Lecture –Notes

Restructuring Power System

Subject Code: 5EE5-11

Course: B. Tech.

Year & Semester: III year, Sem.-V

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Department: Electrical Engineering

Subject –Restructuring Power System

Subject Code: 5EE5-11

VISSION OF INSTITUTE

To become a renowned centre of outcome based learning, and work towards academic, professional, cultural and social enrichment of the lives of individuals and communities.

MISSION OF INSTITUTE

- Focus on evaluation of learning outcomes and motivate students to inculcate research aptitude by project based learning.
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- Offer opportunities for interaction between academia and industry.
- Develop human potential to its fullest extent so that intellectually capable and imaginatively gifted leaders may emerge.

VISION OF EE DEPARTMENT

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- Graduates will be able to contribute for the development of automation.
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Program Outcomes

1. Engineering knowledge: Apply the knowledge of mathematics, science, engineering fundamentals, and an engineering specialization to the solution of complex engineering problems.

2. Problem analysis: Identify, formulate, research literature, and analyze complex engineering problems reaching substantiated conclusions using first principles of mathematics, natural sciences, and engineering sciences.

3. Design/development of solutions: Design solutions for complex engineering problems and design system components or processes that meet the specified needs with appropriate consideration for the public health and safety, and the cultural, societal, and environmental considerations.

4. Conduct investigations of complex problems: Use research-based knowledge and research methods including design of experiments, analysis and interpretation of data, and synthesis of the information to provide valid conclusions.

5. Modern tool usage: Create, select, and apply appropriate techniques, resources, and modern engineering and IT tools including prediction and modeling to complex engineering activities with an understanding of the limitations.

6. The engineer and society: Apply reasoning informed by the contextual knowledge to assess societal, health, safety, legal and cultural issues and the consequent responsibilities relevant to the professional engineering practice.

7. Environment and sustainability: Understand the impact of the professional engineering solutions in societal and environmental contexts, and demonstrate the knowledge of, and need for sustainable development.

8. Ethics: Apply ethical principles and commit to professional ethics and responsibilities and norms of the engineering practice.

9. Individual and team work: Function effectively as an individual, and as a member or leader in diverse teams, and in multidisciplinary settings.

10. Communication: Communicate effectively on complex engineering activities with the engineering community and with society at large, such as, being able to comprehend and write effective reports and design documentation, make effective presentations, and give and receive clear instructions.

11. Project management and finance: Demonstrate knowledge and understanding of the engineering and management principles and apply these to one's own work, as a member and leader in a team, to manage projects and in multidisciplinary environments.

12. Life-long learning: Recognize the need for, and have the preparation and ability to engage in independent and life-long learning in the broadest context of technological change.

Syllabus: Restructuring Power System

1. Introduction: Objective, scope and outcome of the course.

2. Introduction to restructuring of power industry: Reasons for restructuring of power industry; Understanding the restructuring process, Entities involved, The levels of competition, The market place mechanisms, Sector-wise major changes required; Reasons and objectives of deregulation of various power systems across the world.

3. Fundamentals of Economics: Consumer and suppliers behaviour, Total utility and marginal utility, Law of diminishing marginal utility, Elasticity of demand and supply curve, Market equilibrium, Consumer and supplier surplus, Global welfare, Deadweight loss.

4. The Philosophy of Market Models: Monopoly model, Single buyer model, Wholesale competition model, Retail competition model, distinguishing features of electricity as a commodity, Four pillars of market design, Cournot, Bertrand and Stackelberg competition model.

5. Transmission Congestion Management: Transfer capability, Importance of congestion management, Effects of congestion, Classification of congestion management methods, ATC, TTC, TRM, CBM, ATC calculation using DC and AC model, Nodal pricing, Locational Marginal Prices (LMPs), Implications of nodal pricing, Price area congestion management Capacity alleviation methods, Re-dispatching, Counter-trade, Curtailment.

6. Ancillary Service Management: Type and start capability service, Provisions of ancillary services, Markets for ancillary services, Co-optimization of energy and reserve services, Loss of opportunity cost, International practices of ancillary services.

7. Pricing of transmission network usage and Market power: Introduction to transmission pricing, Principles of transmission pricing, Classification of transmission pricing, Rolled-in transmission pricing paradigm. Attributes of a perfectly competitive market, the firm's supply decision under perfect competition, Imperfect competition, Monopoly, Oligopoly. Effect of market power, Identifying market power, HHI Index, Entropy coefficient, Lerner index.

Restructuring Power System

Unit-I

Introduction: Objective, scope and outcome of the course.

Course Outcomes

CO1: Understand the need for restructuring of Power Systems, discuss different market models, different stakeholders and market power.

CO2: Understand and generalize the functioning and planning activities of ISO, transmission open access pricing issues and congestion management.

CO3: Analysis of power transfer capability, estimate, ancillary services and understand principles of transmission pricing.

CO-PO Mapping of Restructuring Power System.

CO	PO1	PO2	PO3	PO4	PO5	PO6	PO7	PO8	PO9	PO10	PO11	PO12
CO1	H	H	L	M	L	-	-	-	M	L	-	-
CO2	H	M	L	L	L	-	-	-	M	-	-	-
CO3	M	M	L	L	M	-	-	-	M	-	-	-

Restructuring Power System

Unit-II

Introduction to restructuring of power industry:

The power industry across the globe is experiencing a radical change in its business as well as in an operational model where, the vertically integrated utilities are being unbundled and opened up for competition with private players. This enables an end to the era of monopoly. Right from its inception, running the power system was supposed to be a task of esoteric quality. The electric power was then looked upon as a service. Control consisting of planning and operational tasks was administered by a single entity or utility.

The reason for monopoly can be traced right back to the early days when electricity was comparatively a new technology. The skeptical attitude of the government towards electricity led to investment by private players into the power sector, who in turn, demanded for the monopoly in their area of operation. This created a win-win situation for both- government and the electrical technology promoters. However, the government would not let the private players enjoy the monopoly and exploit the end consumer and hence introduced regulation in the business. Thus, the power industries of initial era became regulated monopoly utilities.

Reasons for restructuring of power industry:

Reasons for restructuring of power industry; Understanding the restructuring process, Entities involved, The levels of competition, The market place mechanisms, Sector-wise major changes required; Reasons and objectives of deregulation of various power systems across the world.

The arrangement of the earlier setup of the power sector was characterized by operation of a single utility generating, transmitting and distributing electrical energy in its area of operation. Thus, these utilities enjoyed monopoly in their area of operation.

The regulations are generally imposed by the government or the government authority. These essentially represent a set of rules or framework that the government has imposed so as to run the system smoothly and with discipline, without undue advantage to any particular entity at the cost of end consumer. All practical power systems of earlier days used to be regulated by the government. This was obviously so. The old era power industries were vertically integrated utilities and enjoyed monopoly in their area of operation. Whenever a monopoly is sensed in any sector, it is natural for the government to step in and set up a framework of way of doing business, in order to protect end consumer interests. Some of the characteristics of monopoly utility are

1. Single utility in one area of operation enjoying monopoly.
2. Regulated Framework: The utility should work under the business framework setup by the government.
3. Universal Supply Obligation (USO): Utility should provide power to all those customers who demand for it.
4. Regulated Costs: The return on the utility's investments is regulated by the government.

Reasons for restructuring or deregulation of power industry, one can sense discontinuation of the framework provided by the regulation. In other words, deregulation is about removing control over the prices with introduction of market players in the sector. However, this is not correct in a strict sense. An overnight change in the power business framework with provision of entry to competing suppliers and subjecting prices to market interaction, would not work successfully. There are certain conditions that create a conducive environment for the competition to work. These conditions need to be satisfied while deregulating or restructuring a system. Sometimes, the word 'deregulation' may sound a misnomer. 'Deregulation' does not mean that the rules won't exist. The rules will still be there, however, a new framework would be created to operate the power industry.

It should be noted that these are the indicative or major reasons for introducing the concept of deregulation in power industry. There are many other reasons as well. One of the important reasons is the condition under which power systems were regulated, did not exist anymore. There was no wind of skepticism about the electrical technology and all the initial investments in infrastructure were already paid back. Further, the deregulation aims at introducing competition at various levels of power industry. The competition is likely to bring down the cost of electricity. Then, the activities of the power industry would become customer centric.

The competitive environment offers a good range of benefits for the customers as well as the private entities. It is claimed that some of the significant benefits of power industry deregulation would include:

1. Electricity price will go down: It is a common understanding that the competitive prices are lesser than the monopolist prices. The producer will try to sell the power at its marginal cost, in a perfectly competitive environment.

2. Choice for customers: The customer will have choice for its retailer. The retailers will compete not only on the price offered but also on the other facilities provided to the customers. These could include better plans, better reliability, better quality, etc.

3. Customer-centric service: The retailers would provide better service than what the monopolist would do.

4. Innovation: The regulatory process and lack of competition gave electric utilities no incentive to improve or to take risks on new ideas that might increase the customer value. Under deregulated environment, the electric utility will always try to innovate something for the betterment of service and in turn save costs and maximize the profit.

Understanding the restructuring process:

Electricity, as a commodity, cannot be compared with any other commodity traded in the market. This is because it has some distinguishing characteristics of its own, which demand satisfaction of technical constraints before accomplishing the commercial trades. Two important features of electricity as a commodity are: need for real time balance and inability to wheel the commodity through desired path (in bulk). Hence, a set of principles laid down by standard micro-economic theory cannot be mapped directly to the electricity commodity markets.

Tackling network congestion is one of the challenging issues of the de-regulated era. Transmission network provides the path through which transactions are made in a power market. But each transmission network has its own physical and operating limits like line flow limits, bus voltage magnitude limits and more. The power injection and withdrawal configuration should be such that no limit gets violated. If the network is operated beyond these limits, it may, even, result in the entire system blackout. Therefore, any arbitrary set of transactions can't be organized on the power network. This has given rise to a new problem under the restructured power system environment, referred to as congestion management. There are many ways in which congestion is formally defined but to explain in simple words, when some components in a power network appear to be overloaded due to a trading arrangement, that particular arrangement is said to create congestion on the network. The purpose of congestion management is to make necessary corrections in order to relieve congestion. It can be easily appreciated that under the vertically integrated structure, network congestion, in fact, is not a challenging task. This is because all the resources in the system are under the direct control of the monopolist. Thus, this is the sole responsibility of the monopolist to maintain its transmission network.

Provision of ancillary services is another tough task carried out by the system operator under the deregulated framework. Ancillary services are defined as all those activities on the interconnected grid that are necessary to support the transmission of power while maintaining reliable operation and ensuring the required degree of quality and safety. Under the deregulated power system environment, the system operator acquires a central coordination role and carries out the important responsibility of providing for system reliability and security. It manages system operations like scheduling and operating the transmission related services. The SO also has to ensure a required degree of quality and safety and provide corrective measures under contingent conditions. In this respect, certain services, such as scheduling and dispatch, frequency regulation, voltage control, generation reserves, etc. are required by the power system, apart from basic energy and power delivery services. Such services are commonly referred to as ancillary services. In deregulated power systems, transmission networks are available for third party access to allow power wheeling. In such an environment, the ancillary services are no longer treated as an integral part of the electric supply. They are unbundled and priced separately and system operators may have to purchase ancillary services from ancillary service providers.

Then, there are certain issues like market design and market power which need regulatory intervention. Issues pertaining to market design revolve around choice made in the selection of dispatch philosophies, choice of various pricing schemes, choice between number of markets with multiple gate closures, etc., from various alternatives. The market architecture, which maps various markets on timeline, is also an important sub-topic of market design process.

Existence of market power shows the signs of deviation from the prefect competition. In general, market power is referred to as ability of market participants to profitably maintain the market price above or below the competitive level for a significant period of time. To tackle the situation, an indirect regulatory intervention in the form of market design rules is needed. Thus, as mentioned earlier, deregulation does not mean ceasing to have rules. It is the 'restructuring' of the power business framework. More rigorous treatment to these issues is given in further chapters.

Benefits of Deregulation: The competitive environment offers a good range of benefits for the customers as well as the private entities. It is claimed that some of the significant benefits of power industry deregulation would include:

1. Electricity price will go down: It is a common understanding that the competitive prices are lesser than the monopolist prices. It significantly reduces the cost of power charged to small business and customers. The cost of electricity generation will be reduced by driving prices through market forces and more competition.

2. Choice for customers: The customer will have choice for its retailer. The retailers will compete not only on the price offered but also on the other facilities provided to the customers. These could

include better plans, better reliability, better quality, etc. This will provide greater incentives for short and long term efficiencies than is provided by economic regulation.

3. Customer-centric service: The retailers would provide better service than what the monopolist would do.

4. Innovation: The regulatory process and lack of competition gave electric utilities no incentive to improve or to take risks on new ideas that might increase the customer value.

5. Under deregulated environment, the electric utility will always try to innovate something for the betterment of service and in turn save costs and maximize the profit.

6. Restructuring in electricity industry will create new business opportunities where new firms selling new products and services will appear, consumers will have alternatives in buying electricity services, and new technologies such as metering and telecommunication devices will develop.

Disadvantages of Deregulation:

1. Improper implementation or quick implementation of restructuring may lead to very high whole sale market prices leading to electricity crisis like that happened in California in 2000-2001, which threatened to collision its economy and caused security damage throughout the West.

2. Employee Uncertainty: Restructuring often causes employees to panic and wonder how the changes will affect their job security. When the news gets out that the company is restructuring, some employees may begin looking for new employment.

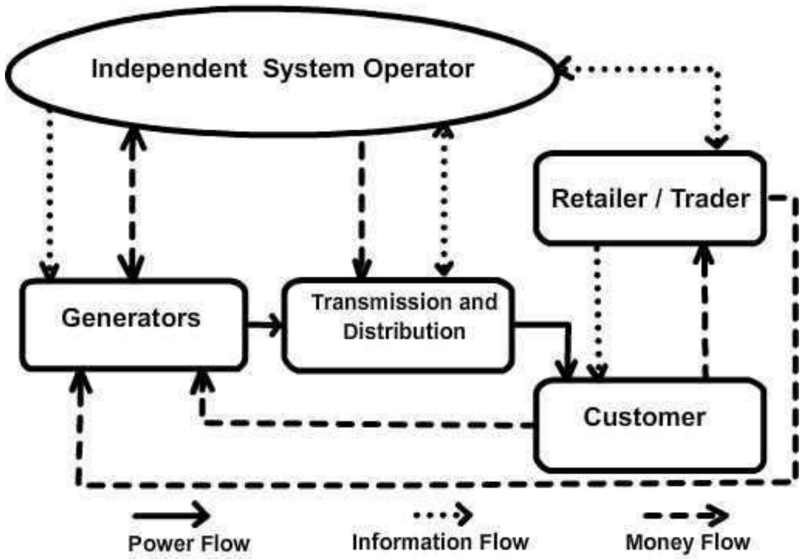
3. The stress of the restructuring sometimes takes away from the staff's focus on their actual work.

Understanding the deregulation process:

The process of deregulation has taken different formats in different parts of the world. Also, the reasons for power sector to adopt the reforms vary from country to country. For the developed countries, introduction of competition to achieve social welfare was probably the most important reason. On the other hand, the developing countries mainly banked on the capacity addition through entry of private players. It is observed that neither, there is lone reason for driving deregulation of power industry nor is there a single objective of the same.

The restructuring process starts with the unbundling of the originally vertically integrated utility. For example, the unbundling of power industry involves separating transmission activity from the generation activity. Further, distribution can be separated from transmission. Thus, these three mutually exclusive functions are created and there are separate entities or companies that control these functions. Then, the competition can be introduced in the generation activity by allowing other private participants in this segment. In contrast to the vertically integrated case where all the generation is owned by the same utility, there is a scope for private players to sell their generation at competitive prices. The generators owned by the earlier vertically integrated utility will then compete with these private generators.

The transmission sector being a natural monopoly is most unlikely to have competing players in the sector. This is because for natural monopolies like transmission companies, the business becomes profitable only when output is large enough. The figure shows the representative structure of deregulated power system. In contrast to the vertically integrated utility structure, it can be seen that there are many alternative paths along which the money flows. It is evident that there are many more other entities present, apart from the vertically integrated utility and the customers. It should be noted that there can be many more versions of deregulated structure.



Various Entities Involved in Deregulation:

The introduction of deregulation has introduced several new entities in the electricity market place and has simultaneously redefined the scope of activities of many of the existing players. Variations exist across market structures over how each entity is particularly defined and over what role it plays in the system. However, on a broad level, the following entities can be identified:

1. Genco (Generating Company): Genco is an owner-operator of one or more generators that runs them and bids the power into the competitive marketplace. Genco sells energy at its sites in the same manner that a coal mining company might sell coal in bulk at its mine.

2. Transco (Transmission Company): Transco moves power in bulk quantities from where it is produced to where it is consumed. The Transco owns and maintains the transmission facilities, and may perform many of the management and engineering functions required to ensure the smooth running of the system. In some deregulated industries, the Transco owns and maintains the transmission lines under the monopoly, but does not operate them. That is done by Independent System Operator (ISO). The Transco is paid for the use of its lines.

3. Discom (Distribution Company): It is the owner-operator of the local power delivery system, which delivers power to individual businesses and homeowners. In some places, the local distribution function is combined with retail function, i.e. to buy wholesale electricity either through the spot market or through direct contracts with Gencos and supply electricity to the end use customers. In many other cases, however, the Discom does not sell the power. It only owns and operates the local distribution system, and obtains its revenue by wheeling electric power through its network.

4. Resco (Retail Energy Service Company): It is the retailer of electric power. Many of these will be the retail departments of the former vertically integrated utilities. A Resco buys power from Gencos and sells it directly to the consumers. Resco does not own any electricity network physical assets.

5. Market Operator: Market operator provides a platform for the buyers and sellers to sell and buy the electricity. It runs a computer program that matches bids and offers of sellers and buyers. The market settlement process is the responsibility of the market operator. The market operator typically runs a day-ahead market. The near-real-time market, if any, is administered by the system operator.

6. System Operator (SO): The SO is an entity entrusted with the responsibility of ensuring the reliability and security of the entire system. It is an independent authority and does not participate in the electricity market trades. It usually does not own generating resources, except for some reserve capacity in certain cases. In order to maintain the system security and reliability, the SO procures various services such as supply of emergency reserves, or reactive power from other entities in the system. In some countries, SO also owns the transmission network. The SO in these systems is generally called as Transmission System Operator (TSO). In the case of a SO being completely neutral of every other activity except coordinate, control and monitor the system, it is generally called as Independent System Operator (ISO).

7. Customers: A customer is an entity, consuming electricity. In a completely deregulated market where retail sector is also open for competition, the end customer has several options for buying electricity. It may choose to buy electricity from the spot market by bidding for purchase, or may buy directly from a Genco or even from the local retailing service company. On the other hand, in the markets where competition exists only at the wholesale level, only the large customers have privilege of choosing their supplier.

Reasons and objectives of deregulation of various power systems across the world:

Restructuring or deregulation is a broad term and can have different meanings in different countries. This is because the changes essential for betterment of power sector depend on the prevailing conditions in the power sector of respective countries. Further, the word – betterment can be looked upon subjectively. For example, well developed, industrialized countries can expect price to go down and these countries can treat the change in the prices as betterment. On the other hand, the developing countries need to make radical changes in the policy and regulation such that barrier to entry for private players is removed. The effective betterment can be looked upon from this perspective for developing countries.

In this section we will see, in brief, the issues that led to restructuring of the power industry for following regions / countries: US, UK, Nordic Pool and developing countries.

The US

The US electric utilities, from the very beginning were privately owned and worked in a vertically integrated fashion. The developed countries like US had well functioning and efficient electricity systems. However for some systems, so long as consumers were concerned, they were not satisfied with the rising costs of electricity. For some other systems, utility management found that running the system was not viable due to low tariff. In some systems, pressure from smaller players to open up the business for competition played a major role. By and large, deregulation took place in developed countries by pressure to reduce costs while simultaneously increasing competitiveness in the market.

Existence of market power shows the signs of deviation from the prefect competition. In general, market power is referred to as ability of market participants to profitably maintain the market price above or below the competitive level for a significant period of time. To tackle the situation and the indirect regulatory intervention in the form of market design rules is needed. Thus, as mentioned earlier, deregulation does not mean ceasing to have rules. It is the ‘restructuring’ of the power business framework.

The UK

The transformation of the British power sector proceeded along three paths. First, the traditional industry was unbundled both vertically and horizontally. High-voltage transmission assets were transferred to a new National Grid Company (NGC). Coal and oil fired units were divided among two companies National Power and Power Gen. Nuclear Electric retained control of all nuclear units. At the outset, National Power had 52 percent of total generating capacity, Power Gen had 33 percent, and Nuclear Power had the remaining 15 percent. The second set of changes involved ownership. Both National Power and Power Gen became private companies whereas the difficulties associated with nuclear power resulted in continued government ownership of all nuclear units. Approximately 30 percent of shares in National Power and Power Gen were sold to the public, an equal amount to foreign and institutional investors. The remaining 40 percent was held by the government. The third set of changes sought to open the system to competition, wherever possible, while continuing necessary regulations. Vertical and horizontal restructuring of power generation was based on the assumption that generation had become workably competitive and would become increasingly so with new market entrants.

A report on reform process was floated by the regulator which stated that wholesale electricity prices had not fallen in line with reductions in generators’ input costs and that a lack of supply side pressure and demand side participation; and inflexible governance arrangements had prevented reform of the arrangements.

The Developing Countries.

The case of developing countries is different from that of other countries. In these countries, the electricity supply is treated as a social service rather than a market commodity. The ownership of the power sector in these countries is directly under the governments of respective countries. These state owned-controlled systems have led to the promotion of inefficient practices over a period. The power sectors of these countries are marked by supply shortages. There has been an inability to add to the generating capacity. The subsidies and high transmission and distribution losses are the major concerns before these systems. Another consequence of state control over electric utilities was the high level of overstaffing.

Restructuring Power System

Unit-III

Fundamentals of Economics:

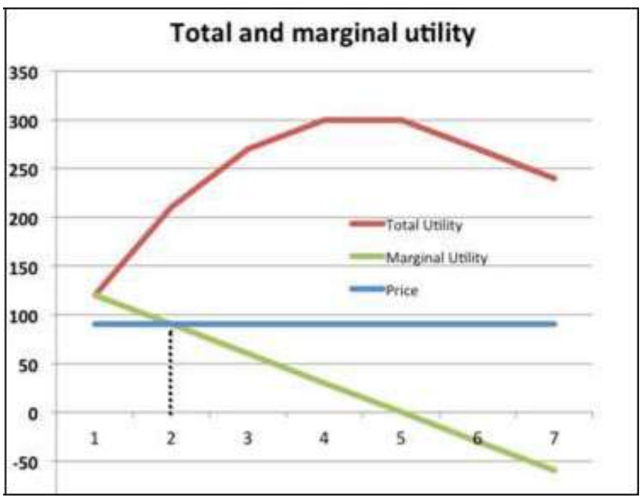
The Concept of Utility: It's Meaning, Total Utility and Marginal Utility

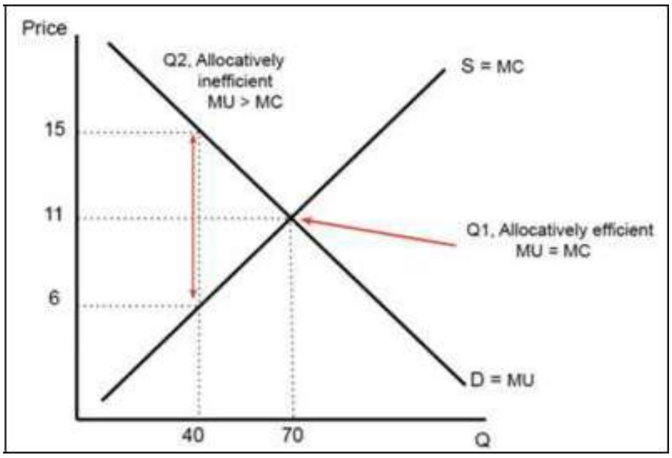
Total utility is the **total** satisfaction received from consuming a given **total** quantity of a good or service, while **marginal utility** is the satisfaction gained from consuming an additional quantity of that item. **Marginal utility** always declines for each successive quantity of consumption. Although the concept of 'taste' and 'satisfaction' are familiar for all of us, it is much more difficult to express these concepts in concrete terms. Can you tell how much are you satisfied from each of these items? Probably you can tell which item you liked more. But, it is very difficult to express "how much" you liked one over the other. It is evident, that we need a more quantitative measure of satisfaction. Due to this reason, economists developed the concept of utility.

Meaning of Utility:
Utility refers to want satisfying power of a commodity. It is the satisfaction, actual or expected, derived from the consumption of a commodity. Utility differs from person- to-person, place-to-place and time-to-time. In the words of Prof. Hobson, "Utility is the ability of satisfaction".

In short, when a commodity is capable of satisfying human wants, we can conclude that the commodity has utility.

How to Measure Utility?
After understanding the meaning of utility, the next big question is: How to measure utility? According to classical economists, utility can be measured, in the same way, as weight or height is measured. For this, economists assumed that utility can be measured in cardinal (numerical) terms. By using cardinal measure of utility, it is possible to numerically estimate utility, which a person derives from consumption of goods and services. But, there was no standard unit for measuring utility. So, the economists derived an imaginary measure, known as 'Util'.





One more way to measure utility:

Utils cannot be taken as a standard unit for measurement as it will vary from individual to individual. Hence, several economists including Marshall, suggested the measurement of utility in monetary terms. It means, utility can be measured in terms of money or price, which the consumer is willing to pay.

In the above example, suppose 1 util is assumed to be equal to Rs. 1. Now, an ice-cream will yield utility worth Rs. 20 (as 1 util = Rs. 1) and chocolate will give utility of Rs. 10. This utility of Rs. 20 from the ice-cream or f I0 from the chocolate is termed as value of utility in terms of money.

The advantage of using monetary values instead of utils is that it allows easy comparison between utility and price paid, since both are in the same units.

Total Utility (TU):

Total utility refers to the total satisfaction obtained from the consumption of all possible units of a commodity. It measures the total satisfaction obtained from consumption of all the units of that good. For example, if the
1st ice-cream gives you a satisfaction of 20 utils and
2nd one gives 16 utils,
then TU from 2 ice-creams is 20 + 16 = 36 utils.
If the 3rd ice-cream generates satisfaction of 10 utils,
then TU from 3 ice-creams will be 20+ 16 + 10 = 46 utils.

TU can be calculated as:

$TU_n = U_1 + U_2 + U_3 + \ldots\ldots\ldots\ldots + U_n$

Where:

TU_n = Total utility from n units of a given commodity
$U_1, U_2, U_3, \ldots\ldots U_n$ = Utility from the 1st, 2nd, 3rd nth unit
n = Number of units consumed

Marginal Utility (MU):

Marginal utility is the additional utility derived from the consumption of one more unit of the given commodity. It is the utility derived from the last unit of a commodity purchased. As per given example, when 3rd ice-cream is consumed, TU increases from 36 utils to 46 utils. The additional 10 utils from the 3rd ice-cream is the MU.
MU can be calculated as: $MU_n = TU_n – TU_{n-1}$

Where: MU_n = Marginal utility from n^{th} unit; TU_n = Total utility from n units;
TU_{n-1} = Total utility from n – 1 units; n = Number of units of consumption
MU of 3^{rd} ice-cream will be: $MU_3 = TU_3 - TU_2 = 46 - 36 = 10$ utils
One More way to Calculate MU
MU is the change in TU when one more unit is consumed. However, when change in units consumed is more than one, then MU can also be calculated as:

MU = Change in Total Utility/ Change in number of units = $\Delta TU/\Delta Q$

Total Utility is Summation of Marginal Utilities:
Total utility can also be calculated as the sum of marginal utilities from all units, i.e.

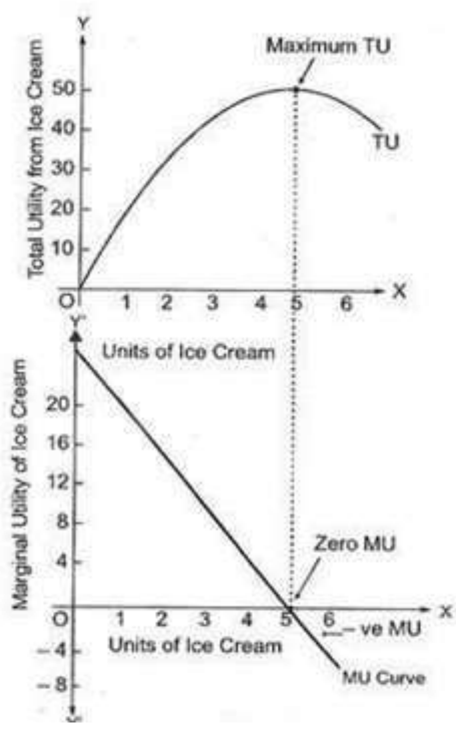
$TU_n = MU_1 + MU_2 + MU_3 + \ldots\ldots + MU_n$ or simply,

$TU = \sum MU$

The concepts of TU and MU can be better understood from the following schedule and diagram:

TU and MU

Ice-creams Consumed	Marginal Utility (MU)	Total Utility (TU)
1	20	20
2	16	36
3	10	46
4	4	50
5	0	50
6	-6	44



In Fig. units of ice-cream, are shown along the X-axis and TU and MU are measured along the Y-axis. MU is positive and TU is increasing till the 4^{th} ice-cream. After consuming the 5^{th} ice-cream, MU is zero and TU is maximum. This point is known as the point of satiety or the stage of maximum satisfaction. After consuming the 6^{th} ice-cream, MU is negative (known as disutility) and total utility starts diminishing. Disutility is the opposite of utility. It refers to loss of satisfaction due to consumption of too much of a thing.

Restructuring Power System

Unit-IV

Philosophy of Market Models

Various models can be classified according to the levels at which the entities are the choice of buying or selling electricity. The choice of choosing a model is a policy decision and dominated by various prevailing conditions. The four basic models of industry structure given below.

1. **Monopoly model**
2. **Single buyer mode**
3. **Wholesale competition model**
4. **Retail competition model**

Monopoly Model

In this model, a single entity takes care of all the businesses such as generation, transmission and distribution of electric power to the end users. In this, a single utility integrates the generation, transmission and distribution of electricity is shown in Figure 1. Usually (but not necessarily), in this kind of model, the monopoly lies with the Government. It is quite natural that this kind of model should have strict regulation in order to protect end consumers against monopoly. Most of the electric power systems followed this model prior to deregulation.

Another version of the monopoly model is shown in Figure 1. In this model, generation and transmission are integrated and operated by a single utility and it sells the energy to local distribution companies, which themselves represent local monopolies.

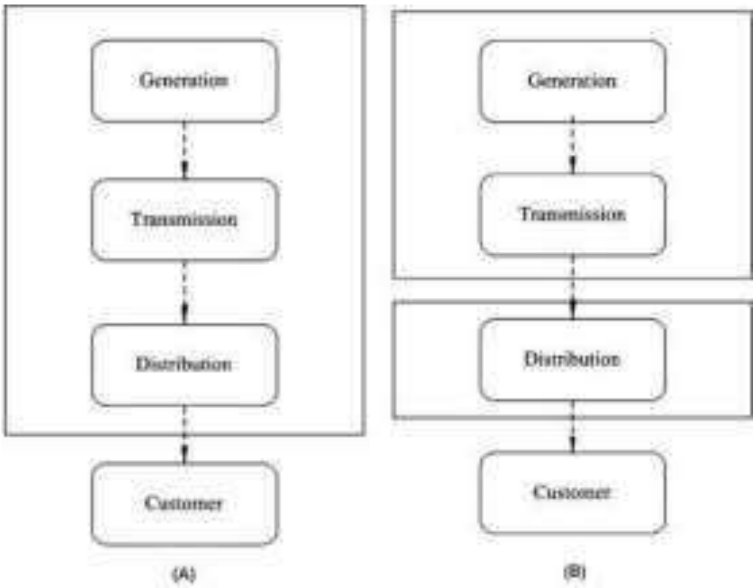


Figure 1: Two different versions of monopoly model

Single Buyer Model

In this model, as shown in Figure , there is competition in the wholesale sector, i.e., generation. Here, the single buyer agency buys power from Independent Power Producers (IPPs) in addition to its own generation. The power purchasing agency in turn sells it to state distribution utilities or distribution companies in the service area. All power generated by generating companies (Gencos) must be sold only to a purchasing agency and not to any other agency. Distribution companies (Discoms) are only able to purchase from the single buyer agency. They do not have a choice of choosing their power supplier.

The single buyer or the existing utility makes a long term contract with IPPs. A contract is necessary because, without it, a generator would be reluctant to invest large amounts of capital in a generating plant. The contracts are generally of life-of-plant type, indicating sale of all capacity of generating units for its lifetime.

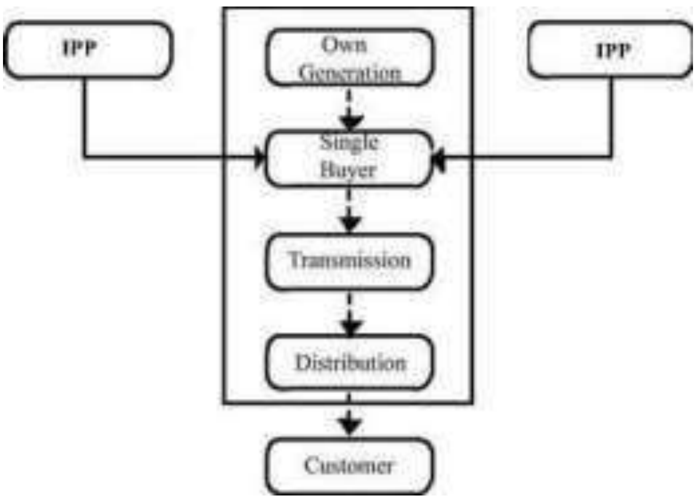


Figure 2: Single buyer model

The version of this model, which has further evolved from the original single buyer model. In this model, the single buyer does not own any generation and buys all the power from IPPs. The distribution and retail activities are also disaggregated. This model has an advantage of introducing some competition between generators without the expense of setting up a competitive market. The tariff set by the purchasing agency must be regulated because it has monopoly over the Discos while monophony over the IPPs. The single buyer model is looked upon as a way of attracting private participation in the generation sector, especially in the developing countries.

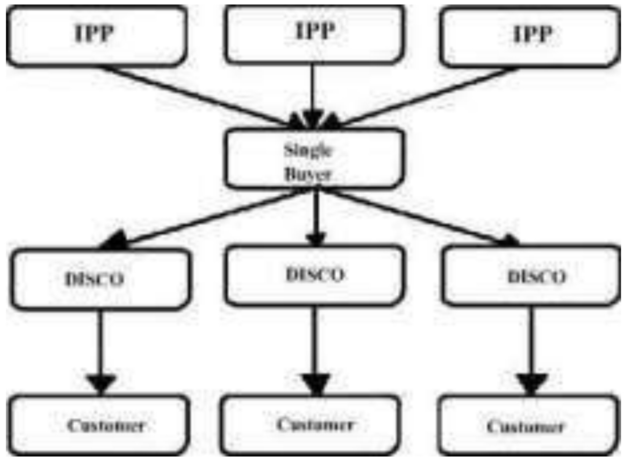


Figure 3: Single buyer model

Merits and demerits of this model are as follows:

Merits:

1. Private participation in power generation.
2. Introduction of some competition without expensive set up for a competitive market.

Demerits:

1. Long term contracts. Setting up a contract is problematic.
2. No true competition.
3. Price is not decided by demand-supply interaction.
4. End consumers' price is regulated.

Wholesale Competition Model

This model is one step closer towards competition. There is an organized market in which the generators can sell their energy at competitive rates. The market may be organized either by a separate entity or may be run by the system operator itself. There is not much choice for the end user. The end user is still affiliated to the Discom or retailer working in that geographical area of operation. The large customers or the bulk customers, so to say, are privileged to choose their energy provider. However, the definition of bulk customer is a subjective matter and changes from system to system.

This model, as shown in Figure 4, provides the choice of supplier to Discoms, along with competition in generation. Implementation of this model requires open access to the transmission network. Also, a wholesale spot market needs to be developed. Since this model permits open access to the transmission wires, it gives the IPPs to choose an alternative buyer. Discoms can purchase energy for their customers either from a wholesale market or through long term contracts with generators.

The customers within a service area still have no choice of supplier. They will be served by a Discom in their area. With this model, the Discoms are under Universal Service Obligation (USO), as they have monopoly over the customers. They own and operate the distribution wires. The transmission network is owned and maintained either by government and/or private transmission companies. System operators manage the centrally accomplished task of operation and control.

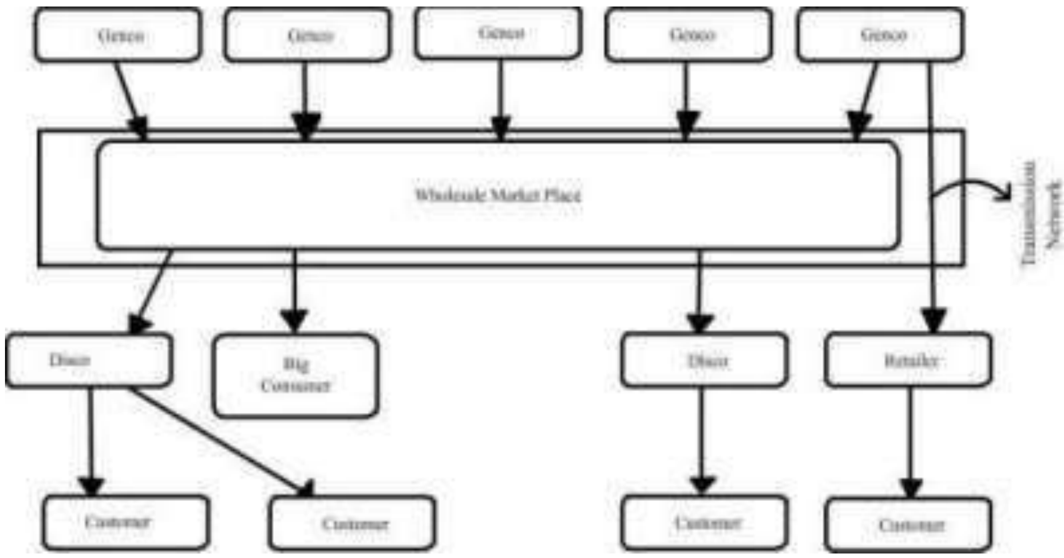


Figure 4: Wholesale Competition Model

The model provides a competitive environment for generators because the wholesale price is determined by the interaction between supply and demand. In contrast, the retail price of electrical energy remains regulated because the small consumers still do not have a choice for their supplier. The distribution companies are then exposed to vagaries of the wholesale price of the commodity. The merits and demerits of this model are as follows:

Merits:

1. Choice of seller provided for Discoms and bulk consumers.
2. The buyers and sellers can make forward contracts or buy from a wholesale Market place.
3. The price is decided by interaction between demand and supply. Hence, indicates truly competitive price.

Demerits:

1. The end consumer still doesn't have a choice. It buys power from the affiliated Discom.
2. Rates for end consumers are regulated rather than competitive.
3. Discoms face competition at wholesale level, while their returns are regulated. · Structural and institutional changes required at wholesale level.

Retail Competition Model

In this model, as shown in Figure 5, all customers have access to competing generators either directly or through their choice of retailer. This would have complete separation of both generation and retailing from the transport business at both transmission and distribution levels. Both, transmission and distribution wires provide open access in this model.

This model is a multi-buyer, multi-seller model and the power pool in this model acts like an auctioneer. It behaves like a single transporter, moving power to facilitate bilateral trading and this is achieved through an integrated network of wires. In this pooling arrangement, there is a provision for bidding into a spot market to facilitate merit order dispatch. The pool matches the supply and demand and determines the spot price for each hour of the day. It collects money from purchasers and distributes it to producers.
The advantage of this model over monopoly utilities is that competition is introduced in both wholesale and retail areas of the system. This model is supposed to be a truly deregulated power market model. The retail price is no longer regulated because small consumers can change their retailer for better price options. This model is economically efficient as the price is set by interaction of demand and supply. In wholesale competition model, with relatively few customers, all of them regulated Discoms, a spot market can be preferable but not essential.

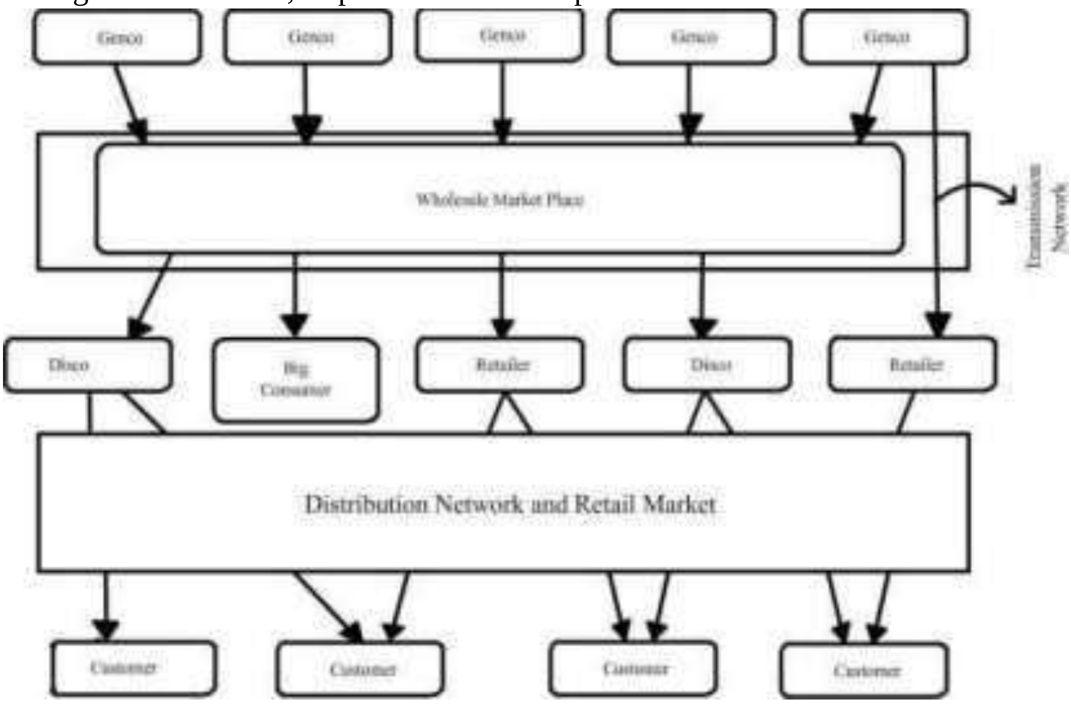


Figure 5: Retail Competition Model

Merits:

1. Supposed to be 100% deregulated model.
2. Every consumer has a choice of buying power.
3. The price is decided by interaction of demand and supply. Hence, it is truly competitive price.
4. There is no regulation in energy pricing.

Demerits:

1. Need constitutional and structural changes at both, wholesale and retail level.
2. Extremely complex settlement system due to large number of participants.

Restructuring Power System
Unit-V

Transmission Congestion Management

Introduction

Transmission Congestion management in a multi-buyer/ multi-seller system is one of the most involved tasks if it has to have a market based solution with economic efficiency. In a vertically integrated utility structure, activities such as generation, transmission and distribution are within direct control of a central agency or a single utility. Generation is dispatched in order to achieve the system least cost operation. Along with this, the optimal dispatch solution using security constrained economic dispatch eliminates the possible occurrence of congestion. This effectively means that generations are dispatched such that the power flow limits on the transmission lines are not exceeded.

The transmission corridors evacuating the power of cheaper generators would get overloaded if all such transactions are approved. Congestion is then said to have occurred when system operator finds that all the transactions cannot be allowed on account of overload on the transmission network. Congestion management is a mechanism to prioritize the transactions and commit to such a schedule which would not overload the network. Despite these measures, congestion can still occur in real time following a forced outage of transmission line. The system operator then handles this situation by means of real time congestion management. Thus, congestion management involves precautionary as well as remedial action on system operator's part, as follows:

- Allow only that set of transactions which, taken together, keeps the transmission system within limits.
- Even if this care is taken, in real time, the transmission corridors may get overloaded due to unscheduled flows. The system operator has to take some remedial action.

The scope of transmission congestion management in the deregulated environment involves defining a set of rules to ensure control over generators and loads in order to maintain acceptable level of system security and reliability.

In a deregulated structure, the market must be modelled so that the market participants (buyers and sellers of energy) engage freely in transactions and play as per market forces, but in a manner that does not threaten the security of the power system. Thus, irrespective of the market structure in place, congestion management has universally become an important activity of power system operators. Universally, the dual objectives of congestion management schemes have been to minimize the interference of the transmission network in the market for electrical energy and to simultaneously ensure secure operation of the power system.

<u>Definition of Congestion</u>

Whenever the physical or operational constraints in a transmission network become active, the system is said to be in a state of congestion. The possible limits that may be hit in case of congestion are: line thermal limits, transformer emergency ratings, bus voltage limits, transient or oscillatory stability, etc. These limits constrain the amount of electric power that can be transmitted between two locations through a transmission network. Flows should not be allowed to increase to levels where a contingency would cause the network to collapse because of voltage instability, etc.

The demand of electric power has to be satisfied on a real time basis. Due to other peculiarities, the flexibility of directly routing this commodity through a desired path is very limited. The flow of electric current obeys laws of physics rather than the wish of traders or operators. Thus, the system operator has to decide upon such a pattern of injections and take-offs, that no constraint is violated.

Transfer capability

Congestion, as used in deregulation parlance, generally refers to a transmission line hitting its limit. The ability of interconnected transmission networks to reliably transfer electric power may be limited by the physical and electrical characteristics of the systems including of the following:

- **Thermal Limits:** Thermal limits establish the maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating.
- **Voltage Limits:** System voltages and changes in voltages must be maintained within the range of acceptable minimum and maximum limits. The lower voltage limits determine the maximum amount of electric power that can be transferred.
- **Stability Limits**: The transmission network must be capable of surviving disturbances through the transient and dynamic time periods (from milliseconds to several minutes, respectively). Immediately following a system disturbance, generators begin to oscillate relative to each other, causing fluctuations in system frequency, line loadings, and system voltages. For the system to be stable, the oscillations must diminish as the electric system attains a new stable operating point. The line loadings prior to the disturbance should be at such a level that its tripping does not cause system-wide dynamic instability.

The limiting condition on some portions of the transmission network can shift among thermal, voltage, and stability limits as the network operating conditions change over time. For example, for a short line, the line loading limit is dominated by its thermal limit. On the other hand, for a long line, stability limit is the main concern. Such differing criteria further lead to complexities while determining transfer capability limits.

Importance of congestion management

If the network power carrying capacity is infinite and if there are ample resources to keep the system variables within limits, the most efficient generation dispatch will correspond to the least cost operation. Kirchoff's laws combined with the magnitude and location of the generations and loads, the line impedances and the network topology determine the flows in each line. These power system security constraints may therefore necessitate a change in the generator schedules away from the most efficient dispatch. In the traditional vertically integrated utility environment, the generation patterns are fairly stable. From a short term perspective, the system operator may have to deviate from the efficient dispatch in order to keep line flows within limits.

The deregulated structures, with generating companies competing in an open transmission access environment, the generation and flow patterns can change drastically over small time periods with the market forces. In such situations, it becomes necessary to have a congestion management scheme in place to ensure that the system stays secure. However, being a competitive environment, the re-dispatch will have direct financial implications affecting most of the market players, creating a set of winners and losers.

Effects of Congestion

The network congestion essentially leads to out-of-merit dispatch. The main results of these can be stated as follows:

- **Market Inefficiency:** Market efficiency, in the short term, refers to a market outcome that maximizes the sum of the producer surplus and consumer surplus, which is generally known as social welfare. With respect to generation, market efficiency will result when the most cost-effective generation resources are used to serve the load. The difference in social welfare between a perfect market and a real market is a measure of the efficiency of the real market. The effect of transmission congestion is to create market inefficiency.
- **Market Power:** If the generator can successfully increase its profits by strategic bidding or by any means other than lowering its costs, it is said to have market power. Imagine a two area system with cheaper generation in area 1 and relatively costlier generation in area 2. Buyers in both the areas would prefer the generation in area 1 and eventually the tie-lines between the two areas would start operating at full capacity such that no further power transfer from area 1 to 2 is possible. The sellers in area 2 are then said to possess market power. By exercising market power, these sellers can charge higher price to buyers if the loads are inelastic. Thus, congestion may lead to market power which ultimately results in market inefficiency.

In multi-seller / multi-buyer environment, the operator has to look after some additional issues which crop up due to congestion. For example, in a centralized dispatch structure, the system operator changes schedules of generators by rising generation of some while decreasing that of others. The operator compensates the parties who were asked to generate more by paying them for their additional power production and giving lost opportunity payments to parties who were ordered to step down.

Desired Features of Congestion Management Schemes

Tackling the congestion problem takes different forms in different countries. It really depends on what type of deregulation model is being employed in a particular region. Certain network topologies, demographic factors and political ideologies influence the implementation of congestion management schemes in conjunction with overall market design.

Any congestion management scheme should try to accommodate the following features:

- **Economic Efficiency:** Congestion management should minimize its intervention into a competitive market. In other words, it should achieve system security, forgoing as little social welfare as possible. The scheme should lead to both, short term and long term efficiency. The short term efficiency is associated with generator dispatch, while long term efficiency pertains to investments in new transmission and generation facilities
- **Non discriminative:** Each market participant should be treated equally. For this, the network operator should be independent of market parties and he should not derive any kind of benefit from occurrence of congestion. Otherwise it provides perverse signals for network expansion.
- **Be transparent:** The implementation should be well defined and transparent for all

participants.

- **Be robust:** Congestion management scheme should be robust with respect to strategic manipulation by the market entities. This again refers back to principle of economic efficiency

Classification Of Congestion Management Methods

The congestion management schemes are strongly coupled with the overall market design. Efficient allocation of scarce transmission capacity to the desired participants of the market is one of the main objectives of congestion management schemes. Thus, distinction among them can be made based on market based congestion management methods and other methods. Market-based solutions to congestion are deemed fairer as they contribute better to economic efficiency than other methods. Methods other than market based make use of some criteria to allocate the transmission capacity. These methods are supposed to introduce some kind of arbitrariness as they do not contribute towards efficient pricing of congested link. Classification of congestion management schemes on these lines is shown in Table

Non - market Methods		Market Based Methods	
1	Type of contract	1	Explicit Auctioning of network capacity
2	First come first serve	2	Nodal pricing (OPF based congestion management)
3	Pro - rata methods	3	Zonal pricing
4	Curtailment	4	Price area congestion management
		5	Re - dispatch
		6	Counter trace

Classification of congestion management schemes

The operator should have knowledge about the network capacity left for settling the market. The transmission network capacity allocation in a coordinated market may take an explicit or implicit form. In other words, there can be a separate market for transmission capacity reservation or it may be integrated with the coordinated market.

Even after capacity allocation, the real time flows may lead to violation of transmission capacities. In order to relieve congestion during real time, congestion alleviation methods are employed.

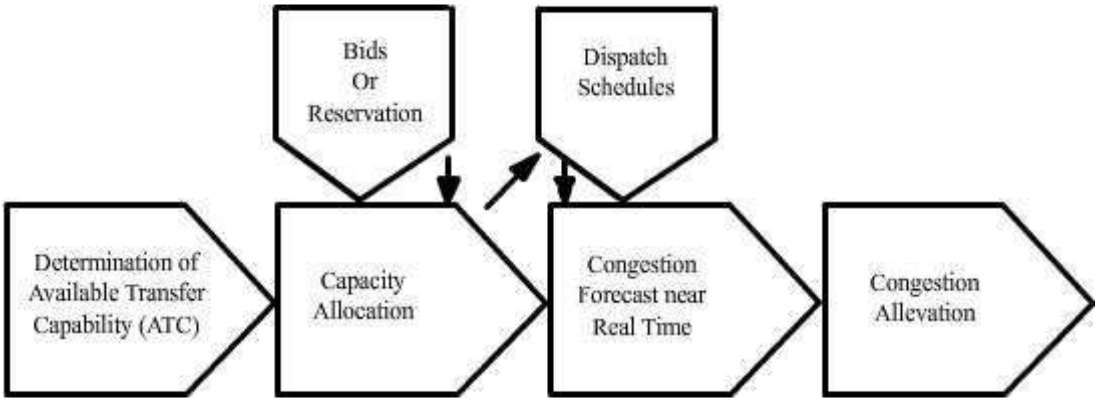


Figure: Phases of network access with respect to congestion

Out of several congestion management techniques listed above, following are exclusively termed as congestion alleviation methods:

1. Re-dispatch
2. Counter Trade
3. Curtailment

It should be noted that the capacity allocation methods usually allocate the transmission capacity in ex-ante manner before physical delivery of energy. The congestion alleviation methods are termed as remedial actions. The procedure of capacity allocation starts with the calculation of Available Transfer Capability (ATC).

Definition of Various Terms

Available Transfer Capability (ATC)

It is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. Mathematically, ATC is defined as the Total Transfer Capability (TTC) less the Transmission Reliability Margin (TRM), less the sum of existing transmission commitments (which includes retail customer service) and the Capacity Benefit Margin (CBM
ATC = TTC - TRM - Existing Transmission Commitments (including CBM)

Total Transfer Capability (TTC)

It is defined as the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of the specific set of defined pre and post contingency system conditions.

Transmission Reliability Margin (TRM)

It is defined as the amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

Capacity Benefit Margin (CBM)

It is defined as the amount of transmission transfer capability reserved by load serving entities to ensure that the interconnected systems do meet generation reliability requirements.

ATC Calculation using PTDF and LODF based on DC Model

One way of calculating ATC from node A to node B is to use DC load flow (explained later) repetitively by increasing the amount of transaction until a limit of any of the corridor is reached. However, this is computationally inefficient. Instead, the Power Transfer Distribution Factor (PTDF) can be used to calculate the maximum allowable flow for a given pair of injection and take-off points. It is also necessary to consider the effects of contingencies like line outages. This can be achieved using Line Outage Distribution Factor (LODF). Let us first see the details of DC load flow model.

DC Load Flow Model

Following are the assumptions when DC model is employed instead of AC model:

- Voltage magnitudes are constant.
- Only angles of complex bus voltages vary.
- The variation in angle is small.
- Transmission lines are lossless.

These assumptions create a model that is a reasonable first approximation for the real power system, which is only slightly nonlinear in normal steady state operation. The model has advantages for speed of computation, and also has some useful properties like linearity and superposition.

With these assumptions, power flows over transmission lines connecting bus i and bus j is given as:

$$P_{lm} = \frac{1}{x_{lm}}(\theta_l - \theta_m)$$

......................(1)

Where,

x_{lm} line inductive reactance in per unit

θ_l phase angle at bus l

phase angle at bus m

The total power flowing into the bus i, Pi, is the algebraic sum of generation and load at the bus and is called a bus power injection. Thus,

$$P_i = \sum_j P_{ij} = \sum_j \frac{1}{x_{ij}}(\theta_i - \theta_j)$$

.....................(2)

This can be expressed in a matrix form as:

$$\begin{bmatrix} P_1 \\ M \\ P_n \end{bmatrix} = \begin{bmatrix} B_X \end{bmatrix} \begin{bmatrix} \theta_1 \\ M \\ \theta_n \end{bmatrix}$$ ....(3)

Where, the elements of the susceptance matrix BX are functions of line reactances. One node is assigned as a reference node by making its angle zero and deleting corresponding row and column in $[B_X]$ matrix. Thus,

$$[X_{init}] = [B_{X,reduced}]^{-1}$$ ....(4)

The dimension $[X_{init}]$ of obtained is $(n-1 \times n-1)$. Let us augment it by adding zero column and row corresponding to reference bus. The angles in equation 3 can be found out as

$$\begin{bmatrix} \theta_1 \\ M \\ \theta_n \end{bmatrix} = [X] \begin{bmatrix} P_1 \\ M \\ P_n \end{bmatrix}.$$ ....(5)

Thus, power flow over line lm can be found out using equation 1

<u>Power Transfer Distribution Factor (PTDF)</u>

From the power transfer point of view, a transaction is a specific amount of power that is injected into the system at one bus by a generator and drawn at another bus by a load. The coefficient of linear relationship between the amount of a transaction and flow on a line is represented by PTDF. It is also called sensitivity because it relates the amount of one change - transaction amount - to another change - line power flow.

PTDF is the fraction of amount of a transaction from one bus to another that flows over a transmission line. $PTDF_{lm,ij}$ is the fraction of a transaction from bus i to bus j that flows over a transmission line connecting buses l and m.

$$PTDF_{lm,ij} = \frac{\Delta P_{lm}}{P_{ij}}$$ ....(6)

<u>Calculation of PTDF Using DC Model</u>

Suppose there exists only one transaction in the system. Let the transaction be of 1 MW from bus i to bus j. Then, the corresponding entries in equation 7 will be: $P_i = 1$ and $P_j = -1$. All other entries will be zero. From equation 5, we get

$$\theta_l = \begin{bmatrix} X_{l,1} & L & X_{l,n-1} \end{bmatrix} \begin{bmatrix} 0 \\ +1 \\ M \\ -1 \\ 0 \end{bmatrix}$$ ....(7)

Similarly,

$$\theta_m = \begin{bmatrix} X_{m,1} & L & X_{m,n-1} \end{bmatrix} \begin{bmatrix} 0 \\ +1 \\ M \\ -1 \\ 0 \end{bmatrix}$$ ....(8)

Thus,

$$\theta_l = X_{li} - X_{lj}$$ ....(9)

$$\theta_m = X_{mi} - X_{mj}$$ ....(10)

Using equations 9, 10 and 1, the PTDF can be calculated as

$$PTDF_{lm,ij} = \frac{X_{li} - X_{mi} - X_{lj} + X_{mj}}{x_{lm}}$$ ....(11)

x_{lm} Reactance of transmission line connecting buses l and m

X_{li} Entry lth row and ith column of the bus reactance matrix X
The change in line flow associated with a new transaction is then

$$\Delta P_{lm} = PTDF_{lm,ij} P_{ij}$$ ....(12)

Where,
l and m buses at the ends of the line being monitored
i and j from and to bus numbers for the proposed new

transactions P_{ij} New transaction MW amount

ATC calculation Using PTDF

ATC is determined by recognizing the new flow on the line from node l to node m, due to a transaction from node i to node j. The new flow on the line is the sum of original flow P^0_{lm} and the change.

$$P_{lm} = P^0_{lm} + PTDF_{lm,ij} P_{ij}$$ ....(13)

Where, P^0_{lm} is the base case flow on the line and P_{ij} is the magnitude of proposed transfer. If the limit on line lm, the maximum power that can be transferred without overloading line lm, is P^{max}_{lm} , then,

$$P^{max}_{ij,lm} = \frac{P^{max}_{lm} - P^0_{lm}}{PTDF_{lm,ij}}$$ ....(14)

$P^{max}_{ij,lm}$ is the maximum allowable transaction from node i to node j constrained by the line from node l to node m. ATC is the minimum of the maximum allowable transactions over all lines.

Using the above equation, any proposed transaction for a specific hour may be checked by calculating ATC. If it is greater than the amount of the proposed transaction, the transaction is allowed. If not, the transaction must be rejected or limited to the ATC.

$$ATC_{ij} = \min\left(P_{ij,lm}^{max}\right)$$

....................(15)

Using the above equation, any proposed transaction for a specific hour may be checked by calculating ATC. If it is greater than the amount of the proposed transaction, the transaction is allowed. If not, the transaction must be rejected or limited to the ATC.

Calculation of PTDF Using AC Model

More accurate PTDFs can be calculated using AC power flow model. Line power flows are simply function of the voltages and angles at its terminal buses. So PTDF is a function of these voltage and angle sensitivities.

Consider an n node system with nodes1....,g as PV nodes (generator buses) and g+1,...,n as the PQ nodes (load buses). Bus 1 is taken as slack bus. A transaction is defined by a set of four parameters (t, i, j, Pt) where t is the transaction number, i and j are the source and sink nodes and Pt is the MWs transacted. The change in flow of an arbitrary line lm can be evaluated by sensitivity analysis as follows.

$$\Delta P_{lm} = \begin{bmatrix} \frac{\partial P_{lm}}{\partial \delta_2} & \cdots & \frac{\partial P_{lm}}{\partial \delta_n} & \frac{\partial P_{lm}}{\partial V_{g+1}} & \cdots & \frac{\partial P_{lm}}{\partial V_n} \end{bmatrix} \begin{bmatrix} \Delta\delta_2 \\ \vdots \\ \Delta\delta_n \\ \Delta|V_{g+1}| \\ \vdots \\ \Delta|V_n| \end{bmatrix}$$

...........(16)

From the converged base case Load Flow solution we have,

$$\begin{bmatrix} \Delta\delta_2 \\ M \\ \Delta\delta_n \\ \Delta|V_{g+1}| \\ M \\ \Delta|V_n| \end{bmatrix} = J^{-1} \begin{bmatrix} \Delta P_2 \\ M \\ \Delta P_n \\ \Delta|Q_{g+1}| \\ M \\ \Delta|Q_n| \end{bmatrix}$$

..................(17)

Where J is load flow Jacobian. For a MW power transaction number t,

$$\Delta P_i = +P_t$$

…...............(18)

$$\Delta P_j = -P_t$$

..................(19)

$$\Delta P_k = 0$$

..................(20)

$$\Delta Q_k = 0$$

..................(21)

Where, $(k = l, \ldots, n, k \neq i, j)$. Substituting the values then final eq. is,

$$\Delta P_{lm} = \left[\frac{\partial P_{lm}}{\partial \delta_2} \cdots \frac{\partial P_{lm}}{\partial \delta_n} \; \frac{\partial P_{lm}}{\partial V_{g+1}} \cdots \frac{\partial P_{lm}}{\partial V_n} \right] \left[J^{-1} \right] \begin{bmatrix} 0 \\ \vdots \\ +P_t \\ 0 \\ \vdots \\ -P_t \\ 0 \end{bmatrix} = d_t P_t \quad \ldots\ldots (22).$$

Locational Marginal Pricing (LMP)

The Locational Marginal Pricing (LMP) mechanism is one of the most commonly employed tools for market settlement in the deregulated power system environment. The Locational Marginal Price (LMP) at a bus signifies the cost of supplying the next increment of load at that bus. The LMP is the sum of supplying energy marginal cost, cost of losses due to the increment and transmission congestion cost, if any, arising from the increment. The LMP is the true indicator of marginal pricing of energy.

Locational marginal pricing is a centralized process of market clearing, where it is the responsibility of the Independent System Operator (ISO) to determine the power dispatch schedules as well as the energy prices. Unlike system uniform pricing (i.e., unconstrained bidding) approach, network limits have to be considered while scheduling generators, loads and bilateral transactions. Since network constraints are considered in the market clearing process, it is not possible to determine the market equilibrium simply by the intersection of a cumulative supply curve and a cumulative demand curve. Instead, the power dispatch schedules and energy prices are calculated through an optimization approach consisting of network and power flow related constraints

An LMP market may be a single settlement or two settlement market. In case of a single settlement market, scheduling is done only in day-ahead, whereas both day-ahead and real-time scheduling is done for a two settlement market. A real-time market is essentially within the hour market. The real-time scheduling and settlement are further done in different time blocks. For example, in PJM, real-time scheduling is done in 5-minute time blocks. The real-time scheduling starts with the state-estimation solution at the beginning of each time block. The state-estimation solution gives the actual injection by each generator and actual withdrawal by each load at the current point of time. It should be noted that the above time frames of settlement are not strict and change depending upon the market needs.

Restructuring Power System

Unit-VI

Ancillary Service Management

Ancillary services are defined as all the activities on the interconnected grid that are necessary to support the transmission of power while maintaining reliable operation and ensuring the required degree of quality and safety. It becomes clear that the ancillary services may include scheduling and dispatch, frequency regulation, voltage control, generation reserves, etc. It is the matter of debate and market design about how to procure these ancillary services. There are some services which can be provided competitively and some services which come under the direct control of the system operator.

The ancillary services under the deregulated environment are not as straight forward as it is described in the vertically integrated structure. Though many reasons can be figured out, the main reason is that the entities providing ancillary services may not be under direct control of the system operator. This issue is highlighted with following two examples. The generators in the competitive market are scheduled as per the bids provided by them to the market. A power system that has generation just enough to support the overall load and losses is still a vulnerable system. The system should have provision for additional generation during contingencies like generator outages. Total capacity of some generating units can be partly dispatched for energy and partly kept ready for reserve. For a particular privately owned generating unit with fast ramp rate, the system operator is likely to schedule most of its capacity as a reserve. The generator, however, may not agree to this unless and until some compensation is provided to it for maintaining its capacity as a reserve. Thus, the development of compensation mechanism for this generator, as well as the cost allocation to customers in an optimal fashion, poses a challenging problem in the restructured environment.

Types of Ancillary Services

A large number of activities on the interconnected grid can be termed as ancillary services. During the process of defining the ancillary services, some of major ancillary services are given below:

1. Regulation: The use of generation or load to maintain minute-to-minute generation-load balance within the control area.
2. Load Following: This service refers to load-generation balance towards end of a scheduling period.
3. Energy Imbalance: The use of generation to meet the hour-to-hour and daily variations in load.
4. Operating Reserve (Spinning): The provision of unloaded generating capacity that is synchronized to the grid and can immediately respond to correct for generation-load imbalances, caused by generation and /or transmission outages and that is fully available for several minutes.
5. Operating Reserve (Supplemental): The provision of generating capacity and curtailable load to correct for generation-load imbalances, caused by generation and /or transmission outages, and that is fully available for several minutes. However, unlike spinning reserves, supplemental reserve is not required to respond immediately.
6. Backup Supply: This service consists of supply guarantee contracted by generators with other generators or with electrical systems, to ensure they are able to supply their consumers in case of scheduled or unscheduled unavailability.
7. System Control: This activity can be compared with the functions of the brain in the human body. System control is all about control area operator functions that schedule generation and transactions and control generation in real time to maintain generation load balance.
8. Dynamic Scheduling: It includes real-time metering, tele-metering along with computer software and hardware to virtually transfer some or all of generator's output or a customer's load from one control area to another.
9. Reactive Power and Voltage Control Support: The injection or absorption of reactive power from generators or capacitors to maintain system voltages within required ranges.
10. Real Power Transmission Losses: This service is necessary to compensate for the difference existing between energy supplied to the network by the generator and the energy taken from the network by the consumer.
11. Network Stability Services from Generation Sources: Maintenance and use of special equipment (e.g., PSS, dynamic braking resistances) to maintain secure transmission system.
12. System Black Start Capability: The ability of generating unit to proceed from a shutdown condition to an operating condition without assistance from the grid and then to energize the

grid to help other units start after a blackout occurs.

It should be noted that identification and definition of a particular ancillary service is system dependent. There is no global definition of a particular ancillary service that is applicable in all systems.

Classification of Ancillary Services

There can be various ways of classifying the above ancillary services. One common approach would be to identify when and how frequently these services are required by the system operator. Thus, three groups can be formed:

1. Services required for routine operation:

These are the services which the system operator requires quite frequently. Some of these may be required to provide corrective action on minute-to-minute basis. Following services can be grouped under this category:

(a) System control
(b) Reactive power support
(c) Regulation
(d) Load following
(e) Energy imbalance
(f) Real power loss displacement

2. Services required to prevent an outage from becoming a catastrophe:

These services prevent the system from going out of step even if a major event occurs. These do not come into picture on daily basis, or rather; no proactive measures are required to be taken either by the system operator or the service provider on daily basis. Their effectiveness is sensed only under contingent situation. Following services fall under this category:

(a) Spinning reserve
(b) Supplemental reserve
(c) Network stability services

3. Services needed to restore a system after blackout:

Re-energizing the system after complete blackout requires support from certain generating stations, which can pickup generation even in the absence of external electricity support. Such generating units provide the system black start capability. These services are very rarely used.

A closer look at the list of ancillary services reveals that they are either related to:

1. Generation-load balancing issues or
2. The network security related issues.

In further sections, load-generation balancing related services, as well as reactive power support services, under the network security domain are discussed in detail.

Provision of ancillary services

In this approach, before a participant is connected to the grid, it has to make sure that it is in a position to provide the ancillary services mandated by the system operator. The system operator lays down the rules to be followed by the participants. The rules for the connection to the grid can be:

- The generator should be equipped with droop characteristics of 5%. This helps in frequency regulation.
- The generator should be able to operate in a power factor range of 0.85 lead to 0.9 lag. It should be equipped with Automatic Voltage Regulator (AVR).

These types of compulsions act more or less like the rules existing in the vertically integrated utility. This will ensure that enough resources will be available towards system security. This approach is a simpler one; however, it does not lead to economic efficiency. Some of the problems associated with this approach are as follows:

- There is a chance that more than sufficient sources are likely to be developed, which is not desired. For example, each and every generating unit need not take part in the frequency regulation process.
- The participants may think that they are denied the profits of the competitive market just because they are forced to supply services at an additional cost.
- The approach does not leave room for technological or commercial innovation.
- Some units may be unable to provide some of the services. For example, nuclear power plants cannot be subjected to rapid changes in its output. Hence, same set of rules cannot be applied to all the participants.

Markets for ancillary services

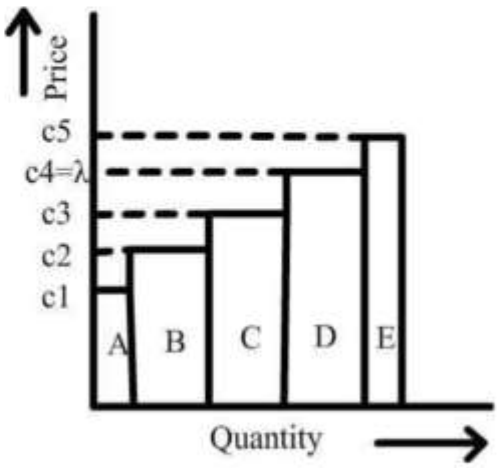
The economic disadvantages and difficulty of practical implementation of compulsory services necessitates introduction of competition in at least some of the ancillary services. The preferred form of mechanism depends on the type of the ancillary service. Services like black start capability can be procured on long term basis. These are the services in which the amount of service provided does not change much with the time. Also, this amount does not depend on the activity of the spot market. The system operator may run a separate market for regulation asking generators to submit their up and down regulation bid. The reserve capabilities can be a mix of two approaches. The system operator may make a long term contract for some part of the reserve requirement, while it can obtain remaining reserve requirement through short term market mechanism.

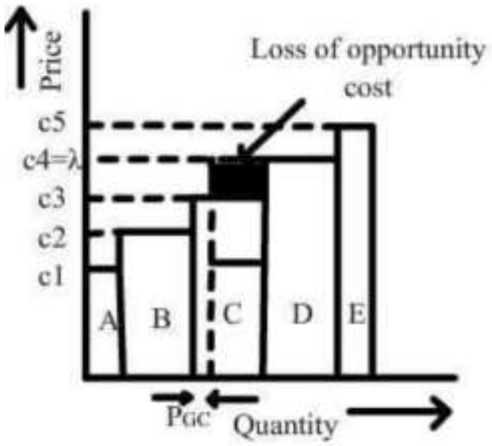
Co-optimization of Energy and Reserve Services

In all the power markets of the early days, energy and reserve were traded in different markets. These markets were cleared successively in a sequence determined by the speed of response of the service. The market for reserve would clear first and then the energy market would be cleared.

The joint-optimization also known as co-optimization will take dispatch decision taking into consideration the availability of resources and the overall cost. The joint optimization of energy and reserve is done in multi-settlement nodal pricing markets like PJM. Suppose the energy and reserve market is being co-optimized. As in the energy market, reserve providers offer to provide reserve. The reserve offers do not reflect the cost of lost opportunity to sell the energy. Instead, they are related to the expected cost of providing reserves, which might include some fixed administrative costs and some variable operating costs associated with providing the reserve.

Suppose five generators are present in the system and they have provided the block bids.





Let us work on standard simplifying assumptions and jump to results such that market clearing price is λ with generator D as marginal generator. Now take the case of combined energy and reserve market. Suppose RD is the system total reserve demand. Suppose, in addition to energy offer, generating unit C:(λ-C_3).RD offers to provide reserve for free.

We have assumed). Then, generator C will have to de-load its scheduled output to PGc-RD. In order to satisfy the power balance, generation D will have to increase its power output to PGc+RD. The shaded portion of Figure represents loss of opportunity cost of generating unit.
Suppose there is a market that operates on a centralized basis, the generators' bids to produce electrical energy are equal to their marginal costs and that the market rules do not include separate bids for the provision of reserve. To clear the market, the operator must determine the dispatch that minimizes the cost of production while respecting operational constraints. For the sake of simplicity, let us assume that the network has infinite capacity. Thus, the optimization

problem can be formulated as:

$$\min_i \sum c_i P_{G_i} \quad \ldots\ldots$$

$$\sum P_{G_i} = PD \quad \ldots\ldots$$

$$\sum R_{G_i} = RD \quad \ldots\ldots$$

$$P_{G_i}^{\min} \leq P_{G_i} + R_{G_i} \leq P_{G_i}^{\max} \quad \ldots\ldots$$

$$R_{G_i}^{\min} \leq R_{G_i} \leq R_{G_i}^{\max} \quad \ldots\ldots$$

The Lagrangian function of the above formulation can be written as:

$$L = \sum c_i P_{G_i} - \lambda_1 \left(\sum P_{G_i} - PD\right) - \lambda_2 \left(\sum R_{G_i} - RD\right) \quad \ldots\ldots$$

$$- \mu_1 \left(P_{G_i}^{\min} - P_{G_i} - R_{G_i}\right) + \mu_2 \left(P_{G_i} + R_{G_i} - P_{G_i}^{\max}\right) \quad \ldots\ldots$$

$$- \mu_3 \left(R_{G_i}^{\min} - R_{G_i}\right) + \mu_4 \left(R_{G_i} - R_{G_i}^{\max}\right) \quad \ldots\ldots$$

By applying standard Kuhn-Tucker conditions:

$$\frac{\partial L}{\partial P_{G_i}} = c_i - \lambda_1 - \mu_1 + \mu_2 \quad \ldots\ldots$$

$$\frac{\partial L}{\partial R_{G_i}} = -\lambda_2 - \mu_1 + \mu_2 - \mu_3 + \mu_4 \quad \ldots\ldots$$

Thus, expressions for λ1 and λ2 can be given as:

$$\lambda_1 = c_i - \mu_1 + \mu_2 \quad \ldots\ldots$$

$$\lambda_2 = -\mu_1 + \mu_2 - \mu_3 + \mu_4 \quad \ldots\ldots$$

Thus, the Lagrange multiplier associated with the constraint on the production-demand balance gives the marginal cost of producing electrical energy. Similarly, the multiplier associated with the reserve requirement constraint gives the marginal cost of providing the reserve. Suppose, no limits are hit,

$\mu 1 = \mu 2 = \mu 3 = \mu 4 = 0$ then, this is equal λ criterion of conventional economic dispatch problem. All generators work on the same marginal cost and marginal cost of providing reserve is zero. Suppose, a particular generator i hits its maximum limit such that

$$P_{G_i} + R_{G_i} = P_{G_i}^{\max} \quad \ldots\ldots$$

then, and and expression for marginal energy costs and marginal reserve costs can be given as:

$$\lambda_1 = c_i + \mu_2 \quad \ldots\ldots$$

$$\lambda_2 = \mu_2 = \lambda_1 - c_i \quad \ldots\ldots$$

From the last equation it becomes clear that the revenue collected by a generator is exactly equal to opportunity cost of not selling the energy. Thus, even if a generator is asked to be available to provide a reserve and thus hits its maximum limit including the energy generation, it does not incur monetary loss because the system marginal cost for energy will be higher than that generator's own marginal cost of production and the difference will be paid to generator which can be assumed to be a loss of opportunity cost.

Restructuring Power System

Unit-VII

Pricing of transmission network usage and Market power

Introduction of Transmission Pricing.

Transmission pricing and loss allocation are highly debated issues after the deregulation of power industry. In the post deregulated era, the transmission provision gets a good deal of importance. Strong transmission system forms the backbone of any successful deregulated power industry. As per the planning policies developed in most of the countries, more emphasis was given on adding more generation to the system rather than improving and strengthening the transmission network. The reasons, the transmission activity remain a monopoly rather than being a competitive activity. And since open access demands a non-discriminatory access to the transmission system by any qualified entity in the business, this monopoly entity has to be regulated by a higher governmental agency. In many countries, the *Transco* are the dis-aggregated part of the then original vertically integrated utility that existed in the region, prior to deregulation.

Loss allocation is another issue, where no single solution can be ultimate solution. The loss allocation problem is different from loss supply. Loss allocation is all about allocating costs of losses amongst various participants. Loss allocation problem is a contentious issue because of the non-linearity associated with power flows.

<u>What is Power Wheeling</u>

The wheeling is the transmission of electrical energy from a buyer to a seller, through transmission or distribution lines owned by a third party. Call a selling utility as Utility S, the buying utility, Utility B. Suppose they are non-contiguous and they are connected by several parallel paths through different utilities in between. One of the utilities connecting them is Utility K. In the context of the term wheeling, the obvious question to be asked is, what does it mean to say that Utility S is wheeling to Utility B, via Utility K.

<u>Displacement or Movement?</u>

It is a popular argument that power doesn't actually move from injecting point to load point. Rather, displacement of power takes place by addition and withdrawal of some MW of power at injecting and take-off points respectively. One analogy given by proponents of this concept is that of a lake that is filled to its maximum capacity. Pouring water at one end of a lake makes an equivalent amount of flow at the other end. However, the poured water does not travel from one end to the other. The electricity pushed into a power pool would also behave in a similar fashion. Thus, it is argued that the transmission users should pay a flat fee regardless of distance between two points.

The opponents of this view state that suppose x gallons of water is added at one end of the lake, it may not travel all the way to the other end, but it causes incremental disturbance in every gallon in the lake. Similarly, pushing some MWs at one point and withdrawing from the other would create an equivalent total change in the system flow. Hence, the user should pay as if its power had been moved over this much distance.

<u>Distance Dependency.</u>

The transmission delivery price should depend on distance. This did not exist in case of a vertically integrated utility as all generation as well as loads were looked after by a single utility. In this case, neither a load near generating station got advantage nor the distant loads felt the brunt of their location.

But in a de-regulated era, the buyers have the choice to choose their generator as local or distant producers. There is an argument that the customers should pay towards transmission usage on the basis of the distance. However, the counter argument to this is that, why should a customer be penalized for its geographical location, which is not in its hand? Thus, one aspect of this distance parameter is the fairness. The other aspect is the generation of price signals high dependency of prices on distance would lead to engineering efficiency.

PRINCIPLES OF TRANSMISSION PRICING

The main purpose of any transmission pricing scheme is not limited to recovery of the sunk costs involved in bringing up the transmission infrastructure. The transmission pricing scheme should do much more than that. In line with the above, following principles should be followed while designing the transmission pricing schemes.

1. The transmission prices should be devised so as to promote the efficiency of day-to-day operation of bulk power market.
2. The transmission prices should signal locational advantages for investment in generation and demand.
3. They should signal the need for investment in the transmission system.
4. The transmission prices should recover the costs of existing transmission assets.
5. Transmission pricing mechanism should be simple and transparent.
6. The mechanism should be politically implementable.

Out of these, the first three objectives are concerned with derivation of appropriate economic signals to either utility or the consumer. However, the fifth objective states that the signals should not be so complicated that one cannot decipher the same and react to it. Fourth and sixth objectives are associated with the allocation strategy of the pricing mechanism. Briefly speaking, the first objective speaks about the short term efficiency, numbers 2-4 with long term efficiency and 5, 6 with implementation.

There is different transmission pricing mechanisms prevailing in different parts of the world. They differ on a lot of parameters like: whether they use incremental methods to price the transactions or they go for rolled-in cost methods; whether generator pays the wheeling charge or the consumer pays for it, or both pay a part of it in some proportion, etc. It is expected that while designing a transmission pricing mechanism, following cost components for providing transmission service should be taken into account.

1. Operating Cost: This includes the cost mainly due to generator rescheduling, maintaining system voltage, reactive power support and line flow limits.
2. Opportunity Cost: It is the cost which a transmission company (Transco) has to forgo due to operating constraints that are caused by the transmission transaction.
3. Reinforcement Cost: This cost is charged to only firm transactions and includes capital cost of new facilities required to meet the transaction.
4. Existing System Cost: The investment cost of existing transmission facilities used by the transmission transaction.

Classification of Transmission Pricing Methods

Almost all existing and proposed transmission pricing models are cost based. That means, they allocate all or part of the existing and new transmission systems to wheeling customers. Based on this, transmission pricing paradigms can be defined which convert the transmission costs into transmission charges. Three basic patterns are:

1.) Rolled-in (embedded) transmission pricing.
2.) Marginal transmission Pricing.
3.) Composite transmission pricing.

The schemes can be categorized into transaction based and non-transaction based. The transaction based schemes essentially should have a defined source point and a sink point (bilateral transaction). On the other hand, non-transaction based schemes refer to the power exchange (PX) trades, where it is not possible to identify source-sink pair. Figure. Shows the broad categorization of various transmission pricing schemes.

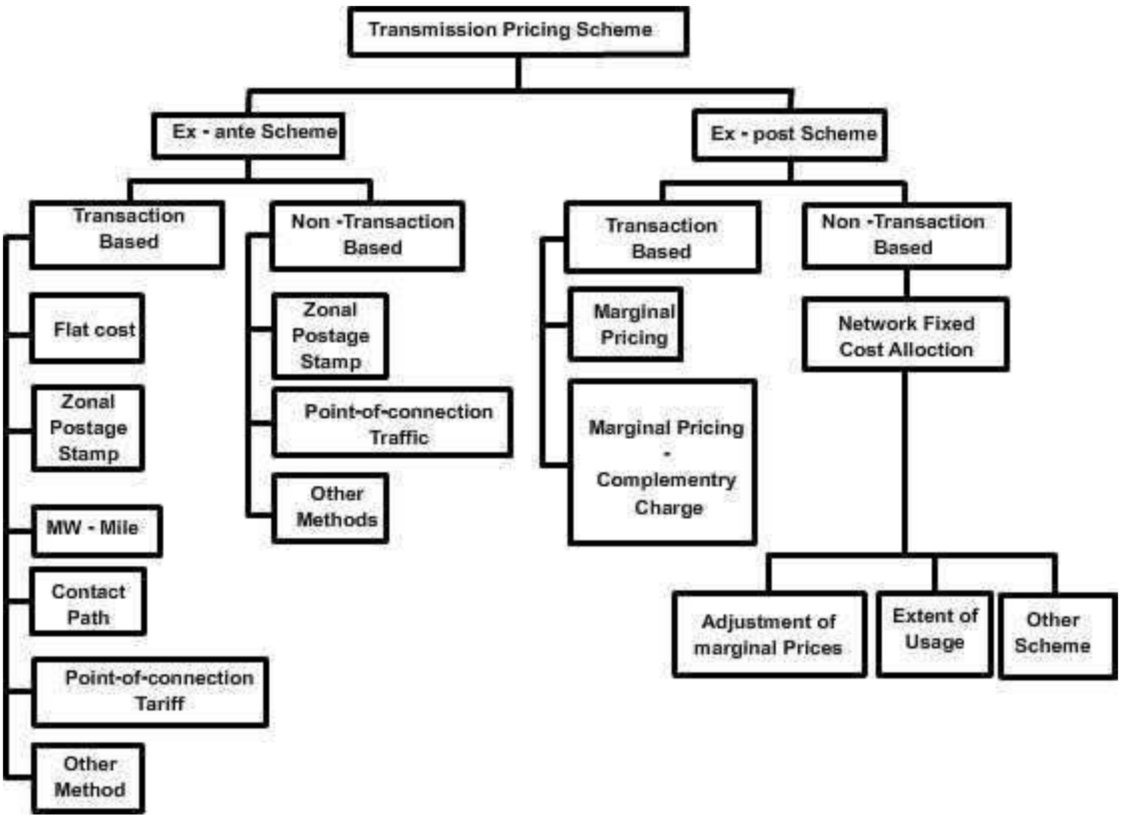


Figure : Classification of transmission pricing schemes

In the above figure, the transmission pricing schemes are classified on the basis of whether they are calculated ex-ante or ex-post. Generally, the ex-ante schemes are made up of pricing methods under rolled-in paradigm. As mentioned earlier, the total costs to be recovered are known a-priori and then they are transformed into transmission prices.

Rolled-In Transmission Pricing Methods

In this paradigm, all the costs incurred during building the infrastructure and the future investment, operating, maintenance costs are summed up (rolled-in) together and then are allocated to various wheeling customers on various basis. The basic philosophy behind this paradigm of transmission pricing paradigm is shown in Figure.

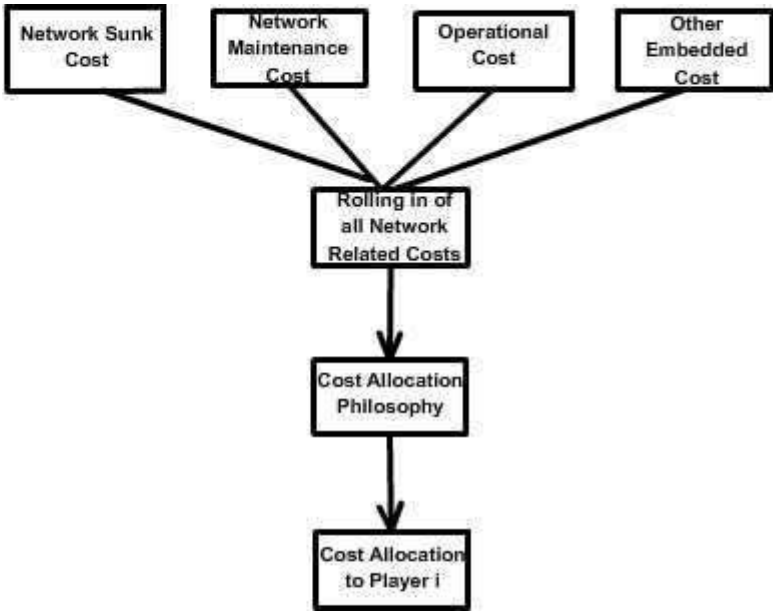


Figure: Rolled-in Paradigm

Effectively, this boils down to directly or indirectly quantifying the extent of usage of the network by each transaction. The diversity of underlying assumptions, methodologies, etc. lead to many choices or versions of methods under this category. Some of the commonly practiced methods are as follows:

1. Postage Stamp Method (transaction / non-transaction)
2. Contract Path Method (transaction based)
3. Distance Based MW-Mile Method (transaction based)
4. Power Flow Based MW-Mile Method (transaction based)
5. Power flow tracing based on proportionate sharing principle (non-transaction)
6. Equivalent bilateral exchange (EBE) method (non-transaction)
7. Z-bus based method (non-transaction)

There are some methods that allocate costs to individual bilateral transactions. These methods are known as transaction based methods. On the other hand the rest of the methods allocate the total costs to all the participants of the pool. These methods are called as non-transaction based methods. All these methods will be explained one by one with an illustrative example in the following sub-sections.

Postage Stamp Method

Postage stamp methodology is the simplest and easy to implement methodology of transmission pricing. A postage stamp rate is a fixed charge per unit of power transmitted within a particular zone. The rate does not take into account the distance involved in the wheeling. There are various versions of postage stamp methodology. In some versions, both, generators and loads are charged for transmission usage, while in others, only loads pay for the same. Some variants charge loads for their peak value while in others, they are charged on the basis of average loads. A simpler version of postage stamp mechanism is explained with the help of following illustration.

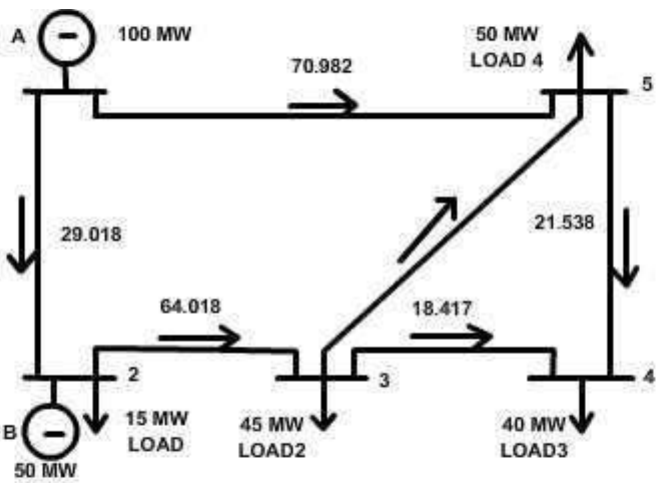


Figure: Sample 5 bus system

Suppose that the rolled-in cost of a region INR1000/day and that there are bilateral transactions as shown in Table.

Sr.No	From Bus	To Bus	MW
1	1	4	40
2	2	2	15
3	2	3	35
4	1	5	50
5	2	3	10

Table1: Bilateral Transactions

There are various ways of expressing the postage stamp rates. Normally it is given in INR/ MW/ day for Indian system. Let us assume that the loads make the whole payment towards the transmission charges. Then, the transmission charges paid by each load will be proportional to its MW. Hence, the transmission price paid per day by each load will be as given in Table 7.2.

Sr.No	Load	Charge per Day (INR)
1	15	100
2	45	300
3	40	266.67
4	50	333.33

Table 2: Transmission Charges by Postage Stamp Method

The postage stamp rates are based on average system costs and may have a variety of rate designs based on energy charges, capacity charges, or both. Rates may include separate charges for peak and off-peak periods, may vary by seasons and in some cases may be different for weekdays and weekends.

Advantages of Postage Stamp Method

- The method is simple and easy to implement.
- It is transparent and is easily understood by all.
- There is no mathematical rigor involved.
- Recovers sunk cost of transmission system.
- Being very simple and straightforward, it is easy to get political backing for it to be implemented.

Herfindahl-Hirschman Index (HHI)

It is the most commonly used method after concentration ratio. It is also known as the Herfindahl-Hirschman Index (HHI), as mentioned in the method section. HHI is a measure of the distribution ranging from 0 to 1. This index is the sum of the squares of the relevant company shares which is determined as a ratio (percentage) of the total volume of the market and is calculated according to the following formula:

$$HHI = \sum_{i=1}^{N} P_i^2$$

$$(HHI = \sum_{i=1}^{n} P_i^2 = P_1^2 + P_2^2 + P_3^2 + ... + P_n^2)$$

N : Total number of firms in the industry
P_i : the market share of i^{th} firm $(i = 1, 2, N)$

If there are an equal number of "N" companies in the industry, the index falls to the smallest value of 1 / N . For this reason, the index is a function of the inverse of the number of firms.

$$HHI = \sum_{i=1}^{N} (1/N_i))^2$$

$$HHI = N\,(1/N)^2 (3)$$

$$\boldsymbol{HHI} = \boldsymbol{1/N} (4)$$

If there is only one company in the industry, the index reaches the highest value of 1. The HHI considers firm distributions as being different from the concentration ratio. But since the squares of the shares are taken, the contribution to the index value of small firms will be low. In other words, the HHI takes into account all the companies in the sector and weighs firms with proportional market shares. As the company shares become smaller, they participate in the lesser evaluation. The index reaches its highest value in the monopoly situation and the smallest value is that all firms have equal shares. When the number of firms with equal volumes is large, HHl approximates 0, when it is a single company; it takes the value 1, which is, as the index value approaches one, the concentration increases. If the HHI Index takes a value between 0

Firm A=0.30, Firm B=0.20, Firm C=0.15, Firm D=0.10, Firm E=0.10, Firm F=0.10, Firm G=0.02, Firm H=0.01, Firm I=0.01, Firm J=0.01

The HHI is calculated as 0.1832 for this market. Assumed that, only the first six firm's market shares are known. HI that relies on these first six firms can be calculated. This value is HHI=0.1800. Then, if all the firms rest in the market are supposed as a single firm, the market share will be 0.05. (This value is the whole current market share of the rest of the firms). In that case, the HHI will be 0.1825. The HHI will be said that it cannot be lower than 0.1825 even if the real sales volume of the firms between firm G and J is known, when it is accepted that the rest of whole market shares of these firms are cumulated in one single firm. Thus, by using these techniques, it is possible to obtain close predictions to real HHI. "Workable competition" can be said if the HHI is below 40%, firm market share is not fixed; pricing is flexible, low profit rate and little cooperation between firms. A country's competition power can be compared by using concentration ratios and HHI. For example, if the concentration rates show that market is in competition for a product, the competition power of that sector is high.

Lerner index

The Lerner index measures how much the sales price is above of the marginal cost in a firm or industry sector. In other words, it tries to determine the magnitude of the difference between the selling price and the marginal cost in the firm or industry. An interest is established between this difference and concentration. The higher the marginal cost () of an industry or the price () determined by a firm, the more concentrated the industry is, the more profitable it will be. The Lerner index tries to measure the dimensions of such a relationship. The Lerner index is calculated as follows.

$$L = (Price - Marginal\ Cost)\ /\ Price$$
$$= (P - MC)\ /\ P$$

As can be understood, the value of L can be between 0 and K with an ambiguous number. It can be said that the closer the index value (L) is to 0, the closer competitive market conditions are. However, in order for the index to be calculated and interpreted, the market for the application must be in equilibrium with maximization of profit. In the absence of MC = MR, the application and interpretation of this index will not yield healthy results. It can also be said that this index leads to a subjective evaluation due to the use of data for firm performance. It is also very difficult to find the data required for the calculation of the index, especially the marginal cost.

Entropy index

The Entropy Index () is an approach that involves identifying and evaluating the properties of a system, such as eligibility, irregularity, and uncertainty. Its use in economic theory has also been adopted in relation to the competition market, because the more unclear the competition conditions, the greater the uncertainty of the environment, the more difficult it will be for consumers to make choices, and the more systematic the system will be. The Entropy Index assesses whether there is a departure from the competitive market conditions in an industry, in a similar way to the Herfindahl Index. However, it resolves the deficiency that may occur because of taking squares of the firm shares in H index (since the squares of the market shares are taken, the proportional differences between firm sizes may be somewhat different) and the error, as well. For this, a correction is made by taking the log of the inverse of the firm share (). So,

$$E = \sum_{i=1}^{n} P_i \cdot (\log 1/P_i)$$

As you can see, the Entropy value () will be between 0 and log n (the logarithmic value of the number of companies in the industry). Near-zero values will be interpreted as the absence of entropy in the system of closeness (high concentration) to monopoly and oligopoly markets. The opposite will be true as the number grows. Likewise, as the inequality between firms' market shares increases, the value of will decrease. When the market shares of the companies are equal $(P_i = 1/N)$, is the maximum. In this case, the value of is calculated using the following equation:

$$E = \sum_{i=1}^{n} (1/N) \log (1/(1/N))$$

$$E = \sum_{i=1}^{n} (1/N) logN$$

$$= (1/N)logN + (1/N)logN + \cdots + (1/N)logN$$

$$E = (N/N)\, logN$$

$$E = logN$$

The entropy index has the same properties as the HHI does. It takes into account the whole of the distribution and it is sensitive to changes in the number and size of firms. Thus, in terms of its use as a measure of business concentration, higher weights are given to smaller firms. Note also that decreasing values of indicate increasing levels of concentration.