Chapter 2

Restructured Electrical Power Network and Available Transfer Capability

2.1 Introduction

The electrical power system is the large integrated network throughout the world to manage the power requirement. Hence, the electric industries has been governed by large utilities (vertically integrated utilities) having overall control in a generation, transmission and distribution within their region of operation. The responsibility of such utilities is not limited to provide demanded power to the entire customer but also keep system healthy and secure. The efficiency of the state-owned structure of electrical utilities tends to 100 % because of restructuring of the power system.

In earlier days, the rules of the monopolistic market has approved a single utility to generate, transfer, distribute and sell electricity in a region, state or a country according to government policies, guidelines and rules and regulation. With monopolistic business, the customer gets affected. The social benefits has been disappeared in such transaction methods.

With growing interconnections and loadings in the modern power system networks all over the world, power utilities are observing a major challenge in maintaining desired superiority and security of power supply. Power system security and analysis forms an essential part of modern energy management system. The economic downturn coupled with environmental and ecological pressures have obliged the electric utilities, all over the world, to serve the augment in load demand without corresponding increase in generation and transmission facilities. This has forced the utilities to operate their generators and transmission systems to their maximum capabilities. Hence, the re-regulation [26] of the power system has been derived for getting maximum economical benefits to the society. In such mechanism generating companies (GENCOS) may submit their bid for selling of power and the bulk customer can make a bid for their requirement of power. The restructuring has expected private investment, increase in efficiency, encouragement of technical enhancement and perk up customer satisfaction due to the competing environment.

All the participants have shared common transmission networks for supplying of power from source to destination. In such scenario, all parties will attempt to acquire the reimbursement of cheaper source and greater turnover margin, which may lead congestion of certain transmission passage. The violation in thermal, voltage and stability limits makes the system unsecured. Some players may try to exercise the market power by exploiting the system limitations. To control all such grievances ISO or Grid operator (Gridco) plays an important role for a healthy system.

As the transmission system become common to all the market players, the system status and the transfer capability available for further commercial transactions must be known. All the traded transactions will be valid if the transaction having value less than the capability of the transmission line. A brief introduction of different electricity market entities and models of the electricity market has been discussed in sections.

2.2 Significance of Restructured Electrical Power Network

Many electrical power utilities has required to change operation strategy from vertical utility integrated to open access electrical market [30]. The main aim of restructuring is set to make an electrical market in open access so the customer gets benefited and get electrical power at a competitive rate. In addition, customers have different choice for selection of electrical power purchase which results in a social benefit to customers. There are many reasons for the changes and varies over regions and countries In developing country, the energy demand has been increasing tremendously. To cope up with this demand management of power has been pointed as a prime factor to be considered. The insufficient power management can affect the investment policy in power sector. Hence, the international funding agencies are pressurized for the restructuring of the power system.

In developed countries, the main goal of the restructure has been set to provide cheaper power with reliability and various choices for power purchase. For open access, one intermediate system has been required to control all activities like balance between generation and demand, calculation power transfer capability of the transmission line. The Independent System Operator (ISO) [62] has been the assigned control over such activities. The ISO can control manifold bilateral transactions for electrical power trading in restructured network to keep system stay secure. The system gets into congestion [22] when the transactions are more than the capability of the line. The Congestion means a violation of operational constraints.

2.3 Regulation and Deregulation

- Regulation:

  Regulation has been defined as the laws and rules Regulation set by the Government that put limits on and define how a particular industry or company can operate.

  Mostly all industries are more or less regulated to some extent. The competitive businesses such as auto manufacturing, airlines and banking has been heavily regulated with myriad government requirements defining what they must, can, and cannot do, and what and to whom and when they must report their activities.

  Regulation of electric utilities is only way the government can control the electric power industry within its jurisdiction. The another way is to own and operate the power company directly, as a government utility.

- Deregulation:

  Deregulation or restructuring in power industry has been defined as restructuring of the rules and economic incentives that government set up to control and drive the electric power industry.

Some other forces supporting the main reasons for motivating the deregulation can also be enlisted as follows:

(i) More staff requirement in the regulated electric industry.

(ii) Global economic crisis.

(iii) Political and ideological changes.

(iv) Managerial inefficiency in the regulated company.

(v) Lack of public resources for the further development.

(vi) More demanding environment issues.

(vii) Pressure of financial institutes.

2.4 Deregulation of power Industry

The traditional electrical power network has been changed to deregulated electrical power network in competitive market. The main goal of restructuring has been set to make an electrical market in open access so the customer gets benefited and get electrical power at a competitive rate.

2.4.1 Disaggregation of traditionally vertically integrated utility

Disaggregation of traditionally vertically integrated utility has been called unbundling of power system. The main objective of unbundled environment is set to minimize the total cost of operation and maximized the social welfare.

The generation and transmission activities has been separated in deregulation. The succeeding step was to set up competition in generation activities, either through the formation of power pools, provision for direct bilateral transactions or bidding in the spot markets.

On the other hand, the transmission system had tendency to become a monopoly. The transmission system thus became a neutral, natural monopoly subject to regulation by public authorities. To overcome the monopolistic characteristic, the trend has established new legal and regulatory frameworks offering third parties open access to the transmission network. The structure of deregulated industry has been discussed as under:

2.4.2 Structure of deregulated industry

The basic structure of regulated environment has been shown in Fig. 2.1. The configuration has been shown in the figure 2.1 may vary depend upon model used. There exist variations across countries and systems.

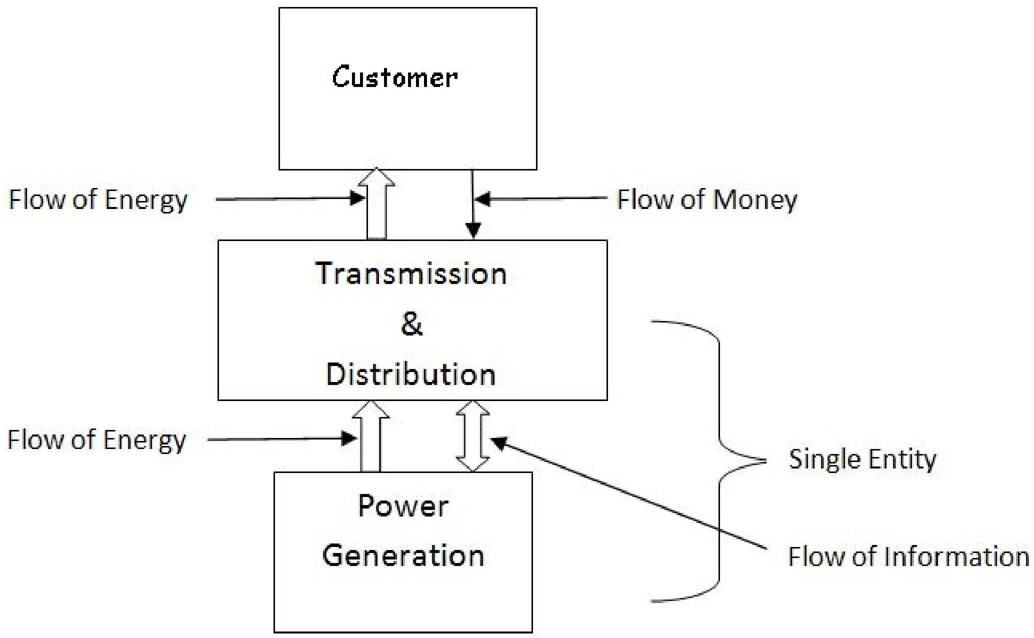

Figure 2.1: Structure of Regulated Environment

A system operator has been appointed for the whole system. It has been entrusted with the responsibility of keeping the system in balance, i.e. to ensure that the production and imports continuously match consumption and exports. Naturally, it is an independent authority without involvement in the market competition. This system operator is known as Independent System Operator (ISO).

Referring to figure 2.1, there is no change as compared to figure 2.2 so long as energy flow is concerned. The Customer transacts the power from a retailer or directly with a generating company, depending upon the type of model.

Different power sellers are ready to deliver their power to their customers through retailers, with the help of Transmission and Distribution (T and D) wires, operated by the independent system operator (ISO). The ISO will look after all the traded transactions such that system must be secured and reliable.

The bill for electricity will be different for regulated and deregulated environment.

Detail segregation of the electricity price as under:

(i) Electrical energy charges.

(ii) Energy delivery (wheeling charges) charges.

(iii) charges for other ancillary services.

2.4.3 Market Entities and Model for Electricity

The conventional entities of the vertically integrated utility has been changed by the restructuring of electrical power network which can autonomously. The market entities can be generally characterized into:

(1) Market Contributor.

(2) System Operator.

A brief introduction to various Market entities are given below:

- **Generating Companies (GENCOs)**

  The individual of the group of the company worked as GENCOs will produce as well as sale real and reactive power with unfixed sales agreements.

- Transmission Companies (TRANSCOs)

  TRANSCO has been used to transfer power from source (GENCOs) to destination (Customer) through common transmission corridor. The main responsibilities of the TRANSCOs has been assigned as establishing, maintaining, operating secure and reliable operation in certain geographical areas. The investments has been collected by wheeling charges based online flows contributed by each user within the particular areas. The transmission usage charges depend on online flow contribution of each customer.

- **Distribution Companies (DISCOs)**

  A Distribution Company (DISCO), in a certain region has been assigned duty to distribute power to the customer (i.e end-user). They have to purchase wholesale electricity either through the spot markets or through direct contracts with GENCOs and supply electricity to the end-users. A DISCO is responsible for maintaining the desired degree of reliability and availability.

- **Customers :**

  A customer is the end-user of electricity. The bulk customers are connected to the transmission line. The customer may prefer to buy electricity from spot market by bidding for purchase or through direct contracts with GENCOs or even from the local distribution company with the preeminent overall value.

- **Market Operator**

  The operation of the power system under electrical market trading is handled by the market operator. It requests bid from market players and decides the market price for energy for the next day or trading in future-week, month or a year ahead.

- **Independent System Operator(ISO)**

  For the secure and stable operation of power system, ISO [62] has been identified as the main entity of the focus in deregulated power network. It performs the following tasks:

  - Manages transmission congestion.
  - Preservation of the system security.
  - Systematize maintenance scheduling.
  - Harmonize long term planning.

  The ISO does not take part in market trades. The ISO is responsible for managing transactions, re-dispatch of generation and restriction of the load if required at last stage. The ISO can acquire different ancillary services from different entities to manage congestion.

The two possible structure of ISO are given as follows:

(1) ISO_{min} : ISO_{min} has to maintain transmission security in the operation of power market to the level that ISO is able to schedule power transfers in mortified transmission system. This structure has no role in market administration i.e. California Independent System Operator (ISO).

(2) ISO_{max} : ISO_{max} is an independent non-government and non-profit entity, it has certain more responsibility as compared to ISO_{min} :. It decides Market Clearing Price (MCP) in power exchange.

In any market structure, the ISO has following basic functions laid out for it:

(i) **System security:** Operator must assure that the power system continues to operate in a stable, economical manner.

(ii) **Power Delivery:** The operator should provide the power transportation services requested by buyers and sellers.

(iii) **Transmission pricing:** System operator must determine and post the prices for transmission usage, offer to reserve or sell usage, track, bill settlement with user and pass on revenues to transmission owners.

(iv) **Service quality assurance:** The system operator must assure the quality of service it provides.

(v) **Promotion of Economic efficiency and equity:** The overall operations of the system operator should obey economic efficiency and also it should have fairness and equity in its dealing and should not benefit only some players in the system.

The system operator faces many daunting challenges in performing them. But it has many resources, including a large staff of experienced power system operators, engineers, a fully computerized control center, a massive remote data collection system to monitor, analyze and control the power system.

Other entities mention below also play their role in power trading.

- **Aggregators**

  It has the firm which combines customer into buying groups. This group buys the bulk amount of power at the cheaper rates. It is a link between customers and retailers.

- **Brokers**

  It is an entity or firm that acts as a middleman in a marketplace in which energy are priced, purchased and traded. A broker may act as an agent between GENCOs and DISCOs.

- **Retail Companies (RETAILCOs)**

  A Retail Companies (RETAILCOs) gets hold of legal endorsement to sell retail electricity. The electric energy and other necessary services in various packages for sale can be purchased by the retailer.

Fig 2.2 shows a typical structure of a deregulated electricity system with links to information and money flow between various players. The configuration shown in this figure is not a universal one. Here exist variations across countries and systems. The

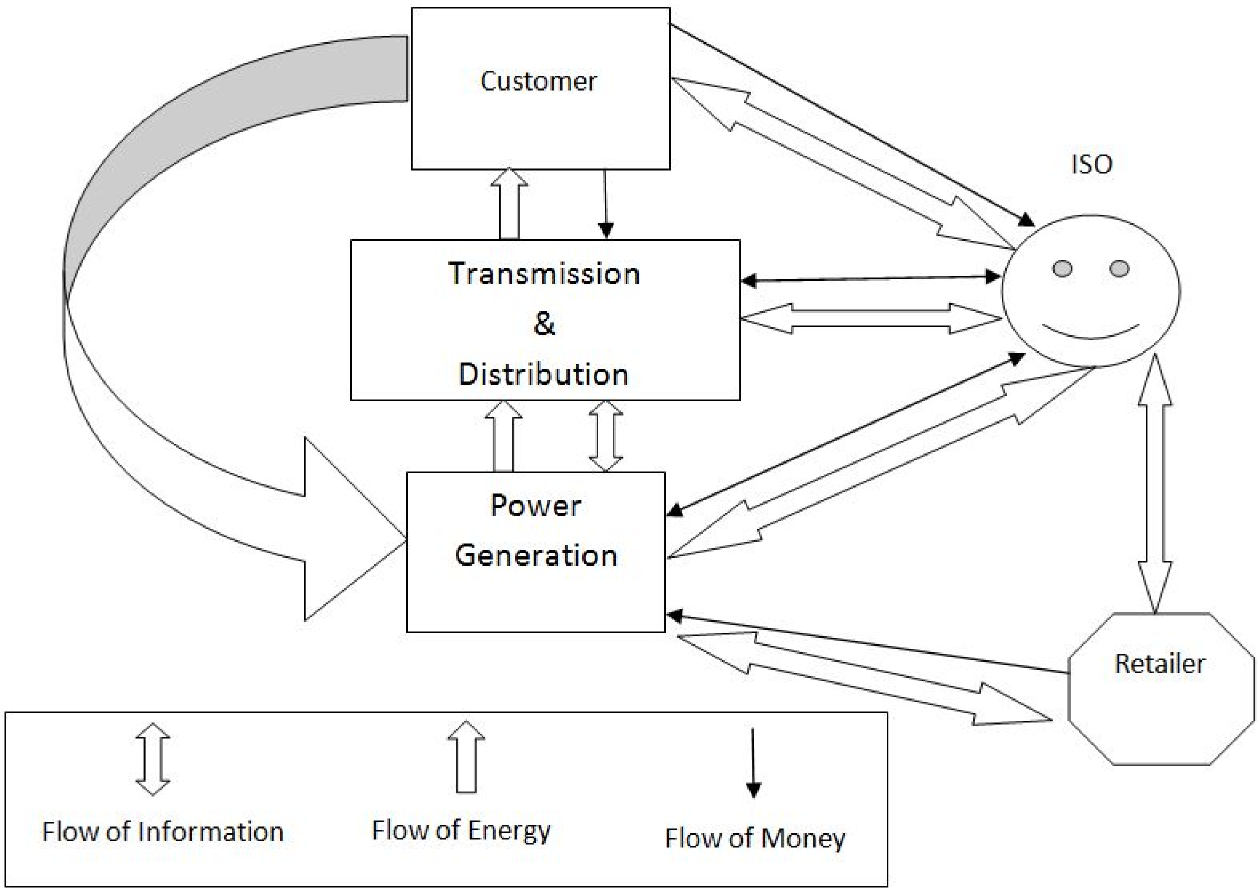

Figure 2.2: Fully Deregulation Market structure

competitive markets may include separate energy market, ancillary service market and the transmission market as follows:

A) Energy market

The competitive trading of electric energy occurs in an energy market. It has centralized mechanism that facilitates energy trading between sellers and buyers. The energy markets operated by ISO or the power exchange (PX).

B) Ancillary service market

Ancillary services are the most important for the power system to function consistently. In the restructured electricity industry, the ancillary services has been mandated to unbundled from the energy services. Ancillary services has been procured through the market competitively. According to North American Reliability Council (NERC) operating policy , the six ancillary services are:

(1) Regulation service.

(2) Load following service.

(3) Contingency reserves service.

(4) Reactive power support service.

(5) Frequency regulation service.

(6) System black start service.

C) Transmission market

In a restructured power system, transmission network plays a vital role to transfer power. The transmission right is defined as a commodity traded in the transmission market. This may be the right to transfer power, the right to bring in power into the network, or the right to take out the power from the network. The ISO will be responsible for conducting auction for purchase and sell of electricity. The maximum revenue generation and maximum social benefits are the main objectives of the ISO.

To achieve a competitive electricity environment, three basic models based on the types of transactions used are listed below:

1. Model based on PoolCo: It has a common market platform that clears the market for the buyers and sellers. The bids from the Electric power sellers/buyers are submitted for the power that they are ready to deliver as and when required to the pool. A sole entity can purchase power from generating companies at cut-throat rates and sell to the retailer or customer at single Market Clearing Price (MCP). The low-cost generators would be given main priority.

2. Bilateral contract model: In this model, the different transaction may take place directly between buyers and sellers for a particular time interval of the day. It may be short-term or long-term transactions.

3. Multilateral transaction: A multilateral transaction is a trade arranged by energy brokers and involves more than two parties.

The comparison between Open access Market and Pool Market is shown in Table 2.1

Table 2.1: Comparison

Open Access	Pool
1.Bulk of the energy transactions are carried out as bilateral trades while there may also exist a day ahead spot market.	1. All energy transactions are carried out through the pool, which may be organized through a day ahead trading mechanism.
2. The ISO is responsible for market administration, generation scheduling or dispatch functions	2. The Poolco Operator is responsible for the market settlements, unit commitment and determination of pool price.
3. Participation in the market by GENCOs is not mandatory	3. Participation by gencos is mandatory
4. The ISO is responsible for system security and control, procuring necessary ancillary services	4. The Poolco operator is responsible for system security and control, procuring necessary ancillary services.
5. Example: Nordic Markets	Example: UK Market

2.5 Deregulation and Current Scenario around the World

In this section, the deregulation and its scenario around the world has been discussed.

2.5.1 History of Deregulation around the world:

- 1982 Chile
- 1990 UK
- 1992 Argentina, Sweden and Norway
- 1993 Bolivia and Colombia
- 1994 Australia
- 1996 New Zeeland
- 1997 Panama, El Salvador, Guatemala, Nicaragua, Costa Rica and Honduras
- 1998 California, USA and several others.

2.5.2 Indian Scenario of Deregulation

The power sector was mainly under the umbrella of government ownership of various states and central government utilities, till 1991. The extraordinary growth of physical infrastructure was facilitated by following main policies:

1. Centralized supply and grid expansion.
2. Large support from government budgets.
3. Development of sector based on original resources.
4. Cross subsidy.

Under the world bank loan, Orissa had began a process of fundamental restructuring of the state power sector in mid-1990s known as WB-Orissa model of reforms. Under the World Bank (WB) loan, the state decided to adopt, what is known as WB-Orissa model of reform. This consisted of a three divided strategy of:

1. Unbundling the integrated utility in three separate sectors of generation, transmission and distribution.
2. Privatization of generation and distribution companies.

3. Establishment of independent regulatory commissions to regulate these utilities.

Soon afterward, several other states such as Andhra Pradesh, Haryana, Uttar Pradesh and Rajasthan also embarked on similar reforms and also availed loans from multilateral development banks such as WB and Asian Development bank, etc. Meanwhile, some moderate steps were taken towards reforms until the Electricity Bill 2003 was approved by Parliament in May 2003. This unified central legislation passed after 10 drafts. The Bill now replaces previous three acts on electricity of 1910, 1948 and 1998 (with their amendments).

2.5.3 The Electricity Act 2003:

The intangible framework underlying this new legislation [63] is that the electricity sector must be opened for competition. The Act moves towards creating a market-based regime in the power sector. The Act also seeks to consolidate, update and rationalize laws related to generation, transmission,distribution, trading and use of power. It focuses on:

1. Creating competition in the industry
2. Protecting consumer interest
3. Ensuring supply of electricity to all areas
4. Rationalizing tariff
5. Lowering the cross-subsidization levels

The major requirements of the Electricity Act are listed as under:

- Removal of licensing for setting up a generating station, subjected to fulfillment with technical standards. This excludes Hydro-Electric power station.
- Exclusion of captive power plants from the scope of licensing and other permissions
- Proviso for issuing more than one license for transmission and distribution in the same environmental area.
- Availability of open access with respect to transmission.

- Beginning of a spot market for bulk electricity.
- Restructuring of the SEBs on the foundation of functions (Generation, Transmission and Distribution).
- Obligatory metering of all consumers in order to get better answerable.
- State Governments will have the liberty to make a decision for the sequence and phases of restructuring, and also keep the integrated structure of the SEB for a limited period.

Power System reforms have began to introduce competition among the generating companies and to provide maximum benefit to the consumer. Despite of many incentives for Independent Power Producers (IPPs) to invest in power generation implementation, it has not been very successful. This is because, investors have been wary about the poor financial health of the State Electricity Boards (SEBs) which were the sole purchasers from the IPPs.

2.5.4 Salient feature of need for open access

The salient feature of the open access has been listed as under:

(1) Poor financial health of SEBs.

(2) Growing annual losses (Technical and Commercial)

(3) High T and D losses

(4) High Cost of Electricity supplied by local utility

(5) Crack between the cost of supply and tariff.

(6) Poor collection efficiency.

(7) Old and poor distribution network leading to frequent outages

(8) Poor Quality of Supply —Voltage, Frequency, Harmonics

(9) Electricity not available for all.

(10) Large gap between Supply and Demand

(11) Lack of investment in power distribution sector

(12) Lack of accountability in distribution setup of SEBs

(13) Failure of expectation from IPPs

(14) Poor performance against capacity addition target.

2.6 Congestion

In deregulated environment all simultaneous transactions will pull the power system in unstable state or it will be in congestion. Any violation in physical or operational constraints will result in congestion. The physical structure of transmission line can not modified as it requires a huge amount of investment. Hence, power can be imported and exported in open access market with the same lines in congestion management. **The possible boundary that may be violated in case of congestion are:**

(1) Thermal limits of transmission lines

(2) Emergency ratings of the Transformer

(3) Voltage limits

(4) System stability.

The power system must remain within above mentioned constraints. The congestion has been observed the in transmission line when the transmission line operates beyond its maximum capability with the simultaneous transactions. The other factors affecting the congestion will be the Line outage or higher load on the transmission line. Congestion management has been identified as the prime important activity for stable and secure power system.

In a deregulated structure, the market must be modeled so that the market participants (buyers and sellers of energy) engage freely in transactions and play as per market forces, but in a manner that does not threaten the integrity of the power system. Thus, irrespective of the market structure in place, congestion management has universally become an important activity of power system operators. The dual objective of congestion management has been identified as minimum interference of transmission network and secure operation of power system.

2.6.1 Effects of Congestion

The Social welfare determines the performance of a market. The social welfare which combines the cost of energy and the benefit of the energy to society has been identified as parameter for congestion management . The difference in social welfare between a perfect market and a real market has been defined as the efficiency of the real market. The effect of transmission congestion has been recognized to create market inefficiency.

In simple bidding, a generator bids at its incremental costs which would maximize its profit. While in strategic bidding, a generator bids other than its incremental cost, in an effort to take advantage of imperfections in the market to increase returns. Such strategic bidding will create market power. The ultimate market power results in inefficiency of the system. The operator faces some problems in multi-seller/ multi-buyer environment as follows:

(1) Forces change the generating schedules so that some GENCOs raise and others reduce output until congestion is eliminated. In pool structure, where central dispatch is done, Poolco operator has to look after this.

(2) Operator compensates the parties who were asked to generate more, paying them for their additional power production and giving lost opportunity payments to parties who were ordered to cut back.

(3) Raising transmission prices during congestion, by collecting congestion fees to compensate affected GENCOs in (2) above.

Congestion management policy is different for different countries. It really depends on what type of deregulation model has been employed in a particular region.

Three main models has been identified all over the world to solve the congestion problem as follows:

(1) Optimal power flow model : This model has been used in United Kingdom, Australia, New Zealand and some parts of United States of America.

(2) The price area congestion control model : This model has been used in Norway, Sweden and Finland;

(3) Transaction based model : ATC model has been used in some parts of United States of America. Each method has strengths and flaws and also, interrelationships to some extent.

Each model maintains power system security depending upon on the economics of the energy market.

2.6.2 Congestion Management

The process has been demanded a change of established models of power system operation and control activities because of several issues such as system control, security, transmission management, optimal bidding.

Congestion management is one of the most complicated characteristics in a multi-buyer/ multi-seller system. All entities such as generation, transmission and distribution are within the single roof of a central energy management system in the vertically integrated utility structure. Economical cost of generation has been defined as key factor under the consideration. The generation pattern depends upon the transmission line capability.

Deregulation has been very complicated as far as operation is concern. Because of too many transactions performed in deregulated surroundings, the transmission system of a state would overload. In this situation, congestion management has been recognized as a main factor under the consideration. The confront of congestion management for the transmission system operator has to frame a set of rules for adequate control over traders and buyers to keep the system healthy in both the short term and long term while maximizing market efficiency. The rules should be fair transparent to all the entities. The patent of congestion management depends on the market model being employed in that particular country/region.

2.6.3 Significance of Congestion Management

According to the line impedance and the network topology, the line flows in each line as per the Kirchoffs laws combined with the magnitude and location of the generations and loads. Hence, the change in generator schedules away from the most efficient dispatch. Hence, major changes in the line will be within short period of time. Hence, effective congestion management will play important role in deregulated environment.

2.6.4 Methods for Congestion Management

Operation and control of restructured electricity market are huge technical confront of the entities. The congestion management has more multifaceted due to the participation of diverse entities. Some of the technical challenges are as under:

1. Available Transfer Capability (ATC) determination.
2. Congestion management.
3. Ancillary services management.
4. Pricing of energy and transmission.

This work has mainly addressed the transmission congestion management as an operational concept. The entire group of customer who wants power at cheaper rates has been taking part in this environment. Due to the simultaneous transaction, the power system has been operated beyond its one or more transfer limits which results in congestion of the power system. The congestion in the power system may not be allowed to remain for a long time. If it persists for a long time, it can cause a sudden rise in the electricity price and intimidate system security. In a different type of market, the method of tackling the transmission congestion may be different. There are three different ways to tackle the network congestion.

2.6.4.1 Price Area Congestion Management

In the Nordic pool, which consists of Norway, Sweden, Denmark and Finland [64] , when congestion has been visualized, the system operator declares that the system has been divided into price areas at the predicted congestion blockage. Spot market bidders must submit separate bids for each price area in which they have generation or loads. In the case of no Congestion, the market will settle at one price and in the case of Congestion, the price areas are separated settled at prices threat satisfy transmission constraints. The area with surplus generation will have lower prices, and those with the surplus load will have higher prices.

2.6.4.2 Optimal Power Flow based Congestion Management

To minimize generators operating cost, optimal power flow has been performed. The generator sends a cost function and customers willing to purchase power send a bid function to the ISO. The ISO has a complete transmission model and performs OPF calculation. OPF solution gives cost/MW at each node of the system. In some countries, zonal pricing method has been followed in which the system is divided into various zones on a geographical basis. The zone prices obtained from OPF are used in the following manner:

(i) Generators are paid zone price of energy.

(ii) The loads must pay the zone price of energy.

The zone price will be same and the generators are paid the same price for their energy as the loads pay in case of no congestion. Each generator has to pay its zone price and the loads has to pay its zone price for the energy in case of congestion. To control the transmission flows and to maintain the transmission security OPF has been a most effective tool for the power system.

2.6.4.3 Available Transfer Capability based Congestion Management

The US Federal Energy Regulatory Commission (FERC) [60] established a system, where each ISO would be accountable for monitoring its own regional transmission system and calculating its ATC for potentially congested paths entering and leaving inside its network. The ATC values for next hour and for each hour in the future has been placed on Open Access Same-Time Information System (OASIS), operated by ISO. Anyone wishing to do transaction would access OASIS [60] web pages and use ATC[27][31] information available to determine validity of their transactions.

In this work, the optimized ATC along with the generation at different generator bus for a specific loading condition has been computed using different Artificial intelligence techniques.

2.7 Available Transfer Capability

Available Transfer Capability (ATC) of the transmission line has been prime component of open access market. Hence, to keep system healthy and secure, ATC should be managed by proper pre-calculation of ATC for a specific transaction. Congestion management has an imperative issue in the power system operation under deregulated environment for proper and accurate trade of electricity. It guarantees the non-violation of operating limits. The direct bidding strategies depend upon the Congestion management since the bids under congestion differ from the normal conditions.

The ATC [65] has been an indicator of an increase in inter-area power transfer without affecting system security. Precise recognition of this capability provides imperative information for both planning and operation of bulk electrical power markets. The system having large inter-area transfer becomes more vigorous as compared to less inter-area transfer.

Thus ATC has been identified as a rough dial of relative system security. In an inter-area system the loss of a generation of one area can be replaced by generation from the other areas. ATC calculations has been used for evaluating the ability of interconnected power for the secure and reliable system. ATC information can help the Independent System Operator (ISO) to determine the validity of bidding results in an open access deregulated. It can also help the power market participants to place bids strategically when congestion happens. The fast ATC calculation has been key role of ISO to respond manifold transactions.

2.7.1 Factors affecting Transfer Capability

The physical and electrical characteristics of the system are the main factors affecting the power flow through the transmission line. The affecting parameters are as listed below:

- **Thermal Limit:** Thermal limits establish the maximum amount of electrical current that a transmission line has to carry over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements.

- **Voltage Limit:** Power System voltage and change in voltage must be maintained within the range of acceptable minimum and maximum limits. A widespread collapse of system voltage can result in a blackout of portions or the entire interconnected network.

- **Stability Limit:** The transmission line must be capable of withstanding disturbance through transient and dynamic time period. All the generators are interconnected in the system and operate with each other with the same frequency. If any disturbance occurs due to frequency changes then it will affect the whole system. The oscillations must diminish as the electric system attains a new stable operating point for the system become instable. If the oscillations will take a long time to stable, the generator loses synchronization with the other generator and the system become instable. The instability will damage the equipment connected to the system.

The limiting conditions on some portions of the transmission network has been shifted among thermal, voltage and stability limits.

2.7.2 Definition of the Terms

- **Available Transfer Capability:**

  Available Transfer Capability has been defined as measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. Mathematically, ATC has been defined as the Whole Transfer Capability (WTC) less the Transmission Consistency Margin (TCM), less the sum of existing transmission commitments (which includes retail customer service) and the Capacity Benefit Margin (CBM)[22]. It has been defined as the reserved capacity of the line. ATC must satisfy certain principles to balance commercial and technical requirement. All the commercial trading depends upon an accurate and fast calculation of ATC.

  $$ATC = WTC - TCM - CBM - ATA \tag{2.1}$$

  Where ATA= Active Transmission Assurance. TCM= Transmission Consistency Margin. CBM = Capacity Benefit Margin.

- **Whole Transfer Capability (WTC):**

  It has been defined as the sum of electric power that can be shifted over the interconnected transmission network in a reliable manner with all defined pre- and post-contingency system conditions.

- **Transmission Consistency Margin (TCM):**

  It is the amount of transmission capability at which system remains secure under certain contingency.

- **Capacity Benefit Margin (CBM):**

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

- **ATC Principles :**

The following ideology recognizes the requirements for the precise calculation and application of ATCs.

(i) ATC computations [66] have to produce commercially feasible results. ATCs produced by the calculations must give realistic and trustworthy indications of transfer capabilities available to the electric power market. The ATC calculations must be steady with the level of commercial activity and congestion.

(ii) ATC calculations must be familiar with time-variant power flow conditions on the whole interconnected transmission network. The manifold transaction in parallel paths must be considered from the reliability point of view. Regardless of the desire for commercial simplification, the laws of physics govern how the transmission network will react to customer demand and generation supply.

(iii) ATC calculations have to distinguish the reliance of ATC on the points of electric power injection, the directions of transfer across the interconnected transmission network, and the points of power extraction. The sufficient information must be supplied by each entity for accurate calculation of ATC.

(iv) Different area coordination is essential to develop and post information that sensibly reflects the ATCs of the interconnected transmission network. ATC calculations must be used in regional, sub-regional and multi-regional systems.

(v) ATC calculations must be conventional to NERC (North American Electric Reliability Council), regional, sub-regional, power pool, and individual system reliability planning. It is also conventional to operating policies, criteria, or guides. Suitable system contingencies must be considered.

(vi) The determination of ATC must provide reasonable consistencies and operating flexibility to ensure the secure operation of the interconnected network. Transmission capability [65] may need to be reserved to meet generation reliability needs.

2.8 Available Transfer Capability and Congestion Management

The Available Transfer Capability and congestion management both has been treated as two sides of the coin. Without one of them, the system cannot survive. For the secure and stable operation of the electrical power network, the congestion management has been considered as a lifeline of the power system.

In a competitive environment, congestion occurs when the network is not able to accommodate all the required transactions in the system. The mission of congestion management has been recognized to alleviate such situations through the use of various physical or monetary mechanisms. As in vertically bundled system all the entities are under the one roof of a single operator, Congestion management is so simple as compared to unbundled systems. Because of number of entities involved in competitive market, congestion management has been more multifaceted and leads to create certain complicated issues which affects the system reliability. The fundamental and latest developments of Congestion management and ATC has been discussed in this section. Following methods has been adopted for the congestion management in real time operation:

(1) Generation rescheduling based on minimum bids, the operation of on load tap changer, phase and regulator add various FACTS devices etc has been identified as the main components of Congestion management.

(2) Prediction of ATC to control users demand at the time of congestion. The price of electricity has been charged more for the congested line and vice-versa.

(3) Verify the validity of the transaction.

The ISO for all time attempts to employ the first alternative, wherever it is possible. The load curtailment has been taken as the last option for the congestion management. ATC computation has been used to manage load during low congestion and take a benefit of low energy cost. An assortment of congestion management methods for different restructuring system has been reported in [67]. Different types of optimization-based methods for computation of optimized ATC have been reported for congestion management.

The congestion cost computation and allotment of the congestion based approaches for congestion management hasbeen reported in [68]. The use of FACTS controllers for the congestion management have been reported in [69].

In real time dispatch, ISO can identify the group of the entities having the same effect on transmission constraints. Available Transfer capability (ATC) based Congestion management has been reported in [22].

The calculation of ATC for every region or zone has been mandatory. After calculating ATC by evaluating all the lines of a given network, the value has been uploaded on a website known as Open Access Same-Time Information (OASIS). Hence, the participated entities can identify that their transactions are valid or not for a specific time intervals. In simple word, a transaction will be invalid if it is more than ATC value and vice-versa. Hence, the calculation of accurate ATC has been identified as a prime issue related to congestion management. The different optimization techniques has been employed for computation of ATC value with valid transactions.

2.8.1 Network Sensitivity Factor based Approach

The main objective of congestion management is to relieve congestion within a fraction of time to stay system secure. Hence, it is prime duty of ISO[62] to identify most sensitive congestion zones. The change in power flow has been identified by the distribution of power transaction in different lines of the network. As line flow changes, the contribution of generator and load can be determined by distribution factors of the line. These factors are known as network sensitivity factors.

The two different methods to find network sensitivity factor are listed below:

(1) Approach based on DC Load Flow (DC Method)

(2) Approach based on AC Load Flow (AC Method)

2.8.2 DC Load Flow Based Approach (DC Method)

DC load flow approach has been discussed in reference[31]. To determine congestion distribution factors (TCDFs), real power flows in a line connected between bus i and bus j using DC power flow formulation is given as:

Transmission Congestion Distribution Factors

Transmission congestion distribution factors (TCDFs) are defined as the change in real power flow ΔP_{ij} in a transmission line-k, connected between bus-i and bus-j, due to unit change in the power injection ΔP_i at bus-i.

$$TCDF_i^k = \frac{\Delta P_{ij}}{\Delta P_i} \tag{2.2}$$

The change in active power flow can be measured by TCDFs. It indicates how much real power flow over a transmission line connecting bus-i and bus-j would alter due to real power inoculation at bus-n. DC method consider for determination of the TCDFs, as describe below:

$$P_i = \frac{\delta_i - \delta_j}{x_{ij}} = b_{ij}(\delta_i - \delta_j) \tag{2.3}$$

Where, x_{ij} and b_{ij} are the series reactance and susceptance of the transmission line. δ_i is the phase angle of the voltage at bus-i. The equation (2.3), can be rewritten in the vector form as:

$$[P_{ij}] = [L_{ij}]^T [\delta] \tag{2.4}$$

A sensitivity vector is given by $[L_{ij}]$ of the line power flow with respect to bus voltage phase angle. All the elements of $[L_{ij}]$ are zero except the i_{th} and j_{th} elements, which are b_{ij} and $-b_{ij}$, respectively. The DC load flow equation describes the association between the bus voltage angle vector δ and real power injection vector [P] for a n-Bus (NB) system, is given as under:

$$[P] = [B]^T [\delta] \tag{2.5}$$

Where, [B] is NB x NB susceptance matrix, whose entries are: $B_{ij} = -b_{ij}$

$$B_{IJ} = \sum_{j=1}^{NB} b_{ij} \tag{2.6}$$

Selecting n_{th} bus to be the reference bus, the row and column of the [B] matrix corresponding to the reference bus can be eliminated. The voltage at other buses relative to this bus can be solved in terms of [P]as:

$$[\delta_{-n}] = [B_{-n}]^T [P_{-n}] \tag{2.7}$$

Where $-n$ represent a vector without n_{th} element or a matrix with corresponding nth row and column eliminated. The actual phase angles can be rewritten by adding the relative phase angle of the reference bus.

$$[\delta] = \frac{[\delta_{-n}]}{0} + \delta(1) \tag{2.8}$$

$$[\delta] = \begin{bmatrix} B_{-n} & 0 \\ 0 & 0 \end{bmatrix} [P] + \delta_n(1) \tag{2.9}$$

Where, $\delta(n)$ is the phase angle of bus n. (1) is a n x 1 unity vector. Combining the equation 2.3 and 2.9 , the power flow in the line connected between buses i and j, can be expressed in terms of real power injections as:

$$[P] = [L_{ij}] \begin{bmatrix} B_{-n} & 0 \\ 0 & 0 \end{bmatrix} [P] + \delta_n(1) [L_{ij}] (1) \tag{2.10}$$

$$[P_{ij}] = \left[D_n^{ij}\right] [P] \tag{2.11}$$

2.8.3 A.C.Load Flow Based Approach

DC based approach work with real transmission congestion distribution factor [68] only. AC based method employes two sensitivity factors namely, real and reactive power distribution congestion factor for more accurate results. The real power transmission congestion distribution factors (TCDFs) has been used for finding the most sensitive zones for congestion to be relieved. The generator situated in this sensitive zone has to be managed by rescheduling.

The reactive power plays an important role in supporting real power transfer. The proper reactive power support can enhance the capability of the line. The manifold transaction will results in voltage collapse. Therefore, procurement of the reactive power supported devices has been important in competitive markets. The reactive power has been recognized as imperative ancillary services [64].

The two sets of sensitivity factors namely, real power transmission congestion distribution factors (PTCDFs) and reactive power transmission congestion distribution factor (QTCDFs) in the competitive market environment has been used in this projected work.

The methods for the ATC computation has been reported in [26],[60],[31],[1] listed below:

(1) Power Transfer Distribution Factor (PTDF) and Line Outage Distribution Factor (LODF) based ATC calculation.

(2) Optimal Power Flow (OPF) based ATC calculation.

(3) Continuation method based ATC calculation.

The Power Transfer Distribution Factor (PTDF) and Line Outage Distribution Factor (LODF) based ATC calculation has been used in this proposed work.

2.8.4 Mathematical Modeling of ATC

PTCDF and LODF based methods have been widely used for ATC calculation. This methods have been elaborated in detail. The most susceptible zones has been identified by a combination of real and reactive line flow sensitivity indices [70]. The sensitivity properties of the Newton-Raphson load flow (NRLF) Jacobian can be used to derive Transmission Congestion Distribution factors (TDCFs). The real power flow (P_{ij}) and reactive power flow (Q_{ij}) in a line-k connected between bus-i and bus-j can be written as:

$$P_{ij} = |V_i||V_j||Y_{ij}| \cos(\theta_{ij} - \delta_j - \delta i) \tag{2.12}$$

$$Q_{ij} = -|V_i||V_j||Y_{ij}| \sin(\theta_{ij} - \delta_j - \delta i) + V_i^2 Y_{ij} \sin(\theta_{ij}) - \frac{V_i^2 Y_{sh}}{2} \tag{2.13}$$

Where, V_i and δ_i are the voltage magnitude and angle at bus-i. Y_{ij} and θ_{ij} is magnitude and angle of $(ij)^{th}$ element of Y_{bus} matrix. Y_{sh} is the shunt charging admittance of line-k.

2.8.4.1 Real Power Congestion Distribution Factor based Available Transfer Capability Calculation

The real and reactive TCDFs are the indicator of change in power due to change in real and reactive power injection respectively. The change in real power flow ΔP_{ij} in a transmission line-k, connected between bus-i and bus-j, due to a unit change in the power injection ΔP_n at bus-n is term as real Power Transmission Congestion Distribution Factors (PTCDFs)[68].

$$PTCDF_n^{ij} = \frac{\Delta P_{ij}}{\Delta P_n} \tag{2.14}$$

The change in reactive power flow ΔQ_{ij} in a transmission line-k, connected between bus-i and bus-j, due to a unit change in the power injection ΔQ_n at bus-i is an expression as the Reactive Power Transmission Congestion Distribution Factors (QTCDFs).

$$QTCDF_n^{ij} = \frac{\Delta Q_{ij}}{\Delta Q_n} \tag{2.15}$$

Taylors series estimation, equation 2.12 and 2.13 can be written by way of ignoring second and higher order terms as:

$$\Delta P_{ij} = \frac{\partial P_{ij}}{\partial \delta_i}\Delta\delta_i + \frac{\partial P_{ij}}{\partial \delta_j}\Delta\delta_j + \frac{\partial P_{ij}}{\partial V_i}\Delta V_i + \frac{\partial P_{ij}}{\partial V_j}\Delta V_j \tag{2.16}$$

$$\Delta Q_{ij} = \frac{\partial Q_{ij}}{\partial \delta_i}\Delta\delta_i + \frac{\partial Q_{ij}}{\partial \delta_j}\Delta\delta_j + \frac{\partial Q_{ij}}{\partial V_i}\Delta V_i + \frac{\partial Q_{ij}}{\partial V_j}\Delta V_j \tag{2.17}$$

$$\Delta P_{ij} = a_{ij}\Delta\delta_i + b_{ij}\Delta\delta_j + c_{ij}\Delta V_i + d_{ij}\Delta V_j \tag{2.18}$$

$$\Delta Q_{ij} = a'_{ij}\Delta\delta_i + b'_{ij}\Delta\delta_j + c'_{ij}\Delta V_i + d'_{ij}\Delta V_j \tag{2.19}$$

The coefficients of the equation 2.18 and 2.19 can be evaluated by partial derivatives of real and reactive power flow equation 2.12 and 2.13 with respect to variables δ and V as:

$$a_{ij} = \frac{\partial P_{ij}}{\partial \delta_i} = V_i V_j Y_{ij} \sin(\theta_{ij} + \delta_j - \delta_i) \tag{2.20}$$

$$b_{ij} = \frac{\partial P_{ij}}{\partial \delta_j} = -V_i V_j Y_{ij} \sin(\theta_{ij} + \delta_j - \delta_i) \tag{2.21}$$

$$c_{ij} = \frac{\partial P_{ij}}{\partial V_i} = V_i V_j Y_{ij} \cos(\theta_{ij} + \delta_j - \delta_i) - 2V_i Y_{ij} \cos(\theta_{ij}) \tag{2.22}$$

$$d_{ij} = \frac{\partial P_{ij}}{\partial V_j} = V_i Y_{ij} \cos(\theta_{ij} + \delta_j - \delta_i) \tag{2.23}$$

$$a'_{ij} = \frac{\partial Q_{ij}}{\partial \delta_i} = V_i V_j Y_{ij} \cos(\theta_{ij} + \delta_j - \delta_i) \tag{2.24}$$

$$b'_{ij} = \frac{\partial Q_{ij}}{\partial \delta_j} = -V_i V_j Y_{ij} \cos(\theta_{ij} + \delta_j - \delta_i) \tag{2.25}$$

$$c'_{ij} = \frac{\partial Q_{ij}}{\partial V_i} = -V_j Y_{ij} \sin(\theta_{ij} + \delta_j - \delta_i) + 2V_i Yij \sin(\theta_{ij}) - V_i Y_{sh} \tag{2.26}$$

$$d'_{ij} = \frac{\partial Q_{ij}}{\partial V_j} = -V_i Y_{ij} \sin(\theta_{ij} + \delta_j - \delta_i) \tag{2.27}$$

The following Jacobian relationship has been used for determination of TCDFs:

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} J \end{bmatrix} \begin{bmatrix} \Delta\delta \\ \Delta V \end{bmatrix} = \begin{bmatrix} J_{11} J_{12} \\ J_{21} J_{22} \end{bmatrix} \begin{bmatrix} \Delta\delta \\ \Delta V \end{bmatrix} \tag{2.28}$$

By ignoring $P - V$ and $Q - \delta$ coupling 2.27 can be simplified as :

$$\Delta P = \begin{bmatrix} J11 \end{bmatrix} \begin{bmatrix} \Delta\delta \end{bmatrix} \tag{2.29}$$

$$\Delta Q = \begin{bmatrix} J22 \end{bmatrix} \begin{bmatrix} \Delta V \end{bmatrix} \tag{2.30}$$

With simplification of equation 2.29 and 2.30, the following equation can be derive as under:

$$\begin{bmatrix} \Delta delta \end{bmatrix} = \begin{bmatrix} J11 \end{bmatrix}^{-1} \begin{bmatrix} \Delta P \end{bmatrix} = \begin{bmatrix} M \end{bmatrix}^{-1} \begin{bmatrix} \Delta P \end{bmatrix} \tag{2.31}$$

$$\begin{bmatrix} \Delta V \end{bmatrix} = \begin{bmatrix} J22 \end{bmatrix}^{-1} \begin{bmatrix} \Delta P \end{bmatrix} = \begin{bmatrix} N \end{bmatrix}^{-1} \begin{bmatrix} \Delta Q \end{bmatrix} \tag{2.32}$$

Equation 2.31 and 2.32 can be simplified in the following form:

$$\Delta\delta_i = \sum_{l=1}^{NB} m_{il} \Delta P_l \tag{2.33}$$

$$\Delta V_i = \sum_{l=1}^{NB} n_{il} \Delta Q_l \tag{2.34}$$

where $i = 1, 2, 3......NB$ **,** $i \neq s$

Where, NB is the number of buses in the system and s is the slack bus. By neglecting effect of change in the bus voltage on real power flow and bus angle on reactive power flow, the equation 2.18 and 2.19 can be form as:

$$\Delta P_{ij} = a_{ij} \Delta\delta_i + b_i \Delta\delta_j \tag{2.35}$$

$$\Delta Q_{ij} = c'_{ij}\Delta V_i + d'_i\Delta V_j \tag{2.36}$$

Putting equation 2.33 into equation 2.35 and equation 2.34 into equation 2.36, results following equation:

$$\Delta P_{ij} = a_{ij}\sum_{l=1}^{NB} m_{il}\Delta P_l + b_{ij}\sum_{l=1}^{NB} m_{jl}\Delta P_l \tag{2.37}$$

$$\Delta Q_{ij} = c'_{ij}\sum_{l=1}^{NB} n_{il}\Delta Q_l + d'_{ij}\sum_{l=1}^{NB} n_{jl}\Delta Q_l \tag{2.38}$$

Equation 2.36 and 2.37 can be long-drawn-out as:

$$\Delta P_{ij} = (a_{ij}m_{i1} + b_{ij}m_{j1})\Delta P_1 + (a_{ij}m_{i2} + b_{ij}m_{j2})\Delta P_2 + ... + (a_{ij}m_{in} + b_{ij}m_{jn})\Delta P_n \tag{2.39}$$

$$\Delta Q_{ij} = (c'_{ij}n_{i1} + d'_{ij}n_{j1})\Delta Q_1 + (c'_{ij}n_{i2} + d'_{ij}n_{j2})\Delta Q_2 + ... + (c'_{ij}n_{in} + d'_{ij}n_{jn})\Delta Q_n \tag{2.40}$$

Equation 2.39 and 2.40 can be rewritten as:

$$\Delta P_{ij} = PTCDF_1^k\Delta P_1 + PTCDF_2^k\Delta P_2 + ... + PTCDF_n^k\Delta P_n \tag{2.41}$$

$$\Delta Q_{ij} = QTCDF_1^k\Delta Q_1 + QTCDF_2^k\Delta Q_2 + ... + QTCDF_n^k\Delta Q_n \tag{2.42}$$

Where , the equation for Distribution transmission Factors are give as under:

$$PTCDF_n^k = a_{ij}m_{in} + b_{ij}mjn \tag{2.43}$$

$$QTCDF_1^k = c'_{ij}n_{in} + d'_{ij}n_{jn} \tag{2.44}$$

The transaction has been carried out at source bus n. These TCDFs are the real and reactive transmission congestion distribution factors corresponding to a bus-n and a line-k connected between bus-i and bus-j. ATC can be calculated by recognizing new flow on line from i to j (line k) due to transaction between source and destination bus(transaction 'n') The new flow is given by

$$P_{ij}^{new} = P_{ij}^0 + \Delta P_{ij} \tag{2.45}$$

$$P_{ij}^{new} = P_{ij}^0 + PTCDF_n^k\Delta P_n \tag{2.46}$$

where,

P_{ij}^0 = base case flow on the line and

P_n = Transaction at bus n

The maximum power that can be transferred without overloading line i-j is P_{ij}^{max} then, Maximum allowable Power transfer from source bus to destination bus (transaction 'n') limited by line i-j (line k) is given by the following equation.

$$\Delta P_n^{ijmax} = \frac{P_{ij}^{max} - P_{ij}^0}{PTCDF_n^{ij}} \tag{2.47}$$

if $\Delta P_n = P_n$ then, **??** can be given as under

$$P_n^{ijmax} = \frac{P_{ij}^{max} - P_{ij}^0}{PTCDF_n^{ij}} \tag{2.48}$$

ATC has been computed given by minimum of the maximum allowable transaction over all the lines.

$$ATC_n = min(P_n^{ij,max}) \tag{2.49}$$

The condition for multiple transaction validity as follows:

- ΔP_n^k is less than ATC_n : Transaction is valid
- ΔP_n^k is more than ATC_n : Transaction is invalid or limited to ATC.

The ATC value has been posted on website known as Open Access Same-Time Information system (OASIS) [22], [69]. Thus ATC can be used as an approximate pointer of relative system security[22]. The ISO [62] can use timely ATC information to decide the validity of bidding results in an open access deregulated[30] Electric market. The market players also submit bid strategically when congestion take place. When ISO [62] posts the ATC on OASIS for the particular transaction, the following facts must be cleared:

(1) The entire network is competent enough to carry out the posted ATC MW for a particular transaction

(2) It does not mean that the ATC is the capacity of the interface connecting node i-j

2.8.4.2 Line Outage Distribution Factor based Available Transfer Capability Calculation

While calculating ATC, the system contingencies must be considered for the accurate results. The effect of line outage along with PTCDFs are involved in ATC calculation. Line

Outage Distribution Factors (LODFs) and Power Transmission Congestion Distribution Factors (PTCDFs) has been used to calculate the first contingency incremental transfer capability, which is the maximum increase in transaction amount from one bus to another bus which still meets $(n-1)$ test

At time of line outage, the power can be redistributed onto the remaining lines. The LODF[64] is the measure of the redistribution. $LODF_{ij(l)}^{rs(u)}$ is distribution factor for line $(r-s)(u)$ outage with examine line $(i-j)(l)$.

$$LODF_l^u = \frac{N_u x_u (x_{ir} - x_{jr} - x_{is} + x_{js})}{N_l x_l (N_u x_u - x_{rr} - x_{ss} + 2x_{rs})} \tag{2.50}$$

where, N_u = Number of line connecting between,

r to s bus,

N_l number of line connecting between i to j bus

At the time of congestion management the calculation of ATC along with the line outage has to be considered. If the transaction between m to n node and the outage line from bus r to bus s(u-line), then change in flow on line (r-s) due to transaction is:

$$\Delta P_{rs} = PTCDF_{rs,mn} P_{mn}^{new} \tag{2.51}$$

when line r-s (line-u) is outage, part of the flow appears on line i-j (line-l) resulting from both the line r-s and a new transaction from bus m to n is given by

$$\Delta P_{ij,rs}^{new} = (PTCDF_{ij,mn} + LODFij, rsPTCDFrs, mn)\Delta P_{mn}^{new} \tag{2.52}$$

$$P_{ij,rs}^{new} = P_{ij}^0 + \Delta P_{ij,rs}^{new} \tag{2.53}$$

The maximum contingency limited transfer from bus m to n, limited by $(i-j)$ line with the line $(r-s)$ outage :

$$P_{mn,ij,rs}^{max} \leq \frac{P_{ij}^{max} - P_{ij}^0}{PTCDF_{ij,mn} + LODF_{ij,rs} PTCDF_{rs,mn}} \tag{2.54}$$

P_{ij}^{max} is the post contingency flow limit on line $i-j$ which is usually higher then the steady state limit.

2.8.4.3 Available Transfer Capability computation

To find contingency limited by ATC, all possible combination of outage line and the limiting line must be checked along with steady state transfer limit.

ATC can be calculated with consideration of PTCDF and LODF using equation 2.49 and 2.54

$$ATC_{mn,rs} = min(P_{mn,ij}, P_{mn,ij,rs}) \tag{2.55}$$

Using above equation 2.55 any proposed amount of the transaction for the specific Hr. may be checked by calculating ATC. If it is greater than the amount of the proposed transaction then the transaction is allowed otherwise it is rejected or limited to ATC.

2.9 Conclusion

The basic concept of restructuring and congestion management has been discussed in this chapter. The mathematical modeling for the ATC calculation with the help of PTCDF and LODF has been reported in this work. The algorithm has been developed to calculate ATC for any system with this mathematical modeling.