

ENERGY PRICING

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Executive Summary

The electricity industry, historically dominated by regional monopolies, is moving into an era of greater competition. This transformation, properly termed as restructuring, involves all aspects of the industry, including transmission. Over the past decades many countries in the world have embarked on the road of restructuring with the aim to achieve a leaner and more efficient electricity supply industry. Restructuring involves overcoming a number of difficult problems and one of the most controversial problems is the development of an efficient transmission pricing methodology.

The pricing of electricity is discussed by considering all the cost components associated with power transfer:

- Capital & operating cost of the power system
- Cost of ancillary services
- Cost associated with power losses
- Cost caused by system congestion
- Cost for the procurement of the ancillary services (AS)

Here, ancillary services (AS), 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 required degree of quality and safety. This service varies with types of electricity markets. The largest part of power transmission cost is the system capital and operating cost. Congestion costs may also constitute a significant proportion of the power transmission costs depending on the nature of congestion. Therefore, pricing of electricity should recover power transmission cost and also the cost of ancillary service support required to ensure reliable operation of the power system.

Various transmission pricing models, namely Postage Stamp, MW-Mile, Nodal Pricing, Contract Path, are discussed in detail. The nodal Pricing method is the most complex but accurate way of calculating transmission tariffs. It is an advanced pricing model based on distance-based pricing to model the relationship between demand and load flow in the transmission network and then to price each location in the network according to costs imposed on the system through location marginal consumption. In this report, the consultation paper of CERC on transmission pricing, Electricity Act 2003 on open access policies and charges and tariff regulations are discussed in details. International experiences on transmission pricing and reactive power management have also been presented.

Due to the wide variation in frequency in the grid, Central Electricity Regulatory Commission (CERC) introduced Availability Based Tariff (ABT) order on 4th January 2000 for power generation pricing. The key objective of ABT is to enforce grid discipline by controlling the variations of

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frequency, voltage or reactive power. Thus the ABT is a system of incentives and disincentives based on actual performance of the market participants. This report discusses the methodology of calculation of UI charges. It also discusses the actions necessary to introduce intra-state ABT.

The economic and social effects of loss of electric service have significant impacts on both the utility supplying electric energy and the end users of electric service. The power system is vulnerable to system abnormalities such as control failures, protection or communication system failures, and disturbances, such as lightning, and human operational errors. Therefore, maintaining a reliable power supply is a very important issue for power systems design and operation. Reliability is a key aspect of power system design and planning and has been discussed in this report. Distributed generators (also known as Distributed Resources) come in many forms including gas turbine driven synchronous generators, wind powered induction generators, fuel cells with inverter circuitry, and others. The role of distributed resources to improve the power system reliability has also been highlighted.

This report discusses the issues affecting Power Trading in India and enhancing the same include lack of proper market mechanism, inadequate transmission capacity, lack of statutory provisions for direct sale by IPPs/CPPs licensees outside the state, grid indiscipline and financial viability of state utilities, among others in details.

Here, as power system margins reduced because of emphasis on the greater use of generation and transmission, power system dispatchers must operate their systems much closer to their technical limits. Real-time pricing of reactive power address the important issue of providing information on both the utility and consumers about the true burden on the system, in terms of cost and other system parameters viz. voltage drops and increased transmission losses, from time to time has been presented. Along with this reactive power pricing policies based on power factor penalties and disadvantages of that method are also highlighted.

Restructuring of the electric supply sector is taking place, all over the world, in different forms and at a different pace. Competition has been introduced in power systems based on the premise that it will increase the efficiency of this industrial sector and reduce the cost of electrical energy of consumers. Electrical energy is not, however, a simple commodity unlike other forms of energy that can easily stored in large quantities. Continuity of supply thus has been a value that can be much higher than the cost of energy consumed. In Asian countries such as India, China and Thailand, the restructuring is also underway with different objectives. India has already taken the first step in the direction of restructuring, in the form of unbundling the generation, transmission and distribution business. This will follow the privatization of some of their facilities and introduction of competition at different levels. However, the competition in electricity production and trading raises various problems concerning optimal market design, risk estimation, and strategy optimization for power producers, transmission network owners and retailers.

Pricing of electricity includes costs of generation, transmission and distribution. The generation cost typical would include fixed & variable costs as well as cost associated with unscheduled interchange (under ABT scheme). In addition to this cost may include environment protection costs also. In general, the costs associated with the power transfer may be categorized as follows:

- Capital & operating cost of the power system
- Cost of ancillary services
- Cost associated with power losses
- Cost caused by system congestion
- Cost for the procurement of the ancillary services (AS), which 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 required degree of quality and safety.

Congestion Cost

The congestion cost may also be significant part of the power transmission cost depending on the nature of congestion. In India, the ABT scheme cannot be understood as a mechanism for congestion management. It may or may not be able to control congestion. Hence complete methodologies will need to be evolved to discourage congestion. One of the familiar methods is to use the ancillary services for congestion reduction or avoidance. The pricing of ancillary services therefore becomes part of pricing of electricity.

Presently, there is considerable confusion with regard to transmission-pricing to be opted in the country. Even though approvals are awarded, one needs to study all the components contributing to facilitation of open access. In practice, two technical problems prevent electricity from being traded as a normal commodity. The first problem, *the balancing problem*, is that the demand and the supply of electricity have to be equal at any time. The second problem, *the constraints problem*, is that the trading is restricted by congestion of the electrical grid. While we do have a structure for pricing of power, with dramatic changes envisaged in the post Electricity Act environment, energy pricing will need to be reviewed with dramatic alterations in the structure of production, transmission and distribution of power. Furthermore this new structure would need to address transitional issues as we move from our present system to a new system. This transition phase would produce a structure that is not strictly comparable to other countries owing to:

- Demand (Supply) exceeds generation
- Congestion in distribution and sub transmission levels
- Heavy technical and non technical losses
- Poor quality of supply and service
- Low consumer satisfaction level
- Poor understanding of contracts and their legal implications
- Lack of knowledge of intricacies of system operation

Since there is possibility of gaming strategies and business opportunities driven by the profit motive, bewildered consumers may be left wondering what the future might hold for electricity prices and what it all means for their business. These questions require a careful examination especially with regard to the direction that public policy and regulation will take in the wake of widespread market failures, in addition to a sound analysis of supply and demand conditions.

Congestion management should be based on locational marginal pricing and should utilize tradable transmission rights as a hedging tool to increase price certainty and reduce volatility. Congestion costs should be paid by those responsible for creating congestion.

Uncertainties

There are number of uncertainties that are important in the electricity market such as load demand, seasonal variation availability of network, load factor, plant factor occurring of faults and load shedding. It is practically impossible to anticipate all possible scenarios of operation for both the consumer and the supplier and hence risks involved for both parties will be required to be addressed in some form. In properly functioning markets, prices would either be negotiated under competitive bilateral contracts or set by dynamic short-term markets. In electricity "spot markets" suppliers submit bids to the system manager for a particular quantity of power at a particular price for a particular period of time. The dispatcher then calls up generating facilities in the order of lowest to highest bids. The highest bid needed to meet demand in a particular time period becomes the price paid to all generators during that period. In theory, prices should generally reflect the marginal cost of producing power. This type of marginal cost pricing is common in many commodity markets and generally works fairly for both sellers and buyers.

Supply and Demand Fundamentals

In addition to the regulatory uncertainties discussed above, competitive electricity pricing is also a function of supply and demand. Prices tend to go up, for example, when demand increases due to heat waves or economic booms, or when supply decreases because a power plant goes

down or new plants aren't built. Beyond the laws of supply and demand, the price of electricity also reflects some of its unique characteristics: 1) electricity cannot be easily or cost-effectively stored, 2) there are few if any substitutes, depending on what it is used for, and 3) generally, users cannot simply terminate consumption without significant disruptions in production. These unique factors magnify the impact of supply and demand imbalances on electricity prices because, in the short run, consumers cannot alter their demand much in response to price fluctuations. Most businesses have probably experienced this extreme price "inelasticity" when they have not been able to easily avoid high or volatile electricity prices.

The individual electric users can control their business decisions. On-site cogeneration, load shedding protocols, energy efficient motors, and high efficiency lighting can provide great returns on company investment for many applications.

A pricing regime has to encourage investment in the power sector but at the same time policy frameworks have to keep in mind its social implications such as subsidies and cross subsidies provided by the government. Energy pricing must encourage energy efficiency, supply and demand side management of local resources of energy and renewable and alternate energy sources to ensure the long-term reliable energy sources, at competitive prices, to support sustainable economic development is available.

Energy shortages are likely to be a trend as the newer and larger economies begin to modernize. Policy frameworks will need to address very seriously the consumption patterns of energy through the pricing mechanism. Hence these frameworks should also try to improve efficiency and promote conservation in the production and consumption of electricity, heating fuels, and transportation fuels and encourage uses of renewable energy sources. They should protect competitiveness, fairness, and the environment, while balancing the economic and social needs.

India is at a stage where we will need to develop an electricity industry that is based on the market mechanism with growing private participation in all three major areas: generation, transmission and distribution. In the transition, the public sector will remain the largest single entity and hence has a major responsibility to ensure a smooth transition between a wholly publicly provided system to one that is market orientated. This shift would create an electricity market, which would be driven by demand and supply at one level and at the other by the financial capacity of both the producer and customer. The market structure would govern electricity prices and the market structure would depend upon largely the customer mix and available resources in the region.

Subsidies

Developing countries tend to subsidize energy prices on the consumer or end-user side, while industrialized countries and economies in transition still employ certain practices aimed at providing support on the producer side. Producer subsidies take many forms, such as tax credits, special transportation tariffs, and energy technology R&D expenditures by government agencies. The objectives of such subsidies are usually to guarantee a certain level of revenues, to reduce the cost of producing energy, or to assure technical progress.

Initially electricity is priced by governments in a manner that is inefficient because prices not related to marginal costs, in order to reach as much of the population as possible and because individual electricity users are also voters. Hence, residential consumers are often cross-subsidized by other categories of consumer's viz. industrial users. Due to cross-subsidies for a group of consumers privatization could result in price discrimination.

Poorly designed subsidies have various negative effects that could overwhelm the social benefits of improving accessibility for the poorest segment of the population. Energy price subsidies, which encourage energy consumption by keeping prices below costs, impose heavy burdens on economic efficiency, environmental quality and government budgets. We discuss here the issues related to subsidies and cross subsidies in the Indian context.

In all circumstances, prices should be set at a level, which allows energy providers to recover the long run marginal cost of delivering the service, including a fair return on investment. In order to

accomplish this, governments, regulators and utilities (whether publicly or privately owned) must implement cost of service determination to calculate the actual long run marginal cost of delivering energy to each customer category, based on usage patterns, in order to quantify tariffs for each category. Lack of costing transparency and an inadequate costing structure are major constraints to achieving a sustainable energy system.

Price Regulation

Cost-of-Service regulation

Historically, to improve energy efficiency with the increase of service quality and reliability, the cost of service or rate of return model for tariff determination is largely used in the electricity market. The scheme provides incentives to the electric companies for the expansion and the up gradation of the system while reducing its financial risk. This model also creates incentives for the expansion of volume of energy sales.

In the cost of service regulation the revenue requirement is based on recovering all expenses such as return on equity, interest on debt, depreciation, O&M charges etc. This revenue can be determined calculating these components of ARR. This scheme of regulation can provide a risk with no conditional reward and causes utility managers to be more responsive to regulators than to customers or financial incentives.

After the cost of service regulation model, developed countries introduced performance-based regulation to increase the economic efficiency and environment friendly while providing energy at lower prices to the end users.

Performance-Based Regulation

The PBR is basically considered the essential aspects of incentive regulation. PBR is therefore linked with the good understanding of the incentive characteristics of traditional cost of service regulation. The prices in such a system are generally fixed for a longer period than that in the cost plus methodology. The PBR (performance-based regulation) system has distinct advantage in terms of providing an incentive to the utility to minimize the costs. This incentive however needs to be counter balanced by monitoring the prescribed quality standards so that the reductions in cost do not lead to a reduction in the supply standards. There are several mechanisms and parameters such as the generating plant reliability, T&D loss, outages at the customer level, customer complaint handling and satisfaction, etc., around which a PBR system can be designed. The PBR presents a number of advantages over the cost of service regulation. The tariff in this model is regulated by a price and revenue cap. This regulates the market power in the electricity business. During the last decade the model has been seen to increase production and encourage cost reduction. Performance-based regulation has overcome the problems encountered in the cost-of-service model of regulation. The model provides the costs, which are proportional to the sales volume of energy. The model thus produces more profits when production crosses the level forecast by regulators. If the sales volume is lower than the forecasted level, the company would be at financial risk. The model, however, does not support the energy efficient demand side management by delivering services at lower prices than the end users invest in energy efficient technologies.

Transmission Pricing

The electric utility industry is today undergoing rapid and irreversible changes. Volatile fuel costs, less predictable load growth, a more complex regulatory environment and a deceleration in conventional technical progress are important examples of these changes. Yet the need for growth in productivity and efficiency, and for increased flexibility to handle future uncertainties, is stronger and more challenging than ever.

The transmission process is a vital element in the supply of electricity and indeed in the possible emergence of a workable market system. (Secondary markets cannot operate efficiently if the transmission network does not offer substitutability). Because by nature network investments

cannot be duplicated they emerge as regulated monopolies that include common carrier principles. Without a national grid, transmission facilities need to be used efficiently and the pricing mechanism needs to ensure that producers and distributors of electricity are incentivised accordingly. Very often power has to be transmitted over long distances but equally those issues with short wheeling between producers and consumers. How can transmission costs most appropriately be related to transmission tariffs in this scenario? Transmission pricing is therefore one of the crucial elements of a market oriented power system and is discussed at some length.

The transmission industry, being the link between generators and loads, should ensure the reliability of the transmission grid by coordinating efficiently the activity of grid users by introducing prices as coordinating (control) variables. An investment in transmission capacity has an economic value. It enables the import of inexpensive power from low-cost regions to high-cost regions. The new industry structure should then be able to invest in transmission capacity, in order to provide the transmission services users that consumers are required to pay for. Efficient transmission pricing is necessary to assure economic dispatch of existing generation capacity; delivery of electricity to consumers at its minimum cost including both generation and transmission costs.

A robust transmission system is essential to delivering the benefits of competition to customers, including greater access for new competitive generation resources, reduction of congestion costs, and greater reliability. Standard market design should provide appropriate price signals so that market participant can make economically efficient investment decisions regarding transmission, generation, and demand response.

Economic theory maintains that a monopolist will always try to maximize profits at that level of output where its marginal cost equals its marginal revenue. The monopolist has power to set price and maximize its profits because it is the only entity, which supplies power to the entire market. The price setting in monopolistic situation is not absolute but operated by the demand. A monopolist can charge each consumer the price what the consumer would pay. Introducing competition in the market prevents the monopoly.

Pricing of transmission services: The pricing of transmission services should be carried out to achieve the following goals:

- Recover capital and operating costs
- Encourage efficiency of use and investment
- Provide equal opportunity to all users
- Understandable price structure
- Implementable structure

Characteristics of good transmission pricing mechanism:

Economic Efficiency: A good pricing system has to give correct incentives to the market participants. In the case of electricity transmission, it implies:

- Encouraging an efficient use of the existing network
- Encouraging an efficient location of new generation units and customers
- Encouraging investments in the existing network and network expansion.

Cost reflectiveness: Prices reflect costs in different ways. For economic efficiency, social welfare and least-cost operation, prices should ideally reflect marginal costs. It should not permit cross subsidization between services, and prevent a monopolist from engaging in predatory pricing.

Simplicity and Transparency: Price transparency is key to a good market model. The process of tariff calculation should be easy to understand.

Equity or Non-Discrimination: The prices should be non-discriminating. Identical clients buying a good / service at the same place and at the same time should pay the same price.

Follow competition rules: Tariffs need to abide by the principles of competition.

Stability over time: This is considered important to facilitate investment decisions. Customers will favour prices that are reasonably stable or atleast predictable from year to year.

Cost Component of Transmission System

Electricity moves according to Kirchoff's Laws, following the path of least resistance. As a result of these physical laws, electricity moves across many parallel lines, often in circuitous routes. Kirchoff's Law and the resulting loop flows imply that cost attribution of certain parts of the network to certain users becomes very difficult, since one network user's power flows affect those of all other network users. The following cost components are involved in a transmission system

- Operating Cost: This includes the variable cost mainly due to generator rescheduling, maintaining system voltages, reactive power support and line flow limits
- Loss of Opportunity Cost: It is a cost which transmission company (Transco) has to forego to meet the transactions such as it could not use cheaper generation or could not realize revenue from firm contracts due to line flow reaching the limits
- Reinforcement Cost: This cost is charged to only firm transactions and includes capital cost of new facilities required to meet the transaction.
- Existing Cost: This includes capital cost of the existing facilities and need to be allocated to various transactions on some rational basis.

The transmission pricing should be computed such that the total transmission charge includes cost of all the above components and allows a small-regulated amount of profit to the transmission owners.

Transmission Tariff Methods: A number of methods, either based on embedded cost methodology or based on incremental cost calculation have been suggested in the literature. The consultation paper of CERC on transmission pricing also referred to some of these methods.

Postage stamp method

A postage stamp rate is a flat per kW charge for network access within a particular zone, based on average system costs. Postage stamp transmission tariffs allocate total system costs to consumers on the basis of load share: a customer pays a transmission charge equal to the total system cost-weighted according to their consumption divided by total consumption. The method results in higher costs above marginal costs because it incorporates historical fixed costs. The cost for transmitting within the zone is independent of the transmission distance. A generator transmitting to a load in a different zone would have to pay the postage stamp charges for the zone of origin and the zone of delivery, and also any intervening zones. This accumulation of zone access charges is often called "pancaking." Although transmission within a zone is independent of distance, longer distances increase the likelihood that more than one zone will be crossed, which would increase the total transmission cost. Although postage stamp rates provide a way to recover the fixed costs of the network, they provide no information about congestion when used by them. The advantage of using this method is that it is easy to administer. But it does not reflect marginal costs except in a special circumstance where all generators are at equal distances from the load and where the load on each line is equal.

MW-Mile method

In this method rates explicitly reflect the fact that the cost of transmission depends on the distance the power is transmitted and how much power is transmitted. Megawatt mile pricing involves load flow analysis to model the power flows on the transmission network to determine transmission charge. These distances and power flow, if computed correctly, more accurately reflect the impact of a transmission arrangement on the system. The cost of transmission per megawatt mile is the total cost averaged over megawatt- miles of usage. The Megawatt-Mile pricing is based on the economic principle that the buyer pays only for the transmission capacity they use and nothing else. Many economists prefer the Megawatt-Mile pricing concept because it encourages the efficient use of the transmission facility and the expansion of the system.

Contract path method

Contract path pricing calls for transmission from point A to point B based on the cost of single identified path. The price includes a capacity charge to cover the capital costs, and energy charges based on losses and other operating costs. This method requires the identification of the supply and the receipt point for a bilateral transaction and a “contract path” between the two nodes. This method directs the amount of contracted capacity as well as the distance associated with the contract path. In this method the network charges are allocated to individual transaction. The contract path is fiction path method. The physical load flow of a single transaction may be different from the contractual load flow, particularly in the meshed electricity network. Transmission pricing becomes complex when electricity does not flow over the contracted path. The problems associated with this method are the direction of the load flow, congestion management, allocation of charges for ancillary services and system control for single transactions. The other problems associated with contract path include:

- Fixed cost of transmission network are not recovered
- Pricing manipulation
- Difference between short term and long term prices
- Calculation of available transfer capacity is difficult
- Transmission affects the other parallel paths in the electricity-meshed networks.
- Power can flow on different paths depending upon the generation schedule.

The flow of power may and often does diverge widely from contract paths. As a result, the supposed economies of the contract path have little to do with the actual costs of power transfer.

Incremental postage stamp method:

CERC added the incremental postage stamp rate assigned to a zone to make this method distance sensitive. According to CERC such rate can be assigned by drawing grid lines 100 Km apart on the map of India from north to south and from east to west. The wheeling charges could also be comprehended as the crosses the square zone of 100x100 Km, provided that the circuit path is straight and parallel to the side. Although postage stamp rates provide a way to recover the fixed costs of the network, but they provide no information about congestion.

Marginal Cost Pricing and Opportunity Cost Pricing

The marginal cost of production is the cost incurred to serve an additional unit of consumption at a particular time. Since it represents the true cost of putting resources to a particular use, a price equal to marginal cost gives right economic signal to consumers. The interaction between supply and demand in an environment where the costs of production increase as output increases has the effect of creating economically efficient outcomes. The increasing-cost nature of the particular industry invites new producers to enter the market in the hope of producing at a lower cost, thus winning consumers and profits. Thus the competitive electricity market drives down the price to the lowest possible point for a given demand. The concept of marginal cost pricing is useful in attempting to optimize the allocation of resources. However, the higher tariffs that may result from the application of this principle could be detrimental to a country's industrial competitiveness or might deprive lower income consumers of an essential service. In any case, marginal cost valuation provides valuable guidance in establishing the tariff structure even if the level of marginal costs is not totally recovered in the average tariff.

If transmission is priced below its marginal cost, it becomes profitable to import power from distant generating sources, even though less-distant sources might entail a lower (social) cost. If, on the other hand, transmission is priced too high, the geographic market for electricity is artificially narrowed, which limits the importation of low-cost generation and the competitiveness of the generation market in general.

The fact that Electricity Transmission is a Natural Monopoly needs no reiteration. It is also well accepted that the regulated firms should be given a price so that they earn a “reasonable return” the marginal costs curves of such firms lie below the average cost curves. Hence to enable the

firms to operate at the minimum of their average “efficient” cost curves the variable part of the charges must equal the nodal prices (marginal costs) and the fixed charges should cover the fixed costs. The fixed costs must be charged to the various users in a manner, which takes into account their “demand elasticities”. This can be done by unbundling transmission transaction as Long Term and Short Term. These can further be categorized as Firm (defined as transactions for more than one month) and Non-Firm transactions (for less than one month).

Locational marginal price (LMP) (or Nodal pricing) based pricing model

It is an advanced pricing model, based on distance-based pricing to model the relationship between demand and load flow in the transmission network and to price each location in the network according to costs imposed on the system through location marginal consumption. Short term nodal pricing does not recover the embedded costs of the transmission system. However it gives the best short and long-term price signals for investment in both transmission and generation. The nodal pricing approach manages congestion and sets transmission prices through a centralized energy market based on economic dispatch. The basic idea of the method is to organize the market as a pool in which generators and loads submit hourly bids for node specific injections and withdrawals of power to an Independent System Operator (ISO) with full coordination and price setting authority.

Short-Run Marginal cost (SRMC): The Short Run marginal Cost of Transco is the cost incurred in supplying an additional 1 MW of power in a transaction. This can be calculated from the difference in marginal costs at the supply bus and the delivery bus. This requires a complete network representation of the system in lines of an OPF and dual variables associated with the demand balance equation (load flow equation) denote the marginal costs. The transaction price can be determined by multiplying the power transaction with the marginal cost to evolve the SRMC based price.

Long-Run Marginal cost (LRMC): In these methods, a long-term transmission planning analysis is included within the transactions. The models simultaneously determine the new transmission line additions over a period of time (about few years) and how and which power transaction brought these additions. The Lagrange multipliers from such a model will provide the long-run marginal cost, which is used for pricing to address the issues of capital cost recovery.

However, it should be noted that the computational complexity of such models is much higher due to the presence of integer variables (in new line selection), and the dynamics planning framework (due to the multiple years planning consideration). The LMP may inflate the economic costs of transmission constraints, may encourage the use of generation market power, may encourage uneconomic investments to relieve transmission constraints, may encourage gaming of rebates and may discourage the development of bilateral contracts.

Transmission Tariffs: Indian Context

Separate provisions for transmission tariff do not explicitly exist in any of the electricity laws. Transmission as an unbundled entity came into existence with the establishment of Powergrid in 1989. Powergrid was treated as a generating company as per the Electric Supply Act and was recognized as a central transmission utility (CTU) through the Electricity Laws Amendment, 1998. Transmission Tariffs were notified by the central government, to formalize the methodology of tariff setting in the country. The tariff prescribes a single part tariff comprising all costs on account of interest on outstanding loans & working capital, return on equity, depreciation, operation & maintenance expenses (O&M), and income tax.

The services that impose a fixed cost on the system are as follows:

- Provision of transmission facility including reserves
- Provision of adequate reactive power support and voltage control
- Investment planning
- Reinforcement costs, or the cost of providing additional capacity for accommodating an additional transaction
- Costs incurred in the Regional Load Despatch Centers (RLDC) for operation and maintenance of the regional grid.

The services that impose a variable cost on the system are as follows:

- o Transmission loss
- o Billing and Collection costs
- o Analysis, arrangement of transactions and the incremental operating costs of matching demand with supply on a real time basis.

As part of more general sector reform, many countries around the world have rebalanced power transmission prices. The rationale for this is to provide the right signals for investment and consumption decisions; these would come from prices reflecting underlying marginal costs. Marginal costs in an unconstrained transmission network relate to power losses. In a constrained system, short-run marginal cost relates to power losses plus congestion costs. In the long run, congestion can be eased through new investment; this is reflected in long-run marginal cost, which reflects power losses plus costs associated with system expansion.

Tariff Issues in the Electricity Act 2003: Open Access and Access Charge

It is required to determine transmission charge, which provides adequate signals for use of transmission resources under congestion, loss reduction and optimal siting of generators, loads and reactive supports. Some mechanism will be required to determine sharing of transmission charges between various beneficiaries across regions and within a region.

Salient features of Electricity Act 2003 on Open Access for different entities in Electricity Markets

Captive Generation: Every person, who has constructed a captive generating plant and maintains and operates such plant, shall have the right to open access for the purposes of carrying electricity from his captive generating plant to the destination of his use:

Provided that such open access shall be subject to availability of adequate transmission facility and such availability of transmission facility shall be determined by the Central Transmission Utility or the State Transmission Utility, as the case may be:

Provided further that any dispute regarding the availability of transmission facility shall be adjudicated upon by the Appropriate Commission

Central Transmission Utility and functions: One of the functions of CTU is

- o To provide non-discriminatory open access to its transmission system for use by
 - (i) Any licensee or generating company on payment of the transmission charges; or
 - (ii) Any consumer as and when such open access is provided by the State Commission under sub-section (2) of section 42, on payment of the transmission charges and a surcharge thereon, as may be specified by the Central Commission:

Provided that such surcharge shall be utilized for the purpose of meeting the requirement of current level cross-subsidy:

Provided further that such surcharge and cross subsidies shall be progressively reduced and eliminated in the manner as may be specified by the Central Commission:

Provided also that such surcharge may be levied till such time the cross subsidies are not eliminated:

Provided also that the manner of payment and utilization of the surcharge shall be specified by the Central Commission:

Provided also that such surcharge shall not be leviable in case open access is provided to a person who has established a captive generating plant for carrying the electricity to the destination of his own use.

State Transmission Utility and functions: One of the functions of STU is

- o To provide non-discriminatory open access to its transmission system for use by-
 - (i) any licensee or generating company on payment of the transmission charges ; or
 - (ii) any consumer as and when such open access is provided by the State Commission under sub-section (2) of section 42, on payment of the transmission charges and a surcharge thereon, as may be specified by the State Commission:

Provided that such surcharge shall be utilized for the purpose of meeting the requirement of current level cross-subsidy:

Provided further that such surcharge and cross subsidies shall be progressively reduced and eliminated in the manner as may be specified by the State Commission:

Provided also that such surcharge may be levied till such time the cross subsidies are not eliminated:

Also provided that, the manner of payment and utilization of the surcharge shall be specified by the State Commission.

Provided also that such surcharge shall not be leviable in case open access is provided to a person who has established a captive generating plant for carrying the electricity to the destination of his own use.

Duties of Transmission Licensees: One of the functions of Transmission licensee should be

- o To provide non-discriminatory open access to its transmission system for use by-
 - (i) any licensee or generating company on payment of the transmission charges; or
 - (ii) any consumer as and when such open access is provided by the State Commission under sub-section (2) of section 42, on payment of the transmission charges and a surcharge thereon, as may be specified by the State Commission:

Provided that such surcharge shall be utilized for the purpose of meeting the requirement of current level cross-subsidy:

Provided further that such surcharge and cross subsidies shall be progressively reduced and eliminated in the manner as may be specified by the Appropriate Commission:

Provided also that such surcharge may be levied till such time the cross subsidies are not eliminated:

Provided also that the manner of payment and utilization of the surcharge shall be specified by the Appropriate Commission:

Provided also that such surcharge shall not be leviable in case open access is provided to a person who has established a captive generating plant for carrying the electricity to the destination of his own use.

State Regulatory Commissions: One of the functions of State Regulatory Commission is

- o determine the tariff for generation, supply, transmission and wheeling of electricity, wholesale, bulk or retail, as the case may be, within the State:

Providing that where open access has been permitted to a category of consumers under section 42, the State Commission shall determine only the wheeling charges and surcharge thereon, if any, for the said category of consumers;

Salient features of Electricity Act 2003 on Tariff (Transmission)
Tariff Regulations

The Appropriate Commission shall, subject to the provisions of this Act, specify the terms and conditions for the determination of tariff, and in doing so, shall be guided by the following,

- (i) the principles and methodologies specified by the Central Commission for determination of the tariff applicable to generating companies and transmission licensees;
- (ii) the generation, transmission, distribution and supply of electricity are conducted on commercial principles;
- (iii) the factors which would encourage competition, efficiency, economical use of the resources, good performance and optimum investments;
- (iv) safeguarding of consumers' interest and at the same time, recovery of the cost of electricity in a reasonable manner;
- (v) the principles rewarding efficiency in performance;

- (vi) multi year tariff principles;
- (vii) that the tariff progressively reflects the cost of supply of electricity and also, reduces and eliminates cross-subsidies within the period to be specified by the Appropriate Commission;
- (viii) the promotion of co-generation and generation of electricity from renewable sources of energy;
- (ix) the National Electricity Policy and tariff policy:

Determination of Tariff

1. The Appropriate Commission shall determine the tariff in accordance with provisions of this Act for
 - a. supply of electricity by a generating company to a distribution licensee: Provided that the Appropriate Commission may, in case of shortage of supply of electricity, fix the minimum and maximum ceiling of tariff for sale or purchase of electricity in pursuance of an agreement, entered into between a generating company and a licensee or between licensees, for a period not exceeding one year to ensure reasonable prices of electricity;
 - b. transmission of electricity;
 - c. wheeling of electricity;
 - d. retail sale of electricity. Provided that in case of distribution of electricity in the same area by two or more distribution licensees, the Appropriate Commission may, for promoting competition among distribution licensees, fix only maximum ceiling of tariff for retail sale of electricity;
2. The Appropriate Commission may require a licensee or a generating company to furnish separate details, as may be specified in respect of generation, transmission and distribution for determination of tariff;
3. The Appropriate Commission shall not, while determining the tariff under this Act, show undue preference to any consumer of electricity but may differentiate according to the consumer's load factor, power factor, voltage, total consumption of electricity during any specified period or the time at which the supply is required or the geographical position of any area, the nature of supply and the purpose for which the supply is required;
4. No tariff or part of any tariff may ordinarily be amended more frequently than once in any financial year, except in respect of any changes expressly permitted under the terms of any fuel surcharge formula as may be specified;
5. The Commission may require a licensee or a generating company to comply with such procedures as may be specified for calculating the expected revenues from the tariff and charges which he or it is permitted to recover;
6. If any licensee or a generating company recovers a price or charge exceeding the tariff determined under this section, the excess amount shall be recoverable by the person who has paid such price or charge along with interest equivalent to the bank rate without prejudice to any other liability incurred by the licensee;

International experience in Transmission pricing:

The following objectives must be kept in mind while designing electricity transmission prices. The prices should

- o Promote the efficient day-to-day operation of the bulk power market
- o Signal locational advantages for investment in generation and demand
- o Signal the need for investment in the transmission system
- o Compensate the owners of existing transmission assets
- o Be simple and transparent
- o Be politically implementable

Argentina

The Argentine transmission network has a number of entry and exit nodes at which hourly spot market prices for electrical energy are determined. Differences in these energy prices define the short-run marginal cost of transmission between nodes. When transmission between two nodes is constrained, the difference in spot prices reflects the differences in the marginal costs of supply between the two nodes. This difference comprises not only marginal losses but also “congestion rent”. Congestion rent is what is left over after deducting that portion of the difference in energy prices that is attributed to marginal losses.

Chile

The current pricing structure for the use of the transmission system evolved from 1982 to 1990. It receives income from energy and capacity charges, which are derived from spot price differences, corresponding to nodal price differences for energy and power. Fixed costs are recovered through wheeling rates charged to generators. The Energy Law provides payments for each line allocated among all users in proportion to the maximum transported power by each user, in respect of the total maximum transmitted power.

England & Wales

National Grid’s (NGC) (Transmission Utility) method “Investment Cost-Related Pricing (ICRP), has been calculated in a very transparent manner. The company uses a simple model to assess the cost of expanding the system to cope with additional demand or generation at each node in turn. The model is a linear program, which minimizes the MW-Km of transport, assuming that electricity flows along the shortest route between nodes with net generation and net demand. The distances are measured along NGC’s existing “wayleaves” and increased along those where the wayleave is an underground line, to reflect the higher cost of those lines. The demand at each node is equal to the forecast peak demand at that node, while the generation capacity at each node is scaled down by the ratio of the forecast level of demand to total generation capacity. The model calculates the extra transmission capacity required by additional demand at each node, which is multiplied by an “expansion constant” to give the marginal cost of that demand. Points with similar costs are grouped into zones, and the transport charge for each zone is based on the average cost of the points with it.

Japan

In 1996, the major utilities published wholesale electricity wheeling price lists for Independent Power Producers (IPPs). Although wholesale wheeling prices are similar to the megawatt-mile approach, the transmission line cost and the average local transmission costs are treated separately. The present transmission charges are predetermined based on generating capacity and peak demand. Utilities have set their transmission charges to recover all of the revenue that the government allows.

New Zealand

A market based on full nodal AC pricing is still under consideration but since October 1996, a market has been operated using a DC flow approximation with piecewise linear losses. The model produces prices for approximately 600 nodes in the physical network, and active power prices are published for some 150 points at which power is bought and sold.

Norway

From 1993, a system with point tariffs has been implemented at all grid levels. This system implies that the price for access and utilization of the grid is unaffected by the power contracts of the grid customers. The tariffs in the central grid consist of four elements: two elements that are dependent on the short-run utilization of the grid and two elements that are fixed on an annual basis. The variable elements are compensation for losses and congestion fees. Congestion fees are only intended to generate income rather than influence the behavior of producers or consumers.

Pennsylvania-New Jersey – Maryland Interconnection (PJM)

In April 1998, PJM implemented locational marginal prices corresponding to a nodal pricing market where prices at each location correspond to the marginal cost of supplying an increment of energy to that location on the system. This includes the marginal cost of generation, the marginal cost of system transmission losses and the effect of congestion. The PJM ISO began posting locational prices for 1,277 locations. The price paid for energy bought and sold in the PJM Interchange Energy Market reflects the hourly Locational Marginal Price at each load and generation bus.

Sweden

As of January 1, 1995, Sweden reformed its transmission-pricing model, new tariff model is more market oriented. Transmission tariffs consist of a power fee, an energy fee and in some cases, an investment fee. The power fee is based on subscribed maximum input and output at connection points. The energy fee is calculated by applying a marginal loss factor to energy off takes and injections. Marginal loss coefficients have been determined for 150 connection points. An investment fee is applied if a new connection is planned requiring significant investment. The fee is intended to recover any additional costs imposed on the national grid.

WEPEX

Transmission pricing comprises connection charges, access fees and usage charges. The costs of any connection facilities are borne by the party requesting connection. There are three types of access charges – Non-self sufficient access charges between utilities, Wheeling Access Charges between utilities and Direct Access end- user access charges. Access charges for transmission services are charged at point of delivery and are paid to the participating operator. These charges are intended to recover that portion of the transmission revenue requirement not recovered through transmission revenue credits. Transmission usage charges are based on nodal pricing principle, but this approach has been simplified by combining nodes into pricing zones.

The England and Wales Electricity Model

The E & W model of power supply is very radically transformed model in power supply history. It was transformed from a state owned monopoly to an unbundled system via some intermediate stages. This model has provided some lessons for developing countries to develop their own electricity market. Some innovative features of the E & W model are:

- o Competition is price-based in the wholesale electricity market
- o Price-based regulation for franchised services through caps on average revenues,
- o A structure giving ownership and operation of the transmission network to an entity that is separate from generators and distributors in order to ensure open access to the network

This model offers the most sustainable long-term benefits because it gives the strongest efficiency incentives to suppliers. But it is also risky, especially for developing countries, because the strong incentives have to be regulated firmly, impartially, and transparently to ensure that they remain consistent with the interests of consumers and society.

The Electricity Act 2003

Objective of the Bill

The conceptual framework underlying this new legislation is that the electricity sector must be opened for competition. The Bill moves towards creating a market-based regime in the power sector as stated earlier the bill seeks to consolidate, update and rationalize laws related to generation, transmission, distribution, trading and use of power. It focuses on creating competition in the industry, protecting consumer interests, ensuring supply of electricity to all areas, rationalizing tariff for lowering cross-subsidization levels and encouraging autonomous regulation with the separation of policy, regulatory and operational aspects. The bill provides an opportunity for open access in the distribution and to phase out cross-subsidies. In the following sections we have analyzed the impact of the bill on generation, transmission and distribution .We also look at

the impact of the introduction of power trading and the open access system and the change in the industry structure that the Bill proposes to bring out.

Generation

- Removal of license requirement to shorten project cycles
- Captive power generators will be allowed to use power for not only captive use also for the use of a group of industries.
- Open access to transmission for independent power producers (IPP) and captive power producers. This change in regulation will allow generators to sell excess power at more remunerative prices than before, leading to increased capacity utilization for captive plants.

Transmission

- Allows open access and thereby an impetus for power trading

Distribution

- No exclusive monopolies in distribution circles.
- Open access to increase competition The Bill provides for open access in distribution also, thus opening the way for competition in the retail supply segment.

Impact of the introduction of power trading

- Distinct licenses required trading in power
- Role of the regulator will become very important for promoting competition, fixing reasonable charges for transmission, generating tariffs, fixing wheeling and cross-subsidy charges and in protecting the consumers from the rising prices of electricity, more so in times of shortage.

The Electricity Bill permits the setting up of generating plants without licenses, grants licenses for transmission, distribution and trading, allows third party sale by generating companies, and allows open access to transmission infrastructure and a phased open access for the distribution systems. Further, with an open access to the transmission system and a market for power, the bottlenecked capacities of the captive power plants will be better utilized, which in turn will lead to the promotion of new captive generation. This will provide tremendous potential for investment in generation, transmission and distribution segments. Increased investment will lead to improved infrastructure, which is critical for the Indian power sector. In the medium to long term, competition created among various categories of players will lead to improved efficiency and better customer service standards. In addition, with the freedom to buy and sell power in the wholesale market, and eventually in the retail market, the end user will benefit in terms of choice of supplier, reliability of supply and competitive tariffs.

Availability Based Tariff

The Central Electricity Regulatory Commission (CERC) introduced Availability Based Tariff (ABT) order on 4th January 2000 for power generation pricing. CERC declared modified ABT order, which has come into force on 01.04.2004. The key objective of ABT is to maintain the much needed grid discipline by controlling the variations of frequency, voltage or reactive power. These variations lead to incremental line losses and grid failure. In the open access deregulated electricity market, where the generators are directly in contact with the beneficiaries, energy transfer should be scheduled to maintain grid discipline. The ABT is drafted on the scheduling of generators and beneficiaries a day ahead based on 15-minute time blocks and charges for deviation from their schedules are levied (by penalizing or rewarding as the case may be) on them. Thus the ABT is a system of incentives and disincentives based on actual performance of the market participants.

The ABT dictates a three-part tariff including capacity charges, energy charges and UI charges. The first part is the fixed charge for the capacity offered to LDCs in time blocks given one day in advance. The second part is the energy charge determined by the fuel cost in case of thermal plants. The third part is the Unscheduled Interchange charges, which are based on deviation from schedule. These UI charges are levied upon both generators and beneficiaries.

The mechanism of Inter-state ABT may need some modifications to be implemented within a state. Creating regulations, which would reduce the gap between scheduled and actual electricity transfers, may bring the discipline in state distribution utilities/companies. The one-day-ahead schedule will be submitted to SLDC by state distribution companies, (Discos) and generators. The tariff structure would be put in place so that the demand of Discos and the supply by Gencos converge close to schedule.

At state level to promote open access consumers and power trading with maintaining grid discipline the Intra-State ABT mechanism should be properly prepared. At the intra-state level, voltage variation is a major problem and the grid discipline will demand an immediate attention to them. The wide voltage variations cause increased losses in the system, overheating of the components and grid voltage collapse with subsequent loss of customer's load. The voltage variations are due to excess drawal/injection of reactive power from/on the grid. In a state there are some more market participants like captive power plants, state generations, IPPs and Discos which affect the grid operations critically and needed much grid discipline at intra-state level.

The CERC order of ABT cannot be directly mapped to the state level because at state level the grid disturbances are more frequent and reflects the performance of the entire electrical system. The calculation of UI charges in Intra-state ABT requires a modified mechanism to maintain the secure and reliable operation of the grid. These UI charges would be calculated on the deviation from active and reactive power schedules. The scheduling of ABT given by CERC can also be framed out separately for the Intra-state ABT to minimize the gap between the scheduled energy and the actual energy, considering the availability of communication techniques.

The load dispatch centers always try to minimize the gap between scheduled generations/drawals and real time generations/drawals with the key issue of grid discipline. The grid discipline is broadly divided into two parts – frequency and voltage control. At the transmission level or bulk power transfer level the main factor for UI charges depends on frequency. However, at distribution level, this can also depend on voltage, which then is very important for grid discipline.

Merit Order Dispatch

Economic efficiency dictates that least cost power should be dispatched in preference to more costly power (merit order dispatch). Before ABT there is no explicit provision for the least cost power to be dispatched in preference of a costlier power. The maximization of generation during peak load hours and backing down of generator to match the system load reduction during off peak hours should be in view of the merit order of generation.

Infirm Power/Captive Power Plants:

It is difficult to assess the quantities of captive generation at every 15 minute block as captive generation is always sold in excess of the demand been utilized by the generating company. If captive power generation gives benefits to any utility through its generation more than its schedule it should be rewarded. Captive power plants should also submit their schedules similar to the local generators.

For implementing the ABT at intra-state level the following special cases should be considered.

- When the off take of different utilities under SLDC are varied from the schedules, the utilities drawing excess energy in peak hours or drawing less energy in off-peak hours should be penalized. SLDC is not a profit making company, the rates of UI should be charged as per ABT regulations of CERC.
- In case of any transmission line between two utilities is broken and secondary path of electricity is available. The rules for UI charges will remain the same but additional transmission line losses, if any, will have to be shared between utilities using a secondary path. In case where no secondary path is available the local generators and beneficiaries would be asked to revise their schedule before some fixed time blocks.

- In real time operation outage of a generator also lead to change in power flow and therefore additional transmission line losses. The SLDC would ask to cut their demand by beneficiaries if there is no extra generation available. In case of availability of local generation, the generators having excess capacity would be requested to generate more to balance the demand schedule. The penalty would be levied on the outgoing generator and beneficiaries\ incoming generator would be compensated.

Calculation of UI charge in different cases

UI charge based on frequency deviations

This is same as the ABT order of CERC. Increase of frequency deviations at RLDCs happen due to unscheduled interchanges at Discos level, the SLDC pays the money to RLDC as penalty. The penalty money would be charged to Discos.

UI charge based on voltage deviations

Voltage deviations must be added to ABT. At the state level the reactive power schedule is also required with the scheduling of active power. The deviation from the schedule of reactive power would be measured in terms of voltage variations. RLDC would also be paid by SLDC at rate fixed by CERC. This penalty is required to be apportioned among the responsible Discos.

UI charge based on the active power drawals

This is the case when the schedules for active power drawals in a SLDC are changed but the sum of the total drawls is same as the scheduled drawals in RLDC. In this case the electricity supply by the central generating station to the state load dispatch center is fixed. The SLDC allows the beneficiaries to draw per as per their schedules. But some of these beneficiaries draw more and some draw less so that the sum of their actual offtake is equal to the sum of the scheduled offtake. This will lead to increased line losses. When total demand equals to total power supply so frequency would be constant and therefore the UI charges should be based on deviation from their schedule. In this case the SLDC will not pay any UI charges to RLDC but the SLDC will have to charge to responsible utilities for incremental losses.

Actions to implement intra-state ABT

The state level ABT would only be in place when the gap between the schedule and dispatch is narrowed preferably to zero while maintaining grid discipline. There are number of strategies which can be implemented to formulate the intra-state ABT. The strategies for ABT would be such that it would not permit gaming, the preference would be to fulfill demand of state first and then trade the power outside the state. Intra-State ABT is somewhat different from the inter-state ABT and thus requires different mechanism and regulations. With the key objective of ABT, was to bring about much needed grid discipline. The grid disturbances are much more at the distribution level so these should be considered under the Intra-state ABT. Captive power plants, IPPs and Discos added some more cases to be solved under Intra-State ABT.

Scheduling

At Intra-state level scheduling of both active power and reactive power should be done in the 15 minutes time blocks. These time blocks should be in synchronism with the time blocks of the RLDC. Schedules submission by generators and beneficiaries to the SLDC and the revised schedule by SLDC are communicated as soon as possible and the communication system should be made advanced and with standby feature. The failure of communication should be treated as per the regulation made by the SERC. The scheduling should be closer to the real time transactions. Scheduling may be 12 hours ahead or less but provide sufficient time for the schedule revising and communication among various market participants. This shifting of schedules may help to minimize the gap between the scheduled and the actual supply of electricity. CERC drafted detailed schedule for ABT at inter-state level. The scheduled for the intra-state should be draft on the similar lines with above considerations. The communication system for declaring the

schedule/revised schedule by the market participants and SLDC should be very advanced and secure in order to avoid abuses.

Metering

Metering of the various parameters at the market participants' end plays an important role in the ABT. Online data acquisition by SCADA and visualization of energy meter data for real time transactions and record of historical data are required in ABT implementation. The metering should have standby meters in case of failure or maintenance of main meters. For intra-state ABT the quantities like MW, MVAR, Current, Frequency and Voltage are necessary to be measured and displayed in a display panel. The data are simultaneously measured and stored in both the meters to make the metering system more reliable. These meters should be synchronized in time blocks.

Regulatory Issues

The State Electricity Regulatory Commission should have to draft regulations for any abuses in market and also to provide gaming. The regulations for the under declaration or over declaration of capacities or offtake by the market participants for gaming should be made on similar lines as per the CERC order. The determination of UI charges under different strategies and the coordination of UI charges with SLDC and RLDC should be under the regulatory issues. In case of must run power plants like nuclear power plant the tariff should be determined by the CERC based on capital cost. These performance based tariff is to improve the grid discipline and if required it should be reviewed by the regulators.

The prerequisites for successful trading and how these are fulfilled in ABT, is described below:

Adequate authority with CLDs and Transparency

The Chief Load Dispatcher of each utility has the requisite authority to negotiate over the telephone the quantum and price of such trading with his counterparts, and is willing to take crucial on-the-spot decisions having high monetary value.

In ABT, the incremental cost vs. frequency relationship would be identical for all SEBs, all utilities can reasonably be assumed to be having the same incremental cost at a particular time, such that the transparency is automatic and therefore, no negotiations between load dispatchers are necessary regarding fixation of transaction price, substantially meeting the intents of the this requirement.

Adequate transparency and/or faith between Utilities

In economy transactions, incremental costs of available/avoided generation as stated by one utility must be accepted by other in good faith. This requirement for effective economy transactions disappears in case of ABT where the system-wide incremental costs are well known to all. This Section is not clear and needs to be reworded.

Advanced Load Dispatch & Communication Facilities

Each utility must have full-fledged load dispatch and communication facilities for continuous monitoring of its actual interchange and for on-line regulation of its generating units to minimize deviations from its interchange schedule.

Measurement of deviations

There must be a mechanism for determining periodic (15-minute block-wise) deviations from net-interchange schedule for each utility, and then either attaching a monetary value to it or making a compensatory adjustment in future schedules. Special energy meters have to be installed on all inter-utility ties, to record energy flows for every 15-minute time-block along with average frequency for each time-block.

Willingness to draw as per schedule

There should be willingness on part of all utilities to maintain their draws from the grid as per schedules even during conditions of generation shortage. They should be willing to buy the deficit from their neighbors through advance negotiations to meet their consumers' total demand and they should have the capability to pay a reasonable price for the same. In ABT, deviations from schedules would be permissible, but will be appropriately priced at frequency-linked rates thus the requirement made redundant.

Power Market

The Wholesale transactions for electric power globally are through spot contracts, forward and future contracts and long-term bilateral contracts. The primary driver for change in the power market in India today, at least from the consumers' point of view, is the desire to see lower prices in the wholesale electricity market. For this objective to be realized, attention has to be paid to the ideal power exchange for India backed with adequate regulations, as poor exchange design may lead to market failures. The envisaged power market will rely on competition, instead of regulation, to minimize generation costs and additionally will obtain long-term financing for power systems/generating companies.

The Wholesale transactions may be broadly segregated into two market mechanisms:

1. Bilateral contracts (market model)

This allows direct contracting between counter parties, paying generators what they bid, and introducing an optional balancing market, which will bring the market price to marginal cost. Generators and consumers who have contracted for physical deliveries of electricity, through the forward or short-term market, will be responsible for self-dispatching those contracts.

2. Pool (optimization process)

In this mechanism, a contractual arrangement is entered into by Generators and Suppliers that provides the wholesale market mechanism for trading electricity. The Pool does not itself buy or sell electricity; those trading in the Pool do so against a defined set of rules. Generators sell electricity into a "pool" and suppliers purchase out of this pool. Participation in the market is through membership of the Pool under certain agreements.

In both mechanisms the bids are made daily or hourly on a day-ahead basis.

The Physical nature of Reactive Power

Providing electrical energy to consumers requires two kinds of power:

- 1 Real power (measured in watts)
- 2 Reactive power (measured in volt-amperes reactive or VARs).

Even though only real power actually accomplishes useful work e.g., rotates motors and illuminates lamps, reactive power is an inseparable part of any alternating current power system. The function of reactive power is to support the voltages required to perform useful work.

Reactive power has a profound effect on the security of power systems because it affects voltages throughout the system. Here two points are to be noted

- o Deficiencies of reactive power cause voltages to fall
- o Excess of it cause voltages to rise.

Voltages play an important role in the system. Voltage that is too high or too low can result in the following

- 1 Increased power system losses
- 2 Overheating of motors and other equipment,
- 3 System voltage collapse
- 4 Consequent loss of customer load.

Therefore, for proper operation of a power system, the production and consumption of reactive power must be balanced. Because voltages and reactive power are so tightly related, power system voltages can be controlled through the supply and absorption of VARs. As with real power, generators produce reactive power, but reactive power can also be supplied by components of the transmission and distribution system.

Theory of Reactive Power Pricing

There is a significant body of economic-engineering literature that describes how static demands for reactive power should be optimally priced for given a fixed stock of capital equipment. The main findings of this literature are that optimal reactive power prices can be estimated by optimal power flow (OPF) programs that minimize power system costs subject to constraints on generator outputs, transmission flows, and bus voltages. These prices, which should vary by time and location, equal the change in power system costs that accompanies a change in reactive power demand, because reactive power supplied at one location is costly (or impossible) to transport to distant locations, there can be wide geographic variation in reactive power marginal costs.

Retail prices for reactive power service must be based upon wholesale prices. Two primary sorts of criterion may judge these retail prices:

- Those related to investment efficiency
- Those related to consumption efficiency

These criteria, along with a few others, are as follows:

1. Do the retail reactive power prices allow the ISO to recover the costs of providing reactive power services?
2. Do providers of reactive power services:
 - Have incentives to invest in efficient quantities of both slow and rapidly varying devices for the control of reactive power?
 - Have incentives to efficiently site reactive power devices?
 - Have a fair chance of earning "normal" profits on these services?
3. What impact do the retail reactive power prices have on the consumption of reactive power by loads? Do these prices provide customers with incentives to reduce the rapidly changing reactive power loads that are particularly costly to serve?
4. Is the approach toward retail reactive power pricing sufficiently simple to gain wide acceptance?

So reactive power price should have two fundamental characteristics, first, they should allow the providers of reactive power service a fair chance of earning normal profits (or, equivalently, of recovering costs) on these services. Second, they should provide retail price signals that encourage customers to make efficient choices about how they use or conserve reactive power. Because reactive power costs are the foundation for reactive power pricing.

The Characteristics of Reactive Power Demand

There are two fundamental types of reactive power demands.

- 1) There are the direct reactive power requirements that are associated with loads that have power factors less than one. These requirements arise from the reactive power consumption that can be directly metered *at the* customer site.
- 2) Second, there are reactive power requirements that result from flows of power.

A key characteristic of reactive power demand is the speed at which it changes over time. Power system requirements for reactive power are continually varying because of load changes, contingencies, and the changing reactive support requirements for power transfers. At one end of the spectrum, static loads require constant quantities of reactive power support, with reactive power equipment that is generally located close to the loads. At the other end of the spectrum, dynamic demands require variable quantities of reactive power support, with equipment that may be located throughout the power system. In between are the slowly varying demands that are associated with daily load variations.

Reactive Power Control

Reactive power control has a profound effect on grid security because it directly affects the voltage variations throughout the system. As reactive power can not flow at a long distance the reactive power supporting devices are located at the load end. The reactive power scheduling and transfers should also be managed for grid discipline in a deregulated environment. The reactive

power support is considered as an ancillary service in electricity market in developed countries. For controlling reactive power SLDC should penalize the reactive power drawn by different utilities to curb reactive drawal and this money should be utilized for installation of reactive power supporting devices viz. static capacitor, VAr compensator, synchronous condenser etc.

Many of the deregulated markets are yet to establish a mechanism for financial compensation for reactive power ancillary services e.g., the developing countries. On the other hand, some market does have schemes for payment for reactive support services, which are given as follows

UK

In UK the national grid company, which carries out the functions of the ISO, invites tenders for reactive power support through bids composed of capacity components (price per MVA and quantity on offer) and an unification component (MVARh price curve). The selected bidders get into annual bilateral counteracts with NGC are paid for both the capability and utilization components.

New York

In the New York system, the ISO (NYISO) is responsible for procuring reactive power support service, and the service is provided at embedded cost-based prices. Generating resources, which operate within their capability limits, are directed by the ISO to produce or absorb reactive power to maintain voltages within limits. Further, the NYISO also provides for compensation to generators in case of revenue lost due to increased reactive power generation requests. If the ISO dispatches or directs a generator to reduce its real power output the generator receives a lost opportunity cost for the amount output the generator revenue it loses from the lost generation and energy sell.

Australia

The Australian electricity market and its ISO (NEMCO) also recognize reactive power as an ancillary service and financial compensation is provided to generators and synchronous compensators for their service provisions. All reactive support providers are eligible for the availability payment component for their preparedness to provide the service. When called for synchronous compensators, they also receive the enabling payment component paid when their service is activated by the ISO for use. On the other hand a generator receives the compensation payment component, which is based on its opportunity cost and paid when it has been constrained from operating according to its market decisions. For example if a generator has to provide reactive power where it has to reduce its real power generation in order to operate within the unit's field and armature winding heating limits, the generator will be compensated for its lost real power generation.

Table 1: International Experiences in Reactive Power Management

Country	Reactive Power Management
New Zealand	Distributors pay three voltage support charges - Nominated peak charge Actual monthly peak charge Residual charge
U. K.	Generators can bid for reactive power support through bids composed of capacity component, utilization component.
New England	Reactive power cost is shared among customers according to network load & point to point capacity
New York	Based on embedded cost based prices.
Australia	Reactive power is given by synchronous generators and synchronous condensers as an ancillary services

Costs of Reactive Power Service

The costs of reactive power service depend upon the choice of reactive compensation devices, which depends on the nature of the load. Slowly changing loads require slowly changing or static reactive support equipment such as capacitors and reactors. Capacitors supply VARs and boost local voltage, while reactors absorb VARs and reduce local voltage. On the other hand, rapidly changing loads, such as arc furnaces, require rapid or dynamic reactive support equipment such as static VAR compensators (SVCs), synchronous condensers, and generators. The first two of these devices can rapidly supply or absorb VARs, while generators can change VAR output at a less rapid speed.

The costs of satisfying static reactive power demands are much lower than those of satisfying dynamic reactive power demands. The reason is that the capital costs of static sources of reactive power, such as capacitors, are orders of magnitude lower than the capital costs of dynamic sources, such as SVCs and synchronous condensers. The costs of providing reactive power also encompass some non-capital costs of generator fuel and staffing, sometimes including significant impacts on system losses, but over the long run, the capital costs tend to be larger than the non-capital costs. The costs of reactive power service are affected by several other factors. First, because reactive power does not travel far, reactive power compensation must be somewhat dispersed throughout the system, injecting reactive power far from where it is needed generally increases both reactive power requirements and real power losses. Second, because the power system itself consumes reactive power, it is necessary to control voltages throughout the transmission system. Third, because of the varying nature of loads, it is sometimes necessary to both supply and absorb VARs at the same location in the system depending on the time of the day. Fourth, power systems require reactive power resources that exceed anticipated reactive power needs.

Charges for Direct Reactive Power Consumption

For using reactive power outside of a standard power factor range, the customer should pay a charge based upon some combination of peak kVAR and total kVARh consumption. This approach would provide incentives for customers to install their own reactive power compensation equipment.

Several authors comment on reactive power charges that are based upon consumer's power factors. The irrationality of cost recovery based upon power factors, partly because of the lack of a causal relationship between power factors and reactive power costs, and partly because of the wildly inconsistent ways that different utilities use power factors to develop reactive power charges. Researchers find that "Reactive power pricing based on power factor penalties is unable to provide accurate price signals to customers under voltage constraint. Power factor penalties are unable to give accurate price signals to customers, while real-time prices provide such signals."

Power factor penalties are unable to provide appropriate incentives to customers and/or suppliers to alter their reactive power usage/supply patterns when voltage limits are reached, the precise times when the price of reactive power is most important to regulating system voltage. Real-time locational reactive power pricing does provide appropriate incentives.

Charging Distribution companies on the basis of their metered consumption of reactive energy offers significant attractions in terms of sending accurate signals to those companies, which need to invest in power factor correction most urgently. This Reactive Charge should ideally be derived by examining the proportion of the reactive energy, which is required on the system, which is specifically associated with *demand*, rather than inherent transmission network requirements. This can be done analytically by evaluating in broad terms the approximate proportion of the reactive requirements of the system, which is associated with reactive power losses in transmission lines, and subtracting this from the total system reactive requirement. The balance may be categorized as that reactive energy which is required to supply the reactive demands associated with distribution systems and Transmission connected customers.

Special Voltage Charges

When a market participant's behavior or characteristics creates significant voltage control costs, it may be reasonable to levy a special charge on that participant. Circumstances that can create such special voltage needs can include:

Rapidly Changing Real Power Production and Loads

Some abnormal and very costly voltage problems arise from certain generators (e.g., wind turbines) or consumers (e.g., arc furnaces) that have erratic real power production or consumption. The effect of this behavior is to create rapidly changing real power flows through out a transmission network (or a portion of the network), which often creates a need for expensive dynamic reactive power compensation throughout the network as well as large reactive power reserve margins. In principle, generators and consumers who create these problems and costs should pay for them. It is partly a matter of fairness, since they are the parties who create the costs by imposing on the power system a need for extra or special voltage control equipment. It is also a matter of efficiency, because these parties can often respond to price incentives to improve their behavior and can thereby reduce the power system's costs. In practice, there are two difficulties in determining the charges for abnormal voltage problems. First, it is technically challenging to estimate the costs associated with the rapidly changing outputs and loads of erratic generators and consumers. Getting a reasonable estimate requires power flow analyses of costs with and without the erratic behavior under a variety of system conditions; and the estimates are subject to error. The second difficulty is political: a generator or consumer that is large enough to create a voltage problem may be able to prevent imposition of appropriate sanctions.

Locational Aspects of Reactive Supply

Suppliers and consumers that are in locations that require special voltage regulation services should bear the associated costs if the costs significantly differ from those of most other suppliers and consumers. For example, remote generation facilities may require special reactive power compensation schemes, possibly in the form of static VAR equipment or other fast responding VAR resources, along the long lines that connect them to the main power grid. Another example would be a large load located far away from any sources of reactive power supply, requiring the installation of special equipment or the frequent use of out-of-merit dispatch in order to meet the requirements of the load. The customer's need for reactive power can vary a great deal according to their location. Long transmission lines or medium length cables have the tendency to have poor voltage regulation characteristics. This means that the longer the line or cable that connects a customer to the grid, the more the voltage at the receiving end will tend to change as a result of changes in both active and particularly reactive power consumption at the receiving end. The bottom line is that the rate of change in voltage as a result of a change in power injection cannot become excessively large. Even an infinite amount of reactive power at the sending end will do no good to the regulation of voltage at the receiving end when the reactive resource needs to be at or near the receiving end. In the case of long lines, reactive resources in the middle of the line are also required.

Voltage/Reactive Power Support Service

Reactive power injections at major system buses (both generating and buses) are necessary to maintain an acceptable voltage profile on the system during normal and emergency conditions. The magnitudes of the reactive power requirements are dependent on system loading. The effectiveness of reactive power injection is generally local in nature, and the sources for the required injection must be sited according to network topology. In a power system, reactive power support is provided by a combination of generator capability, reactive compensating devices such as capacitor banks and SVC and new power electronics controllers. Such network compensation is becoming increasingly important especially owing to a heavily loaded system. The amount of reactive power required to support system voltage also increases with system loading, and the transmission of reactive power from remote sources to support affected buses itself further increases the loading (this is one major factor leading to voltage instability). Hence the greater the need for reactive support, the more important is that it should be supplied where it is needed, and not from remote locations as in the case of real power.

In order to maintain voltages on the transmission system within the acceptable limits, generation facilities under the control of the SO are operated to produce (or absorb) reactive power. The amount of voltage support service that must be supplied will be determined based on the reactive power support necessary to maintain transmission voltages within the limits that are generally accepted in the region and consistently adhered by the SO. The SO coordinates the power system voltages throughout the its Control Area. Transmission owners are responsible for the local control of the reactive power resources that are connected to their network. Suppliers are expected to operate their resources within their demonstrated reactive capability limits.

Method for determining the payment for Voltage Support Service

The Voltage Support Service Rate can be computed by sum of Total annual embedded costs and any applicable Lost Opportunity Costs to provide the Voltage Support Service.

Methods for determining Reactive Power Costs

Reactive power costs can be determined by calculating according to reactive power use as measured by either maximum reactive demand (in kVar) or by total reactive energy (in kVarh). This can be done by monitoring the actual power factor, by locational spot pricing or by pricing based upon fixed cost and variable cost of reactive power equipment

Real-Time Pricing of Reactive Power (Spot-Price Approach)

The traditional theory of spot pricing sets prices equal to the marginal (short run) costs of electricity supply, in order to maximize social welfare. The theory can be extended to pricing both real and reactive power, by setting prices based on the dual variables of an AC optimal power flow (ACOPF) model.

An Integrated Approach Optimal Reactive Power Planning and It's Spot-Pricing

Power system operators ensure the quality and reliability of supply to the customers by maintaining the load bus voltages in their permissible limits. Generally power losses in the transmission of electrical energy cause a loss of revenue. So, even a small percentage of savings in loss will be very much appreciated since the total generated power is on the order of megawatts. Any changes to the configuration or in power demands can result in higher or lower voltages in the system. This situation can be improved by operators by reallocating reactive power generation in the system, i.e., by adjusting transformer taps, changing generator voltages, and by switching VAR sources. Also, it is possible to minimize the system losses by reactive power redistributions in the system.

As power system margins reduce because of emphasis on the greater use of generation and transmission, power system dispatchers must operate their systems much closer to their technical limits. Real-time pricing of reactive power address the important issue of providing information on both the utility and consumers about the true burden on the system, in terms of cost and other system parameters viz. voltage drops and increased transmission losses, from time to time. Berg. et al. point out the inconsistency and inadequacy of the pricing policies based on power factor penalties. They suggest that given the present of high cost of additional investments by electric utilities, price should be derived from economic principles, which support a pricing approach that has price equal marginal costs that would also reflect today's technological constraints.

The reactive power-planning (RPP) problem involves optimal allocation and sizing of reactive power sources at load buses to improve the system voltage profile and reduces losses such that the investment costs as well as operating costs are minimum. The criteria used for RPP have been to minimize total operating cost of the system and the cost of new reactive power sources (capacitors).

Power System Reliability

Prior to the 1960's the reliability of power systems was often estimated by extrapolating the experience obtained from existing systems and using rule-of-thumb methods to forecast the

reliability of new systems. The economic and social effects of loss of electric service have significant impacts on both the utility supplying electric energy and the end users of electric service. The cost of a major power outage confined to one state can be on the order of tens of millions of dollars. If a major power outage affects multiple states, then the cost can exceed 100 million dollars. The power system is vulnerable to system abnormalities such as control failures, protection or communication system failures, and disturbances, such as lightning, and human operational errors. Therefore, maintaining a reliable power supply is a very important issue for power systems design and operation. Reliability is a key aspect of power system design and planning.

The function of an electric power system is to satisfy the system load requirement with a reasonable assurance of continuity and quality. The ability of the system to provide an adequate supply of electrical energy is usually designated by the term of reliability. The concept of power-system reliability is extremely broad and covers all aspects of the ability of the system to satisfy the customer requirements. The systems reliability can be envisaged in two ways: system adequacy and security. Adequacy relates to the existence of sufficient facilities within the system to satisfy the consumer load demand. These include the facilities necessary to generate sufficient energy and the associated transmission and distribution facilities required to transport the energy to the actual consumer load points. Security relates to the ability of the system to respond to disturbances arising within that system. Security is therefore associated with the response of the system to perturbations.

Reliability Assessment Techniques

Power System Planner face a broad range of uncertainties which includes uncertainty in the location, capacity, timing and availability of generation, uncertainty in the direction of the power flow along the critical lines as results of diverse wholesale transaction and shifting demand and uncertainty in the regulatory constraints and rules. In order to take into account these new uncertainties and complexities, planners will need an innovative approaches to calculating the power system reliability.

Measuring Service Quality: Performance Indices

A basic problem in distribution reliability assessment is measuring the efficiency of past service. A common solution consists of condensing the effects of service interruptions into indices of system performance. The two performance indices are SAIDI (system average interruption duration index) and CAIDI (customer average interruption duration index). SAIDI is determined by dividing the sum of all customer interruption durations during a year by the number of customers served and CAIDI is determined by dividing the sum of all customer interruption durations by the number of customers experiencing one or more interruptions over a one-year period. These two performance indices express interruption statistics in terms of system customers.

Improving Power System Reliability using Distributed Generators

Distributed Generators

Distributed generators (also known as Distributed Resources) come in many forms including gas turbine driven synchronous generators, wind powered induction generators, fuel cells with inverter circuitry, and others. The use of distributed resource generation is projected to grow. This growth is due to cost reductions available with distributed generators. The cost reductions may be the result of released system capacity or reductions in generation costs at peak conditions.

Small scale power generating technologies, such as gas turbines, small hydro turbines, photovoltaic, wind turbines and fuel cells, are gradually replacing conventional generating technologies in various applications, in the electric power system. These distributed technologies have many benefits, such as high fuel efficiency, short construction lead time, modular installation, and low capital expense, which all contribute to their growing popularity. The prospect of independent ownership for distributed and other new generators, as encouraged by the current regulation of the generating sector, further broadens their appeal. In addition the industry restructuring process is moving the power sector in a general away from the traditional vertical integration and cost based regulation and toward increased exposure to market forces. Competitive

structures for generation and alternative regulatory structures for transmission and distribution are emerging from this restructuring process.

These changes introduce a set of significant uncertainties. How will the siting of numerous small scale generators in distribution feeders impact the technical operations and control of the distribution system, a system is designed to operate with a small number of large, central generating facilities? How will the power system architecture evolve as a result of both technological advances and competitive market forces? In response to the new and potentially conflicting economic and technical demands of a growing number of independent generators, what balance between market forces and real time control will be found to coordinate distribution system operations? How will ancillary services be maintained in the new environment?

The development of a competitive market for generation creates the opportunity for distributed generators to participate in energy and related markets as independent producers. Two factors influence the ability of small generators to participate in emerging markets.

- The first factor is the legal and regulatory structure which may constrain the extent to which small generators are allowed to participate in these markets. In particular the growth of retail competition and the designation of distributed generation as part of the distribution versus the generation sector will both shape the role of DG in the emerging competitive markets.
- A second issue is the day to day, and minute to minute operation of these technologies, and the creation of a competitive market to coordinate such short run operation within the distribution system.

For a system with distributed generation to operate reliably and efficiently the system's operation and control strategy must accommodate both the engineering need to maintain collective system services and the economic push for independent and decentralized decision making.

As the industry continues to evolve under the restructuring process it is likely that multiple distributed generators will be sited in each distribution system. The industry restructuring process raises engineering concerns of maintaining system performance levels (frequency and voltage in particular), as a growing number of active devices with the diverse characteristics are sited within the distributed system. The potential affects on the distribution system behaviour introduced by distributed generation may demand that the issue of distribution system stability be revisited. Strengthening the technical capability for decentralized control and dispatch of generation, to parallel the growing potential for independent ownership will also be of interest in the restructured industry.

Role of DG in providing voltage support:

On the high voltage grid in quasi-steady state operation there is essentially a single system frequency which is observable throughout the system. Frequency control schemes such as automatic generation control (AGC) use this system wide variable to regulate the system frequency to the desired value. In the distribution system, which directly supplies customers, voltage regulation should be much tighter than at the transmission level to avoid either adversely affecting customer load or causing annoyance from flickering lights.

DGs, being sited within the distribution system, and therefore close to customers, are well suited to provide voltage support. The small generators improve the voltage profile simply by supplying power close to the load, which decreases the need to transmit power from more distant buses. DGs will be in position to compensate for the reactive power mismatch near the load centers, and so facilitate the long distance power sales. The DGs can also provide VAR support by controlling the power electronics in the power conditioning equipment so that the voltage at the generators bus is held constant. The DGs can be operated much as static VAR compensator, and provide a valuable service even when their real power output is zero. Distributed generation is likely to be introduced slowly, as the power system evolves toward a more distributed architecture. A competitive setting may come to facilitate an increased penetration of distributed generation, if the competitive

environment is such that maintaining system reliability, voltage profile and frequency become the responsibility of the local provider rather than of central authority.

Distributed generators can increase reliability and power quality by allowing them to be placed near the load and ensuring proper voltage and UPS and storage battery bear up functions during loss of grid power. Local generation increases overall system efficiency as well as it reduces investment in traditional generation, bulk transmission and distribution facilities. Increasing industrial economic awareness places considerable pressure upon the utilities to keep down the cost by most efficient use of fuels, maximum availability of most efficient generating units and by avoiding use of less efficient plant to fill the demand load gap. Unlike most other industrial processes, electricity generation has to meet a wide variation in demand on daily and seasonal basis.

Hydel power plants:

Although Hydel power is the cheapest source of power and almost zero pollution yet for no technical reasons, full potential of the sector could not be exploited. The total hydel capacity in the country is about 25000 MW only against potential feasible installed capacity of 1, 48, 700 MW and a potential of 84,044 MW at 60% PLF. A thermal-hydel mix of 60:40 improves the power quality and solves the problem of peaking shortages most economically. The hydel projects have however high initial costs, high construction risks and long construction periods and the problem of rehabilitation of people affected by construction of large dams, and submergence. Small hydel are also being promoted to utilize the energy available on irrigation canals and other channels. Due to high initial and operating cost and uncertainty of availability of water, some apprehensions are made in justifying the viability of such projects.

Renewable generation sources:

The renewable generation sources constitute merely 3% of the installed capacity. It mainly consists of solar energy, wind energy, biomass power, small hydels, and energy from wastes. Other non-conventional sources, for which development work is going on, include fuel cells, hydrogen energy, geothermal energy, ocean energy etc. Among these wind power is fastest growing. Due to high initial capital investment, low energy density i.e. several wind generators are spread over a vast area, limited options of the site selections and low efficiency, complete potential of this sector also could not be utilized so far. By improvement in rotor designs and other modifications in generator and turbine control, wind plants can run more efficiently.

Solar power:

Solar power is available in abundant, sunlight on a clear day provides 1 KW/m². But there is no economical method to convert it into electrical energy and store. PV generation converts solar energy into electric power in DC form. DC power can be converted into AC power by using inverters. Although this power is not proved economically efficient, the researches are going on in this area.

Wind power:

Wind has a huge amount of power and can be used to drive the fans attached with the rotor of an AC generator. It can be a better alternative for power at remote places or isolated places where laying of distribution lines is not economic. They have some problems like noise, non-dispatchability and esthetics. But they have many advantages like they run by wind so no fuel cost, no pollution and suitable for distributed generation.

Power from Biomass:

The biomass includes weeds, grass clippings, bio waste. These fuels are freely available to generate electric power. The power thus generated is cheap and the waste can be utilized reducing the pollution.

Integration of distributed generation into the electricity market:

In the existing distribution and transmission systems, only a skeleton of the institutional structure required for market driven operation is in place. The growth of competition in the generation sector demands that this framework be expanded. To fully integrate small scale generators into the markets, this institutional framework must extend to all the markets in which distributed generators can participate-long run contract, wholesale, scheduling, and short run energy and services markets. To coordinate distributed generator actions in the shorter term operations and control of the spot energy and ancillary services markets, a new pricing signal is needed. A competitive market should be developed at the distribution level and distributed generators will be allowed not only to enter into contracts at the wholesale and retail levels, and participate in Power Exchange, but also provide ancillary services to the ISO and local customers on a competitive basis.

The pricing signal should be introduced to the generation sector to aid in the creation of the desired competitive market. Market based institutions must be purposefully created as regulatory oversight is decreased in the generation sector, or it is likely that the sector will simply become unregulated monopoly rather than a competitive market. An adequate pricing signal should also provide a decentralized control mechanism which allows each generator to operate independently while also providing an incentive for the generators in aggregate to produce at the efficient level.

Distributed Generation:

In India about 95 % of power is generated by conventional sources (Thermal 72 %, Hydro 24 %, Nuclear 3 %) and renewable 1 % which may be increased to 10 % by 2010. Conventional sources create large amount of pollution, global warming and produces waste. Waste disposal is again a severe problem.

Solar, Wind and hydropower are renewable sources. Low head hydro (small, mini, micro and Pico) is feasible and economically competitive.

Run-of-river types are economical but non-dispatchable.

Distributed Generation where small generators are scattered through out the systems and normally installed near to the load centers. These distributed generations reduces the requirements of large transmission lines, reduces cost and environmental impact.

A distributed generation of the order of 2 to 50 MW is possible.

Disadvantages Of distributed generation:

Poor grid stability

Low frequency operation

Low power factor

Power Trading

Electric power is a matter of immediate transfer i.e. once it is generated, it should be transmitted. The electricity is the perfect commodity and it unlike other commodity it differs in location, time of delivery and firmness. In a market situation, the market participants should be provided with knowledge of quality and availability of the commodity. Like other product, electric power is associated with the economic aspects of the market. It should be the responsibility of the System Operator to provide all necessary information to market participants. The communication between the System Operator and market participants is very important in a market especially for electricity market where flow of information and electricity, both, would be simultaneous. For these reasons, online power trading in deregulated market is growing rapidly.

Issues affecting Power Trading in India

The present level of inter-regional electricity exchange is still quite limited. The constraints for enhancing the same include lack of proper market mechanism, inadequate transmission capacity, lack of statutory provisions for direct sale by IPPs/CPPs licensees outside the state, grid indiscipline and financial viability of state utilities, among others.

Financial viability and commercial awareness of State utilities

Power sector in India has been operating in an environment of resource constraint for decades and is not run as commercial entities. They do not charge economic prices and, therefore, are unable to pay their bills. Their inability to generate even the minimum rate of return as per statutory requirements have failed to build investor confidence and proved a deterrent for private investment as well as inter-utility trading. Needless to say, paying capacity of these utilities will be a major factor in promoting electricity trading because in the absence of proper payment arrangement, there will be no impetus for supply of electricity from surplus to the deficit regions.

Lack of proper Market Mechanism

Incremental costs do not figure in the present inter-utility tariffs. In services like electricity, unless there is a rule that relates pricing to the cost of generation, there will not be any tangible progress towards a competitive power market. Basic tariff design should be such that costs are allocated in accordance with technical and commercial principles and in a reasonable and consistent manner. The Central Electricity Regulatory Commission (CERC) has notified the Availability Based Tariff (ABT) which would enforce commercial principles in bulk electricity supply by Central Stations and its use by SEBs, and its implementation is already beginning to show results, though largely in the form of improved grid discipline at present.

Lack of adherence by SEBs to contractual commitments for service

The power supply industry in India is yet to develop a commitment of providing adequate service to its consumers as required under a supply / service contract. Disconnection of supply is still the preferred response to a shortage situation rather than an earnest endeavour to find more electricity. Similarly, penal provisions for violation of contracts by the consumers are not enforced, though some States have now begun to treat electricity theft more seriously.

Lack of statutory Provision for Sale of Captive Power

As per an estimate, Captive Power capacity in the country is about 20,000 MW of which about 14,000 MW is grid connected. Surplus is available with many Captive Power plants and also with IPPs and Licensees of some of the States. They need permission from the State Govt. as well as consent for usage of SEB's transmission network, which besides being difficult to come by, is also usually irrationally priced. Many Captive plants are keen to trade their power at a remunerative tariff, but there is no statutory provision presently for direct sale of surplus power by them to outside States. A provision for this however, exists in the Electricity Bill.

Grid Discipline

Lack of grid discipline is also a major issue and this discourages promotion of trading. Non-adherence to the schedule by one constituent affects the drawl of other constituents. Day-to-day problems of regional grid operation continue to persist, with wide fluctuations in voltage and frequency, causing tripping and interruption of supply to large blocks of consumers and leading even to breakdown of the regional grid. There is however, some noticeable improvement with introduction of ABT.

Inadequate Transmission Capacity

Major part of the EHV transmission system in India has been designed generally to off-take power from generating stations to specified locations (in States, and then the State Grid takes care of further distribution and supply within the State). In such a scenario, there is limited flexibility for diverting power from one region to another in the absence of adequate inter-regional power connections. For example, the present inter-regional capacity to transfer Eastern Region surplus power is not adequate to fully evacuate surplus power to the deficit regions. This is also likely to have an adverse effect in utilizing new generation capacities expected to be commissioned in the North-Eastern Region in coming years. On the other hand, even the full utilization of the new HVDC links between Eastern and Northern Region (2x250 MW Sasaram back-to-back) and between Eastern and Southern Region (Talcher Kolar line) is affected due to weaknesses in the upstream/downstream transmission system, including the issue of reactive power management. Many of the State transmission schemes face time/cost overruns and the capacity becomes available only after

considerable time delay, thus limiting the exchange. However, inter-regional links are being now substantially augmented.

Opportunities for trading

Opening up of the transmission sector to the private sector, formation of the Central Electricity Regulatory Commission (CERC) & State Electricity Regulatory Commissions (SERCs) in many States has created new opportunities for power trading. Reforms undertaken by the States and increasing operations of the power trading companies for trading of surplus power and facilitating development of private projects are positive factors in pushing ahead power trading opportunities. CERC orders on the Grid Code and Availability Based Tariff are inducing utilities to follow grid discipline and find commercial solutions for handling surpluses and deficits.

Bhutan and Nepal have large hydro potential and Bangladesh has large natural gas resources. India offers a potential market for trading power especially with reference to the projected demand scenario. Cross-border trading is presently based on conventional / traditional commercial principles rather than on mechanisms that would encourage significant increase in volumes of trading. Apart from Chukha and Kurichu projects in Bhutan from which India already imports power, the 1020 MW Tala Hydro-electric project is also under construction, power from which will be sold to India. With ongoing hydro projects, Nepal too will be in a surplus position in the coming years to export power to India. Increase in trading from such sources will call for a greater commercial basis for contracts.

Transmission Planning is undergoing change and focus is shifting towards formation of transmission highways and strong inter-regional transmission systems so that power from surplus to deficit regions can flow without hindrance. The present links under construction and the ones added in recent months would augment the inter-regional power transfer capacity by another 3500 MW towards formation of National Grid. It is expected that cumulative Inter-regional transmission capacity of the proposed National Grid would be about 30,000 MW by the year 2012.

An enormous potential lies untapped in the form of under-utilized captive capacities, estimated at around 20,000 MW. These are currently not granted access to the grid by SEBs because of the misplaced fear of losing highest paying customers. As we move towards more rational tariffs coupled with open access, much of this capacity would get released, giving considerable relief especially on peak-hour shortages.

In the Electricity Bill, which is placed before Parliament, there are provisions for establishment of bulk electricity market and setting up of generating stations without license, non-discriminatory access to the transmission system and gradual introduction of open access for the distribution system. Promotion of competition from multiple suppliers also figures in the Bill. Obviously, such enabling provisions will go a long way in encouraging power trading in the country.

Hydro Generation Tariffs

Hydro generation differs from thermal generation in a very important aspect that the fuel cost in case of hydro generation is nil. Hydro plant's operation depends upon the availability of fuel (water supply). This is not under the control of the utility. The hydro plants may be a run-of-river, peaking and continuous operation plant. Each is dependent on the characteristics of water availability. The hydro generation tariff can be an incremental energy cost type tariff (IECTT), fixed cost tariff (FCT) or hybrid cost allocation tariff (HCAT). The IECTT is a one part tariff based on each unit's fixed and operational costs and its energy generation. The fixed cost is determined for each unit with different rate of depreciation as compared to thermal generation tariff. The O & M expenses are taken as 0.5 % of the capital cost. The tariff may differ depending on the type of plant (availability of water). The disadvantage of this method is that rates may vary because they depend on the forecast and rates are artificial. They recover only fixed cost and not used for merit order dispatch. In FCT a fixed cost and a certain amount of profit is collected from the customer. But the drawback of this method is that in case of multiple owners, if generation is optimized for entire system, it may be optimal for individual utility. In HCAT fixed cost is charged on the basis of the

availability of the plant and different rates are charged for off-peak and on-peak. These are based on incremental cost. In Indian context, the hybrid tariff structure is most appropriate and the allocation of fixed cost may vary from type of plant.