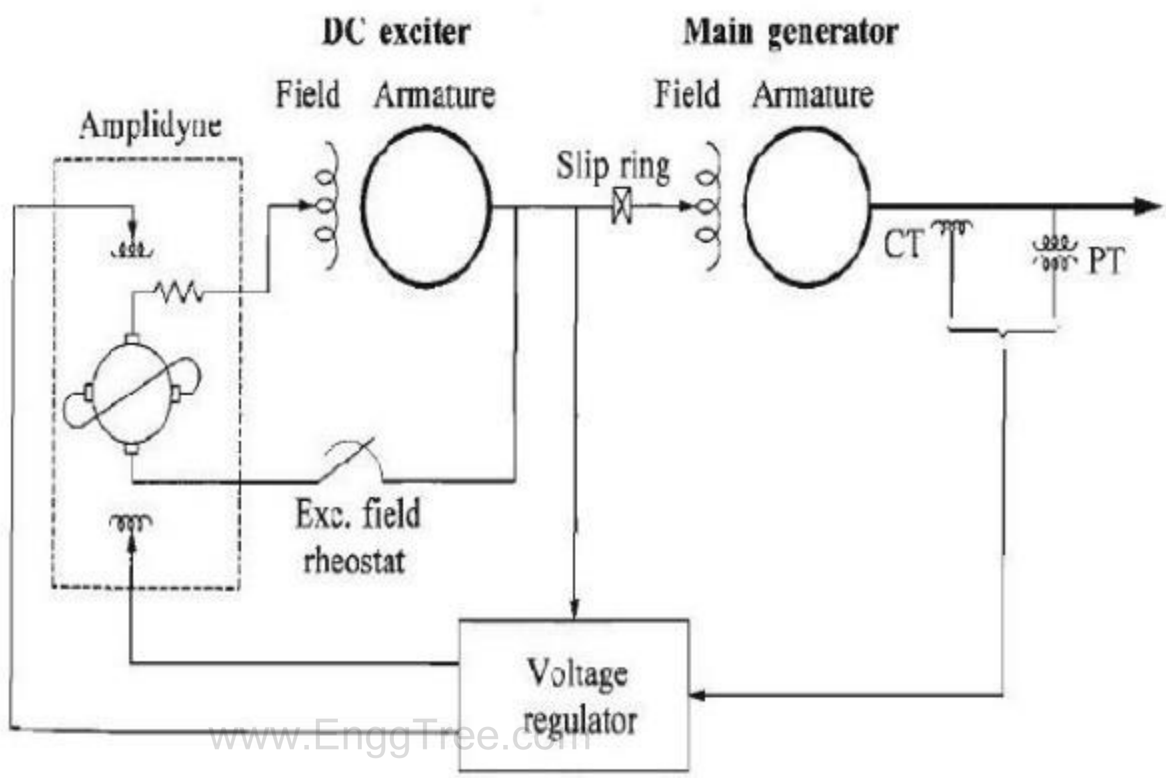
4. DC EXCITATION SYSTEM

➢ The excitation system of this category utilize dc generator as source of excitation power and provide current to the rotor of the synchronous machine through slip ring.

➢ The exciter may be driven by a motor or the shaft of the generator. It may be either self excited or separately excited.

➢ When separately excited, the exciter field is supplied by a pivot exciter comprising a·permanent magnet generator.

➢ Below figure a simplified schematic representation of a typical dc excitation system. It consists of a dc commutator exciter which supplies direct current to the main generator field through slip ring.



DC Excitation System

- ➢ Dc machine having two sets of brush 90 electrical degree apart, one set on its direct
- (d) axis and the other set on its quadrature (q) axis.
- ➢ The control field winding is located on the d axis.
- ➢ A compensating winding in series with the d axis armature current, thereby cancelling negative feedback of the armature reaction.
- ➢ The brushes on the q axis are shorted, and very little control field power is required to produce a large current in the q axis armature.
- ➢ The q axis current is supplied mechanically by the motor.

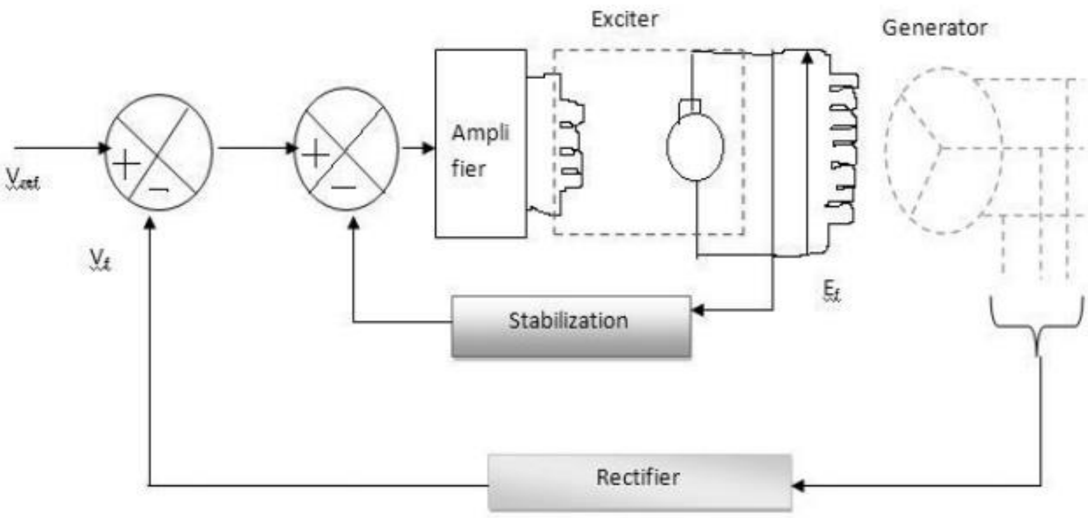
MODELING OF EXCITATION SYSTEM

- Mathematical model of excitation system are essential for the assessment of desired performance requirement, for the design and coordination of supplementary control and protective circuits, and for system stability studies related to the planning and purpose of study.

Generator Voltage Control System

- The voltage of the generator is proportional to the speed and excitation (flux) of the generator.
- The speed being constant, the excitation is used to control the voltage.
- Therefore, the voltage control system is also called as excitation control system or automatic voltage regulator (AVR).
- For the alternators, the excitation is provided by a device (another machine or a static·device) called exciter.

- For a large alternator the exciter may be required to supply a field current of as large as 6500A at 500V and hence the exciter is a fairly large machine.
- Depending on the way the dc supply is given to the field winding of the alternator
- (which is on the rotor), the exciters are classified as:
  - i) DC Exciters;
  - ii) AC Exciters; and
  - iii) Static Exciters.
- Accordingly, several standard block diagrams are developed by the IEEE working group to represent the excitation system.



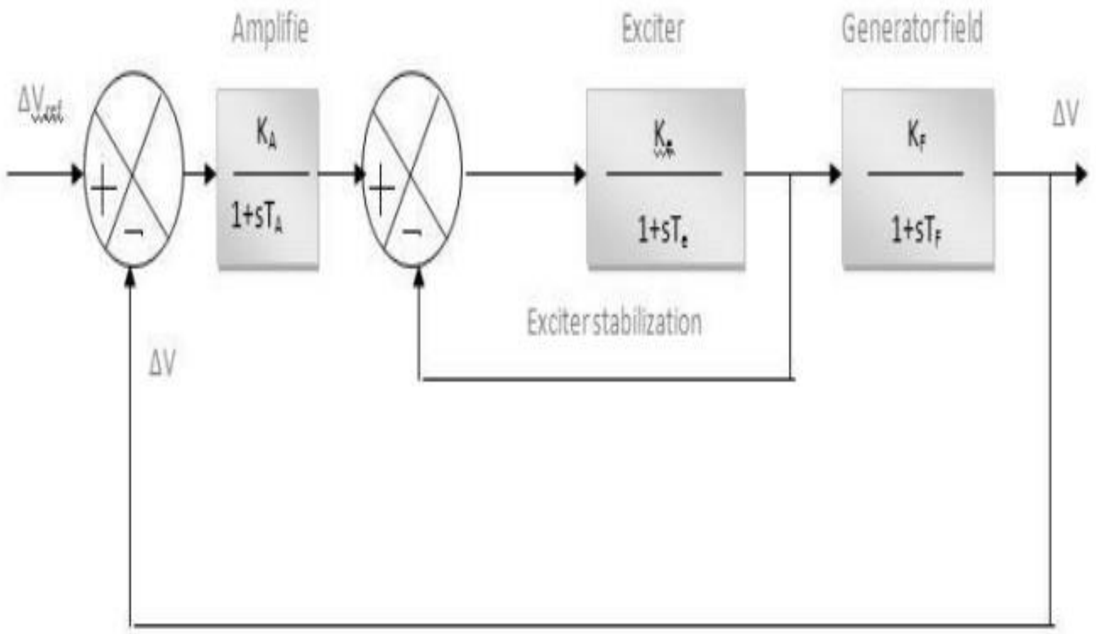
A schematic of Excitation (Voltage) Control System.

- A simplified block diagram of the generator voltage control system .
- The generator terminal voltage Vt is compared with a voltage reference Vref to obtain a voltage error signal ΔV.

- This signal is applied to the voltage regulator shown as a block with transfer function KA/ (1+TAs).
- The output of the regulator is then applied to exciter shown with a block of transfer function Ke/ (1+Tes).
- The output of the exciter Efd is then applied to the field winding which adjusts the generator terminal voltage.
- The generator field can be represented by a block with a transfer function KF/(1+sTF). The total transfer function

$$\frac{\Delta V}{\Delta V_{re}} = \frac{G(s)}{1+G(s)} \quad \text{Where,} \quad G(s) = \frac{K_A K_e K_F}{(1+sT_A)(1+sT_e)(1+sT_F)}$$

The stabilizing compensator shown in the diagram is used to improve the dynamic response of the exciter. The input to this block is the exciter voltage and the output is a stabilizing feedback signal to reduce the excessive overshoot.



A simplified block diagram of Voltage (Excitation) Control System.

Performance of AVR loop

- The purpose of the AVR loop is to maintain the generator terminal voltage within acceptable values.
- A static accuracy limit in percentage is specified for the AVR, so that the terminal voltage is maintained within that value.
- For example, if the accuracy limit is 4%, then the terminal voltage must be maintained within 4% of the base voltage.

VOLTAGE CONTROL METHOD

1. Reactors

- Inductive reactors absorb reactive power and may be used in circuits, series or shunt connected, while series connected reactors are used to limit fault currents, shunt reactors are used for var control.
- Reactors installed at line ends and intermediate substations can compensate up to 70% of charging power while the remaining 30% power at no-load can be provided by the under excited operation of the generator.
- With increase in load, generator excitation may be increased with reactors gradually cut-out.
- Figure shows some typical shunt reactor arrangements

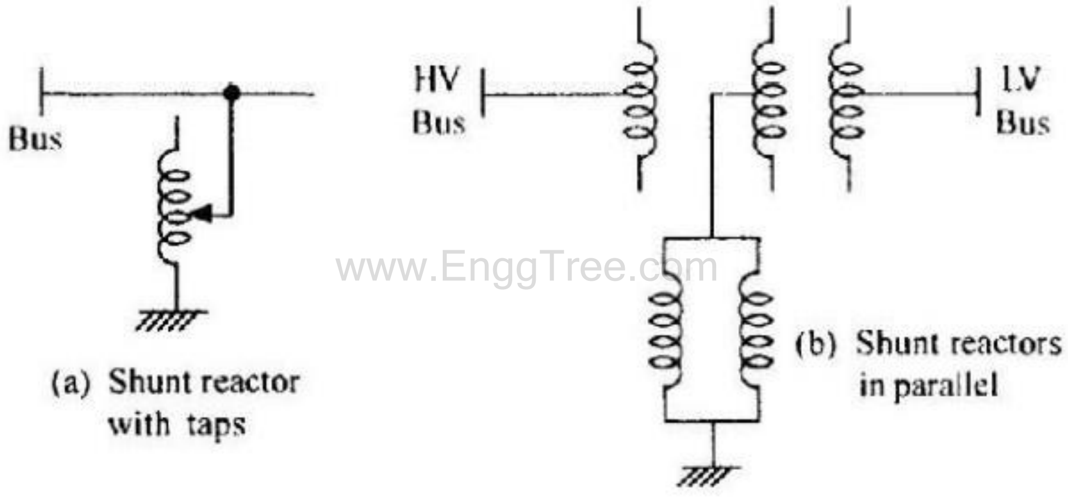
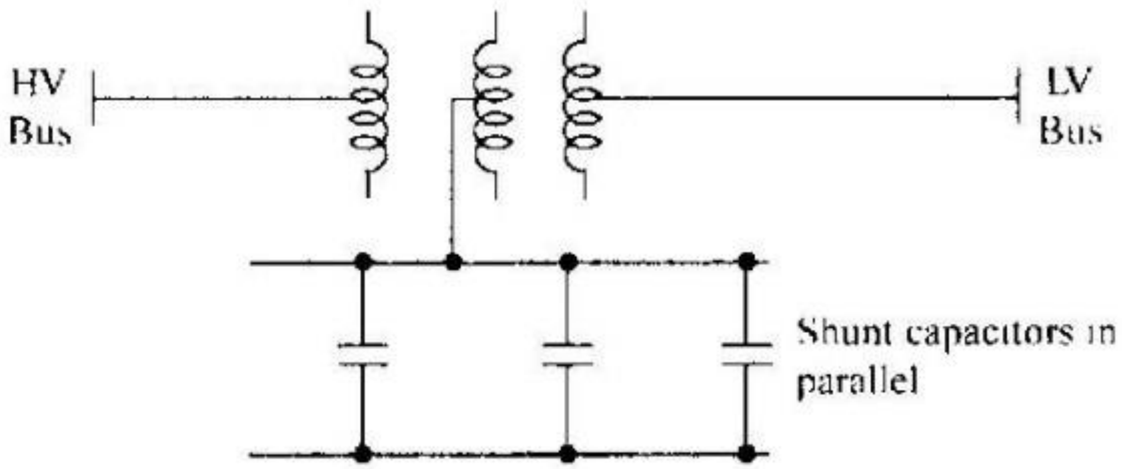


Figure - Typical Shunt Reactor

2. Shunt Capacitors

- Capacitors produce var and may be connected in series or shunt in the system.
- Series capacitors compensate the line reactance in long overhead lines and thus improve the stability limit.
- However, they give rise to additional problems like high voltage transients, sub-synchronous resonance, etc.
- Shunt capacitors are used for reactive compensation.
- Simplicity and low cost are the chief considerations for using shunt capacitor.
- Further, for expanding systems additions can be made.

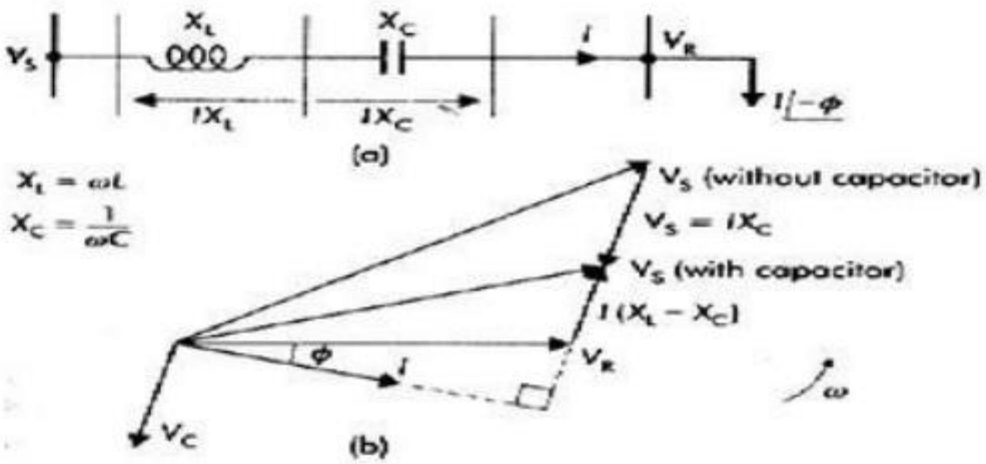
- Fig. shows the connected of shunt capacitors through the tertiary of a transformer.



Shunt capacitor

3. Series capacitors

- Here the capacitors are connected in series with the line.
- The main aim is to reduce the inductive reactance between supply point and the load.
- The major disadvantage of the method is, whenever short circuit current flows through the capacitor, protective devices like spark gaps and non linear resistors are to be in corporate.
- Phasor diagram for a line with series capacitor is shown in the figure (b).



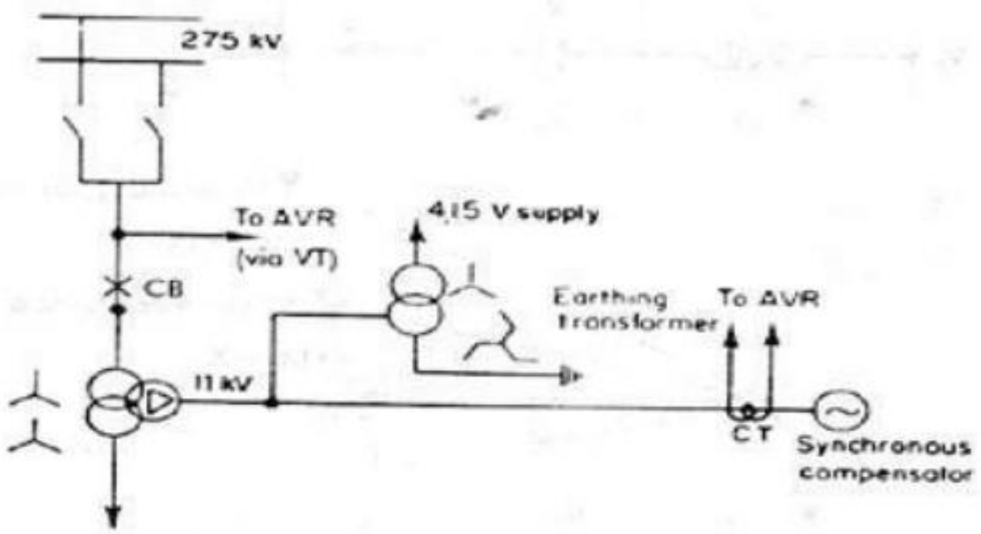
a) Series capacitor b) Phasor diagram

4. Relative merits between shunt and series capacitors.

- If the load var requirement is small, series capacitors are of little help.
- If the voltage drop is the limiting factor, series capacitors are effective; also to some extent the voltage fluctuations can be evened.
- If the total line reactance is high, series capacitors are very effective and stability is improved.
- With series capacitors the reduction in line current is small, hence if the thermal considerations limits the current, little advantage is from this, so shunt compensation is to be used.

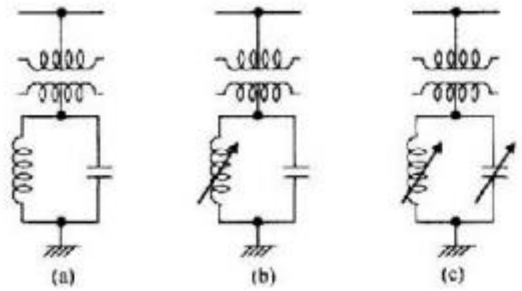
Synchronous compensators:

- A synchronous compensator is a synchronous motor running without a mechanical load and depending on the excitation level; it can either absorb or generate reactive power.
- When used with a voltage regulator the compensator can automatically run overexcited at times of high loads and under excited at light loads.
- A typical connection of a compensator is shown in the figure along with the associated voltage – var output characteristics
- A great advantage of the method is the flexible operation for all load conditions.
- Being a rotating machine, its stored energy is useful for riding through transient disturbances, including voltage drops.



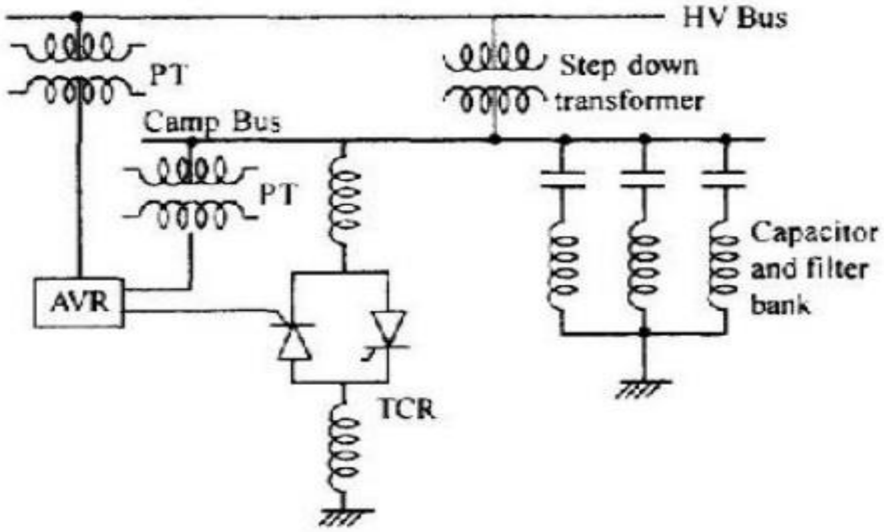
Synchronous Compensator

STATIC VAR COMPENSATORS



Static VAR Compensator

- The term static var compensator is applied to a number of static var compensation devices for use in shunt reactive control.
- These devices consist of shunt connected, static reactive element (linear or non linear reactors and capacitors) configured into a var compensating system.
- Some possible configurations are shown in above Figure.
- Even though the capacitors and reactors in are shown in figure connected to the low voltage side of a down transformer, the capacitor banks may be distributed between high and low voltage buses.
- The capacitor bank often includes, in part, harmonic filters which prevent the harmonic currents from flowing in the transformer and the high voltage system.
- Filters for the 5th and 7th harmonics are generally provided.
- The thyristor controlled reactor (TCR) is operated on the low voltage bus.
- In another form of the compensator illustrated in Figure the reactor compensator is connected to the secondary of a transformer.

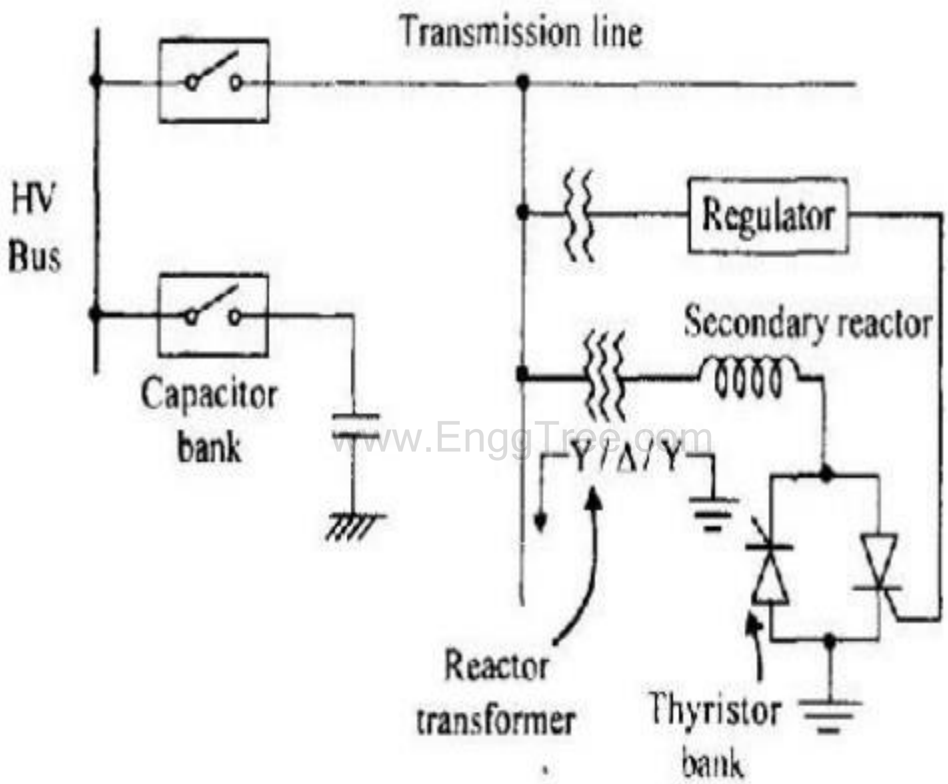


Reactor Compensator

- With this transformer, the reactive power can be adjusted to anywhere between 10% to the rated value.
- With a capacitor bank provided with steps, a full control range from capacitive to inductive power can be obtained.
- The reactor's transformer is directly connected to the line, so that no circuit breaker is needed.
- The primary winding is star connected with neutral grounded, suitable to the thyristor network.
- The secondary reactor is normally nonexistent, as it is more economical to design the reactor transformer with 200% leakage impedance between primary and secondary windings.
- The delta connected tertiary winding will effectively compensate the triple harmonics.
- The capacitor bank is normally subdivided and connected to the substation bus bar via one circuit breaker per sub bank.
- The regulator generates firing pulses for the thyristor network in such a way that the reactive power required to meet the control objective at the primary side of the compensator is obtained.
- The reactor transformer has a practically linear characteristic from no load to full load condition.Thus, even under all stained over voltages; hardly any harmonic content is generated due to saturation.
- The transformer core has non ferromagnetic .Gaps to the required linearity.

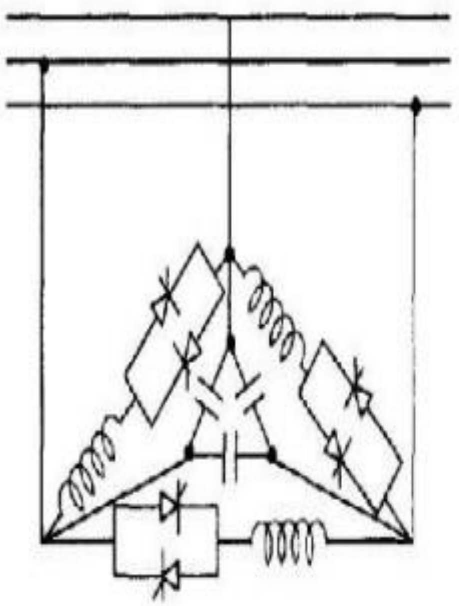
The following requirements are to be borne in mind while designing a compensator.

- Reaction should be possible, fast or slow, whenever demanded. No switching of capacitor should take place at that time to avoid additional transients in the system. Commutation from capacitor to reactor and vice versa should be fast.
- No switching of the capacitors at the high voltage bus bar, so that no higher frequency Transients is produced at EHV level.
- Elimination of higher harmonics on the secondary side and blocking them from entering the system.
- In a three phase system the thyristor controlled inductors are normally delta connected as shown in Figure to compensate unbalanced loads and the capacitors may be star or delta connected



Unbalanced loads

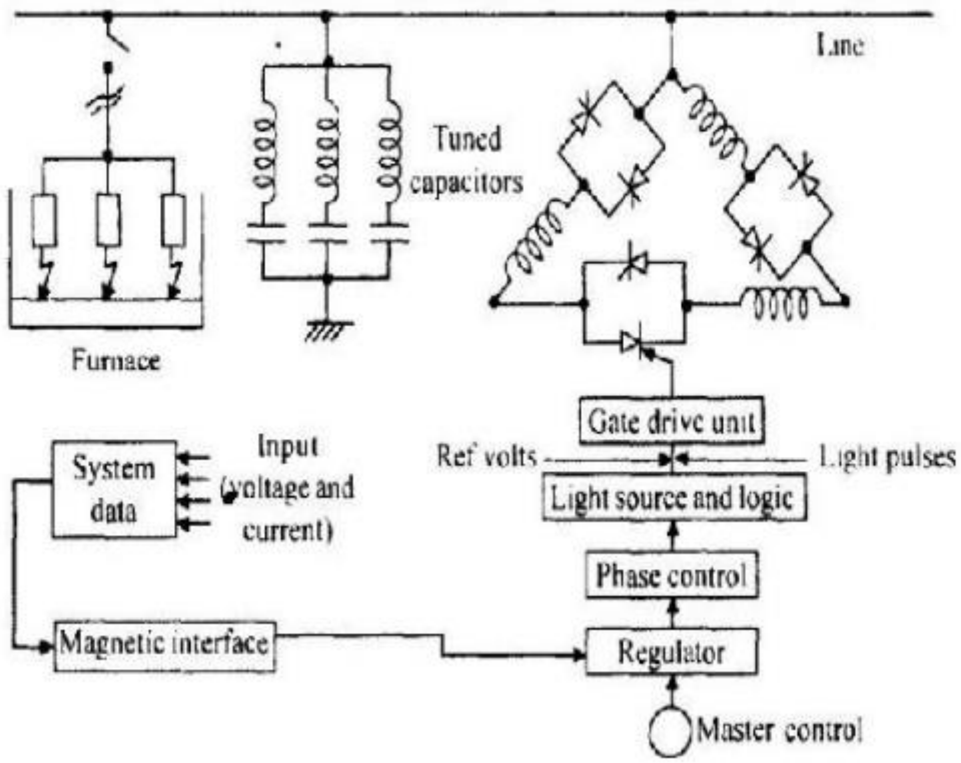
- In the thyristor controlled reactor, the inductive reactance is controlled by the thyristors.
- For a limited range of operation the relationship between the inductive current i_L and the applied voltage V is represented in Figure. As the inductance is varied, the susceptance varies over a range within the limits B_{Lmin} and B_{Lmax} (corresponding to X_{Lmax} and X_{Lmin}) while the voltage Changes by v volts.



Fixed capacitor, thyristor controlled inductor type var compensator

Unbalanced loads

- The current flowing in the inductance would be different in each half cycle, varying with the conduction angle such that each successive half cycle is a smaller segment of a sine wave.
- The fundamental component of inductor current is then reduced to each case.
- Quick control can be exercised within one half cycles, just by giving a proper step input to the firing angle control Static var compensators when installed reduce the voltage swings at the rolling mill and power system buses in drive system applications.
- They compensate for the average reactive power requirements and improve power factor.
- Electric arc furnaces impose extremely difficult service requirements on electrical power systems since the changes in arc furnace load impedance are rapid. Random and non symmetrical.
- The three phases of a static var compensator can be located independently so that it compensates for the unbalanced reactive load of the furnace and the thyristor controller will respond quickly in order to minimize the voltage fluctuations or voltage flicker seen by the system.



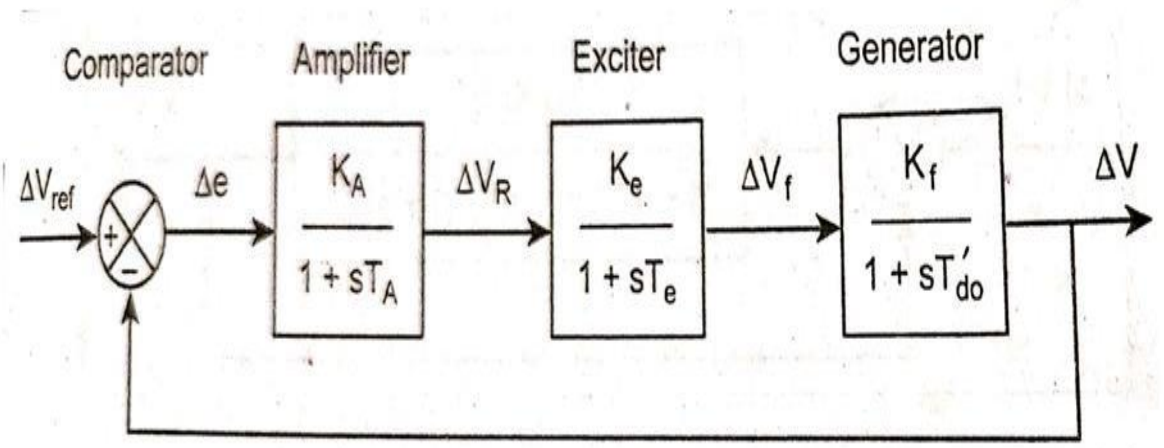
Application of the static VAR compensator

- Thus, the furnace characteristics are made more acceptable to the power system by the static var compensator.
- Above figure shows the application of the static var compensator to an arc furnace installation for reactive power compensation at the HV bus level.

STATIC ANALYSIS OF AUTOMATIC VOLTAGE REGULATOR LOOP

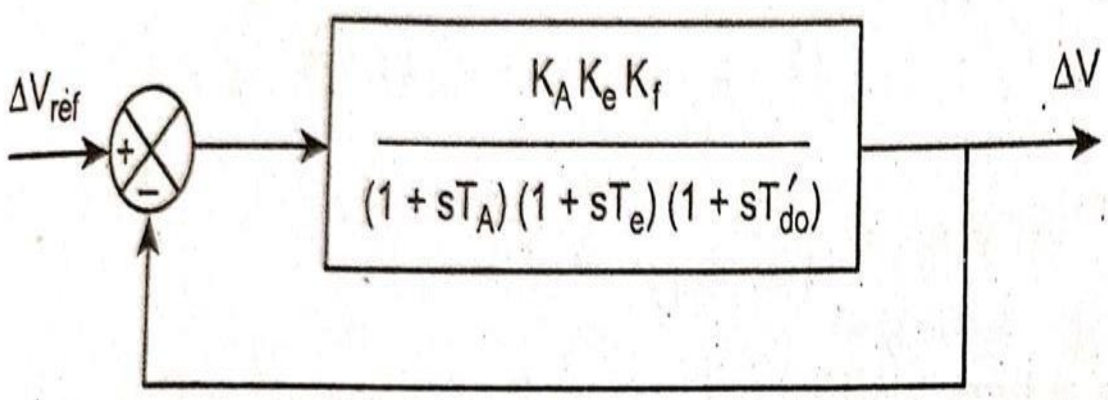
- The automatic voltage regulator must regulate the terminal voltage |V| within the required static accuracy limit.
- It must have sufficient speed response.
- It must be stable.

The block diagram of AVR is as shown in Fig.



Initial error, $\Delta e_0 = \Delta|V|ref_0 - \Delta |V|_0$

Open loop T.F, $G(s) = \frac{K_A \quad K_e \quad K_f}{(1 + sT_A) \ (1 + sT_e) \ (1 + sT^{F}_{d0})}$



At initial condition, $\Delta |V|_0 = \frac{G(s)}{1 + G(s)} \Delta|V|_{ref0}$ ....(1)

Δe_0 must be less than some specified percentage P of reference voltage $\Delta|V|_{ref0}$. The static accuracy specification is :

$\therefore \Delta e_0 < \frac{P}{100} \Delta|V|_{ref0}$ ....(2)

For a constant input, the transfer function is obtained by setting s=0

Substituting equation (1) in (2) we get,

$$\Delta e_0 = (\Delta|V|_{ref0}) - (\frac{G(s)}{1 + G(s)} \Delta|V|_{ref0})$$

$$\Delta e_0 = \Delta|V|_{ref0} [\frac{1}{1 + G(s)}]$$

Putting S = 0,

$$\Delta e_0 = (\Delta|V|_{ref0}) [\frac{1}{1 + \lim_{s\to 0} G(s)}] = \frac{\Delta|V|_{ref0}}{1 + k_p}$$

Position error constant, $K_p = \lim_{s\to 0} G(S)$

$$K_p = \lim_{s\to 0} G(S)$$

$$= \lim_{s\to 0} G(S) = \lim_{s\to 0} \frac{K_A \quad K_e \quad K_f}{(1 + sT_A) \ (1 + sT_e) \ (1 + sT'_{do})}$$

$$K_p = K_A \quad K_e \quad K_f$$

$$\Delta e_0 = \frac{\Delta|V|_{ref0}}{1 + K}$$

If K increases, Δe_0 decreases, so static error decreases with an increased loop gain.

To find the value of K;

$$\therefore \Delta e_0 < \frac{P}{100} \Delta|V|_{ref0}$$

$$\frac{\Delta|V|_{ref0}}{1 + K} < \frac{P}{100} \Delta|V|_{ref0} \quad = \frac{1}{1 + K} < \frac{P}{100}$$

$$1 + K > \frac{100}{P}$$

$$K > \frac{100}{P} - 1$$

If Δe_0 is less than 1%, K must exceed 99%.

Steady state response for a closed loop Transfer Function

$$\text{Closed loop T.F} = \frac{\Delta V(s)}{\Delta V_{ref}(s)} = \frac{\frac{K_A \ K_e \ K_f}{(1 + sT_A)\ (1 + sT_e)\ (1 + sT'_{d0})}}{1 + \frac{K_A \ K_e \ K_f}{(1 + sT_A)\ (1 + sT_e)\ (1 + sT'_{d0})}}$$

$$\Delta V(s) = \frac{K_A \ K_e \ K_f \Delta V_{ref}(s)}{(1 + sT_A)\ (1 + sT_e)\ (1 + sT'_{d0}) + K_A \ K_e \ K_f}$$

For a step input $\Delta V_{ref}(s) = \frac{1}{s}$

Applying final value theorem,

$$\Delta V_{stat} = \lim_{s \to 0} s\, \Delta V(S)$$

$$\Delta V_{stat} = \lim_{s \to 0} \frac{s \, x \, K_A \ K_e \ K_f \Delta V_{ref}(s) x \frac{1}{s}}{(1 + sT_A)\ (1 + sT_e)\ (1 + sT'_{d0}) + K_A \ K_e \ K_f}$$

$$\Delta V_{stat} = \frac{K_A \ K_e \ K_f}{1 + K_A \ K_e \ K_f}$$

$$\Delta V_{stat} = \frac{K}{1 + K}$$

Dynamic Analysis of AVR Loop

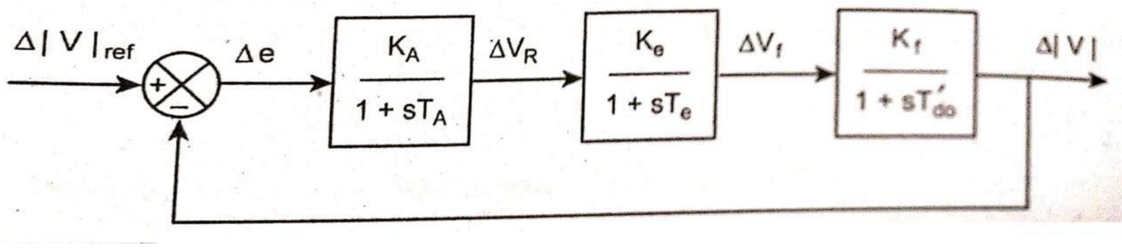


Fig Block diagram of AVR

Open loop T.F $G(s) = \frac{K_A \quad K_e \quad K_f}{(1 + sT_A)\ (1 + sT_e)\ (1 + sT'_{d0})}$

$\Delta V(s) = \frac{G(s)}{1 + G(s)} \Delta V_{ref}(s)$

Taking inverse Laplace transform

$\Delta V(s) = L^{-1} [\Delta V(s)]$

The response depends upon the eigen values or closed loop poles, which are obtained from the characteristic equation
1+ G(s) = 0.

Find roots of characteristic equation [Eigen values] s_1, s_2, s_3 .

Case I : Roots are real and distinct

The open loop transfer function G(s) is of 3rd order. There are three eigen values s_1, s_2, s_3.

$\Delta V(t) = L^{-1} \left[\frac{k_1}{s - s_1} + \frac{k_2}{s - s_2} + \frac{k_3}{s - s_3}\right]$

Transient response $= k_1 e^{s_1 t} + k_2 e^{s_2 t} + k_3\ e^{s_3 t}$

Case II : Two roots (Eigen values) are complex conjugate ($\sigma \pm j\omega$)

The transient response is $Ae^{\sigma t}\sin(\omega t + \beta)$

For AVR loop to be stable, the transient components must vanish with time.

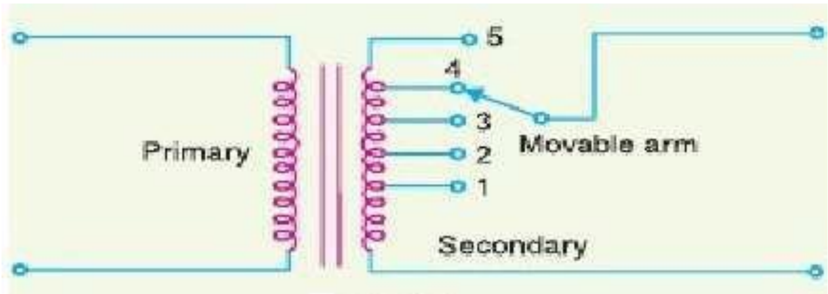
All the eigen values are located in left half of s-plane. Then the loop possesses good tracking ability i.e the system is stable.

For high speed response, the loop possesses eigen values located far away to the left from origin in s-plane.

The closer the eigen value is located to the $j\omega$ axis, the more dominant it becomes.

Tap changing transformer:

- when the movable arm makes contact with lower positions such as 1, the secondary voltage is minimum, during the period of light inductive load
- When the movable arm contact with higher position such as 5 ,the secondary voltage is maximum, during the period of high inductive load



Advantage of tap changing transformer

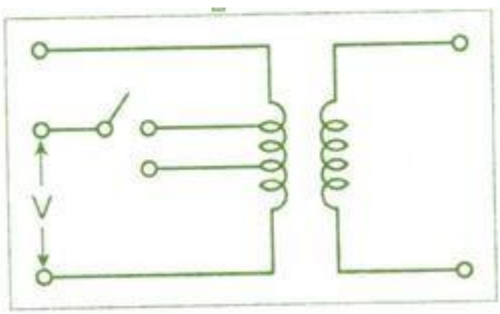
- During high system load conditions, network voltages arekept At highest practical level to minimize reactive power requirements increase effectiveness of shunt capacitors to compensated reactive power
- During light load conditions, it is usually required to lower network voltages avoid under excited operation of generators
- All power transformers on transmission lines are provided with taps for control of secondary voltage. The tap changing transformers do not control voltage by regulating the flow of reactive VARs but by changing transformation ratio.

There are two types of tap changing transformers.

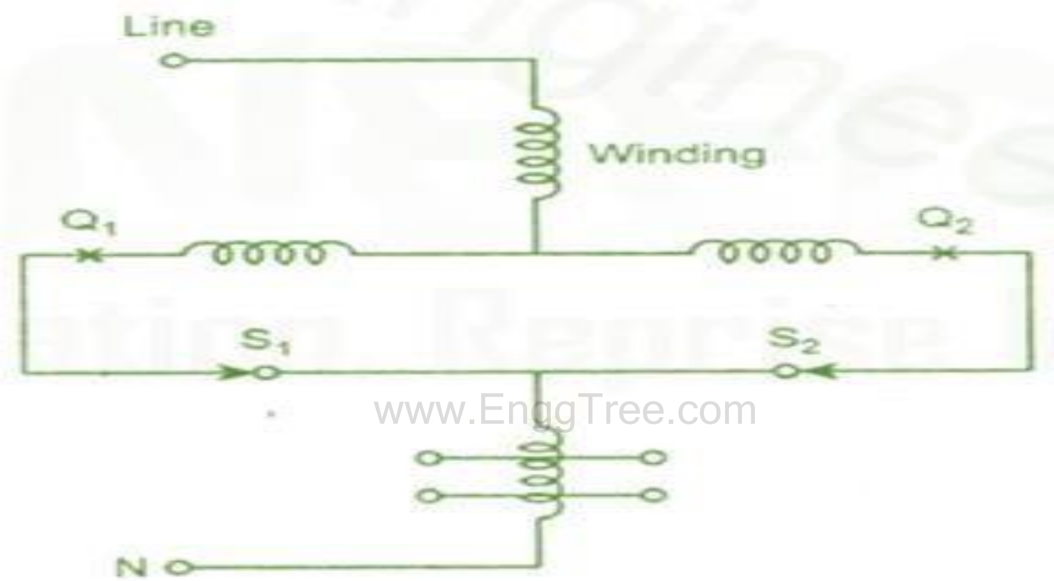
- Off-load tap changing transformers.
- On-load (Under-load) tap changing transformers (OLTC).

Off-load tap changing transformers:

The off-load tap changing transformer as shown in figure which requires the disconnection of the transformer when the tap setting is to be changed. Off-load tap changers are used when it is to be operated in frequently due to load growth or some seasonal change.



- On-load tap changing transformer is used when changes in transformer ratio to be needed frequently, and no need to switch off the transformer to change the tap of transformer.
- It is used on power transformers, auto transformers and bulk distribution transformers and at other points of load service.
- The modern practice is to use on-load tap changing transformer which is shown in figure.
- In the position shown, the voltage is maximum and since the currents divide equally and flow in opposition through the coil between Q1 and Q2, the resultant flux is zero and hence minimum impedance.



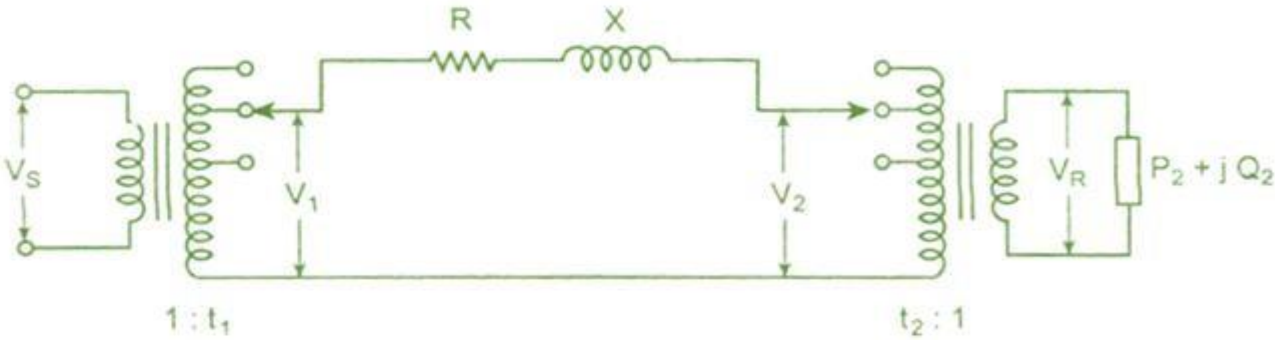
On-load tap changing transformers (OLTC):

- To reduce the voltage, the following operations are required in sequence:
- Open Q1.
- Move selector switch S1 to the next contact. Close Q1.
- Open Q2.
- Move selector switch S2 to the next contact. Close Q2.
- Thus, six operations are required for one change in tap position. The voltage change between taps is often 1.25 % of the nominal voltage.

System Level Control using Generator Voltage Magnitude Setting:

- Transformers transfer the reactive power from one side to another side by altering the inphase component of the system voltage. Let us consider the tap changing transformer at both ends of a line is shown in figure.
- Let t1, t2 be the functions of nominal transformation ratio. i.e., tap ratio/nominal voltage

- The actual voltage will be t1V1 and t2V2. Let V1, V2 be the nominal voltage at the ends of the line. Since, the line has impedance, it is necessary to compensate the voltage drop in the line so that the voltage at the receiving end is maintained at a desired level.



$$t_1|V_1| = t_2|V_2| + \left|\left|P_2R + Q_2X\right|/t_2|V_2|\right|$$

$$t_1|V_1| = \frac{|V_2|}{t_1} + \frac{(P_2R + Q_2X)t_1}{|V_2|}$$

$$t_1|V_1| = \frac{|V_2|^2 + (P_2R + Q_2X)(t_1)^2}{t_1|V_2|}$$

$$(t_1)^2\left[|V_1||V_2| - (P_2R + Q_2X)\right] = |V_2|^2$$

Dividing by we get

$$(t_1)^2\left[1 - \frac{(P_2R + Q_2X)}{|V_1||V_2|}\right] = \frac{|V_2|}{|V_1|}$$

$$(t_1) = \sqrt{\frac{\frac{|V_2|}{|V_1|}}{\left[1 - \frac{(P_2R + Q_2X)}{|V_1||V_2|}\right]}}$$

For complete line drop compensation

$$|V_1| = |V_2|$$

$$(t_1) = \sqrt{\frac{1}{\left[1 - \frac{(P_2R + Q_2X)}{|V_1|^2}\right]}}$$

Sending end voltage,

$$t_1 V_1 = V_S$$

Now ,

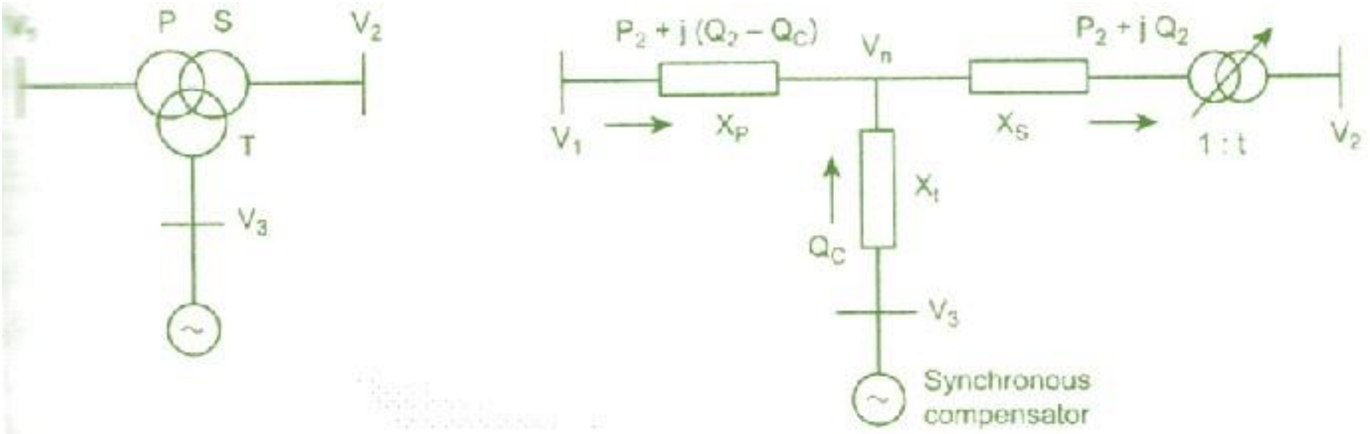
$$t_2 = \frac{1}{t_1}$$

Sending end voltage $V_S = t_1 V_1$

- For a given load, given the nominal voltages, we can find t1 and t2 as to keep V2 constant at a specific value.
- For high line drops, the tap changing transformers do not improve voltage profile because it does not have any reactive power generation capability.
- For small voltage variation or line drop, tap changing transformer is used to improve voltage magnitude of the system.

Combined use of Tap changing Transformers and Reactive Power Injection:

- Normally tap setting are provided in steps for the range of ± 20 %. If the setting exceeds this range, it is necessary to inject VARs at the load end to maintain the voltage profile and to minimize transmission loss.
- A synchronous compensator is connected to the tertiary winding of a three winding transformer as shown in figure.
- The equivalent circuit is shown in figure.



Quadrature voltage drop, $\delta V = \dfrac{P_2(X_P)}{|V_n|}$

$$|V_1|^2 = \left(|V_n| + \triangle V\right)^2 + \delta V^2$$

$$|V_1|^2 = \left[|V_n| + \frac{(Q_2 - Q_C)X_P}{|V_n|}\right]^2 + \left[\frac{P_2 X_P}{|V_n|}\right]$$

$$|V_1|^2 = \left[\frac{|V_n|^2 + (Q_2 - Q_C)X_P}{|V_n|}\right]^2 + \left[\frac{P_2 X_P}{|V_n|}\right]^2$$

$$|V_1|^2|V_n|^2 = |V_n|^4 + 2|V_n|^2(Q_2 - Q_C)X_P + \left[(Q_2 - Q_C)X_P\right]^2 + (P_2)^2(X_P)^2$$

$$|V_n|^4 + 2|V_n|^2\left[2(Q_2 - Q_C)X_P - |V_1|^2\right] + \left[(Q_2 - Q_C)X_P\right]^2 + (P_2)^2(X_P)^2 = 0$$

Solving the above equation, we get $|V_n|$

We can find out off nominal tap setting t,

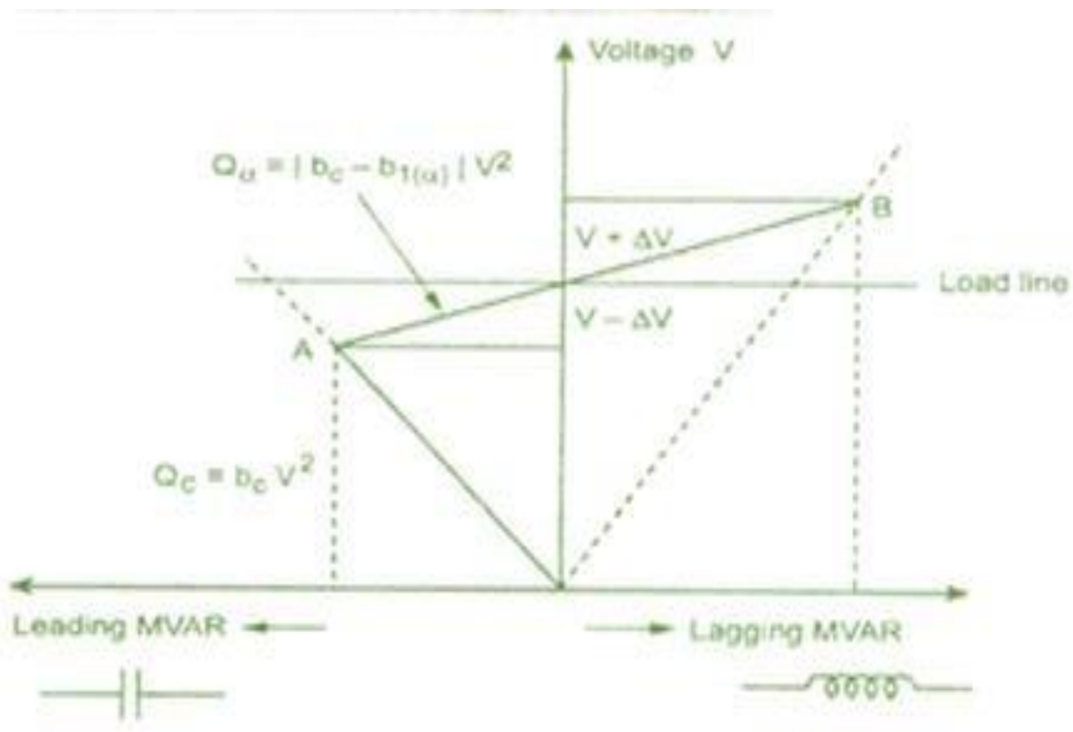
$$t = \frac{|V_2|}{|V_n|}$$

Fixed Capacitor and Thyristor Controlled Reactor [FC – TCR]

- The circuit diagrams of a FC – TCR, with switched filtersare as shown in figure. This arrangement provides discrete leadings VARs from the capacitors and continuously lagging VARs from thyristor controlled reactor.
- The capacitors are used as tuned filters, as considerable harmonics are generated by thyristor control.
- The steady state characteristics of a FC – TCR is shown in figure. The control range is AB with a positive slope, determine by the firing angle control.

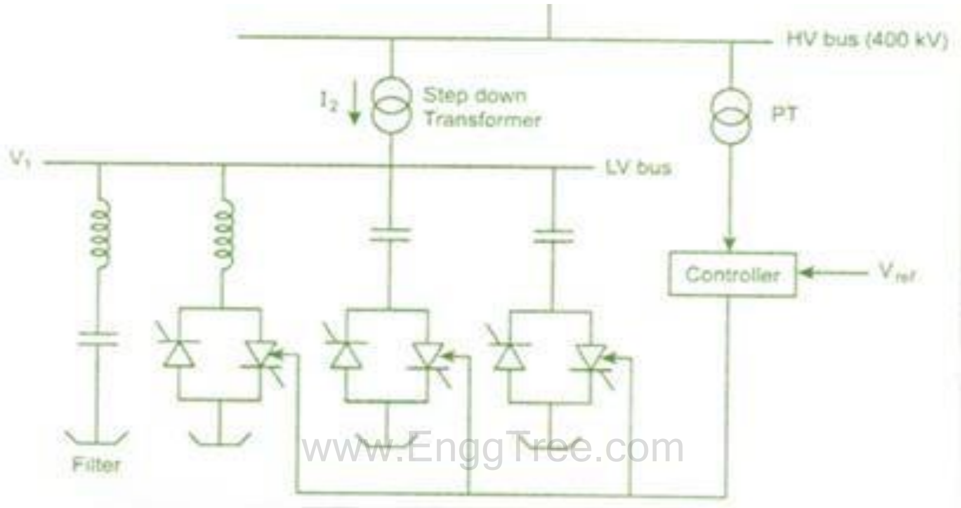
$$Q\alpha = \left| b_c - b_{1(\alpha)} \right| V^2$$

- Where bc is the susceptance of the capacitor, b1(α) isthe susceptance of the inductor at firing angle α.
- As the inductance is varied, the susceptance varies overa large range. The voltage varies within limits V ± ΔV. Outsidethe control interval AB, the FC – TCR acts like an inductor in thehigh voltage range and like a capacitor in the low voltage range.
- The response time is of the order of one or two cycles. The compensator is designed to provide emergency reactive and capacitive loading beyond its continuous steady state rating.



Thyristor Switched Capacitor and Thyristor ControlledReactor [TSC – TCR]

- To control the current through a reactor, with new elements Thyristor Controlled Reactor (TCR) and Thyristor Switched Capacitor (TSC) to meet reactive power generationand absorption demands.
- Improved performance under largesystem disturbance and lower power loss are obtained.

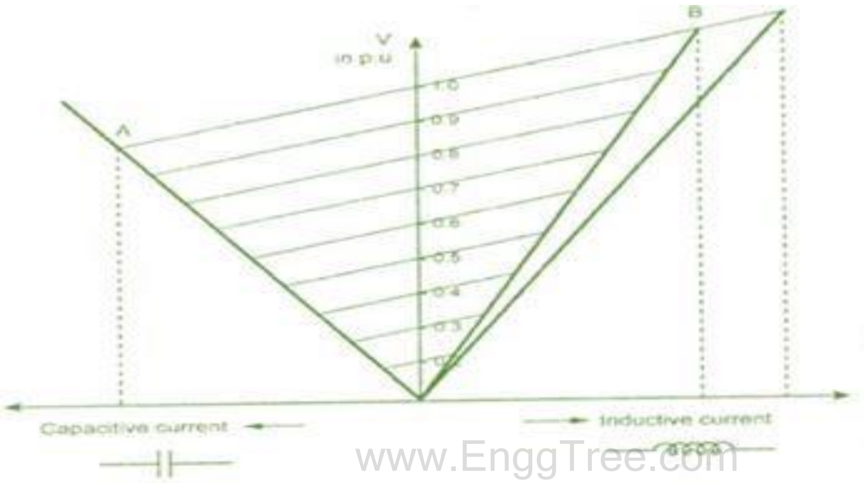


TSC-TCR

- Each thyristor switch is built up from two thyristor stacks connected in anti-parallel.
- Each single phase thyristor switchedcapacitor consists of the capacitor, thyristor switch and reactorto limit the current through the thyristors and to prevent resonance with the network as shown in figure.
- The problem of achieving transient free switching ON ofthe capacitor is overcome by keeping the capacitor charged to the positive or negative peak value, when they are in the stand by state.
- The switching on instinct is then selected at thetime when the network has its maximum or minimum value and the same polarity as the capacitor voltage. Switching of the capacitor is accomplished by separation of the firing pulses to the anti-parallel thyristors so that the thyristors will block as soon as the current becomes zero.
- The capacitor will then remain charged to the positive or negative peak voltage and be prepared for the new transientfree switching on.
- The V-I characteristics is as shown in figure. A certain short time overload capability id

provided both in the maximum inductive and capacitive regions.

- Voltage regulation with a given slope can be achieved in the normal operating range.
- The maximum capacitive current decreases linearly withthe system voltage and the SVC becomes a fixed capacitor when the maximum capacitive output is reached.
- The voltage support capability decreases with decreasein system voltage.



VI characteristics of an SVC (TSC-TCR)

ADVANTAGES

- SVCs are suited to control the varying reactive power demand oflarge fluctuating loads (i.e., rolling mills and arc furnaces).
- It is used in HVDC converter stations for fast control of reactivepower flow.
- The midpoint voltage will vary with the load and an adjustablemidpoint susceptance is required to maintain constant voltagemagnitude.
- The transmitted electrical power can be increased be capacitiveVARs when the machine accelerates and it can be decreased byreactive VARs when the machine decelerates because it has no inertia.
- Less maintenance.
- Possibility to regulate the phases individually

STATCOM

- A STATCOM is a controlled reactive-power source. It provides the desired Reactive-power generation and absorption entirely by means of electronic processing of the voltage and current waveforms in a voltage-source converter (VSC).
- A single-line STATCOM power circuit is shown in Figure(a), where a VSC is connected to a utility bus through magnetic coupling.
- In Figure.(b), a STATCOM is seen as an adjustable voltage source behind a reactance—meaning that capacitor banks and shunt reactors are not needed for reactive-power generation and absorption, thereby giving a STATCOM acompact design, or small footprint, as well as low noise and lowmagnetic impact.
- The exchange of reactive power between the converter and the ac system can be controlled by varying the amplitude of the 3-phase output voltage, Es, of the converter, as illustrated in Figure(c).
- That is, if the amplitude of the output voltage is increased above that of the utility bus voltage, Et, then a current flows through the reactance from the converter to the ac system and the converter generates capacitive- reactive power for the ac system.
- If the amplitude of theoutput voltage is decreased below the utility bus voltage, then the current flows from the ac system to the converter and the converter absorbs inductive-reactive power from the ac system.
- If the output voltage equals the ac system voltage, the reactive-power exchange becomes zero, in which case the STATCOM is said to be in a floating state.
- On the basis of explanations provided in the previous sections it should be clear to the reader that, on the one hand, in the linear operating range the V-I characteristic and functional compensation capability of the STATCOM and the SVC are similar.
- However, the basic operating principles of the STATCOM, which, with a converter based var generator, functions as a shunt-connected synchronous voltage source,are fundamentally different from those of the SVC, which, with thyristor-controlled reactors and thyristor-switched capacitors, functions as a shunt-connected, controlled reactive admittance.
- This basic operational difference (voltage source versus reactive admittance)accounts for the STATCOM's overall superior functional characteristics, better performance, and greater application flexibility than those attainable with the SVC.

- These operational and performance characteristics are summarizedhere, with the underlying physical reasons behind them, and with the corresponding application benefits.

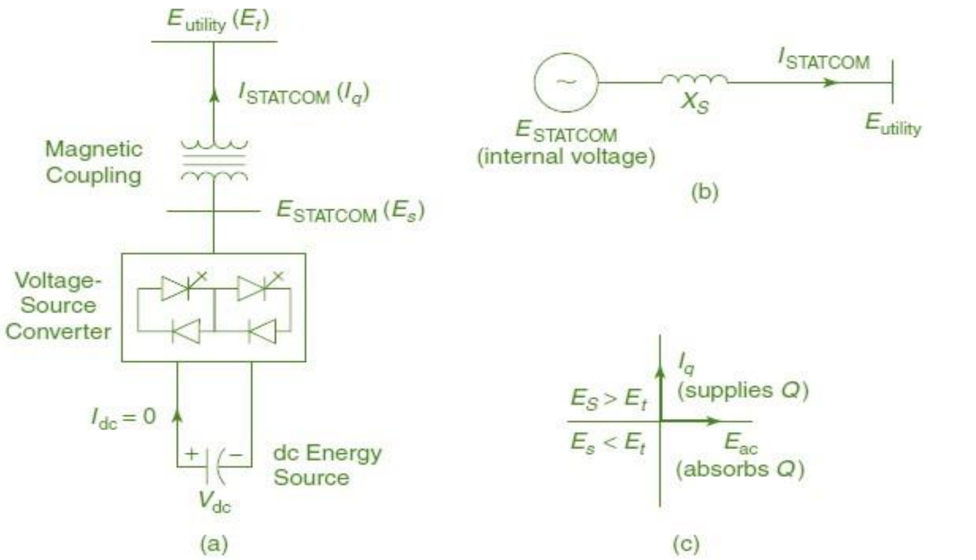


Figure 10.1 The STATCOM principle diagram: (a) a power circuit; (b) an equivalent circuit; and (c) a power exchange.

V-I and V-Q Characteristics

- The STATCOM is essentially an alternating voltage source behind a coupling reactance with the corresponding V-I and V-Q characteristics shown in Figure.
- These show that the STATCOM can be operated over its full output current range even at very low (theoretically zero), typically about 0.2 p.u system voltage levels.
- In other words, the maximum capacitive or inductive output current of the STATCOM can be maintained independently of the ac system voltage , and the maximum var generation or absorption changes linearly with the ac system voltage.
- In contrast to the STATCOM, the SVC, being composedof (thyristor-switched capacitors and reactors, becomes a fixed capacitive admittance at full output.
- Thus, the maximum attainable compensating current of the SVC decreases linearly with ac system voltage, and the maximum var output decreases with the square of this voltage ,as shown in Figures
- (b) and (b), respectively. The STATCOM is, therefore superior tothe SVC in providing voltage support under large system disturbances during which the voltage excursions would be welloutside of the linear operating range of the compensator.

- The capability of providing maximum compensating current.at reduced system voltage enables the STATCOM to perform in a variety of applications the same dynamic compensation as an SVC of considerably higher rating.

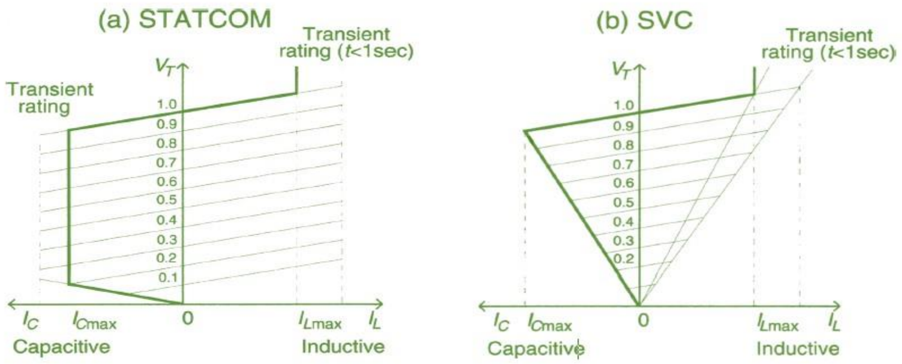


Figure 5.59 *V-I* characteristic of the STATCOM (a) and of the (SVC) (b).

ECONOMIC OPERATION OF POWER SYSTEM

- A power system has several power plants. Each power plant has several generating units.
- At any point of time, the total load in the system is met by the generating units in different power plants.
- Economic dispatch control determines thepower output of each power plant and power output of each generating units within a power plant, which will maximize the overall cost of the fuel needed to serve the system load.
- The factors considered by the load dispatcher are when to interchange energy from one station to another station, how much energy to interchange, the cost of supplying energy to the interconnection, the cost of received energy fromthe interconnection.
- The other factors affecting the economy of operation arevariation fuel cost, labour cost, and weather conditions, normal and emergency equipment rating, reserve requirements, voltage limitations, characteristic's of prime moves, transmission losses etc.,
- The main economic factor in power system operation is the cost ofgenerating real power.
- The main factor controlling the most desirable load allocationbetween the various generating units is the total cost.
- Interconnected power system is the more reliable, convenient to operate and offers economical operating cost.
- Forthe purpose of economy interchange so it is necessary to consider not only the incremental fuel cost but also the incremental transmission loss for the optimum economy. The economic system operation is necessary because
- In many cases economic factors and the availability of primary essentials such as coal, water etc., it indicates that new generating plants is located at greater distances from the load Centres
- Power systems are in interconnecting for purpose of economy interchange and reduction of reserve capacity In a number of areas of the country, the cost of fuel is rapidly increasing.

Statement of Economic Dispatch Problem:

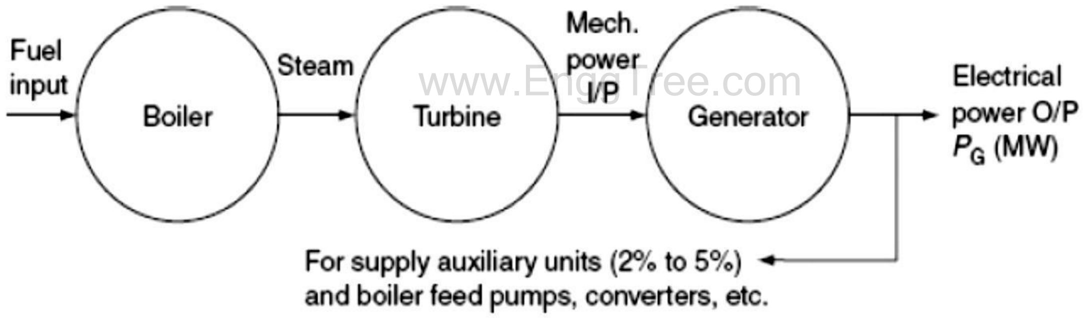
- The complexity of interconnections and the size of the areas of electric power systems that are controlled in a coordinated way is rapidly increasing.
- This entails optimal allocation of the outputs of a large number of participating generators.
- Whether a generator should participate in sharing the load at a given interval of time is a problem of unit commitment.
- Once the unit commitment problem has been solved, it becomes a problem of optimal allocation of the available generations to meet the forecasted load demand for the current interval.
- At a modern-day energy management center, highly developed optimization techniques are used to determine not only the optimaloutputs of the participating generators, but also the optimal settings of various control devices such as the tap settings of load tap changers (LTCs), outputs of VAR compensating devices, desired settings of phase shifters etc.
- The desired objective for such optimization problems can be many, such as the

minimization of the cost of generation, minimization of the total power loss in the system, minimization of the voltage deviations, and maximization of the reliability of the power supplied to the customers.

- One or more of these objectives can be considered while formulating the optimization strategy.
- Determination of the realpower outputs of the generators so that the total cost of generation in the system is minimized is traditionally known as the problem of economic load dispatch (ELD).

Input and Output Characteristics of Thermal Plant

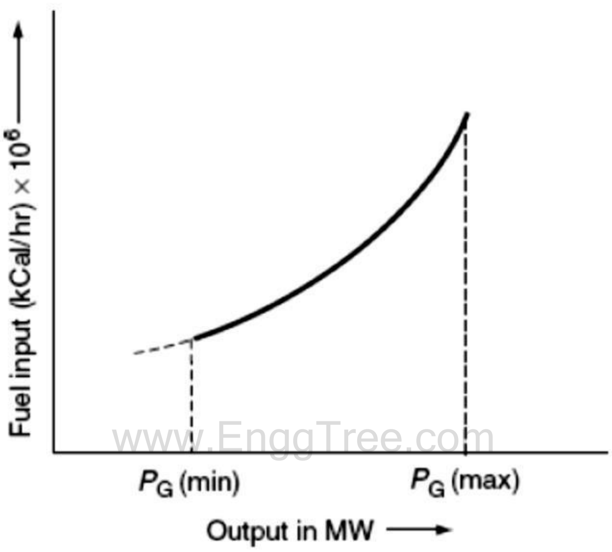
- In analysing the economic operation of a thermal unit, input–output modeling characteristics are significant.
- For this function, consider a single unit consisting of a boiler, a turbine, and a generator as shown in Fig This unit has tosupply power not only to the load connected to the power system but also to the local needs for the auxiliaries in the station, which may vary from 2%to 5%.
- The power requirements for station auxiliaries are necessary to drive boiler feed pumps, fans and condenser circulating water pumps, etc The total input to the thermal unit could be British thermal unit (Btu)/hr or Cal/hr in terms of heat supplied or Rs./hr in terms of the cost of fuel (coal or gas).
- The total output of the unit at the generator bus will be either kW or MW



- To analyze the power system network, there is a need of knowing thesystem variables. They are:
- Control variables - real and reactive-power generations
- Disturbance variables - real and reactive-power demands
- State variables - bus voltage magnitude V and its phase angle δ
- Scheduling is the process of allocation of generation among different generating units.
- Economic scheduling is a cost-effective mode of allocation of generation among the different units in such a way that the overall cost of generation should be minimum.
- This can also be termed as an optimal dispatch
- Let the total load demand on the station = P_D and the total number ofgenerating units = n.
- The optimization problem is to allocate the total load P_D among these ‗n' units

in an optimal way to reduce the overall cost of generation

- Let P_{G1} , P_{G2} , P_{G3} , …, P_{Gn} be the power generated by each individual unit to supply a load demand of P .
- To formulate this problem, it is necessary to know the ‗input–output characteristics of each unit'.
- It establishes the relationship between the energy input to the turbine andthe energy output from the electrical generator.
- The input to the turbine shown on the ordinate may be either in terms of the heat energy requirement, which is generally measured in Btu/hr or kCal/hr or in terms of the total cost of fuel per hour in Rs./hr. The output is normally the net electrical power output of that steam unit inkW or MW.



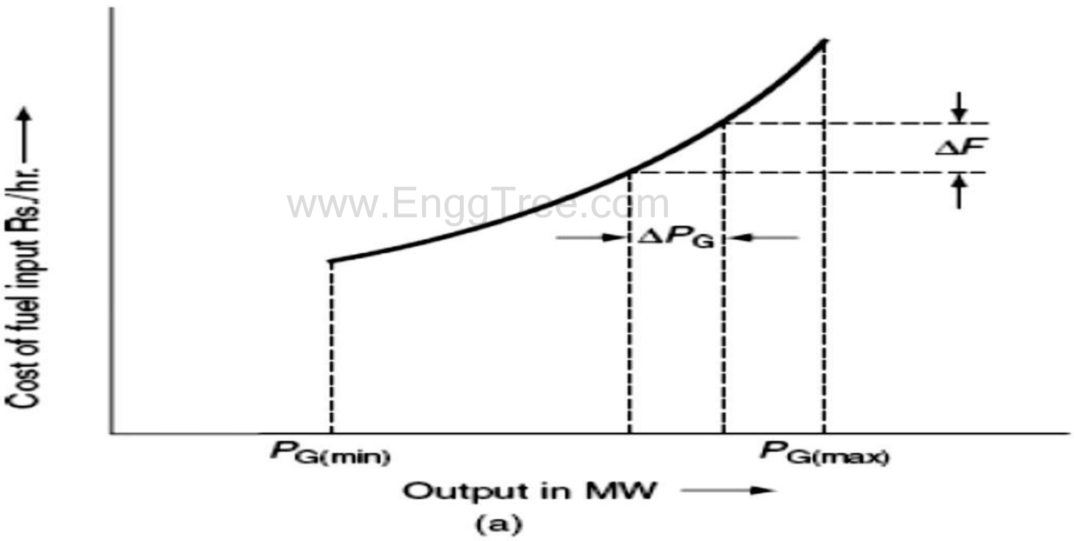
- The steam turbine-generating unit curve consists of minimum and maximum limits in operation, which depend upon the steam cycle used, thermal characteristics of material, the operating temperature etc.
- To convert the input–output curves into cost curves, the fuel input per hour is multiplied with the cost of the fuel (expressed in Rs./million kCal)

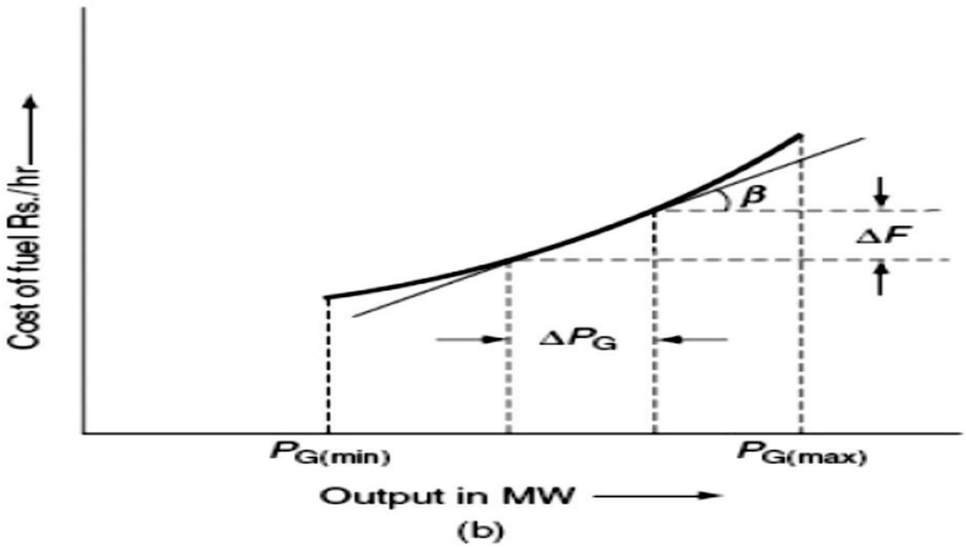
Incremental cost curve

- From the input–output curves, the incremental fuel cost (IFC) curve can be obtained.
- The IFC is defined as the ratio of a small change in the input to the corresponding small change in the output

$$\text{Incremental Fuel Cost} = \frac{\textit{Small Change in Input}}{\textit{Small Change in Output}} = \frac{\Delta F}{\Delta P_G}$$

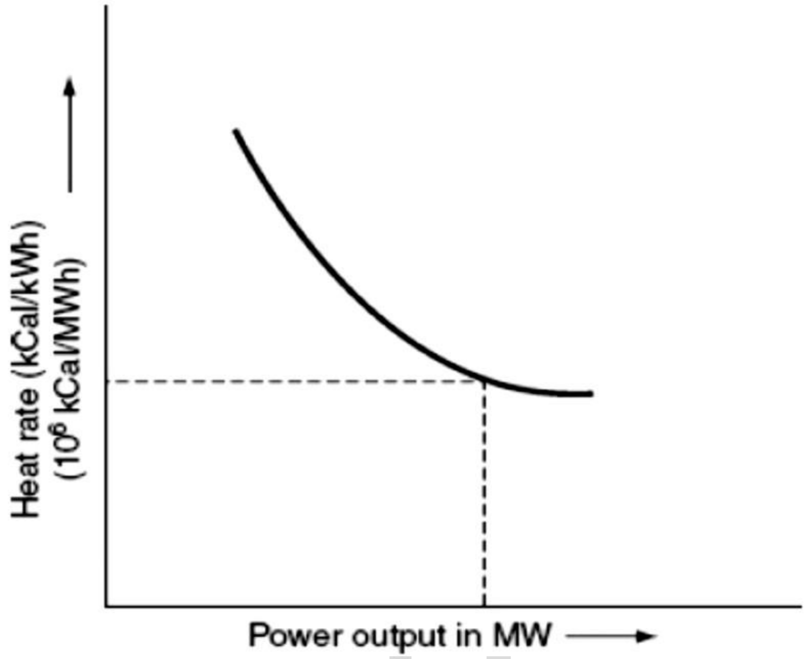
- where ΔF represents small changes. As the ΔP_G quantities become progressively smaller, it is seen that the IFC is $d(input)$ and is expressed in Rs./MWh. $d(output)$ A typical plot of the IFC versus output power is shown in Fig
- The incremental cost curve is obtained by considering the change in the cost of generation to the change in real power generation at various points on the input–output curves, i.e., slope of the input– output curve as shown in Fig





Heat Rate Curve

- The heat rate characteristic obtained from the plot of the net heat rate in Btu/kWh or kCal/kWh versus power output in kW Let Hi be the heat rate in kCal/kWh which is the heat energy obtained by the combustion of the fuel in Kcal needed to generate one unit of electric energy.



- The thermal unit is most efficient at a minimum heat rate, which corresponds to a particular generation P . The curve indicates an increase in heat rate at low and high power limits.
- Thermal efficiency of the unit is affected by the following factors: condition of steam, steam cycle used, re-heat stages, condenser pressure, etc.

$$\text{Normally, Heat Rate} = \frac{Input\ in\ Rs/Hr}{Output\ in\ MW}$$

<u>Incrémental Heat Rate:</u>

- It is the ratio of change in input to the corresponding change in output at any operating point.

$$\text{Incremental Heat Rate} = \frac{\Delta input}{\Delta output} = \frac{\Delta F}{\Delta P}$$

<u>Incremental Efficiency:</u>

- The reciprocal of the incremental fuel rate or heat rate, which is defined as the ratio of output energy to input energy, gives a measure of fuel efficiency for the input

$$\text{Incremental Efficiency} = \frac{\Delta output}{\Delta input} = \frac{\Delta P}{\Delta F}$$

Cost Function

Let the cost of the Fuel be K Rs/Mkcal. Then the fuel input cost $C_i(P_{Gi})$ is

$$C_i(P_{Gi}) = K\ F_i(P_{Gi})$$

Here C_i is the cost expressed in Rs/hr of producing energy in the generator unit i. $F_i(P_{Gi})$ is the Fuel Energy input

$$F_i(P_{Gi}) = P_{Gi}\ H_i\ (P_{Gi})$$

$H_i\ (P_{Gi})$ is obtained from the heat rate curve

Substitute the value of $F_i(P_{Gi})$ in $C_i(P_{Gi})$

$$C_i(P_{Gi}) = K\ P_{Gi}\ H_i\ (P_{Gi})$$

The heat rate curve can be approximated why because the initial portion of curve decrease, reaches minimum point and then increases.

$$H_i\ (P_{Gi}) = \frac{c'_i}{P_{Gi}} + b'_i + a'_i P_{Gi}$$

Where a_i, b_i and c_i are positive coefficients

Input Energy Rate $F_i(P_{Gi}) = P_{Gi}\ H_i\ (P_{Gi}) = P_{Gi}\ [\frac{c'_i}{P_{Gi}} + b'_i + a'_i P_{Gi}]$

$$= a' P^2{}_{Gi} + b'\ P_{Gi} + c'_i$$

Fuel Cost $C_i(P_{Gi}) = K\ F_i(P_{Gi})$

$$\boxed{C_i(P_{Gi}) = aP^2{}_{Gi} + b\ P_{Gi} + c_i}$$

Economic Dispatch Without Loss

Solution of λ iteration method without loss (Algorithm)

Case (i) operating limits of power generation are not specified

$$\lambda = \frac{P_D + \sum_{i=1}^{N} \frac{b_i}{2a_i}}{\sum_{i=1}^{N} \frac{1}{2a_i}}$$

Step 2: compute P_{gi} corresponding to λ using the equation

$$C_i(P_{Gi}) = aP^2{}_{Gi} + b\,P_{Gi} + c_i$$

$$\text{Incremental cost (IC)} = \frac{dC_i(P_{gi})}{dP_{gi}} = 2a_iP_{gi} + b_i = \lambda$$

$$P_{gi} = \frac{\lambda - b_i}{2a_i}$$

Step 3: compute $\sum_{i=1}^{n} P_{gi}$

Step 4: check for power balance equation $P_D = \sum_{i=1}^{N} P_{Gi}$

The power balance equation is satisfied, then the optimum solution is obtained otherwise go to next step.

Step 5:

$$if \sum_{i=1}^{N} P_{gi} < P_D$$

Assign λ + Δ λ (i.e.,) increment λ and go to step 2

$$if \sum_{i=1}^{N} P_{gi} > P_D$$

Assign λ - Δ λ (i.e.,) increment λ and go to step 2

Where

$$\Delta\lambda = \frac{\Delta P}{\sum_{i=1}^{N} \frac{1}{2a_i}}$$

Δ P is change in demand

Case (ii) operating limits of power generation are specified

Step 1 : Assign the initial values of λ or calculate using

$$\lambda = \frac{P_D + \sum_{i=1}^{N} \frac{b_i}{2a_i}}{\sum_{i=1}^{N} \frac{1}{2a_i}}$$

Step 2: compute P_{gi} corresponding to λ using the equation

$$P_{gi} = \frac{\lambda - b_i}{2a_i}$$

Step 3: if the computed P_{gi} satisfies the operating limits,

$$P_{Gi\,min} < P_{Gi} < P_{Gi\,max}$$

For i = 1,2,…., N, then the optimum solution is obtained, otherwise go to next step

Step 4: if P_{gi} violates the operating limits, hen fix the generation at the respective limit.

$$P_{Gi} < P_{Gi,min}, then\ Fix\ P_{Gi} = P_{Gi,min}$$

$$P_{Gi} > P_{Gi,max}, then\ Fix\ P_{Gi} = P_{Gi,max}$$

Step 5: Redistribute the remaining system load P_D

$$P_{D\,new} = P_{D\,old} - sum\ of\ fixed\ generations\ to\ the\ remaining\ unit$$

Step 6: compute λnew using $P_{D\,new}$ and compute the remaining generations using

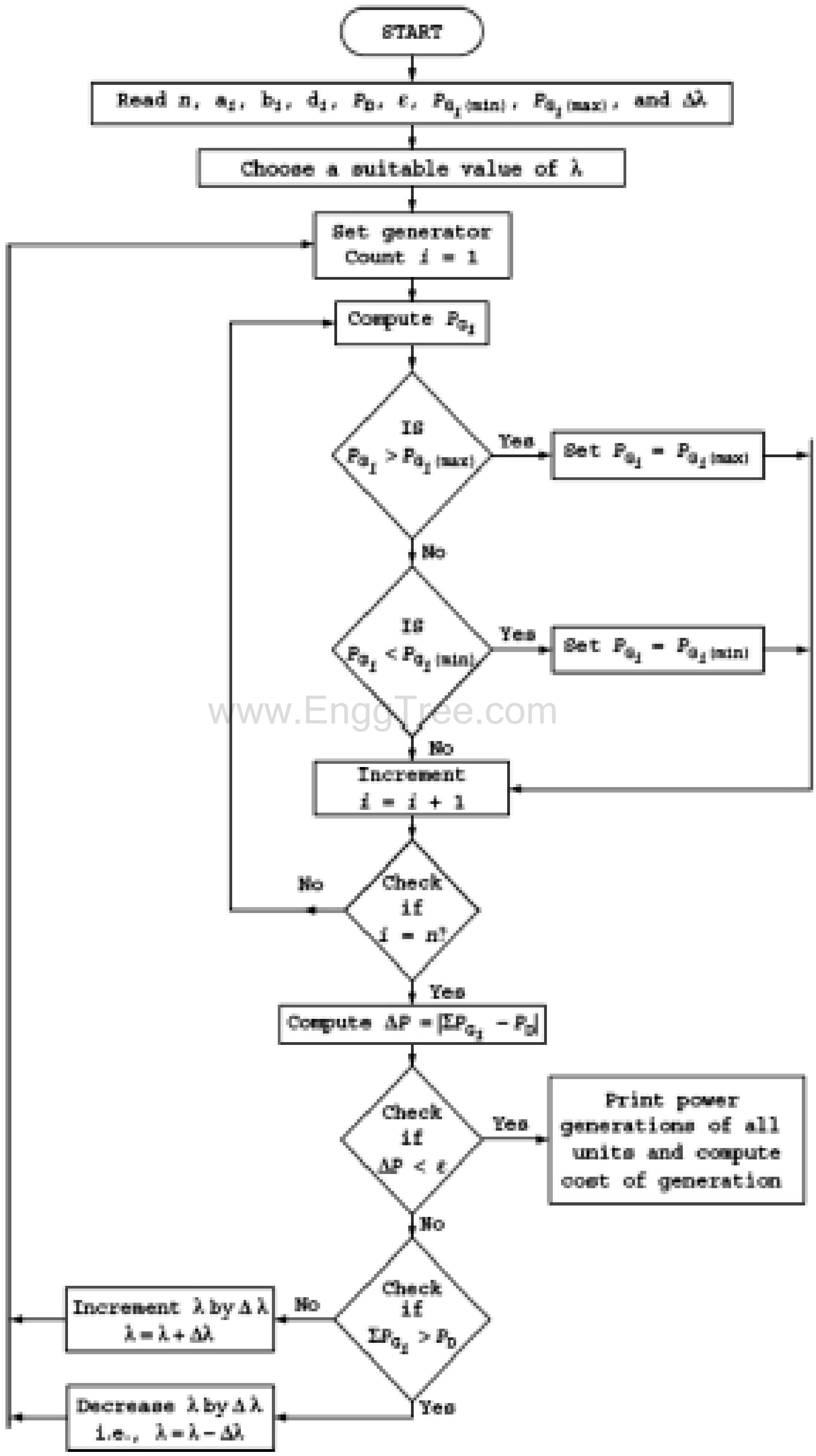
$$P_{gi} = \frac{\lambda_{new} - b_i}{2a_i}$$

Step 7: check whether optimal conditions is satisfied. If the condition is satisfied then stop. Otherwise release the generation schedule fixed at $P_{Gi,min}$ or $P_{Gi,max}$ of those units not satisfying the optimal condition. Include these units in the remaining units and modify the new power demand

$$P_{D\,new,1} = P_{D\,new} + sum\ of\ fixed\ generators\ \text{not satisfying the optimal condition}$$

And go to step 6

EDC neglecting losses flowchart



UNIT COMMITMENT

Introduction:

- In power systems, demand variation is associated with human activities. Load is always light during night hours and it starts increasing right from morning and usually readies its peak level in the evening, and again falls during late evening period.
- The demand is also affected during weekends as well as by weather. Hence, many methods have been developed for load forecasting.
- The methods for load forecasting can predict the load for period varying from as small as few seconds to days. Based on these load forecasts, the usual practice is to prepare a commitment schedule of start-up and shut-down of units.
- The commission of a generating unit means to bring it to speed, synchronize it to the system and then connect it to the system so that it can deliver the load reliably.
- In the early stages, the main criteria of unit commitment were efficiency of units. Units used to be ordered as per efficiencies.
- The most efficient unit used to be committed first and then the next unit, if necessary to meet the load demand, from priority list used to be committed.
- Soon, it was realized that optimum unit commitment may be obtained using input-output characteristics, termed as cost curves; and today all commitment techniques are based on these cost curves.
- Classically, unit commitment is the determination of optimal schedule and generation level of each unit over a specific time horizon. Time horizon may be hours or a week.
- Baldwin (Scientist name) was the first to report the study of economic shut down of generating units. Since then, many optimization techniques have been used to obtain solution of unit commitment problem prominent among these are dynamic programming, branch and bound, Lagrangian relaxation.

STATEMENT OF UNIT COMMITMENT (UC) PROBLEM

- The unit commitment problem (UC) in electrical power production is a large family of mathematical optimization problems where the production of a set of electrical generators is coordinated in order to achieve some common target, usually either match the energy demand at minimum cost or maximize revenues from energy production.
- The total load of the power system is not constant but varies throughout the day and reaches a different peak value from one day to another.
- It follows a particular hourly load cycle over a day. There will be different discrete load levels at each period.
- Due to the above reason, it is not advisable to run all available units all the time, and it is necessary to decide in advance which generators are to start up, when to connect

them to the network, the sequence in which the operating units should be shut down, and for how long.

- The computational procedure for making such decisions is called unit commitment (UC), and a unit when scheduled for connection to the system is said to be committed.
- The problem of UC is nothing but to determine the units that should operate for a particular load. To commit‘ a generating unit is to turn it on‘, i.e., to bring it up to speed, synchronize it to the system, and connect it, so that it can deliver power to the network.

COMPARISON WITH ECONOMIC LOAD DISPATCH

- Economic dispatch economically distributes the actual system load as it rises to the various units that are already on-line.
- However, the UC problem plans for the best set of units to be available to supply the predicted or forecast load of the system over a future time period.

NEED FOR UC

- The plant commitment and unit-ordering schedules extend the period of optimization from a few minutes to several hours.
- Weekly pattern scan be developed from daily schedules. Likewise, monthly, seasonal, and annual schedules can be prepared by taking into consideration the repetitive nature of the load demand and seasonal variations.
- A great deal of money can be saved by turning off the units when they are not needed for the time. If the operation of the system is to be optimized, the UC schedules are required for economically committing units in plant to service with the time at which individual units should be taken out from or returned to service.
- This problem is of importance for scheduling thermal units in a thermal plant; as for other types of generation such as hydro their aggregate costs (such as start-up costs, operating fuel costs, and shutdown costs) are negligible so that the iron-off status is not important.

CONSTRAINTS IN UC

There are many constraints to be considered in solving the UC problem.

Spinning reserve

It is the term used to describe the total amount of generation available from all Synchronized units on the system minus the present load and losses being supplied.

Here, the synchronized units on the system may be named units spinning on the system.

$$\text{Spinning Reserve} = \begin{bmatrix} \textit{Total generation output oa} \\ \textit{all synchronized units at a} \\ \textit{particular time} \end{bmatrix} - \begin{bmatrix} \textit{Present} \\ \textit{Load + Losses} \\ \textit{at that time} \end{bmatrix}$$

Static reserve:

- To meet the load demand under contingency of failure of a generator or its derating caused by minor defect, it is made so that the total installed capacity of the generating station greater the yearly peak load by certain margin. This is called static reserve.

Thermal Unit Constraints

- Thermal units require crew to operate them especially where turned on or off. A thermal unit may undergo only gradual temperature changes and this translates into increased number of hours required to bring it on line. Therefore the various constraints that arise one.

a)Minimum Up time

- Once the unit is running, it should not be turned off immediately.

b)Minimum Down Time

- Once the unit is decommitted, there is a minimum time before it can be recommitted.

c)Crew Constraints

- If a plant consists of 2 or more units, they cannot be turned on at the same time
- since there are not enough staff to attend all the units at a time.

d) Start Up Cost

- A start-up cost is incurred when a generator is put into operation. The cost is dependent on how long the unit has been inactive.
- While the start-up cost function is nonlinear, it can be discretized into hourly periods, giving a stepwise function.
- The start-up cost may vary from a maximum _cold start' value to a very small value if the unit was only turned off recently, and it is still relatively close to the operating temperature.
- Two approaches to treating a thermal unit during it's _down' state:
- The first approach (cooling) allows the unit's boiler to cool down and then heat back up to a operating temperature in time for a scheduled turn-on.
- The second approach (banking) requires that sufficient energy be input to the boiler to just maintain the operating temperature.

- Similarly, shut-down cost is incurred during shutting down generating units. In general, it is neglected from the unit commitment decision.

OTHER CONSTRAINTS

In addition to system and unit constraints, there are other constraints that need to be considered in the UC decision. They are described as follows:

A.Fuel Constraints:

- Due to the contracts with fuel suppliers, some power plants may have limited fuel or may need to burn a specified amount of fuel in a given time.
- A system in which some units have limited fuel, or else have constraints that require them to burn a specified amount of fuel in a given time, presents a most challenging unit commitment problem.

B.Must Run Units:

- Some units are given a must-run status during certain times of the year for reason of voltage support on the transmission network or for such purposes as supply of steam for uses outside the steam plant itself.
- The must run units include units in forward contracts, units in exercised call/put options, RMR units, nuclear power plants, some cogeneration units, and units with renewable resources such as wind- turbine units and some hydro power plants.

C.Must-off Units:

- Some units are required to be off-line due to maintenance schedule or forced outage. These units can be excluded from the UC decision.

D.Emission Constraints:

- There are some emissions like sulphur dioxide ($SO2$), nitrogen oxides (NOx), carbon dioxide ($CO2$), and mercury which are produced by fossil-fuelled thermal power plants.
- The amount of emission depends on various factors such as the type of fuel used, level of generation output, and the efficiency of the unit.
- The production cost minimization may need to be compromised in order to have the generation schedule that meets the emission constraints.

Unit Commitment Solution Methods

The Unit commitment problems are very difficult to solve, for that consider the following situation,

1.A loading pattern for the M periods using load curve must be established.

2.Number of units should be committed and dispatched to meet out the load.
3.The load period and number of units should supply the individual loads and any combination of loads.
There are many classical approaches have been developed and implemented successfully. Some of the approaches are

1. Enumeration Technique or Brute Force technique
2. Priority List Method
3. Dynamic Programming
4. Lagrange Relaxation
5. Integer and Mixed integer programming
6. Benders decomposition
7. Branch and Bound

Other non – classical approaches are

1. Genetic Algorithms
2. Greedy random adaptive search procedure
3. Particle swarm optimization
4. Simulated annealing

Dynamic Programming Method

- In dynamic programming method, the unit commitment table is to be arrived at for the complete load cycle.

Advantages

- Reductions in the dimensionality of the problem i.e number of combinations to be tried are reduced in number.
- If a strict priority order is imposed, the numbers of combinations for a 4 unit case are:
- Priority 1 unit
- Priority 1 unit + Priority 2 unit
- Priority 1 unit + Priority 2 unit + Priority 3 unit
- Priority 1 unit + Priority 2 unit + Priority 3 unit + Priority 4 unit

The priority listing can be used only if:

- No load costs are zero.
- Unit input-output characteristics are linear between 0 output and full load
- Phase shift transformer tap position
- Switched capacitor settings
- Reactive injection for static VAR compensator
- Load shedding
- DC line flow.

Assumptions:

- Total number of units available, their individual cost characteristics and the load cycle on the station are assumed priori(previously)
- A state consists of an array of units with specified units operating and the rest off- line.
- The start-up cost of a unit is independent of the time it has been off-line(i.e., fixed amount).
- There are no costs for shutting down a unit.
- There is a strict priority order and in each interval a specified minimum amount of capacity must be operating.

Forward Dynamic programming method Advantages

- Algorithm to run forward in time from the initial hour to the final hour.

- Forward dynamic programming is suitable if the start-up cost of a unit is a function of the time it has been off-line(i.e, fixed amount)
- Previous history of the unit can be computed at each stage.
- Initial conditions are easily specified.

Algorithm

- One could set up a dynamic-programming algorithm to run backward in time starting from the final hour to be studied, back to the initial hour.
- Conversely, one could set up the algorithm to run forward in time from the initial hour to the final hour.
- The forward approach has distinct advantages in solving generator unit commitment. For example, if the start-up cost of a unit is a function of the time it has been off-line (i.e., its temperature), then a forward dynamic-program approach is more suitable since the previous history of the unit can be computed at each stage.
- There are other practical reasons for going forward.
- The initial conditions are easily specified and the computations can go forward in time as long as required.

- A forward dynamic-programming algorithm is shown by the flowchart
- The recursive algorithm to compute the minimum cost in hour K with combination Fcost (K,I) = min { Pcost (K,I) + Scost (K-1,L;K,I) }

Where

Fcost(K.I) = R (K,I)

Fcost(K, I) = least total cost to arrive at state (K , I) Pcost(K,I) = production cost for state (K ,I)

Scost(K - 1, L: K , I)= transition cost from state (K - 1, L) to

state (K , I **)**

State (K, 1) is the Zth combination in hour K. For the forward dynamic programming approach, we define a strategy as the transition, or path, from one state at a given hour to a state at the next hour.

Note that two new variables, X and N, have been introduced in Figure. X

= number of states to search each period

N = number of strategies, or paths, to save at each step

These variables allow control of the computational effort (see below Figure).For complete enumeration, the maximum number of the value of X or N is $2^N - 1$

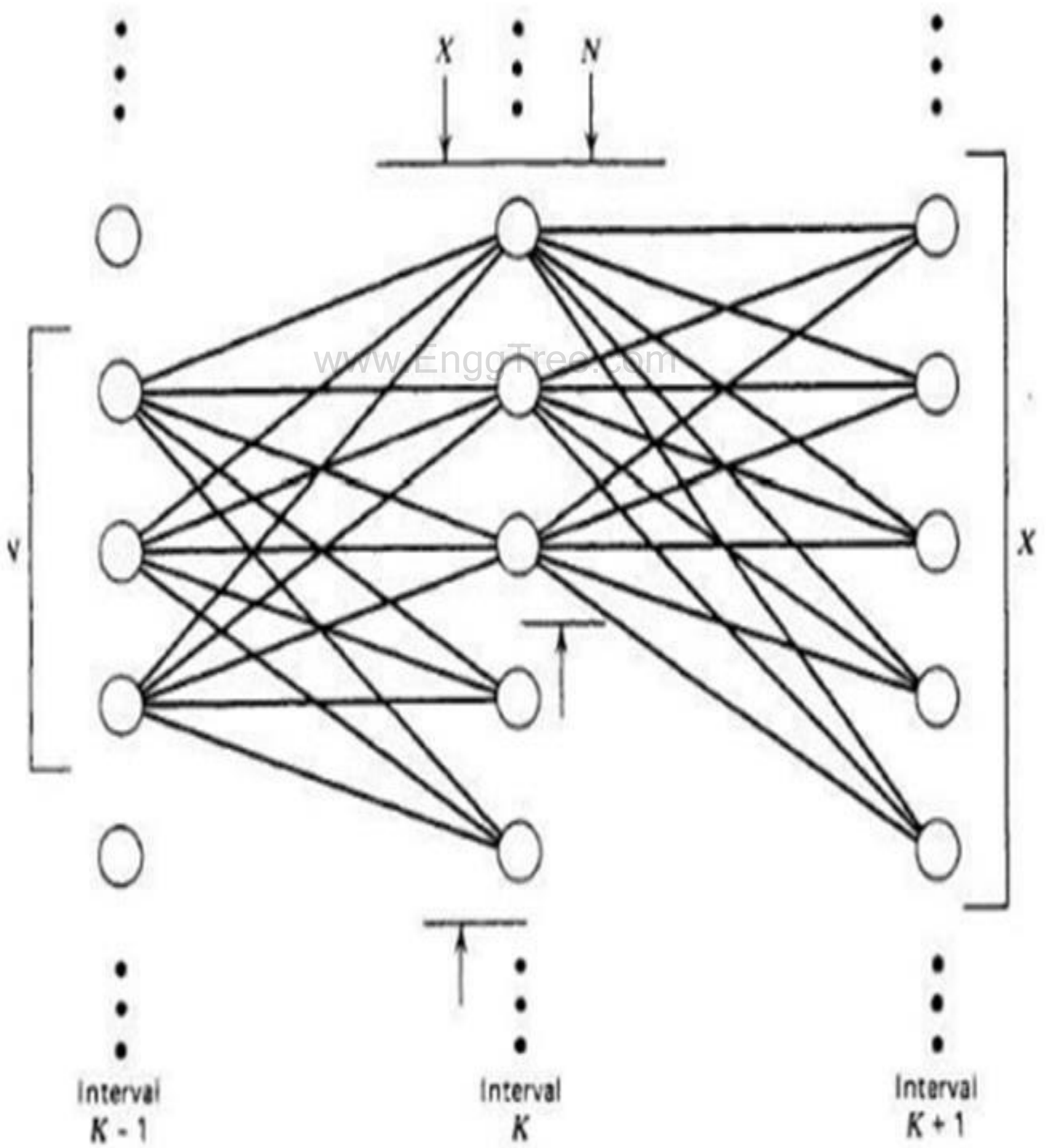
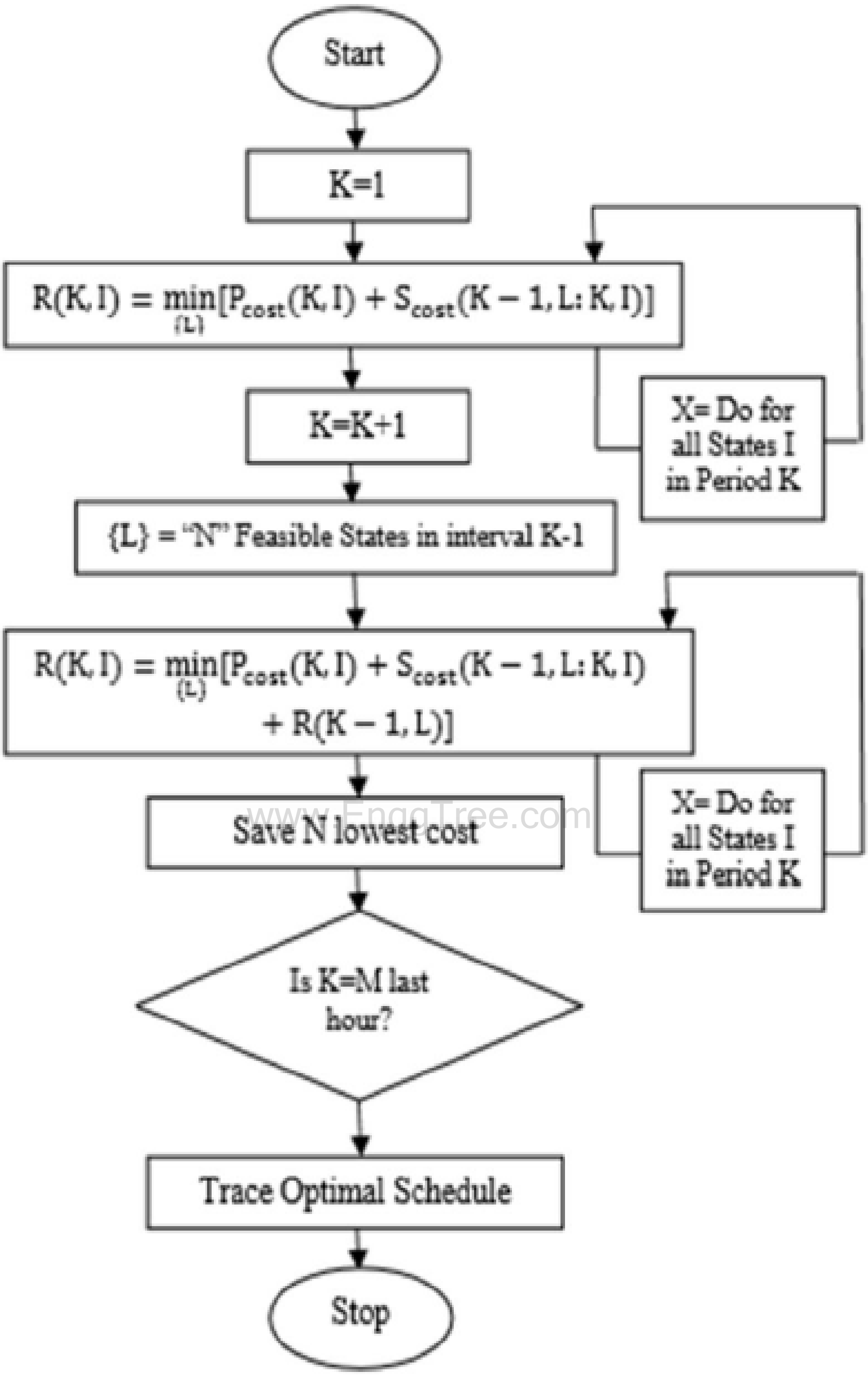


Fig.1Dynamic programming algorithm


Start
K=1
R(K, I) = min_{L}[P_cost(K, I) + S_cost(K − 1, L: K, I)]
X= Do for all States I in Period K
K=K+1
{L} = "N" Feasible States in interval K-1
R(K, I) = min_{L}[P_cost(K, I) + S_cost(K − 1, L: K, I) + R(K − 1, L)]
X= Do for all States I in Period K
Save N lowest cost
Is K=M last hour?
Trace Optimal Schedule
Stop

Priority List Method (Using full load average Production cost FLAPC)

- Priority list method is the simplest unit commitment solution method which consists of creating a priority list of units.
- The priority list can be obtained by noting the full-load average production cost of each unit.
- Full load average Production cost = { Net heat rate at full load} x Fuel cost

$$\text{FLAPC} = \frac{C_i \ (P_{Gi})}{P_{Gi}}$$

Assumptions

- No load costs are zero.
- Unit input – output characteristics are linear between zero output and full load. Start-up costs are a fixed amount
- Ignore minimum up time and minimum down time

Steps to be followed or Method of solving

- Determine the full load average production cost for each units.
- Form priority order based on average production cost,(Ascending order)
- Commit number of units corresponding to the priority order.
- Calculate PG1,PG2,……………..PGN from economic dispatch problem for the feasible combinations only.
- For the load curve, each hour load is varying.
- Assume load is dropping or decreasing, determine whether dropping the next unit will supply generation and spinning reserve.
- If not, continue as it is, If yes, go to next step.
- Determine the number of hours H, before the unit will be needed again. Check H < Minimum shut down time

If yes, go to last step, If not, go to next step. Calculate two costs

- 1.Sum of hourly production costs for the next H hours with the unit up.
- 2.Recalculate the same for the unit down + start-up cost for either cooling or banking. If the second case is less expensive, the unit should be on.

Repeat this procedure until the priority list.

Merits

- No need to go for ―N‖ Combinations. Take only one constraint
- Ignore the minimum up time and minimum down time. Complication reduced.

Demerits

- Start-up cost are fixed amount No load costs are not considered

Need of computer control of power systems

The computer control of power systems are needed in

- Power system Planning
- System Monitoring
- Automatic generation control
- Security control
- Voltage or reactive power control
- Unit commitment
- Economic dispatch
- State estimation
- Contingency analysis
- Load forecasting

Increase in unit size, growth of interconnected and the need to maintain the system innormal mode requires sophisticated control, instrumentation and protection.

- The multiplicity of monitoring instruments in the control room and their distance apart make the observation of more than a few vitalises almost impossible, especially during the intense activity of plant start-up.
- The operation of changing plot parameters and take critical decisions.
- These requirements led to the development and application of more advanced solid
- state modular electronic instruments, computer based direct control and date processing systems.

Computer Configuration Trend

- The computer system used at power system has been undergoing continuous development over the years. Formerly, all the functions such as data acquisition, logging display, and control and performance calculations were performer by computer processing unit (CPU).
- In such system failure of any of the elegant leads to the total system breakdown. Thus, the need for a dual computer configuration arose which is quite costly.

- The further advancement in communication technology and powerful microprocessors has resulted in the cheap and reliable microprocessor basedDistributed Processing System (DPS).
- It is based on the principle of LAN. Today, in all process industries including power plant, this system is employed for data acquisition and control.
- DPS consists of a number of microprocessors connected through data highway, which is passive in nature. Each processor is assigned a specific task independently.

Energy control centres

When the power system increases in size-the number of substations, transformers, switchgear and so on-their operation and interaction become more complex. So it becomes essential to monitor this information simultaneously for the total system which is called as energy control centre.

A fundamental design feature of energy centre is that, it increases system reliability and economic feasibility. In other words, Energy Management (EM) is performed at control centre called system control centre.

Fig. shows the schematic diagram showing the information flow between various functions to be performed in an operations control centre computer system. The system gets information about the power system from remote terminal units (RTU) that encode measurement transducer outputs and operand/closed status information into digital signals that are transmitted to the operations centre over communication circuits.

The control centre can transmit control information such as raise/lower commandsto the speed changer and in turn to the generators and open/close commands to circuit breakers (CBs). The information coming into the control centre is breaker/switch status indications and analog measurements.

The analog measurements of generator outputs must be used directly by the Automatic Generation Control (AGC) program, whereas, all other data will be processed by the state estimator before being used by the other programs. Real time operations are in two aspects.

Three level control

- Turbine-governor to adjust generation to balance changing load-instantaneous control.
- ACG (called Load Frequency Control (LFC)) maintains frequency and net powerinterchange –action repeated at 2-6 sec. interval.
- Economic Dispatch Control (EDC) distributes the load among the units suchthat fuel cost is minimum-executed at 5-10 minutes intervals.

Primary voltage control

- Excitation controls regulate generator bus voltage.
- Transmission voltage control device includes SVC (Static VAR Controllers),shunt capacitors, transformer taps, etc

Automatic Generation Control

Automatic generation control (AGC) consists of two major and several minor functions that operate online in real time to adjust the generation against load at minimum cost. The major functions are load frequency control and economic dispatch, each of which is described below. The minor functions are reserve monitoring, which assures enough reserve on the system; interchange scheduling, which initiates and completes scheduled interchanges; and other similar monitoring and recording functions

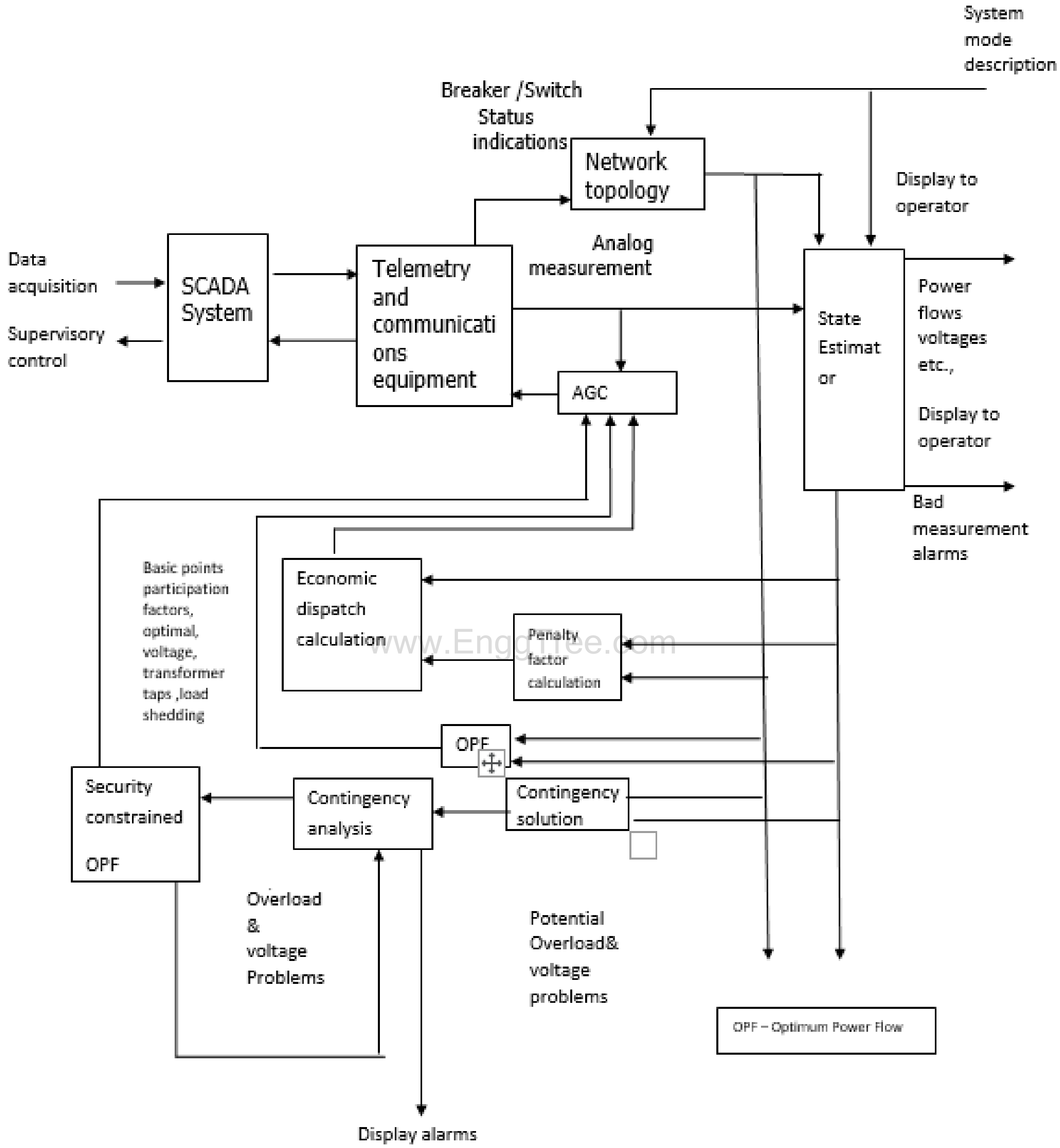


Fig. Energy control centres

ECC Functions

The practice of all communication links between equipment and the control centrecould be interrupted and still, electric service is being maintained. The generating in the system remains synchronized to the transmission network and maintains its existing power output level even without signals received from control centre.

Monitoring

An energy control centre fulfills the function of coordinating their response of the system elements in both normal operation and emergency conditions.

The burden of repetitious control in normal situations is delegated to the digital computer and selective monitoring is performed by human operators.

The digital computer is used to process the incoming stream of data to detect abnormalities and the human operator via lights, buzzers and CRT presentations. Many lower level or less serious cases of exceeding normal limits are routinely handled by digital computer. A more serious abnormality detected by the digital computer may cause suspension of normal control functions

In emergencies such as loss of a major generator or excess power demands by a neighboring utility on the tie lines, many alarms could be detected and the systemcould enter an emergency state.

Data Acquisition and Control

Data acquisition provides operators and computer control systems with status and measurement information needed to supervise overall operations. Security control analyses the consequences of faults to establish operating conditions.

A SCADA system consists of a master station and remote terminal unit (RTU). Master station communicates information to the RTU for observing and controllingplants.

RTUs are installed at generating station or transmission substation or distribution substation. RTUs transmitting status of the device and measurements to master station and receive control commands from the master station.

In a computer aided data acquisition scheme, the steady state reading can be acquired simultaneously from various instrument locations and can be saved for future analysis.

The transient may result in the form of voltage or current fluctuations. In a real power system, the transient may result in the failure of components and it is sometimes difficult to trace the origin of disturbance. Using a Data Acquisition system, the transients can be reduced and analyzed.

Phasor Measurement Units for Power Systems (PMU):

A phasor measurement unit (PMU) is a device used to estimate the magnitude and phase angle of an electrical phasor quantity (such as voltage or current) in the electricity grid using a common time source for synchronization. Time synchronization is usually provided by GPS or IEEE 1588 Precision Time Protocol, which allows synchronized real-time measurements of multiple remote points on the grid. PMUs are capable of capturing samples from a waveform in quick succession and reconstructing the phasor quantity, made up of an angle measurement and a magnitude measurement. The resulting measurement is known as a synchrophasor. These time synchronized measurements are important because if the grid's supply and demand are not perfectly matched, frequency imbalances can cause stress on the grid, which is a potential cause for power outages.

PMUs can also be used to measure the frequency in the power grid. A typical commercial PMU can report measurements with very high temporal resolution, up to 120 measurements per second. This helps engineers in analysing dynamic events in the grid which is not possible with traditional SCADA measurements that generate one measurement every 2 or 4 seconds. Therefore, PMUs equip utilities with enhanced monitoring and control capabilities and are considered to be one of the most important measuring devices in the future of power systems. A PMU can be a dedicated device, or the PMU function can be incorporated into a protective relay or other device.

Existing systems in power grid such as Energy Management System (EMS) and Supervisory Control and Data Acquisition system (SCADA) have the capability to provide only steady state view of power system with high data flow latency. In Supervisory Control and Data Acquisition system (SCADA) it was not possible to measure the phase angles of bus voltages of power system network in real time, due to technical difficulties in synchronising measurements from distant locations.

Measurements were obtained at slower rates; it was not possible to get dynamic behaviour of power system as well as limited situational awareness was conveyed to the operator. Advent of Phasor Measurement Units (PMUs) alleviated this problem by synchronising voltage and current waveforms at widely dispersed locations with respect to global positioning system. PMU is superior to SCADA withrespect to speed, performance and reliability.

As per definition of IEEE, PMU is defined as device that produces synchronised phasor, frequency and rate of change of frequency estimates from voltage and/or current signals and time synchronising signal. PMUs provide real time synchronised measurements in power system with better than one microsecond synchronisation accuracy, which is obtained by Global Positioning System (GPS) signals. PMUs are situated in power system substations, and provide measurement of time stamped positive sequence voltages and currents of all monitored buses and feeders. Data from various substations are collected at suitable site, and by aligning time stamps of measurements a coherent picture of the state power system is created. PMUs are time synchronised, high speed measurement units that monitor current and voltage waveforms (sinusoids) in the grid, convert them into a phasor representation through high end computation and securely transmit the same to centralised server.

PMU technology is well suited to track grid dynamics in real time, the data obtained can be used for wide area monitoring, stability monitoring, dynamic system ratings and improvement in state estimation, protection and control. It enables utilities to proactively plan energy delivery and prevent failures.

PMU application

- Post disturbance analysis
- Stability monitoring
- Thermal overload monitoring
- Power system restoration
- State estimation
- Real time control
- Adaptive protection

System Hardware Configuration

The supervisory control and the data acquisition system allow a few operators to monitor the generation and HV transmission system. Consistent with principles of high reliability and fail safe failures, electric utilities have almost universally applieda redundant set of dual digital computers for the function of remote date acquisition control, energy management and system security.

Both computers have their own core memory and drive an extensive number of input-output devices such as printers, teletypes, and magnetic tape drive, disks. Usually one computer, the on-line units, is monitoring and controlling the power system. The backup computer may be executing off-line batch programs such as load forecasting or hydro-thermal allocation

The on-line computer periodically updates a disk memory shared between the two computers. Upon a fail over or switch-in status command, the stored information of the common disk is inserted in the memory of the on-line computer.

The information used by the on-line computer has a maximum age of update cycle. All of the peripheral equipment is interfaced with the computer through input- output microprocessors that have been programmed to communicate, as well as pre-process the analog information, check for limits, convert to another system of units and so on.

The microprocessors can transfer data in and out of computer memory without interrupting the central processing unit. As a result of these precautions, for all critical hardware functions, there is often a guaranteed 99.8% or more availability.

Software also allows for multilevel hardware failures and initialization of application programs, if failures occur. Critical operation and functions aremaintained during either preventive or corrective maintenance.

Besides hardware, new digital code to control the system may be compiled and tested in the backup computer, then switched to on-line status. The digital computers are usually employed in a fixed cycle operating mode, with priority interrupts wherein computer periodically performs a list of operations. The most critical functions have the fastest scan cycle. Typically, the following categories are scanned every 2 seconds.

- All status points such as switchgear position, substation loads and voltages, transformer tap positions and capacitor banks.
- Tie-line flow and interchanges schedules.
- Generator loads, voltage, operating limits and boiler capacity.
- Telemetry verification to detect failures and error in the remote bilateralcommunication links between the digital computer and remote equipment.

The turbine-generators are often commanded to new power levels every 4 seconds, sharing the load adjustment based on each unit‘s response capabilityin MW/min. The absolute power output of each unit‘s response capability is typically adjusted every 5 min by the computer executing an economic dispatch program to determine the base power settings.

Energy Management System (EMS)

Energy management is the process of monitoring, coordinating and controlling thegeneration, transmission and distribution of electrical energy. It is performed at centers called 'system control centers', by a computer system called Energy Management System (EMS). Data acquisition and remote control is performed by the computer system called SCADA, which forms the front end of EMS. The EMS communicates with generating, transmission and distribution systems through SCADA systems.

Energy management system consists of energy management, AGC, Security control, SCADA, load management as shown in figure.

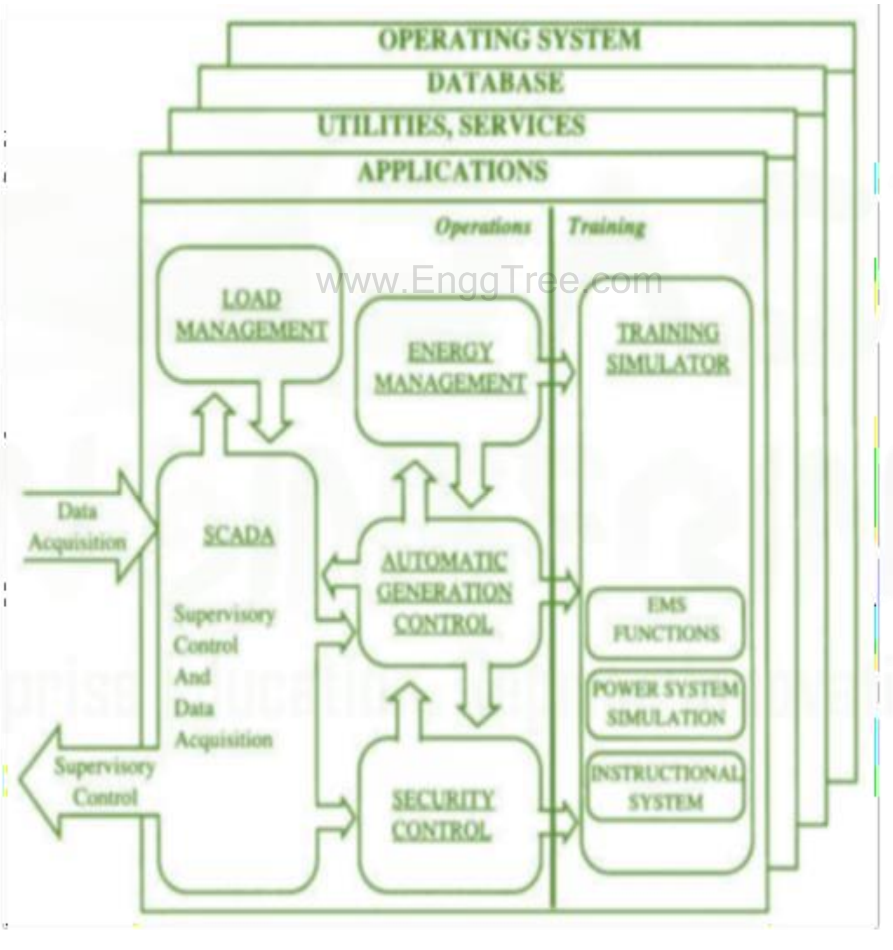


Fig. Energy Management System

Energy Management

Automatic generation control and economic dispatch minimize the production cost ad transmission cost. Commit the number of units to be operated to minimize the cost and schedule hydro-thermal plants properly have come under energy management.

The functions of energy management systems are:

System load forecasting – Hourly energy, 1 to 7 days
Unit commitment – 1 to 7 days.
Fuel scheduling to plants.
Hydro-thermal scheduling – up to 7 days.
MW interchanges evaluation
Transmission loss minimization.
Maintenance scheduling.
Production cost calculation.

Load Management – Carried out at Distribution Control Centre

Remote terminal unit (RTU) installed at distribution substations, can provide status and measurements for distribution substation. RTU can monitor switches, interrupters, control voltage, customer meter reading, etc.

The functions

1. Data acquisition
2. Monitoring, sectionalizing switches and create circuit configuration
3. Feeder switch control and preparing distribution map
4. Preparation of switching orders
5. Customer meter reading
6. Load management
7. Fault location and circuit topology configuration
8. Service restoration
9. Power factor and voltage control
10. Implementation time dependent pricing

11. Circuit continuity analysis.

12. To control customer load through appliance switching and indirectly through voltage control

Power System Data Acquisition and Control

- A SCADA system consists of a master station that communicates with remote terminal units (RTUs) for the purpose of allowing operators to observe and controlphysical plants.
- Generating plants and transmission substations certainly justify RTUs, and their installation is becoming more common in distribution substations as costs decrease. RTUs transmit device status and measurements to, and receive control commands and set point data from, the master station.
- Communication is generally via dedicated circuits operating in the range of 600 to 4800 bits/s with the RTU responding to periodic requests initiated from the master station (polling) every 2 to 10 s, depending on the criticality of the data.
- The traditional functions of SCADA systems are summarized:

✓ Data acquisition: Provides telemetered measurements and status information tooperator.

✓ Supervisory control: Allows operator to remotely control devices, e.g., open andclose circuit breakers. A "select before operate" procedure is used for greater safety.

✓ Tagging: Identifies a device as subject to specific operating restrictions andprevents unauthorized operation.

✓ Alarms: Inform operator of unplanned events and undesirable operating conditions. Alarms are sorted by criticality, area of responsibility, and chronology.
Acknowledgment may be required

✓ Logging: Logs all operator entry, all alarms, and selected information.

✓ Load shed: Provides both automatic and operator-initiated tripping of load in response to system emergencies.

✓ Trending: Plots measurements on selected time scales.

Energy Management

Since the master station is critical to power system operations, its functions are generally distributed among several computer systems depending on specificdesign. A dual computer system configured in primary and standby modes is mostcommon. SCADA functions are listed below without stating which computer has specific responsibility.

- Manage communication circuit configuration
- Downline load RTU files
- Maintain scan tables and perform polling
- Check and correct message
- Detect status and measurement changes
- Monitor abnormal and out-of-limit conditions
- Log and time-tag sequence of events
- Detect and annunciate alarms
- Respond to operator requests to:

  - Display information
  - Enter data
  - Execute control action
  - Acknowledge alarms Transmit control action to RTUs
- Inhibit unauthorized actions
- Maintain historical files
- Log events and prepare reports
- Perform load shedding

Automatic Generation Control

- Automatic generation control (AGC) consists of two major and several minor functions that operate online in real time to adjust the generation against load at minimum cost.
- The major functions are load frequency control and economic dispatch, each

of which is described below.

- The minor functions are reserve monitoring, which assures enough reserve on the system; interchange scheduling, which initiates and completes scheduled interchanges; and other similar monitoring and recording functions.
- **Load Frequency Control**

Load frequency control (LFC) has to achieve three primary objectives, which are stated below in priority order:

1. To maintain frequency at the scheduled value
2. To maintain net power interchanges with neighboring control areas at thescheduled values
3. To maintain power allocation among units at economically desired values.

The first and second objectives are met by monitoring an error signal, called area control error (ACE), which is a combination of net interchange error and frequency error and represents the power imbalance between generation and loadat any instant.

- This ACE must be filtered or smoothed such that excessive and random changes in ACE are not translated into control action.
- Since these excessive changes are different for different systems, the filter parameters have to be tuned specifically for each control area.
- The filtered ACE is then used to obtain the proportional plus integral control signal
- This control signal is modified by limiters, dead bands, and gain constants that aretuned to the particular system.
- This control signal is then divided among the generating units under control by using participation factors to obtain unit control errors (UCE).
- These participation factors may be proportional to the inverse of the second derivative of the cost of unit generation so that the units would be loaded according to their costs, thus meeting the third objective.
- However, cost may not be the only consideration because the different units mayhave different response rates and it may be necessary to move the faster generators more to obtain an acceptable response.

- The UCEs are then sent to the various units under control and the generating units monitored to see that the corrections take place.
- This control action is repeated every 2 to 6 s. In spite of the integral control, errors in frequency and net interchange do tend to accumulate over time.
- These time errors and accumulated interchange errors have to be corrected by adjusting the controller settings according to procedures agreed upon by the whole interconnection.
- These accumulated errors as well as ACE serve as performance measures forLFC.
- The main philosophy in the design of LFC is that each system should follow its own load very closely during normal operation, while during emergencies; each system should contribute according to its relative size in the interconnection without regard to the locality of the emergency.
- Thus, the most important factor in obtaining good control of a system is its inherent capability of following its own load.
- This is guaranteed if the system has adequate regulation margin as well as adequate response capability.

SUPERVISORY CONTROL AND DATA ACQUISITION(SCADA)

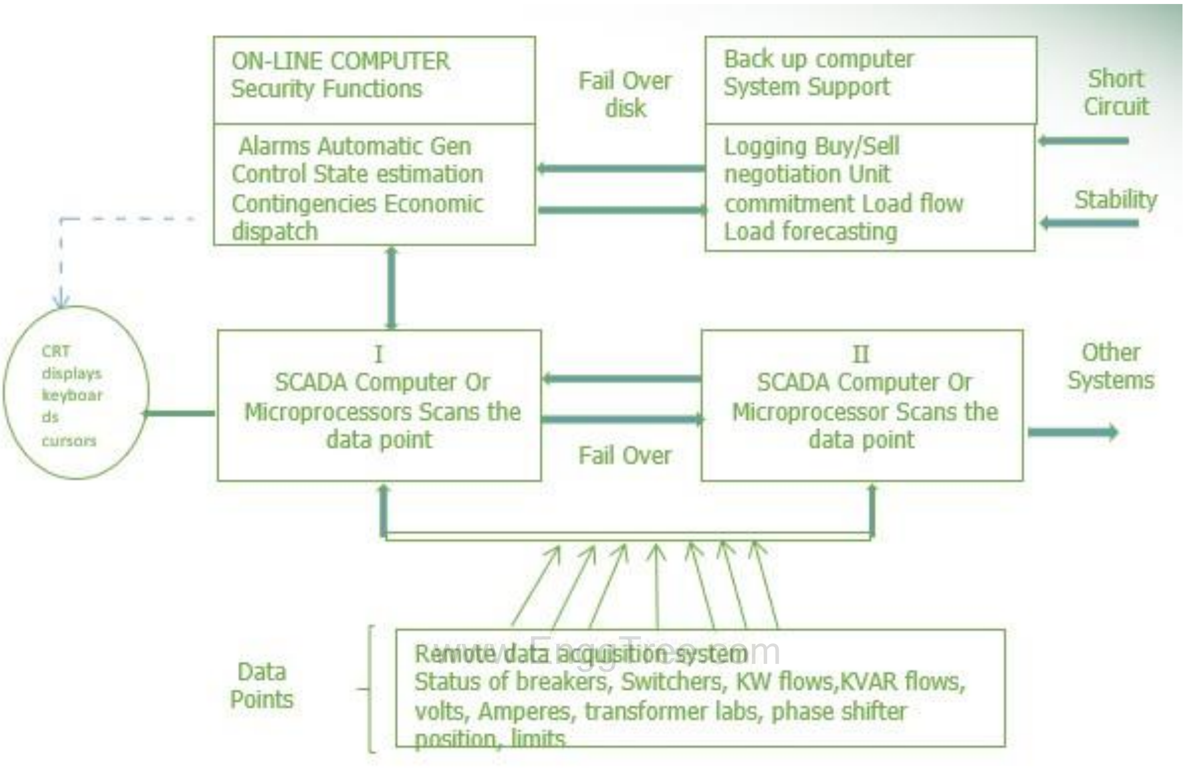
- There are two parts to the term SCADA Supervisory control indicates that the operator, residing in the energy control center (ECC), has the ability to control remote equipment.
- Data acquisition indicates that information is gathered characterizing the state of the remote equipment and sent to the ECC for monitoring purposes.
- The monitoring equipment is normally located in the substations and is consolidated in what is known as the remote terminal unit (RTU).
- Generally, the RTUs are equipped with microprocessors having memory and logic capability. Older RTUs are equipped with modems to provide the communication link back to the ECC, whereas newer RTUs generally have intranet or internet capability.
- Relays located within the RTU, on command from the ECC, open or close selected control circuits to perform a supervisory action.
- Such actions may include, for example, opening or closing of a circuit breaker or switch, modifying a transformer tap setting, raising or lowering generator MW output or terminal voltage, switching in or out a shunt capacitor or inductor, and the starting or stopping of a synchronous condenser.
- Information gathered by the RTU and communicated to the ECC includes both analog information and status indicators.
- Analog information includes, for example, frequency, voltages, currents, and real and reactive power flows.
- Status indicators include alarm signals (over-temperature, low relay battery voltage, illegal entry) and whether switches and circuit breakers are open or closed.
- Such information is provided to the ECC through a periodic scan of all RTUs. A 2 second scan cycle is typical.

SCADA

It consists of a master station and RTU linked by communication channel. Thehardware components can be classified into

1. Process computer and associated hardware at the energy control center

2. RTU and the associated hardware at the remote stations.
3. Communication equipment that links the RTUs and process computers at themaster station
4. Fig. Digital computer control and monitoring for power system



System Hardware Configuration:

The supervisory control and data acquisition system allows a few operators to monitor the generation and HV transmission system. Consistent with principles of high reliability and fail safe features, electric utilities have almost universally applied a redundant set of dual digital computers for the functions of remote data acquisition control, energy management and system security. Both computers have their own core memory and drive an extensive number of input- output devices such as printers, teletypes, magnetic tape drive, and disks and so on.

Usually one computer, the on-line units, is monitoring and controlling the power system. The backup computer may be executing off-line batch programs such as load forecasting to hydro-thermal allocation. The on-line computer periodically updates a disk memory shared between the two computers.

Upon a fail over or switch-in status command, the stored information of the common disk is inserted in the memory of the on-line computer.

The information used by the on-line computer has a maximum age of update cycle. The figure gives a detailed block diagram of a typical digital computer control and monitoring for power systems.

- All of the peripheral equipment is interfaced with the computer through input-output microprocessors that have been programmed to communicate, as well as preprocess the analog information, check for limits, convert to another system of units and so onThe microprocessors can transfer data in and out of computer memory witprocessing unit. As a result of these precautions, for all critical hardware functions, there is often a guaranteed 99.8 % or more availability. Software also allows for multilevel hardware failures and initialization of application programs, iffailures occur. Critical operations and functions are maintained during either preventive or corrective maintenance.
- Besides hardware, new digital code to control the system may be compiled and tested in the backup computer, then switched to on-line status. The digital computers are usually employed in a fixed cycle operating mode, with priority interrupts wherein the computer periodically performs a list of operations. The most critical functions have the fastest scan cycle. Typically, the following categories are scanned every two seconds.
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- Telemetry verification to detect failures and errors in the remote bilateral communication links between the digital computer and the remote equipment
- The turbine generators are often commanded to new power levels every four seconds, sharing the load adjustment based on each unit's response capability in MW/min. The absolute power output of each unit's response capability is typicallyadjusted every five min by the computer executing an economic dispatch program to determine the base power setting.
- Most low priority programs may be executed on demand by the operator for studypurposes or to initialize the power system. An operator may also alter the

digital computer code in the execution if system. The computer software compiler and data handlers are designed to be versatile and readily accepts operator inputsa parameter changes in the system.

Types of SCADA systems and areas of applications:

- **Type 1**: Small distribution systems, small hydro stations, HVDC links.
- **Type 2**: Medium sized power system (plant control center), power station HVDC link distribution systems.
- **Type 3**: Regional control center, distribution system in large urban areas several hydro power stations with cascade control.
- **Type 4**: National and Regional control center distributed systems in large urban areas, several hydro power station with cascade control.

Components of SCADA

- SENSORS - Analog and digital sensors are used to interface the systems
- RELAYS– Relays are used to sense the abnormal conditions and protect the system.
- REMOTE TERMINAL UNITS – RTU's are microprocessors controlled electronics devices which are used to collect various data's and transmit to SCADA system.
- MASTER UNIT- Master unit act as a central processor computer.
- COMMUNICATION LINKS- It is used to link RTU's and SCADA system. Satellite communication, microwave communication, fiber optic communication maybe used for communication purpose.

AREA CONTROL ERROR

To maintain a net interchange of power with its neighbors, an AGC uses real power flow measurements of all tie-lines emanating from the area and subtractsthe scheduled interchange to calculate an error value. The net power interchange, together with a gain, b , the frequency bias, as a multiplier on the frequency is called area control error.

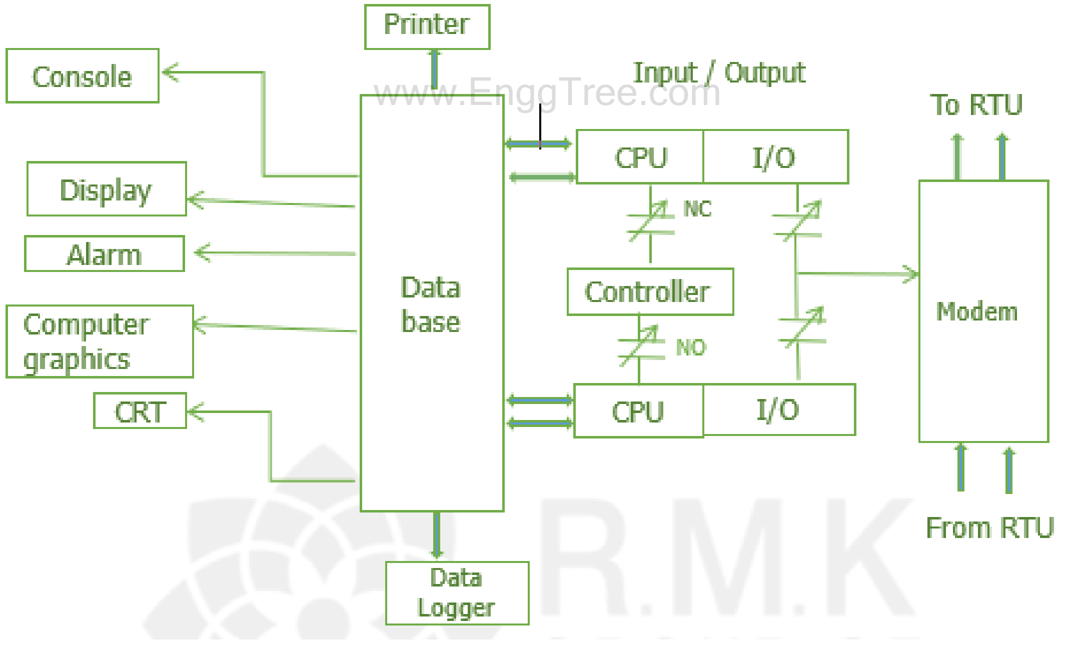
The interchange power Ps, is generally scheduled for periods of the day and is changed as 'blocks' of MWhr are bought or sold to neighboring utilities. A positive ACE or positive net exchange of power represents a flow out of the area.

$$ACE = \sum_{K=1}^{n} P_K + P_S + 10b(f_{act} - f_0)$$

Where,
Pk – MW tie flow defined as positive out of the area
Ps – Scheduled MW interchange
f_0- Scheduled base frequency

MASTER STATION

Master unit is provided with a digital computer with associated interfacing devices and hardware to receive information from RTU, process data and display salient information to the operator.



The hardware at the master station includes the following

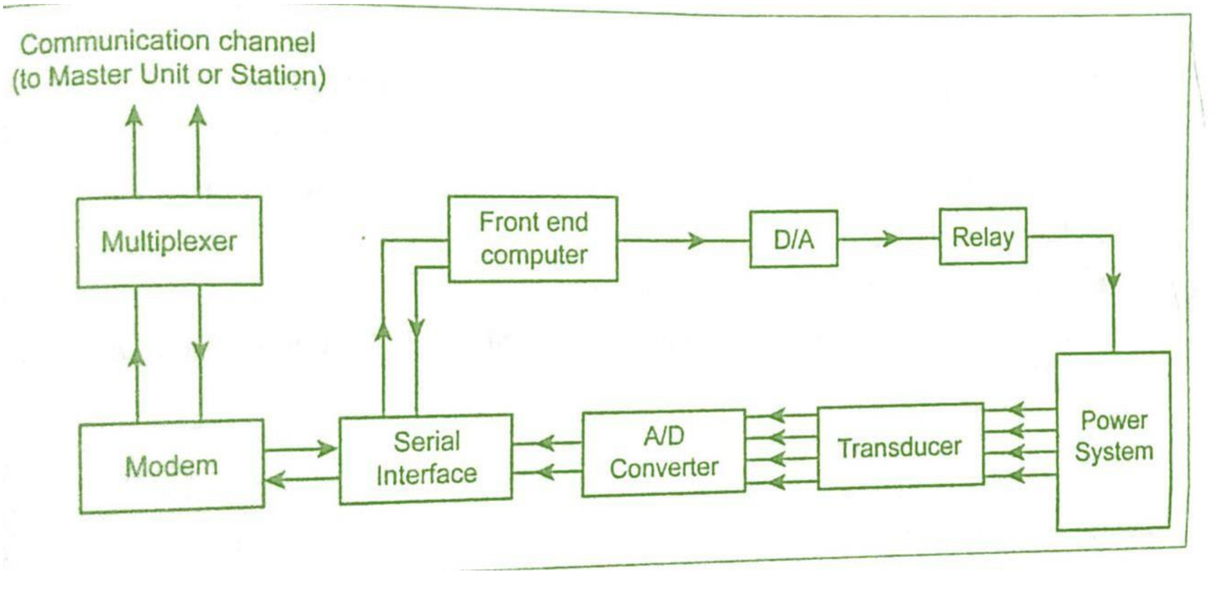
1. Process computer
2. CRT display
3. Printer
4. Data logger

5. Computer graphics
6. Control console
7. Keyboard
8. Alarm panel
9. Instrument panel
10. Modem
11. Multiplexer

REMOTE TERMINAL UNIT

The RTU'S are installed at selected power stations and substations. Thehardware components of RTU may include the following.

1. Transducers
2. A/D and D/A converters
3. Serial Interface
4. Modems
5. Multiplexers
6. Front end Computer
7. Control relays



REMOTE TERMINAL UNITS

The analog quantities like voltage , MW, MVAR and frequency measured at stations are converted into DC voltage or current signals, through transducers andfed to the A/D converters with convert the analog signals into digital from suitable for transmission. The digital signal is fed to the front end computer and modems through the serial interface . MODEM sends the information to the master unit through multiplexer. MODEM will also receive commands from master units to control the station equipment's through the control relays. In addition to measure quantities, status of various devices is informed to master station.

The master station scans the RTU sequentially and gathers information on the system operating condition i.e Voltage, Current, line flows, generation, output, etc as well as equipment status. Computer, using real time data can check operatinglimits of various quantities and give an alarm to operator if overloading or any otherabnormal condition is detected, the system real time information is presented to the operator through CRT, computer graphic terminals, alarm panels, alarm printer so that the operator can supervise minute by minute, system operating condition and take control action to prevent system disturbances whenever emergency conditions and system status at specified interval is printed by data loggers.

FUNCTIONS OF SCADA SYSTEMS

1. Data acquisition
2. Information display.
3. Supervisory Control (CBs : ON/OFF, Generator: stop/start, RAISE/LOWER command)
4. Information storage and result display.
5. Sequence of events acquisition
6. Remote terminal unit processing.
7. General maintenance.
8. Runtime status verification.

9. Economic modeling.
10. Remote start/stop.
11. Load matching based on economics.
12. Load shedding.

CONTROL FUNCTIONS

- Control and monitoring of switching devices, tapped transformers, auxiliarydevices, etc.
- Bay-and a station-wide interlocking
- Dynamic Bus bar coloring according to their actual operational status.Automatic switching sequences
- Automatic functions such as load shedding, power restoration, and high speedbus bar transfer
- Time synchronization by radio and satellite clock signal

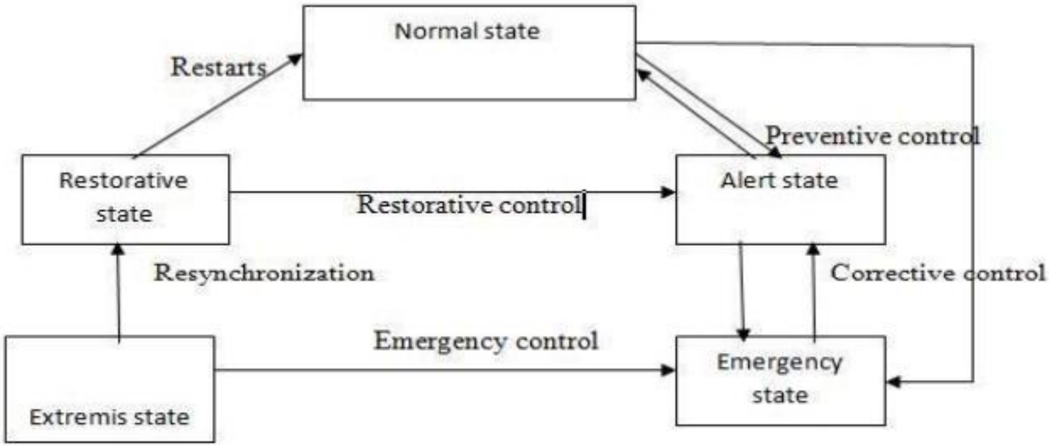
MONITORING FUNCTIONS:

- Measurement and displaying of current, voltage, frequency, active and reactivepower, energy, temperature, etc.
- Alarm functions. Storage and evaluation of time stamped events.Trends and archiving of measurements
- Collection and evaluation of maintenance data Disturbance recording and evaluation

PROTECTION FUNCTIONS:

- Substation protection functions includes the monitoring of events like start, tripindication and relay operating time and setting and reading of relay parameters.
- Protection of bus bars. Line feeders, transformers, generators.
- Protection monitoring (status, events, measurements, parameters, recorders)
- Adaptive protection by switch-over of the active parameter set.

VARIOUS OPERATING STATES:



Operating states

1. Normal state
2. Alert state
3. Emergency state
4. Extremis state
5. Restorative state

Normal state:

A system is said to be in normal if both load and operating constraints are satisfied .It is one in which the total demand on the system is met by satisfying all the operating constraints.

Alert state:

- ➢ A normal state of the system said to be in alert state if one or more of the postulated contingency states, consists of the constraint limits violated.
- ➢ When the system security level falls below a certain level or the probability of disturbance increases, the system may be in alert state .

- All equalities and inequalities are satisfied, but on the event of a disturbance, the system may not have all the inequality constraints satisfied.
- If severe disturbance occurs, the system will push into emergency state. To bring back the system to secure state, preventive control action is carried out.

Emergency state:

- The system is said to be in emergency state if one or more operating constraints are violated, but the load constraint is satisfied .
- In this state, the equality constraints are unchanged.
- The system will return to the normal or alert state by means of corrective actions,·disconnection of faulted section or load sharing.

Extremis state:

- When the system is in emergency, if no proper corrective action is taken in time, then it goes to either emergency state or extremis state.
- In this regard neither the load or nor the operating constraint is satisfied, this result is islanding.
- Also the generating units are strained beyond their capacity .
- So emergency control action is done to bring back the system state either to the emergency state or normal state.

Restorative state:

- From this state, the system may be brought back either to alert state or secure state .The latter is a slow process.
- Hence, in certain cases, first the system is brought back to alert state and then to the secure state .
- This is done using restorative control action.

SECURITY ANALYSIS & CONTROL:

Security monitoring is the on line identification of the actual operating conditions of a power system. It requires system wide instrumentation to gather the system data as well as a means for the on line determination of network topology involving an open or closed position of circuit breakers. A state estimation has been developed to get the best estimate of the status .the state estimation provides the database for security analysis shown in fig

Data acquisition:

1. To process from RTU
2. To check status values against normal value
3. To send alarm conditions to alarm processor
4. To check analog measurements against limits.

Alarm processor:

1. To send alarm messages
2. To transmit messages according to priority

Status processor:

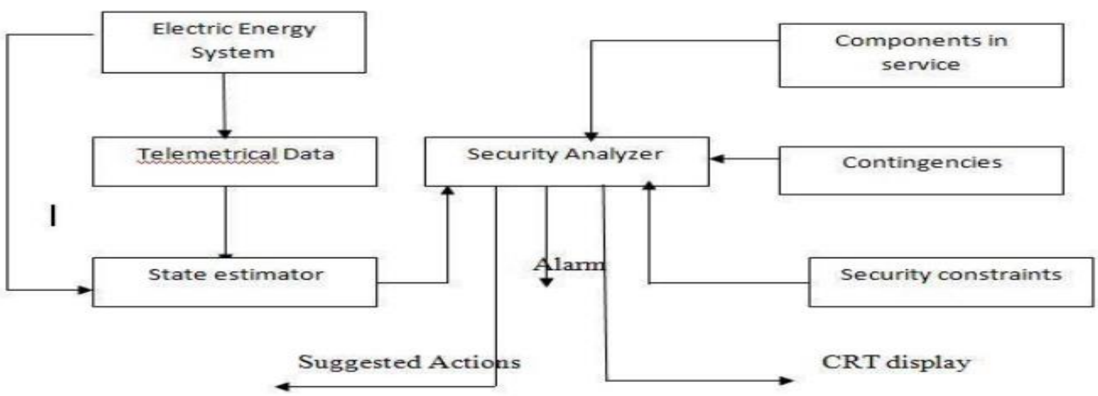
1. To determine status of each substation for proper connection.

Reserve monitor:

1. To check generator MW output on all units against unit limits

State estimator:

1. To determine system state variables
2. To detect the presence of bad measures values.
3. To identify the location of bad measurements
4. To initialize the network model for other programs



Practical Security Monitoring System

Security Control Function:

- Ø Network Topology processor-mode of the N/W
- Ø State estimator.
- Ø Power flow-V, δ,P,Q.
- Ø Optimal power flow.
- Ø Contingency analysis.
- Ø Optimal power flow.

Security enhancement-existing overload using corrective control action. Preventive action.

System Security

1. System monitoring.
2. Contingency analysis.
3. Security constrained optimal power flow

Security Assessment

- Security assessment determines first, whether the system is currently residing in an acceptable state and second, whether the system would respond in an acceptable manner and reach an acceptable state following any one of a pre-defined contingency set.
- A *contingency* is the unexpected failure of a transmission line, transformer, or generator.
- Usually, contingencies result from occurrence of a *fault*, or short-circuit, to one of these components.
- When such a fault occurs, the protection systems sense the fault and remove the component, and therefore also the fault, from the system.
- Of course, with one less component, the overall system is weaker, and undesirable effects may occur.
- For example, some remaining circuit may overload, or some bus may experience an undervoltage condition. These are called *static* security problems.
- *Dynamic* security problems may also occur, including uncontrollable voltage decline, generator overspeed (loss of synchronism), or undamped oscillatory behavior

Security Control

- Power systems are designed to survive all probable contingencies.

- A contingency is defined as an event that causes one or more important components such as transmission lines, generators, and transformers to be unexpectedly removed from service.
- Survival means the system stabilizes and continues to operate at acceptable voltage and frequency levels without loss of load.
- Operations must deal with a vast number of possible conditions experienced by the system, many of which are not anticipated in planning.
- Instead of dealing with the impossible task of analyzing all possible system states, security control starts with a specific state: the current state if executing the real-time network sequence; a postulated state if executing a study sequence.
- Sequence means sequential execution of programs that perform the following steps:

1. Determine the state of the system based on either current or postulated conditions.
2. Process a list of contingencies to determine the consequences of each contingency on the system in its specified state.
3. Determine preventive or corrective action for those contingencies which represent unacceptable risk.

- Security control requires topological processing to build network models and uses large-scale AC network analysis to determine system conditions.
- The required applications are grouped as a network subsystem that typically includes the following functions:

Topology processor:

Processes real-time status measurements to determine an electrical connectivity (bus) model of the power system network.

State estimator:

Uses real-time status and analog measurements to determine the best estimate of the state of the power system. It uses a redundant set of measurements; calculates voltages, phase angles, and power flows for all components in the system; and reports overload conditions.

Power flow:

Determines the steady-state conditions of the power system network for a specified generation and load pattern. Calculates voltages, phase angles, and flows across the entire system.

Contingency analysis:

Assesses the impact of a set of contingencies on the state of the power system and identifies potentially harmful contingencies that cause operating limit violations.

Optimal power flow: Recommends controller actions to optimize a specified objective function (such as system operating cost or losses) subject to a set of power system operating constraints.

Security enhancement:

Recommends corrective control actions to be taken to alleviate an existing or potential overload in the system while ensuring minimal operational cost.

Preventive action:

Recommends control actions to be taken in a "preventive" mode before a

contingency occurs to preclude an overload situation if the contingency were to occur.

Bus load forecasting:

Uses real-time measurements to adaptively forecast loads for the electrical connectivity (bus) model of the power system network

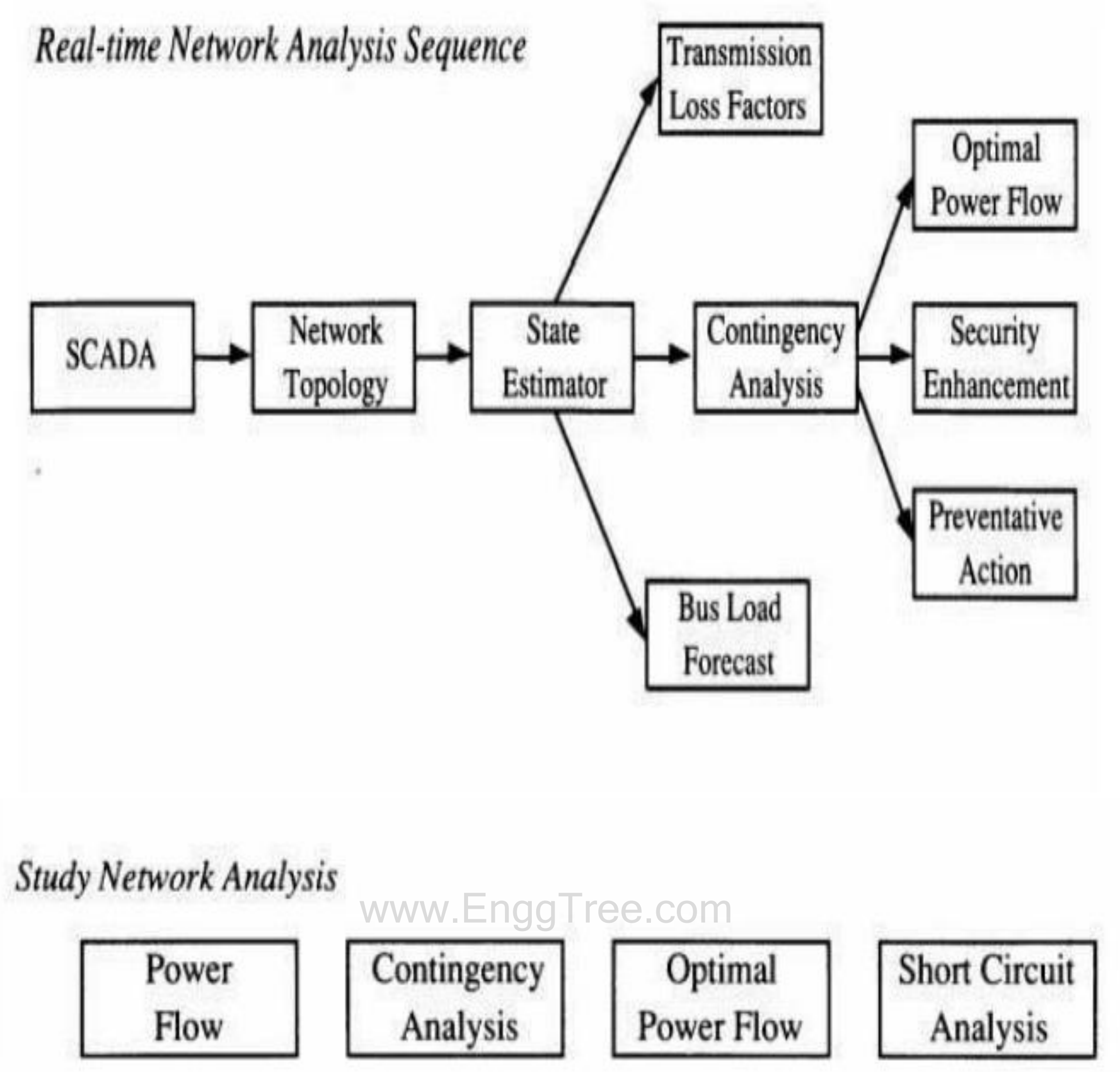
Transmission loss factors:

Determines incremental loss sensitivities for generating units;

calculates the impact on losses if the output of a unit were to be increased by 1 MW.

Short-circuit analysis:

Determines fault currents for single-phase and three-phase faults for fault locations across the entire power system network.



Real-time and study network analysis sequences.