A Course Module

on

POWER SYSTEM OPERATION & CONTROL
(20A02701A)

Prepared by

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UNIT- I
ECONOMIC OPERATION OF POWER SYSTEMS

BRIEF DESCRIPTION ABOUT ELECTRICAL POWER SYSTEMS:

An electric power system is a network of electrical components deployed to supply, transfer, and use electric power. An example of a power system is the electricalgrid that provides power to homes and industries within an extended area. The electrical grid can be broadly divided into the generators that supply the power, the transmission system that carries the power from the generating centers to the load centers, and the distribution system that feeds the power to nearby homes and industries.

Smaller power systems are also found in industry, hospitals, commercial buildings, and homes. A single line diagram helps to represent this whole system. The majority of these systems rely upon three-phase AC power—the standard for large-scale power transmission and distribution across the modern world. Specialized power systems that do not always rely upon three-phase AC power are found in aircraft, electric rail systems, ocean liners, submarines, and automobiles.

INTRODUCTION TO POWER SYSTEM OPERATION AND CONTROL:

One of the earliest applications of on-line centralized control was to provide a central facility, to operate economically, several generating plants supplying the loads of the system. Modern integrated systems have different types of generating plants, such as coal fired thermal plants, hydel plants, nuclear plants, oil and natural gas units etc. The capital investment, operation and maintenance costs are different for different types of plants.

The operation economics can again be subdivided into two parts.

i) Problem of economic dispatch, which deals with determining the power output of each plant to meet the specified load, such that the overall fuel cost is minimized.

ii) Problem of optimal power flow, which deals with minimum–loss delivery, where in the power flow, is optimized to minimize losses in the system.

In this chapter we consider the problem of economic dispatch. During operation of the plant, a generator may be in one of the following states:

i) Base supply without regulation: the output is a constant.

ii) Base supply with regulation: output power is regulated based on system load.

iii) Automatic non-economic regulation: output level changes around a base setting as area control error changes.

iv) Automatic economic regulation: output level is adjusted, with the area load and area control error, while tracking an economic setting. Regardless of the units operating state, it has a contribution to the economic operation, even though its output is changed for different reasons.

The factors influencing the cost of generation are the generator efficiency, fuel cost and transmission losses. The most efficient generator may not give minimum cost, since it may be located in a place where fuel cost is high. Further, if the plant is located far from the load centers, transmission losses may be high and running the plant may become uneconomical.

The economic dispatch problem basically determines the generation of different plants to minimize total operating cost.

Modern generating plants like nuclear plants, geo-thermal plants etc, may require capital investment of millions of rupees. The economic dispatch is however determined in terms of fuel cost per unit power generated and does not include capital investment, maintenance, depreciation, start-up and shutdown costs etc.

ECONOMICS OF GENERATION:

Load Curves:

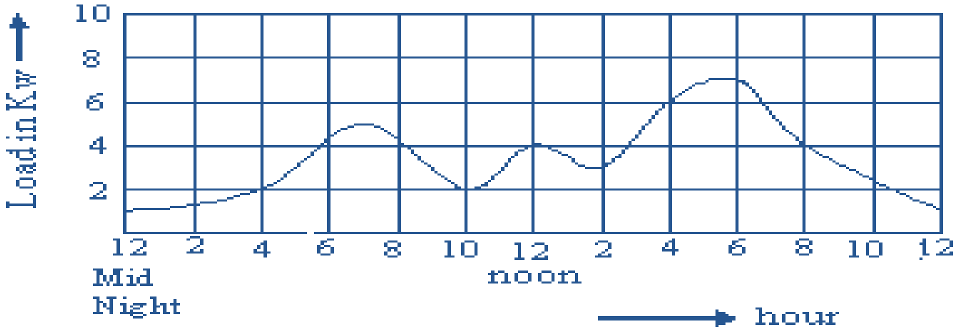


Fig 1.1 Load Curve

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

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

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

Types of Load Curve:

Daily load curve–Load variations during the whole day

Monthly load curve–Load curve obtained from the daily load curve

Yearly load curve-Load curve obtained from the monthly load curve

Daily load curve

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

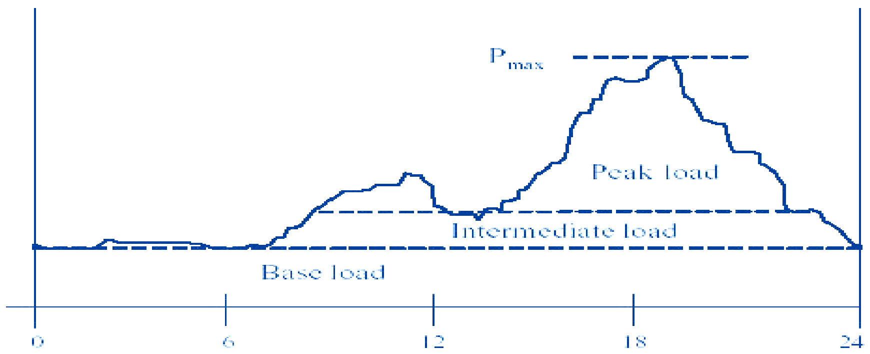


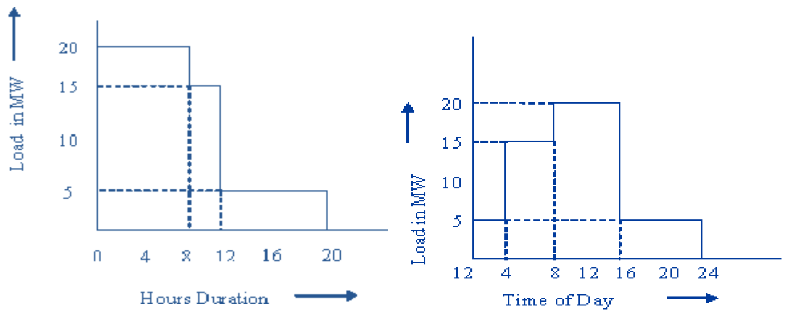
Fig 1.2 Daily Load Curve

Load duration curve:

When the elements of a load curve are arranged in the order of descending magnitudes

The load duration curve gives the data in a more presentable form

- The area under the load duration curve is equal to that of the corresponding load curve
- The load duration curve can be extended to include any period of time



- ***Fig 1.3 Load Duration Curve***

IMPORTANT TERMINALOGIES

Connected load

It is the sum of continuous ratings of all the equipment's connected to supply systems.

Maximum demand

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

Demand factor

It is the ratio of maximum demand to connected load.

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

Average demand

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

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

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

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

Load factor:

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

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

Diversity factor:

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

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

Capacity factor:

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

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

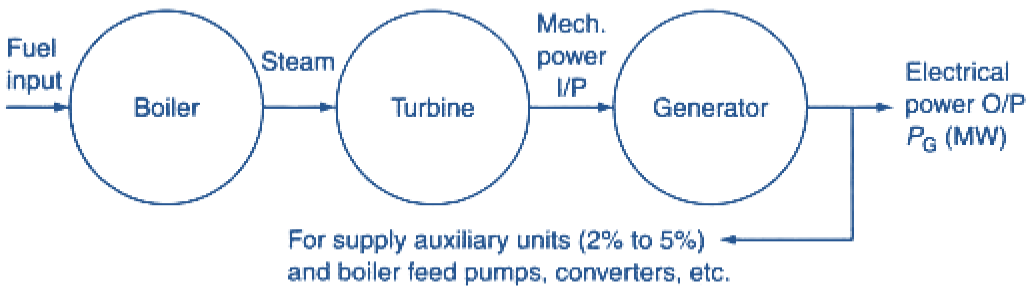
Plant use factor:

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

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

CHARACTERISTICS OF VARIOUS STEAM UNITS:

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



Thermal Generating System:

SYSTEM CONSTRAINTS:

There are two types of constraints

- Equality constraints are basic load flow equations.
- Inequality constraints

Inequality constraints are of two types

i) Hard type: example – tapping range of an on-load tap changing transformer

ii) Soft type: example – Nodal voltages and phase angles

INEQUALITY CONSTRAINTS:

a) Generator constrains:

$$P_{G(min)} \leq P_G \leq P_{G(max)}$$

Maximum active power generation of a source is limited by thermal consideration and minimum active power generation of the system is limited by flame instability of a boiler.

Similarly, maximum and minimum reactive power generation of a source is limited.

$$Q_{G(min)} \leq Q_G \leq Q_{G(max)}$$

The maximum reactive power is limited because of overheating of the rotor.

The minimum reactive power is limited because of stability limit of the machine.

Hence the generator reactive power can't be outside the range stated by inequality.

b) Voltage Constraints:

The voltage magnitudes and phase angles at various modes should vary within certain limits.

The voltage magnitudes should vary within certain limits because otherwise most of the equipments connected to the system will not operate satisfactorily (or) additional use of voltage regulating devices will the system uneconomical.

$$|V_{P(min)}| \leq |V_P| \leq |V_{P(max)}|$$

$$\delta_{P(min)} \leq \delta_P \leq \delta_{P(max)}$$

c) Running spare capacity constraints:

These constraints are required to met

i) Forced outages of one or more alternators on the system.

ii) Unexpected load on the system.

$$G \geq P_G + P_{So}$$

Where P_{So} is some specified power and G is the total generation. A well planned system is one in which this space capacity P_{So} is minimum.

d) Transformer tap setting:

If an auto-transformer is used, minimum tap setting could be zero and maximum be one.

$$\text{i.e., } 0 \leq t \leq 1.0$$

Similarly for a two winding transformer if tappings are provided on the secondary side.

$$0 \leq t \leq n$$

Where n is the transformation ratio.

e) Transmission line constraints:

The flow of active and reactive power through the transmission line is limited by the thermal capacity or capability of the circuit and is expressed as $C_P \leq C_{Pmax}$.

Where C_{Pmax} is the maximum capacity loading capacity of P^{th} line.

SYSTEM VARIABLES:

To analyze the power system network, there is a need of knowing the system variables.

They are:

(i) Control variables.
(ii) Disturbance variables.

(iii) State variables.

Control variables (P_G and Q_G)

The real and reactive-power generations are called control variables since they are used to control the state of the system.

Disturbance variables (P_D and Q_D)

The real and reactive-power demands are called demand variables since they are beyond the system control and are hence considered as uncontrolled or disturbance variables.

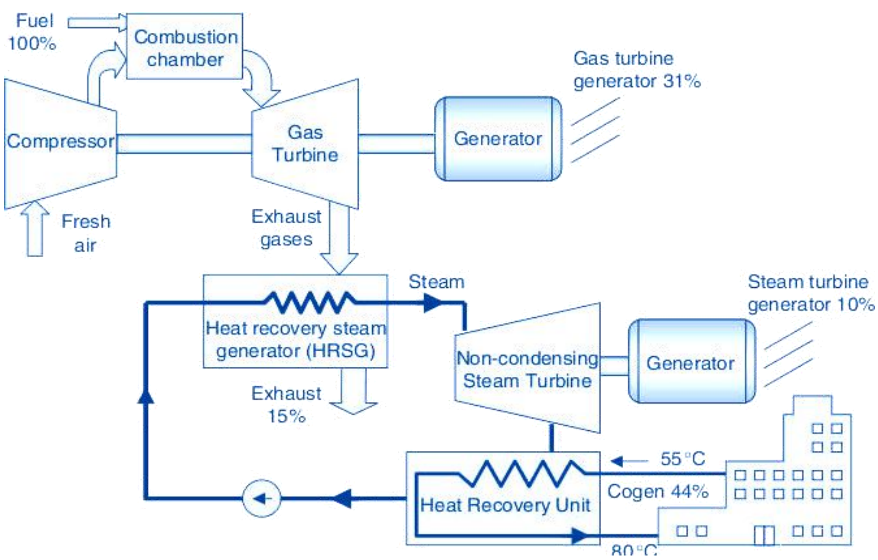
State variables (V and δ)

The bus voltage magnitude V and its phase angle <5 dispatch the state of the system. These are dependent variables that are being controlled by the control variables.

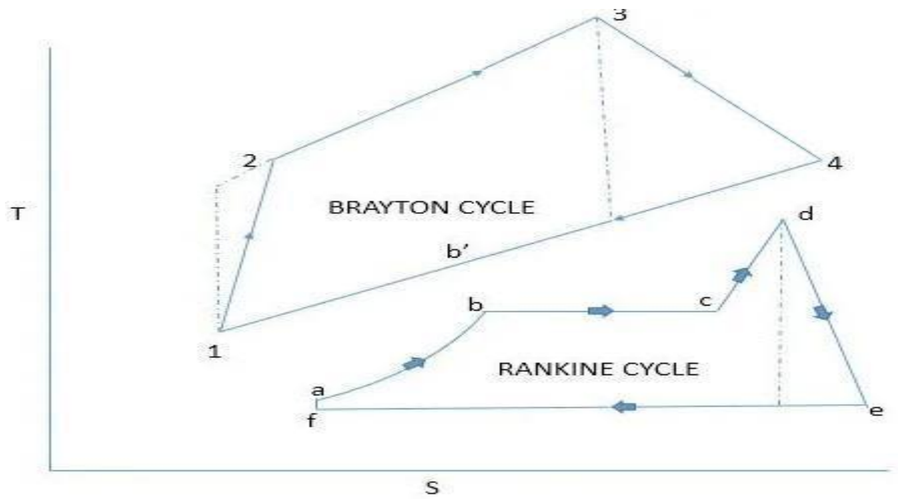
<u>Introduction of Combined Cycle Power Plant:</u>

In a combined cycle power plant (Fig. 1), electricity is produced by two turbines; a gas turbine, and a steam turbine. The gas turbine is operated by the combustion products of the fuel (Brayton cycle), while the steam turbine (Rankine cycle) is operated by the steam generated by HRSG from the heat content of the exhaust gases leaving the gas turbine.

The name combined cycle power plant is provided because the gas turbine operates according to the Brayton cycle and the steam system operates according to the Rankine cycle. So, two cycles generate power combined. Fig. below shows a schematic overview of a combined cycle power plant.



The gas turbine cycle works in the high-temperature region. Once the work is produced by the Brayton Cycle, the exhaust heat is routed to the near by steam turbine for producing extra power by the Rankine cycle. Fig. below shows both Brayton and Rankine Cycle.



Components of a Combined Cycle Power Plant:

The main components of a combined cycle power plant are

- A Gas Turbine (GT)
- An HRSG or Heat Recovery Steam Generator
- A Steam Turbine And
- Other Accessories or Associated Items.

Gas Turbine

A gas turbine in a combined cycle power plant converts natural gas or fluid into mechanical energy. A simple gas turbine has three sections: a compressor, a combustor, and a power turbine. It operates on the Brayton cycle principal. The working philosophy of gas turbines is simple. The compressed air is mixed with fuel and then burned under constant pressure. Then the hot gas flows through the turbine to produce work.

The HRSG receives the exhaust gases from the Gas Turbine discharge. The exhaust gas, flowing in the counter flow direction with respect to the steam/water coils, cools down by transferring heat to steam/water. The flue gas temperature at the stack is about 110°C. Lower temperatures 93°C can be used if the fuel gas is very clean and sulfur-free.

The HRSG is similar to a heat exchanger in which the shell side carries the flue gas and the tube side carries steam or water. It also has the characteristics of a boiler because there are steam drums, where the generated steam is separated from boiling water before entering the super heaters.

The HRSG can be horizontal or vertical, according to the direction of the flue gas path. The horizontal HRSGs are most common. The vertical ones mainly are limited to installations where space is very tight.

HRSG Pressure and Temperature Levels

The HRSG can have one, two, or three pressure levels according to the size of the plant.

- For plant sizes of 200–400 MW, the pressure levels used are HP, IP, and LP.
- Plants down to 30–60 MW usually have two pressure levels (HP and LP),
- Smaller units only have one pressure level. Sometimes, with three pressure levels, the LP section produces the steam needed for desecration only.
- The following tube banks are used for each pressure level (starting from the GT exhaust): 1) steam super heaters, 2) evaporator, and 3) economizer.

HRSG Design Features

Sometimes empty module is inserted in the flue gas ducts of large HRSGs where flue gas temperature is 350–380°C, which can be used in the future for the installation of a selective catalytic reduction unit for further NOx abatement. Sometimes, a spool piece for the future addition of an oxidation catalyst for CO abatement is included for the same purpose as the SCR and located in the same position.

The pressure drop across the HRSG on the flue gas path is in the range of 200–375 mm water column. This pressure drop is the back-pressure of the GT and influences its generated power and efficiency by 1 and 2%, respectively. The HRSGs are provided with a set of motor-operated valves that are installed in the steam and water lines.

The feed water inlet lines to the economizers are also provided with on/off shut-off valves. Having these shut-off valves allows the ―bottling in‖ of the HRSG by closing all inlet and outlet lines, thereby to keep the boiler pressurized when the shut-down period is expected to be short. Additional motor-operated valves are used to remotely and automatically operate the drains in the super heaters.

The HRSG also includes a pressurized blow-down tank and an atmospheric blow-off tank and is also equipped with chemical injection pumps to maintain the water and steam chemistry specifications. The HRSG is also equipped with nitrogen connections for purging (dry lay-up) to prevent corrosion in case of long shut-down periods.

Steam Turbine

Steam turbines in a combined cycle power plant extract energy from the steam and convert it to work, which rotates the shaft of the turbine. The amount of energy that the steam turbine extracts from the steam depends on the enthalpy drop across the machine.

The enthalpy of the steam is a function of its temperature and pressure. As inlet and outlet temperature and pressure are known, one can use a Mollier diagram to determine the amount of energy available. Steam turbine (Fig. 4) sizes range from a few kilowatts to over 1000 megawatts.

Operating Control modes of Steam Turbine:

Steam Turbine operates in three control modes:

- *Fixed pressure mode*– Below 50% load, which corresponds to about 50% of the live steam pressure, the steam turbine will be operated in a fixed pressure mode. In this mode of operation, pressure from the steam generator remains constant and is controlled by main control In case the steam turbine is not taking all produced steam, the pressure of a steam generator is controlled by the bypass valves.
- *Sliding pressure mode*– When the 50% load is reached the main control valve is fully open. With increasing gas turbine loads the steam turbine will be operated in sliding pressure mode. In this case, the live steam pressure varies proportionally with the steam flow.
- *Load control*– when the generator is synchronized to the grid, its frequency is governed by the grid. The turbine controller maintains the base load by adjusting the steam flow.

ADVANTAGES OF COMBINED CYCLE POWER PLANT

- The major advantages of a combined cycle power plant are:
- *Increases overall plant efficiency*: plant efficiency increases by 50% or more
- *Reduced investment cost:* Investment cost reduces by 30% as compared to a conventional steam power plant.
- Reduced water requirement.
- Phased installation is possible.
- Fully Automatic Operation, so less staff required.
- Lower environmental impact.

- Highly reliable and Flexible
- Can start-up and shut down quickly.
- Lower maintenance and installation costs.
- Lowest global warming effect
- Lower construction time.

DISADVANTAGES OF COMBINED CYCLE POWER PLANT

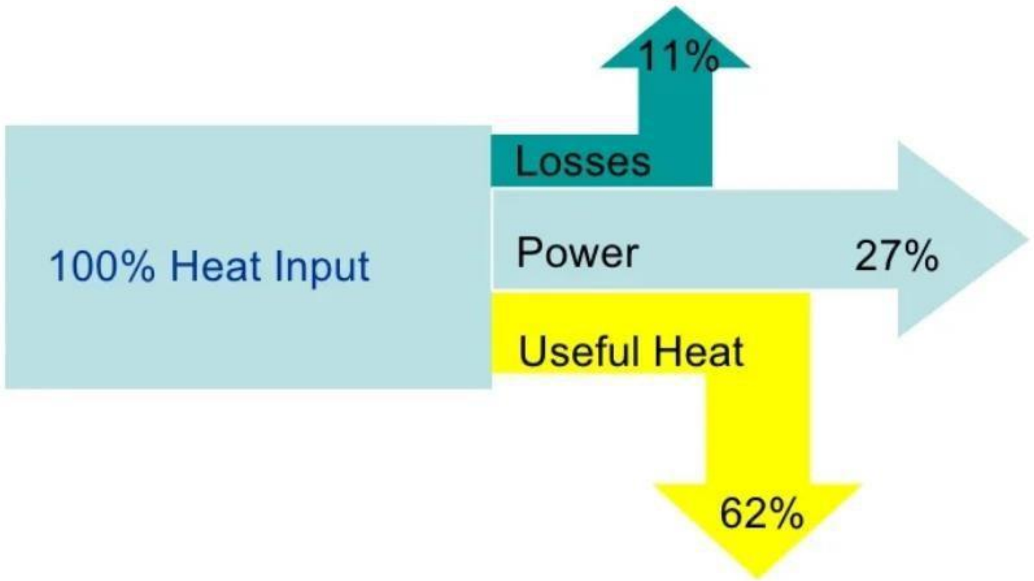
- Few disadvantages of a combined cycle power plant are:
- Technologies are complex and expensive which increases the initial investment.
- The efficiency of part-load demand is poor.
- To operate at high temperature and pressure, special metals are required.
- Limited fuel switching capability.

CO-GENERATION PLANT:

What Is Cogeneration?

Cogeneration or CHP (combined heat and power) is the utilization of a heat engine for generating both heats as well as electricity simultaneously. In general, thermal power stations, as well as heat engines, do not change the existing energy into electrical energy. Most of the engines waste half of the main energy due to surplus heat. By capturing the surplus heat, combined heat and power utilizes heat that would be wasted in a standard power station, potentially attaining a total efficiency ranges from 80 to 95%, contrasted by at most 40% for the standard power plants. This means that a low fuel to be utilized for producing the equal quantity of required energy. Because there is a high capacity in energy efficiency, CHP is considered to be the main provider to weather change improvement as presenting reasonable as well as consistency benefits on the supply of energy. This article gives an overview of Cogeneration and its types.

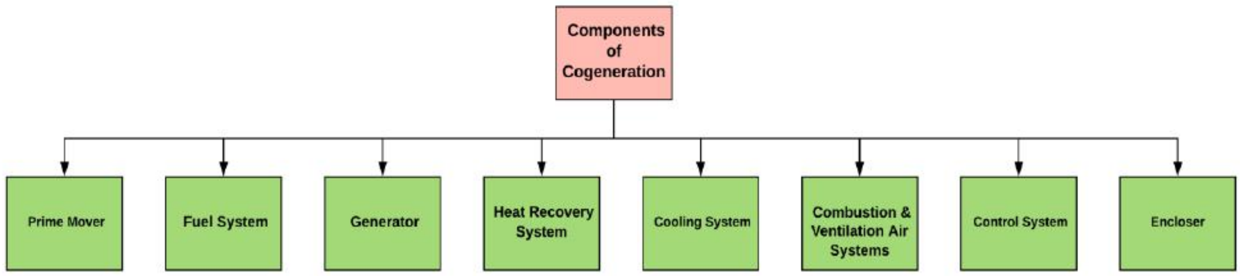
COGENRATION CONCEPT



Components of Cogeneration

The fundamental components of a combined heat and power system include the following.

- Prime Mover is an engine used to make the generator run.
- Fuel System
- The Generator is used to generate electricity from the power distribution system into the building's
- Heat Recovery System is used to pick up utilizable heat from the locomotive (engine).
- Cooling System for dissipating heat which is rejected from the locomotive that cannot be improved
- Combustion & Ventilation Air Systems for supplying clean air and to carry waste gases left from the engine,
- Control System is used for maintaining secure & proficient operation
- The Enclosure is used for achieving the protection for the engine as well as machinists, and also for reducing noise.



WHAT FUELS ARE USED IN COGENERATION PLANTS?

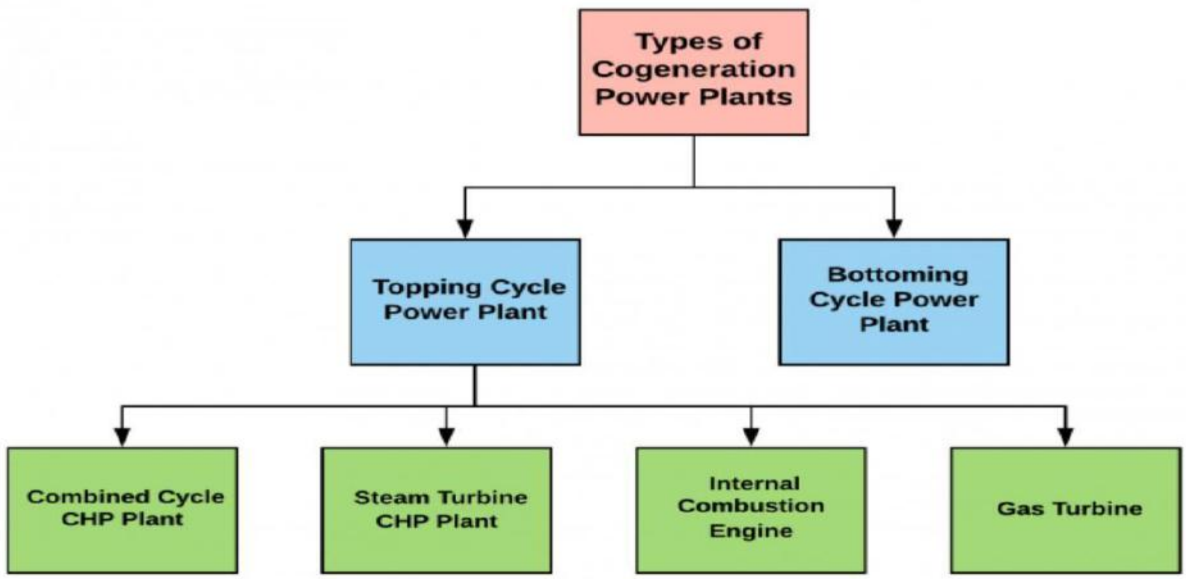
A variety of fuels can be used in cogeneration plants, including:

- natural gas
- diesel
- gasoline
- coal
- bio-fuels

The use of bio-fuels in cogeneration typically includes renewable resources, likewaste gases from landfills and solid waste from agriculture.

Types of Cogeneration Power Plants:

Basically, the types of cogeneration power plants are classified based on the operating process and energy utilization series. Therefore, the types of cogeneration systems are a topping cycle and a bottoming cycle.



TWO TYPES OF CHP SYSTEMS

- *Topping cycle plants:* A topping cycle system starts with electricity generation
- *Bottoming cycle plants:* Generating heat is first — waste heat produces steam that is then used to generate electricity

Bottoming cycle plants are found in industries that use very high-temperature furnaces. They're less common than topping cycle plants in part because it's easier to sell excess electricity.

A Topping Cycle

In this type of power plant, if the supplied fuel is used first for generating power then, afterward in the procedure it generates thermal energy. This energy is mainly used for satisfying process heat otherwise other thermal supplies. This type of cogeneration is the most popular as well as the widely used cogeneration system. A topping cycle power plants are basically classified into four types.

(a) ***Combined Cycle CHP Plant*:**

A combined cycle CHP plant mainly comprises of a diesel engine otherwise a gas turbine which generates electrical power or mechanical power tracked through aheat improvement system which is useful in generating steam as well as drives a resultant steam turbine.

(b) ***Steam Turbine CHP Plant*:**

Steam turbine CHP plant is used to generate electrical power & process vapor through burning coal for generating high force vapor, which is afterward agreed by a steam turbine for generating the required power, and then the exhaust vapor is used as low force procedure steam to heat up water intended for a variety of purposes.

(c) Internal Combustion Engine:

An internal Combustion Engine CHP plant includes a cover of cooling system water is flowing through a heat recovery system for producing vapor otherwise hot water for gap heating.

(d) Gas Turbine:

In this gas turbine CHP plant, a normal gas turbine is used to drive a generator for electricity generation. The turbine exhaust is supplied using a heat recovery boiler for generating process heat and steam.

Need for Cogeneration

The need for Cogeneration include the following:

- Cogeneration reduces the manufacturing price and enhances output.
- The plant efficiency can be progressed.
- It helps to conserve utilization of water as well as the cost of water.
- This is used to reduce an air emission of specific material like mercury, sulfur dioxide, carbon dioxide, otherwise, it would lead to the greenhouse effect.
- These systems are inexpensive when we contrasted to the usual power station.

How to Select Cogeneration System?

There are many factors that are taken into consideration while selecting the cogeneration system.

- Electrical -load matching
- Thermal- load matching
- Base-electrical load matching
- Base-thermal load matching
- Heat-to- power ratio
- The quality of thermal energy required
- Load outlines
- Existing Fuels

When Should We Consider CHP?

- It should always be considered when:
- Designing a new building
- Fitting new boiler plant
- Replacing or refurbishing the existing plant
- Reviewing Electrical Supply
- Primary energy fuel
- Motor element supplier of mechanical work to the shaft

Thus, this is all about Cogeneration and Its types, and the cogeneration applications in power plants mainly involved in an extensive range of sectors namely wastewater treatment, military, industrial, data centers, leisure, hotels, hospitals, prisons, education establishments, horticulture, mixed developments, etc. Here is a question for you, where the linden cogeneration plant located?

STEAM UNITS ECONOMIC DISPATCH PROBLEM (OR)

PROBLEM OF OPTIMUM DISPATCH-FORMULATION:

Scheduling is the process of allocation of generation among different generating units. Economic scheduling is a cost-effective mode of allocation of generation among the different units in such a way that the overall cost of generation should be minimum. This can also be termed as an optimal dispatch.

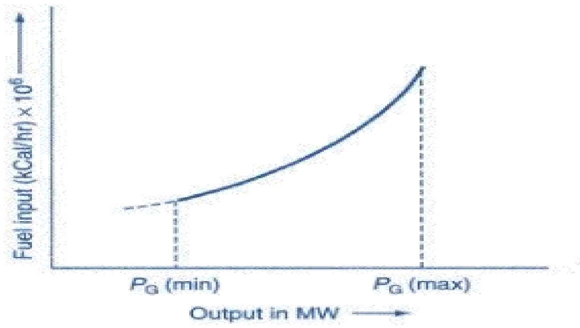
Let the total load demand on the station = P_D and the total number of generating units=n.

The optimization problem is to allocate the total load P_D among these ' n' units in an optimal way to reduce the overall cost of generation.

Let P_{G1}, P_{G2}, P_{G3} ... P_{Gn} be the power generated by each individual unit to supply a load demand of P_D, To formulate this problem, it is necessary to know the 'input-output characteristics of each unit.

INPUT-OUTPUT CHARACTERISTICS

The idealized form of input-output characteristics of a steam unit is shown in Fig. 2.2. It establishes the relationship between the energy input to the turbine and the energy output from the electrical generator. The input to the turbine shown on the ordinate may be either in terms of the heat energy requirement, which is generally measured in Btu/hr or kCal/hr or in terms of the total cost of fuel per hour in Rs. Ihr. The output is normally the net electrical power output of that steam unit in kW or MW. Inpractice, the curve may not be very smooth, and from practical data, such an idealized curve may be interpolated. The steam turbine-generating unit curve consists of minimum and maximum limits in operation, which depend upon the steam cycle used, thermal characteristics of material, the operating temperature, etc.

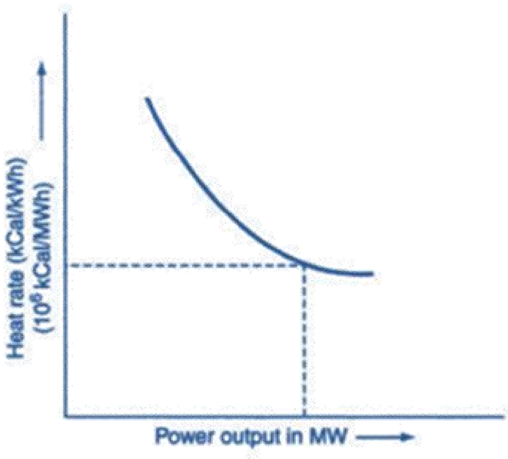


Input-Output Characteristics of Steam Unit

UNITS OF TURBINE INPUT

In terms of heat, the unit is 10^6kCal/hr (or) Btu/hr or in terms of the amount of fuel, the unit is tons of fuel/hr, which becomes millions of kCal/hr.

COST CURVES



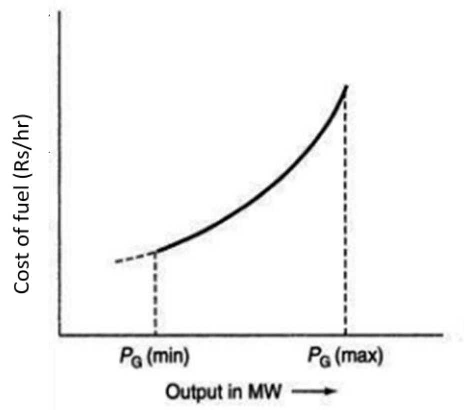
To convert the input-output curves into cost curves, the fuel input per hour is multiplied with the cost of the fuel (expressed in Rs/milion kCal).

i.e.,

$$\frac{kCal \times 10^6}{hr} \times Rs./\ million\ kcal$$

$$= million \frac{kCal}{hr} \times Rs./million\ kcal$$

HATE RATE CURVES:



The heat rate characteristics obtain from the plot of the net heat rate in Btu/kWh (or) kCal/kWh versus power in kW as show in figure.

Hate Rate Curve

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

INCREMENTAL FUEL COST CURVE

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

Incremental fuel cost = Δ Input/ Δ Output = $\Delta F / \Delta P_G$

Where Δ represents small changes.

As the Δ quantities become progressively smaller, it is seen that the IFC is ∂(input)/∂(output) and is expressed in Rs./MWh. A typical plot of the IFC versus output power is shown in Fig.1.6 (a).

The incremental cost curve is obtained by considering the change in the cost of generation to the change in real-power generation at various points on the input-output curves,

i.e., slope of the input-output curve as shown in Fig. 1.6(b).

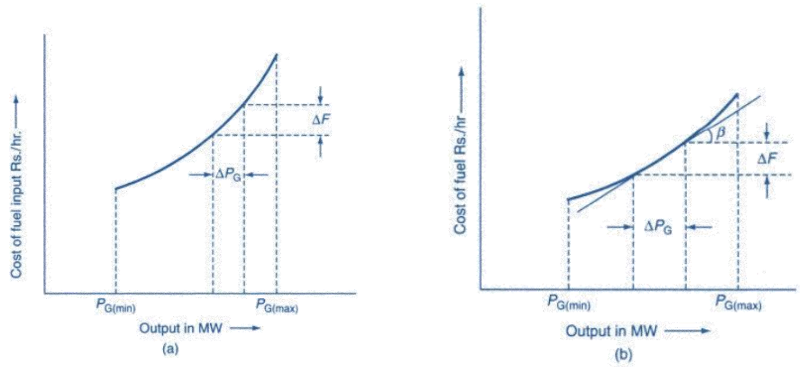


FIG. ***(a) Incremental cost curve; (b) Incremental fuel cost characteristicin terms of the slope of the input-output curve***

The IFC is now obtained as

$(IC)_I$ = Slope of the fuel cost curve

i.e., $\tan\beta = \frac{\Delta F}{\Delta Pg}$ $in\ Rs./MWh$

The TFC (IC) of the I^{th} thermal unit is defined, for a given power output, as the limit of the ratio of the increased cost of fuel input (Rs/hr) to the corresponding increase in power output (MW), as the increasing power output approaches zero.

i.e., $(IC)_i = P_{Gi} \lim_{\to 0} \frac{6F}{6PGi}$

$= \frac{dFi}{dPG}$

$(IC)_i = \frac{dC_i}{dP_{Gi}} * \therefore \frac{dF_i}{dP_{Gi}} = \frac{dC_i}{dP_{Gi}} = Incremental\ fuel\ cost\ of\ the\ i^{th}\ unit$

Where C_i is the cost of fuel of the i^{th} unit and P_{Gi} is the power generation output of the i^{th} unit.

Mathematically, the IFC curve expression can be obtained from the expression of the cost curve.

Cost-Curve Expression,

$$C_i = \frac{1}{2} a_i P_{Gi}^2 + b_i P_{Gi} + d_i$$

The IFC,

$$\frac{dC_i}{dP_{Gi}} = (IC)_i = a_i P_{Gi} + b_i$$ (linear approximation) for all i=1,2,3……… ,n

Where $\frac{dC_i}{dP_{Gi}}$ is the ratio of incremental fuel energy input in Btu to the incremental energy output in kWh, which is called ―the incremental heat rate‖.

The fuel cost is the major component and the remaining costs such as maintenance, Salaries, etc. will be of very small percentage of fuel cost, hence, the IFC is very significant in the economic loading of a generating unit.

INCREMENTAL EFFICIENCY

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

Performance Curves Input-Output Curve

This is the fundamental curve for a thermal plant and is a plot of the input in British Thermal units (Btu) per hour versus the power output of the plant in MW as shown in Fig.

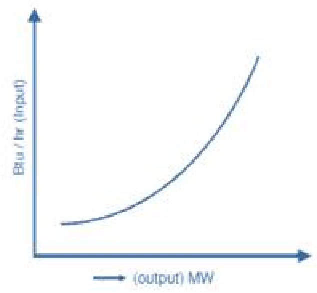


Fig: Input-Output Curve

Incremental Fuel Rate Curve

The incremental fuel rate is equal to a small change in input divided by the corresponding change in output.

Incremental Fuel Rate = $\frac{\Delta Input}{\Delta 0utput}$

The unit is again Btu / KWh. A plot of incremental fuel rate versus the output is shown in Fig

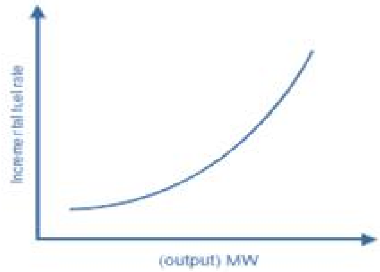


Fig: Incremental fuel rate curve

Incremental cost curve

The incremental cost is the product of incremental fuel rate and fuel cost (Rs / Btu) the curve is shown in Fig. 4. The unit of the incremental fuel cost is Rs / MWhr.

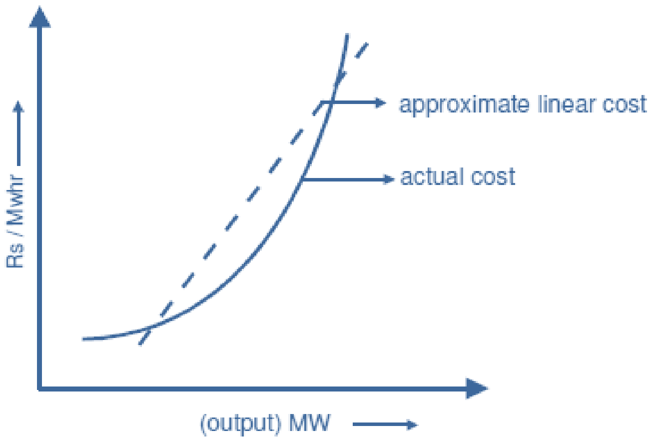


Fig : Incremental cost curve

In general, the fuel cost F_i for a plant, is approximated as a quadratic function of the generated output P_{Gi}.

$$F_i = a_i + b_i P_{Gi} + C_i P_{Gi} Rs/h$$

The incremental fuel cost is given by

$$\frac{dF_i}{dP_{Gi}} = b_i + 2C_i P_{Gi}\ Rs/MWh$$

The incremental fuel cost is a measure of how costly it will be produce an increment of power. The incremental production cost, is made up of incremental fuel cost plus the incremental cost of labor, water, maintenance etc. which can be taken to be some percentage of the incremental fuel cost, instead of resorting to a rigorous mathematical model. The cost curve can be approximated by a linear curve. While there is negligible operating cost for a hydel plant, there is a limitation on the power output possible. In any plant, all units normally operate between P_{Gmin}, the minimum loading limit, below which it is technically infeasible to operate a unit and P_{Gmax}, which is the maximum output limit.

OPTIMIZATION PROBLEM-MATHEMATICAL FORMULATION

(NEGLECTING THE TRANSMISSION LOSSES):

An optimization problem consists of:

1. Objective function.
2. Constraint equations.

1. Objective function:

The objective function is to minimize the overall cost of production of power generation. Cost in thermal and nuclear stations is nothing but the cost of fuel.

Let *n* be the number of units in the system

and C1 the cost of power generation of unit 'i':

:. Total cost $C=C1+C2+C3+\cdots+Cn$

$$\text{i.e.}, C = \sum_{i=1}^{n} C_i$$

The cost of generation of each unit in thermal power plants is mainly a fuel cost.

The generation cost depends on the amount of real power generated, since the real-power generation is increased by increasing the fuel input. The generation of reactive power has negligible influence on the cost of generation, since it is controlled by the field current. Therefore, the generation cost of the i^{th} unit is a function of real-power generation of that unit and hence the total cost is expressed as

$$\text{i.e.}, C = \sum_{i=1}^{n} C_i\,(P_{Gi})$$

$$\text{i.e.,} \qquad C = C_1(P_{G1}) + C_2(P_{G2}) + C_3(P_{G3}) + - - + C_n(P_{Gn})$$

This objective function consists of the summation of the terms in which each term is a function of separate independent variables. This type of objective function is called a separable objective function. The optimization problem is to allocate the total load demand *(P_D)* among the various generating units, such that the cost of generation is minimized and satisfies the following constraints.

2. <u>Constraint equations</u>:

The economic power system operation needs to satisfy the following types of constraints.

(1) Equality constraints

The sum of real-power generation of all the various units must always be equal to the total real-power demand on the system.

$$\text{i.}e., \; P_D = \sum_{\text{i}=1}^{n} P_{G\text{i}}$$

$$or$$

$$\sum_{\text{i}=1}^{n} P_{G\text{i}} - P_D = 0$$

$$Where \sum_{\text{i}=1}^{n} P_{G\text{i}} =$$

$$Total\ real\ power\ genration\ and\ PD\ \text{is}\ the\ total\ real\ power\ demand\ Equation\ \text{is}\ known\ as\ the\ real\ power\ balance\ equation\ when\ losses\ are\ neglected$$

(2) Inequality constraints

These constraints are considered in an economic power system operation due to the physical and operational limitations of the units and components.

Section I: Economic Operation of Power System

- Economic Distribution of Loads between the Units of a Plant
- Generating Limits
- Economic Sharing of Loads between Different Plants

In an early attempt at economic operation it was decided to supply power from the most efficient plant at light load conditions. As the load increased, the power was supplied by this most efficient plant till the point of maximum efficiency of this plant was reached. With further increase in load, the next most efficient plant would supply power till its maximum efficiency is reached. In this way the power would be supplied by the most efficient to the least efficient plant to reach the peak demand. Unfortunately, however, this method failed to minimize the total cost of electricity generation. We must therefore search for alternative method which takes into account the total cost generation of all the units of a plant that is supplying a load. Economic Distribution of Loads between the Units of a Plant

To determine the economic distribution of a load amongst the different units of a plant, the variable operating costs of each unit must be expressed in terms of its power output. The fuel cost is the main cost in a thermal or nuclear unit. Then the fuel cost must be expressed in terms of the power output. Other costs, such as the operation and maintenance costs, can also be expressed in terms of the power output. Fixed costs, such as the capital cost, depreciation etc., are not included in the fuel cost.

The fuel requirement of each generator is given in terms of the Rupees/hour. Let us define the input cost of a unit- *i*, *fi* in Rs/h and the power output of the unit as *Pi*. Then the input cost can be expressed in terms of the power output as

$$f_i = \frac{a_i}{2} P_i^2 + b_i P_i + C_i \quad Rs/h \qquad \text{----------------} \qquad (1.1)$$

The operating cost given by the above quadratic equation is obtained by approximating the power in MW versus the cost in Rupees curve. The incremental operating cost of each unit is then computed as

$$\lambda i = \frac{df_i}{dP_i} = a_i P_i + b_i \quad \text{Rs/MWhr} \qquad \text{----------------} \qquad (1.2)$$

Let us now assume that only two units having different incremental costs supply a load. There will be a reduction in cost if some amount of load is transferred from the unit with higher incremental cost to the unit with lower incremental cost. In this fashion, the load is transferred from the less efficient unit to the more efficient unit thereby reducing the total operation cost. The load transfer will continue till the incremental costs of both the units are same. This will be optimum point of operation for both the units. The above principle can be extended to plants with a total of *N* number of units. The total fuel cost will then be the summation of the individual fuel cost *fi* , *i* = 1, ... , *N* of each unit, i.e

$$f_T = f_1 + f_2 + --- + f_N = \sum_{k=1}^{N} f_k \quad -------- (1.3)$$

Let us denote that the total power that the plant is required to supply by P_T , such that

$$P_T = P_1 + P_2 + - - - + P_N = \sum_{k=1}^{N} P_k \quad - - - - - - - - (1.4)$$

Where $P1$, ... , PN are the power supplied by the N different units.

The objective is minimizing f_T for a given P_T. This can be achieved when the total difference df_T becomes zero, i.e.

$$df_T = \frac{\partial f_T}{\partial P_1} dP_1 + \frac{\partial f_T}{\partial P_2} dP_2 + - - + \frac{\partial f_T}{\partial P_N} dP_N = 0 \text{ -------------- } (1.5)$$

Now since the power supplied is assumed to be constant we have

$$dP_T = dP_3 + dP_2 + - - - - + dP_N = 0 \quad \text{---------------} (1.6)$$

Multiplying (1.6) by λ and subtracting from (1.5) we get

$$\left(\frac{\partial f_T}{\partial P_1} - \lambda\right) dP_1 + \left(\frac{\partial f_T}{\partial P_2} - \lambda\right) dP_2 + - - - - - - + \left(\frac{\partial f_T}{\partial P_N} - \lambda\right) dP_N = 0 - - - - (1.7)$$

The equality in (5.7) is satisfied when each individual term given in brackets is zero. This gives us

$$\frac{\partial f_T}{\partial P_i} - \lambda = 0, \ i = 1, - - - -, n - - - - - - - \qquad (1.8)$$

Also the partial derivative becomes a full derivative since only the term fi of fT varies with Pi, i = 1... N.

We then have

$$\lambda = \frac{\partial f_1}{\partial P_1} = \frac{\partial f_2}{\partial P_2} = - - - - = \frac{\partial f_N}{\partial P_N} \quad - - - - - - -(1.9)$$

Generating Limits

It is not always necessary that all the units of a plant are available to share a load. Some of the units may be taken off due to scheduled maintenance. Also it is not necessary that the less efficient units are switched off during off peak hours.

There is a certain amount of shut down and start up costs associated with shutting down a unit during the off peak hours and servicing it back on-line during the peak hours. To complicate the problem further, it may take about eight hours or more to restore the boiler of a unit and synchronizing the unit with the bus. To meet the sudden change in the power demand, it may therefore be necessary to keep more units than it necessary to meet the load demand during that time. This safety margin in generation is called spinning reserve.

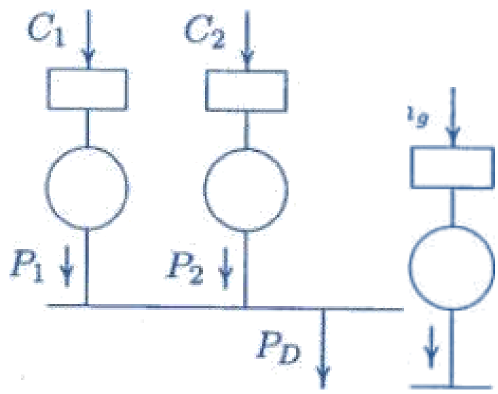
The optimal load dispatch problem must then incorporate this startup and shut down cost for without endangering the system security.

The power generation limit of each unit is then given by the inequality constraints

$P_{min,i} \leq P_i \leq P_{max,i}$, $i = 1,2,---,N$ ---------- (1.10)

The maximum limit P_{Gmax} is the upper limit of power generation capacity of each unit. On the other hand, the lower limit P_{Gmin} *pertains* to the thermal consideration of operating a boiler in a thermal or nuclear generating station. An operational unit must produce a minimum amount of power such that the boiler thermal components are stabilized at the minimum design operating temperature.

ECONOMIC DISPACH NEGLECTING LOSSES:



- It is the simplest economic dispatch problem
- Assume that the system is only one bus with all generation and loads connected to it.
- A cost function C_i is assumed to be known for each plant.
- The problem *is* to find the real power generation for each plant such that the objective function (i.e., total production cost) as defined by the equation.

Total Cost C_t =

$= C_1 + C_2 + ---- + C_{ng}$

$= \alpha_i + \beta_i P_i + \gamma_i P_i^2$

Is minimum, subjected to the constraints. $P_i = P_d$

A typical approach is to augment the constraints into objective function by using the Lagrange multipliers.

$L = C_t + \lambda\{P_D - \sum_{i=1}^{ng} P_i\}$

$L = ZC_t P_i - \lambda\{\sum P_i - P_D\}$

For minimization, $\frac{dL}{dP_i} = 0 \rightarrow \frac{dC_i}{dP_i} = \lambda$ i=1,2, ----,ng

The minimum of this unconstrained function is found at the point where the partials of the function to its variables are zero.

$dL/dP_i = 0$

$dL/ d\lambda = 0$

For the given condition $dC_t/dP_i + \lambda(0-1) = 0$

$$\frac{dL}{dP_i} = \frac{dC_i}{dP_i} - \lambda[1-0]$$

$$\frac{dC_i}{dP_i} - \lambda = 0$$

$$\frac{dC_i}{dP_i} = \lambda, i = 1,2, - - - , ng$$

Since $C_t = C_1 + C_2 + \text{----} + C_{ng}$

and therefore the condition for optimum dispatch is $dC_i/dP_i = \lambda$ (i=1,2, - ng)

or

$\beta_i + 2\gamma_i P_i = \lambda$

Where dC_i/dP_i = IFC of the i^{th} Generation (Rs/MWh)

λ = Lagrangian Multiplier

- When losses are neglected with no generator limits, for most economic operation. All plants must operate at equal incremental production cost.
- Production of each plant can be found by

$$P_i = (\lambda - \beta_i) / 2\gamma_i$$

This equation is known as the coordination equation For analytic solution we can find λ by

$$(\lambda - \beta_i) / 2\gamma_i = P_D$$

$$\lambda = \frac{P_e + \sum_{i=1}^{ng} \frac{\beta_i}{2\gamma_i}}{\sum_{i=1}^{ng} \frac{1}{2\gamma_i}}$$

In an iterative technique, starting with a value of λ and the process is continued until ΔP_i is within a specified accuracy

Corresponding to this λ, $\sum_{i=1}^{ng} P_{i=1}^{(k)}$

is calculated, and the power mismatch is calculated by $\Delta P^{(k)} = P_D - \sum_{i=1}^{ng} P_i^{(k)}$

Update value of λ by $\Delta\lambda^{(k)} = \frac{\Delta P^{(k)}}{\sum \frac{1}{2\gamma_i}}$

$$\lambda^{(k+1)} = \lambda^{(k)} + \Delta\lambda^{(k)}$$

ECONOMIC OPERATION OF POWER SYSTEM

Optimum generation allocation including the effect of transmission line losses-loss coefficients-transmission line loss formula.

Consider the objective function $C_t = \sum_{i=1}^{ng} C_i P_i$

Subject to the following.

(i) Equality Constraints

$\sum P_i = P_L + P_D$ or $\sum P_i - P_L - P_D$ -------(1)

Where P_L is the total transmission losses (MW)

P_D is the total real power demand (MW) and

P_i is the total real power generation at the i^{th} unit (MW)

(ii) Inequality Constraints

Pmin < P < Pmax

Qmin < Q < Qmax

Vmin < V < Vmax

δmin < δ < δ max

To solve the problem, we write lanrangian as

$$L = \Sigma C_i(P_i) - \lambda\{\textstyle\sum_{i=1}^{ng} P_i - P_D - P_l\}$$

$$P_L = P_L(P_1, P_2, P_3, - - - - - -, P_n)$$

For optimum real power dispatch

$$\frac{dL}{dP_i} = \frac{dC_i}{dP_i} - \lambda\left[1 - \frac{dP_L}{dP_i}\right] = 0$$

Rearranging above equations and we get The output of only one plant can affect the cost only that plant, we have

$$\frac{\left(\frac{dC_i}{dP_i}\right)}{*1 - \frac{dP_L}{dP_i}+} = \lambda$$

or

$$\frac{dC_i}{dP_i} L_i = \lambda$$

Where

$$\frac{1}{*1 - \frac{dP_L}{dP_i}+} = L_i$$

is called penalty factor of i^{th} plant

The lagrange multiplier λ is in rupees per MW-hr, when fuel cost is in per-hour

Economic Dispatch Neglecting Losses and Including Generator limits:

The output power of any generator should neither exceed its rating nor should it be below that necessary for the stable operation of a boiler. Thus, the generations are restricted to lie within given minimum and maximum limits. The problem is to find the active power generation of each plant such that the objective function (i.e., total production cost) is minimum, subject to the equality constraint and the in equality constraints are

$\sum_{i=1}^{n} P_{Gi} = P_D$ and $P_{Gi(min)} \leq P_{Gi} \leq P_{Gi(max)}$

Respectively

The solution algorithm for this case is the same as discussed in previous section with minor modification. If any generating unit violates the above inequality constraints, set its generation at its respective limit as given below. In addition, the balance of the lad is then shared between the remaining units on the basis of equal incremental cost.

The necessary conditions for optimal dispatch when losses are neglected:

$$\frac{\partial C_i}{\partial P_{Gi}} = \lambda \, for \, P_{Gi(min)} \leq P_{Gi} \leq P_{Gi(max)}$$

$$\frac{\partial C_i}{\partial P_{Gi}} \leq \lambda \, for \, P_{Gi} = P_{Gi(max)}$$

$$\frac{\partial C_i}{\partial P_{Gi}} \geq \lambda \, for \, P_{Gi} = P_{Gi(min)}$$

Flowchart for Obtaining Optimal Scheduling of Generating Units by Neglecting the Transmission Losses:

The optimal scheduling units is representing by the flowchart as shown in fig.

Economical Load Dispatch-In other units:

The economical load dispatch problem has been solved for a power system area consisting of fossil fuel units. For an area consisting of a mix of different types of units, i.e.-fossil fuel units, nuclear units, pumped storage hydro-units, hydro-units, etc. solving the economical load dispatch problem will become different.

ECONOMIC DISPATCH INCLUDING LOSSES:

When power is transmitted over long distances transmission losses are a major factor that affect the optimum dispatch of generation.

One common practice for including the effect of transmission losses is to express the total transmission loss as a quadratic function of the generator power outputs. The simplest quadratic form is

$$P_L = \sum_{i=1}^{ng} \sum_{j=1}^{ng} P_i B_{ij} P_j$$

The coefficients B_{ij} are called loss coefficients or B-coefficients.

The economic dispatching problem is to minimize the overall generating cost Ci, which is the function of plant output.

$$C_t = \sum_{i=1}^{ng} C_i$$

$$= \sum_{i=1}^{n} \alpha_i + \beta_i P_i + \gamma_i P_i^2$$

Subject to the constraint that generation should equal total demands plus losses, i.e., Satisfying the inequality constraints, expressed as follows:

$$\sum_{i=1}^{ng} P_i = P_D + P_L$$

$$P_{i(min)} \leq P_i \leq P_{i(max)} \quad i = 1, \ldots\ldots, ng$$

Using the langrage multiplier

$$L = C_t + \lambda \left(P_D + P_L - \sum_{i=1}^{ng} P_i\right)$$

Minimum of this function is fount at the points where the partials of the function to it's variables are zero

$d_L/dPi = 0$

$$\frac{\partial C_t}{\partial P_i} + \lambda \left(0 + \frac{\partial P_L}{\partial P_i} - 1\right) = 0$$

Since

$C_t = C_1 + C_2 + \ldots\ldots\ldots + C_{ng}$

Then

$$\frac{\partial C_t}{\partial P_i} = \frac{\partial C_i}{\partial P_i}$$

and therefore the condition for optimum dispatch is

$$\frac{\partial C_i}{\partial P_i} = \lambda \frac{\partial P_L}{\partial P_i} = \lambda$$

The term $\frac{6PL}{6P_i}$ is known as the incremental transmission loss. Second condition, given by

$$\sum_{i=1}^{ng} P_i = P_D + P_L$$

$$\left(\frac{1}{1 - \frac{6P_L}{6P_i}}\right) \frac{dC_i}{dP_i} = \lambda$$

i=1,.......,n_g

or

j=1,.......,n_g

Where L_i is known as the penalty factor of plant i and is given by

$$L_i \frac{dC_i}{dP_i} = \lambda$$

$$L_i = \left(\frac{1}{1 - \frac{6P_L}{6P_i}}\right)$$

ITERATION METHOD:

Initially assume a λ value. Then find out the generation from each plant using the equations.

$$P_i^{(k)} = \frac{\lambda^{(k)} - \beta_i}{2(\gamma_i + \lambda^{(k)} B_{ii})}$$

Calculate the power mismatch

$$\Delta P^{(k)} = P_D + P_i^{(k)} - \sum_{i=1}^{ng} P_i^{(k)}$$

$$P_L = \sum_{i=1}^{ng} B_{ii} P_i^2$$

Where

Calculate $\Delta\lambda^{(k)} = \frac{\Delta P^{(K)}}{\sum\left(\frac{dP_i}{d}\right)^{(k)}}$

$$\sum_{i=1}^{ng} \left(\frac{\partial P_i}{\partial \lambda}\right)^{(k)} = \sum_{i=1}^{ng} \frac{\gamma_i + B_{ii} \beta_i}{2(\gamma_i + \lambda^{(k)} B_{ii})^2}$$

Where

Update value of λ

$\lambda^{(k+1)} = \lambda^{(k)} + \Delta\lambda^{(k)}$

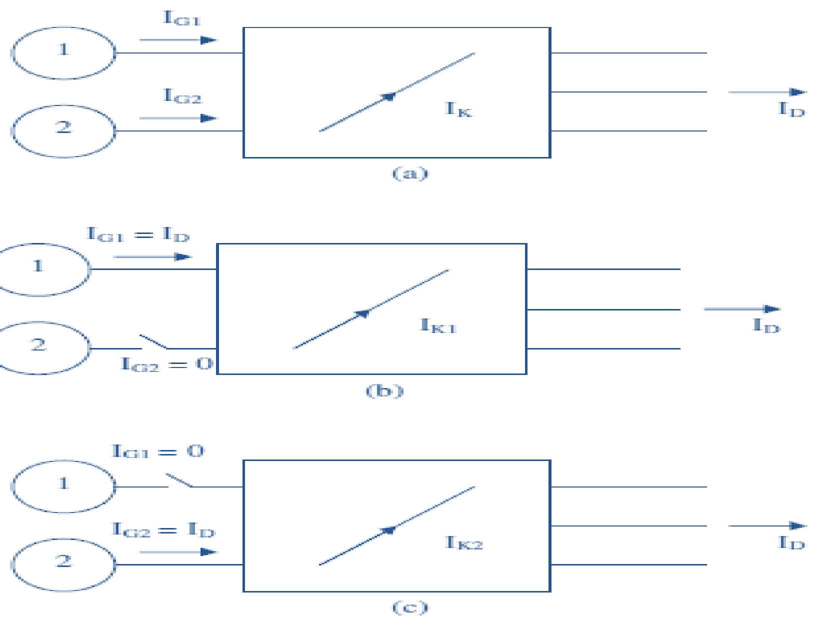
Repeat the procedure with new value of Z until the power mismatch is within the limit

General Transmission Line Loss Formula (Loss Coefficients):

An accurate method of obtaining general loss coefficients has been presented by Kroc. The method is elaborate and a simpler approach is possible by making the following assumptions:

1. The power factor of plants remain constant.
2. All load currents maintain constant ratio to the total current.
3. Voltage magnitudes at all the plants remain constant.
4. Voltage phase angles at plant buses remain fixed.
5. The ratio X / R is the same for all the network branches

Consider the simple case of two generating plants connected to an arbitrary number of loads through a transmission network as shown in Fig a



Two plants connected to a number of loads through a transmission network

Let's assume that the total load is supplied by only generator 1 as shown in Fig b. Let the current through a branch K in the network be I_{K1}. We define

$$N_{k1} = \frac{I_{k1}}{I_D}$$

It is to be noted that $I_{G1} = I_D$ in this case. Similarly with only plant 2 supplying the load

Current ID, as shown in Fig c, we define

$$N_{k2} = \frac{I_{k2}}{I_D}$$

N_{K1} and N_{K2} are called current distribution factors and their values depend on the impedances of the lines and the network connection. They are independent of I_D. When both generators are supplying the load, then by principle of superposition $I_K = N_{K1} I_{G1} + N_{K2} I_{G2}$

$$I_{G1} = |I_{G1}|\angle\sigma_1 \; and \; I_{G2} = |I_{G2}|\angle\sigma_2$$

Where σ_1 and σ_2 are phase angles of I_{G1} and I_{G2} with respect to a common reference. We can write

$$|I_k|^2 = (N_{k1}|I_{G1}|\cos\sigma_1 + N_{k1}|I_{G1}|\cos\sigma_2)^2 + (N_{k1}|I_{G1}|\sin\sigma_1 + N_{k1}|I_{G1}|\sin\sigma_2)^2$$

$$= N_{k1}^2|I_{G1}|^2[\cos^2\sigma_1 + \sin^2\sigma_1] + N_{k2}^2|I_{G2}|^2[\cos^2\sigma_2 + \sin^2\sigma_2]$$

$$+ 2[N_{k1}|I_{G1}|\cos\sigma_1 N_{k1}|I_{G2}|\cos\sigma_2 + N_{k1}|I_{G1}|\sin\sigma_1 N_{k1}|I_{G2}|\sin\sigma_2]$$

$$= N^2 |I_{G1}|^2 + N^2 |I_{G2}|^2 + 2N_{k1}N_{k2}|I_{G1}||I_{G2}|\cos(\sigma_1 - \sigma_2)$$

Now

$$|I_{G1}| = \frac{P_{G1}}{\sqrt{3}|V_1|\cos\phi_1} \text{ and } |I_{G2}| = \frac{P_{G2}}{\sqrt{3}|V_2|\cos\phi_2}$$

Where P_{G1}, P_{G2} are three phase real power outputs of plant1 and plant 2; V_1, V_2 are the line to line bus voltages of the plants and Φ_1 and Φ_2 are the power factor angles.

The total transmission loss in the system is given by

$$P_L = \sum_{k=1}^{n} 3|I_k|^2 R_k$$

Where the summation is taken over all branches of the network and R_K is the branch

$$P_L = \frac{P^2_{G1}}{|V_1|^2(\cos\varphi_1)^2}\sum_K N_{k1}^2 R_k + \frac{2P_{G1}P_{G2}\cos(\sigma_1 - \sigma_2)}{|V_1||V_2|\cos\varphi_1\cos\varphi_2}\sum_k N_{k1}N_{k2}R_K$$

$$+ \frac{P^2_{G2}}{|V_2|^2(\cos\varphi_2)^2}\sum_K N_{k2}^2 R_k$$

$$P_L = P_{G1}^2 B_{11} + 2P_{G1}P_{G2}B_{12} + P_{G2}^2 B_{22}$$

Where

$$B_{11} = \frac{1}{|V_1|^2(\cos\varphi_1)^2}\sum_K N_{k1}^2 R_k$$

$$B_{12} = \frac{\cos(\sigma_1 - \sigma_2)}{|V_1||V_2|\cos\varphi_1 \cos\varphi_2}\sum_k N_{k1} N_{k2} R_K$$

$$B_{22} = \frac{1}{|V_2|^2(\cos\varphi_2)^2}\sum_K N_{k2}^2 R_k$$

The loss – coefficients are called the B – coefficients and have unit MW-1

General Transmission Line Loss Formula (Loss Coefficients):

If the system has K plants supplying the total load through transmission lines then the transmission loss is given by

$$P_L = \sum_{m=1}^{k}\sum_{n=1}^{k} P_{Gm}B_{mn}P_{Gn}$$

$$P_L = \sum_{m=1}^{2}\sum_{n=1}^{2} P_{Gm}B_{mn}P_{Gn}$$

$$P_L = \sum_{n=1}^{2}[P_{G1}B_{1n}P_{Gn} + P_{G2}B_{2n}P_{Gn}]$$

$$P_L = [P_{G1}B_{11}P_{G1} + P_{G1}B_{12}P_{G2} + P_{G2}B_{21}P_{G1} + P_{G2}B_{22}P_{G2}]$$

If the system has two plants i.e., K=2

$$P_L = P_{G1}^2 B_{11} + 2P_{G1}P_{G2}B_{12} + P_{G2}^2 B_{22}$$

In general

$$\frac{\partial P_L}{\partial P_{G1}} = \sum_{j=1}^{n} 2B_{IJ}P_{Gj}$$

We know that the IFC of the ith units is

$$\frac{\partial C_i}{\partial P_{Gi}} = (IC)_i = a_i P_{Gi} + b_i$$

Substitute Equations above equations we get

$$\therefore \frac{\partial C'}{\partial P_{Gi}} = (a_i P_{Gi} + i) - \lambda * 1 - 2\sum_{j=1}^{n} B_{\mathbf{jj}} P_{G\mathbf{j}} + = 0$$

$$a_i P_{Gi} + b_i - \lambda + 2\lambda [\sum_{\substack{j=1 \\ i=1}}^{n} (B_{jj}P_{G1} + B_{jj}P_{Gj})] = 0$$

$$[a_i + 2\lambda B_{ii}]P_{Gi} = \lambda - 2\lambda \sum_{\substack{j=1 \\ j=1}}^{n} (B_{IJ} P_{Gj}) - b_i$$

Dividing the above equation by λ we get

$$\therefore P_{G1} = \frac{1 - 2\sum_{\substack{j=1 \\ j=1}}^{n} (B_{JJ} P_{Gj}) - \frac{b_i}{\lambda}}{\left(\frac{a_i}{\lambda} + 2B_{ii}\right)}$$

To solve this allocation problem, solve the co-ordination equation for a particular value of λ iteratively starting with an initial set of value of P_{Gi} (such as all P_{Gi} set to minimum values) and get the solution within a specified tolerance till all P_{Gi}'s converge then check for power balance and if it is to be satisfied, then it is the optimal solution. If the power balance equation is not satisfied, modify the value of λ to a solution value and solve the coordinator equation.

Penalty Factor:

$$\frac{\partial C'}{\partial P_{Gi}} = \frac{\partial C_i}{\partial P_{Gi}} - \lambda \left[1 - 0 - \frac{\partial P_L}{\partial P_{Gi}}\right] = 0$$

$$\therefore \frac{\partial C_i}{\partial P_{Gi}} = \lambda \left[1 - \frac{\partial P_L}{\partial P_{Gi}}\right]$$

The above equation can be written as

$$\therefore = \lambda \frac{\frac{\partial C_i}{\partial P_{Gi}}}{[1 - (ITL)_i]} = \frac{Incremental\ Fuel\ Cost}{[1 - Incremental\ Transmission\ Loss]}$$

Where

$$L_i = \frac{1}{\left(1 - \frac{\partial P_L}{\partial P_{Gi}}\right)}$$

is called the penalty factor of the i^{th} *station*

$$L_i = \frac{1}{\left(1 - \frac{\partial P_L}{\partial P_{Gi}}\right)} = \frac{1}{[1 - (ITL)_i]}$$

The penalty factor of any unit is defined as the ration of a small change in power at the unit to the small change in received power when only that unit supplies this small change in received power.

INTRODUCTION

Hydro-thermal Coordination

Characteristics of various types of hydro-electric plants and their models

Introduction to hydro-thermal Coordination

Scheduling energy with hydro-thermal coordination

Short-term hydro-thermal scheduling

UNIT-II

HYDROTHERMAL COORDINATION AND OPTIMAL POWER FLOW

INTRODUCTION:

Hydrothermal scheduling is an important issue in the field of power system economics. The aim of the short-term hydrothermal scheduling is to optimize the hourly output of power generation for different hydrothermal units for certain intervals of time to minimize the total cost of generations.

Block Diagram Representation of an Isolated Power System consists of

- Generator load model
- Turbine model
- Speed governor mechanism

CHARACTERISTICS OF VARIOUS TYPES OF HYDRO-ELECTRIC PLANTS:

1. In case of hydro-units without thermal units in the system, the problem is simple.

The economic scheduling consists of scheduling water release to satisfy the hydraulic constraints and to satisfy the electrical demand.

2. Where hydro-thermal systems are predominantly hydro, scheduling may be done by scheduling the system to produce minimum cost for the thermal systems.

3. In systems where there is a close balance between hydro and thermal generation and in systems where the hydro-capacity is only a fraction of the total capacity, it is generally desired to schedule generation such that thermal generating costs are minimized.

CO-ORDINATION OF RUN-OFF RIVER PLANT AND STEAM PLANT:

A run-off river hydro-plant operates as the water is available in needed quantities. These plants are provided with a small poundage or reservoir, which makes it possible to meet the hourly variation of load.

The ratio of run-off during the rainy season to the run- off during the dry season may be as large as 100. As such the run-off river plants have very little from capacity. The usefulness of these run-off river plants can be considerably increased if such a plant is properly co- ordinated with a thermal plant. When such co-ordination exists, the hydro-plant may carry the base load up to its installed capacity during the period of high stream flows and the thermal plant may carry the peak load. During

the period of lean flow, the thermal plant supplies the base load and the hydro-plant supplies the peak load. Thus, the load met by a thermal plant can be adjusted to conform to the available river flow. This type of co- ordination of a run-off river hydro-plant with a thermal plant results in a greater utilization factor of the river flow and a saving in the amount of fuel consumed in the thermal plant.

LONG-TERM CO-ORDINATION

Typical long-term co-ordination may be extended from one week to one year or several years. The co-ordination of the operation of reservoir hydro-power plants and steam plants involves the best utilization of available water in terms of the scheduling of water released. In other words, since the operating costs of hydro-plants are very low, hydro-power can be generated at very little incremental cost. In a combined operational system, the generation of thermal power should be displaced by available hydro-power so that maximum decrement production costs will be realized at the steam plant. The long-term scheduling problem involves the long-term forecasting of water availability and the scheduling of reservoir water releases for an interval of time that depends on the reservoir capacities and the chronological load curve of the system. Based on these factors during different times of the year, the hydro and steam plants can be operated as base load plants and peak load plants and vice versa.

For the long-term drawdown schedule, a basic best policy selection must be made. The best policy is that should the water be used under the assumption that it will be replaced at a rate based on the statistically expected rate or should the water be released using a worst-case prediction?

Long-term scheduling is made based on an optimizing policy in view of statistically treated unknowns such as load, hydraulic inflows, and unit availability (i.e., steam and hydro-plants).

The useful techniques employed for this type of scheduling problems include:

1. The simulation of an entire long-term operational time period for a given set of operating conditions by using the dynamic programming method,
2. Composite hydraulic simulation models, and
3. Statistical production cost models.

For the long-term scheduling of a hydro-thermal system, there should be required generation to meet the requirements of load demand and both hydro and thermal generations should be so scheduled so as to maintain the minimum fuel costs. This requires that the available water should be put to an optimum use.

SHORT-TERM CO-ORDINATION

The economic system operation of thermal units depends only on the conditions that exist from instant to instant. However, the economic scheduling of combined hydro-thermal systems depends on the conditions existing over the entire operating period. This type of hydro-thermal scheduling is required for one day or one week, which involves the hour-by-hour scheduling of all available generations on a system to get the minimum production cost for the given time. Such types of scheduling problems, the load, hydraulic inflows, and unit availabilities are assumed to be known. Here also, the problem is how to supply load, as per the load cycle during the period of operation so that generation by thermal plants will be minimum. This condition will be satisfied when the value of hydro-power generation rather than its amount is a maximum over a certain period. The basic problem is that determining the degree to which the minimized economy of operating the hydro-units at other than the maximum efficiency loading may be tolerated for an increased economy with an increased load or vice versa to result in the lowest total thermal power production costs over the specified operating period.

The factors on which the economic operation of a combined hydro-thermal system depends are as follows:

Load Cycle

Incremental fuel costs of thermal power station. Expected water inflow in hydro power station.
Water head that is a function of water storage in hydro power station.
Hydro power generation. Incremental transmission loss

The following are the few important methods for short-term hydro-thermal co-ordination:

1. Constant hydro-generation method.
2. Constant thermal generation method.
3. Maximum hydro-efficiency method.
4. Kirchmayer"s method.

6.6.1 Constant hydro-generation method

In this method, a scheduled amount of water at a constant head is used such that the hydro-power generation is kept constant throughout the operating period.

6.6.2 Constant thermal generation method

Thermal power generation is kept constant throughout the operating period in such a way that the hydro-power plants use a specified and scheduled amount of water and operate on varying power generation schedules during the operating period.

6.6.3 Maximum hydro-efficiency method

In this method, during peak load periods, the hydro- power plants are operated at their maximum efficiency; during off-peak load periods they operate at an efficiency nearer to their maximum–efficiency with the use of a specified amount of water for hydro-power generation.

2.1 TURBINE MODEL

The Model required relation between changes in power output of the steam turbine to the changes in steam valve opening ΔX_E.

The steam turbines are usually of two types.

(i) Reheat type

(ii) Non reheat type

(i) Reheat type steam turbine:

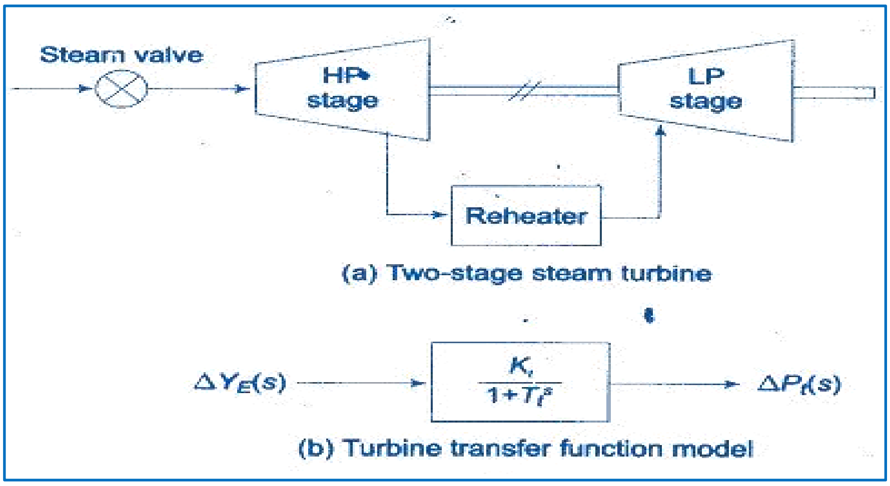
Figure. a shows a two stage steam turbine with a reheat unit.

The dynamic response is largely influenced by two factors,

(i) Entrained steam between the inlet steam valve and first stage of the turbine.

(ii) The storage action in the re-heater which causes the output of the low pressure stage to lag behind that of the high pressure stage.

Thus, the turbine transfer function is characterized by two time constants.



(a) Two-stage steam turbine

(b) Turbine transfer function model

For ease of analysis it will be assumed here that the turbine can be modeled to have a single equivalent time constant. Figure b shows the transfer function model of a steam turbine. Typically, the time constant "T_t" lies in the range 0.2 to 2.5 sec.

In non-reheat type turbine, there is neither an intermediate pressure section nor re-heater unit. In this case, the steam is directly passed to the LP section.

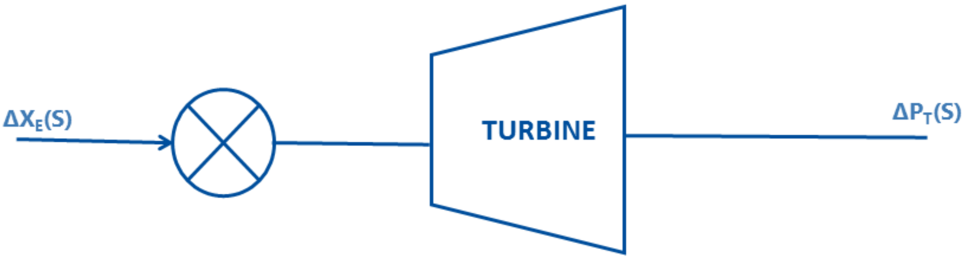
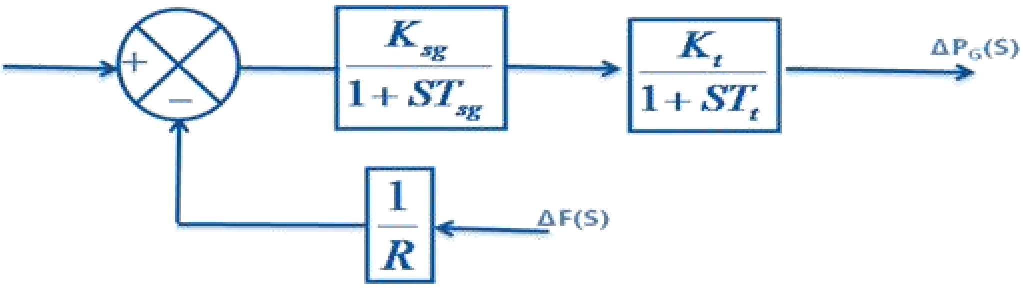


Fig shows linearized model of non-reheat turbine along with speed governing mechanism.



From the figure, the combined transfer function of turbine and speed governor mechanism will be

$$\frac{K_{sg}K_t}{\quad}$$

$(1 + ST_{sg})(1 + ST_t)$

$$\frac{\Delta P_G(s)}{[\Delta P_c(S) - \frac{1}{R}\Delta F(s)]} = \frac{K_{sg}K_t}{(1 + ST_{sg})(1 + ST_t)}$$

GENERATOR LOAD MODEL

The increment in power input to the generator-load system is

$\Delta P_G - \Delta P_D$

Where $\Delta P_G = \Delta P_t$ incremental turbine power output (assuming generator incremental loss to be negligible) and ΔP_D is the load increment.

This surplus power can be absorbed by the system into two different ways. They are

- Rate of increase of stored kinetic energy in the generator rotor. At scheduled frequency (f°), the stored energy is

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- Rate of increase of stored kinetic energy in the generator rotor. At scheduled frequency (f°), the stored energy is

$$W^o_{ke} = H \times P_r \text{ kW} = \text{sec (kilojoules)}$$

Where Pr is the kW rating of the turbo-generator and H is defined as its inertia constant.

The kinetic energy being proportional to square of speed (frequency), the kinetic energy at a frequency of ($f°$ + Δf) is given by

$$W_{ke} = W^o{}_{ke}\left(\frac{f^o + \Delta f}{f^o}\right)^2$$

$$\simeq HP_r\left(1 + \frac{2\Delta f}{f^o}\right)$$

Rate of change of kinetic energy is therefore

$$\frac{d}{dt}(W_{ke}) = \frac{2HP_r}{f^o}\frac{d}{dt}(\Delta f)$$

- As the frequency changes, the motor load changes being sensitive to speed, the rate of change of load with respect to frequency, i.e. δPD/δf can be regarded as nearly constant for small changes in frequency Δf and can be expressed as

$$(\partial P_D/\partial f)\ \Delta f = B\ \Delta f$$

Where

The constant B can be determined empirically.

D is positive for a predominantly motor load.

Writing the power balance equation, we have

$$\Delta P_G - \Delta P_D = \frac{2W^0}{f^0}\frac{d}{dt}(\Delta f) + \left(\frac{\partial P_D}{\partial f}\right)\Delta f$$

$$\Delta P_G - \Delta P_D = \frac{2HP_r}{f^0}\frac{d}{dt}(\Delta f) + B\Delta f$$

Dividing throughout by Pr and rearranging, we get

$$\Delta P_G(\text{pu}) - \Delta P_D(\text{pu}) = \frac{2H}{f^o}\frac{d}{dt}(\Delta f) + B(\text{pu})\ \Delta f$$

Taking Laplace transformation on both sides we get

$$\Delta f(s) = \frac{\Delta P_G(s) - \Delta P_D(s)}{\left(\frac{2HP}{f^0}S + D\right)}$$

$$\Delta f(s) = \frac{1}{D}\left[\frac{\Delta P_G(s) - \Delta P_D(s)}{\left(\frac{2HP}{Df^0}S + 1\right)}\right]$$

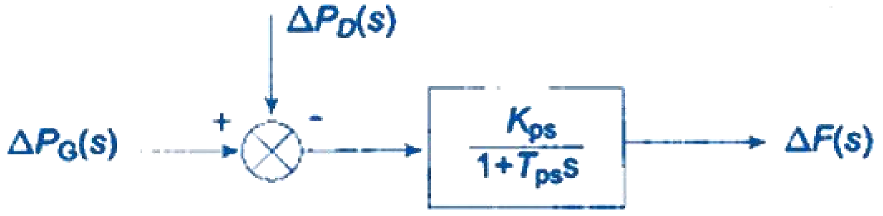
$$\Delta f(s) = \left(\frac{K_{PS}}{1 + T_{PS}S}\right)[\Delta P_G(s) - \Delta P_D(s)]$$

Where

$$T_{PS} = \frac{2HP}{Df^0} = Power\ System\ time\ constant$$

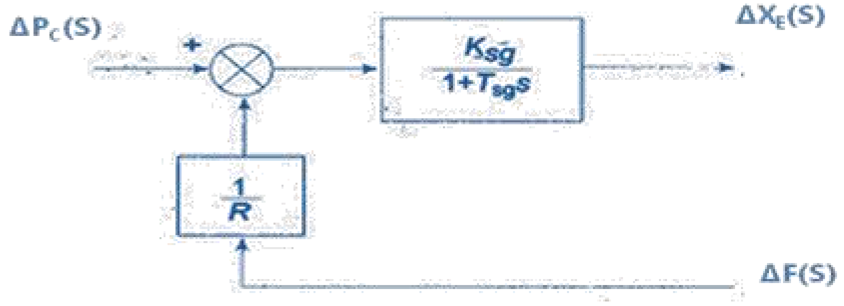
$$K_{PS} = \frac{1}{D} = Power\ System\ gain$$

The block diagram representing above equation is

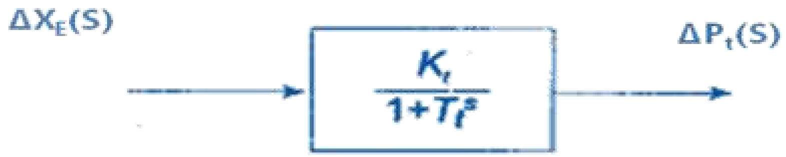


ISOLATED POWER SYSTEM

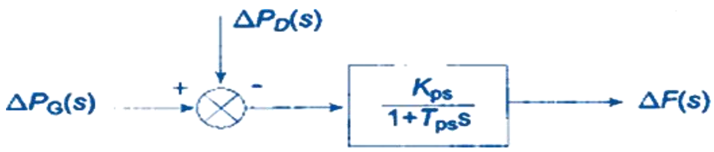
A complete block diagram representation of an isolated power system comprising turbine, generator, governor and load is easily obtained by combining the block diagrams of individual components. The complete block diagram with feedback loop is shown in Fig.



Block Diagram representation of speed governing for steam turbine



Block Diagram representation of Turbine transfer function model



Block Diagram representation of Generator Load Model

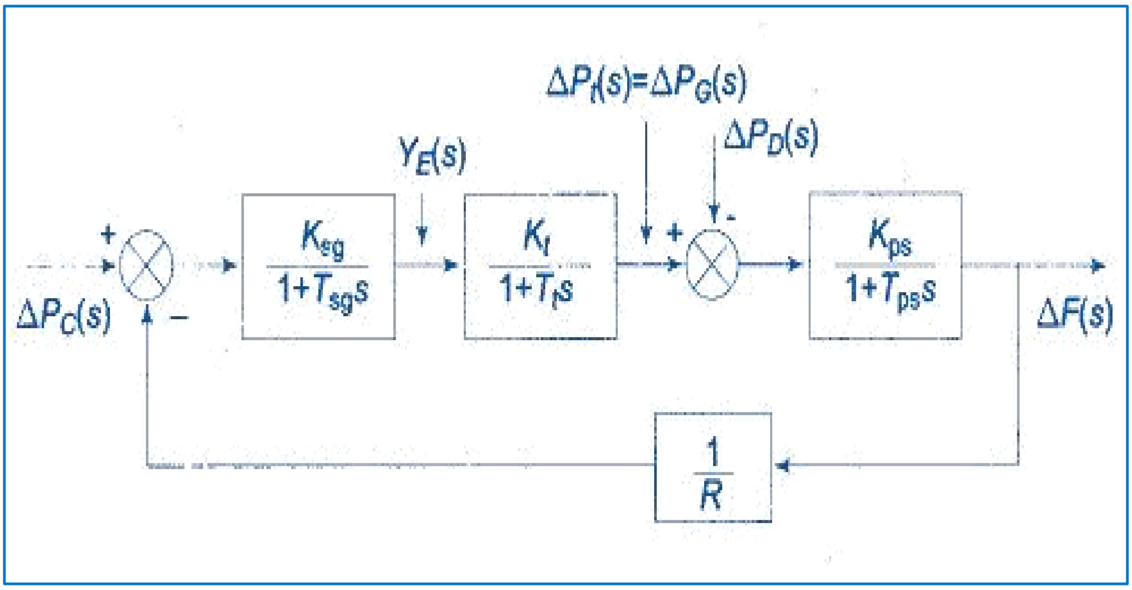


Fig: Complete Block Diagram Representation of Load Frequency Control of an Isolated Power System.

2.2 OPTIMAL SCHEDULING OF HYDROTHERMAL SYSTEM

No state or country is endowed with plenty of water sources or abundant coalor nuclear fuel. In states, which have adequate hydro as well as thermal power generation capacities, proper co-ordination to obtain a most economical operating state is essential. Maximum advantage is to use hydro power so that the coal reserves can be conserved and environmental pollution can be minimized. However in many hydro systems, the generation of power is an adjunct to control of flood water or the regular scheduled release of water for irrigation. Recreations centers may have developed along the shores of large reservoir so that only small surface water elevation changes are possible. The whole or a part of the base load can be supplied by the run-off river hydro plants, and the peak or the remaining load is then met by a proper mix of reservoir type hydro plants and thermal plants. Determination of this by a proper mix is the determination of the most economical operating state of a hydro-thermal system. The hydro-thermal coordination is classified into long term co-ordination and short term coordination.

The previous sections have dealt with the problem of optimal scheduling of a power system with thermal plants only. Optimal operating policy in this case can be completely determined at any instant without reference to operation at other times. This, indeed, is the static optimization problem. Operation of a system having both hydro and thermal plants is, however, far more complex as hydro plants have negligible operating cost, but are required to operate under constraints of water available for hydro generation in a given period of time. The problem thus belongs to the realm of dynamic optimization. The problem of minimizing the operating cost of a hydrothermal system can be viewed as one of minimizing the fuel cost of thermal plants under the constraint of water availability (storage and inflow) for hydro generation over a given period of operation.

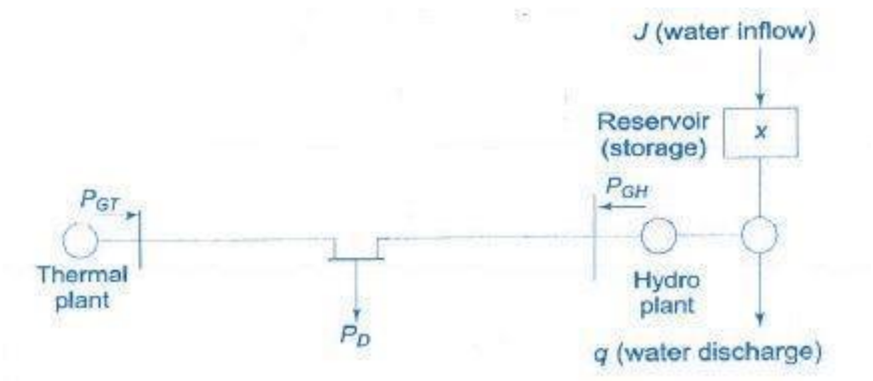


Fig. 2.1 Fundamental hydrothermal system

For the sake of simplicity and understanding, the problem formulation and solution technique are illustrated through a simplified hydrothermal system of Fig. 2.1. This system consists of one hydro and one thermal plant supplying power to a centralized load and is referred to as a fundamental system. Optimization will be carried out with real power generation as control variable, with transmission loss accounted for by the loss formula.

Mathematical Formulation

For a certain period of operation T (one year, one month or one day, depending upon the requirement), it is assumed that (i) storage of hydro reservoir at the beginning and the end of the period are specified, and (ii) water inflow to reservoir (after accounting for irrigation use) and load demand on the system are known as functions of time with complete certainty (deterministic case). The problem is to determine q(t), the water discharge (rate) so as to minimize the cost of thermal generation.

$$C_T = \int_0^T C'(P_{GT}(t))dt$$

For the sake of simplicity and understanding, the problem formulation and solution technique are illustrated through a simplified hydrothermal system of Fig. This Hydrothermal System consists of one hydro and one thermal plant supplying power to a centralized load and is referred to as a Fundamental Hydrothermal System.

For a certain period of operation T (one year, one month or one day, depending upon the requirement), it is assumed that

- Storage of hydro reservoir at the beginning and the end of the period are specified
- Water inflow to reservoir (after accounting for irrigation use) and load demand on the system are known as functions of time with complete certainty (deterministic case).

The problem is to determine q(t), the water discharge (rate) so as to minimize the cost of thermal generation

In this we consider time interval „T" (which can be One year, month, day or hours)

We have to determine the water discharge rate i.e. q(t) as to minimize the cost of thermal generation Under the following constraints

MEETING THE LOAD DEMAND

$P_{GT}(t)+P_{GH}(t)-P_L(t)-P_D(t)=0, t \in [0,T]$

$P_{GT}(t)$=Thermal power generation $P_{GH}(t)$=Hydro power generation

$P_L(t)$=Total loss in line $P_D(t)$=Total load demand

This is called the power balance equation.

2) WATER AVAILABILITY

$$X'(T) - X'(0) - \int_0^T J(t)dt + \int_0^T q(t)dt = 0$$

Where X"(T) and X"(0) are the water level at the end and beginning

J(t) is the water inflow.

3) HYDRO GENERATION

$P_{GH}(t) = f(X'(t), q(t))$

Here we discrtitize time interval T into M intervals for our calculations

Using these constraints and Langrangian optimization technique, we find the most optimal equation for hydrothermal scheduling.

2.3 HYDRO THERMAL SCHEDULING PROBLEM

It can be categorized into two. They are:

a. Long term scheduling problem
b. Short term scheduling problem

2.3.1 LONG TERM SCHEDULING PROBLEM:

The long-range hydro-scheduling problem involves the long-range forecasting of water availability and the scheduling of reservoir water releases (i.e., “drawdown”) for an interval of time that depends on the reservoir capacities. Typical long range scheduling goes anywhere from 1 wk. to 1 yr. or several years. For hydro schemes with a capacity of impounding water over several seasons, the long-range problem involves meteorological and statistical analyses.

The long term scheduling problem is divided into three categories.

- **Multi storage hydro electric system.**
- **Cascaded hydro electric system.**
- **Multi-chain hydro electric system.**

2.3.2 SHORT TERM HYDROTHERMAL SCHEDULING

The short term hydrothermal scheduling problem is concerned with allocating generation among hydro and thermal units over one week, usually discretized in hourly intervals. The problem formulation must take into account many system operating constraints, including hydraulic, thermal and electrical aspects.

Short term scheduling problem is divided into 2 categories.

Constant head hydro thermal scheduling:

The head of water in large capacity reservoir is assumed to be constant over a period of the operation.

Variable head hydro thermal scheduling:

If the capacity of the reservoir is small than the head of water in that reservoir is variable. The load demand should meet the total generation with losses. The coordination equation of short term scheduling problem is simple and easy.

Short-range hydro-scheduling (1 day to I wk.) involves the hour-by-hour scheduling of all generation on a system to achieve minimum production cost for the given time period. In such a scheduling problem, the load, hydraulic inflows, and unit availabilities are assumed known. A set of starting conditions (e.g., reservoir levels) is given, and the optimal hourly schedule that minimizes a desired objective, while meeting hydraulic steam, and electric system constraints, is sought.

Hydrothermal systems where the hydroelectric system is by far the largest component may be scheduled by economically scheduling the system to produce the minimum cost for the thermal system. The schedules are usually developed to minimize thermal generation production costs, recognizing all the diverse hydraulic constraints that may exist.

SHORT TERM SCHEDULING PROBLEM BY KIRCHMAYER'S METHOD:

Problem formulation:

The objective function is to minimize the cost of generation:

i.e.,

$$\min \sum_{i=1}^{\alpha} \int_0^T C_i \, dt$$

Subject to the equality constraints

$$\sum_{i=1}^{\alpha} P_{GT_i} + \sum_{j=\alpha+1}^{n} P_{GH_j} = P_D + P_L$$

and

$$\int_0^T w_j \, dt = K_j \quad \text{for } j = \alpha+1, \alpha+2, \ldots, n \quad \text{———— (3)}$$

Where

W_j is the turbine discharge in the j^{th} plant in m3 /s and

K_j the amount of water in m3 utilized during the time period T in the j^{th} hydro-plant.

The coefficient γ must be selected so as to use the specified amount of water during the operating period.

Now, the objective function becomes

$$\min C = \sum_{i=1}^{\alpha} \int_0^T C_i dt + \sum_{j=\alpha+1}^{n} \gamma_i K_j$$

Substituting K_j from Equation (3) in the above equation, we get

$$\min C = \sum_{i=1}^{\alpha} \int_0^T C_i \, dt + \sum_{j=\alpha+1}^{n} \gamma_i \int_0^T w_j \, dt \text{-----------------------(4)}$$

For a particular load demand P_D, Equation (2) results as

For a particular hydro-plant *x*, Equation (5) can be rewritten as

$$\Delta P_{\mathrm{GH}_x} - \frac{\partial P_{\mathrm{L}}}{\partial P_{\mathrm{GH}_x}} \Delta P_{\mathrm{GH}_x} = -\sum_{i=1}^{\alpha} \Delta P_{\mathrm{GT}_i} - \sum_{\substack{j=\alpha+1 \\ j \neq x}}^{n} \Delta P_{\mathrm{GH}_j}$$

$$+ \sum_{i=1}^{\alpha} \frac{\partial P_{\mathrm{L}}}{\partial P_{\mathrm{GT}_i}} \Delta P_{\mathrm{GT}_i} - \sum_{\substack{j=\alpha+1 \\ j \neq x}}^{n} \frac{\partial P_{\mathrm{L}}}{\partial P_{\mathrm{GH}_j}} \Delta P_{\mathrm{GH}_j} = 0$$

By rearranging the above equation, we get

$$\Delta\left[\sum_{i=1}^{\alpha} \int_0^T C_i \,\mathrm{d}t + \sum_{j=\alpha+1}^{n} \gamma_j \int_0^T w_j \,\mathrm{d}t\right] = 0$$

UNIT-III

INTRODUCTION

Speed governing mechanism

Modeling of speed governing mechanism

Models of various types of thermal plants (first order)

Definitions of control area, Block diagram representation of an isolated power system

Automatic Load Frequency control of single area system with and without control

Steady state and dynamic responses of single area ALFC loop

Numerical examples

FUNDAMENTALS OF SPEED GOVERNING MECHANISM AND MODELLING

Let

P_{GTi} be the power generation of i^{th} thermal plant in MW,

P_{GHj} be the power generation of j^{th} hydro-plant in MW,

$\frac{dci}{dpGTj}$ Be the incremental fuel cost of i^{th} thermal plant in Rs./MWh,

w_j be the quantity of water used for power generation at j^{th} hydro-plant in m^3 /s,

$\frac{dWj}{dPGHj}$ be the incremental water rate of j^{th} hydro-plant in m^3 /s/MW,

$\frac{dPl}{dPGTi}$ be the incremental transmission loss of i^{th} thermal plant,

$\frac{dPl}{dPGHj}$ be the incremental transmission loss of j^{th} hydel plant,

λ be the Lagrangian multiplier,

γ_i be the constant which converts the incremental water rateof hydro plant "j" into incremental cost

n be the total number of plants,

α be the number of thermal plants,

n-a be the number of hydro-plants, and

T be the time interval during which the plant operation is considered.

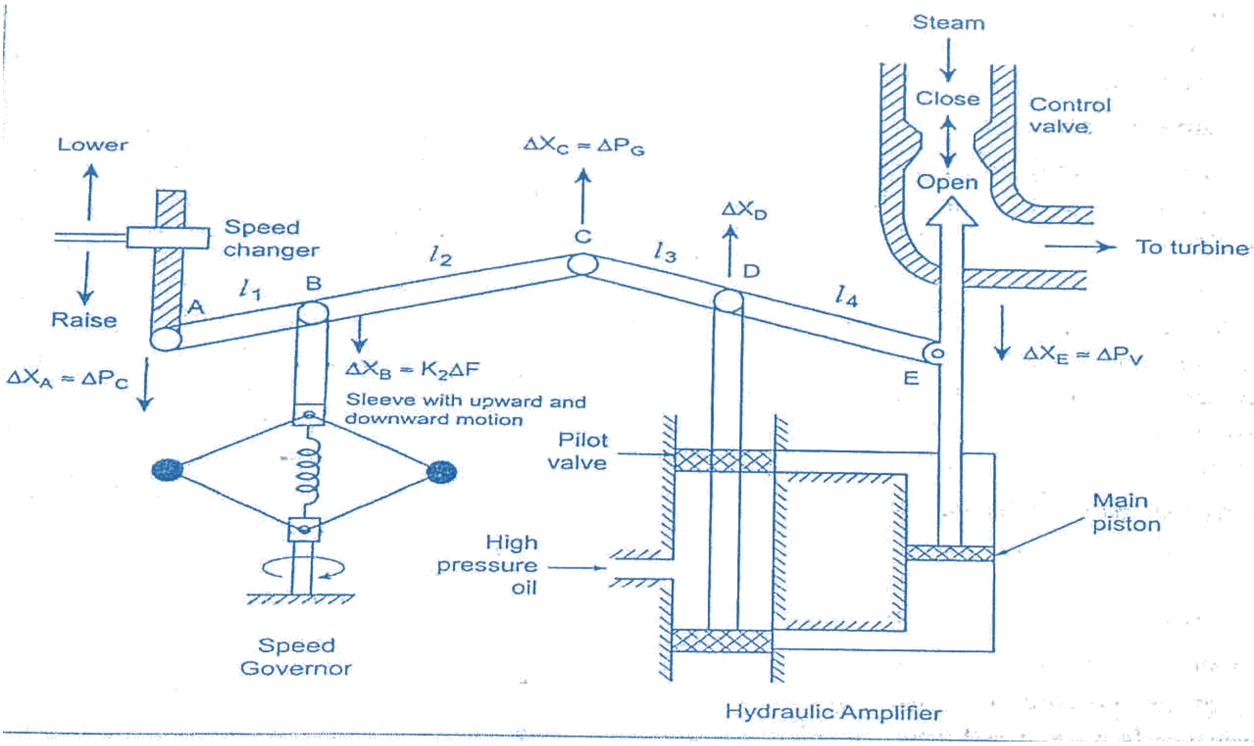
The Speed Governing System of the steam Turbine. By controlling the position of the control value or gate, we can exert control over the flow of high pressure Steam (or water) through the turbine.

Fly ball speed governor:

It is purely mechanical speed – sensitive device coupled directly to the hydraulic amplifier which adjusts the control value opening via the linkage mechanism. As the load increase, speed of the Turbine decrease and the speed changer gives raise command, so the fly balls move outwards and the point B moves downwards and the reverse happens with the increased speed.

Speed changer:

- It makes it Possible to restore the frequency to the initials (nominal) value after the operation of the speed governors which has steady state characteristics.
- A Small download movement of the linkage point A Corresponds to an increase ΔPc in the reference power setting.



Hydraulic amplifier:

It consists of pilot valve and main piston with this arrangement, a low power pilot valve movement is converted into high power level movement is converted into high power level movement of the oil – servomotor piston. The input to this amplifier is the position XD of the pilot Valve. The output is the position XE of the main piston. Hydraulic amplification is necessary so that the steam valve or gate could be operated against high pressure steam.

Linkage mechanism :

- ABC is a rigid link pivoted at B and CDE is another rigid link pivoted at D. The function of the link mechanism is to control the steam valve or gate

- ➢ We get feedback from the movement of the steam valve via link CD.

Working:

As load increases, the speed of the turbine decreases, the speed changer gives raise command and fly balls outwards and the point B moves downloads and D moves upwards and high pressure oil enters into the upper pilot valve and presses the main piston downwards and opens the valve or gate (i.e) increases the flow of steam to the turbine. Thereby, speed of flow of steam to the turbine increases and maintains constant frequency.

MODELLING OF SPEED GOVERNOR MECHANISM:

We shall develop the mathematical model Based on small deviations around a nominal steady state. Consider the steam is operating under steady state and is delivering power PG from the generator at nominal frequency f. Let Xs be the steam value setting. Let us assume that raise command Pc to the speed changer, the point A be moved downwards by a small amount XA which causes the turbine power output to change.

Therefore $\Delta XA = kc\Delta Pc$

Let assume +ve direction for downward movement and –ve direction for upward movement.

Movement of c:

1) ΔXA contributes $[\frac{-l_2}{l_1}]\Delta X_A = K_C \Delta P_c$

2) Increase in frequency causes the fly balls to moves outwards so that B moves downloads by a proportional amount $K_1\Delta f$.

$$\Delta X_A + \Delta X_c = K_1\Delta f$$

Therefore net moment of ‗C‛ is given by

$$\Delta X_c = K_1\Delta f - K_2\Delta P_c[\Delta X_A \infty \Delta P_c]$$

Movement of D:

Net moment of ‗D‛ is given by

$$\Delta X_D = [\frac{l_4}{l_3 + l_4}]\Delta X_c + [\frac{l_3}{l + l_4}]\Delta X_4$$

$\Delta X_D = K_3\Delta X_c + K_4\Delta X_E$ ------------------------(2)

Movement of ΔX_E :

The volume of oil admitted to the cylinder is thus proportional to the time integral of ΔX_D.

net moment of ‗E‵ is given by

$$\Delta X_E = k_5 \int_0^t -\Delta X_D\, dt - - - - - - - - (3)$$

Taking L.T of equation (1), (2),(3)

$$\Delta X_c(s) = -k_1 k_c \Delta P_c(s) + k_2 \Delta f(s) - - - - - - - - -(4)$$

$$\Delta X_D(s) = k_3 \Delta X_c(s) + k_4 \Delta X_E(s) - - - - - - - - - - (5)$$

$$\Delta X_E(s) = \frac{-k_5}{s} \Delta X_D(s) - - - - - - - - (6)$$

$$\Delta X_E(s) = \frac{-k_5}{s}[k_3 \Delta X_c(s) + k_4 \Delta X_E(s)]$$

$$\Delta X_E(s)\left[1 + \frac{k_4 k_5}{s}\right] = \frac{-k_5 k_3}{s}[\Delta X_c(s)] - - - - - - -(7)$$

$$\Delta X_E(s)\left[1 + \frac{k_4 k_5}{s}\right] = \frac{-k_5 k_3}{s}[-k_1 k_c \Delta P_c(s) + k_2 \Delta f(s)]$$

$$\Delta X_E(s)\left[\frac{s + k_4 k_5}{s}\right] = \left[\frac{k_5 k_3 k_1 k_c \Delta P_c(s) - k_2 k_5 k_3 \Delta f(s)}{s}\right]$$

$$\Delta X_E(s) = \frac{k_5 k_3 k_1 k_c \left[\Delta P_c(s) - \frac{k_2}{k_1 k_c}\Delta f(s)\right]}{k_4 k_5\left[1 + \frac{s}{k_4 k_5}\right]}$$

Put (5) in (6), we get

$$\Delta X_E(s) = \frac{k_3 k_1 k_c \left[\Delta P_c(s) - \frac{k_2}{k_1 k_c}\Delta f(s)\right]}{k_4\left[1 + \frac{s}{k_4 k_5}\right]}$$

The output of a generating as a gives system frequency can be varied only by changing its load reference or control point which is integrated with the speed governing mechanism.

$$\Delta X_E(s)\left[1 + \frac{k_4 k_5}{s}\right] = \frac{-k_5 k_3}{s}[\Delta X_c(s)] - - - - - -(7)$$

$$\Delta X_E(s)\left[1 + \frac{k_4 k_5}{s}\right] = \frac{-k_5 k_3}{s}[-k_1 k_c \Delta P_c(s) + k_2 \Delta f(s)]$$

$$\Delta X_E(s)\left[\frac{s + k_4 k_5}{s}\right] = \left[\frac{k_5 k_3 k_1 k_c \Delta P_c(s) - k_2 k_5 k_3 \Delta f(s)}{s}\right]$$

$$\Delta X_E\ (s) = \frac{k_5 k_3 k_1 k_c \left[\Delta P_c(s) - \frac{k_2}{k_1 k_c}\Delta f(s)\right]}{k_4 k_5 \left[1 + \frac{s}{k_4 k_5}\right]}$$

$$\Delta X_E\ (s) = \frac{k_3 k_1 k_c \left[\Delta P_c(s) - \frac{k_2}{k_1 k_c}\Delta f(s)\right]}{k_4 \left[1 + \frac{s}{k_4 k_5}\right]}$$

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

The above equation can also be written as

$$\Delta X_E\ (s) = \left[\Delta P_c(s) - \frac{1}{R}\Delta f(s)\right] \times \frac{k_G}{1 + sT_G} - - - - - - -(8)$$

Where, Value of TG < 100 msec.

$$R = \frac{K_2}{K_1} = Speed\ Regulation\ Governor$$

$$K_{SG} = \frac{K_2 K_3}{K_4} = Gain\ of\ speed\ governor$$

$$T_{sg} = \frac{1}{K_4 K_5} = Time\ Constant\ of\ speed\ governor$$

$$\Delta X_E(S) = \frac{K_{sg}}{1 + ST_{sg}} \left[\Delta P_c(s) - \Delta F\ (s) \cdot \frac{1}{R}\right]$$

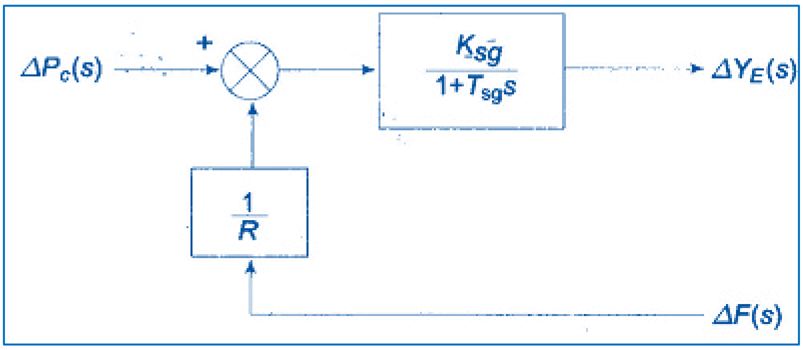


Fig: Block diagram of speed governor.

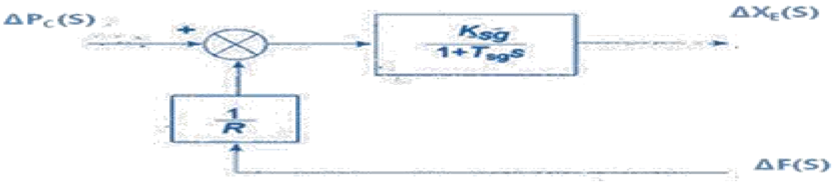
The adjustment of load reference set point is accomplished by operating the —speed changer motor|| this in effect moves the speed droop char UP down.

The speed governing system of a hydro-turbine is more involved.

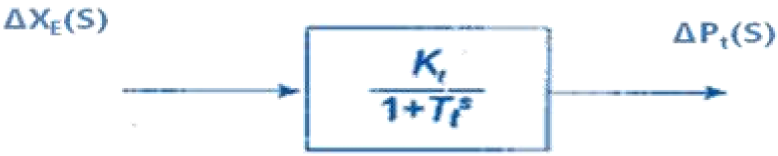
An additional feedback loop provides temporary droop compensation to prevent instability. This is necessitated by the large inertia of the penstock gate which regulates the rate of water input to the turbine.

ISOLATED POWER SYSTEM:

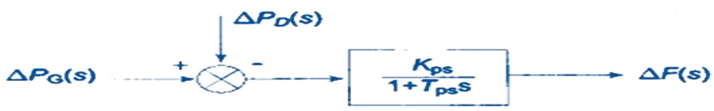
A complete block diagram representation of an isolated power system comprising turbine, generator, governor and load is easily obtained by combining the block diagrams of individual components. The complete block diagram with feedback loop is shown in Fig.



Block Diagram representation of speed governing for steam turbine



Block Diagram representation of Turbine transfer function model



Block Diagram representation of Generator Load Model

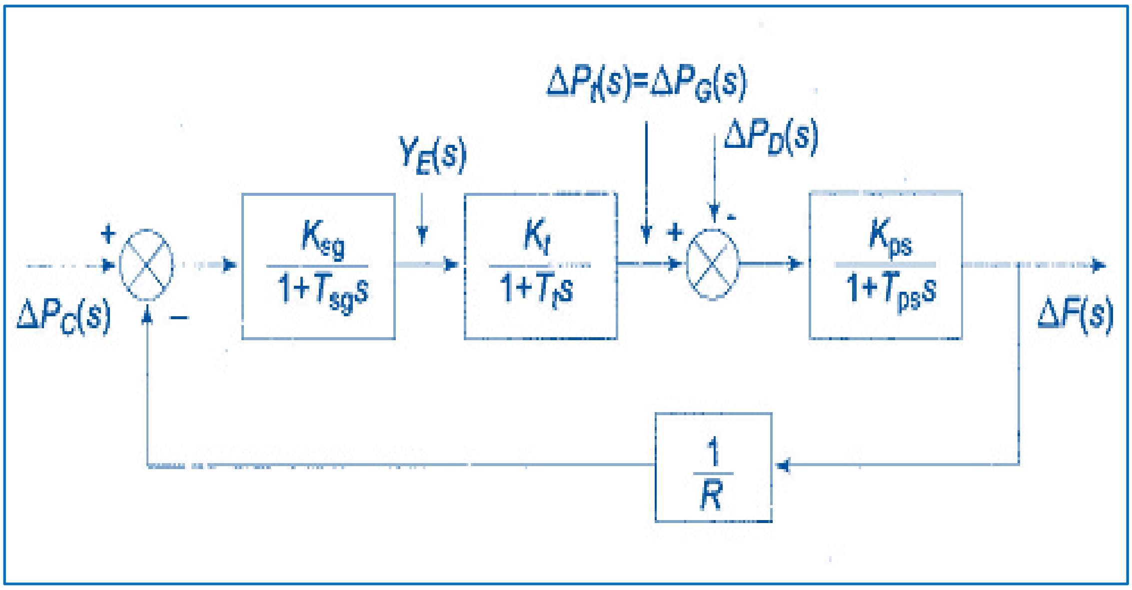


Fig: Complete Block Diagram Representation of Load Frequency Control of an Isolated Power System.

3.1 NECESSITY FOR PARALLEL OPERATION

1. Alternators may be put in parallel because of the following reasons.
2. Local or regional power use may exceed the power of a single available generator.
3. Parallel Alternators allow one or more units to be shut down for scheduled or emergency maintenance while the load is being supplied with power.
4. Generators are in efficient at part load, so shutting down one or more generators allows the remaining load to be carried with less machines that are efficiently loaded.
5. Available machine prime movers and generators can be matched for economic cost and flexible use.

3.1.1 REQUIREMENTS FOR PARALLEL OPERATION

1. Alternators to be operated in parallel should meet the following requirements.
2. They must have the same output voltage rating.
3. The rated speeds of the machines should be such as to give the same frequency.
4. The alternators should be the same type so as to generate voltage of the same waveform; they may differ in their KVA rating.
5. The alternators should have reactance in their armatures; otherwise, they will

not operate in parallel successfully.

3.1.2 CONDITIONS FOR PROPER SYNCHRONISING

1. The Terminal voltage of the incoming machine must be exactly equal to that of the other or of the bus bars connecting them.
2. The speed of the incoming machine must be such that, its frequency equals bus bar frequency.
3. The phase of the incoming machine voltage must be the same as that of the bus– bar voltage relative to the load.
4. The phase sequence of the incoming machine is the same as that of the bus bars.

3.1.3 CONCEPT OF CONTROL AREA

1. A control area is defined as a system to which a common generation control scheme is applied
2. The electrical interconnection within each control area is very strong as compared to the Ties with the neighboring areas.
3. All the generators in a control area swing in coherently or it is characterised by a single frequency.
4. It is necessary to be considered as many control area as number of coherent group.

3.2 LOAD FREQUENCY CONTROL OF SINGLE AREA SYSTEM

To analyze the LFC of an isolated system, first build mathematical model from the block diagram.

Let ΔPc be the incremental control input.

Let ΔPD be the incremental disturbance input.

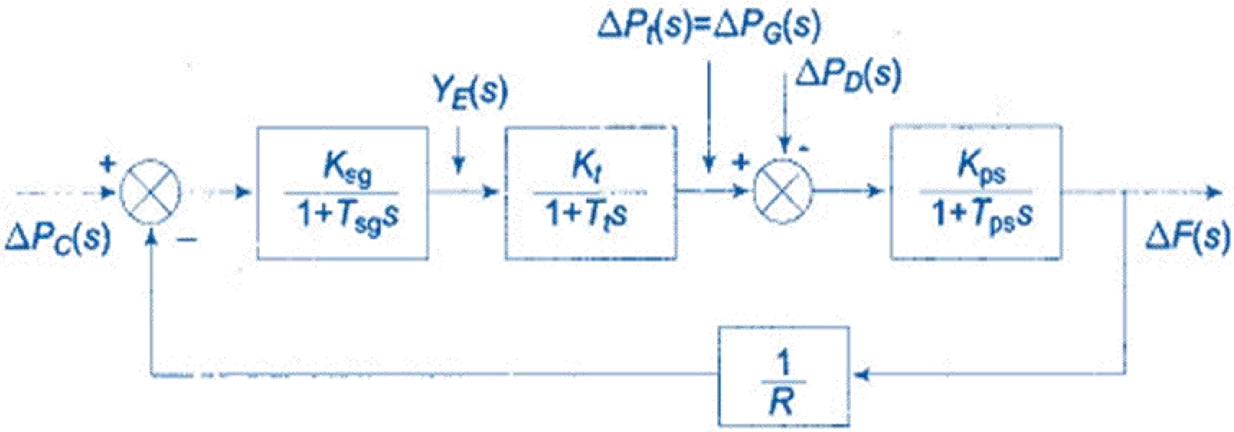
The incremental control input is due to the change in the speed changer setting, while the incremental disturbance is due to the change in load demand.

There are two responses:

5. Steady state or static response.
6. Dynamic state response.

3.3 STATIC ANALYSIS OF UNCONTROLLED CASE

Consider the speed changer has a fixed setting under this condition $\Delta Pc=0$ and the load demand changes. This is known as free governor operation.



$$\Delta F(s) = \frac{\frac{k_p}{1+sT_p}}{1+\frac{k_p}{1+sT_p}\times\frac{k_p k_G k_t}{R(1+sT_G)(1+sT_t)}}\times[-\Delta P_D(s)]$$

$$\Delta F(s) = \frac{\frac{k_p}{1+sT_p}}{1+sT_p+\frac{k_p k_G k_t}{R(1+sT_G)(1+sT_t)}}\times[-\Delta P_D(s)]$$

$$\Delta P_D(s) = \frac{\Delta P_D}{s}$$

$$\Delta F(s) = \frac{-k_p}{1+sT_p+\frac{k_p k_G k_t}{R(1+sT_G)(1+sT_t)}}\times\left[\frac{\Delta P_D}{s}\right]$$

For a step load change

Apply final value theorem,

$$\Delta f_{stat} = \lim_{s\to 0} s.\Delta F(s) = \frac{-k_p}{1+\frac{k_p k_G k_t}{R}}\times\Delta P_D$$

Practically $k_G k_t = 1, [k_t\ is\ fixed\ \&\ k_G\ adjusted\ by\ changing\,]$

$$\Delta f_{stat} = \frac{-k_p}{1+\frac{k_p}{R}}\times\Delta P_D$$

Since $k_p = \frac{1}{B}\ \&\ \Delta P_D = M$

Where,

B = Load damping constant.

ΔP_D= Increase in load.

$$\Delta f_{stat} = \frac{-\frac{1}{B}\Delta P_D}{1+\frac{1}{BR}} = \frac{-M}{B+\frac{1}{R}} = \frac{-M}{\beta}$$

Where,

$$\beta = B + \frac{1}{R}$$

$\beta = Area\ frequency\ response\ coefficient.$

The system performance in terms of how the change in power effects the change in frequency is evaluated through AFRC.

In practice B<<I/R, neglecting B

$$\Delta f_{stat} = -R\Delta P_D\ Hz.$$

$$\frac{\Delta f_{stat}}{\Delta P_D} = -R\ [HZ/MW]$$

Where,

R = Speed Regulation.

Δf_{stat}= Change in steady state frequency.

$$\Delta f_{stat} = -R\Delta P_D\ Hz.$$

When several generators with governor speed regulation R_1, R_2……… R_n is connected to the system. The steady state deviation in frequency.

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

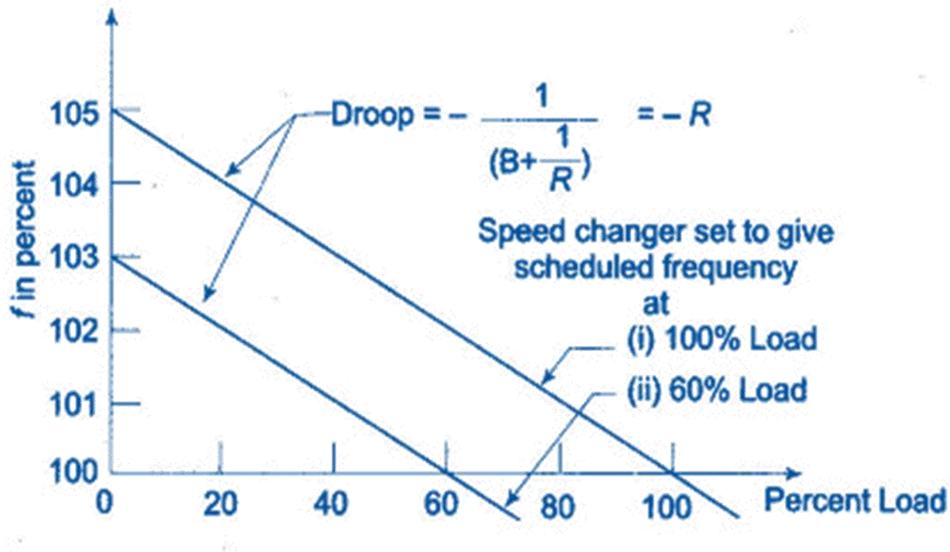


Figure 3.2 % Frequency VS % Load

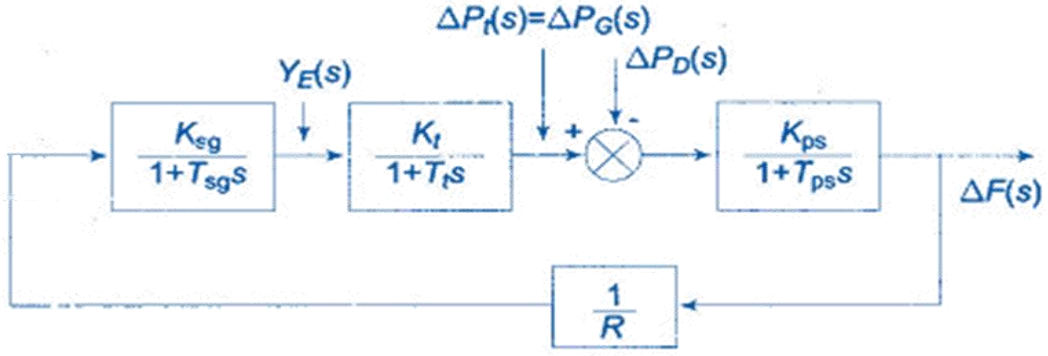
DYNAMIC ANALYSIS OF UNCONTROLLED CASE OF SINGLE AREA

A static response of LFC loop will inform about frequency accuracy, whereas the dynamic response of LFC loop will inform about the stability of the loop.

To obtain the dynamic response representing the changing frequency as a function of time for a step change in load.

Put

$\Delta Pc(S)=0$



$$\Delta F(s) = \frac{\frac{k_p}{1+sT_p}}{1+\frac{k_p k_G k_t}{R(1+sT_G)(1+sT_t)}} \times [-\Delta P_D(s)]$$

Take LT $^{-1}$ for an expression $\Delta F(s)$ is tedious, because the denominator will be third order.

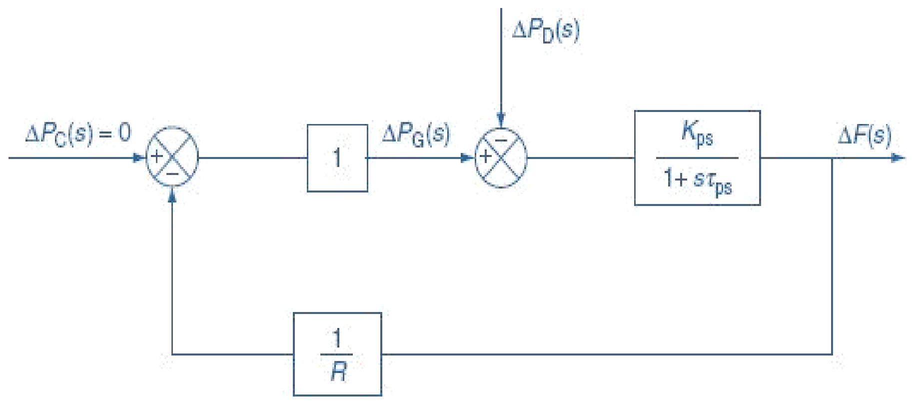
Assumptions,

1. The action of speed governor and turbine is instantaneously compared with rest of the power system.

2. The time constant of the power system Tp-= 20sec.

Time constant of governor TG = 0.4 sec. Time constant of Turbine Tt = 0.5 sec

Approximate Analysis. Let Tt = TG = 0 KG Kt = 1



$$\Delta F(s) = \frac{k_p}{1 + sT_p \times \frac{k_p}{R}} \times [-\Delta P_D(s)]$$

For a step change $\Delta P_D(s) = \Delta P_D/S$

$$\Delta F(s) = \frac{k_p}{T_p\left[s + \frac{1}{T_p} + \frac{k_p}{RT_p}\right]} \times \left[\frac{-\Delta P_D}{s}\right]$$

Applying partial fraction method,

$$= \frac{-\Delta P_D k_p}{T_p\ s\left[s + \frac{R+k_p}{RT_p}\right]} \qquad \Delta F(s) = \frac{-\Delta P_D k_p}{T_p}\left[\frac{A}{s} + \frac{B}{s + \left[\frac{R+k_p}{RT_p}\right]}\right]$$

$$As + A\left[\frac{R + k_p}{RT_p}\right] + Bs = 1$$

$$As + A\left[\frac{R + k_p}{RT_p}\right] + Bs = 1$$

$$\Delta F(s) = \frac{-\Delta P_D k_p}{T_p}\left[\frac{A}{s} + \frac{B}{s + \left[\frac{R+k_p}{RT_p}\right]}\right]$$

Comparing the coefficients,

$$A + B = 0.$$

$$A = \frac{RT_p}{R + k_p}, B = \frac{-RT_p}{R + k_p}$$

$$\Delta F(s) = \frac{-\Delta P_D k_p}{T_p}\left[\frac{RT_p}{R + k_p}\left[\frac{1}{s} + \frac{1}{s + \left[\frac{R+k_p}{RT_p}\right]}\right]\right]$$

$$\Delta f(t) = LT^{-1}\Delta F(s)$$

$$\Delta f(t) = \frac{-\Delta P_D k_p R}{R + k_p}\left[1 - e^{\left(\frac{R+k_p}{RT_p}\right)t}\right]$$

$$\Delta f(t) = \frac{-M k_p R}{R + k_p}\left[1 - e^{-\left(\frac{R+k_p}{RT_p}\right)t}\right]$$

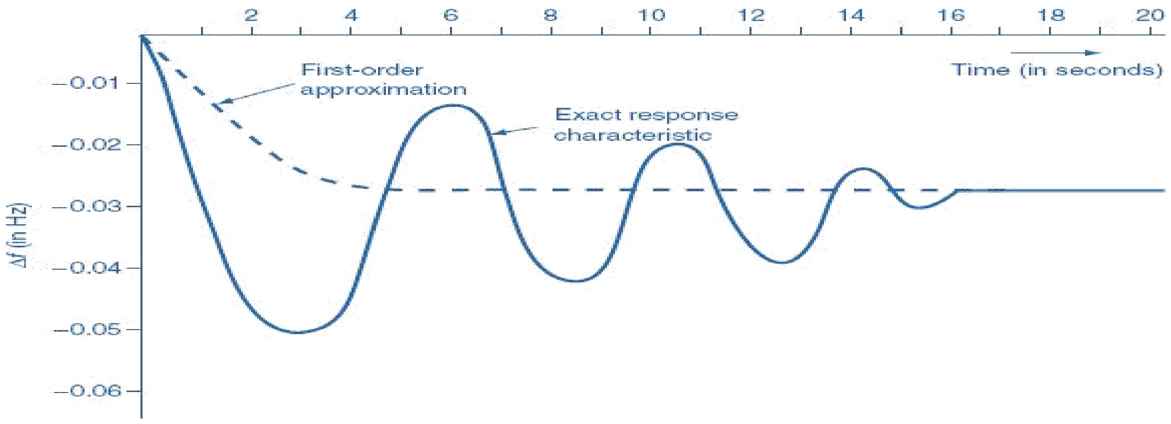


Figure Response if T_G, T_t are included and neglected

Above $\Delta F(t)$ = Dynamic response to a step load.

TWO AREA LOAD FREQUENCY CONTROL SYSTEM MODELLING:

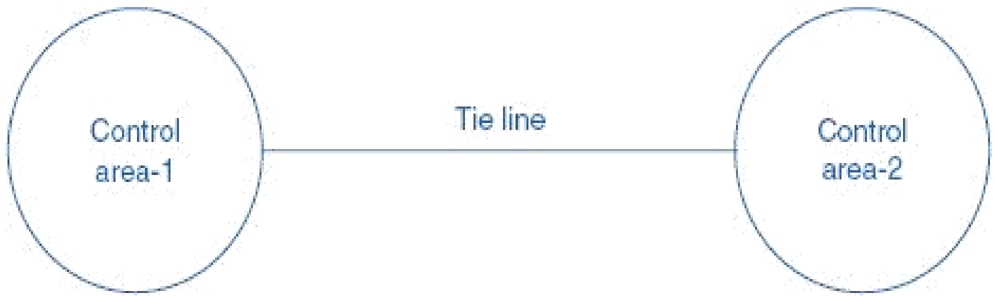
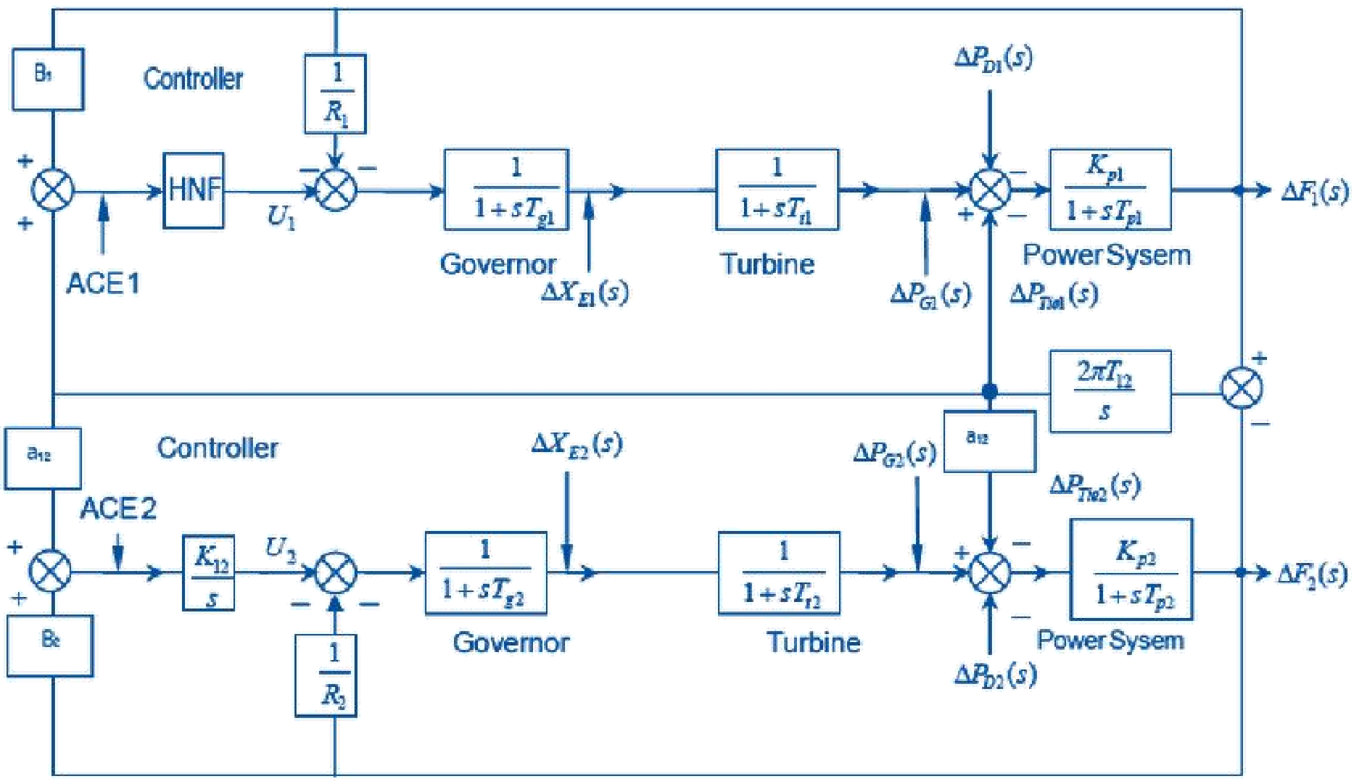


Figure : Two area load frequency control system modeling

1. The control objective now is to regulate the frequency of each area and to simultaneously regulate the tie line power as per inter area power contracts.
2. As in the case of frequency, proportional plus integral controller will be installed so as to give zero steady state error in the tie line flow as compared to the contracted power.



STATIC ANALYSIS OF UNCONTROLLED CASE

$\Delta P_c(1)=\Delta P_c(2)=0$

ie, No need to change the position of speed changer suppose there is a sudden increase in load demand in the areas by incremental steps $\Delta P_D(s)$ & $\Delta P_D(s)$. Frequency drops in the steady state and these drops will be equal.

$\Delta F_{1stat}= \Delta F_{2stat}= \Delta F_{stat}$

At steady state condition, we will have incremental tie line power,

$$\Delta P_{G1,stat} = \frac{-1}{R_1}\Delta f_{stat}$$

$$\Delta P_{G2,stat} = \frac{-1}{R_2}\Delta f_{stat} ----------- (1)$$

$$\Delta P_{G1,stat} - \Delta P_{D1} - \Delta P_{tie1,stat} \times \left[\frac{k_{p1}}{1+sT_{p1}}\right] = \Delta f_{stat}$$

$$\Delta P_{G1,stat} - \Delta P_{D1} - \Delta P_{tie1,stat} \times \left[\frac{\frac{1}{B}}{1+\frac{2Hs}{f^0 B}}\right] = \Delta f_{stat}$$

$$\Delta P_{G1,stat} - \Delta P_{D1} - \Delta P_{tie1,stat} \times \left[\frac{\frac{1}{B}}{1+\frac{2Hs}{f^0 B}}\right] = \Delta f_{stat}$$

$$\Delta P_{G1,stat} - \Delta P_{D1} - \Delta P_{tie1,stat} = B_1 \Delta f_{stat} - - - - - - - - (2)$$

$$\Delta P_{G1,stat} - \Delta P_{D1} - \Delta P_{tie1,stat} = \left[B + \frac{2Hs}{f^0}\right] \Delta f_{stat}$$

$$\Delta P_{G1,stat} - \Delta P_{D1} - \Delta P_{tie1,stat} = B\Delta f_{stat} + \frac{2H}{f^0}\frac{d}{dt}\Delta f_{stat}$$

Put $\frac{d}{dt}\Delta f_{stat} = 0$ for area 1, we get

$\frac{d}{dt}\Delta f_{stat} = 0 \; for\ area\ 1, we\ get,$

Similarly for area 2

$\Delta P_{G2,stat} - \Delta P_{D2} = B_2 \Delta f_{stat} + \Delta P_{tie2,stat}$

$\Delta P_{G2,stat} - \Delta P_{D2} = B_2 \Delta f_{stat} - a_{12} \Delta P_{tie2,stat}$

$\Delta P_{G2,stat} - \Delta P_{D2} = B_2 \Delta f_{stat} - a_{12} [\Delta P_{G1,stat} - \Delta P_{D1} = B_1 \Delta f_{stat}]$-----------(3)

Sub. equation (1) in equation (3) we get

$$\frac{-1}{R_2}\Delta f_{stat} - \Delta P_{D2} = B_2 \Delta f_{stat} + \frac{a_{12}}{R_1}\Delta f_{stat} - a_{12}\Delta P_{D1} + a_{12} B_1 \Delta f_{stat}$$

$$\Delta f_{stat}\left[\frac{-1}{R_2} - B_2 - \frac{a_{12}}{R_1} - a_{12}B_1\right] = -a_{12}\Delta P_{D1} + \Delta P_{D2}$$

$$\Delta f_{stat} = \frac{-[a_{12}\Delta P_{D1} + \Delta P_{D2}]}{\left[B_2 + \frac{1}{R_2}\right] + a_{12}\left[B_1 + \frac{1}{R_1}\right]} - - - - - - - - (4)$$

$$\Delta P_{tie1,stat} = \Delta P_{G1,stat} - \Delta P_{D1} - B_1 \Delta f_{stat}$$

$$= \frac{-1}{R_1}\Delta f_{stat} - \Delta P_{D1} - B_1 \Delta f_{stat}$$

$$\frac{-1}{R_2}\Delta f_{stat} - \Delta P_{D2} = B_2 \Delta f_{stat} + \frac{a_{12}}{R_1}\Delta f_{stat} - a_{12}\Delta P_{D1} + a_{12} B_1 \Delta f_{stat}$$

$$\Delta f_{stat}\left[\frac{-1}{R_2} - B_2 - \frac{a_{12}}{R_1} - a_{12}B_1\right] = -a_{12}\Delta P_{D1} + \Delta P_{D2}$$

$$= -\Delta f_{stat}\left[B_1 + \frac{1}{R_1}\right] - \Delta P_{D1} - - - - - - (5)$$

$$\Delta f_{stat} = \frac{-[a_{12}\Delta P_{D1} + \Delta P_{D2}]}{\left[B_2 + \frac{1}{R_2}\right] + a_{12}\left[B_1 + \frac{1}{R_1}\right]} - - - - - - - - (4)$$

Sub. equation (4) in equation (5)

$$\Delta P_{tie1,stat} = \frac{[a_{12}\Delta P_{D1} + \Delta P_{D2}]}{\left[B_2 + \frac{1}{R_2}\right] + a_{12}\left[B_1 + \frac{1}{R_1}\right]}\left[B_1 + \frac{1}{R_1}\right] - \Delta P_{D1}$$

$$= \frac{[a_{12}\Delta P_{D1} + \Delta P_{D2}]\left[B_1 + \frac{1}{R_1}\right] - \Delta P_{D1}\left[B_2 + \frac{1}{R_2}\right] - a_{12}\Delta P_{D1}\left[B_1 + \frac{1}{R_1}\right]}{\left[B_2 + \frac{1}{R_2}\right] + a_{12}\left[B_1 + \frac{1}{R_1}\right]}$$

$$= \frac{[\Delta P_{D2}]\left[B_1 + \frac{1}{R_1}\right] - \Delta P_{D1}\left[B_2 + \frac{1}{R_2}\right]}{\left[B_2 + \frac{1}{R_2}\right] + a_{12}\left[B_1 + \frac{1}{R_1}\right]}$$

Let $\beta_1 = B_1 + \frac{1}{R_1}$ & $\beta_2 = B_2 + \frac{1}{R_2}$

$$\Delta P_{tie1,stat} = \frac{[\Delta P_{D2}]\,\beta_1 - [\Delta P_{D1}]\beta_2}{\beta_2 + a_{12}\,\beta_1}$$

$$\Delta f_{stat} = \frac{-[a_{12}\Delta P_{D1} + \Delta P_{D2}]}{\beta_2 + a_{12}\,\beta_1}$$

For two identical areas,

$\beta_1 = \beta_2 = \beta.$

$R_1 = R_2 = R.$

$B_1 = B_2 = B.$

$$a_{12} = \frac{P_{r1}}{P_{r2}} = 1.$$

$$\Delta f_{stat} = \frac{-[\Delta P_{D1} + \Delta P_{D2}]}{2\beta}$$

$$\Delta P_{tie1,stat} = -\Delta P_{tie2,stat} = \frac{[\Delta P_{D2}] - [\Delta P_{D1}]}{2}$$

Suppose a step load change occurs at area (1)

$\Delta P_{D2} = 0$

$$\Delta f_{stat} = \frac{-\Delta P_{D1}}{2\beta}$$

$$\Delta P_{tie1,stat} = \frac{-[\Delta P_{D1}]}{2}.$$

For interconnected power system the steady state frequency error is reduced by 50% and the change in tie line power is also reduced by 50 %.

DYNAMIC RESPONSE OF UNCONTROLLED CASE

Let us now turn our attention during the transient period for the sake of simplicity. We shall assume the two areas to be identical further; we shall be neglecting the time constants of generators and turbines as they are negligible as compared to the time constants of power system.

$$T_{p1} >> T_{t1}, T_{G1}; T_{p2} >> T_{t2}, T_{G2}$$

For uncontrolled case ($\Delta P_{c1} = \Delta P_{C2} = 0$)

We can write the following conditions or equation from the block diagram depicted

$$\Delta f_1(s) = \frac{-k_{p1}}{1+sT_p}\left[\frac{\Delta f_1(s)}{R_1} + \Delta P_{D1}(S) + \Delta P_{tie1}(s)\right] ---------(1)$$

$$\Delta f_2(s) = \frac{-k_{p2}}{1+sT_p}\left[\frac{\Delta f_2(s)}{R_2} + \Delta P_{D2}(S) + \Delta P_{tie2}(s)\right] ---------(2)$$

$$\Delta P_{tie}(s) = \frac{2\Pi T_{12}}{S}\left[\Delta f_1(s) - \Delta f_2(s)\right] ---------(3)$$

For identical case

$\Delta P_{tie2} = -\Delta P_{tie1}$

$a_{12} = 1$

$R_1 = R_2 = 1$

$K_{p1} = K_{p2} = K_p$

From equation (1)

$$\Delta f_1(s)\left[1 + \frac{k_p}{R\left(1+sT_p\right)}\right] = \frac{-k_p}{1+sT_p}\left[\Delta P_{D1}(s) + \Delta P_{tie1}(s)\right]$$

$$\Delta f_1(s)\left[\frac{\left(R+sRT_p\right)+k_p}{R\left(1+sT_p\right)}\right] = \frac{-k_p}{1+sT_p}\left[\Delta P_{D1}(s) + \Delta P_{tie1}(s)\right]$$

$$\Delta f_1(s) = \frac{-k_pR}{R+sRT_p+k_p}\left[\Delta P_{D1}(s) + \Delta P_{tie1}(s)\right]$$

From equation (2)

$$\Delta f_2(s) = \frac{-K_p R}{R+sRT_p+K_p}\left[\Delta P_{D2}(s) + \Delta P_{tie1}(s)\right]$$

Substituting $\Delta f_1(s)$ & $\Delta f_1(s)$ in equation3

$$\Delta P_{tie1}(s) = \frac{2\pi T_{12}}{s}\left[\frac{-k_p R}{R+sRT_p+k_p}\right] \times \left[\Delta P_{D1}(s) - \Delta P_{D2}(s) + 2\Delta P_{tie1}(s)\right]$$

$$\Delta P_{tie1}(s)\left[1+\frac{4\pi T_{12} k_p R}{R+sRT_p+k_p}\right] = \frac{-2\pi T_{12} k_p R}{s(R+sRT_p+k_p)}\left[\Delta P_{D1}(s) - \Delta P_{D2}(s)\right]$$

$$\Delta P_{tie1}(s)\frac{\left[s^2RT_p + s(R+sk_p) + 4\pi T_{12} k_p R\right]}{s\left[sRT_p + (R+k_p\right]} = \frac{2\pi T_{12}}{s}\left[\frac{-k_p R}{R+sRT_p+k_p}\right]\left[\Delta P_{D1}(s) - \Delta P_{D2}(s)\right]$$

$$\Delta P_{tie1}(s) = \frac{-2\pi T_{12} k_p}{T_p\left[s^2 + \left(\frac{R+k_p}{RT_p}\right)s + \frac{4\pi T_{12} k_p}{T_p}\right]}\left[\Delta P_{D1}(s) - \Delta P_{D2}(s)\right]$$

We know $K_p = 1/B$

$$\Delta P_{tie1}(s) = \frac{-2\pi T_{12}\left[\Delta P_{D1}(s) - \Delta P_{D2}(s)\right]}{T_p B\left[s^2 + \left(\frac{R+\frac{1}{B}}{RT_p}\right)s + \frac{4\pi T_{12}}{BT_p}\right]}$$

Power system time constant

$$T_p = \frac{2H}{Bf_o}$$

$$\Delta P_{tie1}(s) = \frac{2\pi T_{12}\,[\Delta P_{D2}(s) - \Delta P_{D1}(s)]}{\frac{2H}{f_o}\left[s^2 + \left(\frac{RB+1}{\frac{2HR}{f_o}}\right)s + \frac{4\pi T_{12}}{\frac{2H}{Bf_o}}\right]}$$

$$\Delta P_{tie1}(s) = \frac{2\pi T_{12} f_o\,[\Delta P_{D2}(s) - \Delta P_{D1}(s)]}{2H\left[s^2 + \frac{f_o}{2H}\left(B + \frac{1}{R}\right)s + \frac{2\pi T_{12} f_o}{H}\right]}$$

$S^2 + 2\alpha S + \omega^2 = (S+\alpha)^2 + \omega^2$ -

Where,

$$\alpha = \frac{f_o}{4H}\left(B + \frac{1}{R}\right)$$

$$\omega^2 = \frac{2\pi T_{12} f_o}{H}$$

Since α & ω^2 are positive, therefore, the system is stable & damped. The roots of the characteristic equation are

$$S_{1,2} = \frac{-2\alpha \pm \sqrt{(2\alpha)^2 - 4\omega^2}}{2} = -\alpha \pm \sqrt{\alpha^2 - \omega^2}$$

We have three conditions. α^2

1. If α = ω the system is critically damped, the roots becomes, $S_{1,2} = \omega$

2. If α > ω the system is critically damped, the roots becomes,

$$S_{1,2} = -\alpha \pm \sqrt{\alpha^2 - \omega^2}$$

3. If α < ω the system is critically damped, the roots becomes,

$$S_{1,2} = -\alpha \pm \sqrt{\omega^2 - \alpha^2}$$

$$S_{1,2} = -\alpha \pm j\omega_d$$

Where,

α = Damping Factor

ω_d = Damped Angular Frequency

$\omega_d = \sqrt{\omega^2 - \alpha^2}$

$$\sqrt{\frac{2\pi T_{12} f_0}{H} - \left[\frac{f_0}{4H}\left(B + \frac{1}{R}\right)\right]^2}$$

Assume the load not varying with frequency B=0

$$\therefore \ \alpha = \frac{f_0}{4HR}$$

The system damping is strongly dependent upon the α parameter. Since f_0 and H = constant.

The damping will be a function of R. Low value of R will give strong damping. High value of R will give weak damping.

If R=α, ω_d=ω

Where,

ω = natural angular frequency (ie) there is not speed governor action. The system will perform un-damped oscillation.

Dynamic response of two identical area systems.

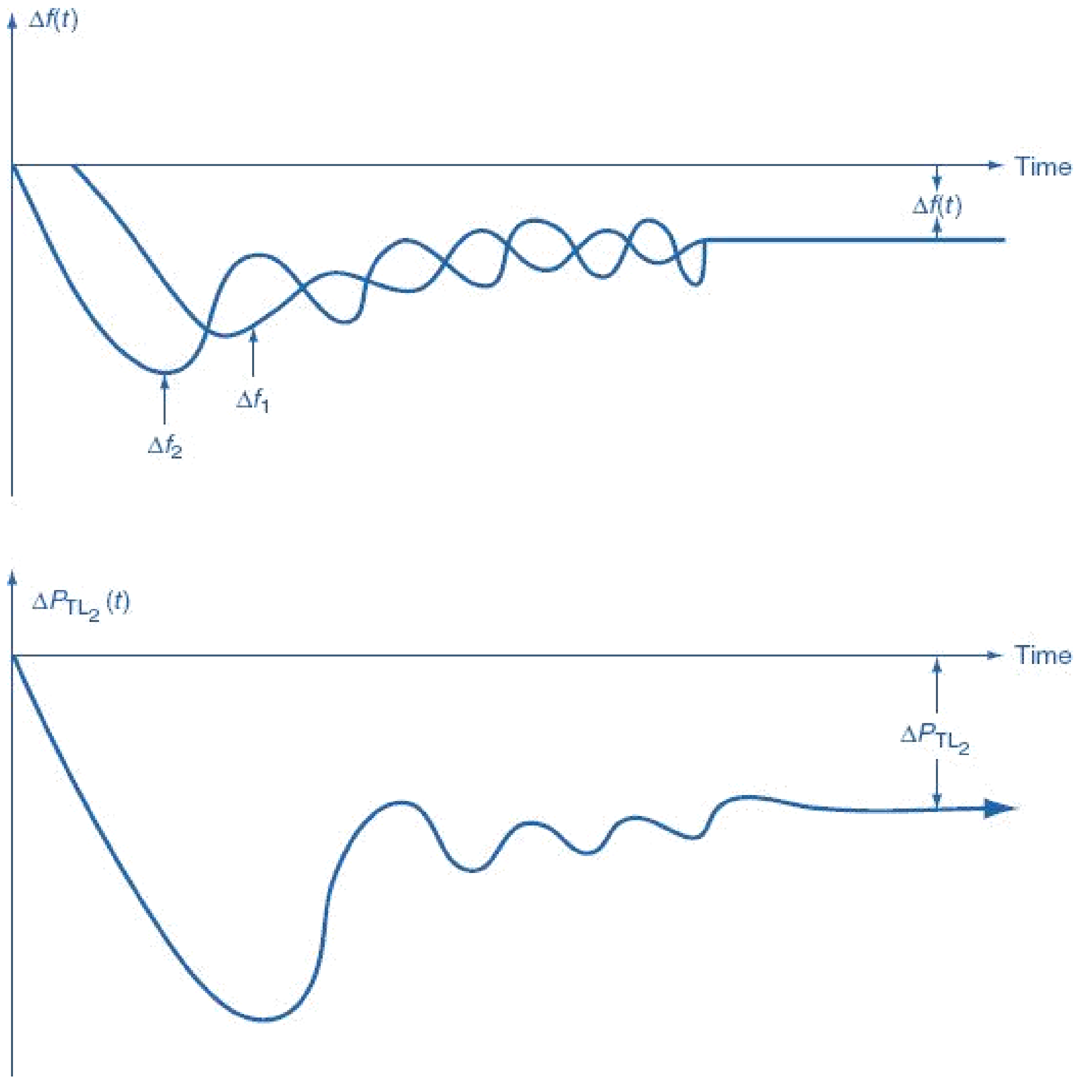


Figure 3.5 Dynamic response of two identical area systems.

ADVANTAGES OF TWO AREA CONTROL OF MUTIAREA SYSTEM

1. Under normal operating conditions besides meeting respective area loads, scheduled interchange between areas can take place.
2. Under abnormal conditions, such as loss of generation in area, power can flow from other areas, through the interconnection.
3. Such pool operation where mutual assistance is possible which reduces the reserve capacity need.

4. For a large with many areas, the kinetic energy of the rotator inertia is high. A sudden load change may not cause any considerable transient frequency deviation.

3.7 LOAD FREQUENCY CONTROL AND ECONOMIC DISPATCH CONTROL

Load frequency Control and Economic Dispatch Control – Load frequency control with integral controller achieves zero steady state frequency error and a fast dynamic response, but it exercises no control over the relative loadings of various generating stations (i.e. economic dispatch) of the control area. For example, if a sudden small increase in load (say, 1%) occurs in the control area, the load frequency control changes the speed changer settings of the governors of all generating units of the area so that, together, these units match the load and the frequency returns to the scheduled value (this action takes place in a few seconds).

However, in the process of this change the loadings of various generating units change in a manner independent of economic loading considerations. In fact, some units in the process may even get overloaded. Some control over loading of individual units can be exercised by adjusting the gain factors (Ki) included in the signal representing integral of the area control error as fed to individual units. However, this is not satisfactory.

A satisfactory solution is achieved by using independent controls for load frequency and economic dispatch. While the load frequency controller is a fast acting control (a few seconds), and regulates the system around an operating point; the economic dispatch controller is a slow acting control, which adjusts the speed changer setting every minute (or half a minute) in accordance with a command signal generated by the central economic dispatch computer.

Figure gives the schematic diagram of both these controls for two typical units of a control area. The signal to change the speed changer setting is constructed in accordance with economic dispatch error, [PG (desired) — PG (actual)], suitably modified by the signal representing integral ACE at that instant of time. The signal PG (desired) is computed by the central economic dispatch computer (CEDC) and is transmitted to the local economic dispatch controller (EDC) installed at each

station. The system thus operates with economic dispatch error only for very short periods of time before it is readjusted.

UNIT IV

REACTIVE POWER CONTROL

In an ideal AC-power system, the voltage and the frequency at every supply point would remain constant, free from harmonics and the power factor (p.f.) would remain unity. For the optimum performance at a particular supply voltage, each load could be designed such that there is no interference between different loads as a result of variations in the current taken by each one.

Most electrical power systems in the world are interconnected to achieve reduced operating cost and improved reliability with lesser pollution. In a power system, the power generation and load must balance at all times. To some extent, it is self-regulating. If an unbalance between power generation and load occurs, then it results in a variation in the voltage and the frequency. If voltage is propped up with reactive power support, then the load increases with a consequent drop in frequency, which may result in system collapse. Alternatively, if there is an inadequate reactive power, the system's voltage may collapse.

Here, the quality of supply means maintaining constant-voltage magnitude and frequency under all loading conditions. It is also desirable to maintain the three-phase currents and voltages as balanced as possible so that under heating of various rotating machines due to unbalancing could be avoided. In a three-phase system, the degree to which the phase currents and voltages are balanced must also be taken into consideration to maintain the quality of supply.

To achieve the above-mentioned requirements from the supply point of view as well as the loads, which can deteriorate the quality of supply, we need load compensation. Load compensation is the control of reactive power to improve the quality of supply in an AC-power system by installing the compensating equipment near the load.

The objectives of load compensation are:

i. Power Factor Correction.

ii. Voltage regulation improvement.

iii. Balancing of load.

Power Factor Correction: Generally, load compensation is a local problem. Most of the industrial loads absorb the reactive power since they have lagging p.f.'s. The load current tends to be larger than it is required to supply the real power alone. So, p.f. correction of load is achieved by generating reactive power as close as possible to the load, which requires it to generate it at a distance and transmit it to the load, as these results not only in a large conductor size but also in increased losses. It is desirable to operate the system near unity p.f. economically.

Voltage regulation improvement: All loads vary their demand for reactive power, although they differ widely in their range and rate of variation. The voltage variation is due to the imbalance in the generation and consumption of reactive power in the system. If the generated reactive power is more than that being consumed, voltage levels go up and vice versa. However, if both are equal, the voltage profile becomes flat. The variation in demand for reactive power causes variation (or regulation) in the voltage at the supply point, which can interfere with an efficient operation of all plants connected to that point. So, different consumers connected to that point get affected. To avoid this, the supply utility places bounds to maintain supply voltages within defined limits. These limits may vary from typically ± 6% averaged over a period of a few minutes or hours. To improve voltage regulation, we should strengthen the power system by increasing the size and number of generating units as well as by making the network more densely interconnected. This approach would be uneconomic and would introduce problems such as high fault levels, etc. In practice, it is much more economic to design the power system according to the maximum demand for active power and to manage the reactive power by means of compensators locally.

Load balancing: Most power systems are three-phased and are designed for balanced operation since their unbalanced operation gives rise to wrong phase sequence components of currents (negative and zero-sequence components). Such components produce undesirable results such as additional losses in motors, generators, oscillating torque in AC machines, increased ripples in rectifiers, saturation of transformers, excessive natural current, and so on. These undesirable effects are caused mainly due to the harmonics produced under an unbalanced operation. To suppress these harmonics, certain types of equipment including compensators are provided, which yield the balanced operation of the power system.

IDEAL COMPENSATOR

An ideal compensator is a device that can be connected at or near a supply point and in parallel with the load. The main functions of an ideal compensator are instantaneous p.f. correction to unity, elimination or reduction of the voltage regulation, and phase balance of the load currents and voltages. In performing these interdependent functions, it will consume zero power. The characteristics of an ideal compensator are to:

- Provide a controllable and variable amount of reactive power without any delay according to the requirements of the load,
- Maintain a constant-voltage characteristic at its terminals, and
- Should operate independently in the three phases.

SPECIFICATIONS OF LOAD COMPENSATION

The specifications of load compensation are:

- ✓ Maximum and continuous reactive power requirement in terms of absorbing as well as generation.
- ✓ Overload rating and duration.
- ✓ Rated voltage and limits of voltage between which the reactive power rating must not be exceeded.
- ✓ Frequency and its variation.
- ✓ Accuracy of voltage regulation requirement.
- ✓ Special control requirement.
- ✓ Maximum harmonic distortion with compensation in series.
- ✓ Emergency procedure and precautions.
- ✓ Response time of the compensator for a specified disturbance.
- ✓ Reliability and redundancy of components.

THEORY OF LOAD COMPENSATION

Power Factor Correction: Consider a single-phase load with admittance YL = GL + jBL with a source voltage as shown in Fig. 4.1(a).

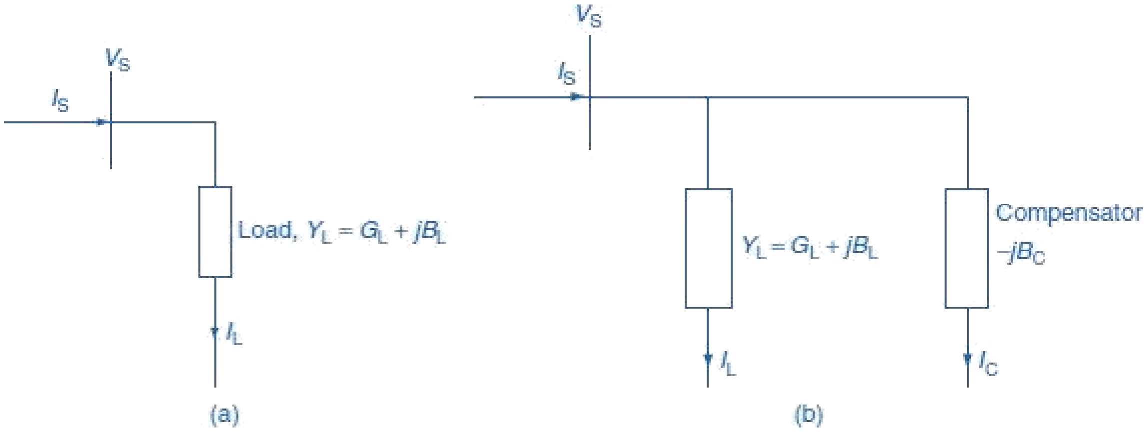


FIG. Representation of single-phase load; (a) without compensation; (b) with compensation

The load current I_L is given by I_L = Vs (GL + jBL) = Vs GL + jVsBL = $I_a + jI_r$

Apparent power of the load, $S_L = V_s I_L^* = V_S^2 G_L - jV_S^2 B_L$ = PL + jQL

Where P_L is the active power of the load and QL the reactive power of the load. For inductive loads, B_L is negative and QL is positive by convention. The current supplied

to the load is larger than when it is necessary to supply the active power alone by the factor.

The objective of the p.f. correction is to compensate for the reactive power, i.e., locally providing a compensator having a purely reactive admittance jBC in parallel with the load as shown in Fig. 4.1(b). The current supplied from the source with the compensator is

Is = IL + IC

= Vs (GL + jBL) – Vs (jBC) = VsGL = Ia (∵ BL = BC)

which makes the p.f. to unity, since Ia is in phase with the source voltage Vs. The current of the compensator, Ic = VsYc = −jVsBc

The apparent power of the compensator, Sc = VsIc*

Sc = jVs2 BC = −jQC (∵ SC = PC − jQC, for pure compensation PC = 0) We know that QL = PL tan ϕL

For a fully compensated system, i.e., QL=QC

$$\therefore Q_C = S_L \sin\phi_L$$
$$= S_L\sqrt{1-\cos^2\phi_L} \quad (\because \sin^2 Q_L + \cos^2 Q_L = 1)$$

The degree of compensation is decided by an economic trade-off between the capital cost of the compensator and the savings obtained by the reactive power compensation of the supply system over a period of time.

Voltage regulation: It is defined as the proportional change in supply voltage magnitude associated with a defined change in load current, i.e., from no-load to full load. It is caused by the voltage drop in the supply impedance carrying the load current. When the supply system is balanced, it can be represented as single phase model as shown in Fig. 4.2(a).

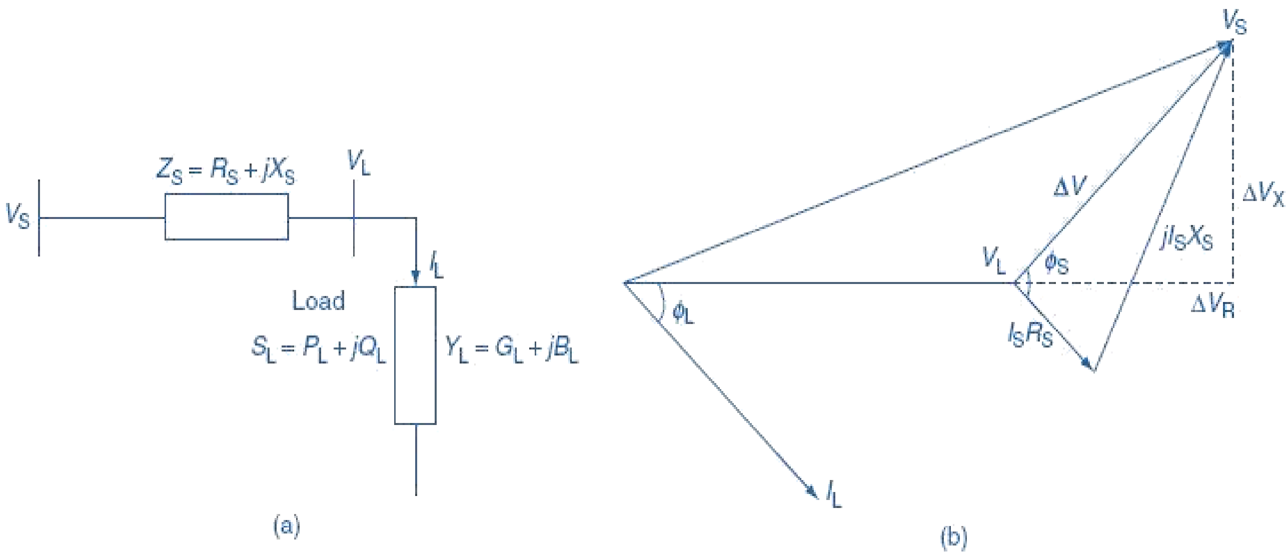


FIG. (a) Circuit model of an uncompensated load and supply system; (b) phasor diagram for an uncompensated system

The voltage regulation is given by

$$\frac{|V_s| - |V_L|}{|V_L|}$$

Where |VL| is the load voltage.

Without compensator: From the phasor diagram of an uncompensated system, shown in Fig. (b), the change in voltages is given by $\Delta V = V_s - V_L = Z_s I_L$ -----(1)

Where Zs = Rs + jXs & the load current,

$$I_L = \frac{P_L - jQ_L}{V_L} \quad \text{------------- (2)}$$

Substituting Zs and IL in Equation (1), we get

$$\therefore \Delta V = (R_s + jX_s)\left(\frac{P_L - jQ_L}{V_L}\right)$$

$$= \frac{R_s P_L + X_s Q_L}{V_L} + j\frac{X_s P_L - R_s Q_L}{V_L} \quad \text{----------- (3)}$$

$$\Delta V = \Delta V_R + j\Delta V_X$$

From Equation (3), it is observed that the change in voltage depends on both real and reactive powers of the load considering the line parameters to be constant.

With compensator: In this case, a purely reactive compensator is connected across the load as shown in Fig. 4.3(a) to make the voltage regulation zero, i.e., the supply voltage (|Vs|) equals the load voltage (|VL|). The corresponding phasor diagram is shown in Fig. (b).

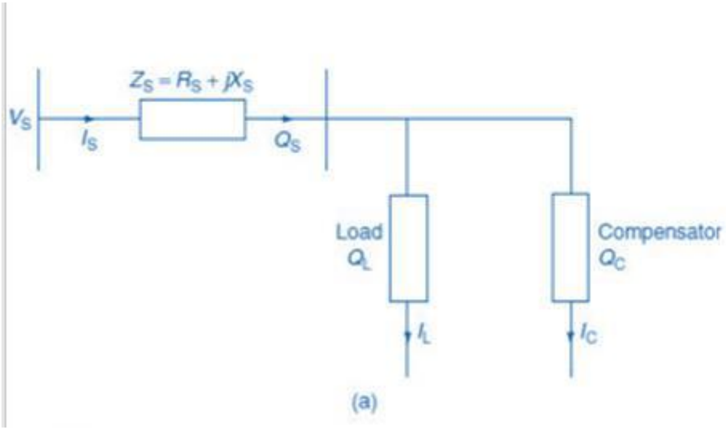
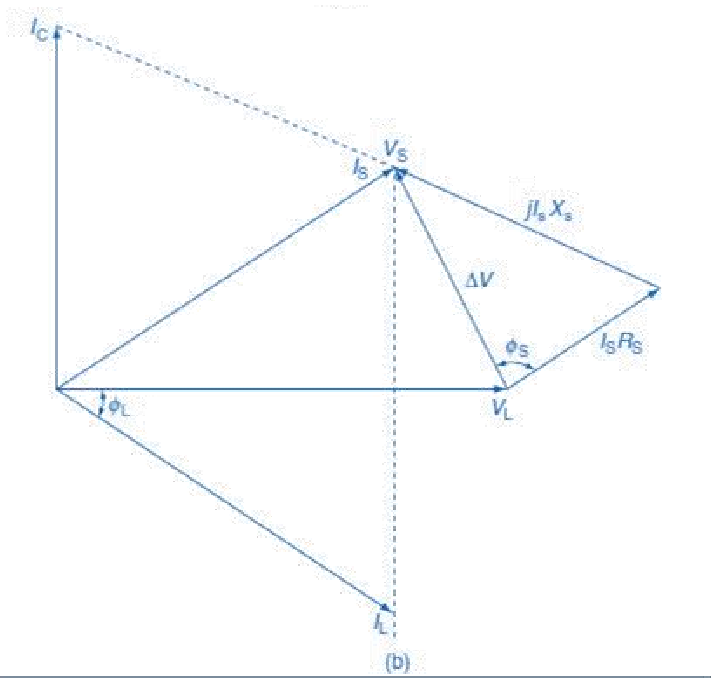


FIG.4.3 (a) Circuit model of a compensated load and supply system; (b) phasor diagram for a compensated system The supply reactive power with a compensator is Qs = QC + QL QC is adjusted in such a way that ΔV = 0 i.e., |Vs| = |VL|

From Equations (1) and (3), we get



$$|V_s^2| = \left[|V_L| + \frac{R_s P_L + X_s Q_s}{|V_L|}\right]^2 + \left[\frac{X_s P_L - R_s Q_s}{V_L}\right]^2 \quad \text{------------ (4)}$$

Simplifying and rearranging equation (4),

$$|V_s^2| = |V_L^2| + \left[\frac{R_s P_L + X_s Q_s}{|V_L^2|}\right]^2 + 2(R_s P_L + X_s Q_s) + \frac{X_s^2 P_L^2 + R_s^2 Q_s^2 - 2X_s P_L R_s Q_s}{|V_L^2|}$$

$$= |V_L^2| + \frac{R_s^2 P_L^2 + X_s^2 Q_s^2 + 2R_s P_L Q_s X_s}{|V_L^2|} + 2(R_s P_L + X_s Q_s) + \frac{X_s^2 P_L^2 + R_s^2 Q_s^2 - 2X_s P_L R_s Q_s}{|V_L^2|}$$

$$|V_s^2 V_L^2| = |V_L^4| + R_s^2 P_L^2 + X_s^2 Q_s^2 + 2(R_s P_L + X_s Q_s)|V_L^2| + X_s^2 P_L^2 + R_s^2 Q_s^2$$

$$= Q_s^2(R_s^2 + X_s^2) + Q_s(2|V_L^2|X_s) + |V_L^4| + P_L^2(R_s^2 + X_s^2) + 2R_s P_L |V_L^2|$$

$$\therefore Q_s^2(R_s^2 + X_s^2) + Q_s(2|V_L^2|X_s) + |V_L^4| + P_L^2(R_s^2 + X_s^2) + 2R_s P_L |V_L^2| - |V_s^2 V_L^2| = 0$$

The above equation can be represented in a compact form as aQs2 + bQs + c = 0 where

$$a = R_s^2 + X_s^2$$

$$b = 2|V_L^2|X_s$$

$$c = (V_L^2 + R_S P_L)^2 + X_S^2 P_L^2 - |V_S^2 V_L^2|$$

$$Q_S = \frac{-b \pm \sqrt{b^2 - 4ac}}{2a}$$

The value of QC is found using the above equation by using the compensator reactive power balance equation |Vs| = |VL| and QC = Qs – QL. Here, the compensator can perform as an ideal voltage regulator, i.e., the magnitude of the voltage is being controlled, its phase varies continuously with the load current, whereas the compensator acting as a p.f. corrector reduces the reactive power supplied by the system to zero i.e., Qs = 0 = QL + QC. Equation (3) can be reduced to

$$\Delta V = \frac{R_S P_L + jX_S P_L}{V_L} = (R_S + jX_s)\frac{P_L}{V_L} \quad \text{------------ (5)}$$

So, ΔV is independent of the load reactive power.

From this, we conclude that a pure reactive compensator cannot maintain both constant voltage and unity p.f. simultaneously.

4.2 UNCOMPENSATED TRANSMISSION LINES (For Reference)

An electric transmission line has four parameters, which affect its ability to fulfill its function as part of a power system and these are a series combination of resistance, inductance, shunt combination of capacitance, and conductance. These parameters are symbolized as R, L, C, and G, respectively. These parameters are distributed along the whole length at any line. Each small length at any section of the line will have its own values and concentration of all such parameters for the complete length of line into a single one is not possible. These are usually expressed as resistance, inductance, and capacitance per kilometer. Shunt conductance that is mostly due to the breakage over the insulators is almost always neglected in a power transmission line. The leakage loss in a cable is uniformly distributed over the length of the cable, whereas it is different in the case of overhead lines. It is limited only to the insulators and is very small under normal operating conditions. So, it is neglected for an overhead transmission line.

Fundamental transmission line equation: Consider a very small element of length Δx at a distance of x from the receiving end of the line. Let z be the series impedance per unit length, y the shunt admittance per unit length, and l the length of the line.

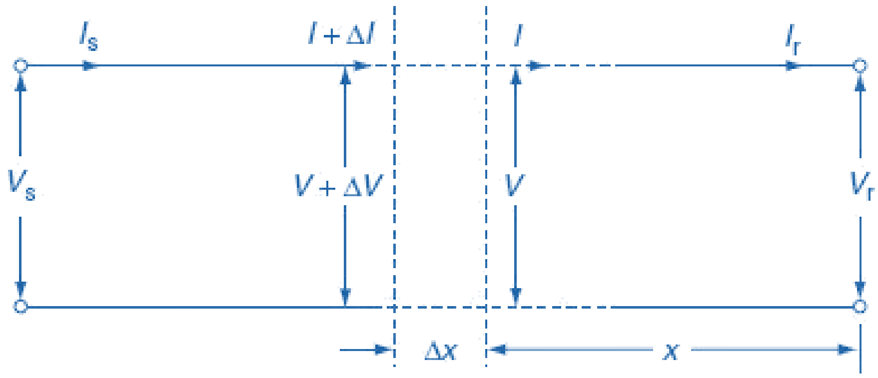


FIG. 4.4 Representation of a transmission line on a single-phase basis

Then,

Z = zl = total series impedance of the line Y = yl = total shunt admittance of the line

The voltage and current at a distance x from the receiving end are V and I, and at distance x + Δx are V + ΔV and I + ΔI, respectively (Fig. 4.4). So, the change of voltage, ΔV = IzΔx, where zΔx is the impedance of the element considered:

$$\frac{\Delta V}{\Delta x} = Iz$$

$$\underset{\Delta x \to 0}{\mathrm{Lt}} \frac{\Delta V}{\Delta x} = \frac{dV}{dx} = Iz \qquad \text{----------- (6)}$$

Similarly, the change of current, ΔI = VyΔx, where yΔx is the admittance of the element considered:

$$\frac{\Delta I}{\Delta x} = Vy$$

$$\lim_{\Delta x \to 0} \frac{\Delta I}{\Delta x} = \frac{dI}{dx} = Vy \quad \text{----------} (7)$$

Differentiating Equation (9.6) with respect to x, we get

$$\frac{d^2V}{dx^2} = z\frac{dI}{dx} \quad \text{---------------} (8)$$

Substituting the value (di/dx) of from Equation (7) in Equation (8), we get

$$\frac{d^2V}{dx^2} = zyV \quad \text{------------} (9)$$

Equation (9) is a second-order differential equation and its solution is

$$V_{(x)} = Ae^{\sqrt{yz}\,x} + Be^{-\sqrt{yz}\,x} \quad \text{------------} (10)$$

Differentiating Equation (10) with respect to x, we get

$$\frac{dV_{(x)}}{dx} = A\sqrt{yz}\,e^{\sqrt{yz}\,x} - B\sqrt{yz}\,e^{-\sqrt{yz}\,x} \quad \text{----------} (11)$$

$$\therefore I(x) = A\sqrt{\frac{y}{z}}\,e^{\sqrt{zy}\,x} - B\sqrt{\frac{y}{z}}\,e^{-\sqrt{zy}\,x} \quad \text{-----------} (12)$$

From Equations (6) and (11), we have

From Equation (10), we have

$V(x) = Ae^{\gamma x} + Be^{-\gamma x}$---------------------(13)

From Equation (12), we have

$$I_{(x)} = \frac{A}{Z_C}e^{-\gamma x} + \frac{B}{Z_C}e^{-\gamma x} \quad \text{-----------} (14)$$

Where Z_C is known as characteristic impedance or surge impedance

The propagation constant.

The constants A and B can be evaluated by using the conditions at the receiving end of the line.

The conditions are

at x = 0, V = Vr and I = Ir

Substituting the above conditions in Equations (11) and (12), we get ∴ Vr = A + B-(15)

And

$$I_r = \frac{1}{Z_C}(A - B) \qquad \text{----------} (16)$$

Solving Equations (15) and (16), we get

$$A = \frac{V_r + I_r Z_C}{2} \quad \text{and} \quad B = \frac{V_r - I_r Z_C}{2}$$

Now, substituting the values of A and B in Equations (13) and (14), then we get

$$V_{(x)} = \frac{V_r + I_r Z_C}{2} e^{\gamma x} + \frac{V_r - I_r Z_C}{2} e^{-\gamma x}$$

$$= V_r \left[\frac{e^{\gamma x} + e^{-\gamma x}}{2}\right] + I_r Z_C \left[\frac{e^{\gamma x} - e^{-\gamma x}}{2}\right]$$

$$\therefore V_{(x)} = V_r \cos h\, \gamma x + I_r Z_C \sin h\, \gamma x \qquad \text{----------} (17)$$

$$I_{(x)} = \frac{1}{Z_C}\left[\frac{V_r + I_r Z_C}{2} e^{\gamma x} - \frac{V_r - I_r Z_C}{2} e^{-\gamma x}\right]$$

$$= \frac{1}{Z_C} V_r \left(\frac{e^{\gamma x} - e^{-\gamma x}}{2}\right) + I_r \left(\frac{e^{\gamma x} + e^{-\gamma x}}{2}\right)$$

$$\therefore I_{(x)} = \frac{V_r}{Z_C} \sin h\, \gamma x + I_r \cos h\, \gamma x \qquad \text{----------} (18)$$

where V(x) and I(x) are the voltages and currents at any distance x from the receiving end. For a lossless line γ = jβ and the hyperbolic functions,

i.e., cos h γ x = cos h jβx = cos βx and sin h γ x = sin h jβx = j sin βx.

Therefore, Equations (17) and (18) can be modified as

$$V_{(x)} = V_r \cos \beta x + jI_r Z_C \sin \beta x \qquad \text{------------} (19)$$

And

$$I_{(x)} = j\frac{V_r}{Z_C} \sin \beta x + I_r \cos \beta x \qquad \text{-----------} (20)$$

Where β is the electrical length of the line (radians or wavelength)

$$\beta = \omega\sqrt{LC} = \frac{2\pi f}{\upsilon} = \frac{2\pi}{\lambda}$$

$$\upsilon = \text{velocity of light} = 3 \times 10^8 \text{ m/s}$$
$$\lambda = \text{wavelength of light}$$

Characteristic impedance

The quantity z is a complex number as y and z are in complex. It is denoted by ZC or

Z0. It has the y

dimension of impedance, since

$$\sqrt{\frac{z}{y}} = \sqrt{\frac{\text{ohms/unit length}}{\text{ohms/unit length}}} = \text{ohms}$$

$$Z_c = \sqrt{\frac{z}{y}} = \sqrt{\frac{r + j\omega L}{g + j\omega C}}$$

For a lossless line, r = g = 0, the characteristic impedance becomes

$$Z_C = \sqrt{\frac{L}{C}}$$

The characteristic impedance is also called the surge or natural impedance of the line.

The approximate value of the surge impedance for overhead lines is 400 Ω and that for underground cables is 40 Ω, and the transformers have several thousand ohms as their surge impedance. Surge impedance is the impedance offered to the propagation of a voltage or current wave during its travel along the line.

Surge impedance or natural loading

The surge impedance loading (SIL) of a transmission line is the MW loading of a transmission line at which a natural reactive power balance occurs (zero resistance).

$$\therefore \text{SIL (MW)}, \quad P_0 = \frac{V_{L-L}^2}{\text{surge impedance}}$$

4.3 UNCOMPENSATED LINE WITH OPEN CIRCUIT

In this section, we shall discuss the cases: (a) voltage and current profiles, (b) symmetrical line at no- load, and (c) under excited operation of generators.

(a) Voltage and current profiles

A lossless line is energized at the sending end and is open-circuited at the receiving end. From Equations (19) and (20) with I r = 0

$$V(x) = V_r \cos \beta x \text{ ---------------------(25)}$$

$$I(x) = j\left[\frac{V_r}{Z_c}\right]\sin \beta x \qquad \text{--------------- (26)}$$

Voltage and current at the sending end are given by equations with x = l as V(x) = Vs, I(x) = I (s)

$$V_s = V_r \cos\theta \text{ ------------------------------------ (27)}$$

where θ = βl

$$I_s = j\left[\frac{V_r}{Z_c}\right]\sin\theta = j\left[\frac{V_s}{Z_c}\right]\tan\theta \quad \left(\because V_r = \frac{V_s}{\cos\theta}\right) \qquad \text{----------- (28)}$$

Equations (25) and (26) are modified as

$$V(x) = V_s \frac{\cos\beta x}{\cos\theta} \quad \left(\because V_r = \frac{V_s}{\cos\theta}\right) \qquad \text{-------------- (29)}$$

And the current profile equation,

$$I(x) = j\frac{V_s}{Z_c}\frac{\sin\beta x}{\cos\theta} \qquad \text{------------ (30)}$$

(b) The symmetrical line at no-load

This is similar to an open-circuited line energized at one end. This is a line identical at both ends, but with no power transfer. Suppose the terminal voltages are maintained as same values, i.e., Vs = Vr From Equations (19) and (20) with x = l, We have Vs = Vr cos θ + j Zc Ir sin θ ----------------- (31)

$$I_s = j\left[\frac{V_r}{Z_c}\right]\sin\theta + I_r\cos\theta \qquad \text{-------------- (32)}$$

The electrical conditions are the same (Vs = Vr); there would not be any power transfer. Therefore, by symmetry Is = -Ir. Substituting the above condition in Equations (32), we get

$$\therefore -I_r = j\left[\frac{V_r}{Z_c}\right]\frac{\sin\theta}{1+\cos\theta} \qquad \text{----------------- (33)}$$

$$= j\frac{V_r}{Z_c}\tan\frac{\theta}{2} \qquad \text{-------------- (34)}$$

Substituting Equation (33) in Equation (31), we get

From Equation. (34), we have

$$V_s = V_r\cos\theta + j\,Z_c\left\{-j\left[\frac{V_r}{Z_c}\right]\frac{\sin\theta}{1+\cos\theta}\right\}\sin\theta$$

$$= \frac{V_r(\cos\theta + \cos^2\theta + \sin^2\theta)}{1+\cos\theta} \qquad \text{--------------- (35)}$$

$$\therefore V_s = V_r$$

$$I_s = j\frac{V_s}{Z_c}\tan\frac{\theta}{2} \quad (\because V_s = V_r; I_s = -I_r) \qquad \text{------------ (36)}$$

A comparison of Equations (35) and (36) with Equation (28) shows that the line is equivalent to two equal halves connected back-to back. Half the line-charging current is supplied from each end. By symmetry, the midpoint current is zero, whereas the midpoint voltage is equal to the open-circuit voltage of the line having half the total length. From Equation (31) the midpoint voltage is

$$V_m = \frac{V_s}{\cos\left(\frac{\theta}{2}\right)} \quad (\because V_r = V_m; \quad I_r = 0)$$

(c) Under excited operation of generators due to line-charging

No load at the receiving ends, i.e., Ir = 0. The charging reactive power at the sending end is Qs = Imag (VsIs*)

From Equation (28), we have

Line-charging current at the sending end,

$$I_s = j\left[\frac{V_s}{Z_c}\right]\tan\theta$$

∴ Line-charging power at the sending end, Qs = −P0 tan θ

For a 300-km line, Qs is nearly 43% of the natural load expressed in MVA. At 400 kV, the generators would have to absorb 172 MVAr. The reactive power absorption capability of a synchronous machine is limited for two reasons:

- The heating of the ends of the stator core increases during under excited operation.
- The reduced field current results in reduced internal e.m.f of the machine and this weakens the stability.

Using a compensator, this problem can be reduced by two ways:

- If the line is made up of two (or) more parallel circuits, one (or) more of the circuits can be switched off under light load (or) open-circuit conditions.
- If the generator absorption is limited by stability and not by core-end heating, the absorption limit can be increased by using a rapid response excitation system, which restores the stability margins when the steady-state field current is low. The under-excited operation of generators can set a more stringent limit to the maximum length of an uncompensated line than the open- circuit voltage rise.

4.4 THE UNCOMPENSATED LINE UNDER LOAD

In this section, the effects of line length, load power, and p.f. on voltage as well as reactive power are discussed.

Radial line with fixed sending-end voltage: A load (Pr+jQr) at the receiving end of a radial line draws the current. i.e.,

$$I_r = \frac{P_r - jQ_r}{V_r}$$

From Equation (19), with x = l, for a lossless line, the sending-and receiving-end voltages are related as

$$V_s = V_r \cos\theta + jZ_c \sin\theta\left(\frac{P_r - jQ_r}{V_r}\right) \qquad \text{----------------- (37)}$$

If Vs is fixed, this quadratic equation can be solved for Vr. The solution gives how Vr varies with the load and its p.f. as well as with the line length. Several fundamental important properties of AC transmission are evident from Fig. 4.5.

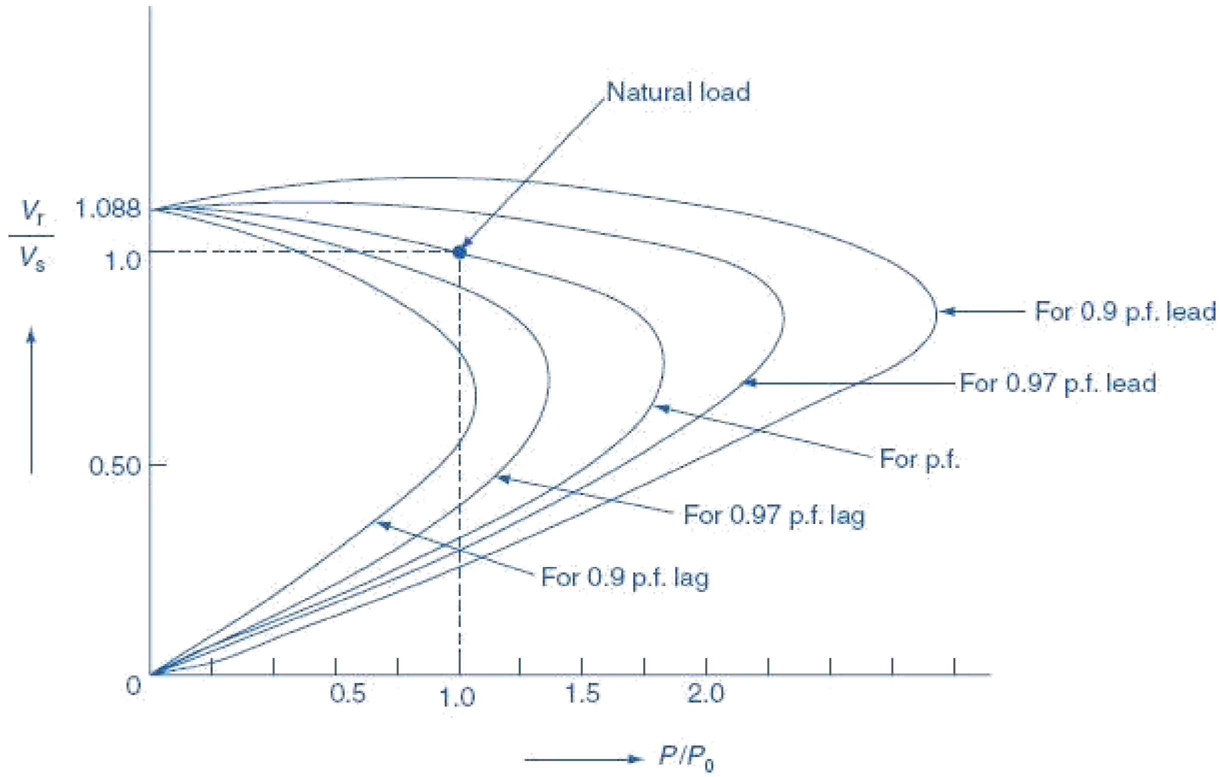


FIG. 4.5 Magnitude of receiving-end voltage as a function of load and load p.f.

- For each load p.f., there is a maximum transmissible power.
- The load p.f. has a strong influence on the receiving-end voltage.
- Uncompensated lines between about 150-km and 300-km long can be operated at normal voltage provided that the load p.f. is high. Longer lines, with large voltage variations, are impractical at all p.f.'s unless some means of voltage

compensation is provided.

The midpoint voltage variation on a symmetrical 300-km line is the same as the receiving-end voltage variations on a 150-km line with a unity p.f. load.

Reactive power requirements: From the line voltage and the level of power transmission, the reactive power requirements can be determined. It is very important to know the reactive power requirements because they determine the reactive power ratings of the synchronous machines as well as those of any compensating equipment. If any inductive load is connected at the sending end of the line, it will support the synchronous generators to absorb the line-charging reactive power. With the absence of the compensating equipment, the synchronous machines must absorb or generate the difference between the line and the local load reactive powers.

The equations of voltage and current for the sending-end half of the symmetrical line is

$$V_s = V_m \cos\frac{\theta}{2} + jZ_0 I_m \sin\frac{\theta}{2} \quad (\because V_r = V_m ; I_r = I_m) \text{ -------------- } (38)$$

$$I_s = j\frac{V_m}{Z_0}\sin\frac{\theta}{2} + I_m \cos\frac{\theta}{2} \text{ -------------- } (39)$$

The power at midpoint is

Pm+jQm = VmIm* = P = transmitted power

Since Qm = 0, because no reactive power flows at the midpoint. The power at the sending end is Ps + j Qs = VsIs*

Substituting Vs and Is from Equations (38) and (39) in the above equation, we get

$$P_s + j\,Q_s = P + j\frac{\sin\theta}{2}\left[Z_0 I_m^2 + \frac{V_m^2}{Z_0}\right]$$

If the line is assumed to be lossless, then Ps = Pr = P

$$\therefore Q_s = P_0\frac{\sin\theta}{2}\left[\left(\frac{P}{P_0}\right)^2\left(\frac{V_0}{V_m}\right)^2 - \left(\frac{V_m}{V_0}\right)^2\right]$$

The above expression gives the relation between the midpoint voltage and the reactive power requirements of the symmetrical line. If the terminal voltages are continuously adjusted so that the midpoint voltage, Vm = V0 = 1.0 p.u. at all levels of power transmission

$$\therefore Q_s = P_0 \frac{\sin\theta}{2}\left(\left(\frac{P}{P_0}\right)^2 - 1\right)$$

The uncompensated line under load with consideration of maximum power and stability:

Consider Equation (37) as

$$V_s = V_r \cos\theta + jZ_c\left(\frac{P_r - jQ_r}{V_r}\right)\sin\theta \qquad \text{------------ (40)}$$

If Vr is taken as reference phasor, then:

$$V_s = V_s e^{j\delta} = V_s(\cos\delta + j\sin\delta) \text{----------------- (41)}$$

Where δ is the phase angle between Vs and Vr and is called the load angle (or) the transmission angle. Equating real and imaginary parts of Equations (40) and (41), we get

$$V_s \cos\delta = V_r\cos\theta + Z_c\frac{Q_r}{V_r}\sin\theta$$

$$V_s \sin\delta = Z_c\frac{P_r}{V_r}\sin\delta$$

$$\therefore P_r = \frac{V_s V_r}{Z_c \sin\theta}\sin\delta \qquad \text{(since neglecting the losses)}$$

For an electrically short line, $\sin\theta = \theta = \beta l$:

$$\beta l = \omega l\sqrt{LC}$$

Then,

$$Z_c\theta = \sqrt{\frac{L}{C}}\left(\omega l\sqrt{LC}\right) = \omega L = X_L,$$

the series reactance of the line:

$$\therefore P_r \approx \frac{V_s V_r}{X_L}\sin\delta$$

$$= P_{max}\sin\delta$$

Where

$$P_{max} = \frac{V_s V_r}{X_L}$$

4.5 COMPENSATED TRANSMISSION LINES

The change in the electrical characteristics of a transmission line in order to increase its power transmission capability is known as line compensation. While satisfying the requirements for a transmission system (i.e., synchronism, voltages must be kept near their rated values, etc.), a compensation system ideally performs the following functions:

- It provides the flat voltage profile at all levels of power transmission.
- It improves the stability by increasing the maximum transmission capacity.
- It meets the reactive power requirements of the transmission system economically.

The following types of compensations are generally used for transmission lines:

i. Virtual-Z0.

ii. Virtual-θ.

iii. Compensation by sectioning.

The effectiveness of a compensated system is gauged by the product of the line length and maximum transmission power capacity. Compensated lines enable the $\sqrt{X_L X_c}$ transmission of the natural load over larger distances, and shorter compensated lines can carry loads more than the natural load. The flat voltage profile can be achieved if the effective surge impedance of the line is modified as to a virtual value Z0′, for which the corresponding virtual natural load $\left(\frac{V^2(kV)}{Z_0'}\right)$ is equal to the actual load. The surge impedance of the uncompensated line, which can be writtenas, if the series and /or the shunt reactance XL and/or Xc are modified, respectively. Then, the line can be made
to have virtual surge impedance Z0′ and a virtual natural load P′ for which $P' = \frac{V^2(kV)}{Z_0'}$ Compensation of line, by which the uncompensated surge impedance Z0 is modified to virtual surge impedance Z0′, is called virtual surge impedance compensation or virtual Z0 compensation.

Once a line is computed for Z0, the only way to improve stability is to reduce the effective value of θ. Two alternative compensation strategies have been developed to achieve this.

- Apply series capacitors to reduce XL and thereby reduce θ, since θ = βl = $\omega\sqrt{LC}l = \sqrt{\frac{X_L}{X_c}}$ at fundamental frequency. This method is called line-length compensation (or) θ compensation.
- Divide the line into shorter sections that are more (or) less independent of one

another. This method is called compensation by sectioning. It is achieved by connecting constant voltage compensations at intervals along the line.

4.5.1 EFFECTS OF SERIES AND SHUNT COMPENSATION OF LINES

The objective of series compensation is to cancel part of the series inductive reactance of the line using series capacitors, which results in the following factors.

I. Increase in maximum transferable power capacity.
II. Decrease in transmission angle for considerable amount of power transfer.
III. Increase in virtual surge impedance loading.

From a practical point of view, it is desirable not to exceed series compensation beyond 80%. If the line is compensated at 100%, the line behaves as a purely resistive element and would result in series resonance even at fundamental frequency since the capacitive reactance equals the inductive reactance, and it would be difficult to control voltages and currents during disturbances. Even a small disturbance in the rotor angles of the terminal synchronous machine would result in flow of large currents.

The location of series capacitors is decided partly by economical factors and partly by the selectivity of fault currents as they would depend upon the location of the series capacitor. The voltage rating of the capacitor will depend upon the maximum fault current that likely flows through the capacitor. The net inductive reactance of the line becomes Xl-net = Xl – Xsc

The connection of the transmission line and the series capacitor behaves like a series resonance circuit with inductive reactance of line in series with the capacitance of the series capacitor.

The effects of series and shunt compensation of overhead transmission lines are as follows:

- For a fixed degree of series compensation, the capacitive shunt compensation decreases the virtual surge impedance loading of the line. However, the inductive shunt compensation increases the virtual surge impedance and decreases the virtual surge impedance loading of the line.
- If the inductive shunt compensation is 100%, then the virtual surge impedance becomes infinite and the loading is zero, which implies that a flat voltage profile exists at zero loads and the Ferranti effect can be eliminated by the use of shunt reactors.

- Under a heavy-load condition, the flat voltage profile can be obtained by using shunt capacitors.
- A flat voltage profile can be obtained by series compensation for heavy loading condition.
- Voltage control using series capacitors is not recommended due to the lumped nature of series capacitors, but normally they are preferred for improving the stability of the system.
- Series compensation has no effect on the load-reactive power requirements of the generator and, therefore, the series-compensated line generates as much line-charging reactive power at no load as completely uncompensated line of the same length.
- If the length of the line is large and needs series compensation from the stability point of view, the generator at the two ends will have to absorb an excessive reactive power and, therefore, it is important that the shunt compensation (inductive) must be associated with series compensation.

4.8.1 SHUNT COMPENSATOR or Shunt Compensation

A shunt-connected static VAr compensator, composed of thyristor switched capacitors (TSCs) and thyristor-controlled reactors (TCRs), is shown Fig. 4.6. With proper co-ordination of the capacitor switching and reactor control, the VAr output can be varied continuously between the capacitive and inductive rating of the equipment. The compensator is normally operated to regulate the voltage of the transmission system at a selected terminal, often with an appropriate modulation option to provide damping if power oscillation is detected.

Thyristor-controlled reactor: A shunt-connected thyristor-controlled inductor has an effective reactance, which is varied in a continuous manner by partial-conduction control of the thyristor valve. With the increase in the size and complexity of a power system, fast reactive power compensation has become necessary in order to maintain the stability of the system. The thyristor-controlled shunt reactors have made it possible to reduce the response time to a few milliseconds. Thus, the reactive power compensator utilizing the thyristor-controlled shunt reactors become popular. An elementary single-phase TCR is shown Fig. 4.7.

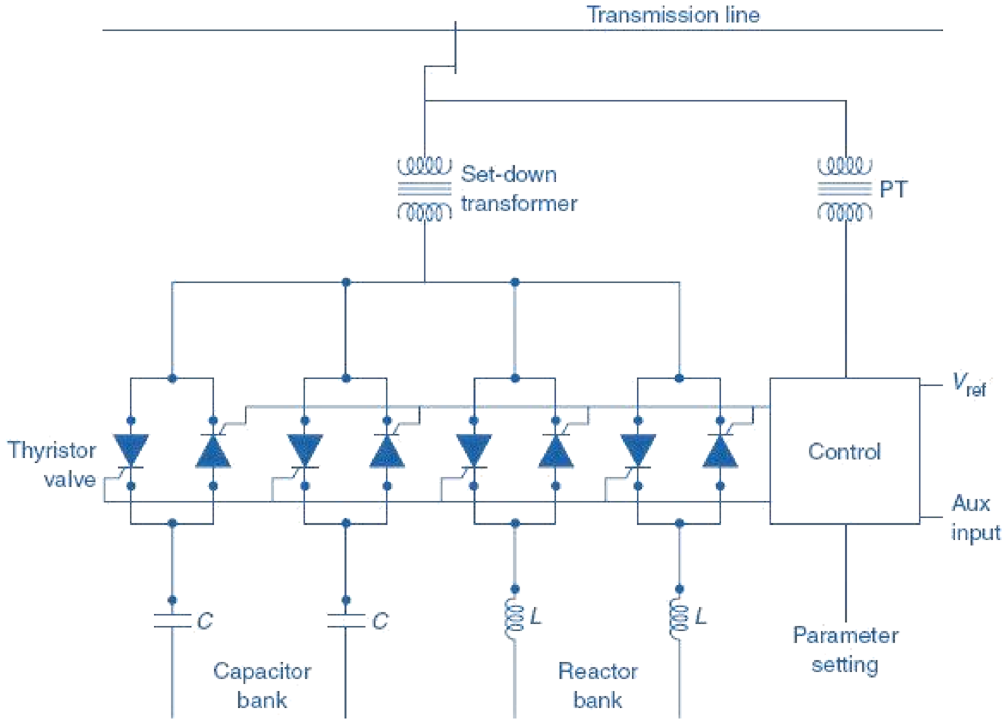


FIG. 4.6 Static VAr compensator employing TSCs and TCR

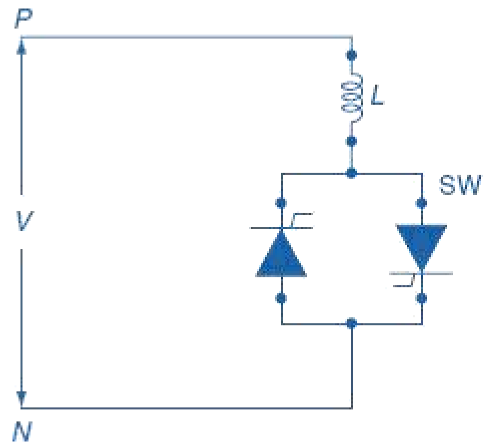


FIG. 4.7 TCR

It consists of a fixed reactor of inductance L and a bidirectional thyristor valve. The thyristor valve can be brought into conduction by the application of a gate pulse to the thyristor, and the valve will be automatically blocked immediately after the AC current crosses zero. The current in the reactor can be controlled from maximum to zero by the method of firing angle control. Partial conduction is obtained with a higher value of firing angle delay. The effect of increasing the gating angle is to reduce the fundamental component of current. This is equivalent to an increase in the inductance of the reactor, reducing its current. As far as the fundamental component of current is concerned, the TCR is a controllable susceptance, and can, therefore, be used as a static compensator.

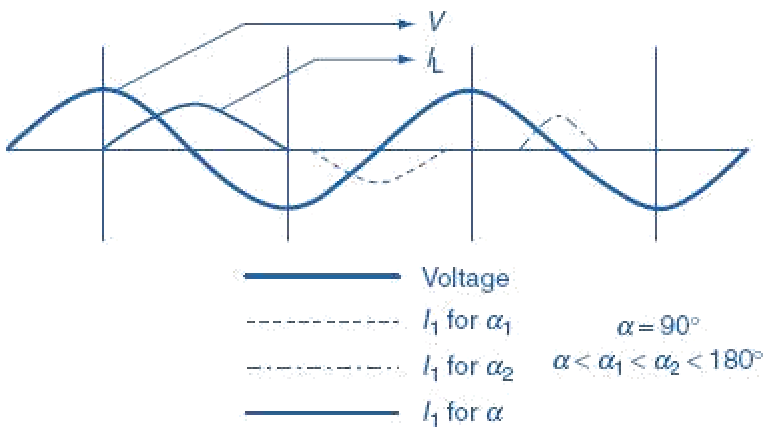


FIG. 4.8 TCR waveform

The current in this circuit is essentially reactive, lagging the voltage by 90° and this is continuously controlled by the phase control of the thyristors. The conduction angle control results in a non- sinusoidal current wave form in the reactor. In other words, the TCR generates harmonics. For identical positive and negative current half-cycle time, only odd harmonics are generated as shown in Fig.4.8. By using filters, we can reduce the magnitude of harmonics.

TCR's characteristics are:

- Continuous control.
- No transients.
- Generation of harmonics

Thyristor-switched capacitor: A shunt-connected TSC shows that an effective reactance is varied in a step-wise manner by full- or zero-conduction operation of the thyristor valve.

The TSC is also a sub-set of SVC in which thyristor-based AC switches are used to switch in and switch out shunt capacitors units in order to achieve the required step change in the reactive power supplied to the system. Unlike shunt reactors, shunt capacitors cannot be switched continuously with a variable firing angle control.

Depending on the total VAr requirement, a number of capacitors are used, which can be switched into or out of the system individually. The control is done continuously by sensing the load VArs. A single-phase TSC is shown in Fig. 4.9.

It consists of a capacitor, a bidirectional thyristor valve, and relatively small surge current in the thyristor valve under abnormal operating conditions (e.g., control malfunction causing capacitor switching at a 'wrong time'); it may also be used to avoid resonance with system impendence at particular frequencies.

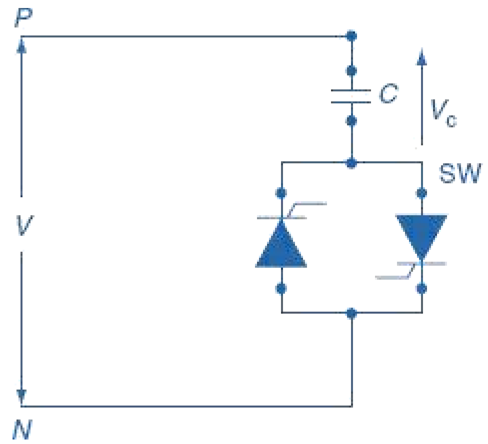


FIG. 4.9 TSC

The problem of achieving transient free switching of the capacitors is overcome by keeping the capacitors charged to the positive or negative peak value of the fundamental frequency network voltage at all times when they are in the stand-by state. The switching-on-transient is then selected at the time when the same polarity exists in the capacitor voltage. This ensures that switching on takes place at the natural zero passage of the capacitor current. The switching thus takes place with practically no transients. This is called zero-current switching.

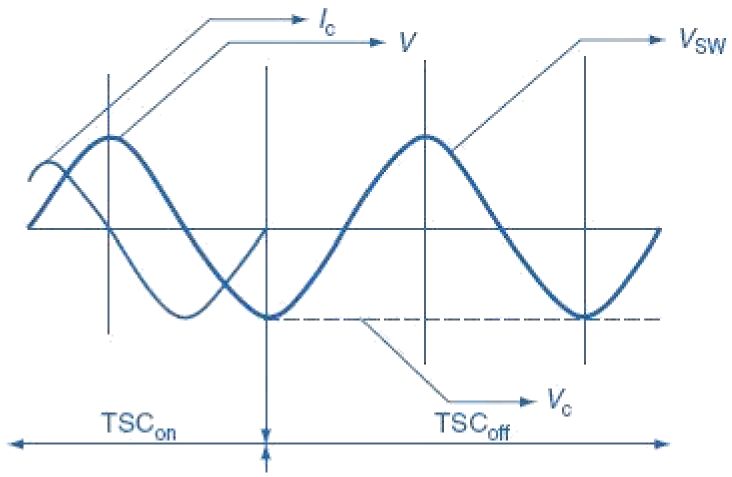


FIG. 4.10 TSC waveforms

Switching off a capacitor is accomplished by suppression-offering pulses to the anti-parallel thyristors so that the thyristors will switch off as soon as the current becomes zero. In principle, the capacitor will then remain charged to the positive or negative peak voltage and be prepared for a new transient- free switching-on as shown in Fig. 4.10.

TSC's characteristics are:

- Steeped control.

- No transients.
- No harmonics.
- Low losses.
- Redundancy and flexibility

4.8.2 SERIES COMPENSATOR

In the TSC scheme, increasing the number of capacitor banks in series, controls the degree of series compensation. To accomplish this, each capacitor bank is controlled by a thyristor bypass switch or valve. The operation of the thyristor switches is co-ordinated with voltage and current zero-crossing; the thyristor switch can be turned on to bypass the capacitor bank when the applied AC voltage crosses zero, and its turn-off has to be initiated prior to a current zero at which it can recover its voltage-blocking capability to activate the capacitor bank. Initially, capacitor is charged to some voltage, while switching the SCR's, they may get damaged because of this initial voltage. In order to protect the SCR's from this kind of damage, resistor is connected in series with capacitor as shown in Fig. 4.11.

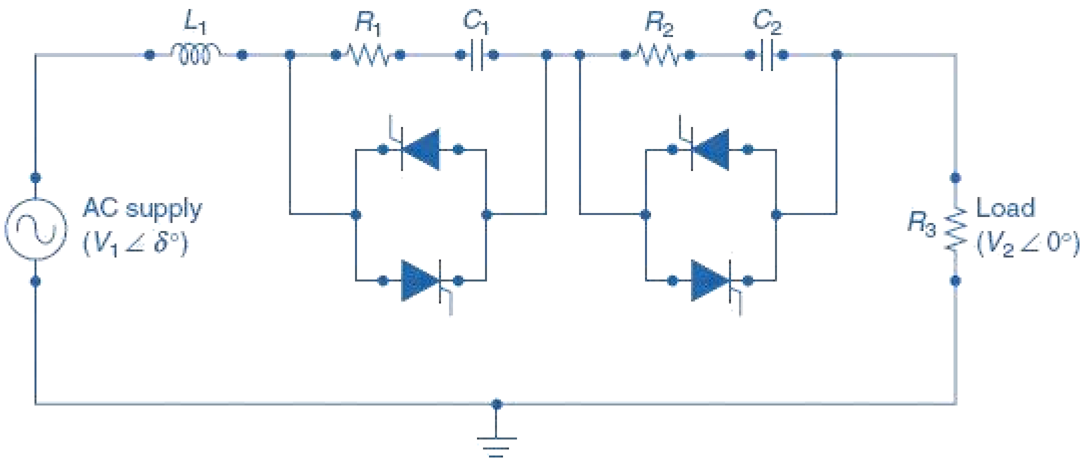


FIG. 4.11 Series compensator

In a fixed capacitor, the TCR scheme as shown in Figs. 4.12 and 4.13, the degree of series compensation in the capacitive operating region is increased (or decreased) by increasing (or decreasing) the current in the TCR. Minimum series compensation is reached when the TCR is switched off.

The TCR may be designed for a substantially higher maximum admittance at full thyristor conduction than that of the fixed shunt connected capacitor. In this case, the TCR, time with an appropriate surge current rating can be used essentially as a bypass switch to limit the voltage across the capacitor during faults and the system contingencies of similar effects.

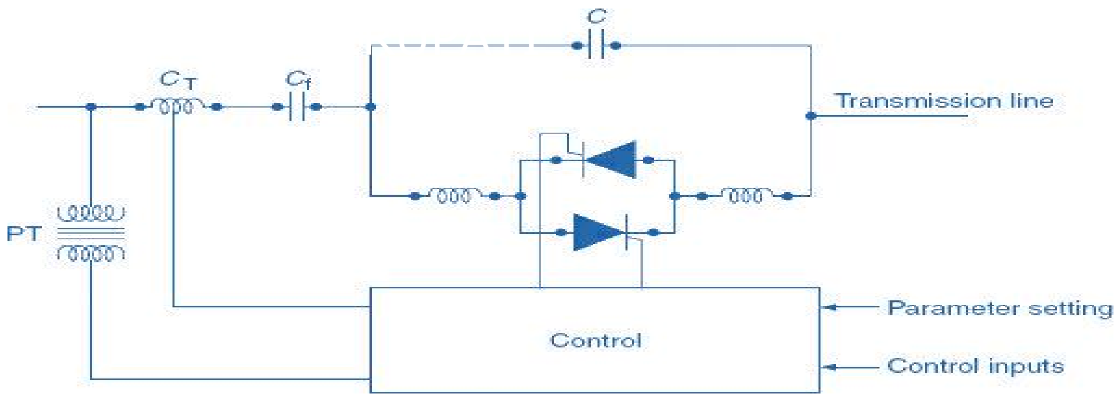


FIG. 4.12 Thyristor-controlled capacitor

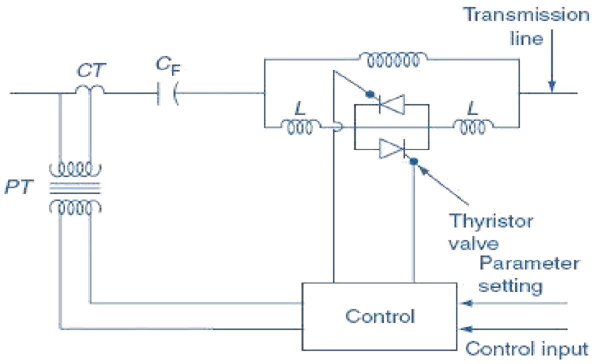


FIG. 4.13 TCR

Controllable series compensation can be highly effective in damping power oscillation and preventing loop flows of power. The expression for power transferred is given by $P = \frac{V_s V_r}{X} \sin\delta$.

Where Vs is the sending-end voltage, Vr the receiving-end voltage, δ the angle between Vs and Vr, and X = XL – XC.

In interconnected power systems, the actual transfer of power from one region to another might take unintended routes depending on impedances of transmission lines connecting the areas. Controlled series compensation is a useful means for optimizing power flow between regions for varying loading and network configurations. It becomes possible to control power flows in order to achieve a number of goals that are listed below:

- Minimizing system losses.
- Reduction of loop flows.
- Elimination of line overloads.
- Optimizing load sharing between parallel circuits.
- Directing power flows along contractual paths.

4.9 ADVANTAGES AND DISADVANTAGES OF DIFFERENT TYPES OF COMPENSATING EQUIPMENT FOR TRANSMISSION SYSTEMS

Compensating equipment	Advantages	Disadvantages
Switched shunt reactor	Simple in principle and construction	Fixed in value
Switched shunt capacitor	Simple in principle and construction	Fixed in value-switching transients. Required
		overvoltage protection and sub-harmonic filters
		Limited overload capacity
Series capacitor	Simple in principle	High-maintenance requirements
	Performance relatively sensitive to location	Slow control response
	Has useful overload capability	
Synchronous condenser	Fully controllable	Performance sensitive to location
	Low harmonics	Requires strong foundations
Poly phase saturated reactor	Very rugged construction	Essentially fixed in value.
	Large overload capability	Performance sensitive to location and noisy
	No effect on fault level	
	Low harmonics	
TCR	Fast response	Generator harmonics performance sensitive to location
	Fully controllable	
	No effect on fault level	
	Can be rapidly repaired after failures	
	Can be rapidly repaired after failures	No inherent absorbing capability to limit over voltages

TSC	No harmonics	Complex bus work and controls low frequency resonance with system
		Performance sensitive to location

4.10 VOLTAGE STABILITY—WHAT IS IT?

Voltage instability does not mean the problem of low voltage in steady state condition. As a matter of fact, it is possible that the voltage collapse may be precipitated even if the initial operating voltages may be at acceptable levels. Voltage collapse may be either fast or slow. Fast voltage collapse is due to induction motor loads or HVDC converter stations and slow voltage collapse is due to on-load tap changer and generator excitation limiters.

Voltage stability is also sometimes termed load stability. The terms voltage instability and voltage collapse are often used interchangeably. It is to be understood that the voltage stability is a sub-set of overall power system stability and is a dynamic problem. The voltage instability generally results in monotonically (or a periodically) decreasing voltages. Sometimes, the voltage instability may manifest as undamped (or negatively damped) voltage oscillations prior to voltage collapse.

Voltage stability:

Definition: A power system at a given operating state and subjected to a given disturbance is voltage stable if voltages near the loads approach post-disturbance equilibrium values. The disturbed state is within the regions of attractions of stable post-disturbance equilibrium. The concept of voltage stability is related to the transient stability of a power system.

Voltage collapse: Following voltage instability, a power system undergoes voltage collapse if the post-disturbance equilibrium voltages near the load are below acceptable limits. The voltage collapse may be either total or partial. The absence of voltage stability leads to voltage instability and results in progressive decrease of voltages. When destabilizing controls (such as OLTC) reach limits or due to other control actions (under voltage load shedding), the voltages are stabilized (at acceptable or unacceptable levels). Thus, abnormal voltage levels in the steady state may be the result of voltage instability, which is a dynamic phenomenon.

tem in the case study.

UNIT-V

5.1 INTRODUCTION

For many decades, vertically integrated electric utilities monopolized the way they controlled, sold and distributed electricity to customers in their service territories. In this monopoly, each utility managed three main components of the system: generation, transmission and distribution. Analogous to perceived competitions in airline, telephone, and natural gas industries which demonstrated that vertically integrated monopolies could not provide services as efficiently as competitive firms, the electric power industry plans to improve its efficiency by providing a more reliable energy at least cost to customers. A competition is guaranteed by establishing a restructured environment in which customers could choose to buy from different suppliers and change suppliers as they wish in order to pay market-based rates.

To implement competition, vertically integrated utilities are required to unbundle their retail services into generation, transmission and distribution; generation utilities will no longer have a monopoly, small businesses will be free to sign contract for buying power from cheaper sources, and utilities will be obligated to deliver or wheel power over existing lines for a fee that is the same as the cost (non-discriminatory) delivering the utility's own power without power production costs. The vertically integrated system is steadily restructuring to a more market based system in which competition will replace the role of regulation in setting the price of electric power.

5.2 RESTRUCTURING MODELS

Three major models are being discussed as alternatives to the current vertically integrated monopoly. The three models are:

a) PoolCo Model
b) Bilateral Contracts Model
c) Hybrid Model

Elements of a certain electric power industry define the nature of competition and models or institutions that support the competition process. In adopting a model, the following issues are being debated regularly:

- Who will maintain the control of transmission grid?
- What types of transactions are allowed?
- What level of competition does a system warrant?

A PoolCo is defined as a centralized marketplace that clears the market for buyers and sellers where electric power sellers/buyers submit bids and prices into the pool for the amounts of energy that they are willing to sell/buy. The ISO or similar entities (e.g. PX) will forecast the demand for the following day and receive bids that will satisfy the demand at the lowest cost and prices for electricity on the basis of the most expensive generator in operation (marginal generator). On the other hand, in the second model, bilateral trades are negotiable and terms and conditions of contracts are set by traders without interference with system operators.

5.2.1 PoolCo Model:

The PoolCo model is comprised of competitive power providers as obligatory members of an independently owned regional power pool, vertically integrated distribution companies, vertically integrated transmission companies and a single and separate entity responsible for: establishing bidding procedures, scheduling and dispatching generation resources, acquiring necessary ancillary services to assure system reliability, administering the settlements process and ensuring non-discriminatory access to the transmission grid. PoolCo does not own any generation or transmission components and centrally dispatches all generating units within the service jurisdiction of the pool. PoolCo controls the maintenance of transmission grid and encourages an efficient operation by assessing non-discriminatory fees to generators and distributors to cover its operating expenses.

In a PoolCo, sellers and buyers submit their bids to inject power into and out of the pool. Sellers compete for the right to inject power into the grid, not for specific customers. If a power provider bids too high, it may not be able to sell power. On the other hand, buyers compete for buying power and if their bids are too low, they may not be getting any power. In this market, low cost generators would essentially be rewarded. Power pools would implement the economic dispatch and produce a single (spot) price for electricity, giving participants a clear signal for consumption and investment decisions. Winning bidders are paid the spot price that is equal to the highest bid of the winners. Since the spot price may exceed the actual running of selected bidders, bidders are encouraged to expand their market share which will force high cost generators to exit the market. Market dynamics will drive the spot price to a competitive level that is equal to the marginal cost of most efficient firms.

To give the reader an idea on how price signals could play an important role in a restructured environment, we consider the following example.

Example 5.1: Impact of Price Signals on Demand Consumption

Figures 1.1 and 1.2 show the idea of price signals and their impact on consumption behavior. Let's assume that an Industrial Customer (IndustCo) consumption pattern in a vertically integrated electric industry, in a certain day, would look like that shown in Figure l.1. In this figure, the price of electricity in Rs/KWh is fixed, and the IndustCo has no incentives to change its consumption pattern. While in a competition-based market, when the IndustCo receives a real time price signal, it could change its consumption pattern in response to the price (See Figure 1.2). In Figure 1.2, the IndustCo reduces its usage at times high prices. As the price jumps from 6Rs/KWh at 5 a.m. to 8Rs/KWh at 9 a.m. the IndustCo starts decreasing its consumption. As the price continues to increase from 8Rs/KWh at 9 a.m. to

16Rs/KWh at 6 p.m. the IndustCo continues decreasing its consumption. When the price decreases after 6 p.m. the IndustCo increases its usage of electricity.

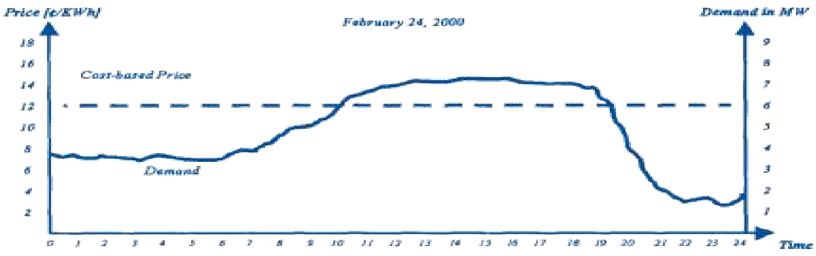


Figure 1.1 Behavior of a Demand in a Vertically Integrated Power Market

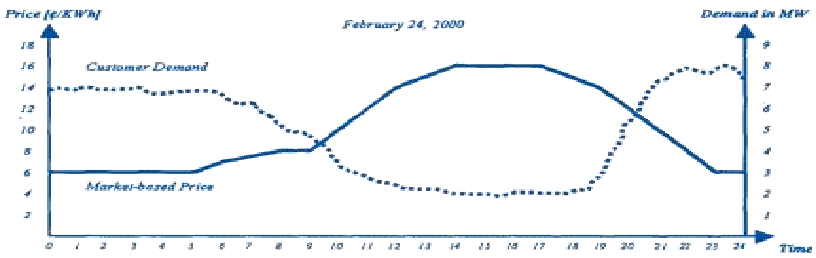


Figure 1.2 Response of a Demand to Price Signals

Although buyers and sellers in a PoolCo are prevented from making individual contracts for power, participants may hold optional financial instruments called Contracts for Differences (CFDs). These contracts are long-term price hedging bilateral contracts between generators and distribution utilities or retail customers. These contracts allow a physical dispatch of individual generating units by their owners and allow consumers to establish long-term prices. When used, a power seller is paid a fixed amount over time that is a combination of short-term market price and an adjustment for the difference. CFDs are established as a mechanism to stabilize power costs to customers and revenues for generators. These contracts are suggested due to the fact that the spot price set by PoolCo fluctuates over a wide range and is difficult to forecast over long periods. Using CFDs, any differences between the spot price and the contract price would be offset by cash payments by generators to customers; in other words, by holding these contracts, customers gain protection against unexpected spot price increases and generators could obtain greater revenue stability.

5.2.2 Bilateral Contracts (Direct Access) Model.

The Bilateral Contracts model has two main characteristics that would distinguish it from the PoolCo model. These two characteristics are: the ISO's role is more limited; and buyers and sellers could negotiate directly it/the marketplace. In this model, small customers' aggregation is essential to ensure that they would benefit from competition.

This model permits direct contracts between customers and generators without entering into pooling arrangements. By establishing non-discriminatory access and pricing rules for transmission and distribution systems, direct sales of power over a utility's transmission and distribution systems are guaranteed. Wholesale suppliers would pay transmission charges to a transmission company to acquire access to the transmission grid and pays similar charges to a distribution company to acquire access to the local distribution grid. In this model, a distribution company may function as an aggregator for a large number of retail customers in supplying a long-term capacity. Also, the generation portion of a former integrated utility may function as a supplier or other independent generating companies, and transmission system would serve as a common carrier to contracted parties that would permit mutual benefits and customer's choice. Any two contracted parties would agree on contract terms such as price, quantity and locations, and generation providers would inform the ISO on how its hourly generators would be dispatched.

5.2.3 Hybrid Model:

The hybrid model combines various features of the previous two models. The hybrid model differs from the PoolCo model as utilizing the PX is not obligatory and customers are allowed to sign bilateral contracts and choose suppliers from the pool. The pool would serve all participants (buyers and sellers) who choose not to sign bilateral contracts. The Califomia model is an example of the hybrid model. This structure has advantages over a mandatory pool as it provides end-users with the maximum flexibility to purchase from either the pool or directly from suppliers. A customer who would choose a PX option with CFDs could acquire the economic equivalent of bilateral contracts.

The existence of the pool can efficiently identify individual customer's energy requirements and simplify the balancing process of energy supply. The hybrid model would enable market participants to choose between the two options based on provided prices and services. The hybrid model is very costly to set up because of separate entities required for operating the PX and the transmission system. In the following, we learn more about the functions of an ISO in a restructured power system.

5.3 INDEPENDENT SYSTEM OPERATOR (ISO)

5.3.1 Background:

In a vertically integrated monopoly, utilities created regional centrally dispatched power pools to coordinate the operation and planning of generation and transmission among their members in order to improve operating efficiencies by selecting the least-cost mix of generating and transmission capacity, coordinating maintenance of units, and sharing operating reserve requirements and thus lowering the cost to end-use electricity customers. The centrally dispatched power pools are classified as:

- **Tight power pools:** they have customarily functioned as control areas for their members; perform functions such as unit commitment, dispatch and transaction scheduling services. Examples of this kind of pools are New York Power Pool (NYPP), New England Power Pool (NEPOOL), Pennsylvania, New Jersey, Maryland (PJM) Interconnection, Colorado Power Pool and Texas Municipal Power Pool.
- **Loose power pools:** they have generally had more limited roles, and in contrast to tight pools, have a low level of coordination in operation and planning. The most significant role of these pools has provided support in emergency conditions. Loose power pools did not provide control area services.
- **Affiliate power pools:** in this kind of pools, generated power which was owned by the various companies was dispatched as a single utility. Pools have had extensive agreements on governing the cost of generation services and use of transmission systems.

Power pools controlling access to regional transmission systems made it difficult for non-members to use pool members' transmission facilities by establishing complex operating rules and financial arrangements. Also, restrictive membership and governance of pools were practiced occasionally in a way that large utilities prevented changes in policies and rules of the pool which led to closing pool membership to outsiders. Unfair industry practices generally impacted the growth of a competitive generation market and were motive forces for the FERC to order transmission owners to provide other parties an open access to transmission grids.

A competitive generation market and retail direct access necessitated an independent operational control of the grid. However, the independent operation of the grid was not guaranteed without an independent entity, the so-called Independent System Operator (ISO). An ISO is independent of individual market participants such as transmission owners, generators, distribution companies and end-users. The basic purpose of an ISO is to ensure a fair and non-discriminatory access to transmission services and ancillary services, maintain the real-time operation of the system and facilitate its reliability requirements.

5.3.2 The Role of ISO:

The primary objective of the ISO is not dispatching or re-dispatching generation, but matching electricity supply with demand as necessary to ensure reliability. ISO should control generation to the extent necessary to maintain reliability and optimize transmission efficiency. The ISO would continually evaluate the condition of transmission system and either approve or deny requests for transmission service.

In its Order No. 888, FERC developed eleven principles as guidelines to the electric industry restructuring to form a properly constituted ISO, through which public utilities could comply with FERC's non-discriminatory transmission tariff requirements. The eleven principles for ISOs are:

1) The ISO's governance should be structured in a fair and non- discriminatory manner.
2) An ISO and its employees should have no financial interest in the economic performance of any power market participant. An ISO should adopt and enforce strict conflict of interest standards.
3) An ISO should provide open access to the transmission system and all services under its control at non-pancaked rates pursuant to a single, unbundled, grid-wide tariff that applies to all eligible users in a non-discriminatory manner.
4) An ISO should have the primary responsibility in ensuring short-term reliability of grid operations. Its role in this responsibility should be well defined and comply with applicable standards set by NERC and the regional reliability council.
5) An ISO should have control over the operation of interconnected transmission facilities within its region.
6) An ISO should identify constraints on the system and be able take operational actions to relieve those constraints within the trading rules established by the governing body. These rules should promote efficient trading.
7) An ISO should have appropriate incentives for efficient management and administration and should procure services needed for such management and administration in an open market.
8) An ISO's transmission and ancillary services pricing policies should promote the efficient use of and investment in generation, transmission, and consumption. An ISO or a Regional Transmission Group (RTG) of which the ISO is a member should conduct such studies as may be necessary to identify operational problems or appropriate expansions.
9) An ISO should make transmission system information publicly available on a timely basis via an electronic information network consistent with the Commission's requirements.
10) An ISO should develop mechanisms to coordinate its activities with neighboring control areas.
11) An ISO should establish an Alternative Dispute Resolution (ADR) process to resolve disputes in the first instance.

According to the FERC Order 888, the ISO is authorized to maintain transmission system reliability in real-time. To comply with the FERC Order 888, each ISO may take one of the following structures:

The first structure is mainly concerned with maintaining the transmission reliability by operating the power market to the extent that the ISO would schedule transfers in a constrained transmission system. An example of this proposal is the Midwest ISO.

The second proposal for an ISO includes a PX that is integral to the ISO's operation. In some proposals such as those of the UK and the PJM interconnection, the PX would function within the same organization and under the control of the ISO; the ISO is responsible for dispatching all generators and would set the price of energy at each hour based on the highest price bid in the market.

In its Order 888, FERC also defined six ancillary services that must be provided by or made available through transmission providers. These ancillary services include:

1) Scheduling, Control and Dispatch Services
2) Reactive Supply and Voltage Control
3) Regulation and Frequency Response Services
4) Energy Imbalance Service
5) Operating Reserve, Spinning and Supplemental Reserve Services
6) Transmission Constraint Mitigation

As Order 888 implies, transmission customers may self-provide these services or buy them through one of the following methods.

(i) Providers of these services advertise their availability via the OASIS or commercial exchanges

(ii) The ISO provides these services in real-time and charges transmission users.

To make these services available, the ISO contracts with service providers so that the services are available under the ISO's request. When a service provider is called by the ISO, the provider is paid extra to cover its operating costs. Capacity resources are contracted seasonally by the ISO and providers send their bids to an auction operated by the ISO. The ISO chooses successful providers based on a least-cost bid basis. When determining the winners, the ISO takes into account factors such as time and locational constraints and the expected use of resources. If the ISO finds that spot market services are less expensive than contracted ones, the ISO experiences its authority by acquiring these services from the energy spot market.

The following example illustrates the role of ISO in providing operating reserves.

Example 5.2: (Operating Reserves)

Assume that a hydroelectric generator, which has a 30 MW capacity and can be brought up and running in 4 minutes, offers its 30 MW capacity in the operating reserve market. It submits a reserve price offer of $2.5/MW for each hour of the entire next day, along with an energy offer price of $42.5/MWh. Also, assume that there are two customers, C1 and C2 that can cut back quickly their usage of electricity. C can cut up to 15 MW in 5 minutes, so it decides to submit a bid to the operating reserve market of 15 MW at $1.5/MW for each hour of the entire next day and a maximum energy bid price of $55/MWh. C2 can cut up to 10 MW in 5 minutes, so it decides to submit a bid to the operating reserve market of 10 MW at

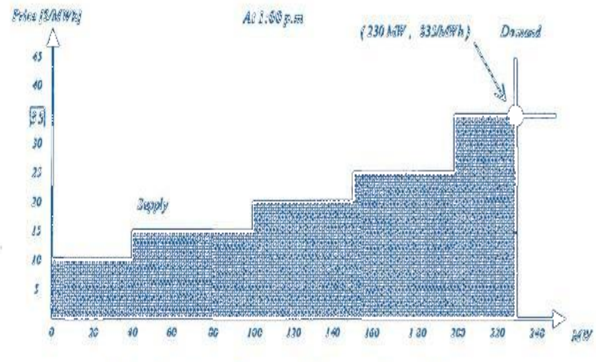
$2/MW for each hour of the entire next day and a maximum energy bid price of $70/MWh.

The ISO anticipates that it will need a large operating reserve, say 55 MW, so it accepts the generator's offer and the customers' bids. Assume that the MCP of the operating reserves is $2.5/MW/h. Each winning participant in the operating reserve market will be paid the MCP to stand by in case of contingency. The generator will be paid $1800 (or $2.5/MW/h×30MW×24h), C will be paid $900 (or $2.5/MW/h×15MW×24h), and C2 will be paid $600 (or $2.5/MW/h×10 MW×24 h).

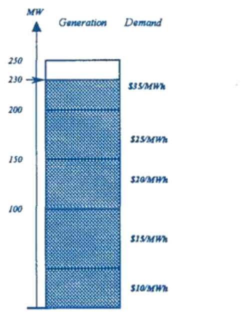
In the next day, say at 1:00 p.m., let's assume that supply and demand equilibrium is initially established at 230 MW (in the spot market). The spot market price of electricity at this point is $35/MWh.

The net supply curve of all generating units is as shown in Figure 1.3. The supply segment of $20/MWh is offered by a single generating unit that has a capacity of 50 MW. As segment) that is dispatched last (in of its total capacity of 50 MW, and shown in Figure 1.3, the unit (supply the spot market) is producing 30 MW has available capacity of 20 MW.

Now suppose the generating unit that is producing 50 MW at $20/MWh tripped out due to severe weather conditions at 1:10 p.m. which disconnected the line joining this generating unit to the system. The supply curve after the unit outage is shown in Figure 1.4. At 1:10 p.m., demand is still 230 MW, and the supply has a shortage of 50 MW. At this point, the ISO has to replace the sudden loss of capacity in the remainder of the hour (from 1:10-2:00 p.m.), before more capacity can be dispatched in the spot market. So the ISO has to reduce the demand if possible or/and provide the required power from operating reserves.

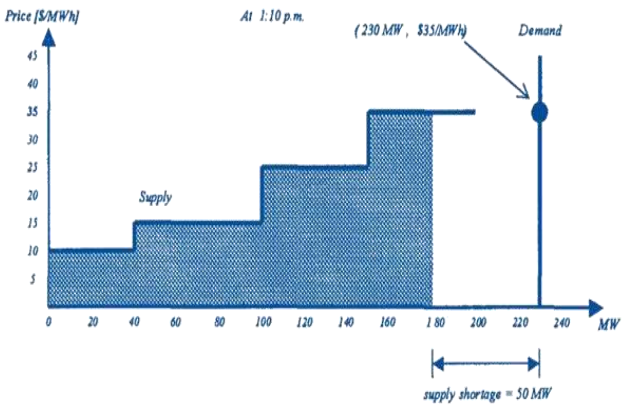


1.3.a Supply and Demand Curves of Initial Situation

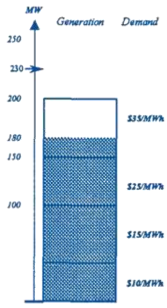


1.3.b Total Production and Production of each Generating Unit of the Initial Situation

Figure 1.3 Initial Situation



1.4.a Supply and Demand Curves after the Unit Outage



1.4.b Total Production and Production of each Generating Unit after the Outage

Figure 1.4 Situation after the Unit Outage

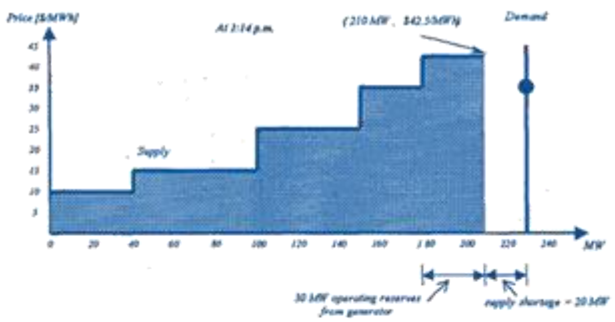
The ISO dispatches the 30 MW generator (see Figure 1.5), and the generator is paid $42.5/MWh. To restore the balance, the ISO also dispatches off 15 MW from C1 and 5 MW from C2 (See Figure 1.6). The ISO pays $20/MWh (or $55/MWh-$35/MWh) to C~ and $35/MWh (or $70/MWh-$35/MWh) to C2 for the electricity that it has dispatched off. The payments to the three participants (generator, C1 and C2) continue until replacement energy can be provided from the spot market.

5.4 POWER EXCHANGE (PX)

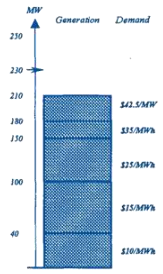
Even though short-term and long-term financial energy transactions could be in bilateral forms in the electricity industry where contracted parties agree individually for certain terms such as price, availability and quality of products, industry restructuring proposals have concluded the necessity of creating a new marketplace to trade energy and other services in a competitive manner. This marketplace is termed Power Exchange (PX) or, as sometimes called, spot price pool. This marketplace permits different participants to sell and buy energy and other services in a competitive way based on quantity bids and prices. Participants include utilities, power marketers, brokers, load aggregators, retailers, large industrial customers and co-generators.

PX is a new independent, non-government and non-profit entity which accept schedules for loads and generation resources. It provides a competitive marketplace by running an electronic auction where market participants buy and sell electricity and can do business quickly and easily. Through an electronic auction, PX establishes an MCP for each hour of the following day for trades between buyers (demands) and sellers (supplies). In this marketplace, PX does not deal with small consumers. Add to that, PX manages settlement and credit arrangements for scheduling and balancing of loads and generation resources. As a main objective in its work, PX guarantees an equal and non-discriminatory access and competitive opportunity to all participants. It is claimed that participants entering the PX get more cost-effectiveness by removing the complexities of arranging generation, transmission and energy purchases.

In general, the PX includes a day-ahead market and an hour-ahead market. Here we discuss these markets in general, and later we elaborate on them when we discuss some market models in the United States.

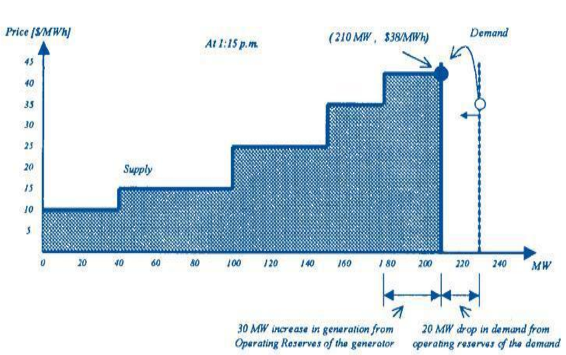


1.5.a Supply and Demand Curves after the ISO dispatches the 30 MW generator

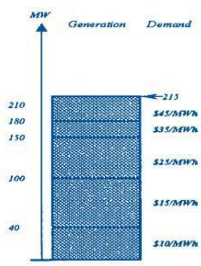


1.5.b Total Production and Production of each Generating Unit after the ISO dispatches the 30 MW generator

***Figure 1.5** Situation after Using Available Operating Reserves*



1.6.a Supply and Demand Curves after the ISO dispatches off the 20 MW



1.6.b Total Production and Production of each Generating Unit after the ISO dispatches off the 20 MW

***Figure 1.6** Situation after Drop of C_1 and C_2 Demand*

5.4.1 Market Clearing Price (MCP):

PX accepts supply and demand bids to determine a MCP for each of the 24 periods in the trading day. Computers aggregate all valid (approved) supply bidsand demand bids into an energy supply curve and an energy demand curve. MCP is determined at the intersection of the two curves and all trades are executed at the MCP, in other words, the MCP is the balance price at the marketequilibrium for the aggregated supply and demand graphs. Figure 1.7 shows thedetermination of MCPs for certain hours when demand (Di) varies. Generators are encouraged to bid according to their operating costs because bidding lower would lead to financial losses if MCP is lower than the operating cost and biddinghigher could cause units to run less frequently or not run at all.

5.5 MARKET OPERATIONS:

5.5.1 Day-Ahead and Hour-Ahead Markets:

In the day-ahead market and for each hour of the 24-hour scheduling day, sellers bid a schedule of supply at various prices, buyers bid a schedule of demand at various prices, and MCP is determined for each hour. Then, sellers specify the resources for the sold power, and buyers specify the delivery points for the purchased power. PX schedules supply and demand with the ISO for delivery. Supply and demand are adjusted to account for congestion and ancillary services and then PX finalizes the schedules.

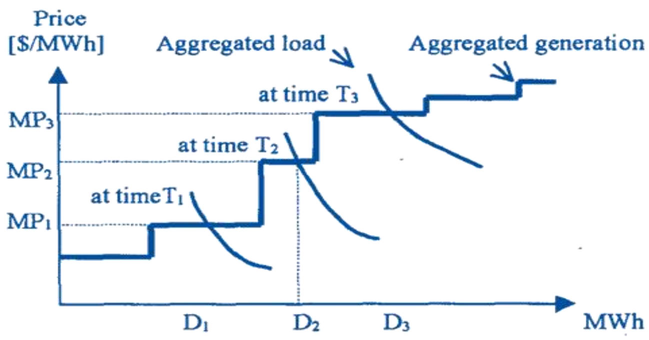


Figure 1.7 Process of Determining MCP in PoolCo

The hour-ahead market is similar to day-ahead, except trades are for 1 hour, and the available transfer capability (ATC) is reduced to include day-ahead trades, and bids are not iterative in this market. Once the MCP is determined in the PX, market participants submit additional data to the PX. The data would include individual schedules by generating unit; take out point for demand, adjustment bids for congestion management and ancillary service bids. After this stage, the ISO and the PX know the injection points of individual generating units to the transmission system. A schedule may include imports and/or exports. To account for transmission losses, generator's schedules are adjusted where real losses are only known after all metered data are processed.

5.5.2 Elastic and Inelastic Markets.

An inelastic market does not provide sufficient signals or incentives to a consumer to adjust its demand in response to the price, i.e., the consumer does not have any motivation to adjust its demand for electrical energy to adapt to market conditions. In a market that has a demand; MCP for energy is determined by the price structure of supply offers. The concept of inelastic demand is directly related to the concept of firm load, which formed the basis of the electricity industry for many decades before the introduction of open access and energy markets. Customers use the concept of elastic demand when they are exposed to and aware of the price of energy and arrange their affairs in such a fashion as to reduce their demand as the price of the next available offer exceeds a certain level.

The following example illustrates how the elasticity of demand in a market has some serious impacts on the energy market and the power system itself, and demonstrates how the pool price cap (price ceiling) energy markets with inelastic and elastic demand may play important role. The example also illustrates the need for capacity reserves.

5.6 MARKET POWER:

One of the main anti-competitive practices or difficulties that may prevent competition in the electric power industry, especially in generation, is market power. When an owner of a generation facility in a restructured industry is able to exert significant influences (monopoly) on pricing or availability of electricity, we say that market power exists, and if so it prevents both competition and customer choice. Market power may be defined as owning the ability by a seller, or a group of sellers, to drive price over a competitive level, control the total output or exclude competitors from a relevant market for a significant period of time. Other than price, any entity that exercises market power would reduce competition in power production, service quality and technological innovation. The net result of practicing market power is a transfer of wealth from buyers to sellers or a misallocation of resources.

There are two types of market power:

1- Vertical Market Power: It arises from a single-firm's or affiliate's ownership of two or more steps in a production and market delivery process where one of the steps provides the firm with a control of a bottleneck in the process. The bottleneck facility is a point on the system, such as a transmission line, through which electricity must pass to get to its intended buyers. A control of a bottleneck process enables the firm to give preference to itself or its affiliate over competitive firms.

2- Horizontal Market Power: It is the ability of a dominant firm or group of firms to control production to restrict output and thereby raise prices. It arises from a firm's local control or ownership concentration of a single process step in productive assets within a defined market area. If such concentration is sufficient with respect to certain other market conditions, the firm can influence the supply-demand equilibrium, and hence prices, simply by withholding production. This type of market power cannot be resolved by the ISO.

Concentration in a market measures the market dominance (degree of monopoly experienced by a firm in a competitive market) using market share data, i.e., how many firms exist in the market, and what are their relative sizes determine the market dominance.

Example 5.6: (How is Market Power Exercised?)

(A) Exercising Market Power when a Power Supply has a Large Market Share,

Figure 1.14 shows a 3-bus system with three generating companies, one at each bus. The three generating companies are $GenCo_1$ with a maximum capacity of 120 MW, $GenCo_2$ with a maximum capacity of 250 MW, and $GenCo_3$ with a maximum capacity of 630 MW.

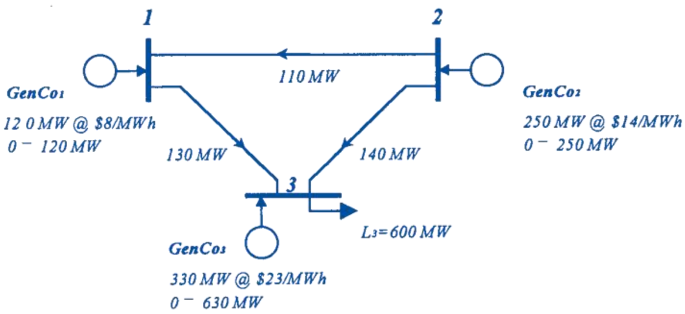


Figure 1.14 Exercising Market Power when a Power Supply has Large Market Share

The HHI for this situation is

$$HHI = \sum_{1}^{3} S_i^2 = (\tfrac{120}{1000})^2 + (\tfrac{250}{1000})^2 + (\tfrac{630}{1000})^2$$
$$= 0.0144 + 0.0625 + 0.3969 = 0.4738 \text{ (in per unit basis)}$$

or,

$$HHI = \sum_{1}^{3} S_i^2 = (\tfrac{120}{1000} \times 100)^2 + (\tfrac{250}{1000} \times 100)^2 + (\tfrac{630}{1000} \times 100)^2$$
$$= 144 + 625 + 3969 = 4738 \text{ (in percent basis)}$$

Note that $GenCo_3$ owns the maximum share of the total generation capacity (=630MW/1000MW=63%). By ignoring the limitation transmission lines, $GenCo_3$ monopolizes the market, because L_3 needs much more than the total capacity of the other cheaper resources ($GenCo_1$ can generate up to 120 MW at $8/MWh and

$GenCo_2$ can generate up to 250 MW at \$14/MWh). It means when $GenCo_3$ wants to exercise its market power, it can ask for any price for its electric power production to fulfill L_3's need.

(B) Exercising Market Power when Transmission System is Congested

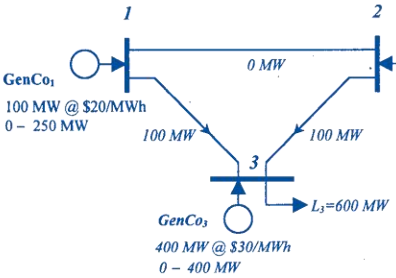
Figure 1.15 shows a 3-bus system with three generating companies, one at each bus. The three generating companies are $GenCo_1$ with a maximum capacity of 250 MW, $GenCo_2$ with a maximum capacity of 350 MW, and $GenCo_3$ with a maximum capacity of 400 MW. The HHI for this situation is

$$HHI = \sum_{1}^{3} S_i^2$$
$$= (\frac{250}{1000})^2 + (\frac{350}{1000})^2 + (\frac{400}{1000})^2$$
$$= 0.0625 + 0.1225 + 0.1600 = 0.345 \text{ (in per unit basis)}$$

or,

$$HHI = \sum_{1}^{3} S_i^2 = (\frac{250}{1000} \times 100)^2 + (\frac{350}{1000} \times 100)^2 + (\frac{400}{1000} \times 100)^2$$
$$= 625 + 1225 + 1600 = 3450 \text{ (in percent basis)}$$

In this case $GenCo_1$, $GenCo_2$ and $GenCo_3$ own, respectively, 25%, 35%, and 40% of the total generation capacity. Transmission line limits are imposed on the system in this case, as shown in Figure 1.15. Even though the cheapest resources ($GenCo_1$and $GenCo_2$) have a total capacity of 600 MW, which is adequate to cover the 600 MW required by L_3, the limitations of the transmission lines do notpermit L_3 to use $GenC0_1$ and $GenC0_2$. This situation may lead to exercising market power by $GenCo_3$ by imposing a higher than competitive price.



line	Limit
1-2	100 MW
1-3	100 MW
2-3	100 MW

Figure 1.15 Exercising Market Power when Transmission is Congested

5.7 STRANDED COSTS:

A major and a debatable issue associated with the electric utility restructuring is the issue of stranded costs; how to be determined, how to be recovered and who pays for recovery. Stranded cost is a terminology created under restructuring process. Multiplicity of definitions and interpretations of stranded costs confused people working on restructuring, but in general this term refers to the difference between costs that are expected to be recovered under the rate regulation and those recoverable in a competitive market.

In a vertically integrated monopoly, utilities are used to cover their costs of doing business in rates charged to customers. Costs include operating costs and invested capital costs, where utilities cover these costs and considerable returns on their capitals through rates imposed on customers. But when restructuring is proposed to open market-based competition, and due to the fact that market-based prices are uncertain and sometimes less than vertically integrated rates, financial obligations of vertically integrated utilities may become unrecoverable in a competitive market and the level of revenue earned by a utility may no longer be adequate to cover its costs. If market prices are lower than vertically integrated rates, as many expect, utilities could be faced with investments that are unrecoverable in the competitive market.

Stranded costs still need a more clear definition (what costs should be strandable? what costs are unrecoverable? and to what extent (totally or partially) should be recovered?) and quantification. On the other hand, the duration of recovery or who will pay for recovery is not clear yet and varies from model to model in the United States. In this regard, the big question is whether different participants should pay for uneconomical previous investments.

5.8 TRANSMISSION PRICING

FERC recognized that transmission grid is the key issue to competition, and issued guidelines to price the transmission. The guidelines are summarized such that the transmission pricing would:

(i) Meet traditional revenue requirements of transmission owners
(ii) Reflect comparability: i.e. a transmission owner would charge itself on the same basis that it would charge others for the same service
(iii) Promote economic efficiency
(iv) Promote fairness
(v) Be practical

Even though transmission costs are small as compared to power production expenses and represent a small percent of major investor owned utilities operating expenses, a transmission system is the most important key to competition because it would provide price signals that can create efficiencies in the power generation market. The true price signals are used as criteria for adding transmission capacity, generation capacity, or future loads. Adding transmission capacity to relieve transmission constraints could allow high-cost generation to be replaced by less expensive generation, which would result in additional savings to consumers.

5.8.1 Contract Path Method:

It has been used between transacted parties to price transmission where power flows are assumed to flow over a predefined path(s). Despite its ease, this technique was claimed be a bad implementation of true transmission pricing as power flows would very seldom correspond to predefined paths. Physically, electrons could flow in a network over parallel paths25 (loop flows) owned several utilities that may not be on the contract path. As a result, transmission owners may not be compensated for the actual use of their facilities. Added to parallel flows, the pancakin~6 of transmission rates is another shortcoming of this method.

As a solution to the pancaking effect, zonal pricing schemes have been proposed by most ISOs. Using a zonal scheme, the ISO-controlled transmission system is divided into zones and a transmission user would pay rates based on energy prices in zones where power is injected or withdrawn. When the zonal approach is used, rates are calculated regardless of paths between the two zones or how many other zones are crossed.

5.8.2 The MW-Mile Method:

Several ISOs are using a MW-Mile approach to price transmission. The MW-Mile rate is basically based on the distance between transacted parties (from the generating source to the load) and flow in each line resulted from the transaction. This approach takes into account parallel power flows and eliminates the previous problem that transmission owners were not compensated for using their facilities. This approach does not give credit for counter-flows on transmission lines. The method is complicated because every change in transmission lines or transmission equipment requires a recalculation of flows and charges in all lines.

5.9 CONGESTION PRICING:

The condition where overloads in transmission lines or transformers occur is called congestion. Congestion could prevent system operators from dispatching additional power from a specific generator. Congestion could be caused for various reasons, such as transmission line outages, generator outages, changes in energy demand and uncoordinated transactions. Congestion may result in preventing new contracts, infeasibility in existing and new contracts, additional outages, monopoly of prices in some regions of power systems and damages to system components. Congestion may be prevented to some extent (preventive actions) by means of reservations, rights and congestion pricing. Also, congestion can be corrected by applying controls (corrective actions) such as phase shifters, tap transformers, reactive power control, re-dispatch of generation and curtailment of loads.
FERC has set guidelines for a workable market approach to mange congestion, which are:
(1) The approach should establish clear and trade able rights for transmission usage,
(2) The approach should promote efficient regional dispatch,
(3) The approach should support the emergence of secondary markets for transmission rights,

(4) The approach should provide market participants with the opportunity to hedge locational differences in energy prices,
(5) Congestion pricing method should seek to ensure that the generators that are dispatched in the presence of transmission constraints are those that can serve system loads at least cost, and
(6) The method should ensure that the transmission capacity is used by market participants who value that use most highly.
As such, FERC declares that some approaches appear to have more advantages than others. Even though LMP scan be costly and difficult to implement, especially by entities that have not previously operated as tight power pools, FERC suggests that markets that are based on LMP and financial rights for firm transmission service will provide an efficient congestion management framework, and this is due to the following facts:

I- LMP assigns congestion charges directly to transmission customers in a fashion that agrees with each customer's actual use of the system and the actual dispatch that its transactions cause.

II- LMP facilitates the creation of financial transmission rights, which enable customers to pay known transmission rates and to hedge against congestion charges.

III- Financial rights entitles their holders to receive a share of congestion revenues, and consequently the availability of such rights congestion pricing resolve the problem of the over recovery of transmission costs.

To solve the congestion problem, several alternatives could be considered such as re-dispatching existing generators or dispatching generators outside the congested area to supply power. The latter alternative is referred to as out-of-merit dispatch. In both alternatives, congestion has costs based on differences in energy prices between locations. In a vertically integrated monopoly, congestion costs were either ignored or hidden as bundled into the transmission charges that in turn were considered as a shortcoming in previous transmission pricing schemes. It was considered a shortcoming because it did not provide a true price signal for efficient allocation of transmission resources or allocated congestion costs to transmission customers who were not causing the congestion.

5.9.1 Congestion Pricing Methods:

All new restructuring proposals are taking congestion costs into account by developing appropriate approaches to measure congestion costs and allocate these costs to transmission system users in a fair way that reflects actual use of the transmission system. These approach evolved in three basic methods based on:

1- **Costs of out-of-merit dispatch:** This is appropriate to systems with less significant transmission congestion problems. In this approach, congestion costs are allocated to each load on the transmission system based on its load ratio share (i.e., individual load expressed as a percent of total load).

2- **Locational Marginal Prices (LMPs):** This technique is based the cost of supplying energy to the next increment of load at a specific location on the transmission grid. It determines the price that buyers would pay for energy in a competitive market at specific locations and measures congestion costs by considering the difference in LMPs between two locations. In this approach LMPsa re calculated at all nodes of the transmission system based on bids provided to the PX.

3- **Usage charges of inter-zonal lines:** In this approach, the ISO region is divided into congestion zones based on the historical behavior of constrained transmission paths. Violations of transmission lines between zones (inter-zonal lines) are severe while in the congestion zone transmission constraints are small.

All transmission users who use the inter-zonal pay usage charges. These charges will be determined from bids submitted voluntarily by market participants to decrease or increase (adjust) power generation. Adjustment bids reflect a participant's willingness to increase or decrease power generation at a specified cost. An example of this approach is the case of California.

5.9.2 Transmission Rights:

These rights are used to guarantee an efficient use of transmission system capacity and to allocate transmission capacity to users who value it the most. These rights are tradable rights referred to as the right to use transmission capacity and represent a claim on the physical usage of the transmission system. Moreover, these rights enable utilities to purchase existing transmission rights more cheaply than expanding the system, thereby avoiding unneeded investments. Efficient usage of the transmission can be improved by willingness to offer capacity reservations to those who value them more.

Another form of these rights is the concept of financial rights (some times called Fixed Transmission Right), which is equivalent to the physical rights. This form is proposed because it is easier for trading and less costly because the usage of a transmission system need not be tied to ownership rights. A financial right is defined for two points on the transmission grid: injection and withdrawal points.

5.10 MANAGEMENT OF INTER-ZONAL/INTRAZONAL CONGESTION

Transmission network plays a major role in the open access restructured power market. It is perceived that phase-shifters and tap transformers play vital preventive and corrective roles in congestion management. These control devices help the ISO mitigate congestion without re-dispatching generation away from preferred schedules. In this market, transmission congestion problems could be handled more easily when an inter-zonal/intra-zonal scheme is implemented.

Existing approaches to manage congestion are based on issuing orders by the ISO to various parties to re-schedule their contracts, redispatch generators, cancel some of the contracts that will lead to congestion, use various control devices, or shed loads. Other solutions are based on finding new contracts that re-direct flows on congested lines. Phase shifters, tap transformers and FACTS devices may play an important role in a restructured environment where line flows can be controlled to relieve congestion and real power losses can be minimized.

5.10.1 Solution Procedure:

Once the ISO receives preferred schedules from the PX, it performs contingency analysis by identifying the worst contingency for modeling in the congestion management. To rank the severity of different contingencies, the ISO may use a Performance Index (PI) to list and rank different contingencies. PI is a scalar function of the network variables such as voltage magnitude, real and reactive power flows. PI has essentially two functions, namely, differentiation between critical and non-critical outages, and prediction of relative severity of critical outages. There are available criteria in the literature to decide how many cases on the contingency list ought to be chosen for additional studies. A few critical contingencies at the top of the list will have the major impact on system security and should be used by the ISO during congestion management.

Economically, these price-quantity values represent what each SC is willing to pay to or receive from the ISO to remove congestion. Each schedule coordinator may trade transactions with others before submitting preferred schedules to the ISO; these parties may trade power again when preferred schedules are returned to them for revision. The preferred schedules submitted to the ISO by SC and PX are optimal schedules determined by the market clearing price, and schedules submitted by schedule coordinators are basically bilateral contracts that take into consideration the benefits of contracted parties. In this process, adjustment bids (incremental and decremental) represent the economic reformation on which the ISO will base its decisions to relieve congestion. Adjustment bids include suggested deviations from preferred loads and generation schedules provided by SCs. At each bus, ranges of power deviations along with deviations in price are submitted to the ISO. Incremental bids may be different from decremental bids for adjusting the preferred schedule.

The ISO uses incremental/decremental (inc/dec) bids to relieve congestion. Since inter-zonal congestion is more frequent than intrazonal congestion with system-wide effects, the ISO first solves interzonal congestion while ignoring intra-zonal constraints. In the inter-zonal congestion management, primary controls are zonal real power generation and loads at both ends of congested inter-zonal lines. Instead of changing preferred schedules in these zones, the ISO starts by adjusting generations and loads at buses directly connected or in proximity of these inter-zonal lines. If these controls do not accomplish the task, it is perceived that other controls away from these lines will probably not be able to mitigate inter-zonal congestion either. Then the ISO looks for other control devices (such as phase shifters, tap transformers and FACT devices) close to inter-zonal lines, however, this option requires an AC-OPF model for inter-zonal congestion management.

If no congestion is detected in any zone or on inter-zonal lines, then the submitted preferred schedules are accepted as final real time schedules.

5.10.2 Formulation of Inter-Zonal Congestion Subproblem:

The objective of the inter-zonal subproblem is represented by a modified dc load flow for adjusting preferred schedules, where the ISO minimizes the net cost of re-dispatch as determined by the " SC's submitted incremental/decremental price bids. In this case, the objective is equivalent to the net power generation cost used in a conventional OPF.

For each deviation from the associated preferred schedule, a price function is provided, i.e., adjusting a generation (inc/dec) at a certain point may have a different price than that of other generators. Also, adjusting a load (dec) may present a price different from that generation or other load. These prices may represent a linear or nonlinear function of deviations, and price coefficients associated with deviations from preferred schedules reflect the SCs desire to be economically compensated for any increase or reduction in their preferred schedules. If a SC does not provide the ISO with inc/dec bids, the ISO will use inc/dec bids of other SCs for congestion management, and the SC who did not submit inc/dec bids would be automatically forced to pay congestion charges calculated according to other inc/dec bids. The formulation of this subproblem is given as follows:

Objective

- Modified dc power flow to adjust preferred schedules
- Minimize the net cost of re-dispatch as determined by incremental/decremental price bids
- Objective is equivalent to the net power generation cost used in a conventional OPF

Control variables

- SC's power generation in all congestion zones. For each generator a set of generation quantities with associated adjustments for incremental/decremental bids are submitted by SCs
- SCs' curtailable (adjustable) loads. For each load, a set of load quantities with associated adjustments for deeremental .bids are submitted by SCs. These adjustments are implicit bids for transmission across congested lines

Constraints

- Limits on control variables
- Nodal active power flow balance equations
- Inter-zonal line flow inequality constraints
- Market separation between SCs

5.10.3 Formulation of Intra-Zonal Congestion Subproblem: At each congested zone, the ISO will use a modified AC-OPF to adjust preferred schedules. The main goal is to minimize the absolute MW of re-dispatch by taking into account the net cost of redispatch as determined by the SC's submitted incremental/decremental price bids. This objective is equivalent to the MW security re-dispatch with incremental and decremental cost-based MW weighting factors to ensure that less expensive generators are incremented first and more expensive generators are decremented first during the adjustment process. For loads, most expensive loads will be decremented first.

In each zone, congestion management is performed separately while inter-zonal constraints are preserved. The formulation may assume that loads in each zone (at each bus) can contribute to the congestion relief.any generator or load at any zonal bus is not involved in congestion management and would not submit inc/dec bids, then its minimum and maximum limits are set to preferred schedule values. The formulation of this subproblem is given as follows:

Objective

- Modified AC-OPF To adjust preferred schedules
- Minimizet he MW re -dispatch by taking into account the net cost of re-dispatch as determined by the SC's submitted incremental/decremental price bids
- The objective is equivalent to the MW security re-dispatch with incremental/decremental cost-based weighting factors to ensure that less expensive generators are incremented first and more expensive generators are decremented first during the adjustment process. For loads, the moste xpensive ones will be decremented first.

Control variables

- SCs' power generation in congested zones. For each generator a set of generation quantities with associated adjustments for incremental/decremental bids are submitted by SCs

- SCs’ curtailable (adjustable) loads in the congested zone. For each load, a set of load quantities with associated adjustments for decremental bids are submitted by SCs
- Reactive power controls including:

1. Bus voltages
2. Reactive power injection
3. Phase shifters
4. Tap-transformers

Constraints

- Limits on control variables
- Nodal active and reactive power flow balance equations
- Intra-zonal MVA, MW, and MVAR line flow limits (inequality constraints)
- Active power flow inequality constraints of inter-zonal lines connected to the congested zone
- Voltage limits
- Stability limits
- Contingency imposed limits

Equality constraints represent the net injection of real and reactive power at each bus in the zone. Inequality constraints reflect real power flows between buses, and stability and thermal limits define line limits. If the MVA flow limit on lines is of interest, then the MVA in equality constraint is included.

The effect of phase-shifters and tap-transformers may be seen as injections of active power and reactive power at two ends of a line between nodes where phase-shifters and tap transformers are connected. Phase-shifters and tap-transformers could also be included in the formulation by modifying the network admittance matrix.

During the intra-zonal congestion management inter-zonal line flows to the zone under study are modeled as constant loads or generations (depending on the direction of flows in inter-zonal lines) buses connected to inter-zonal lines. This modeling has two advantages:

(1) It disregards inter-zonal line constraints that should be added to intra zonal constraints, and

(2) It cancels interactions between inter-zonal and intra-zonal congestion subproblems while solving the intra-zonal congestion subproblem. The schedules which will be adjusted in the intra-zonal subproblems are the schedules obtained from the inter-zonal congestion subproblem.

In the intra-zonal congestion management the incremental cost coefficient of a generator at a certain node in a zone is the same as the incremental bid price. The decremental cost coefficient of a generator at a certain node in a zone is anti-symmetric with the decremental bid price with respect to the average of decremental bids in that zone. This assumption is for economical consideration, where less expensive generators would be incremented first to relieve congestion, and more expensive generators would be decremented first when generation reduction is needed.

For example, if we have two generators with decremental price bids of $10/MWh for generator G_A and $16/MWh for generator GB then the average decremental price bid is (1O+16)/2=$13/MWh. The decremental cost coefficients of these generators are $16/MWh for G_A(or 2×13- 10) and $10/MWh(or 2x13 - 16) for GB. The same argument is made for load reduction where more expensive loads in a zone are adjusted (decremented) first, where load increment is not considered. For the case that we have more than one provider at each bus or more than one demand, in other words, we have more than one SC at one bus, we would indexdifferent providers at different locations in each zone. For that reason, we set three different indices in our formulation that would refer to SC, zone and bus.

Example 1.9

(a) Inter-Zonal Congestion Management

Fig. 1.23 shows a simple 2-bus, 2-zone system in a certain hour, with two scheduling coordinators (SCs), where G1,1, G1,2, refer to generation of generation of SC1 in zone 1(bus 1) and zone 2(bus 2), respectively. Also, D1,1and D1,2 refer to load of SC1 in zone 1 and zone 2, respectively, and D2,1 and D2,2 refer to load of SC2 in zone1 and zone2, respectively. The figure shows the preferred (initial) schedule of both SCs. Submitted incremental bids are given next to each generation in this figure. Incremental/deceremental bids of any SC represent its implicit bids for congested paths

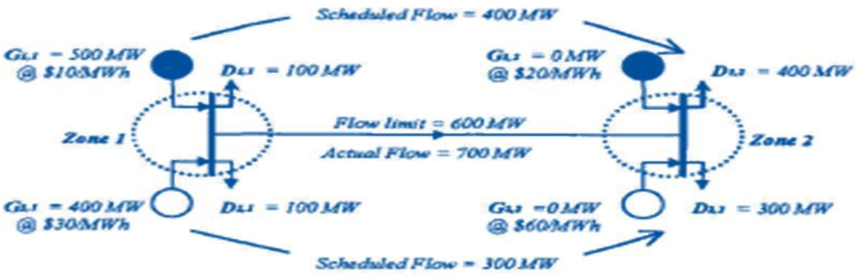


Figure 1.23 Preferred Schedules (before Congestion Management) of Example 1.19

As shown from figure 123, preferred schedule would result in a 100MW violation on the inter-zonal line between zone 1 and zone 2. SC1, produces 500MW in zone 1, where 100MW goes to its demand in this zone, and the rest (400MW) cross the inter-zonal line. Also SC2 produce 400MW in zone1, where 100MW goes to its demand in this zone, and the rest (300MW) crosses the inter-zonal line. For both SCs the flow from 1 to 2 would be 700MW.

Congestion charges:

SC_1 is the marginal user of the congested inter-zonal line. Therefore, SC_1 sets the price of the congested line at $10/MWh. The congestion charges for one hour are calculated as follows:

$$\begin{aligned} &SC1\ pays:\ 300\ MWh \times \$10/MWh &= \$3{,}000 \\ &SC2\ pays:\ 300\ MWh \times \$10/MWh &= \underline{\$3{,}000} \\ &\qquad\qquad\qquad\qquad\qquad Total &= \$6{,}000 \end{aligned}$$

The ISO receives $6,000 congestion charges from both SCs and then allocates the money to the transmission owner(s) and/or transmission right holder(s) on the path.

(b) Intra-zonal congestion management:

Let's assume that the 2-bus system shown in Figure 1.25 represents a certain congestion zone, and the values shown in the figure represent the schedules after the inter-zonal congestion management. We notice that the intra-zonal line connecting buses 1 and 2 is congested.

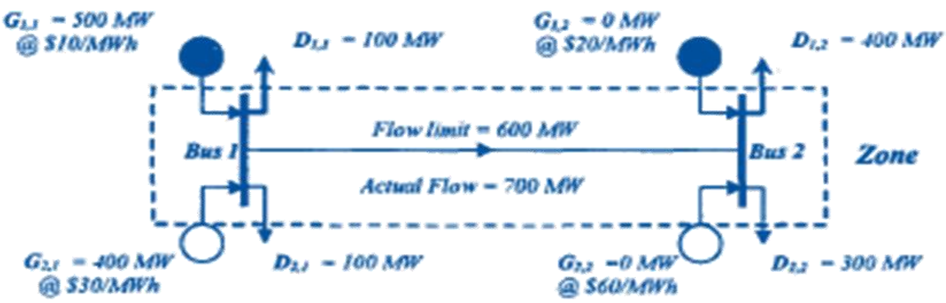


Figure 1.25 Schedules inside a Zone before Intra-zonal Congestion Management

The generator that has the highest decremental bid at bus 1 is $G_{2,1}$, so this generator will be decremented first. Also, the generator that has the lowest decremental bid at bus 2 is $G_{1,2}$, so this generator will be incremented first. We need to decrease the flow in the intra-zonal line by 100 MW, so $G_{2,1}$ is decreased by 100 MW and $G_{1,2}$ is increased by 100 MW. The solution is shown in Figure 1.26.

Intra-zonal congestion settlement:

$G_{2,1}$ which belongs to SC_2 decreased its output by 100 MW.
Payment by SC_2 to the ISO for $G_{2,1}$ is

$$100 \text{ MWh} \times \$30/\text{MWh} = \quad \$3{,}000$$

$G_{1,2}$ which belongs to SC_1 increased its output by 100 MW.
Payment by ISO to SC_1 for $G_{1,2}$ is

$$100 \text{ MWh} \times \$20/\text{MWh} = \quad \$2{,}000$$

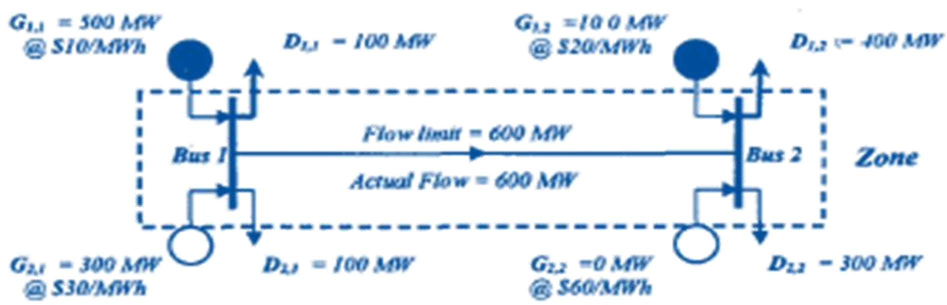


Figure 1.26 Schedules inside a Zone after Intra-zonal Congestion Management

Total balance of the ISO = \$3,000 - \$2,000 = \$1,000 (The ISO has a net of \$1,000). The balance (1,000) is located as a zonal uplift to SCs according to their load in and exports from the zone:

SC_1 gets : \$1,000 × 500 MW / 900 MW= \$555.56
SC_2 gets : \$1,000 × 400 MW / 900 MW= \$444.44

5.11 ELECTRICITY PRICE VOLATILITY: INTRODUCTION

The demand for electricity could vary significantly according to the time of day. Electricity demand is generally higher during day-time hours, known as the peak period and lower during night-time hours, known as the off-peak period.

In the restructured electric power industry, it is common to read or hear expressions such as "the volatility of electricity prices has been high during the period of

January and February % "the PX market will create an environment with volatile pricing - very low at times of low demand, high at times of high demand, and very high at times of high demand and limited supply ", "annualized volatility of on-peak prices ", "annualized volatility of off-peak prices '; "electricity markets are highly volatile", and similar expressions which point out the volatility of electricity market. This section provides a detailed explanation of volatility and its impact on electricity pricing. In addition, the section gives a brief mathematical background on volatility, shows some examples and discusses the main motive forces for causing volatility in electricity markets.

The fact that the cost of generating electricity is based mainly on the cost and the availability of the fuel used in generation does not change by switching from regulated monopoly to open access restructured markets. Utilities used to average their fluctuating hourly costs of electricity (which were based on economic dispatch) and come up with a single cost-based rate, and users on the other side were mandated to accept this rate. Some large customers were buying electricity on an hourly-based price. In a restructured environment, hourly prices are expected to swing as they used to, with a main difference that a competitor should be competing with a large number of other competitors. In this environment, competitors bid into the market, not necessarily based on their costs but on anticipated price that takes into account movements of other competitors, market situation and supply-demand condition. This behavior would cause increased price volatility and motivates customers to take proper actions.

In order to reduce price volatility in the energy market, a trading system may allow customers to sell electric energy back through the trading system in certain hours. In the following, we further discuss the factors which could contribute to volatility in electricity markets.

5.11.1 Factors in Volatility:

Every electricity market is expected to have variable price patterns while proceeding from one stage to the next. This .procession could be due to many factors such as entry of new players to the market, destructive gaming, bidding behavior, and availability of generation units and transmission components. As time passes, the market could correct itself to reach a final phase where prices would be predictable to a large extent and adequate rules could be implemented in modeling the whole marketing process.

During transient stages of restructuring in Britain, the electricity market experienced less price volatility due to the existence of what is called *vesting contracts,* but market participants suffered considerably from increasing uplift costs associated with ancillary services. As time passed, market rules were modified to correct the market behavior and stabilize prices. The Nordic Power Exchange (Nord Pool) has large price volatility because of its dependence on hydroelectric generation, which is in turn dependent on weather conditions, whether it is dry or rainy.

Various factors resulting in volatility include:

- **Load Uncertainty:** The power generation required to meet the load is directly correlated with weather conditions, which are sometimes unpredictable. Due to unexpected temperature changes, especially from low to high, the actual load could be at times very different from the forecasted load. If the weather forecast is uncertain, the load forecast could be uncertain.

- **Fuel Prices:** The fuel used by generating units to produce electricity is a volatile commodity with its price depending on market conditions such as demand-supply convergence conditions, transportation, storage expenses and other factors. Fossil fuel, hydro, nuclear and unconventional sources of energy could be used in generating electricity, with different costs, which are reflected on electricity prices. When marginal generating units use a certain type of fuel with fluctuating price, the electricity price could fluctuate as well.

- **Irregularity in Hydro-Electricity Production:** In some regions, hydro-electricity is produced rather inexpensively in certain times of the year due to the availability of water resources; in the remaining times of the year, thermal units are used when water quantity is reduced, which could impact electricity prices.

- **Unplanned Outages:** The imbalance between the supply and demand could cause large fluctuations in prices: When supply is less than demand or when demand is changing rapidly, price spikes could arise and when this is accompanied by a generation outage at peak hours, price spikes could be very high.

- **Constrained Transmission (Congestion):** When transmission capability is insufficient to withstand scheduled flows, the price of electricity on the load side of a congested path could be increasingly volatile and uncertain because smaller low-cost generation cannot be transmitted to loads during hours when transmission congestion exists.

- **Market Power:** Exercising market power by electricity market participants could manipulate prices and cause price volatility. In California, the PX monitors market operations, and trading rules would be altered to prevent market manipulation when these practices could arise. Market participants may use financial contracts to hedge price volatility risks. At the same time that the volatility in prices could cause large losses, it could also cause large profits if predicted earlier.

- **Market** Participant: Market participants themselves may cause price volatility in one of two ways: either by misrepresenting the actual amount of their loads or by performing gaming practices. In the first type, participants either under-schedule or over-schedule their loads. Both cases would require a response from the ISO in the imbalance energy market. Under-scheduled load may significantly change the price of energy in the imbalance market when reserves are inadequate.

5.11.2 Measuring Volatility:

Historical volatility is defined as the annualized standard deviation of percent changes in futures prices over a specific period. It is an indication of past volatility in the marketplace. In historical volatility, a financial variable's volatility is directly estimated from recent historical data for the variable's value. Historical volatility gives an indication of how volatile the variable has been in the recent past for which historical data is tracked. Implied volatility is a measurement of the market's expected price range of the underlying commodity futures based on market-traded options premiums3. Implied volatility is a timely measure, which reflects the market's perceptions today. Implied volatility can be biased, especially if they are based upon options that are thinly traded.

We use *standard deviation (σ),* which measures the uncertainty or dispersal of a random variable. When a financial variable (random variable) such as electric energy price is described as highly volatile, it means that it has a high standard deviation. In other words, standard deviation is a measure of the volatility of a random variable such as spot price. Figure 7.2 illustrates how standard deviation would measure the high volatility (Figure 7.2.a) and low volatility (Figure 7.2.b). Probability distribution functions in both cases are given in Figures 7.2.c and 7.2.d.

As shown in Figure 7.2, standard deviation for a specific range of a random variable X is a measure of the width of the probability distribution of the variable X. Standard deviation (i.e., square root of variance) is a measure of risk. On the other hand, the variance (expected value of squared deviations from the mean) is a measure of the dispersion of a probability distribution. As we all know,

Standard deviation =

$$\sigma = \sqrt{\text{Expected value of } [X^2] - (\text{Expected value of } [X])^2}$$

$$= \sqrt{E[X^2] - (E[X])^2}$$

Variance $= \sigma^2 = E[X^2] - (E[X])^2$

Volatility[5] $= v = \sigma / \sqrt{t}$; t=1/252[6]

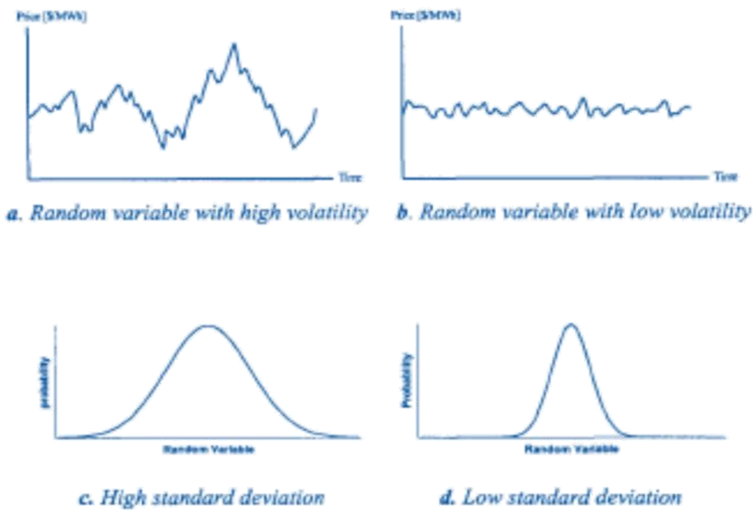


Figure 7.2 Volatility-Standard Deviation Relations

5.12 ELECTRICITY PRICE INDEXES:

To analyze price volatility, Dow Jones (D J) price indexes are used. Dow Jones publishes volume-weighted price indexes for the following locations (as was available on January 13, 2001):

- **California Oregon Border:** The Dow Jones California Oregon Border (D J-COB) Electricity Index is the weighted average price electric energy traded at the California-Oregon and Nevada-Oregon Borders, quoted in dollars per megawatt hour. Volume is in megawatt hours.
- **Palo Verde:** The Dow Jones Palo Verde (DJ-PV) Electricity Index the weighted average price of electric energy traded at Palo Verde and West Wing, Arizona, quoted in dollars per megawatt hour. Volume is in megawatt hours.
- **PJM Sellers' Choice:** The Dow Jones Pennsylvania-New Jersey- Maryland (DJ-PJM) Sellers' Choice Electricity Index is the weighted average price of electric energy traded for delivery in the Pennsylvania, New Jersey, Maryland market, quoted in dollars per megawatt hour. Volume is in megawatt hours.
- **PJM Western Hub:** The Dow Jones Western Hub Electricity Index is the weighted average price of electric energy traded at PJM Western Hub quoted in dollars per megawatt hour. Volume is in megawatt hours.
- **Mid-Columbia:** The Dow Jones Mid-Columbia Electricity Index is the weighted average price of electric energy traded for delivery at Mid-Columbia quoted in dollars per megawatt hour. Volume is in megawatt hours.
- **Four corners (4C):** The Dow Jones Four Corners (DJ-4C) Electricity Index is the weighted average price of electricity traded for delivery at Four Corners, Ship

rock and San Juan, New Mexico, quoted in dollars per megawatt hour. Volume is in megawatt hours.

- **NP-15:** The Dow Jones NP-15 Electricity Index is the weighted average price of electric energy traded for delivery at NP- 15 quoted in dollars per megawatt hour. Volume in megawatt hours.
- **SP-15:** The Dow Jones SP-15 Electricity Index is the weighted average price of electricity traded for delivery at SP-15 quoted in dollars per megawatt hour. Volume is in megawatt hours.
- **Cinergy:** The Dow Jones Cinergy Electricity Index is the weighted average price of electricity traded into the Cinergy Control Area quoted in dollars per megawatt hour. Volume is in megawatt hours.
- **Mead/Market P lace:** The Dow Jones Mead/Market Place Electricity Index is average price of electric energy traded for delivery at Mead, Market Place, McCullough and Eldorado quoted in dollars per megawatt hour. Volume is in megawatt hours.

DJ on-peak price index for COB may be compared with the on-peak PX day-ahead prices. Likewise, DJ on-peak price index for the Palo Verde (PV) may be compared with the on-peak PX day-ahead prices. Analyzing different trade operations, some specific factors are compared such as average prices, volumes of trades and volatility. The analysis can give an indication of price stability during a time period, trends in prices either declining or inclining and comparisons of volumes of trade between different locations. For example, in California, a comparison could be made for volumes traded on PX, COB and PV.

5.12.1 Basis Risk: The difference between the electricity spot price and the price of the nearest futures contract for the electricity at any given time is called basis. Basis risk represents the uncertainty as to whether the cash-futures spread will widen between the times a hedge position is implemented and liquidated.

5.13 CHALLENGEST O ELECTRICITY PRICING:

5.13.1 Pricing Models: One of the major problems facing market participants, especially hedgers, in restructured electricity markets in the U.S. is the problem of large errors caused by using unsophisticated versions of the Black-Scholes1° model to price physical power options. This model was originally derived as a pricing model to value European securities options and futures options. In addition to other assumptions, this model assumes that the price volatility is constant and the price series is continuous. Some alternatives to pricing physical power options have been proposed based on this model to take into consideration the nature of electricity that is different from other commodities.

Some market participants insist on utilizing pricing models other than the Black-Scholes model. It is claimed that using the Black-Scholes model to price electricity options would result in large errors due to the assumptions that this model applies to electricity without taking into account the market's special circumstances. The Black-Scholes proposes the following price dynamics.

$$\frac{dF(t,T)}{F(t,T)} = b\,dW(t)$$

where,

$F(t,T)$	Price at time t for future delivery of power at time T
b	Constant Volatility
dW(t)	Standard Brownian motion[11] (also known as Wiener Process)

When this model is used to price the hourly or daily delivery of electric power, some problems could arise. These problems are:

(1) Customer loads are following complex daily patterns and are sensitive to weather fluctuations which implies high volatility: The classical Black-Scholes model assumes a constant volatility, does not take into account the weather impact on volatility over the period of the option and does not discriminate between on-peak and off-peak conditions.

(2) Electricity is a non-storable commodity: The short-term supply is largely affected by physical system dynamics such as generation and transmission outages that would result in large price spikes. The Black-Scholes model assumes smooth price changes under these circumstances.

(3) Generating units could be forced out in unplanned manner during peak-demand summer months. Unplanned outages cause electricity prices to increase dramatically in the market due to the fact that more expensive units will be needed to serve the load.

In a nutshell, any frame work to price physical power options should take some factors into consideration. These factors include the physical nature of electricity, generation availability, dynamic volatility, transmission limitations and changeable load.

5.13.2 Reliable Forward Curves:

A forward curve of electricity presents a set of forward prices for electricity, i.e. it determines a set of current market prices for the sale of electricity at specified times in the future; the curve determines the present value of electricity to be delivered in the future. For other commodities that have been traded for a long time, forward curves are readily established, but for electricity in a restructured environment, much of the appropriate market information is not yet available due to the short experience. The challenge is to construct and use forward curves based on limited available data.

Forward curves in electricity markets work as bench mark or index of value. When the curve shows higher future prices, current values of production facilities and purchase agreements will increase. On the other hand, a decreasing forward curve means that the value of existing sales agreements and a utility's customer base are decreasing. In the next section, we will elaborate on forward curves.

Constructing forward curves should take the risk explicitly into account: incorporate estimates of market uncertainty in ways that will be most useful for decision-making and integrate forward curves into participants' own analytical models. To build a forward curve for midterm prices, futures and options prices should be analyzed coupled with the probabilistic system modeling. Even though the load growth and fuel price shifts affect long-term electricity prices considerably, long-term electricity prices are driven by performance improvements such as improvements in new generation technology. For long-term prices, market data provide little guidance in constructing forward curves and building the curve is mainly based on the probabilistic system modeling, asset investment and retirement analysis.

5.14 CONSTRUCTIONO F FORWARDP RICE CURVES:

5.14.1 Time Frame for Price Curves: Constructing a forward curve depends mainly on a time frame, which may be for a few months (short-term), a few years (medium-term) or over several years (long-term). In short-term, the price of electricity changes mainly with changes in weather conditions, supply outages, and interregional power flows. In short-term, guidance is offered by historical spot price data coupled with deterministic system modeling. Load growth, shifts in fuel price, and customer response to retail price changes would determine medium-term price fluctuations.

5.14.2 Types of Forward Price Curves:

As was mentioned in the preceding section, one of the major challenges facing market participants is the lack of reliable long-dated forward prices. In restructured power markets, suppliers are competing to reach end-use customers with the lowest possible price that would guarantee profits. Wining a customer's contract is generally based on pricing strategies that would take into account electricity market trends and the information on the true cost of serving customers. The forward price of electricity is the key in pricing retail and wholesale electricity. Forward curves represent a good starting criterion to price electricity and, if utilized with experience in knowing variations in customer characteristics and supply/demands situations, they produce hedging strategies for different market participants such as suppliers, marketers, independent power suppliers and others.

In this section, we highlight this topic which is very important in restructured electricity markets and the resources on this topic are very rare.

- Forward curves take on three behaviors: Backwardation, Contango, and a combination of the two.

- **Backwardation:** It. is a market situation in which futures prices are lower in each succeeding delivery month. In other words, backwardation refers to markets where shorter-dated contracts are traded at a higher price than that of longer-dated contracts. Backwardation is also called the inverted market, and it is expressed by plotting the price variation with time as shown in Figure 7.8, where electricity price curve slops downwards as time increases. Backwardation gives a forward/spot market relationship in which the forward price is lower than the spot price. The cause of backwardation in electricity markets is that it is necessary for forward prices to trend upward towards the expected spot price in order to attract speculators (buyers) to enter into trades with hedgers (sellers). The opposite of backwardation is contango.

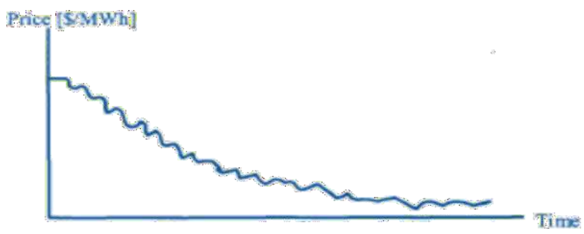


Figure 7.8 Illustration of Backwardation (Inverted Market)

- **Contango:** Opposite to the case of backwardation, contango is a term often used to refer to electricity markets where shorter-dated contracts traded at a lower price than longer-dated contracts in futures markets. Whena market situation exists such that prices are higher in the succeeding delivery months thanin the nearest delivery month, we say contango exists. It is expressed by plotting the prices of contracts against time, where electricity price curve slops upwardsas time increases as shown in Figure 7.9. contango gives a forward]spot market relationship in which the forward price is greater than the spot price. Often, the forward price exceeds the spot price by approximately the net cost to carry/finance the spot electricity or security until the settlement date of the forward contract.

- **Combination:** Figure 7.10 shows a combination of the two previously mentioned behaviors of forward curves. This is an example of a situation when the forward curve takes a backwardation form in the short-term part of the curve and a combination of two in the long-term part of the curve. The behavior of the curve depends on expectations regarding the supply/demand balance in the market in addition to other seasonal factors that drive prices. In the following, we will discuss the forecasting process for the short-term price of electricity.

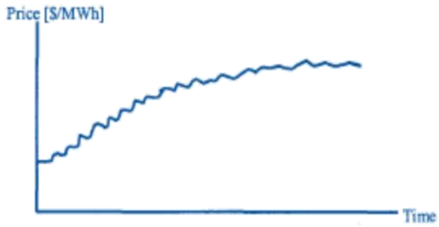


Figure 7.9 Illustration of Contango

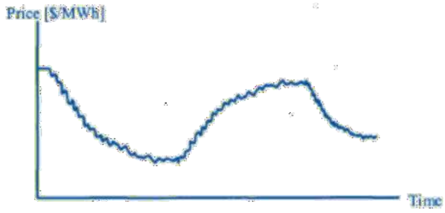


Figure 7.10 A Forward Curve Combines Backwardation and Contango

5.15 SHORT-TERM PRICE FORECASTING:

There are many physical factors that would impact short-term electricity price. In practice, it would be impossible to include all these factors in price forecasting, because either the factors are unknown or the related data are unavailable. The sensitivity analysis is a good way of selecting the prominent factors in price forecasting. Given a factor, if the price is insensitive to this factor, we could claim that the factor is not impacting the price and could be ignored with minute error in price forecasting.

5.15.1 Factors Impacting Electricity Price:. An analysis of price movements presents a conceptual understanding of how factors could affect the price. For simplicity, we only discuss variations of spot price, or market clearing price (MCP) in this section.

After an auctioneer (ISO or PX) receives supply and demand bids, aggregates the supply bids into a supply curve (S) and aggregates the demand bids into a demand curve (D). The intersection (S) and represents the MCP, as is illustrated in Figure 7.11.

According to this figure, we would present the following discussions.

(1) Basic Analysis of Price Movements

- Case BI: S curve is shifted upward: MCP increases and quantity decreases.
- Case B2: S curve is shifted downward: MCP decreases and quantity increases.
- Case B3: D curve is shifted upward: MCP increases and quantity increases.
- Case B4: D curve is shifted downward: MCP decreases and quantity decreases.
- Case B5: S curve is shifted to the left: MCP increases and quantity decreases.
- Case B6: S curve is shifted to the right: MCP decreases and quantity increases.
- Case B7: D curve is shifted to left: MCP decreases and quantity decreases.
- Case B8: D curve is shifted to right: MCP increases and quantity increases.

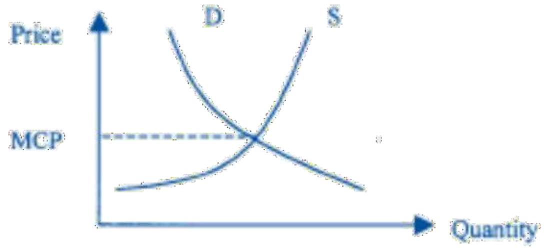


Figure 7.11 Calculation of MCP

(2) Actual Cases Pertaining To The Above Price Movements

- Case A1: Supplier would decrease the price. This is case B2.
- Case A2: Demand would increase the price. This is case B3.
- Case A3: A generator would be force-outaged (or a bid is withdrawn). This is case B5.
- Case A4: A new supplier would enter the market. This is case B6.
- Case A5: A generator would be restored. This is case B6.
- Case A6: A new demand would enter the market. This is case B8.
- Case A7: Gas (or oil) price would decrease. Suppliers would then decrease their prices. So, it is case B2.
- Case A8: Gas (or oil) price would increase. Suppliers would then increase their price. So, it is case B1.

It is vital to perform the above seemingly simple analysis, as it would exhibit the variation of price in practical markets. For example, we would learn, from the above analysis, that the price of gas (or oil) could affect MCP.

5.15.2 Forecasting Methods:

- **Simulation Method:** Usually the analysis of price volatility is based on the probability distribution for each of a series of key drivers. The users can determine the distribution of input variables using historical data. For example providers could use a beta distribution, which requires the estimation of the maximum, minimum and the most likely value of input variables. To capture the effects of uncertainty, samples are drawn from the distribution of the input variables using Monte Carlo methods and a scenario is created. For each scenario the tool is used to simulate the market prices. Running a sufficient number of scenarios then produces a stable distribution of long-term market prices.

- **Artificial Neural Network Method:** The artificial neural network method has received more attention in the field of forecasting because of its clear model, easy implementation and good performance. The method was applied before to load forecasting in electric power systems. Here, we use the MATLAB for training the artificial neural network in short-term price forecasting, which provides a very powerful tool for analyzing factors that could impact electricity prices.

5.15.3 ANALYZING FORECASTING ERRORS:

Let V_a be the actual value and V_f the forecast value. Then, Percentage Error (PE) is defined as

$$PE = (V_f - V_a) / V_a \times 100\% \tag{7.6}$$

and the Absolute Percentage Error (APE) is

$$APE = |PE| \tag{7.7}$$

then, the Mean Absolute Percentage Error (MAPE) is given as

$$MAPE = \frac{1}{N} \sum_{i=1}^{N} APE_i \tag{7.8}$$

MAPE is widely used to evaluate the performance of load forecasting. However in price, forecasting, MAPE is not a reasonable criterion as it may lead to inaccurate representation. The problem with this MAPE is that if the actual value is large and the forecasted value is small, then APE will be close to 100%.I n addition, if the actual value is small, APE could be very large if the difference between actual and forecasted values is small. For instance, when the actual value is zero APE could reach infinity if the forecast is not zero. So, there is a problem with using APE for price forecasting. It should be noted that this problem does arise in load forecasting, since actual values are rather large, while price could be very small or even zero.

Alternate Definition of MAPE: On e proposed alternative is as follows. First we definethe average value for a variable V:

$$\overline{V} = \frac{1}{N} \sum_{i=1}^{N} V_a \tag{7.9}$$

Then, we redefine PE, APE and MAPE as follows:

Percentage Error (PE):

$$PE = (V_f - V_a) / \overline{V} \times 100\% \tag{7.10}$$

Absolute Percentage Error (APE):

$$APE = |PE| \tag{7.11}$$

Mean Absolute Percentage Error (MAPE):

$$MAPE = \frac{1}{N} \sum_{i=1}^{N} APE_i \tag{7.12}$$

The point here is that we would use the average value as the basis to avoid the volatility problem.

5.15.4 Practical Data Study: In this section, we use artificial neural networks to study price forecasting based on the practical data. We will study the impact of data pre-processing, quantities of training vectors, quantities of impacting factors, and adaptive forecasting on price forecasting. We will also compare the artificial neural network method with alternative methods. The new definition of MAPE is illustrated with practical data and its advantages are discussed.

5.15.4.1 Impact of Data Pre-Processing:

The improvement in training MAPE is due to the disappearance of price spikes (excluded or limited). Consequently, without price spikes, network training can find a more general mapping between input and output. Thus, testing MAPE will also be improved.

Since price spikes are the indicative of abnormality in the system, we do not intend to delete them from the training process. Hence, we adhere to the option of limiting the magnitude of spikes, rather than eliminating them totally.

5.15.4.2 Impact of Training Vectors:

At first, by introducing more training vectors, we present a more diverse set of training samples, which would result in a more general input-output mapping. Thus, the forecasting performance, measured by the testing MAPE, would improve. However, as we keep increasing the number of training vectors, the diversity of training samples would no longer expand and the additional training would not improve the forecasting results. Thus, the forecasting performance would remain fiat. We should point out that by further increasing the number of training vectors, the artificial neural network could be over trained. In other words, the artificial neural network would have to adjust its weights to accommodate the input-output mapping of a large number of training vectors that may not be similar to the testing data to a large extent. Thus, the forecasting performance could get worse with further increasing the number of training vectors.

5.15.4.3 Impact of Adaptive Forecasting: We can either use the fixed training weights or upgrade the weights frequently and adaptively according to the test results. We refer to the latter case as our adaptive forecasting method. Studying the profile of price curves, we would expect that the adaptive modification of network weights would provide a better forecast.

5.16 CONCLUSIONS:

The demand for price transparency increased ever since the restructuring process began and the number of participants and marketing operations increased. This is due to the need to enhance the financial stability of electricity markets, which is in turn due to changes in strategies or approaches to buy and sell electricity, which is completely different from the traditional methods under the regulated monopoly.

Add to that is mergers of new financial tools and entry of non-electricity participants in electricity markets. All these facts motivated participants to demand efficient tools for price discovery in order to hedge their risks and survive in a competitive market. In this chapter, we have reviewed some basic concepts in electricity price forecasting, such as price calculation and price volatility. Becauseof its importance, we also discussed the issue on factors impacting electricity price forecasting, including time factors, load factors, historical price factor, etc. We used the artificial neural network method to study the relationship between thesefactors and price. We proposed a more reasonable definition on MAPE to avoid the demerits of traditional methods on measuring forecasting in the context of electricity price forecasting. Practical data study showed that a good data pre- processing was helpful, i.e., using too many training vectors or considering too many factors is not good for price forecasting. Practical data study also showed adaptive forecasting could improve forecasting accuracy. We concluded that theartificial neural network method is a good tool for price forecasting as comparedto other methods in terms of accuracy as well as convenience.