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Dissertation Report on

Financial Risk and Their Hedging Process in Power Trading and Analysis of Trading Prospect in West Bengal

By

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Guided By

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**A DISSERTATION REPORT SUBMITTED IN PARTIAL FULFILLMENT
OF THE
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This is to acknowledge with thanks the help, guidance and support that I have received during the Dissertation.

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Declaration by the Guide

This is to certify that the Mr Samir Bhowmik, a student of (MBA (Power Management)), Roll No 500025241 of UPES has successfully completed this dissertation report on "**Financial risk and their hedging process in Power trading and analysis of trading prospect in West Bengal**" under my supervision.

Further, I certify that the work is based on the investigation made, data collected and analyzed by him and it has not been submitted in any other University or Institution for award of any degree. In my opinion it is fully adequate, in scope and utility, as a dissertation towards partial fulfillment for the award of degree of MBA.

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Table of Contents:

List of Table and Illustration:

List of Figure:

ABBREVIATION:

DVC	Damoder Valley Corporation
GENCOM	Generation Comapay
TRANSCOM	Transmission Commission
DISCOM	Distribution company
NTPC	National Thermal Power Corporation Ltd
STOA	Short Term Open Access
MTOA	Medium Term Open Access
LTA	Long Term Access
SEBs	State Electricity Board
CERC	Central electricity regulatory commissions
NLDC	National Load Dispatch Centre
RLDC	Regional Load Dispatch Centre
SLDC	State Load Dispatch Centre
CTU	Central Transmission Utilities
STU	State Transmission Utilities
PPA	Power Purchase Agreement
ER	Eastern Regions
NER	North Eastern Region
NR	Northern Region
WR	Western Region
ER	Eastern Region
MW	Mega Watt
REA	Regional Energy Account
UI	Unscheduled Interface
CEA	Central Electricity Authority

CPP	Captive Power Plants
IPP	Independent Power Plants
ISGSs	Inter-state Generating System
RTS	Regional Transmission System
IR Link	Inter-Regional link
PTC	Power trading Corporation
RPC	Regional Power Committees
IEX	Indian Energy Exchange
ATC	Available Transmission Corridor
TTC	Total Transmission Corridor
WBSETCL	West Bengal State Electricity Transmission Company Ltd.
WBSEDCL	West Bengal State Distribution Electricity Distribution Company Ltd.

Executive summary:

In Electricity Act'2003 Trading has been acknowledged as a licensed activity, which promotes power traders for trading within the system. Power trading is an activity, which have huge financial risk. The risk mainly comes due its spot price volatility and the spot price volatility comes due its physical attribute. So aim of this thesis is to find out those financial risks in power trading and there are so many processes to reduce the risk, but in this thesis we should only focus on hedging process and trading arrangement to reduce the risk.

First we go through brief history and growth of installed capacity, transmission line capacity, energy demand and energy demand forecast. Development of electricity regulatory framework and changes in tariff structure before ES (A)'1948 to after era of EA'03 also discussed.

Then we review power trading vide development of power trading, electricity market model, existing and emerging market structure, trading scenario before and after EA'03, regulatory framework in trading, mechanism of trading, existing trading scenario and role of power exchange in trading.

Open access is essential for sustainable power trading. So, a light of discussion given on type of open access, regulatory framework, pricing-loss charge calculation, landed cost calculation, calculation of total transfer capability (TTC), available transfer corridor (ATC), transfer reliability margin (TRM). Then we go through the business framework and trading process.

The key outcome of risk is spot price volatility and maximum possible of system collapse. Electricity spot prices are volatile due to the unique physical attributes of electricity in its production and distribution function i.e. non-storability, uncertain and inelastic demand and a steep supply function. Uncontrolled exposure to market price risks can lead to devastating consequences for market participants in there structured electricity industry.

In this thesis the risk factor are divide into 3 (three) category i.e. technical, financial, management risk. Out of these three type factor first 2 (two) type factor readily converted into price volatility. Lessons learned from the financial markets suggest that financial derivatives, when well understood and properly utilized, are beneficial to the sharing and controlling of undesired risks through properly structured hedging strategies. We review different types of electricity financial instruments and the general methodology for utilizing and pricing such instruments. In particular, we highlight the roles of these electricity derivatives in mitigating market risks and structuring hedging strategies for generators, load serving entities, and power marketers in various risk management applications.

Then we review different current technical and cost parameters of Gencom, Discom and Transcom of West Bengal. We will find out present scenario of Gencom, Transcom, energy demand and demand forecast in zone wise- district wise of West Bengal. We compare sustainability of diff. power sources w.r.t. average power generation cost in case power trading started in full phase and review the applicability of hedging process in power trading in West Bengal.

Finally, we conclude by pointing out the existing challenges in current electricity markets for increasing the breadth, liquidity and use of electricity derivatives for achieving economic efficiency.

Chapters:

This is the main section of the dissertation report. Here we discussed introduction, literature review, research methodology, analysis, interpretation of result and conclusion and further scope of study one by one.

Chapter 1: Introduction.

1.1.Introduction:

India is 5^{th} largest power producer and 6^{th} largest power consumer in the world. India's energy demand is growing rapidly due mainly 02 reason i.e. population growth and per capita economic growth. India's compound annual growth rate (CAGR) of energy is 3.1%. The total projected primary energy demand in 2016-17 will be 732 Mtoe with 8%constant elasticity as per IEP - 2006 report. If we concentrate on power sector it is observed that power demand increase @ 3.6% in last thirty years and 8% in last six years. The installed capacity enhanced 1700MW in 1950 to 272 GW in April'2015 and a target is taken to add capacity of 1, 00,000 MW in 12^{th} five year plan and 930 GW in 2030. So, it is found that there is a huge scope in growth in energy sector as well in power sector. To maintain a sustainable economic development in power sector competition is introduce in Electricity Act'2003 by means of more private participation, open access and power trading. In this thesis we should concentrate on power trading and associated financial risk and reducing the risk by hedging process and next we will analyze prospects of trading in West Bengal.

Now what is trading, in Electricity Act'2003 Trading has been acknowledged as a licensed activity, which promote power traders for trading within the system. India is a large country with spatial varieties and culture. Due to this India faces seasonal surplus-deficit generation among various regions. This crates main opportunity of power trading. It is also observer that pockets of surplus power due to projected load growth not taking place commensurate with addition in generation capacity, there still exists a gap between supply and demand of power in large parts of the country, which also create opportunity of trading.

There are various risks in trading. In this paper, various financial risks hedging instruments and trading arrangements of Indian market is discussed.

In west Bengal there is a huge gap in supply-demand due to decline demand growth and proposed power project. This creates ground of power trading.

1.2.The Objective of Study:

A robust trading system is very important for free and fair competitive electricity market operation. Trading system should be capable of risk hedging associated with price volatility and other unexpected changes. Operating behavior of a competitive power market is significantly affected by the trading arrangements, strategic bidding, market model and rule. So, our objectives are to discuss the risks and strategy for reducing risk and power trading yet not started in West Bengal, so to find out the ground, limitation and opportunity of trading in West Bengal.

1.3.Problem Definition:

As power is not a storable commodity, Power trading is having highly financial risk due to its price volatility, transmission congestion and unexpected changes. So, due to this problem the trading agency may suffer huge financial loss and system may collapse in real time. So, the problem domain of the thesis is to find out the risk causes in power trading.

1.4. Scope of Work:

This is an exploratory type research on the basis of objective and secondary data needed to analyze the problem. In this thesis I have got secondary data from GENCOM, TRANSCOM, DISCOM of West Bengal, current & future load demand of West Bengal, their comparison and analysis of opportunity & problem of trading in West Bengal.

1.5. Conclusion:

A robust trading system is very important for free and fair competitive electricity market operation. If consumers participate in trading, then actual economic price will be reflected in the market and this oligopolistic sector will be more economic. High risk is hindering the growth of power trading. The solution of the problem i.e. high financial risk is the hedging process. In this thesis we will discuss about derivative instrument, transmission right, trading arrangement, strategic bidding, market model and rule as a solution.

Chapter 2: Literature Review

Prabodh Bajpai and S. N. Singh in their paper **"Electricity Trading in Competitive Power Market: An Overview and Key Issues"** discuss about Electricity derivative instrument and Transmission right as a risk hedging process.

CERC in their paper "Open Access, Electricity Trading and Challenges in Organizing Electricity Trading Thorough a Power Exchange in India" discuss about open access charges, trading mechanism through power exchange, issue and road map for trading through power exchange.

Geert Jongen in his paper "Risk Management Practices in Electricity Trading" on February'12 discussed about different risk and their management practice in electricity market for trading. In his paper he discussed about price risk, imbalance risk and their hedging is possible with future, forward, spot and option contract and shows minimum hedging qty.

S.J. Deng, S.S. Oren in their paper "Electricity derivatives and risk management" shows different risk and using of electricity derivative instrument as a risk hedging for generators, load serving entities and power market.

Singh Harry et.al [1998] this paper studies the management of costs associated with transmission constraints (i.e., transmission congestion costs) in a competitive electricity market. The paper examines two approaches for dealing with these costs. The first approach is based on a nodal pricing framework and forms the basis of the so-called pool model. The paper also provides an analysis of financial instruments proposed to complement nodal pricing and includes illustrative test results on a large scale system. The second approach is based on cost allocation procedures proposed for the so-called *bilateral* model. The paper explains the basis for this model including a game-theoretic evaluation of some of its aspects. Both the pool and bilateral models have been at the center of the electric utility restructuring debate in California.

S.B. Warkad et.al [2005] in journal "**Optimal Electricity Nodal Price Behaviour: A Study In Indian Electricity Market**" identifies that the electric power industry has now entered in an increasingly competitive environment where the trend of electricity market is heading towards Transmission Open Access. In India, the Electricity Act 2003has implemented to undertake comprehensive market reforms in electricity sector. Transmission Open Access seeks to achieve the objective of ensuring optimal development of transmission network, to promote efficient utilization of generation and transmission asset in the country and to attract the required investment in transmission sector and to provide adequate returns.

Ravinder, Talegaonkar Ajay in his journal [**Developing Power Exchanges in India : Issues and challenges**] [2008, Vol. 65, Issue 3] discussed the introduction of open access for inter-state transmission as per the new electricity legislation in India has facilitated bilateral trading resulting in better resource optimization within an overall deficit scenario. While the volume of traded electricity is tiny compared to the total consumption, nonetheless it has electrified an otherwise grim scenario. As a result, the Indian power sector has started at tracing private investment in hydro and thermal generation at an unprecedented scale.

Hari Natarajan in his paper **[An approach to introduce competition in The Indian Power Sector]** proposed a model allowing bilateral between IPPs and large users. Given the current state of transmission infrastructure, the generating companies should be allowed to contract with industrial customers in their own region with first preference to customers within the state in which the generating company is going to be located.

Schweppe et al [1988. Portland, Oregon] in journal **[Mandatory Wheeling: A Framework for Discussion. in IEEE/PES Summer Meeting]** mentions that "wheeling is a mongrel concept resulting from the mating of two inherently different economic concepts; an ideal world of regulated utilities and an ideal deregulated competitive market. Wheeling would not exist in either extreme."

CERC Concept Paper on **[Open Access in Inter-state Transmission] [August 2003]** highlights the issues associated with open access and frame regulations as the outcome of the exercise. It also describes the transmission pricing schemes designed to promote efficient day to day operation of bulk power market including power trading. It gives economic signals for efficient use of transmission resources, investment in transmission, location of new generation and loads, compensating owner of transmission system. It also describes energy accounting e.g. Active Energy, Reactive Energy etc. The paper concluded that:

- The existing long-term transmission agreements should be honoured until modified; else the issue of stranded assets would arise.
- To begin with only spare transmission capacity can be made available for open access.
- Since, RLDCs will have a key role to play in the open access related issues; neutrality in their functioning is expected.
- In the new scenario, original beneficiaries will also be treated as open access customers at par, for the purpose of power trading and bilateral exchanges. However, the original beneficiaries shall continue to pay transmission charges for transmission of allocated power from the ISGS.
- Contract Path Method and Incremental Postage Stamp Methods have been suggested for Open Access Pricing
- The Transmission Service Providers in the country (CTU, STU, Licensees etc.) will have to declare rates for various types of services within the ceiling price as decided by the Commission.
- Special Energy Meters will be installed by the open access customer as and when required.

David A K et.al [1998] said that Managing dispatch in an open access environment is a new challenge facing independent transmission system operators who are mandated to provide a level playing field for all transmission users. Two issues are especially important viz; use-of-transmission-system charges and congestion management. He has examines aspects of these issues with emphasis on the bilateral and multilateral dispatch coordination are explored and mathematical models developed for each case. The practical case when all three modes coexist is discussed with respect to both forward and real time dispatch.

Ilic M et.al [2003] has suggests that many of Transmission Reliability and Security challenges are direct result of the institutional dichotomy within the once vertically integrated industry. Namely, while the generation portion of this industry has made major progress toward becoming for profit, value-based industry, both the delivery (transmission) and the end user (distribution) remainders are left without any clear institutional support to adjust and provide their value to the end users in the changing industry. His work shows that in order to move forward and provide some more natural ways of valuing generation, transmission, distribution and customers' willingness to respond to the changing system constraints, several issues must be resolved. Some possible institutional and technological approaches to solving the system reliability problems in the changing industry were introduced.

S.K. Soonee (C.E.O. POSCO) in his paper [**Open Access in Inter-State Transmission**] cites the significance of Open Access in Trading Market Evolution. It describes various products of Trading; accounts the short term trade in various financial periods

Abhishikta Roy Chowdhury, CII Eastern Region, Kolkata, India Bibek Ray Chaudhuri, Indian Institute of Foreign Trade, Kolkata, India "Manufacturing Sector in West Bengal: Advantages & Potential" shows the growth the Bengal manufacturing industries. They shows highest investment in iron and steel sector.

"Investment and Industrial Policy of West Bengal" by West Bengal government shows the invest in different sector.

"LACK OF AFFORDABLE & QUALITY POWER: SHACKLING INDIA'S GROWTH STORY" by FICCI in 2013 shows lack of power in West Bengal.

Chapter 3: Research Design, Methodology and Plan

This is the main section of the dissertation report. In this section we will start from discussion of brief history of Indian Power sector, then progressively discuss about power trading, open access in trading, landed cost calculation for open access, estimation of available transmission corridor, risk in power trading, hedging process, present and future power scenario of West Bengal from the source of secondary data.

3.1. Brief History of Indian Power Sector:

Here we shall discuss about growth story, present scenario, electricity regulatory framework and electricity institution of India.

3.1.1. Growth Story and present power scenario in India:

Here we discussed about growth of installed capacity and transmission capacity and growth of demand.

3.1.1. (A). Growth of installed capacity:
India has a share of about 3.4% in the world energy but share 17% of world population and a population growth rate of 2%. India's first hydro-electric power station "**Sidrapong Hydel Power Station**" of capacity 2X65 KW was commissioned in Derjeeling district of West Bengal in 10 th November 1897. From this time India's installed capacity increase gradually and at the time of independence the installed capacity was 1362 MW in 1947. Now installed capacity is 272 GW in April'2015 and a target is taken to add capacity of 1, 00,000 MW in 12th five year plan and 930 GW in 2030.

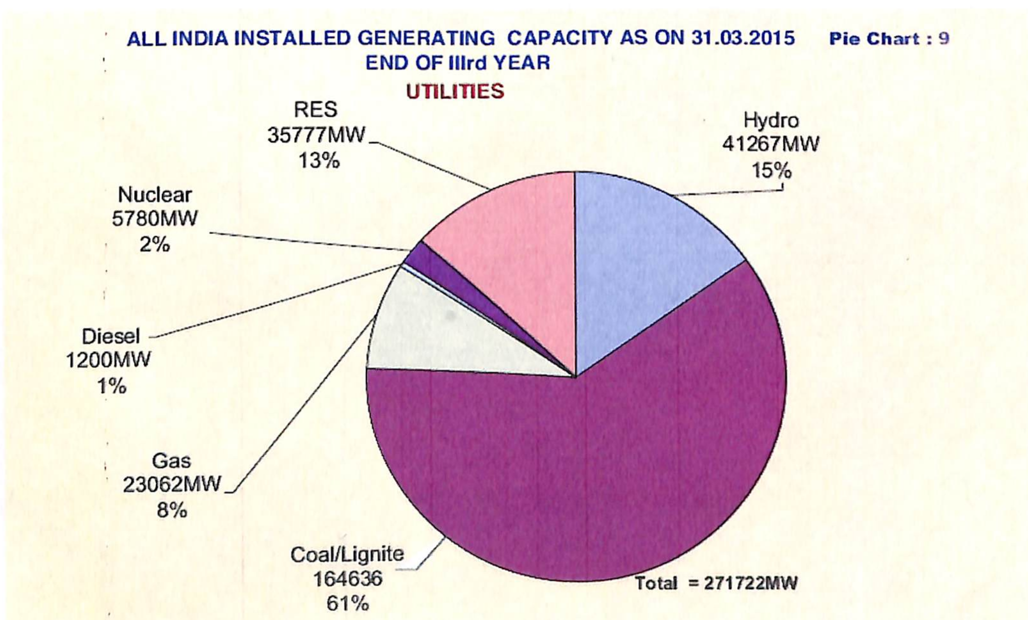

Fig. 1 All India Installed Capacity (Source CEA report)

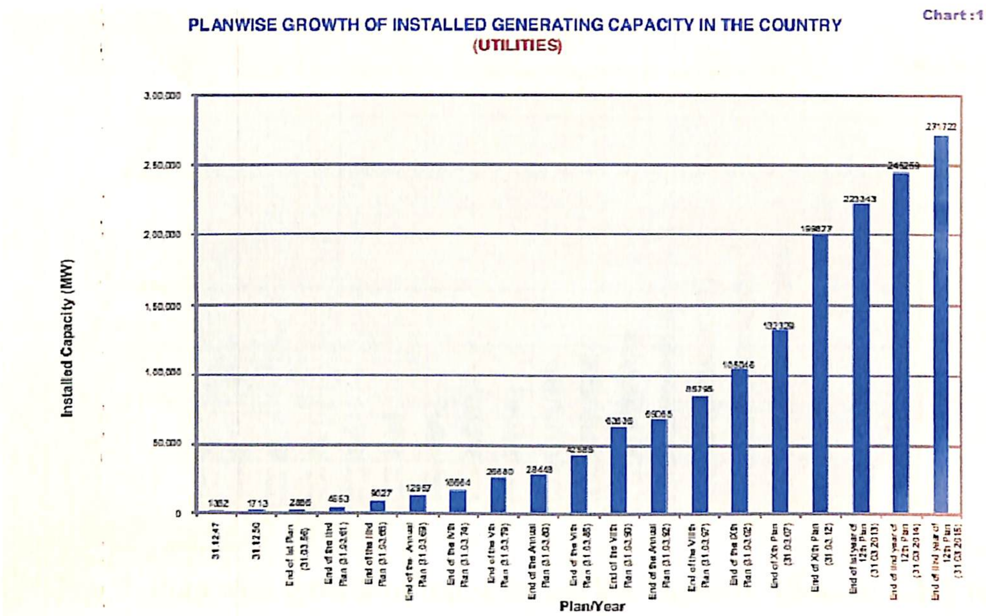

Fig. 2 Plan wise growth of Installed Capacity. (Source: CEA report)

3.1.1. (B). Growth of Transmission capacity:

3.1.1. (B). I. Development of Grid in India as follows:

- ✓ Local grid – at the time of independence.
- ✓ State Grids – emerged in 1960s.
- ✓ Regional Grids – in 1970s.
- ✓ National Grid – Beyond 2000s.

3.1.1. (B). II. Development of Transmission Voltages Levels:

- ✓ 132 kV highest levels at the time of Independence.
- ✓ 220 kV was introduced in 1960.
- ✓ 400 kV was introduced in 1977
- ✓ HVDC back-to-back link was introduced in 1989,
- ✓ 500kV, HVDC bi-pole line was introduced in 1990
- ✓ 765 kV transmission line introduced from 2000 onwards.
- ✓ Planning for introducing 1200KV under process.

3.1.1. (B). III. The growth of transmission line capacity as following figure:

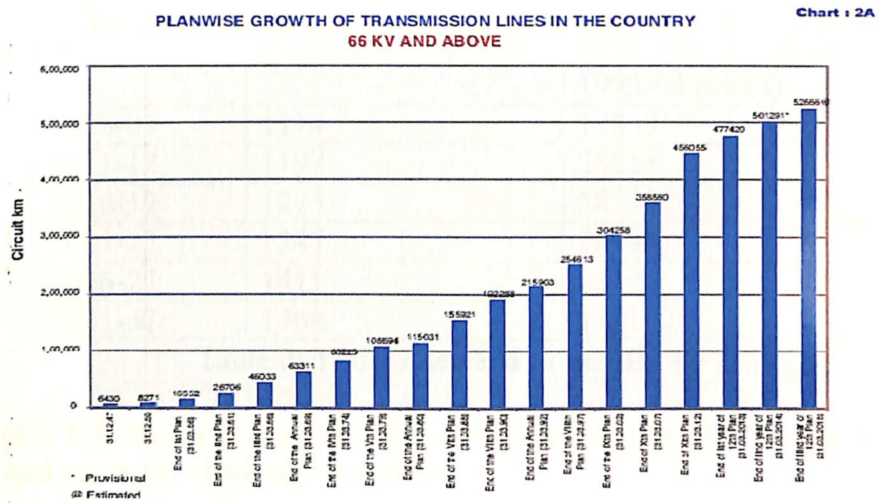

Fig. 3: Plan wise growth of transmission line capacity. (Source: CEA report)

3.1.1. (C). Growth of demand:

India is a fast growing country. There is a close relationship between energy consumption and economic growth. The energy demand is increasing rapidly in day- by- day. The quantum of future energy demand by the lower middle-income country depends on the following factor:

a. The expected income level.
b. Real energy prices
c. The trend of conversion from traditional non-commercial fuel to commercial fuel.
d. The changing to energy- intensive activities due to modernization.

India's compound annual growth rate (CAGR) of energy is 3.1%. The total projected primary energy demand in 2016-17 will be 732 Mtoe with 8%constant elasticity as per IEP -2006 report.

3.1.1. (C). I. As per WEO' 2011 the sectoral primary energy demand growth as follows:

Sl No	Sector	1990	2009	2035
1	Building	42%	29%	18%
2	Industry	22%	22%	22%
3	Power	23%	38%	42%
4	Transport	8%	10%	17%
5	Others	5%	1%	1%

Table 1: Sectoral primary energy demand as per WEO'11.

3.1.1. (C). II. Demand scenario as per IEP'06 for TPCES with 8% GDP and constant elasticity as follows:

Years	Population (million)	GDP (Rs in billion in 1993-94 prices)	TPCES (Mtoe)
2006-07	1114	17839	394
2011-12	1197	26211	537
2016-17	1275	38513	807
2021-22	1347	56588	1142
2026-27	1411	83145	1617
2031-32	1468	122170	2289

Table 2: TPCES demand as per IEP'06.

3.1.1. (C). III. Demand scenario for electricity as per IEP'06 for TPCES with 8% GDP and constant elasticity as follows:

Years	Energy (Billion kWh)		Projected Peak Demand (GW)	Installed Capacity (GW)
	Total	At Bus Bar		
2003-04	633	592	89	131
2006-07	761	712	107	153
2011-12	1097	1026	158	220
2016-17	1524	1425	226	306
2021-22	2118	1980	323	425
2026-27	2866	2680	437	575
2031-32	3880	3628	592	778

Table 3: Electricity demand as per IEP'06

3.1.1. (D). Source of Electricity Generation – One possible scenario as per IEP'06 with 8% GDP & constant elasticity:

Year	Electricity Generation at Bus Bar (BkWh)	Hydo (BkWh)	Nuclear (BkWh)	Wind (BkWh)	Thermal Energy (BkWh)	Fuel Needs		
						Coal (Mt)	NG (BCM)	Oil (Mt)
2003-04	592	74	17	3	498	318	11	6
2006-07	711	87	39	8	577	337	12	6
2011-12	1026	139	64	11	812	463	19	8
2016-17	1425	204	118	14	1089	603	33	9
2021-22	1981	270	172	18	1521	832	52	12
2026-27	2680	335	274	21	2050	1109	77	14
2031-32	3528	401	375	24	2828	1475	119	17

Table 4: Source of Electricity generation as per IEP'06

3.1.2. Development of Regulatory Frame Work:

Electricity is in the concurrent list of Indian constitution, so state and central government is jointly responsible for governing the law. However there are 04 (four) major Act to regulate the power sector. These are as follows:

3.1.2. (A) Indian Electricity Act'1910:
Describe relationship between generators & consumers. It regulates supply and use of electricity energy and rights and obligation of persons.

3.12.(B). Electricity (supply) Act'1948:
It forms CEA & SEBs. It also regulate the power and function of CEA, SEBs & GENCONs.
It was amended 03 (three0 times vide:

i. Amendment 1978: It gives a surplus for SEBs.
ii. Amendment 1983: It gives a surplus of 3% to SEBs.
iii. Amendment 1991: It was done by K.P.Rao committee and proposed 02 (two) part tariff.

3.1.2. (C). Electricity Regulatory Commission Act'1998:
It forms CERS & SERS to avoid government interference in operation and tariff setting of licensee/generating companies in Central as well as state.

3.1.2. (D). Electricity Act'2003:
This act supersedes the all previous act and includes all the regulatory frame work of previous acts. Some features of this Act as follows:

i. Electricity treated as an Industry and not Social Service Obligation.
ii. Enabled Private Sector Participation.
iii. Declared all streams of the Electricity as independent business entities.
iv. Encouraged Govt. Organizations to run as Commercial Units.
v. Setting up Regulatory Mechanism.

3.1.2. (E). Other Electricity Policies:

Inspite of the above mentioned policies there are few policies to govern the market. These are:

- February, 2005- National Electricity Policy
- January 2006- National Tariff Policy
- August 23, 2006 - Rural Electrification Policy
- August 2006- Integrated Energy Policy.
- January 2007- Report submitted by Working Group on Power for 11th Plan constituted by Planning Commission.
- August, 2007 - National Electricity Plan notified.
- June 6, 2008 - Energy Act Amended.

3.1.3. Change of Tariff Structure:

India's current tariff structure comes in a long way and with different changes in time to time. These are as follows:

3.1.3. (A). Tariff Structure Before ES(A)'1948:

Electricity comes in India almost last of 19th century, so electricity is a commodity for last 125 years in India. First electricity act was introduced in 1910. So, up to 1948 pricing of electricity was regulated by EA'1910 with a cost plus approach and single part tariff basis.

3.13. (B). Tariff structure after ES (A)'1948 and up to K.P.Rao Committee'1992:

In this period tariff was determined by Es (A)'1948. As per Section 59 of this act SEBs to earn a minimum of 3% of NFA and as per schedule VI licensees to earn return on equity linked to RBI on cost plus and single part tariff basis. In this process there is lack of tranperancy, clarity and uniformity in tariff setting.

3.13. (C). Tariff structure after K.P.Rao committee and up to EA'1998:

K.P.Rao committee first time proposed for two part tariff instead of single part tariff i.e. capacity charge linked to PLF and energy charge. They also introduce incentive to promote efficiency. But there was no concept of availability.

3.14. (D). Tariff Structure after EA'1998 and up to EA'2003:

EA'1998 forms CERC and SERSs to make a distance from government for making tariff norms. The main features of tariff setting were transparent procedure with open hearing, consumer interest, overall efficiency and economy. CREC and SERCs were responsible for terms and condition of setting up of tariff policy.

3.1.3. (E). Tariff Structure After EA'03:

EA'03 gives the right to CERC and SERCs to make tariff policy as per Section 61, 62, 63, 64, 65 and guideline of CEA to formulate the tariff policy. The main features of tariff setting are transparency, consumer interest, economic, efficiency, and commercialization in power industry towards setting up MYT and availability based tariff.

3.1.4. Electrical Regulatory Institution in India:

The following are the regulatory Institution of Power industry in India:

a. Central Electrical Authority (CEA): It was established under Electricity Act'1948.
b. State Electricity Boards (SEBs): It was established under Electricity Act'1948.
c. Central Electricity Regulatory Commission (CERC): It was established under EA'1998.
d. State Electricity regulatory Commissions (SRECs): It was established under EA'1998.

3.2. Power Trading:

Electricity Industry, throughout the world, is undergoing restructuring for last thirty years. Deregulated industry structure is the common path adopted that is transforming to increase in accountability, increase in efficiency and better utilization of the resources and for providing choice and quality service to the consumers at competitive price. The deregulated structure is envisaged to create an electricity market and introducing competition at various levels of electricity related transactions (other than transmission, which is natural monopoly). Under this structure, a competitive market of electricity is created to enable the generators to compete with each other by availing open access to the network. This is achieved by de-licensing the generation and permitting the generators to supply power to the wholesale/retail customers of their choice by entering into bilateral agreements with or without help of a separate market like power exchange.

The vertically integrated utilities could recover their cost regardless of whether they are operated efficiently or not. However with the introduction of competition there has been an important shift from this approach. Producers have ceased to be protected by their exclusive rights to generate and supply electricity. Competitive markets are providing the driving force for generators to innovate and operate in most efficient and economic manner in order to remain in business and recover their cost. Other benefits of competitive market include customer benefits, generation economies of scale and investment signals.

Operation and control of restructured electricity market poses technical challenges far more complex than the conventional monopolistic market. The complexity arises due to involvement of several market entities, many types of contractual obligations, and separation of primary and ancillary services and varying models of market management. Some of the technical challenges include congestion management, market power, price volatility and ancillary services management.

The various aspect of power trading discussed below:

3.2.1. Development of Power Trading:

Disintegrated power system started integrating into the state level power system after nationalization of power sector in the year 1948 onwards. On account of seasonal variation in availability of power from Hydro Power Station and seasonal variation in demand of different states depending upon a nature of load, it was considered useful to create facilities for exchange of power amongst variation states during different season. Some inter-state power lines were built and made operational in late 1950's and exchange of power started in bilateral mode. In this kind of exchange of power that was a form of trading, states having more Hydro Power could supply power during rainy season, to be taken back during the winter season when generation from Hydro Power Stations goes down.

This kind of power trading was found to be very useful. Government of India took a view for integration of power system on regional basis, divided India into 5 regions. Regional Electricity Board and Regional Load Dispatch Centre were constituted for operation of inter-connected power system for each region separately. This was a land mark decision for promotion of power trading and construction of many more inter-state lines was taken up.

Look into the advantage of exchange of power amongst various states within a region, further steps was taken for inter-connection of different regions through inter-regional lines and Government of India started construction of many lines across different regions. This step gave further opportunities for trading of power amongst various states, majority of bilateral basis a some on purchase/sale basis. In due course of time, industrial growth in Eastern Region (the state of Bihar, West Bengal and Orissa) could not take place as visualized. With the result, that generating capacity installed in the regional was in excess of the requirement.

Using interregional lines, Eastern Region constituents could trade the surplus power to states like Andhra Pradesh, Assam etc. in a big way. Looking the benefits of the above kind of power of trading, Government of India constituted Power Trading Corporation of India Limited in the year 1999 to promote trading of power. Even though The Electricity Act (supply) did not recognize power trading as an activity, the Bill for consolidation of Electricity Law was under consideration of the Government of India and had a provision of trading to be a part of power sector activities. Even before the Bill was passed by the Parliament to converted into the Act (The Electricity Act, 2003), power trading started in the structured form in the year 2001 through Power Trading Corporation; have been trading the power in form, purchase of power and sale of power separately. The Electricity Act, 2003, recognized trading to be distinct activity and appropriate commissions format and related for trading of power.

Power trading inherently means a transaction where the price of power is negotiable and options exist about whom to trade with and for what quantum. In India, power trading is in an evolving stage and the volumes of exchange are not huge. All ultimate consumers of electricity are largely served by their respective State Electricity Boards or their successor entities, Power Departments, private licensee's etc. and their relationship is primarily that of captive customers versus monopoly suppliers. In India, the generators of electricity like Central Generating Stations (CGSs), Independent Power Producers (IPP's) and State Electricity Boards (SEB's) have most of their capacities tied up. Each SEB has an allocated share in central sector/ jointly owned projects and is expected to draw its share without much say about the price.

In other words, the suppliers of electricity have little choice about whom to sell the power and the buyers have no choice about whom to purchase power from.

The pricing has primarily been fixed/controlled by the Central and State Governments. However, this is now being done by the Regulatory Commissions at the Centre and also in the States wherever they are already functional. Power generation/transmission is highly capital intensive and the Fixed Charge component makes up a major part of tariff. India being a predominantly agrarian economy, power demand is seasonal, weather sensitive and there exists substantial difference in demand of power during different hours of the day with variations during peak hours and off peak hours. Further, the geographical spread of India is very large and different parts of the country face different types of climate and different types of loads.

Power demand during the rainy seasons is low in the States of Karnataka and Andhra Pradesh and high in Delhi and Punjab. Whereas many of the States face high demand during evening peak hours, cities like Mumbai face high demand during office hours. The Eastern Region has a significant surplus round the clock, and even normally power deficit states with very low agricultural loads like Delhi have surpluses at night. This situation indicates enough opportunities for trading of power. This would improve utilization of existing capacities and reduce the average cost of power to power utilities and consumers.

In view of high fixed charges, average tariff becomes sensitive to PLF. Trading of power from surplus State Utilities to deficit ones, through marginal investment in removing grid constraints, could help in deferring or reducing investment for additional generation capacity, in increasing PLF and reducing average cost of energy. Over and above this, the Scheduled exchange of power will increase and un-scheduled exchange will reduce bringing in grid discipline, a familiar problem.

3.2.2. Electricity Market Model:

Electricity Market Models Based on different structural characteristics are:

Model 1: Monopoly
Model 2: Single buyer
Model 3: Wholesale competition
Model 4: Retail Competition

Characteristic	Model 1	Model 2	Model 3	Model 4
Definition	Monopoly at all level	Competition in generation & single buyer.	Competition in generation and choice for discom.	Competition in generation and choice for final consumer.
Competing Generators	No	Yes	Yes	Yes
Choice for Retailers	No	No	Yes	Yes
Choice for Final Consumer	No	No	No	Yes

Table 5: Characteristic of electricity market.

3.2.2. (A). Model 1: Vertically Integrated Utility:

This is a monopoly market mechanism. In this mechanism there is no difference between generators and power supplier in the retail market. So, the consumers have no option to buy power except the monopoly supplier.

3.2.2. (B). Model 2: Single Buyer:

There is single buyer in market in this mechanism. So, there is no choice for consumer to buy power except the already available supplier in the market.

3.2.2. (C). Model 3: Wholesale Competition:

This is 02 (two) types:

a. Open access, without traders: In this mechanism open access is allow. DISCOMs can take power from their choiceable GENCOs for retail sale.
b. Traders as market makers: In this mechanism traders and open access is available. Consumer can take power from traders with the help of open access.

3.2.2. (D). Model 4: Retail Competition.

There are 4 (four) types market:

a. Choice for large consumer: In this mechanism there is single trader and open access available. The large consumer can take power from traders or from GENCOMs directly with the help of open access.
b. Choice for Small Consumer: In this mechanism there are many traders in market and small consumer can take power from any one as per their choice.
c. Unorganized market: In this mechanism wholesale market, many traders and open access is available. Consumers can take power from wholesale market through traders or from GENCOMs with the help of open access.
d. Organized market through power exchange: In this market power exchange is available in wholesale market to regulate the market. In this mechanism consumers can take power from wholesale market through their choiceable traders vide power exchange or from GENCOMs directly with the help of open access.

3.2.3. Existing Market Structure: Major portion of India is having market structure of Model 2, i.e. the electricity industry is unbundled, single buyer and competition in generation.

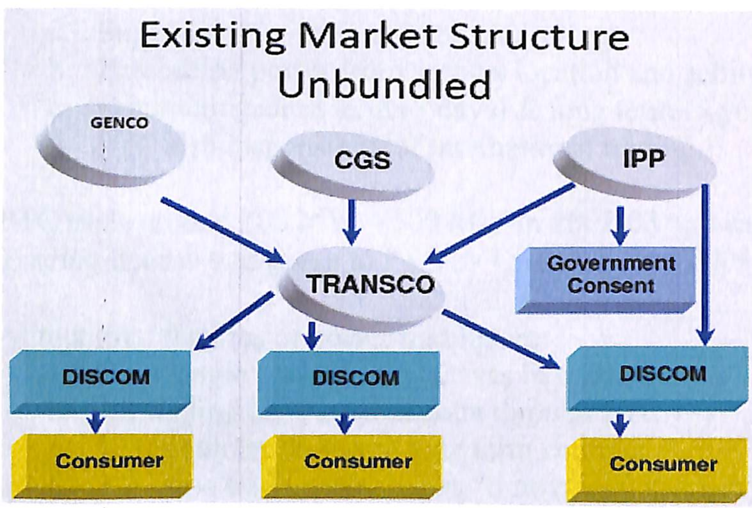

Fig. 4: Existing Market Structure.

3.2.4. Emerging Market Structure: With the EA'03 the market is unbundled and traders are introduced in system for facilitating competition in generation and to provide choice for final consumer.

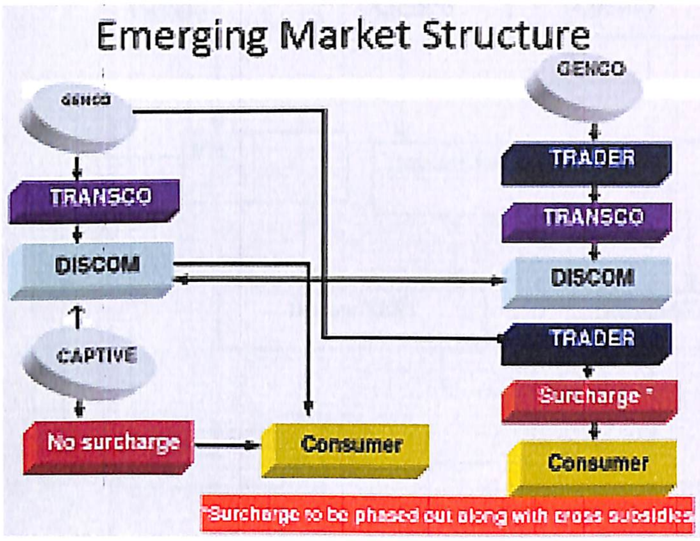

Fig. 5: Emerging Market Structure.

3.2.5. Trading Scenario before EA'03:

Before EA'03 Power Trading Corporation was set-up in 1999 for regulating power trade in India. The function of PTC was:

a. Supervision of inter-state mega projects.
b. Purchasing power from surplus location and selling it to deficit location.
c. Contracting short term (3 days) & long term (5 years) contracts to trade.
d. PTC also responsible for international trading.

PTC trade around 300 MW – 500 MW in 2002-03 and earned a trade margin of 5 paisa per kWh. Trading license was given to PTC by CERC in June 2004.

At that time features of power trading are:

a. Only single player i.e. PTC was in market.
b. All trading contract was done through PTC.
c. PTC contract short and long term contract.
d. PTC also trade power under "time of day concept"
e. Trading was done between Central Sector generation and SEBs.
f. PTC also helps to sell surplus power of IPPs by trading.
g. International trading contract also done like Nepal & Bhutan.
h. Sporadic interchange of power between states was accounted for in regional energy accounting and based on pool basis.
i. Coordination with agencies for load dispatch, metering, billing, revenue realization and energy accounting was under PTC.
j. The trading relationship was as follows:

The relationship in the market as follows:

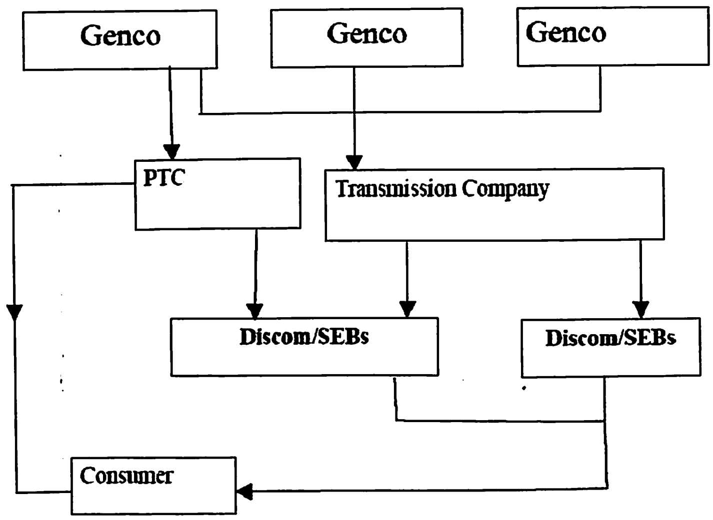

Fig. 6: Trading Scenario before EA'03.

3.2.6. Trading scenario after EA'03:

Indian Electricity Act 2003 define Power trading as "Purchase of electricity for resale there of". It created a liberal & transparent framework for power development, facilitated investment by creating competitive environment and reforming distribution segment. It removed/reduced entry barriers, by de-licensing generation, freedom to captive generation including group captive. It recognized trading as an independent license activity and open access in transmission (already in place). The main features of EA'03 are:

After EA'03 the main players in the market are:

a. Generators.
b. Transoms.
c. Discoms.
d. System Operators.
e. Traders.

In the new mechanism traders may purchase electricity from generating company or from another trade and will sell to its customers, through the network of transmitters or distributors, which may be a distribution company, another trader, consumer (bulk or captive).

The relationship in the market as follows:

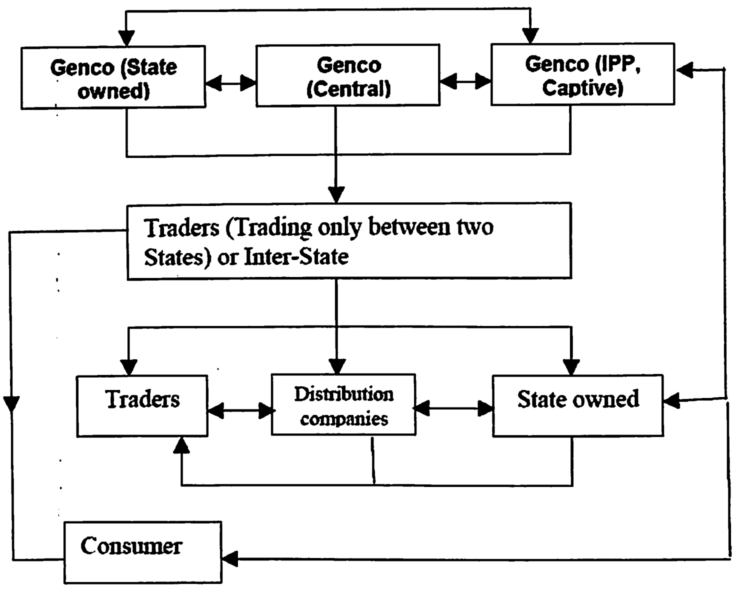

Fig. 7: Trading Scenario after EA'03.

Generating company can purchase electricity from another generating company to meet their contractual obligation which may arise from any undesired situation. It would be necessary to inform at the outset here that regulator will fix the generation tariff only for distribution companies not for traders. This will create competition between traders to purchase maximum quantum of electricity from a generator who is supplying at the lesser price. This will also create the competition between generators to capture the maximum market for this electricity. There is also a possibility that a hierarchal system depending on the area of service may come up in the future as this is a case in stock market. A trader (inter-State) can sell power directly to any consumer of a State.

3.2.7. Regulatory frame work in EA'03:

Different section and provision of trading in EA'03 are tabulated below:

Section	PROVISION
2(26)	"electricity trader" means a person who has been granted a license to undertake trading in electricity under section 12;
2(71)	"trading" means purchase of electricity for resale thereof and the expression "trade" shall be construed accordingly;

12	No person shall – a. transmit electricity; or b. distribute electricity; or c. undertake trading in electricity, unless he is authorized to do so by a license issued under section 14, or is exempt under section 13:
12	Trading as a distinct activity permitted with licensing.
14	Provided also that a distribution licensee shall not require a license to undertake trading in electricity.
15 (5) B	Private transmission companies to be licensed by the appropriate Commission after giving due consideration to views of the Transmission Utility.
26,27,31	Provided Regional & State Load Dispatch Centre shall not engage in the business in trading of electricity.
38(1)	Provided Central Transmission Utility shall not engage in the business in trading of electricity.
39(1)	Provided State Transmission Utility shall not engage in the business in trading of electricity.
41	Provided also that no transmission licensee shall enter into any contract or otherwise engage in the business of trading in electricity.
42	1. Open access in distribution to be allowed by SERC in phases and to provide open access to all consumers having requirement of 1MW or more within 5 year 2. In addition to wheeling charges provision for surcharge if open access is allowed before elimination of cross subsidies, to take care of Current level of cross subsidy & Licensee's obligation to supply. 3. Surcharge & cross subsidy to be progressively eliminated. 4. In case of captive generating plant carrying the electricity to the destination of his own use, no surcharge shall be leviable.
66	Regulatory Commission to promote development of market including trading.

79(1)(j)	The Central Commission shall discharge the following functions, namely: to fix the trading margin in the inter-State trading of electricity, if considered, necessary
86(1)(j)	The State Commission shall discharge the following functions, namely: fix the trading margin in the intra-state trading of electricity, if considered, necessary;

3.2.8. Trading Arrangement in EA'03:

3.2.8. (A). Types of Trading and Regulation by Regulator:

The EA'03 distinguishes trading broadly into 2 (two) category according to geographical spread of the activity undertaken as follows:

a. Inter state trading.
b. Intra state trading.

Accordingly those licensees are classified. CREC is responsible for forming rules & regulation of interstate trading and SERCs is responsible for intra state trading regulation with the guide line of CERC.

3.2.8. (B). Action of CERC for Interstate trading regulation:

Guidelines were prepared by CREC on January'2004. Some features are:

a. Trading application should be in public notice & posted on web site to invite comments
b. License tenure will be 25 years.
c. Technical & financial requirements were defined by CERC.
d. Traders cannot take over a utility or undertake transmission system.
e. Quarterly reports to be furnished by traders to CERC and posted on web site.

3.2.8. (C). Action taken by WBERC for Intra state trading:

As per EA'03 West Bengal Electricity Regulatory Commission (Licensing and Conditions of Licence) Regulations, 2004 issued under notification No. 17/WBERC dated 9th June 2004 for regulation of Trading and it is repealed and replaced by 58/WBERC dated 03.09.2013. Some features of guideline in this regulation are:

a. It state procedure for granting license.
b. Technical requirements.
c. Capital adequacy Requirement and Creditworthiness.
d. Obligations of the Trading Licensee.
e. Conditions for Trading Margin.
f. Submission of Information format.
g. Revocation of Trading License.

3.2.9. Mechanism of Trading:
Mechanism of trading is discussed in the form of market structure and procedure in trading.

3.2.9. (A). Market Structure:
Market can be divided into 4 (four) categories according to time frame as per follows:
i. Years / Month Ahead.
ii. Weeks Ahead.
iii. Day Ahead.
iv. Intra-Day

3.2.9 (B). The properties of the markets are discussed below:

	Years/Month Ahead	Weeks Ahead	Day Ahead	Intra-Day
Commercial Name:	Forward Market	Short-Term Forward Market	Spot Market	Real time balancing Market
Properties:	a. Physical Market. b. Financial Market. c. Long Term Hedging. d. Speculation	a. Physical Market. b. Financial Market. c. Weather driven.	a. Physical Market. b. Balancing Market. c. Scheduling/ dispatch. d. Ancillary Service.	

3.2.9. (C). Essential Requirements:

Essential requirements for power trading are:
i. Seller ready to sell at a particular time at a particular rate.
ii. Buyer ready to buy at the same particular time and at the given rate, transmission & other charges (including trading charges).
iii. Trader is necessity for trading to take place between the two parties.
iv. Transmission/distribution corridor capacity for power flow must be available.
v. Wholly Automated Trading system.
vi. Members to require permission of the Exchange to start trading.
vii. Unique identity number to Members.
viii. Unique identity number to Clients.
ix. Member can connect to the Exchange from anywhere in India through MPLS Connectivity.

3.2.9. (D). Procedure in Trading:
The tenders of various sellers & buyers are tracked by the business development & Operations team. The tender document then shall be sent to buyers & sellers. The related terms & conditions and price to be quoted shall be discussed with the interested sellers & buyers. Based on which the EMD/BG requirements are forwarded to the finance department. Once the term & conditions and other qualifying criterion are finalized, the bid shall be submitted via fax/courier/online/by hand depending upon the mode of submission prescribed in the tender document.

The EMD/BG can be refunded in case a trader does not qualify the Bid Evaluation. Although, the successful trader shall be issued with LoI/LoA for the following reasons:

I. Clients for their information & confirmation if required.
II. Operation team for Open Access corridor booking activities.
III. Commercial team for billing related activities.
IV. MIS team for capturing the commercial conditions in the MIS.

3.2.10. Concept of Electricity Trader:

Traders are an entity in the electricity system, who is powered by EA'03 for power trading. The category of traders, technical requirement, capital adequacy etc. as per regulation of CERC is discussed below:

3.2.10. (A). Category of Traders:

Previously the trader's licenses were categorized in six different categories from A to F; F being the category of a trader who is trading the highest volumes i.e. above 1000 million units. But the traders are now categorized in four categories i.e. I, II, III and IV. In below given table categories of various licenses are given as amended in timely manner:

<table>
<tr><th>Category of the License (As per Notification dated6.2.2004)</th><th>Category of the License (As per Notification dated24.2.2009)</th><th>Category of the License (As per Notification dated11.10.2012)</th></tr>
<tr><td>F (Above 1000 MU's)</td><td rowspan="3">I (No Limit)</td><td>I (No Limit)</td></tr>
<tr><td>E (between 700 and 1000 MU's)</td><td rowspan="2">II (Not more than 1500 MU's)</td></tr>
<tr><td>D (between 500 and 700 MU's)</td></tr>
<tr><td>C (between 200 and 500 MU's)</td><td rowspan="2">II (Not more than 500 MU's)</td><td rowspan="2">III (Not more than 500 MU's)</td></tr>
<tr><td>B (between 100 and 200 MU's)</td></tr>
<tr><td>A (Unto 100 MU's)</td><td>III (Up to 100 MU's)</td><td>IV (Not more than 100 MU's)</td></tr>
</table>

Table 6: Category of various trading licensee.

3.2.10. (B). Technical Requirements:

The technical requirements are:

A. The applicant shall have at least one full-time professional having, experience in each of the following disciplines, namely:
   i. Power system operations,
   ii. Finance, commerce and accounts.

B. The technical requirement of staff shall be complied with before undertaking trading activities, notwithstanding the fact that the Commission has granted the license for inter-state trading.

C. The applicant shall furnish to the Commission the details of the professional and the supporting staff engaged by him on full-time basis before undertaking inter-state trading.

3.2.10. (C). Capital Adequacy Requirement and Credit worthiness:
Considering the volume of inter-state and intra-state trading proposed to be undertaken by the applicant on the basis of the inter-state trading license, the minimum net worth of the electricity trader at the time of application shall not be less than the amounts specified hereunder:

Category of the Trading License	Volume of electricity proposed to be traded in a year including intra-state trading, where applicable	Minimum Net Worth (Rs. In Crore)
Category I	No Limit	50
Category II	Not more than 1500 MU's	15
Category III	Not more than 500 MU's	5
Category IV	Not more than 100 MU's	1

Table 7: Minimum net worth requirement.

The Annual Subscription Fee for a trader shall be payable as per CERC (Payment of Fees & Charges) Regulation, 2012. The fee shall be paid within thirty days of the date of grant of license and thereafter, annually by 30th April of each year. The application fee for trading license is Rs. 1, 00,000/- and shall be specified by government in timely manner. The Annual fee for various categories is given below:

Category of license	Fee per annum (Rs.in lakh)
Category-I (No Limit)	40
Category-II (Upto 1500 MU annually)	15
Category-III (Upto 500 MU annually)	6
Category-IV (Upto 100 MU annually)	3

Table 8: Annual fee for trading licensee

3.2.11. Current no of Licensed Interstate Trader:

Table 9: List of interstate trader as on 31.12.2014:

Sl. No.	Name of licensees	Category of licence
1.	Tata Power Trading Company Ltd.	I
2.	Adani Enterprises Ltd.	I
3.	PTC India Limited	I
4.	Reliance Energy Trading Ltd.	I
5.	Vinergy International Private Limited	I
6.	NTPC Vidyut Vyapar Nigam Ltd.	I
7.	National Energy Trading and Services Ltd.	I
8.	MMTC Limited	II
9.	DLF Power Limited	III
10.	Jindal Steel & Power Limited	III
11.	Sarda Energy & Minerals Ltd.	III
12.	GMR Energy Limited	I
13.	Karam Chand Thapar & Bros. (Coal Sales) Limited	I
14.	Subhash Kabini Power Corporation Ltd.	IV
15.	Special Blasts Ltd.	IV
16.	Maheshwary Ispat Limited	IV
17.	Instinct Infra & Power Ltd.	III
18.	Essar Electric Power Development Corporation Limited	II
19.	Suryachakra Power Corporation Ltd.	IV
20.	JSW Power Trading Company Limited	I
21.	BGR Energy Systems Limited	I
22.	Malaxmi Energy Trading Private Limited	III
23.	Visa Power Limited	IV
24.	Pune Power Development Private Limited	IV
25.	Patni Projects Pvt. Limited	III
26.	Ispat Energy Limited	IV
27.	Greenko Energies Private Limited	II
28.	Vandana Global Limited	III
29.	Vandana Vidhyut Limited	IV
30.	Indrajit Power Technology Pvt. Ltd.	III
31.	Adhunik Alloys & Power Ltd.	IV
32.	Indiabulls Power Trading Limited	IV
33.	Indiabulls Power generation Limited	III
34.	Ambitious Power Trading Company Limited	IV
35.	RPG Power Trading. Co. Ltd.	II
36.	Basis Point Commodities Pvt. Ltd.	III
37.	GMR Energy Trading Limited	I
38.	Jain Energy Ltd.	III
39	Righill Electrics Limited	IV
40.	Shyam Indus Power Solutions Pvt. Ltd.	IV
41.	Global Energy Private Limited	I

42.	Knowledge Infrastructure Systems Pvt. Ltd.	I
43.	Mittal Processors Private Limited	II
44.	Godawari Power and Ispat Limited	IV
45.	Shree Cement Limited	I
46.	PCM Power Trading Corporation Ltd., Kolkata	III
47.	Abellon Clean Energy Limited, Ahmadabad	IV
48.	Jay Polychem (India) Limited, New Delhi	III
49.	Jaiprakash Associates Limited, Noida.	I
50.	My Home Power Private Limited, Hyderabad	III
51.	Customized Energy Solution India Private Limited, Pune	IV
52.	BS TransComm Ltd., Hyderabad	III
53.	Chromatic India Limited, Mumbai	III
54.	Kandla Energy and Chemical Limited, Ahmadabad	III
55.	Marquis Energy Exchange Limited	III
56.	DLF Energy Private Limited, Gurgaon	III
57.	GEMAC Engineering Services Private Limited, Chennai	IV
58.	SN Power Markets Pvt. Ltd., Noida	I
59.	Manikaran Power Limited, Kolkata	II
60.	Greta Power Trading Limited	IV
61	Arunachal Pradesh Power Corporation Pvt. Ltd., Itanagar	III
62.	Green Fields Power Services Private Limited, Visakhapatnam	IV
63.	HMM INFRA LIMITED, Chandigarh	IV
64.	Newfields Advertising Private Limited, New Delhi	IV
65.	Vedprakash Power Private Limited, Mumbai	IV
66	Pan India Network Infravest Limited, Mumbai	I
67	Solar Energy Corporation of India, New Delhi	III
68	Parshavnath Power Projects Private Ltd	IV
69	Rajasthan Renewable Energy Corporation Limited, Jaipur	III
70.	Jai International Private Limited, Mumbai	III
71.	IL & FS Energy Development Company Limited	I

3.2.12. Existing Power Supply and Trading Scenario:

Bulk electric power supply in India is mainly tied in long-term contracts. The bulk suppliers are mostly the central or state owned generating stations, as also a few Independent Power Producers (IPPs). Previously the bulk buyers were generally the State Electricity Board (SEBs), which are in the process of being unbundled. The power allocations from various generating stations are being assigned to Distribution companies as part of the unbundling process mandated by the Electricity Act, 2003. The Appropriate Commission regulates the price of bulk supply of a generating station to distribution utilities on the basis of its Terms and Conditions of Tariff or as per the Power Purchase Agreement (PPA). Thus, most of the existing bulk supply is locked up in long terms contracts having station wise tariff, usually in two-part viz. capacity charge and energy charge.

The SEBs / Distribution companies who have the obligation to provide electricity to their consumers mainly rely on supplies from these long-term contracts. However, it is neither feasible nor economical to meet short term, seasonal or peaking demand through long-term contracts. Be it a deficit scenario or otherwise, power trading is essential for meeting the short terms demand at an optimum cost. Similarly, power trading is essential for distribution utilities for selling short-term surpluses in order to optimize the cost of procurement. A few captive generating plants participate in trading in order to optimize their operating cost and in the process, supply electricity to the grid. The Open Access Regulations and Inter-State Trading Regulations of the Central Commission have facilitated power trading in an organized manner.

Today, it is possible to trade electricity between any two points in India through inter-State Open Access on advance reservation basis, on contingency, day ahead and first come first serve. Transmission charges for trading are applied on Rs./MW/Day basis. Open Access charges are transaction specific depending on the regions/transmission systems involved between point of injection and point of drawl. At present, power is mostly being traded between power surplus distribution utilities in Eastern Region (ER) and Northeastern Region (NER) on one-hand and deficit utilities in Northern Region (NR) and Western Region (WR) on the other.

Table 10: Electricity Traded in short term market as on July'2015.

Sr. No	Short-term transactions	Volume (MUs)	% of short-term transactions	% of Total Generation
1	Bilateral	6599.73	60.21	7.10
	(i) Through Traders and PXs	*4255.70*	38.83	4.58
	(ii) Direct	*2344.03*	21.39	2.52
2	Through Power Exchanges	2535.31	23.13	2.73
	(i) IEX	*2521.06*	23.00	2.71
	(ii) PXIL	*14.25*	0.13	0.02
3	Through DSM	1825.34	16.65	1.96
	Total	**10960.37**	**100.00**	**11.80**
	Total Generation	**92917.85**	–	–
Source: NLDC				

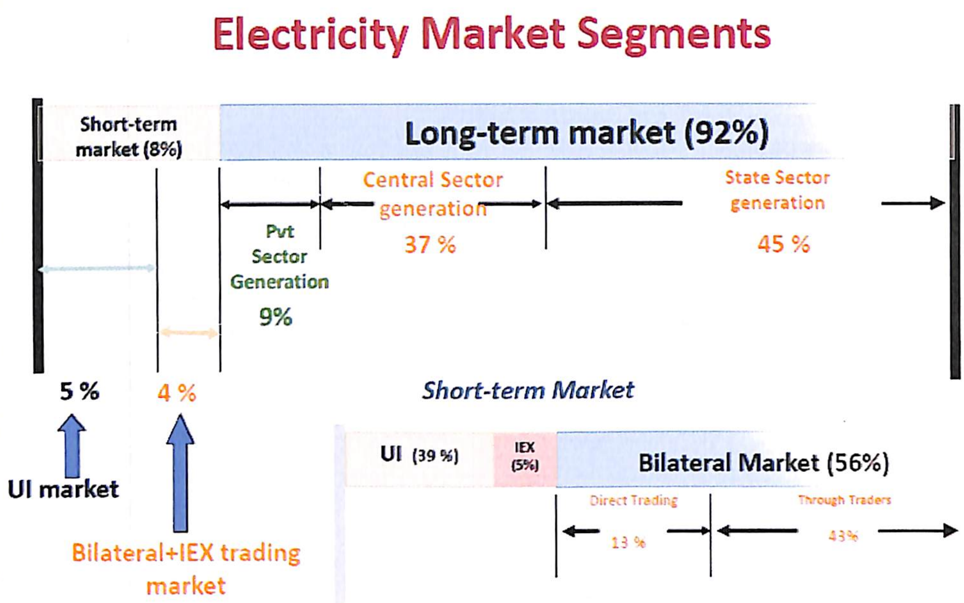

Fig. 8: Electricity market segment.

3.2.13. Trend in Short Term Market:

Total volume of short-term transactions of electricity increased from 65.90BU in 2009-10 to 98.99BU in 2014-15. The annual growth in volume was 24% from 2009-10 to 2010-11, 16% from 2010-11 to 2011-12, 5% from 2011-12 to 2012-13, 6% from 2012-13 to 2013-14 and -5% from 2013-14 to 2014-15. Total volume of short-term transactions of electricity as percentage of total electricity generation was varied between 9% and 11% during the period from 2009-10 to 2014-15 as shown in table:

Year	Total Volume of Short-term Transactions of Electricity (BU)	Total Electricity Generation (BU)	Total volume of Short-term Transactions of Electricity as % of Total Electricity Generation
2009-10	65.90	764.03	9%
2010-11	81.56	809.45	10%
2011-12	94.51	874.17	11%
2012-13	98.94	907.49	11%
2013-14	104.64	962.90	11%
2014-15	98.99	1045.09	9%

Source: NLDC

Table 11: Trend in short term market.

Share of traders and power exchange in short term market as follows:

Year	Electricity Transacted through traders (BUs)	Electricity Transacted through IEX (BUs)		Electricity Transacted through PXIL (BUs)		Electricity Transacted through IEX and PXIL (BUs)	Total (BUs)
		Day Ahead Market	Term Ahead Market	Day Ahead Market	Term Ahead Market		
2008-09	21.92	2.62		0.15		2.77	24.69
2009-10	26.72	6.17	0.095	0.92	0.003	7.19	33.91
2010-11	27.70	11.80	0.91	1.74	1.07	15.52	43.22
2011-12	35.84	13.79	0.62	1.03	0.11	15.54	51.38
2012-13	36.12	22.35	0.48	0.68	0.04	23.54	59.66
2013-14	35.11	28.92	0.34	1.11	0.30	30.67	65.78
2014-15	34.56	28.12	0.22	0.34	0.72	29.40	63.96

Table 12: Share of traders and power exchange in short term market as follows:

Also, the role of power exchanges has been dominating since the inception of Central Electricity Regulatory Commission (Power Market) Regulations, 2010. However, the total transactions through these exchanges is less, but it is expected that in coming years their role will be more radical. The development of power market will accommodate competition in the power sector and make it more attractive for both buyers and sellers interested to transact through exchange. Recently government's decision of FDI 49% in the power trading has increased the scope of retail market. So, it is expected that in near future the proportion of these power exchanges will intensify.

3.3. Open Access:

Open Access on Transmission and Distribution on payment of charges to the Utility will enable number of players utilizing these capacities and transmit power from generation to the load centre. This will mean utilization of existing infrastructure and easing of power shortage. Trading; now a licensed activity and regulated will also help in innovative pricing which will lead to competition resulting in lowering of tariffs.

3.3.1. Definition:

As per EA'03 the non-discriminatory provision for the use of transmission lines or distribution system or a associated facilities with such lines or system by any licensee or consumer or a person engaged in generation in accordance with the regulations specified by the "Appropriate Commission"

In simple word open access may be defined as enabling of non-discriminatory sale/purchase of electric power/energy between two parties utilizing the system of an in-between (third party), and not blocking it on unreasonable grounds. It was envisaged in the National Electricity Policy 2005 that open access in transmission will promote competition and in lead to availability of cheaper reliable power supply.

3.3.2. The Advantages of Open Access are:

a) Freedom to buy/sell, and access to market.
b) Adequacy of intervening transmission.
c) Transmission/wheeling charges reduction.
d) Treatment of transmission losses.
e) Energy accounting, scheduling, metering and UI Settlement.

3.3.3. The Need of Open Access in Power Trading:

Power trading in physical market done either bilateral /OTC or power exchange through power trader in intra state or inter-state. Either cases open access is required for fulfillment of committed power dispatch on point to point. The below mentioned table shoes amount of power that could not be scheduled due to congestion as follows:

DETAILS OF CONGESTION IN POWER EXCHANGES, JULY 2015			
Details of Congestion	**IEX**		**PXIL**
A	Unconstrained Cleared Volume* (MUs)	2836.08	15.25
B	Actual Cleared Volume and hence scheduled (MUs)	2521.06	14.25
C	Volume of electricity that could not be cleared and hence not scheduled because of congestion (MUs) (A-B)	315.02	1.00
D	Volume of electricity that could not be cleared as % to Unconstrained Cleared Volume	11.11%	6.55%

E	Percentage of the time congestion occurred during the month (Number of hours congestion occurred/Total number of hours in the month)	94.72%	90.32%
F Congestion occurrence (%) time block wise			
0.00 - 6.00 hours	22.60%		23.81%
6.00 - 12.00 hours	25.79%		25.15%
12.00 - 18.00 hours	26.11%		24.85%
18.00 - 24.00 hours	25.51%		26.19%
** This power would have been scheduled had there been no congestion.*			
Source: IEX & PXIL& NLDC			

Table 13: Congestion in power exchange.

In the month of July 2015, congestion occurred in both the power exchanges. The details of congestion are shown in the above table. The volume of electricity that could not be cleared due to congestion and could not be transacted through power exchanges is the difference between unconstrained cleared volume (volume of electricity that would have been scheduled, had there been no congestion) and actual cleared volume. During the month, the volume of electricity that could not be cleared in IEX and PXIL due to congestion was 11.11% and 6.55% of the unconstrained cleared volume respectively. In terms of time, congestion occurred was 94.72% in IEX and 90.32% in PXIL. So open access is required for normal flow of contracted power.

3.3.4. Classification of Open Access:

Under CERC (Open Access in inter-state Transmission) Regulation, 2008; it is categorize under as:

a) Bilateral Transactions

b) Collective Transactions

3.3.5. Regulatory Frame Work:

Open Access in Indian power sector are governed mainly by following Acts, Policies & Regulations

1. Indian Electricity Act 2003, with amendments.

2. National Electricity Policy 2005.

3. Central Electricity Regulatory Commission (Open Access in Inter-state Transmission) (With amendments) Regulations, 2008.

4. Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-State Transmission and related matters) (with amendments) Regulations, 2009.

5. Central Electricity Regulatory Commission (Sharing of Inter State Transmission Charges and Losses Regulations), 2010.

3.3.5. (A). The Electricity Act, 2003 with amendments:

Main features of Indian Electricity Act 2003 regarding Open Access:

Section 2(Definitions), Sub-section (47):
Open access means the non-discriminatory provision for the use of transmission lines or distribution system or associated facilities with such lines or system by any licensee or consumer or a person engaged in generation in accordance with the regulations specified by the Appropriate Commission.

Section 9 (Captive Generation), Sub-section (2):
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.

Section 38 (Central Transmission Utility and functions), sub-section (2):
(d) 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.

Section 39 (State Transmission Utility and functions), sub-section (2):
One of the functions of State Transmission Utility is 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.

Section 42 (Duties of distribution licensee and open access), sub-section (42):
The State Commission shall introduce open access in such phases and subject to such conditions, (including the cross subsidies, and other operational constraints) as may be specified within one year of the appointed date by it and in specifying the extent of open access in successive phases and in determining the charges for wheeling, it shall have due regard to all relevant factors including such cross subsidies, and other operational constraints:
Provided that such open access shall be allowed on payment of a surcharge in addition to the charges for wheeling as may be determined by the State Commission:
Provided further that such surcharge shall be utilised to meet the requirements of current level of cross subsidy within the area of supply of the distribution licensee:

Provided also that such surcharge and cross subsidies shall be progressively reduced in the manner as may 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:
Provided also that the State Commission shall, not later than five years from the date of commencement of the Electricity (Amendment) Act, 2003, by regulations, provide such open access to all consumers who require a supply of electricity where the maximum power to be made available at any time exceeds one megawatt.

Section 49. (Agreement with respect to supply or purchase of electricity):
Where the Appropriate Commission has allowed open access to certain consumers under section 42, such consumers, notwithstanding the provisions contained in clause (d) of sub-section (1) of section 62, may enter into an agreement with any person for supply or purchase of electricity on such terms and conditions (including tariff) as may be agreed upon by them.

Section 86. (Functions of State Commission) (1) The State Commission shall discharge the following functions, namely: -
(a) determine the tariff for generation, supply, transmission and wheeling of electricity, wholesale, bulk or retail, as the case may be, within the State: Provided 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;

3.3.5. (B). The National Electricity Policy, 2005:

As per Section 3 of Electricity Act, 2003, the central government has notified The National Electricity Policy, 2005.
The relevant section for Open Access is elaborated below:

Section 5.3.3 Open access in transmission has been introduced to promote competition amongst the generating companies who can now sell to different distribution licensees across the country. This should lead to availability of cheaper power. The Act mandates non-discriminatory open access in transmission from the very beginning. When open access to distribution networks is introduced by the respective State Commissions for enabling bulk consumers to buy directly from competing generators, competition in the market would increase the availability of cheaper and reliable power supply. The Regulatory Commissions need to provide facilitative framework for non-discriminatory open access. This requires load dispatch facilities with state-of-the art communication and data acquisition capability on a real time basis. While this is the case currently at the regional load dispatch centers, appropriate State Commissions must ensure that matching facilities with technology upgrades are provided at the State level, where necessary and realized not later than June 2006.
Section 5.3.6 The necessary regulatory framework for providing non-discriminatory open access in transmission as mandated in the Electricity Act 2003 is essential for signalling efficient choice in locating generation capacity and for encouraging trading in electricity for optimum utilization of generation resources and consequently for reducing the cost of supply.

Section 5.4.2 The Act provides for a robust regulatory framework for distribution licensees to safeguard consumer interests. It also creates a competitive framework for the distribution business, offering options to consumers, through the concepts of open access and multiple licensees in the same area of supply.

3.3.5. (C). Central Electricity Regulatory Commission (Open Access in Inter-state Transmission) (With amendments) Regulations, 2008:

According to Regulation 2(Definitions),

Bilateral transaction means a transaction for exchange of energy (MWh) between a specified buyer and a specified seller, directly or through a trading licensee or discovered

exchange through anonymous bidding, from a specified point of injection to a specified point of drawl for a fixed or varying quantum of power (MW) for any time period during a month.

Collective transaction means a set of transactions discovered in power exchange through anonymous, simultaneous competitive bidding by buyers and sellers.

Short-term open access means open access for a period up to one (1) month at one time.

Short-term customer means a person who has availed or intends to avail short term open access.

According to this regulation nodal Agency for

□ Collective transaction-National Load Despatch Centre

□ Bilateral transaction-Regional Load despatch centre

This regulation states Nodal agency has to prepare "detailed procedure", which involves whole process from filing of application, scheduling, settlement and curtailment. Procedure is briefly explained in later part of report.

3.3.5. (D). Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-State Transmission and related matters Regulations, 2009:

Following are the main features of this regulation-

These regulations apply to the grant of connectivity, long-term access and medium-term open access, in respect of inter-State transmission system:

Provided that a generating station, including captive generating plant or a bulk consumer, seeking connectivity to the inter-State transmission system cannot apply for long-term access or medium-term open access without applying for connectivity:

Provided further that a person may apply for connectivity and long-term access or medium-term open access simultaneously.

Applicant for this regulation:

(i) The following in respect grant of connectivity:

(a) A generating station with installed capacity of 250 MW and above, including a captive generating plant of exportable capacity of 250 MW and above or;

(b) A Hydro Generating station or generating station using renewable source of energy, of installed capacity between 50 MW and 250 MW.

(c) One of the Hydro Generating stations or generating stations using renewable sources of energy, individually having less than 50 MW installed capacity, but collectively having an

aggregate installed capacity of 50 MW and above, and acting on behalf of all these generating stations, and seeking connection from CTU at a single connection point at the pooling sub-station under CTU, termed as the lead generator, or;
(d) A bulk consumer.
(ii) a generating station including a captive generating plant, a consumer, an Electricity Trader or a distribution licensee, in respect of long-term access or medium-term open access , as the case may be;
Long-term access means the right to use the inter-State transmission system for a period exceeding 12 years but not exceeding 25 years;
Long-term customer means a person who has been granted long-term access and includes a person who has been allocated central sector generation that is electricity supply from a generating station owned or controlled by the Central Government;
Medium-term open access means the right to use the inter-State transmission system for a period exceeding 3 months but not exceeding 3 years;
Medium-term customer means a person who has been granted medium-term open access
Nodal Agency
The nodal agency for grant of connectivity, long-term access and medium term open access to the inter-State transmission system shall be the Central Transmission Utility.

3.3.5. (E). Sharing of Inter State Transmission Charges and Losses Regulations, 2010:

3.3.5. (E). I. Principles for sharing ISTS charges and losses:
(1) Based on the Yearly Transmission Charges of ISTS Transmission Licensees and transmission losses in the ISTS network, the Implementing Agency shall compute the Point of Connection charges and Loss Allocation Factors for all DICs:-
(a) Using load-flow based methods; and
(b) Based on the Point of Connection Charging method.
(2) A detailed explanation of the Hybrid methodology to be applied for sharing the ISTS charges and losses amongst the Designated ISTS Customers is set out in Annexure – I to these regulations, which may be reviewed by the Commission from time to time either upon an application by any interested party or otherwise .

3.3.3. (E). II. Mechanism to share ISTS transmission charges:
(1) The sharing of ISTS transmission charges between Designated ISTS Customers shall be computed for an Application Period and shall be determined in advance and shall be subject to periodic true-up as specified subsequently in these regulations;
(2) The sharing of ISTS transmission charges shall be based on the technical and commercial information provided by various Designated ISTS Customers, ISTS Transmission Licensees, and any other relevant entity, including the NLDC, RLDCs and SLDCs to the Implementing Agency. Provided that in the event of such information not being available within the stipulated timeframe or to the level of detail required, the Commission may authorize the Implementing Agency to obtain such information from alternative sources as per the procedure as may be approved by the Commission in this behalf.
(3) The mechanism for sharing of ISTS charges shall ensure that:-

(a) The Yearly Transmission Charge of the ISTS Licensees are fully and exactly recovered; and
(b) Any adjustment towards Yearly Transmission Charge on account of change in commissioning schedule of elements of the power system and change in factors constituting the transmission charge, approved by the Commission, e.g., FERV, Changes in interest rates shall be fully and exactly recovered etc., as specified subsequently in these regulations.
(4) The Point of Connection transmission charges shall be computed in terms of Rupees per MegaWatt per month. The amount to be recovered from any Designated ISTS Customer towards ISTS charges shall be computed on a monthly basis as per these regulations. The Point of Connection transmission charges for short term open access transactions shall be in terms of Rupees per MegaWatt per hour and shall be applicable for the duration of short term open access approved by the RLDC/NLDC.
(5) The Implementing Agency may, after seeking approval of the Commission, conduct studies from time to time to refine the mechanism for sharing of transmission charges and losses as detailed in Annexure – I to these Regulations.

3.3.5. (E).III. Mechanism of sharing of ISTS losses.
(1) The schedule of electricity of Designated ISTS Customers shall be adjusted to account for energy losses in the transmission system as estimated by the Regional Load Despatch Centre and the State Load Despatch Centre concerned. These shall be applied in accordance with the detailed procedure to be prepared by NLDC within 30 days of the notification of these regulations. The losses shall be apportioned based on the loss allocation factors determined using the Hybrid methodology.
(2) The sharing of ISTS losses shall be computed based on the information provided by various Designated ISTS Customers, ISTS Licensees, and any other relevant entity, including the NLDC, RLDCs and SLDCs and submitted to the Implementing Agency. Provided that in the event of such information not being available within the stipulated timeframe or to the level of detail required, the Commission may authorize the Implementing Agency to obtain such information from alternate sources as may be approved for use by the Commission.
(3) The applicable transmission losses for the ISTS shall be declared in advance and shall not be revised retrospectively.
(4) The Implementing Agency may, after seeking approval of the Commission, conduct studies from time to time to refine the ISTS loss allocation methods.

3.4. Landed Cost Calculation for Short Term Open Access:

3.4.1. Different types of open access charges:

There are major charges to be paid by open access consumers to distribution licensee, transmission licensees and other related entities, other than the power purchase cost paid to the generator or supplying entity. These charges include:

1. Wheeling Charges/Distribution Charges:

Distribution charges are those charges which are paid to distribution licensee for the use of distribution system and associated facilities by another person for the conveyance of electricity.
The licensees, generating stations, captive generating plants and consumers shall be eligible for open access to distribution system of a distribution licensee on payment of the wheeling charges as may be determined by the Commission

Applicability: These charges are applicable to generating stations, captive generating plants and consumers who are connected to Discoms network i.e., at 11 and 33 kV. (132kV in exceptional states)

2. Wheeling Loss or Distribution Loss:

Distribution losses are the technical losses for the distribution system. It is determined by the Commission for various voltage levels for the applicable year, based on prudence check of the submissions of the Distribution Licensee during their Tariff determination process and shall be apportioned in proportion to the actual energy drawl by the Open Access consumers and shall be payable in kind at relevant voltage level.

Applicability: This loss is applicable to generating stations, captive generating plants and consumers who are connected to Discoms network i.e., at 11 and 33 kV.

3. Transmission Charges or STU Charges:

Transmission charges are those charges which are paid to transmission licensee for the use of transmission system and associated facilities by another person for the conveyance of electricity.

Applicability: These charges are applicable to generating stations, captive generating plants and consumers who are connected to state transmission network i.e., at 66 or 132 kV and Discoms network i.e. at 11 and 33 kV.

4. Transmission Losses or STU Losses:

Transmission losses are those losses which are there in the transmission system. The buyers and sellers shall absorb apportioned energy losses in the transmission system in accordance with the provisions specified by the Central Commission.

Applicability: This loss is applicable to generating stations, captive generating plants and consumers who are connected to state transmission network i.e., at 66 or 132 kV and Discoms network i.e. at 11 and 33 kV.

5. PoC Charge & PoC Losses:

It is a transmission charge pricing methodology introduced for sharing of Inter State Transmission Systems (ISTS) charges and Losses among the Designated ISTS Customers (DICs) depending on their location and sensitive to their distances from load centers (generators) and generation (customers) and the direction of the node in the grid.

Applicability: This charges and losses are applicable to generating stations, captive generating plants and consumers who are connected to central transmission network or to state transmission network i.e. at 66 or 132 kV and Discoms network i.e. at 11 and 33 kV.

6. Cross Subsidy Surcharge:

If open access facility is availed of by a subsidizing consumer of a distribution licensee of the State, then such consumer, in addition to transmission and/or wheeling charges, shall pay cross subsidy surcharge determined by the Commission. Cross subsidy surcharge determined on Per Unit basis shall be payable, on monthly basis, by the open access customers based on the actual energy drawn during the month through open access. The amount of surcharge shall be paid to the distribution licensee of the area of supply from whom the consumer was availing supply before seeking open access.

Applicability: This charge is paid by open access consumers irrespective of voltage or connectivity level.

7. Application Fees:

A person seeking Open Access shall make an application in the prescribed format to the Distribution Licensee to which it is connected. The application fees in general for short term open access consumer is Rs 5000/application.

8. SLDC Charge:

A composite operating charge Rs.2000/- per day in general or part of the day shall be payable by a short-term open access customer for each transaction to the SLDC or as determined by the Commission from time to time. The operating charge includes fee for scheduling and system operation, energy accounting, fee for affecting revisions in schedule on bonafide grounds and collection and disbursement of charges.

Applicability: This charge is payable to both injecting and drawing SLDC.

9. RLDC Charge

A composite operating charge @ Rs.2,000/day/RLDC is payable by a short-term open access customer for each transaction to the RLDC or as determined by the Commission from time to time.

Applicability: This charge is payable to all the RLDC whose network is used.

10. Other Charges:

In addition to above mentioned charges there are some other charges which have a very small impact on the final landed cost of electricity through open access, these charges are:

- ✓ **NLDC Application Fees**: Rs 5000/ (No. of Successful bidders), applicable for power exchange transactions.
- ✓ **NLDC Scheduling and Operating Charges:** Rs 5,000.00 x (Regional Entity Buyers + Regional Entity Sellers) / (No. of Successful Portfolios), applicable for power exchange transactions.
- ✓ **Trading Margin:** trading margin exceeding seven (7.0) paisa/kWh in case the sale price is exceeding Rupees three (3.0)/kWh and four (4.0) paisa/kWh where the sale price is less than or equal to Rupees three (3.0)/kWh.

- ✓ **Exchange Charges:** Rs 20/MWh, applicable for power exchange transactions.
- ✓ **Service Tax:** 12.36% of Exchange Charges (Rs/MWh), applicable for power exchange transactions.

3.4.2. One Example for Landed Cost from Buyer/Beneficiary's Perspective (for Collective Transactions):

Illustration 1. Calculation of landed cost as per data in table 14.

To calculate the landed cost following assumptions are made:

A. Information as per Daily Obligation Report (DOR) of Exchange:

Details	Value	Unit
Bidding Quantum	5.20	MW
Total Cleared Power at exchange as Per DOR	74.07	MWh
Basic Amount as Per DOR	192267.53	Rs.
No. of hrs. of bid / day	14.24	Hrs.
No. of days of bid / month	1.00	Days
Market Clearing Price on the exchange	**2.60**	**Rs/kwh**

Table:14.

B. Calculation of scheduled & actual consumption (Losses)

Details	132 KV	Unit
Scheduled Drawl during the day (No. of Units)	74065.00	KWh
Losses at Regional Periphery (POC losses)	2%	%
Units Available after Losses at regional Periphery	72583.70	KWh
Losses at State Periphery (STU losses)	3.16%	%
Units Available after Losses at state Periphery	70290.06	KWh
Losses at Distribution Level (Wheeling Losses)	00	%
Actual Units Available to Consumer	702900.6	KWh

C. Calculation of total outlay by the consumer :

Details	Particulars	132 KV	Unit
Regional Transmission charges (CTU)	Rs 0.151/KWh	11183.82	Rs./day
State Transmission charges (STU)	Rs 0.29 /KWh	21478.85	Rs./day
NLDC Operating Charges	Approx. Rs 200-400/day	225.00	Rs./day
SLDC Operating Charges	Rs 2000 /day	2000.00	Rs./day
NLDC Application Fees	Approx. Rs 4-10 /day	4.33	Rs./day
Trading Margin of IEX	Rs 0.02 /KWh	1481.30	Rs./day

Service tax @ 12.36% of Transaction Charges		183.09	Rs./day
Total Amount payable as per Daily Obligation Report		**228823.91**	Rs./day
NOC from SLDC	Rs 10000/month	333.33	Rs./day
IEX Registration fees	Rs 100,000+ 12.36%/ year	307.84	Rs./day
Trading Margin of NETS	Rs 0.02 /KWh	1481.30	Rs./day
REC Purchase Obligation	Rs 0.07/KWh	5184.55	Rs./day
Wheeling Charges	Rs 0.0/KWh	**0.00**	Rs./ kwh
Cross subsidy Surcharge	Rs 0.81/KWh	59992.65	Rs./ kwh
Total Amount		296123.58	Rs./day
Net Landed Cost		**4.21**	**Rs/ Kwh**

D. Comparison of cost between available commercial power and open access power:

Available commercial Tariff for Industrial Consumers	4.61	Rs/ Kwh
Open Access power tariff	4.21	Rs/ Kwh
Per Unit Saving	0.40	Rs/ Kwh
Per Day Saving	70290.06	Rs.
Per Month Saving	2108701.652	Rs.
Per year Savings	25655870.1	Rs.

3.5. Calculation of Available Transmission Corridor (ATC) for Short Term Transaction:

3.5.1. Introduction:

Indian power system is continuously evolving and Open access is now playing crucial role in Indian Power sector by giving right to consumer, licensee and utilities to access the distribution and transmission system. Short term power market is increasing every year after implementation of Short term open access (STOA). As per the procedure RLDC approves application in case of STOA application. Customers file their application to RLDC, but they don't know whether their application will be approved or not or partially approved because of the availability of transmission corridor.

Also there is no such mechanism or way to know about the available margin for STOA on Inter-regional links before putting application. We are suggesting method which can be further developed as model to find out Available corridor for STOA. With help of this customer will know about the available inter-regional transmission corridor for STOA, so they can take advantage and analyze this information.

Interstate transmission system of India is divided in five regions NR, ER, WR, NER and SR, and the regions are synchronized. These Inter-regional links helps in transferring power from one region to other region or to transfer power from surplus region to deficit region. Transmission system is liable to their transfer capability, so that system will work in reliable manner.

3.5.2. Transfer Capability

Transfer Capability can be defined as the measure of the ability of interconnected electric systems to reliably move power from one control area to another over all transmission lines (or paths) between those areas under specified system conditions. It is directional in nature and is highly dependent upon the generation, customer demand and transmission system conditions assumed during the time period analyzed.

Control area means an electrical system bounded by interconnections (tie lines), metering and telemetry, where it controls its generation and/or load to maintain its interchange.

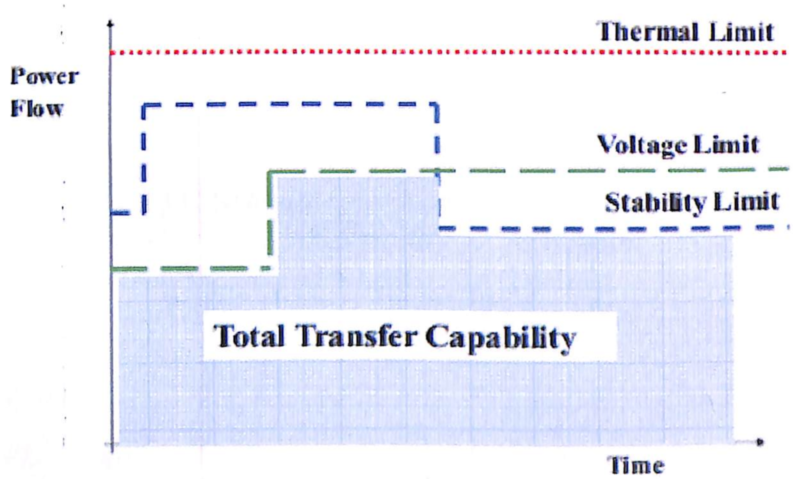

Fig. 9: Total transfer capability.

TTC is dependent upon the network topology, point and quantum of injection/ drawl and power flows in other paths of the interconnected network as well as prevailing voltage profile in the network during the assessment period.

TTC is directional in nature and the transfer capability for import of power in a region or control area from another region or control area may be different from the transfer capability for export of power from that region or control area to the other region or control area. Total Transfer Capability is time variant and there could be different figures for different time of the day/ month/ season/ year.
As per the procedure, NLDC shall assess the TTC, TRM and ATC of inter and intra-regional links/ Corridors respectively for three months in advance for each month up to the fourth month and put this on their website and revise due to change in system condition or inputs received from SLDC/RLDC. In this sheet NLDC provides information about:

(1) TTC
(2) TRM
(3) ATC
(4) Approved Long Term Access & Medium Term Open Access
(5) Margin available for STOA

Application for LTA and MTOA is already processed and scheduled 3 months before the final delivery, while in case of STOA, application can't be applied prior to 3months before actual delivery. Applications for STOA are processed by Nodal RLDC (in which drawl is taken place). Application comes under following categories:

i. Advanced
ii. First come first serve
iii. Collective (Power Exchange)
iv. Day ahead
v. Intra-day Contingency

Nodal RLDC has to put information regarding their acceptance to the application put by the customers on their website.

3.5.3. Following steps are required to determine "Available Inter-regional Corridor":

(1) Taking the latest revised "TTC-ATC" data from NLDC website.
(2) From that sheet we can get the "Margin available for STOA".

Revised ATC-TTC Schedule for August 2015 as per NLDC

Corridor	Total Transfer Capability (TTC)	Reliability Margin	Available Transfer Capability (ATC)	LTA/MTOA	Margin Available for STOA after LTA/MTOA
ER-NER	580	35	545	230	315
ER-NR	4000	300	3700	2189	1511
ER-SR	1100	0	1100	612	488
ER-WR	1000	300	700	700	0

NER-ER	400	100	300	0	300
NR-ER	1000	200	800	0	800
NR-WR	2500	500	2000	286	1714
SR-ER	800	0	800	197	603
SR-WR	1000	0	1000	0	0
WR-ER	1650	300	1350	0	1350
WR-NR	5700	500	5200	2787	2413
WR-SR	1000	0	1000	1000	0

Table 15: ATC-TTC schedule for Augst'15.

(3) Taking the "STOA approved application" from all the RLDC's website.

(4) Where 3 regions are involved breaking that in two separate Inter-regional flows like NR-WR-SR can be taken as NR-WR, WR-SR.

3.5.4. Methodology to determine TTC, TRM & ATC

The methodology shall be in harmony with the detailed procedure of the Central Transmission Utility (CTU) prepared under the Central Electricity Regulatory Commission (Grant of Connectivity, Long-term access and Medium-term Open Access in inter-State Transmission and related matters) Regulations, 2009 so as not to have different methodology for determination of TTC, TRM and ATC by the CTU in respect of long-term access and medium-term open access and NLDC/ RLDCs in respect of short-term open access.

The CTU shall notify the following on 31st day of March of each year: Total Transfer Capability (TTC) for 4 (four) years i.e. on 31st March, 2010, TTC shall be declared for period 1st April, 2011 to 31st Mar 2015. This may be revised by CTU due to change in anticipated network topology or change of anticipated generation or load at any of the nodes, giving reasons for such change.

Available Transfer Capability (ATC) for MTOA will be worked out after allowing the already approved applications for Long-term access, Medium Term Open Access and Transmission reliability margin. The grant of MTOA shall be subject to ATC.

TTC and TRM shall be assessed with the help of simulation studies carried out for a representative scenario to arrive at an initial or base case. Simulation studies may require setting up of a power system model and obtaining a power flow solution. The construction of an accurate base case power system model is a key step in the execution of a meaningful study.
Transmission Reliability Margin (TRM) shall be kept in the total transfer capability to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. Computation of TRM for a region or control area or group of control areas would be based on the consideration of the following:

I. Two percent (2%) of the total anticipated peak demand met in MW of the control area/group of control area/region (to account for forecasting uncertainties)
II. Size of largest generating unit in the control area/ group of control area/ Region

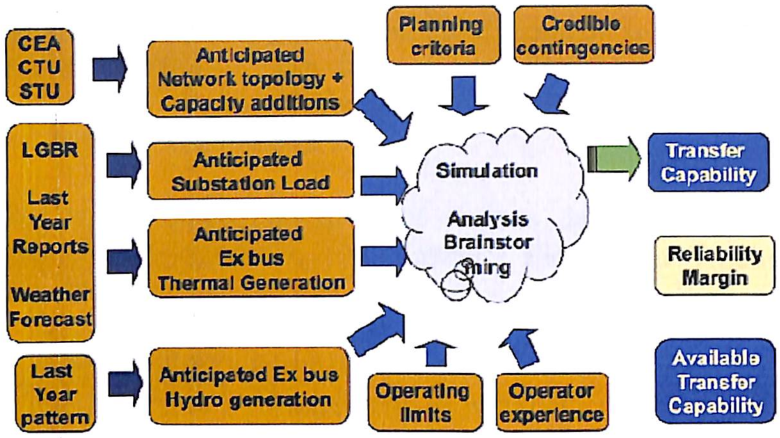

Fig. 10: TTC, TRM, ATC.

3.5.5. Procedure for declaration of TTC, TRM, ATC and anticipated Constraints:

State Load Despatch Centre (SLDC) shall assess the Total Transfer Capability (TTC), Transmission Reliability Margin (TRM) and Available Transfer Capability (ATC) on its inter-State transmission corridor considering the meshed intra State corridors for exchange (import/ export) of power with inter-State Transmission System (ISTS). These figures along with the data considered for assessment of TTC would be forwarded to the respective RLDC for assessment of TTC at the regional level. The details of anticipated transmission constraints in the intra State system shall also be indicated separately.

Regional Load Despatch Centers shall assess TTC, TRM and ATC for inter-regional corridors at respective ends, intra-regional corridors (group of control areas) and for individual control areas within the region (if required) for a period of three months in advance. During assessment of TTC, the RLDCs would duly consider the input provided by the SLDCs. The TTC, TRM and ATC figures for the inter-regional corridors, intra-regional corridors (group of control areas) and for individual control areas within the region (if required) along with all the input data considered shall be forwarded to NLDC. The details of anticipated transmission constraints in the intra-regional system shall also be indicated separately.

National Load Despatch Centre (NLDC) shall assess the TTC, TRM and ATC of inter and intra-regional links/ Corridors respectively for three months in advance for each month up to the fourth month based on:

(a) The inputs received from RLDCs

(b) TTC/ TRM/ ATC notified/ considered by CTU for medium-term open access.

NLDC shall inform the TTC/ TRM/ ATC figures along with constraints observed in inter-regional/ intra-regional corridors to the RLDCs. These shall be put on the website of RLDCs as well as NLDC.

NLDC may revise the TTC, TRM and ATC due to change in system conditions (including commissioning of new transmission lines/ generation), vis-à-vis earlier anticipated system conditions which includes change in network topology or change in anticipated active or reactive generation or load, at any of the nodes in the study. Revisions may be done by NLDC based on its own observations or based on inputs received from SLDCs/ RLDCs. Revised TTC, TRM and, ATC shall be published on website of NLDC and RLDCs along with reasons thereof.

3.6. Business Framework of Power Trading:

As per the Act, the trader is essentially "a person who has been granted a license to undertake trading in electricity". The trader must obtain a license to trade as per Central Electricity Regulatory Commission (Procedure, Terms and Conditions for grant of trading licence and other related matters) Regulations, 2010.

Trading is a process and involves various departments and those departments' approaches towards certain objective. The Business Flow of a Trading Company consists of various departments; such as:

- ✓ Business Development
- ✓ Commercial Department
- ✓ Management Information System (MIS)
- ✓ Operations
- ✓ Finance
- ✓ Legal

Each of department has their own importance and must be viewed differently. Function of each of these departments will be explained in the below given business flow of a trading company.

3.6.1. Identification of Buyers & Sellers:

The Identification of Buyers & Sellers is the prime importance and results in business development. Therefore, a dedicated business development team has been developed by many of the traders for identifying potential buyers & sellers to match up with the competitive market players. This business development representative communicates the advantage of trading through trader.

3.6.2. Business Framework of Bilateral Transaction through Power Trader

In current market scenario as much as 28% of total bilateral trade is traded through direct transactions. The operations and business development team enquires on continuous basis buyers and seller for surplus/deficit power conditions. In case confirmation from buyer/seller is received, the detailed terms and conditions are sent to both buyers and sellers. If various terms & conditions are acceptable to the buyers and sellers, a LoI is forwarded to the trader and further a Power Purchase Agreement (PPA) shall be signed, if required.

3.6.3. Tendering Process:

The tenders of various sellers & buyers are tracked by the business development & Operations team. The tender document then shall be sent to buyers & sellers. The related terms & conditions and price to be quoted shall be discussed with the interested sellers & buyers. Based on which the EMD/BG requirements are forwarded to the finance department. Once the term & conditions and other qualifying criterion are finalized, the bid shall be submitted via fax/courier/online/by hand depending upon the mode of submission prescribed in the tender document.
The EMD/BG can be refunded in case a trader does not qualify the Bid Evaluation. Although, the successful trader shall be issued with LoI/LoA for the following reasons:

a) Clients for their information & confirmation if required
b) Operation team for Open Access corridor booking activities
c) Commercial team for billing related activities
d) MIS team for capturing the commercial conditions in the MIS

3.6.3. (A). Issuance of LOI/LOA (Letter of Intent/ Letter of Acceptance):

After receiving the LoI from the seller/buyer, they are crossed checked for any discrepancies; same is brought to the notice of BD team. Next step is signing the Power Purchase agreement (PPA) with the parties.

3.6.3. (B). Terms & conditions of PPA:

The various features included in PPA are:

1. Quantum of Power to be sold /purchased.
2. Supply/Take-off timings.
3. Type of Transaction.
4. Source/ Destination.
5. Delivery Point.
6. Rates/Prices.
7. Taxes/Duties.
8. Billing Cycle.
9. Payment terms.
10. Rebate clause.
11. Surcharge for delayed payment.
12. Conditions for Open Access Charges
13. Force Measure Conditions.
14. SLDC/STU concurrence terms.

3.6.4. Power Exchange:

Any company limited by shares incorporated as a public company within the meaning of the Companies Act, 1956 and engaged in the business of trading of power.

3.6.4. (A). Need of a power exchange:

In market driven economy market forces are contradictory. Buyer wants low price, seller wants otherwise. These conflicting forces determine the correct price of a commodity at a given time. It is thus important that market forces must remain faceless and anonymous. Facelessness and anonymity creates a level field for all players. Today's power is no more a service, it is a commodity. On an electronic power exchange, buyers and sellers of power from the length and breadth of the country can converge without revealing their identity. For this we need a nationwide Power Exchange to allow the Power Market to be driven by genuine market forces of demand and supply. Along with trans-losses and UI risks, payment uncertainties prevented the true market driven economy in power market. A Power Exchange shall function with the following objectives:-

(i) Ensure fair, neutral, efficient and robust price discovery
(ii) Provide extensive and quick price dissemination
(iii) Design standardized contracts and work towards increasing liquidity in such contracts

As per the CERC power market regulation, 2010, the Power Exchange shall function according to its Byelaws and Rules as approved by the Commission, which amongst other requirements would cover the following:

(a) Price Discovery and matching mechanism;
(b) Rights and liabilities of its members;
(c) Market surveillance and investigation;
(d) Clearing and settlement procedure;
(e) Risk management;
(f) Default and Penalty mechanism;
(g) Penalty for contractual deviations;
(h) Transaction charge and the mechanism of its determination;
(i) Brokerage and Commission Charges of its members;
(j) Maintenance of records and accounts;
(k) Preparation of annual accounts and audit thereof;
(l) Arbitration, dispute resolution and conciliation;
(m) Mechanism for redressal of grievances;
(n) Opening and closing of transaction hours, transaction and settlement calendar;
(o) Procedure from opening of the platform up to its scheduling by LDC;
(p) Procedure for handling a default, i.e., failure to schedule the transaction finalized;
(q) Details of market splitting methodology for handling transmission congestion; this shall be elucidated with examples Inter-face design with system operator/Regional Load Dispatch Centres;
(r) The details of the Exit Scheme;
(s) Qualifications for membership, exclusion, suspension and expulsion
(t) Indemnification of Central Transmission Utility, National Load Despatch Centre, Regional Load Despatch Centres, State Load Despatch Centres by the Power Exchange.

3.7. Risk in Power Trading:

Risk can be broadly classified into 03 (three) category as follows:

3.7.1. Technical Risk:

a. Congestion risk.
b. Wheeling charge high risk.
c. Operational risk.
d. Market structure risk.
e. Imbalance risk.
f. Unexpected changes.

3.7.2. Financial Risk:

a. Price volatility risk.
b. Credit risk.
c. Late payment risk.
d. Inflationary risk

3.7.3. Management Risk:

a. Regulatory risk.
b. Political risk.
c. Default risk.
d. Contract dishonor risk.

3.7.4. Details of this risk are discussed below:

a. Regulatory Risks:
Pricing of Open Access Surcharge, wheeling charges & methodology for tariff determination.

b. Political Risk:
Government's will (or fancy) in implementing policies and change of policies due to political uncertainty or political values.

c. Transmission & System Operations Risk:
Adequacy of transmission capacities, line outages and principle of merit order operation to ensure

d. Credit Risks:
Diverse range of players with varying credit risks and payment security becomes an issue and adds to the transaction costs Credit risk becomes a central factor when assessing the commercial benefit of participating in a trade

e. Operational Risk:
Risk associated with contracts that may infringe on legal & regulatory provisions and volumetric risks based on the ability of the operation.

f. Pricing Risks:
In long term contracts, if a percentage of the contracted power is reserved for spot market, it will face the volatility of spot markets and exposure to Forex fluctuations in long term contracts.

g. Contract Risk:
In short term contracts, penalty clauses may exist if the contracted power is not delivered. In long term contracts, termination clauses amounting to a few months billing in that case.

h. Market Structure Risk:
The institutional set-up of Market could make a significant difference to the final market price, if supply or demand is dominated by a few large players, liquid markets may not develop, If market power exists, massive price & capacity squeezes occur causing liquidity to contract, and the essential process of price discovery collapses. Optimization may be destroyed by tactical bidding of prices and availabilities by produces and traders.

3.7.5. Out of the above mentioned risk major risks like price risk, imbalance risk and transmission congestion risks are discussed detailed below:

3.7.5. (A). Price Risk:
Mostly in trading transaction with the customer usually involves a fixed transaction price P that is determined at contract origination. The price for transactions with the wholesale markets is not known in advance. The hourly PX spot price St that will be used to settle the energy transfers through trading is unknown and highly volatile. Therefore the margin that is earned is also highly volatile and unknown. In a formula the total cash flow that results from the transaction is shown in the formula.

$$\pi_t = \mathrm{D}(P - S_t)$$

The size and sign of this cashflow is uncertain and stochastic as it is dependent upon the PX spot price St. First, the sign can depend on the type of customer; a producer has a negative demand, while a consumer will have a positive demand. This influence the sign that the premium (P-St) needs to have. A positive spread is associated with a positive demand, while a negative spread should account for negative demand. The fact that the resulting cashflow can be negative is called price risk.

3.7.5. (B). Imbalance Risk:
In order to maintain a reliable electricity grid, it is necessary to continuously balance supply and demand. If supply is too low then the frequency of the electricity current drops below 50Hz and if it drops too far machines will no longer work. On the other hand, if the frequency increases too much then machines will break because of overloading of their systems. Hence, the TSO acts as the central counterparty to all players that continuously buys and sells the surplus or shortage from the market participants to other market participants. The price at which the transactions between the TSO and the market participants are settled is called the settlement price. Hence, backup generators needs that are capable of producing electricity to counter the market shortage, and it need a list of market parties that are willing to increase consumption if the market has surplus. These were the general goals when the market system was developed.

A bid system is required to maintain by system operator. As the market moves in one direction, the bids are activated and the marginal settlement price increases or decrease. The system operator takes step to make one directional system to a zero sum game by transferring wealth from one market participant to another participant. This curve changes exponential in both directions. A small increase does not influence the settlement price much, but as the distance from equilibrium increases, the price increases exponentially. So imbalance in the market causes uneven cash flow in either side.

3.7.5. (C). Transmission Congestion Risk:

Transmission congestion risk arises due to overloading of a transmission line capacity. Every transmission line has a limiting capacity, beyond which electricity flow may cause trip of the line. Line may be congested in peak hour. So, if the line congested the contracted power cannot be dispatched to desire location which is high risk for trading and may cause huge financial loss.

3.8. Risk Hedging Process in Power Trading:

As discussed above risks are categorized in three types. Out of this first 02 (two) types risk i.e. technical and financial risk mainly causes to abruptly change in the spot price of electricity. Electricity spot prices in the emerging power markets are volatile, a consequence of the unique physical attributes of electricity production and distribution. Uncontrolled exposure to market price risks can lead to devastating consequences for market participants in the restructured electricity industry. Lessons learned from the financial markets suggest that financial derivatives, when well understood and properly utilized, are beneficial to the sharing and controlling of undesired risks through properly structured hedging strategies. All the risk effects on price volatility and causes to system collapse. These risks potential may be controlled by electricity derivative instrument contract through exchanges or over OTC.

3.8.1. The Electricity Derivatives are grouped as follows:

3.8.1. (A). Obligatory Derivative Contract:

a. Electricity Forward Contract.
b. Electricity future contract.
c. Electricity swaps contract.

3.8.1. (B). Electricity Option Contract:

a. Plain call and put option.
b. Spark spread option.
c. Callable and putable forwards.
d. Swing option.

3.8.1. (C). Structured Transaction:

a. Tolling contract.
b. Load serving full requirement contract.

3.8.1. (D). Electrical Derivatives on Transmission Capacity:

a. Financial Transmission rights.
b. Flowgate rights.

3.8.2. The derivatives are discussed below:

3.8.2. (A). Obligatory Derivatives contract:

In this type of contract there is a obligation between seller and buyer. The plainest forms of electricity derivatives are forwards, futures and swaps. Being traded either on the exchanges or over the counters, these power contracts play the primary roles in offering future price discovery and price certainty to generators and LSEs.

I. Electricity forwards:

Electricity forward contracts represent the obligation to buy or sell a fixed amount of electricity at a pre-specified contract price, known as the forward price, at certain time in the future (called maturity or expiration time). In other words, electricity forwards are customer tailored supply contracts between a buyer and a seller, where the buyer is obligated to take power and the seller is obligated to supply. The payoff of a forward contract promising to deliver one unit of electricity at price F at a future time T is:

Payoff of a Forward Contract = $(S_T - F)$.

Where S_T is the electricity spot price at time T. Although the payoff function appears to be the same as for any financial forwards, electricity forwards differ from other financial and commodity forward contracts in that the underlying electricity is a different commodity at different times. The settlement price S_T is usually calculated based on the average price of electricity over the delivery period at the maturity time T.

Consider a forward contract for the on-peak electricity on day T. "On-peak electricity" refers to the electricity delivered over the daily peak-period, traditionally defined by the industry as 18:00 - 24:00. The daily "off-peak" period is the remaining hours of the day. In this case, S_T is obtained by averaging the 6 hourly prices from 18:00 to 24:00 on day T.

Based on the delivery period during a day, electricity forwards can be categorized as forwards on on-peak electricity, off-peak electricity, or "around-the-clock" (24 hours per day) electricity. As almost all electricity derivatives have such categorization based on the delivery time of a day, we will not repeat this point.

Generators such as independent power producers (IPPs) are the natural sellers (or, short side) of electricity forwards while LSEs such as utility companies often appear as the buyers (or, long-side). The maturity of an electricity forward contract ranges from hours to years although contracts with maturity beyond two years are not liquidly traded. Some electricity forwards are purely financial contracts, which are settled through financial payments based on certain market price index at maturity, while the rest are physical contracts as they are settled through physical delivery of underlying electricity.

Electricity forward contracts are the primary instruments used in electricity price risk management. LSEs (e.g., local distribution companies) typically combine several months of forward/futures contracts to form a close match to the long-term load shape of their customers. Other power marketers usually use forwards to hedge their positions in electricity options and other complex electricity derivatives.

II. Electricity Future:

First traded on the NYMEX in March 1996, electricity futures contracts have the same payoff structure as electricity forwards. However, electricity futures contracts, like other financial futures contracts, are highly standardized in contract specifications, trading locations, transaction requirements, and settlement procedures. The most notable difference between the specifications of electricity futures and those of forwards is the quantity of power to be delivered. The delivery quantities specified in electricity futures contracts are often significantly smaller than that in forward contract.

Electricity futures are exclusively traded on the organized exchanges while electricity forwards are usually traded over-the-counter in the form of bilateral transactions. This fact makes the futures prices more reflective of higher market consensus and transparency than the forward prices. The majority of electricity futures contracts are settled by financial payments rather than physical delivery, which lower the transaction costs. In addition, credit risks and monitoring costs in trading futures are much lower than those in trading forwards since exchanges implement strict margin requirements to ensure financial performance of all trading parties. The OTC transactions are vulnerable to financial non-performance due to counterparty defaults. The fact that the gains and losses of electricity futures are paid out daily, as opposed to being cumulated and paid out in a lump sum at maturity time, as in trading forwards, also reduces the credit risks in futures trading.

In summary, as compared to electricity forwards, the advantages of electricity futures lie in market consensus, price transparency, trading liquidity, and reduced transaction and monitoring costs while the limitations stem from the various basis risks associated with the rigidity in futures specification and the limited transaction quantities specified in the contracts.

III. Electricity swap:

Electricity swaps are financial contracts that enable their holders to pay a fixed price for underlying electricity, regardless of the floating electricity price, or vise versa, over the contracted time period. They are typically established for a fixed quantity of power referenced to a variable spot price at either a generator's or a consumer's location. Electricity swaps are widely used in providing short- to medium-term price certainty up to a couple of years. They can be viewed as a strip of electricity forwards with multiple settlement dates and identical forward price for each settlement.

Electricity location basis swaps are also commonly used to lock in a fixed price at a geographic location that is different from the delivery point of a futures contract. That is, a holder of an electricity location basis swap agrees to either pay or receive the difference between a specified futures contract price and another location spot price of interest for a fixed constant cash flow at the time of the transaction. These swaps are effective financial instruments for hedging the basis risk on the price difference between power prices at two different physical locations.

3.8.2. (B). Electricity options contract:

The emergence of the electricity wholesale markets and the dissemination of option pricing and risk management techniques have created electricity options not only based on the underlying price attribute (as in the case with plain vanilla electricity call and put options), but also other attributes like volume, delivery location and timing, quality, and fuel type. Basically, a counterpart of each financial option can be created in the domain of electricity options by replacing the underlying of a financial option with electricity.

I. Plain call and put options:

Electricity call and put options offer their purchasers the right, but not the obligation, to buy or sell a fixed amount of underlying electricity at a pre-specified strike price by the option expiration time. They have similar payoff structures as those of regular call and put options on financial securities and other commodities. The payoff of an electricity call option is:

Payoff of an electricity call option = max(S_T - K,0)
Where S_T is the electricity spot price at time T and K is the strike price.

II. Spark spread options:

An important class of non-standard electricity options is the spark spread option (or, spark spread). Spark spreads are cross-commodity options paying out the difference between the price of electricity sold by generators and the price of the fuels used to generate it. The amount of fuel that a generation asset requires to produce one unit of electricity depends on the asset's fuel efficiency or heat rate (Btu/kWh). The holder of a European- spark spread call option written on fuel G at a fixed heat rate $H K$ has the right, but not the obligation, to pay at the option's maturity $H K$ times the fuel price at maturity time T and receive the price of one unit of electricity. Thus, the payoff at maturity time T is

Payoff of a spark spread call = max (S_T -K_H.GT,0).

Where S_T and G_T are the electricity and fuel prices at time T, respectively.

Abstracting away the operational characteristics of a fossil fueled power generator (e.g., startup cost and ramping constraints), the per kW benefit of owning the right to use the generator is equivalent to having one kW spark spread call option with a strike heat rate matching the generator's operating heat rate. Based on this observation, it is clear that spark spread call options play important roles in hedging the price risk of the output electricity of fossil fueled power plants and further serve as key instruments in valuing those generation assets.

III. Callable and putable forwards:

Two interesting types of electricity derivatives termed as callable forward and putable forward are used to mimic the interruptible supply contracts and the dispatchable independent power producer contracts. In a callable forward contract, the purchaser of the contract longs one forward contract and shorts one call option with a purchaser-selected strike price. The seller of the forward contract holds opposite positions and can exercise the call option if the electricity price exceeds the strike price, effectively canceling the forward contract at the time of delivery. The purchaser gets an "interruptibility" discount on the forward price which is equal to the option premium at the time of contracting continuously compounded to the delivery time. In a putable forward, the purchaser longs one forward contract and one put option with a seller-selected strike price. The seller holds the corresponding short positions. The purchaser exercises the put option if the electricity price drops below the strike price at the maturity time, effectively canceling the forward contract. At the time of contracting, the purchaser needs to pay a "capacity availability" premium over the forward energy price, which equals the put option price at that time, continuously compounded to the maturity time.
One variation of the callable forwards is proposed by adding an earlier notification date for exercising the call option in a callable forward before the contract matures. This emulates an interruptible service contract with early notification.

IV. Swing options:

Electricity swing options are adopted from their well-known counterparts in the natural gas industry. Also known as flexible nomination options, swing options have the following defining features. First, these options may be exercised daily or up to a limited number of days during the period in which exercise is allowed. Second, when exercising a swing option, the daily quantity may vary (or, swing) between a minimum daily volume and a maximum volume.

However, the total quantity taken during a time period such as a week or a month needs to be within certain minimum and maximum volume levels. Third, the strike price of a swing option may be either fixed throughout its life or set at the beginning of each time period based on some pre-specified formula. Last, if the minimum-take quantity of any contract period is missed by the buyer, then a lump sum penalty or a payment making up the seller's revenue shortfall needs to be paid (i.e., take-or-pay).

3.8.2. (C). Structured transactions:

Structured bilateral transactions are powerful tools for power market participants to share and control a variety of risks including price and quantity risks over a potentially long time horizon.

I. Tolling contracts:

Tolling is one of the most innovative structured transactions embraced by the power industry. A tolling agreement is similar to a common electricity supply contract signed between a buyer (e.g., a power marketer) and an owner of a power plant (e.g., an IPP) but with notable differences. For an upfront premium paid to the plant owner, it gives the buyer the right to either operate or control the scheduling the power plant with the ISO or simply take the output electricity during pre-specified time periods subject to certain constraints. In addition to inherent operational constraints of the underlying power plant, there are often other contractual limitations in the contract on how the buyer may operate the power plant or take the output electricity. For instance, a tolling contract almost always has a clause on the maximum allowable number of power plant restarts. These constraints make the pricing of tolling contracts a very challenging task. The analogy between holding a tolling contract and owning the underlying merchant power plant, however, leads to a numerical approach for valuing and hedging tolling contracts. Alternatively, one may use a statistical approach for benchmarking the price reasonableness of tolling contracts based on historical electricity price and fuel costs.

II. Load-serving full-requirement contracts:

Most large electricity consumers prefer a power supply contract with flexible consumption terms. Specifically, they desire to pay a fixed rate per unit of energy for the actual consumption quantity, regardless of the quantity being high or low. Such a contract is termed as a load-serving full-requirement contract. Suppose an electricity supplier (or, LSE) signs a full-requirement contract with a customer and then utilizes futures contracts to lock in a fixed quantity of electricity supply at a fixed cost for hedging the expected energy consumption of the customer. The LSE is then at the risk of either under- or over-hedging, as the consumption quantity of the customer will almost surely deviate from the amount hedged by the futures contracts. When the electricity spot price is high (low), the total demand for electricity is likely to be high (low) as well. A case in point is the periods of unusual cooling/heating needs. Hence, if the market price of electricity is higher than the fixed contract rate for serving electricity, chances are that the customer's energy consumption level is significantly higher than the hedged quantity. As a result, the LSE is under-hedged relative to its load obligation and must purchase electricity in the open market to serve its customer at a loss because the wholesale spot price most likely exceeds the contracted price paid by consumers. Conversely, when the electricity spot price is low, the LSE faces the risk of being over-hedged and having to sell the surplus in the spot market or settle it financially at a price below its long-term contract price.

The above illustrates the under- and over-hedging exposures faced by an LSE due to the volumetric uncertainty in customers' load and the positive price-load correlation. To hedge the volumetric risk, the LSE would need to buy an electricity option on the consumption quantity of its customers. Unfortunately, such an option is usually unavailable in the marketplace. Although perfect hedging may not be possible, weather derivatives that exploit the correlation between load and temperature can be used.

3.8.2. (D). Financial derivatives on electricity transmission capacity:

Open access to, efficient utilization of, and adequate investment in transmission networks are critical for the electricity wholesale markets and retail competitions to be workable and efficient. Intuitively, rights are required for using transmission networks and rules are needed for rationing transmission usage when networks become congested. There are two major proposals for using financial instruments as transmission rights: (a) the point-to-point financial transmission rights (FTRs) and (b) the flowgate rights (FGRs), as outlined in the Standard Market Design (SMD). FTRs and FGRs are electricity derivatives, with their values derived from the network transmission capacity.

I. FTR and FTR options:

In an electricity market such as the PJM that employs locational market price (LMP), a point-to-point FTR is specified over any two locations in the power transmission grid. An FTR entitles its holder to receive compensation (or pay) for transmission congestion charges that arise when the grid is congested. The congestion charge/payment (or, payoff) associated with one unit of FTR is equal to the difference between the two locational prices of one unit of electricity resulting from the re-dispatch of generators out of merit order to relieve transmission congestion.

II. FGRs:

Flowgates are defined over all transmission elements such as lines, transformers, or linear combinations of them. Each transmission element has two elemental flowgates, one in each direction. An elemental flowgate has a rated capacity in megawatts in its pre-specified direction corresponding to the capacity of an underlying transmission element. Thus, flowgate rights are link-based transmission rights for hedging transmission risks. The values of flowgate rights can be established through auctions conducted by the ISOs. The spot price upon which the settlement of flowgate rights is based is given by the real time shadow price on the corresponding constrained element, determined by the security constrained economic dispatch algorithm employed by an ISO. Since these shadow prices are nonnegative, FGRs are inherently defined as options.

3.8.3. Pricing of Electricity Derivatives:

There are mainly two competing approaches to the problem of modeling electricity price processes:

(a) "Fundamental approach" that relies on simulation of system and market operation to arrive at market prices;

(b) "Technical approach" that attempts to model directly the stochastic behavior of market prices from historical data and statistical analysis.

While the first approach provides more realistic system and transmission network modeling under specific scenarios, it is computationally prohibitive due to the large number of scenarios that must be considered. Such analysis may be necessary for pricing financial transmission rights (in particular, flowgate rights) but not for the other electricity derivatives. Therefore, we shall focus our attentions on the second approach and review the corresponding methodologies for pricing electricity derivatives.

Approaches to characterize market prices include discrete-time time series models such as GARCH and its variants, Markov regime-switching models, continuous-time diffusion models such as mean-reversion, jump-diffusion, and other diffusion models. There are also models proposed for direct modeling of electricity forward curves.

While a straightforward application of the maximum likelihood estimation (MLE) method yields the parameter estimates of a discrete-time time series model, it does not yield analytic expressions for derivative prices. In fact, Monte Carlo simulation and lattice-based approaches are the only feasible derivative pricing methods under time-series price models. For continuous-time diffusion models, model parameters can be estimated by applying moment based methods, such as the generalized method of moments, which may not be as efficient as the MLE method. Nonetheless, more option pricing methods (e.g., the analytic solution approach and the partial differential equation (PDE) approach) become applicable under the diffusion price models.

Another method, multifactor affine jump diffusion (AJD) processes to model electricity spot prices under several specifications, including regime switching and stochastic volatility. Under the assumption that electricity prices follow AJD processes, an extended Fourier transform technique developed and can be applied to derive analytic expressions (up to Fourier inversion) for a variety of derivative prices. Specifically, prices of forwards, calls/puts and spark spreads were derived under three different electricity price models, and prices of callable forwards with an early notification were obtained. When there is a large set of market data available, the most appropriate approach to pricing electricity options is to infer the risk-neutral distribution of the underlying electricity price from the market data and then obtain the prices of the electricity derivatives based on the premise of no-arbitrage. If there is not enough forward-looking market information for implementing a no-arbitrage pricing model, then equilibrium models can be applied to obtain derivative prices for forward prices and for spark spreads. In certain cases, statistical benchmark analysis based on historical data can provide a sense of the reasonableness on the electricity options prices.

The binomial/multinomial lattice and Monte Carlo simulation methods are powerful numerical tools for pricing electricity options with complex structures and/or under a complicated model for the electricity price process. For instance, given the complex structure of a swing option or a tolling contract, it is impossible to obtain prices of such contracts either in closed-forms or through PDEs. Thus, swing options are priced by lattice models or by approximation methods for obtaining price lower bounds. The pricing of tolling contracts requires a combination of Monte Carlo simulation with dynamic programming.

3.9. Risk Management Application:

3.9.1. Hedging a Generator's Output:

Simple payoff structures, forwards, swaps, and call options are effective tools for a generator with fixed per unit cost to lock in profits by selling forwards, fixed-price swaps, and call options on electricity. When the forward/swap rate or the strike price of the call options is higher than the fixed cost, the generator's profits are guaranteed. However, if the generating costs are market-based (e.g., a natural gas fired merchant power plant that burns natural gas at market price), the selling forwards, swaps and calls will expose the generator to potential fuel cost increases. In such a case, a properly constructed portfolio of spark spread calls would be the right tool for hedging a generator's revenue stream over a given time period. The operational efficiency of a natural gas fired power plant is characterized by its operating heat rate. Therefore, the financial benefit of owning a portfolio of spark spread calls with strike heat rates identical to the operating heat rate of the plant is the same as owning the power plant during the time period of the options' maturity times. This observation leads to the valuation and hedging method for generation capacity proposed. When taking into account the operational characteristics, lattice-based method and simulation method are necessary to determine pricing and hedging strategies of generation capacity. In the case where the electricity forward market at the generator's location is not liquidly traded, electricity forwards from adjacent trading hubs or even forwards on the input fuel, which are liquidly traded, can be utilized to cross-hedge the electricity output price.

3.9.2. Ensuring generation adequacy:

Generation adequacy may be ensured by call options as obligations imposed on the LSEs. Call options provide an attractive alternative to artificial capacity products such as installed capacity (ICAP). By requiring LSEs to purchase a proper portfolio of options, a regulator can achieve spot price volatility reduction by implementing price insurance while using the premium to stabilize generators' income and enhance investment incentives. For ensuring generation capacity we may divide the market into the following 4 (four) category and calculating risk minimizing hedge quantity:

i. Base load contract at deterministic demand:

The minimum hedging quantity given by the following equation:

$$Q = \frac{1}{2}\frac{\sum_{i=1}^{I}\sum_{j=1}^{I}(D_i + D_j)Cov(\tilde{S}_i, \tilde{S}_j)}{\sum_{i=1}^{I}\sum_{j=1}^{I}Cov(\tilde{S}_i, \tilde{S}_j)}$$

Where D=demand, S= expected spot price. This equation is valid for forward market.

ii. Base load contract at stochastic demand:

$$Q = \frac{1}{2}\cdot\frac{\sum_{i=1}^{I}\sum_{j=1}^{I}Cov(\tilde{S}_i, \tilde{D}_j\tilde{S}_j) + Cov(\tilde{D}_i\tilde{S}_i, \tilde{S}_j) - \mathrm{P}Cov(\tilde{S}_i, \tilde{D}_j) - \mathrm{P}Cov(\tilde{D}_i, \tilde{S}_j)}{\sum_{i=1}^{I}\sum_{j=1}^{I}Cov(\tilde{S}_i, \tilde{S}_j)}$$

Where D=demand, S= expected spot price. This equation is valid for forward market.

iii. Base load and peak load contract at deterministic demand:

$$Q_B^* = \frac{1}{2}\frac{\left(\sum_{i,j\in P}^{I}(-2Q_P + D_i + D_j)Cov(\tilde{S}_i,\tilde{S}_j) + \sum_{i,j\in B}^{I}(D_i + D_j)Cov(\tilde{S}_i,\tilde{S}_j) + 2\sum_{i\in P,j\in B}^{I}(-Q_P + D_i + D_j)Cov(\tilde{S}_i,\tilde{S}_j)\right)}{\sum_{i,j}^{I}Cov(\tilde{S}_i,\tilde{S}_j)}$$

$$Q_P^* = \frac{1}{2}\cdot\frac{\sum_{i,j\in P}^{I}(-2Q_B + D_i + D_j)Cov(\tilde{S}_i,\tilde{S}_j) + \sum_{i\in P,j\in B}^{I}2(-Q_B + D_j)Cov(\tilde{S}_i,\tilde{S}_j)}{\left(\sum_{i,j\in P}^{I}Cov(\tilde{S}_i,\tilde{S}_j)\right)}$$

Where Q_B= Base load qty, Q_P = peak load qty, D= demand, S = spot price. This is valid for forward contract.

iv. Base load and peak load contract at stochastic demand:

$$Q_B^* = \frac{1}{2}\frac{\left(\sum_{i,j}^{I}Cov(\tilde{S}_i,\tilde{S}_j\tilde{D}_j) + Cov(\tilde{S}_j,\tilde{S}_i\tilde{D}_i) - PCov(\tilde{D}_j,\tilde{S}_i) - PCov(\tilde{D}_i,\tilde{S}_j) - 2Q_P\left[\sum_{i\in B,j\in P}^{I}Cov(\tilde{S}_i,\tilde{S}_j) + \sum_{i,j\in P}^{I}Cov(\tilde{S}_i,\tilde{S}_j)\right]\right)}{\sum_{i,j}^{I}Cov(\tilde{S}_i,\tilde{S}_j)}$$

$$Q_P^* = \frac{1}{2}\frac{\sum_{i,j\in P}^{I}[Cov(\tilde{S}_i,\tilde{S}_j\tilde{D}_j) + Cov(\tilde{S}_j,\tilde{S}_i\tilde{D}_i) - PCov(\tilde{D}_i,\tilde{S}_j) - PCov(\tilde{D}_j,\tilde{S}_i)] - 2Q_B\left(\sum_{i,j\in P}^{I}Cov(\tilde{S}_i,\tilde{S}_j) + \sum_{i\in B,j\in P}^{I}Cov(\tilde{S}_i,\tilde{S}_j)\right)}{\sum_{i,j\in P}^{I}Cov(\tilde{S}_i,\tilde{S}_j)} + \frac{1}{2}\frac{\sum_{i\in B,j\in P}^{I}2Cov(\tilde{S}_j,\tilde{S}_i\tilde{D}_i) - 2PCov(\tilde{D}_i,\tilde{S}_j)}{\sum_{i,j\in P}^{I}Cov(\tilde{S}_i,\tilde{S}_j)}$$

Where Q_B= Base load qty, Q_P = peak load qty, D= demand, S = spot price. This is valid for forward contract.

3.9.3. Hedging Demand Side Risk by Callable Forwards and Interruptible Service Contracts:

The restructured electricity markets have shown little demand response to price spikes. The enormous price volatility affirms the need for demand responsiveness to make these markets workable. As load curtailment can provide an efficient substitute for generation capacity in meeting balancing energy and reserves needs, flexible loads are viable and valuable resources in taming price volatility.

Consider the traditional utility interruptible service contracts utilized in demand-side management (DSM) to mitigate supply shortages. These interruptible contracts are readily implementable through standard electricity derivatives. For instance, a synthetic interruptible service contract offered by an LSE is a callable forward under which the LSE sells a forward to and buys a call option from its customer. Furthermore, with a liquid electricity derivative market, the discounts offered to the interrupted services would be set through market trading instead of bilateral negotiations thus making the pricing of the interruptible services more transparent and efficient.

3.9.4. Hedging Congestion Risk of Transmission Network:
From the perspective of new power network transmission users, FTRs can be viewed as an instrument for hedging their exposure to congestion cost risk. A one-megawatt (MW) bilateral transaction between two points in a transmission network is charged (or credited) the nodal price difference between the point of withdrawal and the point of injection. At the same time (assuming that transmission rights are fully funded), a one MW FTR between two points is an entitlement (or obligation) for the difference between the nodal prices at the withdrawal node and the injection node. Thus regardless of how the system is dispatched, a one MW FTR between two nodes is a perfect hedge against the uncertain congestion charge between the same two nodes.

The hedging properties of FTRs make them ideal instruments for converting historical entitlements to firm transmission capacity into tradable entitlements that hold the owners of such entitlements harmless, while enabling them to cash out when someone else can make more efficient use of the transmission capacity covered by these entitlements. In other words, FTRs make it relatively easy to preserve the status quo while opening up the transmission system to new and more efficient use. A word of caution is that the hedging function of FTRs may not be perfect due to changing network operating conditions and potential inherent trading inefficiency. Some ISOs derate FTR settlements in order to cover congestion revenue shortfalls due to transmission contingencies not accounted for in the FTR auction. In such cases, depending on the derating approach, FTRs may not provide perfect hedges either.

3.9.5. Hedging Volumetric Risks:
LSEs providing electricity service at regulated prices in restructured electricity markets are wary of both price and quantity risks. As the electricity markets are inherently incomplete, the quantity risk cannot be perfectly hedged. Commonly proposed hedging alternatives include the implementation of a minimal variance hedge through purchasing electricity forwards and the utilization of weather derivatives.

3.10. Power Scenario of West Bengal:

State of West Bengal has four DISCOMs namely, West Bengal State Electricity Distribution Company Limited (WBSEDCL), CESC Limited (CESC), Durgapur Projects Limited (DPL), Dishergarh Power Supply Company Limited (DPSCL). These DISCOMs are Distribution cum Generating companies with own generating stations. West Bengal also has a state owned generating company West Bengal State Power Development Corporation Limited with present installed capacity of 2900 MW.

The West Bengal State Electricity Board (WBSEB), post restructuring on 1st April 2007, was replaced by West Bengal State Electricity Transmission Company Limited (WBSETCL) and West Bengal State Electricity Distribution Company Limited (WBSEDCL). The sales mix in West Bengal is dominated by industrial (small and large) followed by Domestic, which together form about 73% of the total sales. The generation capacity of WBPDCL is purely coal-based with hydel plants managed by WBPDCL. In terms of regulatory ratemaking, West Bengal followed the Annual Revenue Requirement (ARR) approach till FY 07 and the first MYT was launched with effect from FY 08 with control period of one year (mainly to establish proper base-line data) and next MYT period was initiated from FY 09 with control period of three years. Now it is running fourth control period.

3.10.1. Scenario of Generators:

The generators can be classified into 3 (three) categories namely:

a. State sector.
b. Central sector.
c. IPP.

The detail of each sector tabulated below:

Sl No	Name of Sector	Coal Based (MW)	Hydro (MW)	Gas based (MW)	Diesel (MW)	RES (MW)	Total (MW)
1	State Sector	4691	1124.5	100	12.06	91.95	6019.51
2	Central Sector	3019(42% 0f 93% of 7960 installed)	279.2				3298.2
3	IPP	1767.8			0.14	39.76	1806.9
Sub Total (MW)							11124.61

Table 16: Sector wise generation in West Bengal

3.10.2. Each sector wise installation detail given below:

a. State sector:

In state sector generators are:

a. WBPDCL.
b. DPL.
c. WBSEDCL.
d. WBREDA.

The installed capacity is given below:

Sl No	Name of Generators	Name of Power station	Installed capacity	Date of commercial operation	Total installed capacity
1	WBPDCL	Kolaghat	1260 MW	1990,84,86,95,91,94	3800 MW
		BkTPS	1050 MW	2000,01,01,05,05	
		STPS	500 MW	2009,2012	
		SgTPS	600 MW	2008,08	
		BTPS	390 MW	1965,65,66,66,83	
2	DPL	U #III,IV,V	77 MW	June 1964	891 MW
		U#IV	77 MW	June 1964	
		U#V	77 MW	July 1966	
		U# VI	110 MW	From 1987	
		U# VII	300 MW	From 2008	
		U# VIII	250 MW	July2014	
3	WBSEDCL	Rammam	51 MW	-	1236.56 MW
		Jaldakha	44 MW	-	
		TCF U#I,II,III	67.5 MW	-	
		PPSP	900 MW	2013	
		Small Hydro	89 MW	-	
		Gas plant	100 MW	-	
		Diesel plant	12.06	-	
4	WBREDA	Small Plant	91.95 MW	-	91.95 MW

Table 17: Installed capacity of State sector.

b. Central Sector:
   Central sector generators are:
   1. NTPC- Farakka.
   2. NTPC – JV: Durgarpur.
   3. DVC.
   4. DVC- TATA JV.
   5. NHPC.

The installed capacity is given below:

Sl No	Name of Generators	Name of Power station	Installed capacity	Date of commercial operation	Total installed capacity
1	NTPC-Farakka	U#I	200 MW	January'1986	2100 MW
		U#II	200 MW	December'1986	
		U#III	200 MW	August' 1987	
		U#IV	500 MW	September'1992	
		U#V	500 MW	February'1994	
		U#VI	500 MW	March'2011	
2	NTPC –JV	Durgapur	120 MW	-	120 MW
3	DVC	MTPS U# I	210 MW	December'1997	4837.2 MW
		MTPS U#	210 MW	March'1999	

		MTPS U#III	210 MW	September'1999	
		MTPS U#IV	210 MW	February'2005	
		MTPS U#V	250 MW	February'2008	
		MTPS U#VI	250 MW	September'2008	
		MTPS U#VII	500 MW	August'2011	
		MTPS U#VII	500 MW	August'2012	
		DTPS U# III	175 MW	December'1966	
		DTPS U# IV	175 MW	September'1982	
		DSTPS U#I	500 MW	May'2012	
		DSTPS U#II	500 MW	March'2013	
		RTPS U#I	500 MW	October'2014	
		RTPS U#II	500MW	March'2015	
		MHS U # I,II,III	63.2 MW	1957-58	
		PHS U I & II	80 MW	1959, 1991	
		THS	4 MW	1953	
4	DVC-TATA JV	MPL U#I	525 MW	March'2011	1050 MW
		MPL U#II	525 MW	Sep' 2014	
5	NHPC	Teesta Low dam U#I,II,III,IV	132 MW	January'2013	132 MW

Table 18: Installed capacity of Central Sector.

c. IPP:

The main IPP players are:

a. CESC.
b. HEL.
c. DSCL.
d. Others Captives.

The installed capacity given below:

Sl No	Name of Generators	Power Station	Installed capacity	Date of commercial operation	Total installed capacity
1	CESC	Budge Budge U#I	250 MW	1997	1125 MW
		Budge Budge U#I	250 MW	1999	
		Budge Budge U#I	250 MW	2010	
		Titagarh U#I	120 MW	1983	
		Titagarh U#II	120 MW	1984	
		Southern	135 MW	1990-91	
2	DPSCL	Dishergarh	12.8 MW	87years running	42.8 MW

		Chinakuri	30 MW	87years running	
3	HEL	Haldia U#I	300 MW	July'2013	600 MW
		Haldia U#II	300 MW	Feb'14	

Table 19: Installed capacity of IPP

Upcoming projects:

a. NTPC : Farakka – 500 MW.
b. NTPC: Katwa – 2 x 660 MW.
c. WBPDCL: SgTPP- 2 x 500 MW.

3.10.3. Scenario of Discom. / Wholesaler:

Sl No	Name of Discom/ Wholesaler	Total CKMs of distribution line	No of distribution sub station	Normative distribution loss	No of consumer	Distribution Area
1	WBSEDCL	614210.59	530	24.2%	15064240	Entire WB except other licensee
2	DPL	1522	8	5.2%	140000	Durgapur
3	CESC	22502	105	14.3%	3074100	Kolkata , 24 pgs.
4	DPSCL	532	4	5.4%	359	Asansol-Ranigang belt
5	DVC	5993	32	2.2%	246	South Bengal

Table 20: Diff technical parameter of Discom / Wholesaler in WB.

3.10.4. Scenario of Transcom:

The main transcom utility in West Bengal is WBSETCL which was created on 1st April'2007 according to EA'03. Now it has allocated capacity for F.Y: 2015-16 is 5690 MW and total installed capacity 23327.3 MVA. The grid in West Bengal is control by WBSEDCL. After WBSETCL large transcom utility is DVC which has own network, customer and network control room. Other than SETCL and DVC, CESC and DPL has its transmission network for its own distribution purpose. The technical parameters of different Transcom are given below:

Sl No	Parameter	WBSETCL	DVC (in WB)	CESC	DPL
Sub Station					
1	400 KV	4	2		
2	220 KV	21	5	3	1
3	132 KV	76	11	2	2
4	66 KV	8	-		-
5	Switching Sub station	3	-	-	-
Transmission Line (CKM)					
6	400 KV	1644.7	1240.7	-	-
7	220 KV	2841.8	1564	300.5	165.8
8	132 KV	6968.79	3262	202.1	178.3
9	66 KV	421.08		57.3	-
10	Installed MVA capacity	23327.3	7000.5	3205.4	2101.2
Tie Line					-
11	Tie with PG (in WB)	26 nos	5 nos	-	-
12	Tie with DVC	4 nos		-	-
13	Tie with SETCL	-	-	3	2

Table 21: Diff. Technical parameters of Transcom

3.10.5. Demand in West Bengal:

In West Bengal there are 4 (four) distribution licensee i.e. WBSEDCL, CESC, DPL & DPSCL and 1 (one) bulk/ wholesaler i.e. DVC. So, the total demand can be calculated with addition of individual demand in each command area. The total demand tabulated below:

Sl No	Name of Discom / Wholesaler	Own Generation (MU)	Power Purchase from other Utilities (MU)	Power Sale to other Utilities (MU)	Total Demand in command area (MU)	Peak Demand (MW)
1	WBSEDCL	1379.61	40067.17	6160.41	35286.37	6441
2	CESC	7484	3574	33	11025	1295
3	DPL	4038.36	191.41	1114.49	3115.28	380
4	DSPL	160	394.22	84.94	469.28	60
5	DVC	8032.73	1357.87	1003	8387.6	1075
Swub Total					58283.53	9251

Table 22: Energy demand in West Bengal for F.Y 2015-16:

3.10.6. The sector wise demand of 58283.53 MU energy is tabulated below:

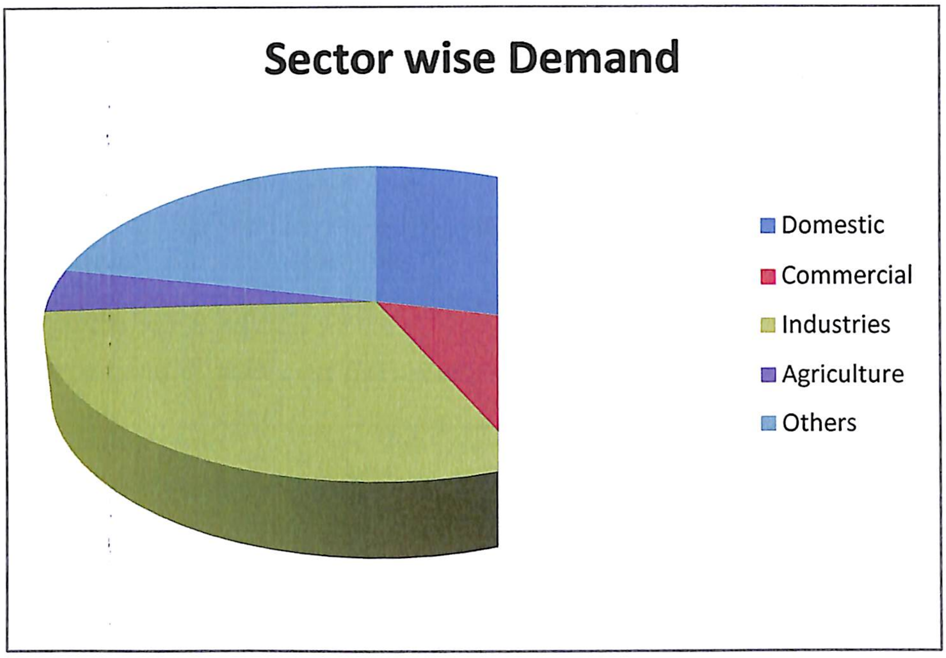

Fig. 11: Sector wise demand in West Bengal.

3.10.7. Future Demand Growth:
At present i.e. current F.Y: 2015-16 West Bengal has a cumulative energy demand of 58283.53 MU and a peak demand of 9251 MW. The demand share comprising domestic 28.7%, commercial 14.7%, industries 30.8%, agriculture 4.5% and others 21.3%. Forecasting demand with the base year as 2015-16 and a GDP growth of 8% with considering 0.8 constant elasticity. It is observed that at the F.Y. 2021-22 the energy requirement is 84565.97 MU.

Demand forecast with 0.8 constant elasticity and 8% GDP growth:

Sector	1990-91 (MU)	2000-01 (MU)	2006-07 (MU)	2015-16 (MU)	2018-19 (MU)	2021-22 (MU)
Domestic	1960.97	4374.25	6547.61	16727.37	20148.96	24270.43
Commercial	1096.12	1910.51	2828.51	8567.68	10320.20	12431.20
Industries	4263.95	6870.80	11109.15	17951.33	21623.27	26046.32
Agriculture	454.01	997.20	940.01	2622.76	3159.24	3805.47
Others	1046.44	1319.98	5132.87	12414.39	14953.76	18012.55
Total	8821.49	15472.74	26558.15	58283.53	70205.43	84565.97

Table 23: Demand forecast of WB.

Chapter 4: Analysis

4.1.Data Source:

All data are secondary data collected from different websites, journals.

4.2.Current Status & comparison of diff. cost parameters of Generators:

Here we discussed about fuel cost, capacity cost, generation sent out, aggregate revenue required, energy charge, capacity charge and average power cost of different power plant of west Bengal for the financial year 2015-16. Here we can observe that average power cost for WBPDCL is lower than others. The details of different parameters are tabulated below:

Comparison of diff. cost parameters of plants for F.Y. 2015-16 of West Bengal:

Sl No	Name of plant	Fuel cost (Lakhs)	Capacity cost (Lakhs)	ARR (4=2+3) Lakhs	Sent out generation (MU)	Energy charge paisa/kWh	Capacity Charge @ 85% PLF paisa/kWh	Avg. Power Cost paisa/Kwh
	1	2	3	4	5	6. (6=2*10/5)	7. (7=3*10/5)	8. (8=6+7)
	WBPDCL							
1	KTPS	171922.48	50097.95	222020.43	7003.73	245.47	71.53(75%)	317.00
2	BkTPS	145263.17	73492.94	218756.11	6714.89	216.33	109.45	325.78
3	BTPS	70238.19	13209.17	83447.36	2598.83	270.27	50.83	321.10
4	STPS	69399.53	45665.47	115065.00	3197.38	217.05	142.82	359.87
5	SgTPP	83349.37	43097.04	126446.41	3836.85	217.23	112.32	329.55
	WBSEDCL							
6	JHP, TCF, RAMAM	-	-	-	-	288.89	-	288.89
7	PPSP	-	-	-	-	390.00	-	390.00
8	**CESC**							
9	Budge Budge TPS	122652.00	56980.53	179632.53	5087	241.11	112.01	353.12
10	Titagarh TPS	44712	15471.44	60183.44	1533	291.66	100.92	392.59
11	Southern TPS	25698	9117.97	34815.97	864	297.43	105.53	402.96
	DPL							
12	U #VI to VII	82185.77	71287.29	153473.06	4038.36	203.51	176.53	380.04
13	**HEL**	70587.9	62268.1	132856	2594	272.12	240.04	512.16
	DSPL							
14	Dishergarh	1602.88	1797.25	3400.13	70	228.98	256.75	485.73
15	Chinakuri	2703.47	1767.8	4471.27	90	300.39	196.42	496.81
16	Tata power Haldia	-	-	-	-	186.00	-	186.00
	Captives:							
17	Maithan RB	-	-	-	-	378.39	-	378.39
18	Adhunik Power	-	-	-	-	311.29	-	311.29
19	Nippon Power	-	-	-	-	360.00	-	360.00
20	Renuka sugsar	-	-	-	-	276.00	-	276.00
21	Concast Bengal					327.00	-	327.00
	DVC							
22	BTPS U # I to III-630 MW	64666.5	46161.97	110828.48	3555.84	181.86	129.82	311.68
23	MTPS U# I to III - 630 MW	94995	55997.76	150992.72	4017.21	236.47	139.39	375.86
24	CTPS U # I to III-390 MW	44556.6	34291.23	78847.8	2102.32	211.94	163.11	375.05
25	DTPS U# III & IV-350 MW	60763.4	28862.86	89626.23	2037.33	298.25	141.67	439.92
26	MTPS U # IV-210 MW	31877.3	24407.63	56284.97	1348.05	236.47	181.06	417.53

27	MTPS U # 5 & 6-500 MW	80417	48951.47	129368.48	3213.21	250.27	152.34	402.61
28	CTPS U#7 & 8-500 MW	83016.6	62872.32	145888.92	3268.37	254.00	192.37	446.37
29	MTPS U 7 & 8 -1000 MW	154798	119750.2	274548.13	6749.42	229.35	177.42	406.77
30	KTPS U# 1 & 2-1000 MW	219297	172850.4	392147.38	6731.65	325.77	256.77	582.54
31	DSTPS U#1&2-1000 MW	219291	140770.5	360061.55	6731.47	325.77	209.12	534.89
32	RTPS U#I & II-1000 MW	195533	172966	368499.02	6002.18	325.77	288.17	613.94
33	MHS U # I,II,III-63.2 MW	0	3783.78	3783.78	113.00	0.00	334.85	334.85
34	PHS U I & II-80 MW	0	2788.98	2788.98	141.91	0.00	196.53	196.53
	NTPC							
35	Farakka	-	-	-	-	378.00	-	378.00
	PTC India Ltd	-	-	-	-		-	
36	Chukha HEP	-	-	-	-	159.00	-	159.00
37	Kuruchhu HEP	-	-	-	-	213.00	-	213.00
38	Tala HEP	-	-	-	-	202.00	-	202.00
	NHPC							
39	Rangeet HEP	-	-	-	-	276.2	-	276.2
40	Teesta HEP	-	-	-	-	208.4	-	208.4
41	**Maithon Power Ltd.**	-	-	-	-	384.9	-	384.9
	Non Renewable	-	-	-	-		-	
42	Solar	-	-	-	-	890.00	-	890.00
43	Non-solar	-	-	-	-	504.00		504.00

Table 24: Diff. cost parameters of power station of WB

4.3.The rank of different power plant on the basis of average power cost is tabulated below:

Ranking of all power stations is tabulated on the basis of average power cost. The average power cost is calculated on the summation of fuel cost and capacity cost.

Sl No	Name of plant	Avg power cost (paisa/ kWh)	Sl No	Name of plant	Avg power cost (paisa/ kWh)
1	Chukha HEP (NHPC)	159.00	22	MTPS U# I to III -630 MW (DVC)	375.86
2	Tata power Haldia	186.00	23	Farakka (NTPC)	378.00
3	PHS U I & II-80 MW (DVC)	196.53	24	Maithan RB	378.39
4	Tala HEP (NHPC)	202.00	25	DPL U #VI to VII	380.04
5	Teesta HEP (NHPC)	208.40	26	Maithon Power Ltd. (DVC JV)	384.90
6	Kuruchhu HEP (NHPC)	213.00	27	PPSP (WBSEDCL)	390.00
7	Renuka sugsar	276.00	28	Titagarh TPS (CESC)	392.59
8	Rangeet HEP (NHPC)	276.20	29	MTPS U # 5 & 6-500 MW (DVC)	402.61
9	JHP, TCF, Rammam (wbsedcl)	288.89	30	Southern TPS (CESC)	402.96
10	Adhunik Power	311.29	31	MTPS U 7 & 8 -1000 MW (DVC)	406.77
11	BTPS U # I to III-630 MW (DVC)	311.68	32	MTPS U # IV-210 MW (DVC)	417.53
12	KTPS (WBPDCL)	317.00	33	DTPS U# III & IV-350 MW (DVC)	439.92
13	BTPS (WBPDCL)	321.10	34	CTPS U#7 & 8-500 MW (DVC)	446.37
14	BkTPS (WBPDCL)	325.78	35	Dishergarh (DPSCL)	485.73

15	Concast Bengal	327.00	36	Chinakuri (DPSCL)	496.81
16	SgTPP (WBPDCL)	329.55	37	Non-solar (WBREDA)	504.00
17	MHS U # I,II,III-63.2 MW (DVC)	334.85	38	HEL	512.16
18	Budge Budge TPS (CESC)	353.12	39	DSTPS U#1&2-1000 MW (DVC)	534.89
19	STPS (WBPDCL)	359.87	40	KTPS U# 1 & 2-1000 MW (DVC)	582.54
20	Nippon Power	360.00	41	RTPS U#I & II-1000 MW (DVC)	613.94
21	CTPS U # I to III-390 MW (DVC)	375.05	42	Solar (WBREDA)	890.00

Table 25: Ranking of power station.

From the above table it is observed that hydro power plants are getting top of the rank, though they have very small installed capacity. Among the thermal power plant WBPDCL plant are taking the position on the top.

4.4.The average power costs of different GENCOM/Power source are tabulated below:

The average power cost from different Gencom of West Bengal is calculated at the point of connection (POC) considering all charges.

Sl No	Name of Source	Average Power cost (paisa/kWh) @ POC
1	PTC	242.65
2	Captive power	257.10
3	WBSEDCL	288.89
4	WBPDCL	327.64
5	DPL	387.24
6	NTPC	414.54
7	NHPC	415.51
8	DVC	424.02
9	DPSCL	540.00
10	CESC	610.00

Table 26: Ranking of Gencom.

From this table it is observed that hydro power through PTC is the cheapest power.

4.5.Comparison of supply and demand:

The calculated demand for the current F.Y:2015-16 is 58283.53MU. Now considering this year as a base year and the demand as the base demand and assuming no deficit / surplus in the current year, the demand for F.Y 2018-19 and 2021-22 projected as 70205.43 MU and 84565.97 MU. The supply projected at a 3% reduction rate of generation output of current installed capacity plus 50% allocation of NTPC upcoming project and considering 85% PLF of WBPDCL upcoming project. We observed that there is a deficit of 2383.53 MU in 2018-19 and 18439.12 MU in 2021-22.

Years	Supply				Demand	
	Generation from current installed capacity (MU)	Generation from proposed installed capacity (MU)		Total Generation (MU)	Demand (MU)	Deficit / Surplus (MU)
		NTPC -1820 MW	WBPDCL-1000 MW			
2015-16	58283.53	0	0	58283.53	58283.53	0
2018-19	56535.02	4400.32	6887.55	67822.89	70205.43	-2382.53
2021-22	54838.97	4400.32	6887.55	66126.84	84565.97	-18439.12

Table 27: Comparison of Supply and Demand.

4.6.Current Status & District Wise Coverage of Transmission Network:

In West Bengal there are mainly 2 (two) discom. namely WBSETC and DVC. The current allocated transmission capacity of WBSETCL is 5690 MW, installed MVA 23327.3 and DVC has installed capacity 7000.5MVA. WBSETCL has covered almost entire area of West Bengal for transmission.

The district wise substation of SETCL is given below:

Sl No	District	Name of sub station	Voltage Level	Qty	Sl No	District	Name of sub station	Voltage Level	Qty
1	Bankura	New Bishnupur	220 Kv	5 nos	53		Hamiltongang	66 Kv	
2		Bankura	132 Kv		54		Hasimara	66 Kv	
3		Barjora	132 Kv		55	Malda	Malda	132 Kv	2 nos
4		Khatra	132 Kv		56		Samsi	132 Kv	
5		Bishnupur	132 Kv	3 nos	57	Murshidabad	Gokarna	220 Kv	6 nos
6	Birbhum	Rampurhat	132 Kv		58		Berhampur	132 Kv	
7		Saithian	132 Kv		59		Amtala	132 Kv	
8		Bolpur	132 Kv		60		Dhulian	132 Kv	
9	Burdawn	Durgapur	440 Kv	10 nos	61		Ragunathgang	132 Kv	
10		Durgapur	220 Kv		62		Lalgola	132 Kv	
11		Asansol	220 Kv		63	Nadia	Krishna Nagar	220 Kv	6 nos
12		Satgachia	220 Kv		64		Debogram	132 Kv	
13		Ukhra	132 Kv		65		Kalyani	132 Kv	
14		Mahachanda	132 Kv		66		Dharmapur	132 Kv	
15		Raina	132 Kv		67		Ranaghat	132 Kv	
16		Mankar	132 Kv		68		Bagula	66 Kv	
17		Kalna	132 Kv		69	N 24 Pgs.	Jeerat	400 Kv	10 nos
18		Katwa	132 Kv		70		N Town III	220 Kv	
19	Coochbehar	Coochbehar	132 Kv	I no	71		Barasat	132 Kv	
20	S Dinajpur	Balurghat	133 Kv	2 nos	72		Mohispota	132 Kv	
21		Gangarampur	132 Kv		73		Asokenagar	132 Kv	

22	N Dinaj	Dalkhola	220 Kv	3 nos	74		Basirhat	132 Kv	
23		Raigang	132 Kv		75		Bongoan	132 Kv	
24	Darjeeling	Darjeeling	132 Kv		76		Salt Lake	132 Kv	
25		NBU	132 Kv	3 nos	77		Titagarh	132 Kv	
26		Kurseong	132 Kv		78		N Town I	132 Kv	
27		Kalimpong	66 Kv		79	S 24 Pgs.	Lakhsmikantapur	220 Kv	7 nos
28	Hoogly	Arambag	400 Kv	10 nos	80		Subhasgram	220 Kv	
29		Rishra	220 Kv		81		Kasba	220 Kv	
30		Singur	220 Kv		82		Behala	132 Kv	
31		Jangipara	132 Kv		83		Falta	132 Kv	
32		Khanyan	132 Kv		84		Kakdwip	132 Kv	
33		Chanditala	132 Kv		85		Sonarpur	132 Kv	
34		Belmuri	132 Kv		86	Medinipur(E)	New Haldia	220 Kv	7 nos
35		Bighati	132 Kv		87		Haldia	132 Kv	
36		Adisaptagram	132 Kv		88		Haldia NIZ	132 Kv	
37		Tarakeswar	132 Kv		89		Tamluk	132 Kv	
38	Howrah	Howrah	220 Kv	5 nos	90		Kolaghat	132 Kv	
39		Domjur	220 Kv		91		Contai	132 Kv	
40		Liluah	132 Kv		92		Egra	132 Kv	
41		Ulberia	132 Kv		93	Medinipur(W)	Kharagpur	400 Kv	8 nos
42		Bagnan	132 Kv		94		Medinipur	220 Kv	
43	Jalpaiguri	New Jaipaiguri	220 Kv	12 nos	95		Jhargram	132 Kv	
44		Alipurduar	132 Kv		96		C K Road	132 Kv	
45		Birpara	132 Kv		97		Birsingha	132 Kv	
46		Chalsa	132 Kv		98		Hizli	132 Kv	
47		Maynaguri	132 Kv		99		Pingla	132 Kv	
48		Siliguri	132 Kv		100		Kgp. WBIIDC	132 Kv	
49		Banarhat	66 Kv		101	Purulia	Purulia	132 Kv	3 nos
50		Nagrakata	66 Kv		102		Raghunathpur	132 Kv	
51		Odlabari	66 Kv		103		Bagmundi	132 Kv	
52		Kamakhyaguri	66 Kv						

Table 28: District wise substation of SETCL.

The district wise substation of DCV network:

Sl No	District	Sub station	Voltage Level
1	Bardhaman	Durgapur	400 KV
2		Burnpur	220 KV
3		Kalyaneswari	220 KV
4		Durgapur	220 KV
5		Asansol	132 KV
6		Burdwan	132 KV
7		Kalipahari	132 KV
8		Jamuria	132 KV
9	Bankura	Barjora	220 KV
10	Purulia	Raghunathpur	400 KV
11		Parulia	220 KV
12		Parulia	132 KV
13		Ramkanali	132 KV
14	Howrah	Howrah	132 KV
15	Hoogly	Belmuri	132 KV
16	E. Medinipur	Kolaghat	132 KV
17	W. Medinipur	Kharagpur	132 KV
18		Kumardubi	132 KV

Table 29: District wise Substation of DVC.

4.7.Details of Load Centre and Zone wise Demand Projection:

The projected peak demand for F.Y. 2015-16 in west Bengal is 9251 MW, comprising WBSEDCL 6441 MW, CESC 1295 MW, DVC 1075 MW, DPL 380 MW, DPSCL 60 MW.
The collecting substation / primary substation / load centre wise demand is collected and tabulated below:

Sl No	Command Area	Name of zone	Name of District	Name of Load centre/ collecting or primary substation	Avg. of Peak Load demand F.Y 2015-16 (MW)	Total Peak Demand (MW)
1	WBSEDCL	I	Darjeeling, Jalpaiguri, N. Dinajpur, S. Dinajpur, Coachbehar	NBU	30	666
2				Kursiung	60	
3				Kalimpong	18	
4				Rammam	60	
5				Birpara	118	
6				NJP	150	
7				Dalkhola	230	
8		II	Nadia,	Kalyani	220	1187

9			Murshidabad, Malda	Dharampur	240	
10				Gokarna	110	
11				Farakka	210	
12				Berhampur	280	
13				Malda	127	
14				Asansol	260	
15		III	Burdwan, Birbhum	Satgachiya	320	930
16				Durgapur	350	
17				Bagnan	104	
18				Uleberai	70	
19				Howrah	120	
20				Liluah	60	
21				Arambag	200	
22				Adisaptagram	120	
23		IV	Howrah, Hoogly, N 24 Pgs., S 24 Pgs	Bighati	80	2038
24				Khanyan	60	
25				Chanditala	150	
26				Jeerat	340	
27				Rajarhat	214	
28				Bidhannagar	210	
29				Subhasgram	310	
30				Tamluk	240	
31				Kolaghat	80	
32				Haldia	150	
33		V	E Medimipur, W Medinipur, Purulia, Bankura	Kharagpur	560	1620
34				Hura	160	
35				Purulia	130	
36				Bishnupur	300	
37	CESC	Kolkata	Kolkata and nearby area	Kolkata	1295	1295
38	DVC	DVC	South Bengal	Total 18 nos substation	1075	1075
39	DPL	DPL	Durgapur	Durgapur	380	380
40	DPSCL	DPSCL	Asansol-Ranigong	Asansol	60	60
Cumulative Peak Demand						9251

Table 30: Load centre wise demand.

From the above table it is observed that WBSEDCL is divided in 5 (five) nos zone and Zone-IV is having the highest peak load demand.

4.8.Comparison and Ranking of Power Generator in diff. Zone w.r.t. avg. Power cost:

Here we discuss demand in a zone and compare with the available power source in that zone with nearest available source of other zone and calculate existing transmission facility i.e. EHV substation, EHV line, tie line etc. This comparison is done to find out possibility of intra-state trading and all over inter-state trading. It is also done to find out technical aspect i.e. demand projection, availability of transmission facility and transmission corridor.

Sl No	Command Area	Zone	Area Name	Peak Demand (MW)	Supply		Avg. generation cost of power (paisa/kWh)	Avalable tie-line connected sub station	Available transmission facility
					Power Station in the zone	Nearest power station			
1	WBSEDCL	I	Darjeeling, Jalpaiguri, N. Dinajpur, S. Dinajpur, Coachbehar	666	JHP, TCF, Rammam		288.89	BIRPARA (PG)	In this zone 21 nos EHV substation, 220 KV, 132 KV EHV line and 7 nos tie line with PG is availabe
2						NTPC-Farakka	414.54	NBU (PG)	
3						WBPDCL-SgTPP	329.56	NJP (PG)	
4						Tala	202.00	Rammam (PG)	
5						Rangeet	256.72	DALKHOLA (PG)	
6						Teesta V	226.07	KURSIUNG (PG)	
7						Teesta III	613.74	KALINGPONG (PG)	
8						Teesta IV	461.70		
9		II	Nadia, Murshidabad, Malda	1187	NTPC-Farakka		414.54	SgTPP (PG)	In this zone 14 nos EHV substation, 400 KV, 220 KV, 132 KV EHV line and 2 nos tie line with PG is available
10					WBPDCL-SgTPP		329.56	Malda (PG)	
11						Teesta V	226.07		
12						Teesta III	613.74		
13						Teesta IV	461.70		
14						WBPDCL-BkTPS	325.78		
15						DPL	380.04		
16						DPSCL	491.96		
17						DVC	431.81		
18		III	Burdwan, Birbhum	930	BkTPS		325.78	Durgapur (PG)	In this zone 25 nos EHV substation, 400 KV, 220 KV, 132 KV EHV line and 2 nos tie line with PG is available
19					DPL		380.04	Kalyaneswari (PG)	
20					DPSCL		491.96		
21					DVC		431.81		
22					Concast Bengal		327.00		
23					Adhunik Power		311.29		
24					Maithan RB		378.39		
25						NTPC-Farakka	414.54		
26						WBPDCL-SgTPP	329.56		

27						WBPDCL-STPS	359.88		
28		IV	Howrah, Hoogly, N 24 Pgs., S 24 Pgs	2038	Nippon Power		360.00		In this zone 34 nos EHV substation, 400 KV, 220 KV, 132 KV EHV line and 2 nos tie line with PG and 1 no tie with DVC is available
29					ECL		253.00		
30						WBPDCL - KTPS	317.00	Bidhannagar (DVC)	
31						DPL	380.04	Subhasgram (PG)	
32						DVC	431.81	Rajarhat (PG)	
33						DPSCL	491.96		
34						CESC	366.96		
35									
36		V	E Medimipur, W Medinipur, Purulia, Bankura	1620	WBPDCL – KTPS		317.00	Kharagpur (DVC)	In this zone 30 nos EHV substation, 400 KV, 220 KV, 132 KV EHV line and 1 nos tie line with PG and 3 no tie with DVC is available
37					DVC		431.81	Kolaghat (DVC)	
38					WBPDCL-STPS		359.88	Purulia (DVC)	
39					Renuka sugar		276.00	Santaldih (PG)	
40					Rasnmi cement		284.00		
41					PPSP		390.00		
42						DPL	380.04		
43						DPSCL	491.96		
44	CESC	Kolkata	Kolkata and nearby area	1295	CESC		366.96	Bypass	In this zone 5 nos EHV substation, 220 KV, 132 KV EHV line tie line with SETCL is availabe
45						WBPDCL - KTPS	317.00		
46						DVC	431.81		
47	DVC	DVC	South Bengal	1075	Mejia, kodarma, Hydro		431.81	Bidhanagar (SETCL)	
48						DPL	380.04	Kolaghat (SETCL)	In this zone 18 nos EHV substation, 400 KV, 220 KV, 132 KV EHV line and 2 nos tie line with PG and 4 no tie with DVC is availabe
49						DPSCL	491.96	Kharagpur (SETCL)	
50						WBPDCL - KTPS	317.00	Purulia (SETCL)	
51						WBPDCL-STPS	359.88	Kalyaneswari (PG)	
52						CESC	366.96	Parulia (PG)	
53	DPL	DPL	Durgapur	380	DPL		380.04	Durgapur (SETCL)	In this zone 3 nos EHV substation,220 KV, 132 KV EHV line and tie line with SETCL is availabe
54						DVC	431.81		
55						WBPDCL-STPS	359.88		
56						WBPDCL-BkTPS	325.78		
57						DPSCL	491.96		
58	DPSCL	DPSCL	Asansol-Ranigong	60	DPSCL		491.96	Durgapur (SETCL)	This is very small area and tie line with
59						DVC	431.81		

60						WBPDCL-STPS	359.88		SETCL is available
61						WBPDCL-BkTPS	325.78		

Table 31: Comparison of power station of diff. zone.

From the table no 22 it is found that demand in WB for F.Y: 58283.58 MU and peak demand 9251 MW and table no 27 shows the comparison of demand-supply in the current year and future year. For the analysis part it is consider that energy demand for 2015-16 is equal to energy supply. But we can observer form table 16, which shows installed capacity 11124.61 MW in WB is much higher than peak demand i.e. 1873.6 MW excess installed capacity. Furthermore, capacity addition program by NTPC and WBPDCL will add more 2820 MW in the coming year. Moreover recent RBI report shows declined industrial growth in WB .So, at present there is excess installed capacity and declined industrial growth creates a surplus pocket of power in WB which providing chance of intra-state power trading and excess power can be utilized for interstate and international power trading. In future the demand-supply scenario as per table no 27 shows a minor deficit in energy supply considering current use of installed capacity but excluding excess installed capacity. The upcoming project in pipeline and present excess installed capacity will cater the deficit and moreover, if the present declined industrial growth continue may create fruitful environment of power trading in West Bengal.

Table 24 shows different cost parameters of all power station of west Bengal and it is observed that old hydro station providing power at minimum cost and among the thermal power station captive generation is cheaper than others and among coal base power station, comparatively old station which has capacity cost minimum is providing lower cost power with a slight lower PLF than new power station. Table 25 shows ranking of power station with respect to average power cost of generation which shows that Chukha (NHPC) hydo is having the lowest power cost of 159 paisa/kWh and solar power of WBREDA is the highest power cost of 890 paisa/kWh. It is also observed from table that WBPDCL plants has relatively lower power cost than CESC, NTPC and DVC. In case of power trading the power will be dispatched according to the merit order and the high cost power producer will face a existence problem.

Table 26 shows the average power cost of different generators at their point of connection. It shows hydro power through PTC is the lowest cost power of 242.65 paisa/kWh and CESC is the highest cost power of 610 paisa/kWh. In case of power trading high cost GENCOMs may face trouble and subsistence problem. Table 30 shows zone wise demand, available power source in this zone and nearest power source, avg. power cost and available transmission facility. From this table it is observed that zone IV of SEDCL command area is the highest peak demand with minimum of its own installed capacity. This zone is having adequate transmission facility and the nearby zone i.e. Zone III & IV is having adequate power source, which create surplus power pocket. This creates an opportunity of trading. Zone II, III & IV of SEDCL command area, DPL & DVC command area has its surplus of power in their respective zone. So a trading opportunity creates among the power producer in their respective zone and near-by zones to supply power according to average cost of power.

For sustainable power trading availability of transmission network capacity is vital. In West Bengal state transmission utility is WBSETCL. Inspite of this DVC has its own transmission network and central transmission utility Power Grid has wide network and network capacity augmentation is in progress. From table 21 we observer that SETCL has 112 nos EHV substation and 11876.37 CKM of EHV lines which makes it prime transmission utility in the state. DVC has 18 nos EHV substation and 6066.7 CKM of EHV transmission line. Table 21 shows other technical parameters of all transmission utility in the state. Table 28 and 29 shows district wise EHV substation of WBSETCL and DVC. Table 30 shows details of load centre/ collecting substation / primary substation as per zone wise in command area of different transmission utility. It shows zone IV of SEDCL command area is having the highest peak load demand of 2038 MW and DPSCL minimum peak load demand of 60 MW.

Chapter 5: Interpretation of Result

Zone wise installed capacity, peak demand average power cost, transmission facility and ranking of power station w.r.t. avg. power cost are tabulated below:

Sl No	Command Area	Zone	Supply: Power Station in the zone	Supply: Nearest power station (as per merit order)	Avg. generation cost of power (paisa/kWh)	Installed capacity (MW)	Total in the zone (MW)	Peak Demand (MW)	Avalable tie-line connected station	Available transmission facility
1	WBSEDCL	I	JHP, TCF, Rammam		288.89	251.50	251.50	666	BIRPARA (PG)	In this zone 21 nos EHV substation, 220 KV, 132 KV EHV line and 7 nos tie line with PG is availabe
2				Tala	202.00				Rammam (PG)	
3				Teesta V	226.07				KURSIUNG (PG)	
4				Rangeet	256.72				DALKHOLA (PG)	
5				WBPDCL-SgTPP	329.56				NJP (PG)	
6				NTPC-Farakka	414.54				NBU (PG)	
7				Teesta IV	461.70					
8				Teesta III	613.74				KALINGPONG (PG)	
9		II	WBPDCL- SgTPP		329.56	600.00	1482.00	1187	Malda (PG)	In this zone 14 nos EHV substation, 400 KV, 220 KV, 132 KV EHV line and 2 nos tie line with PG is availabe
10			NTPC- Farakka		414.54	882.00			SgTPP (PG)	
11				Teesta V	226.07					
12				WBPDCL-BkTPS	325.78					
13				DPL	380.04					
14				DVC	431.81					
15				Teesta IV	461.70					
16				DPSCL	491.96					
17				Teesta III	613.74					
18		III	Adhunik Power		311.29		4051.80	930		In this zone 25 nos EHV substation, 400 KV, 220 KV, 132 KV EHV line and 2 nos tie line with PG is availabe
19			BkTPS		325.78	1050.00			Durgapur (PG)	
20			Concast Bengal		327.00					
21			Maithan RB		378.39	1050.00				
22			DPL		380.04	891.00			Kalyaneswari (PG)	
23			DVC		431.81	982.00				
24			DPSCL		491.96	42.80				
25				WBPDCL-SgTPP	329.56					
26				WBPDCL-STPS	359.88					
27				NTPC-Farakka	414.54					
28		IV	ECL		253.00			2038		In this zone 34 nos EHV substation, 400 KV, 220 KV, 132 KV EHV line and 2 nos tie line
29			Nippon Power		360.00					
30				WBPDCL - KTPS	317.00				Bidhannagar (DVC)	
31				CESC	366.96					

32				DPL	380.04				Subhasgram (PG)	with PG and 1 no tie with DVC is availabe
33				DVC	431.81				Rajarhat (PG)	
34				DPSCL	491.96					
35		V	Renuka sugar		276.00		3710.00	1620	Santaldih (PG)	In this zone 30 nos EHV substation, 400 KV, 220 KV, 132 KV EHV line and 1 nos tie line with PG and 3 no tie with DVC is availabe
36			Rasnmi cement		284.00					
37			WBPDCL - KTPS		317.00	1260.00			Kharagpur (DVC)	
38			WBPDCL-STPS		359.88	500.00			Purulia (DVC)	
39			PPSP		390.00	900.00				
40			DVC		431.81	1050.00			Kolaghat (DVC)	
41				DPL	380.04					
42				DPSCL	491.96					
43	CESC	Kolkata	CESC		366.96	1125.00	1125.00	1295	Bypass	In this zone 5 nos EHV substation, 220 KV, 132 KV EHV line tie line with SETCL is availabe
44				WBPDCL - KTPS	317.00					
45				DVC	431.81					
46	DVC	DVC	Mejia, kodarma, Hydro		431.81	2032.00	2032.00	1075	Bidhanagar (SETCL)	In this zone 18 nos EHV substation, 400 KV, 220 KV, 132 KV EHV line and 2 nos tie line with PG and 4 no tie with DVC is availabe
47				WBPDCL - KTPS	317.00				Purulia (SETCL)	
48				WBPDCL-STPS	359.88				Kalyaneswari (PG)	
49				CESC	366.96				Parulia (PG)	
50				DPL	380.04				Kolaghat (SETCL)	
51				DPSCL	491.96				Kharagpur (SETCL)	
52	DPL	DPL	DPL		380.04	891.00	891.00	380	Durgapur (SETCL)	In this zone 3 nos EHV substation,220 KV, 132 KV EHV line and tie line with SETCL is availabe
53				WBPDCL-BkTPS	325.78					
54				WBPDCL-STPS	359.88					
55				DVC	431.81					
56				DPSCL	491.96					
57	DPSCL	DPSCL	DPSCL		491.96	42.80	42.80	60	Durgapur (SETCL)	Tsis is very small area and tie line with SETCL is available
58				WBPDCL-BkTPS	325.78					
59				WBPDCL-STPS	359.88					
60				DVC	431.81					

Table 32: Zone wise ranking of power station.

In case of power trading the review of possibility and availability of transmission capacity is discussed below zone wise:

Zone I:

From table 30, 31 &32 it is observed that zone I of SEDCL command area is having peak demand of 666 MW and with its own generating station at JHP, TCF, Rammam of installed capacity 251.5 MW which have cheaper power cost. The nearby power station of this zone i.e. different hydro station under NHPC, NTPC-Farakka, WBPDCL –SgTPP will be called for power supply as per merit order as tabulated above. This zone is having 21 nos EHV substation and 7 nos tie line. So, transmission corridors will not a problem for trading.

Zone II:

From above table it is observed that Zone II of SEDCL command area is having peak demand of 1187 MW and its own generation station at NTPC-Farakka, WBPDCL-SgTPP of capacity 1482 MW, which has excess installed capacity. The nearby zone I is a deficit zone and Zone III is a surplus zone with cheaper power cost. So, this forms a trading opportunity. Trading may be done by providing excess power to zone I , within the zone II according demand and lower cost power dispatched, zone III which have lower power cost installation may supply power to this zone and international trading may be done to Bangladesh through Power Grid Berahmpur substation. This zone is having 14 nos EHV substation and 2 nos tie line. Though the transmission capacity is sufficient but transmission system augmentation is required in this zone, as because international trade is being done through this zone. Hedging in this zone may be eliminated with the help of FTR or FGR.

Zone III:

From table 30, 31 & 32 it is observed that Zone III of WBSEDCL command area is having the highest installed capacity of 4051.8 MW and a demand of 930 MW. The highest installed capacity due to abutment of pit heads coal. This zone creates a trading opportunity to its nearest zone II, IV, V of SEDCL command area and CESC also, within this zone according to merit order of power. Small hydro stations are also available in this zone. This zone is having 25 nos of EHV substation and 2 nos tie line with PG. This zone is having good numbers of primary collecting substation for evacuating power. So, transmission facility is available in this zone for power trading.

Zone IV:

From table 30, 31, 32 it is observed that in this zone there is no such major generators, only few captives generators are available. But this zone is having the maximum demand in West Bengal. This is having 34 nos EHV substation, 2nos tie with PG and 1 no tie with DVC and DVC own transmission network. So, this creates a trading opportunity for the nearest zone generators.

Zone V:

From table it is observed that this zone is having demand of 1620 MW and installed capacity of 3710 MW. It has cheaper cost power generator, 30 nos EHV substation, 1 no tie with PG and 3 nos tie with DVC. This creates trading opportunity with the nearby zone IV, III and within this zone as per merit order as mention in table.

CESC:

CESC is a discom with its own generating station. From the table it is observed that CESC has a demand of 1295 MW and installed capacity 1125 MW. It has 5 nos EHV substation and tie with SETCL. The deficit power in this zone and relatively higher cost power generation creates a trading opportunity for nearer zone III, V, DVC, DPL.

DVC:

DVC is a generating company and wholesaler in West Bengal. It has no licensee for retail sale in West Bengal. DVC was established by a central law in 1956. West Bengal has its share of its installed capacity. DVC has its own transmission network in the area of south Bengal for its wholesale customers. In this there are also generators like WBPDCL, DPL and CESC exists. From the table 30, 31 and 32 it is observed that demand in its own network is 1075 MW. In the command area there are also generators who have lower cost power generation. This creates a trading opportunity for the low cost power generators to the wholesale customers of DVC.

DPL:

DPL is a distribution licensee with generators. From the table 30, 31 and 32 it is observed that it has excess installed capacity, which creates trading opportunity for it. It is also observed that there are low cost generators nearby area which creates trading opportunity for them within the command area of DPL.

DPSCL:

DPSCL is a small IPP in WB running since last 87 years. From table 30, 31 and 32 it is observed that it has deficit as well as high cost generation, which creates trading opportunity for low cost generators in this zone.

Chapter 6: Conclusion and Scope of Future Work

Risk management should be the main concern for any electricity trader. The fact that this trader has no direct control on the production or consumption of the customers makes traders especially vulnerable to both price and imbalance risk. First, an operational hedge was designed by pooling different customers with price or imbalance risk together. Next, financial hedges were incorporated to reduce exposures even further.

In electricity market restructuring, electricity derivatives play an important role in establishing price signals, providing price discovery, facilitating effective risk management, inducing capacity investments in generation and transmission, and enabling capital formation. Custom design of electricity financial instruments and structured transactions can provide energy price certainty, hedge volumetric risk, synthesize generation and transmission capacity, and implement interruptible service contracts.

Admittedly, many exotic forms of electricity options can meet specific needs for hedging and speculation. However, we emphasize the importance of standardization. Future research should focus on identifying standardized electricity derivatives and utilization of financial engineering tools to synthesize and replicate alternative contracts using standardized instruments. Such standardization will reduce transaction costs and produce liquidity, which in turn will improve the efficiency of risk management practices.

It is important to investigate a better pricing model. Electricity prices are extremely hard to quantify because of the combination of stable returns and extreme spikes. So a further study is required for better electricity pricing model.

In India FTR, FGR and derivative exchange trading till not allowed by CERC. So, a scope of study is there for implementation of this.

At present West Bengal has excess installed capacity than its demand, which creates possibility of power trading in intra-state mode as well inter-state mode. In the background of present generation capacity enhancement programme, demand scenario and falling industrial growth in West Bengal the inefficient power station will suffer more loss if, they don't take programme to increase efficiency.

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