POWER SYSTEM OPERATION AND CONTROL

Unit 1: CONTROL CENTRE OPERATION OF POWER SYSTEMS

Syllabus :

Introduction to SCADA, control centre, digital computer configuration, automatic generation control, area control error, operation without central computers, expression for tie-line flow and frequency deviation, parallel operation of generators, area lumped dynamic model.

General

Electrical Technology was founded on the remarkable discovery by Faraday that a changing magnetic flux creates an electric field. Out of that discovery, grew the largest and most complex engineering achievement of man : the electric power system. Indeed, life without electricity is now unimaginable. Electric power systems form the basic infrastructure of a country. Even as we read this, electrical energy is being produced at rates in excess of hundreds of giga-watts (1 GW = 1,000,000,000 W). Giant rotors spinning at speeds up to 3000 rotations per minute bring us the energy stored in the potential energy of water, or in fossil fuels. Yet we notice electricity only when the lights go out!

While the basic features of the electrical power system have remained practically unchanged in the past century, but there are some significant milestones in the evolution of electrical power systems.

1.0 Introduction

Electrical energy is an essential ingredient for the industrial and all round development of any country. It is generated centrally in bulk and transmitted economically over long distances.

Electrical energy is conserved at every step in the process of Generation, Transmission, Distribution and utilization of electrical energy. The electrical utility industry is probably the largest and most complex industry in the world and hence very complex and challenging problems to be handled by power engineering particularly, in designing future power system to deliver increasing amounts of electrical energy. This calls for perfect understanding, analysis and decision making of the system. This power system operation and its control play a very important task in the world of Electrical Power Engineering.

Power Quality

Power quality is characterized by –

a. Stable AC voltages at near nominal values and at near rated frequency subject to acceptable minor variations, free from annoying voltage flicker, voltage sags and frequency fluctuations.

b. Near sinusoidal current and voltage wave forms free from higher order harmonics

All electrical equipments are rated to operate at near rated voltage and rated frequency.

Effects of Poor PowerQuality

Maloperation of control devices, relays etc.

Extra losses in capacitors, transformers and rotating machines

Fast ageing of equipments

Loss of production due to service interruptions

Electro-magnetic interference due to transients

power fluctuation not tolerated by power electronic parts

Major causes of Poor Power Quality

Nonlinear Loads

Adjustable speed drives

Traction Drives

Start of large motor loads

Arc furnaces

Intermittent load transients

Lightning

Switching Operations

Fault Occurrences

Steps to address Power Quality issues

- Detailed field measurements
- Monitor electrical parameters at various places to assess the operating conditions in terms of power quality.
- Detailed studies using a computer model. The accuracy of computer model is first built to the degree where the observed simulation values matches with those of the field measurement values. This provides us with a reliable computer model using which we workout remedial measures.

- For the purpose of the analysis we may use load flow studies, dynamic simulations, EMTP simulations, harmonic analysis depending on the objectives of the studies.
- We also evaluate the effectiveness of harmonic filters through the computer model built, paying due attention to any reactive power compensation that these filters may provide at fundamental frequency for normal system operating conditions.
- The equipment ratings will also be addressed to account for harmonic current flows and consequent overheating.

Power Quality Solutions:

Poor power quality in the form of harmonic distortion or low power factor increases stress on a facility's electrical system. Over time this increased electrical stress will shorten the life expectancy of electrical equipment. In addition to system degradation, poor power quality can cause nuisance tripping and unplanned shutdowns within electrical system.

In an increasingly automated electrical world, it is important for a facility to evaluate power quality. Harmonic distortion, low power factor, and the presence of other transients can cause severe damage to electrical system equipment. PSE provides system analysis and evaluation of power quality issues and makes recommendations for system design solutions

Structure of Power Systems

Generating Stations, transmission lines and the distribution systems are the main components of an electric power system. Generating stations and distribution systems are connected through transmission lines, which also connect one power system (grid, area) to another. A distribution system connects all the loads in a particular area to the transmission lines.

For economical technical reasons, individual power systems are organized in the form of electrically connected areas or regional grids.

As power systems increased in size, so did the number of lines, substations, transformers, switchgear etc. Their operation and interactions became more complex and hence it is necessary to monitor this information simultaneously for the total system at a focal point called as Energy Control Centre. The fundamental design feature is increase in system reliability and economic feasibility.

Major Concerns of Power System Design and Operation

- Quality : Continuous at desired frequency and voltage level
- Reliability :Minimum failure rate of components and systems
- Security : Robustness - normal state even after disturbances
- Stability : Maintain synchronism under disturbances
- Economy : Minimize Capital, running and maintenance Costs

Need for Power System Management

- Demand for Power Increasing every day
- No of transmission line, Sub-stations, Transformers, switchgear etc.,
- Operation and Interaction is more and more complex
- Essential to monitor simultaneously for the total system at a focal point – ENERGY LOAD CENTRE

Components of power system operation and control

- Information gathering and processing
- Decision and control
- System integration

Energy Load Centre

The function of energy load centre is to control the function of coordinating the response in both normal and emergency conditions. Digital Computers are very effectively used for the purpose. Their function is to process the data, detect abnormalities, alarm the human operator by lights, buzzers, screens etc., depending on the severity of the problem.

Control Centre of a Power System

- Human Machine Interface – equipped with
- CRT presentations
- Keyboards – change parameters
- Special function keyboards- alter transformer taps, switch line capacitors etc.,
- Light-Pen cursor – open or close circuit breakers
- Alarm lights, alarms, dedicated telephone communications with generating stations and transmission substations, neighboring power utilities

Control Features – ControlCentre

- System Commands – Mode of control
- Units – base / peak load
- AGC – Automatic Generation Control
- Data Entry
- Alarms – To find source of alarm and necessary action
- Plant/Substation selection
- Special Functions - To send/retrieve data etc.,
- Readout control – Output to CRT/printers etc.,
- CPU control – Selection for the computer

Functions of ControlCentre

- Short, Medium and Long-term Load Forecasting
- System Planning
- Unit Commitment and maintenance Scheduling
- Security Monitoring
- State Estimation
- Economic Dispatch
- Load Frequency Control

SCADA – Supervisory Control and Data Acquisition

One of key processes of SCADA is the ability to monitor an entire system in real time. This is facilitated by data acquisitions including meter reading, checking statuses of sensors, etc that are communicated at regular intervals depending on the system.

A well planned and implemented SCADA system not only helps utilities deliver power reliably and safely to their customers but it also helps to lower the costs and achieve higher customer satisfaction and retention.

SCADA – Why do we need it?

- If we did not have SCADA, we would have very inefficient use of human resources and this would cost us (Rs,Rs,Rs)
- In today's restructured environment SCADA is critical in handling the volume of data needed in a timely fashion
- Service restoration would involve travel time and would be significantly higher
- It is essential to maintain reliability

SCADA - Architecture

- Basic elements are sensors which measure the desired quantities
- Current Transformers CTs – measure currents and Potential Transformers PTs- measure voltages.
- Today there is a whole new breed of Intelligent electronic devices (IEDs)
- This data is fed to a remote terminal unit (RTU)
- The master computer or unit resides at the control center EMS

SCADA - Process

- Master unit scan RTUs for reports, if reports exist, RTU sends back the data and the master computer places it in memory
- In some new substation architectures there could be significant local processing of data which could then be sent to the control center.
- The data is then displayed on CRTs and printed SCADA - Logging
- The SCADA provides a complete log of the system
- The log could be provided for the entire system or part of the system
- Type of information provided
    - Time of event
    - Circuit breaker status
    - Current measurements, voltage measurements, calculated flows, energy, etc.
    - Line and equipment ratings

SCADA as a System

There are many parts of a working SCADA system. A SCADA system usually includes signal hardware (input and output), controllers, networks, user interface (HMI), communications equipment and software. All together, the term SCADA refers to the entire central system. The central system usually monitors data from various sensors that are either in close proximity or off site (sometimes miles away).

For the most part, the brains of a SCADA system are performed by the Remote Terminal Units (sometimes referred to as the RTU). The Remote Terminal Units consists

of a programmable logic converter. The RTU are usually set to specific requirements, however, most RTU allow human intervention, for instance, in a factory setting, the RTU might control the setting of a conveyer belt, and the speed can be changed or overridden at any time by human intervention. In addition, any changes or errors are usually automatically logged for and/or displayed. Most often, a SCADA system will monitor and make slight changes to function optimally; SCADA systems are considered closed loop systems and run with relatively little human intervention.

SCADA can be seen as a system with many data elements called points. Usually each point is a monitor or sensor. Usually points can be either hard or soft. A hard data point can be an actual monitor; a soft point can be seen as an application or software calculation. Data elements from hard and soft points are usually always recorded and logged to create a time stamp or history

User Interface – Human Machine Interface (HMI)

A SCADA system includes a user interface, usually called Human Machine Interface (HMI). The HMI of a SCADA system is where data is processed and presented to be viewed and monitored by a human operator. This interface usually includes controls where the individual can interface with the SCADA system.

HMI's are an easy way to standardize the facilitation of monitoring multiple RTU's or PLC's (programmable logic controllers). Usually RTU's or PLC's will run a pre programmed process, but monitoring each of them individually can be difficult, usually because they are spread out over the system. Because RTU's and PLC's historically had no standardized method to display or present data to an operator, the SCADA system communicates with PLC's throughout the system network and processes information that is easily disseminated by the HMI.

HMI's can also be linked to a database, which can use data gathered from PLC's or RTU's to provide graphs on trends, logistic info, schematics for a specific sensor or machine or even make troubleshooting guides accessible. In the last decade, practically all SCADA systems include an integrated HMI and PLC device making it extremely easy to run and monitor a SCADA system.

Today’s SCADA systems, in response to changing business needs, have added new functionalities and are aiding strategic advancements towards interactive, self healing smart grids of the future. A modern SCADA system is also a strategic investment which is a must-have for utilities of all sizes facing the challenges of the competitive market and increased levels of real time data exchange that comes with it (Independent Market Operator, Regional Transmission Operator, Major C&I establishments etc). A well planned and implemented SCADA system not only helps utilities deliver power reliably and safely to their customers but it also helps to lower the costs and achieve higher customer satisfaction and retention. Modern SCADA systems are already contributing and playing a key role at many utilities towards achieving :

- New levels in electric grid reliability – increased revenue.
- Proactive problem detection and resolution – higher reliability.

- Meeting the mandated power quality requirements – increased customer satisfaction.
- Real time strategic decision making – cost reductions and increased revenue

Critical Functions of SCADA

Following functions are carried out every 2 seconds :

- Switchgear Position, Transformer taps, Capacitor banks
- Tie line flows and interchange schedules
- Generator loads, voltage etc.,
- Verification on links between computer and remote equipment

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Digital Computer Configuration

Major functions

- Data acquisition control
- Energy Management
- System Security

For best/secured operation 100% redundancy is used – Dual Digital Computers

i) on-line computer – monitors and controls the system

ii) Backup computer – load forecasting or hydro thermal allocations

The digital computers are usually employed in a fixed-cycle operating mode with priority interrupts wherein the computer periodically performs a list of operation. The most critical functions have the fastest scan cycle. Typically the following categoties are scanned every 2 seconds :

- All status points such as switchgear position (open or closed), substation loads and voltages, transformer tap positions, and capacitor banks etc.,
- Tie line flows and interchange schedules
- Generator loads, voltage, operating limits and boiler capacity
- Telemetry verificationto detect failures and errors in the bilateral communication links between the digital computer and the remote equipment.

Important Areas of Concern in power System

- Automatic Generation Control(AGC)

On-line Computer Control that maintains overall system frequency and net tie- line load exchange through interconnection

- Economic Load Dispatch

On-line computer control to supply load demand using all interconnected system's power in the most economical manner

AGC is the name given to a control system having three major objectives :

a. To hold system frequency at or very close to a specified nominal value (50 or 60Hz)
b. To maintain the correct value of interchange power between control areas
c. To maintain each unit's generation at the most economic value.

To implement an AGC system, the following information is required :

- Unit megawatt output of each committed unit
- Megawatt flow over each tie line to neighboring systems
- System frequency

Usually, neighboring power companies are interconnected by one or more transmission lines called Tie Lines. The objective is to buy or sell power with neighboring systems whose operating costs make such transactions profitable. Also, even if no power is being transmitted over ties to neighboring system, if one system has a sudden loss of a generating unit, the units throught all the interconnection will experience a frequency change and can help in restoring frequency.

Advantages of interconnected system

- Reduces Reserve Capacity – thus reduces installed capacity
- Capital Cost/kW is less for larger Unit
- in India single unit can support >500MW because of interconnection
- Effective Use of Generators
- Optimization of Generation – installed capacity is reduced
- Reliability

Disadvantages of interconnected system

- Fault get Propagated – calls for fast switchgear
- CB rating increases
- Proper management required – EMS and it must be automated – Economic load dispatch - Base load and Peak Load

National Regional Electricity Boards

- Northern Regional Electricity Board
- Western Regional Electricity Board
- Southern Regional Electricity Board
- Eastern Regional Electricity Board
- North-east Regional Electricity Board

Goal – To have National Grid to improve efficiency of the whole National Power Grid

Control Area Concept

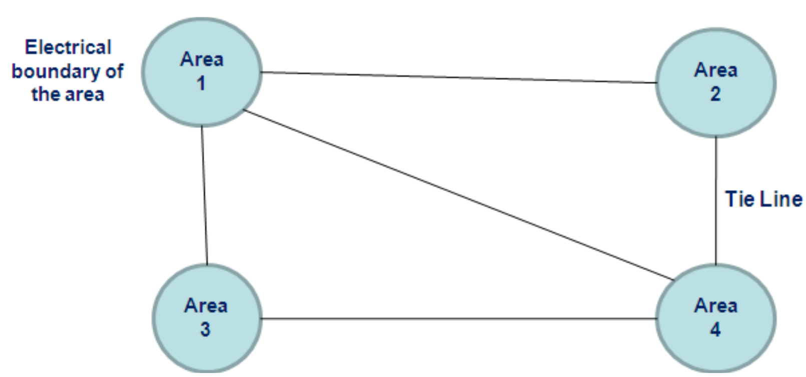
All generators are tightly coupled together to form – Coherent Group

- all generators respond to changes in load or speed changer setting

Control Area – frequency is assumed to be constant throughout in static and dynamic conditions

For the purpose of analysis, a control area can be reduced to a single speed governor, turbo generator and load system

Interconnected Power System



Functions

- Exchange or sale of power
- Disturbed areas taking other area's help
- Long distance sale and transfer of power

Area Control Error – ACE

To maintain a net interchange of power with its area neighbors, an AGC uses real power flow measurements of all tie linesa emanating from the area and subtracts the scheduled interchange to calculate an error value. The net power interchange, together with a gain, B (MW/0.1Hz), called the frequency bias, as a multiplier on the frequency deviation is called the Area Control Error (ACE) given by,

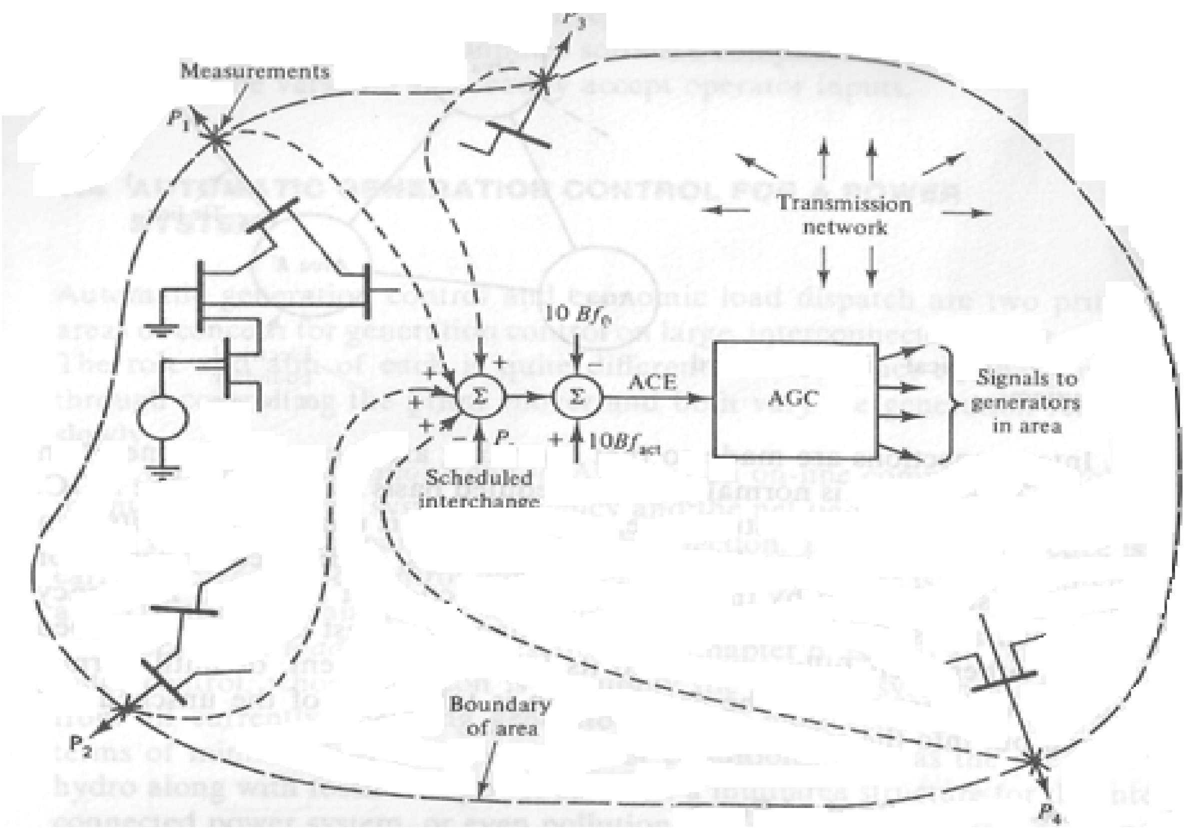
$$\sum_{k=1}^{k} P_k - P_s + B(f_{act} - f_0)\ MW$$

P_k = Power in Tie lIne - +ve – out of the area P_s – Scheduled Power Interchange

f_0 – Base frequency, f_{act} – Actual frequency

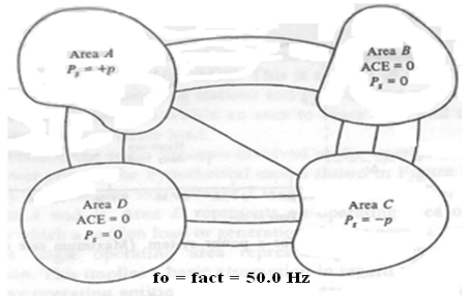
+ve ACE indicates flow out of the area.

ACE – Input to AGC



The real power summation of ACE loses information as to the flow of individual tie lines but is concerned with area net generation. The tie lines transfer power through the area from one neighbor to the next, called 'Wheeling Power'. The wheeling power cancels algebraically in the ACE. Thus one area purchases or sells blocks of power (MWh) with non-neighbor utilities.

Power Sale from A to C

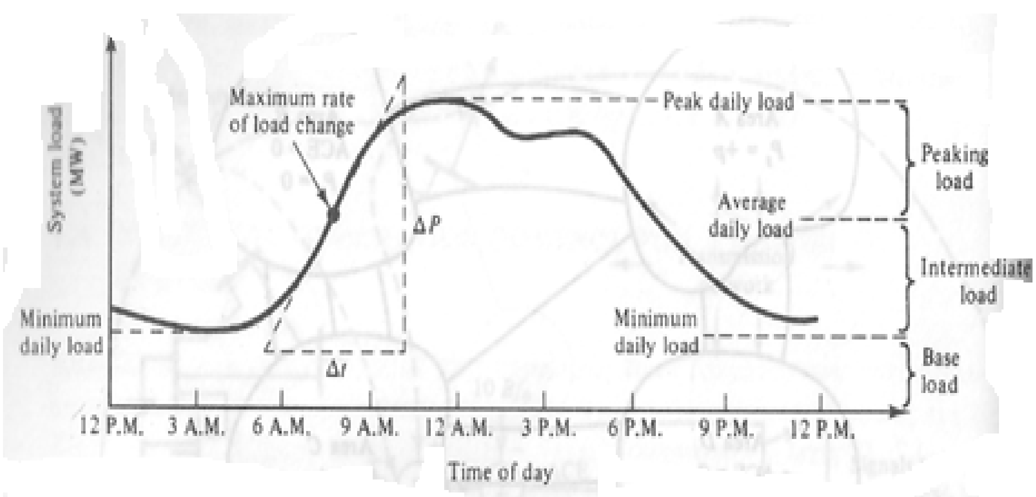


- A – selling a power 'p' to C, then ACE for A = p
- Power export starts until its AGC forces ACE to become zero
- Area C introduces '-p' into its ACE
- Power flows in to area C until its ACE becomes zero
- Areas B & C must be aware of the power exchange as they are also interconnected

The minimum requirements of AGC on controlling the interchange of power and frequency have been established by NERC – North American Electric Reliability Council, which is comprised of representatives of the major operating power pools. This committee specifies the following criteria as minimum performance expected by AGC. A. Normal System Conditions

- ACE = 0 at least once in 10 min period
- Deviation of ACE from zero must be within allowable limits B. Disturbances Conditions
- ACE must return to zero within 10 min
- Corrective action from AGC must be within a minimum disturbance

Daily Load Cycle



The allowable limit, L_d of the average deviation on power systems (averaged over 10 minutes) is :

$L_d = 0.025\Delta L + 5.0$ MW

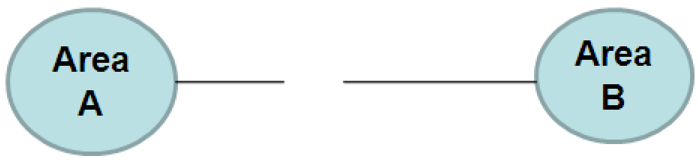
$\Delta L = \Delta P / \Delta t$ MW/hr

The value of ΔL is determined annually and is taken from the daily load cycle. A power system is said to be in a disturbance condition if the ACE signal exceeds 3Ld.

Operation without Central Computers or AGC

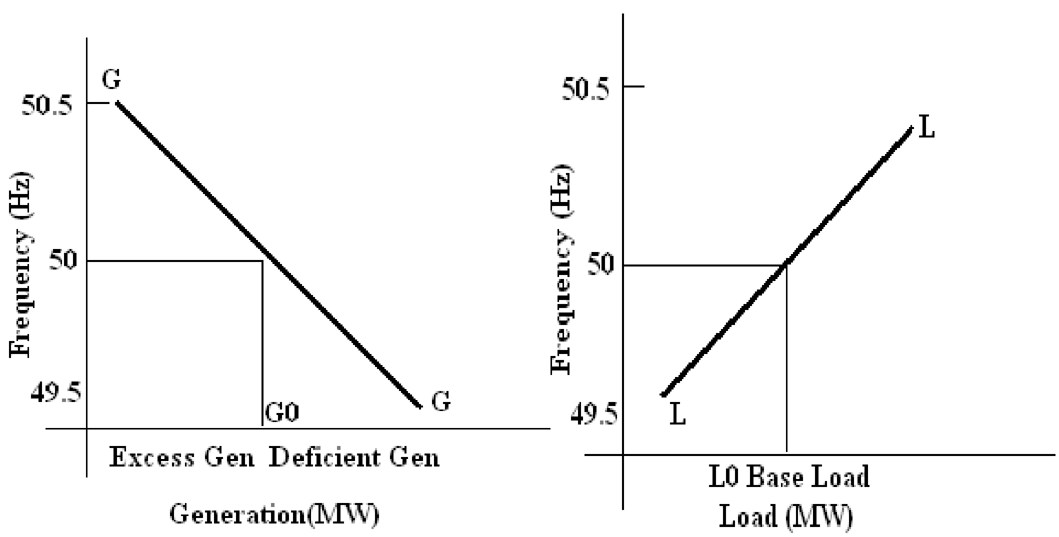
Power Systems are capable of functioning even *without* Central Computer and/or AGC

- Due to a result of Turbine Generator speed controls in the generating station and natural load regulation
- Thus generators within an area are forced to share load and cause interconnected areas to share load



Generation Frequency Characteristic Curve

Let there be two independent areas A and B without tie line flow as the circuit breaker is open. Let there be a sudden change in load occurs in the area D. Area A is considered as a single operating area representing the remainder of the interconnection. It is further assumed that the areas share the disturbance in proportion to their generating capacity and operating characteristics. Let the area generation- frequency characteristics be represented by the curve GG which is a composite response curve from all the generators in area A. The characteristic curve has a negative slope with frequency.



The area connected load is defined by the curve LL as shown. As there is increase in load the rotating machinery in the area is forced to increase the speed.

Basic Equations

$G_A = G_0 + 10\beta_1 (f_{act} - f_0)$ MW $L_A = L_0 + 10\beta_2 (f_{act} - f_0)$ MW

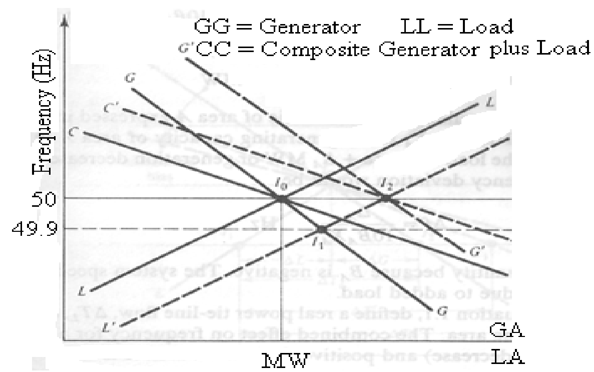
G_A = Total Generation, G_0 = Base generation

L_A = Total Load, L_0 = Base load, f_{act} = System frequency, f_0 = Base frequency β_1 = Cotangent of generation-frequency characteristic,

MW/0.1 Hz < 0

β_2 = Cotangent of load-frequency characteristic, MW/0.1 Hz > 0

Isolated Operation in A – response to load change



For Steady State Frequency – Total generation = Total effective load This is defined by the intersection of GG and LL curves as shown – Io.

Combined characteristic of GG and LL is CC. The composite generation load frequency characteristics is given by,

$G_A = G_0 + 10\beta_1 (f_{act} - f_0)$, $L_A = L_0 + 10\beta_2 (f_{act} - f_0)$ $G_A - L_A = G_0 + 10\beta_1 (f_{act} - f_0) - L_0 - 10\beta_2 (f_{act} - f_0)$

Increase in load in 'A' moves the load frequency curve to position L'L'. The new system frequency will now be defined by the intersection labeled as I_1 at 49.9Hz.Then it is desired to return the system frequency to 50.0Hz i.e., point I_2.

Setting AGC in 'A'- shifting of GG to G'G' takes place to meet frequency demand of 50.0Hz – I2

Resulting combined characteristic is C'C' In terms of increments,

$\Delta_A = G_A - G_0 + L_0 - L_A = 10\beta_1 (f_{act} - f_0) - 10\beta_2 (f_{act} - f_0)$

$= 10 B_A X_A \Delta f$ MW

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$= 10 B_A X_A \Delta f$ MW

B_A - Natural regulation characteristic - % gen for 0.1Hz X_A – Generating Capacity of A, MW

Frequency deviation = $\Delta f = \Delta_A / 10 B_A X_A$ Hz Considering Tie line flow, Frequency deviation

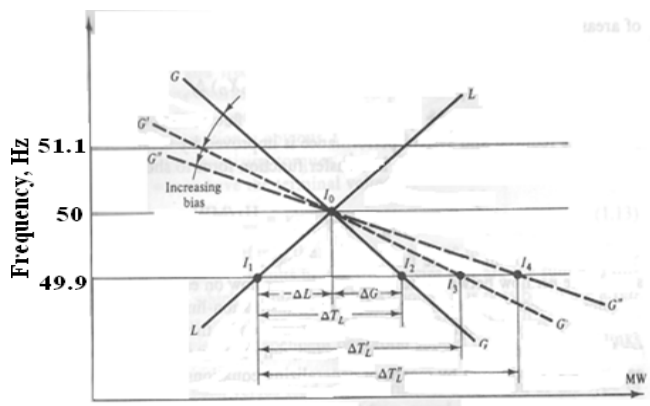
$\Delta f = (\Delta_A + \Delta T_L) / (10 B_A X_A)$ Hz

$\Delta_A + \Delta T_L$ - Net Megawatt change

$\Delta T_L = \Delta G_A - \Delta L_A$

Effect of Tie Line Flow - Interconnected operation

Let two areas A and B are interconnected through a Tie Line. Thus both Generation and Load frequency are equal to 50.0 Hz. There is no initial Tie Line Power Flow.



- Disturbance occur at B causing frequency to drop to 49.9Hz
- Area generation does not match with effective load in A
- Difference between I1 and I2 – difference between generation and load – net excess power in the area – flows out of A towards B
- Contributory effects in A are decrease in load power ΔL and increase in generation ΔG
- Tie Line Flow from A to B = $\Delta T_L = (\Delta G_A - \Delta L_A)$ MW
- If area A has AGC, tie line flows increases – ΔT_L' and ΔT_L'' representing increased amounts of bias due to AGC.

Frequency change due to disturbance Δ_B for a tie line power flow from A to B is

$\Delta f = \Delta_B - \Delta T_L / (10 B_B X_B)$ Hz

$\Delta T_L = (10 B_A X_A) \Delta_{AB} / (10 B_A X_A + 10 B_B X_B)$ MW

Net power change in B is

$= \Delta_{AB} - \Delta T_L$

$= (10 B_B X_B) \Delta_{AB} / (10 B_A X_A + 10 B_B X_B)$

$\Delta_{AB} = (10B_A X_A + 10B_B X_B)\Delta f$

Hence, $\Delta f / \Delta_{AB} = 1/(10B_A X_A + 10B_B X_B)$

Example

Two areas A and B are interconnected. Generating capacity of A is 36,000Mw with regulating characteristic of 1.5%/0.1Hz. B has 4000MW with 1%/0.1Hz. Find each area's share of +400MW disturbance (load increase) occurring in B and resulting tie line flow.

$\Delta f = \Delta_{AB} / (10\, B_A X_A + 10\, B_B X_B = 400 / -10(0.015)(36{,}000) - 10(0.01)(4000)$

$= -0.06896$ Hz

Tie Line flow = $\Delta T_L = (10B_A X_A)\, \Delta_{AB} / (10B_A X_A + 10B_B X_B) = 5400*400/4800$

= 372.4MW

Smallersystem need only 27.6 MW Frequencyregulationismuchbetter

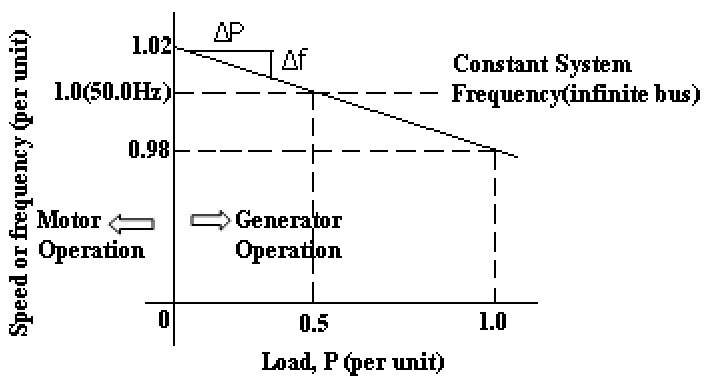
Parallel Operation of Generators

Tie line flows and frequency droop described for interconnected power areas are composite characteristics based on parallel operation of generators. Each area could maintain its speed w = 2 f, then aload common to both areas, by superposition have Π

the terminal voltage,

$V_{load} = V_1 \sin w_1 t + V_2 \sin w_2 t$, Where, 1&2 represents areas and 't' time in secs. Generator speed versus load characteristics is a function of the type of the governor used on the prime mover- type 0 – for a speed droop system and type 1 – forconstant speed system.

Parallel operation of generator with infinite bus

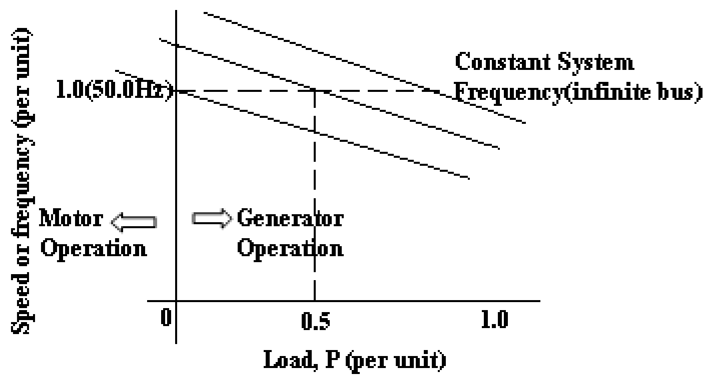


The generator characteristic is such that it is loaded to 50% of its capacity when paralleled to the bus.

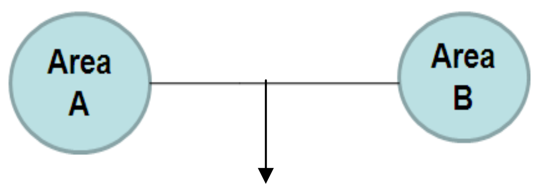
Therefore, Unit speed regulation = R = $\Delta f(pu)/\Delta P(pu)$

$$= \frac{\Delta f(Hz)/50(Hz)}{\Delta P(MW)/P_{rate}(MW)}$$

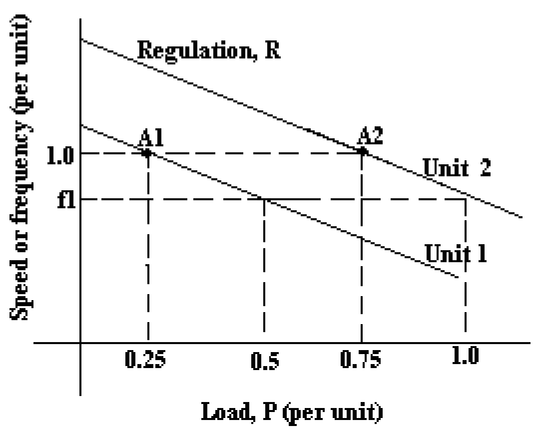
If it is desired to increase the load on the generator, the prime mover torque is increased, which results in a shift of the speed-droop curve as shown below. The real power flow is given by, $P = V_1V_2 \sin(\theta_1 - \theta_2) / X$, where X = synchronous reactance



Parallel operation of two identical units



Load



Two generators paralleled have different governor-speed-droop characteristics. Because they are in parallel, power exchange between them forces them to synchronize at a common frequency. Since the two units are of equal capacity having equal regulation are initially operating at 1.0 base speed as shown above.

If unit is operated at point A_1 satisfies 25% of the total load and unit 2 at point A_2 supplies 75%. If the total load is increased to 150%, the frequency decreases to f_1. Since the droop curves are linear, unit 1 will increase its load to 50% of rating and unit 2 to be overloaded.

Parallel operation of two units with different capacity and regulation

The case when two units of different frequency and regulation characteristics are operated in parallel is as shown below. The regulation characteristics are

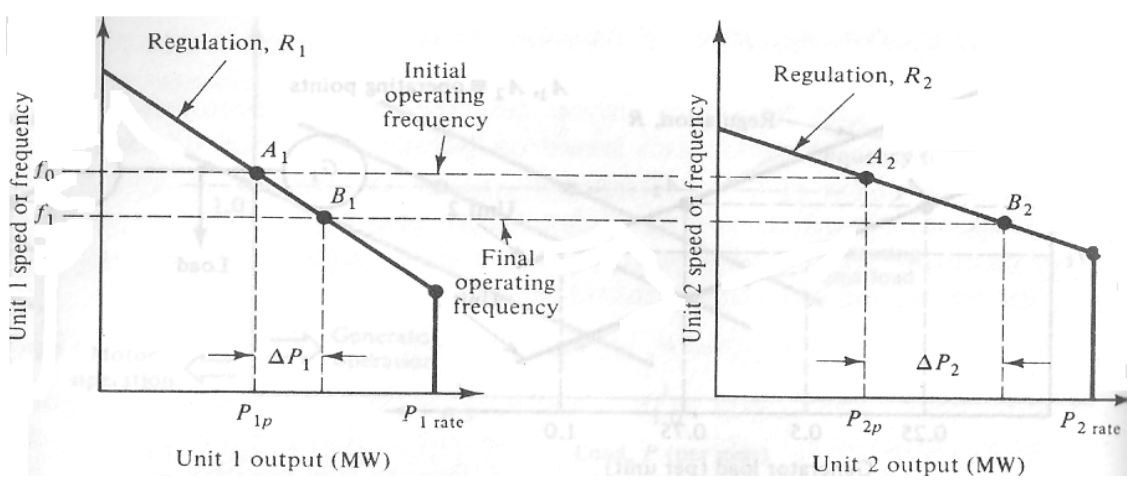
R1 = Δf(pu) / ΔP1 (pu), R2 = Δf(pu) / ΔP2 (pu)

$$\frac{\Delta P_1}{\Delta P_2} = \frac{R_2}{R_1} \frac{P_{1\,rate}}{P_{2\,rate}}$$

Initial Loads - P1 and P2, change in load

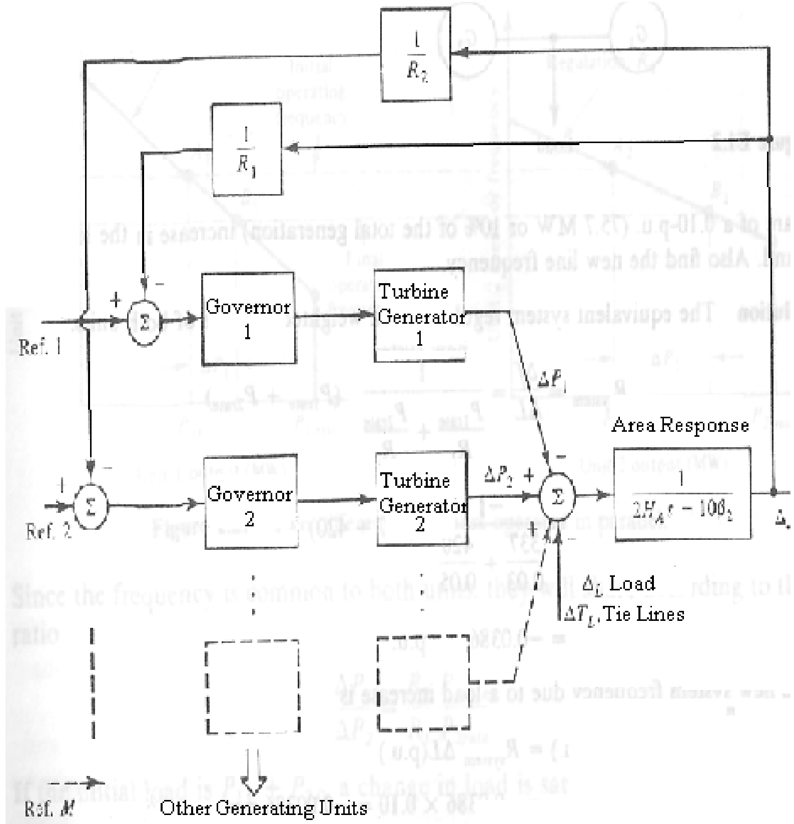
$$\Delta L = \Delta P1 + \Delta P2 = \frac{\Delta f\, P_{1\,rate}}{R_1} + \frac{\Delta f\, P_{2\,rate}}{R_2}$$

$$\text{Equivalent System Regulation} = \Delta f / \Delta L = \frac{1}{\frac{P_{1\,rate}}{R_1} + \frac{P_{2\,rate}}{R_2}}$$



Area Lumped Dynamic Model

The model discussed so far is one macroscopic behavior because there is no effort made to indicate instantaneous power flow within the system due to a tie line disturbance, magnitudes of the internal line flows, the time history of generator phase angles and so on. The power system macro model may be described by means of a block diagram as shown in the block diagram.



H_A = Effective Inertia of rotating machinery loads B_2 = Load frequency characteristics, MW/0.1Hz P_{irate} = Rated power output of Gen 'i'

ΔP_i = Power Increment for gen 'i'

$1/R_i$ = Droop characteristic of gen 'i', Hz/MW

Analysis – Isolated Power Area without Tie Lines

Steady State value of Frequency deviation Δf for a load change ΔL

$$= \Delta_A/S$$

Hence,

$\Delta f/ \Delta_A = 1/(10\beta_1 - 10\beta_2)$

Combining droop characteristics of M gen,

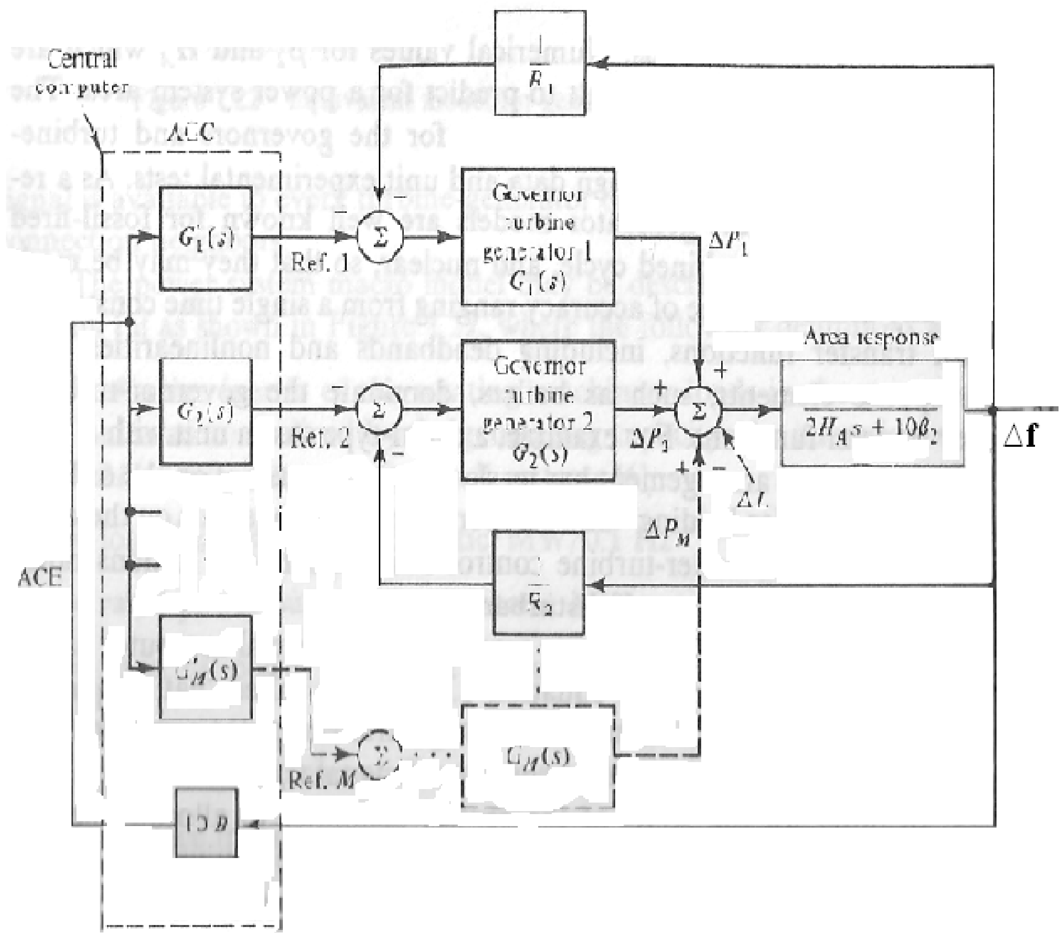
$$-10\beta_1 = \frac{P_{1\,rate}}{R_1} + \frac{P_{2\,rate}}{R_2} + \ldots\ldots \frac{P_{M\,rate}}{R_M}$$

Analysis - Isolated Power Area with AGC

- Area with AGC sensing only frequency – **Flat Frequency**
- To determine frequency error by AGC- equivalent transfer function and gain of all generators is considered

$$\frac{\Delta f(s)}{\Delta L(s)} = \frac{-1}{(2H_A S + 10\beta_2) + \sum_{i=1}^{M}\left[\frac{G_i(s)}{R_i}\right] + 10B\sum_{i=1}^{M} G_i'(s)G_i(s)}$$

- AGC sensing frequency error contributes to natural regulation
- Contribution of AGC is often **"Supplement Control"** - effect depends on transfer function



Unit 2 & 3: Automatic Generation Control

Introduction

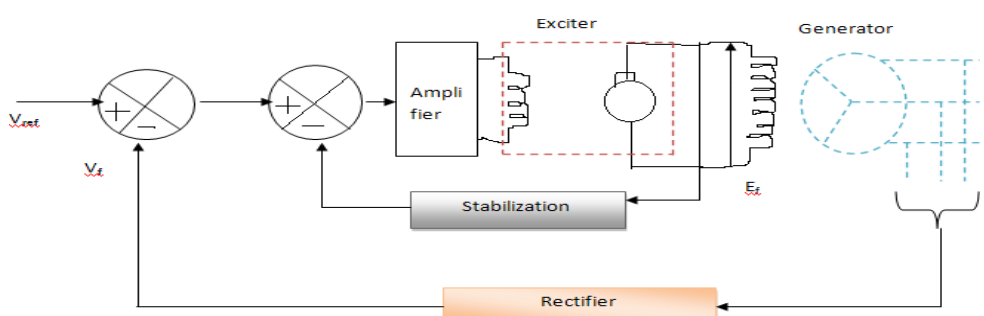
The main objective of power system operation and control is to maintain continuous supply of power with an acceptable quality, to all the consumers in the system. The system will be in equilibrium, when there is a balance between the power demand and the power generated. As the power in AC form has real and reactive components: the real power balance; as well as the reactive power balance is to be achieved.

There are two basic control mechanisms used to achieve reactive power balance (acceptable voltage profile) and real power balance (acceptable frequency values). The former is called the automatic voltage regulator (AVR) and the latter is called the automatic load frequency control (ALFC) or automatic generation control (AGC).

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 an excitation control system is shown in Fig2.1.



A schematic of excitation (voltage) control system

Fig2.1: A schematic of Excitation (Voltage) Control System.

A simplified block diagram of the generator voltage control system is shown in Fig2.2. The generator terminal voltage V_t is compared with a voltage reference V_{ref} to obtain a voltage error signal ΔV. This signal is applied to the voltage regulator shown as a block with transfer function $K_A/(1+T_As)$. The output of the regulator is then applied to exciter shown with a block of transfer function $K_e/(1+T_e s)$. The output of the exciter E_{fd} 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 $K_F/(1+sT_F)$. The total transfer

function is

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

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.

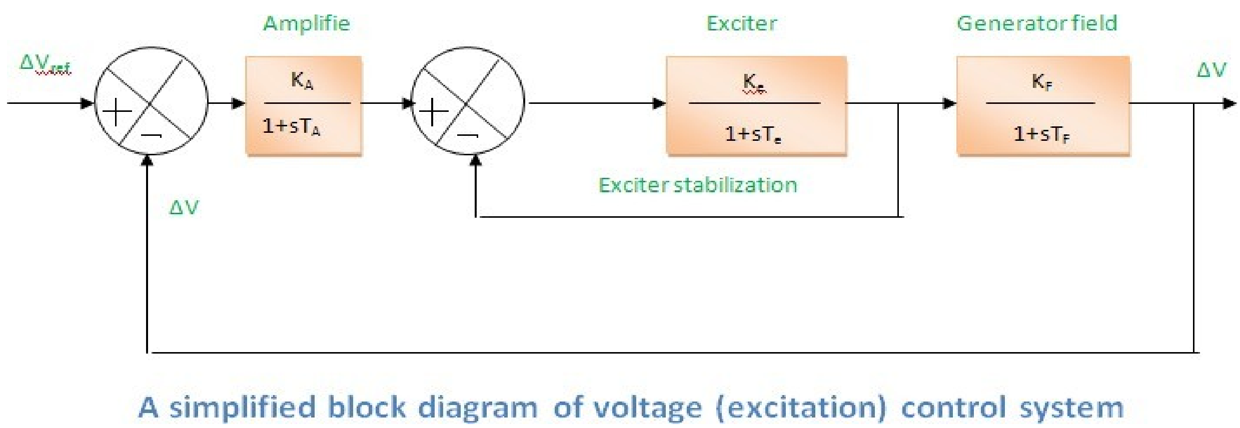


Fig2.2: A simplified block diagram of Voltage (Excitation) Control System.

Performance of AVR Loop

The purpose of the AVR loop is to maintain the generator terminal voltage with in 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 with in 4% of the base voltage.

The performance of the AVR loop is measured by its ability to regulate the terminal voltage of the generator within prescribed static accuracy limit with an acceptable speed of response. Suppose the static accuracy limit is denoted by A_c in percentage with reference to the nominal value. The error voltage is to be less than $(A_c/100)\Delta|V|_{ref}$.

From the block diagram, for a steady state error voltage Δe;

$$\Delta e = \Delta|V|_{ref} - \Delta|V|_t < \frac{Ac}{100}\Delta|V|_{ref}$$

$$\Delta e = \Delta|V|_{ref} - \Delta|V|_t = \Delta|V|_{ref} - \frac{G(s)}{1+G(s)}\Delta|V|_{ref}$$

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

For constant input condition, ($s \rightarrow 0$)

$$\Delta e = \{1 - \frac{G(s)}{1+G(s)}\}\Delta|V|_{ref} = \{1 - \frac{G(0)}{1+G(0)}\}\Delta|V|_{ref}$$

$$= \frac{1}{1+G(0)}\Delta|V|_{ref} = \frac{1}{1+K}\Delta|V|_{ref}$$

where, $K = G(0)$ is the open loop gain of the AVR. Hence,

$$\frac{1}{1+K}\Delta|V|_{ref} < \frac{Ac}{100}\Delta|V|_{ref} \quad \text{or} \quad K > \{\frac{100}{Ac} - 1\}$$

Example1: Find the open loop gain of an AVR loop if the static accuracy required is 3%.

Solution: Given $A_c = 3\%$. $K > \{\frac{100}{Ac} - 1\} = K > \{\frac{100}{3} - 1\} = 32.33$. Thus, if the open loop gain of the AVR loop is greater than 32.33, then the terminal voltage will be within 3% of the base voltage.

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} are 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 Fig2.3

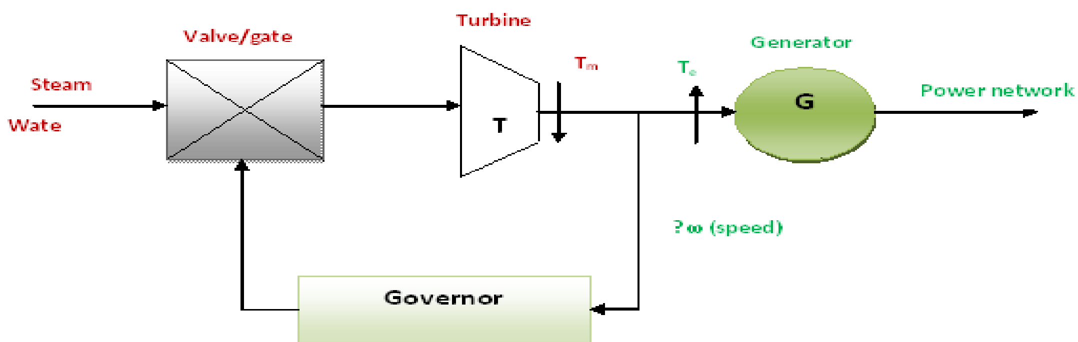


Fig2.3: The Schematic representation of ALFC system

For the analysis, the models for each of the blocks in Fig2 are required. 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 modeled by $\frac{2Hd^2\Delta\delta}{\omega_s dt^2} = \Delta P_m - \Delta P_e$. Expressing the speed deviation in pu,

$\frac{d\Delta\omega}{dt} = \frac{1}{2H}(\Delta P_m - \Delta P_e)$. This relation can be represented as shown in Fig2.4.

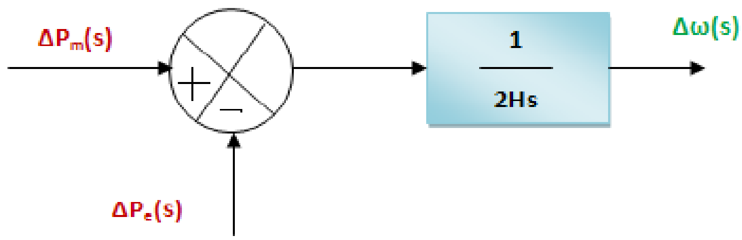


Fig2.4. The block diagram representation of the Generator

The load on the system is composite consisting of a frequency independent component and a frequency dependent component. The load can be written as $\Delta P_e = \Delta P_0 + \Delta P_f$ where, ΔP_e is the change in the load; ΔP_0

is the frequency independent load component;

ΔP_f is the frequency dependent load component. $\Delta P_f = D\Delta\omega$ 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 Fig2.5

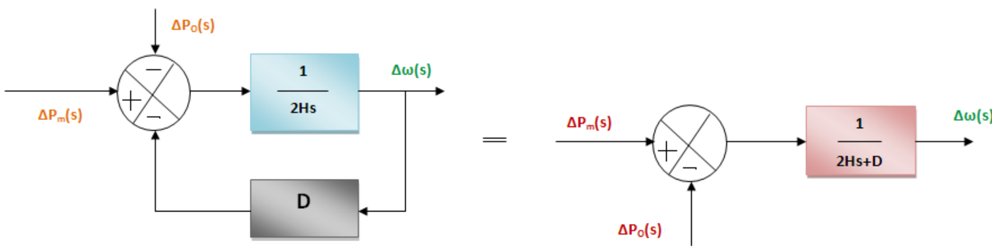
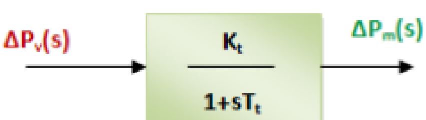


Fig2.5. The block diagram representation of the Generator and load

The turbine can be modeled as a first order lag as shown in the Fig2.6



$$G_t(s) = \frac{\Delta P_m(s)}{\Delta P_V(s)} = \frac{K_t}{1+sT_t}$$

$G_t(s)$ is the TF of the turbine; $\Delta P_V(s)$ is the change in valve output (due to action).

$\Delta P_m(s)$ is the change in the turbine output

Fig2.6. The turbine model.

The governor can similarly modeled as shown in Fig2.7. The output of the governor is by

$\Delta P_g = \Delta P_{ref} - \dfrac{\Delta\omega}{R}$ where ΔP_{ref} is the reference set power, and $\Delta\omega/R$ is the power given by governor speed characteristic. The hydraulic amplifier transforms this signal ΔP_g into valve/gate position corresponding to a power ΔP_V. Thus $\Delta P_V(s) = (K_g/(1+sT_g))\Delta P_g(s)$.

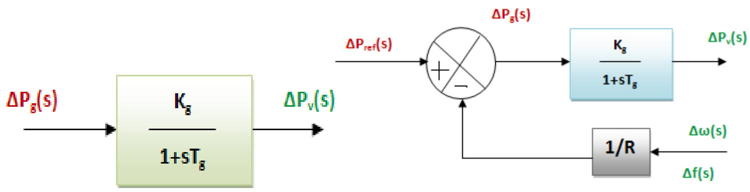


Fig2.7: The block diagram representation of the Governor

All the individual blocks can now be connected to represent the complete ALFC loop as shown in Fig2.8

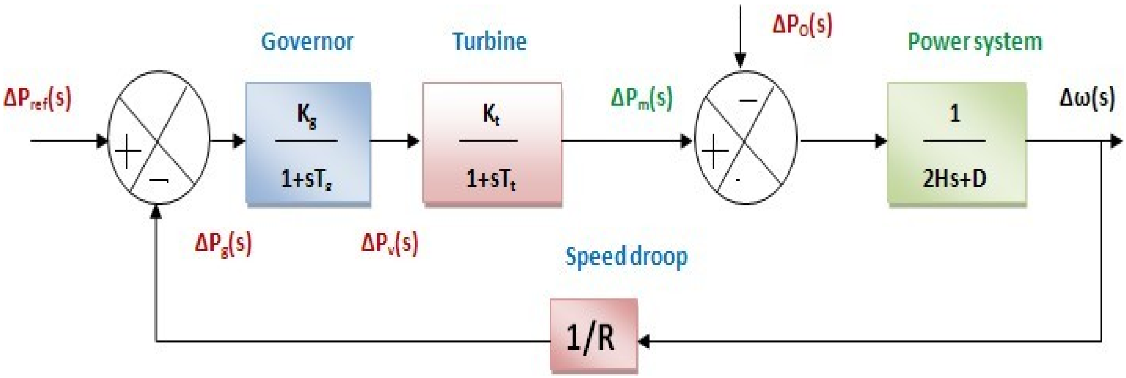


Fig2.8: The block diagram representation of the ALFC

Steady State Performance of the ALFC Loop

2.4 Steady State Performance of the ALFC Loop

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

With $s \rightarrow 0$, Gg(s) and Gt(s) become unity, then, (note that $\Delta P_m = \Delta P_T = \Delta P_G = \Delta P_e = \Delta P_D$; That is turbine output = generator/electrical output = load demand)

$$\Delta P_m = \Delta P_{ref} - (1/R)\Delta\omega \quad \text{or} \quad \Delta P_m = \Delta P_{ref} - (1/R)\Delta f$$

When the generator is connected to infinite bus ($\Delta f = 0$, and $\Delta V = 0$), then $\Delta P_m = \Delta P_{ref}$.

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

$$\Delta P_m = -(1/R)\Delta f \quad \text{or} \quad \Delta f = -R\,\Delta P_m.$$

If the frequency dependent load is present, then

$$\Delta P_m = \Delta P_{ref} - (1/R + D)\Delta f \quad \text{or} \quad \Delta f = \frac{-\Delta Pm}{D + 1/R}$$

If there are more than one generator present in the system, then

$\Delta P_{m.\ eq} = \Delta P_{ref.eq} - (D + 1/R_{eq})\Delta f$

where, $\Delta P_{m.\ eq} = \Delta P_{m1} + \Delta P_{m2} + \Delta P_{m.3} + \ldots.$

$\Delta P_{ref.\ eq} = \Delta P_{ref1} + \Delta P_{ref2} + \Delta P_{ref3} + \ldots..$ $1/R_{eq} = (1/R_1 + 1/R_2 + 1/R_2 + \ldots.)$

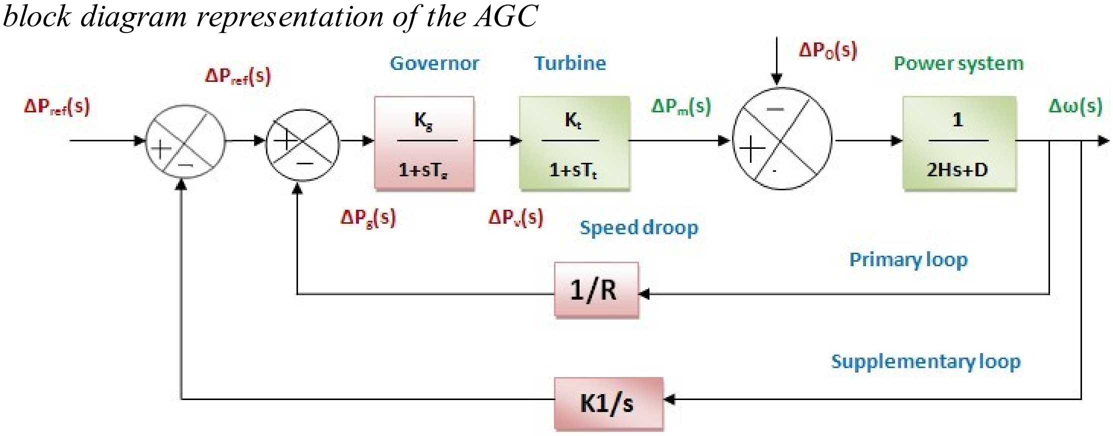
The quantity $\beta = (D + 1/R_{eq})$ is called the area frequency (bias) characteristic (response) or simply the stiffness of the system.

Concept of AGC (Supplementary ALFC Loop)

The ALFC loop shown in Fig2.8, is called the primary ALFC loop. It achieves the primary goal of real power balance by adjusting the turbine output ΔP_m to match the change in load demand ΔP_D. 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 Fig2.9. The main objectives of AGC are i) to regulate the frequency (using both primary and supplementary controls); ii) 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).

Fig2.9: The 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.2.9) which uses the integral controller to change the reference power setting so as to change the speed set point. The integral controller gain K_I needs 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.

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 Fig2.10 for the interconnected system operation. For a total change in load of ΔP_D, the steady state deviation in frequency in the two areas is given by $\Delta f = \Delta\omega_1 = \Delta\omega_2 = \dfrac{-\Delta P_D}{\beta_1 + \beta_2}$ where, $\beta_1 = (D_1 + 1/R_1)$; and $\beta_2 = (D_2 + 1/R_2)$.

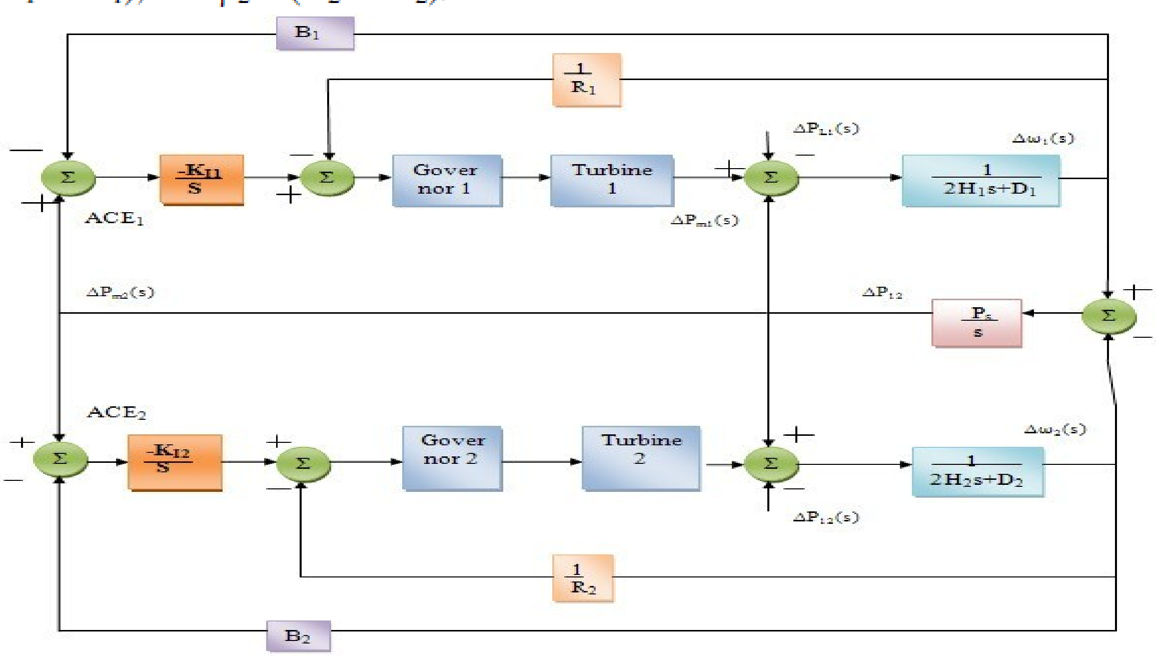


Fig.2.10. AGC for a multi-area operation.

Expression for tie-line flow in a two-area interconnected system

Consider a change in load ΔP_{D1} in area1. The steady state frequency deviation Δf is the same for both the areas. That is $\Delta f = \Delta f_1 = \Delta f_2$. Thus, for area1, we have

$$\Delta P_{m1} - \Delta P_{D1} - \Delta P_{12} = D_1 \Delta f$$

where, ΔP_{12} is the tie line power flow from Area1to Area 2; and for Area 2

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

The mechanical power depends on regulation. Hence

$$\Delta P_{m1} = -\frac{\Delta f}{R_1} \quad \text{and} \quad \Delta P_{m2} = -\frac{\Delta f}{R_2}$$

Substituting these equations, yields

$$\left(\frac{1}{R_1} + D_1\right)\Delta f = -\Delta P_{12} - \Delta P_{D1} \quad \text{and} \quad \left(\frac{1}{R_2} + D_2\right)\Delta f = \Delta P_{12}$$

Solving for Δf, we get

$$\Delta f = \frac{-\Delta P_{D1}}{(1/R_1 + D_1) + (1/R_2 + D_2)} = \frac{-\Delta P_{D1}}{\beta_1 + \beta_2}$$

and $$\Delta P_{12} = \frac{-\Delta P_{D1}\beta_2}{\beta_1 + \beta_2}$$

where, β_1 and β_2 are the composite frequency response characteristic of Area1 and Area 2 respectively. An increase of load in area1 by ΔP_{D1} results in a frequency reduction in both areas and a tie-line flow of ΔP_{12}. A positive ΔP_{12} is indicative of flow from Area1 to Area 2 while a negative ΔP_{12} means flow from Area 2 to Area1. Similarly, for a change in Area 2 load by ΔP_{D2}, we have $$\Delta f = \frac{-\Delta P_{D2}}{\beta_1 + \beta_2}$$

and $$\Delta P_{12} = -\Delta P_{21} = \frac{-\Delta P_{D2}\beta_1}{\beta_1 + \beta_2}$$

Frequency bias tie line control

The tie line deviation reflects the contribution of regulation characteristic of one area to another. The basic objective of supplementary control is to restore balance between each area load generation. This objective is met when the control action maintains

- Frequency at the scheduled value
- Net interchange power (tie line flow) with neighboring areas at the scheduled values

The supplementary control should ideally correct only for changes in that area. In other words, if there is a change in Area1 load, there should be supplementary control only in Area1 and not in Area 2. For this purpose the area control error (ACE) is used (Fig2.9). The ACE of the two areas are given by

For area 1: $ACE_1 = \Delta P_{12} + \beta_1 \Delta f$ For area 2: $ACE_2 = \Delta P_{21} + \beta_2 \Delta f$

Economic Allocation of Generation

An important secondary function of the AGC is to allocate generation so that each generating unit is loaded economically. That is, each generating unit is to generate that amount to meet the present demand in such a way that the operating cost is the minimum. This function is called Economic Load Dispatch (ELD).

Systems with more that two areas

The method described for the frequency bias control for two area system is applicable to multiarea system also.

Note: *The regulation constant R is negative of the slope of the Δf verses Δp_m curve of the turbine-governor control. The unit of R is Hz/MW when Δf is in Hz and Δp_m is in MW. When Δf and Δp_m are in per-unit, R is also in per-unit.*

The area frequency characteristic is defined as $\beta = \{1/(D+1/R)\}$, where D is the frequency damping factor of the load. The unit of β is MW/Hz when Δf is in Hz and Δp_m is in MW. If Δf and Δp_m are in per unit, then β is also in per unit.

Examples:

Ex 1. A 500 MVA, 50 Hz, generating unit has a regulation constant R of 0.05 p.u. on its own rating. If the frequency of the system increases by 0.01 Hz in the steady state, what is the decrease in the turbine output? Assume fixed reference power setting.

Solution: In p.u. $\Delta f = 0.01/50 = 0.0002$ p.u.

With $\Delta p_{ref} = 0$, $\Delta p_m = -1/R(\Delta f) = -0.004$ p.u. Hence, $\Delta p_m = -0.004\ S_{base} = -2$ MW.

Ex. 2. An interconnected 60 Hz power system consists of one area with three generating units rated 500, 750, and 1000 MVA respectively. The regulation constant of each unit is R= 0.05 per unit on its own rating. Each unit is initially operating at one half of its rating, when the system load suddenly increases by 200MW. Determine (i) the area frequency response characteristic on a 1000 MVA system base, (ii) the steady state frequency deviation of the area, and (iii) the increase in turbine power output.

Regulation constants on common system base are ($R_{pu\ new} = R_{pu\ old}$ ($S_{base\ new}/S_{base\ old}$): R1 = 0.1; R2 = 0.0667; and R3 = 0.05.

Hence $\beta = (1/R1 + 1/R2 + 1/R3) = 45$ per unit.

Neglecting losses and frequency dependence of the load, the steady state frequency deviation is $\Delta f = (-1/\beta)\Delta p_m = -4.444 \times 10^{-3}$ per unit $= (-4.444 \times 10^{-3})60 = -0.2667$ Hz.

$\Delta p_{m1} = (-1/R1)(\Delta f) = 0.04444$ per unit = 44.44 MW

$\Delta p_{m2} = (-1/R2)(\Delta f) = 0.06666$ per unit = 66.66 MW

$\Delta p_{m3} = (-1/R3)(\Delta f) = 0.08888$ per unit = 88.88 MW

Ex.3. A 60 Hz, interconnected power system has two areas. Area1 has 2000 MW generation and area frequency response of 700 MW/Hz. Area 2 has 4000 MW generation and area frequency response of 1400 MW/Hz. Each area is initially generating half of its rated generation, and the tie-line deviation is zero at 60 Hz when load in Area1 is suddenly increases by 100 MW. Find the steady state frequency error and tie line error of the two areas. What is the effect of using AGC in this system?

In the steady state, $\Delta f = (-1/\beta)\ \Delta p_m = \{\Delta p_m / -(\beta 1 + \beta 2)\} = (-100/2100) = -0.0476$ Hz.

Assuming $\Delta p_{ref} = 0$,

$\Delta p_{m1} = -\beta 1\ \Delta f = 33.33$ MW; and $\Delta p_{m2} = -\beta 2\ \Delta f = 66.67$ MW.

Thus in response to 100 MW change in Area1, both areas will change their generation. The increase in Area 2 generation will now flow through tie line to Area1.

Hence $\Delta p_{tie1} = -66.67$ MW; and $\Delta p_{tie2} = +66.67$ MW.

With AGC, the Area control error is determined as follows. ACE 1 = $\Delta p_{tie1} + B_1 \Delta f$ where B_1 is the frequency bias constant.

ACE 2 = Δp_{tie2} ($= -\Delta p_{tie1}$) $+ B_2 \Delta f$ where B_2 is the frequency bias constant.

The control will actuate such that in the steady state the frequency and tie line deviations are zero. Thus till ACE1= ACE2 = 0, the control signal will be present.

Unit 4: Control of Voltage and Reactive Power

Reactive power is an odd topic in AC (Alternating Current) power systems, and it's usually explained with vector mathematics or phase-shift sine wave graphs. However, a non-math verbal explanation is possible.

Note that Reactive power only becomes important when an "electrical load" or a home appliance contains coils or capacitors. If the electrical load behaves purely as a resistor, (such as a heater or incandescent bulb for example,) then the device consumes "real power" only. Reactive power and "power factor" can be ignored, and it can be analysed using an AC version of Ohm's law.

Reactive power is simply this: when a coil or capacitor is connected to an AC power supply, the coil or capacitor stores electrical energy during one-fourth of an AC cycle. But then during the next quarter-cycle, the coil or capacitor dumps all the stored energy back into the distant AC power supply. *Ideal coils and capacitors consume no electrical energy, yet they create a significant electric current.* This is very different from a resistor which genuinely consumes electrical energy, and where the electrical energy flows continuously in one direction; moving from source to load.

In other words, if your electrical appliance contains inductance or capacitance, then electrical energy will periodically return to the power plant, and it will flow back and forth across the power lines. This leads to an extra current in the power lines, a current which heats the power lines, but which isn't used to provide energy to the appliance. The coil or capacitor causes electrical energy to begin "sloshing" back and forth between the appliance and the distant AC generator. Electric companies must install heavier wires to tolerate the excess current, and they will charge extra for this "unused" energy.

This undesired "energy sloshing" effect can be eliminated. If an electrical load contains both a coil and capacitor, and if their resonant frequency is adjusted to exactly 60Hz, then the coil and capacitor like magic will begin to behave like a pure resistor. The "energy sloshing" still occurs, but now it's all happening between the coil and capacitor, and not in the AC power lines. So, if your appliance contains a large coil induction motor, you can make the motor behave as a pure resistor, and reduce the current in the power lines by connecting the right value of capacitance across the motor coil.

Why is reactive power so confusing? Well, the math is daunting if not entirely obscure. And the concept of "imaginary power" puts many people off. But this is not the only problem. Unfortunately most of us are taught in grade school that an electric current is a flow of energy, and that energy flows back and forth in AC power lines. This is completely wrong. In fact the energy flows constantly forward, going from source to load. It's only the charges of the metal wires which flow back and forth.

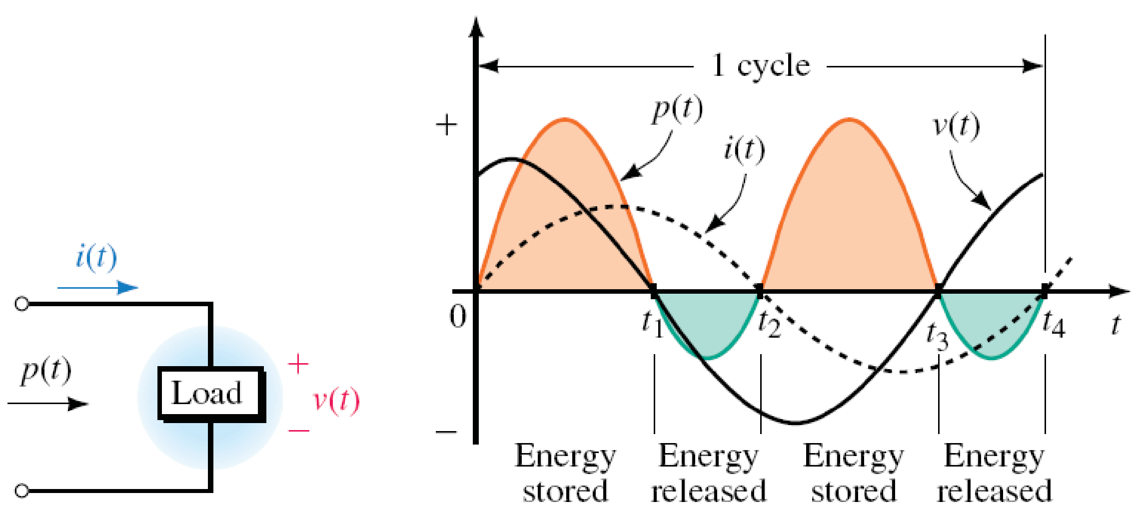
Imagine that we connect a battery to a light bulb. Electric charges already present inside the wires will begin to flow in the circle, and then electrical energy moves almost instantly to the light bulb. The charge flow is circular like a belt, but the energy flow is one-way. Now imagine that we suddenly reverse the connections to the battery. The voltage and current will reverse... but the energy still flows in the same direction as before. It still goes from battery to bulb. If we keep reversing the battery connections over and over, we'd have an AC system. So, in an AC system, only the voltage and current are "alternating," while the electrical energy flows one- way, going from source to load. Where AC resistive loads are concerned, electrical energy does not "alternate." To understand energy flow in AC systems, it's critically important that we understand the difference between charge flow (current, amperes) and energy flow (power, watts.)

What is imaginary power? Simple: it's the unused power which flows backwards and forwards in the power lines, going back and forth between the load's coil or capacitor and the distant AC generator. If your appliance was a pure capacitor or inductor, then it would consume no electrical energy at all, but instead ***all*** the flowing energy would take the form of "sloshing energy," and we'd call it "imaginary power." Of course it's not actually imaginary. Instead it's reflected by the load.

What is real power? Even more simple: it's the energy flow which goes continuously from the AC generator and into the appliance, without any of it returning back to the distant generator.

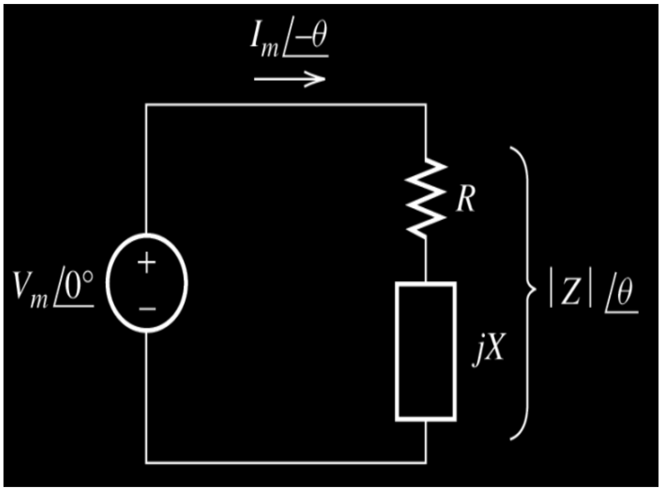
Finally, what is "reactive" power? It's just the combination of the above two ideas: it is the continuous-forward-moving or "real" energy flow, combined with the sloshing or "imaginary" energy flow.

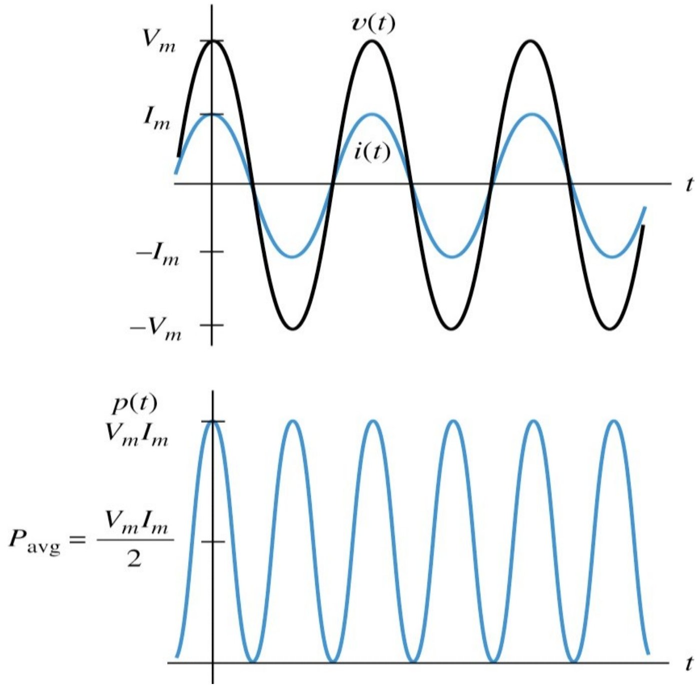
- ✓ Power in A.C. Networks
  - Active Power
  - Reactive Power
  - Apparent Power
  - Power Factor (p.f.)
  - Power Factor Correction
  -
- ✓ Instantaneous power, $p(t) = v(t)i(t)$
- ✓ Power, $p(t)$ value
  - *positive* – power transmit/dissipate by load
  - *negative* – power return from the load
- ✓ Since p(t) is power transmits by load, then it is the average power, P at load
- ✓ Sometimes P is also known as *active power, real power* or *true power* measured in unit of Watts.

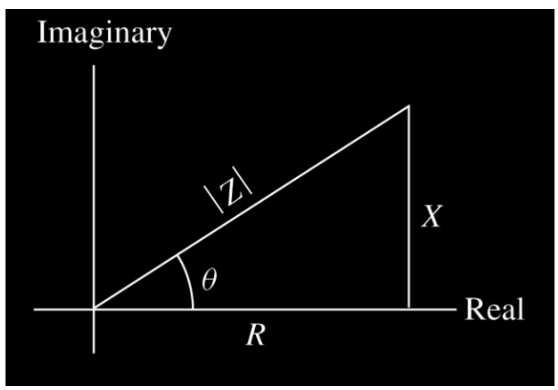


ACTIVE POWER

$\mathbf{Z} = R$ (purely resistive)







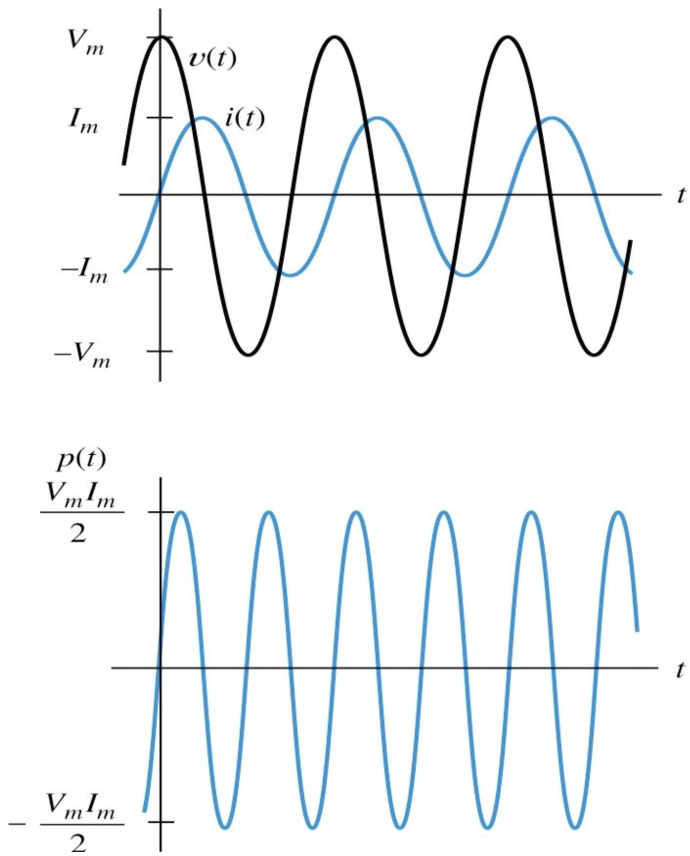
$$P = VI = I^2R = V^2/R \text{ (Watt)}$$

REACTIVE POWER

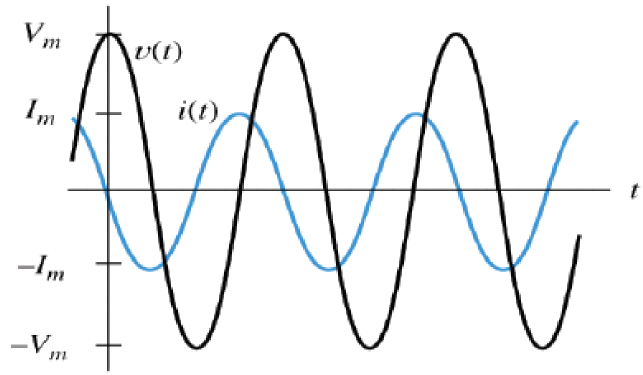
$\mathbf{Z} = jX_L$ (inductive)

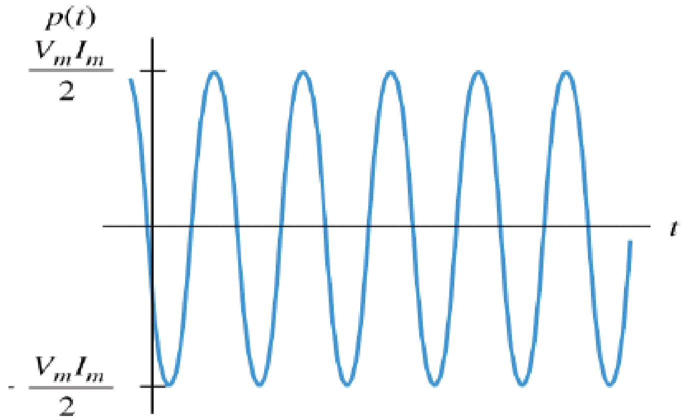
Instantaneous power $p(t) = v(t)i(t) = VI \sin 2\omega t$

- ✓ Average power is zero
- ✓ The product of VI is called **reactive power** (Q_L) with unit Volt-Amp Reactive (VAR)
- ✓ Reactive power (inductive) $Q_L = VI = I^2 X_L = V^2/X_L$ (VAR)



$\mathbf{Z} = -\,jX_C$ (capacitive)



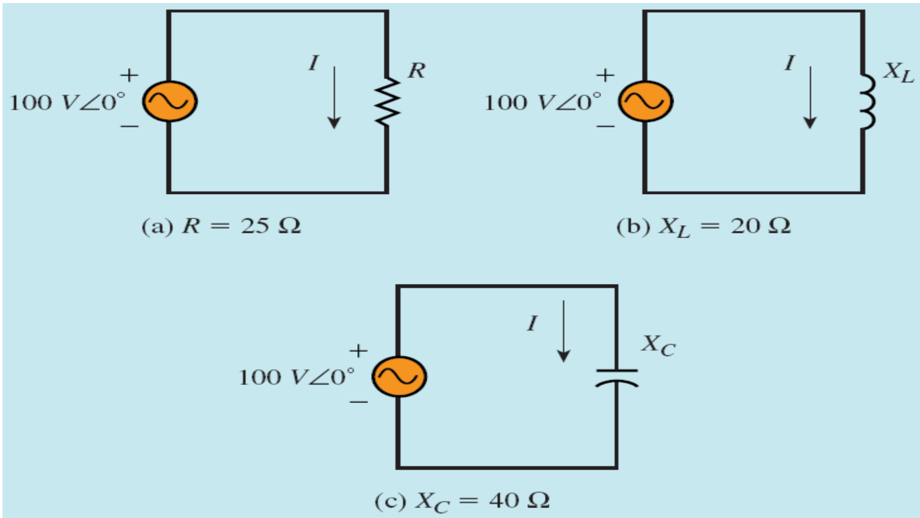


✓ Reactive power (capacitive) $Q_C = VI = I^2X_C = V^2/X_C$ (VAR)

Note:

To distinguish between inductive reactive power (Q_L) and capacitive reactive power (Q_C), we use two different signs (+ or –) depending on our reference (i or v), for example jQ_L and $-\,jQ_C$ or otherwise.

ACTIVE/REACTIVE POWER – Example



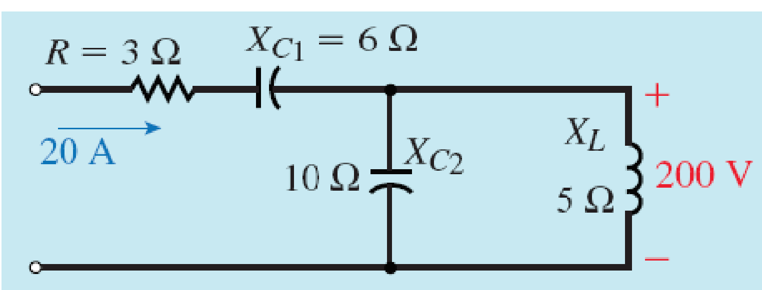
(a) $I = 100\ V/25\ \Omega = 4\ A$, $P = VI = (100\ V)(4\ A) = 400\ W$, $Q = 0\ VAR$

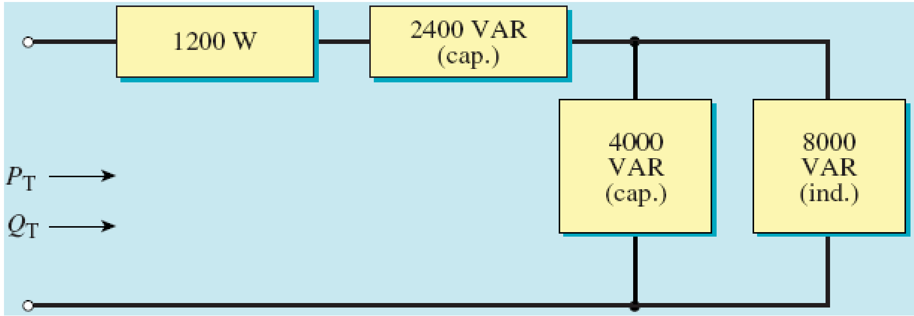
(b) $I = 100\ V/20\ \Omega = 5\ A$, $P = 0$, $Q_L = VI = (100\ V)(5\ A) = 500\ VAR$ (inductive)

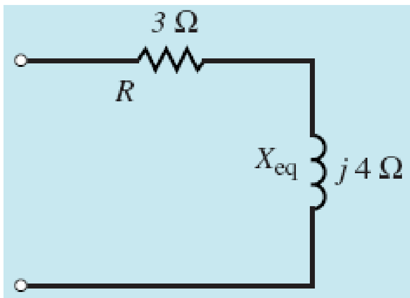
(c) $I = 100\ V/40\ \Omega = 2.5\ A$, $P = 0$, $Q_C = VI = (100\ V)(2.5) = 250\ VAR$ (capacitive) $= -250\ VAR$

Note: use the magnitude of I and V

Determine the total P_T and Q_T for the circuit. Sketch the series equivalent circuit.







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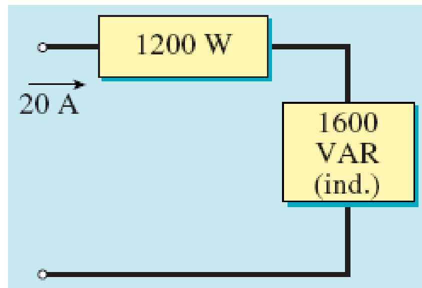


$$R = P_T/I^2 = 1200/20^2 = 3\ \Omega$$

$$X_{eq} = X_L = Q_T/I^2 = 1600/20^2 = 4\ \Omega$$

$$P = I^2R = (20\text{ A})^2(3\ \Omega) = 1200\text{ W}$$

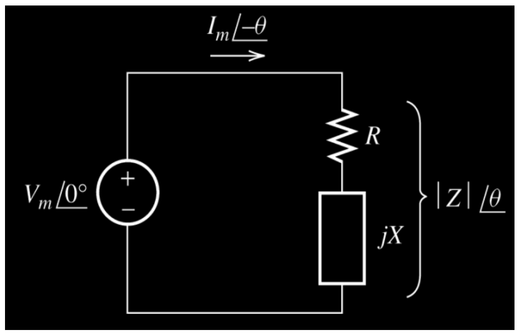
$$Q_{C_1} = I^2X_{C_1} = (20\text{ A})^2(6\ \Omega) = 2400\text{ VAR (cap.)}$$

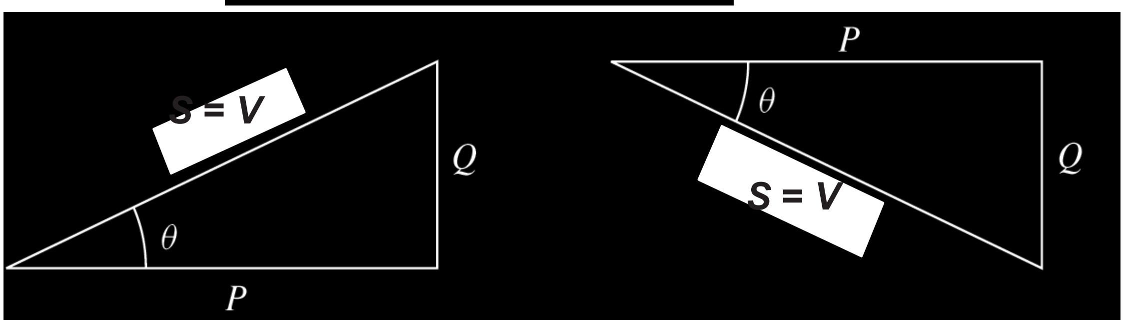
$$Q_{C_2} = \frac{V_2^2}{X_{C_2}} = \frac{(200\text{ V})^2}{(10\ \Omega)} = 4000\text{ VAR (cap.)}$$

$$Q_L = \frac{V_2^2}{X_L} = \frac{(200\text{ V})^2}{5\ \Omega} = 8000\text{ VAR (ind.)}$$

APPARENT POWER

For load consisting of series resistance and reactance, $Z = R \pm jX = \mathbf{Z}\ \underline{/\pm\theta}$, the power produced is called *Apparent Power* or *Complex Power*), S or P_S with unit Volt-Amp (VA)





$\mathbf{S = P + jQ_L}$

$\mathbf{S = P - jQ_C}$

θ positive, inductive load

θ negative, capacitive load

$S = VI$ (VA)

$P = VI\cos\theta = I^2R = V_R^2/R$ (W)

$= S\cos\theta$ (W)

$Q = VI\sin\theta = I^2X = V_x^2/X$ (VAR)

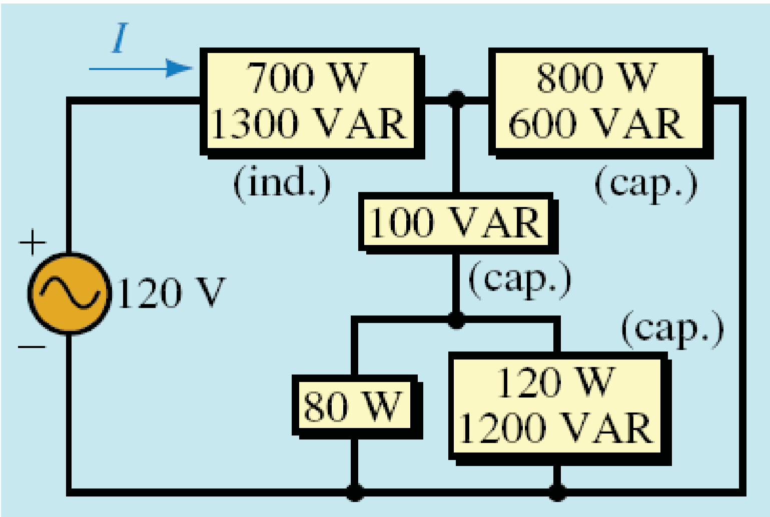
$= S\sin\theta$

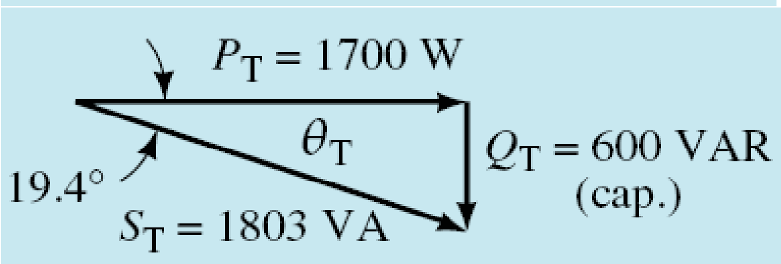
$S = \sqrt{(P^2 + Q^2)} = \mathbf{V^* I}$ $\quad V\underline{/0°}$

Power Triangle

POWER TRIANGLE – Example

Sketch the power triangle.





$$P_T = 700 + 800 + 80 + 120 = 1700 \text{ W}$$
$$Q_T = 1300 - 600 - 100 - 1200 = -600 \text{ VAR} = 600 \text{ VAR (cap.)}$$
$$\mathbf{S}_T = P_T + jQ_T = 1700 - j600 = 1803\angle -19.4^\circ \text{ VA}$$

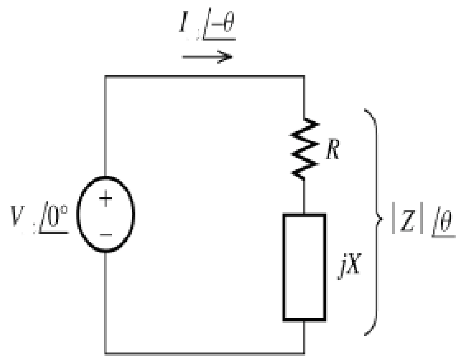
Note that Reactive power only becomes important when an "electrical load" or a home appliance contains coils or capacitors. If the electrical load behaves purely as a resistor, (such as a heater or incandescent bulb for example,) then the device consumes "real power" only. Reactive power and "power factor" can be ignored,

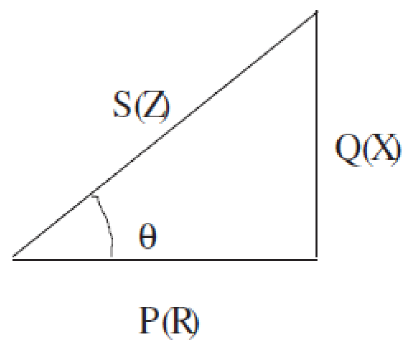
- Reactive power is simply this: when a coil or capacitor is connected to an AC power supply, the coil or capacitor stores electrical energy during one-fourth of an AC cycle. But then during the next quarter-cycle, the coil or capacitor dumps all the stored energy back into the distant AC power supply. *Ideal coils and capacitors consume no electrical energy, yet they create a significant electric current.* This is very different from a resistor which genuinely consumes electrical energy, and where the electrical energy flows continuously in one direction; moving from source to load.

POWER FACTOR

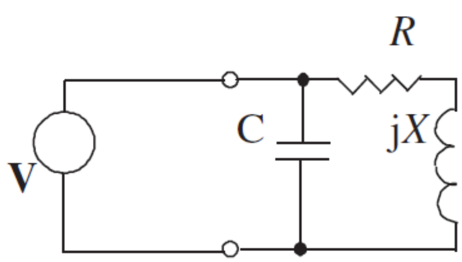
Power factor, p.f. = cos $\theta = P/S = R/Z$

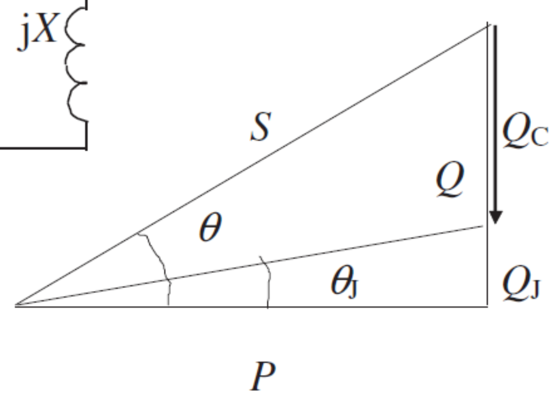
- ✓ p.f. depends on the load type:
  - ✓ Purely resistive load, R , p.f. = 1
  - ✓ Inductive load, RL, p.f. <1 (lagging) and
  - ✓ Capacitive load, RC, p.f. < 1 (leading)
- ✓ Most of the loads are inductive (lagging p.f.) and must be *corrected* until p.f. approximately become unity (p.f. = 1) using capacitor.





POWER FACTOR – Correction





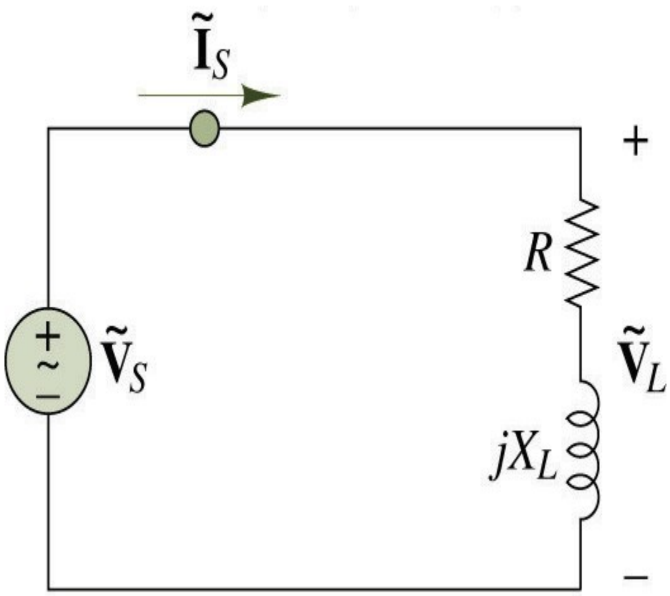
Leading p.f. (final) = cos θ_J; $Q_J = P \tan \theta_J$

$Q_C = Q - Q_J$

$Q_C = V^2/X_C$; $X_C = 1/ j\omega C = V^2/ Q_C$

POWER FACTOR – Example

Find the complex power for the circuit. Correct the circuit power factor to p.f. = 1 using parallel reactance.



Given: $\mathbf{V}_s = 117\angle 0$ V, $R = 50\ \Omega$, $jX_L = 86.7\ \Omega$, $\omega = 377$ rad/s

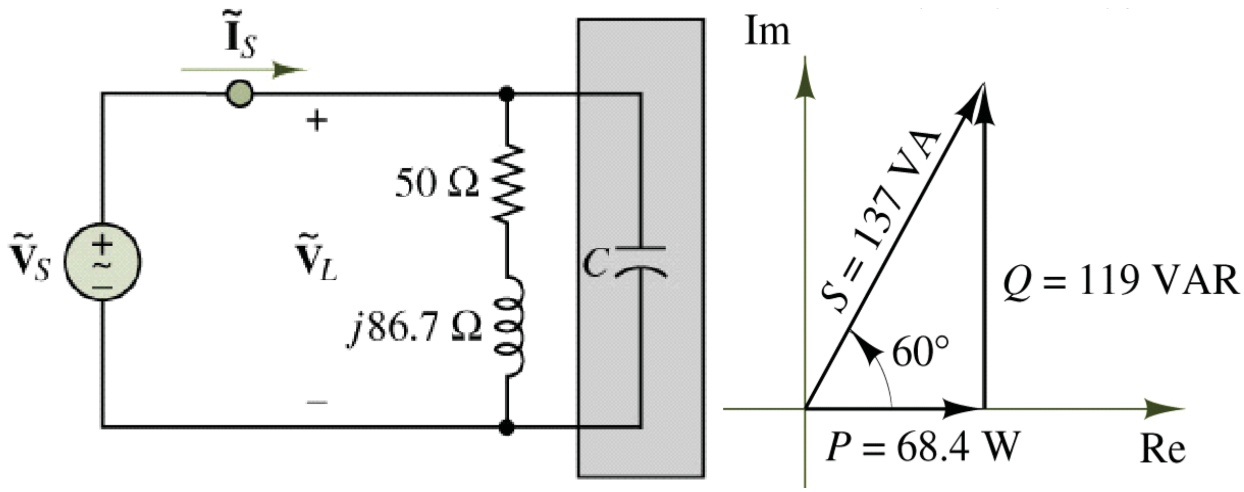
$\mathbf{Z}_L = 50 + j86.7 = 100\angle 60\ \Omega$

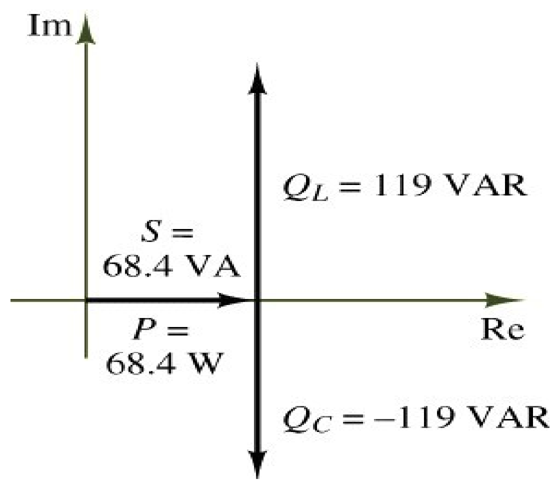
$\mathbf{I}_L = \mathbf{V}_L/\mathbf{Z}_L = (117\angle 0\ )/(100\angle 60) = 1.17\angle{-60}$ A

$\mathbf{S} = \mathbf{V}_L\mathbf{I}_L^* = 137\ \angle 60) = 68.5 + j118.65$ VA

$Q_C = -118.65$ VAR $\quad X_C = V_L^2/118.65 = -j115\ \Omega$

$C = 1/\omega X_c = 23.1\ \mu F$





Importance of Reactive Power

Refers to the circulating power in the grid that does no useful work Results from energy storage elements in the power grid (mainly inductors and capacitors)

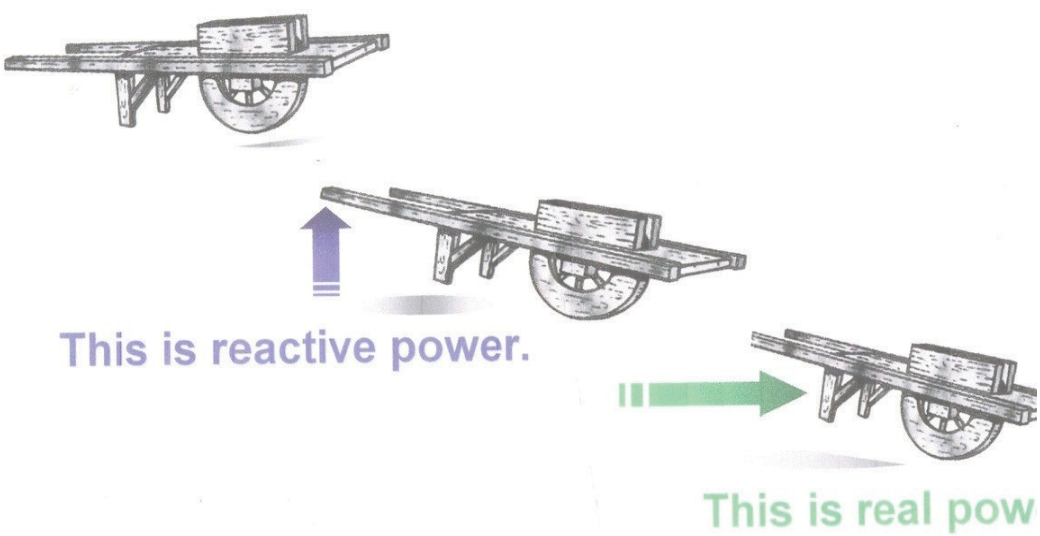
Has a strong effect on system voltages
It must balance in the grid to prevent voltage Problems Reactive power levels have an effect on voltage collapse

Significant Differences between Real and Reactive Services
Real power can be delivered over much greater distances. Reactive resources must be distributed throughout the system.
Generation of real power requires conversion from some energy sources like thermal, nuclear, wind, hydrogen.
Reactive power requires almost no energy to produce

Reactive Power and Real Power:
Balance is Critical

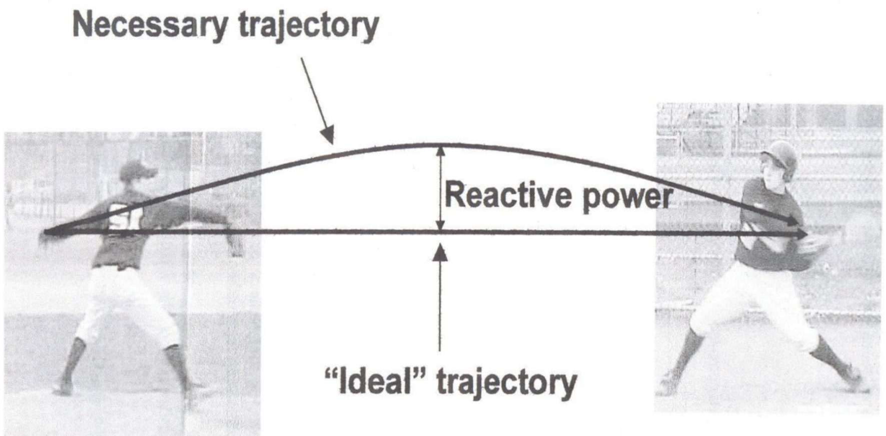
Too little – <u>or</u> too much – reactive power makes it impossible to apply real power

Reactive Power and Real Power:
Balance is Critical



Without reactive power, real power can't get the work done!

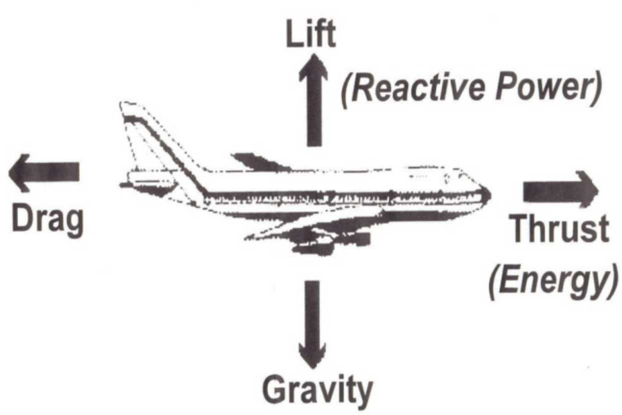
The loft analogy



The upward component of the trajectory does not contribute to getting the ball any closer to the batter, but without it the ball won't get there

Analogy courtesy of Pete Sauer

The "lift" analogy



"Lift" does not get you any closer to your destination,
but without it you are driving, not flying.

What would you think if, after you are in the air, the lift requirements changed and you discovered you did not have enough?

Reactive Power is a Byproduct of Alternating Current (AC) Systems

- **Transformers, transmission lines, and motors require reactive power**
- **Transformers and transmission lines introduce inductance as well as resistance (Both oppose the flow of current)**
- **Must raise the voltage higher to push the power through the inductance of the lines (Unless capacitance is introduced to offset inductance)**
- **The farther the transmission of power, the higher the voltage needs to be raised**
- **Electric motors need reactive power to produce magnetic fields for their operation**

Generation and Absorption of Reactive Power

Synchronous Generators - Synchronous machines can be made to generate or absorb reactive power depending upon the excitation (a form of generator control) applied. The ability to supply reactive power is determined by the short circuit ratio.

Synchronous Compensators - Certain smaller generators, once run up to speed and synchronized to the system, can be declutched from their turbine and provide reactive power without producing real power.

Capacitive and Inductive Compensators - These are devices that can be connected to the system to adjust voltage levels.

A capacitive compensator produces an electric field thereby generating reactive power

An inductive compensator produces a magnetic field to absorb reactive power.

Compensation devices are available as either capacitive or inductive alone or as a hybrid to provide both generation and absorption of reactive power.

Overhead Lines, Underground Cables and Transformers.

- Overhead lines and underground cables, when operating at the normal system voltage, both produce strong electric fields and so generate reactive power.
- When current flows through a line or cable it produces a magnetic field which absorbs reactive power.
- A lightly loaded overhead line is a net generator of reactive power while a heavily loaded line is a net **absorber of reactive power**. In the case of cables designed for use at 275 or 400kV the reactive power generated by the electric field is always greater than the reactive power absorbed by the magnetic field and so **cables are always net generators of reactive power.**

- Transformers always absorb reactive power.

Relation between voltage, Power and Reactive Power at a node

The phase voltage V at a node is a function of P and Q at that node.

i. e $\quad V = f(P,Q)$

The voltage is also independent of adjacent nodes and assume that these are infinite busses.

the total differential of V,

dV = (6v/ 6p) . dp + (6v/ 6Q) . dQ and using the relation (6p/ 6v) . (6v/ 6p) = 1 and

(6Q/ 6v) . (6v/ 6Q) = 1

dv = dp /(6p/ 6v) + dQ / (6Q/ 6v) --------------------------------------(1)

From the above equation it is seen that the change in voltage at a node is defined by two quantities,

(6p/ 6v) and (6Q/ 6v)

Normally (6Q/ 6v) is the quantity of greater interest and can be experimentally determined using Network Analyser by injecting known quantity of VARs at the node in question and measuring the difference in voltage produced.

Methods of voltage control

- By Reactive Power Injection
- By Tap Changing Transformers
- Combined use of Tap Changing Transformers and Reactive Power Injection
- Booster Transformers.

Reactive Power Injection

This is the most fundamental method and is used only in places where the transformer alone is not sufficient to control the voltage.

since many years we use capacitors to improve the power factors of industrial loads. The injection of reactive power required for the power factor improvement is determined like this.

A load of P_1 kw at a lagging power factor of $\cos\varphi_1$ has a KVA of $P_1 / \cos\varphi_1$. If this power factor is improved to $\cos\varphi_2$, the new KVA is $P_1 / \cos\varphi_2$.

The reactive power required from the capacitors is

$(P_1 \tan\varphi_1 - P_1 \tan\varphi_2)$ **KVAr**

Now the question is why the power factor is to be improved. What if the power is transmitted at non unity power factor.

We all know very well that the voltage drop depends on reactive power (Q) while the load angle (or) power transmission angle (6) depends on real power (P)

At non unity power factors if the power is transmitted then it results in higher line currents which increases the I^2R losses and hence reduces the thermal capability.

one of the ideal place for the injection of reactive power is at the loads itself.

Generally reactive power injections are of the following types.

- **Static shunt capacitors**
- **Static series capacitors**
- **Synchronous compensators**

Shunt capacitors and Reactors:

shunt capacitors are used for lagging power factor circuits whereas shunt reactors are used for leading power factors that are created by lightly loaded cables. In both the cases the effect is to supply the required amount of reactive power to maintain the voltage.

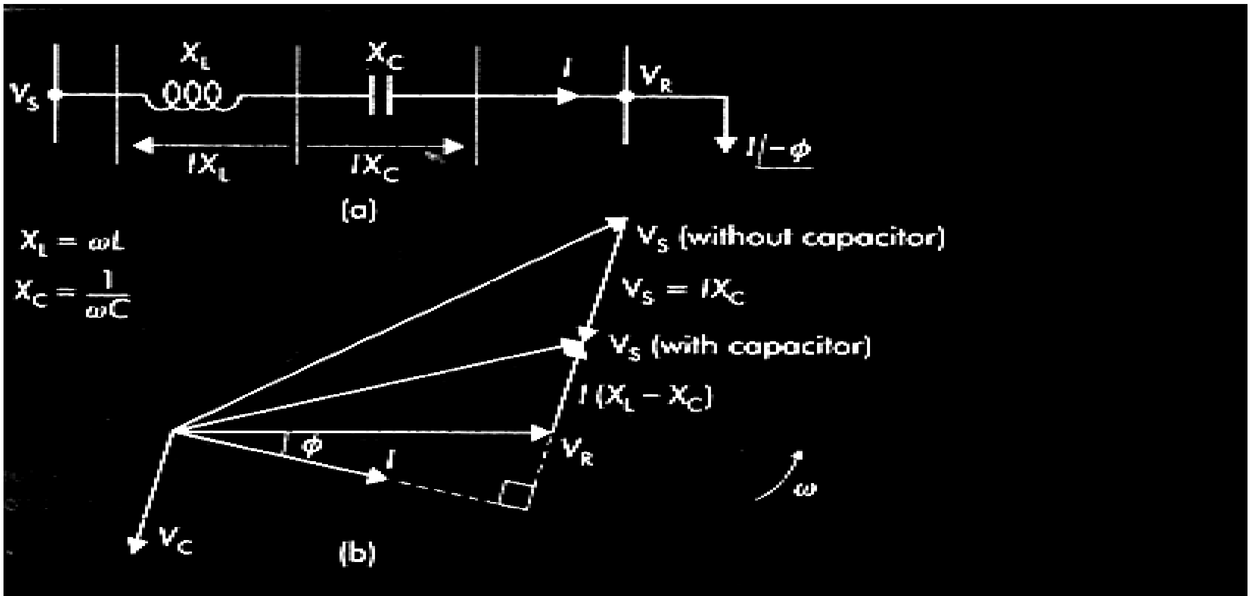
Capacitors are connected either directly to the bus bar or to the tertiary winding of the main transformer and are distributed along the line to minimise the losses and the voltage drops.

Now when the voltage drops, the vars produced by shunt capacitor or reactor falls, so when required most, the effectiveness of these capacitors or the reactors also falls.

On the other hand, on light loads when the voltage is high, the capacitor output is large and the voltage tends to rise to excessive level, so some of the capacitors or reactors are to be switched out by over voltage relays.

For fast control of voltages in power systems, switched capacitors in parallel with semiconductor controlled reactors are generally used to provide var compensation

- Series capacitors:



(a) Line with series capacitor, *C* load. (b) Phasor diagram for fixed V_R

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 a short circuit current flows through the capacitor, protective devices like spark gaps and non linear resistors are to be incorporated.

Phasor diagram for a line with series capacitor is shown in the figure (b).

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.

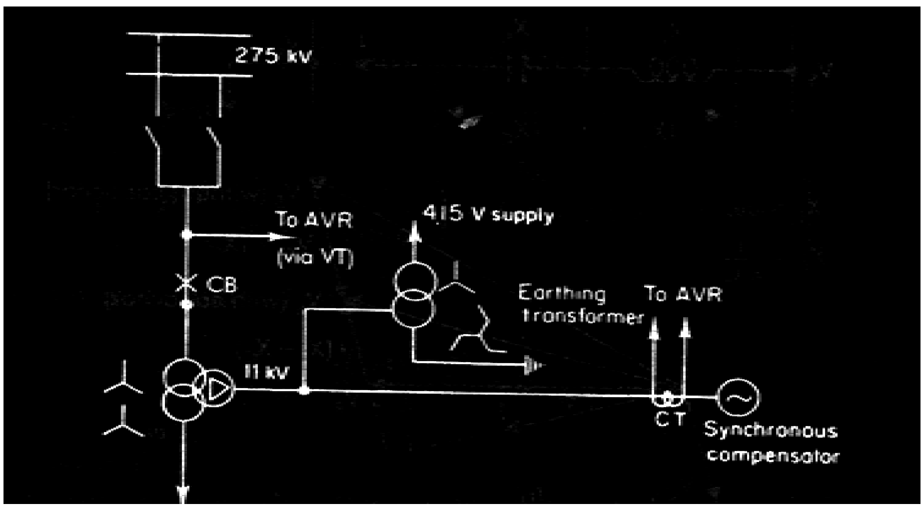


Fig: Typical Installation with synchronous compensator connected to tertiary (delta) winding of main transformer.

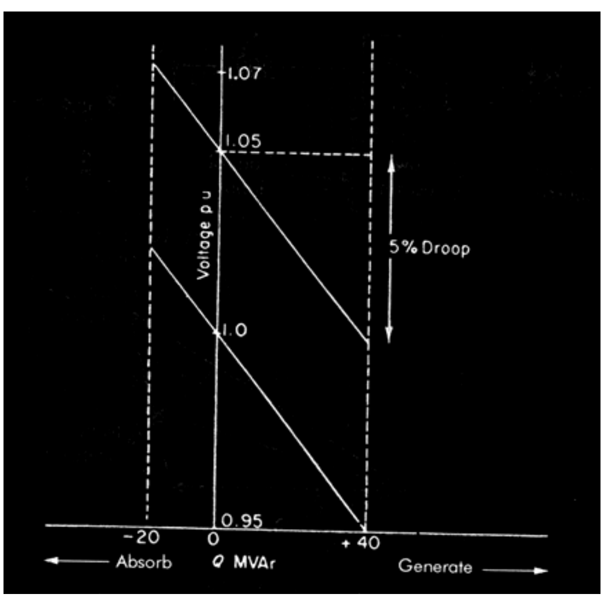


Fig: Voltage-reactive power output of a typical 40MVAr synchronous compensator

- 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.

Sub Synchronous Resonance

Series capacitors are installed in series with long lines for providing compensation of reactive power and giving higher power transfer ability.

Series compensated lines have a tendency to produce series resonance at frequencies lower than power frequencies. This is called **Sub Synchronous Resonance (SSR)**

The sub synchronous resonance currents produce mechanical resonance in Turbo generator shafts, which causes the following in the generator shaft-

(i) Induction generator effect

(ii) torsional torques and (iii) transient torques.

These problems have resulted in damage to rotor shafts of turbine generators.

Therefore the sub synchronous resonance is analysed in the design of series compensated lines.

Now let us derive a relationship between the normal frequency and the sub synchronous resonance frequency.

Let f_n be the normal frequency (synchronous)

let f_r be the sub synchronous frequency of series compensated line.

$2\Pi f_n L$ be the series inductive reactance of EHV line at normal frequency.

$1/2\Pi f_n C$ be the series capacitive reactance of series compensation at normal frequency.

$K = X_c/X_L$ be the degree of compensation.

$X = (X_L - X_c) = X_L(1 - K)$ is the equivalent reactance of the compensated line.

Let the SSR occur at a frequency f_r. Then

$$f_r^2 = (1/ 2\Pi L) * (1/ 2\Pi C)$$

(OR) $(f_r / f_n)^2 = X_c / X_L = K$

or

$$\mathbf{f_r = f_n *sqrt(K)}$$

Thus SSR occurs at a frequency fr which is the product of normal frequency and the root of the degree of compensation K.

The condition of SSR can occur during the faults on the power system, during switching operations and changing system configurations.

Solution to SSR problems

1. Use of filters: For eliminating/damping the harmonics.

The various filters include: static blocking filters, bypass damping filters, dynamic filters.

2. Bypassing the series capacitor bank under resonance condition
3. Tripping of generator units under conditions of SSR

Reactive Power and Voltage Collapse

Voltage collapse is a system instability and it involves many power system components and their variables at once. Indeed, voltage collapse involves an entire power system although it usually has a relatively larger involvement in one particular section of the power system.

Voltage collapse occurs in power systems which are usually
Heavily loaded, faulted and/or have reactive power shortages.

Voltage collapses can occur in a transient time scale or in a long term time scale. Voltage collapse in a long term time scale can include effects from the transient time scale; for example, a slow voltage collapse taking several minutes may end in a fast voltage collapse in the transient time scale.

Changes in power system contributing to voltage collapse

There are several power system disturbances which contribute to the voltage collapse.

i. increase in inductive loading

ii. Reactive power limits attained by reactive power compensators and generators.

iii. On Load Tap Changing operation

iv. Load recovery dynamics.

v. Generator outage

vi. Line tripping.

most of these factors have significant effects on reactive power production, transmission and consumption.

Switching of shunt capacitors, blocking of OLTC operation, generation rescheduling, bus voltage control, strategic load shedding and allowing temporary reactive power over loading of generators may be used as some of the effective countermeasures against voltage collapse.

Voltage Stability

The voltage stability may be defined as the ability of a power system to maintain steady acceptable voltage at all busses in the system at normal operating conditions and after being subjected to disturbances/ perturbations.

OR

Voltage stability is the ability of a system to maintain voltage so that when load admittance is increased, load power will increase, and so that both power and voltage are controllable.

Power system is "Voltage Stable "if voltages at respective busses after a disturbance are close to the voltages at normal operating conditions.

So voltage instability is that appears when the attempt of load dynamics to restore power consumption is just beyond the capability of the combined transmission and generator system.

Though voltage instability may be a local problem, its consequences may have a widespread effect.

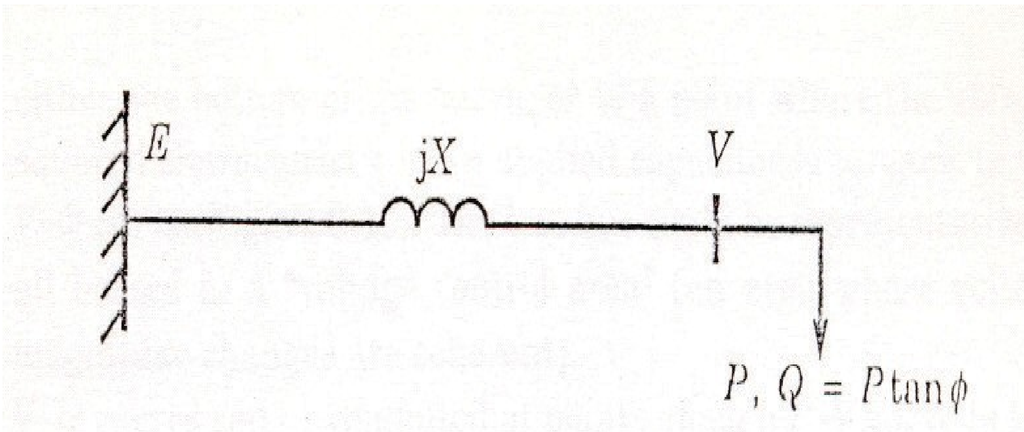
Voltage collapse is the catastrophic result of a sequence of events leading to a sudden low-voltage profile in a major part of the system, i.e. in a significant part of the system.

Voltage Stability can also be called Load Stability. A Power system lacks the capability to transfer an infinite amount of electrical power to the loads. The main factor causing voltage instability is the inability of the power system to meet the demands for reactive power in the heavily stressed system keeping desired voltages. Other factors contributing to voltage instability are the generator reactive power limits.

Transfer of reactive power is difficult due to extremely high reactive power losses, which is why the reactive power required for voltage control is generated and consumed at the control area.

A classification of power system stability is shown in the table below. The driving forces for instability are named **generator– driven and load-driven.** It is to be noted that these terms do not exclude the effect of other components to the mechanism. **The time scale is divided into short and long-term time scale.**

Now let us analyse voltage stability using Q-V curves.
Consider a simple system as shown below and its P-V curves.



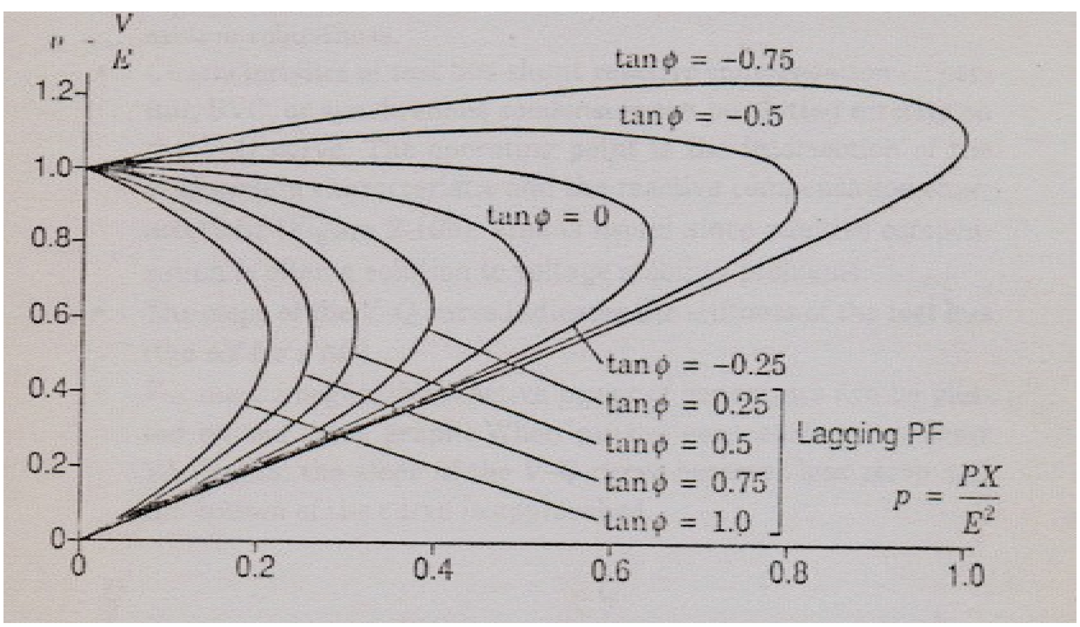


Fig: Normalised P-V curves for fixed (infinite) source.

Now map the normalised P-V curves onto V-Q curves.
for constant value of P, note the values of Q and V and then re plot to get Q-V curves as shown below.

from P-V curves it is observed that the critical voltage is very high for high loadings. V is above 1.0p.u for P = 1.0p.u

The right side represents normal conditions where applying a capacitor bank raises voltage.

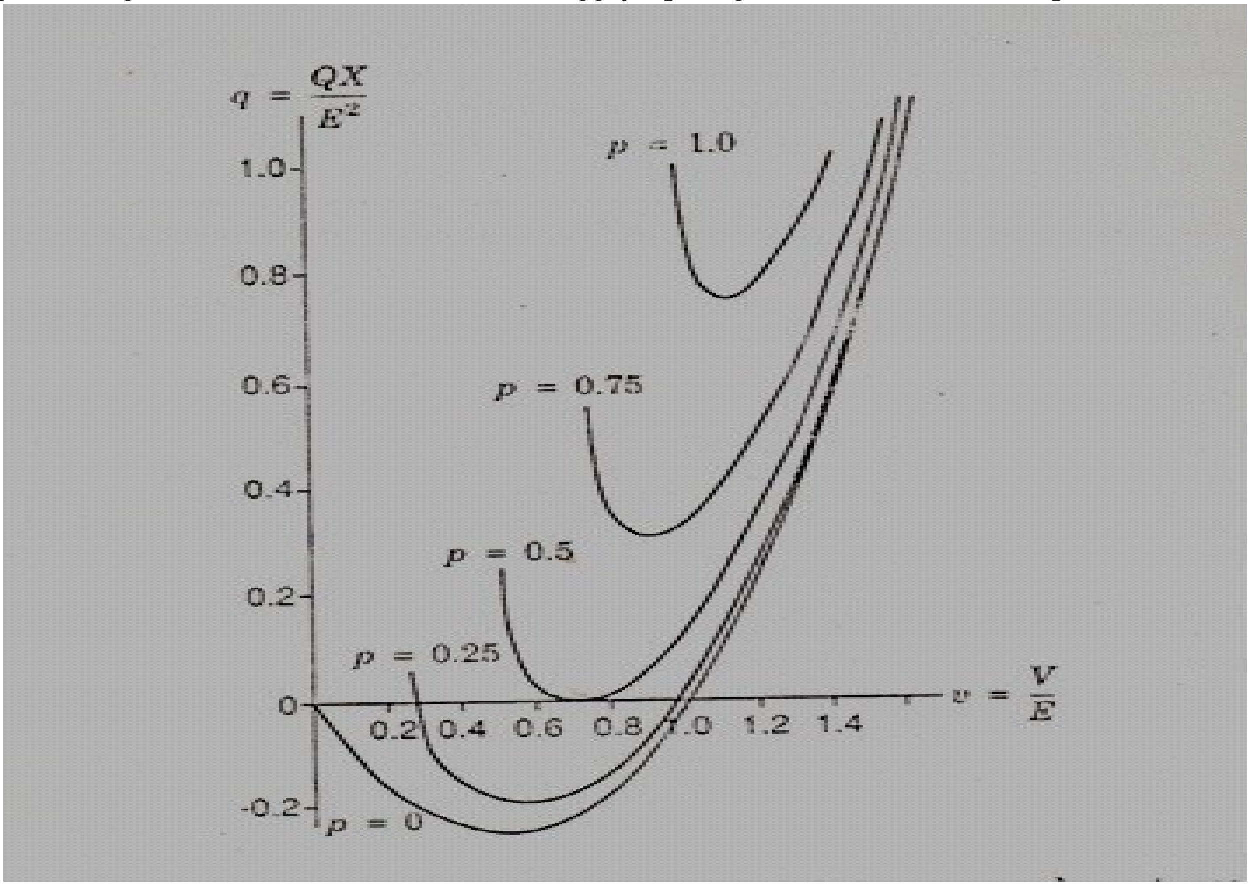


Fig : Normalised Q-V curves for fixed (infinite) source.

Fig : Q – V Curves

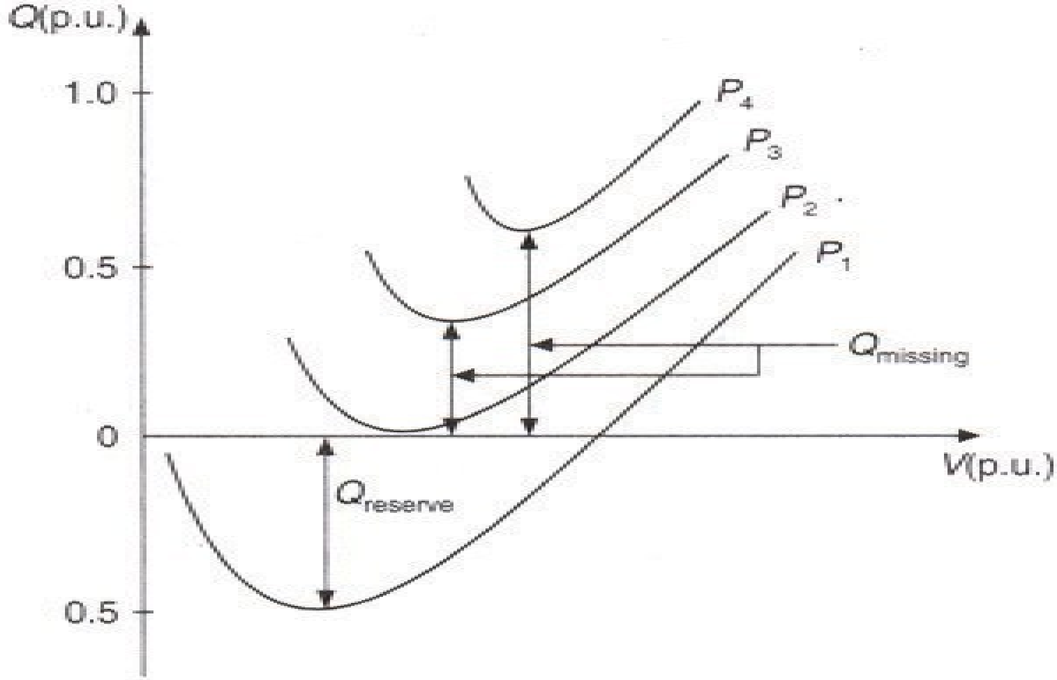


Figure shows the Q-V diagram of a bus in a particular power system at four different loads: P_1, P_2, P_3, P_4. the Q axis shows the amount of additional reactive power that must be injected into the bus to operate at a given voltage. The operating point is the intersection of the power curve with the voltage axis, where no reactive power is required to be injected or absorbed. If the slope of the curve at the intersection point is **positive**, the system is **stable,** because any additional reactive power will raise the voltage and vice-versa.

Hence for P_1 load, there is a reserve of reactive power that can be used to maintain stability even if the load increases.

For load P_2 the system is marginally stable.

For higher load P3 and P4 the system is not stable

(Since a certain amount of reactive power must be injected into the bus to cause an intersection with the voltage axis.)

Thus the measure of Q reserve gives an indication of the margin between stability and instability.

The slope of the Q-V curve represents the stiffness of the test bus.

when nearby generators reach their Var limits, the slope of the Q-V curve becomes less steep and the bottom of the curve is approached.
curves are presently the workhorse method of voltage stability analysis at many utilities. Since the method artificially stresses a single bus, conclusions should be confirmed by more realistic methods.

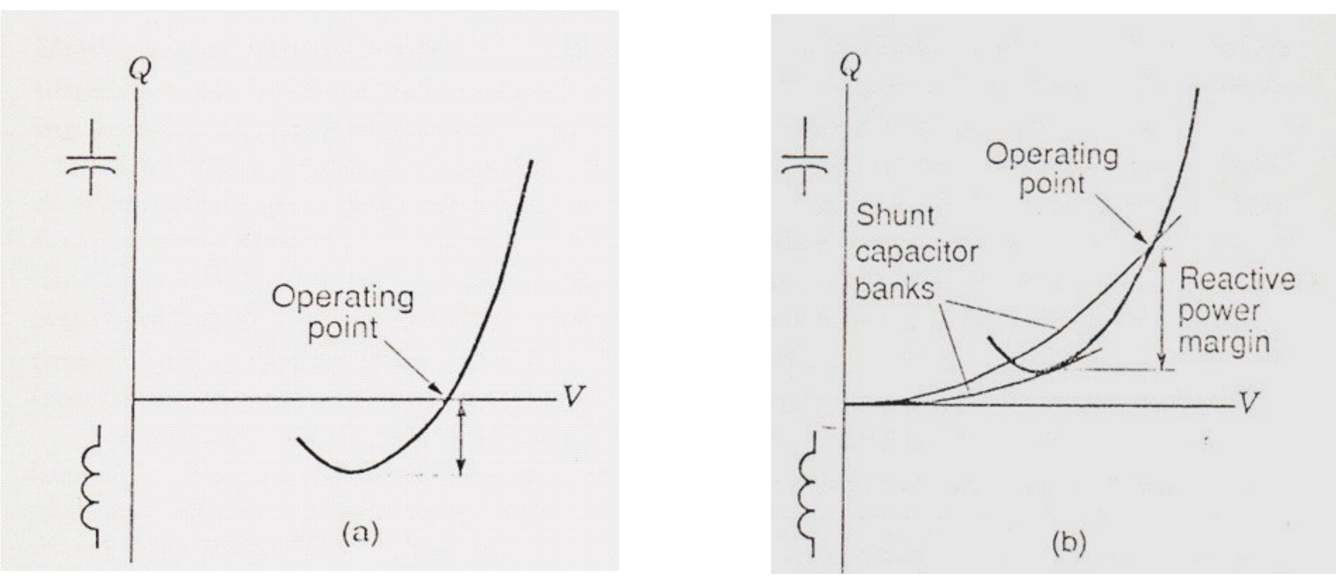


Fig: Reactive Power Margins

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UNIT - 6

Power system security

System security involves practices designed to keep the system operating when components fail. e.g. a generating unit may have to be taken off-line because of auxiliary equipment failure. By maintaining proper amounts of spinning reserve, the remaining units on the system can make up the deficit without too low a frequency drop or need to shed any load.

Similarly transmission line may be damaged by a storm & taken out by automatic relaying. the remain transmission lines can take the increased loading & still remain within limit.

Power system equipment is designed to be operated within certain limits, most of the equipments are protected by automatic devices, that can cause equipment to be switched out of the system if these limits are violated.

If any event occurs on a system that leaves it operating with limits violated, the event may be followed by a series of further actions that switch other equipment out of service. If this process of cascade failure continues, the entire system or large part of it may completely collapse. This is usually referred to as a system blackout.

* Large power systems install equipment to allow operations personnel to monitor & operate the system in a reliable manner

* The study of ~~tequ~~ techniques & equipments used to monitor

UNIT – 6

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* Large power systems install equipment to allow operations personnel to monitor & operate the system in a reliable manner

* The study of ~~teqttl~~ techniques & equipments used to monitor

operate the system reliably is called system security.

System security can be broken down into 3 major functions

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

System monitoring -

* It provides the operators of the power system with up-to-date information on the conditions on the power system.
* effective operation of the system requires measurement of critical quantities & the readings to be transmitted to a central location.
* such system of measurement & data transmission is called telemetry system.
* It monitors voltages, currents, power flows & the status of circuits breakers & switches in every substation in power system transmission n/w
* In addition, frequency, generator unit o/ps, transformer tap position can also be telemetered.
* To handle such a huge data digital computers are installed to in control centers to gather the telemetered data, process them & place them in a data base from which operators can display information on large display monitors.
* computers can check incoming information against prestored limits & alarm the operator in the event of overload or out-of-limit voltage.

* such systems are usually combined with SCADA systems that allows operators to control C.B.s & disconnect switches & transformer taps remotely.

* SCADA system allows a few operators to monitor the generation & high voltage transmission systems & to take action to correct overloads or out-of-limit voltages.

Contingency Analysis -

* It allows systems to be operated defensively.

* many problems occur on a power system can cause serious trouble within such a quick time period that the operator could not take action fast enough. This is ~~op~~ often the case with cascading failures.

* so computers are equipped with contingency analysis ~~proble~~ programs, that model possible ~~system~~ troubles before they arise.

* contingency analysis scheme involve fast solⁿ methods, automatic contingency et event selection & automatic initializing of the contingency power flows

3) Security - constrained optimal powerflow -

* In this ~~analysis~~ function, contingency analysis is combined with an optimal power flow which seeks to make changes to the optimal dispatch of generation & other adjustments, so that when a security analysis is run, no contingencies result in violations.

To demonstrate this, power system is divided into four operating states.

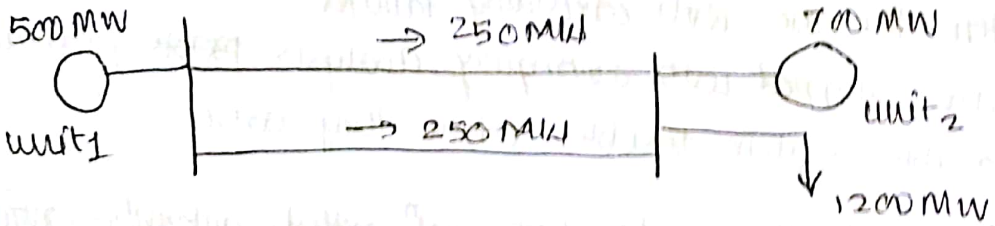
I) Optimal Dispatch - This is the state prior to any contingency It is optimal w.r.t. economic dispatch, but may not be secure.

II) Post contingency - This is the state after a contingency, assume that it has a security violation.

III) Secure dispatch – is the state with no contingency outages but with corrections to the operating parameters to account for security violations.

IV Secure post contingency: is the state of the when contingency is applied to the base operating condition – with corrections

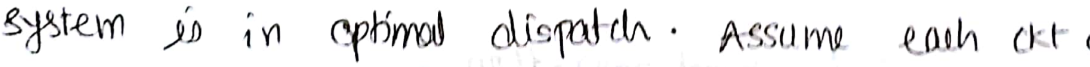
consider an example, with two generators, a load & a double ckt line, is to be operated with both generators supply the load

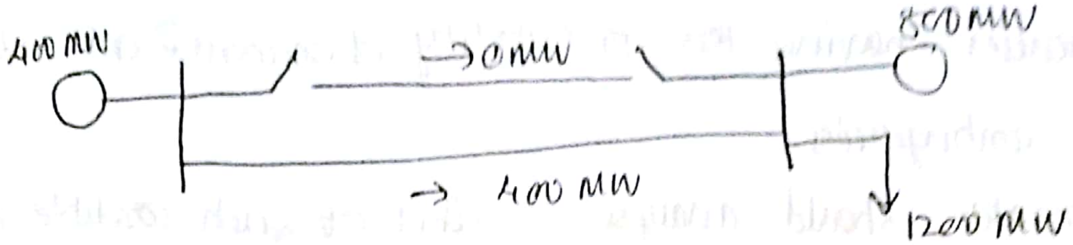


Optimal Dispatch

system is in optimal dispatch. Assume each ckt of the double ckt line can carry a maximum of 400 MW, so no loading problem in the base-operating conditions.

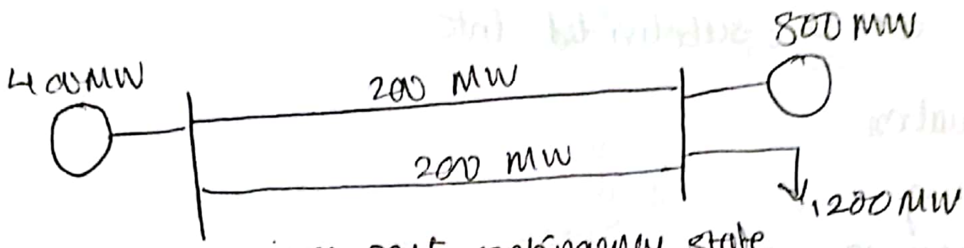
* Now assume one of the two ckts has been opened bcos of a failure This results in





Secure dispatch

Now if the same contingency analysis is done, the post contingency condition is



secure post contingency state

This is called as security corrections

* Programs which can make control adjustments to the base or pre-contingency operation to prevent violations in the post-contingency conditions are called "security-constrained optimal power flows" or SCOPF

* These programs can take account of many contingencies & calculate adjustments to generator MW, generator voltages, transformer taps etc.

Contingency Analysis –

A power system may face contingencies such as

i) Generating unit may go out of order
ii) an important line may tripped off
iii) demand may undergo a large change from forecasted value & soon

Only those having high probability of occurrance are to be considered. such contingencies are known as credible contingencies

* The contingencies having less probability of occurance are called non credible contingencies
* System operator should analyse the effect of such credible contingency as, this helps ~~the~~ to cope with such cases in case they occure.
* Analysis of credible contingencies is called security of operation & hence forms a part of the planning & operation of power systems

Contingency Analysis can be subdivided into

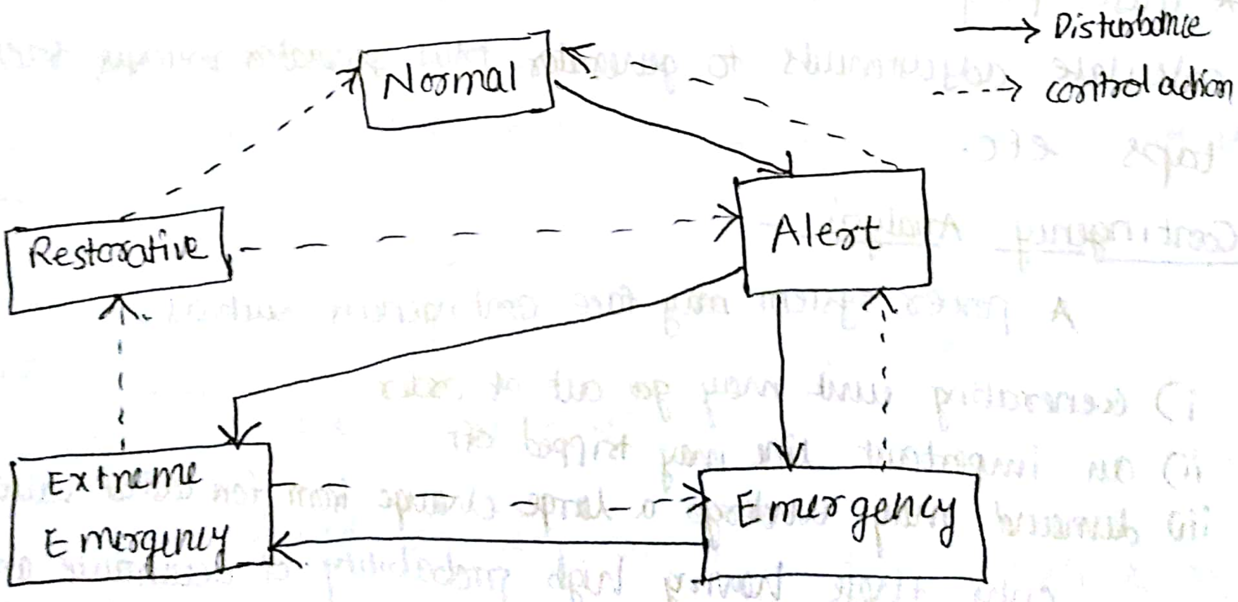
i) contingency evaluation
ii) contingency ranking
iii) contingency monitoring
iv) contingency screening

<u>Contingency evaluation</u> -

* secured system is one which has the ability to undergo a set of disturbances without getting into an emergency condition.

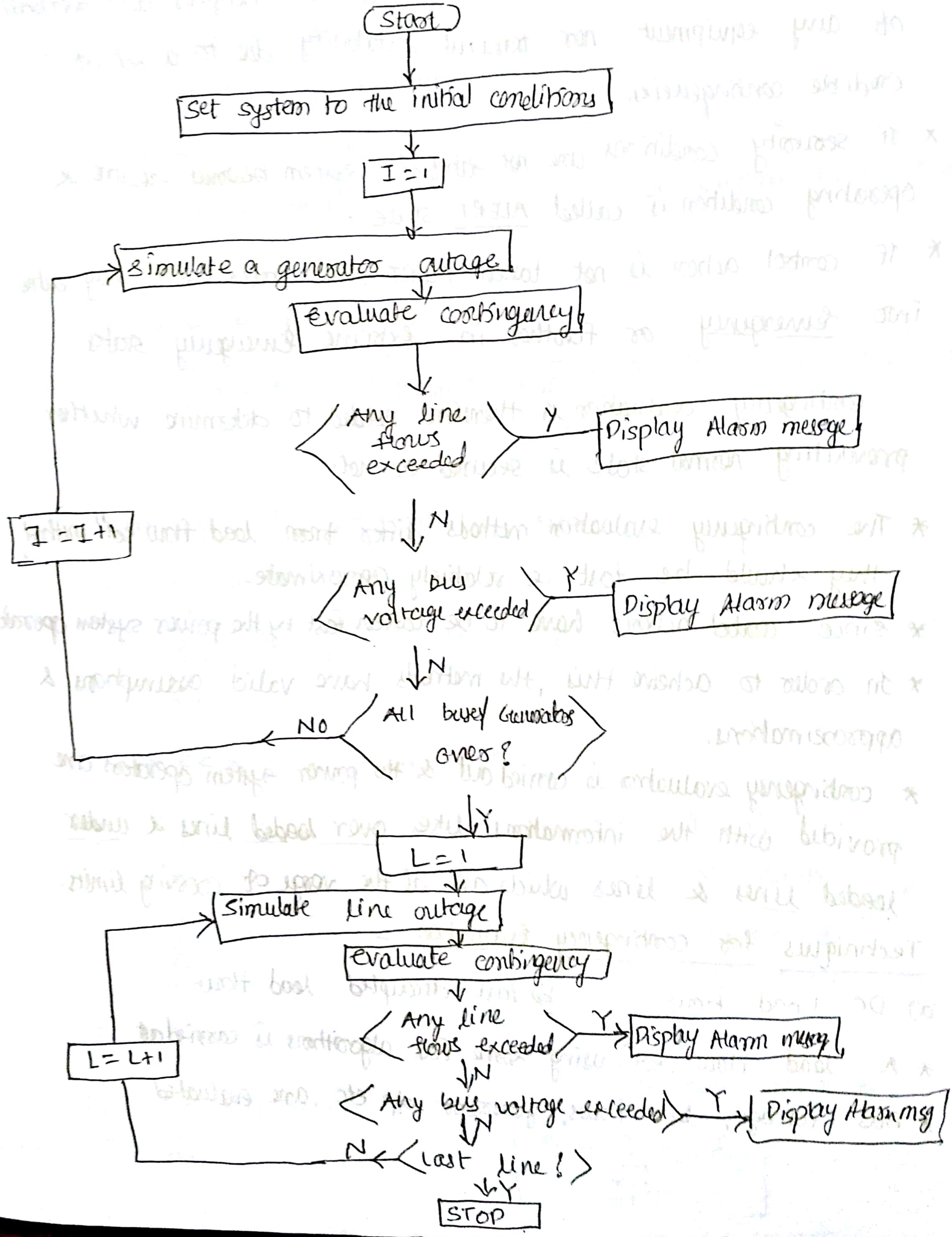
<u>states of power system</u> - are classified into 5 states

1) Normal 2) Alert 3) Emergency 4) extreme emergency 5) Restorative



States of Power System & transition from one state to another

Flowchart for contingency analysis



* Normal state is considered as secured if neither any overloading of any equipment nor transient instability due to a set of credible contingencies.
* If security conditions are not satisfied, system becomes insecure & operating condition is called ALERT state.
* If control action is not taken ALERT state, power system may enter into Emergency or further in extreme emergency states

contingency evaluation is therefore needed to determine whether prevailing normal state is secured or not.

* The contingency evaluation methods differ from load flow solⁿ method, they should be fast & relatively approximate.
* since control actions have to be taken fast by the power system operators
* In order to acheive this, the methods have valid assumptions & approximations.
* contingency evaluation is carried out & the power system operators are provided with the informations like over loaded lines & under loaded lines & lines which are at the verge of crossing limits.

Techniques for contingency Evaluation -

a) DC Load Flow   b) fast decoupled load flow

* A load flow solⁿ using some fast algorithms is carried out
* Bus voltage, line flows, generator o/p etc are evaluated

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a) DC Load flow method -

Following assumptions are made

i) The line resistances are negligible as $R << X$

ii) The voltage level is same throughout & is equal to 1 PU.

iii) Bus loadings are small & hence the phase angle difference is very small

iv) All shunt elements are neglected.

Real power P_i is given by

$$P_i = V_i^2 G_{io} + V_i^2 \sum_{\substack{m=1 \\ m \neq i}}^{n} G_{im} + V_i \sum_{\substack{m=1 \\ m \neq i}}^{n} V_m Y_{im} \cos\{(\delta_i - \delta_m) - \theta_{im}\} \quad -(1)$$

neglecting 1^{st} & 2^{nd} terms ∵ small

from assumptions

$$P_i = V_i \sum_{\substack{m=1 \\ m \neq i}}^{n} V_m Y_{im} \{\cos(\delta_i - \delta_m) \cos\theta_{i\theta} + \sin(\delta_i - \delta_m) \cdot \sin\theta_{im}\} \quad - (2)$$

$r << x$; ∴ $\theta_{im} = 90°$

$Y_{im} = B_{im}$, $V_i = V_m = 1$ PU $\qquad Y = \frac{1}{Z}$

$Y = G \pm jB \qquad G = \frac{1}{R}$

$$\therefore P_i = \sum_{\substack{m=1 \\ m \neq i}}^{n} B_{im} \sin(\delta_i - \delta_m) \quad - (3)$$

∵ $\cos 90 = 0$

∵ $\sin 90 = 1$

if $\delta_{im} = (\delta_i - \delta_m)$

$$P_i = \sum_{\substack{m=1 \\ m \neq i}}^{n} B_{im} \sin\delta_{im}$$

∵ δ is small $\quad \sin\delta = \delta$

&

$$\boxed{P_i = \sum_{m=1}^{n} B_{im} \delta_{im}} \quad - (4)$$

eq^n ③ or ④ are solved iteratively using G-S method

Comments – * The accuracy of DC load flow method is poor

* only MW flows of n/w can be obtained

* Method is extremely fast & can be adopted where voltage profile is not important.

b) Fast - Decoupled load flow method – (AC load flow method)

We have

$$P \propto \theta \quad \& \quad Q \propto V$$

P weakly coupled with V & Q weakly coupled with θ

In a Power system

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} \frac{\partial P}{\partial \theta} & \frac{\partial P}{\partial V} \\ \frac{\partial Q}{\partial \theta} & \frac{\partial Q}{\partial V} \end{bmatrix} \cdot \begin{bmatrix} \Delta \theta \\ \Delta V \end{bmatrix} \quad — ①$$

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} H & N \\ L & M \end{bmatrix} \begin{bmatrix} \Delta \theta \\ \Delta V \end{bmatrix}$$

$$\begin{bmatrix} \Delta \theta \\ \Delta V \end{bmatrix} = \begin{bmatrix} H & 0 \\ 0 & M \end{bmatrix}^{-1} \begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} \quad — ②$$

$$\therefore \left.\begin{aligned} \Delta \theta &= H^{-1} \cdot \Delta P \\ \Delta V &= M^{-1} \Delta Q \end{aligned}\right\} \quad — ③$$

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* The N-R method requires computation of Jacobian elements H, N, L & M & inversion of Jacobian matrix

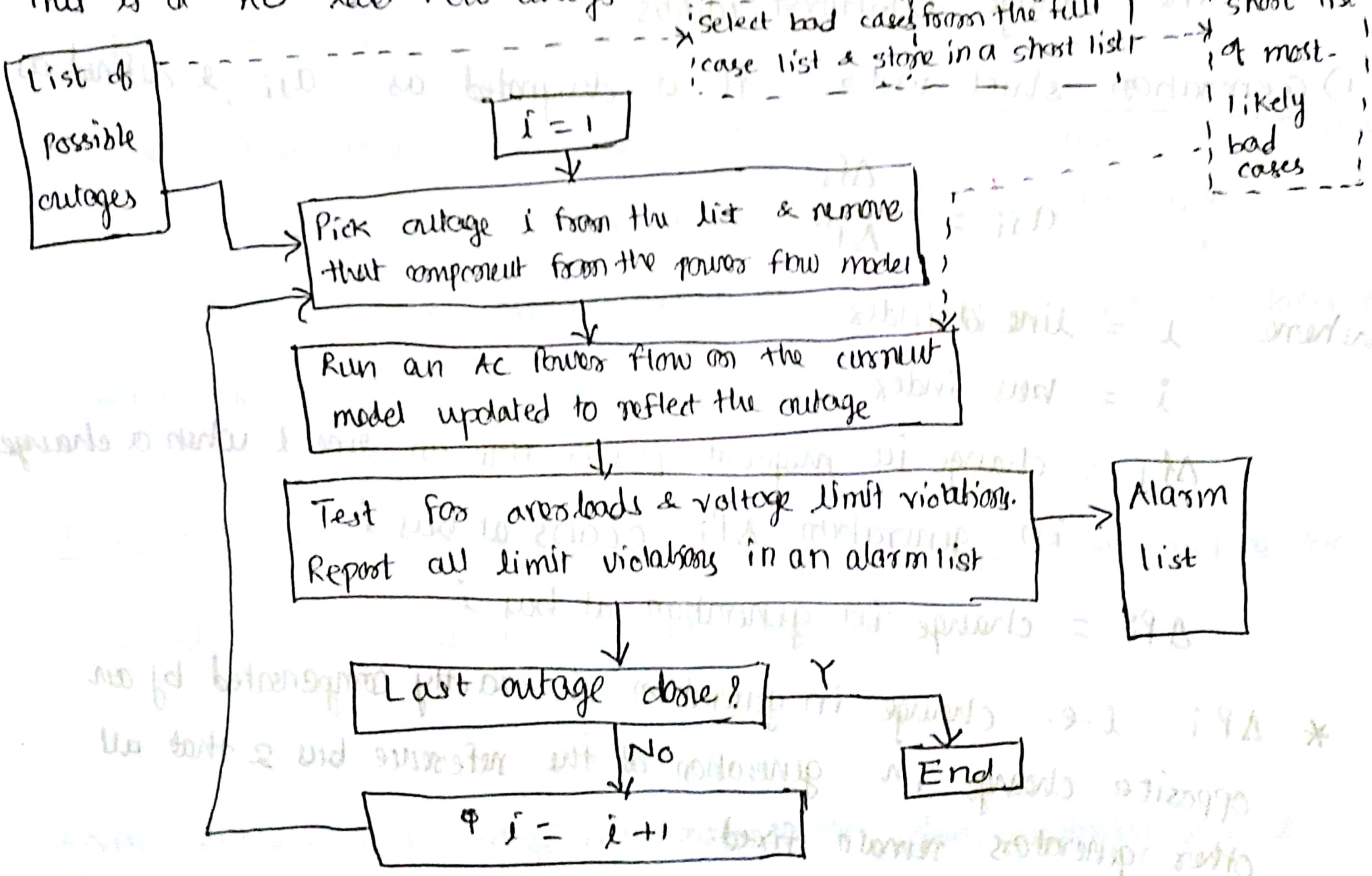
* This difficulty can be reduced by fast decoupled load flow techniques.

* As P is weakly coupled with V & Q is " " " θ

* eq^n (3) is solved seperately for Δθ & ΔV

* method is more faster than N-R method.

* This is a AC load flow analysis where voltage magnitudes are important



A C power flow security analysis

with - - - - dotted line including → AC power flow security analysis with contingency case selection

Contingency Analysis using Linear sensitivity factors -

* The problem of studying thousands of possible outages becomes very difficult to solve, if it is desired to present the results quickly.
* One of the easiest ways to provide a quick calculation of possible overloads is to use linear sensitivity factors.
* These factors show the approximate change in line flows for for changes in generation on the n/w configuration & are derived from D.C. load flow
* These factors are of two type
  1) Generation shift factors
  2) Line outage distribution factors.

1) Generation shift factor - It is designated as a_{li}, & defined as

$$a_{li} = \frac{\Delta f_l}{\Delta P_i}$$

where l = line id index

i = bus index

Δf_l = change in megawatt power flow on line l when a change in generation, ΔP_i, occurs at bus i

ΔP_i = change in generation at bus i

* ΔP_i i.e. change in generation is exactly compensated by an opposite change in generation at the reference bus & that all other generators remain fixed.
* The ~~a_{li}~~ a_{li} factor then represents a sensitivity of the flow on line l to a change generation at bus i.

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Let a large generating unit is failed & it was generating P_i^0 MW

we would represent ΔP_i as

$$\Delta P_i = -P_i^0$$

& the new power flow on each line in the n/w could be calculated using a precalculated set of 'a' factor as follows

$$\hat{f}_l = f_l^0 + a_{li} \Delta P_i \qquad \text{for } l = 1, \ldots L$$

$\hat{f}_l$ = flow on line l after the generator on bus i fails

f_l^0 = flow before the failure

* The outage flow $\hat{f}_l$, on each line can be compared to its limit & those exceeding their limit, flagged for alarming.
* It would tell the operator that the loss of generator on bus i would result in an overload on line

Line outage distribution factor – This factor apply to the testing for overloads when transmission ckts are lost.

$$d_{l,K} = \frac{\Delta f_l}{f_K^0}$$

where $d_{l,K}$ = line outage distribution factor when monitoring line l after an outage on line K

Δf_l = change in MW flow on line l

f_K^0 = original flow on line K before it was outaged

If one knows the power on line l & line k, the flow on line l with the ~~l~~ line k out can be determined using "d" factors

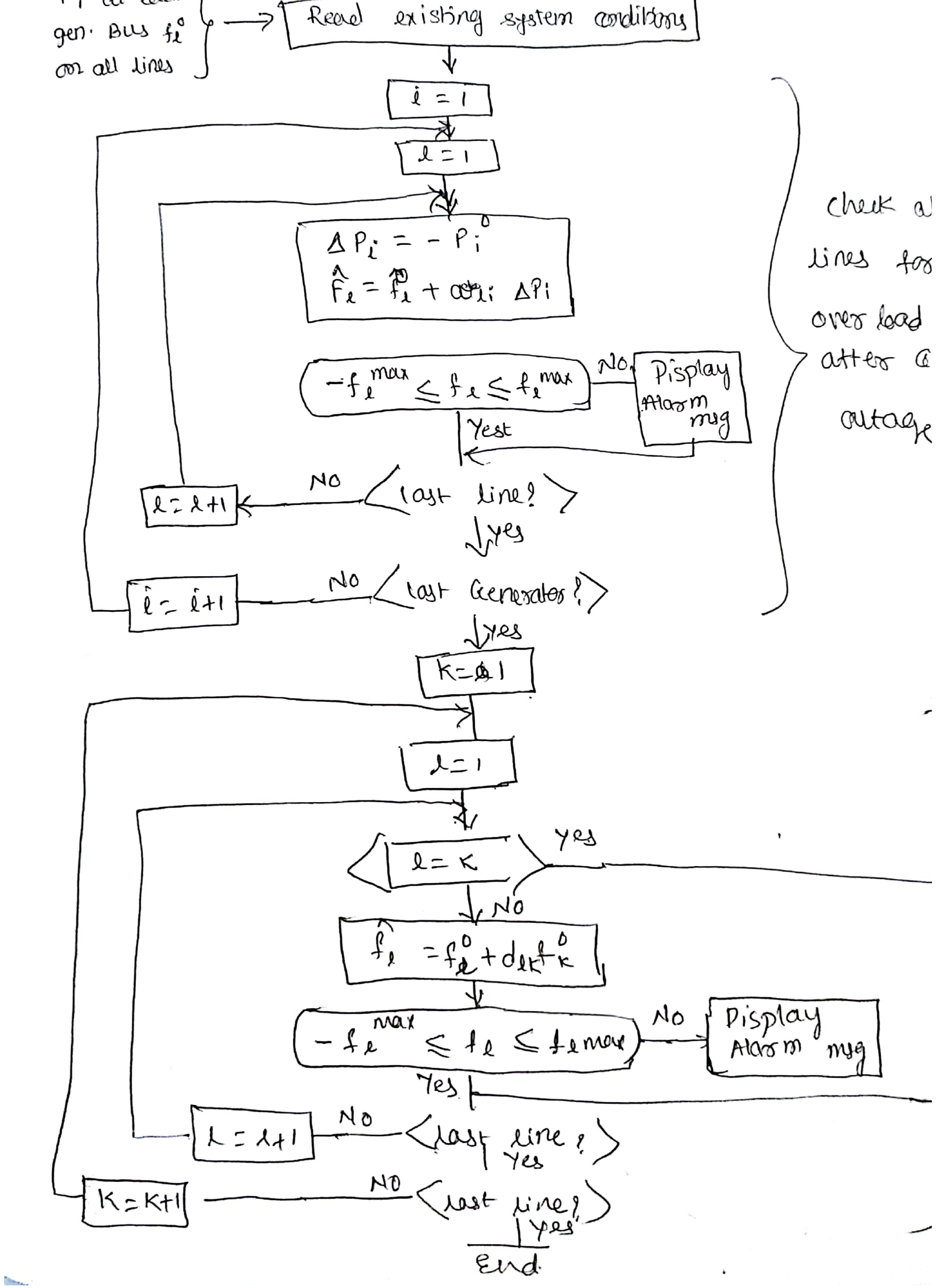
$$\hat{f}_l = f_l^0 + d_{lk} f_k^0$$

where f_l^0, f_k^0 = preoutage flow on lines l & k respectively

$\hat{f}_l$ = flow on line l with line k out

* By precalculating the line outage distribution factors, a very fast procedure can be set up to test all lines in the n/w ~~for~~ overload for the outage of a particular line.

* using the generator & line outage procedures, one can program a digital computer to execute


gen. Bus f_l^0
on all lines
Read existing system conditions
i = 1
l = 1
$\Delta P_i = -P_i^0$
$\hat{f}_l = f_l^0 + \alpha_{li}\,\Delta P_i$
$-f_l^{max} \le f_l \le f_l^{max}$
No
Display Alarm msg
Yes
No
last line?
l = l+1
yes
No
last Generator?
i = i+1
Yes
K = 1
l = 1
l = K
yes
NO
$\hat{f}_l = f_l^0 + d_{lK} f_K^0$
$-f_l^{max} \le f_l \le f_l^{max}$
No
Display Alarm msg
Yes
No
last line?
l = l+1
Yes
NO
last line?
K = K+1
yes
End
check all lines for over load after outage

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Unit - 5

Optimal system Operation & Unit commitment

03

Introduction -

* Human activity follows cycles e.g. transportation systems, communication systems as well as electric power system.
* In case of ele. power system, the total load on the system will generally be higher during the daytime & early evening when industrial loads are high, lights are on & so forth, lower during the late evening & early morning.
* Use of ele. power has a weekly cycle, the load being low over weekend days than weekdays.
* This is a problem in the oper^n of an ele. power syst
* We can't just simply commit enough units to cover the maximum system load & leave them running. as is the question of economics.

"Commit" a generating unit is to "turn it on", that is, bring the unit up to speed, synchronize it to the syste connect it so it can deliver power to the n/w

* It is quite expensive to run too many generating units, mo can be saved by turning units off (decommitting them) wh they are not needed.

Example 1. suppose one had the three units given here

Unit 1 : Min = 150 MW

Max = 600 MW

$H_1 = 510 + 7.2P_1 + 0.00142 P_1^2$ MBtu/h

04 MBtu/h — mega British thermal unit/h — unit for heat/temperature

H_1 — I/P / O/P curve

Unit 2 Min = 100 MW

Max = 400 MW

$H_2 = 310.0 + 7.8 P_2 + 0.00194 P_2^2$ MBtu/h

Unit 3 Min = 50 MW Max = 200 MW

$H_3 = 78.0 + 7.97 P_3 + 0.00482 P_3^2$ MBtu/h

with fuel costs :

Fuel cost 1 = 1.1 ₹ / MBtu

" " 2 = 1.0 ₹ / MBtu

Fuel cost 3 = 1.2 ₹ / MBtu

Load Demand $P_D = 550$ MW

Fuel cost can be calculated in ₹/h as follows

$F_1 = H_1 \times 1.1$

$\therefore F_1 = 561 + 7.92 P_1 + 0.001562 P_1^2$ ₹/h

$F_2 = H_2 \times 1.0 = 310 + 7.85 P_2 + 0.00194 P_2^2$ ₹/h

$F_3 = H_3 \times 1.2 = 93.6 + 9.564 P_3 + 5.784 \times 10^{-3} P_3^2$ ₹/h

If Load = 550 MW, what combination of units should be used to supply this load most economically?

To solve this problem, simply try all combination of the three units

05

U_1 unit1	U_2 unit2	U_3 unit3	Max. Gen	Min Gen	P_1	P_2	P_3	F_1	F_2	F_3	Total Ge. cost $F_1+F_2+F_3$
0	0	0	0	0				Infeasible			
0	0	1	200	50				Infeasible			
0	1	0	400	100				Infeasible			
0	1	1	600	150	0	400	150	0	3760	1658	5418
1	0	0	600	150	550	0	0	5389	0	0	5389
1	0	1	800	200	500	0	50	4911	0	586	5497
1	1	0	1000	250	295	255	0	3030	2440	0	5471
1	1	1	1200	300	267	233	50	2787	2244	586	5617

1 - on , 0 - off

Some combinations will be infeasible if the sum of all max MW for the units committed is less than the load OR sum of all min MW for the units committed is greater than the load

* From above table - the least expensive way to supply the generation optimal commitment is to only run unit 1, the most economic unit
* By running most economic unit, load can be supplied by that unit operating closer to its best efficiency.
* If another unit is committed, both unit 1 & the other unit will be loaded further from their best efficiency pts.

* suppose the load follows a simple "peak-valley" pattern as shown in fig

06

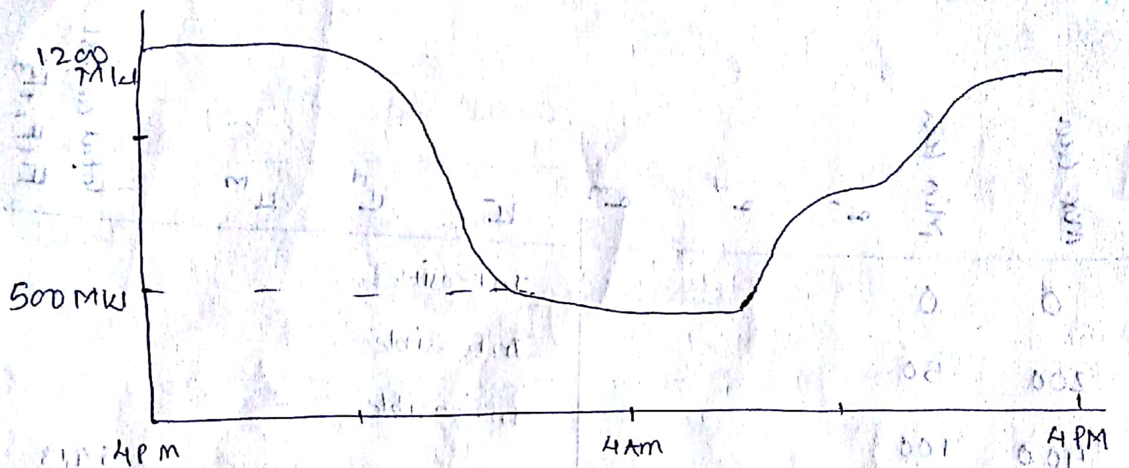


fig - a

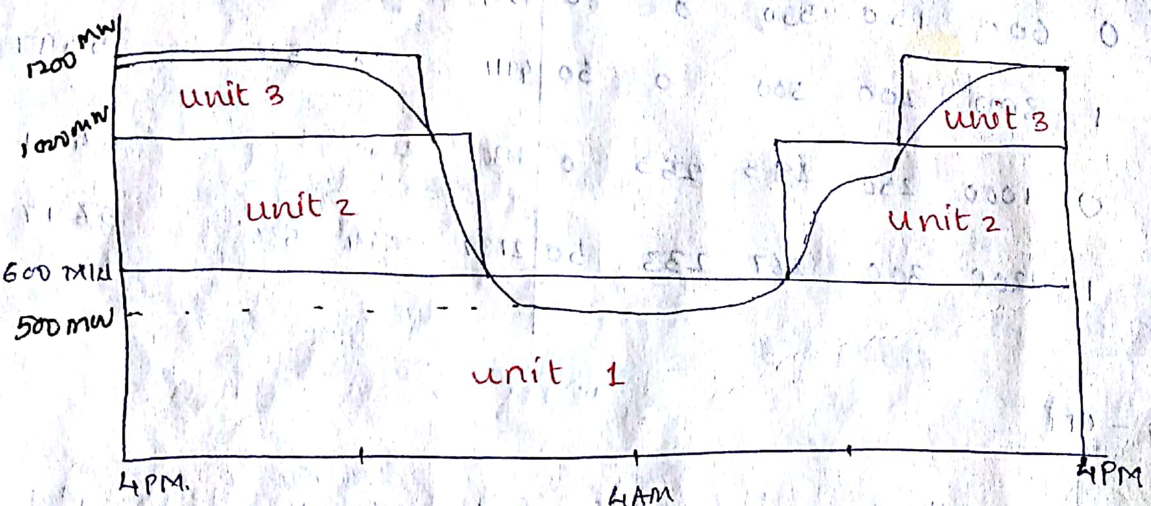


fig - b

* If operation of the system is to be optimized, units must be shut down as the load goes down & then recommitted as it goes back up.
* ~~we would~~ we wish to know which units to drop as a function of system load. with the load varying from a peak of 1200 MW to a valley of 500 MW. For each load value taken in steps of 50 MW from 1200 to 500. The results of applying this brute-force tech. are given in Table followed.

Our shut-down rule is quite simple

> When load is above 1000 MW, — run all three units 07
> bet^n 1000 MW & 600 MW — run units 1 & 2
> below 600 MW, — run only unit 1

Shut-down Rule Derivation

Load	Optimum combination unit 1	unit 2	unit 3
1200	on	on	on
1150	on	on	on
1100	on	on	on
1050	on	on	on
1000	on	on	off
950	on	on	off
900	on	on	off
850	on	on	off
800	on	on	off
750	on	on	off
650	on	on	off
600	on	off	off
550	on	off	off
500	on	off	off

* fig b shows the unit commitment schedule derived from this shut-down rule as applied to the load curve of fig-a

* so far we have

Spinning Reserve -

08 * Spinning reserve is the term used to describe the total amount of generation available from all units synchronized (i.e. spinning) on the system, minus the present load & losses being supplied

Spinning reserve = Total generation available from all units − Present load + losses

* Spinning reserve must be carried so that the loss of one or more units does not cause too far a drop in system frequency.
* If one unit is lost, there must be ample reserve on the other units to make up for the loss in a specified time period.
* Typical rules specify that reserve must be a percentage of forecasted peak demand OR reserve must be capable of making up the loss of the most heavily loaded unit in a given period of time.
* reserves must be allocated among fast-responding units & slow responding units, this allows the automatic generation control system to restore frequency & interchange quickly in the event of a generating-unit outage.
* beyond spinning reserve, the UC problem may involve "scheduled reserves or off-line reserves. These include quick-start diesel or gas-turbine units as well as most hydro-units & pumped storage hydro-units that can be brough on-line, synchronized & brought up to full capacity quickly.
* Reserves must be spread around the power system to avoid transmission system limitations

Thermal unit constraints

* Thermal unit usually require a crew to operate them while the unit is turned on & turned off.

* A thermal unit can undergo only gradual temp changes, & this translates into a time period of some hours required to bring the unit on-line. As a result of such restrictions in the operation of a thermal plant, following constraints arise

1. Minimum up-time – once the unit is running, it should not be turned off immediately.

2. Minimum down time – once the unit is decommitted, there is a minimum time, before it can be recommitted.

3. Crew constraints – If a plant consists of two or more units, they cannot both be turned on at the same time since there are not enough crew members to attend both units while starting up.

* As the temperature & pressure of the thermal unit must be moved slowly a certain amount of energy must be expended to bring the unit on line. This energy does not result in any MW generation from the unit & is called as a "start-up cost."

* Start up cost is maximum if the unit is to start from "cold start" & is minimum if the unit was only turned off recently & is relatively close to operating temperature

* There are two approaches to treating a thermal unit during its down period :- cooling & banking

Cooling : allows the unit's boiler to cool down & then heat back up to operating temperature in time for a scheduled turn on.

Banking : requires that sufficient energy be input to the boiler to just maintain operating temperature.

The costs for the two can be compared so that, if possible, the
10 best approach can be chosen.

start-up cost when cooling = $C_c(1 - e^{-t/\alpha}) \times F + C_f$

where

C_c = cold - start cost (MBtu)

F = fuel cost

C_f = fixed cost (including crew expense, maintenance expenses) in R

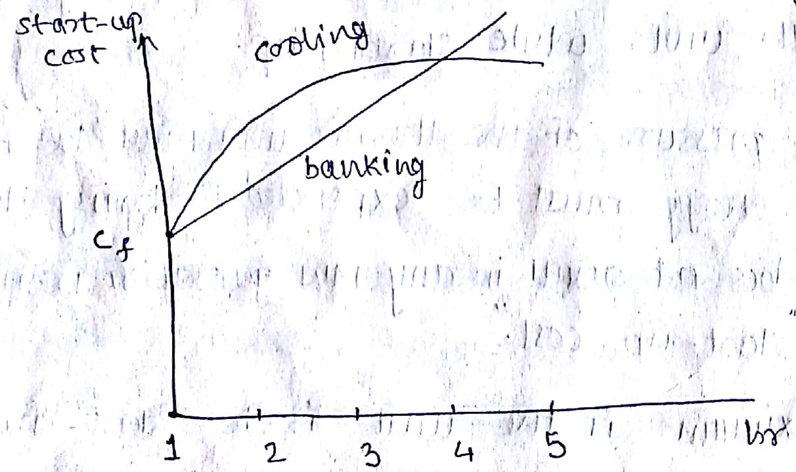
α = thermal time constant for the unit

t = time (h) the unit was cooled

Start up cost when banking = $C_t \times t \times F + C_f$

where

C_t = cost (MBtu/h) of maintaining unit at operating temp.



Time dependent start-up cost

up to certain number of hrs, the cost of banking will be less than cost of cooling.

<u>Other constraints</u>

<u>Hydro-constraints</u> - UC problem must consider hydro constraints

1) <u>Must Run</u> - some units are given a must-run status during certain times of the year for main

support on the tra. n/w

2) **Fuel constraints** – 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.

Unit commitment solⁿ methods

* The commitment problem can be very difficult. As a theoretical exercise, let us postulate the following situation

1. we must establish a loading pattern for M periods
2. we have N units to commit & dispatch
3. The M load levels & operating limits on the N units are such that any one unit can supply the individual loads & that any combination of units can also supply the loads.

Next, assume

The total no of combinations we need to try each hr is,

$$C(N,1) + C(N,2) + \cdots + C(N,N-1) + C(N,N) = 2^N - 1$$

where $C(N,j)$ is the combination of N items taken j at a time. That is

$$C(N,j) = \left[\frac{N!}{(N-j)!\,j!}\right]$$

$$j! = 1 \times 2 \times 3 \times \cdots \times j$$

For the total period of M intervals, the maximum no. of possible combinations is $(2^N - 1)^M$, which can become a horrid no. to think about.

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for example, take a 24-h period & consider systems with 5, 10, 20 & 40 units. The value of $(2^N - 1)^{24}$ becomes the 12 following

N	$(2^N-1)^{24}$
5	6.2×10^{35}
10	1.73×10^{72}
20	3.12×10^{144}
40	Too big

* The real practical barrier in the optimized unit commitment problem is the high dimensionality of the possible sol^n space.

* Different techniques for the sol^n of the unit commitment problem are:

1) Priority-list schemes,
2) Dynamic Programming (DP)
3) Lagrange relation (LR)

1) <u>Priority-List Methods</u> –

* The simplest unit commitment sol^n method consists of creating a priority list of units

* As seen in example 1, a simple shut-down rule or priority-list scheme could be obtained

* The priority-List of example-1 could be obtained in a much simpler manner by noting the full-load average production cost of each unit, where the full load average production cost is simply the net heat rate at full load

multiplied by the fuel cost.

Example 2 – Construct a priority list for the units of example-1

First, the full-load avg production cost will be calculated

unit	Full load, Avg production cost ₹/MWh
1	9.79
2	9.48
3	11.188

i.e. $H_1 = 510 + 7.2P_1 + 0.00142 P_1^2$ MBtu/h

fuel cost 1 = 1.1 ₹/MBtu.

Min = 150 MW, Max = 600 MW.

$F_1 = H_1 \times$ fuel cost1 $= 561 + 7.92P_1 + 0.001562P_1^2$ ₹/h.

Now at full load $P_1 = 600$

$\therefore F_1 = 561 + 7.92(600) + 0.001562(600)^2$

$F_1 = 5875.32$ ₹/h

Agv Production cost $= \frac{5872.32 \text{ ₹/h}}{600 \text{ MW}} = 9.7922$ ₹/MWh

A strict priority order for these units, based on the avg production cost, would order them as follows

unit	₹/MWh	Min MW	Max MW
2	9.48	100	400
1	9.79	150	600
3	11.188	50	200

the commitment scheme would simply use only the following combinations

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Combination	Min MW from combination	Max MW from combination
2+1+3	300	1200
2+1	250	1000
2	100	400

Most priority list schemes are built around a simple shut down algorithm that might operate as follows

1) At each hr when load is dropping, determine whether dropping the ~~load~~ next unit on the priority list will leave sufficient generation to supply the load plus spinning-reserve requirements. If not, continue operating as it is, if yes, go on to the next step. (Think about spinning reserve)

2) Determine the number of hrs, H, before the unit will be needed again. Assume that the load is dropping & will then go back up some hrs later. (Think about duration for which unit is shutdown)

3) If H is less than the minimum shut-down time for the unit, keep commitment as it is & go to last step, if not, go to next step.

4) Calculate two costs. The first is the sum of the hourly production costs for the next H hrs with the unit up. (Think about profit from shutting down the unit) Then recalculate the same sum for the unit down & add in the start up cost for either cooling the unit or banking it, whichever is less expensive. If there is sufficient savings from shutting down the unit, it should be shut down, otherwise keep it on.

5) Repeat this entire procedure for the next unit on the priority list. If it is also dropped, go to the next & so forth.

Dynamic Programming Sol^n —

* The chief advantage of Dynamic programming over the enumeration scheme is reduction in the dimensionality of the problem.

* Suppose we have four (4) units in a system & any combination of them could serve the load. There would be a maximum of $2^4 - 1 = 15$ combinations to test.

If strict priority order is imposed there are only 4 combinations as discussed. i) Priority 1 unit ii) Pri. 1 unit + Pri 2 unit iii) Pri. 1 unit + Pri 2 unit + Pri. 3 unit iv) Pri 1 + Pri 2 + Pri 3 + Pri 4 but it will work if following conditions fulfill

1) No load costs are zero
2) Unit i/p - o/p chars. are linear betn zero o/p & full load
3) No other restrictions
4) start-up costs are a fixed amount

In Dynamic programming we assume that

1) A state consists of an array of units with specified units operating & rest off line
2) start-up cost is independent of the time it has been off line
3) no costs for shutting down
4) strict priority order & in each interval specified minimum amount of capacity operates.

feasible state — committed units can supply required load

Forward DP Approach —

* Here the algorithm is set to run forward in time from initial hr to find

* If start-up cost of a unit is a function of the time it 16 has been off-line, then a dynamic pgm 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 & the computations can go forward in time as long as required.

* The recursive algorithm to compute the minimum cost in hour K with combination I is,

$$F_{cost}(K, I) = \min_{\{L\}} \left[P_{cost}(K, I) + S_{cost}(K-1, L : K, I) + F_{cost}(K-1, L) \right] \quad -(1)$$

where

$F_{cost}(K, I)$ = least total cost to arrive at state (K, I)

$P_{cost}(K, I)$ = production cost for state (K, I)

$S_{cost}(K-1, L : K, I)$ = transition cost from state $(K-1, L)$ to state (K, I)

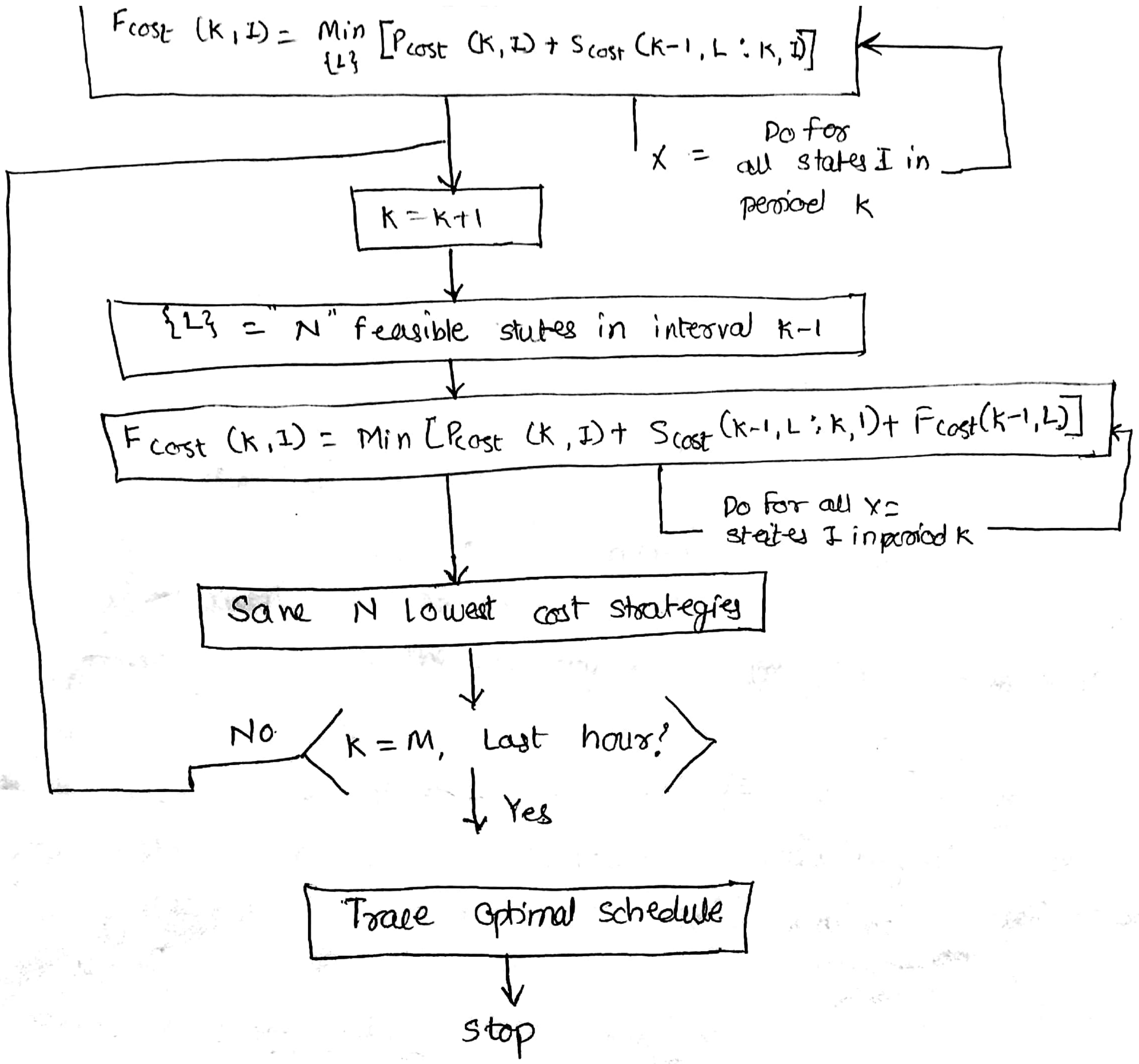
state (K, I) is the I^{th} combination in hour K

* For dynamic programming, we define a strategy as the transition or path, from one state at a given hour to a state at the next hr

* two new variables X & N have been introduced

X = number of states to search each period

N = " " strategies or paths, to save at each step



unit commitment via forward dynamic programming

Power System Reliability

Unit-8

Introduction - The purpose of an ele. power system is to generate electrical energy & then to transmit & distribute it through an extensive n/w. So assessment of reliability of system is of importance.

Reliability - 1) is the ability of the system to perform its intended function.

2) The overall performance of the system in a desirable manner is often qualitatively designated as reliability

3) Probability of the system or any of it's components to perform its function adequately

* Measure of reliability is the availability of the system, expressed in a quantitative manner.

* It is indicated by the frequency of failure of the system or it's components.

* If no failures, system is 100% reliable, but it becomes unreliable if the frequency of failure increases beyond an acceptable limit. So modes of failures of a system need to be studied.

Modes of failures of a system -

The failures to which a system suffers are of three types

i) early failure,
ii) wear-out failure
iii) chance failure

i) early failure - are due to the use of substandard components & can be effectively eliminated by trial runs before the actual operation. This is known as debugging where the substandard components are detected & then replaced.

ii) Wear-out failure — It happens because of the wearing-out of the components & can be prevented by periodic overhaulting or preventive replacement during the operation.

iii) Chance failure — It occurres after the component have been debugged & before they begin to wear out during operation. These failures occur unexpectedly & at random intervals.

* ~~These~~ Reliability Engg deals with this type failure. The time of occurrence of such failures cannot be accurately predicted, the, probability of their occurance in an operating state can be calculated by the theory of probability.

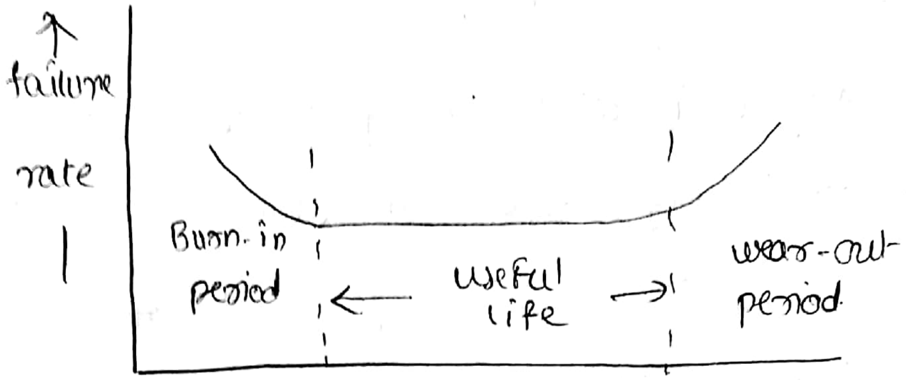
* From the above discussion, it may be noted that the life of a system or a component consists of the following three periods.

1) The burn-in period when the system is given a trial run to eliminate the sub-standard components.
2) The useful period during which chance failure can occur.
3) The wear-out period which start when the wear out of components occures.

* It may be noted that reliable operation is only possible during the useful period & as such no system equipment should be operated beyond its useful period. As failures are random during this period the probability theory

can be applied to predict their probability of occurring

* Fig shows these three periods with the variation of failure rates in each period.



Generating System → Life & it's performance →

Generating system & it's performance -

* The purpose of the generating system is to ensure adequate generation of ele. energy
* The system includes steam generating equipment, turbines, generators & their various auxilliaries & components.
* Installed capacity is sum of name plate ratings of all units installed
* Installed capacity should be more than peak load of the system.
* this excess is known as reserve capacity
* this reserve is needed for scheduled maintenance of units & to replace those units which develop faults during operation. following are the types of faults

1) Planned outage - components of generating system, boilers, turbines & generators should be periodically overhauled to keep them in good working condition.

* Periodic overhauling almost always prevents ageing of the unit & thus a trouble free performance for longer days is obtained.
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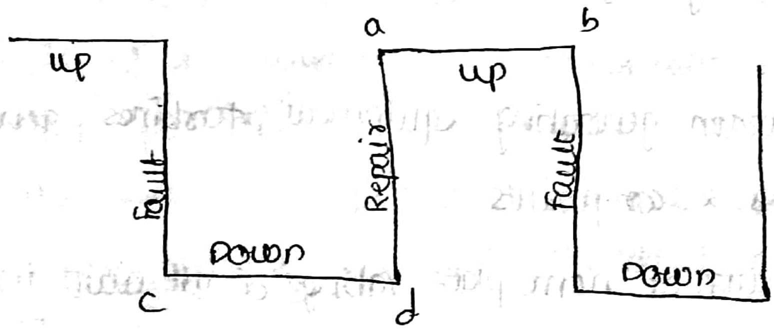
* During the period of maintenance component is not available for service & thus constitutes planned outage

2) Forced outage – Any unit while in operⁿ can develop faults & during such a contingency condition the unit is to be taken out of service, this is called forced outage.

Derivation of Reliability index –

* The generating unit may be either up or down, i.e. available or not available for service resp.
* when it is in up state, it may enter into down state due to a fault
* from down state, up state is entered through repair.



Display of up & down states

* The time interval ab represents an operating period betⁿ two successive failures & if a large no. of such intervals are noted, the mean time betⁿ the failures (MTBF) can be calculated in the following way

$$MTBF = \frac{\text{sum of operating periods}}{\text{Number of failures}} = m$$

* MTBF represents mean up-state & is indicated by m

* MTBF indicates average period during which failure-free operation is expected

* Similarly instances may be found out when failure occurs after a longer operating time. The reciprocal of MTBF i.e.

$$\frac{\text{Number of failures}}{\text{sum of operating periods}} = \lambda \text{ (mean failure rate)}$$

* The time interval cd in the figure represents a down-state betn two successive up-states & therefore the mean down-time r is given by

(mean down time) $r = \dfrac{\text{Total down-time}}{\text{Total number of down-states}}$

* since repair is taken up as soon as a unit is down, therefore, the reciprocal of r is the mean repair rate μ

(mean repair rate) $\mu = \dfrac{1}{r}$

Steady state Reliability Expression -

from above discussion, the probability of a unit remaining in the up-state is given by

$$P_{up} = \frac{m}{m+r}$$

∴ reliability of a unit is its probability of remaining in operating condition

∴ reliability of a unit $R = P_{up} = \dfrac{m}{m+r} = \dfrac{m}{T}$ — (1)

where - m - mean operating time

$T = (m+r)$ = mean cycle time

28 eq^n (1) signifies the average availability rate, similarly, unreliability Q of a unit is it's probability of failure & can be expressed as

$$Q = P_{down} = \frac{r}{m+r} = \frac{r}{T} \quad - (2)$$

$\because$ $m = \frac{1}{\lambda}$ & $r = \frac{1}{\mu}$ eq^n (1) & (2) can be expressed as

$$R = \frac{\mu}{\lambda+\mu} \quad - 1a$$

$$\& \quad Q = \frac{\lambda}{\lambda+\mu} \quad - 2b$$

Assume Q = 0.02 for a unit for a cycle time of = 1 year

$\therefore$ the forced outage period is $0.02 \times 365 = 7.3$ days / year

$\therefore$ eq^n (2) is forced outage rate of a unit

* since failure & operation are complimentary

$$R + Q = 1$$

<u>General Reliability expression</u> -

eq^n (1) & (2) give the steady - state value of reliability & unreliability resp. of a unit after considering a large number of up states & down states. The probability of failure of a unit at a given time t may be found using the following exponential relation

$$P_{down} = \frac{\lambda}{\lambda+\mu} \left(1 - e^{-(\lambda-\mu)t}\right)$$

~~sheet~~ 6

Reliability measure for N unit system –

A system having two units may encounter the following states

states of Two-unit system

state no.	unit 1	unit 2
1	up	up
2	down	up
3	up	down
4	down	down

The probability of encountering these states can be found by simple probability combinations. Thus

probability of state 1, $P_1 = P_1 up \cdot P_2 up$

" " 2, $P_2 = P_1 down \cdot P_1 up$

" " 3, $P_3 = P_1 up \cdot P_2 down$

" " 4, $P_4 = P_1 down, P_2 down$

∴ for 2-unit system, the possible no. of states is $4 = 2^2$

For a system having n units " 2^n

Then the states can be signified in following manner

31)

state code	state description
0	normal, i.e. all units are operating
i	unit i on forced outage, others are operati[ng]
ij	units i & j on forced outage, "

The probability of encountering the above states can be obtained [by] extending the method adopted for a 2-unit system. Thus th[e] probability of the normal state of a n-unit system

$$P_0 = P_{1up} \cdot P_{i\,up} \cdot P_{k\,up} \cdot \cdots P_{n\,up}$$

$$= \prod_{i=1}^{n} P_{i\,up}$$

similarly the probability of encountering the states i, ij etc ar[e]

$$P_i = P_{i\,down} \cdot \prod_{\substack{j=1 \\ j \neq i}}^{n} P_{j\,up}$$

$$P_{ij} = P_{i\,down} \cdot P_{j\,down} \prod_{\substack{k=1 \\ k \neq i,j}}^{n} P_{k\,up}$$

By defination P_0, P_i, P_{ij} are also the reliability of the generating system in the specified condition.

Problem 1) A system has 3 generating units of 50 MW capacity. The forced outage rate (FOR) of each unit is 0.03. find the total number of states & their probability of occurrence. Also calcula[te] the outage probabilities of different blocks of generation.

Sol^n - Total No. of states $= 2^3 = 8$

State No		State description	capacity available in MW
0	111	3 units are operating	150
1	110	First unit is out only	100
2	101	second unit "	100
3	011	Third " "	100
4	100	First & second units are out	50
5	010	First & third "	50
6	001	second & third "	50
7	000	Three units are out.	0

Probability of occurance of above states

Since the FOR of each unit is 0.03, the availability rate is 0.97

$P_0 = 0.97 \times 0.97 \times 0.97 = 0.9126.$

$P_1 = P_2 = P_3 = 0.03 \times 0.97 \times 0.97 = 0.028227$

$P_4 = P_5 = P_6 = 0.03 \times 0.03 \times 0.97 = 0.000823$

$P_7 = 0.03 \times 0.03 \times 0.03 = 0.000027$

outage probabilities of diff. blocks of generation

The probability of no-outage is the same as the reliability of operation of 3 units, III^{ly} the probability of 50 MW outage is the same as the reliability of 100 MW generation. Thus

Probability of 0 MW outage $= P_0 = 0.912673$

" " 50 MW " $= P_1 + P_2 + P_3 = 0.084681$

" " 100 MW " $= P_4 + P_5 + P_6 = 0.002619$

" " 150 MW " $= P_7 = 0.000027$

****

Planning of generating capacity - Loss of Load Probability (LOLP)

→ The outages of generating capacities are of little concern if
32 these do not result in load-shedding i.e. loss of load.

→ Outage can give rise to insufficient generating capacity & thus the system load may not be fully supplied.

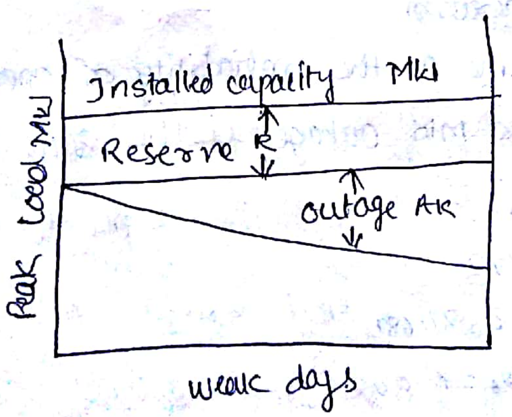
→ therefore, to combine the generation outage probabilities with the forecasted peak loads of the system throughout a year & thus to evaluate the number of days during which the system may have a shortage of the generating capacity resulting in a loss of load.

→ To evaluate loss of load probability from the outage probability the following data are needed

1. List of generating units with their FOR
2. List of forecasted daily peak loads for a period of one year

→ From the given values of FOR of diff. generating units, the probability of outage of diff. quanta of the generating capacity can be calculated from the forecasted peak load values.

The peak load variation curve over a one-year period is



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→ examination of fig shows that a

capacity outage ≤ system reserve R

NO Loss of Load.

capacity outage > R → produce insufficient capacity

for a period varying from 0 → days to 260 days (excluding week-end days) depends on the amount by which the outage exceeds the reserve capacity R.

→ If outage A_K has the probability P_K & if due to the outage, the peak load cannot be supplied for t_K days

probability of loss of load $= A_K f_K$

summing up all such probabilities, the system loss-of-load probability

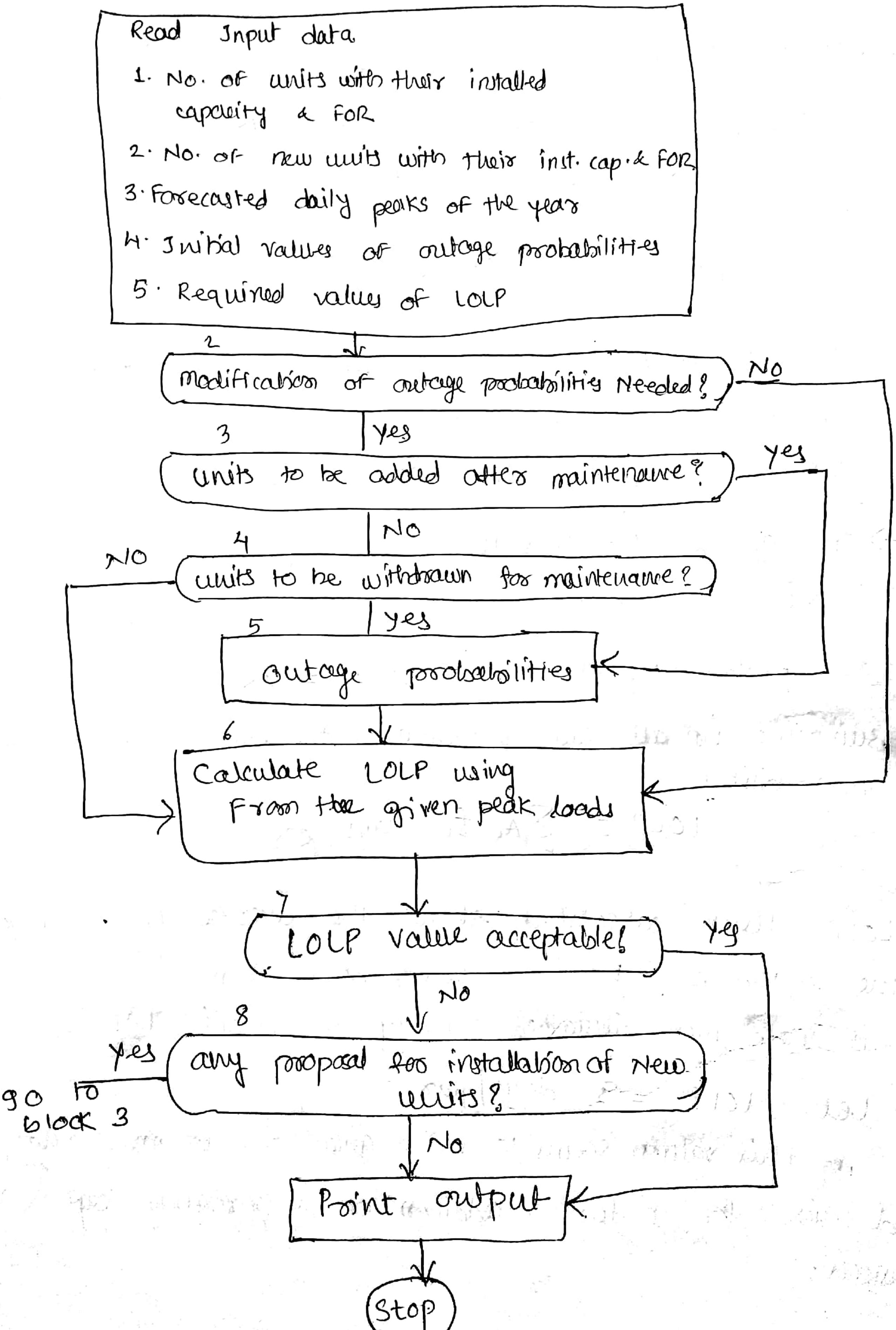
$$LOLP = \sum_K A_K f_K \text{ days/year}$$

→ LOLP thus calculated shows the average no. of day/year the system may have a shortage of generation

→ it need more installed capacity to avoid LOL

→ Let LOLP = 8 days/year

if this values seems to be a great risk to management, the decision for a further addition of the generating cap. may be taken.



Flow diagram for calculation of LOLP

* * * *

Cumulative probability of outages

The probability of outage of a particular block of generation or more is known as cumulative probability. These values can be calculated in the following way

outage in MW	cumulative probability
150 or more	0.0000027
100 or more (it include 150)	0.0000027 + 0.002619 = 0.002646
50 or more (it include 100 & 150)	0.002646 + 0.084681 = 0.087327
0 or more	0.087327 + 0.912673 = 1.0

* It shows that the cumulative probability of losing a certain amount of generating capacity is a certainty
* In above example generating units system having three identical units with identical FOR is shown.
* In realistic system the no. of units is more & their ratings & FOR are not identical.
* In power plant, units are periodically removed from service for inspection & maintenance as per planned pgm.
* No. & capacity of units available in each moment is therefore not constant & hence it is necessary to construct a different outage probability table for each month of the year.
* So volume of calculations involved will be more & a digital computer can be suitably programmed to do these calculations using recursive relation.

* A Power plant has generating units with data shown in table below. Prepare the capacity outage probability table & indicate the cumulative probabilities.
36

unit No	capacity in MW	failure rate/year (λ)	Repair rate years (μ)
1	100	1.0	19
2	150	0.1	4.9
3	250	1.1	73.0

Soln -

$R = \frac{\mu}{\lambda+\mu}$; $Q = \frac{\lambda}{\lambda+\mu}$

for unit 1 $P_{1up} = R = \frac{19}{19+1} = 0.95$ $P_{1down} = Q = \frac{\lambda}{\lambda+\mu} = \frac{1}{1+19} = 0.05$

unit 2 $R = \frac{4.9}{0.1+4.9} = 0.98$ $\Rightarrow = 0.1/_{1.1+4.9} = 0.02$

$Q = \frac{1.1}{1.1+73} = 0.01484$

unit 3 $R = \frac{73}{1.1+73} = 0.985$ $Q = 0.01484$

capacity outage probability table

state U_1 U_2 U_3	cap. out	cap. in	P_i	CP
1 1 1	0	500	(0.95) (0.98)(0.985)	1
0 1 1	100	400		0.082965
1 0 1	150	350		0.0347
1 1 0	250	250		0.015985
0 1 0	350	150		2.169×10^{-3}
1 0 0	400	100		1.44×10^{-3}
0 0 1	250	250		1.484×10^{-5}
0 0 0	500	0		

$P_1 = P_{1up} \times P_{2up} \times P_{3up} = 0.95 \times 0.98 \times 0.985 = 0.917035$

$P_2 = P_{1down} \times P_{2up} \times P_{3up} = 0.05 \times 0.98 \times 0.985 = 0.048265$

$P_3 = P_{1up} \times P_{2down} \times P_{3up} = 0.95 \times 0.02 \times 0.985 = 0.018715$

$P_4 = P_{1up} \times P_{2up} \times P_{3down} = 0.95 \times 0.98 \times 0.015 = 0.013965$

$P_5 = P_{1down} \times P_{2up} \times P_{3down} = 0.05 \times 0.98 \times 0.015 = 0.000735$

$P_6 = P_{1up} \times P_{2down} \times P_{3down} = 0.95 \times 0.02 \times 0.015 = 0.000285$

$P_7 = P_{1down} \times P_{2down} \times P_{3up} = 0.05 \times 0.02 \times 0.985 = 0.000985$

$P_8 = 0.05 \times 0.02 \times 0.01484 = 1.484 \times 10^{-5}$

Frequency & Duration of a state -

38 * The forced outage rate Q of a unit does not indicate anything about the duration of an outage state or the frequency of encountering that state.

* Let outage rate = 0.01, it doesn't state whether the outage occurs once in 100 days for a duration of one day or once in 500 days for a duration of 5 days

* The frequency f_i of encountering an outage state can be determined in the following way

r = mean down time
μ = mean repair rate
λ = mean failure rate
m = mean up state

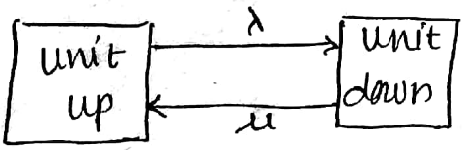
$$\because \quad Q = \frac{r}{T}$$

frequency of outage state $= f = \frac{1}{T}$ $\quad \therefore \quad f = \frac{Q}{r} = Q\mu \quad \because \; r = \frac{1}{\mu}$

||ly the frequency of encountering the up-state can be calculated as

$$F = \frac{1}{T} = \frac{R}{m} = R\lambda$$

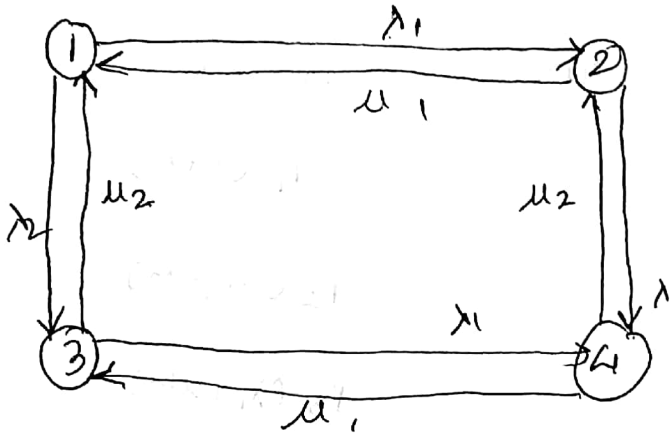
This is for one-unit system, state transition can be represented as



for a two m/c system the no. of possible states are 4

state	U_1	U_2
1	up	up
2	down	up
3	up	down
4	down	down

λ & μ can now be taken as the departure rates from the states previously occupied.



State transition Diagram for a two - M/C repairable system

From table it is found that 2 & 3 might follow 1 due to failure of any one of the units

. Hence rate of departure from state 1 is given by sum of failure rates of two units $(\lambda_1+\lambda_2)$

from state 2 either 1 or 4 may be entered

repair of U_1 (μ_1), state 2 to state 1

or failure of U_2 (λ_2) state 2 to stat 4

∴ Departure rates from state 2 is $= (\mu_1+\lambda_2)$

||ly " " " 3 is $= (\lambda_1+\mu_2)$

" " " " 4 is $= (\mu_2+\mu_1)$

The frequency of encountering a particular state fi is given by

$f_1 = P_1 *$ (Rate of departure from state)

Table : state description of a Two unit system

state No	Rate of departure	frequency
1	$\lambda_1+\lambda_2$	$P_1(\lambda_1+\lambda_2)$
2	$\mu_1+\lambda_2$	$P_2(\mu_1+\lambda_2)$
3	$\lambda_1+\mu_2$	$P_3(\lambda_1+\mu_2)$
4	$(\mu_1+\mu_2)$	$P_4(\mu_1+\mu_2)$

It is noted that :-

$$\text{mean duration time in each state} = \frac{1}{\text{rate of departure of state}}$$

$$\text{\& mean cycle time} = \frac{1}{\text{frequency of state}}$$

Let a Two unit system with following data

unit	capacity (MW)	FOR	Mean down Time, r (days)	failure rate λ	Repair rate μ
1	20	0.02	2.040816	0.01	0.49
2	30	0.02	2.040816	0.01	0.49

Their states, availabilities & mean time betn encountering the states are (mean-cycle times) shown in Table

state No	capacity available (MW)	Availability	Departure rate	Mean cycle Time (days)
1	50	0.9604	0.02	52.0616
2	30	0.0196	0.5	102.0408
3	20	0.0196	0.5	102.0408
4	0	0.0004	0.98	2555.02

For state 1

State 1 = 1 1 both units ON

∴ capacity available = 20+30 = 50 MW

Availability = $P_1 = P_{1up} \cdot P_{2up}$

$= 0.98 \times 0.98$

$= 0.9604$

P_1 down = P_2 down = 0.02

∴ P_1 up = 1 − 0.02 = 0.98 = P_2 up

Departure rate for state 1 = $\lambda_1 + \lambda_2$ = 0.01 + 0.01

= 0.02

Mean cycle time = $\frac{1}{\text{frequency}}$

frequency = P_1 × (rate of departure)

= 0.9604 × 0.02

= 0.019208

Mean cycle time = $\frac{1}{0.019208}$ = 52.06

∴ From Table it may be noted that state 1 has minimum cycle time

& state 4 has maximum cycle time